PROBABILISTIC TRANSIENT STABILITY STUDIES USING THE BC HYDRO SYSTEM

by

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Date  AUGUST 19, 1997
The power utility industry in North America is quickly evolving from a monopolistic environment to a competitive one. Traditional dynamic security assessment methods and tools which have served the industry well in the past cannot provide the risk analysis needed to extract more value out of existing assets. BC Hydro’s current deterministic practice is to study the “worst case”, where all faults are assumed to be 3φ bus faults with unsuccessful reclosing, at a load factor of 100%. A review of historical fault data from BC Hydro’s 500 kV system over the past 20 years has shown these assumptions do not reflect the true nature of the power system. However, they are in place to ensure that minimum operating reliability mandated by regulatory agencies are met.

Based on historical statistics, the probabilistic states of load factor, fault type, fault location, fault clearing, and automatic reclosing were applied to a generation rejection study on the Peace system and a transfer limit study on the Columbia system. For each study, 1000 simulations were carried out on a full model of the BC Hydro interconnected system, with the probabilistic states chosen via Monte Carlo techniques. The results were quantified using a BC Hydro developed transient stability assessment module in conjunction with a commercial load flow and dynamic simulation package (PTI’s PSS/E).

The results showed that BC Hydro’s existing deterministic criteria are very conservative, with a risk of instability between 0% and 0.2% in the Peace case and 0.1% in the Columbia case. Although the risk of instability was calculated as 0% for the Peace
case, this an approximation error due to the number of samples used. The studies also
revealed that the deterministic criteria does not always correspond to the “worst case” as
normally assumed.

An analysis of the effectiveness of each probabilistic factor considered showed
that fault type and successful/unsuccessful reclosing were the more significant factors,
while fault location on the line was the least significant. This research has shown that
considering the probabilistic nature of the power system in dynamic security assessment
can lead to less remedial actions and increased transfer limits.
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1. INTRODUCTION

In most industrialized nations today, the seemingly endless and uninterrupted supply of electricity is demanded and expected. Over the past 100 years, power system engineers have planned and designed systems to supply customers with their needs in a reliable and economic fashion. However, the evolution of the power utility industry from a monopolistic environment to a competitive one has created a need for new assessment tools and methodology.

The traditional design of power systems involves deterministic methods to test the stability of the system under the most severe conditions and contingencies, with no regard to the likelihood of such events. This “worst case” approach has served the industry well as it provided a robust system that could handle most single and some double contingencies without noticeable ill effects. However, in a competitive environment, there is an emphasis on extracting more value out of existing assets (i.e., transmission lines and generating plants). Utilities are now starting to employ probabilistic factors in either their assessment methods or their post-study analyses to obtain a more realistic appraisal of their system stability and to determine if existing limits can be safely increased.

1.1 BRIEF REVIEW OF TRANSIENT STABILITY

The ability of a utility to provide reliable services can be subdivided into the areas of system adequacy and system security [1]. System adequacy can be described as the static assessment of the power system — the ability to meet the load demands of customers under pre-disturbance conditions. A disturbance in the power system has been
defined by an IEEE Power Engineering Society Committee as a sudden change or a sequence of changes in one or more of the parameters of the system, or in one or more of the operating quantities [2].

System security relates to the dynamic behaviour of the system, including voltage stability analysis, transient stability analysis, and other dynamic assessment methods. Transient stability studies assess the ability of generators in a system to maintain synchronism after a disturbance. In general, a power system can be considered transiently stable for a particular pre-disturbance (i.e., steady-state) operating condition and for a particular disturbance if, after that disturbance, the system reaches an acceptable (albeit new) steady-state operating condition [3]. Although transient instability can usually be detected after the first swing, where the generator rotor angles are changing quickly and widely, some swings may be multi-modal, leading to a first-swing stability but subsequent instability. Thus, most transient stability studies are concerned with up to the first ten seconds of behaviour after a disturbance. Figures 1.1a - 1.1c illustrate the concepts of transient stability in relation to the first rotor swing.

Traditionally, transient stability studies have been carried out off-line, allowing complete and detailed analysis for each credible contingency. However, since the actual topology of the network can change daily (or even hourly) these operating conditions rarely match those previously studied. Some utilities, like BC Hydro, have employed or are starting to employ on-line stability assessment programs that take the current operating condition into account when assessing certain contingencies. However, these studies are still deterministic in nature and generally do not consider the probabilistic nature of power system disturbances.
Chapter I: Introduction

Figure 1.1 - Graphs of Rotor Angles Illustrating the Concept of Transient Stability [3]

1.2 PROBABILISTIC vs. DETERMINISTIC

Traditional transient stability studies have been deterministic in nature. That is, they follow a step-by-step process in which the factors such as the fault type, fault location, load level, etc., are selected beforehand, usually in accordance to the “worst-case” philosophy described earlier. For example, a power system engineer may decide to look at maximum transfer capability for a specific transmission corridor during the summer of 1998, knowing that some maintenance is going to take place. The disturbance parameters are chosen as a 3φ permanent fault at the busbar of one of the line ends,
cleared after 4 cycles, but with unsuccessful reclosing, resulting in the line being tripped out for the immediate future. The block diagram in Figure 1.2 outlines the usual procedure.

![Block Diagram of Procedure for Deterministic Transient Stability Studies](image)

**Figure 1.2 - Block Diagram of Procedure for Deterministic Transient Stability Studies [3]**

Probabilistic studies, however, take into account the stochastic nature of the power system. Some consideration is given to the credibility and probability of a certain event occurring. No longer are limits based solely on the “worst case” criteria normally applied. Probability distributions (either discrete or continuous) for a given disturbance
location, type, and sequence are used instead of merely selecting the "worst case". Some conditions like the initial load level may still be selected using enumeration as there are relatively few load steps that need to be considered. Figure 1.3 shows the procedure for including probabilistic factors in transient stability studies.

Figure 1.3 - Block Diagram of Procedure for Probabilistic Transient Stability Studies
Unlike the deterministic approach, this process must be repeated many times to include a spectrum of different states with their probabilities of occurrence.

1.3 REVIEW OF PREVIOUS WORK

The use of probabilistic techniques in transient stability studies was presented in a series of papers by Billinton & Kuruganty [4-6]. Starting with a simple system (single machine, double circuit, infinite bus) and gradually moving to a 33-bus simplified model of the Saskatchewan Power Corporation (SPC) system, they considered and described the probabilistic nature of fault type, fault location, fault clearing, and system operating conditions. Using fault incidence data taken from the United Kingdom Electricity Board (1968 - 1974), the Canadian Electrical Association (CEA) Reliability Committee Report, and the SPC system, they were able to show that 3-phase (3ϕ) faults, most commonly used in deterministic transient stability studies, were the least likely to occur. The major findings by Billinton & Kuruganty were:

1. The probability of stability increases as the fault location moves away from the generator bus;
2. The severity of fault type increases from single line to ground (SLG) through to 3ϕ;
3. The probability of stability for a given power level decreases as the clearing time is increased; and
4. Machine inertia is related to the critical clearing time (CCT).

Billinton & Kuruganty were also used the conditional probability approach to develop a single stability index for any fault. Since the probabilistic factors considered
Chapter 1: Introduction

were all mutually exclusive, the conditional probability can be used to assess the system transient stability. The single index they developed can be described by:

\[
\Pr(\text{stability}) = \sum_{all \ j} \sum_{all \ i} \Pr(\text{stability} \mid \text{fault}_j \text{ and load}_i) \times \Pr(\text{fault}_j) \times \Pr(\text{load}_i)
\]  

(1)

Through these three papers, Billinton & Kuruganty helped lay the foundation for the work of others. They developed models for the protection system and transient stability indices for each line in a small test system, taking into account the stochastic factors of fault type, fault location, fault clearing time, and system operating conditions. However, the stability index formula derived from these studies do not consider simultaneous faults, which are not mutually exclusive in nature.

Anderson & Bose in a paper [7] and an Electric Power Research Institute (EPRI) report [3] discussed the broader subject of probabilistic power system stability. Their approach to transient stability analysis involved a complex transformation of a 3ϕ fault event into a new random variable that could be evaluated to determine the probability of stability. They concede, however, that the analytic transformation is difficult, if not impossible to obtain. Furthermore, this approach to stability assessment is approximate. To obtain some numerical results, they turned to Monte Carlo simulation to choose the system state. This allowed the development of a stability histogram for analysis of the results.

they computed the probability of every fault event on fourteen 345 kV transmission lines. Then, using an optimal power flow program to obtain the pre-fault operating conditions, they derived the joint probability distribution function for the CCT and each of the five variables considered. An advantage of their method is that the contribution of each variable can be separated out, allowing the cause of system transient instability to be analyzed using Baye’s Theorem. The major finding of their study was that their existing fault clearing criteria of 6 cycles was too fast — in other words, the current deterministic criteria was too conservative. If the present load level was maintained, they could allow slower clearing, or by maintaining the present clearing criteria, they could accommodate more load.

