LOAD CURTAILMENT ON ISOLATED POWER SYSTEMS

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by

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Abstract

This thesis concerns the design and application of load curtailment schemes to isolated power systems. Load curtailment or loadshedding is a methodology employed to relieve a power system of a severe overload and restore nominal system operation through reduction of total system load. An overload on a power system may be detrimental to the continued stability of the system especially during operation with inadequate reserves. The PSS/E software package is utilized to simulate the system voltages and frequency during underfrequency and undervoltage events.

The general loadshedding methodology developed is to shed increasing amounts of load from the power system in response to increasingly severe contingencies. These contingencies, such as the loss of a major transmission line or generator, may negatively impact the frequency and voltage stability of the power system and load curtailment is presented as an effective mitigating action. The developed methodology is first applied to a simple test system to demonstrate the necessity and effectiveness of loadshedding as a remedial action following extreme operating contingencies. Subsequently, the methodology is applied to the interconnected system of the island of Newfoundland. This system operates at a maximum transmission voltage of 230 kV and has approximately 8500 MJ of connected inertia at peak operating capacity.

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List of Abbreviations and Symbols

UFLS	: Underfrequency Loadshedding
UVLS	: Undervoltage Loadshedding
PSS/E	: Shaw Technologies Power Simulator
SPS	: Special Protection System
P-V	: Power – Voltage
AGC	: Automatic Generation Control
AVR	: Automatic Voltage Regulator
df/dt	: Rate of Change of Frequency
MJ	: Megajoule
COI	: Centre of Inertia
MVAr	: Mega VAr
BDE1	: Bay d'espoir generator 1
BDE2	: Bay d'espoir generator 2
BDE3	: Bay d'espoir generator 3
BDE4	: Bay d'espoir generator 4
BDE5	: Bay d'espoir generator 5
BDE6	: Bay d'espoir generator 6
BDE7	: Bay d'espoir generator 7
HRD1	: Holyrood generator 1

HRD2	: Holyrood generator 2
HRD3	: Holyrood generator 3
CAT1:	Cat Arm generator 1
CAT2	: Cat Arm generator 2
USL	: Upper Salmon generator
HLK	: Hind's Lake generator
PRV	: Paradise River generator
SVL	: Stephenville
GT	: Gas turbine
SC	: Synchronous condenser
DLP	: Deer Lake Power
SLK	: Star Lake
RBK	: Rattle Brook
LOU	: Largest Online Unit
Ld	: Quantity of loadshed
HWDCB1	: Hardwoods Capacitor Bank 1
HWDCB2	: Hardwoods Capacitor Bank 2
OPDCB1	: Oxen Pond Capacitor Bank 1
OPDCB2	: Oxen Pond Capacitor Bank 2
LHRCB1	: Long Harbour Capacitor Bank 1
OLTC	: On-Load Tap Changer
O/S	: Overshed

Chapter 1

Introduction

1.1 Power System Stability

The reliable generation and transmission of electricity is fundamental for the modern power utility. To this end, system designers and operators must ensure that there are adequate reserves of active and reactive capacity available to meet load variations and operating contingencies. These requirements are achieved by constant monitoring of system variables through a sophisticated network of controls and through adequate system design with respect to the location and availability of active and reactive power reserves. The effective and safe utilization of electric power requires that electricity be delivered to consumers at nominal operating values for voltage and frequency.

The maintenance of power quality is complicated by disturbances that occur regularly on the power system and may range from continual changes in customer load to the sudden failure of a system component or element. The severity of these disturbances will determine the appropriate countermeasures necessary to maintain power quality and ensure continued system stability. Some of the options available to preserve system stability following extreme operating contingencies are underfrequency loadshedding (UFLS) and undervoltage loadshedding (UVLS).

The stability of a power system may be defined as:

"Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact" [1].

This definition requires that most of the power system return to stable and reliable operation following any disturbance or contingency. A disturbance or contingency may be the result of a change in loading, a fault on the system or an equipment malfunction. For example, a lightning discharge to a transmission line will cause a significant change in the energy transmitted by the line and requires appropriate countermeasures to isolate the affected portion of the system to prevent equipment damage and maintain system stability. These countermeasures will ensure that the energy associated with the lightning strike is safely dissipated and is usually accomplished through the operation of protective relaying and circuit breakers. Once the protective relay operates and the circuit breaker is opened, the network topology is altered and the system must adapt to the new operating condition with voltage and frequency at all points within the system remaining within normal limits. As per definition [1], the system is said to be stable if, despite the loss of a transmission line or similar contingency, the system remains intact with most variables bounded within normal operating limits.

An overload on a power system may result in significant variation in the nominal voltage and frequency and may have a detrimental effect on system stability. One possible method to remove the overload and to restore nominal operating values is to initiate a process of automatic load curtailment through UFLS or UVLS and is the subject of the current thesis. The processes are considered separately and are initiated following a period of overload on the system. An excess of load to available generation will result in a less than nominal system frequency whereas system operation with inadequate reactive reserves will result in less than nominal voltage during an overload.

There are five operating states that represent different levels of security for the power system; these are: normal, alert, emergency, in extremis, and restorative. Figure 1.1 provides a summary of the operating states as well as the possible transitions that may occur to move a power system from one operating state to another [2].

While a power system is operating in the normal state, there is a continuous balance between generation and load and all currents and voltages remain at nominal values on the system. The normal operating state may be further sub-divided into the secure and insecure states. While in the secure state, the system has adequate reserve margins on generation and transmission capacity to tolerate the loss of a major system element (an N-1 contingency) whereas in the insecure operating state an N-1 contingency may result in system instability.

The alert state occurs when the power system is insecure but still operating normally and may be in danger of passing to the emergency or in extremis states due to depleted operating reserves. Transition to either the emergency or in extremis states may result following a moderate operating contingency while transition to the in extremis state is the result of a severe contingency. The system will move from the alert state back to the normal state if additional reserves become available through either synchronizing additional generation or by switching additional reactive sources into the circuit.

During the emergency state, system elements will be overloaded and the voltage may fall below acceptable stability limits at some of the system buses. Corrective actions, such as the clearing of system faults through breaker operation, adjustment of field excitation current on generators or the reduction of system load through loadshedding will move the system to a more secure operating condition.

While operating in the in extremis state, the balance between generation and load is compromised and the system will be operating with other than nominal voltages and currents. Cascading outages are possible during this time and only extreme corrective measures, such as out of step tripping or load curtailment will prevent a total system collapse.

During the restorative time frame, the system is being reconstructed and may pass to either the alert state or the normal state depending on the corrective actions taken while in the in extremis or emergency states [2, 3, 4].

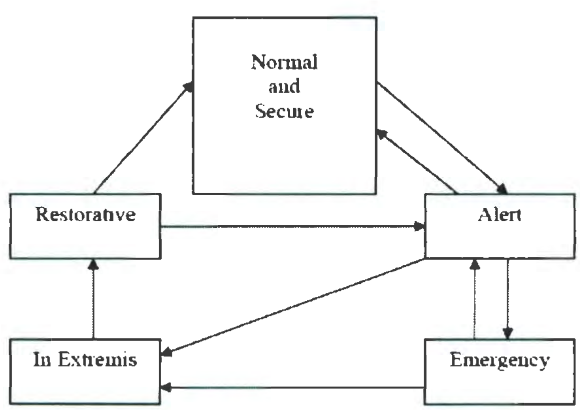

Figure 1.1: Operating States of a Power System [2]

1.2 Aim of the Thesis

A load curtailment methodology is developed and first applied to a simplified test system to demonstrate the viability of UFLS and UVLS following severe operating contingencies. Subsequently, the methodology is applied to the interconnected island system of Newfoundland to compensate for severe operating contingencies and to minimize service interruptions. The results obtained for several different operating scenarios are used to determine the more optimum loadshedding schedules.

The application of load curtailment to preserve or restore system frequency or voltage stability must be undertaken in a decisive manner once it is determined that instability is present on the power system. Such instability will typically be manifested as a depressed voltage or frequency and is more likely to occur on systems that have inadequate active and reactive reserves capabilities. A load curtailment strategy is particularly relevant for isolated power systems that may be constrained to operate with minimum reserves due to economic or operational reasons.

Numerous authors have investigated the design and application of UFLS and UVLS schemes and it is the prevalence and necessity of such schemes which makes them compelling as areas of study [6, 8, 10, 12, 15, 19, 20, 23, 26, 29, 30, 32]. The design of a loadshedding scheme must primarily ensure that system stability is maintained but should also be constrained by the magnitude of the resulting service interruptions since continuity of service is actively sought after by practically all utilities.

1.3 Organization of the Thesis

Chapter 2 of this thesis discusses the general aspects of power system stability including consideration of the operating states of the power system during system emergencies, and the general aspects of rotor angle, frequency and voltage stability.

Chapter 3 of this thesis focuses on power system protection, in particular, the protective systems that are used to detect power system overloads and their modes of operation. Consideration is given to the methodology employed in the development of Special Protection Systems (i.e. SPS), such as UFLS or UVLS, for general system protection.

Chapter 4 expands the conventional methodology associated with load curtailment during underfrequency events as relates to isolated power systems. Some of the variables considered are the total amount of load assigned to a particular UFLS schedule, the number of loadshedding stages, and the determination of the frequency tripping thresholds.

Chapter 5 presents the conventional methodology concerned with undervoltage loadshedding during periods of depressed system voltages. The variables associated with UVLS are discussed and include the total amount of loadshed during undervoltage events, the location of loadshedding and the time delays required for operation of UVLS schemes.

Chapter 6 contains the application of the load curtailment methodologies contained in chapter 4 and chapter 5 to a simple test system. The necessity and effect of a load curtailment scheme is presented and discussed.

Chapter 7 contains a description of the Newfoundland island interconnected system and presents the application of the load curtailment methodology developed in chapter 4 to the island system. The generation dispatch scenarios employed during the evaluation of the underfrequency loadshedding schedules and the results obtained for the underfrequency case are presented and discussed. The chapter concludes with a recommendation for an UFLS schedule.

Chapter 8 contains the application of the undervoltage methodology presented in chapter 5 to the Newfoundland island system. The results obtained for the undervoltage case are presented and discussed. The chapter concludes with a recommendation for an UVLS schedule

In Chapter 9, the thesis summary is presented and highlights the contribution of the present research and suggestions for future work.

Chapter 2

Power System Stability

2.1 Introduction

The purpose of an electric power system is to provide a means for the transformation and transmission of energy. The energy may be transmitted over significant distances to areas of consumption where it is retransformed to heat, light or motion. An electrical power system has several essential components that enable the production and distribution of electrical energy to consumers. Some of these components are generators, transformers, transmission lines and circuit breakers. Other essential power system components are compensation devices (for voltage control), revenue metering and protective relaying.

An electrical system can be comprised of only a few of the above-mentioned elements and can be relatively simple with a simple system requiring only a generator and a load. Modern power systems, such as the North American power system, are much more involved and can have several thousand generators, transformers and transmission lines providing energy to millions of customers at controlled voltages and frequency. Load curtailment strategies may be required to maintain system stability if voltages and frequency diverge significantly from normal operating values.

2.2 Electric Power System Operation

Figure 2.1 depicts the power transfer between the sending and receiving sections of a simple two-bus system. In general, the power angle and the bus voltages control the flow of active power with the power angle being the dominant indicator of power flow. Inspection of equation 2.1 reveals that when the power (or torque) angle is zero there will be zero active power flow between the sending and receiving ends of a transmission line regardless of the voltage magnitude. Similarly, a relative increase in the bus voltages will alter the flow of active power between the sending and receiving ends of the transmission line for any value of power angle (other than zero). Further, the power angle and voltage magnitude can be varied independently during normal operation. Inspection of equation 2.2 reveals that the flow of reactive power is determined mainly by the relative voltage magnitudes between sending and receiving ends of the line with the power angle being a secondary indicator of reactive power flow. The result is that reactive power will flow from a region of greater voltage to a region of lesser voltage. The magnitude of the transmission line impedance limits both the flow of active and reactive power in electrical systems [2].

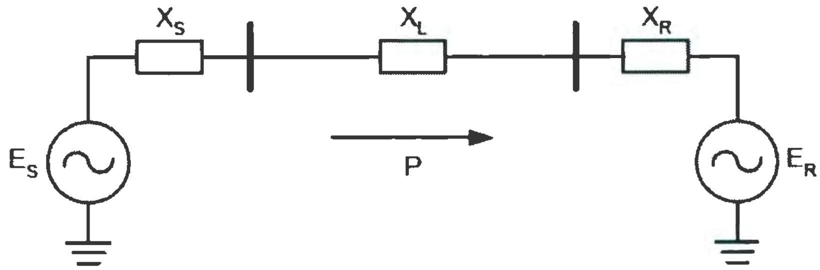

Figure 2.1: Representation of a two-bus power system

$$P_R = \frac{E_R\, E_S\, \sin\delta}{X} \tag{2.1}$$

$$Q_R = \frac{E_S E_R \cos\delta}{X} - \frac{E_R^2}{X} \tag{2.2}$$

with P_R representing the receiving end active power (pu), Q_R representing the receiving end reactive power (pu), E_R representing the receiving end voltage (pu), E_S representing the sending end voltage (pu), X representing the reactance between E_R and E_S and δ representing the angular difference E_S and E_R.

Reactive and active power losses, primarily due to transmission line impedance, have a significant effect on the manner in which the system is operated. It is ideal that power systems operate without a voltage gradient between the sending and receiving sections and that reactive power be supplied to load buses by local sources [3]. An increased voltage gradient implies increased reactive flow resulting in increased line losses, reduced transmission capacity and reduced operating efficiency. The limitation on the flow of reactive power in an electrical system results from the inductance of transmission lines and is proportional to the square of the current flowing in the transmission line. For this reason, the voltage gradient between the sending and receiving ends of a transmission line will usually not exceed 5% of nominal during normal power system operation [4]. The losses associated with the resistance of the line elements are usually neglected since their effect is minimal when compared to the corresponding line reactance.

2.3 Classifications of System Stability

The stability of any system may be generally characterized as the ability of the system to reestablish equilibrium following any disturbance. With respect to modern power systems, this general definition of stability is subdivided to include rotor angle stability, voltage stability and frequency stability as shown is Figure 2.2. Rotor angle stability relates to the dynamics of rotor oscillations and the effect these oscillations have on the machine power angles and generation capacity whereas voltage and frequency stability refer to the ability of the system to maintain acceptable voltages and frequencies on the system following a disturbance. As already stated, modern power systems have a number of sophisticated controls and protective devices designed to ensure that the system response to disturbances is controlled and predictable. These disturbances may range from a short circuit on a transmission line or an element fault to a load change on the system.

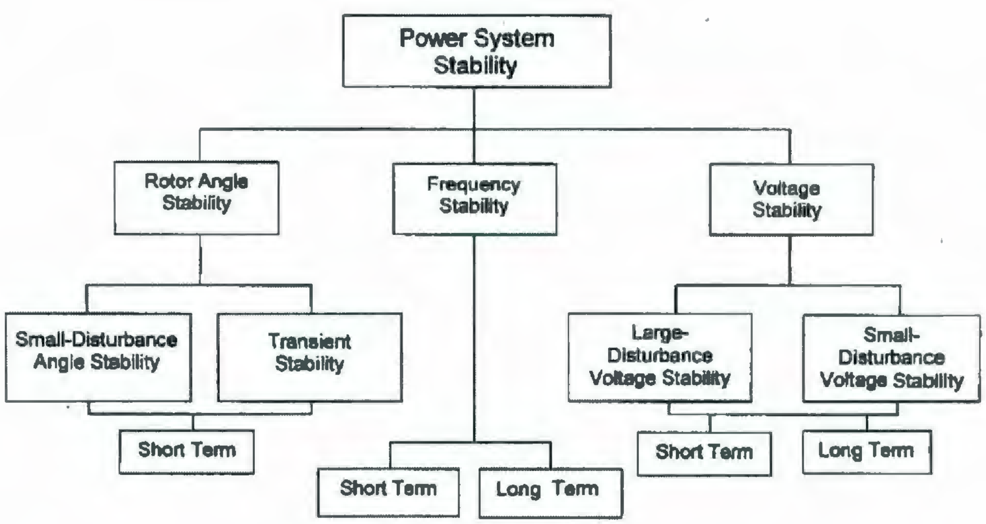

Figure 2.2: Classifications of power system instability [1]

When the system is operating in a steady state condition, there is a balance between power generated and power consumed. However, the equilibrium of the system may be compromised when the system is perturbed or acted upon by an external disturbance. If the disturbance is sufficient to significantly alter the active or reactive power balance, the system may change to an unstable operating condition. If unstable operation continues, the system may collapse and undergo a complete failure.

Rotor angle instability, frequency instability or voltage instability can occur separately or simultaneously. In general, a system may experience voltage instability without experiencing frequency instability whereas frequency instability will affect the voltage and generator rotor angles. These effects are all concurrent but it is usually not necessary to consider them together in the context of the stability problem since each disturbance on the system will typically involve only a limited part of the system and may predominately affect a single aspect of stability. For these reasons, it is often convenient to consider only the affected elements of the system and the effects these elements have on a particular aspect of system stability [4].

During a disturbance, the speed of some machines will increase with respect to others both in the short term, as transient oscillations, and in the longer term as an increase or decrease in rotational velocity. The effect of a speed increase is to cause those machines, which are accelerated, to produce more power than those machines operating at a reduced speed. The effect of this power redistribution among the machines (i.e. generators) is to reduce the speed of the faster machines and increase the speed of the slower machines. The transfer of energy from faster to slower machines is the principal mechanism by which transient oscillations are damped and enables the power system to return to a state of equilibrium [2]. Other system elements that contribute to the damping of oscillations are the generator prime movers, load characteristics, speed governors, AVRs, and the optimum usage of the fast reactive reserves from the system generators [5].

Figure 2.3 depicts the time frames and system elements that are affected by instability. To summarize, generator exciters, induction motors, static VAr compensators and high voltage DC transmission lines are the equipment types that are affected in the transient time frame of system instability (less than 10 seconds). Longer-term instability (10 seconds to several minutes) generally affects load tap changers, generator governors, and thermal plant boilers. Note that protective relaying associated with underfrequency loadshedding (UFLS) and undervoltage loadshedding (UVLS) may function during any time frame but is usually operational over the longer term.

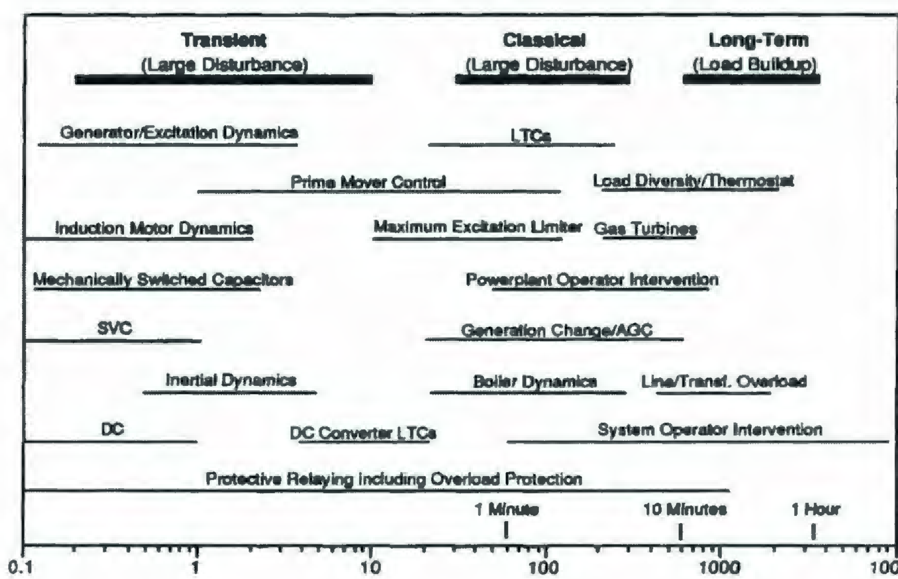

Figure 2.3: Equipment and time frames of system instability [6]

The distinction between the short term and long term time frames is not absolute. In general, the short-term time frame spans the first 10 seconds of an event whereas the longer-term time frame will typically exist for 10 seconds to 60 minutes. Control events that were initiated in the short-term time frame may endure into the long-term frame and the distinction depends on the duration of the event and the type of equipment that responds to or is affected by an event. For example, longer-term problems may be largely related to on-load tap changers, AGC (i.e. automatic generation control) or other "slower devices" whereas short-term stability issues usually involve generator field current or the rotational dynamics of generators and loads [5]. The events of primary interest in this thesis are the longer-term problems associated with frequency stability and voltage stability. In general, frequency stability relates to the active power balance between generation and load and is independent of network structure whereas voltage stability relates to the reactive power balance between reactive sources and loads and is dependent upon network structure.

2.3.1 Rotor Angle Stability

Rotor angle stability is a short-term phenomenon and concerns the ability of generators to remain in synchronism following a disturbance. The electromechanical dynamics of rotor oscillations following a disturbance is of primary interest and includes the ability of the system to damp these oscillations and return the rotor and system to a stable and non-oscillatory operating state.

Equation 2.3 is known as the "swing equation" and describes the electro-mechanical oscillations of a synchronous machine rotor following a disturbance. This expression is used in stability studies to model the motion of machine rotors for disturbances on the power system. A power system containing (N) generators could be modeled with (N) swing equations and the determination of the system dynamics requires the simultaneous solution of the set of swing equations [3].

$$J\frac{d^2\delta_m}{dt^2} = T_a = T_m - T_e \tag{2.3}$$

with J representing the total moment of inertia of the rotor masses, T_a representing the net accelerating torque, T_e representing the electrical torque, T_m representing the mechanical torque and δ_m representing the angular displacement of the rotor in mechanical radians

Rotor angle stability is subdivided based on time duration into (1) small signal or small disturbance rotor stability and (2) transient rotor stability. Whether the rotor instability is small signal or transient in nature depends on the severity of the initiating disturbance. Small disturbances (or perturbations) result in small signal instability and manifest themselves, on stable systems, as oscillations in rotor speed (and voltage), superimposed upon the synchronous speed of the rotor, and usually decay in several cycles as damped sinusoids. These types of disturbances occur on the power system regularly and are typically caused by load changes. In contrast, transient rotor angle instability may endure for several seconds and is a result of a large disturbance, such as a system fault, and causes large swings in generator power angles as well as voltage variations [2, 5].

Inspection of equation 2.4 reveals that electrical torque may be divided into synchronizing torque and damping torque with synchronizing torque proportional to changes in rotor angle and damping torque proportional to speed changes. Small signal instability is caused by either insufficient synchronizing torque, in which case a continuous increase in rotor angle may cause a loss of synchronism, or insufficient damping torque, which may result in rotor angle oscillations that increase in magnitude until synchronism is lost. Adequate synchronizing torque is usually not a stability issue for modern systems with continuous voltage control since increases in the machine voltage will increase the air gap flux and will exert a restraining force on the machine rotors. Insufficient damping torque is of greater concern in modern systems and may result in rotor oscillations between closely coupled machines caused by control inefficiencies due to improperly tuned speed governors or excitation controls [4]. Improperly tuned governors may create a condition in which increases in generation output occur with different time constants at several different generators and may result in large frequency and rotor angle excursions.

$$\Delta T_e = T_S \Delta\delta + T_D \Delta\omega \tag{2.4}$$

with ΔT_e representing the change in electrical torque, T_S representing the synchronizing torque coefficient, $\Delta\delta$ representing the incremental change in rotor angle, T_D representing the damping torque coefficient and $\Delta\omega$ representing the incremental change in speed.

Transient rotor instability is caused by a large disturbance on the power system such as a three-phase fault or the loss of a generation unit, and can result in one or more machines pulling out of synchronism with the rest of the system. Following a generation fault, there is a significant change in power flow and requires that the power deficiency be redistributed among the remaining online units. This will result in an increase in power angle and may cause some of the machines to loose synchronism depending on their initial loading, the fault clearing time, the generator rotor inertias and other factors.

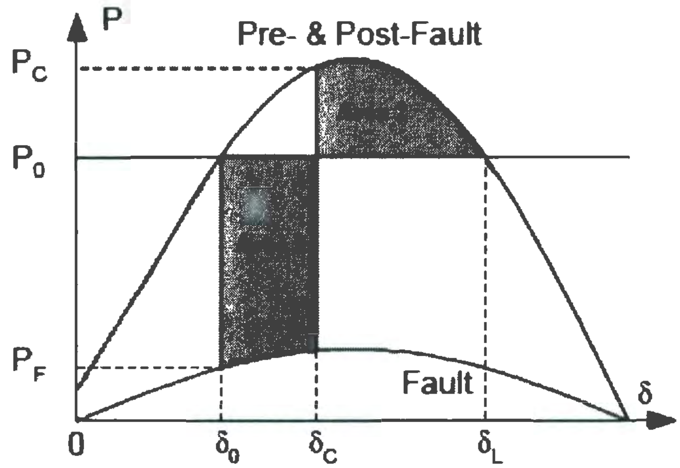

Figure 2.4: Equal angle criterion applied to a transiently stable system [7]

Figure 2.4 illustrates the classical analysis of rotor angle stability utilizing the equal area criterion. Briefly, a transmission line fault that occurs while a generator is at an initial operating angle (δ_0) must be cleared before the machine rotor advances beyond the critical clearing angle (δc). The critical clearing time corresponding to the critical clearing angle is the maximum time delay between initiation and final clearing of a fault while maintaining generator synchronism. If fault clearing is delayed beyond the critical clearing angle, there will be insufficient time to decelerate the rotor and the generator will pull "out of step" with the rest of the system. In this condition, the rotating stator field and the rotor field are no longer operating in synchronism and large fluctuations in voltage, rotor angle and frequency will activate protective relays resulting in a trip of the generation unit [2, 4].

2.3.2 Voltage Stability

The balance between the supply and demand of reactive power is fundamental to the voltage stability of a power system. Reactive demand by all loads must be simultaneously supplied by the system reactive sources (i.e. generators or capacitor banks) just as the instantaneous demand for active power must be supplied by active generation sources. In general, an excess of reactive power will result in voltage rises and a deficit will result in voltage drops or sags.

Voltage stability is subdivided into either 1) small disturbance (short-term) voltage stability or 2) large disturbance (long-term) voltage stability depending on the magnitude of the initiating event. A system is small disturbance voltage stable if the system voltages are restored to normal following a small disturbance, such as may occur during a load change and may involve the action of continuous voltage control due to the variable field excitation of synchronous generators. Large disturbance voltage stability is concerned with the ability of the system controls to restore nominal operating voltages following large disturbances, such as a system fault or a generation loss. Small disturbance voltage stability is evaluated on a near instantaneous basis whereas the time frame involved for large disturbance voltage stability may be several seconds to several minutes. Note that small disturbance voltage instability may be a consequence of small signal rotor instability since the two phenomena are closely related [4].

The optimal operating point for a transmission system is to maintain a constant voltage magnitude at all points on the system and to operate the system at the maximum rated voltage. This requires reactive injection at load centers and at points across the system either from generators or other capacitive devices. It is advantageous to operate the system with a consistent voltage profile since this will minimize reactive losses caused by significant voltage gradients.

The reactive output of the synchronous generator does not depend on the bus voltage but rather the magnitude of the machine field current. Hence the reactive output of the generator will not decrease due to low bus voltage as would occur for shunt capacitors. The reactive output of capacitors varies as the square of the voltage and in direct proportion with frequency. Clearly, capacitors will function with decreased efficacy during any system contingency involving either a decrease in frequency or voltage.

Furthermore, voltage stability will be improved through generator operation at near unity power factor. This will maximize the availability of a fast reactive reserve from generation sources resulting from the minimized field current required at unity power factor while the actual reactive reserves available from a generator will vary with generator capability and current loading. This generator reactive reserve is particularly valuable during short-term contingencies since the generator automatic voltage regulator (AVR) will respond quickly to meet changing reactive demand on the system.

2.3.2.1 Voltage Collapse Scenarios

Voltage instability may occur when the system is unable to meet the reactive requirements of the load and is most likely to occur on a heavily loaded system. A typical scenario for a long term voltage collapse would be subsequent to the tripping of one or more transmission lines or during a period when generation sources near load centers are out of service.

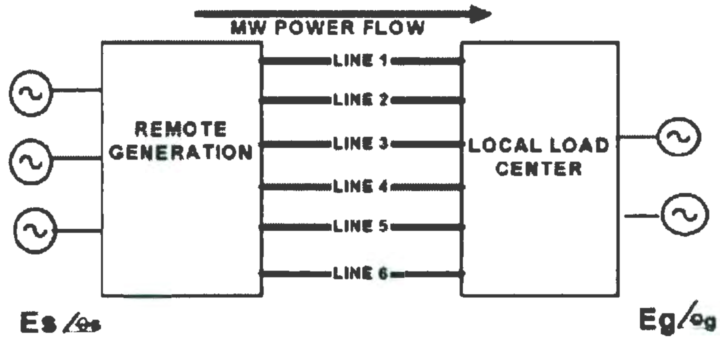

Figure 2.5: Sample multi-line power system [8]

Consider Figure 2.5, which depicts a simple system in which several parallel transmission lines are employed to service a large load center. If one of more of these transmission lines trip, the system will require that a greater amount of power be transmitted over fewer lines. This will result in increased reactive losses on the remaining in service transmission lines and a decreased voltage at the receiving end of the line (near low voltage distribution centers). Typically, on-load tap changers will operate after a few minutes to raise the distribution voltage and restore the nominal load demand. The additional reactive demand will be displaced to compensation devices elsewhere on the system (especially those close to the area of low voltage) and long term voltage instability is possible if reactive reserves are insufficient to meet the current demand.

Three power voltage (P- V) curves are depicted in Figure 2.6. The A curve shows normal operation and the B and C curves represent the system characteristic for N-1 and N-2 transmission line loss contingencies. The loss of a single circuit (i.e. transmission line) requires that the system operate with a reduced active power capability or stability limit. For example, if a power system is operating at the point A2 and a trip occurs on one of the parallel transmission lines, the maximum power transfer capability is reduced to

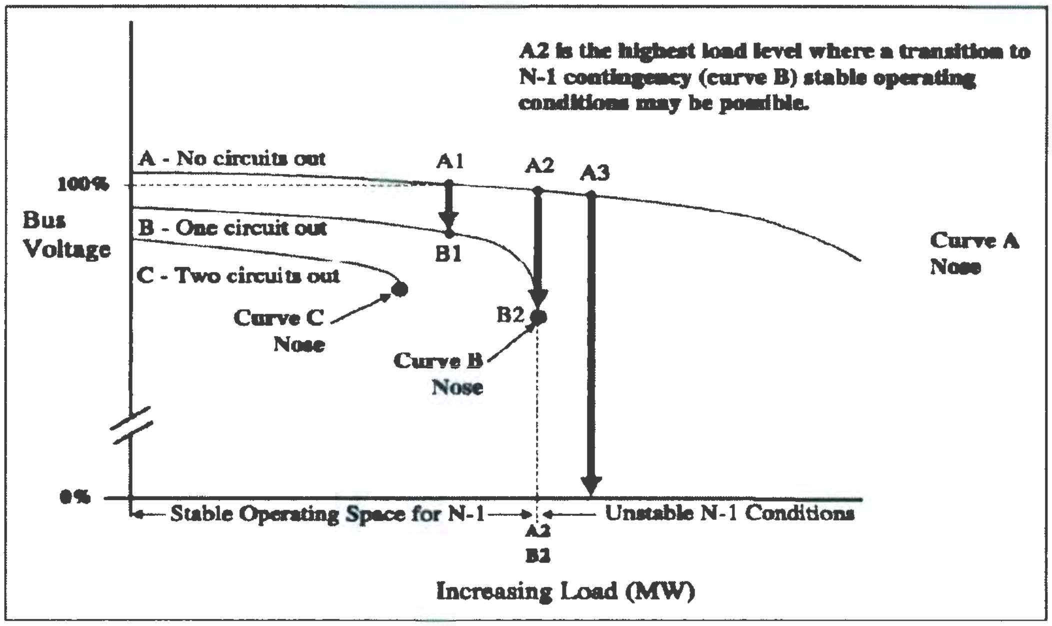

Figure 2.6: Stable operating margins for system voltages [8]

the point B2. Further, operation at the point A3 would result in system instability following a line loss contingency since the remaining transfer capacity would be insufficient to maintain acceptable voltages and will require load curtailment if adequate reserves are unavailable. Movement between the points B1 and B2 will occur as the system loading changes or in response to a variation in the availability of reactive reserves (such as a capacitor bank malfunction or operation of generator overexcitation limiters) with operation past the knee point (point B2) resulting in a system voltage collapse [9].

2.3.3 Frequency Stability

Frequency stability has not received the same attention in the literature concerning power system stability when compared with investigations into rotor angle or voltage stability. One possible explanation for this is that most power systems in the world are large interconnected systems that do not exhibit frequency instability and contain sufficient inertia and generation reserves to prevent any significant frequency deviation from nominal. This is not however the case for smaller isolated systems that may be operated with a minimum of spinning reserve (for economic reasons) and are very limited with respect to rotating inertia. For these smaller systems, frequency stability may be of more concern than rotor angle stability since the loss of any generator may initiate a period of frequency instability and may require the application of a load curtailment strategy [10].

The distinction between short term and long term frequency stability, also known as mid term and long term frequency stability, is based on the presence of synchronizing power oscillations among the system generators. Specifically, the time frame prior to the damping of speed oscillations is termed the mid term period whereas the period after these oscillations have been damped is called the long-term period. Damping of speed oscillations on a power system is derived from several sources with the most effective source being the inertia of the generators themselves while other system elements, such as the generator governor, motor loads and reactive power compensators function as effective secondary sources [2].

Synchronizing power oscillations are a short-term frequency phenomenon and are dependent on the power system response to disturbances. These oscillations are the exchange of mechanical kinetic energy among groups of generators. Inspection of equation 2.5 reveals that the power output of the ith generator is dependent upon the ith rotor angle and voltage as well as the rotor angle and voltage of every other generator synchronized to the system. In addition, note that the power flow between generators is inversely proportional to the transient reactance of the machines [11].

$$P_{sij} = \frac{E_i}{X_i^{'}} \sum_{j=1}^{m} \left(\frac{E_j}{X_j^{'}} Z_{ij} \cos\left(\delta_i - \delta_i - \zeta_{ij}\right) \right) \qquad (2.5)$$

with P_{sij} representing the power transfer between the ith and jth generators, E_i and E_j representing the line terminal voltages, δ_i and δ_j representing the line terminal voltage angles, Z_{ij} and ζ_{ij} representing the complex impedance between ith and jth generators and X_i and X_j representing the transient reactance of ith and jth generators.

The synchronizing co-efficient defines the power output relationship between the ith and jth generators and is given by equation 2.6.

$$K = E_i E_j Y_{ij} \cos(\delta_i - \delta_j) \qquad (2.6)$$

with K representing the synchronizing co-efficient , E_i and E_j representing the line terminal voltages, δ_i and δ_j representing the line terminal voltage angles and Y_{ij} representing the admittance between the ith and jth generators.

The synchronizing power (or torque) co-efficient is the slope of the power angle curve at the initial operating angle (δ_0) and describes the change in the electrical power generated by a machine due to the change in the angle between the generator internal voltage with respect to another system bus following a disturbance [2]. When the slope is positive, as will occur when δ is between 0 and 90 degrees, the motion of the rotor subsequent to a disturbance, will exhibit simple harmonic motion and decay as a damped sinusoid. Conversely, when the synchronizing power co-efficient is negative, as will occur when the operating angle is between 90 and 180 degrees, the rotor will oscillate with increasing amplitude. Synchronizing power coefficients indicate the strength of the connection between two generators with a large co-efficient indicating a strong connection or coherency. The effects of the machine voltage and the impedance can be seen through inspection of equation 2.6. Increased voltages will increase the degree of coupling between the machines whereas increased impedance will decrease it. Hence generators that are electrically close (i.e. lesser impedance) to areas of power deficiency will be affected to a greater extent than those machines that are further removed.

For isolated power systems, the loss of a single generator can have a significant effect on the frequency stability of the system. There may be large fluctuations in voltage, frequency and power flows immediately after the generation trip. The effect of the generation deficiency on the remaining synchronized generators is that the reduced electrical torque will decelerate all machines and may cause the system frequency to display relative oscillations among the system busses. The initial excess power demand will be distributed among the synchronized generators in proportion to their respective synchronizing co-efficients (during the short term time frame) and later (in the long term time frame) by their inertia, with larger generators absorbing most of the deficiency. If the remaining synchronized generators cannot compensate for the generation deficiency through active power contributions from either spinning reserve or by bringing additional generators online, the lower frequency may initiate protective relaying operations and result in the creation of system islands or potentially in a total system collapse. This condition may be addressed with the application of underfrequency loadshedding (UFLS). Generally, preselected portions of the system load are disconnected (or tripped) as the frequency declines in an attempt to reestablish the balance between generation and load and thereby a nominal system frequency [12].

2.4 Load Curtailment on a Test System

The following section contains a précis of the load curtailment application strategy contained in chapter 6 for a test system. The intention is to introduce the reader to the necessity and potential effectiveness of load curtailment with regards to the maintenance of system stability during operating contingencies.

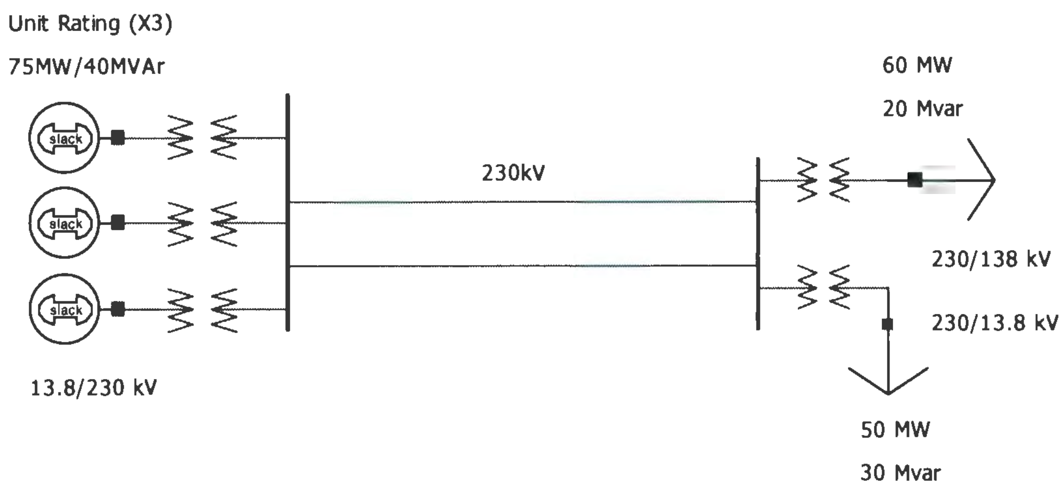

Figure 2.7: Load curtailment test system

Figure 2.7 depicts the application system as contained in chapter 6. The system in question contains three identical 85 MVA generators. The 110 MW and 50 MVAr load demand is serviced through a parallel circuit 230 kV transmission line. The test system does not contain tap changers or shunt capacitors.

