POWER SYSTEM STABILITY: NEW OPPORTUNITIES FOR CONTROL[1]

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Abstract

The electric power generation-transmission-distribution grid in developed countries constitutes a large system that exhibits a range of dynamic phenomena. Stability of this system needs to be maintained even when subjected to large low-probability disturbances so that the electricity can be supplied to consumers with high reliability. Various control methods and controllers have been developed over time that has been used for this purpose. New technologies, however, in the area of communications and power electronics, have raised the possibility of developing much faster and more wide-area stability control that can allow safe operation of the grid closer to its limits. This paper presents a conceptual picture of these new stability control possibilities.

I. Introduction

The power system networks in North America and Europe are the largest man-made interconnected systems in the world. The Eastern Interconnection in North America that stretches from the East Coast to almost the Rocky Mountains is the largest in terms of geographic area covered, total installed generation capacity and total miles of transmission lines. Moreover, all the rotating generators in one network rotate synchronously producing alternating current at the same frequency, that is, all the generators operate together in dynamic equilibrium. Any unbalance in the energy distribution of the system caused by disturbances tends to perturb the system. Large disturbances, usually caused by short circuits of high voltage equipment, can make the power system become unstable.

Large power systems exhibit a large range of dynamical characteristics, very slow to very fast, and various controllers have been developed over time to control various phenomena. Many of the controls are on-off switches (circuit breakers) that can isolate short-circuited or malfunctioning equipment, or shed load or generation. Others are discrete controllers like tap-changers in transformers or switching of capacitor/reactor banks. Still others are continuous control like voltage controllers and power system stabilizers in rotating generators or the newer power electronic controls in FACTS devices (Flexible AC Transmission Systems refers to modern electronic devices like High Voltage DC Transmission or Static VAR Controllers that can control power flows or voltage).

However, all the controls (especially the fast ones) are local controls, that is, the input and the control variables are in the same locale (substation). Most dynamic phenomena in the power

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system, on the other hand, are regional or sometimes system-wide. Thus designers of power system control have been constrained to handle system-wide stability problems with local controllers. The only system-wide control in the power system is the balancing of the slowly changing system electrical load by adjusting generation levels; this slow dynamical phenomenon allows a slow communication system to reach all the generators in the system in time for the adjustments to be effective. The only other way to implement non-local control has been to dedicate a communication channel between the input variable in one substation to the control variable in another, an expensive proposition that has limited its use.

The tremendous breakthroughs in computer communications of the last decade, both in cost and bandwidth, have opened opportunities that are yet to be fully utilized in the control of power systems. The availability of many new control devices, e.g. FACTS devices, and of accurate time synchronizing signals through the GPS are also factors in this new equation. It is certainly possible now to design fast system-wide controls. However, much research and development is needed to bring such designs to fruition.

In this paper, we first survey the state of the art in stability control of power systems. Then we outline the new technologies that can be brought to bear on this problem. Finally, we lay out a possible development path for system-wide controls in which simple extensions of existing controls can start helping power system operations right away to concepts that will require significant time and effort to control more complex phenomena. The goal, as always, is to provide more efficient operation, that is, be able to transmit more power over existing transmission lines with more flexibility.

II. Power System Stability

A power system is a complex conglomeration of equipment all connected together electrically. A simple description of the power system and its model is described first so that power system stability and related control can be discussed conceptually without getting bogged down in the details. Of course, readers must be cautioned that often the feasibility of proposed controls depends on these details and implementation of such controls in a power system is a complex undertaking.

2.1 Power System Model

A power system consists of a transmission network, the nodes of which can be connected to generators or distribution feeders. The transmission network is made up of three-phase transmission lines that carry alternating current at 60Hz (50Hz in some countries). It is a meshed network, the mesh having developed over time and geography to provide adequate capacity to transmit the electric power from the generators to the distribution feeders. This transmission network can be modeled as a standard mesh circuit

$$\underline{I} = Y.\underline{V} \tag{1}$$

with the frequent assumption that the three phases are balanced and thus only a single phase needs to be represented. A large transmission network can easily have thousands of nodes thus determining the size of (1). Also, the elements of (1) are complex quantities representing an AC circuit, which can also be written as an equation of real quantities of twice the size.

The current injections I are either from generators that are inputting power into the transmission network or from distribution feeders that are taking power out of the network to the electrical loads. As the main consideration is the movement of electric power from the generators to the loads, the current injections I, per se, are of less interest than the power injections S. Thus, instead of (1) the transmission network is often represented as

$$\underline{S} = \underline{g}\,(\underline{V}) \tag{2}$$

where $\underline{g}$ represents the nonlinear functions that relate power injections to the node voltages. Note that the steady-state representation of the power system then is a very large set of nonlinear algebraic equations, the nonlinearities being multiplications of complex quantities.

