Chapter 3

PRACTICES FOR OFF-LINE STUDIES

This chapter first describes in section 3.1 the basic tools and techniques that can be used for voltage stability analysis. Section 3.2 discusses in detail the modeling requirements to capture short term and long term voltage instabilities. This section also provides examples and case studies of modeling effect on system behavior. Section 3.3 presents a power flow based fast voltage stability assessment technique that can be used to identify various causes that may lead to voltage instabilities. Section 3.4 provides the remedial measures needed to mitigate voltage instability. Finally section 3.5 includes information related to published case studies.

3.1 TOOLS AND TECHNIQUES

3.1.1 Introduction

Traditionally, power system engineers have used two main classes of programs for analysis of bulk power system performance: 1) power flow and 2) transient stability. Historically, voltage, active power and reactive power flow problems have been analyzed using static power flow programs. This approach was satisfactory since these problems have been governed by essentially static or time-independent factors. Power flow analysis allows simulation of a snapshot of time, such as after automatic actions but before operator actions.

Static analysis involves only the solution of algebraic equations and therefore is computationally much more efficient than dynamic analysis. Static analysis is ideal for the bulk of studies in which voltage stability limits for many pre-contingency and post-contingency cases must be determined.

Dynamic issues, such as first swing transient angle stability problems have normally been addressed using transient stability programs. These programs ordinarily include dynamic models of the synchronous machines with their excitation systems, turbines and governors, as well as other dynamic models, such as loads, High Voltage Direct Current (HVDC) transmission, Static Var Compensators (SVC) and other fast acting devices. These component models and the accompanying solution algorithm are suitable for analysis of phenomena from tens of milliseconds (e.g., machine subtransient dynamics) up to several seconds or tens of seconds.

With the evolution of modern, heavily compensated power systems, voltage stability has emerged as the limiting consideration in many systems [1]. The phenomenon of voltage collapse is dynamic, yet frequently evolves very slowly, from the perspective of a transient stability program. For example, the 1987 collapse of the Tokyo Electric Power Company system [2] evolved over a period of about 30 minutes (1800 seconds). The time frame of such an event is roughly two orders of magnitude longer than either the component models or the solution algorithm which transient stability programs are designed to handle.

It is well known that slower acting devices, such as under-load tap-changing (ULTC) transformers, generator over excitation limiters (OEL), and the characteristics of the system loads will contribute to the evolution of a voltage collapse [1]. In a power flow program, these effects are taken into account, if at all, by enforcement of their steady-state (algebraic) response. Conversely, the transient stability program will typically assume that these phenomena are slow, and corresponding variables will remain constant. In actual practice, neither of these assumptions can be relied upon, thus leaving voltage collapse in a no-mans-land between these two analytical domains.

The recent emergence of a new class of computer simulation software provides utility engineers with powerful tools for analysis of long term dynamic phenomena. The ability to perform long-term dynamic simulations either with detailed dynamic modeling or simplified quasi-steady-state modeling permits more accurate assessment of critical power system problems than is possible with conventional power flow and transient stability programs.

Dynamic analysis provides a replication of the time responses of the power system. Accurate determination of the time sequence of the different events leading to system voltage instability is essential for post-mortem analysis and the coordination of protection and control. However, time-domain simulations are time consuming in terms of CPU and engineering required for analysis of results. Also, dynamic analysis does not readily provide information regarding the sensitivity or degree of instability. These may make dynamic analysis impractical for examination of a wide range of system conditions or for determining stability limits unless combined with other techniques. Therefore, the most effective approach for studying voltage stability is to make complementary use of static and dynamic analysis techniques.

By use of traditional techniques and more advanced analytical approaches, it is possible for utility engineers to develop a better understanding of the true limits of their systems, rather than be constrained by the limitations of their computer tools. This allows engineers to evaluate the interactions between the equipment controls and the system response. This understanding can be used to make better operations and planning decisions, which are neither overly conservative nor overly optimistic.

The following sections describe how to use a combination of static and dynamic analysis tools for practical assessment of voltage stability of large systems.

3.1.2 Power Flow Analysis

Traditional power flow programs are constrained by a set of modeling assumptions, which are valid for a wide range of system problems. These constraints (with minor variations by individual program) are:

1. Fixed real power dispatch of generators with a Swing Bus to handle the slack
2. Constant P-Q Loads (no voltage or frequency sensitivity)
3. Instantaneous ULTC action
4. Fixed or instantaneously switched capacitors and reactors
5. Generator capability represented as maximum and minimum reactive power limits
6. Perfect voltage control at PV buses

The algorithms typically used for solution of the power flow equations also have some limitations. The most common solution technique is some type of Newton iteration on the power equations. The most notable limitation of these algorithms is that the Newton iterations tend to become ill-conditioned, and ultimately non-convergent, as the system nears the point of voltage collapse. This is primarily because the Jacobian of the network equations approaches singularity [3]. While a number of researchers have attempted to use this information to determine the system maximum power transfer, currently the unfortunate system engineer is faced with the task of determining whether poor behavior of the power flow reflects an actual *system* problem, or merely a numerical aberration. Several newer power flow algorithms have modifications for more robust performance near the point of collapse [4].

When used for voltage stability analysis, these modeling and algorithm constraints often distort the results. Power system analysts are often of the opinion that these constraints give conservative results, and hence their use is justified. While often true, this is not necessarily the case. Furthermore, there are circumstances under which the results are unnecessarily conservative, and may result in lost revenues (from curtailed power transfer or sales) or unnecessarily expensive system reinforcements. The following example will show a very simple case in which power flow assumptions result in overly *optimistic* results. Then in the next section, we will examine some more complex issues, and analytical alternatives to power flow analysis.

3.1.3 Example: Load Voltage Dependence and Compensation

Considering a radial load feeder, such as that shown in Figure 3.1-1, we can show a relatively simple relationship between the load voltage and power delivered to that bus.

Selection of the size and switching criteria for the capacitor shown in Figure 3.1-1 is a common planning problem. The change in the bus voltage as the load power varies results in the well known “nose” curve shown in Figure 3.1-2, as a solid line. If the minimum acceptable voltage on the bus corresponds to point A, then a capacitor should be switched on when the voltage drops to that point.

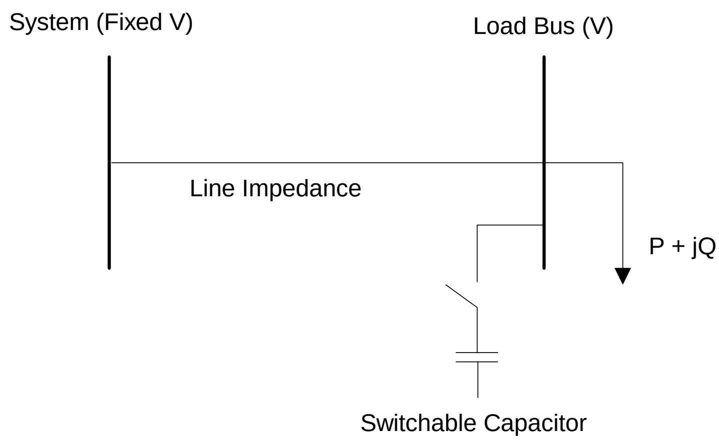

Figure 3.1-1. Simple radial load feeder with switchable capacitor.

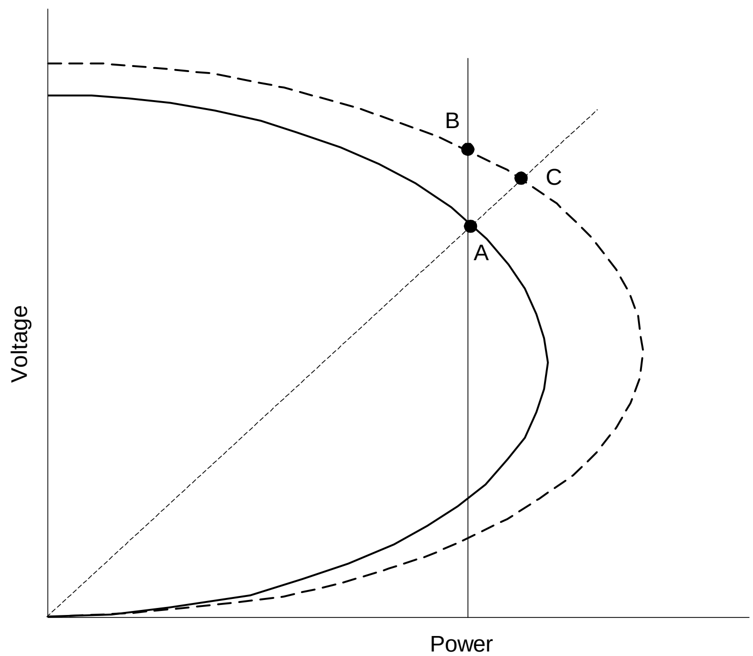

Figure 3.1-2. P-V curve for radial power system.

Following addition of the capacitor, for a typical power flow with constant power loads, the voltage solution will be on the dashed nose curve, at point B. Point B is directly above point A, since the load power is not affected by the voltage. However, most system loads do exhibit some voltage sensitivity. If we consider a load that varies linearly with voltage (i.e., constant current), the resulting solution will be point C. From a planning and operations perspective, the difference between points B and C is significant. The actual load power after capacitor switching is greater than that predicted by the power flow, and the resulting voltage is lower. Thus, the capacitor has not done as much as the power flow result suggested towards relieving the stress on the feeder. Utilities that base peak load forecasts on the *actual load* levels observed during peak conditions, characterized by widespread depressed voltage, are at risk of underestimating the peak *nominal load*. This may then compromise the effectiveness of proposed compensation schemes, and make estimates of spinning reserve low, if the voltage profile is corrected by compensation.

A final observation on this example relates to the behavior of most conventional power flow algorithms near the point of maximum power transfer. As noted above, the Jacobian matrix of the system equations becomes singular near the end of the nose. Calculation of the points along the upper side of the curve becomes progressively more difficult, until most programs fail to converge. Calculation of points under the curve may be impossible, even though for loads with a high degree of voltage sensitivity, operating points at, or even beyond (under), the nose are possible on some systems, at least for short periods of time. At points below the nose, but far from the nose, a Newton Raphson algorithm should again successfully obtain solutions.

3.1.4 Quasi-Steady-State Analysis

Model and algorithm adaptations have resulted in simulation tools dedicated to the long-term dynamics of voltage phenomena. Among them, Quasi Steady-State (QSS) simulation has revealed a powerful approach [5]-[8]. It can be used any time the instability risk is known to originate from long-term dynamics. The QSS technique offers a good compromise between the simplicity and efficiency of load flow-type methods, on one hand, and the advantages of time simulation (higher accuracy, handling of time-dependent controls, absence of numerical problems around the critical point), on the other hand.

QSS long-term simulation is used as the "simulation motor" in various voltage security analyses, such as contingency evaluation, loadability limit computation [5], [6], secure operating limit determination [9], identification of instability modes and suggestion for corrective actions [5], [6].

QSS long-term simulation is dramatically fast. For instance, on the 1200-bus system described in [5] and [6], the simulation of system behavior over 15 minutes following a major contingency, takes about 15 seconds. Reference [8] reports on QSS simulations found three orders of magnitude faster than complete time simulation (numerical integration with fixed time step size) for the same accuracy in terms of voltage stability limits.

The complete dynamic simulation tool and the QSS-based tool complement each other. The former serves as a benchmark, since its model is quite exhaustive. It is used for simulating special scenarios, for which the kind of phenomena is not known a priori. It is also used when there is a risk for the system to loose stability during the short-term (or transient) period following a disturbance. On the other hand, when focusing on long-term dynamics, the efficiency of the QSS approach makes it appropriate for large-scale studies (numerous network situations, remedial action determination, etc.).

As discussed above, voltage dependence is an essential aspect of voltage stability. Load voltage dependence can be included in most power flow programs, but there are some aspects of load behavior that make this issue even more complicated. In particular, thermostatic effects and load motor dynamics can play a significant role. Modeling of load behavior is discussed in detail in Section 3.2.3 below.

The consideration of load voltage dependence and thermostatic effects is further complicated by the actions of ULTC transformers. In many systems, voltage-regulating ULTCs are controlled to maintain distribution or subtransmission voltages within a fixed range. Depending on the equipment involved, this action occurs over a range of tens of seconds to a few minutes following a significant change in voltage. Of course, if the control range of the ULTCs is exhausted, the regulating action stops. If and when the voltage near the loads (i.e., on the regulating or low side of the transformer) is restored to its pre-disturbance level, the voltage dependence *as viewed from the bulk system* is eliminated. This is because while the high side system voltage may have changed significantly, the voltage seen by the load has returned to its pre-disturbance state. Therefore, the power consumed, regardless of the load voltage dependence, is constant.

Another aspect of system performance, which is normally lost in the analytical domain between the power flow and the transient stability program, is proper accounting for the reactive power capabilities of the generators. Ordinarily, generators have maximum and minimum reactive power limits specified in the power flow, based on steady-state capability. In the transient stability program, the voltage regulation capability of the generator is dictated by the response and limits of the excitation system. Normally, this transient capability afforded by the excitation system is considerably higher than the steady-state capability of the generator. If, following a disturbance, this transient capability is required, the machine field protection will eventually act to drive the excitation back to a level that is consistent with the steady-state rating of the machine. This excitation runback will only be required if these conditions persist for a few minutes. This is much longer than the time frame of a transient stability simulation. Even after this maximum steady-state field voltage is enforced by either generator protection or the plant operator, the power flow’s application of a maximum reactive power output does not accurately reflect the limit due to fixed field voltage. While this is a relatively minor consideration under most conditions, more accurate modeling can affect the response of a system near voltage collapse.

Modeling of these various important components is discussed in the next section.

3.1.5 Transient Stability

The previous case approached the modeling of a voltage collapse by looking at the system dynamics from the perspective of traditional power flow analysis and adding consideration of some of the important slow dynamics. Next we will examine a case for which the transient performance would normally have been the starting point for analysis.

In this case, a relatively tightly interconnected 500 kV test system is initially stressed with a heavy level of transfer from the generation rich northern region towards an area with both heavy loads and a considerable amount of local generation. This test system contains a wide range of realistically modeled power plants and system components. Figure 3.1-3 shows the transient response of this system to a fault that leads to an outage of a large generator. The fault is cleared by tripping a 500 kV tie-line. As the figure shows, the system is transiently stable, with system oscillations showing relatively good damping. Post-disturbance voltages are depressed, but appear to be sustainable at the end of the twenty-second simulation.

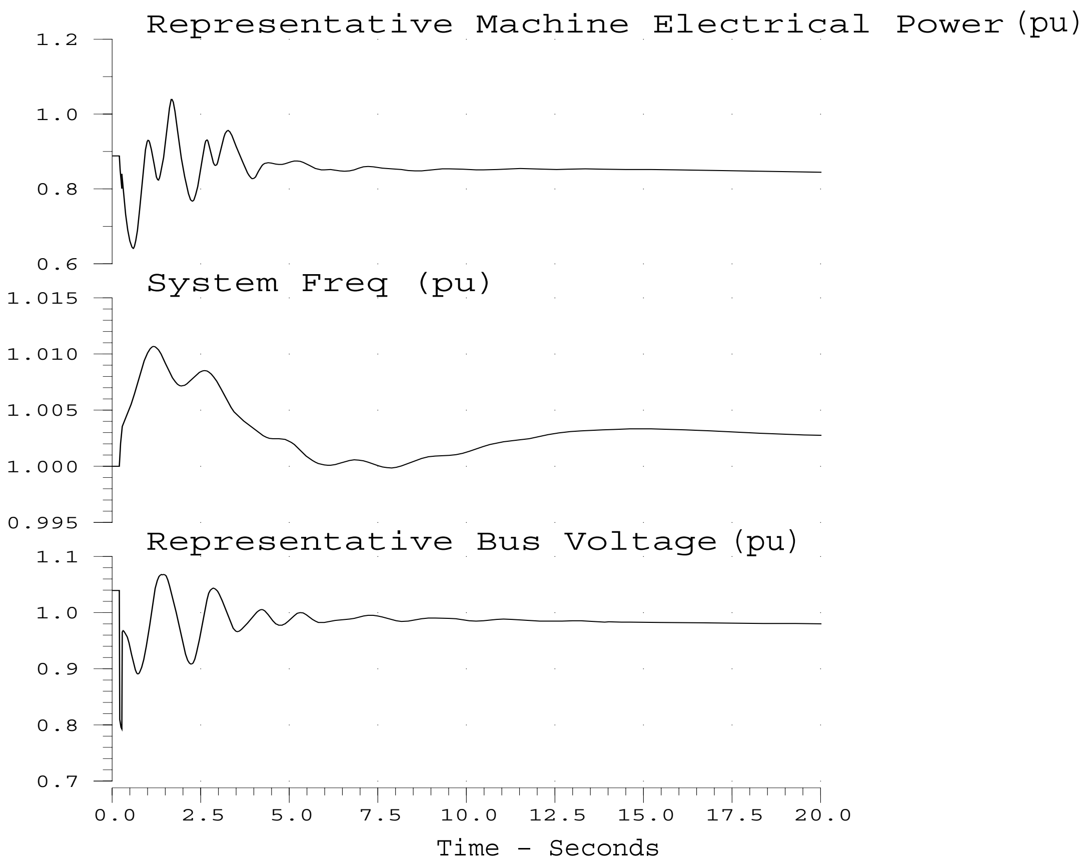

Figure 3.1-3. Transient stability simulation of a line and plant trip scenario.