The application of the UFLS schedule contained in Table 2.1 is demonstrated for the loss of a single 85 MVA generator. This schedule contains three frequency tripping thresholds with each containing 25 MW of load. Similarly, the application of the UVLS schedule contained in Table 2.2 is demonstrated for a loss contingency involving one of the transmission lines. Time domain simulations are provided for the underfrequency and undervoltage cases in chapter 6 and clearly demonstrate that system stability is conserved subsequent to the application of the load curtailment schedules. The reader is directed to chapter 6 for additional details of the application.

Table 2.1: UFLS schedule for test system

Frequency Threshold (Hz)	Loadshed (MW)
59.0	25
58.5	25
58.0	25

Table 2.2: UVLS schedule for test system

Voltage Threshold (Volt)	Loadshed (MW)	Time Delay (sec)
0.91	20	0

2.5 Summary

This chapter has provided a general survey of power system stability. The effects of contingencies on the system, such as the failure or tripping of a system component, have been described as relates to rotor angle, voltage and frequency stability. The time frames and characteristics of stability have been described in general terms and the application of a load curtailment strategy to mitigate the effects of long term voltage and frequency instability have been introduced.

Chapter 3

Power System Elements and Protection

3.1 Introduction

A power system disturbance will affect the balance between active and reactive generation and load. The disturbance magnitude will determine the change in the operating state of the power system and whether protective schemes are tripped or operated. In general, the most vulnerable part of a power system is the transmission line network since the lines are more exposed to faults caused by geography and weather, such as salt contamination or tree contacts, than are other system components. In addition, the percent of maximum loading on the system will also have a significant effect on how the system responds to a fault due to variation in the availability of power reserves. Power system operation will return to a stable condition, following a line or generator trip, if the new system configuration is stable and the fault is cleared within the critical clearing time. Instability will result if there is insufficient reactive reserve or real power generation capacity available to support the system following a successful relay operation. The mitigation of insufficient reserve capability can be achieved through application of an UVLS (i.e. undervoltage loadshedding) or UFLS (i.e. underfrequency loadshedding) scheme and is the subject of the current chapter.

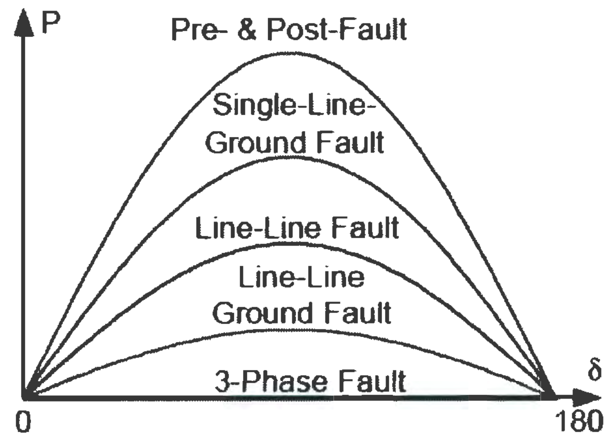

Figure 3.1: Power transfer capability during system faults [13]

The typical response of the system protection for a fault on the power system will not involve the operation of either UFLS or UVLS schemes. The energy that was previously flowing to the load will now flow into the fault since the generator turbine cannot instantaneously decrease power output through the adjustment of the machine wicket gates or boiler valves. The voltage at the point of fault may decrease significantly on some or all phases of the power system, as shown in Figure 3.1, and the power transfer capability of the system will be severely limited. Concurrently, the rotor angle will advance due to stored energy in the rotating mass of the machine turbine and the generator will attempt to restore the bus voltage by increasing its field current. This (faulted) operating condition will persist until the appropriate breakers open and isolate the affected element(s). If the breakers then close, to restore the system, the generator automatic voltage regulator (AVR) will act to decrease the field current, and therefore the bus voltage, and the generator governor control will begin to slow the machine causing the rotor to decelerate. Once the fault has cleared, the system will settle to a new steady state operating condition with possibly fewer transmission lines [7].

As power systems have evolved, they have become more complex both in design and in operation. This increased complexity may also increase the vulnerability of the system to instability and collapse due to possible protection misoperations. When a major system disturbance occurs, protective relaying must respond in a timely manner to isolate the cause of the system anomaly and restore stability to the system. This is achieved through a variety of protective systems that monitor either (or both) the voltage and current and typical protective schemes can be grouped according to which system element they protect. For example, generator protection can include loss of field, rotor imbalance or excessive stator current relaying. In general, when the ratings of the machine are exceeded or the machine deviates from a normal operating condition, protective relaying will initiate the operation of circuit breakers and isolate the affected machine. Other system elements, transmission lines and transformers for example, can also have specialized protective systems, such as distance relaying or differential relaying. These systems are designed to protect a single system element whereas other types of protection schemes such as UFLS, UVLS or out of step protection are designed to respond to the operating state of the power system.

3.2 General System Response to Generation Loss

Subsequent to the trip of a system generator, the remaining synchronized generation will experience a transient rotor oscillation with those generation units closest to the tripped generator experiencing the greatest perturbation. If the system has sufficient damping, these oscillations will decay in a few seconds and the inertia of the system (the combined rotating mass of the remaining synchronized generator rotors and turbines) will limit the rate at which the frequency decays. The variation in rotor angle will be experienced almost instantaneously by all generators for smaller systems and will expand in a wavelike manner for larger systems [2].

The time frame for long-term frequency stability begins after the synchronizing oscillations have been damped and a common frequency exists at all system buses whereas the mid-term time frame is characterized by the existence of speed oscillations [2]. Immediately after a generation loss, the remaining generators still synchronized to the system will oscillate in the transient time frame as determined by their synchronizing coefficients. The extent of the speed change for each generator is partially determined by the inertia of the turbine generator mass with larger machines being perturbed less from synchronous speed. The effect of variable machine inertias across the system during a sudden generation loss is therefore to create oscillations among the machines while the system attempts to synchronize to a common frequency. These mechanical intermachine oscillations (or synchronizing oscillations) will usually be damped in 1-2 seconds principally by the inertia of the machine itself but also by load frequency (and voltage) characteristics, generation governors and excitation systems [14]. Equation 3.1 indicates that the redistribution of power among the remaining generators is in proportion to the inertia of the generator with the larger units contributing most of the "inertial" generation. Similarly, the per unit (pu) power returned to the system by a specific generator during a period of frequency decline (from f1 to f2) is given by equation 3.2 [15].

$$P_i = P_{Total}\left(H_i \Big/ \sum_j H_j \right) \tag{3.1}$$

with P_i representing the power allocation to generator i, P_{Total} representing the total generation deficiency, H_i representing the inertia constant of generator i and H_j representing the inertia of each generator on the system.

$$P_{AVG} = \frac{H}{\Delta t}\left[\left(\frac{f_1}{f_0}\right)^2 - \left(\frac{f_2}{f_0}\right)^2\right] \tag{3.2}$$

with f_0 representing the nominal frequency, f_1 representing the initial frequency, f_2 representing the final frequency, H representing the inertia constant of the generator, Δt representing the time interval and P_{AVG} representing the power returned to the system (pu).

The generator speed governor will become active after the generation loss has occurred and will detect the decrease in unit speed and increase the turbine power to the generator to compensate. A governor is a mechanical or electrical device that controls the power output of the prime mover (whether a steam valve in the case of a thermal unit or a wicket gate for a hydraulic turbine), and will not usually significantly contribute to the damping of intermachine oscillations [16]. Typically, the machine governors will begin to compensate for the generation loss after approximately 2 seconds and the system frequency will ultimately be restored to nominal values after several minutes by the actions of the automatic generation controller (AGC) at selected generators [17].

Concurrent with the frequency decay following the loss of a generator will be voltage decay in the region of the power system nearest the failed generator. The ability of the power system to restore the system voltage, at the affected busses, will depend upon the placement of reactive reserves and contributions by other generators or shunt capacitors. Generation sources will increase their excitation to compensate for the reduced voltage and other local compensation devices (i.e. shunt capacitors) will contribute reactive energy to the system within their capability. For an isolated system in this condition, the emergency or in extremis states, load curtailment may be required to avert a system collapse whereas larger interconnected systems may have sufficient reserves to compensate for any probable generation contingency [4].

3.3 Protective Relaying

Protective relaying provides continuous monitoring of system voltage and current levels. When the voltage or current on the system is outside of an expected range, the protective relay will initiate a circuit breaker operation and disconnect the malfunctioning or overloaded element from the power system. For the purposes of the present research, the relaying of interest (voltage and frequency relaying) is intended to detect conditions that threaten either frequency or voltage stability and will respond in a predetermined manner by initiating a load curtailment strategy and disconnect selected portions of the system load.

All protective relaying must abide by the classical credo of "reliability versus selectivity". A relay that correctly identifies an abnormal system condition and responds correctly to that condition is said to be reliable. The reliability of protective schemes is often improved by the installation of independent backup or secondary systems that ensure the correct operation of a relaying scheme if the primary protection fails to operate. In contrast, the selectivity of a protection scheme refers to the ability of protective relaying to correctly identify a faulted system element and to trip only the affected equipment while leaving the remainder of the system intact. There is therefore an inherent trade off between the selective and reliable operation of protective devices on a power system since it is required that the relay operate and open the necessary circuit breakers to clear the fault but it is also important that the protection operation not interrupt more of the power system than is required. Other important considerations with respect to the correct implementation of protective relays are speed, simplicity and cost [18].

Within the context of load curtailment, reliability and selectivity refer to the predictable response of the protective relaying controlling the schedule. It is vital that the frequency and voltage relays operate when the trip settings become active and thereby enable the load curtailment schedule to respond to the system contingency. Reliability is enhanced by the presence of frequency and voltage relays at several different locations on the system monitoring different distribution feeders. Hence, if one of the relays misoperates, compensation will be achieved through the operation of other relays at the same tripping threshold. Similarly, the selectively of the load curtailment schedule is achieved through consideration of the probable system response to a contingency. The threshold settings are adjusted according to the expected variation in voltage and frequency to ensure that the benefit of loadshedding to the system is realized prior to the activation of subsequent tripping thresholds. It is desired that the process of successive load curtailment occur in proportion to the severity of the system contingency through the predictable operation of the appropriate protective relaying and thereby prevent load loss in excess of that which is required.

3.4 Frequency and Voltage Relays

Modern digital relays typically have accuracies greater than 99%. Typical precision for a frequency relay is 0.01 Hz when identifying frequency and 0.1 Hz/sec for identification of the rate of change of frequency. Depending on the design of the relay, there will also be an operating delay of 2 to 4 cycles for execution of the relay frequency algorithm. Similarly, voltage relays have typical accuracies of greater than 99% and are generally considered to operate instantaneously.

The time delay required for determination of the df/dt (i.e. the rate of change of frequency) varies among relay manufacturers but a conservative figure would be approximately 200 mSec (that is, it requires 200mSec for the relay to sample a sufficient number of cycles to determine the df/dt). In digital relays, the sampling time and the number of monitored cycles are variable and can employ a moving time average window to calculate the df/dt of successive waveforms. A two-cycle algorithm is illustrated in Figure 3.2 and will measure the time intervals between two successive periods (i.e. zero crossings of the voltage waveform) and calculate the df/dt on a per cycle basis as shown in equation 3.3. The accuracy of the df/dt calculation using a time-averaged value will increase when an increased number of cycles are used for the calculation. The caveat is that increasing the number of monitored cycles will also allow more time for the frequency to decay pending relay operation but will decrease the error inherent in the df/dt calculation resulting from possible frequency variations among the system busses. Recall that systems containing limited inertia may exhibit local frequency oscillations as the generators attempt to synchronize to a common frequency following a disturbance.

$$\frac{df}{dt} = \frac{f(t_4) - f(t_2)}{t_4 - t_2} = \frac{1}{t_4 - t_2} * \left(\frac{1}{t_4 - t_2} - \frac{1}{t_2 - t_0} \right) \qquad (3.3)$$

with df/dt representing the rate of change of frequency, t_0 representing the time of the initial zero crossing, t_1 representing the time of the second zero crossing and so on.

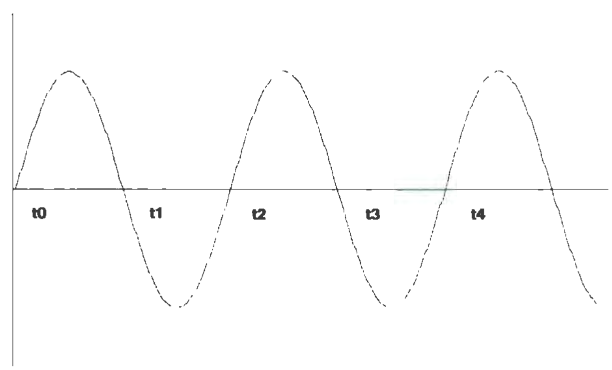

Figure 3.2: Zero crossing of successive voltage waveforms

3.5 Special Protection Systems

A Special Protection System (SPS) is a protective system that is intended to prevent a power system collapse during extreme operating contingencies such as the loss of a major transmission line or large system generator. This type of protection scheme will typically function while the power system is in an emergency or in extremis state and should take decisive action to prevent a system collapse. The required action is to separate potentially large sections of load from the system in an effort to maintain system stability. As already stated, some examples of this type of protection system are undervoltage loadshedding, underfrequency loadshedding and out of step protection. In general, the purpose of an SPS scheme, is to protect the power system from events that threaten system stability and are more far reaching in their effects than those applications that protect only a single system element; such as a line overcurrent relay or a transformer differential relay [19].

An SPS may be either "centralized" or "de-centralized" in design with the distinction depending on the tripping information required for relay operation. Centralized schemes usually rely on high-speed communications and a central relay or computer processor to make the decision to initiate load curtailment whereas relays in de-centralized schemes act independently and will trip based only on the local variables available to the relay. An SPS will respond to an N-1 or greater contingency depending on the subsequent variation in the system voltage and frequency. This is especially true for isolated systems that, with a limited inertia and generation, may be susceptible to instability following any N-1 or greater contingency. These types of protective schemes will typically operate subsequent to the time frames of other protective relaying systems and in this sense the SPS scheme is often the last line of defense for the maintenance of power system stability.

3.6 Power System Loads

In general, the power demanded by the system is affected by the variation in the operating voltages and frequency. Some commonly used figures which are used to reflect this variation are a 1 - 7% decrease in load demand for a 1% decrease in frequency and a 1% decrease in load power demanded for a 1% decrease in voltage. The actual values are system specific and depend on the characteristics of the system loads. Nonetheless, power system operation at reduced voltages and frequencies will introduce a "load damping" factor during disturbances and utilities have conducted studies to determine the potential effects of operation at reduced voltages and frequencies [20] [21]. The exact value by which a system load is sensitive to variations in frequency and voltage is generally not known with certainty (without detailed studies) and often requires approximations through the use of aggregate load models [22].

If UFLS schedules do not activate or are not part of the system protection scheme, the frequency will stabilize at a value less than nominal depending on the severity of the overload and the frequency characteristics of the load [23]. Figure 3.3 and equation 3.4, describe the expected settling frequency for a power system following differing degrees of overload assuming a 2% reduction in load for a 1% reduction in frequency. Note that systems with smaller H constants (containing a lesser amount of stored kinetic energy in the rotating mass of the generator turbine) have an increased rate of frequency decay when compared to systems that contain larger generators.

$$f_{final} = f_0\left[1 - \frac{\Delta P}{d\left(1+\Delta P\right)}\right] \tag{3.4}$$

with f_{final} representing the new stable operating frequency, f_0 representing the nominal frequency, ΔP representing the per unit generation reduction (based on remaining generation) and d representing the per unit change in load for per unit change in frequency.

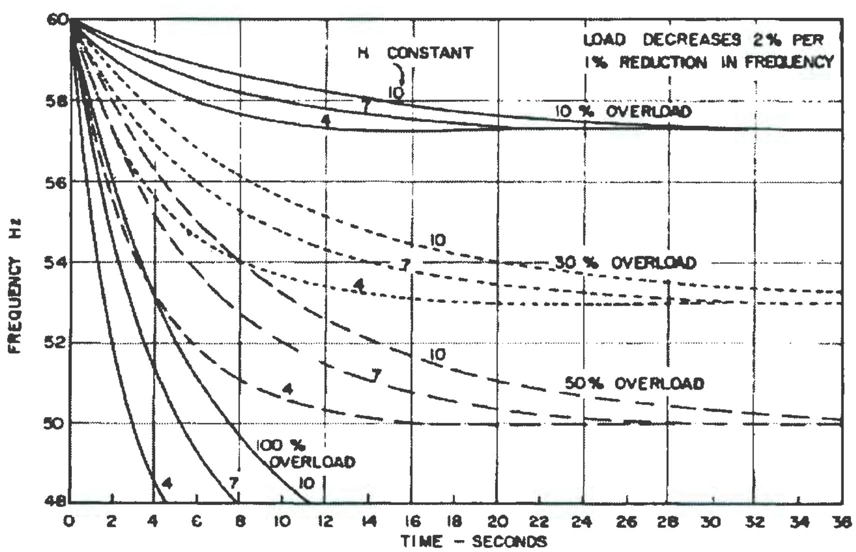

Figure 3.3: Settling frequency after generation loss due to load damping [23]

The modeling of loads for power system simulation with respect to voltage and frequency variation can have a pronounced effect on the results obtained. However, simulations are often conducted with the operating assumption that a power system load will behave with a “constant power and constant impedance” characteristic. The effect of this assumption is that the load will be invariant for transient changes in voltage and frequency and while this approach does admit as margin of error, it will provide a reasonable approximation with respect to actual load behavior [24]. The current research will also employ a constant power and constant impedance model for simulation of power system loads and the results obtained will be consistent since the assumption will apply for all simulations.

Induction motors may be modeled as constant power loads for steady state simulations such that a decrease in voltage will accompany a proportionate increase in power demand. Another dominant load type that is voltage sensitive and may contribute to voltage collapse are thermostatically controlled resistive loads. During periods of prolonged low voltage, the switching on and off of thermostats will increase the system loading and will exacerbate any voltage stability problem since thermostatic loads will be active for longer periods of time at reduced voltages and will therefore increase the proportion of system loading which is resistive in nature [4].

3.7 Summary

In this chapter, the importance of system protection during disturbances has been emphasized. The system response to a generation loss was briefly discussed as well as the role of SPS schemes during generation contingencies. Finally, the effect of load model variation on power system response during operation at low voltages and frequencies is discussed for some of the prevalent system loads.

Chapter 4

Underfrequency Loadshedding

4.1 Introduction

The purpose of an UFLS schedule is to restore the balance between generation and load before a decline in the system frequency compromises stability. Reduced frequency operation will cause overfluxing and heating of magnetic materials on the power system due to high Volts/Hertz ratios and may exacerbate an existing generation-load imbalance by forcing a shutdown of thermal plant generators by reducing the output of induction motors servicing necessary thermal plant auxiliaries [9]. Therefore the operation of an UFLS scheme should be automatic and decisive once the system frequency has decayed to the threshold frequencies of the schedule. The principal method through which UFLS is achieved is through disconnecting preselected portions of the system load as the frequency decays to the threshold trip settings such that an increasing amount of load is disconnected for increasing severity of underfrequency. Other UFLS methods are to incorporate df/dt relaying into the control logic of the frequency relays or to initiate loadshedding manually through operator intervention.

Design of UFLS schemes is complicated by the lack of foreknowledge regarding the disposition of the power system, such as the generation dispatch or the system loading, immediately preceding a generation loss contingency. Therefore, UFLS schedules must be designed to function correctly for every generation loss contingency. To reiterate, if the system frequency declines to the point where UFLS is required there is a significant generation imbalance (at least an N-1 generation contingency) on the system and corrective action is required. Rather than risk a total system collapse, it is prudent to disconnect enough of the system load to preserve system stability. UFLS schedules may also provide protection for N-2 contingencies through the addition of lower frequency threshold settings and thereby continue to disconnect load in proportion to the generation loss contingency.

The general structure of an UFLS schedule is a series of frequency thresholds defined by frequency trip points with a predetermined amount of load assigned to each. Consider Table 4.1, which shows an illustrative UFLS schedule. There are three frequency threshold trip points (i.e. trip settings) assigned to trip 10% of the system load once activated. As the frequency decays in response to a generation loss, the underfrequency relays will trip the indicated portion of the system load in an attempt to restore the system generation – load balance. If the frequency decays to a value less than 58.0 Hz (with reference to the UFLS schedule contained in Table 4.1), 30% of the system load will be disconnected.

Table 4.1: Illustrative UFLS schedule

Frequency Trip Point	Total Load Shed
59.0	10%
58.5	10%
58.0	10%

An expression that describes the relation between the generation-load imbalance, the system inertia and the rate of change of frequency (i.e. df/dt) is given by equation 4.1. This is a simplified expression that does not consider load dynamics, governor effectiveness or synchronizing power oscillations but is accurate and adequate for the creation of the frequency relay settings contained in an UFLS schedule [25].

$$\frac{df}{dt} = \frac{P}{2H_{SYSTEM}} \tag{4.1}$$

with df/dt representing the rate of change of frequency (Hz/second), P representing the pu system power deficiency and H_{SYSTEM} representing the system inertia constant (Joules/MVA). A negative generation deficiency implies that electrical demand is greater than the available prime mover power and will result in a negative df/dt.

The point of "frequency turnaround" is the moment when the df/dt changes from negative to positive (i.e. df/dt = 0) and indicates that the generation deficiency has been redressed. The constant H is the ratio of the generator moment of inertia to the unit capacity and H_{SYSTEM} is the equivalent constant when considering all generators on the system. Inertia is a physical constant which is analogous to mass for linear systems and defines the ability of a rotating object to store kinetic energy. The kinetic energy associated with a rotating machine varies according to size with values of 300 MJ to 2000 MJ being typical for smaller electrical systems. For example, if a generator has an inertia constant of 5 (i.e. H=5) and has 500 MJ of stored energy at rated speed, then that generator can supply it's rated output (500 MJ) for 5 seconds prior to stopping assuming that the power output and load demand remain constant during the deceleration process.

The rate of change of frequency (df/dt), as defined by equation 4.1, indicates that the expected rate at which frequency will decay is proportional to the generation deficiency and inversely proportional to the total inertia of all synchronized generation.

4.2 Active Power Reserves

The total system inertia is the defining characteristic that distinguishes the response of isolated systems to generation deficiencies from that of larger systems. A large interconnected system will have several hundred (or more) large generators and several thousand megajoules (MJ) of rotating kinetic energy whereas a smaller, isolated system may have a total kinetic energy of only 10,000 MJ. Inspection of equation 4.1 reveals that the effect of tripping a single generator on frequency stability will be much more pronounced on an isolated system than on larger interconnected systems as a consequence of the vast difference in total stored energy or “inertial generation”. This underscores the effect of having the synchronized rotating mass (i.e. the kinetic energy) of several thousand generators available to compensate for a generation deficiency on larger systems whereas the loss of a single generator for an isolated system may represent a significant portion of the total system energy. For large interconnected systems, it is unlikely that frequency stability will be a concern since the probability of losing a significant portion of the system generation is remote.

For an individual generator, spinning reserve is the difference between the rated power output and the current loading. From the system point of view, the total spinning reserve is the sum of the synchronized and unutilized generation capacity for all units and in general, the frequency stability of a system is largely dependent on the availability of spinning reserve (and inertia). Clearly, for a large interconnected system, the quantity of spinning reserve (and inertia) available, at all times, is much greater than that available to an isolated system, as a consequence of the number of generators synchronized to the system. To reiterate, tripping a single generation unit on an isolated system, removes a much greater proportion of the spinning reserve (and rotating inertia) than would occur on a larger system [4, 10].

4.3 Frequency Variation on the Network

The selective operation of frequency relays may be a stability issue for small inertia systems since relays at individual buses across the system, may "misoperate" in responding to the local frequency (and df/dt) rather than the frequency (and df/dt) of the center of inertia (COI) as seen in equation 4.2 and equation 4.3.

The average system frequency may be thought of as the frequency of a fictitious bus called the center of inertia (COI) [26].

$$f_{COI} = \frac{\sum_{i=1}^{N} H_i f_i}{\sum_{i=1}^{N} H_i} \tag{4.2}$$

with H_i representing the inertia constant of each system generator, f_i representing the frequency at each generator bus and f_{COI} representing the frequency of the COI.

Similarly, the average df/dt may be defined for the COI as:

$$\left(\frac{df}{dt}\right)_{COI} = \frac{\sum_{i=1}^{N} H_i \, {}^{df_i}\!/_{dt}}{\sum_{i=1}^{N} H_i} \tag{4.3}$$

with H_i representing the inertia constant of each system generator, df_i/dt representing the rate of change of frequency at each generator bus, f_{COI} representing the frequency of the COI and df/dt_{COI} representing the df/dt of the center of inertia.

The security of df/dt relaying can be improved through the use of logical permissives and by availing of the time delays inherent in frequency relay df/dt calculation. For example, df/dt initiated frequency relay operation can require that the logical AND condition for frequency and df/dt be present prior to initiating a trip signal (i.e. frequency trip AND df/dt trip must occur concurrently). Similarly, the typical time delay required for a frequency relay to reliably calculate the df/dt is approximately 200mSec (longer time delays can be selected for some relays) and will commence when the frequency declines to the supervising trip frequency. With reference to Figure 4.2, the frequency will decay by ΔF during the time required for completion of the df/dt algorithm (Δt for this case). This introduces an additional time delay for the damping of intermachine oscillations and decreases the probability of df/dt relay misoperation in the short term time frame of frequency stability.

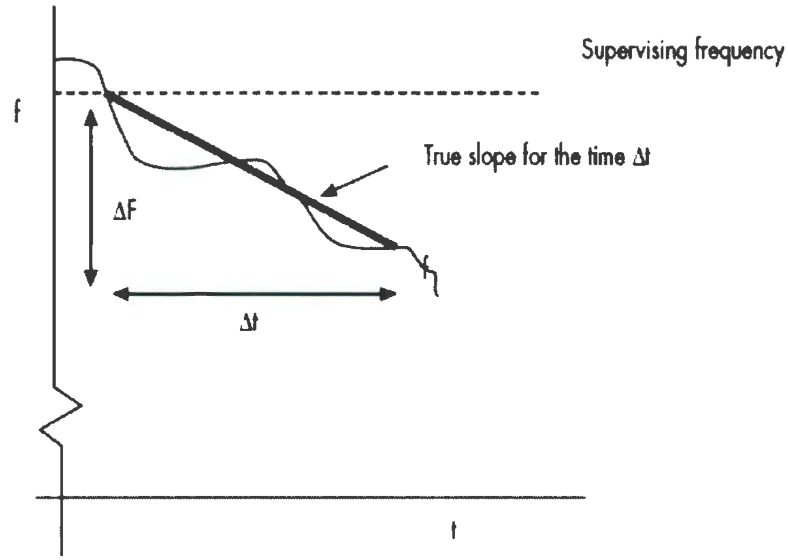

Figure 4.1 df/dt and frequency variation during a generation deficiency [27]

4.4 Underfrequency Loadshedding Methodology

This section focuses on the fundamental parameters that must be considered during the formulation of an UFLS scheme; these are the frequency threshold trip points, the separation of the threshold trip points, the total amount of load to be shed and the amount of load assigned to each threshold. The methodology associated with the development of UFLS schedules has been investigated in several articles contained in the literature. It is the intention of the present work to attempt a formalization for some aspects of the development of UFLS schedules as relates to isolated systems. The performance of an UFLS schedule may be evaluated through consideration of the total overshedding and undershedding of load as well as the expected minimum frequency after activation of the UFLS schedule. "Overshedding" (O/S) refers to loadshedding in excess of the initial generation loss whereas "undershedding" implies that the total load shed is less that the initial generation loss.

In general, it is desirable that the load assigned to the UFLS schedule be distributed, where possible, across the system. This distribution will ensure that voltages remain at acceptable levels during the operation of the UFLS schedule since shedding a large amount of load at a heavily loaded bus will result in overvoltages at the affected area and will have the effect of increasing the load seen by the system due to the damping effect of voltage on resistive load. This is especially true for compensated systems as there may be significant voltage increases at local buses following the operation of feeder breakers or reclosers. Another reason for distribution of load is that the schedule is formulated to respond to all possible generation and transmission contingencies and a wide dispersion of the available shedable load will promote the generality of the schedule since the location and extent of a system contingency is not known in advance [10].

4.4.1 Total amount of load shed

An UFLS schedule is designed to respond to system contingencies involving generation loss. For an isolated power system, an N-1 contingency will probably require activation of the UFLS schedule to preserve system frequency stability with the loss of the largest synchronized generator representing the worst-case scenario. To this end, an important consideration with respect to UFLS methodology is to determine the relation between the magnitude of the possible generation loss and the total amount of load assigned to the UFLS schedule.

The illustrative UFLS schedule contained in Table 4.1 has three frequency trip points (59.0 Hz, 58.5 Hz, 58.0 Hz) with each assigned to trip 0.1 pu of the total peak load. For example, if a peak load of 1000 MW is assumed, the schedule will trip 100 MW at each frequency threshold and 300 MW in total. The present research assumes that 50% of the peak load assigned to an UFLS schedule will be available to trip when the power system is at 50% of maximum load. This is a reasonable expectation since the loading of the feeders which will be disconnected from the system during an underfrequency event will probably be loaded at 50% when the total system load is 50% of maximum. Therefore, if the system is loaded at 500 MW, the total amount of load assigned to the UFLS schedule will be 150 MW in total or 0.05 pu or 50 MW (0.1 pu * 0.5) at each threshold.

The amount of load assigned to the UFLS schedule will impose a limitation on the size of the generation loss contingency for which a specific UFLS can provide adequate security and will thereby determine the size of the largest online generation unit (and the worst case N-1 contingency). Therefore, if governor action and load damping effects are neglected, the amount of load assigned to the UFLS schedule must be greater than or equal to the current loading of the largest online unit (i.e. LOU) if an UFLS schedule is to provide adequate security for an N-1 contingency. The total amount of load which must be assigned to an UFLS schedule for system protection during N-2 or greater contingencies can be determined through consideration of the system generation dispatch. Specifically, the total amount of load assigned to the schedule should be at least sufficient to counter the worst case N-2 contingency.

4.4.2 Determination of Frequency Tripping Levels

The determination of the maximum and minimum frequency threshold trip points requires knowledge of the normal frequency variation on the system in question. The maximum trip frequency must not be set such that the schedule is activated for normal frequency and load variations. The determination of what constitutes a normal frequency variation depends on the system characteristics given that isolated systems experience a much greater normal frequency variation than larger interconnected systems. For example, a frequency variation of 0.05 Hz may be considered excessive for a large interconnected system whereas a frequency variation of 0.5 Hz might be commonplace for some isolated systems. Clearly a detailed knowledge of the system response to normal load variations is required prior to establishing the maximum permissible tripping threshold. Furthermore, there is no benefit for system stability if the schedule is triggered for situations in which UFLS is not required. For cases of marginal generation loss, the mitigation of the generation-load imbalance may be achieved through the effects of spinning reserve and will not require UFLS.

The minimum permissible frequency threshold may be established by reference to the damage curves for thermal generation units since it is clearly preferable to correct system frequency instability before it becomes necessary to trip thermal generation units. These units are susceptible to turbine blade damage during operation at reduced frequencies and it is necessary that such operation be time restricted [28]. If a system does not contain thermal units then the minimum acceptable frequency may be established through customer requirements or by the possibility of damage to other system components.

4.4.3 Separation of Loadshedding Stages

The minimum separation of the load shedding stages is determined by the maximum expected df/dt on the system during an underfrequency event as this will determine the amount of time required for the frequency to decay through successive frequency trip settings. Consider a generation loss scenario which results in a frequency decline of 1 Hz/sec. Assuming a linear relation between frequency and time, this implies that it will take 500 mSec for the frequency to decay by 0.5 Hz or equivalently, 1 Sec for a 1.0 Hz decay, etc. If the time required for a typical frequency relay (and auxiliaries) to operate is 100 mSec (a conservative figure) and the time required for the circuit breaker contacts to open is approximately 100 mSec (also, a conservative figure), then there must be at least 200 mSec between two consecutive frequency trip points at any expected df/dt in order for the benefits of UFLS at a specific frequency threshold to be realized. If the blocks are too close together then a declining frequency, with a high df/dt, may trip more load stages than is required due the lack of coordination between the frequency settings of the UFLS. This suggests that the minimum separation of the frequency trip points, for this case, is 0.2 Hz. To summarize, the correct separation of frequency stages will depend on the maximum possible df/dt that is possible on the system and the speed of operation for protective relaying and related equipment.

4.4.4 Number of Loadshedding Stages

The response of an UFLS schedule to generation losses of varying size will be improved by increasing the number of frequency tripping points or blocks of shedable load. The increased selectivity of the schedule will minimize the possibility of significant overshedding during generation loss contingencies as a consequence of the total shedable load being divided into a greater number of loadshedding blocks.

This approach is preferred to shedding fewer and larger blocks of load since the amount of loadshedding will be minimized for generation loss contingencies which do not involve the largest online generation unit. However, the number of loadshedding stages is always at the discretion of the schedule designer and does admit an element of subjectivity with respect to the approach selected. The optimum number of loadshedding stages depends on knowledge of the system being protected and the probable size of the generation loss contingencies that are encountered. Consider a loss contingency that does not involve the loss of the largest online unit. In this case, large blocks of shedable load will result in loadshedding in excess of that required to provide adequate compensation for the generation loss contingency.

Since it is impossible to predict the severity of a generation loss contingency in advance of an actual event, it is impossible to determine, in advance, how much loadshedding will be required. Hence, in order to improve the selectivity of an UFLS schedule to generation loss contingencies of varying size, the number of loadshedding stages should be the maximum number possible.

4.4.5 Assignment of Load to Trip Stages

The determination of the amount of load to assign to each tripping threshold of an underfrequency schedule is also somewhat arbitrary and does admit some measure of subjectivity on the part of the designer in a manner similar to that involved in the determination of the number of loadshedding thresholds. In general terms, UFLS schedules must be designed to protect the system against the loss of the largest online generator (an N-1) or greater contingency and if there is sufficient load assigned to the schedule to achieve this end, then the schedule will perform its primary function and preserve system stability during generation loss contingencies. However, it may be possible to grade the amount of load assigned to each threshold such that the schedule can respond to generation loss contingencies that do not involve the largest online unit with a reduced amount of loadshedding. The effectiveness of disconnecting a block of load depends on what proportion of the generation deficiency it represents and the implementation of this approach requires detailed knowledge of the system under consideration.

Another possible consideration is that reducing the amount of load assigned to each of the tripping thresholds will attempt to maximize the effectiveness of spinning reserve through tripping a lesser amount of load than the probable generation loss. This will enable the power system to recover a portion of the generation deficiency through availing of the available spinning reserve on the system. Of course, if the system is operated with negligible spinning reserve, the potential benefit of this approach is limited. [7, 29].

4.4.6 Intentional Time Delays

The introduction of intentional time delays into UFLS schedules must be undertaken only after the overall effectiveness of the schedule has been assessed and it has been determined that a time delayed stage will have benefit. This is usually only true for those cases where the frequency has stalled at a subnominal level and additional automatic loadshedding is required to complete the frequency recovery. Otherwise, there is no discernable benefit to introducing intentional time delays into UFLS schedules [30].

4.6 Summary

This chapter has presented a survey of the variables present in the design of an UFLS scheme. The effects of system inertia in limiting the severity of frequency excursions following generation deficiencies is considered as well as the variability introduced into the system frequency by electromechanical oscillations. A methodology is described in section 4.4 that details the considerations involved in UFLS development and attempts to underscore the significance of system inertia for isolated power systems.

Chapter 5

Undervoltage Loadshedding

5.1 Introduction

The automatic disconnection or tripping of load initiated by an undervoltage SPS is a corrective measure of last resort utilized to mitigate an impending voltage collapse and functions as a "safety net" to prevent a major blackout or brownout condition. One of the characteristics of modern power systems is that significant generation sites near load centers have been previously developed. This has compelled utilities to develop sources of generation that are relatively remote from major load centers and has required the use of long, high voltage transmission lines. One possible consequence of this new generation or system development is that the security margins that existed on the system prior to the new development may have been compromised and N-1 contingencies are more of a threat to system stability than previously [8]. The impedance and loading of a long, radial transmission line will increase the vulnerability of the power system to rotor angle instability, due to the reduction in synchronizing power, and voltage instability due to the increased reactive losses in the line. In addition, there may be environmental and cost restrictions regarding the construction of new transmission or generation assets. The implication is that large-scale contingencies will threaten power system security for systems that have undergone significant generation development and may require the implementation of an UVLS scheme [6].

5.2 Voltage Integrity and Reactive Reserves

Voltage instability, as outlined in chapter 2, can be either a short or long-term phenomenon and may be initiated by severe system contingencies (tripping a transmission line for example) or by other system events such as on-load tap changer operation or field current limitation on generators. A voltage decline can develop into a voltage collapse if additional transmission lines are tripped or if other reactive compensation devices are unavailable (shunt capacitors, static VAr compensators or system generators) [31]. In addition to difficulties associated with induction motors, other voltage sensitive loads, such as thermostatic load (i.e. electric space heating) can be a significant component of voltage collapse scenarios during cold weather. The probability of voltage collapse is increased if high system loading occurs coincidentally with a system element loss (transmission line or generator) [4].

Reactive compensation may be inserted into the system during the design stage to counter possible reactive deficiencies that may be expected to develop following a system contingency. This may include the judicious placement of capacitor banks or synchronous condensers (at the end of long lines, for example) or by permitting the short term operation of generator exciters at greater than nominal limits. The timesaving can be used by system operators to increase reactive generation or to initiate manual loadshedding.

A synchronous condenser is a three phase synchronous generator that does not contain a turbine. As such, it is not capable of active power generation and is intended solely to provide (or absorb) reactive power to (from) a system. These devices possess a near instantaneous voltage control that will stabilize the system voltage during disturbances and will enhance transient voltage stability. The synchronous condenser will increase the machine terminal voltage by increasing the magnitude of the field excitation current and thereby increase the flow of reactive power to the system during periods of low voltage. However, the maximum field current limits the reactive support the condenser will provide. If the maximum field excitation is exceeded, the machine will trip offline and further reduce the availability of reactive reserves. This eventuality can have disastrous effects for the system and requires that tripping due to excessive field current be properly coordinated to occur subsequent to the activation of other system devices such as on-load tap changers or mechanically switched capacitors.

Mechanically switched shunt capacitors are capacitors that can be activated either automatically or remotely in response to low system voltages. The delay time that is present in these devices is the time required for circuit breaker operation, typically 5 to 6 cycles as well as any delay introduced into the design of the switching arrangement. For example, a predetermined time delay may be necessary to prevent overvoltages if the capacitors are switched into the system at an inappropriate time, as may be the case for moderate voltage sags. A significant disadvantage of mechanically switched shunt capacitors, with respect to the preservation of system voltage, is the response of the capacitor itself to a low bus voltage. The reactive power output of these devices is proportional to the square of the applied voltage and implies that the reactive support offered by capacitor banks will decrease during periods of low voltage. Consequently, these devices may be an ineffective means to the restoration of a nominal system voltage. Similarly, shunt reactors may be present on large electrical systems as a means to lower the system voltage and may be switched out of a system during periods of low voltage prior to other mitigating actions [32].