Recently, Billinton & Aboreshaid [9-10] have advanced the pioneering work of Billinton & Kuruganty. They have developed refined stochastic models used for high-speed reclosing and employed the method of bisection to speed up the calculation of the critical clearing time.

This previous work has provided insights regarding the probabilistic nature of power systems. Billinton & Kuruganty and later Billinton & Aboreshaid, studied the effect of fault type, fault location, fault duration, fault clearing, and system conditions. They used the conditional probability in developing system transient stability indices and presented novel methods for incorporating the protection system into the stability studies. Hsu & Chang considered the impact of seasonal loading and were the only ones to use a non-equivalenced, realistic system (the actual Taiwan Power system) for their studies. Their method allows the “weak points” of a system to be identified and showed significant conservatism on the part of current deterministic practices in setting breaker
clearing times. Anderson & Bose presented a complex transformation method that proved to be analytically difficult, but showed that Monte Carlo simulation is a practical and often desirable alternative. It is only through the use of Monte Carlo techniques that reliability data of an operating system can be considered in transient stability studies.

1.4 SCOPE OF THESIS

Previous work as described above has confirmed the probabilistic nature of power systems. However, with the exception of Hsu & Chang’s study on the Taiwan Power System and Billinton & Kuruganty’s studies on the reduced model of the Saskatchewan Power System, there has been very little previous research using a large scale, realistic system. Also, there have been no discussions on how the use of probabilistic factors can change realistic stability limits (i.e., generation shedding requirements or transfer limit capabilities).

Existing work has focused on developing stability indices and not on the needs of a power utility. In a power utility environment, system instability is not an acceptable outcome. Instead, the remedial action required to avert system instability is a more appropriate outcome. Previous work with probabilistic factors has not considered this aspect. This research considers the probabilistic factors and uses them on a full model of the BC Hydro interconnected system (4000 buses, 500 machines). Two specific contingencies are studied to determine the impact probabilistic factors have on generation rejection and transfer limits. The research contributions of this thesis are that:

1. It uses a realistic system and historical data from that system;
2. It provides a direct comparison between existing deterministic limits and probabilistic limits, taking into consideration the remedial actions that are required to maintain system stability during and after disturbances.

1.5 ORGANIZATION OF THESIS

This chapter provides a brief review of the theory of transient stability and the previous research that has been conducted by others in the area. Chapter 2 gives an overview of the BC Hydro system which was used in the research and some of the current dynamic assessment methods employed at BC Hydro. Chapter 3 describes the historical data that was collected and the various models and tools that were developed in support of this work. Chapter 4 details the probabilistic transient stability studies carried out and discusses the impact these factors had on the results. Chapter 5 summarizes the findings and gives some suggestions for future research.
2. REVIEW OF CURRENT BC HYDRO PRACTICE

In many respects, BC Hydro is considered on the leading edge of dynamic security assessment methods. Along with the usual off-line time domain simulations, BC Hydro has also implemented a voltage stability assessment program (VSLIM) and an online transient stability assessment program (TSA). However, these methods still employ deterministic criteria and do not take into account probabilistic factors.

2.1 OVERVIEW OF THE BC HYDRO SYSTEM

BC Hydro is a provincial Crown corporation, established in 1964. The third-largest electric utility in Canada, BC Hydro serves more than 1.4 million customers in an area containing over 92 percent of British Columbia's population. Between 45,000 and 50,000 gigawatt-hours (GWh) of electricity are generated annually, depending on prevailing water levels. The present generating capacity of BC Hydro is about 10,500 Megawatts (MW) with approximately 9,300 MW of hydroelectric and 1,200 MW of natural gas generation.

Electricity is delivered to customers through an interconnected system of over 70,000 kilometres of transmission and distribution lines. Bulk power is transmitted to the major load centres by high voltage alternating current (AC) transmission lines operating at 60, 138, 230, 287, 360 and 500 kilovolts (kV) and by two high voltage direct current (HVDC) lines between the Lower Mainland and Vancouver Island. Power delivery to individual customers is at 4, 12 and 25 kV. Figure 2.1 shows the major transmission and generation system, commonly referred to as the bulk system.
Chapter 2: Review of Current BC Hydro Practice

Figure 2.1 - BC Hydro’s Bulk System

For system security studies, BC Hydro’s bulk system is generally divided into two main subsystems, the Peace system and the Columbia system. The Peace system has a total generating capacity of 3430 MW and transmits most of this power over 1000 km of 500 kV transmission corridor to the Lower Mainland, while the Columbia system has a generating capacity of 4750 MW and transmits this power over 500 km of transmission corridor to the South Interior and the Lower Mainland. This large transfer of power over long distances makes BC Hydro’s system transient stability limited, and has led to the
application of stability measures like fast fault clearing, 50% series compensation on 500 kV lines, braking resistors, automatic generation shedding, and high speed reclosing.

2.2 DETERMINISTIC CRITERIA USED

BC Hydro, as a member of the Western Systems Coordinating Council (WSCC), must comply with system dynamic security criteria set by the North American Reliability Council (NERC). This requires the simulation of complex switching sequences for all credible events and currently does not allow for the use of probabilistic factors. The minimum operating reliability criteria mandated by these councils is generally quoted as:

“The bulk power systems will be operated at all times so that general system instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. A single contingency may generally be assumed to mean the loss of a single system element; however, the outage of multiple system elements should be treated as a single contingency if caused by a single event of sufficiently high likelihood. Multiple contingency outages of a credible nature will be examined, and the system will be operated to protect against general system instability, uncontrolled separation or cascading outages for these contingencies.” [11]

The criteria for the Peace system are based on the fact that all 500 kV lines have 50% series compensation, high-speed fault clearing and reclosing, and up to 400 MW of braking resistors are available at G.M. Shrum generating station. The current criteria for this system are shown in Table 2.2.1.
Chapter 2: Review of Current BC Hydro Practice

Table 2.2.1 - Current BC Hydro Deterministic Criteria for Peace System Studies

<table>
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<th>Time (cycles)</th>
<th>Event</th>
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<tr>
<td>0</td>
<td>Apply a 3Φ fault at a 500 kV bus</td>
</tr>
<tr>
<td>2</td>
<td>Bypass series capacitor if rating is exceeded</td>
</tr>
<tr>
<td>4</td>
<td>Clear fault, trip line</td>
</tr>
<tr>
<td>9</td>
<td>Switch 200-400 MW of braking resistor on, depending on the accelerating power calculated</td>
</tr>
<tr>
<td>9</td>
<td>Trip amount of generation required to maintain stability</td>
</tr>
<tr>
<td>35</td>
<td>Reclose onto fault (i.e., fault has not been cleared) at the master end of the faulted line</td>
</tr>
<tr>
<td>39</td>
<td>Clear fault, trip line</td>
</tr>
<tr>
<td>44</td>
<td>Switch braking resistors off</td>
</tr>
<tr>
<td>180</td>
<td>End simulation</td>
</tr>
</tbody>
</table>

The criteria for the Columbia system are similar to the ones for the Peace system, except that braking resistors are not available. Some lines are also equipped with selective single pole switching and reclosing, so those contingencies are also normally studied. The longer reclose time for the Columbia system is a strategy employed by the transmission planners to ensure that the reclose occurs on a down swing of the rotors and not on an upswing (worst case). The current criteria for this system are shown in Table 2.2.2.
Table 2.2.2 - Current BC Hydro Deterministic Criteria for Columbia System Studies

<table>
<thead>
<tr>
<th>Time (cycles)</th>
<th>Event</th>
</tr>
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<tbody>
<tr>
<td>0</td>
<td>Apply a 3φ or SLG fault at a 500 kV bus</td>
</tr>
<tr>
<td>2</td>
<td>Bypass series capacitor if rating is exceeded</td>
</tr>
<tr>
<td>4</td>
<td>Clear fault</td>
</tr>
<tr>
<td>4</td>
<td>Trip line (3φ faults only)</td>
</tr>
<tr>
<td>9</td>
<td>Trip amount of generation required to maintain stability</td>
</tr>
<tr>
<td>60</td>
<td>Reclose onto fault (i.e. fault has not been cleared) at the master end of the faulted line</td>
</tr>
<tr>
<td>64</td>
<td>Clear fault</td>
</tr>
<tr>
<td>64</td>
<td>Trip line (3φ faults only)</td>
</tr>
<tr>
<td>180</td>
<td>End simulation</td>
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</table>

From the above switching sequences, it can been seen that BC Hydro’s current deterministic practice is to assume the “worst case”. All faults are assumed to be 3φ bus faults, except for lines where single pole reclosing is employed, and unsuccessful reclosing is always assumed. These assumptions do not reflect the true nature of the events recorded over the past 20 years. However, they are in place to ensure that the minimum operating reliability mandated by WSCC and NERC are met.

2.3 SYSTEM OPERATING ORDERS

Like all major utilities, BC Hydro relies mainly on off-line stability studies to determine pre-contingency limits and post-contingency remedial actions. These studies
are used to develop System Operating Orders which specify maximum lines flows for all credible operating conditions, voltage and frequency control, switching guidelines, and generation shedding requirements. These operating orders are updated periodically, but do not account for every possible contingency. Instead, they look mainly at “worst case” scenarios and remedial actions.