Most of the generators and some of the loads are rotating machines and at steady state they rotate at 60Hz or synchronous speed. (To be more precise, the electrical field in these machines rotate at 60Hz. The actual mechanical rotational speed depends on the design of the machine itself with synchronous machines having speeds that are a multiple of 60Hz and induction machines slightly off from such multiples of 60Hz.) The system, however, is never at steady state because the loads are always varying as customers constantly change their electricity consumption. Thus the power system is continuously subjected to random perturbations. If these changes are relatively small compared to the inertia of the total rotational mass of all the machines, the machine rotational speed does not deviate much from synchronous speed. As long as the small imbalances between generation and load are continually corrected the system will stay close to synchronous speed, that is, in synchronism.

If the disturbance is large – loss of a large generator or load, short circuit on a high voltage transmission line or substation – it is quite possible that some of the machines will deviate significantly from the 60Hz. In some cases machines deviating much from synchronous speed may become unstable, that is, not recover and lose synchronism. Obviously, this is not desirable but large disturbances do happen, albeit infrequently, and the power system has to be designed and operated such that such credible disturbances do not actually disrupt power supply to customers. The usual reliability target for North America is to limit large disruptions of power supply to once in ten years.

The dynamics of a rotating machine can be represented in the usual manner as

$$M\omega' + D\delta' = Pa = Pm - Pe \tag{3}$$

where δ is the deviation of the shaft rotational angle from synchronous, $\omega = \delta'$ is the deviation from synchronous speed, M is the rotational inertia and D is the damping. Thus the movement of the shaft away from steady state 60Hz is dependent on the accelerating power Pa which is the difference between the mechanical and electrical powers Pm and Pe to the shaft. Equation (3) can be written as two first order differential equations and so the dynamics of each rotating machine can be represented by two such differential equations.

This second order model is somewhat approximate because the electrical power Pe is the real power injection in at the electrical node where this rotating machine is connected and is related nonlinearly to the voltage at that node. But the terminal voltage of a generator is dependent on the speed of the machine and is not an independent variable. Moreover, to keep this voltage within certain limits it is controlled by the exciter which can be modeled by differential equations. Sometimes, especially in those power systems that are prone to sustained oscillations, generators are fitted with power system stabilizers (PSS) which is another feedback loop from the shaft speed to the exciter. On the mechanical side, Pm is controlled by the governor which also has describable dynamics. Thus the dynamics of a rotating machine can be represented minimally by two differential equations and more accurately by up to a dozen differential equations. In practice, the details of the representation depend on the importance (size, proximity, etc.) of the machine and the sophistication of the controls in the machine. So the power system dynamics can then be represented as a set of nonlinear differential equations

$$\underline{X}' = f(\underline{X}) \tag{4}$$

where $\underline{X}$ is the set of variables like shaft angle, shaft speed, terminal voltage, and internal variables of the machine, exciter and governor. This machine terminal voltage is the same as the node voltage, where the generator is connected, as used in (2). The electrical power Pe used in (4) is also the real component of the complex power S used in (2). Thus equation (2) representing the static network and (4) representing the dynamic machines are connected through the power injection and the voltage at the generator nodes.

To summarize, the power system model needed for the purposes of this paper can be represented by the nonlinear differential and algebraic equations

$$\underline{X}' = f(\underline{X},\underline{V},\underline{S}) \tag{5}$$

$$\underline{S} = g(\underline{V}) \tag{6}$$

where the number of differential equations can vary from 2 to 12 per rotating machine and the number of algebraic equations are approximately twice the number of nodes. Thus a large interconnected power system will typically be represented by several hundred differential and several thousand algebraic equations.

The dynamic behavior of this system, as can be expected from the nature of the equations, is quite complex and varies quite a bit from system to system. The North American eastern interconnection and the West European interconnection is characterized by short transmission lines connecting large load centers. These tend to be more stable than the North American Western interconnection which is characterized by long transmission lines. In general, large disturbances tend to make the system unstable and lose synchronism in a second or two – this is known as transient instability. The less stable systems, however, can exhibit undamped oscillations that can go unstable after many seconds. Such systems have natural oscillatory modes that are exhibited under certain operating conditions. Finally, some systems are now susceptible to voltage collapse which can occur when the system is operating close to its voltage limits when the disturbance occurs.