3.1.6 Longer Term Analysis

The response of the system in the previous case, appeared to result in a satisfactory post disturbance condition. However, if we continue the simulation for a longer period, the response of the system becomes rather alarming.

Simulation of the system for more than about ten seconds requires consideration of a number of longer term dynamic phenomena. The behavior of the loads, ULTCs and generator field protection are discussed below. In addition, it is important to consider the response of power plant controls, boiler dynamics, and (very important in this case) the AGC [10].

During the first twenty seconds, the transient response is dominated by the machine excitation systems and by the turbine-generator governors. Typically, the governor dynamics are the slowest phenomena taken into account. However, in this particular case, the system has suffered a significant loss of generation. Following the inertial response of the system, the action of the governors will dictate where the changes in incremental power occur. However, as the boiler steam reserves are depleted, the thermal plant dynamics enter the picture. The AGC will then redispatch the system to attempt to reset the system frequency to its nominal value. The redispatch by the AGC may actually increase the stress on the system, by increasing loading on the most economic generation, which is not necessarily in the best place to serve the now compromised system.

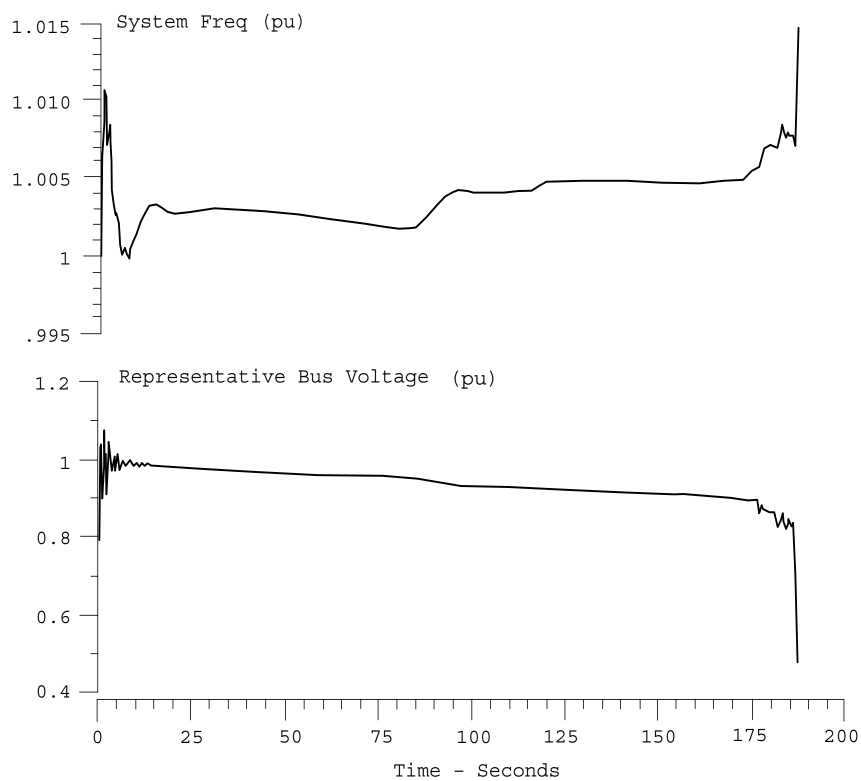

Figure 3.1-4. Longer term simulation of a line and plant trip scenario.

Figure 3.1-4 shows a continuation of the simulation started above. Notice that as the simulation progresses over the space of a few minutes, a number of the slow dynamic phenomena manifest themselves. In this study system, the loss of the critical plant and transmission line has a strong influence on the system voltage. In fact, the drop in voltages results in a drop in the actual load power of sufficient magnitude that the system experiences a condition of excessive power generation and high frequency, in spite of the loss of generation. For the two minutes or so after the initial machine swings settle out, the combination of the load and ULTC dynamics result in a steadily declining system voltage. This decline is further aggravated by the system AGC, which is reducing generation in order to try to bring the system frequency down to nominal. Unfortunately, the machines that are backed down first (according to the area control error parameters) are relatively near the most adversely affected load centers. This change in dispatch increases the voltage stress on the already weakened system. After about eighty seconds, some of the machines that were required to produce reactive power beyond their steady-state field current capability have their field over excitation limit controls engaged. This control action reduces the field voltage and consequently the output of those machines. This causes the most severely affected region to expand.

At about 160 seconds, additional machines lose voltage control capability through field protection. This causes a widespread and relatively fast voltage decline, resulting in some wild oscillatory behavior before a number of machines trip due to activation of their out-of-step protection or undervoltage protection. Figure 3.1-5 shows a few details of these actions thirty seconds before complete voltage collapse and system breakup. A summary of the significant automatic events and their timing over the course of this disturbance is shown in Table 3.1-1.

This case demonstrates a potential danger associated with conventional transient stability analysis. The response of this system over the first 20 seconds or so was relatively reassuring. However, in the space of 3 minutes it experienced a complete voltage collapse and system breakup. In order to protect the system from this severe, but somewhat unlikely occurrence, a good understanding of the dynamics shown here would be needed.

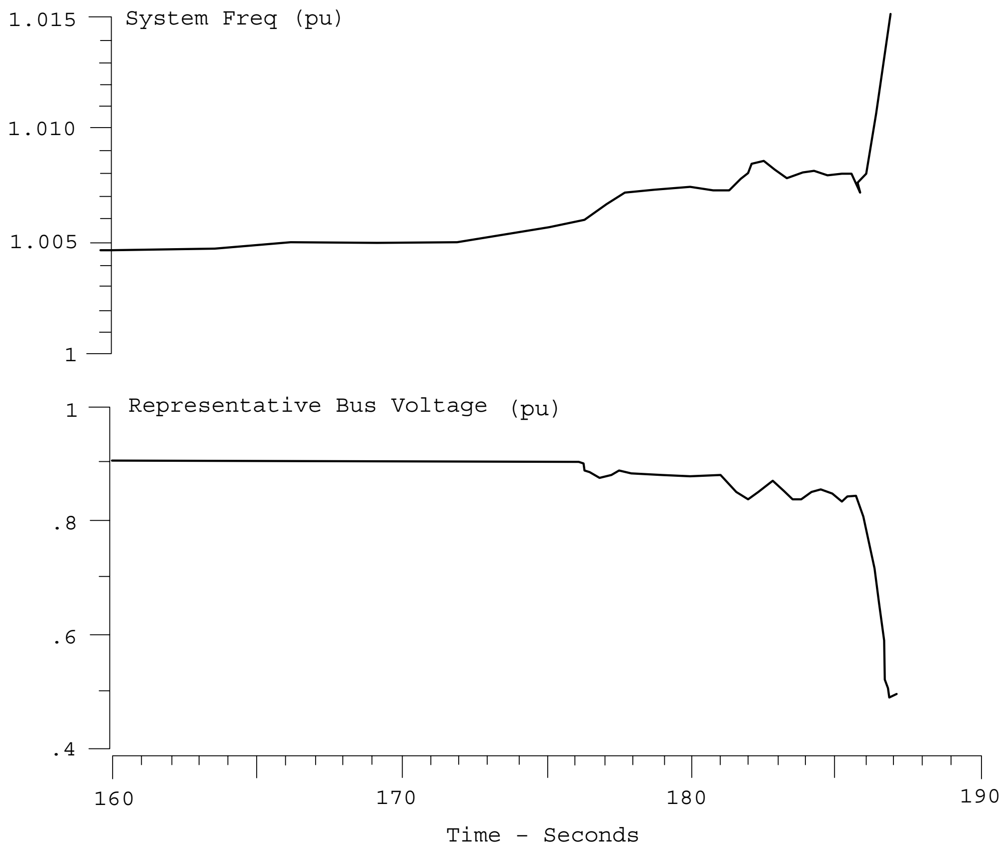

Figure 3.1-5. Details of system breakup.

Time (seconds)	Event
.2	Fault Applied
.27	Fault Cleared Plant 22 Tripped on Loss of Synchronism 500 kV Line Opened
80.395	Plant 4 Field Over-Excitation Control Engages
84.716	Plant 15 Field Over-Excitation Control Engages
85.996	Plant 3 Field Over-Excitation Control Engages
91.745	Plant 16 Field Over-Excitation Control Engages
114.610	Plant 12 Field Over-Excitation Control Engages
137.854	Plant 20 Field Over-Excitation Control Engages
161.390	Plant 2 Field Over-Excitation Control Engages
170.814	Plant 1 Field Over-Excitation Control Engages
176.357	Plant 4 Tripped on Low Voltage
181.175	Plant 3 Tripped on Low Voltage
181.666	Plant 19 Field Over-Excitation Control Engages
181.851	Plant 18 Field Over-Excitation Control Engages
185.682	BWR 1 Tripped on Low Voltage
186.363	Plant 28 Tripped on Loss of Synchronism
>186.363	(remaining units trip on overspeed)

Table 3.1-1. Summary of discrete events.

Assuming that the risk *was* recognized, the options include: 1) hope it never happens; 2) reinforce the system enough that it can stand the event; or 3) design protection (e.g., undervoltage load shedding), which would act within the first minute or so to save the system. Of these three alternatives, option 3) has the most appeal in terms of sound engineering and economics. Alternative 1) is certainly easiest, but the consequences may be severe. Alternative 2) is the most robust, but might be prohibitively expensive. In order to have reasonable confidence in any protective scheme required for alternative 3), the system engineer needs to have a good feel for the dynamics of the system leading up to the collapse. Regardless of the alternative selected, good information about what actually might happen during a severe event allows the decision to be made on a more rational basis.

There are other classes of problems and possible solutions that can be simulated with longer term dynamics. Table 3.1-2 shows a brief summary that also includes some of the risks of ignoring the accompanying long term dynamics. In each of these classes of problems, traditional computational tools provide, at best, partial information to the planning and operations engineer.

Problem/Solution	Risks of Conventional Analysis
Setting Undervoltage Load Shedding	Poor Settings: Too Low, High, Fast, Slow
Cascading Outages (due to protective devices)	Failure to Recognize
Unstable or Poorly Behaved Plant/AGC dynamics	Not Normally Considered
Balance of Controlled Vars: Fast-vs-Slow (e.g., SVC vs. Mechanically Switched Capacitors)	Too Much Fast Vars: Excessive Cost Too Few Fast Vars: Voltage Collapse

Table 3.1-2. Some Analytical Problems Not Well Suited to Conventional Analysis

3.1.7 Example: Hydro-Quebec Experience

Hydro-Quebec (HQ) uses post-contingency power flow and long term stability simulations in order to validate post-contingency analysis. Long term simulations are required to adjust automatic systems such as switched shunt reactors on the bulk power system. In recent years, high speed of computers has allowed the long term package to be run more often.

Analyses such as V-Q curves were utilized more often in early studies of voltage instability. Computation of the transfer capability in real time, uses P-V curves with an automatic iterative method.

An automatic switched shunt reactor system (MAIS) is used to control both over and undervoltages. Voltage stability problems could either happen at under or over voltages. The switched shunt system is activated by local variables such as voltage level, delta voltage, or compensators' reactive power generation. Almost all 735 kV substations are equipped with this MAIS switched shunt system. The large number of stations and reactors in each of them bring a certain level of redundancy. Being able to switch off 735 kV reactors, HQ has added large shunt capacitor banks in order to put reactors back in-service. On the other hand, too many capacitors cannot be added or the system becomes voltage sensitive. The Hydro-Quebec system is characterized by long distances between the generation and the load area. Due to the distant location of the power plants, voltage control near the load area is mainly insured by compensators. Its long EHV lines present high series reactance and high shunt capacitance value. Therefore, with the exception of heavy load, the excess reactive power generated by the EHV lines is mainly compensated by switchable 330 and 165 MVAr shunt reactor located at 735 kV substations. When the system is heavily loaded (in winter), the series reactive losses increase and shunt reactor are gradually switched off. A slight variation in the power transfer involves a large reactive power adjustment. That variation could be related to normal operation conditions and also to actions of load shedding and/or power rejection automatisms.

In this way, load shedding and power rejection schemes are commonly used to stabilize severe disturbances. The more severe the disturbance is, the greater are the quantities of load rejected or shed. The power rejection is limited to the biggest power plant under extreme contingencies. Load shedding is set by the underfrequency scheme. A part of the quantity of shed load can be activated remotely. Underfrequency load shedding automatism act on rate-of-change and level of system frequency. Reactive shunt compensation (capacitor banks) is also shed. This underfrequency load shedding is mostly used for transient purposes, but will have measurable effects on long term behavior.

In the Hydro-Quebec system, frequency is also a major concern. Frequency is tied to voltage. "Frequency Collapse" can happen if during restoration of voltage the active generation reserve is not sufficient. By restoring the voltage, load will increase and this can create lack of active generation. Based also on that concern, all data should be modified to properly consider frequency deviation using frequency dependent parameters.

HQ plans to add an undervoltage load shedding scheme that will have to react after the transient, when the load begins to recover. All these automatic systems and automatisms are taken into account in simulation.

3.1.8 Summary

For various classes of power system problems related to voltage stability, there are a range of tools and techniques that can be used to make operations and planning decisions based on higher fidelity simulations. These better informed decisions have the potential to improve system performance and reliability and to save money as well, particularly when compared to system reinforcement or operating margins based on approximate and potentially inadequate analytical techniques.

3.2 MODELING REQUIREMENTS

3.2.1 Introduction

As noted above, traditional analytical tools, including power flow and transient stability programs may not be particularly well suited to the analysis of all voltage stability problems. Longer term (also variously called long-term, mid-term and extended-term) dynamic simulations, in particular, require good models of the slow dynamics associated with voltage collapse. Better component models give utility engineers the ability to conduct detailed studies that more realistically reflect the behavior of power systems. This requires the modeling of important slow acting controls and protective devices.

Traditionally used transient stability programs ordinarily include dynamic models as described in section 3.1.1. The time frame of voltage collapse can be as much as two orders of magnitude longer than either the component models or the solution algorithm of a transient stability program are designed to handle. Furthermore, it is well known that slower acting devices, such as ULTC transformers, generator over excitation limiters (OEL), and the characteristics of the system loads will contribute to the evolution of a voltage collapse [1], [11]. In a power flow program, these effects are taken into account, if at all, by enforcement of their steady-state (algebraic) response. Conversely, the transient stability program will typically assume that these phenomena are slow, and corresponding variables will remain constant. In actual practice, neither of these assumptions can always be relied upon, thereby requiring analysis of long term dynamic phenomena. The use of these techniques, including the effects of slow acting devices, allows utility engineers to develop a better understanding of the true limits of their systems. The impact of these devices on voltage stability is discussed below.

3.2.2 Extent of System Representation

Establishing the base case for voltage stability assessment involves determining: (a) to what degree of detail the internal (study area) and external systems should be represented and, (b) how to model all the devices that are important for voltage stability.

Ideally, the entire interconnected system including both the internal and external systems should be represented in as much detail as possible. In reality, however, some form of system reduction may be necessary to keep the size of the system manageable. In such cases, there is a need for new reduction techniques for voltage stability studies that focus on retaining the same reactive power demand-supply characteristics for the original system and the reduced system. For some studies, the relatively local nature of the phenomenon, the representation of the external system may not have to be as extensive as in the case of rotor angle stability. However, more detailed representation of the distribution network of the internal system is required for accurate determination of voltage stability limits.

3.2.3 Load Modeling

The fact that loads are generally voltage dependent is a critical aspect of voltage stability analysis. As noted above, the voltage sensitivity of the loads can provide some system relief following a voltage depression. However, some types of loads, particularly heating loads, exhibit a thermostatic effect. Here, the reduced power consumption of the individual loads results in the thermostats leaving the loads on longer. The aggregate effect of this is to gradually push the consumed load back towards the pre-disturbance level. Thus, the actions of the ULTCs and the thermostatic effects of the loads will cause any load relief to be short-lived. Other loads, such as air conditioners, have characteristics that tend to maintain their active power consumption and actually increase their reactive demand as the voltage drops. Failure to model the voltage dependence and thermostatic effects of the loads can lead to erroneous conclusions about the state of the system and the control actions required following a contingency.

For purposes of system studies, the term “load” refers to the equivalent representation of the aggregate effect of many individual load devices and the interconnecting distribution and subtransmission systems that are not explicitly represented in the system model. Generally, the load is represented by some combination of static and dynamic models to approximate the voltage (and frequency) sensitivity of the aggregate load. The effect of the series impedance of feeders and transformers between the system bus and the loads is usually neglected or included as a lumped impedance and tap ratio.

Many papers have been written describing the nature of the load and various approaches to modeling it. Recent IEEE Task Force papers have attempted to summarize this information [12], recommend standard load models [13], and provide a bibliography

[14]. However, the representation of loads for voltage stability analysis involves several aspects not required for conventional stability analyses, including: longer-term dynamics due to thermostatically-controlled loads and due to voltage regulating devices; and nonlinearities in the voltage characteristics at low voltages (e.g., due to motor stalling and tripping, discharge lighting, and inverter or switching power supplies). The modeling of these effects is not well-established and is still the subject of ongoing investigation.

In this section, we discuss the key load dynamic characteristics affecting voltage stability performance and models that have been proposed to represent these effects.