BC Hydro also uses an on-line transient stability assessment (TSA) tool as part of its energy management system at the System Control Centre. Although TSA uses real-time operating conditions (i.e., the current state of the high voltage network), it does not use probabilistic factors. The criteria considered are still NERC compliant, using the “worst case” scenarios.

To update these operating orders, transmission planning engineers at BC Hydro annually produce an Electric System Operating Guide. This guide includes updated loadflows with estimated summer and winter peak loads, normal and extreme operating conditions, and bulk system operating limits. Since the power system is constantly evolving, these annual updates are necessary to account for system reconfigurations and modifications.

2.4 TOOLS AND MODELS

BC Hydro uses a combination of commercial software packages and in-house developed packages to conduct stability studies and analyses. In addition, commercial packages have been customized with the addition of modules to model the behaviour of specific system components (e.g., braking resistors).
Chapter 2: Review of Current BC Hydro Practice

To conduct regular studies on the transmission and generation network, BC Hydro uses the Power System Simulator (PSS/E) package from Power Technologies, Inc. This package is an integrated set of computer programs which allows load flow analysis, balanced and unbalanced fault analysis, dynamic simulations, and network equivalence construction. BC Hydro currently runs version 20 of PSS/E on a network of SUN SparcStation computers for Transmission Planning and Grid Operations. The load flow portion of PSS/E uses conventional Newton-Raphson technique to find solutions, while the dynamic simulations are classical time domain simulations that allow complete control over the disturbance sequence.

The Control Centre Technologies department has also developed an on-line transient stability assessment (TSA) module for a commercial energy management system at BC Hydro’s System Control Centre [13,14]. This module employs a novel algorithm, called the “Second Kick”, conceived of by BC Hydro engineers. The algorithm uses system energy properties for fast termination of simulations, as well as associating a margin of stability with each case. No modeling assumptions are used to calculate the potential energy, kinetic energy, and corrected kinetic energy.

The algorithm starts by calculating the minimum corrected kinetic energy after the contingency. If the minimum is greater than zero, the system is unstable and the transient energy margin is simply the value of the corrected kinetic energy. The output of the module indicates that the system is unstable by this value. If the minimum is zero, the system is stable and a second fault (hence, second kick) of duration 10 cycles is applied to ensure that the system becomes unstable. This allows a second minimum of kinetic energy to be calculated. The kinetic energy injected into the system by this second kick,
minus the value of the kinetic energy left in the system at the second minimum, gives the transient energy margin. After adjusting the margin for the potential energy change during the second kick, the module returns a value indicating the margin of stability. BC Hydro has found the second kick method is robust, provides efficient formulation, and allows full modeling on existing transient stability programs.

A version of the TSA module was used in conjunction with PSS/E to conduct the studies for this research. Using the module greatly simplified the calculation of generation shedding or transfer limit reduction required to maintain system stability. Including the use of probabilistic factors in the studies was accomplished by developing a new simulation shell to dynamically construct PSS/E command files. This will be further discussed in Chapter 3.
3. SELECTION OF PROBABILISTIC FACTORS AND DEVELOPMENT OF FAULT MODELS

In conducting probabilistic transient stability studies, it is very important to gather relevant historical data that can be used as stochastic factors. Previous work by others has shown that almost all the deterministic factors currently used in dynamic security studies are, in fact, probabilistic in nature. The development of proper models for the various fault types, network configurations, and load levels considered also play an important role in the accuracy and usefulness of the results.

3.1 COLLECTION OF HISTORICAL DATA

For the research conducted, historical data from the BC Hydro system was used to determine the probabilistic states for the load level, fault type, fault location, fault duration, and successful/unsuccessful reclosing. In practical systems like the BC Hydro system, the load is not constant throughout the year, nor even throughout the day. As shown in previous work [4-6,8,9-10], a multi-step load model derived from the hourly annual load duration curves for the system can be used to provide a reduced, yet fairly accurate, load model. For an average year, the BC Hydro load profile, expressed on a per-unit value of 10,000 MW is shown in Figure 3.1.1. Taking the actual hourly load data from the BC Hydro 1995/96 fiscal year (April 1, 1995 - March 31, 1996), a load duration curve as shown in Figure 3.1.2, was developed.

Based on the probabilities from this load duration curve, the load forecast for the 1997 summer season was divided into 6 semi-equal load steps (not including exports) as
shown in Table 3.1.1. These load steps formed the basis for developing the different load flows to be further described later.

Figure 3.1.1 - BC Hydro Average Load Profile and Dependable Capacity Curve [12]

Figure 3.1.2 - BC Hydro Load Duration Curve for 1995/96 Fiscal Year
Table 3.1.1 - Probability of Different Load Levels (based on 1997 Summer Peak)

<table>
<thead>
<tr>
<th>Load Step</th>
<th>Load (%)</th>
<th>Load (MW)</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>100%</td>
<td>7420.2</td>
<td>0.0263</td>
</tr>
<tr>
<td>2</td>
<td>95%</td>
<td>7049.2</td>
<td>0.2192</td>
</tr>
<tr>
<td>3</td>
<td>90%</td>
<td>6678.2</td>
<td>0.1504</td>
</tr>
<tr>
<td>4</td>
<td>85%</td>
<td>6307.2</td>
<td>0.1458</td>
</tr>
<tr>
<td>5</td>
<td>80%</td>
<td>5936.2</td>
<td>0.2034</td>
</tr>
<tr>
<td>6</td>
<td>70%</td>
<td>5194.1</td>
<td>0.2550</td>
</tr>
</tbody>
</table>

Fault type, fault location, and probability of successful automatic reclosing were derived from actual BC Hydro 500 kV fault incidence data from 1977 to 1996, retrieved from BC Hydro's corporate mainframe computers. During this time, a total of 2,419 faults were recorded on the 500 kV transmission system, for an average of 121 events per year. Prior to 1989, data regarding the location of faults were not recorded, so only the data from the events recorded after 1989 were used to gather statistics on fault location. Unlike previous work by others [6,9] models to calculate the probability of successful automatic high-speed reclosing were not employed. In reviewing the cause of the historical fault events, it was noted that there was a very high correlation between the cause of the fault and the probability of successful automatic reclosing. In over 90% of the faults caused by lightning, automatic reclosing was successful, but that was the case in less than 50% of faults due to all other causes. It was decided that using the cause of the fault to decide whether or not automatic reclosing was successful would provide a fairly
accurate model while maintaining simplicity. Faults caused by lightning were assumed to reclose successfully, while all other faults were assumed to be permanent (i.e., unsuccessful reclose). Table 3.1.2 shows the probability of successful and unsuccessful automatic reclosing used in the studies.

**Table 3.1.2 - Probability of Successful/Unsuccessful Automatic Reclosing**

<table>
<thead>
<tr>
<th>Cause of Fault</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lightning (successful reclosing)</td>
<td>0.8251</td>
</tr>
<tr>
<td>Other (unsuccessful reclosing)</td>
<td>0.1749</td>
</tr>
</tbody>
</table>

To determine the probability of fault location, with respect to the master end of the line, each 500 kV transmission line was divided into three parts:

- close-in (first 20% of the line)
- mid-line (middle 60% of the line)
- far-end (last 20% of the line)

Recorded data from the faults between 1989 - 1996 were used to calculate the fault location probabilities as shown in Table 3.1.3.

**Table 3.1.3 - Fault Location Probabilities**

<table>
<thead>
<tr>
<th>Fault Location</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Close-in</td>
<td>0.1307</td>
</tr>
<tr>
<td>Mid-line</td>
<td>0.7021</td>
</tr>
<tr>
<td>Far-end</td>
<td>0.1672</td>
</tr>
</tbody>
</table>
Studies concerning the frequency of the different fault types have been carried out in the past and cited in previous work [4,15]. The BC Hydro data, although not always complete, seems to agree with previously published data. Of the 2,419 fault events recorded, 43 did not have the fault type noted. Although these cases could have been ignored or allocated based upon the derived probabilities, it was decided to consider this unknown events as $3\phi$ faults, (primarily in accordance with the traditional “worst-case” utility approach). Table 3.1.4 shows the probability of fault type and compares it to numbers published by an IEEE Power Systems Relaying Committee Working Group [15].

<table>
<thead>
<tr>
<th>Fault Type</th>
<th>BC Hydro System</th>
<th>IEEE Report [15]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Phase-to-Ground</td>
<td>88.51%</td>
<td>93%</td>
</tr>
<tr>
<td>Double Phase-to-Ground</td>
<td>4.38%</td>
<td>2%</td>
</tr>
<tr>
<td>Phase-to-Phase</td>
<td>4.01%</td>
<td>4%</td>
</tr>
<tr>
<td>Three-Phase</td>
<td>1.32%</td>
<td>1%</td>
</tr>
<tr>
<td>Unknown</td>
<td>1.78%</td>
<td>0%</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

3.2 DEVELOPMENT OF FAULT MODELS

An important part in the accuracy of the results is the development of the fault models. For transient stability analysis, faults are generally divided into two major
categories: shunt (short circuit) and longitudinal (open circuit). For these studies, only shunt faults were considered. These faults can occur on the transmission line itself or on the bus, with the worst case being at the generator bus. As the fault moves away from the generator bus, the severity decreases, resulting in higher critical clearing times.