2.2 Power System Control

Given the complexity of the power system and its dynamic phenomena, one would expect that various controls have been developed over time to control various phenomena. These developments have followed the availability of enabling hardware technologies (e.g. electronics, communications, microprocessors) as well as the evolution of control methodologies. In this section, a brief survey is presented of the various controls available today. The survey is neither comprehensive nor complete but is meant to provide a general feel for the technologies being utilized today and the phenomena that are being controlled.

2.2.1 Power System Protection

From the very beginning there was the necessity of protecting electrical equipment from burning up due to a short circuit. From the humble fuse to today’s microprocessor based relay, protection gear and methodology have progressed to the point where protection can be looked upon as a fast method of control. The many types of protection technology used in many ways are obviously outside the scope of this section and only a few applications that affect power system stability are mentioned.

When a fault (short circuit) occurs, the faulted equipment has to be isolated. A short circuit is characterized by very low voltages and very high currents, which can be detected and the faulted equipment identified. If the fault is on a shunt element, like a generator or a distribution feeder, the relay will isolate it by opening the connecting circuit breakers. If the fault is on a series element, like a transmission line or transformer, the breakers on both sides have to be opened to isolate it. The main characteristic of the protection system is that it operates quickly, often in tens of milliseconds, so as to protect the equipment from damage.

In addition, protective relays can be used to do such switching of circuit breakers under other circumstances. For example, if the frequency deviates much from 60Hz or the voltage from nominal, this may be an indication that the system may be going into an unstable state. Generation or load can be shed (isolated) by the protective relays to correct the situation.

The main characteristics of protective systems are that they are fast and usually triggered by local variables. Circuit breakers that are switched are close to the detection points of the anomalous variables. This obviously makes sense when the purpose is to isolate faulted equipment. However, communication technology today makes it possible to open circuit breakers far from the detected anomalies and this raises the possibility of remote or wide-area control.

2.2.2 Voltage Control

As is mentioned before, one way to control node voltages is by varying the excitation of the rotating generators. This is done by a feedback control loop that changes the excitation current in the generator to maintain a particular node voltage. This control is very fast.

Another way to control node voltage is to change the tap setting of a transformer connected to the node. Other ways are to switch shunt capacitors or reactors at the nodes. These changes can be made manually by the operator or automatically by implementing a feedback control that senses the node voltage and activates the control. Unlike the generator excitation control, transformer taps and shunt reactances can only be changed in discrete quantities. Often this type of control schemes has time delays built into them to avoid excessive control actions.

More recently power electronic control devices have been introduced in the shunt reactance voltage control schemes. This makes the control much more continuous and often is done it a much faster time frame than the usual shunt switching. These static var controllers (SVC) are becoming more common.

As is obvious, voltage control is always a local control. However, controlling the voltage at one node affects the neighboring nodes. In Europe, controllers that coordinate the voltage control over an area are being tried and such area controls may be introduced in the North American systems.

2.2.3 Transmission power flow control

Most power systems have free flowing transmission lines. This means that although power injections and node voltages are controlled quite closely, the power flow on each transmission line is usually not controlled. However, such control is feasible.

A phase shifting transformer can control the power flow across it by changing the phase using taps. This has been used, especially on the Eastern interconnection in North America. The control is local, discrete and slow. A power electronic version of this is now under experimentation.

The major advantage of the AC transmission grid is its free flowing lines with relatively less control and so the wholesale control of every transmission line is not desirable and is not contemplated. However, controls on some lines have always been necessary and some new advantages may be realized in the more deregulated power system when monitoring transactions between buyers and sellers have to be better controlled.

Flow over DC transmission lines is always controlled and the control is very fast. The number of DC lines is only a handful.

2.2.4 Frequency Control

Frequency is controlled by balancing the load with generation. The governors on every generator senses any change in the rotational speed and adjusts the mechanical input power. This governor control is the primary control for maintaining frequency. A secondary control to set the governor setpoints is used to ensure that the steady state always returns to 60Hz. The governor control is local at the generator and fast. The secondary control is done over the whole system. This secondary control is done by the central controller and is slow. This control is also known as Automatic Generation Control (AGC) or Load Frequency Control (LFC).

In North America and Western Europe, the frequency is controlled quite tightly whereas in many other places, even in developed economies as the United Kingdom and Scandinavia, frequency is allowed to vary over wider range. As the deviation of frequency from 60Hz is a symptom of the imbalance between generation and load, the frequency control performance requirement depends on how well one wants to control the power supply commitments made between seller and buyer.

2.2.5 Control Center

As mentioned in the above sections most of the controls are local. The only area wide control is the secondary frequency control or AGC. This is implemented as a feedback control loop in which the generator outputs and tie-line flows are measured and brought back to the control center and the governor control setpoints are calculated and sent out to the generators from the control center. The data rate – both input and output – is between 2 and 4 seconds.