Another system element that plays a significant role in voltage regulation is the on-load tap changer. An on-load tap changer is a device that may be incorporated into a transformer and will change the effective transformation ratio through a process of "tapping up" or "tapping down". This will allow the transformer to regulate or control the low side voltage of the transformer. The effect of this tap changing operation is to redistribute the reactive load present on the secondary side of the transformer to the primary or line side. The displaced reactive demand must therefore be supplied by reactive sources on the primary or high voltage side of the transformer. The operation of tap changers may be either detrimental or beneficial in maintaining voltage stability depending on the system and the current operating state. During periods of low voltage, tapping up (or increasing the regulated voltage) will increase the demand of resistive elements and will exacerbate a low voltage condition whereas for reactive loads tapping up will be beneficial in that increased voltage will restore nominal reactive demand. The latter is especially true for systems which contain shunt capacitors on the regulated side of the transformer since the increased voltage due to tap changing will increase the reactive output from installed capacitors [4]. Electrical loads are however neither entirely resistive or reactive but some aggregation. Hence, the effect of tap changer operation may not be easily predicted for actual system conditions.

5.3 Undervoltage Loadshedding Methodology

Undervoltage loadshedding involves disconnecting portions of the system load in an area of the system where a voltage collapse is imminent. Since reactive power cannot be transmitted long distances, undervoltage loadshedding must occur at the site of undervoltage and will usually be at a large load center. The nominal minimum operating voltage is normally greater than 0.95 pu and this may be the first stage in an undervoltage loadshedding scheme depending on the system. Typically, the settings at which UVLS schemes are enabled are approximately 8% to 15% below the nominal operating voltages and should be activated by the unregulated line side voltage of transformers. UVLS settings may be time-supervised meaning that the undervoltage condition must persist for a specified period of time before protective relaying operates and trips the predetermined circuit breakers. Subsequent to protective relay initiated breaker operation, additional manual load shedding may be required to correct the abnormal condition.

The most important consideration, and the reason for implementing any sort of protection scheme, is system protection and integrity. It is vital that enough load be shed to either correct the problem outright or to allow sufficient time for system operators to recognize and correct the voltage difficulty. In general, the considerations involved during design of an UVLS schedule are: (1) the amount of load to be shed, (2) the time delay associated with loadshedding and (3) the location of shedable load.

UVLS schemes should respond only for drops in the positive sequence voltage and should be prevented from operating when negative sequence voltages are present on the system. A negative sequence voltage will be present only when there is an imbalance on the system, such as would occur during a phase to ground or phase to phase fault, and would not represent a balanced voltage decrease. Similarly, for three phase faults on the system, it is incumbent upon other protective relaying schemes, such as distance or overcurrent relaying, to operate and restore the system. In this case, UVLS schemes are prevented from operating by time delays built into the scheme. A typical UVLS scheme is presented in Table 5.1. Note that 15% of the total load associated with a specific area is assigned to trip at predetermined voltages following specified time delays.

Table 5.1: Illustrative UVLS schemes [6]

Voltage	Load Shed	Time Delay
0.92	5%	8.0 seconds
0.92	5%	5.0 seconds
0.90	5%	1.5 seconds

5.3.1 Total Amount of Load Shed

In general, the amount of load shed during an undervoltage event will depend on the severity of the undervoltage in that a larger voltage drop will initiate a greater amount of loadshedding. The actual amounts of load to be shed and the associated time delay are system dependent and developing an UVLS schedule requires optimization for the system under consideration. UVLS might be applied to 10 to 50 % of the load serviced in a given area and should respond to protect the system for probable loss contingencies. Power systems are generally designed with sufficient overcapacity to withstand N-1 contingencies, such as the tripping of a capacitor bank or nearby generation. However, the robustness of the system to contingencies is dependent upon the system in question.

5.3.2 Loadshedding Time Delay

The time delay required before loadshedding occurs depends to a large degree on the predominant loading for the system under consideration. If the load is mostly motor load it may be advantageous to trip load quickly (within 1 to 2 seconds) so as to assist motors in reaccelerating following a voltage sag. Conversely, the voltage sag may be a longer-term event, perhaps caused by an increase in thermostatic load. In this case, the loading will increase as more thermostats are enabled thereby increasing the load and further lowering the voltage. The time delay inherent in the UVLS schedule is not as critical as for those systems in which thermostatic loading is dominant and usually will be several seconds before loadshedding is initiated [6].

5.3.3 Location of Loadshedding Events

Any methodology that is used to determine the amount of load to be shed during a system contingency must account for the practical aspects of distribution loading. Breaker operations at a specific station will disconnect a specific feeder but it is impossible to know, in advance, how heavily loaded the feeder will be or what type of load will be connected to it at the time of actual loadshedding. It is certain however, that a voltage collapse may be inevitable unless enough load is shed to meet the contingency. The caveat is that if too much load is shed then other problems, such as over voltage or over frequency, may be created. The best alternative is to study the effect of a proposed UVLS schedule using system specific simulations but it is generally recommended that loadshedding occur at different points on the system so as to minimize the probability of overvoltages on lightly loaded busses. Furthermore, the difficulties involved in transmitting reactive power dictate that UVLS should be limited to areas where the undervoltage is detected and where there is load available to shed as it is of no benefit to shed load that is far removed from the location of the undervoltage.

5.4 Security of Undervoltage Loadshedding Schemes

The security of an UVLS scheme can be improved through the use of positive and negative sequence voltages as a means to allow voltage relaying to discriminate between legitimate undervoltage events and other system events that may affect the voltage. During a voltage depression that does not involve a fault on the system, such as may be created due to overload, there will be only positive sequence voltages present during the voltage depression since the system remains balanced. It is therefore advisable to monitor and trip using these positive sequence voltages and to restrain (or restrict) tripping by using the negative sequence voltage. A tripping scheme that employs this logic is presented in Figure 5.1.

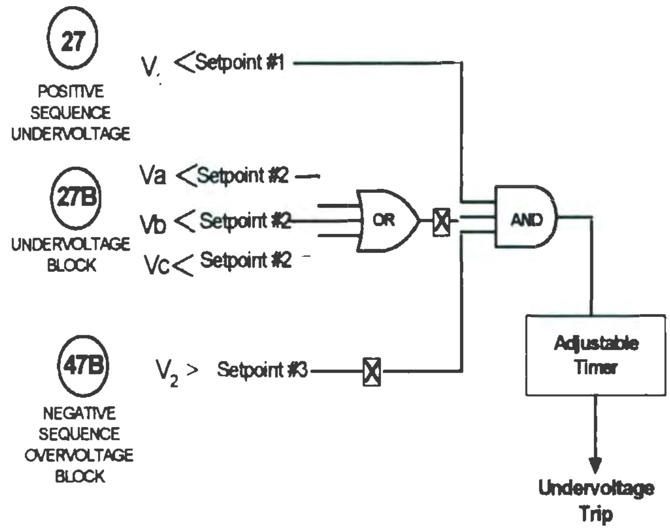

Figure 5.1: UVLS tripping logic [8]

Inspection of Figure 5.1 reveals the presence of an undervoltage block. For example if there is a phase to ground fault on the system, the operation of the UVLS scheme will not be desirable and it is preferred that any system problem be resolved through the operation of other protective relaying; such as time delayed overcurrent relays or distance relaying. UVLS schemes will only operate for those occasions in which all three phases are depressed equally and in the absence of negative sequence voltages. Further, time delays must be incorporated to ensure that the SPS does not operate during a three-phase fault on the system.

5.5 System Operating Margin

In order to determine the settings at which UVLS should be initiated it is necessary to conduct system studies to develop a P-V curve for the system at variable dispositions and dispatch scenarios. Presumably, the weakest system bus (or buses) will be monitored with UVLS where the weakest bus is that bus which exhibits the greatest dV/dQ during increased loading. The P-V curve can be used to determine the system voltage at a specific loading and will indicate the amount of loadshedding required for an operating contingency. With respect to Figure 5.2, the base case (N-0) P-V curve shows the expected voltage for the maximum system loading (point 1) and the maximum voltage following an N-1 contingency (point 2). Therefore, if the system suffers the worst case N-1 contingency, the loading must be reduced from 2000MW to 1500MW to maintain acceptable voltages. Further, operation of the system at point 3, will provide a 75 MW operating margin with respect to the maximum knee point (point 2).

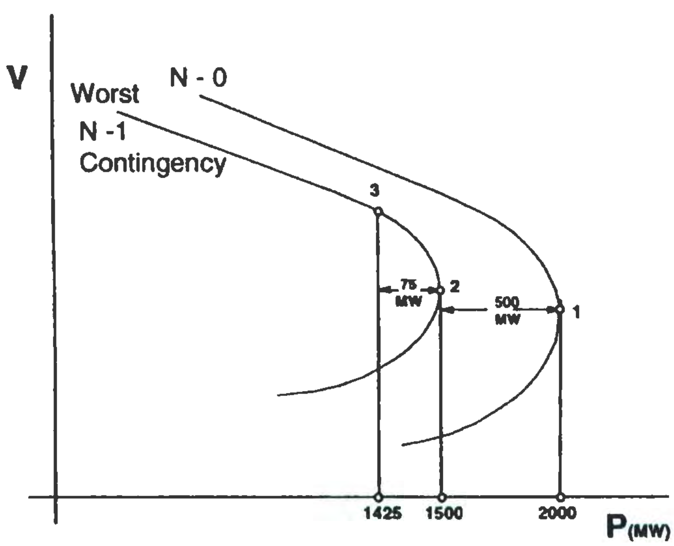

Figure 5.2: Illustrative power voltage (P-V) curve [33]

5.6 Summary

This chapter has presented a methodology for loadshedding during undervoltage emergencies. The importance of a system design which incorporates adequate reactive reserves is outlined as well as the effects and importance of an undervoltage SPS. The primary concerns relating to the development of an undervoltage SPS are highlighted; these include the trip settings for voltage relays, the amount and location of load shed during contingencies and the appropriate time delays required. Finally, acceptable operating margins are discussed which are intended to ensure that a system can continue with normal operation following the activation of an UVLS scheme for the worst case contingency.

Chapter 6

Application: Load Curtailment on a Test System

6.1 Introduction

The development of a load curtailment strategy will be investigated using a simple test system prior to application to the Newfoundland island system in subsequent chapters. The application on a smaller system will demonstrate the concepts associated with a load curtailment strategy and the potential benefits with respect to the maintenance of system stability.

6.2 Test System Description

The test system for the demonstration of the load curtailment strategy is detailed in Figure 6.1. There are three identical hydraulic generators modeled for the system with ratings of 85 MVA at a 0.9 pf. These units supply a peak load of 110 MW and 50 MVAr as well as system losses on the lines and transformers. Two parallel 230kV transmission lines service the load. The transformers do not have a tap changing capability. The simulation software is the Shaw Power Technologies power system analysis program PSS/E. An overview of PSS/E is given in appendix A.

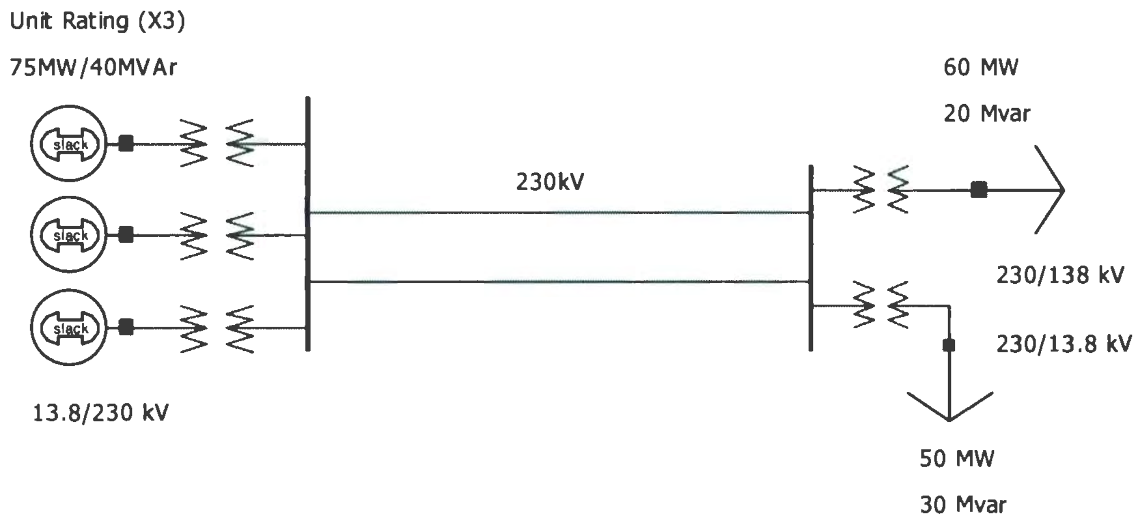

Figure 6.1: Test system schematic

6.3 UFLS on the Test System

The methodology described in section 4.4 will be applied to develop an N-1 UFLS schedule for the test system. The system has three generators with capacities of 75 MW each; hence the LOU is 75 MW at peak loading and the total load allocated to the UFLS schedule must be sufficient to compensate for this generation loss contingency. The acceptable minimum operating frequency is assumed to be 59.0 Hz and will therefore represent the first UFLS trip point. The system does not contain thermal generation units and so reference to thermal unit damage curves is unnecessary. However, for the purposes of illustration, the minimum acceptable frequency is assumed to be 58.0 Hz and implies a 1.0 Hz bandwidth for operation of the UFLS schedule.

The maximum expected df/dt for an N-1 contingency is 2.25 Hz/sec assuming 500 MW*sec of stored energy for each machine at rated speed (that is 2.25 Hz/sec =

30(75)/1000) since the tripped machine does not contribute to the total system inertia. At this rate of decline, the frequency will require 0.44 sec to decrease by 1 Hz and assuming that 200mSec is required for breaker and relaying operation, implies that 0.5 Hz will be required between successive tripping thresholds of any proposed UFLS schedule to maintain minimum co-ordination. Further, assuming a minimum separation of the loadshedding stages (i.e. 0.5 Hz) and commencing at the minimum permissible operating frequency (i.e. 59.0 Hz), indicates that the loadshedding stages for this application will be 59.0 Hz, 58.5 Hz and 58.0 Hz. If the available shedable load is partitioned equally among the stages, the load assigned to each stage will be 75/3 = 25 MW as illustrated in Table 6.1.

Table 6.1: UFLS schedule for test system

Frequency Threshold (Hz)	Loadshed (MW)
59.0	25
58.5	25
58.0	25

Figure 6.2 depicts the response of the system frequency during the simulation of a 75MW generation loss contingency that is assumed to have occurred at 0.5 sec during the simulation. Inspection of the figure reveals that the frequency did not decrease below 58.4 Hz and that tripping of the final loadshedding threshold at 58.0 Hz was not required to restore the generation load balance. This may be attributed to the availability of sufficient spinning reserve to correct the remaining 25 MW deficiency. Further, the

voltage at the receiving bus remained within acceptable levels and stabilized at 1.075 pu volts following UFLS operation at 58.5 Hz.

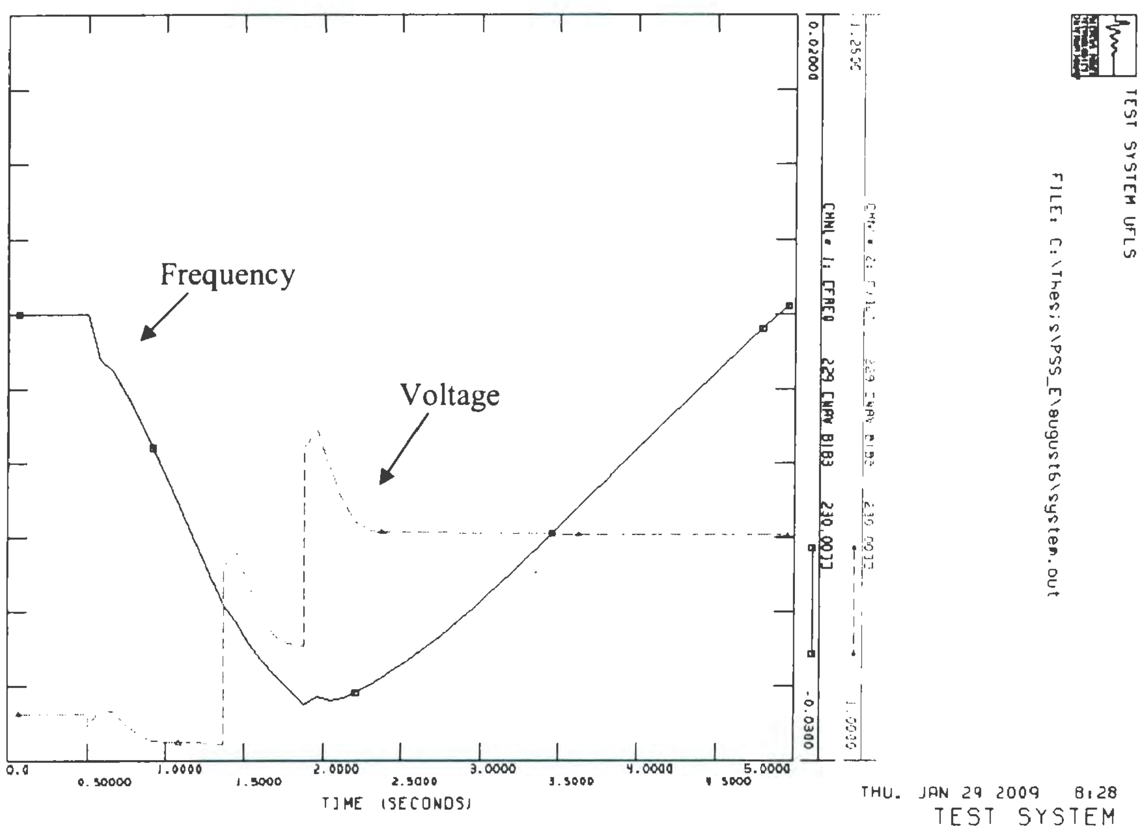

Figure 6.2: Voltage and frequency response for loss of 75 MW unit

6.4 UVLS on the Test System

The considerations associated with development of an UVLS scheme are the total amount of load shed, the time delay associated with loadshedding and the location of the shedable load. The operating contingency for which UVLS will be applied is the loss of one of the 230kV transmission lines. Figure 6.3 depicts the P-V curves of the test system measured at the receiving 230kV bus and indicates the total amount of loadshedding required to compensate for the line loss contingency. Inspection of the figure reveals that the maximum load transfer capability has been restricted as a consequence of tripping a line from approximately 100 MW at a voltage of 0.97 pu to approximately 80MW at 0.97 pu following loss of the line. The location of the shedable load will be the 13.8kV bus since this is the principal load center for the system. The time delay associated with the UVLS schedule is arbitrarily set to zero and the intention is to explore the application of UVLS in the short-term time frame since the test system is unlikely to be affected by long term voltage issues due to the lack of OLTC or a relative scarcity of reactive reserves. The undervoltage trip threshold is assumed to be 0.91 pu. The test UVLS schedule is presented in Table 6.2.

Note that the values used to indicate the required amount of loadshedding for the line loss contingency are approximate and correspond to a voltage of 0.97pu. This was necessary because the load flows used to construct the P-V curves would not converge for voltages less than 0.97pu.

Table 6.2: UVLS schedule for test system

Voltage Threshold (Volt)	Loadshed (MW)	Time Delay (sec)
0.91	20	0

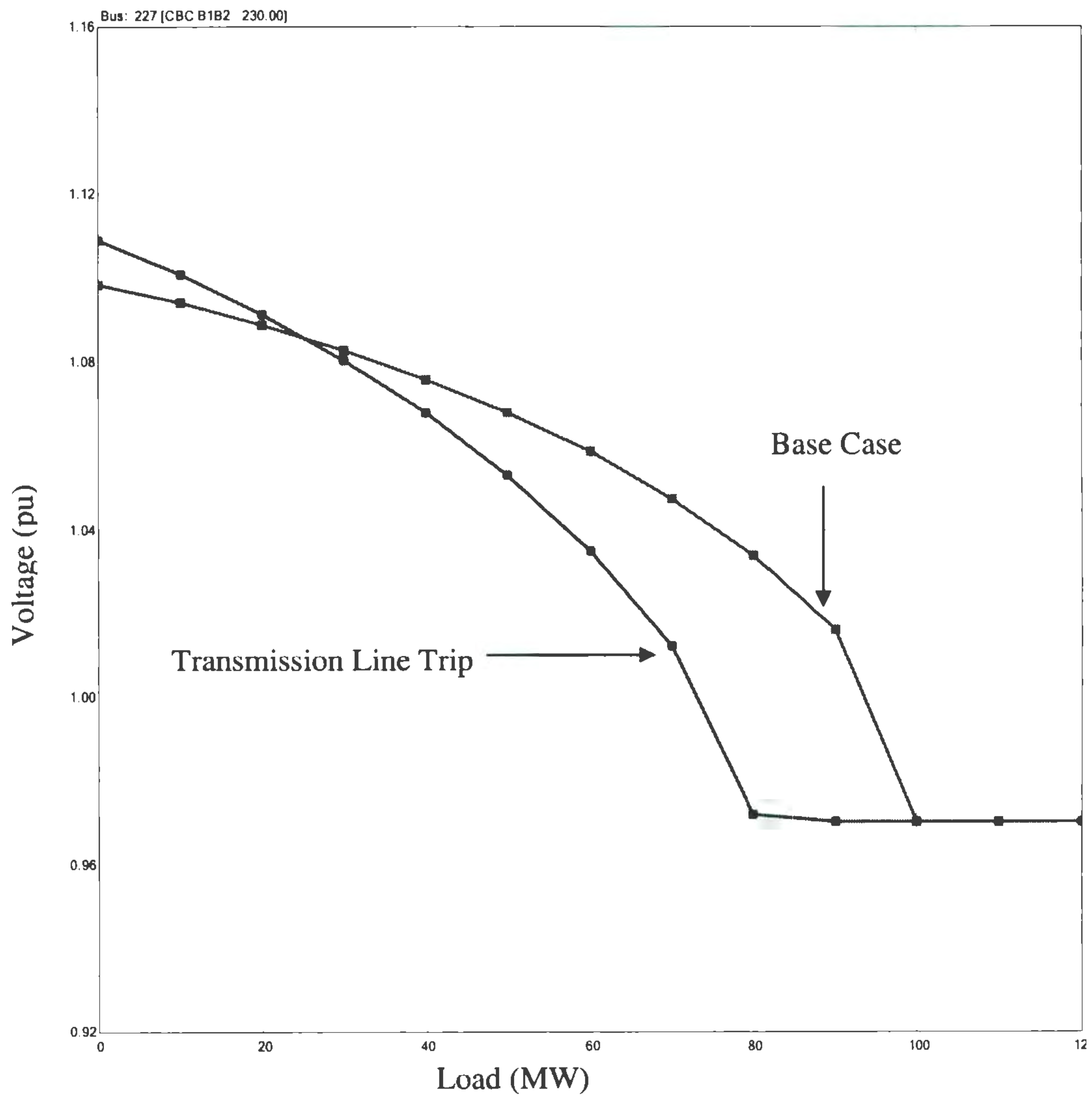

Figure 6.3: P-V curve for test system

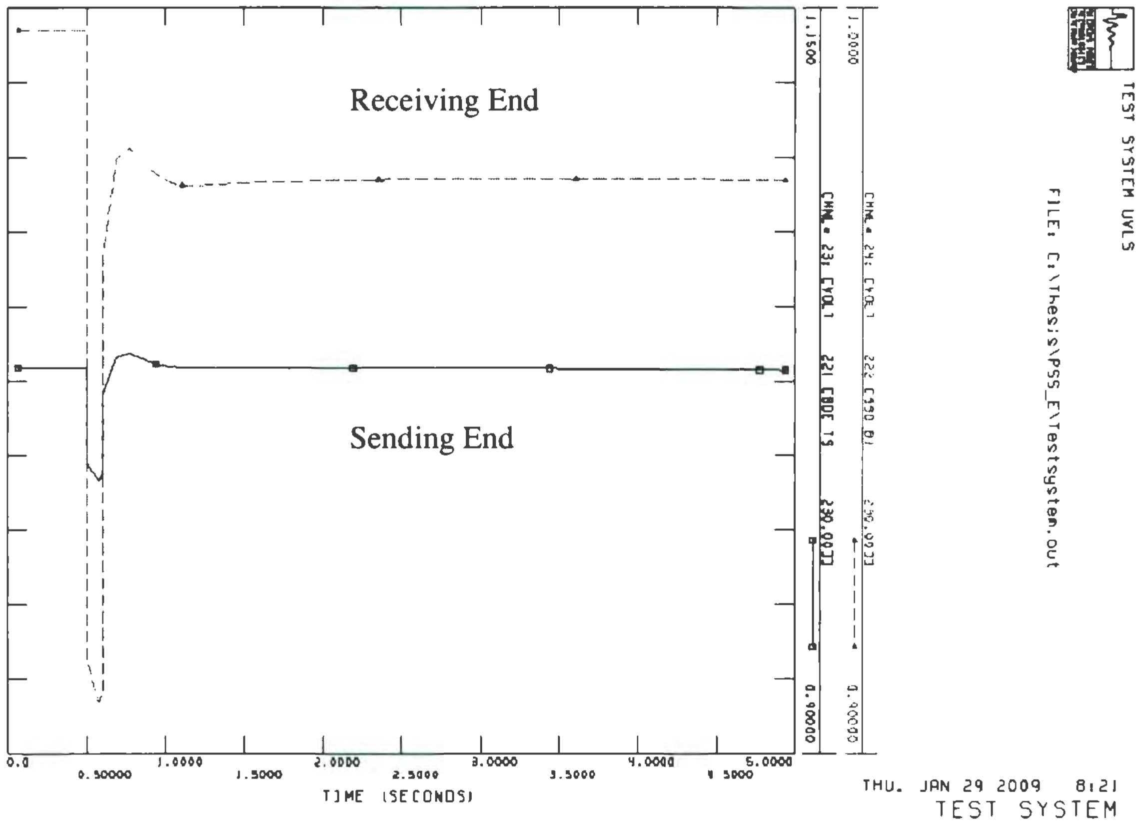

Figure 6.4: Voltage response following loss of transmission line and UVLS

Figure 6.4 depicts the system response for the application of the UVLS scheme to the test system following the line loss contingency. Inspection of the figure reveals that the receiving voltage decreases significantly (to approximately 0.90 pu) following the contingency and recovers to near nominal values following curtailment of 20 MW of load at the receiving bus. However, inspection of the figure reveals that the receiving end voltage stabilized at less than 0.98 pu following load curtailment and indicates that additional loadshedding or other corrective action may be required to restore the voltage to precontingency values.

6.5 Summary

The application of a load curtailment strategy in response to a low frequency or low voltage is demonstrated for a simple test system. The effectiveness of the strategy is evident from the restoration of voltage and frequency stability following either a generation or transmission loss contingency.

Chapter 7

Application: UFLS Methodology on the Newfoundland System

7.1 Introduction

The interconnected island power system of Newfoundland is electrically isolated from the North American power system and is significantly smaller in respect to total inertia. The principal generation sources for the Newfoundland system are hydralic and thermal with hydralic sources providing approximately 65% of the peak generation. The system is depicted in detail in Figure 7.1. The 230 kV system interconnects all primary generators and forms the voltage backbone of the system. Other transmission voltages, 138 kV and 69 kV, comprise the remainder of the system and interconnect other load centers on the island. The inset of Figure 7.1, showing the Labrador interconnected system, is not electrically connected to the island grid and is not considered in this thesis.

For the current thesis, it is assumed that the operating philosophy of the interconnected island system is to operate all generators at maximum efficiency. The system cannot rely upon external sources of generation to meet demand during contingencies and therefore has a limited operating reserve. These operating characteristics require implementation of an UFLS schedule to maintain frequency stability following generation loss contingencies since the system cannot recover from a significant generation deficiency through reliance on external sources.

7.2 System Description

The electrical grid of the island of Newfoundland operates as an isolated power system and has a total combined peak generating capacity of approximately 1700MW. There are other smaller generation sources connected to the system but these units are synchronized only during emergency conditions and, for the present work, are not considered as part of the peak system inertia. The interconnected island system under consideration is comprised of a thermal generating plant, two gas turbines and nine hydraulic plants with a combined inertia of some 8500 MJ. The hydraulic generation assets include plants at Bay d'Espoir (616 MW), Hinds Lake (75MW), Upper Salmon (84 MW), Cat Arm (127 MW), Paradise River (8 MW) and Granite Canal (42 MW) as well as other smaller non-dispatchable hydraulic generation.

The two gas turbines, Stephenville on the west coast and Hardwoods on the east coast, have a combined generation capacity of 108 MW, and are used primarily during periods of peak operation as active generation sources but routinely function as synchronous condensers and thereby contribute to system voltage regulation. The 500 MW thermal facility, situated on the east coast, contains three generators and functions as an important source of active generation for the system as well as providing voltage support for the east coast. Further, one of the units at Holyrood is capable of operation as a synchronous condenser and has a rated output of approximately 150 MVAr. The transmission system contains approximately 3800 km of high voltage transmission lines and includes 1600 km of 230 kV lines, 1500 km of 138 kV lines and 650 km of 69 kV lines.

Table 7.1: Newfoundland island system primary generator listing

Generator Summary of Newfoundland System				
Machine	**MVA**	**MW**	**H (MW*sec/MVA)**	**MW*sec**
BDE 1	85	75	5.2	442
BDE 2	85	75	5.2	442
BDE 3	85	75	5.2	442
BDE 4	85	75	5.2	442
BDE 5	85	75	5.2	442
BDE 6	85	75	5.2	442
BDE 7	172	160	4	689
HRD 1	194	175	2.6	502
HRD 2	194	175	2.6	502
HRD 3	177	150	2.8	499
HRD 3(S/C)	177		1.3	229
CAT 1	75.5	68	4.5	338
CAT 2	75.5	68	4.5	338
USL	88	84	3.7	324
HLK	83	77	6.7	558
PRV	8.9	8	3.5	31
SVL GT	63.5	54	2.2	140
HWD GT	63.5	54	2.2	140
GCL	45	41	4	180

A detailed listing of the primary generation assets is given in Table 7.1. There are seven hydraulic generators located at Bay d'Espoir (BDE), three thermal generators at Holyrood (HRD), two gas turbines at Stephenville (SVL) and Hardwoods (HWD) as well as other hydraulic generators at Upper Salmon (USL), Cat Arm (CAT), Hind's Lake (HLK) and Paradise River (PRV). The remainder of the island generation is comprised primarily of non-dispatchable hydraulic and thermal sources. Also indicated are the H constants and the inertia values for each of the primary generators.

Figure 7.1: Newfoundland interconnected electrical system [34]

7.3 Spinning Reserve

During a generation deficiency the action of the system governors will increase total system generation output and compensate for any deficiency within the limits of the remaining online generation capacity. In general, the system governors will attempt to increase or decrease generation output with time in direct proportion to the generator droop setting and the system load/generation imbalance. The governor will increase the speed of the generator by opening the machine wicket gates and allowing more water to pass through the turbine, for a hydraulic generator, or through additional opening of the steam values for a thermal unit. The variability in generator droop settings and possible generation dispatch scenarios implies that the response of spinning reserve capacity will be variable for every generation loss contingency and depends on which generators are online and their percentage loading. Some of the factors affecting governor/generator response and reaction time are the generator loading, gate opening times, water start times, boiler conditions and the generator governor droop setting. Deviations from the nominal operating frequency of 60 Hz occur in response to load variation and the continual efforts of the system governors to match the generator output to the current system loading. Generator turbines are massive devices and may weigh in excess of 100 tonnes, therefore speed and frequency variation occur continuously since frequency control through the action of the governor system is not instantaneous.

The generator droop settings for the Newfoundland interconnected system are listed in Table 7.2. Droop in an operating characteristic of generators, expressed in percent, which relates the change in turbine input power to the change in turbine rotational speed. For example, a 2% droop setting implies that the machine will increase turbine input power from 0% to 100% for a 2% change in speed (assuming the machine is initially at a no load condition) and that machines with lower droop settings will respond more quickly to speed deviations than machines with larger droop settings. Inspection of Table 7.2 reveals that the droop settings on the Newfoundland system vary between 2% and 7% and that the BDE and USL generators function as the primary frequency regulators for the system.

In general, the compensation required following a generation loss contingency is equal to the sum of the total amount of loadshedding and the contribution from spinning reserve. However, the active power contribution of spinning reserve is not instantaneous and is dependent on the system in question. Hence, the benefits of spinning reserve may not significantly offset the amount of load curtailment required following generation loss contingencies but will contribute to frequency restoration.

Table 7.2: Newfoundland island system governor droop settings

Summary of Generator Droop Settings		
Generator	Turbine Type	Droop Setting
HRD 1	Thermal	0.050
HRD 2	Thermal	0.050
HRD 3	Thermal	0.045
BDE 1	Hydro	0.020
BDE 2	Hydro	0.020
BDE 3	Hydro	0.020
BDE 4	Hydro	0.020
BDE 5	Hydro	0.020
BDE 6	Hydro	0.020
BDE 7	Hydro	0.020
USL	Hydro	0.020
HLK	Hydro	0.050
CAT 1	Hydro	0.040
CAT 2	Hydro	0.040
SVL	Gas	0.070
HWD	Gas	0.069

7.4 UFLS Evaluation Scenarios

The generation dispatch and the system inertia are determined by the system loading. As illustrated in Figure 7.2, the system demand exhibits considerable seasonal variation with typical values between approximately 450 MW to 1500 MW. In accordance with the operating philosophy of maintaining maximum economic efficiency, the unit commitment is adjusted as required to meet load variation in an attempt to match a generator with its most economic operating point. Hence, the disposition of the power system is highly variable and is not known in advance of a loadshedding event. This requires that the UFLS schedule accommodate multiple possible scenarios of generation loss and also function correctly as the system loading changes.

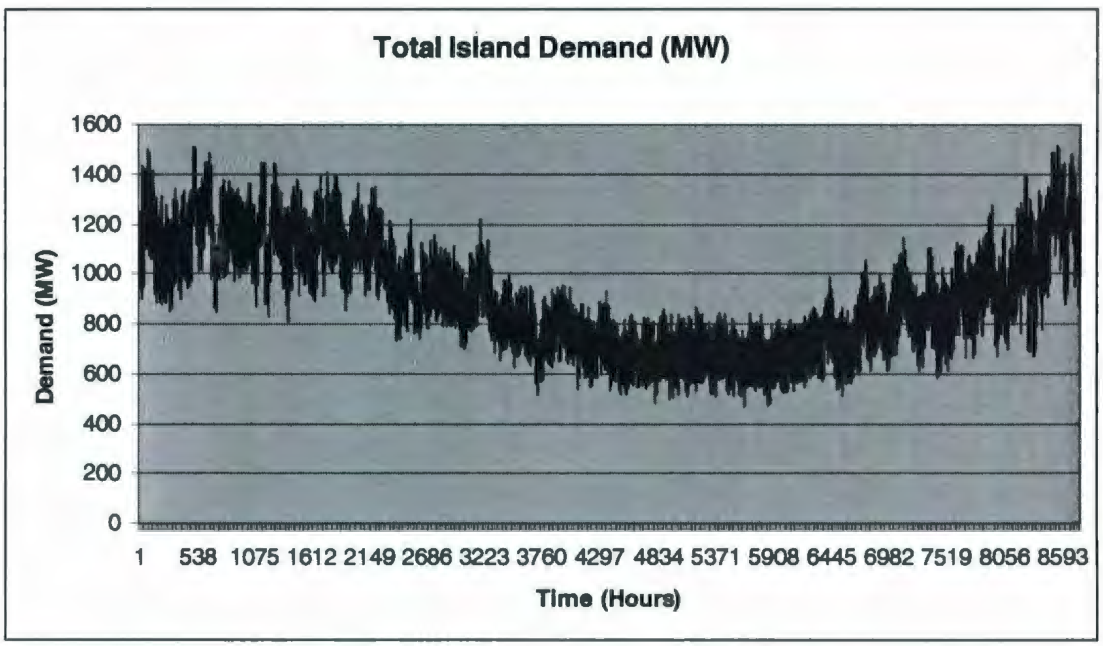

Figure 7.2: Newfoundland island annual demand variation

It is therefore necessary to simulate the response of the power system for all possible operating scenarios in order to ensure that the system remain intact following generation loss contingencies of various magnitudes. To that end, several possible generation loss contingencies, ranging from 50 MW to 175 MW will be investigated in accordance with seasonal variation in the system loading as represented in Table 7.3 to Table 7.7. These operating scenarios are summarized in Table 7.8 and will be utilized in evaluating the performance of all test UFLS schedules for variable generation loss contingencies.

Table 7.3 contains a listing of the maximum generation capability of the principal generators on the island system as well as the extreme light load case. The actual loading of the generators is detailed as well as the generation dispatch required to satisfy the load demand. Also noted is the total spinning reserve available for the operating scenario and the total stored energy in the system generators (the total inertia). The remaining tables, Table 7.4 through to Table 7.7 contain the detailed generation dispatch required to meet the load demand for the other variations possible in the system loading. Inspection reveals that actual generator loading, the total inertia and the available spinning reserve are noted for the spring 1, spring 2, summer 1, summer 2, fall 1, fall 2, winter 1 and finally, winter 2 cases. It was necessary to divide the seasonal cases into two disparate parts to accommodate maintenance cycles and to identify the variation that is possible with respect to the dispatch of the thermal units at Holyrood. These units are operated only if required and preference is given to operation of the hydraulic units provided sufficient water resources are available.