The PSS/E unbalanced fault analysis module was used to calculate the fault currents for the different fault types considered. The normal PSS/E basecases used for static load flows and dynamic stability analyses only include the positive sequence data as the program assumes a balanced network, so equivalent admittances have to be developed for all faults except 3φ faults. Since BC Hydro also uses PSS/E to model system protection schemes, a working case which included data for all three sequences (positive, negative, and zero sequence) was easily obtained. This allowed a quick and accurate calculation for all the different fault types and locations considered.

Although a review of BC Hydro historical fault data (where fault location information was recorded) showed that less than 0.7% of all faults occurred at the bus, close-in faults were assumed to take place at the near bus. Mid-line faults were placed 50% away from the near bus, and far-end faults 80% away from the near bus. Once the various equivalent positive sequence faults admittances were calculated, another PSS/E utility was used to convert these admittances into equivalent shunt loads, the traditional way in which BC Hydro models fault events.

The process of clearing faults is composed of three distinct components: the fault detection, the relay operation (including communications time), and the high voltage breaker operation. Traditional BC Hydro studies have used a deterministic mean value of 4 cycles (and have assumed zone 1 clearing). However, upon discussions with protection
and equipment specialists at BC Hydro, it was found that the breaker operating time was strictly fixed at 1.5 or 2.0 cycles, depending on which side of the breaker opened first. Since no other data on breaker operation was available, it was assumed that the probability of breaker operation was evenly split between the two times. However, it was decided that the relay operating time could be modeled using a normal distribution with a mean of 2 cycles and a 10% standard deviation. Fault detection was assumed to occur instantaneously.

In essence, a linear combination of two normal distributions, with means of 3.5 and 4.0 cycles respectively, was developed. The actual probability density function used is represented by Equation (2) and shown in Figure 3.2.1. The discrete fault clearing times were obtained by entering Equation (2) into the commercial software package @RISK and asking it to generate an appropriate set of numbers.

\[
f(x) = \frac{1}{2\sigma\sqrt{2\pi}} e^{-\frac{(x-3.5)^2}{2\sigma^2}} + \frac{1}{2\sigma\sqrt{2\pi}} e^{-\frac{(x-4)^2}{2\sigma^2}}
\]

(2)

where \( \sigma = 0.2 \) cycles
Chapter 3: Selection of Probabilistic Factors

Figure 3.2.1 - Probability Density Function Used for Fault Clearing Times

3.3 DEVELOPMENT OF SYSTEM LOADFLOWS

The selection of which static loadflows to use in dynamic simulation studies is always an important factor. To ensure usefulness of the results, it was decided to start with an actual basecase used in the development of the BC Hydro 1996/97 Electric System Operating Guide. The 1997 Summer Peak Load basecase was selected and appropriately scaled to produce the six load factor cases (100%, 95%, 90%, 85%, 80%, 70%). The BC Hydro basecases divide the load into industrial and non-industrial (commercial and residential) and group them according to their geographical location. For all the load factor cases, the industrial load was maintained at 100%, while the non-industrial load was scaled down to provide the reduction in load. The required export and
import levels were obtained by changing the generation or load in the appropriate
neighbouring utility and setting the interchange amount between each utility.

These six “new” basecases were then modified to fit the generation pattern and
network topology used in the generation rejection study on the Peace system and the
transfer limit study on the Columbia system. Powerflow diagrams of all 12 basecases
developed in the research are included as Appendix A.

3.4 DEVELOPMENT OF SIMULATION SHELL

Although the studies conducted used a version of BC Hydro’s on-line transient
stability assessment program (using the second-kick method as described in Chapter 2), it
was necessary to develop another simulation shell to incorporate the use of the
probabilistic factors. The main purpose of the shell was to dynamically construct the
PSS/E command files based on whatever probabilistic states were randomly selected.
These PSS/E command files specify the complete disturbance sequence for a dynamic
simulation and allow it to be carried out in an automated fashion. Since the variations in
the script were known and limited to less than 20, a UNIX script was developed to “piece
together” the PSS/E command file depending on which pieces were required. This
allowed the disturbance sequence for each particular simulation to be dynamically
constructed. The inputs to the script were the relay operating time, the load level, the
fault type, the fault location, and fault cause. The algorithm used by the simulation shell
is shown in Table 3.4.1.
Chapter 3: Selection of Probabilistic Factors

Table 3.4.1 - Simulation Shell Algorithm

1. Take command line arguments and load them into the variables.

2. Remove existing links to the load flow and the PSS/E script file used.

3. Create a link to the correct loadflow based on the load level specified on the command line.

4. Select the correct files to use based on the fault type and fault location specified on the command line.

5. Set the relay operating time based on the command line value.

6. Merge the selected files into a new PSS/E script file.

7. Run the simulation and record the results in a file.

The listing for this simulation shell is included as Appendix B.
4.0 EXPERIMENTAL SETUP AND RESULTS

To compare how effective the use of probabilistic factors are in transient stability analyses on a realistic system, a generation rejection study on the Peace system and a transfer limit study on the Columbia system were conducted and the results were compared to the limits obtained using traditional deterministic methods. For each study, 1000 simulations were carried out, with the probabilistic factors selected based on the historical data outlined in Chapter 3.

4.1 GENERATION REJECTION STUDIES ON THE PEACE SYSTEM

The Peace high voltage transmission system is the longest one in the BC Hydro network. The generators are located over 1000 km away from the major load centre in the Lower Mainland. Extensive studies for most single contingency and credible double contingency outages on this system have been carried out by BC Hydro power system planners and have resulted in switching guidelines and generation shedding tables outlined in BC Hydro System Operating Order 7T-13, used by the system controllers and dispatchers. However, all these studies have been deterministic in nature. In a deregulated environment, these results may be too conservative and prevent the company from extracting more value out of existing assets.

4.1.1 OVERVIEW OF SYSTEM CONDITIONS

To highlight the effectiveness of including probabilistic factors in generation rejection studies, a particularly severe although credible, network topology was chosen. The majority of the Peace transmission system has three parallel 500 kV lines. The
primary stations are the two generating plants (G.M. Shrum and Peace Canyon) and two 500 kV switching substation (Williston and Kelly Lake). To provide 50% series compensation on these long lines, two series capacitor stations, Kennedy and McLeese are located at the midpoint of the lines, as shown in Figure 4.1.1.

The starting point for these studies was a base case used in developing the BC Hydro 1996/97 Electric System Operating Guide. The base load used was the estimated 1997 summer peak load, but the generation pattern was shifted so that G.M. Shrum and Peace Canyon were operating at peak capacity. As described in Chapter 3, six new basecases were developed to account for the load steps used in the study. However, the combined output from the G.M. Shrum and Peace Canyon was maintained at 3430 MW in all cases. In addition to the domestic load, firm exports to (and imports from) neighbouring utilities, as shown in Table 4.1.1, were added to the loadflow. The summer months are prime export periods for BC Hydro and reducing the amount of generation shedding required to maintain system transient stability in the event of a disturbance can lead to increased profits (if the remedial action is required).

<table>
<thead>
<tr>
<th>Utility</th>
<th>Amount (MW)</th>
<th>Import/Export</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alcan Aluminum Co.</td>
<td>150</td>
<td>Import</td>
</tr>
<tr>
<td>Bonneville Power Administration (USA)</td>
<td>2300</td>
<td>Export</td>
</tr>
<tr>
<td>TransAlta Utilities</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>West Kootenay Power</td>
<td>282</td>
<td>Export</td>
</tr>
</tbody>
</table>
Figure 4.1.1 - System Conditions for Peace Studies
For the simulations, 5L2 and 5L12 were taken out of service, while 5L1 was the line under study. Although this scenario could be considered a triple contingency (i.e., a third element out of service or faulted), the fact that this system has 3 parallel lines does make it a plausible scenario as 5L2 and 5L12 could be out for maintenance simultaneously. Figure 4.1.1 showed the conditions for the Peace generation and transmission system used in the studies.