The control center performs many other functions although AGC is the only automatic feedback control function. The main function is real time data acquisition from all over the grid so that the operator can monitor its operation. Another is the manual operation of controls like opening or closing circuit breakers, changing transformer taps, etc. These functions are jointly known as the Supervisory Control and Data Acquisition (SCADA) and the control center is often referred to as SCADA.

These SCADA-AGC functions at central control centers evolved in the earlier part of the last century but in the 60s their implementation was accomplished with digital computers. Remote terminal units (RTU) were positioned in every substation and generating station to gather local data and this data was then transmitted from the RTUs to the control center over communication lines, usually microwave channels but sometimes telephone lines. This scheme is shown in Figure 1. The data normally includes the switching statuses (on/off) of all the circuit breakers as

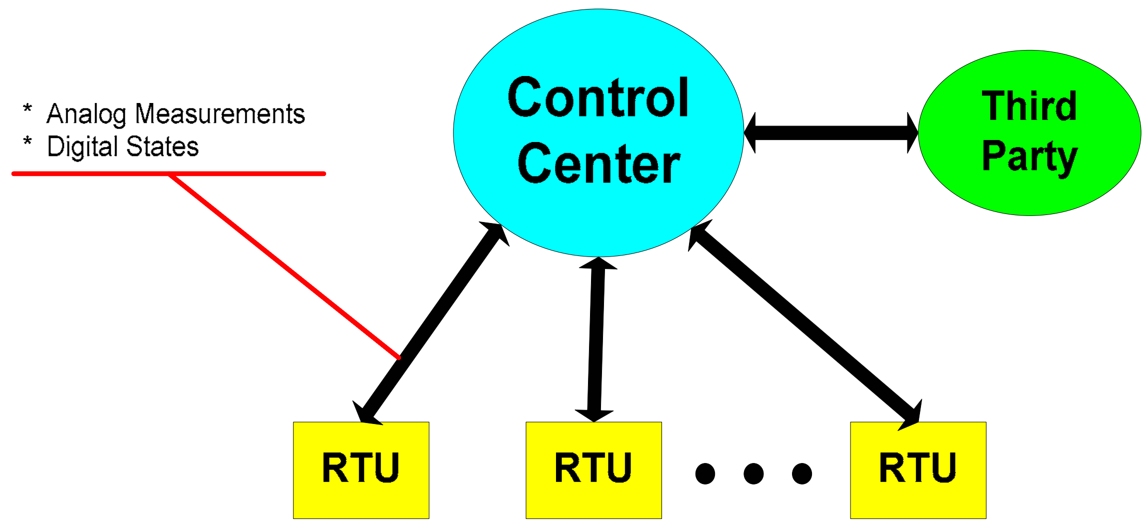

Figure 1: The Control Center has direct communication channels to the Remote Terminal Units (RTU) at each Substation and Generating Station

well as the current values of voltages and complex power (i.e. watts and vars). Although these control centers are quite separate from other computer systems, it does accumulate a large set of historical data that can be utilized for various engineering study and analysis. Thus it is quite common to have a network connection to third party (usually engineering) computers.

As the computational power of the control centers grew, more functions have been added to the control centers. The main one has been the state estimator which calculates the real time steady state model of the network. This real time model can then be used for two kinds of calculations.

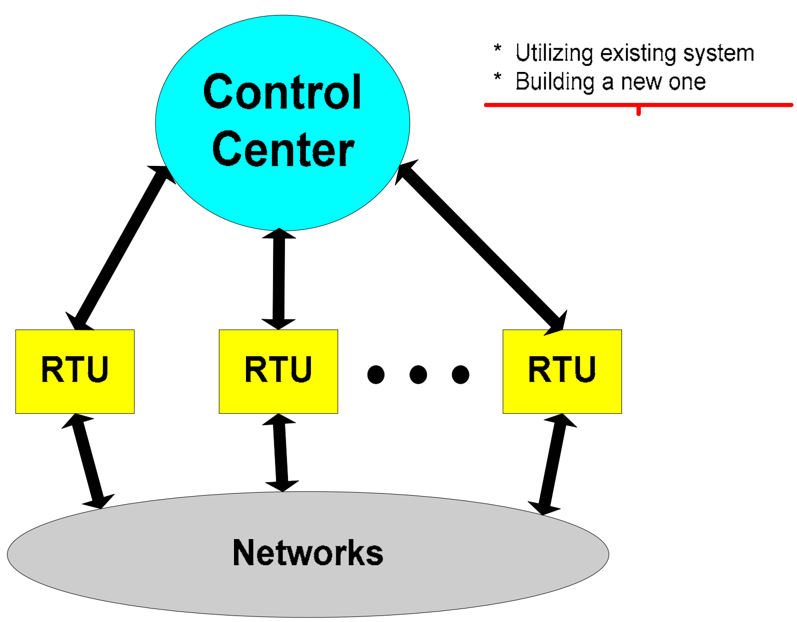

Figure 2. Substations today are measuring more real time data than can be sent over the communication channel capacities to the control center. However, stored data can be moved slowly over other computer networks.