3.2.3.1 Load Dynamic Characteristics

A. Thermostatic Effects An aspect of load behavior that contributes significantly to the voltage stability problem is the effect of thermostatic controls. The voltage dependence of loads in a system, particularly loads such as resistive space and water heating, can give considerable load power relief following a voltage depression induced by a system disturbance. However, this reduction in power does not remove the need to deliver energy, e.g., to maintain constant temperature. Eventually, the reduced power consumption of the individual loads results in thermostats leaving loads connected longer. The aggregate effect is to push the nominal load power up towards a level that will produce the pre-disturbance actual power at the depressed voltage. The time constant associated with this resetting action is open to investigation, but values between 10 and 30 minutes have been suggested. There will be some permanent relief, since not all of the load will reset. In the nearly steady-state realm, this is the basis for conservation voltage reduction. Values of 0.5% steady-state actual load reduction per 1% voltage reduction have been observed in winter peaking systems [15].

It is not always necessary to take into account “thermostat” characteristics, unless significant numbers of on-load tap-changers will reach regulation limits following a disturbance. For long term simulation scenarios that cause sustained voltage depression on the bulk transmission system of more than about 10%, modeling of thermostatic loads may be required.

B. Voltage Control Devices The consideration of load voltage dependence and thermostatic effects is further complicated by the actions of voltage control devices in the underlying distribution and subtransmission network, including ULTC transformers and feeder voltage regulators. In many systems, voltage regulating devices are set to maintain distribution or subtransmission voltages within a specified range. Depending on the equipment involved, this action occurs over a range of tens of seconds to a few minutes following a significant change in voltage. Of course, if the control range of these devices is exhausted, the regulating action stops. If and when the voltage near the loads (i.e., on the regulated side of the device) is restored to its pre-disturbance level, the voltage dependence *as viewed from the bulk system* is eliminated. While the system voltage may have changed significantly, the voltage seen by the load has returned to its pre-disturbance state. Therefore the power consumed, regardless of the load voltage dependence, is relatively constant.

Following bulk system upsets, a typical result is an immediate drop in the power consumption and the system voltages. Over the next few minutes, the action of voltage control devices will typically drive the system into conditions of still lower voltage and possibly collapse. Sometimes, when a system settles down to a condition of steadily declining voltages on the bulk system, it is due to the fact that while most of the voltage control devices have run out of regulating range, the thermostatic effects continue to push the voltage down, possibly into voltage collapse.

If cases such as these are run on a power flow using constant power load modeling, the post-contingency power flow would simply fail to converge. In a conventional power flow, the finite range of the voltage regulating devices between the transmission system and the loads is ignored. This is reflected in the constant power load model connected at transmission buses. The effect of this modeling is to cause the voltage to cascade downward, without hitting the limit imposed by the maximum tap range of the ULTCs. These effects can be included either within the load model, or by explicit modeling of the voltage control devices in the analysis. Dynamic simulation also permits consideration of the timing of voltage control actions, wherein some devices will act before others, thereby changing the course of the scenario. Explicit modeling of these devices is discussed further below.

C. Induction Motors The characteristics of induction motors at low terminal voltages should be properly modeled. For dynamic voltage stability studies, a simplified first order model with slip being the only state variable may be adequate. In static tools, the linearized form of this model must be included in modal analysis.

3.2.3.2 Dynamic Load Model Forms

Most components of power systems can be modeled quite accurately, assuming sufficient resources are available to derive and/or identify model parameters. However loads present a difficulty. Loads are a complex, time-varying mix of many different devices. It is therefore not sensible, and probably not even possible, to model every customer device connected to realistic power systems. Further, depending on the voltage level at which loads are defined, they may also contain several levels of ULTC transformers, switched capacitors, and load controls such as undervoltage load shedding. Certainly large individual, predictable loads such as aluminium smelters, or some motor loads, should be accurately modeled. But in general, generic aggregate load models must be used.

For angle stability studies, aggregate load models have typically represented load powers as simple functions of voltage, i.e., without any form of dynamic response. As an example, loads were historically modeled as constant admittances. More recently they have been modeled as combinations of constant impedance, constant current and constant power (ZIP model), or in a voltage exponent form, e.g., $P(V)=P_0\,V^{\zeta}$, where ζ is a parameter chosen to best represent the voltage dependence of the aggregate load. However, these static models ignore the dynamic behavior exhibited by many loads. In voltage stability studies, this dynamic behavior is of importance.

When loads are subjected to a step change in voltage, they will typically undergo an initial (transient) step change in power. This will often be followed by a period where the load recovers back to a new steady state value. This recovery may be monotonic, or may involve some damped oscillatory behavior. A typical load response is illustrated in

Figure 3.2-1. The following specific load types provide examples of this form of response:

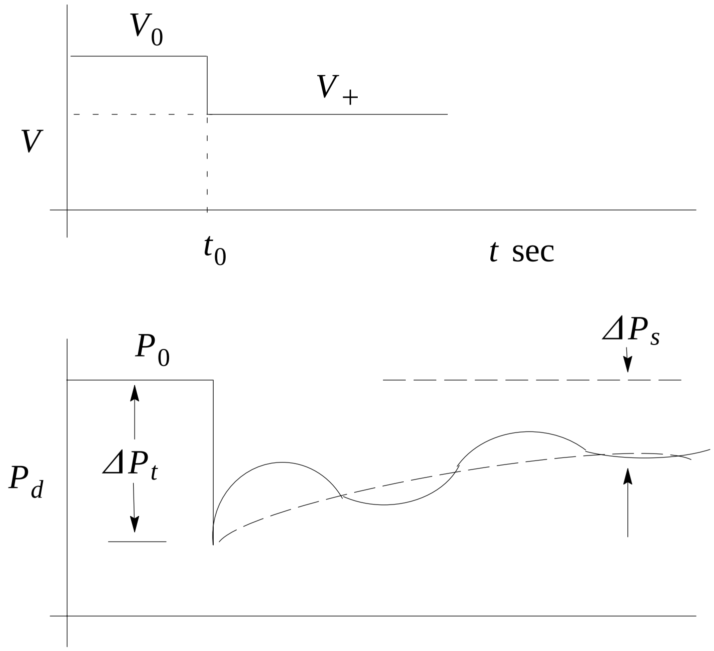

Figure 3.2-1. A typical load response.

- *Induction motor*: When the voltage on an induction motor undergoes a step decrease, the induction motor load will immediately drop. This occurs because the machine slip cannot change instantaneously. However this creates a mismatch between electrical and mechanical power which forces a restoring change in the slip. The load therefore quickly recovers.
- *Implicit ULTC*: As mentioned above, a load may include several levels of “downstream” ULTC transformers. These transformers act to restore load bus voltages, and so lead to a recovery of voltage dependent loads.
- *Heating load*: Thermostat controlled resistance devices, such as those used for space heating, exhibit long-term recovery behavior. When voltage falls, the load resistance initially remains unchanged. Therefore the load power drops. Over time, this reduced electrical heating results in a fall in temperature. Individual thermostats compensate by increasing the on-time of their resistance. Therefore the aggregate load resistance reduces (more devices on) and the aggregate load demand increases. The load will recover to a steady state in which the heater input is equal to the energy being lost to the surrounding environment or in which the load recovery is limited by all the heaters being on continuously.

A. Exponential Recovery Load Model An example of a load model which captures this general form of behavior is the exponential recovery load model [16]. This model can be expressed mathematically in state space form (for real power) as

$$\dot{x}_p = -\frac{1}{T_p} x_p + P_x(V) - P_t(V) = P_s(V) - P_d$$

$$P_d = \frac{1}{T_p} x_p + P_t(V)$$

where x_p is an internal state, P_d is the power demand, and T_p is the time constant which describes the rate of recovery of the load. When the voltage undergoes a step change, the internal state cannot change instantaneously. However the algebraic "output" equation shows that P_d will vary according to the function $P_t(V)$. Over time x_p will respond, driven by the differential equation. Steady state will be reached when P_d=$P_s(V)$. Therefore, the initial transient step change in load, the final value of load, and the recovery rate are described by $P_t(V)$, $P_s(V)$ and T_p respectively. To match this model to an actual load response, parameter T_p, and the parameters of $P_t(V)$ and $P_s(V)$ would need to be identified.

The exponential recovery load model has been illustrated for real power load. A similar set of equations could be used to model reactive power. Alternatively, and more realistically, some coupling between the real and reactive loads should be incorporated into the model. More general forms of the load model are discussed later.

The recovery load model given above in state space form can also be expressed in input-output form. The input-output form of the model is shown in Figure 3.2-2, where the input is voltage V and the output is the power demand P_d. This block diagram form illustrates the interaction between nonlinear functions and a linear transfer function. For the exponential recovery model, the linear transfer function is first order. However higher order dynamic behavior, such as oscillatory recovery, can be modeled by a higher order transfer function involving multiple time constants.

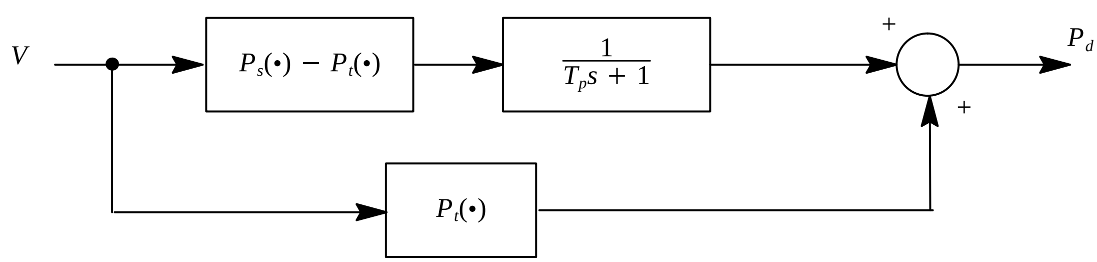

Figure 3.2-2. Input-output form of load model.

The exponential recovery load model is one example of a model which captures dynamic behavior of loads; many others exist. Typically they fit the general form

$$\dot{x} = a(x, V)$$
$$P_d = b_p(x, V)$$
$$Q_d = b_q(x, V)$$

where x may be a vector. The various load models correspond to different functions a, b_p and b_q, and different dimensions for x.

Common generic load models capture smooth load behavior. However hard nonlinearities, resulting for example from limits or protection action, produce load behavior which is not smooth, i.e., which is discontinuous or which is continuous but with a discontinuous rate of change. Examples include undervoltage load tripping or ULTC tap limits. Such effects are difficult to incorporate into generic models; generally a more specific model structure is required. Therefore aggregate loads are often best represented by the collective response of a number of load models.

B. Other Models In references [17]-[20], other simplified dynamic load models are proposed intending to capture the essential behavior of loads with different transient and steady-state characteristics, such as thermostatically-controlled loads and (with considerable care) some motor-driven loads. While the form in which these models are presented appears quite different, it can be shown that all, except for [19], can be generalized to the block diagram shown in Figure 3.2-3. The only difference in the model proposed in [19] is that the final summation is replaced by a multiplication.

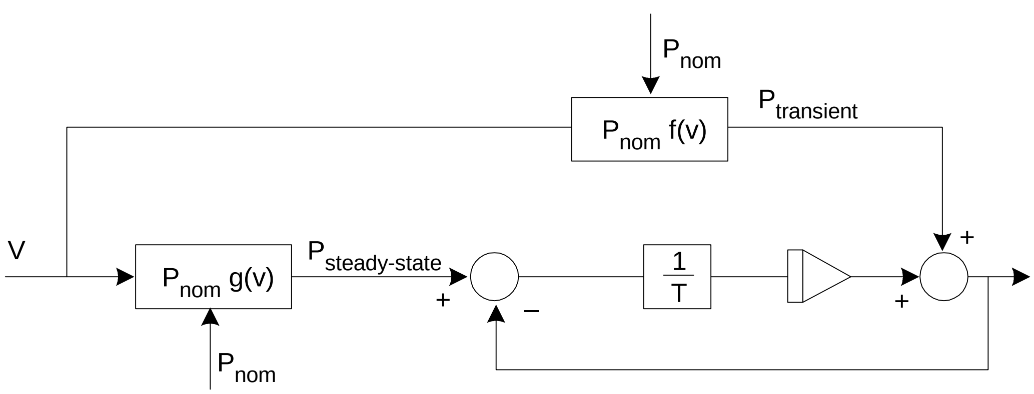

Figure 3.2-3. Simplified dynamic load model.

In this model, the steady-state load-voltage characteristic is represented by the function g(V), which may be an exponential or polynomial in V. For a thermostatic load, this would normally be represented as constant power. The transient characteristic is represented by the function f(V), which will often be constant impedance. Frequency sensitivity can also be included in both of these functions.

The language used to describe loads, when including voltage and frequency considerations is not well standardized. IEEE and CIGRE documents have suggested the use of *nominal load power* as the amount of MW the load would consume at nominal conditions, i.e., 1.0 pu voltage and frequency. This is designated as P_{nom} in Figure 3.2-3.

(It is initially equal to the MW consumed by the load divided by g(V) for the initial voltage.) The *actual or consumed load power*, also measured in MW, is the power consumed by the load under the existing conditions of voltage and frequency, i.e., the power measured by a meter. For this type of analysis it is vitally important to recognize that the *nominal load* is the independent variable, and *not* the actual load power.

A general distinction between the power consumed by a particular load at nominal conditions and under other conditions is given by:

$$P = P_o\, f(V,w,t)$$

$$Q = Q_o\, g(V,w,t)$$

where, by the definitions proposed by CIGRE,

- P_o is the active component of the *nominal load*
- Q_o is the reactive component of the *nominal load*
- P is the active component of the *consumed load*
- Q is the reactive component of the *consumed load*

This requires that the load voltage/frequency sensitivity functions, $f(V,w,t)$ and $g(V,w,t)$, be unity at nominal steady-state conditions:

$$f(V,w,t) = 1.0 \;\; @ \;\; V = 1.0 \text{ pu, } w = 1.0 \text{ pu, and } t \rightarrow \infty$$

$$g(V,w,t) = 1.0 \;\; @ \;\; V = 1.0 \text{ pu, } w = 1.0 \text{ pu, and } t \rightarrow \infty$$

To illustrate the behavior of this model, a simple radial system was simulated, with a load, represented by the model in Figure 3.2-3, connected through a transformer and transmission line to an infinite bus. A constant-impedance transient characteristic was used, with a constant-power steady-state characteristic, and a transition time constant (T) of 1.0 seconds. (Actual values of T for heating loads are much longer – up to several hundred seconds according to Reference [18].) Reactive power was modeled as constant impedance.

Figure 3.2-4 shows the response of this model (both with the summation and with the multiplication) to a 10% upward change in the high-side tap, followed 10 seconds later by a return to the original tap position. The response of the two forms of the model is similar. Because the load bus is not infinitely stiff, the bus voltage changes in response to the changing load power consumption.

Figure 3.2-5 illustrates the response of the dynamic load model to a 10% downward change in the *nominal load power*, followed after 10 seconds by a return to the initial value. There is an initial response due through the transient characteristic, which however is modified by a change in the bus voltage due to the finite system stiffness. In the steady-state, the actual power matches the nominal power due to the constant power steady-state characteristic.

In order to represent in a simplified way the effect of limited voltage control device tap range and the time required to change taps, the model shown in Figure 3.2-6 can be used. The quantity labeled V_{bus} is the system bus voltage, while V_{load} is the voltage that is applied to the load model. This voltage and V_{ref} are normally set to 1.0 pu initially.

The application of these models to realistic system simulations is discussed and illustrated in the next section.

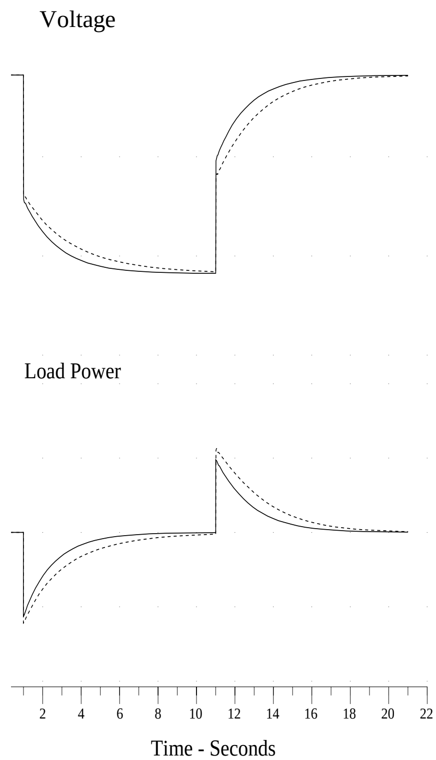

Figure 3.2-4. Dynamic load model response to 10% tap-change. (solid line–summation form; dotted–multiplication form).