The existing deterministic criteria for the switching sequence, as described in Chapter 2, were modified to incorporate the probabilistic factors. The only change in the sequence was the time at which the initial fault was cleared; however, the fault data changed depending on which factors were selected. For cases with unsuccessful reclosing, the initial fault clearing time was added to 35 cycles to obtain the subsequent fault clearing time. Table 4.1.2 shows the disturbance sequences used.
### Table 4.1.2 - Disturbance Sequence Used For Peace Generation Rejection Studies

<table>
<thead>
<tr>
<th>Time (cycles)</th>
<th>Event</th>
<th>Time (cycles)</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Unsuccessful Reclose Sequence</td>
<td></td>
<td>Successful Reclose Sequence</td>
</tr>
<tr>
<td>0</td>
<td>Apply fault on 5L1 (SLG, DLG, PP, or 3ϕ)</td>
<td>0</td>
<td>Apply fault on 5L1 (SLG, DLG, PP, or 3ϕ)</td>
</tr>
<tr>
<td>2</td>
<td>Bypass series capacitor</td>
<td>2</td>
<td>Bypass series capacitor</td>
</tr>
<tr>
<td>$R_1$</td>
<td>Clear fault, trip 5L1</td>
<td>$R_1$</td>
<td>Clear fault, trip 5L1</td>
</tr>
<tr>
<td>9</td>
<td>Switch 200-400 MW of braking resistor on</td>
<td>9</td>
<td>Switch 200-400 MW of braking resistor on</td>
</tr>
<tr>
<td></td>
<td>Trip amount of generation required to maintain stability</td>
<td>9</td>
<td>Trip amount of generation required to maintain stability</td>
</tr>
<tr>
<td>35</td>
<td>Fault remains, unsuccessful reclose on 5L1</td>
<td>35</td>
<td>Successful reclose on 5L1</td>
</tr>
<tr>
<td>$35+R_1$</td>
<td>Clear fault, trip 5L1</td>
<td>44</td>
<td>Switch braking resistors off</td>
</tr>
<tr>
<td>44</td>
<td>Switch braking resistors off</td>
<td>180</td>
<td>End simulation</td>
</tr>
<tr>
<td>180</td>
<td>End simulation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

where $R_1 = \text{fault clearing time selected based on probability density function used}$

### 4.1.2 PROBABILISTIC FACTORS USED

Although historical probabilities were used as the basis for selecting the parameters for each simulation, the actual factors used in the studies do not exactly match the historical tendencies. However, all factors were within 3% of the historical probabilities, well within the margin of error for a sample size of only 1000. Tables 4.1.3 to 4.1.6 show the factors actually used compared to the historical tendencies.
**Table 4.1.3 - Load Level Probabilities Used (Peace Studies)**

<table>
<thead>
<tr>
<th>Load Level (% of 1997 Summer Peak)</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>.255</td>
<td>.255</td>
</tr>
<tr>
<td>80</td>
<td>.199</td>
<td>.2034</td>
</tr>
<tr>
<td>85</td>
<td>.135</td>
<td>.1458</td>
</tr>
<tr>
<td>90</td>
<td>.165</td>
<td>.1414</td>
</tr>
<tr>
<td>95</td>
<td>.219</td>
<td>.2282</td>
</tr>
<tr>
<td>100</td>
<td>.027</td>
<td>.0262</td>
</tr>
</tbody>
</table>

**Table 4.1.4 - Fault Type Probabilities Used (Peace Studies)**

<table>
<thead>
<tr>
<th>Fault Type</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>SLG</td>
<td>.883</td>
<td>.8851</td>
</tr>
<tr>
<td>DLG</td>
<td>.038</td>
<td>.0438</td>
</tr>
<tr>
<td>PP</td>
<td>.046</td>
<td>.0401</td>
</tr>
<tr>
<td>3φ</td>
<td>.033</td>
<td>.031*</td>
</tr>
</tbody>
</table>

*Includes faults of unknown type*
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Table 4.1.5 - Fault Location Probabilities Used (Peace Studies)

<table>
<thead>
<tr>
<th>Fault Location</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Close-in</td>
<td>.123</td>
<td>.1307</td>
</tr>
<tr>
<td>Mid-line</td>
<td>.694</td>
<td>.7021</td>
</tr>
<tr>
<td>Far-end</td>
<td>.183</td>
<td>.1672</td>
</tr>
</tbody>
</table>

Table 4.1.6 - Fault Cause Probabilities Used (Peace Studies)

<table>
<thead>
<tr>
<th>Fault Cause</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lightning (Successful Reclose)</td>
<td>.832</td>
<td>.8251</td>
</tr>
<tr>
<td>Other (Unsuccessful Reclose)</td>
<td>.168</td>
<td>.1749</td>
</tr>
</tbody>
</table>

The initial fault clearing time for each of the 1000 simulations was selected according to the distribution described in Chapter 3. Since a commercial software package was used to generate the discrete numbers, the histogram of the actual numbers is shifted by 1/10 of a cycle due to the way discrete numbers are formed into a histogram. Figure 4.1.2 shows the distribution of the actual fault clearing times selected versus the probability distribution used to select the times.
4.1.3 RESULTS AND DISCUSSION

Comparative studies using existing BC Hydro deterministic criteria (for the identical contingency studied) revealed that a total of 1490 MW of generation shedding (300 MW at Kemano (Alcan) and 1190 MW at GM Shrum) was required to maintain system transient stability. This amounts to severing the tie to Alcan and reducing the output at GM Shrum by 45%. By contrast, the numerical results from the probabilistic studies showed that in 821 of the 1000 cases, no generation shedding was required to maintain system stability and the maximum amount of shedding required was 1240 MW. However, it should be noted that the usual deterministic case of 100% load, 3φ permanent (unsuccessful reclosing) fault, did not appear in the 1000 cases selected using Monte...
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Carlo techniques. If that particular case had been selected, the maximum amount of shedding required would also have been 1490 MW. Table 4.1.7 and Figure 4.1.3 show the distribution of the generation shedding required to maintain stability for all 1000 cases. Figure 4.1.4 shows the risk of instability for each level of generation shedding.

**Table 4.1.7 - Distribution of Generation Shedding for Peace Studies**

<table>
<thead>
<tr>
<th>Shedding Required (MW)</th>
<th>Number of Cases</th>
<th>Cumulative %</th>
<th>Risk %</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>821</td>
<td>82.10%</td>
<td>17.90%</td>
</tr>
<tr>
<td>100</td>
<td>14</td>
<td>83.50%</td>
<td>16.50%</td>
</tr>
<tr>
<td>200</td>
<td>74</td>
<td>90.90%</td>
<td>9.10%</td>
</tr>
<tr>
<td>300</td>
<td>39</td>
<td>94.80%</td>
<td>5.20%</td>
</tr>
<tr>
<td>400</td>
<td>2</td>
<td>95.00%</td>
<td>5.00%</td>
</tr>
<tr>
<td>500</td>
<td>36</td>
<td>98.60%</td>
<td>1.40%</td>
</tr>
<tr>
<td>600</td>
<td>2</td>
<td>98.80%</td>
<td>1.20%</td>
</tr>
<tr>
<td>700</td>
<td>3</td>
<td>99.10%</td>
<td>0.90%</td>
</tr>
<tr>
<td>800</td>
<td>3</td>
<td>99.40%</td>
<td>0.60%</td>
</tr>
<tr>
<td>900</td>
<td>3</td>
<td>99.70%</td>
<td>0.30%</td>
</tr>
<tr>
<td>1000</td>
<td>1</td>
<td>99.80%</td>
<td>0.20%</td>
</tr>
<tr>
<td>1100</td>
<td>0</td>
<td>99.80%</td>
<td>0.20%</td>
</tr>
<tr>
<td>1200</td>
<td>0</td>
<td>99.80%</td>
<td>0.20%</td>
</tr>
<tr>
<td>1300</td>
<td>2</td>
<td>100.00%</td>
<td>0.00%</td>
</tr>
<tr>
<td>1400</td>
<td>0</td>
<td>100.00%</td>
<td>0.00%</td>
</tr>
</tbody>
</table>
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Figure 4.1.3 - Distribution of Generation Shedding Required to Maintain Stability

Figure 4.1.4 - Generation Shedding vs. Risk of Instability
These results indicate that the existing deterministic criteria are very conservative. For the specific contingency studied, current practice would be to arm the generation shedding equipment to shed 1490 MW of generation in the event of a fault on 5L1. Since this contingency also includes firm exports of 2300 MW to the United States, this rejected generation would amount to lost export sales. Although Table 4.1.7 and Figure 4.1.4 show a 0% risk of instability if 1240 MW of generation shedding is armed, this is not quite correct. The actual probability is very small (between 0% and 0.2%), but a rounding error in the experiments resulted in the 0%. This is due to the fact that no case requiring 1490 MW of shedding (corresponding to the normal deterministic case) appeared in the 1000 samples selected in the experiment. The remainder of the results indicate that if the company were willing to accept just a 0.2% chance of instability, then the generation shedding equipment could be armed to shed only 1000 MW in the event of a fault on 5L1. Accepting a risk of 1.4% would reduce this figure by another 500 MW.

4.1.4 SENSITIVITY ANALYSIS

In addition to the 1000 cases, another 100 pre-selected cases were run to highlight the contribution of each probabilistic factor. Only two fault types (SLG and 3Φ) and two load factors (70% and 100%) were used to illustrate the contributions of probabilistic factors. As seen in Figure 4.1.5, varying the initial fault clearing time does not have too much impact on the amount of generation shedding required for SLG faults with unsuccessful reclosing.
Figure 4.1.5 - Sensitivity of Non-reclosed SLG Faults to Initial Clearing Time (Peace)

At the 70% load factor, a particularly slow clearing time of 5 cycles resulted in only an additional 30 MW of shedding compared to a very fast clearing time of 2.5 cycles, or less than 10%. At the 100% load factor, the difference is around 60 MW, still less than 10%. Since normal practice at BC Hydro is to arm generation shedding in blocks of 100 MW, these figures amount to less than one block.