Table 7.3: System generation listing and light load case

System Generation			Light		
Unit	Inertia (MJ)	Rated MW	Actual MW	Inertia	Spinning Reserve
BDE1	442	75	50	442	25
BDE2	442	75	50	442	25
BDE3	442	75			
BDE4	442	75			
BDE5	442	75			
BDE6	442	75			
BDE7	690	160	75	690	85
CAT1	338	65			
CAT2	338	65	55	338	10
HRD1	502	175			
HRD2	502	175			
HRD3	499/229*	150			
HLK	558	75			
USL	324	85	65	324	20
DLP	401	80	79.1	401	0.9
ACG	200	75			
SLK	117	19	17.9	117	1.1
GCL	180	42	30	180	12
SVL GT	131	54			
HWD GT	131	54			
Totals	**7563**	**1724**	422	2934	179
	Peak Values		Total MW	Total Inertia	Total MW Spinning Reserve

Table 7.4: System load variation for spring cases

	Spring1			Spring2		
Unit	Actual MW	Inertia	Spinning Reserve	Actual MW	Inertia	Spinning Reserve
BDE1	50	442	25	58	442	17
BDE2	51	442	24	58	442	17
BDE3	51	442	24	58	442	17
BDE4	51	442	24	58	442	17
BDE5	51	442	24	58	442	17
BDE6	51	442	24			
BDE7	100	690	60	110	690	50
CAT1	63.5	338	1.5	60	338	5
CAT2	63.5	338	1.5	60	338	5
HRD1	130	502	45	100	502	75
HRD2	130	502	45	100	502	75
HRD3		229*				
HLK	75	558	0			
USL	84	324	1	76	324	9
DLP	79.1	401	0.9	79.1	401	0.9
ACG	60	200	15	60	200	15
SLK	17.9	117	1.1	17.9	117	1.1
GCL	42	180	0	42	180	0
SVL GT						
HWD GT						
Totals	1150	7031	316	995	5802	321
	Total MW	Total Inertia	Total MW Spinning Reserve	Total MW	Total Inertia	Total MW Spinning Reserve

Table 7.5: System load variation for summer cases

Unit	Summer1			Summer2		
	Actual MW	Inertia	Spinning Reserve	Actual MW	Inertia	Spinning Reserve
BDE1	60	442	15	50	442	25
BDE2	60	442	15			
BDE3	60	442	15			
BDE4	60	442	15			
BDE5						
BDE6						
BDE7	100	690	60	100	690	60
CAT1	64	338	1	45	338	20
CAT2				45	338	20
HRD1				70	502	105
HRD2						
HRD3		229*				
HLK						
USL	81	324	4	70	324	15
DLP	79.1	401	0.9			
ACG				60	200	15
SLK	17.9	117	1.1	17.9	117	1.1
GCL	42	180	0	25	180	17
SVL GT						
HWD GT						
Totals	624	4047	127	483	3131	278.1
	Total MW	Total Inertia	Total MW Spinning Reserve	Total MW	Total Inertia	Total MW Spinning Reserve

Table 7.6: System load variation for fall cases

Unit	Fall1			Fall2		
	Actual MW	Inertia	Spinning Reserve	Actual MW	Inertia	Spinning Reserve
BDE1	55	442	20	53	442	22
BDE2	55	442	20	53	442	22
BDE3	55	442	20	53	442	22
BDE4						
BDE5						
BDE6						
BDE7	150	690	10	100	690	60
CAT1	50	338	15	45	338	20
CAT2	50	338	15	45	338	20
HRD1	100	502	75	70	502	105
HRD2	100	502	75			
HRD3					229*	
HLK						
USL	70	324	15	70	324	15
DLP	79.1	401	0.9	79.1	401	0.9
ACG				60	200	15
SLK	17.9	117	1.1	17.9	117	1.1
GCL	22	180	20	23	180	19
SVL GT						
HWD GT						
Totals	804	4718	287	669	4645	322
	Total MW	Total Inertia	Total MW Spinning Reserve	Total MW	Total Inertia	Total MW Spinning Reserve

Table 7.7: System load variation for winter cases

Unit	Winter1			Winter2		
	Actual MW	Inertia	Spinning Reserve	Actual MW	Inertia	Spinning Reserve
BDE1	55	442	20	50	442	25
BDE2	60	442	15	50	442	25
BDE3	60	442	15	50	442	25
BDE4	60	442	15	50	442	25
BDE5	60	442	15	50	442	25
BDE6	60	442	15			
BDE7	145	690	15	120	690	40
CAT1	63.5	338	1.5	45	338	20
CAT2	63.5	338	1.5	45	338	20
HRD1	175	502	0	175	502	0
HRD2	170	502	5	175	502	0
HRD3	150	499	0	113	499	37
HLK	75	558	0	60	558	15
USL	84	324	1	75	324	10
DLP	79.1	401	0.9	79.1	401	0.9
ACG	60	200	15	60	200	15
SLK	17.9	117	1.1	17.9	117	1.1
GCL	42	180	0	25	180	17
SVL GT						
HWD GT		131*			131*	
Totals	1480	7432	136	1240	6990	301
	Total MW	Total Inertia	Total MW Spinning Reserve	Total MW	Total Inertia	Total MW Spinning Reserve

Table 7.8: UFLS evaluation scenarios

CASE		System Load (MW)	System Inertia (MJ)	Lost Inertia (MJ)	Lost Generation (MW)	System Loading (pu)	Initial df/dt (Hz/sec)
Winter1	1	1480	7432	502	175	0.86	0.76
	2	1480	7432	690	150	0.86	0.67
	3	1480	7432	502	100	0.86	0.43
	4	1480	7432	558	75	0.86	0.33
	5	1480	7432	338	50	0.86	0.21
Winter2	6	1240	6990	502	175	0.72	0.81
	7	1240	6990	690	150	0.72	0.71
	8	1240	6990	502	100	0.72	0.46
	9	1240	6990	558	75	0.72	0.35
	10	1240	6990	338	50	0.72	0.23
Spring1	11	1150	7031	502	175	0.67	0.80
	12	1150	7031	690	150	0.67	0.71
	13	1150	7031	502	100	0.67	0.46
	14	1150	7031	558	75	0.67	0.35
	15	1150	7031	338	50	0.67	0.22
Spring2	16	995	5802	502	175	0.58	0.99
	17	995	5802	690	150	0.58	0.88
	18	995	5802	502	100	0.58	0.57
	19	995	5802	558	75	0.58	0.43
	20	995	5802	338	50	0.58	0.27
Fall1	21	804	4718	690	150	0.47	1.12
	22	804	4718	502	100	0.47	0.71
	23	804	4718	558	75	0.47	0.54
	24	804	4718	338	50	0.47	0.34
Fall2	25	669	4645	690	100	0.39	0.76
	26	669	4645	558	75	0.39	0.55
	27	669	4645	338	50	0.39	0.35
Summer1	28	624	4047	690	100	0.36	0.89
	29	624	4047	558	75	0.36	0.64
	30	624	4047	338	50	0.36	0.40
Summer2	31	483	3131	690	100	0.28	1.23
	32	483	3131	558	75	0.28	0.87
	33	483	3131	338	50	0.28	0.54
Light	34	422	2934	690	75	0.24	1.00
	35	422	2934	338	50	0.24	0.58
Note: Peak system load is assumed to be 1700 MW							

Table 7.8 contains a summary of the scenarios that will be used to evaluate the performance of potential UFLS schedules. The effect of seasonal load variation on the system generation dispatch and total system inertia is represented by 35-generation loss contingencies. Also indicated in Table 7.8 is the percent of maximum system loading. This parameter has a significant effect on the performance of UFLS schedules since it partially determines the total amount of load that will be shed by an UFLS schedule during a generation loss contingency.

Consider case 1 through case 5 of the winter 1 scenarios in Table 7.8. Recall that the winter 1 scenario, as presented in Table 7.7 corresponds to 1480 MW of total system load and 7432 MJ of system inertia. Case 1 represents the effect of a generation loss contingency for one of the thermal units at Holyrood loaded at 175 MW. Inspection reveals that for the winter 1 scenario, the system is loaded at 0.87 pu of peak (where peak loading is assumed to be 1700 MW) and therefore it is assumed that the distribution feeders on the system are also loaded at 0.87 pu of maximum. Hence, the load available to trip for the purpose of loadshedding will be 0.87 pu (of the peak value assigned to a specific loadshedding schedule) since the load associated with each frequency threshold is represented at its peak value. Similarly, case 2 represents the generation loss scenario for unit 7 at BDE loaded at 150 MW. Also indicated in Table 7.8 is the initial df/dt for the system frequency subsequent to the corresponding generation loss contingency. For example, in case 2, the initial df/dt is 0.67 Hz/sec ((30)(150)/(7432-690)) as per equation 4.1.

7.5 Methodology Application

The UFLS methodology applied will be to disconnect predetermined amounts of load at specific frequency thresholds in response to a generation loss contingency. The load will be disconnected from the power system following the activation of frequency relays at specified tripping thresholds as the system frequency declines. The sequence of relay operations will continue until the decay of the system frequency is arrested and the balance between the available generation and connected load has been restored. Typically, the final restoration of a nominal operating frequency will be achieved through the action of AGC (automatic generation control) on the system generators. The methodology described previously in section 4.4 will now be applied to the Newfoundland island system.

The total load assigned to the UFLS schedules is primarily determined based on the magnitude of the worst case N-1 generation contingency. For the island system, this is the loss of a 175 MW unit at HRD and therefore any proposed UFLS schedule must have at least 175 MW of load assigned to the schedule. However, this assignment is complicated by load variation on the system since the load assigned to the UFLS schedule will change from 1.0 pu to 0.5 pu (for example) in proportion to a corresponding variation in the system load; that is, the amount of load assigned to the schedule varies in proportion to the percent loading of the distribution feeders on the system. Therefore, there must be 175 MW of load assigned to the schedule whenever a 175 MW generator is online. If the system is at 0.5 pu of maximum loading, this dictates that the amount of load assigned to the schedule (for an N-1 contingency) must be 350

MW (i.e. 175/0.5) to ensure system recovery during a 175 MW generation loss contingency. Inspection of the test UFLS schedules in Table 7.9 reflects this fact in that there is a total of 350 MW of load allocated to counter an N-1 contingency. Furthermore, when the system is at 0.5 pu of maximum load, twice as many load shedding trip points will be reached since the frequency excursion will penetrate twice as far into the schedule (this is assuming an absence of generation recovery due to spinning reserve) when compared to system operation at maximum loading. A final block of load is added to the lowest stages of the UFLS schedules and is intended to trip only during unusual generation contingencies. This final block of loadshedding functions as a "safety net" for the power system and is intended to safeguard the system during N-2 or greater contingencies and therefore is expected to operate infrequently.

The trip levels (i.e. frequency relay trip settings) are established by referencing the maximum and minimum acceptable levels for normal frequency operation. In the case of the Newfoundland interconnected system, these levels are assumed to be 59 Hz and 57.7 Hz. The rationale for these choices is that for less severe generation contingencies (i.e. less than 50 MW), the system may recover sufficient generation from stored energy and spinning reserve to maintain an operating frequency greater than 59.0 Hz. The minimum acceptable frequency is established through consideration of the damage curves for the HRD thermal units. To avoid damage caused by operation at reduced frequency, these units will trip instantaneously at 57 Hz and with a inverse time-delayed characteristic at 57.6 Hz.

The separation of the frequency thresholds is established through consideration of the maximum expected df/dt following the worst case N-1 contingency (i.e. a 175 MW generation loss) and the operating time of circuit breakers and auxiliary relaying. When the system is at full load, this contingency will result in a df/dt of approximately 0.7 Hz/sec and implies that the system frequency will require 1.43 sec to decay by 1 Hz. Assuming that circuit breaker operation and all auxiliary relaying requires 200 mSec to operate implies that the minimum separation of the loadshedding trip frequencies is 0.139 Hz to ensure proper co-ordination of the stages. If the tripping thresholds are not coordinated, a lower threshold may operate before the effect of loadshedding at a previous stage is realized and excess loadshedding will occur. At 0.5 pu loading, a 175 MW generation contingency will result in an increased df/dt due to the reduced inertia. For example, at approximately 5000 MJ, a 175 MW deficiency results in a df/dt of 1.05 Hz/sec and requires a minimum separation between tripping stages of 0.21 Hz. It is reasonable therefore, to conclude that the minimum separation of the loadshedding thresholds is 0.2 Hz.

In order to increase the selectivity of the UFLS schedules and to derive maximum benefit from spinning reserve, the number of frequency thresholds will be the maximum number possible. The schedule selectivity is increased by this approach since the greater number of load blocks offer increased variation with respect to the total amount of load shed in response to the variation in possible generation contingencies. Similarly, the greatest possible number of loadshedding blocks will result in more gradual decreases in df/dt following circuit breaker operations and will maximize the total amount of time available for online spinning reserves to become active. Furthermore, the shedding of smaller amounts of load at each frequency threshold will be less disruptive for system voltage integrity than shedding larger blocks of load. For the present application, the number of tripping thresholds is (59 Hz – 57.7 Hz)/0.2 Hz = 6 if the minimum separation is 0.2 Hz for all stages. In addition, any loadshedding that occurs at higher stages of the schedule will decrease the df/dt and will permit a decreased separation of the tripping thresholds at lower stages of the schedule. Hence, 6 tripping thresholds is the minimum number required but if the threshold separation is decreased to 0.1 Hz in the lower stages of the schedule, a slightly greater number of stages may be possible.

To achieve a uniform load distribution in the loadshedding stages, the load assigned to each trip level is simply 175 MW divided into three partitions for the 1.0 pu system loading occurrence and 175 MW divided into six partitions for the 0.5 pu system loading occurrence. Otherwise stated, the load assigned to trip for the upper six stages of any test schedule is 350 MW at full load and 175 MW at 0.5 pu loading and therefore, the schedule can accommodate the loss of the largest online unit (i.e. 175 MW) at 0.5 pu loading while still maintaining security of the UFLS schedule. However, the LOU is restricted to 175 MW when the system is at 0.5 pu of maximum loading. As the system load decreases to values less that 0.5 pu, the size of the largest online unit (LOU) must be reduced proportionately since there will insufficient load available in the underfrequency loadshedding schedule to counter a generation loss contingency involving this unit. The worst case N-1 contingency, the loss of 175 MW, will not require activation of the schedule "safety net" since there should be sufficient load available for loadshedding in the higher stages of the schedule if the system load is greater than or equal to 0.5 pu of maximum.

7.5.1 UFLS Evaluation Schedules

Six UFLS schedules were selected for evaluation and will permit a comparison of schedule variation and performance. These choices were felt to provide an adequate exploration for variation in trip frequencies and amount of load shed (i.e. Ld) per frequency trip point. The schedules are proportionate in that the load assigned to shed at the respective trip frequencies is twice the LOU sizing (i.e. 175 MW) divided by the number of loadshedding levels. The total amount of load available to shed during underfrequency events is arbitrarily preset at 620 MW (approximately 36% of the peak system loading) for each of the six schedules and is a conservative figure representative of the loss of either the BDE or HRD generation facilities. The result is a variation in the amount of load shed at each of the trip frequencies between of 2.9% to 4.1% of the peak system loading and will permit the LOU to be 175 MW for all cases when the system load is between 50% and 100% of maximum capacity. For those cases when the system loading is less than 0.5 pu, the size of the LOU will be proportionately reduced.

Consider the load distribution in Schedule 1 (Table 7.9). The loss of the LOU will result in a frequency excursion which will be countered prior to tripping the schedule "safety net" at 57.9 Hz and 57.8 Hz assuming that the system is at least 0.5 pu of maximum loading. When at maximum loading, the loss of the LOU will be countered after tripping the 58.6 Hz load block. Clearly, the loss of a second generating unit will result in loadshedding beyond the normal contingency loadshedding and may initiate operation of the safety net. The loadshedding stages are equally spaced at 0.2 Hz for the normal contingency cases and generally at 0.1 Hz for the safety net levels. The separation of the trip frequencies (i.e. 0.1 Hz) is justifiable since the df/dt will be greatly reduced through activation of the upper levels of the UFLS schedule. In addition, generation increases due to spinning reserve are expected to further decrease the required separation of the safety net trip settings. The upshot is that the system frequency will require an increased amount of time to traverse the schedule thresholds for the safety net settings due to a reduced df/dt.

To reiterate, the primary function of UFLS is to correct the imbalance between generation and load through the timely application of a loadshedding methodology. The secondary function of UFLS is to minimize service interruptions and requires that the schedule not shed more load than is necessary. The variation in the system loading has a significant effect on the design and functioning of UFLS schedules. The loading values represented in the UFLS schemes (Table 7.9) are peak values and decrease in proportion to the system load. In this thesis, it is assumed that the load blocks associated with an UFLS schedule contain 1.0 pu MW at peak load and decrease in proportion to the decreased system loading such that the UFLS schedule contains 0.5 pu MW at 0.5 pu of peak load. Hence, the effect of a generation loss is exacerbated during light loading since there is reduced load available in the UFLS schedule and fewer online generators to provide spinning reserve and rotating inertia.

Table 7.9: Test UFLS schedules

Schedule 1			Schedule 2			Schedule 3		
Trip Freq	Ld (MW)	Ld (pu)	Trip Freq	Ld (MW)	Ld (pu)	Trip Freq	Ld (MW)	Ld (pu)
59.0	58	0.034	59.0	50	0.029	58.8	70	0.041
58.8	58	0.034	58.8	50	0.029	58.6	70	0.041
58.6	58	0.034	58.6	50	0.029	58.4	70	0.041
58.4	58	0.034	58.4	50	0.029	58.2	70	0.041
58.2	58	0.034	58.2	50	0.029	58.0	70	0.041
58.0	58	0.034	58.1	50	0.029	57.9	100	0.058
57.9	100	0.058	58.0	50	0.029	57.8	170	0.098
57.8	170	0.098	57.9	100	0.058			
			57.8	170	0.098			
Total	620	0.359	Total	620	0.359	Total	620	0.359

Schedule 4			Schedule 5			Schedule 6		
Trip Freq	Ld (MW)	Ld (pu)	Trip Freq	Ld (MW)	Ld (pu)	Trip Freq	Ld (MW)	Ld (pu)
58.8	58	0.034	58.7	58	0.034	58.9	50	0.029
58.6	58	0.034	58.5	58	0.034	58.7	50	0.029
58.4	58	0.034	58.3	58	0.034	58.5	50	0.029
58.2	58	0.034	58.1	58	0.034	58.3	50	0.029
58.1	58	0.034	58.0	58	0.034	58.1	50	0.029
58.0	58	0.034	57.9	58	0.034	58.0	50	0.029
57.9	100	0.058	57.8	100	0.058	57.9	50	0.029
57.8	170	0.098	57.7	170	0.098	57.8	100	0.058
						57.7	170	0.098
Total	620	0.359	Total	620	0.359	Total	620	0.359

7.5.2 Simulation Results

The performance evaluation of the possible UFLS schedules will be primarily based on minimizing both the total amount of excess loadshedding (i.e. overshedding) and maximizing the minimum frequency. Each of these figures is an indicator of schedule performance and are useful when making relative comparisons. The total amount of overshedding for each generation contingency is totaled over the 35 representative cases and the total amount of load shed will be compared to the net generation loss for the set of scenarios. The schedule that exhibits the best performance will have the least amount of overshedding. The minimum amount of overshedding is desirable since this represents a minimum load loss for the utility and a minimum power disruption for customers. In addition, the average load shed per schedule is computed and serves as a secondary indicator of schedule performance. Finally the average minimum frequency and absolute minimum frequency are noted to indicate the relative frequency penetration into the schedule.

The "overshed" is the amount of load that was disconnected from the system in response to the particular generation loss contingency. A negative value of overshed (that is, undershed) indicates that the amount of loadshed was less than the initial generation deficiency whereas a positive value indicates loadshedding in excess of the initial generation deficiency. The minimum frequency is the lowest frequency reached during a particular case and is the point where the df/dt changes from negative to positive. Simulation results for each of the schedules are presented in Tables 7.10 through Table 7.12 and are summarized in Table 7.13.

Table 7.10: UFLS test results – 1

CASE	Schedule 1 Total Load Shed (MW)	Schedule 1 Overshed (MW)	Schedule 1 Minimum Frequency (Hz)	Schedule 2 Total Load Shed (MW)	Schedule 2 Overshed (MW)	Schedule 2 Minimum Frequency (Hz)
1	149	-26	58.54	214	39	58.39
2	149	-1	58.58	129	-21	58.56
3	99	-1	58.79	86	-14	58.77
4	50	-25	58.96	43	-32	58.96
5	0	-50	59.40	0	-50	59.40
6	208	33	58.37	180	5	58.35
7	125	-25	58.51	180	30	58.38
8	83	-17	58.76	72	-28	58.75
9	42	-33	58.93	35	-40	58.91
10	0	-50	59.24	0	-50	59.24
11	193	18	58.36	167	-8	58.34
12	116	-34	58.42	167	17	58.37
13	77	-23	58.76	67	-33	58.71
14	39	-36	58.89	34	-41	58.84
15	0	-50	59.19	0	-50	59.19
16	167	-8	58.32	202	27	58.18
17	167	17	58.35	144	-6	58.33
18	100	0	58.59	86	-14	58.57
19	67	-8	58.77	58	-17	58.77
20	0	-50	58.85	0	-50	58.85
21	135	-15	58.25	163	13	58.16
22	81	-19	58.51	116	16	58.38
23	54	-21	58.68	70	-5	58.59
24	27	-23	58.93	23	-27	58.89
25	112	12	58.37	97	-3	58.35
26	68	-7	58.57	58	-17	58.54
27	45	-5	58.79	39	-11	58.78
28	105	5	58.35	90	-10	58.33
29	63	-12	58.55	90	15	58.39
30	42	-8	58.77	36	-14	58.77
31	113	13	58.17	98	-2	58.14
32	81	6	58.35	70	-5	58.33
33	49	-1	58.58	42	-8	58.57
34	71	-4	58.31	85	10	58.17
35	43	-7	58.56	37	-13	58.43
Summary	Total Load Shed	Total Overshed	Average Frequency	Total Load Shed	Total Overshed	Average Frequency
	2920	-455	58.64	2978	-397	58.59

Table 7.11: UFLS test results – 2

CASE	Schedule 3			Schedule 4		
	Total Load Shed (MW)	Overshed (MW)	Minimum Frequency (Hz)	Total Load Shed (MW)	Overshed (MW)	Minimum Frequency (Hz)
1	180	5	58.37	149	-26	58.35
2	120	-30	58.51	149	-1	58.38
3	60	-40	58.71	50	-50	58.63
4	60	-15	58.78	50	-25	58.77
5	0	-50	59.40	0	-50	59.40
6	151	-24	58.33	167	-8	58.17
7	151	1	58.37	125	-25	58.34
8	101	1	58.58	83	-17	58.58
9	50	-25	58.76	42	-33	58.72
10	0	-50	59.24	0	-50	59.24
11	186	11	58.19	155	-20	58.16
12	140	-10	58.36	116	-34	58.25
13	94	-6	58.57	77	-23	58.57
14	47	-28	58.76	39	-36	58.75
15	0	-50	59.19	0	-50	59.19
16	162	-13	58.14	168	-7	58.07
17	161	11	58.19	134	-16	58.15
18	81	-19	58.54	67	-33	58.41
19	41	-34	58.62	67	-8	58.58
20	0	-50	58.85	0	-50	58.85
21	131	-19	58.02	135	-15	58.01
22	98	-2	58.38	81	-19	58.32
23	66	-9	58.55	54	-21	58.52
24	33	-17	58.76	27	-23	58.77
25	82	-18	58.26	90	-10	58.17
26	54	-21	58.44	67	-8	58.38
27	27	-23	58.71	23	-27	58.65
28	101	1	58.17	105	5	58.09
29	76	1	58.37	63	-12	58.36
30	51	1	58.59	42	-8	58.58
31	98	-2	57.96	97	-3	57.96
32	78	3	58.18	65	-10	58.13
33	40	-10	58.54	49	-1	58.39
34	69	-6	58.12	71	-4	58.06
35	51	1	58.38	43	-7	58.36
Summary	Total Load Shed	Total Overshed	Average Frequency	Total Load Shed	Total Overshed	Average Frequency
	2840	-535	58.51	2650	-725	58.47

Table 7.12: UFLS test results - 3

CASE	Schedule 5 Total Load Shed (MW)	Schedule 5 Overshed (MW)	Schedule 5 Minimum Frequency (Hz)	Schedule 6 Total Load Shed (MW)	Schedule 6 Overshed (MW)	Schedule 6 Minimum Frequency (Hz)
1	149	-26	58.25	171	-4	58.28
2	149	-1	58.28	129	-21	58.56
3	50	-50	58.56	86	-14	58.68
4	50	-25	58.68	43	-32	58.87
5	0	-50	59.40	0	-50	59.40
6	167	-8	58.07	171	-4	58.19
7	125	-25	58.25	144	-6	58.28
8	83	-17	58.47	72	-28	58.66
9	42	-33	58.66	36	-39	58.82
10	0	-50	59.24	0	-50	59.24
11	155	-20	58.06	167	-8	58.17
12	116	-34	58.16	132	-18	58.37
13	77	-23	58.46	67	-33	58.62
14	39	-36	58.65	33	-42	58.77
15	0	-50	59.19	0	-50	59.19
16	167	-8	57.98	173	-2	58.08
17	134	-16	58.05	144	-6	58.18
18	67	-33	58.33	86	-14	58.57
19	67	-8	58.49	58	-17	58.67
20	0	-50	58.85	0	-50	58.85
21	135	-15	57.92	140	-10	57.96
22	81	-19	58.22	93	-7	58.27
23	54	-21	58.42	70	-5	58.58
24	27	-23	58.66	23	-27	58.82
25	90	-10	58.07	97	-3	58.19
26	68	-7	58.28	58	-17	58.23
27	22	-28	58.58	39	-11	58.68
28	84	-16	58.01	90	-10	58.16
29	63	-12	58.26	72	-3	58.39
30	42	-8	58.48	36	-14	58.67
31	98	-2	57.86	98	-2	57.87
32	65	-10	58.04	70	-5	58.17
33	33	-17	58.31	42	-8	58.57
34	71	-4	57.96	73	-2	57.97
35	43	-7	58.27	37	-13	58.42
Summary	Total Load Shed	Total Overshed	Average Frequency	Total Load Shed	Total Overshed	Average Frequency
	2613	-762	58.38	2750	-625	58.50

Table 7.13: UFLS test results - summary

Schedule	Average Minimum Frequency (Hz)	Minimum Frequency (Hz)	Total Overshed (MW)	Total Load Shed (MW)	Average Overshed (MW)	Total Generation Deficiency (MW)
Schedule 1	58.64	58.17	-455	2920	-13.0	3375
Schedule 2	58.59	58.14	-397	2978	-11.3	3375
Schedule 3	58.51	57.96	-535	2840	-15.3	3375
Schedule 4	58.47	57.96	-725	2650	-20.7	3375
Schedule 5	58.38	57.86	-762	2613	-21.8	3375
Schedule 6	58.50	57.87	-625	2750	-17.9	3375
Note: Results Summary for Test UFLS Schedules for 35 Loss Contingencies						

Inspection of the results contained in Table 7.13 reveals that schedules 4, 5, and 6 required less loadshedding than did schedules 1, 2, and 3 and therefore represent superior performance (i.e. total loadshedding required for schedules 4, 5, and 6 was less than 2700 MW). Further inspection reveals that schedules 4 and 6 have a significantly greater average minimum frequency than schedule 5 and that schedule 4 has a greater minimum frequency than schedule 6. Therefore, schedule 4 was chosen as the optimum schedule among those proposed.

The time domain response of the system for voltage and frequency is presented in Figure 7.3 through Figure 7.20 and correspond to the results presented in Table 7.11 for schedule 4. In the interest of brevity, only the worst case generation loss contingencies are presented for each of the seasonal variants in Table 7.8. Specifically, the frequency and voltage response is given for cases 1, 6, 11, 16, 21, 25, 28, 31 and 34 at the Deer Lake, Bay d'Espoir and Western Avalon busses. These choices are intended to convey the variation in system response for the worst case scenarios at representative locations on the system.

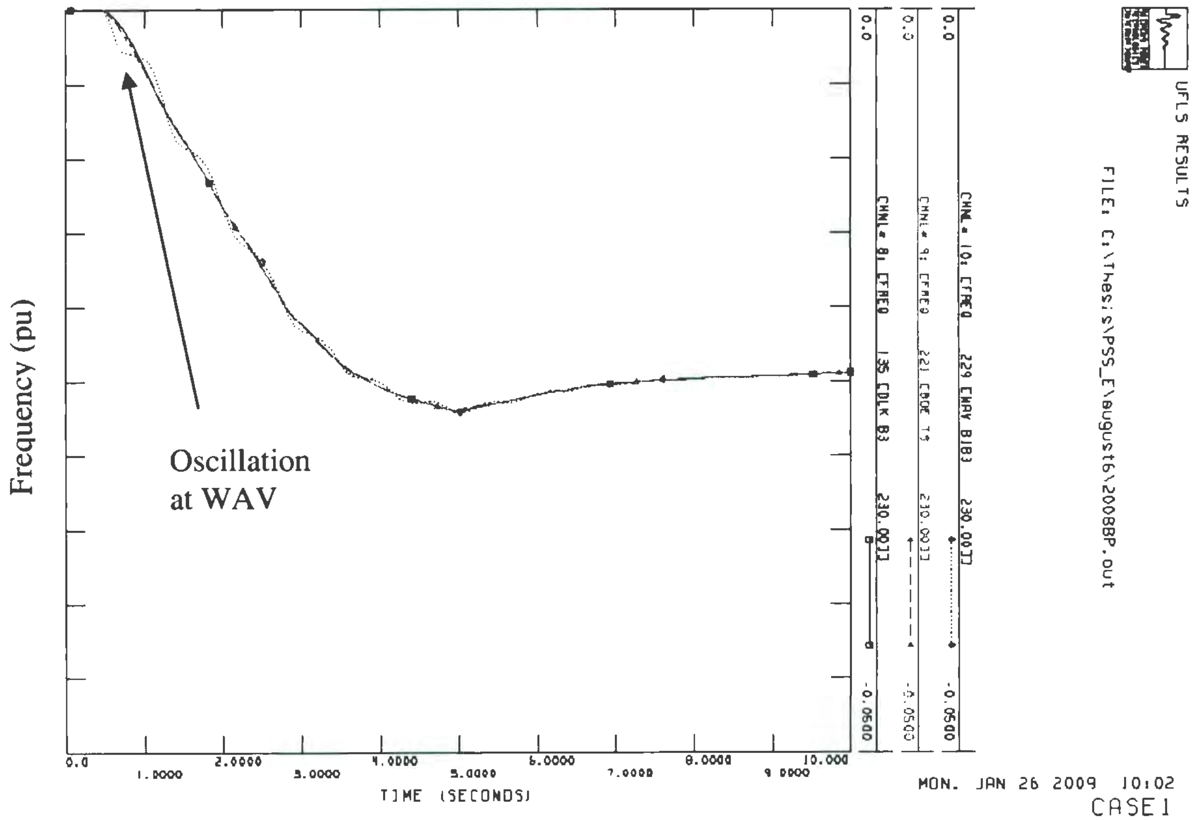

Figure 7.3: Frequency variation for schedule 4 (case 1)

Figure 7.3 depicts the frequency response for loss of a unit at Holyrood loaded at 175 MW. The total connected system inertia after the loss contingency was 6930 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the presence of synchronizing oscillations at WAV following the generation loss contingency. The minimum frequency following loadshedding of 149 MW was 58.35 Hz and indicates that 26 MW was recovered due to governor action during the event.

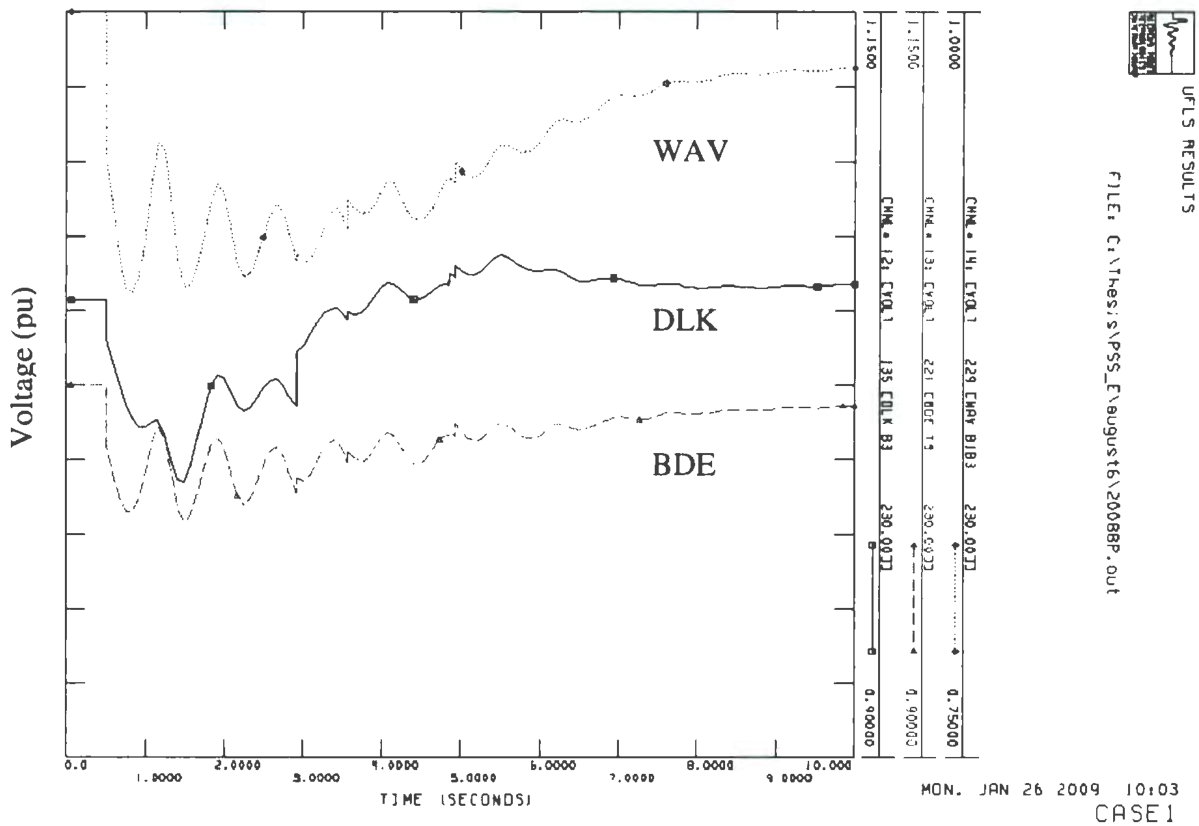

Figure 7.4: Voltage variation for schedule 4 (case 1)

Figure 7.4 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Holyrood unit loaded at 175 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. 0.907 pu. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 0.993 pu, 0.979 pu and 0.907 pu respectively.

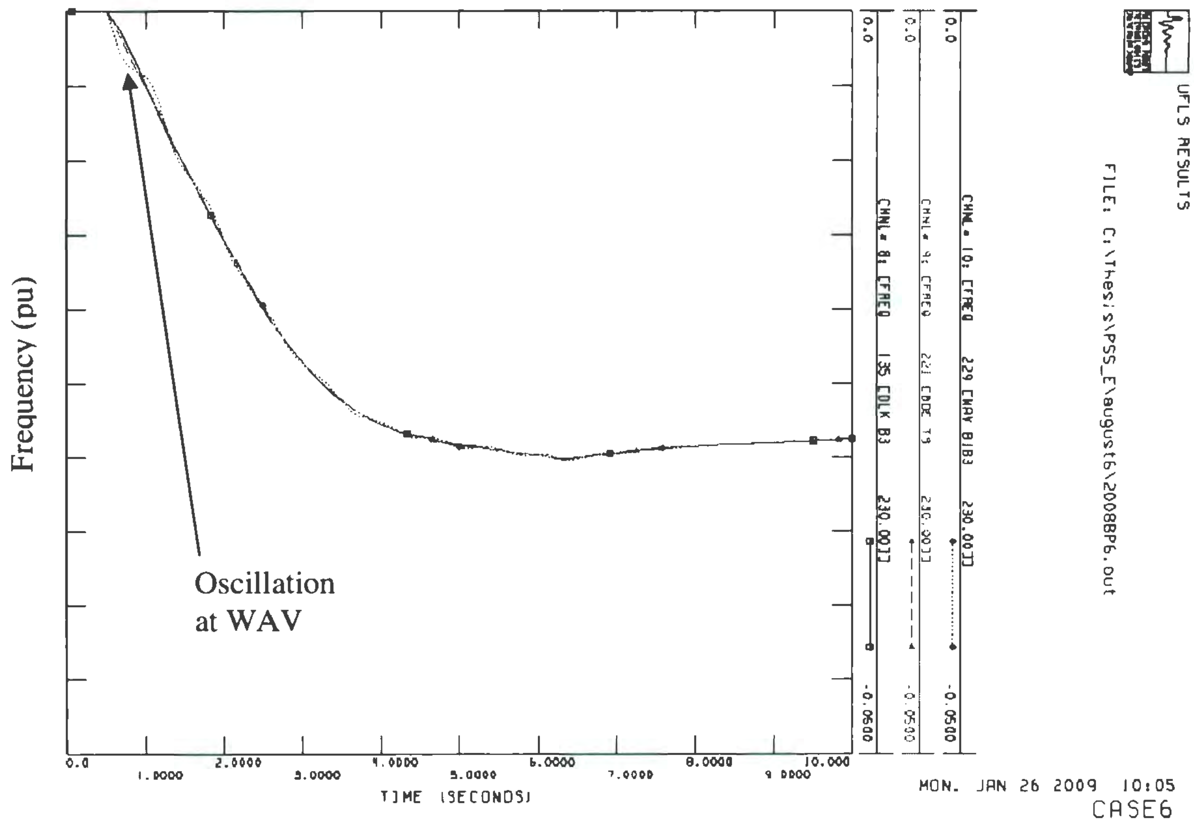

Figure 7.5: Frequency variation for schedule 4 (case 6)

Figure 7.5 depicts the frequency response for loss of a unit at Holyrood loaded at 175 MW. The total connected system inertia after the loss contingency was 6488 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the presence of synchronizing oscillations at WAV following the generation loss contingency. The minimum frequency following loadshedding of 167 MW was 58.17 Hz and indicates that 8 MW was recovered due to governor action during the event.

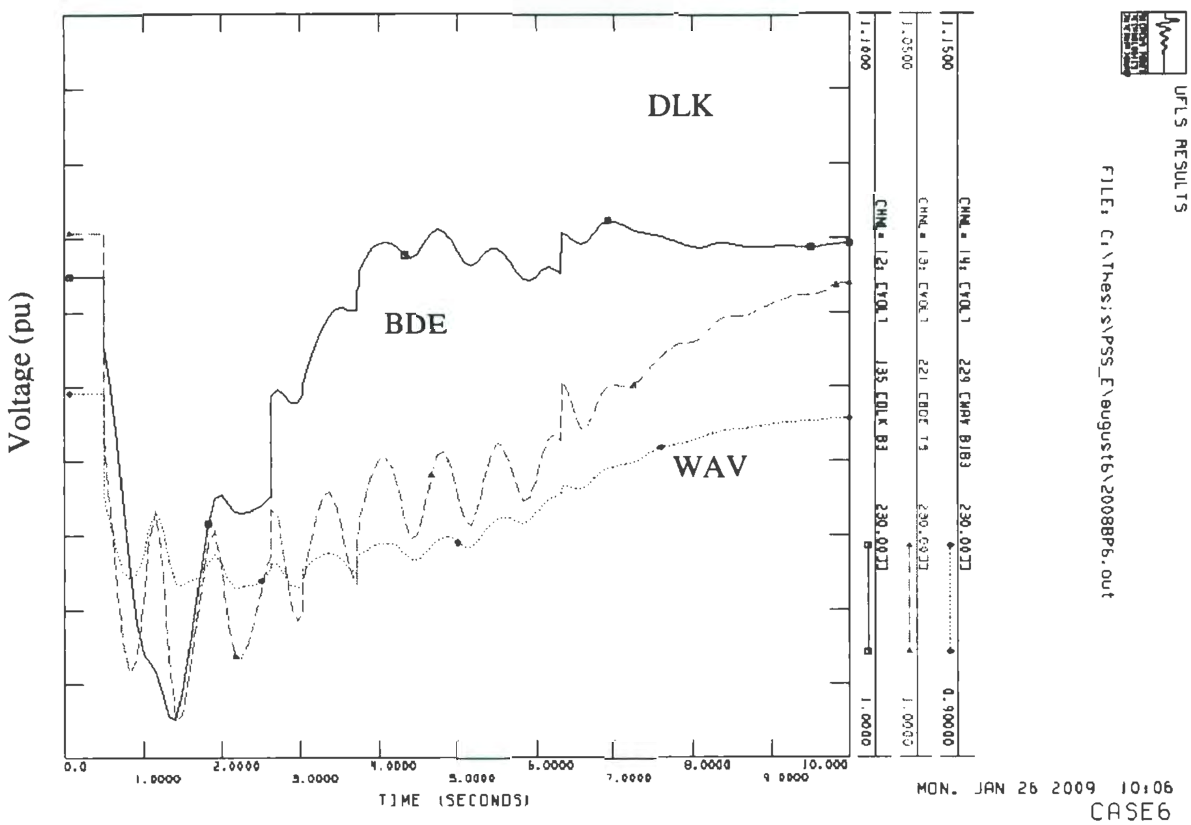

Figure 7.6: Voltage variation for schedule 4 (case 6)

Figure 7.6 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Holyrood unit loaded at 175 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.005 pu, 1.003 pu and 0.957 pu respectively.