One, known as security analysis, can study the effects of disturbances (contingencies) and can alert the operator if the post-contingency conditions violate limits. The other, usually using a family of analysis known as optimal power flow, can suggest better operational conditions. All these analytical tools provide better operational guidance to the operator than the old SCADA systems could and are now known as Energy Management Systems (EMS).

Another recent trend has been the increasing use of microprocessors and faster communication within the substations to gather more real time data. This data gathered at the few milliseconds rate is stored at the substations but is too voluminous as yet to be broadcast. Instead certain sequences of this data – say, after an emergency or disturbance – are then imported, increasingly, over some sort of network and then used for study purposes. This is shown in Figure 2. What this means is that data is now being measured and gathered at the substations at a much faster rate than can be communicated to the control center which are only capable of polling RTU data at the rate of a few seconds. The excess data can be recorded at the substations and for now is gathered only after the fact for studies.

Power system control can then be summarized as follows:

- Most automatic controls are local.
- At the generator there is the governor control of generator output, the exciter control of generator terminal voltage and sometimes, power system stabilizer (PSS) control. These are continuous fast feedback control.
- Node voltages can also be controlled by transformer taps and shunt reactances. These are slow discrete controls but new continuous fast static var controllers (SVC) are becoming available for use.
- Where DC transmission is used, fast continuous control of line flow is available and new tools to do so on AC lines are becoming available. Slow controls using phase shifting transformers are still being used in a few places.
- Protective relays that isolate faulted equipment operate locally but are very fast. With communication from other parts of the network, they have great potential for fast control.
- The secondary frequency control of generator governor setpoints is the only area wide control used today. This slow control implemented through the central control center is discrete at the rate of a few seconds.
- Much more data at very fast rates are being gathered at the substations but the communication and control system to utilize this data for faster controls is lacking.

2.3 Stability Limits

Power systems are designed and operated so that they can survive large disturbances like storms, lightning strikes and equipment failures. This usually means that even though some power system equipment will be separated or isolated as a result of automatic protection and control actions, power supply to customers will not be disrupted or at least, that any such disruptions will be very localized.

Operational limits for the transmission network can then be set using the following logic:

- The maximum power each transmission line can transmit is limited by its current carrying capacity, known as its thermal limit
- The maximum loading of the transmission network is determined by any one of the lines hitting its thermal limit. The loading of each line in the power system is determined by equation (6), and so various combinations of generator and load injections at the nodes – that is, various operating conditions – can produce this limiting condition. The SCADA continually checks for such thermal limit violations as the operating condition changes over time.
- However, operating the system at such a limiting condition is not prudent because the loss of a transmission line or other equipment would probably overload some other lines. Thus the operating limit is not when the first line hits its thermal limit but when the loss of any one piece of equipment will make a line hit its thermal limit. This is known as the N-1 criterion for operation because any one of the N components of the power system can be lost without overloading any part of the system.
- If a disturbance or short-circuit occurs, the first line of protection should isolate the faulted equipment. This is the rationale behind the N-1 criterion. It is possible, however, that the same disturbance may cause instability – determined by equations (5) and (6) - in which case more than just the faulted equipment will be lost. In such a case the maximum loading of the system will have to be lowered so that instability does not occur. This loading limit is thus set by the stability criterion rather than the thermal loading. Those power systems that are stability limited are of interest in this paper.
- If better controls can increase this stability limit, then the system can be loaded at a higher level. This provides better utilization of the transmission network. For example, the north-south power transfer along the west coast of the USA is limited by stability and any increase in this limit has a direct economic benefit by enabling more transactions between generators and customers.

III. Challenges and Opportunities

There are significant economic incentives to increase the transmission limits of existing systems. In fact, the major constraints of the deregulated power markets are the transmission system limits. Today generation companies sell power to distribution companies (or directly to large customers) through bilateral agreements or auction markets. These transactions have to flow over the transmission system and if the transmission capacity was higher than all possible power flows such transactions may produce, then the market would be ideal. This, however, is not the case because the transmission system was built when the power companies were vertically integrated and they were sized for the expected power flows resulting from planned operation of the generators. The transmission system was not designed to accommodate all buy-sell agreements between generators and consumers.