Figure 4.1.6 shows a much different picture for 3φ faults. At a 70% load factor, slow clearing of 5 cycles results in an additional 600 MW of shedding as compared to fast clearing of 2.5 cycles. Furthermore, compared to the normally assumed clearing time of 4
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Figure 4.1.6 - Sensitivity of Non-reclosed 3Φ Faults to Initial Clearing Time (Peace)

cycles, one additional cycle of clearing time requires an additional 350 MW of shedding. At the 100% load factor, the results are even more severe. For anything slower than the normal 4 cycle clearing time, the entire system becomes unstable. Fast clearing reduces the amount of shedding required by 500 MW. Although this is a particularly severe scenario which would probably never occur (i.e., exports would not be at maximum and generation at G.M. Shrum and Peace Canyon would probably be reduced), it does highlight the problems of not considering anything except the normal deterministic criteria.
For faults with successful reclosing, the consideration of probabilistic factors is also very striking. For all SLG faults, regardless of the load factor, no generation shedding was required to maintain system stability, even with slow clearing. Figure 4.1.7 shows the sensitivity of 3φ faults with successful reclosing to the initial fault clearing time. At the 70% load factor, fast clearing resulting in no shedding, while less than 100 MW was required at the normal deterministic clearing time of 4 cycles. At the 100% load factor, even with slow clearing, stability was maintained in all cases. However, slow clearing resulted in an additional 700 MW of shedding needed to maintain stability.

Figure 4.1.7 - Sensitivity of Reclosed 3φ Faults to Initial Clearing Time (Peace)
Figures 4.1.8 and 4.1.9 show that the fault location does not have much impact on the amount of shedding required to maintain stability. For 3φ faults there was no difference in the amount of shedding required, while for SLG faults, the difference was very minimal, averaging less than 10%, to a maximum of 100 MW. This indicates that varying the location of faults does not significantly affect the results.

Figure 4.1.8 - Sensitivity of Unsuccessful Reclosing to Fault Location (4 cycle clearing)
Accurate modeling the reclosing equipment has a significant effect on the amount of generation shedding required to maintain system stability. Although the model employed in these studies was very simple and did not take into account the probabilistic nature of the actual reclosing time, the results were as expected. Very little or no shedding was required for successfully reclosed fault, while much shedding was required for permanent (unsuccessfully reclosed) faults. Figure 4.1.10 shows these results.
Overall, the use of probabilistic factors in generation rejection studies had a big impact on the results. Fault type and successful/unsuccessful reclosing were the most effective factors, while fault location on the line did not affect the results very much. For 3φ faults, the initial fault clearing time also greatly influenced the amount of shedding required.
4.2 TRANSFER LIMIT STUDIES ON THE COLUMBIA SYSTEM

Instead of conducting more generation rejection studies on the Columbia system, it was decided to simulate transfer limit studies, to see if the probabilistic factors had as much impact as in the generation shedding cases. The Columbia system, with a generating capacity of 4750 MW, provides over 40% of the power for the BC Hydro network, and has high voltage inter-connections to Alberta and the United States. Extensive studies for most single contingency and credible double contingency outages on this system have been carried out by BC Hydro power system planners, and have resulted in switching guidelines and generation shedding tables outlined in BC Hydro System Operating Order 7T-34. However, all these studies have been deterministic and have not considered the probabilistic nature of the power system and power system disturbances.

4.2.1 OVERVIEW OF SYSTEM CONDITIONS

Like the generation rejection studies on the Peace system, a particularly severe contingency was selected for these studies. In addition, the method of obtaining transfer limit reduction was also approximation, making these studies more hypothetical in nature than realistic. For a complete transfer limit study, the generation pattern must be changed each iteration to account for the reduction in transfer over a specific corridor. For the BC Hydro system, that would mean shifting the generation from the Columbia to the Peace or vice-versa. However, this requires the development of hundreds of different loadflows to account for the gradually shifting generation patterns. To simplify the process, it was decided to simulate a reduction in transfer limit by applying generation shedding at Mica
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and Revelstoke at 0 cycles (instead of the normal 9 cycles). While this does not account for the increased generation in the Peace system, it does reduce the flow on the transmission line under study before the fault is applied.

The majority of the Columbia system, as shown in Figure 4.2.1, has uncompensated parallel 500 kV (or in some cases 230 kV) transmission lines.

Figure 4.2.1 - System Conditions for Columbia Studies
The exceptions are the two 50% compensated lines between Nicola substation and the Lower Mainland. The major stations are four generating plants (Mica, Revelstoke, Kootenay Canal, Seven Mile), three 500 kV substations (Nicola, Ashton Creek, Selkirk), and one 500 kV capacitor station (American Creek).

The starting point for these studies was a basecase used in developing the BC Hydro 1996/97 Electric System Operating Guide. The base load used was the estimated 1997 summer peak load, but the generation pattern was shifted so that Mica, Revelstoke, Kootenay Canal, and Seven Mile were operating at peak capacity. As described in Chapter 3, six new basecases were developed to account for the load steps used in the study. However, the combined output from the four generating plants was maintained at 4750 MW in all cases. In addition to the domestic load, firm exports to (and imports from) neighbouring utilities, as shown in Table 4.2.1, were added to the loadflow.

Table 4.2.1 - Firm Exports & Imports for Columbia Studies

<table>
<thead>
<tr>
<th>Utility</th>
<th>Amount (MW)</th>
<th>Import/Export</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alcan Aluminum Co.</td>
<td>150</td>
<td>Import</td>
</tr>
<tr>
<td>Bonneville Power Administration</td>
<td>2000</td>
<td>Export</td>
</tr>
<tr>
<td>TransAlta Utilities</td>
<td>300</td>
<td>Import</td>
</tr>
<tr>
<td>West Kootenay Power</td>
<td>282</td>
<td>Export</td>
</tr>
</tbody>
</table>

For the simulations, 5L82 and was taken out of service, while 5L81 was the line under study. This double contingency is not normally studied, although in System
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Operating Order 7T-34, there is a generation shedding table setup for the double contingency of 5L81 or 5L82 out of service and 5L87 faulted. The addition of 300 MW of import from TransAlta utilities makes this contingency more severe. Figure 4.2.1 shows the conditions for the Columbia system used in the studies.

The existing deterministic criteria for the switching sequence, as described in Chapter 2, were modified to incorporate the probabilistic factors. The only change in the sequence was the time at which the initial fault was cleared, however, the fault data changed depending on which factors were selected. For cases with unsuccessful reclosing, the initial fault clearing time was added to 60 cycles to obtain the subsequent fault clearing time. Table 4.2.2 shows the disturbance sequences used.

**Table 4.2.2 - Disturbance Sequence for Columbia Studies**

<table>
<thead>
<tr>
<th>Time (cycles)</th>
<th>Event</th>
<th>Time (cycles)</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>Apply generation shedding at MCA and REV to simulate transfer limit reduction</td>
<td>0</td>
<td>Apply generation shedding at MCA and REV to simulate transfer limit reduction</td>
</tr>
<tr>
<td>0</td>
<td>Apply fault on 5L81 (SLG, DLG, PP, or 3ϕ)</td>
<td>0</td>
<td>Apply fault on 5L81 (SLG, DLG, PP, or 3ϕ)</td>
</tr>
<tr>
<td>2</td>
<td>Bypass series capacitor</td>
<td>2</td>
<td>Bypass series capacitor</td>
</tr>
<tr>
<td>( R_1 )</td>
<td>Clear fault, trip 5L81</td>
<td>( R_1 )</td>
<td>Clear fault, trip 5L81</td>
</tr>
<tr>
<td>60</td>
<td>Fault remains, unsuccessful reclose on 5L81</td>
<td>60</td>
<td>Successful reclose on 5L81</td>
</tr>
<tr>
<td>( 60+R_1 )</td>
<td>Clear fault, trip 5L81</td>
<td>180</td>
<td>End simulation</td>
</tr>
<tr>
<td>180</td>
<td>End simulation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

where \( R_1 \) = fault clearing time selected based on probability density function used
4.2.2 PROBABILISTIC FACTORS USED

In a manner identical to the generation rejection studies on the Peace system, another 1000 different cases were selected using Monte Carlo techniques for the transfer limit studies on the Columbia System. Although historical probabilities were used as the basis for selecting the parameters for each simulation, the actual factors used in the studies do not exactly match the historical tendencies. However, all factors were within 3% of the historical probabilities, well within the margin of error for a sample size of only 1000. Tables 4.2.3 to 4.2.6 show the factors actually used compared to the historical tendencies. The discrete fault clearing times were selected according to the distribution described in Chapter 3 and shown earlier in Figure 4.1.2.