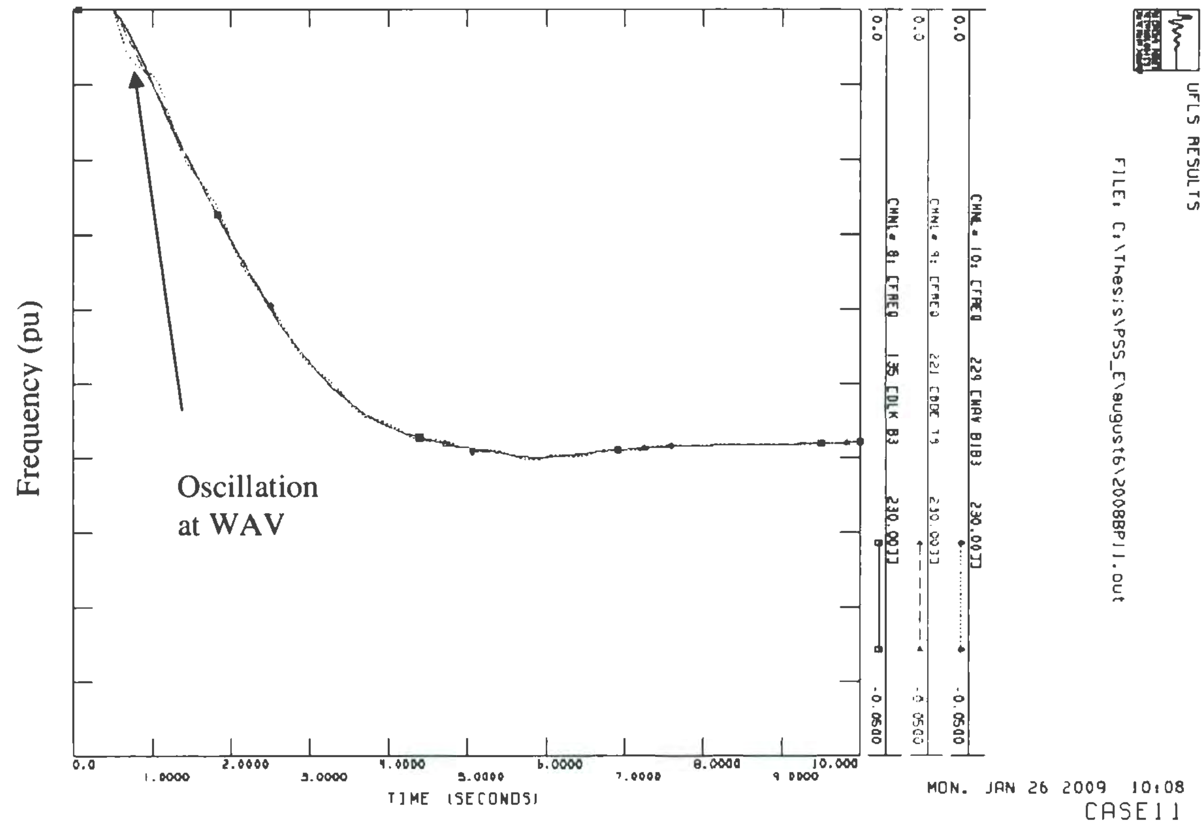

Figure 7.7: Frequency variation for schedule 4 (case 11)

Figure 7.7 depicts the frequency response for loss of a unit at Holyrood loaded at 175 MW. The total connected system inertia after the loss contingency was 6529 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the presence of synchronizing oscillations at WAV following the generation loss contingency. The minimum frequency following loadshedding of 155 MW was 58.16 Hz and indicates that 20 MW was recovered due to governor action during the event.

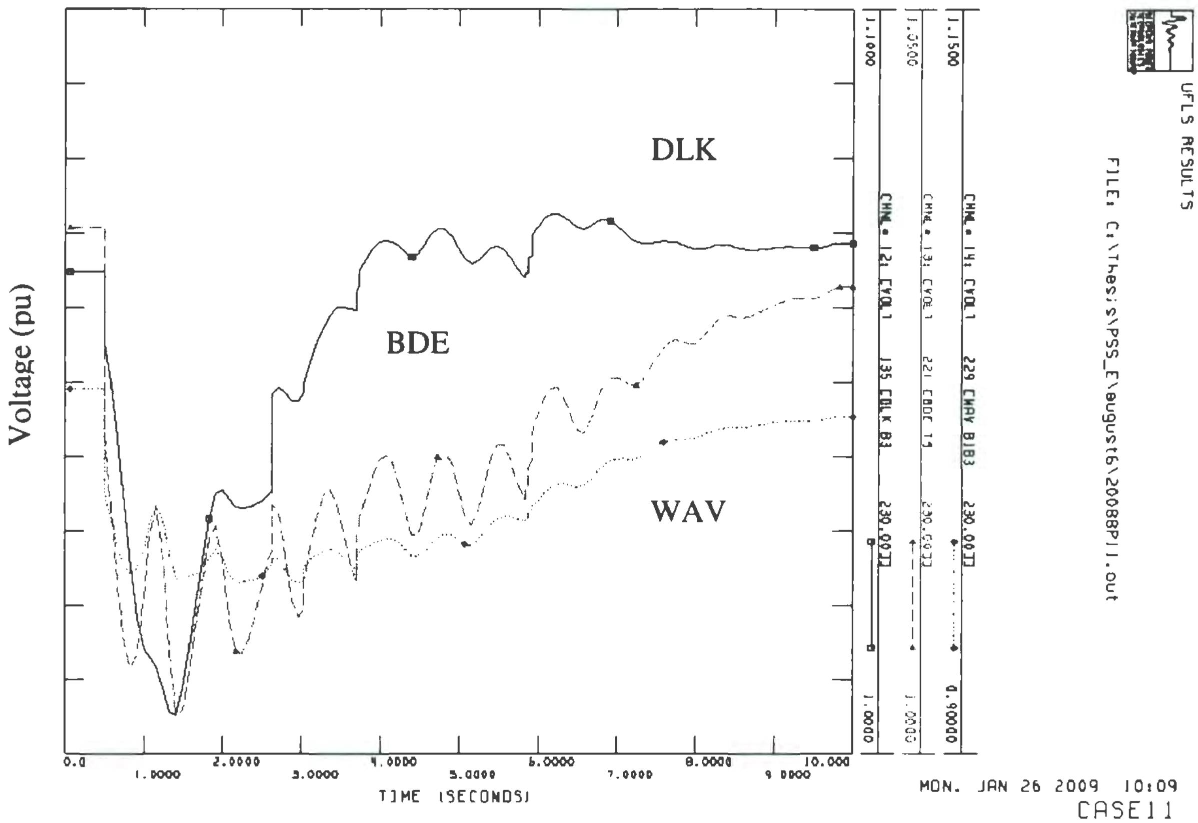

Figure 7.8: Voltage variation for schedule 4 (case 11)

Figure 7.8 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Holyrood unit loaded at 175 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.005 pu, 1.003 pu and 0.957 pu respectively.

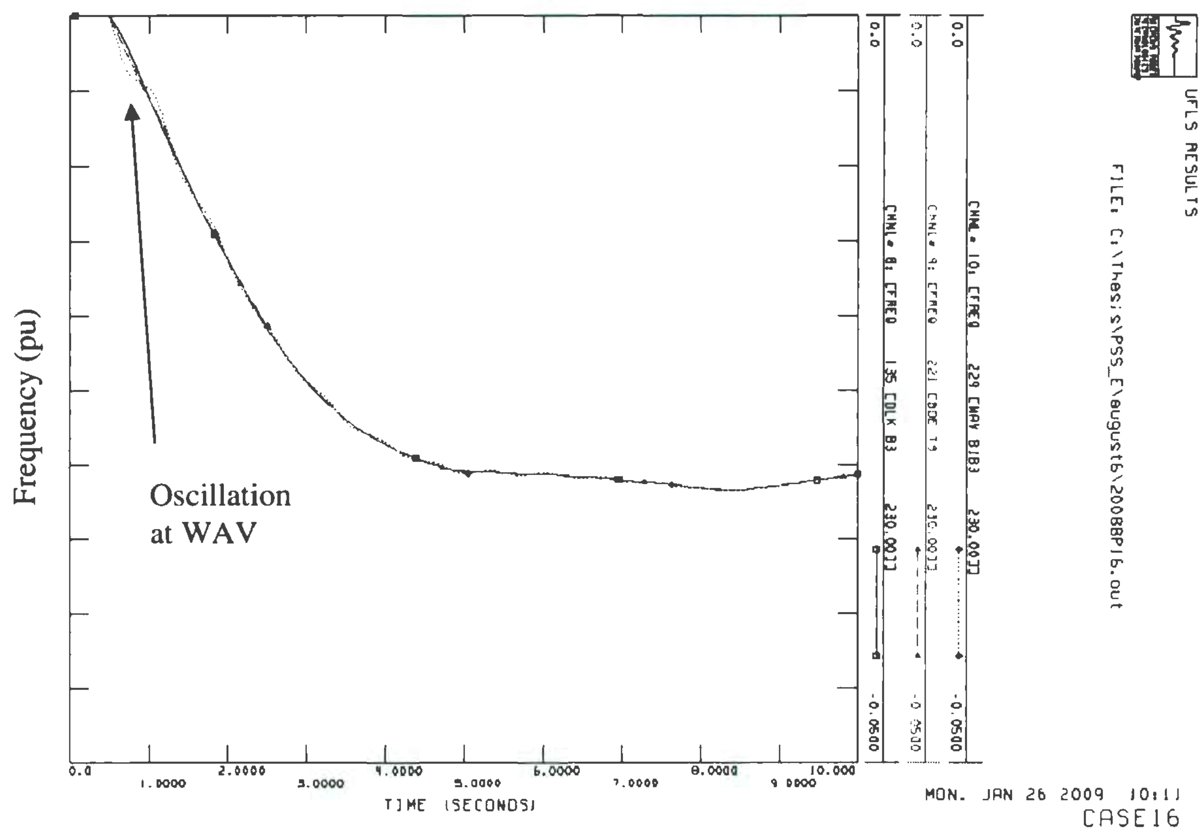

Figure 7.9: Frequency variation for schedule 4 (case 16)

Figure 7.9 depicts the frequency response for loss of a unit at Holyrood loaded at 175 MW. The total connected system inertia after the loss contingency was 5300 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the presence of synchronizing oscillations at WAV following the generation loss contingency. The minimum frequency following loadshedding of 168 MW was 58.07 Hz and indicates that 7 MW was recovered due to governor action during the event.

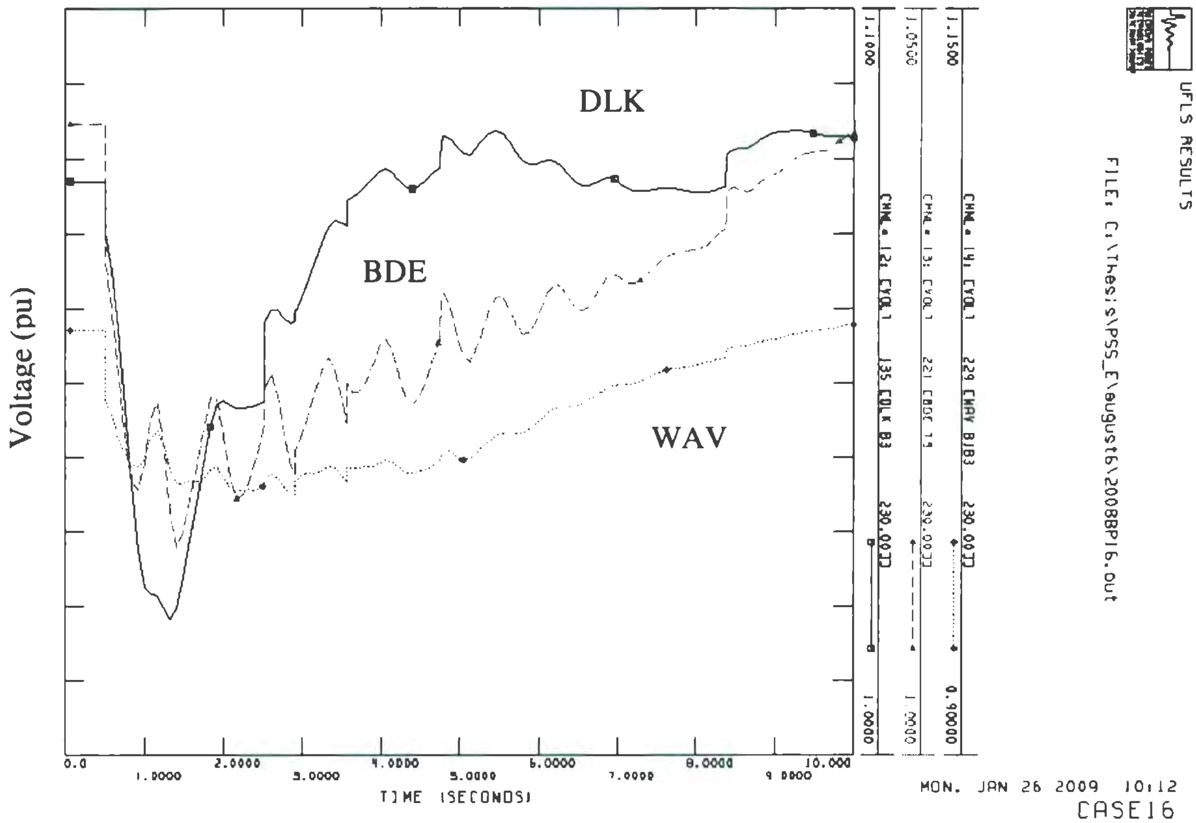

Figure 7.10: Voltage variation for schedule 4 (case 16)

Figure 7.10 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Holyrood unit loaded at 175 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.018 pu, 1.014 pu and 0.988 pu respectively.0.988 pu.

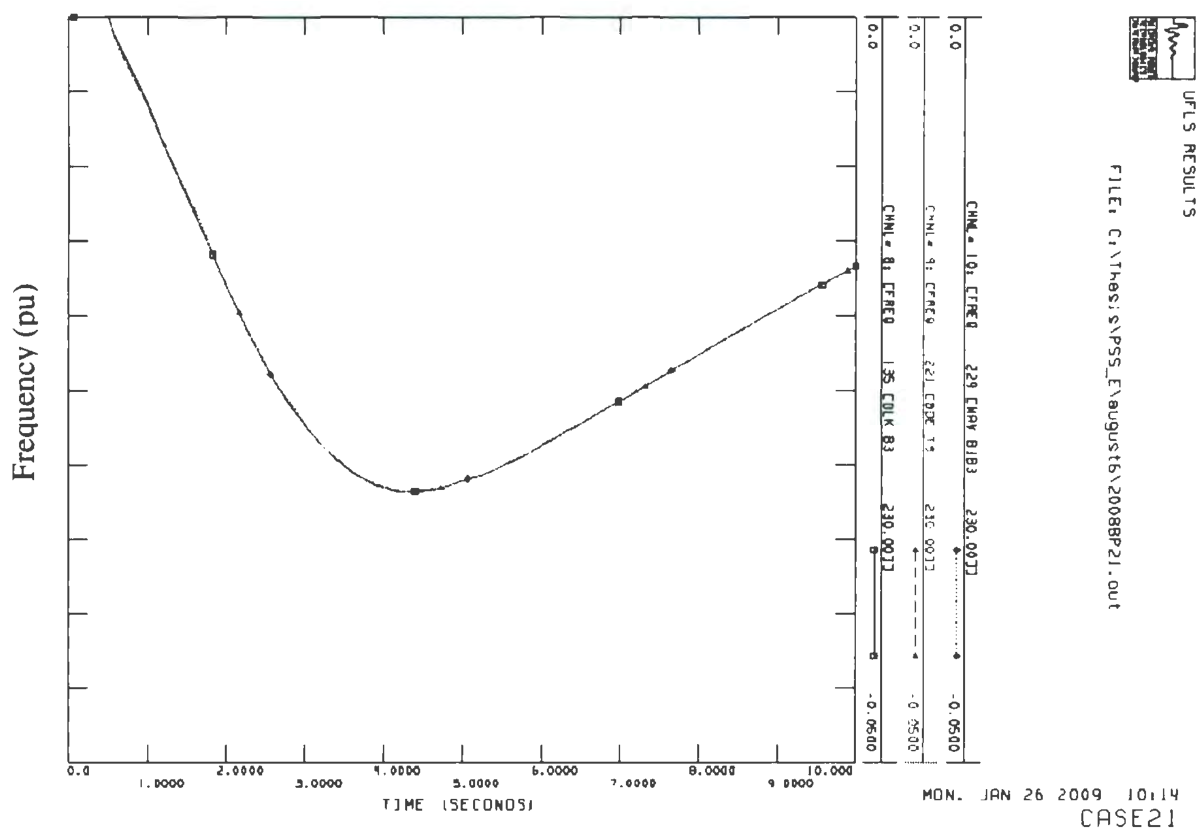

Figure 7.11: Frequency variation for schedule 4 (case 21)

Figure 7.11 depicts the frequency response for loss of a unit at Bay d'Espoir loaded at 150 MW. The total connected system inertia after the loss contingency was 4028 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the absence of synchronizing oscillations following the generation loss contingency. The minimum frequency following loadshedding of 135 MW was 58.01 Hz and indicates that 15 MW was recovered due to governor action during the event.

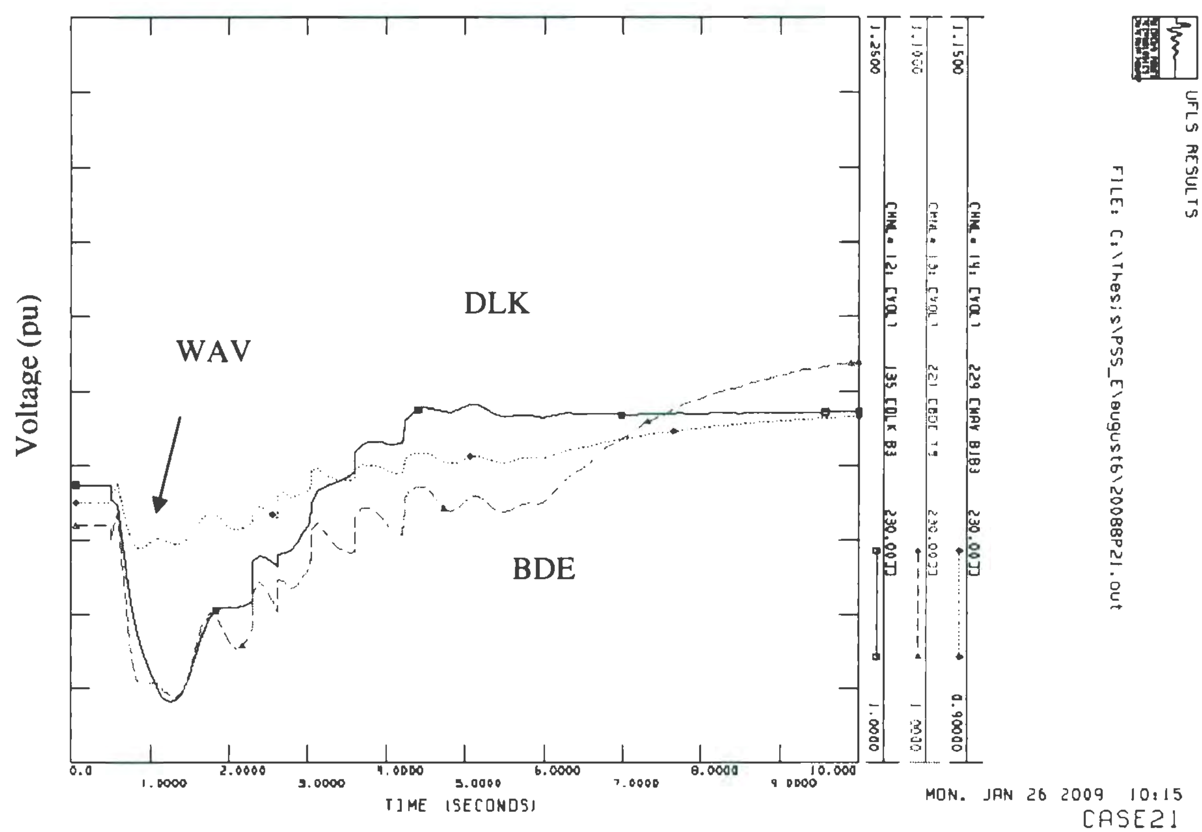

Figure 7.12: Voltage variation for schedule 4 (case 21)

Figure 7.12 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Bay d'Espoir unit loaded at 150 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.02 pu, 1.009 pu and 0.972 pu respectively.

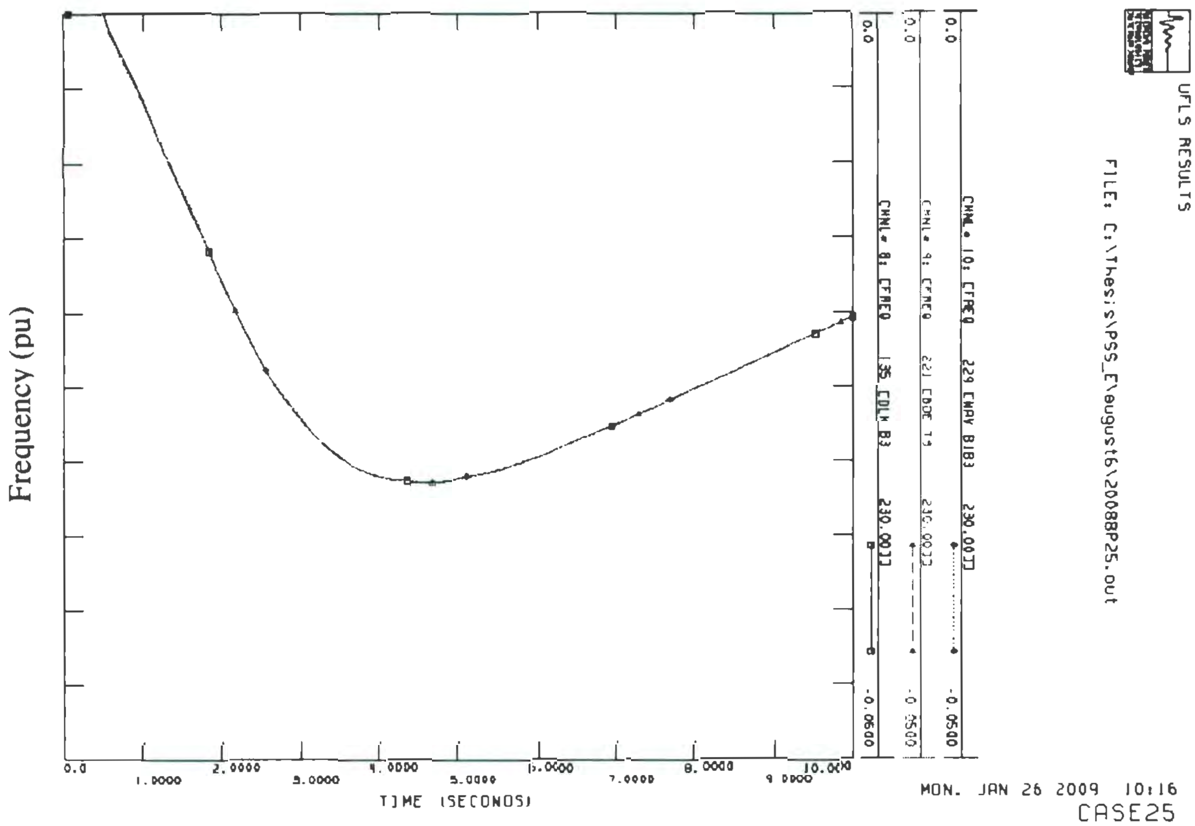

Figure 7.13: Frequency variation for schedule 4 (case 25)

Figure 7.13 depicts the frequency response for loss of a unit at Bay d'Espoir loaded at 100 MW. The total connected system inertia after the loss contingency was 3955 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the absence of synchronizing oscillations following the generation loss contingency. The minimum frequency following loadshedding of 90 MW was 58.17 Hz and indicates that 10 MW was recovered due to governor action during the event.

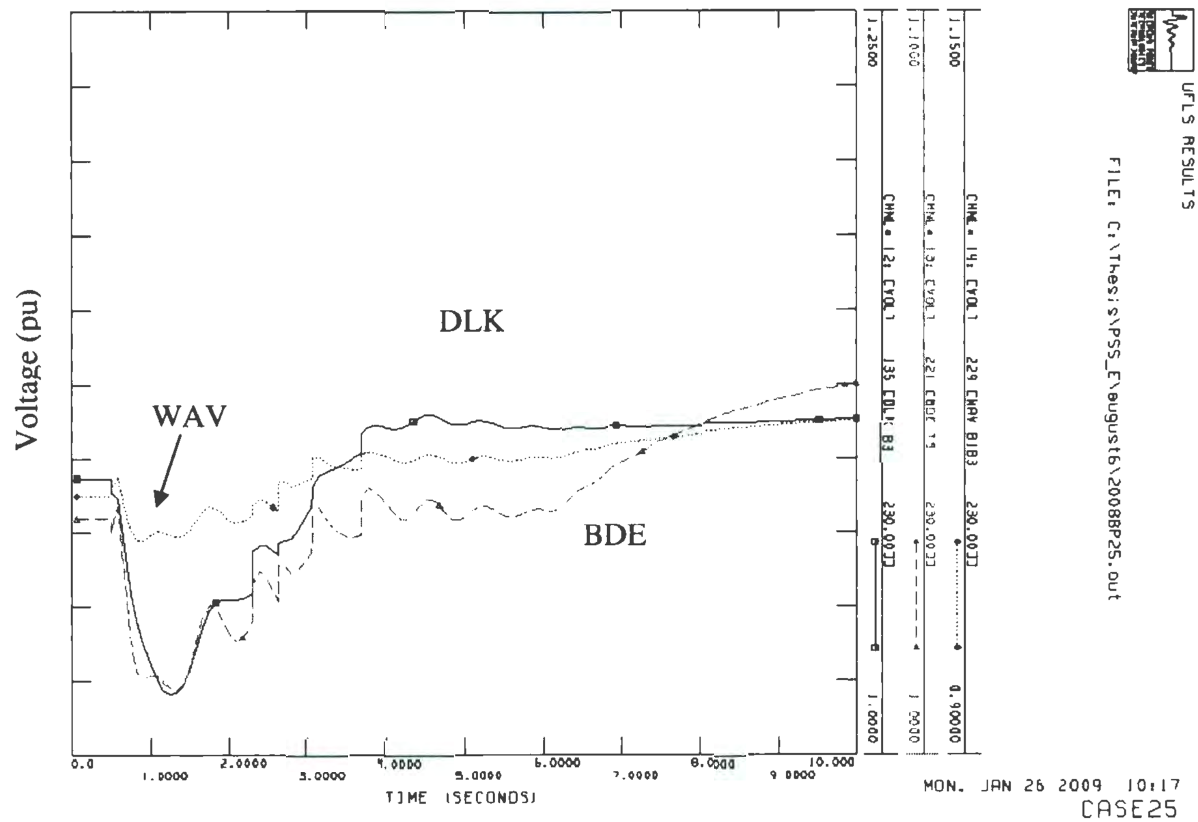

Figure 7.14: Voltage variation for schedule 4 (case 25)

Figure 7.14 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Bay d'Espoir unit loaded at 100 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.02 pu, 1.009 pu and 0.972 pu respectively.

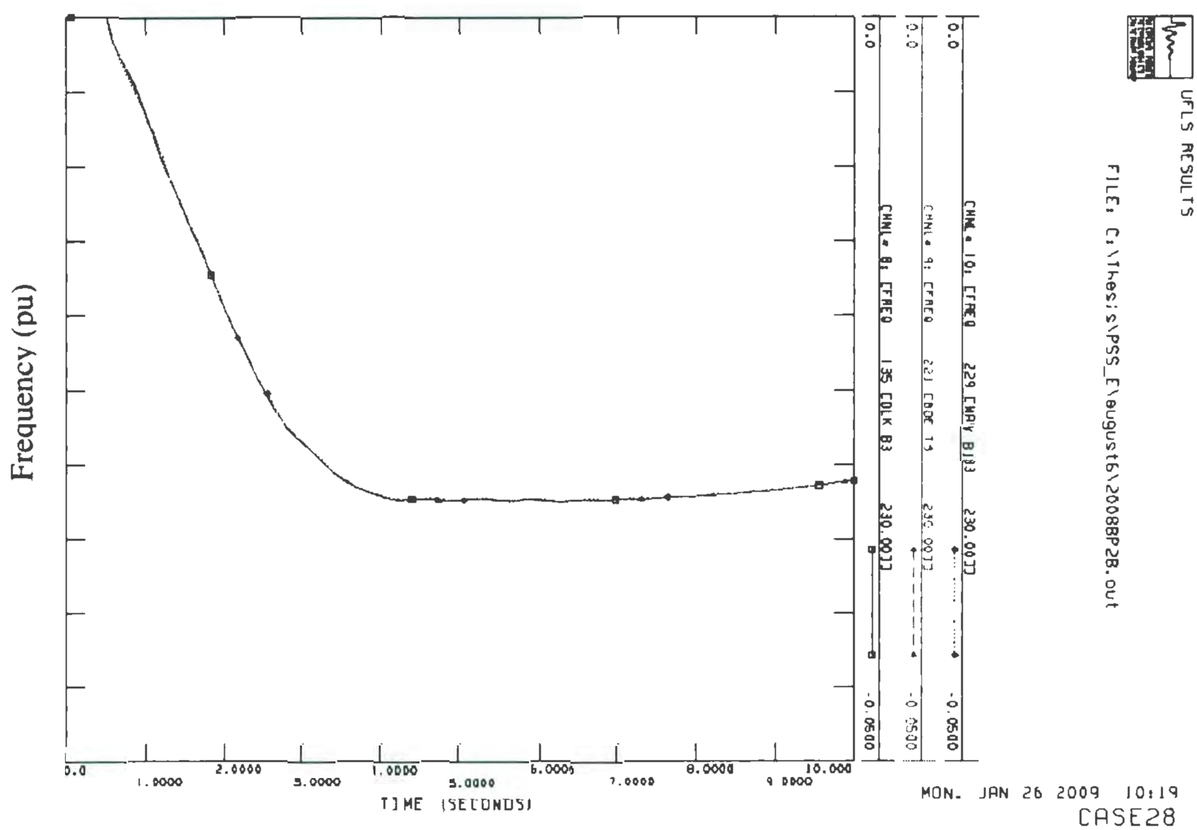

Figure 7.15: Frequency variation for schedule 4 (case 28)

Figure 7.15 depicts the frequency response for loss of a unit at Bay d'Espoir loaded at 100 MW. The total connected system inertia after the loss contingency was 3357 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the absence of synchronizing oscillations following the generation loss contingency. The minimum frequency following loadshedding of 105 MW was 58.09 Hz and indicates that 5 MW of overshedding occurred for this case.

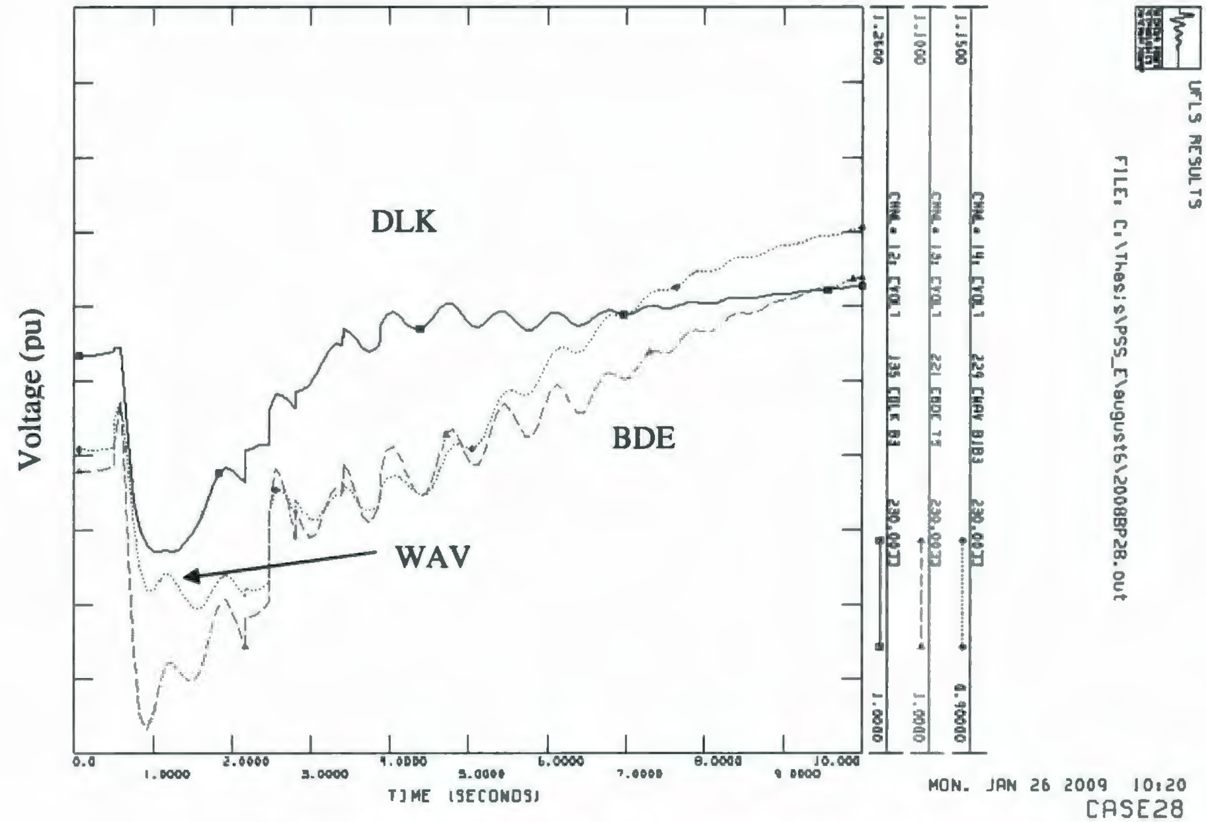

Figure 7.16: Voltage variation for schedule 4 (case 28)

Figure 7.16 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Bay d'Espoir unit loaded at 100 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.07 pu, 1.003 pu and 0.948 pu respectively.

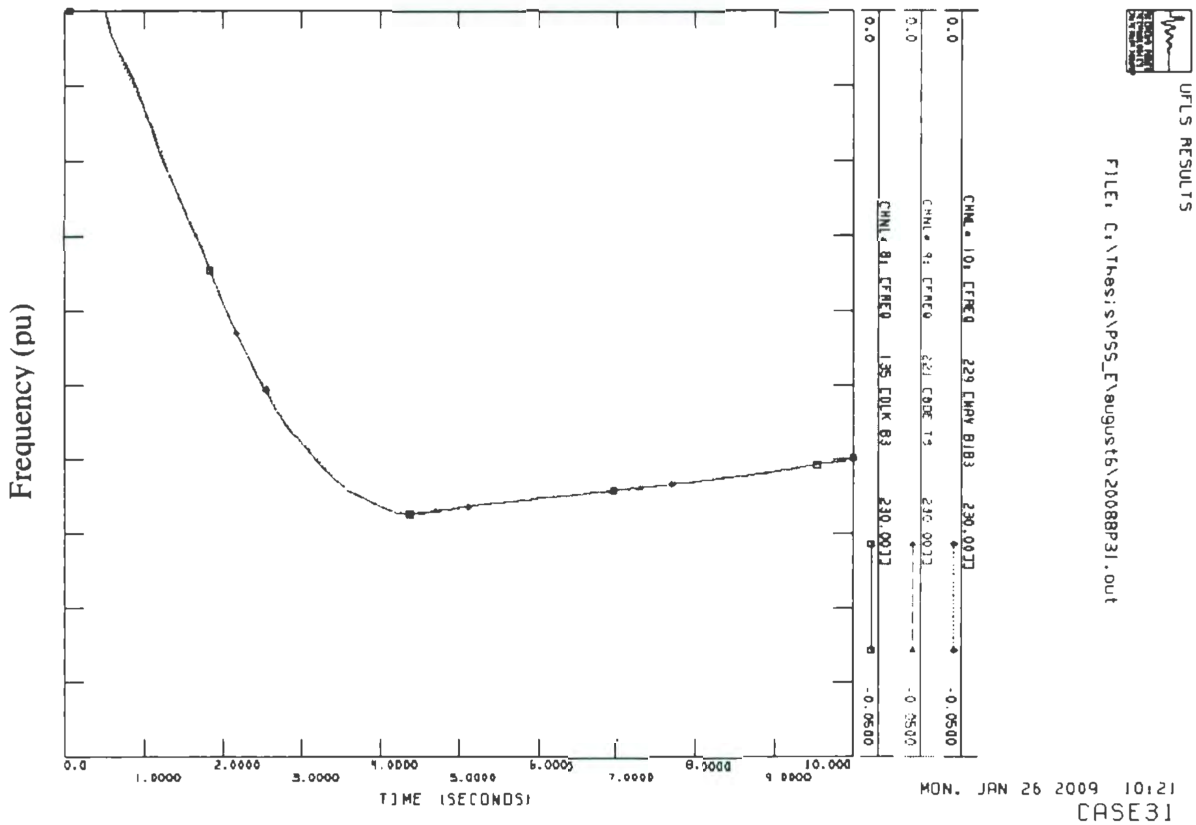

Figure 7.17: Frequency variation for schedule 4 (case 31)

Figure 7.17 depicts the frequency response for loss of a unit at Bay d'Espoir loaded at 100 MW. The total connected system inertia after the loss contingency was 2441 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the absence of synchronizing oscillations following the generation loss contingency. The minimum frequency following loadshedding of 97 MW was 57.96 Hz and indicates that 3 MW was recovered due to governor action during the event.