Thus all power transactions must be checked before-hand to ensure that the flows are within limits. As there may be hundreds of simultaneous transactions between generators and consumers, and because the effects of these transactions on the flows are not linear (2), all simultaneous transactions must be studied together to check whether transmission limits are violated. When they are, it is known as the 'congestion problem.' If congestion is expected, all the transactions cannot be allowed and different power systems have worked out procedures about how and which transactions will have to be cut back. The procedures have to be fair to all parties, fairness may require compensation to some, and an independent referee called a 'security' coordinator has to make the decisions.

These security coordinators are known by various names – independent system operator (ISO), regional transmission operator (RTO), transmission system operator (TSO), etc. They discharge their responsibilities mainly in two steps. First, they have to approve all transactions. Their main tool to check violations is the 'power flow' program that solves (2) and their main tool to advise corrective action in case of anticipated congestion is an optimal power flow (OPF) program that optimizes the correction procedure (e.g. minimum compensation) using (2) as constraints. Then, in real time, the ISO has to watch for unexpected emergencies that causes limit violations, and if it happens, take emergency corrective action. In such emergencies, ensuring the survivability of the power system is more important than minimizing cost.

So the transmission limits are the constraints that also limit the power markets. Systems that are thermally limited, the only way to raise limits is to build more transmission. For those systems that are stability limited, better controls could increase the stability limit. Thus our interest in this paper is on better control of stability.

3.1 New Technologies

Essentially, there are three classes of technologies that are relevant:

- Faster, cheaper computers,
- Broadband, cheap communications, and
- Better power electronic controls (also known as FACTS – flexible AC transmission systems – which covers this class of technology specifically developed to control the AC power system).

Some of these technologies are already in use in the power systems as mentioned in Section 2. What we are proposing here is the development of new controls utilizing a combination of these technologies. These controls will be significantly different in concept than the existing ones, and will be fast and system-wide to dramatically increase stability limits.

3.1.1 Computers

Computers (or microprocessors) are embedded in everything – meters, protective relays, data concentrators, communication switches. They are programmable, that is, the functions of the gadget in which they are embedded can be changed by software. Thus controls that utilize these components can be adapted, through changed settings (simple) or changed logic (more difficult), providing flexibility in the design of this software.

Workstation computers are also much faster and cheaper. Thus very large amounts of calculations can be done very quickly. Such analysis can then be part of the control bringing even more intelligence into the control loop. For example, if a control is devised to shed load to avoid instability, an optimal power flow could determine which loads are to be switched off.

3.1.2 Communications

Electric power companies have always had their own communication systems. As mentioned in Section 2, this has mainly been microwave channels that connect every substation and generating station. The use of optical fiber is now increasing at a tremendous rate. At first, the optical fiber has been used within substations and generating stations, especially the newer installations, but the older ones are being rapidly retrofitted. This is being done to gather more real time data at faster rates at the substations so that fast appearing emergency conditions – like right after a lightning strike – can be better protected against. The data can also be captured but has to be stored locally to be later transmitted over communication networks (Figure 2).

Optical fiber has also been strung along transmission towers. Power companies mainly did this to become communications providers because of the projections of ever-increasing demand for bandwidth. Although this venture into new business has not panned out because of the glut of unused bandwidth, a broadband network is now easily available to the power companies. If this network bandwidth is broad enough, then all the data being collected at the substations can be transmitted in real time to other locations like the control center. In fact, a network can be envisioned (Figure 3) such that the real time data would be available to different computers depending on their function. This opens up the possibility of decentralizing the control center so that functions can be put in different places depending on where it is needed. With a network like this, the stark differentiation today between centralized control and local control would go away and controllers could use the most appropriate data needed for control.

A communication network that can meet the varied needs for the operation of the power system