<table>
<thead>
<tr>
<th>Load Level (% of 1997 Summer Peak)</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>.256</td>
<td>.255</td>
</tr>
<tr>
<td>80</td>
<td>.198</td>
<td>.2034</td>
</tr>
<tr>
<td>85</td>
<td>.157</td>
<td>.1458</td>
</tr>
<tr>
<td>90</td>
<td>.152</td>
<td>.1414</td>
</tr>
<tr>
<td>95</td>
<td>.218</td>
<td>.2282</td>
</tr>
<tr>
<td>100</td>
<td>.019</td>
<td>.0262</td>
</tr>
</tbody>
</table>
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Table 4.2.4 - Fault Type Probabilities Used (Columbia Studies)

<table>
<thead>
<tr>
<th>Fault Type</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>SLG</td>
<td>.890</td>
<td>.8851</td>
</tr>
<tr>
<td>DLG</td>
<td>.047</td>
<td>.0438</td>
</tr>
<tr>
<td>PP</td>
<td>.039</td>
<td>.0401</td>
</tr>
<tr>
<td>3φ</td>
<td>.024</td>
<td>.031*</td>
</tr>
</tbody>
</table>

* Includes faults of unknown type

Table 4.2.5 - Fault Location Probabilities Used (Columbia Studies)

<table>
<thead>
<tr>
<th>Fault Location</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Close-in</td>
<td>.126</td>
<td>.1307</td>
</tr>
<tr>
<td>Mid-line</td>
<td>.703</td>
<td>.7021</td>
</tr>
<tr>
<td>Far-end</td>
<td>.171</td>
<td>.1672</td>
</tr>
</tbody>
</table>

Table 4.2.6 - Fault Cause Probabilities Used (Columbia Studies)

<table>
<thead>
<tr>
<th>Fault Cause</th>
<th>Study Probabilities</th>
<th>Historical Probabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lightning (Successful Reclose)</td>
<td>.797</td>
<td>.8251</td>
</tr>
<tr>
<td>Other (Unsuccessful Reclose)</td>
<td>.203</td>
<td>.1749</td>
</tr>
</tbody>
</table>
4.2.3 RESULTS AND DISCUSSION

Comparative studies using existing BC Hydro deterministic criteria (for the identical contingency studied) revealed that a reduction of 640 MW in transfer capability was required to maintain system transient stability. By contrast, the numerical results from the probabilistic studies showed that in 847 of the 1000 cases, no reduction in transfer capacity was required to maintain system stability and the maximum amount of reduction required was 780 MW.

It is interesting to note that this amount was required at a load factor of 95% (not 100% as might be assumed) and was higher than the 640 MW required when the normal deterministic criteria (i.e., 100% load, 4 cycle clearing, unsuccessful reclose) was applied. This result is due to the fact that at the 95% load factor, the amount of power being transmitted over 5L81 is higher than when the load factor is 100%.

Table 4.2.7 and Figure 4.2.2 show the distribution of the transfer limit reduction required to maintain stability for all 1000 cases. Figure 4.2.3 shows the risk of instability associated with each transfer limit reduction. In contrast to the generation shedding studies on the Peace system, there is no rounding error in these results. The 0% risk of instability associated with reducing the transfer limit on 5L81 by 800 MW is really 0% as the “worst case” scenario did appear in the 1000 samples selected.
### Table 4.2.7 - Distribution of Transfer Limit Reduction for Columbia Studies

<table>
<thead>
<tr>
<th>Transfer Limit Reduction (MW)</th>
<th>Number of Cases</th>
<th>Cumulative %</th>
<th>Risk %</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>847</td>
<td>84.70%</td>
<td>15.30%</td>
</tr>
<tr>
<td>50</td>
<td>1</td>
<td>84.80%</td>
<td>15.20%</td>
</tr>
<tr>
<td>100</td>
<td>0</td>
<td>84.80%</td>
<td>15.20%</td>
</tr>
<tr>
<td>150</td>
<td>0</td>
<td>84.80%</td>
<td>15.20%</td>
</tr>
<tr>
<td>200</td>
<td>32</td>
<td>88.00%</td>
<td>12.00%</td>
</tr>
<tr>
<td>250</td>
<td>1</td>
<td>88.10%</td>
<td>11.90%</td>
</tr>
<tr>
<td>300</td>
<td>14</td>
<td>89.50%</td>
<td>10.50%</td>
</tr>
<tr>
<td>350</td>
<td>38</td>
<td>93.30%</td>
<td>6.70%</td>
</tr>
<tr>
<td>400</td>
<td>19</td>
<td>95.20%</td>
<td>4.80%</td>
</tr>
<tr>
<td>450</td>
<td>0</td>
<td>95.20%</td>
<td>4.80%</td>
</tr>
<tr>
<td>500</td>
<td>7</td>
<td>95.90%</td>
<td>4.10%</td>
</tr>
<tr>
<td>550</td>
<td>31</td>
<td>99.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>600</td>
<td>9</td>
<td>99.90%</td>
<td>0.10%</td>
</tr>
<tr>
<td>650</td>
<td>0</td>
<td>99.90%</td>
<td>0.10%</td>
</tr>
<tr>
<td>700</td>
<td>0</td>
<td>99.90%</td>
<td>0.10%</td>
</tr>
<tr>
<td>750</td>
<td>0</td>
<td>99.90%</td>
<td>0.10%</td>
</tr>
<tr>
<td>800</td>
<td>1</td>
<td>100.00%</td>
<td>0.00%</td>
</tr>
</tbody>
</table>
Figure 4.2.2 - Distribution of Transfer Reduction Required to Maintain Stability

Figure 4.2.3 - Transfer Limit Reduction vs. Risk of Instability (Columbia)
These results indicate that the existing deterministic criteria are conservative and include accepting a 0.1% risk of instability. For the specific contingency studied, current practice would be to reduce the generation output from Mica and Revelstoke by a combined 640 MW, in turn reducing the power transfer on 5L81 by a similar amount. An equivalent amount of generation would need to be obtained by increasing output at other generators in the system, increasing imports, or reducing exports. Since this contingency also includes firm exports of 2000 MW to the United States, this reduction in transfer capability would require exports to be reduced by about 600 MW at the higher load factors. At the lower load factors, there would be enough surplus generation capacity in the system to shift the generation pattern without impacting exports. If the company were willing to accept just a 0.1% chance of instability, then the transfer limit on 5L81 could be increased by 100 MW (when compared to the deterministic reduction of 640 MW). Accepting a 1% chance of instability would increase the limit by a further 100 MW.

4.2.4 SENSITIVITY ANALYSIS

In addition to the 1000 cases, another 100 pre-selected cases were run to highlight the contribution of each probabilistic factor. Only two fault types (SLG and 3ϕ) and two load factors (70% and 100%) were used to illustrate the contributions of probabilistic factors. As shown in Table 4.2.8, the initial fault clearing time does not affect the amount of transfer reduction required for unsuccessfully reclosed SLG faults, regardless of the load factor. For successfully reclosed SLG faults, no reduction in transfer limit was required at any load factor. For 3ϕ faults, no reduction in transfer limit was required for cases with successful auto reclosing. However, there was about a 10% difference in
transfer limit reductions for slow clearing and fast clearing when the automatic reclosing was unsuccessful. Figure 4.2.4 illustrates the difference at a load factor of 100%.

The location of the fault on the line also appears to have very little impact on the amount of transfer limit reduction needed. Figure 4.2.5 shows that at a load level of 100%, there is a small difference for SLG faults with unsuccessful reclosing, but no difference for 3\(\phi\) faults.

Table 4.2.8 - Sensitivity of Non-reclosed SLG Faults to Initial Clearing Time (Columbia)

<table>
<thead>
<tr>
<th>Initial Fault Clearing Time (Cycles)</th>
<th>Transfer Limit Reduction Required (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>70% Load Factor</td>
</tr>
<tr>
<td>2.5</td>
<td>0</td>
</tr>
<tr>
<td>2.75</td>
<td>0</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>3.25</td>
<td>0</td>
</tr>
<tr>
<td>3.5</td>
<td>0</td>
</tr>
<tr>
<td>3.75</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>4.25</td>
<td>0</td>
</tr>
<tr>
<td>4.5</td>
<td>0</td>
</tr>
<tr>
<td>4.75</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>0</td>
</tr>
</tbody>
</table>
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Figure 4.2.4 - Sensitivity of Non-reclosed 3φ Faults to Initial Clearing Time (Columbia)

Figure 4.2.5 - Sensitivity of Unsuccessful Reclosing to Fault Location (4 cycle clearing)
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The biggest impact on the amount on reduction in transfer limit is whether the auto reclosing was successful or unsuccessful. For all cases where the reclosing was successful, no reduction in transfer limit was required. At all load factors except 70%, some reduction was required for faults with unsuccessful reclosing.