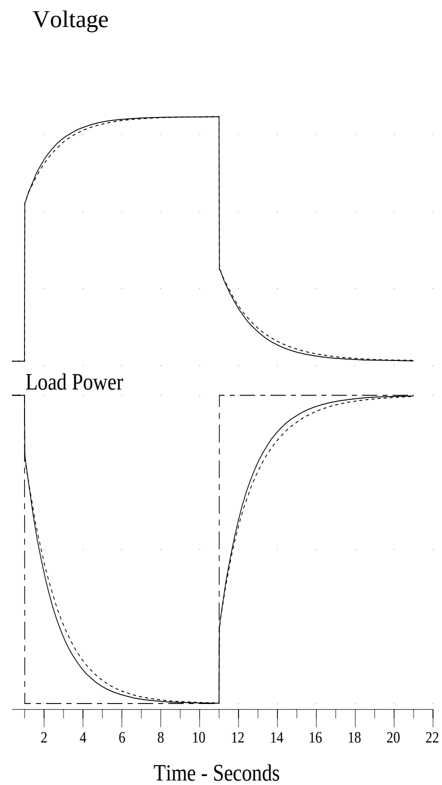

Figure 3.2-5. Dynamic load model response to change in P_{nom} (solid line–summation form; dotted–multiplication form; dash/dot–nominal load power).

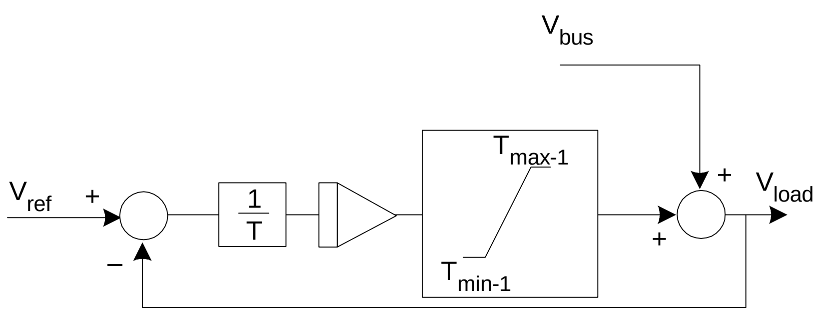

Figure 3.2-6. Simplified voltage control device model.

3.2.3.3 Example: Demonstration of Effects of Load Modeling for a Large Scale System

In this section, the impact of various load modeling assumptions is investigated using a simulation of a generation and bulk transmission system, based on an actual large utility system [21]. The simulation model has 95 buses, 114 branches, and 28 generating units, with a mixture of hydro, thermal and nuclear power plants. Excitation systems, power system stabilizers, turbine/governor systems, power plant dynamics, generator protection functions, including field current limiters, high/low frequency and voltage protection are represented. Two control areas are represented with automatic generation control (AGC) with a 15 second cycle time. Some mechanically switched compensation and transmission level ULTCs are included.

The bulk system has a 500 kV backbone that carries large amounts of power from a relatively less densely loaded region to a heavily industrial region. Disturbances along the bulk transmission system, especially those that have the potential to knock large generating units off-line are of particular concern.

This system has many of the characteristics observed in large modern utilities, including heavy levels of transfer, large amounts of shunt compensation, a variety of voltage control elements, and generating plants of various ages and capabilities. Of course, each system will have its own signature behaviors, and it can be strongly argued that variations such as the ones presented here would be appropriate to help system planners and operators to determine which particular modeling considerations are most critical for their system.

For these simulations, several of the major loads in the receiving portion of the system are represented by the dynamic load model described above (summation form). The steady-state, characteristic of the real and reactive power load is always represented as constant MVA, but different models are used for the transient real power load characteristic (transient reactive power characteristic is assumed to be constant impedance) and for the transition time between transient and steady-state characteristics.

A. Transient Response This first example illustrates the effect of variation in the transient response of the system loads. The disturbance is an EHV line fault and line trip, cleared in primary time, which results in a single large generator unit being knocked off-line. This represents one of the more severe, single contingency cases for this system. Figure 3.2-7 shows some selected system variables for the first 10 seconds of a longer term stability simulation in which the majority of the system loads are modeled as either constant current (solid trace) or constant admittance (dotted trace). The voltage plotted in the figure is a representative transmission node voltage in the vicinity of the region under the worst voltage stress. The load transition time constant is 30 seconds, so it has relatively little influence in this time frame. The resultant oscillatory behavior of the system is basically what would be expected for a highly stressed system, i.e., the constant admittance system shows much better electro-mechanical damping of the power swings than does the constant current model. It is worth noting that even though the disturbance includes tripping of a power plant, the system frequency swings to above nominal, rather than below, due to the transient load relief from the voltage depression.

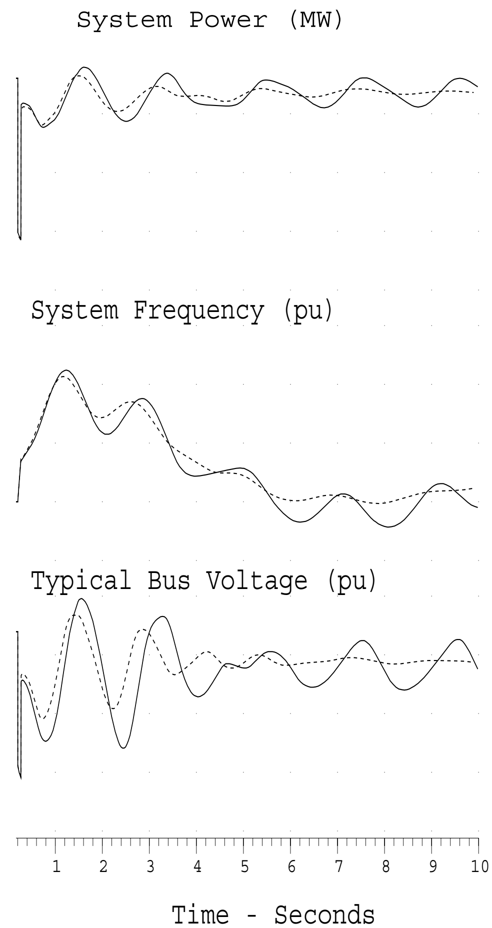

Figure 3.2-7. Fault and line trip with accompanying plant trip: constant I transient load and constant Z transient load (initial 10 seconds).

As we examine the behavior of this system over a longer time, the influence of the transition time constant becomes apparent. Figure 3.2-8 illustrates the same quantities over about a three minute period. Here we see that the inter-machine electro-mechanical oscillations die out, and the load attempts to transition back towards constant MVA. This transition results in further depression of the system voltage. It is interesting to note that the effect of the transition is roughly offset by the further depression in voltage, with the net result being that the actual system load appears to stay roughly constant. Nevertheless, the system is becoming progressively more stressed as the transition proceeds. After a few minutes, the machine over excitation limiters begin to remove machines from automatic voltage control and to runback the excitation. Ultimately, after about three minutes, the dropping out of excitation results in a widespread voltage collapse and system breakup. The somewhat higher stress level associated with the constant current transient model results in a slightly faster system breakup.

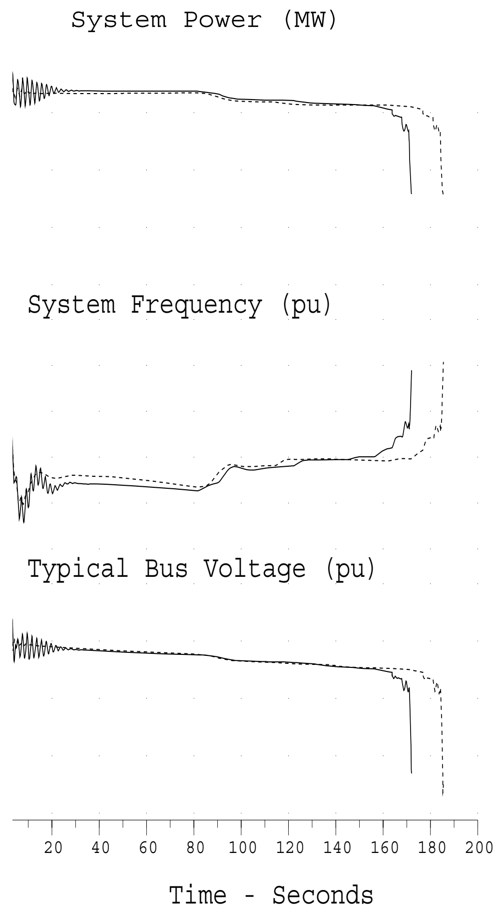

Figure 3.2-8. Fault and line trip with accompanying plant trip: constant I transient load and constant Z transient load.

B. Transition Time In this example, we examine the effect of the transition time between the transient and steady-state characteristic. Constant current transient response and constant MVA steady-state response are the two most common modeling assumptions for the aggregate system load. In Figure 3.2-9, we show three cases, with variations in the transition time constant of 3 seconds (solid trace), 30 seconds (dotted trace) and 300 seconds (dot-dash trace). These are the first few seconds of the simulation.

The case with the very fast transition, which is intended to very roughly approximate a high concentration of motor loads, exhibits negative damping. In Figure 3.2-10, we see that this behavior results in the system breaking up quite quickly. The difference between the 30 second and the 300 second time constant could be ascribed to different aggregate responses of loads and ULTCs. Reference [18] determined time constants with a range from 83 seconds to 364 seconds for the active power term, and 0.1 second to 1,025 seconds for the reactive power term, for the same feeder depending on time of day and season.

In this case, the slower transition time resulted in a later system separation. The difference in timing is somewhat less than might be expected, owing to both cases stressing the generator excitation systems enough to start machines towards OEL operation and reactive power runback.

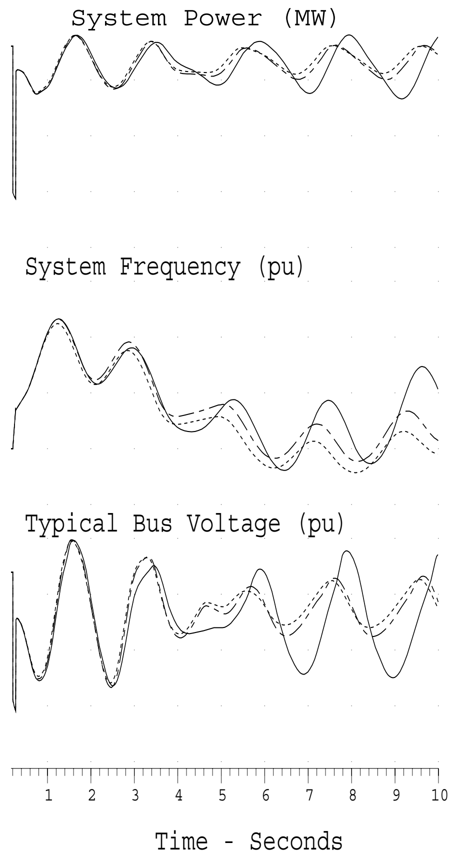

Figure 3.2-9. Fault and line trip with accompanying plant trip – constant I transient load: 3 seconds, 30 seconds and 300 seconds transition time constant (initial 10 seconds).

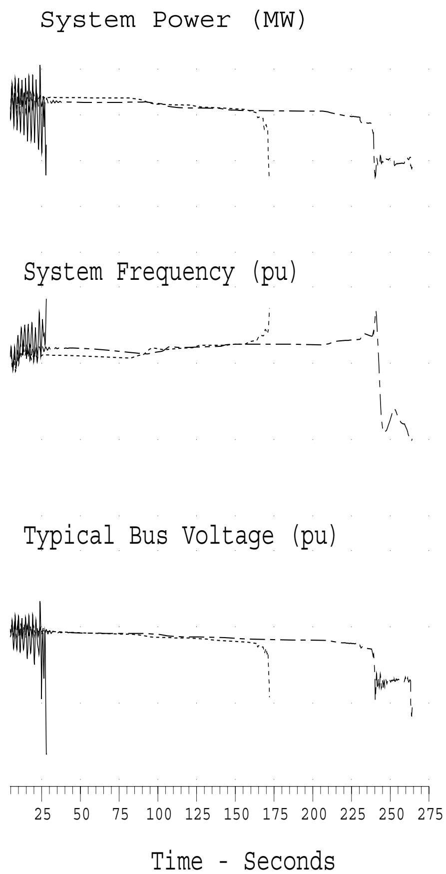

Figure 3.2-10. Fault and line trip with accompanying plant trip: 3 seconds, 30 seconds and 300 seconds transition time constant; constant I transient load.

C. Frequency Effects In systems suffering from very severe disruptions, it is common for significant frequency excursions to be observed simultaneously with voltage excursions. For this example, the disturbance causes a deficiency in active power resulting in a frequency excursion. For this disturbance, a large power plant complex in the exporting region of the system is tripped off-line. Figure 3.2-11 shows the first ten seconds of the event. The plots compare the effect of including a frequency dependent term in the load model. The case including a second order dependence (1.+2 Δf, solid trace) exhibits slightly better damping than the case with no frequency dependence (dotted trace). Because the loss of generation is in the exporting system, the voltages stay relatively healthy in the importing region. Consequently, beyond the deviations due to the electro-mechanical oscillations, there is little change in the actual power due to voltage depression. However, it is clear by the end of 10 seconds that frequency decline diminishes in the frequency dependent case due to the load relief.

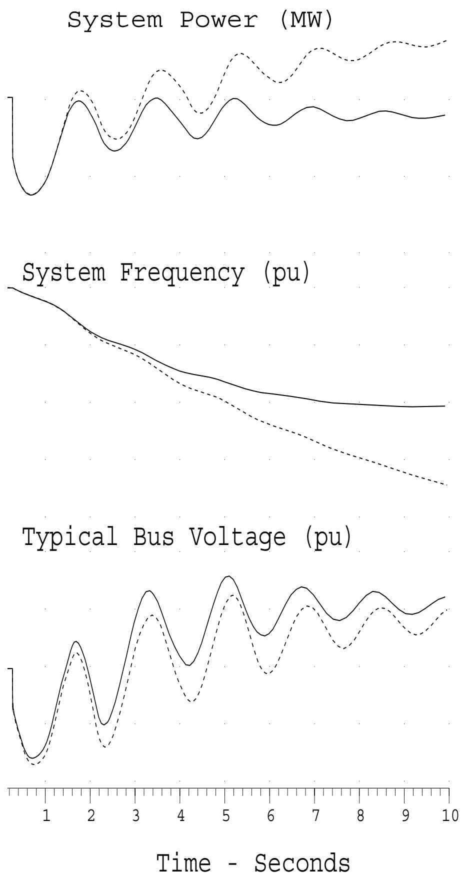

Figure 3.2-11. Exporting system multiple plant trip: with frequency dependent load model and without (initial 10 seconds).

Figure 3.2-12 shows the longer term consequences of that load relief. In the case with frequency dependence, the frequency decay is ultimately stopped and reversed first by the action of the governors, and then by the response of the AGCs. The case without frequency dependence, continues a monotonic decline, resulting in widespread generator tripping on low frequency, and complete blackout. About four minutes after the initial event, in the case with the frequency dependent load model, a number of machine OELs activate resulting in a complete system break-up.

This case illustrates a phenomenon observed in a number of systems. That is, for systems under a very high degree of stress, the character of a system breakup can be radically altered by modifications in the system load model. In this case, we see that for one set of assumptions, the result is a frequency collapse, and for another, the result is voltage collapse.

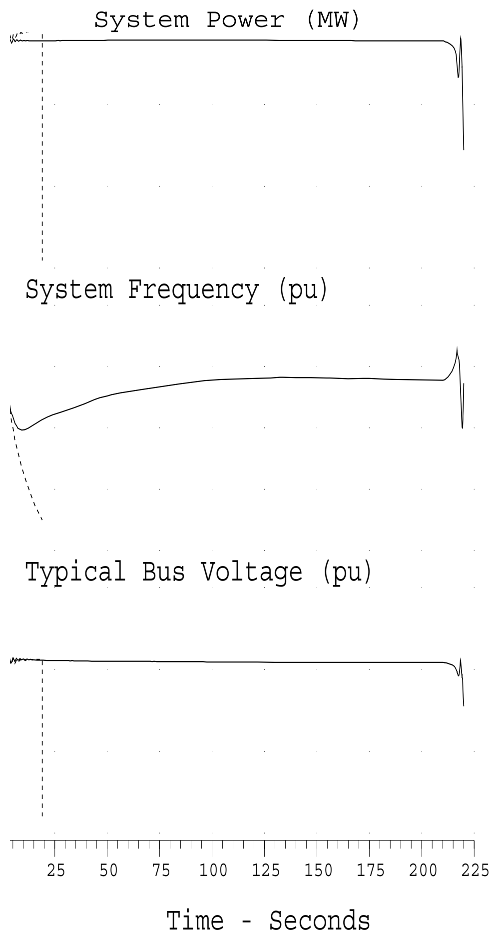

Figure 3.2-12. Response to exporting system multiple plant trip: with frequency dependent load model and without a voltage collapse.

3.2.4 Generator Over Excitation Limiter (OEL)

The reactive power capability of the generators must be modeled in sufficient detail to capture their behavior in the period leading up to a voltage collapse. In a traditional power flow program, the machine reactive limits are modeled using maximum and minimum reactive generation corresponding to the active generation level. Typically, this information is obtained from a unit capability curve. The *Field Current Limit* is of particular concern when studying voltage stability. This section of the capability curve corresponds to the steady-state reactive output of the machine when it is operated at rated terminal voltage and rated excitation voltage. This limit is enforced by the generator overexcitation limits (OEL) control function. When the field current goes above its limit, typically the OEL control resets the field excitation voltage to a value that will bring the field current within limits. At this operating condition, the reactive output of the machine can be greater or less than the value on the capability curve, depending on terminal conditions and active power output.