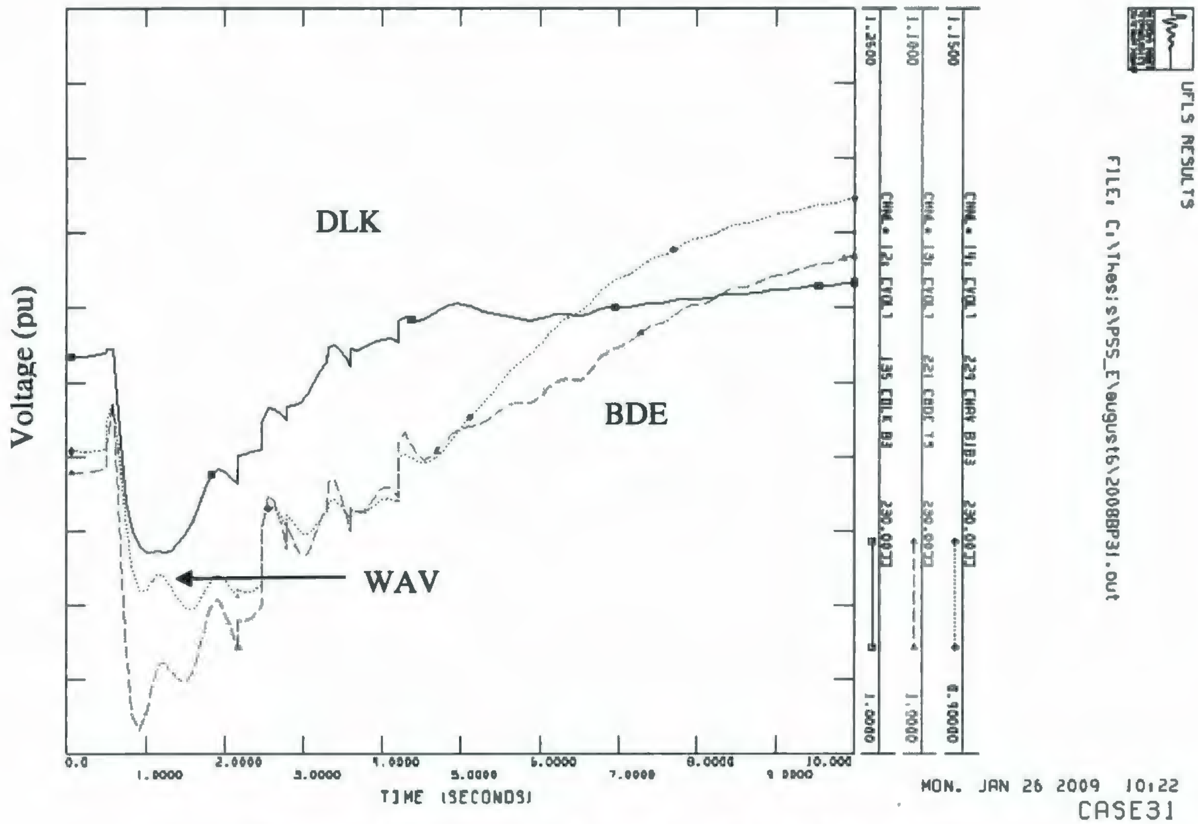

Figure 7.18: Voltage variation for schedule 4 (case 31)

Figure 7.18 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Bay d'Espoir unit loaded at 100 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.07 pu, 1.003 pu and 0.948 pu respectively.

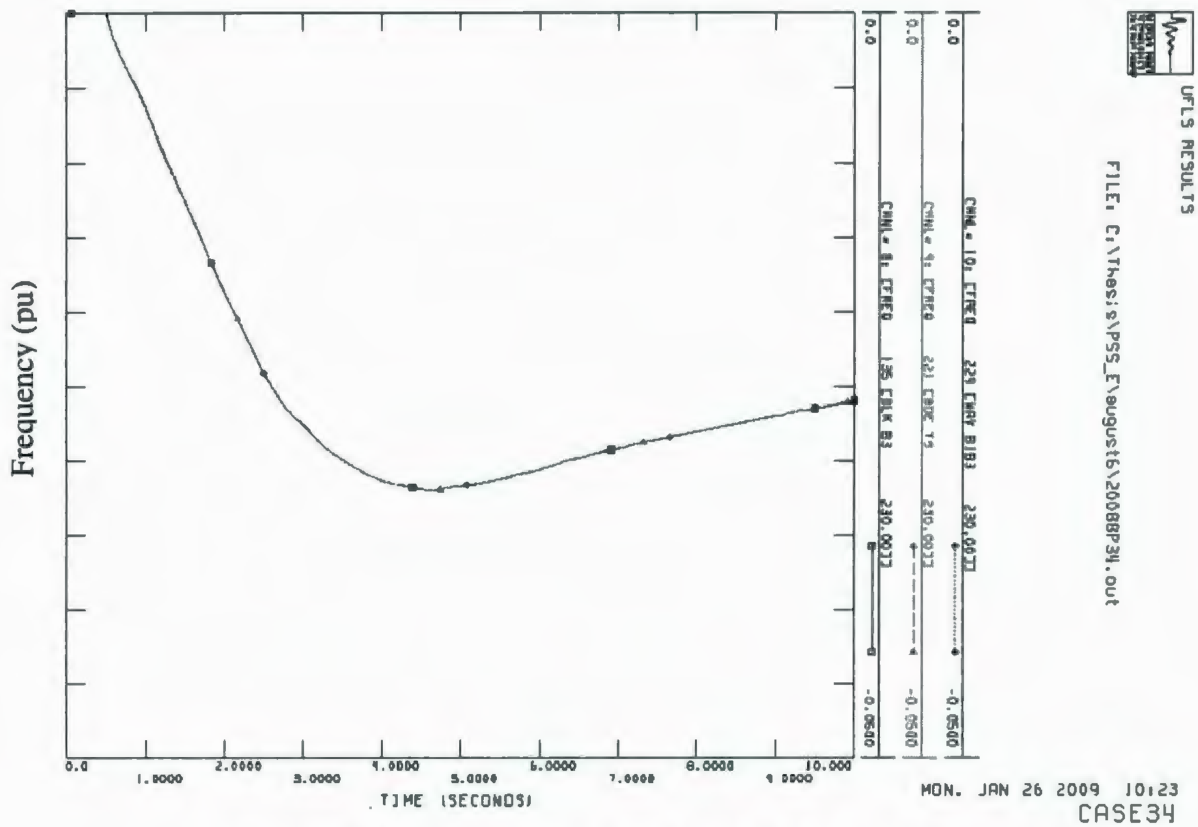

Figure 7.19: Frequency variation for schedule 4 (case 34)

Figure 7.19 depicts the frequency response for loss of a unit at Bay d'Espoir loaded at 75 MW. The total connected system inertia after the loss contingency was 2244 MW*sec. The frequency is depicted at DLK, BDE and WAV. Note the absence of synchronizing oscillations following the generation loss contingency. The minimum frequency following loadshedding of 71 MW was 58.06 Hz and indicates that 4 MW was recovered due to governor action during the event.

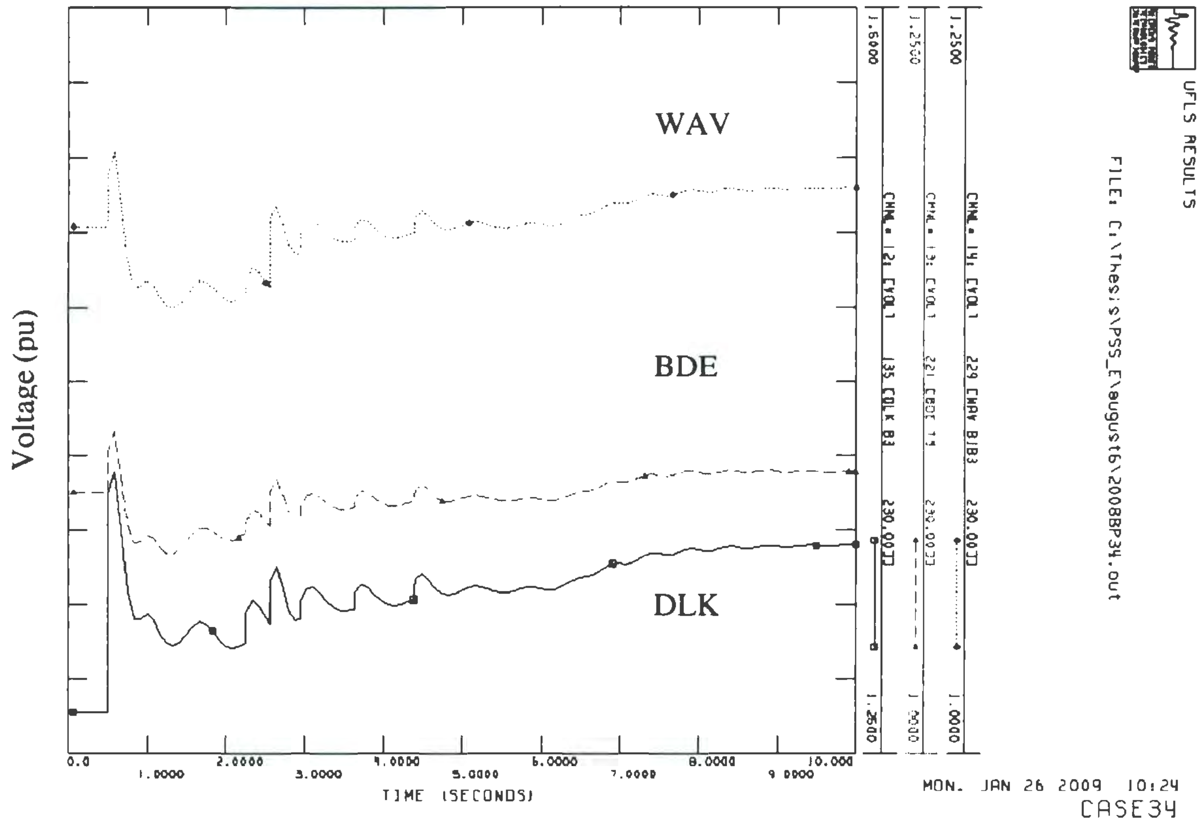

Figure 7.20: Voltage variation for schedule 4 (case 34)

Figure 7.20 indicates the voltage variation encountered at the DLK, BDE and WAV busses following loss of the Bay d'Espoir unit loaded at 75 MW. All voltages return to nominal following the event with the maximum variation occurring at the WAV bus. The voltages at Deer Lake, BDE and WAV subsequent to the loadshedding event had minimum values of 1.26 pu, 1.068 pu and 1.15 pu respectively. Note that the voltage on the west coast (at DLK) rises following the event whereas the voltage at BDE and WAV return to nominal values. This can be attributed to a lack of voltage regulation since the unit at BDE has been removed from the system.

Inspection of the plots in Figures 7.3 through 7.20 reveals the effect of UFLS as per the extreme cases of schedule 4 on the system voltage and frequency. The dynamic variation of the system variables following a trip of either a unit at Bay d'Espoir or Holyrood is presented for different points on the power system and is intended to encompass the range of possible system response for the worst case operating scenarios. The voltage variation at Western Avalon (WAV) experiences the greatest variation with the bus voltage reaching a minimum value near 0.90 pu for a trip of a unit at Holyrood on a heavily loaded system. The minimum frequency was 57.96 Hz for case 31 that involves a trip of a unit at Bay d'Espoir loaded at 100 MW. In all cases, the system variables (voltage and frequency) return to near nominal values subsequent to operation of the underfrequency schedule.

Table 7.14 provides a listing of the largest generating unit (LOU) which can be synchronized to the system for variable system loadings and should not trip the UFLS safety net at 57.9 Hz and 57.8 Hz for normal generation loss contingencies. For example, for the 422 MW loading, the LOU is 84 MW since (0.24*350MW=84 MW); that is schedule 4A has 84 MW of shedable load at 0.24 pu of maximum system loading between 58.8 Hz and 58.0 Hz.

The setting of the largest online unit is critical to maintaining the predictability of the UFLS schedule and is instrumental in maintaining system frequency stability following generation loss scenarios. The amount of load shed for generation contingencies will increase significantly if the limits in Table 7.14 are exceeded since the reserve thresholds of the schedule (at 57.9 Hz and 57.8 Hz) may be required to compensate for normal generation loss contingencies. Since the purpose of UFLS is to preserve system stability, it is prudent to be cautious and to advocate a predictable response from any UFLS scheme.

Table 7.14: Largest synchronized generator summary for schedule 4

System Load (MW)	System Inertia (MJ)	Lost Inertia (MJ)	System Loading (pu)	Largest Online Unit (MW)
1480	7432	502	0.86	175
1240	6990	690	0.72	175
1150	7031	690	0.67	175
995	5802	502	0.58	175
804	4718	690	0.47	164
669	4645	502	0.39	136
624	4047	502	0.36	125
483	3131	502	0.28	98
422	2733	690	0.24	84

7.6 Rate of Change of Frequency Loadshedding

An alternative loadshedding methodology is to shed load based upon a determination of the rate at which the system frequency is declining rather than at specific frequency thresholds. The rate of change of frequency (df/dt) relay can detect the relative severity of a generation deficit through df/dt measurement and can initiate proactive loadshedding immediately instead of delaying until the frequency decline reaches other threshold trip settings. For example, the df/dt relay could sense a relatively large generation deficiency through detection of a high df/dt and initiate loadshedding prior to the frequency declining to 58.8 Hz. The rate of frequency decay (i.e. the df/dt) is decreased immediately after loadshedding and thereby increases the time available for spinning reserves to act and provide compensation for the generation deficiency (provided df/dt loadshedding occurs prior to loadshedding at other frequency thresholds). While it is possible to develop an UFLS schedule that is based on df/dt assessment only, it is preferred to implement the df/dt function as a logical AND with a specific frequency trip point, as shown in section 4.3, in order to minimize the possibility of relay misoperation. In effect, the df/dt function is not enabled until the frequency decays to a predetermined frequency threshold.

Loadshedding based on df/dt assessment should be graded in a manner similar to frequency initiated loadshedding such that an increasing amount of load is shed for an increasingly severe df/dt. This approach will minimize overshedding due to potential misoperations and will improve schedule selectivity.

7.6.1 df/dt Loadshedding Schemes

The design constraints for the development of df/dt UFLS schedules include the separation of the df/dt trip settings, the amount of load assigned to each setting, and the initial tripping frequency (if the df/dt is utilized in concert with a frequency trip setting). The separation of the df/dt loadshedding stages is limited by the accuracy of modern frequency relays. A typical accuracy is 0.1 Hz/sec and therefore successive tripping stages of the df/dt function cannot be less than 0.1 Hz/sec in separation.

The initial tripping frequency of the df/dt function should be made with reference to the possible df/dt variations among the system busses following a generation loss contingency; particularly those closest to the area of the failed generator. For the case of the island interconnected system, df/dt (and frequency) variation in the short term time frame is more pronounced nearest the Holyrood generators following a thermal unit trip (reference Figure 7.3) but appears to be sufficiently damped when the frequency has decayed to approximately 59.5 Hz. Therefore, this frequency, 59.5 Hz, will be designated as the maximum frequency forming part of the df/dt tripping condition in that the frequency decay to 59.5 Hz occur concurrently with the adopted df/dt setting.

The trip settings and the amount of load assigned to trip upon df/dt activation require consideration of the results obtained for schedule 4. Inspection of Table 7.8 reveals that UFLS was not required for Cases 5, 10, 15 and 20 (as evidenced by a total load shed of 0 MW). For these generation loss scenarios, the system was able to recover the lost generation through spinning reserve. Clearly, loadshedding would be undesirable for these cases and it would be prudent therefore to not establish df/dt trip settings for values less than 0.3 Hz/sec since 0.3 Hz/sec was the maximum df/dt value observed for these generation loss contingencies. Similarly, the greatest df/dt that is likely to occur on the system is approximately 1.23 Hz/sec (case 31), during an extreme light system loading.

The approach adopted for df/dt integration with schedule 4 is to shed a portion of the load associated with a specific frequency threshold in concert with df/dt activation and to shed load incrementally using graded df/dt settings. To this end, constant amounts of load will be tripped using a df/dt trip point in concert with the logical AND (i.e. df/dt + f) that is supervised by a specific frequency setpoint (i.e. 59.5 Hz) as outlined in Table

7.15. The df/dt schedule is an addendum to Schedule 4 and will function in concert with it. For example, schedule 4 will trip 58 MW at each of the six initial frequency thresholds and inspection of the minimum frequency for case 1 in Table 7.11 is 58.35 Hz (with an associated df/dt of 0.76 Hz/sec). Therefore, the loadshedding blocks at 58.8 Hz, 58.6 Hz and 58.4 Hz will all trip regardless of whether or not df/dt initiated tripping is implemented. Furthermore, tripping some of the load from either of these load blocks utilizing a df/dt trip setting will not increase the total load shed and it is proposed to trip 10 MW or 20 MW from each of the thresholds at 58.8 Hz, 58.6 HZ and 58.4 Hz in response to a measured df/dt value (greater than 0.3 Hz/sec) at 59.5 Hz. The selection of the amount of load to shed (i.e. 10 MW or 20 MW) is an arbitrary selection and for the current application is derived from the existing schedule.

Consider Table 7.15. The amount of load shed following an underfrequency event will be cumulative for increasingly severe df/dt values. A df/dt of 0.6 Hz/sec will shed, for the 10 MW case, 30 MW in total since a df/dt of 0.6 Hz/sec will also activate all lesser df/dt values (at 0.5 Hz/sec and 0.4 Hz/sec). Similarly, a df/dt of 1.0 Hz/sec, for the 10 MW case, will shed 70 MW of load in total resulting from df/dt activation. The results for this schedule operating in conjunction with Schedule 4 are summarized in Tables 7.16 and Table 7.17.

The load that is tripped using the df/dt will not exceed that which would have been tripped through schedule 4 acting alone. The inclusion of a df/dt function with schedule 4 in the manner indicated will increase the selectivity of the schedule with respect to variable generation loss contingencies but is dependent on the action of spinning reserve for any reduction in loadshedding quantity. Furthermore, if the system spinning reserve does not increase generation output to compensate for the indicated generation deficiency, the total amount of load shed will be identical to that found for schedule 4.

Table 7.15: Proposed df/dt loadshedding for schedule 4

Frequency (Hz)	df/dt (Hz/sec)	Loadshed (MW)	Loadshed (MW)
59.5	0.4	10	20
59.5	0.5	10	20
59.5	0.6	10	20
59.5	0.7	10	20
59.5	0.8	10	20
59.5	0.9	10	20
59.5	1.0	10	20
59.5	1.1	10	20

7.6.2 Simulation Results

Inspection of Table 7.16 reveals that in every case the amount of load shed does not exceed that of Schedule 4 and that shedding load at 59.5 Hz using the df/dt function will require that less load be shed to compensate for a specific generation loss contingency. Note that all measured parameters improve in proportion to the amount of load shed using the df/dt and indicates that df/dt incorporation will improve schedule performance. For the variables examined, the optimum choice would be to assign 20 MW to shed on df/dt activation at 59.5 Hz. Relative to schedule 4, the average minimum frequency and the minimum frequency increase by 0.3 Hz, the total amount of load shed decreases by 120 MW and the average loadshed decreases by 3.4 MW.

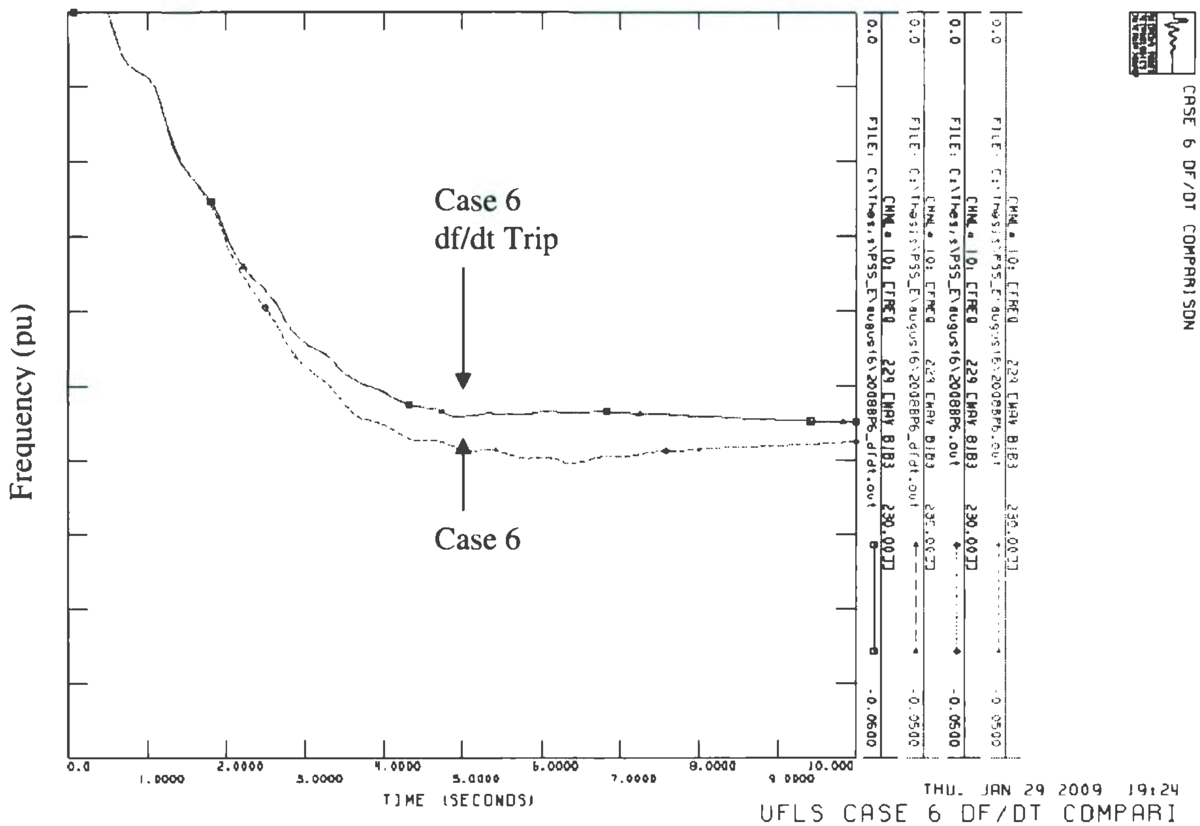

Figure 7.21: Frequency variation for df/dt implementation in case 6 at WAV

Figure 7.21 illustrates the difference in system frequency response for case 6 with and without implementation of the df/dt function at the Western Avalon bus (the WAV bus and case 6 are chosen for the purposes of illustration). This result indicates that proactive loadshedding through df/dt implementation has enabled the system to correct the generation loss contingency (175 MW loss at Holyrood) with a reduced amount of loadshedding and greater minimum frequency.

However, df/dt enabled tripping resulted in a reduced amount of total load shed in only a fraction of the possible test cases. Those cases which are shaded in Table 7.16 represent the occasions in which df/dt implementation resulted in a reduced amount of total loadshedding. Inspection reveals that incremental shedding 20 MW had a greater effect than incremental shedding of 10 MW. This is expected since shedding a greater amount of loadshed at 59.5 Hz represents an increased compensation for the initial generation deficiency. An additional effect of greater loadshedding at 59.5 Hz is to enable an increased contribution from the available spinning reserve.

Table 7.16: Results comparison of df/dt trip and schedule 4

	Schedule 4		Incremental df/dt Trip of 10 MW		Incremental df/dt Trip of 20 MW	
Case	Minimum Frequency (Hz)	Total Load Shed (MW)	Minimum Frequency (Hz)	Total Load Shed (MW)	Minimum Frequency (Hz)	Total Load Shed (MW)
1	58.35	149	58.36	149	58.37	149
2	58.38	149	58.46	108	58.56	117
6	58.17	167	58.19	167	58.31	138
7	58.34	125	58.36	125	58.38	125
11	58.16	155	58.18	155	58.18	155
12	58.25	116	58.29	116	58.32	116
16	58.07	168	58.08	168	58.09	168
17	58.15	134	58.15	134	58.18	134
18	58.41	67	58.43	67	58.46	67
21	58.01	135	58.02	135	58.06	135
22	58.32	81	58.34	81	58.37	81
23	58.52	54	58.54	54	58.56	54
25	58.17	90	58.17	90	58.22	75
26	58.38	67	58.39	67	58.52	53
28	58.09	105	58.16	91	58.19	91
29	58.36	63	58.36	63	58.38	63
31	57.96	97	57.97	97	57.99	97
32	58.13	65	58.14	65	58.17	65
33	58.39	49	58.42	33	58.46	33
34	58.06	71	58.06	71	58.08	71
35	58.36	43	58.36	43	58.36	43

The improved performance of the loadshedding schedule when utilizing the df/dt can be attributed to the increased effect of the system spinning reserve as it responds to the decreased df/dt between 59.5 Hz and 58.8 Hz following loadshedding at 59.5 Hz. Without df/dt loadshedding, as in Schedule 4, the time required for the frequency to decrease from 59.5 Hz to 58.8 Hz is decreased and thereby decreases the effect of spinning reserve since the cumulative effect of spinning reserve is proportional to time for all generators on the system.

Table 7.17: Summary of df/dt loadshedding for schedule 4

	Average Minimum Frequency (Hz)	Total Overshed (MW)	Minimum Frequency (Hz)	Average Overshed (MW)
Schedule 4A	58.47	-725	57.96	-20.7
df/dt: 10 MW	58.48	-796	57.97	-22.7
df/dt: 20 MW	58.50	-845	57.99	-24.1

The tradeoff between the reliable and selective operation of protective schemes is readily apparent when considering design of UFLS schedules. The choice as to which UFLS schedule is optimal is partially subjective in nature with the evaluation complicated by the variation in the system generation dispatch, the availability of spinning reserve, the governor responsiveness and other factors. In particular, the implementation of a df/dt tripping function requires a detailed knowledge of the system response to underfrequency events. The designer must be aware of frequency variations on the system subsequent to generation loss scenarios and thereby minimize the potential for unexpected loadshedding.

7.7 Summary

This chapter presented the application of the UFLS methodology developed in Chapter 4 to the island interconnected system of Newfoundland. Evaluation scenarios based on seasonal load variation were developed and several possible UFLS schedules were considered for multiple generation loss scenarios. Time domain simulations were presented for the probable worst case scenarios on the system and highlighted the frequency and voltage response at different system busses. Finally, it was demonstrated that application of df/dt initiated loadshedding, in the manner proposed, will result in a 4.5% decrease in the total amount of load shed for the Newfoundland island system relative to schedule 4.

Chapter 8

Application: UVLS Methodology on the Newfoundland System

8.1 Introduction

Undervoltage loadshedding (UVLS) is a measure of last resort applied to power systems operating in the emergency or *in extremis* states and for the current application is intended to avert a voltage collapse caused by overload or severe operating contingency. The rationale associated with UVLS is to disconnect preselected portions of the system load in an attempt to preserve system voltage stability. This is reasonable since if corrective action is not taken, the system may collapse and interrupt power to all system load. The current application is to develop an UVLS scheme for the interconnected island system of Newfoundland to safeguard the system against contingencies that may result in a voltage collapse. The nominal operating voltages for which the system is designed are in the range of 0.95 pu to 1.05 pu with emergency voltage levels in the range 0.9 pu to 1.1 pu. The current application will initiate UVLS when the voltages at the WAV station decrease to approximately 0.9 pu or less for a predetermined time. The region of application for the island system is the Avalon Peninsula and specifically, the load busses at Oxen Pond (OPD) and Hardwoods (HWD). The unregulated voltage on the 230 kV system (at WAV) will be monitored and UVLS will be initiated for operating contingencies that threaten voltage stability. These operating contingencies may include the loss of either a capacitor bank, a generating unit or a transmission line. Power – Voltage (P-V) curves are developed for each system contingency to determine the appropriate amount of load to shed and dynamic simulations are employed to examine voltage variation to ensure that voltage stability is maintained.

8.2 System Description

As outlined previously, the island of Newfoundland operates as an isolated system and is therefore more susceptible to the effects of system disturbances than larger interconnected systems. Furthermore, the load distribution and location of significant generation sources on the island has resulted in a system with two distinctive voltage characteristics. The principal load center on the island is located on the province's east coast on the Avalon Peninsula and it is this area of the power system that is more susceptible to voltage stability problems resulting from excessive loading. In contrast, the Western area of the province has significantly less connected load and is susceptible to high voltages. Hence, the operational focus is to maintain acceptability high voltages on the east coast and, conversely, acceptably low voltages on the west coast. Hydroelectric generation at Bay d'espoir, Granite Canal and Upper Salmon comprise the center of the power system and function as a primary site for active power generation and have a significant role in maintaining the voltage stability of the system during different dispatch scenarios.

Table 8.1: Equipment capability ratings for eastern section of power system

Equipment Capability			
		Active Generation (MW)	Reactive Generation (MVAr)
BDE Units 1 to 6		75	35
BDE Unit 7		160	70
HRD Unit1 and 2		175	80
HRD Unit 3		150	88
HRD Unit 3 (SC)		0	150
HWD GT		40	31
HWD GT (SC)		0	40
Capacitor Banks			
	HWD CB1		26.4
	HWD CB2		26.4
	OPD CB1		25.2
	OPD CB2		26.4
	LHR CB1		24

As described in previous sections, there are three relatively large thermal generators located at Holyrood. These generators provide approximately 35% of the required peak active power demand on the island system and approximately 60% of the required reactive demand on the Avalon. These generators are critical sources for maintaining acceptable voltages on the east coast particularly when the Avalon demand exceeds approximately 345 MW when measured at the Western Avalon station. This figure is the maximum power transfer limit given the current system structure, for generation sources and transmission lines from Bay d'espoir, when four of the available five capacitor banks are in service on the Avalon. These capacitor banks are positioned at the principle load busses (i.e. HWD and OPD) as well as near Come by Chance at LHR and total approximately 125 MVAr. The gas turbine (GT) located at Hardwoods (HWD) is frequently operated as synchronous condenser (SC) and provides additional reactive support when required. The ratings and location of the principal equipment for the eastern section of the power system are summarized in Figure 8.1 and Table 8.1.

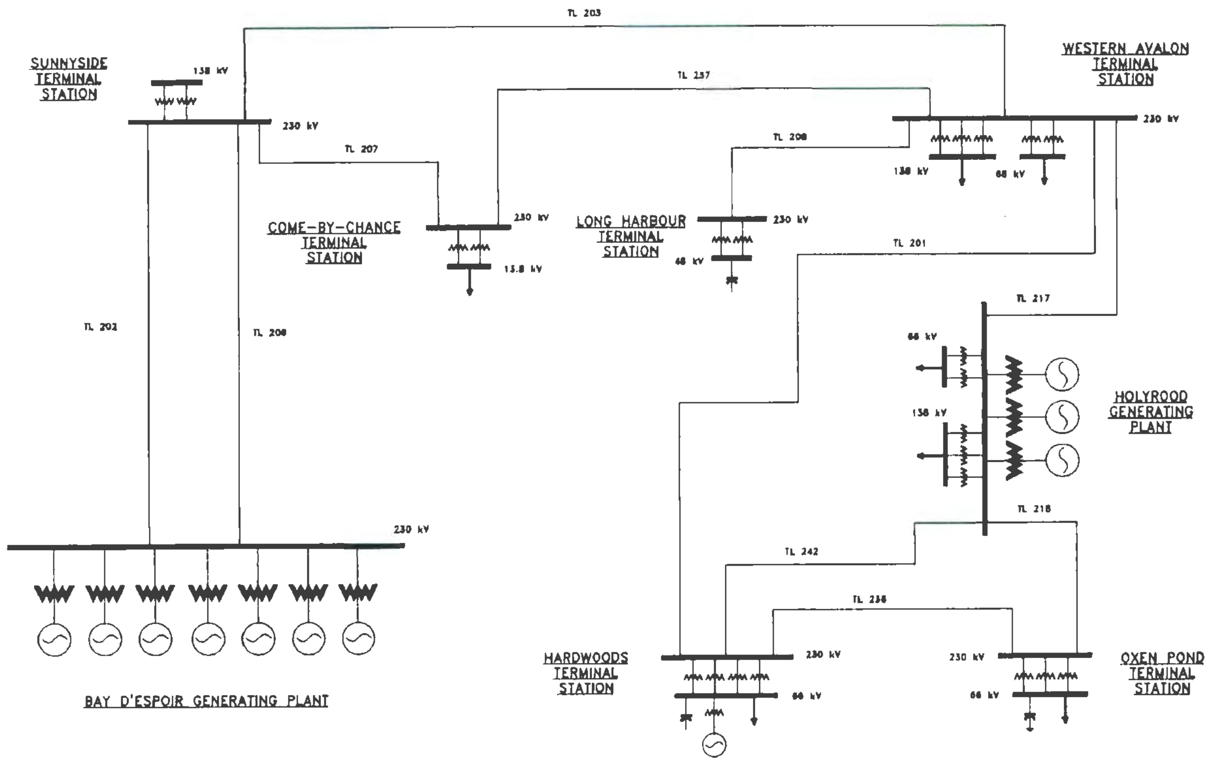

Figure 8.1: Generation and transmission east of Bay d'espoir

The system under consideration will include all equipment and load east of the Bay d'espoir generation site. The equipment will include all 230 kV transmission lines east of Bay d'espoir, the Holyrood and Hardwoods generation facilities as well as the capacitor banks located at Oxen Pond, Hardwoods and Long Harbour. The system load considered will be that which is serviced by the 230 kV lines east of Bay d'espoir and is primarily residential with the exception of the industrial load at Come By Chance. Inspection of Figure 8.2 reveals that the power factor of the load at the Western Avalon station varies between 0.9 and 0.95 (lagging) and is therefore highly resistive in nature. This underscores the fact that the areas east of the Western Avalon station do not contain significant concentrations of industrial load (i.e. induction motors) and is it unlikely that the Avalon will suffer from a rapid voltage collapse due to the mass stalling of induction motors due to low voltage. It is more probable that any voltage collapse experienced at WAV (or east) will be a gradual voltage decrease resulting from overload during system operation with insufficient reactive reserve or will occur following a sudden component failure on the system.

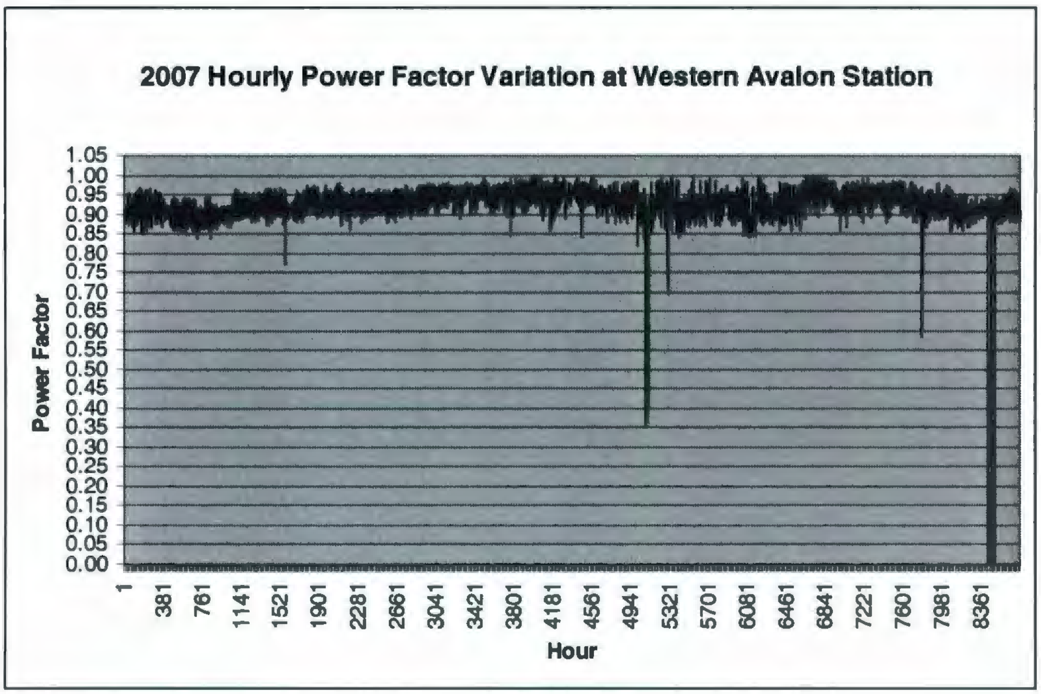

Figure 8.2: Hourly 2007 power factor variation at western Avalon station

As noted previously, the maximum power imported into the Western Avalon station on TL202 and TL206 without causing unacceptably low voltages east of WAV is approximately 345 MW. This figure assumes that generation sources on the Avalon Peninsula (i.e. at Holyrood or at Hardwoods) are offline and that the voltages at all 230 kV busses (WAV and east) are greater than 0.95 pu. Inspection of Figure 8.3 reveals that the limiting value for active power transfer (i.e. 345 MW at 0.95 pu voltage) is not reached between hours 3000 and 7200 or equivalently between the months of April through October. Similarly, the maximum reactive demand during this time (reference Figure 8.4) is approximately 100 MVAr and is supplied by the capacitor banks without assistance from either the HWD GT or units at HRD. Hence, it is not required that generation sources on the Avalon be in operation between these months in order to satisfy the load demand on the Avalon while still maintaining acceptable voltages. This is advantageous from an operational perspective since these units are thermal units and are more expensive to operate and are environmentally less desirable than hydraulic units. However, the reality of actual system operation is complicated by unit availability at Bay d'espoir and Holyrood, adequate reactive reserves on the Avalon and by issues related to the efficient management of water resources.