The probabilistic factors did not have very much impact on SLG faults. Varying the initial fault clearing time did not change the amount of transfer reduction required and moving the fault along the line only changed the amount minimally. For 3φ faults, there was about a 15% increase from very fast clearing (2.5 cycles) to slow clearing (5 cycles). Like the generation rejection studies, successful/unsuccessful reclosing affected the results greatly. For all cases with successful reclosing, no reduction in transfer limit was required, regardless of the load factor, initial clearing time, fault type, or fault clearing. By contrast, in some cases with unsuccessful reclosing, a reduction in the pre-fault transfer limit was required to maintain stability during and after the disturbance.
5.0 CONCLUSIONS AND RECOMMENDATIONS

The evolution of the power utility industry from a monopolistic environment to a competitive one has created the need for new dynamic security assessment tools and methodology. A review of the historical outage data from the BC Hydro 500 kV system has confirmed the probabilistic nature of the power system. A generation rejection study on the Peace system and a transfer limit study on the Columbia system has shown that the existing limits established in a deterministic fashion are very conservative.

5.1 CONCLUSIONS

This research has shown that considering the probabilistic nature of the power system in transient stability studies can reduce the amount of remedial action required and increase pre-disturbance transfer limits. The current deterministic criteria employed by BC Hydro has been shown to be conservative, with a risk of instability between 0% and 0.2% in the Peace case and 0.1% in the Columbia case. Although the risk of instability was calculated as 0% for the Peace case, this is due to an approximation introduced because of the relatively small number of samples used (1,000). The risk calculation would be more accurate if the number of sample was increased to 10,000 or even 100,000. Another interesting result was that no remedial action was required in 821 of the 1000 samples for the Peace cases and no reduction in pre-disturbance transfer limit was required in 847 of the 1000 samples for the Columbia cases.

The existing deterministic criteria are applied partly because of the belief that the system should survive the "worst case" credible contingency, and partly because it is very
time consuming to analyze all credible contingencies. However, the studies on the Columbia system have shown that the deterministic criteria does not always correspond to the "worst case". Line flows are dependent on generation patterns, load levels, and reactive support. Sometimes the highest line flows do not correspond to the 100% load factor case that is normally studied. As seen in the Columbia studies, the worst case for the contingency studied was actually at a load factor of 95%. By employing only the normal deterministic criteria, the "worst case" may actually be missed and a small risk of instability may be unwittingly accepted.

To include all the probabilistic factors considered here may not be practical due to the large number of simulations that must be carried out. However, analyzing the sensitivity of the factors has shown that fault type and successful/unsuccessful automatic reclosing were the two which affected the results the most. Initial fault clearing time (when zone 1 clearing is assumed) and fault location on the line did not affect the results as much. However, it should be noted that previous work by others has shown that extremely slow clearing (zone 2 or zone 3) does affect the results greatly. Including the probability of load factor, fault type, and automatic reclosing in dynamic security assessment can lead to a more realistic appraisal of the health of the system. Considering these probabilistic factors can also help utilities decide how much, if any, risk they are willing to accept in order to reduce remedial actions or increase transfer limits.
5.2 SUGGESTIONS FOR FUTURE RESEARCH

While the research conducted has shown significant gains can be made from considering probabilistic factors in dynamic security assessment studies, the work is far from complete. More benefits will need to be demonstrated before utilities can be persuaded to replace their existing deterministic methods. Suggestions for future work to highlight more benefits include:

- improving the accuracy of the results by significantly increasing the number of samples (to 100,000 or more) so that a better assessment of the risk associated with the deterministic criteria can be made;
- a cost/benefit analysis to establish a new criteria based on the risk worth assessment to the utility (i.e., quantifying the value of the risk) and a comparison to the deterministic criteria, to gauge whether the existing criteria is warranted;
- making modeling improvements, including probabilistic modeling of reclosers and braking resistors, better transfer limit modeling, and inclusion of zone 2 and zone 3 relaying;
- repeating the studies for more (different) contingencies.
BIBLIOGRAPHY


Appendix A

Powerflow Diagrams of Basecases Used in Simulations
FIGURE A.1 - PEACE GENERATION REJECTION STUDIES, 100% LOAD
2300 MW EXPORT TO US
JUN, JUL 13 1997 15:04
Appendix A

FIGURE A.5 - PEACE GENERATION REJECTION STUDIES, 80% LOAD
2300 MW Export TO US

SUN, JUL 13 1997 15:09

10Q2 ARIA 0.95Q UV 1.05Q OV 500 KV 1230 1.500 KV = 500支裝 - MW/MVAR
Appendix B - Simulation Shell Code

# Script Name: fileprep
#
# Written by: Timothy K. Chia
# Date: December 12, 1996
# Version 1.0
#
# Script file to dynamically construct the PSS/E command files for Probabilistic
# Transient Stability Studies
#
# Initialize variables and assign them to command line arguments
#
set relay_time = $argv[1]
@ load_level = $argv[2]
set fault_type = $argv[3]
set fault_loc = $argv[4]
set cause = $argv[5]
#
# Remove links to existing files that need to be reused
#
rm 5L81NIC.idv
rm pf.sav
rm part5.idv
#
# Assign the correct load flow based on load level
#
if ($load_level == 100) then
  ln -s pf100.sav pf.sav
else if ($load_level == 95) then
  ln -s pf95.sav pf.sav
else if ($load_level == 90) then
  ln -s pf90.sav pf.sav
else if ($load_level == 85) then
  ln -s pf85.sav pf.sav
else if ($load_level == 80) then
  ln -s pf80.sav pf.sav
else if ($load_level == 70) then
  ln -s pf70.sav pf.sav
else
    goto badargs
endif
#
# Setup the PSS/E script file
# (5L1GMS.idv for Peace studies; 5L81NIC.idv for Columbia studies)
#
# Construct the first part of the script if the fault type is SLG
#
if ($fault_type == 'SLG') then
    if ($fault_loc == 'NEAR') then
        cat parti.idv slg_near.idv part3.idv >! 5L81NIC.idv
        ln -s slg_near.idv part5.idv
    else if ($fault_loc == 'MID') then
        cat parti.idv slg_mid.idv part3.idv >! 5L81NIC.idv
        ln -s slg_mid.idv part5.idv
    else if ($fault_loc == 'FAR') then
        cat parti.idv slg_far.idv part3.idv >! 5L81NIC.idv
        ln -s slg_far.idv part5.idv
    else
        goto badargs
    endif
#
# Construct the first part of the script if the fault type is DLG
#
else if ($fault_type == 'DLG') then
    if ($fault_loc == 'NEAR') then
        cat parti.idv dlg_near.idv part3.idv >! 5L81NIC.idv
        ln -s dlg_near.idv part5.idv
    else if ($fault_loc == 'MID') then
        cat parti.idv dlg_mid.idv part3.idv >! 5L81NIC.idv
        ln -s dlg_mid.idv part5.idv
    else if ($fault_loc == 'FAR') then
        cat parti.idv dlg_far.idv part3.idv >! 5L81NIC.idv
        ln -s dlg_far.idv part5.idv
    else
        goto badargs
    endif
#
# Construct the first part of the script if the fault type is PP
#
else if ($fault_type == 'PP') then
    if ($fault_loc == 'NEAR') then
        cat parti.idv pp_near.idv part3.idv >! 5L81NIC.idv
        ln -s pp_near.idv part5.idv
    else
        goto badargs
    endif
ln -s pp_near.idv part5.idv
else if ($fault_loc == 'MID') then
  cat part1.idv pp_mid.idv part3.idv >! 5L81NIC.idv
  ln -s pp_mid.idv part5.idv
else if ($fault_loc == 'FAR') then
  cat part1.idv pp_far.idv part3.idv >! 5L81NIC.idv
  ln -s pp_far.idv part5.idv
else
  goto badargs
endif
#
# Construct the first part of the script if the fault type is 3P
#
else if ($fault_type == '3P') then
  if ($fault_loc == 'NEAR') then
    cat parti.idv 3p_near.idv part3.idv >! 5L81NIC.idv
    ln -s 3p_near.idv part5.idv
  else if ($fault_loc == 'MID') then
    cat part1.idv 3p_mid.idv part3.idv >! 5L81NIC.idv
    ln -s 3p_mid.idv part5.idv
  else if ($fault_loc == 'FAR') then
    cat part1.idv 3p_far.idv part3.idv >! 5L81NIC.idv
    ln -s 3p_far.idv part5.idv
  else
    goto badargs
  endif
else
  goto badargs
endif
#
# Read the relay time and input it into the script file
#
echo " $relay_time "21 3 0' >! rel_time
cat rel_time part4.idv >> 5L81NIC.idv
#
# Construct the last part of the script based on fault cause
#
if ($cause == 'LTG') then
  cat reclose.idv >> 5L81NIC.idv
else if ($cause == 'OTHER') then
  cat part5.idv part6.idv >> 5L81NIC.idv
endif
#
# Run TSA Module
# Output results to a file
#
echo 'NEWCASE: "$relay_time $load_level $fault_type $fault_loc $cause"' > inputjnsg
# cat inputjnsg simprep.out >> results

# Error handling
#
badargs:
    echo 'Error in input file' > input_msg
    cat input_msg >> results