In static tools, the effects of OELs can be modeled using generator capability curves. This is valid under the assumption of $X_d=X_q=X_s$. In dynamic tools, the time delays and ramping of the field current must also be modeled. The action of OELs may differ greatly from plant to plant, and if detailed models can not be assembled and implemented, general models should be employed. The dynamic models should include the field current set-points (often a low one for timed ramp-down and a high one for instantaneous ramp-down), ramp-down characteristic, timings, and final current values.

The common response of a generator to a fault that is cleared by tripping a transmission line is after the initial transient has decayed, it settles to a post-contingency steady-state operating condition where the generator field current is above its rated value. At this operating condition, the reactive output may be above the value obtained from the generator reactive capability curve. After several minutes of operation at this condition, the OEL control resets the excitation voltage to its rated value. This typically causes a small oscillation, and brings the field current down to rated. The reset action will cause a reduction in the reactive output and terminal voltage of the machine.

If the system is in a sufficiently stressed state, the loss of the transmission line and subsequent OEL action can cause other machines to reach excitation limits. This action, along with other control actions and the characteristics of the system loads, can drive the system into a voltage collapse. However, the generator may have a short-term overload capability that may provide enough time for automatic corrective actions, such as capacitor switching, to be initiated.

3.2.4.1 Example: Demonstration of Effects of Over Excitation Limiters (OELs)

In this case, we compare the results of the previous case, using a 30 second transition time constant, to the same case with the machine over-excitation limiters disabled, but with other machine protections still enabled. Figure 3.2-13 shows that the case with the OELs (solid trace) is driven to voltage collapse much more quickly than the case without (dotted trace). In the latter case, the most severely affected units are ultimately tripped off-line by their armature current protection. (It is relatively unusual for this protection to be activated before the OEL during voltage collapse events.)

3.2.4.2 Capturing AVR and OEL Effects in Power Flow Calculations

High fidelity modeling of AVR and field current limit effects can be captured in power flow analysis using standard LF elements. Specifically:

- Modeling a generator with active AVR by a PV node gives two optimistic results, while it neglects the voltage droop of the AVR. This voltage droop can easily be modeled with standard LF-elements as follows:
  - Change the generator PV node into a PQ node generating only the active power (and 0 MVAr).
  - Add a PV node generating zero active power connected to the first generator bus through a reactance which corresponds to the AVR’s voltage droop plus, when not explicitly modeled, the step-up transformer reactance.
  - Adjust the voltage of that PV node, such that the right quantity of MVArs is delivered at the first node.

- Modeling a generator with fixed excitation current, e.g., with active excitation current limiter, by a PQ node is slightly pessimistic, while when voltage lowers reactive power output still (slightly) increases. Best results using standard LF-components are obtained by:
  - Transfer all the active and reactive generation from the generator.
  - Add a PV node generating the active power, connected to the first generator bus through a reactance which corresponds to the constant excitation current response of the generator (reactance typically 0.5 – 0.8 pu) plus, when not explicitly modeled, the step-up transformer reactance.
  - Adjust the voltage of the PV node, such that the right quantity of MVArs is delivered at the first node [22].

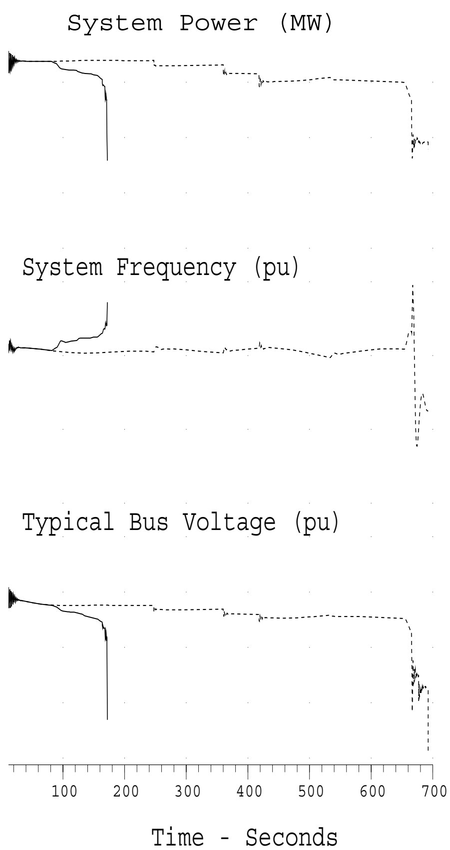

Figure 3.2-13. Fault and line trip with accompanying plant trip: with OELs (solid line) and without OELs (dotted line).

3.2.5 Under-load Tap-changing Transformers (ULTCs) and Voltage Regulators

One modeling technique used to capture the effect of the finite range of ULTC taps is to enforce constant MVA behavior for a range of voltages around nominal. Outside of this range load voltage sensitivity is included. So, for example, a constant current load behind a 10% range ULTC could be modeled as constant MVA load down to 90% voltage, and then constant current below that voltage. This is a simple and effective means of capturing the approximate effect of ULTCs imbedded in the load without making the unrealistic assumption of constant MVA for the voltages.

The ULTCs have a secondary effect on the voltage collapse. When trying to boost the low side voltage, they *drain* reactive power from the high side system and *pump* it to low side. This will place even greater stress on the transmission system and further aggravate the voltage instability.

As with the generation protection, the actions of the ULTCs must be modeled to accurately assess voltage collapse conditions. The automatically regulated ULTCs and distribution voltage regulators must be modeled with their actual tap range and size, voltage controls and deadbands, and settings for tap delay and tap motion time.

3.2.5.1 Example: Demonstration of the Effect of Transformer Tap Range

As was noted above, the amount of available range for regulation by the subsystem ULTCs can have a major impact on the post-contingency viability of a system. In this example, the potential impact is illustrated by modifying the minimum voltage above which the steady-state constant MVA characteristic is enforced (as discussed in the previous paragraph. Figure 3.2-14 shows the results of a base case (solid trace) with constant current transient response and constant MVA steady-state response enforced down to 80% voltage. This represents an assumption of an equivalent of two layers of voltage regulation residing in the equivalenced subsystem. This system exhibits the same behavior as was observed in above. The second trace is for the same case, with only one layer of underlying voltage regulation being imposed, corresponding to a minimum voltage for enforcement of the constant MVA characteristic at 90% voltage. In this case, the load relief in the most severely stressed part of the system is more permanent (thermostatic effects are not modeled in this case). This prevents activation of the machine OELs, and the system remains intact for the duration of the simulation.

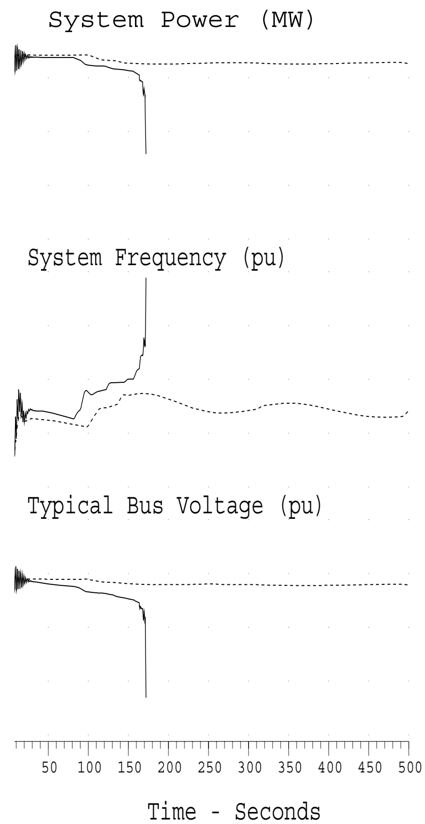

Figure 3.2-14. Fault and line trip with accompanying plant trip: minimum equivalent ULTC range 90% (dotted) vs. 80% (dashed).

3.2.6 Mechanically Switched Capacitors (MSC) and Reactors (MSR)

Automatically controlled MSCs and MSRs are typically switched based on a regulating voltage range and a time delay (some distribution MSCs are switched based on time of day). The timing of these devices can play an important role in the system response following a contingency. For example, MSCs can be installed to prevent a voltage collapse following the loss of infeed. However, they must be regulated to switch on before the ULTCs and generator OEL protection drive the system into a voltage collapse. In some applications, this will require extremely fast switched devices, or even static var compensation (SVC), while other applications may not require such speed. In order to capture the important timing aspects of these switching operations, the modeling of the MSCs and MSRs should include the voltage control settings and the time delays used in switching.

3.2.7 Power Plants and Automatic Generation Control (AGC)

Power plants boiler and turbine dynamics and controls, including Automatic Generation Control (AGC), should be modeled in long term dynamic studies.

3.2.8 Modeling Experience

3.2.8.1 Example: Voltage Collapse Scenario – Loss of Transmission Infeed

The effects of the devices described above will be explained in the following example, where a transmission line is lost on a heavily loaded system. For this example, we will assume that both the active and reactive loads are constant current, which is representative of winter peak loads in this climate. Figure 3.2-15 shows the power transfer characteristics, or *nose curves*, for the pre- and post-contingency systems (these are also referred to as PV curves). These curves show the power transfer across a multi-line interface, and the voltage at a critical 500 kV bus. The point where the curves turn around, or the nose of the curve, represents the maximum power that can be transferred across this interface. For this example, the pre-contingency maximum power transfer is 8700 MW, while the maximum post-contingency transfer is 7950 MW. Also, the critical voltage of the post-contingency system is significantly higher than that of the pre-contingency system. This can present a problem to system operators, who may tend to associate relatively high voltages with a secure system.

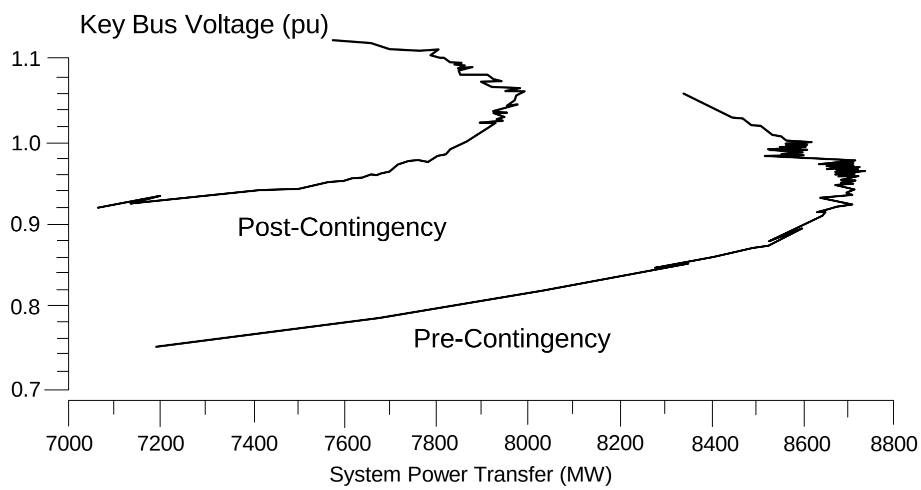

Figure 3.2-15. Pre- and post-contingency power transfer curves.

Note that the curves are jagged, representing the discrete actions of generator OEL protection, MSCs and ULTCs. In a power flow study, the time dependencies of these devices would not be modeled. In addition, the loads would typically be modeled as constant MVA (i.e., not voltage dependent). In this case, if the interface flow was above 7950 MW pre-contingency, the power flow would fail to converge following the loss of the transmission line. This would lead the engineer to believe that this contingency would result in a voltage collapse. However, the engineer may find the contingency to be stable when studied using a traditional transient stability program. Though both of these observations may be correct, they provide little information in determining solutions to avoid the voltage collapse.

In this example, while the post-contingency operating condition may not be desirable, it is not necessarily a catastrophic operating point. If the proper actions are taken quickly enough, the system can remain stable. However, if the correct actions are not taken, or are taken too slowly, the system will be driven into a voltage collapse.

Figure 3.2-16 shows the system load lines and the power transfer curves. The pre-contingency system was operating at a point defined by the intersection of the system and load characteristics: 8400 MW of transfer and a bus voltage of 1.06 pu (point 1). Immediately following the contingency (after the initial transients have decayed), the system goes to point 2 on the post-contingency curve. The bus voltage has dropped to 1.04 pu, and the imports are at 7950 MW. The imports have dropped due to the load relief from the voltage dependence of the loads. However, the actions of the ULTCs and distribution voltage regulators, along with the thermostatic effects on the loads, tend to push the actual consumed loads back to their pre-contingency level. This moves the load towards a constant power characteristic, as shown by the dashed load line. This drives the transmission and distribution system voltage further down (point 3). This failure of the system to move toward a satisfactory and steady voltage condition is referred to as a voltage instability or voltage collapse. The voltage collapse will continue until some action is taken to move the operating point to the upper side of the power transfer curve. The actions can be directed toward moving the power transfer curve (strengthening the system) or moving the load line (reducing the load). The system can reach an unsatisfactory but relatively stable equilibrium on the under side of the nose curve if the ULTCs run out of tap range. There have been a number of incidences in which bulk power systems have settled to either steady or gradually decaying conditions of severely depressed voltages (e.g., 75% of nominal) [1], [2]. Eventually, some other protective actions, such as generator or line thermal relays may disrupt this equilibrium and cause the system to go unstable.

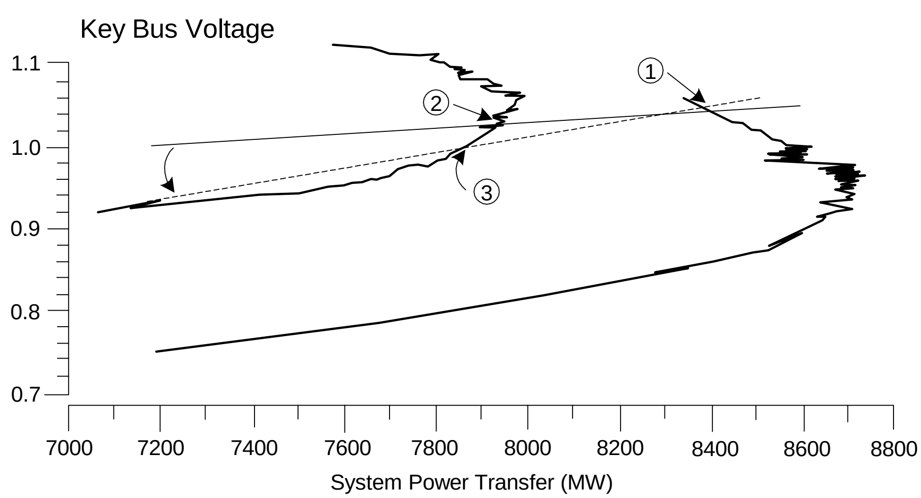

Figure 3.2-16. Effect of ULTC transformers and thermostatic loads

Mechanically switched capacitors can strengthen the post contingency system. It is common to install MSCs for post contingency operation, with the intent that they will allow higher power transfers and prevent a voltage collapse. For this application, it is important that the capacitors are switched on before the OELs and ULTCs are driven into states from which they cannot recover or return. If they are switched on too late, they will have little effect in preventing the voltage collapse. For example, several capacitors switched on at point 2 may be able to prevent the voltage collapse. These same capacitors, switched on at point 3, will provide less benefit since the voltage collapse has progressed further.

Another method to prevent such a voltage collapse gaining wide use among utilities is undervoltage load shedding (UVLS). The intent is to bring the system back to a stable operating point by removing load. This is shown in Figure 3.2-17, where the solid line (points 1 and 2) represents the original system load, and the dashed line represents the load after UVLS operations. Note that if the system was operating on the top portion of the PV curve, shedding load would decrease power transfers. This same load shedding, when performed on the underside of the PV curve, will actually increase power transfers while also raising the system voltage.

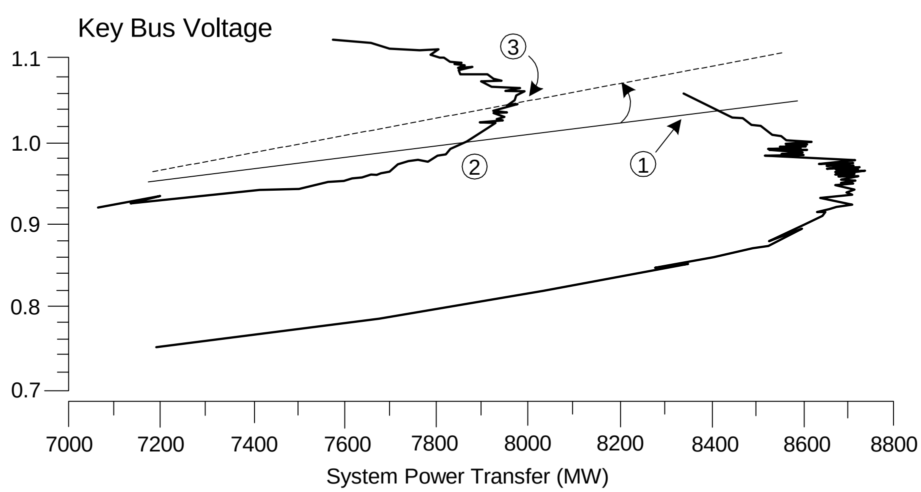

Figure 3.2-17. Effect of undervoltage load shedding.