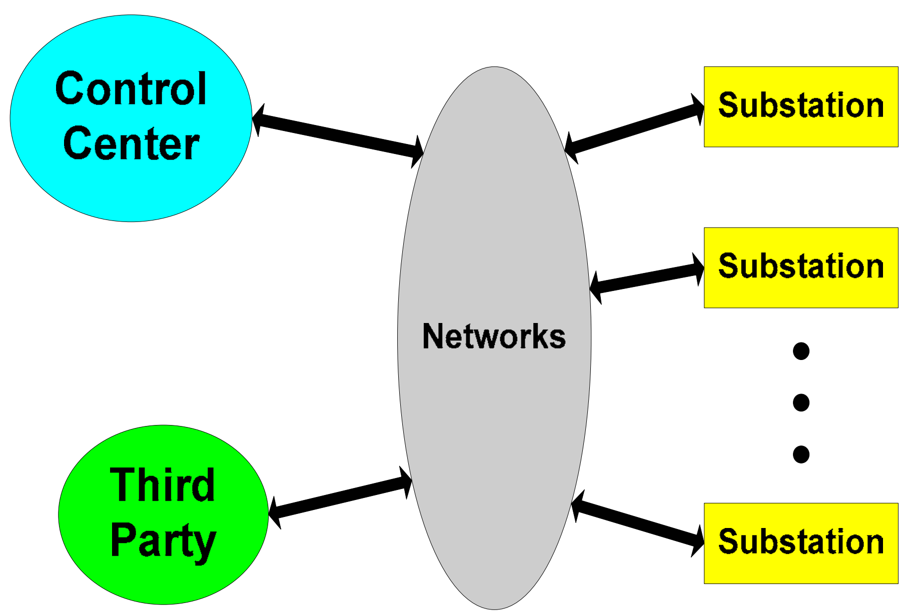

Figure 3. In time the communication channels between substations and control center will be replaced with a high bandwidth dedicated network that will allow faster area-wide controls.

would be much more complex than the simple star network used today for the control center to poll substation RTUs. Moreover, the control functions will not be all concentrated at a central computer in the control center but would be distributed over numerous computers whether they are in substations, generating stations or engineering offices. Such distributed computer communication is being developed today for various applications and is shown conceptually in Figure 4. It shows that some of the functions (measurements or calculations) will be publishers of data while others who will use this data (applications, controls) will be subscribers. The network will be controlled by other computers that will be quality of service (QoS) brokers. Such middleware are being developed for other applications and will have to be developed for the architecture appropriate for the power grid. It should be mentioned that, given the concern for the security of such critical infrastructures as the power grid, such computer communication systems for the power grid must be secure from external intrusions and has to be built into the QoS.

3.1.3 FACTS

FACTS devices available today were discussed in Section 2. Although they are different in detail by model and manufacturer, but they fall into three classes:

- DC transmission controls,
- SVC (static var controller), and
- PFC (power flow controller).

In addition, special controllers can be built for specific purposes using the same principles. One major advantage to these controllers is their speed with control actions taking place in milliseconds which is in the same timeframe as protection actions.

3.2 New controls

The proposed control concepts described here are all wide-area controls. Although local controls

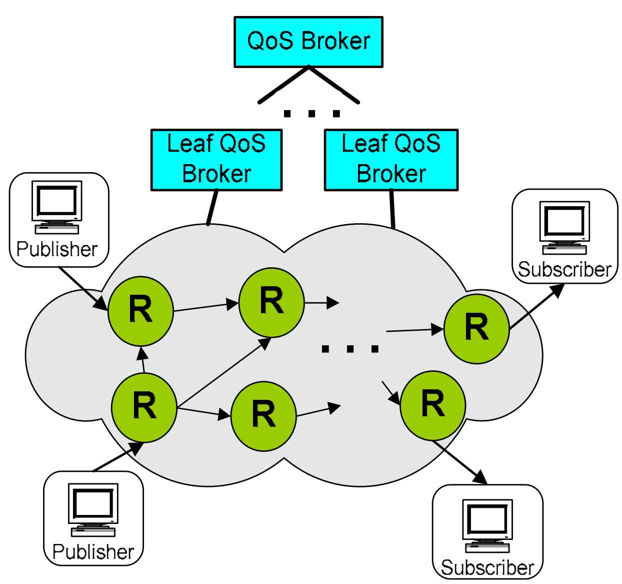

Figure 4. A distributed communication architecture that can be used to meet power system control requirements of the future.

continue to be improved using newer technologies, the conceptual functionality of these local controls will remain the same. The wide-area controls presented here will often take care of the local controllers but the main objective is to improve the overall stability of the power system. The concepts are presented in the order of increasing complexity, also implying that the ones presented first would be easier to implement.

3.2.1 Frequency Control

As noted before, frequency is controlled by balancing load with generation. The primary governor control at the generators is local while the secondary AGC control that adjusts the governor setpoints is area-wide. The primary control is continuous whereas the secondary control is discrete usually using 2-4 second sampling.

Given that all generators in a region are no longer owned by the same organization, this area-wide AGC control will become more decentralized. The Federal Energy Regulatory Commission (FERC) ancillary service regulations do allow third-party AGC but a new communication-computation-control scheme needs to be developed. As this control is quite slow (2-4 second sampling), feasibility of control is not a problem. The more complex communication scheme required is also not a problem; although a meshed communication network is required rather than the present star network, the bandwidth requirement remains modest. However, such a network introduces other modes of failures like signal delays and the control have to be robust enough to handle them.