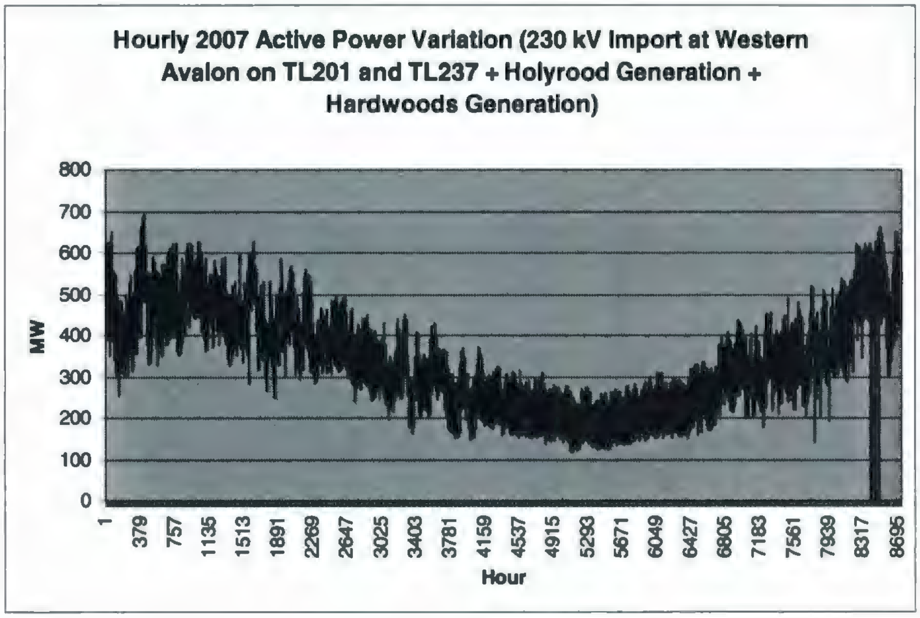

Figure 8.3: Hourly 2007 active demand variation at the western Avalon station

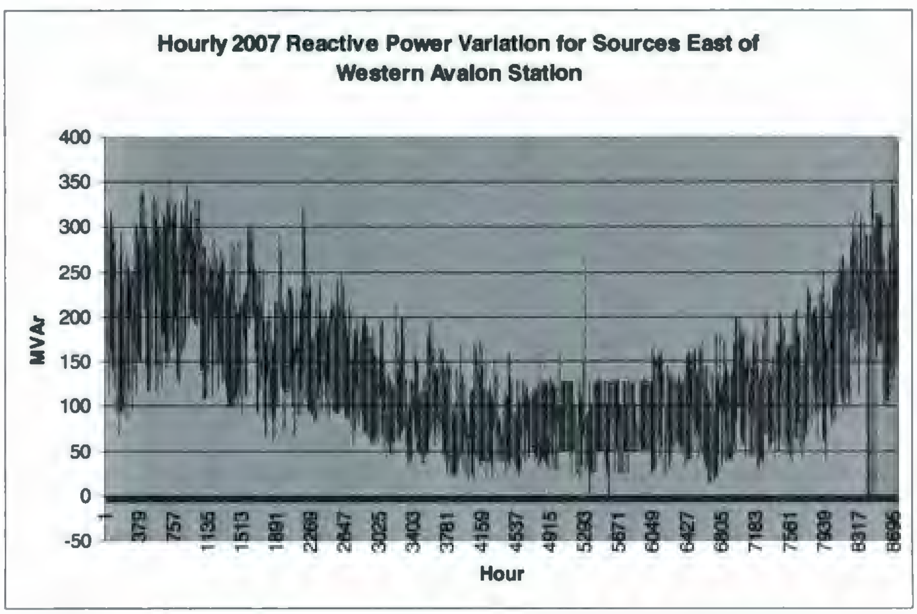

Figure 8.4: Hourly 2007 reactive demand variation at the western Avalon station

8.3 Development of UVLS Schedules

The UVLS methodology employed in this thesis is analogous to that applied to UFLS in that preselected portions of the system load will be disconnected from specific load busses in response to a low voltage. The load will be disconnected from the system following the activation of voltage relays at specific tripping thresholds as the voltage declines. The sequence of relay operation will continue until the decay of the bus voltage has been reversed and nominal operating levels restored. To reiterate, UVLS is a measure of last resort and is applied to systems operating in the emergency or *in extremis* states. The factors that must be considered during implementation of an UVLS scheme are the total load shed, time delay and undervoltage settings as well as the location of load to shed.

For the current thesis, the design of the UVLS scheme will rely primarily on static analysis (P-V curves) developed from load flows on the Avalon Peninsula and will employ dynamic simulation to confirm system stability. The design of an UVLS schedule using P-V curves requires that determination of the amount of loadshed be based on a comparison between the difference in the power demand during worst-case pre-contingency and post-contingency conditions at specific busses.

The variability in the system loading must be accounted for when considering the amount of load that will actually be shed from the power system following an UVLS event. In a manner similar to UFLS, the load assigned to trip for UVLS is assumed to be at a maximum for the peak load case and will decrease in proportion to the system loading. The peak Avalon loading is at least 630 MW with all major generation sources active and includes the effects of power imports from Bay d'espoir and generation sources on the Avalon. Therefore, the peak load assigned to trip for UVLS will be referenced to a maximum value of 630 MW, although Avalon loading values beyond this point are possible as indicated in Figure 8.3.

Tripping fewer loads than necessary will not avert a voltage collapse whereas tripping more load than necessary may result in frequency instability. Consequently, a partial justification for the partitioning of loadshedding blocks in UVLS schedules such that preselected loads are assigned to trip at preselected voltage thresholds is that disconnection of smaller amounts of load will decrease the severity of voltage and frequency variations and possible instability issues during the system transition to a stable operating state. Hence it is desirable to divide any required loadshedding among successive tripping thresholds. Another desirable consequence of grading the total amount of loadshed is that it will enable any proposed UVLS schedule to function for a variety of contingencies and system dispositions while minimizing the total load shed. Another justification for limiting the change in the voltage magnitude as a result of UVLS is that shedding large amounts of load will increase the resistive load demand and will exacerbate any voltage instability.

The time delay required before UVLS can be enabled should be greater than the time required for other voltage regulation and compensation devices to operate. For example, OLTC will typically require 4-5 minutes before tapping out and it would be counterproductive to initiate UVLS prior to the completion of this process. Hence, for the purposes of long term voltage instability due to load buildup, all other system options for improving voltage will ideally have been exhausted; specifically generators have reached their excitation limits, all reactive sources have been deployed, all OLTC have tapped out and all reactors (if present) have been tripped. However, if the trip conditions are met, UVLS will occur regardless of whether or not OLTC, or other system resources, have reached their maximum limits.

It is optimal that UVLS occur at or near the point of low voltage instability and that there be load available at that bus to shed. The tripping of load at locations near the point of instability can also have a limited benefit since the disconnection of load will reduce generation active power output and will offload transmission lines and thereby reduce losses and improve the receiving voltage. This effect is clearly dependent on the network topology variation following the loadshed and the generation dispatch or system loading at the time. The identification of voltage sensitive busses can be made through construction of V – Q curves. One method for performing this analysis is to connect a fictitious synchronous condenser to a bus and to then increase the reactive demand by iteration in order to determine the sensitivity of the bus voltage to increased loading. Those buses that are more voltage sensitive will display a greater rate of change of voltage with respect to VAr demand (dV/dQ) and it is at these busses that UVLS may be employed (provided there is nearby load to shed) [6]. However, for the purpose of the current thesis, dV/dQ analysis was not performed since there are only two busses on the Avalon that contain an appreciable and potentially useful block of load for the purposes of UVLS.

8.4 Methodology Application

In contrast to the time delay inherent in the increase in generator active power output due to spinning reserve, adjustment of synchronous generator or synchronous condenser reactive output is virtually instantaneous due to the rapid reaction of modern digital excitation systems. Hence, reactive compensation increases in synchronous generators will typically restore voltage levels to nominal values in a timely manner (within the capability of the machine limits) after the associated dynamics have decayed. A notable exception is when reactive reserves have been exhausted, possibly due to an operating contingency, and system loading continues to increase. In this case, the voltage on all three phases of the power system will be depressed equally and will begin to slowly decline.

The addition of either active or reactive generation on the Avalon will increase the "baseload" figure of 345 MW at 0.95 pu voltage at the Western Avalon (WAV) station. Inspection of Table 8.2 and Table 8.3 indicate that the increase in the base load value is a consequence of adding generation capacity at either HWD or HRD. Otherwise stated, if the Avalon load exceeds 345 MW at WAV, additional Avalon generation is required. As indicated in Figure 8.3, the additional generation would be required approximately between the months of November and March while the actual dates are based upon real time consideration of the power system and implies a specific generation dispatch on the Avalon (at HRD or HWD) to meet seasonal increases in demand.

The base case loading of 345 MW at WAV represents the system characteristics during the relatively light loading period in summer and requires only the insertion of four capacitor banks into the Avalon system. This measure is sufficient to maintain acceptable voltages for the summer loading condition. There are, in fact, five static capacitor banks on the Avalon with the fifth bank representing reserve capacity. For fall and springtime loading additional reactive support is initially dispatched at either HWD or HRD. As the winter season progresses, additional generation at HRD is required to meet the load increase and maintain acceptable voltages. The maximum loading will generally occur in February and requires that all HRD generators be online at that time.

The present investigation into the voltage stability of the Avalon region will involve the assessment of three potentially problematic operating contingencies: loss of a capacitor bank in summer, loss of a generating unit at HRD and the loss of a transmission line which transfers power to the Avalon (i.e. TL202 or TL206).

The most onerous operating contingency that could occur on the Avalon is the loss of a generation unit at HRD. This N-1 contingency will result in severe voltage and frequency excursions and requires mitigation in the form of loadshedding. This loadshedding will be initiated by underfrequency relaying rather than undervoltage relaying since frequency stability will be compromised to a greater extent than voltage stability. Furthermore, application of undervoltage loadshedding for this contingency may not provide adequate compensation for the restoration of a nominal system frequency and the action of underfrequency loadshedding will provide a sufficient decrease in demand to permit voltage restoration. Inspection of the time domain simulations contained in chapter 7 supports this conclusion since voltage stability is restored subsequent to underfrequency loadshedding for all cases investigated. In a similar manner, the tripping of a capacitor bank will not require UVLS (for the N-1 contingency) since the available reserves are adequate to meet the increased reactive demand.

The final contingency, the loss of transmission line TL202 may be a source of potential voltage instability depending on the available generation reserves on the Avalon and the system loading. If the load displaced by the trip of TL202 is absorbed by the generation units at HRD, or at other smaller sources of generation on the Avalon, voltage stability should be assured. However, if the system is near peak loading and there is a scarcity of generation available on the Avalon, and the displaced load is transferred to the remaining line (TL206), the voltage may begin to decay on the Avalon and voltage stability may become a concern. Inspection of the results contained in Table 8.2 and Table 8.3 indicate that the difference between the maximum loading for the base case minus the maximum loading for the TL202 contingency at 0.95 pu voltage varies between approximately 65 MW (for case 1) to approximately 100 MW (for case 5). Therefore, the total amount of load that will be shed for UVLS will be 100 MW for peak Avalon loading and, analogous to UFLS, will decrease to 65 MW for minimum Avalon loading in proportion to actual system load.

As noted, the total amount of load that will be shed for the UVLS application is 100 MW at either OPD or HWD. These are the most heavily loaded busses and represent reasonable locations for any proposed loadshedding to occur; this is especially applicable since there are not other locations on the Avalon where such a load concentration exists. The typical emergency voltage levels for power system operation are between 0.9 pu and

1.1 pu of rated voltage and the lower limit will similarly constitute the initial UVLS thresholds for the current thesis.

As noted in previous sections, the time frame associated with a voltage collapse will range from a few seconds to several minutes or more and it is difficult to predict the exact nature of any voltage problem since the available reserves will vary with the system generation dispatch as will ability of the system to recover from a stressed voltage condition. Therefore, the time delay that is proposed should provide adequate time for system operators to act for longer-term voltage problems and correct any system deficiency threatening voltage stability. However, if active or reactive reserves are unavailable, the only recourse to preserve voltage stability will be UVLS. However, it is vital that undervoltage loadshedding schemes not operate during three phase faults on the system. To prevent this occurrence, a time delay will be introduced for all tripping thresholds.

8.4.1 UVLS Evaluation

P-V curves are developed for the WAV and OPD busses from a series of load flows in which the load is progressively increased. The network topology is constant, with the exception of the transmission line contingencies, and the load power factor is maintained at 0.9 (lag) and represents the probable worse case for the system as indicated in Figure 8.2. Inspection of the P-V curves will permit the examination of the voltage for a specific bus concurrent with increases in power transfers. As the magnitude of the power transfer is increased, the voltage will decrease for busses on (or near) the power transfer route. For the present investigation, the low voltage transfer limit, or the minimum acceptable voltage, is assumed to be 0.90 pu. For additional increases in power transfer, the voltage will eventually collapse indicating that the transfer capacity of the power route has been exceeded.

Power transfers that exceed the knee point of the P-V curve may result in voltage instability and a possible voltage collapse since it is at the knee point that voltage decreases rapidly for further increases in power flow. Hence, stable power system operation requires that there be a sufficient margin between the point of voltage collapse and the normal operating point on the P-V curves. In addition, the effect of operating contingencies (i.e. the loss of a transmission line) will be evaluated through comparison of the P-V curves for the base case and the operating contingency under consideration. The difference in the loading value, for a constant operating voltage, with respect to the base case and the operating contingency indicates the magnitude of the system overload. This difference must be subtracted from the system loading through UVLS to restore stable operation. The contingencies evaluated with respect to voltage stability on the Avalon are summarized in Tables 8.2 and 8.3 with detailed P-V curves presented in Figures 8.5 to 8.14. The line loss contingencies considered are the loss of TL202, TL201 and TL208.

The loss of TL208 will not affect the system MW loading but will instead decrease the available reactive power on the Avalon. As discussed previously, TL208 connects a 20 MVAr capacitor bank at Long Harbour to the Western Avalon station and disconnection of this reactive source will limit the maximum power transfer but will not initiate undervoltage loadshedding.

Table 8.2: Total power import summary - 1

P-V Curve Summary		Base Case		Trip TL208	
		WAV	OPD	WAV	OPD
CASE 1	Avalon Generation OFF	345 MW	330 MW	325 MW	315 MW
CASE 2	Base Case + HRD 1	435 MW	420 MW	410 MW	404 MW
CASE 3	Base Case + HRD 1 + HRD 2	505 MW	495 MW	486 MW	484 MW
CASE 4	Base Case + HRD 1 + HRD 2 + HRD 3	570 MW	570 MW	565 MW	565 MW
CASE 5	Base Case + HRD 1 + HRD 2 + HRD 3 + HWD	626 MW	615 MW	606 MW	610 MW
Note: All MW values are measured at 0.95 pu voltage at indicated bus					

Table 8.3: Total power import summary - 2

P-V Curve Summary		Trip TL202		Trip TL201	
		WAV	OPD	WAV	OPD
CASE 1	Avalon Generation OFF	281 MW	279 MW	310 MW	288 MW
CASE 2	Base Case + HRD 1	358 MW	358 MW	395 MW	382 MW
CASE 3	Base Case + HRD 1 + HRD 2	430 MW	430 MW	468 MW	466 MW
CASE 4	Base Case + HRD 1 + HRD 2 + HRD 3	483 MW	498 MW	545 MW	547 MW
CASE 5	Base Case + HRD 1 + HRD 2 + HRD 3 + HWD	530 MW	540 MW	590 MW	598 MW
Note: All MW values are measured at 0.95 pu voltage at indicated bus					