As with MSC operation, the voltage set point and time delay used for the UVLS are critical to their ability to prevent a voltage collapse. They must be set to operate before the ULTCs and generator OELs drive the system into a voltage collapse. As the system gets further into a voltage collapse, more load will have to be shed to bring the system back to a stable operating point. This is because there is path dependence associated with the migration of the system down the underside of the power transfer curve. Once the ULTCs and OELs have acted, modest improvements to the bulk system voltage profile will not reverse their actions. Because of this unfortunate effect, settings for undervoltage load shedding that will arrest voltage collapse with the least amount of total load shed may have thresholds that reach into the lower range of "normal" operating voltages. Thus, the engineer may be faced with a choice between settings that risk unnecessary operation and settings that require more load shedding to arrest voltage collapse and restore the system to an acceptable and sustainable voltage profile.

3.2.8.2 Modeling Requirements – Hydro-Quebec Experience

Load behavior is the main part of long term modeling requirements. Hydro-Quebec developed a voltage and frequency based load representation for different seasons of the year with the help of LOADSYN. Field tests were done at several substations and during different periods of the year. An internal working group analyzed the data and recommended the load representation. Motor load behavior will be part of new investigations.

Simulations are done by adding transformers for each load in the system. The HQ also considers thermostatic effects on loads. The HQ load time constant is around seven minutes. Load modeled on high voltage transformer side will hide the actual behavior, especially if the load is not constant power (without voltage dependency).

Synchronous condensers often reach their maximum excitation, so a model takes into account field current limitation. Shunt reactors at 735 kV are switched off to maintain a suitable synchronous condenser MVAr output.

DC models have been translated for use with a long term package. The Z transform representation is used instead of state space variables.

In post-contingency power flow analysis, static var compensators are properly modeled in order to consider their limitations. By using a continuous switched shunt device representation and the droop represented by the branch impedance, SVCs will act as pure shunt capacitors when they reach their limits.

The Hydro-Quebec generators usually do not reach their maximum reactive capability. These generators are mainly located far from the load area. Reactive power available at these plants is not able to increase voltage support. Therefore, little effort has been spent so far on models for these limitations. Most HQ generation (95%) is hydro type, so HQ has spent considerable effort for development of modeling hydro response.

3.2.9 Conclusions

As voltage stability becomes a greater concern for utilities, it is critical that protection engineers understand the voltage collapse phenomena. The interaction of customer loads and system equipment such as generator protection, ULTC transformer control, shunt compensation and undervoltage load shedding plays a major role in the progress of a voltage collapse. Understanding the dynamics associated with these devices will allow the engineer to make the best decisions about protection and control schemes to minimize the occurrence of voltage instabilities.

The dynamic nature of the aggregate system load, that is, the change in characteristics between the transient and long-term period, has important consequences for analysis of voltage stability. In systems where traditional concerns about transient stability and damping are not a major issue, the load transition time is more likely to be an important consideration than the transient load characteristic, itself. Extremely fast transition times will result in less damping of electromechanical oscillations.

Big disturbances frequently involve large frequency as well as voltage excursions. Modeling of frequency dependence of the loads may therefore be as important as voltage dependence. Variations in assumptions regarding frequency dependence can produce qualitatively different responses.

Care should be exercised in establishing the voltage range over which particular voltage dependent behaviors will be enforced, recognizing the action and limits of voltage regulating devices. Consideration of changes in load character at depressed voltages can radically change overall system response.

There is a strong interrelationship between the load modeling and the modeling of other system components, in terms of the overall system response. High fidelity simulations are dependent on good representations of all of these elements.

3.3 VOLTAGE STABILITY ASSESSMENT

3.3.1 Introduction

The examples presented in the previous sections illustrate the complexity of the phenomena of voltage collapse. Use of long term stability models and simulation tools are required if reasonably accurate simulation of voltage instability events is to be possible. However, screening for all the subregions that can experience voltage instability as well as the operating changes, equipment outages, and equipment outage/operating change combinations that can cause voltage instability in each region requires use of a simpler model and computationally fast simulation tool. A simpler model and a computationally fast simulation tool can be helpful since the computation per event using a longer-term transient simulation tool can be quite large. In this section, we present a voltage stability assessment technique proposed in [25]-[27].

With proper use, power flow can be an accurate tool for assessing voltage instability despite its many modeling, algorithmic, and control shortcomings.

Two types of voltage instability exist in a power flow model:

1. A "loss of voltage control" voltage instability that is caused by exhaustion of reactive supply with resultant loss of voltage control on a particular set of generators, synchronous condensers, or SVC's. The loss of voltage control not only cuts off the reactive supply to a subregion requiring reactive power, but increases reactive network losses that prevent sufficient reactive supply from reaching that subregion needing reactive power. (This problem may be associated with limit-induced bifurcations of a nonlinear model of the power system, as discussed in Chapter 2.)
2. A "clogging voltage instability" ("radial" voltage instability) that occurs due to I^2X series reactive losses, tap-changers reaching tap limits, switchable shunt capacitors reaching susceptance limits, and shunt capacitive withdrawal due to decreasing voltage. These network reactive losses that result from the above possibilities can completely choke off the reactive flow to a subregion needing reactive supply without any exhaustion of reactive reserves and loss of voltage control on generators, synchronous condensers, or SVC's. (This problem may be associated with a saddle-node bifurcation of a nonlinear model of the power system, as discussed in Chapter 2.)

Clogging voltage instability is a well understood type of voltage instability and occurs in the distribution network [28], subtransmission network, and occasionally in the transmission network. It occurs due to increased transfer, and can be assessed using a P-V curve or loadability assessment methods, as discussed in Chapter 4. Loss of voltage control instability occurs in the transmission and subtransmission system due to equipment outages as well as operating changes such as:

(a) Line and transformer outages.

(b) Generator outage with a particular active power generation pickup pattern.
(c) Load and generation pattern increase.
(d) Wheeling and transfer pattern increases.

Experience has shown that there are typically several different subregions in a utility that can be vulnerable to voltage instability and that each subregion may be vulnerable to only a couple of the above contingency and operating change combinations (a-d).

Voltage stability assessment can identify the subregions experiencing "loss of voltage control" instability and the set of equipment outage that cause voltage instability in each subregion. This voltage stability assessment will also be effective in assessing where the clogging voltage stability occurs and the equipment outages that cause this clogging voltage instability in each subregion. Similarly, this technique can be used to determine the effectiveness of remedial measures as described in Section 3.6.

3.3.2 Knowledge Development Aspects

Voltage stability assessment must not only identify the subregions that are vulnerable to voltage instability, but also the equipment outages and operating change combinations that make any particular subregion vulnerable to the voltage stability assessment. There are knowledge development and on-line aspects of the voltage stability assessment. The knowledge development aspects identify:

1. *The parameter or parameters that make a particular subregion vulnerable to voltage instability.* A V-Q curve, which adds reactive load in the subregion experiencing voltage instability is chosen to be the stress test that most effectively diagnoses the structural cause of voltage instability in a subregion.
2. *The structural cause of voltage instability in any subregion experiencing loss of voltage control voltage collapse.* A specific set of generator, synchronous condensers, and SVCs are identified as causing the voltage instability in each subregion experiencing a unique collapse problem. This requires a method of identifying the subregions (coherent bus groups of a particular level of coherency) with unique voltage instability problems where a specific set of generators, synchronous condensers, and SVCs must lose voltage control to produce the voltage instability in that specific subregion. The set of generator, synchronous condensers, and SVCs that exhaust reactive reserves and produce voltage collapse in a specific coherent bus group is called the reactive reserve basin and the coherent bus groups is called a voltage control area.
3. *A proximity measure for identifying how close a subregion is to voltage instability.* Two different proximity measures will be discussed.

3.3.2.1 The Structural Cause of Voltage Collapse

The knowledge development aspects of voltage stability assessment are discussed in this section. The first step in the off-line aspects of voltage stability assessment is the selection of the parameters or the stress test that most effectively identifies the structural cause of voltage instability in each subregion.

Since the voltage stability assessment must be able to detect regions that are vulnerable for all operating changes and equipment outages, the technique is based on a stress test that encompasses why any operating change or equipment outage will cause voltage instability in a bus or structurally coherent bus group. Since “loss of voltage control” instability and clogging voltage instability are due to a shortage of reactive supply to a bus or coherent bus group, the structural stress test used must assess when and why a shortage of reactive supply exists. Thus, a V-Q curve is used in this voltage stability assessment methodology since it directly assesses shortage of reactive supply. A P-V curve, although quite useful in assessing transfer or loading limits, does not identify the location of the shortage of reactive supply and its cause. Furthermore, P-V curves can not as effectively identify regions where reactive shortages occur for generator or line outages that are easily identified via V-Q curves. V-Q curves effectively add reactive load at a bus in a manner that is similar to the outage of reactive supply from a generator or outage of the line charging shunts of medium or long transmission lines. Thus, a V-Q curve stress test has similar effects to the contingencies that induce stress on the system. A final reason for using a V-Q curve rather than a P-V curve is that the minimum singular value of the reactive power voltage Jacobian approximates the changes in the minimum singular value of the full power flow Jacobian [4], as discussed in Section 4.3.2; the minimum singular value of the real power angle Jacobian does not change discontinuously with each loss of voltage control at a generator and thus does not approximate the minimum singular value of the full power flow Jacobian. A V-Q curve being a reactive power voltage relationship stresses the system in a manner similar to how the voltage instability occurs.

The second step of the knowledge development voltage stability assessment attempts to find the size of the coherent bus groups that experience unique voltage instability problems and the particular set of generators that must not exhaust reactive reserves if voltage instability is to be avoided in a specific coherent bus group. The algorithm for determining non-overlapping coherent bus groups for a given choice of coherency parameter *a* is [25], [26], [29]:

1. Search for the largest diagonal element (d) of the reactive power voltage Jacobian J_{QV} that includes both load and generator buses:

$$d = \max\{J_{QV}\}_{ii}.$$

2. For each row i of J_{QV}, rank the absolute value of the off-diagonal Jacobian elements from smallest to largest. The Jacobian elements with the smallest absolute values are eliminated from each row and until the sum of the elements eliminated is less than or equal to ad.
3. The groups of buses, that are still interconnected after the weakest branches connected to each bus i are eliminated, are the coherent bus groups for that value of *a*.

A discussion on the difficulty in selecting *a* and a procedure for selecting *a* based on coherency is given in [25]. This procedure cannot guarantee each coherent bus group produced via its selection of *a* has a unique voltage instability problem.

A procedure for correctly selecting the value of *a* is needed that will guarantee that each coherent bus group has a unique voltage collapse problem. The procedure for correctly selecting this value of *a* requires:

(a) Computing a V-Q curve at a bus in an area or utility above a specified voltage rating threshold. This requirement that V-Q curves be computed at those buses above the specified voltage is made because: (1) "loss of voltage control" instability does not generally cause the voltage collapse at subtransmission and distribution networks below 100 kV; and (2) because the method is intended to find subregions with different "loss of voltage control" instability problems. A second less important reason is that the coherent bus group algorithm must be applied to a matrix that is diagonally dominant. If low voltage buses are included, the matrix J_{QV} may not always be diagonally dominant.

(b) Finding an *a* such that the V-Q curve minima $V_{k_{min}}$ and $Q_k(V_{k_{min}})$, and the set of generators exhausted in computing the V-Q curve minimum at a bus k are almost identical for all buses (k) in a coherent bus group. The coherent bus groups that satisfy this criterion are called *voltage control areas* and the set of generators exhausted in computing a V-Q curve at any bus in that voltage control area is called its *reactive reserve basin*.

The reactive reserve basin for any voltage control area contains generators in several neighboring voltage control areas. Reactive reserve basins for different voltage control areas are overlapping even though voltage control areas are non-overlapping. Reactive reserve basins can be classified as global, local, or locally most vulnerable.

Global reactive reserve basins are associated with test voltage control areas containing the different hubs of the EHV transmission grid encircling different load centers. A test voltage control area is the coherent bus group where the V-Q curve is computed to determine the reactive reserve basin. Global reactive reserve basins will in general overlap but are associated with electrically and geographically distinct regions of the transmission system. *Local* reactive reserve basins are associated with test voltage control areas that are either geographically or electrically more remote from generation than the voltage control areas associated with global reactive reserve basins. Local reactive reserve basins are progressively smaller (contains fewer generators) as: (1) the voltage level of the associated voltage control area gets smaller; and (2) the electrical distance to the generation, connected by the highest voltage level of the EHV transmission gets larger. There are one or more of these nested sets of progressively smaller local reactive reserve basins in each global reactive reserve basin. The *locally most vulnerable* reactive reserve basin is one of these locally nested reactive reserve basins. Exhaustion of reactive reserves in a locally most vulnerable reactive reserve basin not only produces a voltage collapse in its associated test voltage control area, but can also cause voltage collapse in test voltage control areas of other larger reactive reserve basins in the nested set when its reserves are exhausted. This result occurs because there is such a large increase in network reactive losses when the reactive reserves in this locally most vulnerable reactive reserve basin exhausts and loss of voltage control occurs on all reactive reserve basin generators. Thus, the reactive reserves in the larger nested reactive reserve basins would either easily or totally exhaust with depletion of reactive reserves in the locally most vulnerable reactive reserve basin. The locally most vulnerable reactive reserve basin is most often electrically remote to the larger of the nested set of reactive reserve basins it belongs to and generally exhausts at the minima of the V-Q curves that are used to compute and define their reactive reserve basins. Thus, the calamity of exhausting reactive reserves of a locally most vulnerable reactive reserve basin is hidden except in rare circumstances when its reactive reserves exhaust before the reactive reserves in larger reactive reserve basins it belongs to.

If more than one voltage control area (coherent bus group with the same voltage collapse problem) has the same reactive reserve basin, then exhaustion of reactive reserves there would cause voltage collapse in all voltage control areas with that reactive reserve basin. This observation leads to the definition of a *voltage collapse region*; which is the set of all voltage control areas with the same reactive reserve basin. The completion of the second step of the knowledge development aspects of the voltage stability assessment method is the determination of all voltage collapse regions in a utility.

3.3.2.2 A Proximity Measure for Voltage Collapse

A *third step* of the knowledge development aspects of voltage stability assessment is to select a proximity measure for voltage collapse in a voltage collapse region that is related by the reactive reserves in its associated reactive reserve basin. Two measures of proximity to voltage collapse can be used. The most obvious measure is the percentage of the reactive reserve basins reactive reserves in the base case, which often is a peak load case with no equipment outages. A second measure of proximity to voltage collapse in the associated voltage collapse region requires that the list of generators in its reactive reserve basin be grouped by the voltage control area they belong to. Usually a reactive reserve basin contains generators in two to ten voltage control areas. Exhaustion of reactive reserves on one generator in a voltage control area that contains several generators does not cause reduction in the reactive supply rate from that voltage control area to the test voltage control area where the V-Q curve is computed. Reactive supply rate from a reactive reserve basin voltage control area to the test voltage control area is the amount of reactive supply the reactive reserve basin voltage control area provides per incremental change in voltage in the test voltage control area. The reactive supply rate from a reactive reserve basin voltage control area is virtually constant as long as the voltage control area has reactive supply on at least one of its generators. It should be noted that the total reactive load to be added at the bus in the test voltage control area where the V-Q curve is computed is very close to the difference between total reactive power received from all reactive reserve basin voltage control areas and the network reactive losses internal to that voltage control area. The reactive power sent from a reactive reserve basin voltage control area to the test voltage control area decreases toward zero, during the process of computing a V-Q curve in the test voltage control area. The reactive sent to a test voltage control area is closest to zero at a point where the reactive reserves on all generators in that reactive reserve basin voltage control area are exhausted. This is a remarkable result because it infers that if one or more generators in a reactive reserve basin voltage control area exhaust reserves, the rate of supply from the remaining generators in that voltage control area increase to maintain the reactive supply rate to the test voltage control area constant until all reactive reserves in that reactive reserve basin voltage control area exhaust. The exhaustion of all reactive reserves in a voltage control area causes loss of voltage control there.

The exact topological behavior of the remaining generators in a reactive reserve basis will be made more complex by the inclusion of AVR voltage droop, with the possible result of shifting boundaries of the basins.

This loss of voltage control causes voltage decline and an increase in network reactive losses in the neighboring voltage control areas that have no reactive sources and voltage control. Exhaustion of reactive reserves causes: 1) loss of reactive supply from that voltage control area; 2) loss of voltage control in that voltage control area; and 3) possibly the most serious consequence, a dramatic increase in network reactive loss rate for any further voltage decline. Each exhaustion of reactive reserves in a reactive reserve basin voltage control area makes the exhaustion of reactive reserves in the next that much easier. Less voltage decline is required due to the increase in network loss rate, resulting from the exhaustion of reactive reserves in a reactive reserve basin voltage control area. Thus, the percentage of voltage control areas in a reactive reserve basin with no reactive reserves after some contingency or operating change is an excellent proximity measure for voltage collapse in the associated voltage collapse region. If the percentage of voltage control areas in a reactive reserve basin that still have reserves is small after a contingency or operating change, the associated voltage collapse region is on the verge of voltage collapse since the rate of increase in reactive losses with voltage decline has increased geometrically with the sequential loss of reactive reserves and voltage control in voltage control areas of a reactive reserve basin. The network reactive loss rate with voltage decline becomes intolerable and uncontrolled at or near the point where all voltage control areas in a reactive reserve basin have exhausted their reactive supply and lost control of voltage.