3.2.2 Regional Voltage Control

Voltage control in North America has always been local, although Europe is trying some regional control schemes. FERC recognizes voltage-VAR control as an ancillary service. Control schemes for such regional control need to be developed but the schemes have to be such as to ensure that such service can be quantified and paid for as an ancillary service. This type of control, like frequency control, is relatively slow and so the feasibility of the control and communication is not an issue. The main hurdle has been the selection of input and output variables of the controller that can handle all the varied operating conditions that the power system endures. Thus this challenge is a classical one of developing a practical robust controller.

3.2.3 Small signal stability control

Small signal instability occurs when a system perturbation, even a small one, excites a natural oscillatory mode of the power system. These oscillations are slow, usually under 1Hz. The main method used today to guard against small signal instability is the off-line tuning of power system stabilizers (PSS). These PSS are local controllers on the generators. Thus local controllers are used to mitigate system oscillation modes, a procedure that is recognized to have significant disadvantages. New controllers need to be developed that can use system-wide inputs (not necessarily more inputs per controller but input signals from further away). Such remote signal inputs will obviously require communication channels which could be dedicated or could use a more flexible communication mesh network.

Another control concept is to adaptively change the PSS setpoints according to the power system operating conditions. This would be analogous to the AGC control by introducing a secondary control scheme that would periodically adjust the setpoints of the local PSS controllers as the system changes. The challenge here is that the calculation of PSS setpoints requires large analytical calculations, which are today done off-line but will have to be done on-line in this case. The speed of calculation is not a major concern as changing the setpoints can be done quite infrequently, probably minutes.

3.2.4 Voltage stability control

Voltage instability occurs when a change in the power system causes an operating condition that is deficient in reactive power support. Guarding against such instability requires the anticipation of such contingencies that can cause voltage instability and taking preventive action. New preventive control schemes are needed that can also include special protection schemes that could isolate those areas with var deficiencies.

This is not a stability control in the traditional sense that responds to a disturbance. This is an action plan to ensure that the system operating condition does not stray into an area where a perturbation can cause voltage instability. The control of the transient condition after a disturbance occurs is handled in the next section.

3.2.5 Transient stability control

The development of such a control scheme is by far the most difficult because a disturbance that can cause instability can only be controlled if a significant amount of computation (analysis) and communication can be accomplished very rapidly. This concept is approached in three increasingly difficult levels:

- The first is to use off-line studies to manually adjust protective schemes which would operate only if the disturbance occurs;
- The second is to automatically adjust these protective schemes with on-line calculations;
- The third and final would be to directly operate the control actions after the disturbance occurs.

3.2.5.1 'Soft-wired' remedial action schemes

A step advance in this direction will be to generalize remedial action schemes (RAS), also known as special protection schemes, to control transient stability. These RAS today are developed from the results of voluminous off-line studies and are implemented with a 'hard-wired' communication system. Thus, the system values and statuses monitored and the breakers controlled cannot be modified. What is proposed here is the development of a generalized communication system that can enable the implementation of new remedial action schemes by software modification. Although a comprehensive communication scheme will be required in this type of control, the computation requirements will be modest as the control schemes are largely defined off-line.

3.2.5.2 On-line setting of remedial action schemes

A step forward will be to develop methods to control transient stability but with less dependence on off-line studies and more use of on-line computation. The main idea here is to use more real-time data to determine what control is needed. What is proposed here is the development of soft-computing techniques using pattern-recognition, neural-networks, expert systems, etc. to process the real-time data to decide the best control action. Of course, much off-line training of the software may still be required off-line but the expectation is that the control action would be much more efficient than those purely decided off-line.

3.2.5.3 Real time control of transient stability

The objective here is to develop a global control for transient stability (with no off-line assists). For this to be feasible, the computation needed to determine the disturbance scenario and then computing the necessary controls for stabilization, has to be in the same time-frame as today's protection schemes (milliseconds). Whether this is indeed possible with today's technology is not known. However, the goal here would be to determine what kind of communication-computation structure will be needed to make this feasible.

IV. CONCLUSION

A roadmap for the development of new controls for power system stability is presented. The challenges are significant but the rewards in terms of economic payoff are high. The ability to push the limits of the transmission system depends on how well stable operation can be maintained against disturbances. The improvements in computers, communications and controllers are already being used in power systems in many ways. By combining them to develop area-wide controls for power systems, stability can be controlled better to increase transmission limits.

The roadmap outlined here ranks the conceptual developments by the difficulty of their implementation. The requirement of more complex computation or communication makes implementation more difficult, but several of the steps outlined above can be taken right now using existing technology without significant new development.

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