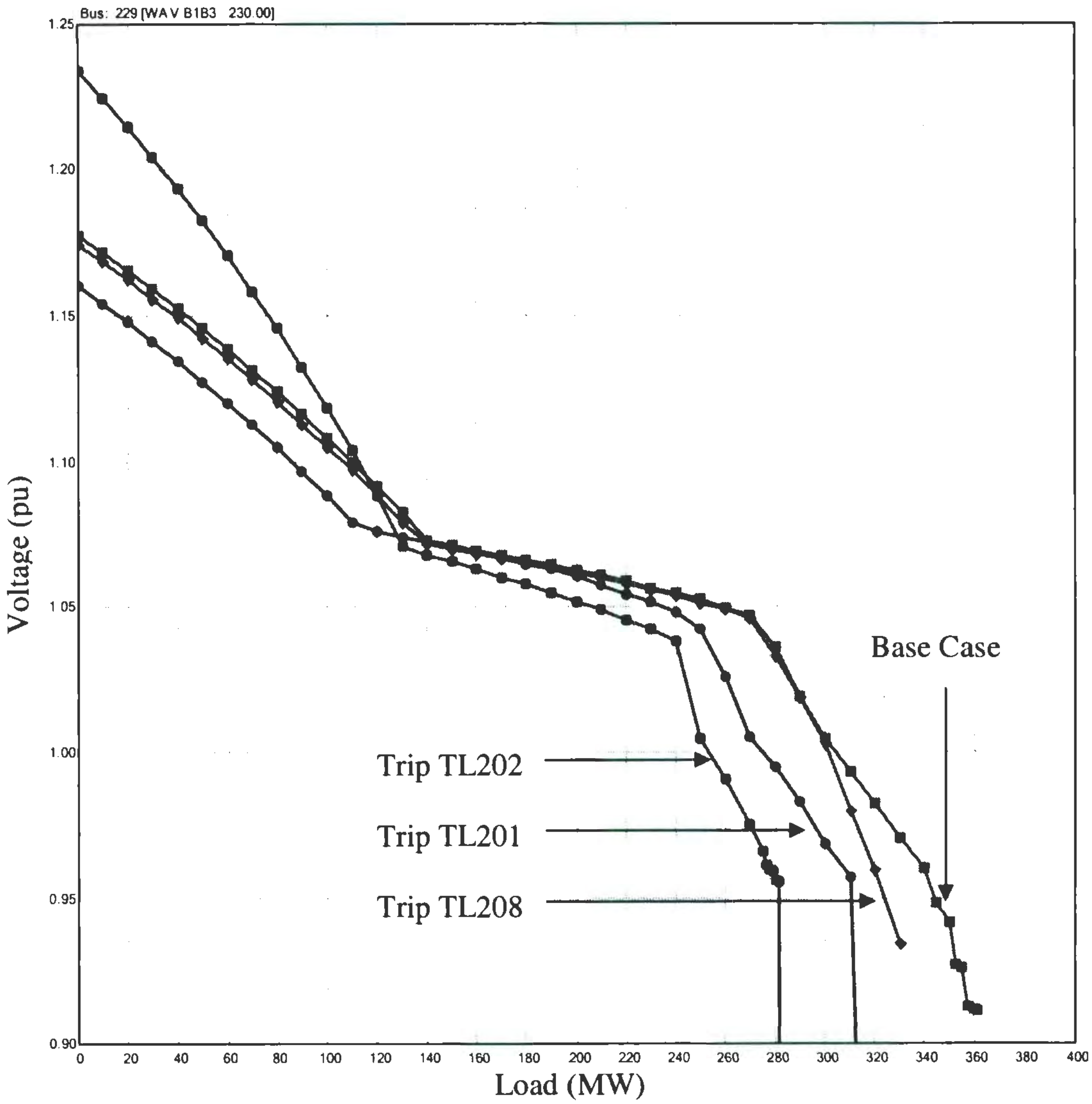

Figure 8.5: Case 1 p-v curve at WAV

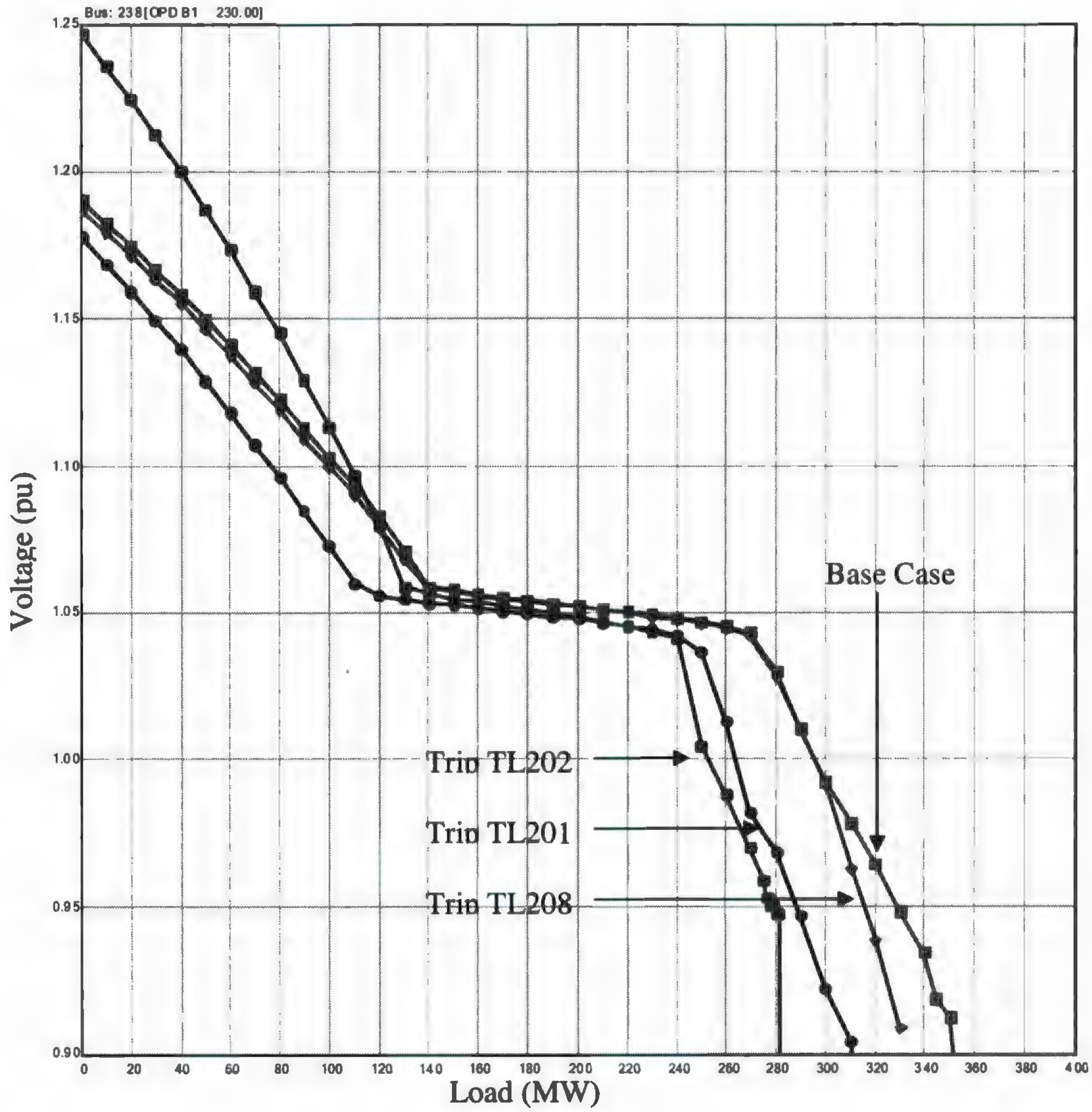

Figure 8.6: Case 1 p-v curve at OPD

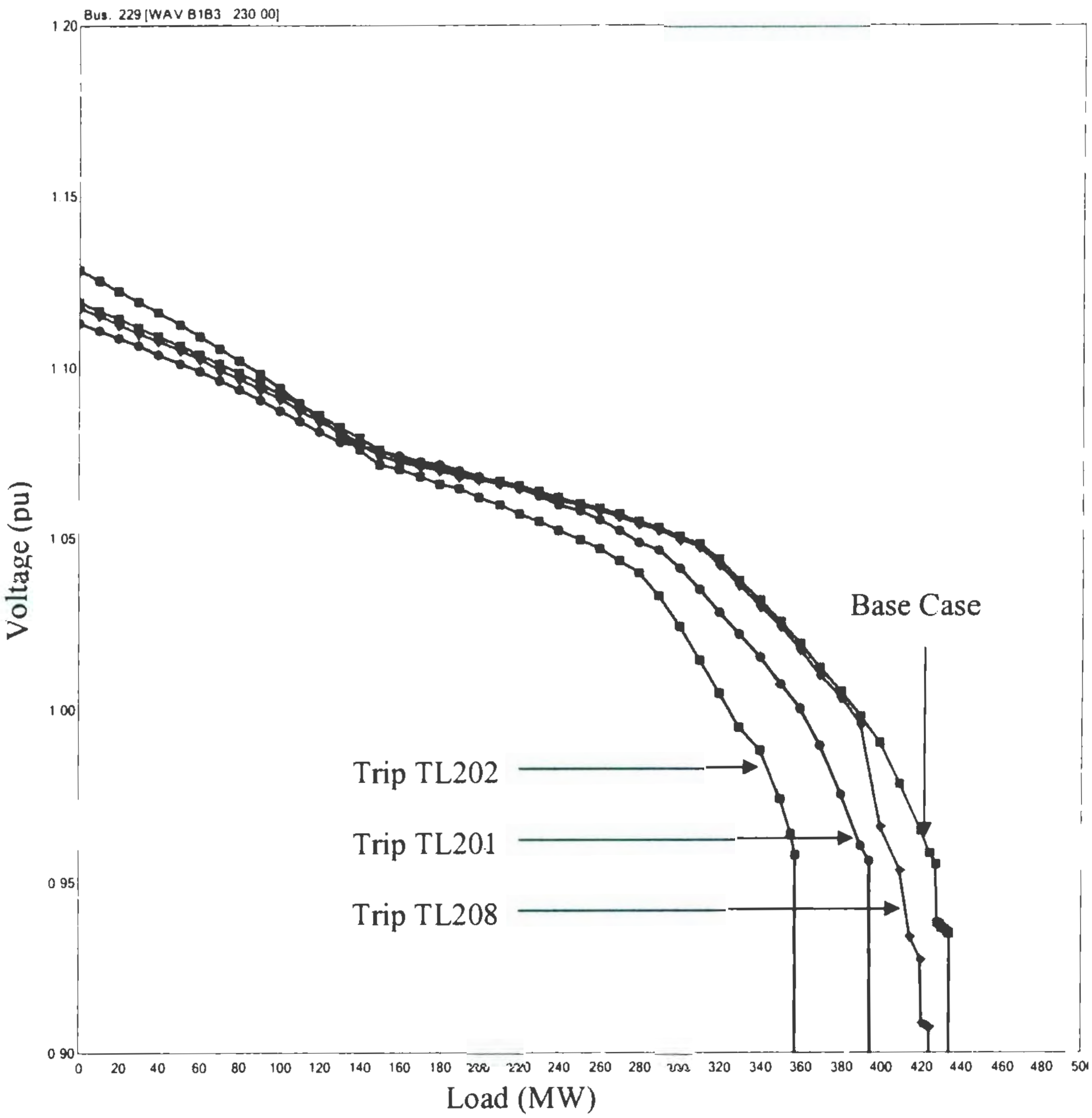

Figure 8.7: Case 2 p-v curve at WAV

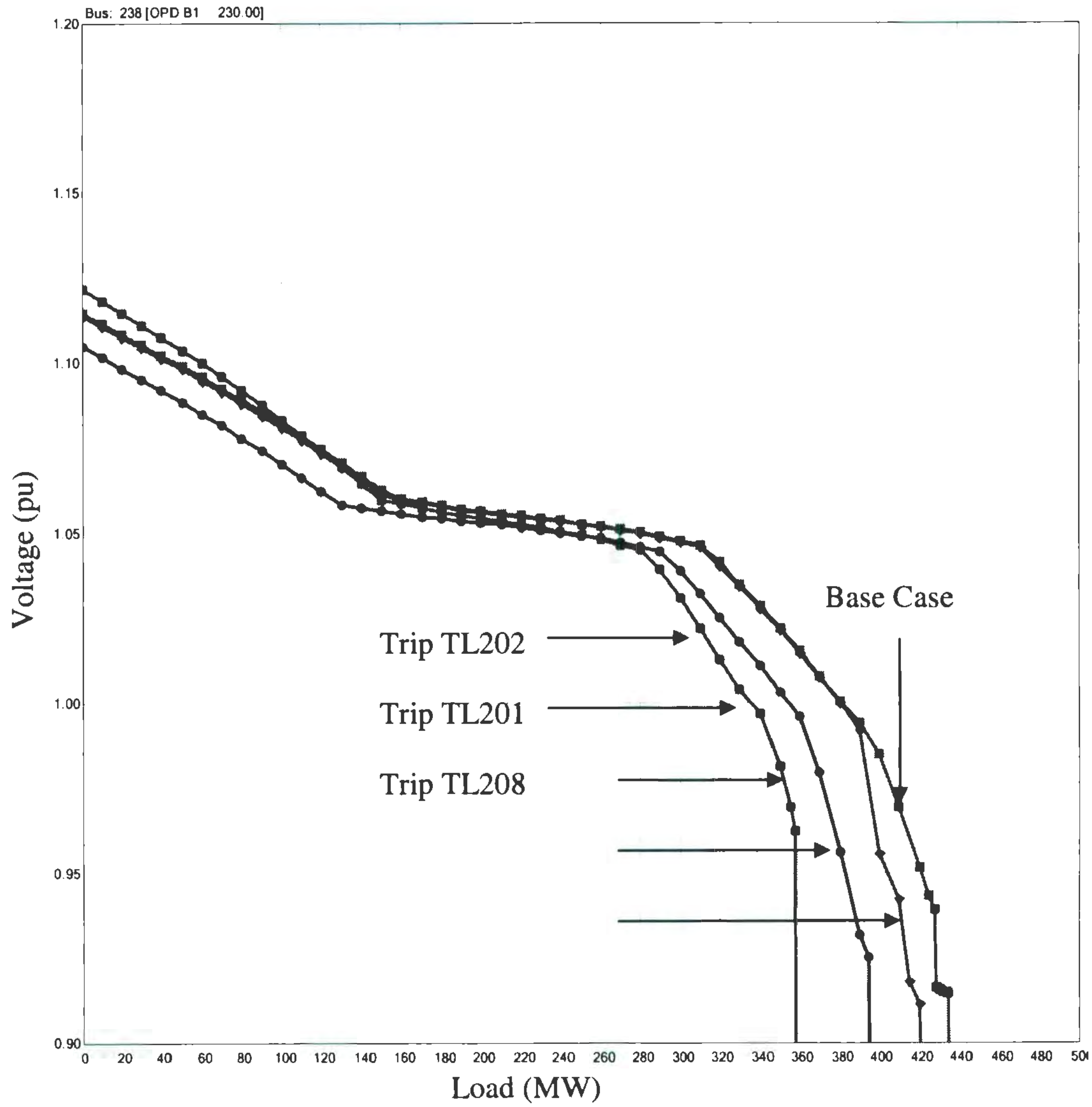

Figure 8.8: Case 2 p-v curve at OPD

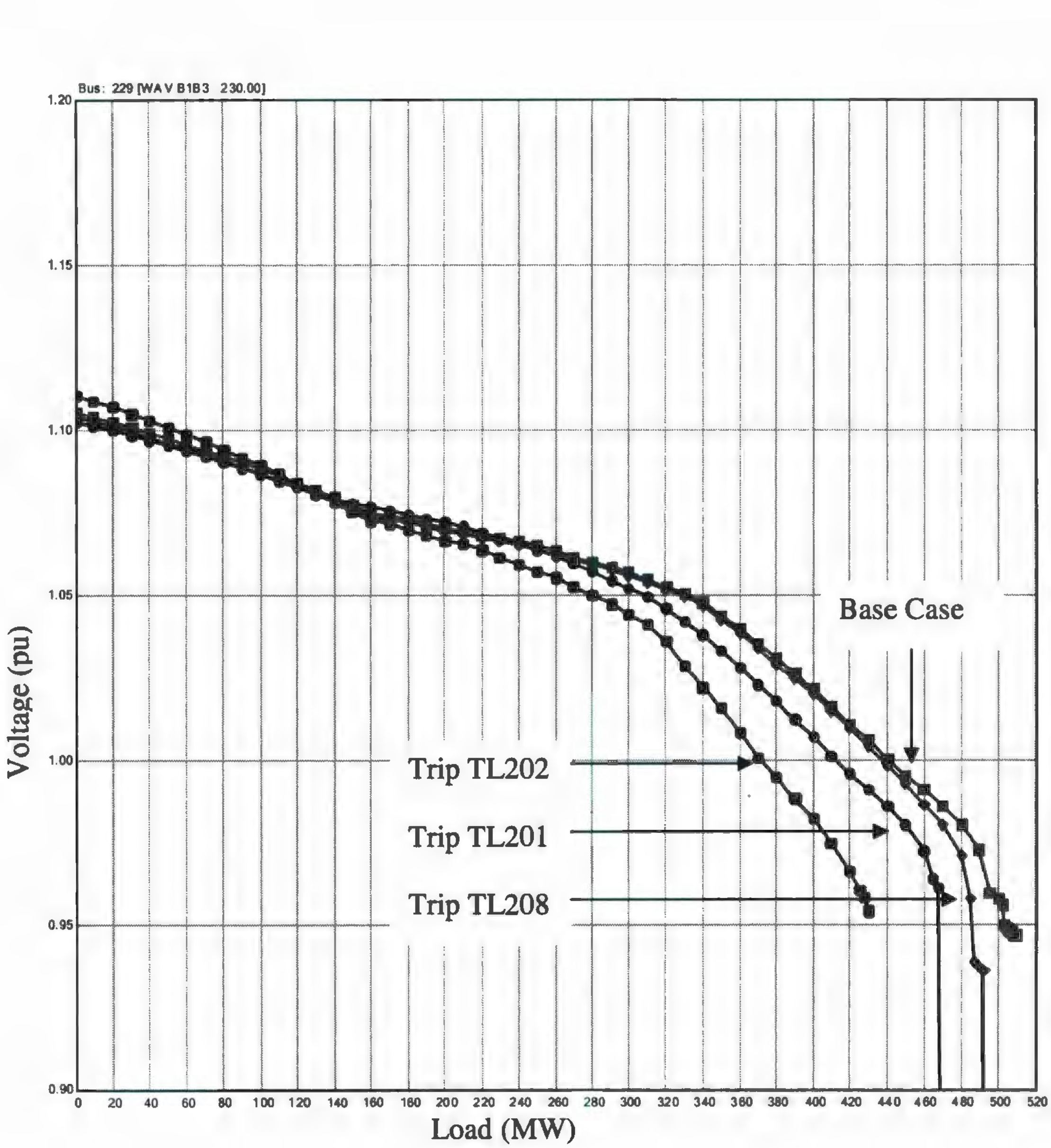

Figure 8.9: Case 3 p-v curve at WAV

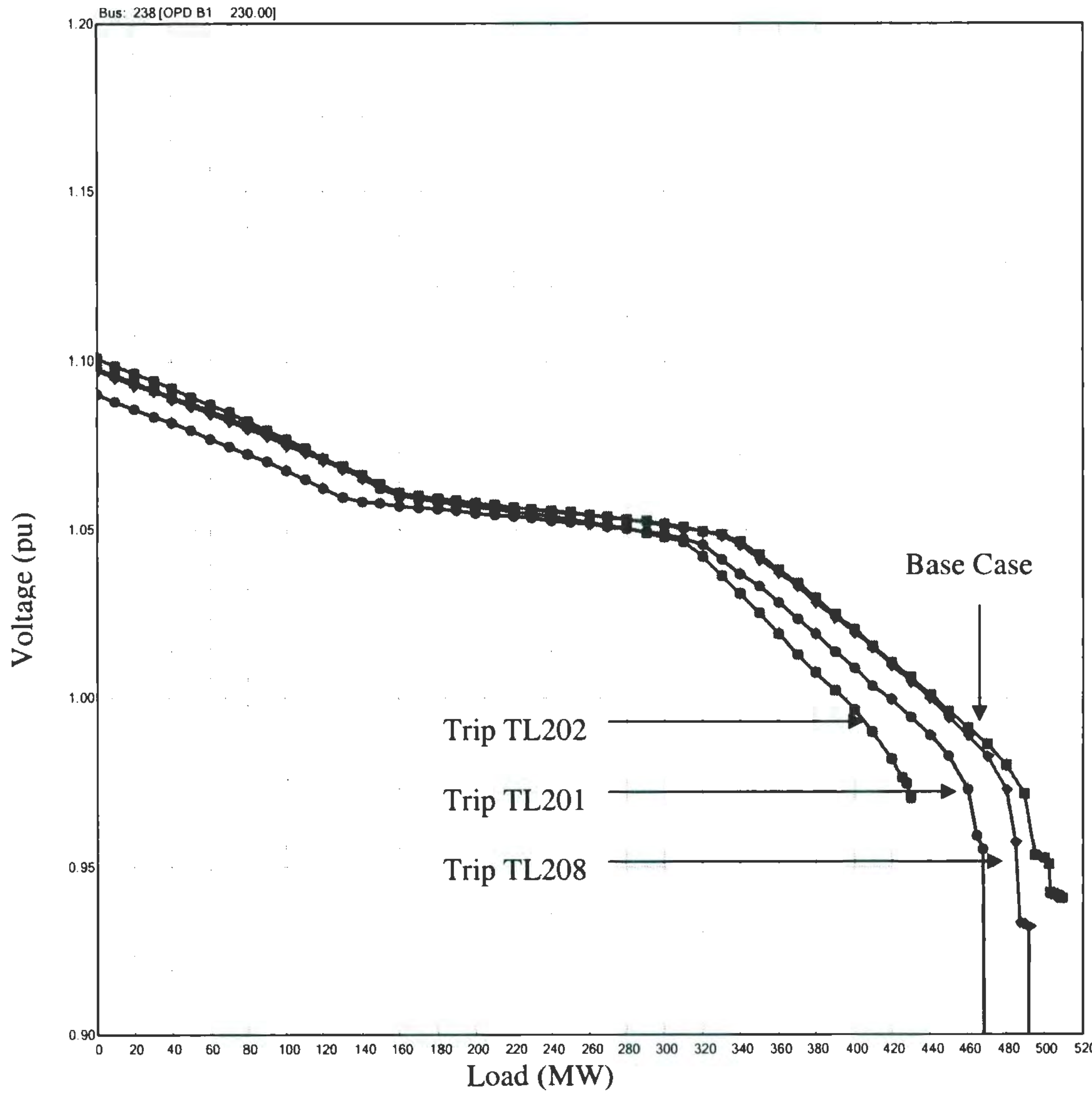

Figure 8.10: Case 3 p-v curve at OPD

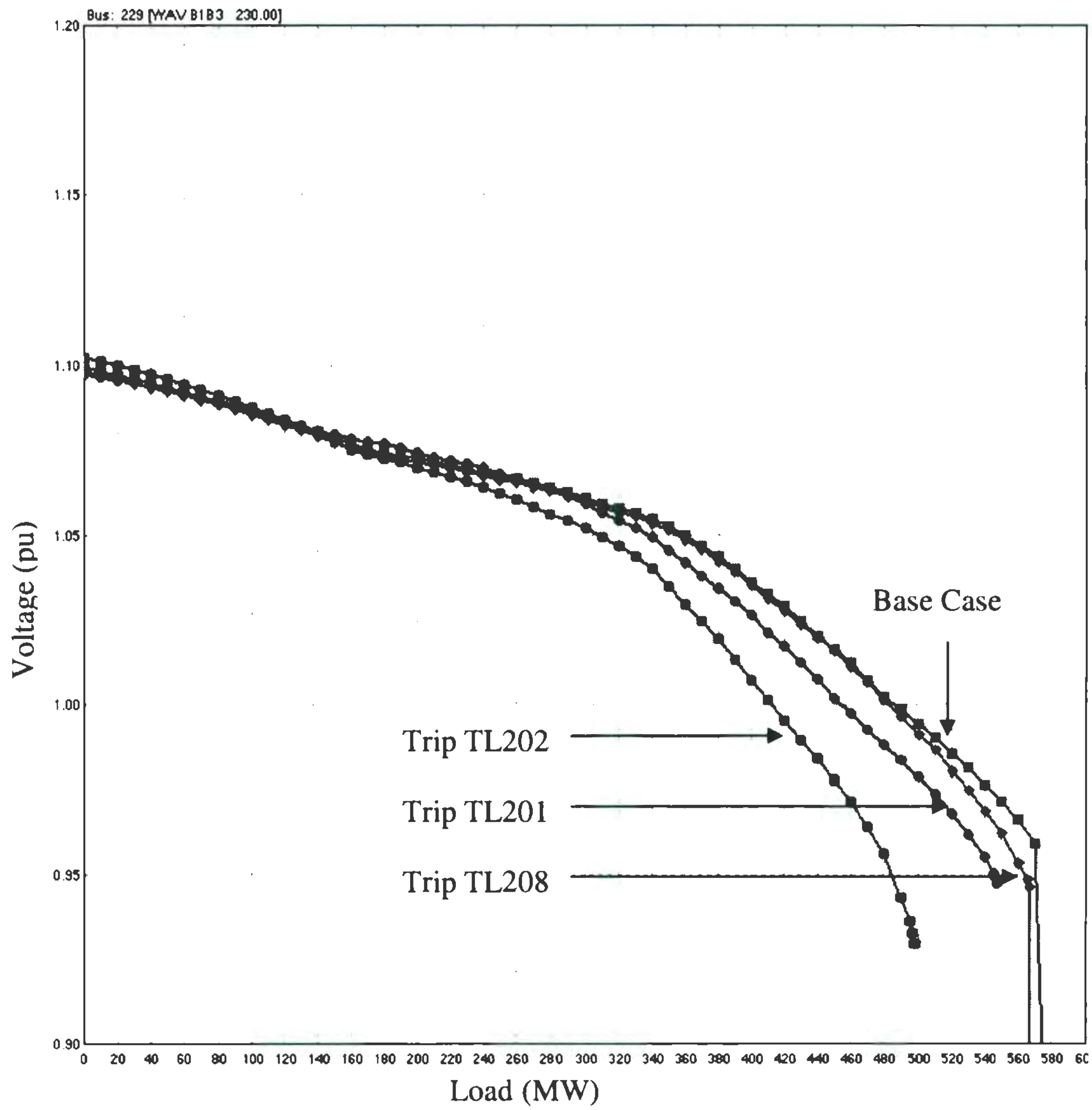

Figure 8.11: Case 4 p-v curve at WAV

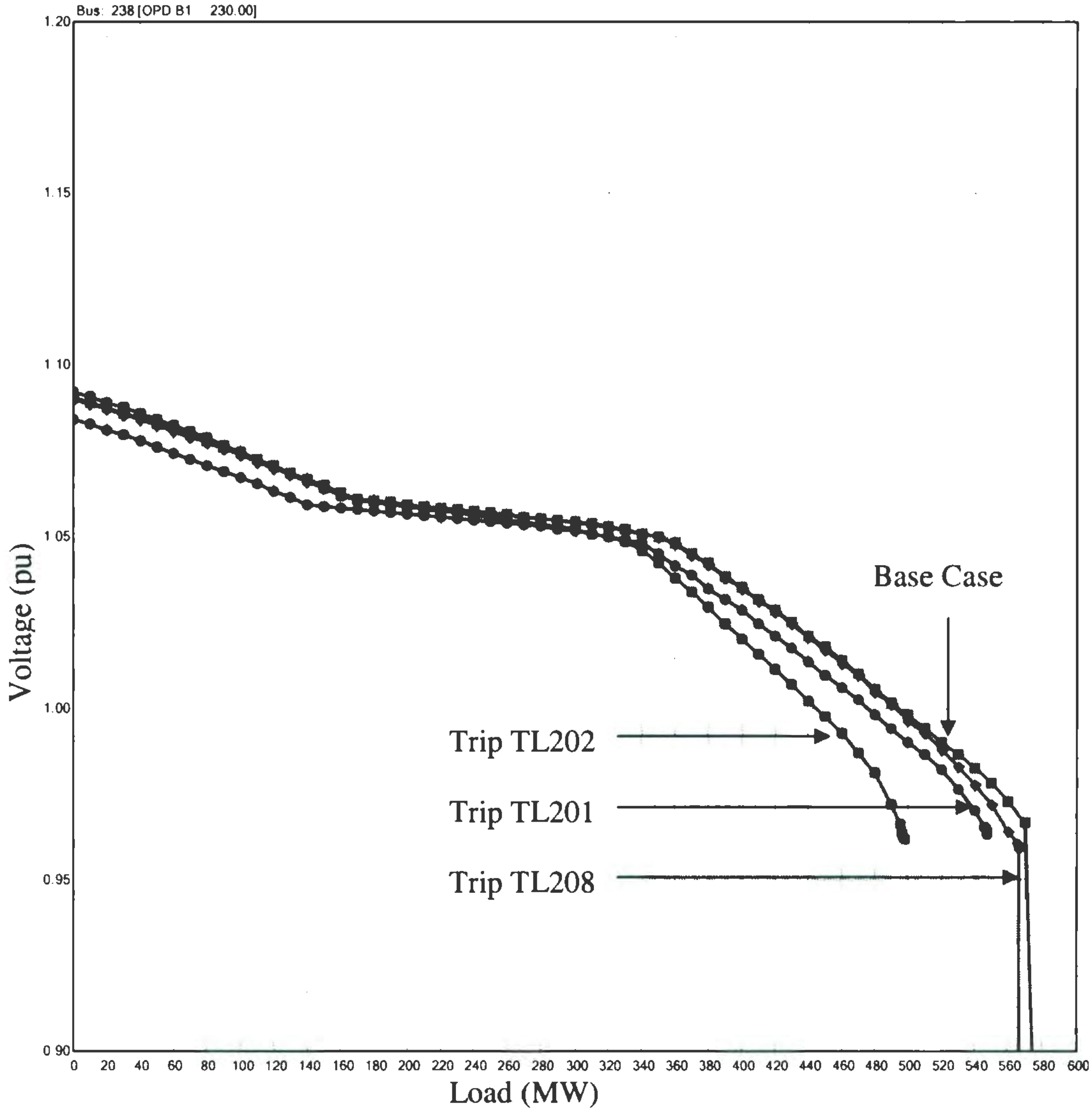

Figure 8.12: Case 4 p-v curve at OPD

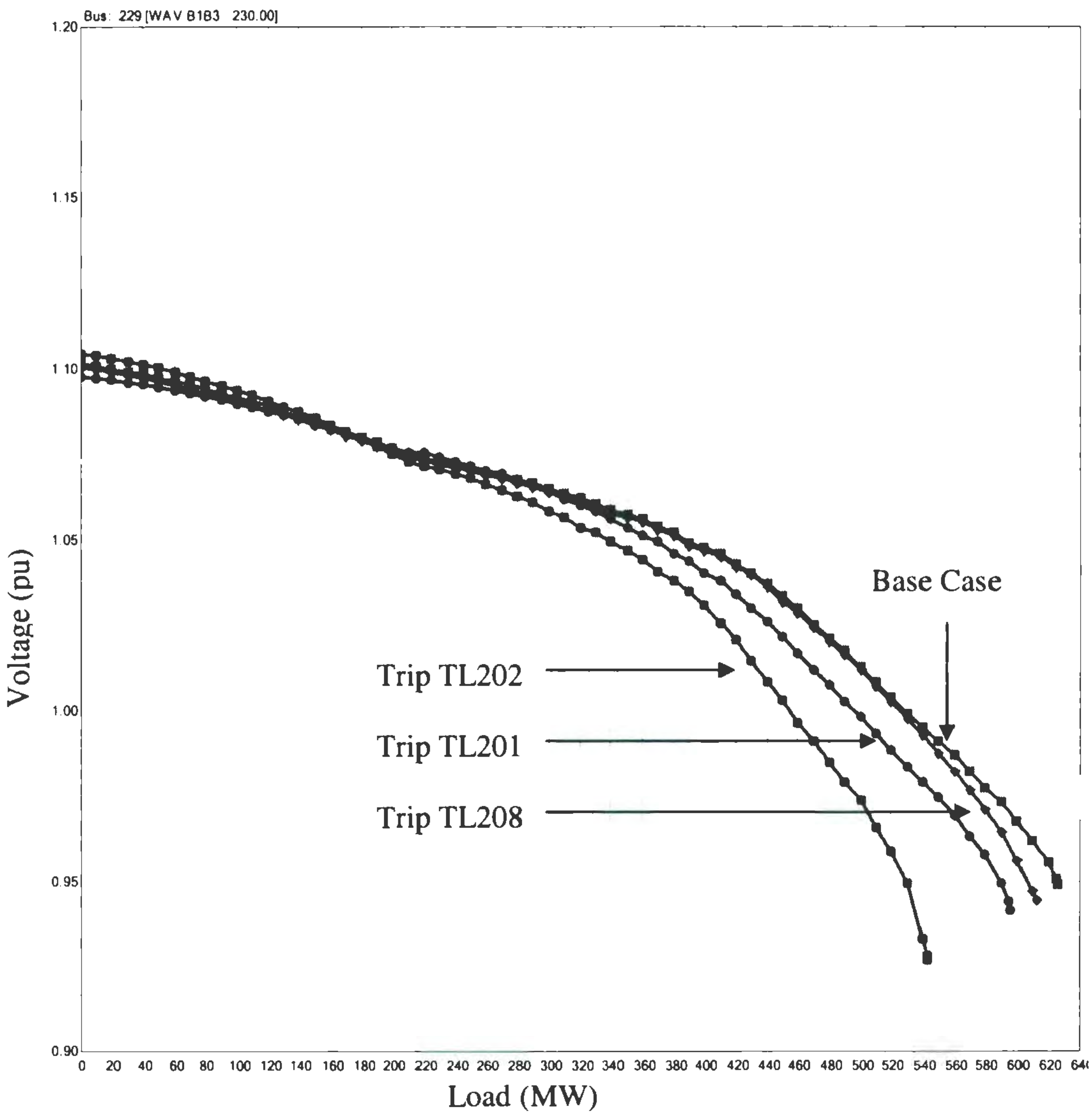

Figure 8.13: Case 5 p-v curve at WAV

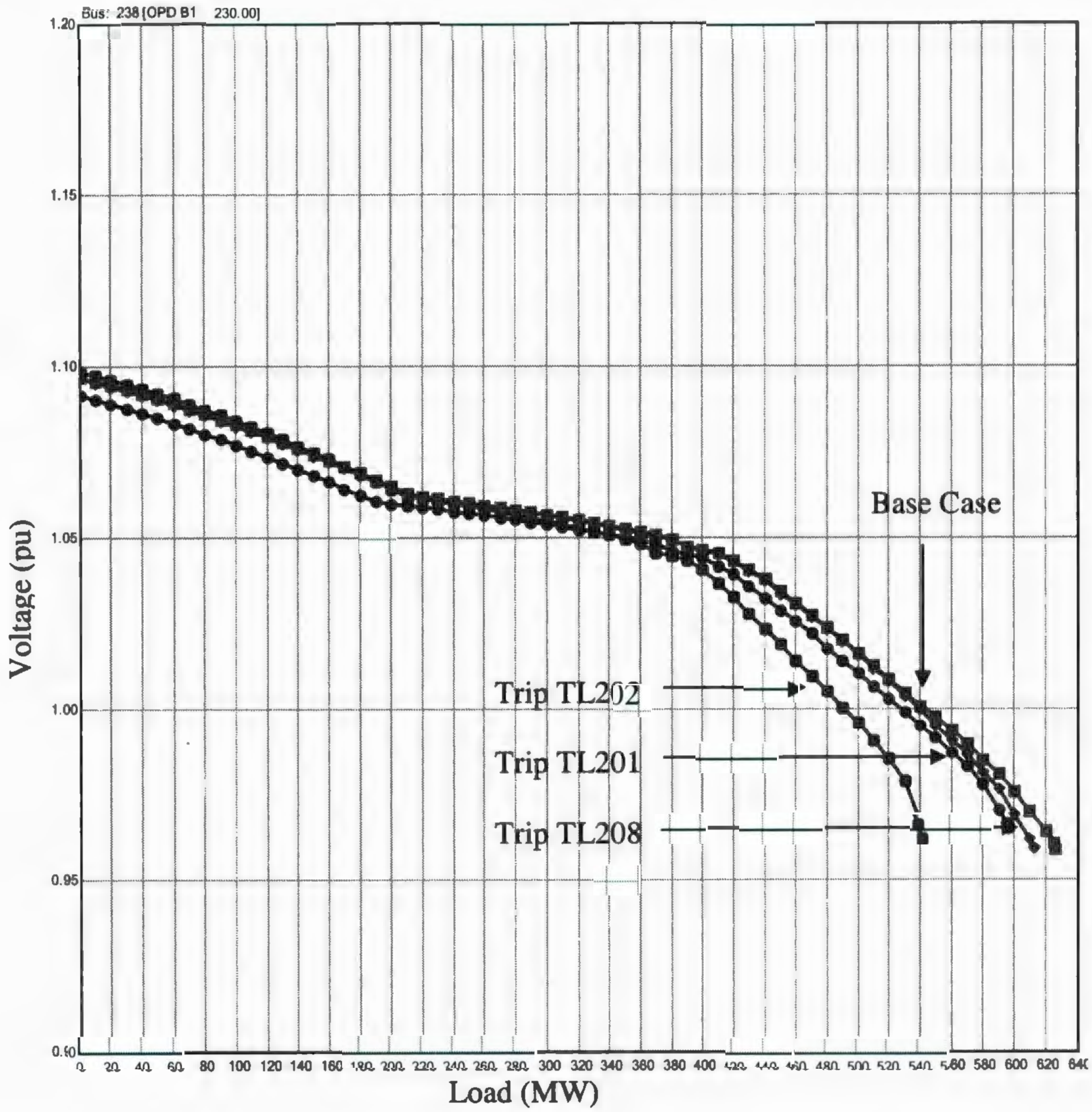

Figure 8.14: Case 5 p-v curve at OPD

8.4.2 Simulation Results

The schedule proposed in Table 8.4 has time graduated settings at 0.92 pu voltage (at 5 second intervals) and also contains two voltage thresholds that will operate on a near instantaneous basis. A shorter time delay is incorporated for the trip settings at the lowest thresholds since there may be contingencies and operating conditions for which more aggressive loadshedding is required. The intention is to minimize any required loadshedding for both the short term and long term time frames and the expectation is that the Avalon voltage will recover or stabilize before it is necessary to shed the entirety of the load contained in the schedule. In addition, note that a 0.25 sec delay is introduced for the 0.90 pu trip to prevent tripping during any three phase faults on the transmission line. The expectation is that distance protection will operate to clear the fault prior to operation of the 0.90 pu threshold.

Table 8.4: Potential UVLS schedule

Voltage Threshold	Time Delay	Loadshed
0.92 pu	5 sec	15 MW
0.92 pu	3 sec	15 MW
0.91 pu	1 sec	30 MW
0.90 pu	0.25	40 MW
Note: Maximum loadshed 100 MW		

There is a margin of error associated with the analysis for the P-V curves in that the load flows required to construct these curves would not converge below approximately 0.95 pu. This error will introduce some uncertainty with respect to the total amount of loadshedding required for operating contingencies that result in voltages of 0.9 pu on the Avalon. Hence the UVLS schedule indicated in Table 8.4, although viable, should be regarded as tentative and subject to change.

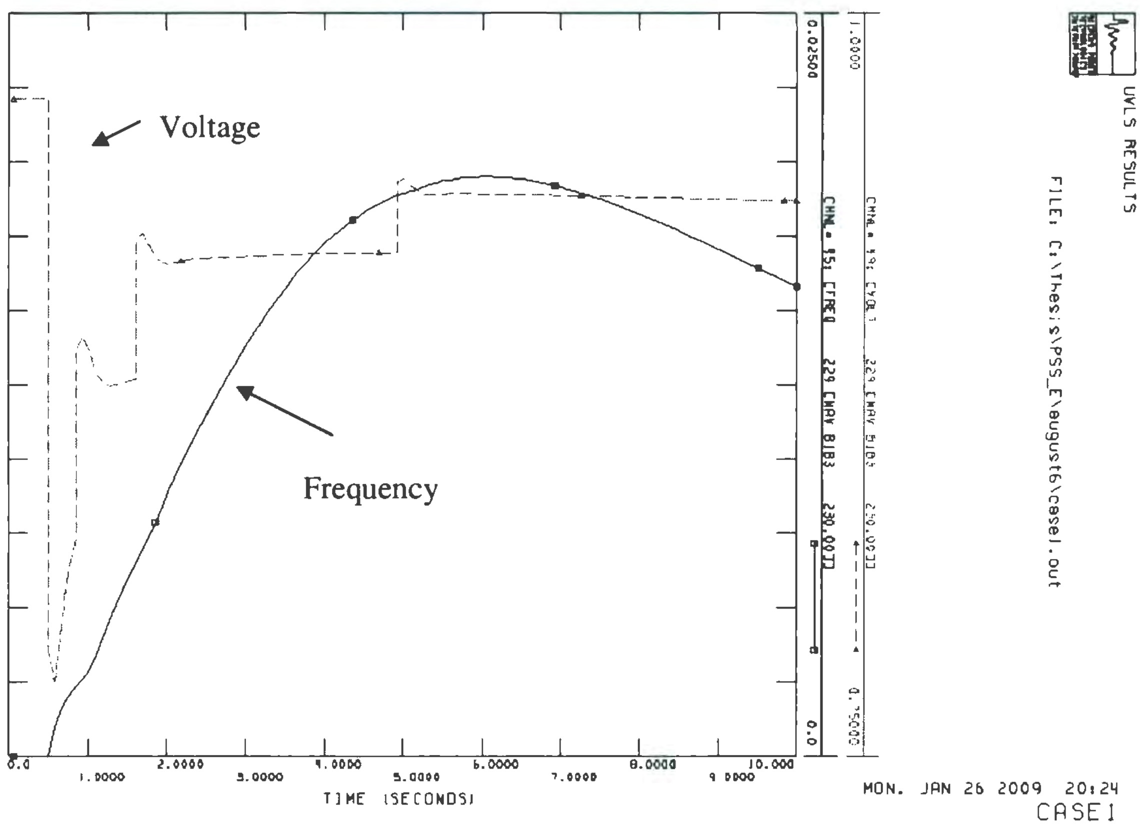

Figure 8.15: Voltage and frequency plot for case 1

Figure 8.15 depicts the operation of the UVLS schedule for case 1 following the TL202 trip operating contingency. Immediately after the line contingency, the voltage drops to 0.77 pu and results in a loadshed of 17.6 MW after a 0.25 sec time delay. Additional operations of the schedule occurred at the 0.91 pu and 0.92 pu trip settings resulting in a total additional loadshed of 19.2 MW. The total loadshed was 36.8 MW and restored the operating voltage to 0.97 pu at the WAV bus. The maximum frequency resulting from schedule operation was 61.17 Hz.

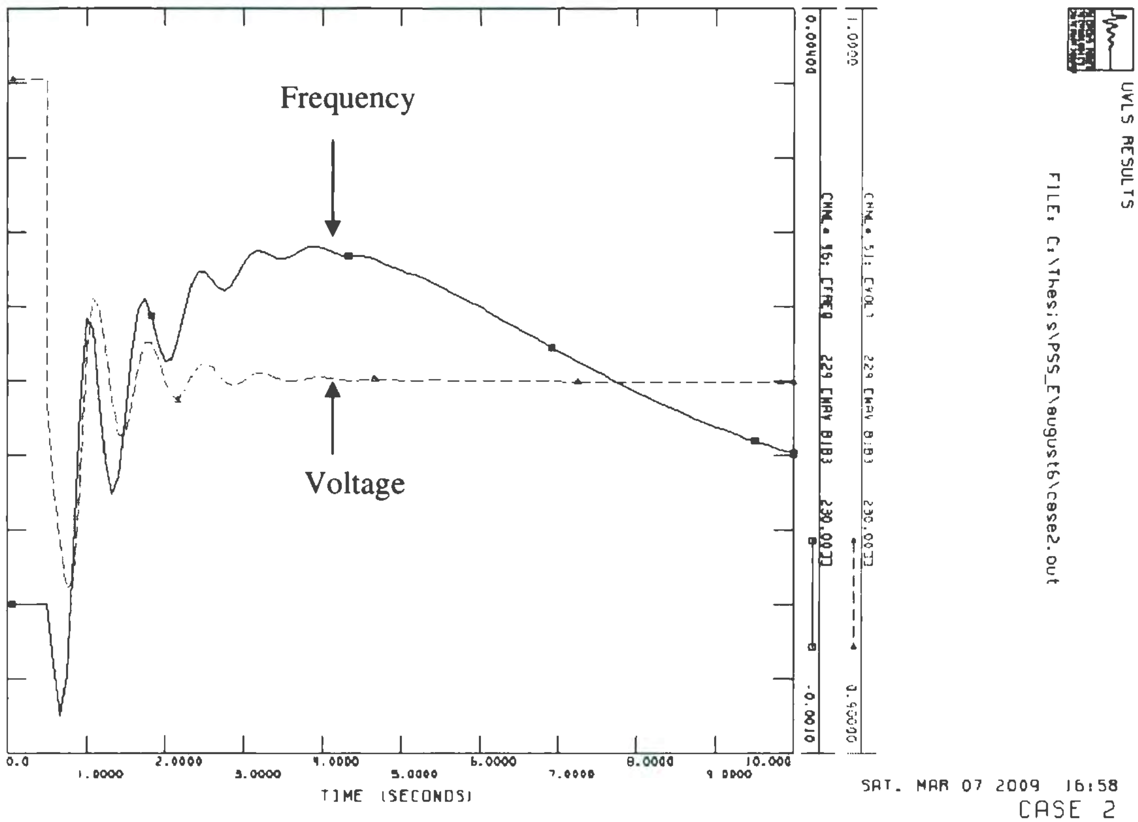

Figure 8.16: Voltage and frequency plot for case 2

Inspection of Figure 8.16 reveals that operation of the UVLS schedule was not required for the transmission line contingency for case 2. Following the trip of the transmission line, the voltage decreased to approximately 0.92 pu and stabilized at 0.95 pu. The frequency at WAV increased to a maximum value of 60.21 Hz. The presence of the Holyrood generation was sufficient to stabilize the voltage and prevent schedule operation.

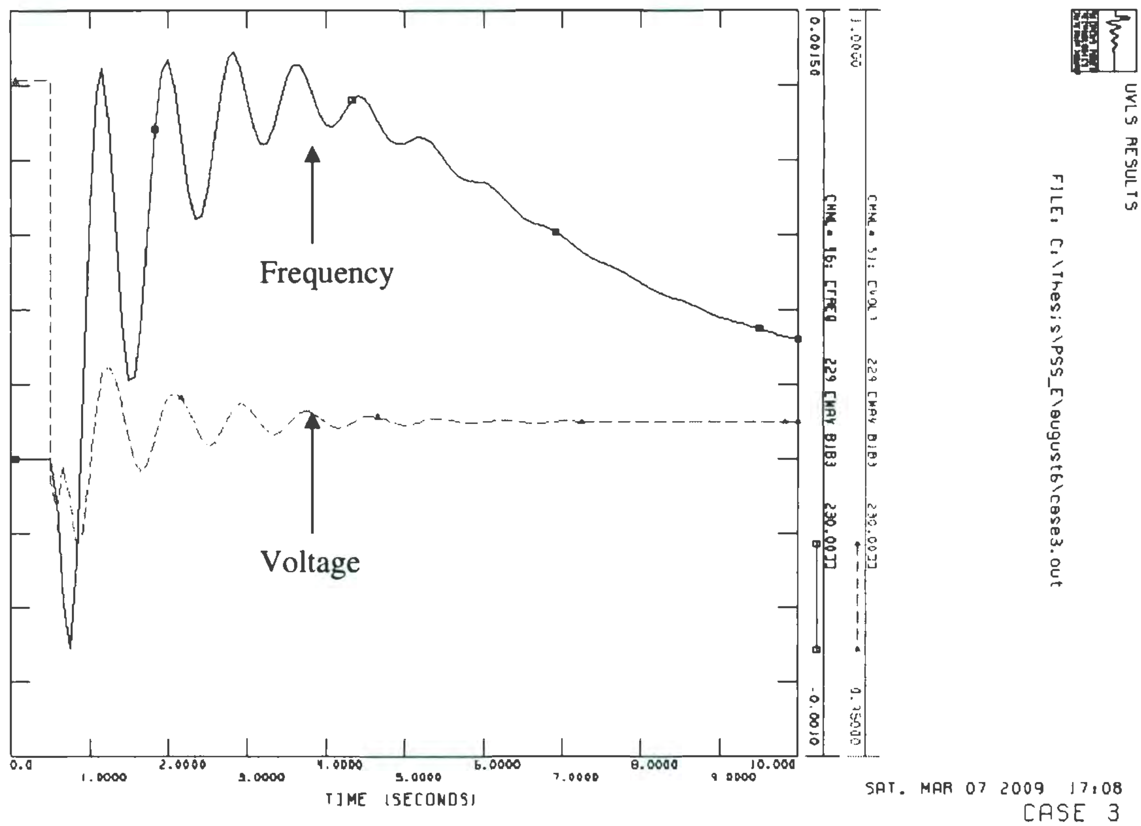

Figure 8.17: Voltage and frequency plot for case 3

Inspection of Figure 8.17 reveals that operation of the UVLS schedule was not required for the transmission line contingency for case 3. Following the trip of the transmission line, the voltage decreased to approximately 0.96 pu and stabilized at 0.973 pu. The frequency at WAV decreased to 59.97 Hz with a peak value of 60.08 Hz. UVLS was not required for this operating scenario and the presence of the Holyrood generation was sufficient to stabilize the voltage and prevent schedule operation.

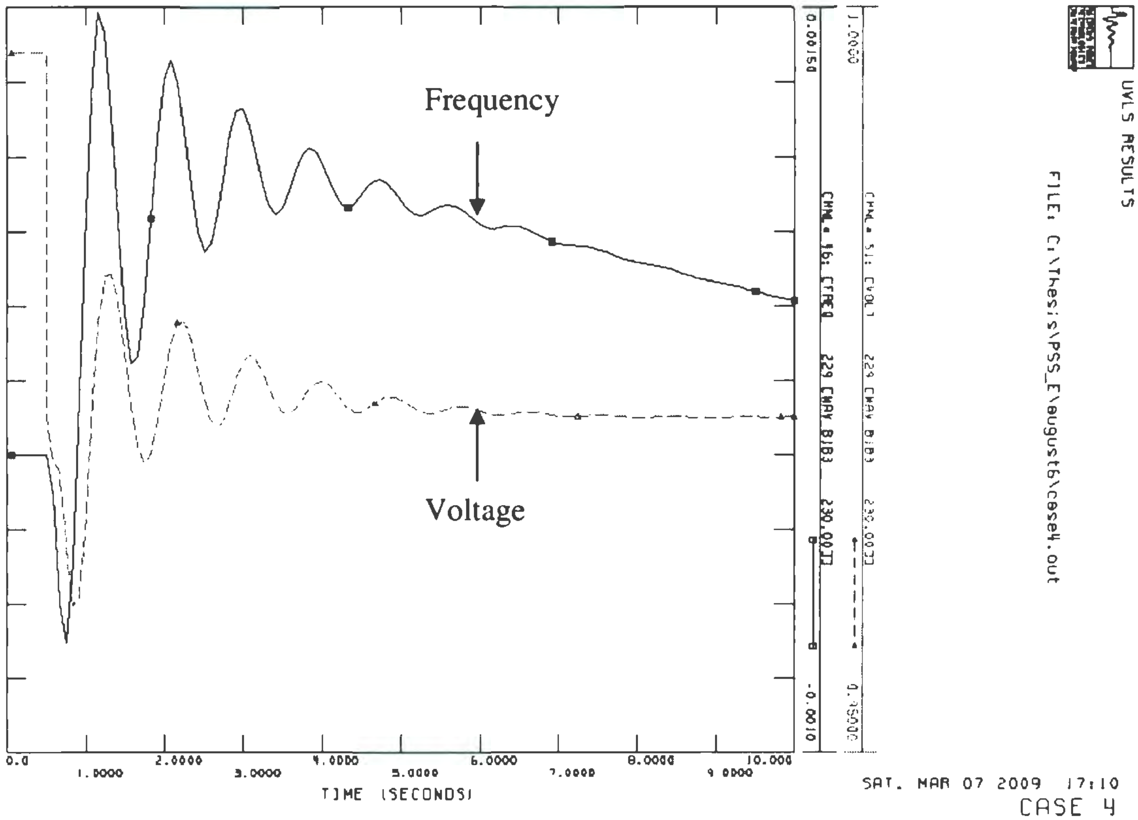

Figure 8.18: Voltage and frequency plot for case 4

Inspection of Figure 8.18 reveals that operation of the UVLS schedule was not required for the transmission line contingency for case 4. Following the trip of the transmission line, the voltage decreased to approximately 0.96 pu and stabilized at 0.973 pu. The frequency at WAV decreased to 59.96 Hz with a peak value of 60.09 Hz. UVLS was not required for this operating scenario and the presence of the Holyrood generation was sufficient to stabilize the voltage and prevent schedule operation.

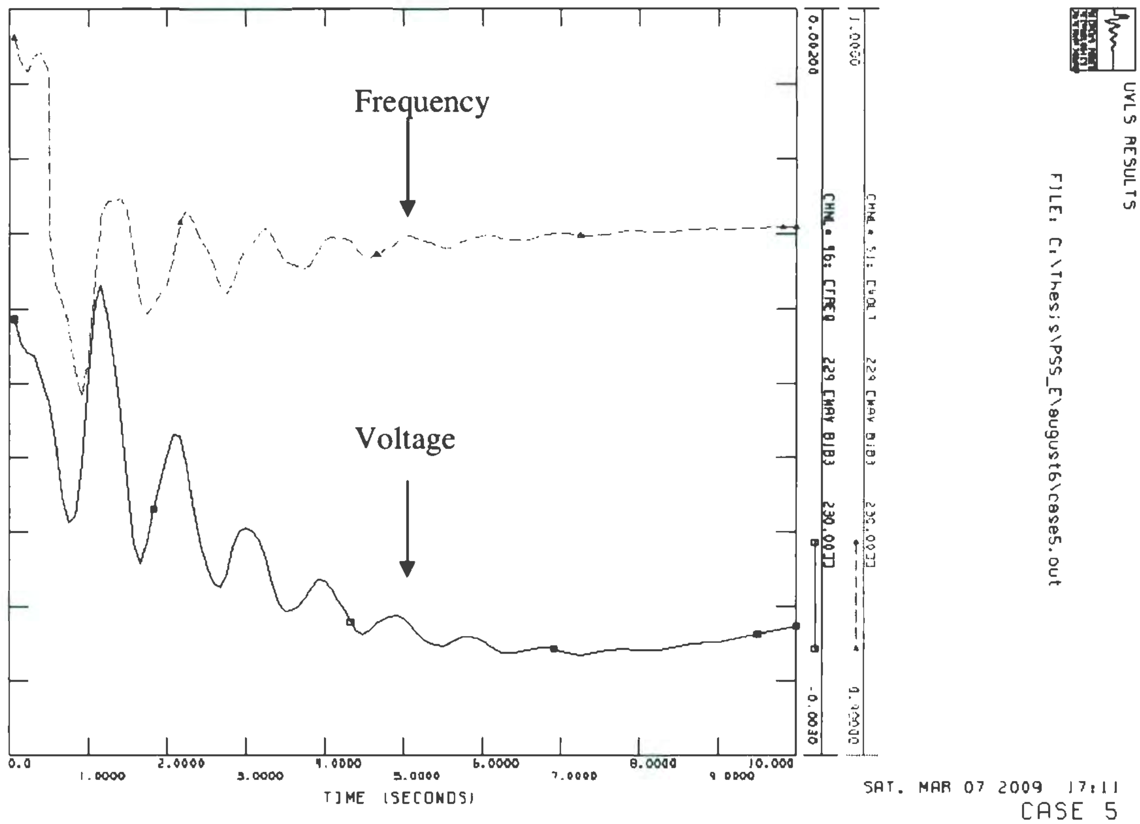

Figure 8.19: Voltage and frequency plot for case 5

Inspection of Figure 8.18 reveals that operation of the UVLS schedule was not required for the transmission line contingency for case 5. Following the trip of the transmission line, the voltage decreased to approximately 0.95 pu and stabilized at 0.972 pu. The frequency at WAV was not significantly perturbed and stabilized at 59.82 Hz with a peak value of 60.06 Hz. UVLS was not required for this operating scenario and the presence of the Holyrood generation was sufficient to stabilize the voltage and prevent schedule operation.

In summation, Figure 8.15 reveals that the voltages decreased at the WAV bus following the TL202 contingency for case 1 (zero generation on the Avalon) to approximately 0.77 pu and activated the lower stages of the UVLS schedule at 0.9 pu and 0.91 pu. The loading on TL202 at the time of the line contingency was approximately 175 MW and the loadshedding required (i.e. 36 MW) corresponds to the values indicated in Figure 8.5 at 0.97 pu voltage. The voltage on the Avalon (at WAV) did recover following activation of the UVLS thresholds and resulted in a total load shed of approximately 36 MW relative to the peak value of 100 MW. The final time delayed threshold (0.92 pu at 5 seconds) associated with the schedule did not trip since the voltage had recovered sufficiently to stabilize above the trip setting. If the final threshold had operated, the voltage would have recovered to nominal values. For this loss scenario, other control actions, such as synchronizing a gas turbine (i.e. GT) or other human intervention would provide the final required compensation necessary to restore the system voltage.

The loss contingency involving the trip of TL202 is the most onerous in terms of maintaining voltage stability on the Avalon (notwithstanding the loss of a generation unit) since the only available generation source (at BDE) is far removed from the principal load center. This system constraint will result in increased line losses in proportion to increased loading and is especially prevalent following the loss of either TL202 or TL206; which constitute the double circuit from Bay d'Espoir to Sunnyside. The application of UVLS, as per the schedule of Table 8.4, is effective at restoring the integrity of the voltage at WAV (and therefore on the Avalon) and is demonstrated to be an effective countermeasure for voltage instability. Figure 8.16 to Figure 8.19 indicate that undervoltage loadshedding was not required following a line loss contingency due to the influence of active and reactive reserves contributed by the HRD thermal units. Therefore, UVLS will not be required for every probable loss contingency on the Avalon but will function if required to preserve voltage stability during periods of depleted system reserves or following unusual operating contingencies. Further inspection of Figures 8.16 to Figure 8.19 reveal the variation in frequency at the WAV bus and illustrates the synchronizing oscillations required before the HRD units and the BDE units redistribute the system demand.

8.5 Summary

This chapter has outlined a methodology for application of an UVLS scheme for the eastern section of the Newfoundland island power system. P-V curves have been employed as the primary analysis tool to determine the loading limits for the representative cases discussed and the amount of loadshedding required for the principal load busses on the Avalon Peninsula at Oxen Pond and Hardwoods. Dynamic simulations of the voltage and frequency are included for the worst case contingencies and demonstrate that voltage stability is maintained following operation of the proposed load curtailment schedule.

Chapter 9

Conclusion

9.1 Contributions of the Research

The requirement that power systems operate in a predictable and reliable manner is fundamental for the power utility and necessarily includes the correct and reliable operation of the system protection. A significant aspect of this requirement is the identification and isolation of abnormal operating conditions on the system.

Concurrent with the advances in relaying technology over the past several decades have been improved modes of application by designers to safeguard the power system and to preserve safe and reliable operation. The current research has applied modern digital relaying utilizing a methodology for UVLS and UFLS to the island system of Newfoundland in an attempt to preserve continuity of service and system stability following severe operating contingencies.

The methodologies employed in the current research are based on the detection of an emergency or in extremis state of operation with mitigation of the contingency and restoration of stability achieved through load curtailment. The loading variation possible on the Newfoundland system was modeled using variable generation dispatch scenarios representative of seasonal loading variation on the system. This was the principal means to ensure the chosen UFLS schedule would function for all possible generation loss contingencies. In addition, an UVLS schedule was developed using P-V curves and dynamic analysis to ensure continued voltage stability on the Avalon Peninsula. The protection scheme will respond following a period of low voltage (at a monitored bus) resulting from operation of the system during periods of insufficient reserves. Both UFLS and UVLS schedules are designed to respond to overload conditions that threaten frequency or voltage stability.

The developed protection schemes are simple, effective and provide timely and decisive compensation following overloads resulting in either low frequency or low voltage. Although the methodology is applied to the island system of Newfoundland, it is sufficiently general in design to be applied to any isolated power system.

9.2 Suggestions for Future Work

The work reported in this thesis can be extended in the following areas:

- The methodologies developed for determination of the optimum UFLS schedule in section 7.5.2 and the UVLS schedule in section 8.4.2 are based on general principles and observation and may not represent the optimum choices. Additional research could be conducted to develop a method for selection of a load curtailment schedule based on specific performance indicators or general statistical methods.
- The UFLS schemes outlined in the present research are "reactionary" in that the response of the SPS occurs after the system variables have reached specific levels. It would be preferred if the required extent of load curtailment could be determined before the system frequency experiences a significant change from nominal. The

development of a dynamic and adaptive UFLS scheme would potentially offer improved performance with respect to minimizing the total amount of load that is shed during a load curtailment event. Neural networks and other adaptive schemes have been developed (by different authors) that attempt to minimize the extent of loadshedding required during operational contingencies and relies upon continuous assessment of the df/dt. A possible refinement to such a scheme would be to develop a neural net (or other adaptive scheme) which would effect the desired amount of loadshedding based on determination of the frequency and df/dt for the system center of inertia in concert with a maximum acceptable operating frequency. The usage of the COI may be desirable depending on the size of the system since there may be frequency and df/dt variation at different generation busses following a generation loss contingency and will thereby prevent the activation or operation of an adaptive scheme which is based on a df/dt value calculated at a single point on the system. The incorporation of a maximum acceptable operating frequency will ensure that the SPS does not become active for generation loss contingencies that can be mitigated by the system spinning reserve. Furthermore, continuous monitoring of the loading on all system feeders would enable load curtailment at near the optimum amount. This scheme would require the use of an extensive communication and control network since remote control and monitoring of the loadshedding feeders will be required as well as the use of a central computer or coordinating relay. The central relay could trip specific increments of load in proportion to the contingency until the load generation balance has been restored. Ideally the relay will determine the required amount of loadshedding in response to a generation deficiency and implement the decision to trip at various parts of the system as constrained by the severity of voltage changes at the busses near the sites of feeder breaker operation. Finally, the amount of loadshedding required could be adaptive in that the size of the incremental loadshed will increase in response to generation loss contingencies of increasing severity.

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Appendix-A

Overview of the PSS/E Software Package

PSS/E (power system simulator) is a software package marketed by Siemens that is widely used in industry for transmission planning. The capabilities of the software include power flow, contingency analysis, probabilistic contingency analysis, dynamic simulation, short circuit analysis as well as optimal power flow and small signal stability analysis. The power system models are based on differential equations and numerical solution techniques utilizing a FORTRAN compiler. Models for all elements of the power system are available and include exciter and governor models, protective relaying models, transmission line models (including the inductances and capacitances of transformers and shunt devices), symmetrical component representation for analysis of unbalanced faults as well as a myriad of other features. Power systems as large as 50,000 or more buses may be analyzed following solution of the nonlinear differential equations associated with the power system models. Further details are available in the PSS/E documentation [35].

The analysis required in this thesis is based on dynamic and static representations of the power system. The static analysis was employed for load flow cases and the development of power-voltage curves to determine maximum Avalon loading whereas the dynamic analysis was employed for frequency and voltage simulations.