It should be noted that a line or transformer outage can in some cases effectively disconnect a reactive reserve basin voltage control area from the voltage collapse region it is intended to protect from voltage collapse. In certain of these cases, the reactive reserves in the effectively disconnected voltage control area are still exhausted by the line outage. In other cases, the line outage will prevent the voltage control area that is effectively disconnected from ever exhausting reserves due to operating change or other equipment outages. Recognizing that when nearly all reactive reserve basin voltage control areas have zero reserves is a condition for virtual voltage collapse guarantees that utilizing a percentage of voltage control area proximity measure will accurately assess proximity to loss of voltage control voltage collapse even when line outages prevent exhaustion of reactive reserves in one voltage control area. The accuracy of a percentage of reactive reserve in reactive reserve basins proximity measure for voltage collapse regions containing low voltage buses may also be effected by contingencies that prevent exhaustion of reactive reserves in one of the few voltage control areas in the associated reactive reserve basins.

3.3.3 Method for Assessing Proximity to Voltage Instability

The voltage stability assessment method will identify which voltage collapse regions are insecure and the equipment outages that make each voltage collapse region and its reactive reserve basin vulnerable to voltage collapse. The voltage collapse planning criteria for different utilities can be quite different. Some utilities desire that their system survive all single contingencies, all double generator contingencies, and all generator and line outage combination contingencies given some stressed base case operating condition. Other utilities would state their voltage stability criteria in terms of requiring the system to survive only single contingencies with the possibility that the an important line or generator is unavailable and transfer, loading, and other operating conditions maximally stress the system.

The procedure used to evaluate voltage stability for single and double contingencies is given below:

1. Rank the N worst single line outages for each reactive reserve basin based on the proximity measure chosen;
2. Determine the reactive reserve basins that have p% or greater of its reactive reserves exhausted for one or more of the single line outage contingencies. Find the two largest reactive capacity generator in each of these reactive reserve basins and place them in a generation contingency list. Find all the single line outage contingencies that exhaust p% or more of the reserves in each of these reactive reserve basins and add them to a line outage contingency list. From the line outage and generator outage contingency lists determine a set of all single and double loss of generation contingencies, a set of combination generator and line outage contingencies, and a set of double line outage contingencies to be used in step 3 of the procedure;
3. Rank the N worst contingencies for each of the reactive reserve basin from the sets of single and double contingencies produced in step 2;

The parameters p and N can be selected by the user and N and p may be chosen in a range of N=5 to 10 and p=20 to 50. The ranking establishes which equipment outages that have a power flow solution bring each voltage collapse region closest to voltage collapse. This result establishes which voltage collapse regions are close to experiencing voltage collapse and which voltage regions and associated reactive reserve basins are not close to voltage collapse.

3.3.4 Methodology for Analysis of Voltage Collapse on Outages with No Power Flow Solution

The most valuable unique aspect of the voltage stability assessment is being able to detect which voltage collapse region and associated reactive reserve basin actually causes the voltage collapse that is evidenced when a power flow algorithm does not produce a solution, as well as detecting if the lack of a power flow solution is an algorithmic converge problem and not a problem evidenced as lack of a power flow solution due to clogging (this may be associated with saddle-node bifurcations as discussed in Chapter 2) or loss of control voltage (this may be associated limit-induced bifurcations as discussed in Chapter 2) instability, as indicated by the description of a diagnosis of clogging and loss of control voltage instability problems in the next two subsections. Equipment outages that cannot be established as caused by clogging or loss of voltage stability using these diagnostics can be identified as being due to algorithmic convergence problems. A method for checking whether a lack of solution is due to numerical convergence problems of the solution algorithm is under development.

3.3.4.1 Clogging Voltage Instability

Of double contingencies cases which do not solve, a cause would be clogging voltage collapse in one or more of the voltage collapse regions if: (a) they do not solve even when infinite reactive reserves are provided to every generator in the system; but (b) they do solve if the power flow is reduced on paths to the associated voltage collapse regions. If a single contingencies exhausts at least 50% of the base case reactive reserves in the associated reactive reserve basin, the resulting double contingencies should thus exhaust reactive reserves in the reactive reserve basin. The voltage collapse is due to clogging because the power flow still does not obtain solutions when the generator reactive supply limits are ignored and thus loss of voltage control and reactive supply on generators in these reactive reserve basins cannot be the cause of the lack of power flow solution. Reducing power flow on paths with large reactive losses and voltage decline into the appropriate voltage collapse region allows a power flow solution to be obtained. This result indicates that the cause of the lack of a power flow solution is due to a clogging voltage instability. Similarly, other double contingencies can cause voltage collapse because: (a) the single contingency components of these contingencies almost exhaust all the reactive reserves in the reactive reserve basin; (b) the double contingencies do not solve when all generators have infinite reactive capacity; and (c) the reduction of flow on paths where there is significant reactive loss and voltage drop allows the power flow to obtain a solution.

3.3.4.2 Loss of Voltage Control Instability

Of double contingencies simulated which do not solve, some will be associated with loss of voltage control instability. Some contingencies that experience loss of voltage control instability will solve when the generators were provided with infinite reactive generation capacity. Reactive reserves for each generator is computed by subtracting the reactive generation from the continuous rating reactive capacity for each of the generators in the reactive reserve basin. The reactive reserves for a reactive reserve basin is then simply the sum of the reactive reserves of all generators in a reactive reserve basin. If a generator is simulated with infinite reactive capacity, its reactive reserves are negative if it produced more reactive generation than its reactive capacity due to having infinite capacity in the power flow simulation but not in the calculation of its reactive reserves. The simulation of contingencies using infinite reactive capacity for every generator allows determination of the reactive reserve basin that actually caused the voltage collapse.

Results suggest that postmortems using a best last iteration are not effective in establishing the cause of the voltage collapse. Using an infinite reactive supply on all generators in a utility is also not a totally effective postmortem analysis because several generators not in the reactive reserve basin causing the voltage collapse can exceed their continuous ratings limits. Finding the generators in the reactive reserve basin that actually causes the voltage collapse may be impossible without knowing that such a structural cause of voltage instability exists since one may not even try to perform the exhaustive search of all combinations of generators that have negative reactive reserves with negative reserves when all generators have infinite reactive capacity. Determining the combination of generators that are most effective in preventing voltage collapse may not be a single reactive reserve basin if the contingency causes voltage collapse in different nested reactive reserve basins.

3.3.5 Summary

Voltage stability assessment requires determination of (1) the parameters and a stress test that establishes the structural cause of voltage collapse in each subregion (exhaustion of reactive reserves in a reactive reserve basin); (2) a method of identifying each subregion (voltage collapse region) that has a unique voltage collapse problem; and (3) a measure of proximity to voltage collapse for each subregion (a measure of reactive reserves or voltage control areas with zero reserves in the reactive reserve basin). This technique identifies the voltage collapse regions that are most vulnerable to voltage instability and the single and double contingencies that make each voltage collapse region either experience voltage instability or come closest to experiencing voltage instability. The ability to diagnose whether a lack of power flow solution is due to voltage instability, whether it is a clogging or loss of control voltage instability, the voltage collapse region that experiences and causes it, and whether additional reactive reserves in the reactive reserve basin or reduction of loading or transfer will prevent it, are unique aspects of this voltage stability assessment.

The method is comprehensive in determining (1) every possible region where a unique voltage instability can occur in a particular utility and (2) all single and double equipment outage contingencies that can cause voltage instability in a voltage collapse region or make that voltage collapse region come closest to voltage instability. The fact that the voltage collapse regions identified as experiencing clogging or loss of control voltage instability for equipment outages do not have a solution, are the same voltage collapse regions where equipment outages that have a power flow solution almost exhaust all reactive reserves gives confidence the methodology is correctly identifying location and cause of voltage instability. The second major advantage of the method is that it is fast since it needs to only simulate slightly more than N contingencies for an N element system using the procedure described rather than N(N-1)\2+N that is required if all single and double contingencies are simulated. The third major advantage is that the proximity measure of reactive reserves in a reactive reserve basin is not only an accurate proximity measure but also a diagnostic for why voltage collapse occurs in a voltage collapse region. This diagnostic can indicate *why* (exhaustion of reactive reserves and voltage control on all generator, synchronous condensers, and SVCs in a reactive reserve basin), *where* (voltage collapse region), and *what to do about the voltage instability* (increase reactive reserves in the reactive reserve basin through unit commitment, change of voltage set points on generators, SVCs, under load tap-changers, and switchable shunt capacitors). Reactive reserves on all generators in a system is well understood to be an excellent proximity measure and yet maximizing reactive reserves as an operational optimization measure often would drive the system into voltage instability by robbing reserves from generators that need it to provide it to generators that did not need it. Reactive reserves on all generators in a system was used as a contingency ranking measure and again would rank contingencies that cause voltage collapse as secure or rank contingencies that gave no threat to voltage stability as severe. Thus, the measure of reactive reserves in a reactive reserve basin is conceptually attractive since it has been associated by engineers and operators as a security measure, is easy to compute, and now restricted to specific generators in a reactive reserve basin has the accuracy and diagnostic properties that were

long associated with it when it was not restricted to generators in a reactive reserve basin but included all the generators in a system or utility.
The voltage stability assessment can identify sub-regions that are vulnerable to loss of voltage control and others that are due clogging voltage instability. There has been no clear differentiation even though industry related documents such as [11] clearly are dealing with loss of voltage control instability. On the other hand many papers on the subject of voltage instability and some utility engineers consider that there is only one type of voltage instability; i.e., clogging voltage instability. Furthermore, sensitivity based voltage stability assessment tools have often ignored the effects of loss of voltage control if they only evaluate the sensitivity measure at one operating point and not after every loss of voltage control. Sensitivity methods can not predict the occurrence of the next loss of voltage control and its effects for loss of voltage control instability when loss of voltage control and its effects are the major cause of this type of voltage instability.

3.4 DETERMINATION OF REMEDIAL MEASURES

In cases for which system voltage stability criterion is not satisfied, remedial measures have to be designed to enhance the system to meet the criterion.

Many different remedial measures can be applied to enhance system voltage stability. Also, different parts of the system (generation, transmission, distribution, and load systems) can be enhanced to improve overall system voltage stability. The practicability and availability of each option depends on each particular system. Some of the possible preventative and corrective remedial measures include active power control, series and shunt reactive compensation, undervoltage load shedding, ULTC blocking, and distribution automation.

For cases in which the VS margin criterion is not satisfied, modal analysis has been used to identify the best location for applying remedial measures. Modal analysis [30] calculates the smallest eigenvalues of the reduced QV Jacobian matrix (J_R) and the bus, branch, and generator participation factors. The smallest eigenvalue and its associated eigenvectors of J_R at the nose of the PV curve define the critical mode of voltage stability. The corresponding bus, branch, and generator participations identify the voltage stability critical area and the elements that have large impact on the voltage stability of this critical mode. The remedial measures should be applied at locations identified by these participations so as to enhance the voltage stability of the critical area and mitigate the negative impact of these elements on system voltage stability. Other techniques, including a variety of sensitivity analyses and more conventional optimization algorithms (e.g., OPF) have also been used successfully to identify locations for application of remedial measures [39]-[41].

3.4.1 Shunt Compensation

3.4.1.1 Shunt Capacitors

It is well understood that application of shunt capacitors increases the maximum transfer capability across power systems. This fact has been exploited by utilities for many years.

For systems with little to moderate amounts of compensation, the addition of shunt capacitors is a very cost effective means of enhancing power flow. The applicability of mechanically switched shunt capacitors (MSCs) as a countermeasure for voltage collapse is primarily dependent on the relative strength of the power system and the amount of shunt compensation in service. Typically, the minimum strength (i.e., the post-contingency condition) will be the limiting factor.

Figure 3.4-1 shows the familiar P-V curves for a radial system, with progressively larger amounts of shunt compensation applied. Each successive curve (to the right) represents the addition of another capacitor of the same size. If we consider a normal deviation of say ±5% on the operating voltages, then it is clear that adding the first few shunt capacitors results in substantially increased power transfer, while maintaining a reasonable voltage. However, as more shunt capacitors are added the system becomes progressively ill-mannered. A number of aspects of this are apparent. Firstly, the increase in power per unit capacitor at nominal voltage declines somewhat. Secondly, and more importantly, the sensitivity of voltage to changes in power increases. The point of maximum power transfer (the end of the nose) also corresponds to the point of infinite voltage sensitivity to changes in power. It is generally considered (at least) ill-advised for this *critical voltage* to be within the range of normal operating voltages.

The amount of change in voltage associated with switching a capacitor bank (as indicated by the vertical distance between the curves in Figure 3.4-1) will frequently dictate the largest size capacitor that can be switched. As the system becomes more stressed, the window of acceptable operation for a particular capacitor size gets progressively narrower. At some point frequent switching of small blocks of compensation becomes uneconomical and unreliable. For example, switching of the banks in the region labeled “A” in the figure would result in unacceptably large changes in voltage, whereas switching the same size bank in the region label “B” would be acceptable.

Transient voltage collapse is typically associated with conditions where, due to a system disturbance, particularly loss of a critical transmission line, the system attempts to migrate dynamically between a pre-disturbance P-V characteristic and post-disturbance characteristic unsuccessfully.

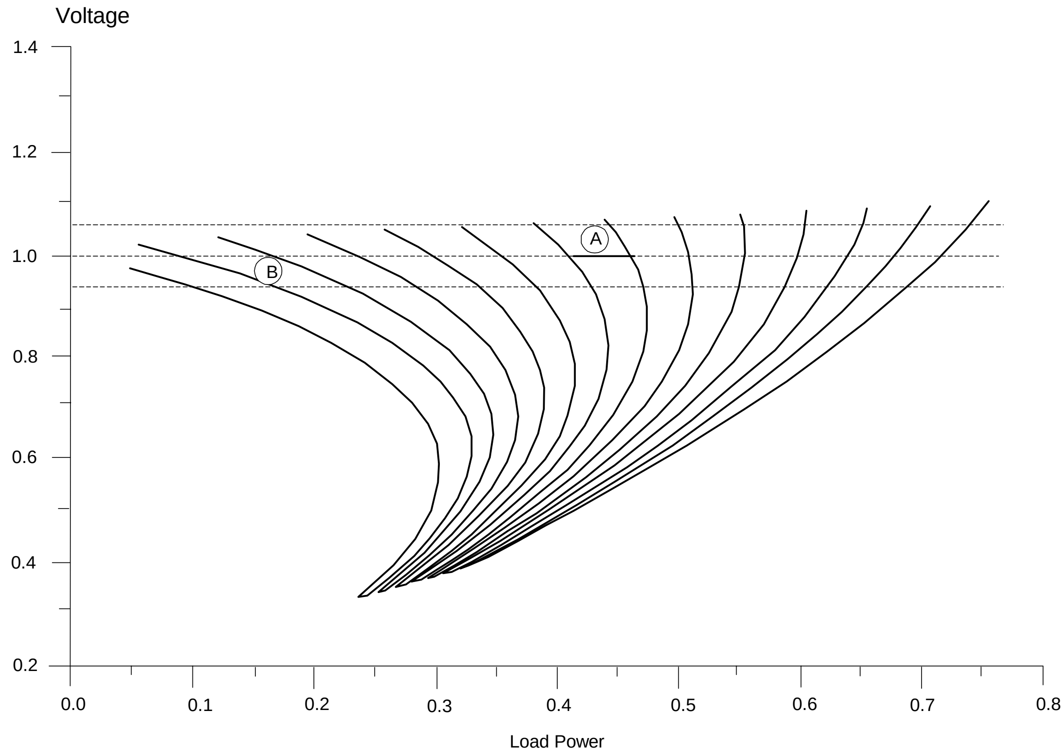

Figure 3.4-1. Effect of increasing shunt compensation on critical voltage.

The immediate or transient (t+) post-disturbance voltage response of the system is primarily dictated by the network topology and the transient voltage dependency of the loads. In this immediate post-contingency time frame, discretely acting equipment such as transformer taps and mechanically switched capacitors will not have time to move. If this post-contingency condition is severe enough to cause immediate system problems, such as wide-spread motor stalling, then some form of very fast acting reactive power control is needed. If the post-contingency condition can be tolerated for a short period of time, perhaps 10 to 20 cycles, fast mechanical switching of capacitors may be an acceptable and economic solution.

The distinction is made here between the low voltage observed at the peak of the first swing of the system electro-mechanical oscillation, and the generally monotonic downward movement of system voltages associated with the movement of the system towards its post-contingency characteristic. For systems subject to severe disturbances and badly degraded post-contingency conditions, this distinction can become blurred. Fortunately, the most effective countermeasures for these very quickly evolving problems tend to be at least similar, if not the same.

3.4.1.2 Static Var Compensation

Static Var Compensators (SVCs) are an option available for mitigation of transient voltage collapse. The ability of SVCs to provide continuously variable susceptance can be viewed as fast switching of capacitors, in arbitrarily small increments. Returning to region “A” in Figure 3.4-1, the continuously variable range of the SVC can be used to very tightly control the system voltage as it transverses between the two adjacent system characteristics. For this simple and highly stressed system, the dynamic range of the SVC must be roughly equal to, or greater than, the change in reactive capability between the adjacent characteristics.

These concepts extend to wider excursions caused by changes in system topology. The tripping of a transmission line might result in the system attempting to cross between two much widely separated characteristics than those shown in Figure 3.4-1. In general, there must be a sufficient amount of fast controllable reactive power available, such as that from an SVC, to allow for smooth voltage regulation between the adjacent characteristics. Once an SVC reaches its maximum capacitive susceptance, its performance becomes identical to that of a simple shunt capacitor. Thus, a critical consideration in the application SVCs is to assure that it has sufficient dynamic range during the most critical events. For this reason, it is common practice for utilities with SVCs to implement some type of reactive power runback, so that the other, more slowly acting var sources take over from the SVC after its initial action.

3.4.1.3 Synchronous Condensers

Synchronous condensers have long been used by the utility industry to provide smooth, continuous voltage control. Synchronous condensers have a number of advantages and disadvantages compared to SVCs as a countermeasure for voltage instability.

The synchronous condenser, being essentially the same technology as a synchronous generator, imposes a voltage on the system via the internal flux linkage of the machine. Therefore, transiently, the machine will deliver reactive current to the system roughly in proportion to the change in voltage. As the flux decays, the reactive amperes are dictated by the field current. Action of the machine excitation system can be very fast, but it must work through the field time constant of the machine. This response is relatively slow, compared to an SVC, but unlike an SVC, it has considerable overload capability. The maximum reactive power output of an SVC (or an MSC for that matter) drops off as the square of the terminal voltage. Therefore, under conditions of highest stress (i.e., low voltage) the effectiveness of the SVC is significantly reduced. The reactive current output of the synchronous condenser actually increases with declining voltage. This, combined with the fact that the machine can tolerate high levels of excitation and current for short periods of time, gives the synchronous condenser considerably higher short term output capability compared to an SVC.

3.4.1.4 STATCOM

Recent developments in the gate turn-off thyristors (GTOs) have opened the door for use of these devices to power handling applications approaching those of conventional power thyristors. The use of these self-commutating valves in reactive compensation devices has some interesting potential benefits [30]. The use of a self-commutating converter results in a device that can deliver reactive current to the power system. By use of a voltage controller, the GTO-based device can maintain a voltage regulation characteristic similar to that of an SVC. The GTO-based device is limited by the current carrying capability of the valves, not the maximum susceptance of the capacitor like an SVC. Thus, when the device is in limits, it delivers reactive current, and therefore the vars only drop off linearly with voltage decline, rather than quadratically. Furthermore, the valves have short term current overload capability that can be exploited by the controller. Events that result is severely depressed voltages, for short periods of time, can potentially be handled very effectively by STATCOM. Examples demonstrating relative performance between STATCOM and SVC can be found in [31].

3.4.1.5 Distributed vs. Lumped Compensation

The issue of where to locate and how to size shunt compensation to mitigate voltage collapse is a difficult one. One often quoted truth about vars is that they do not travel far. This tendency of power systems to benefit the most (on a per var basis) from reactive power applied close to where it is consumed, generally favors compensation that is widely distributed, and in relatively smaller chunks. On the other hand, economies of scale for equipment costs tend to favor fewer installations in larger sizes. As systems become more stressed and more highly compensated, utilities may find that for mitigation of voltage collapse, multiple, similarly sized devices produce substantial performance and economic benefits compared to fewer large installations.

3.4.1.6 Hierarchy

There is a hierarchy that is generally utilized when applying shunt compensation. As a general rule, the cost of compensating to provide voltage security for each incremental unit of power increases with loading. The most economic solution for lightly compensated system is usually to add lumps of switchable shunt compensation. As the stress on a system increases, it becomes essential to provide for either finely or continuously controllable reactive power supplies, at least some of which need to be fast. It is an essential feature of any system with a mixture of slow lumped compensation and fast smooth compensation, that the continuously variable vars maintain regulation range. At some point, the stress on a system becomes sufficiently high, that additional shunt compensation of any variety becomes either unstable, uneconomic, or both. At this point (and often well before this point) it becomes necessary to take other steps to strengthen the system.

3.4.2 Series Compensation

3.4.2.1 Conventional Series Capacitors

Series capacitors for improvement of power transfer capability on EHV transmission systems are in widespread use throughout much of North America. Series compensation reduces the effective impedance between generation and load, and between interconnected systems. Unlike shunt capacitors, series compensation has the very desirable characteristic of increasing reactive power generation as load current increases. While the output of shunt capacitors tends to drop just as the system needs the vars the most (i.e., as the voltage sags), the var output of the series capacitor goes up quadratically with current. In this sense, series capacitors are self-regulating and infinitely fast. Under light load conditions, series capacitors will not generally produce unwanted vars, and will more typically help keep overvoltages due to (for example) excessive line charging down.

Another nice feature of series compensation is that by reducing the effective impedance across a transmission corridor, the angle differential required to satisfy a given level of transfer is reduced. This has two benefits. First, interarea power flows will tend to load up on compensated lines relative to parallel and underlying uncompensated lines. Second, this tends to improve the transient stability of the system.

The production of vars by the series compensation, under heavy load conditions counters the consumption of vars by the line impedance. This substantially reduces the requirement for additional vars from shunt sources. From a transient voltage stability perspective, consider an example where there is a parallel pair of EHV lines 300 miles long. Suppose further, that the desired transfer on the pair of lines is about 1.5 times surge impedance loading (approximately, 1500 MW each for 500 kV). This would be quite sustainable without any series capacitors. It would only require a small amount of additional reactive power to hold an acceptable voltage profile (about 500 MVAr each for 500 kV). However, if this double circuit represents the main corridor of the system, then loss of one circuit may present a very serious voltage stability problem. In order to carry all of this power on one circuit without series compensation, over 3 x SIL (3000 MVAr) in MVAr of shunt compensation would be required to maintain an acceptable voltage. Furthermore, the angle across the line would be over 90°. This means that the reactive power source at the mid-point of the line (at least) would need to be active (e.g., an SVC) in order to maintain stability. Furthermore, (even ignoring the transient swing for this discussion), the very large angle across the line means that other parallel lines would tend to pick up some of the load. If the parallel lines lack the capacity to carry this incremental loading, there is substantial potential for voltage collapse or other cascading failure. If we consider the same problem, with the line (say) 60% compensated, the post-disturbance requirements become more tractable. Roughly, 1 SIL MVAr of shunt compensation will trim the voltage to 1.0 pu, and the resultant angle across the line will be about 35°. Series compensation has been successfully applied in voltage ranges from distribution systems up to 735 kV.

3.4.2.2 Thyristor Controlled Series Compensation

Thyristor controlled series compensation (TCSC) is one of the new Flexible AC Transmission Systems (FACTS) technologies [32]. Functionally, a TCSC appears to the system as a continuously variable series capacitor. The response rate of the TCSC is extremely fast and the device has considerable short term overload capability. The benefits of conventional series compensation for voltage stability improvement are enhanced by the controllability of the TCSC. A TCSC may be capable of delivering two times its steady-state rated capacitive Ohms, at rated line current, for short periods of time. The combination of being able to instantly control the series impedance of the capacitor, and to utilize considerable short-term overload capability, make TCSC an attractive potential countermeasure to both transient and longer time scale voltage collapse.

Subsynchronous resonance and associated turbine-generator torsional interactions are an application limitation for many conventional series compensated transmission projects. Therefore, the ability of a TCSC to avoid SSR is one of its most important performance attributes. This permits higher levels of compensation in networks where interaction with turbine-generator torsional vibrations or with other control or measuring systems are of concern.

3.4.2.3 Unified Power Flow Controller

Unified Power Flow Controller (UPFC) is a new FACTS technology that comprises shunt and series control elements. The controller is basically made out of two voltage-sourced converters (VSC) with semiconductor devices having turn-off capability, sharing a common dc capacitor and connected to a power system through coupling transformers. The basic UPFC structure is depicted in Figure 3.4-2. This figure represents both pulse-width modulation (PWM) and "phase" control strategies.

The main objective of the series converter is to produce an ac voltage of controllable magnitude and phase angle, and inject this voltage at fundamental frequency into the transmission line, exchanging real and reactive power at its ac terminals through the series connected transformer. The shunt converter provides the required real power at the dc terminals; thus, real power flows between the controller shunt and series ac terminals through the common dc link. The reactive power is generated/absorbed independently by each converter and does not flow through the dc link [32], [33]. These control characteristics allow the use of the UPFC in a series of applications in voltage and angle stability. For example, system voltage stability can be improved by utilizing the shunt controller for local voltage control, whereas the series controller can be used to increase the transmission capability of the network.

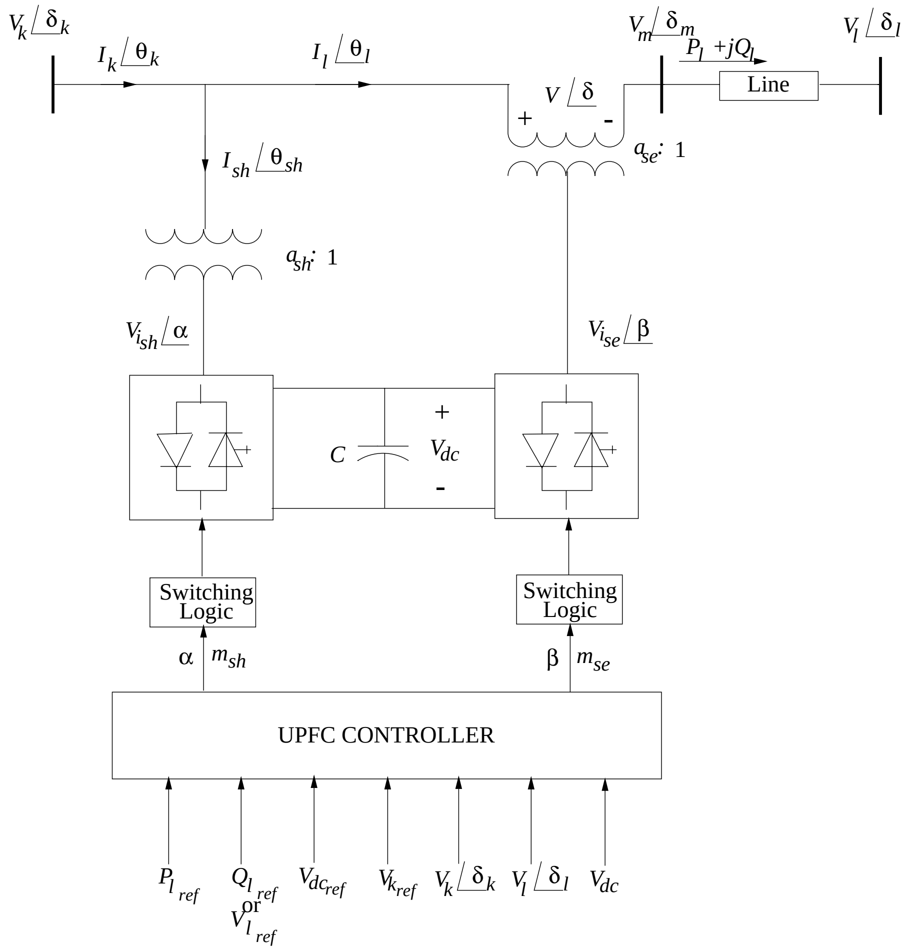

Figure 3.4-2. UPFC functional model.

3.4.3 Undervoltage Load-Shedding

For many utilities, the conditions that may lead to voltage collapse are relatively unusual, possibly being caused by second order contingencies, or only under conditions of unusual load stress. For these utilities, the hardware required to reduce the system's vulnerability to voltage collapse may be too expensive to justify. Since voltage collapse has a tendency to start as a somewhat localized phenomenon, the potential to prevent the spread of the collapse and limit the number of affected customers by load shedding has considerable appeal. A number of utilities around the world have instituted undervoltage load shedding (UVLS) for this purpose [11], [35].

There are a number of technical issues and engineering trade-offs to be considered in the design and application of UVLS, particularly in selecting the settings for these devices. The case described in section 3.2.8.1, and illustrated in Figure 3.2-17, shows the potential benefit of UVLS for system stabilization, as the system can be brought within desired voltage operating ranges by reducing the load power when the voltage decreases below a given threshold, reducing system "stress" and hence improving system stability.

3.5 CASE STUDIES

3.5.1 Hydro-Quebec Example

Blocking of dc line (±450 kV) between James Bay and the HQ load area under a transfer of 2250 MW is a severe contingency based on the reactive power demand. The dc line is operated in parallel with HQ ac system. When blocked, all the power is then transferred on the ac system causing a large reactive power demand. Reactive power mainly comes from SVCs and SCs, as power plants are located on both ends and hence cannot contribute much reactive power. Slow automatic systems such as switchable reactors will act in order to supply remaining needs due to load recovery. As shown in Figure 3.7-1, this contingency is transiently stable. The system needs to switch off shunt reactors to recover to nominal voltage when load is restored by tap-changing transformers; load may be also restored by increasing the voltage.

In this simulated example all loads were assumed to be in service. However, in practice, during severe contingencies, undervoltage relays would switch off industrial loads, among other things, which relieves the stress on the system.

3.5.2 Published Case Studies

Reference [30] describes details of voltage stability studies of four practical systems using VSTAB and ETMSP in a complementary manner for static and dynamic analyses. The voltage stability margins for all contingencies are calculated by VSTAB and the margins of critical contingencies are verified by ETMSP. Modal analysis of VSTAB is used to find the best place for adding an SVC in order to increase the VS margin of the critical contingency.

Stability problems in the WSCC system are discussed in detailed in references [36]-[38]. The events of July 2, 1996 have been determined to be voltage stability problems, whereas the events of August 10, 1996 are considered to be angle stability problems triggered by a lack of voltage support.

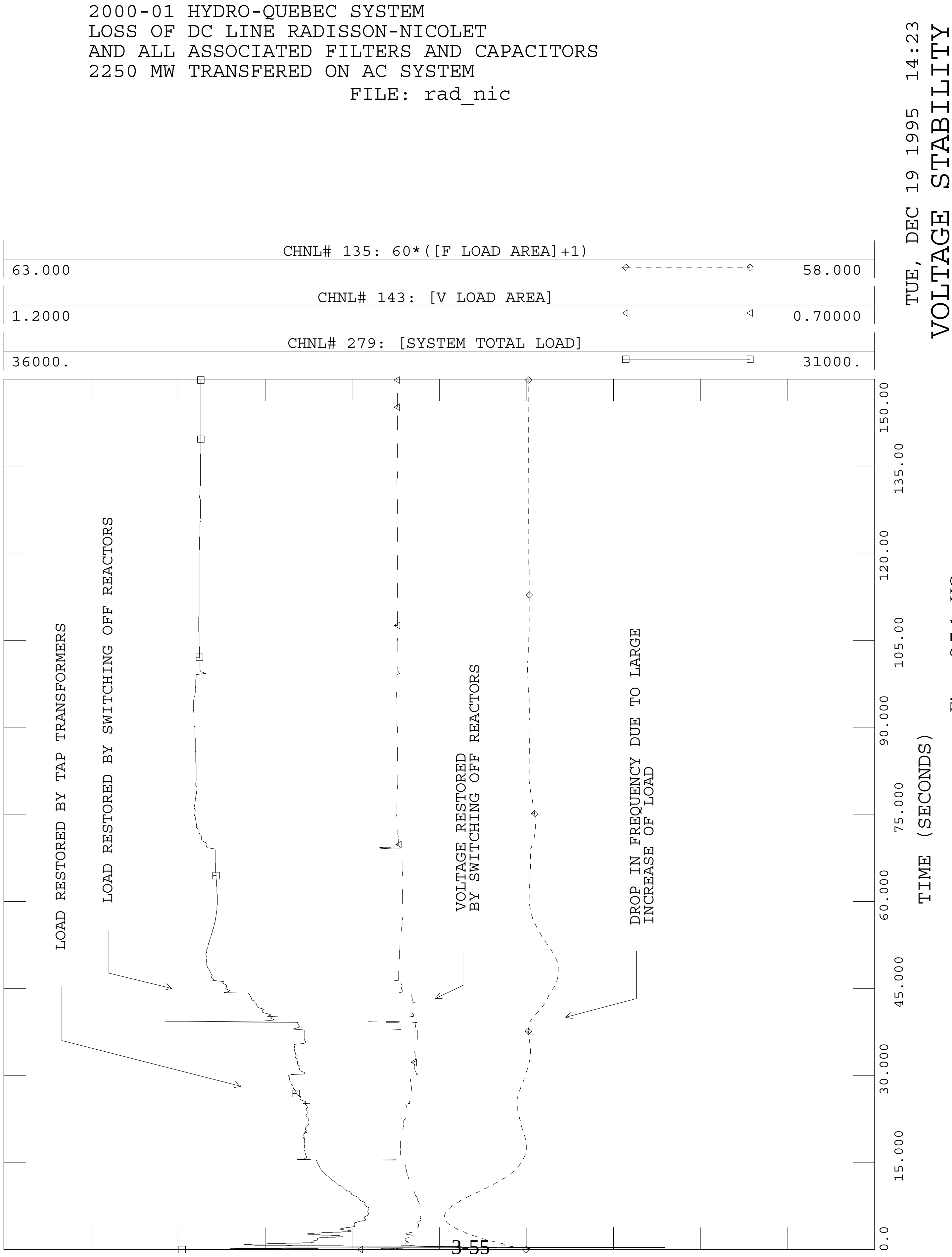

Figure 3.7-1. HQ case.

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