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POWER SYSTEM RELIABILITY ANALYSIS
Volume 2
Composite Power System Reliability Evaluation

Prepares by CIGRE Task Force 38.03.10 - 1992

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The genesis of CIGRE Task Force 38-03-10 lies with the many people who wanted to see the various power system reliability methodologies applied to, and compared on, an operating power system. However, special acknowledgement must go to David H. Thorne of NB Power who secured the use of the NB Power data for this task, and who was involved in the organization of the work in the early stages. Special thanks are extended to the NB Power Corporation for supporting the project, and to all members of the Task Force for their significant contributions.

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EXECUTIVE SUMMARY

In 1988, CIGRE Study Committee 38 published the Power System Reliability Analysis Application Guide. This Guide described various methodologies for power system reliability analysis in use or being developed around the world. The Guide described the approaches, techniques and data requirements for a wide-range of methods. This report supplements that work as an example and comparison of results for combined generation and transmission network reliability evaluations. The key new materials presented here are the results of combined transmission and generation reliability analysis of an actual operating power system. The report presents a complete example, including the data required, the assumptions to be made, and the techniques available for the analysis. Results of the various methods are compared.

CIGRE Task Force 38-03-10 coordinated the development of this example based on the New Brunswick Power Corporation and its forecast conditions for 1996. The Task Force coordinated the analyses made by eight different groups using a variety of computer models to evaluate the New Brunswick system.

The example demonstrates how these techniques and their results may be used to evaluate power system plans. The example presents numeric results from the different models which should be useful in establishing the range of numeric results which may be suitable for setting planning criteria with these models. The example also demonstrates the variety of indices produced by these types of models.

Models Utilized

There were eight participating groups who provided models to evaluate the New Brunswick system. These models use either of two major reliability calculation techniques-State Enumeration or Monte Carlo as summarized in Table 1. Inherent in the models are differences in the way they handle various system components such as hydro generation, loads and interconnections. These are based largely on the different corporate objectives for the various models when they were being developed and written.

Table 1
Summary of Participating Groups and Models

Group	Country	Model	Methodology*
ENEL	Italy	SICRET	MC
EDP	Portugal	ZANZIBAR	MC
USask	Canada	COMREL	SE
		MECORE	MC
National Grid	UK	ESCORT	MC
UMIST	UK	COMPASS	MC
		RELACS	SE
EDF	France	MEXICO	MC
PTI	USA	MAREL/ TPLAN	SE
NB Power	Canada	NB HL1	SE/MC

*Note MC - Monte Carlo, SE - State Enumeration

Cases Evaluated

The New Brunswick system data provided for use by each of the models required transmission reinforcements by 1996. New Brunswick Power provided an appropriate group of transmission network reinforcements. Each of the models was used to evaluate the reliability of the New Brunswick system with and without these network reinforcements.

To help in comparing the various methods, several cases were evaluated for the purpose of making comparisons of the results. First, each of the models was used to evaluate a generation-only reliability case (HL1). Results with all of the models for this analysis were nearly identical. The second series of cases was developed with each of the models evaluating generation and transmission reliability assuming that the peak load exists for the entire year. These cases demonstrated the capabilities for combined generation and transmission reliability analysis (HL2) while maintaining consistency among all the methods in handling hydro-electric dispatch throughout the year, allocation of interconnection power and energy, the number of hours to be considered, scheduling of maintenance and the impact of weather on transmission outages in a full-year analysis. The third series of cases was developed with each of the models which considered the various load levels throughout the year. The number of load levels, and how they and other system components were handled, was somewhat different in each of the models and therefore these cases demonstrated the most significant differences.

Principal Results

All of the models give reasonably consistent results for the basic measure of system reliability, Expected Energy Not Served (EENS). Differences in the modelling techniques and output indices make comparisons between other measures more difficult. All of the models identified the same facilities as being most critical in the initial system and showed the reliability improvements of the transmission reinforcements.

The EENS for the various models are given in Table 2. The results in the generation-only case are nearly identical. The results for the combined generation and transmission analyses have larger variations. The relative changes due to the transmission enhancements are fairly consistent.

Other Results

Many of the models are capable of identifying the cost of redispatching generation as a result of various generation or transmission contingencies. The results of these types of models are especially useful for identifying the relative benefits of strengthening specific circuits or network elements within the system. Some of the models are also capable of showing the improvement in the magnitude, frequency and duration of the outages at specific buses as the network is strengthened. Several of the models are capable of providing additional information for individual circuits such as histograms for the magnitude, frequency, and duration of curtailing interruptible customers.

Limitation of the Evaluation

The techniques used for this evaluation are based on steady-state conditions only. The models evaluate the impact on reliability of various outages within the transmission network and of generation equipment by comparing the steady-state conditions. No analysis is made as to whether the system can survive the transition from one steady-state condition to another. For each of the contingency conditions, the system is redispatched and adjusted so that all elements will be within normal limits after the contingency. The generation redispatch is adjusted to correct any circuit loading and voltage conditions in a simple manner based on a generation dispatch order. In all cases, customer interruptions are the method of last resort.

Table 2
Summary of Results - Expected Energy Not Served
(GWh)

	Generation Only Case (HL1)		Generation and Transmission Cases (HL2)			
			Peak Load		Complete Year	
	Peak	Complete	Transmission Enhancements		Transmission Enhancements	
Model	Load	Year	No	Yes	No	Yes
SICRET	15.5	0.28	72.4	17.7	3.5	1.9
ZANZIBAR	15.1	1.50	50.8	17.4	5.4	2.1
COMREL	--	--	46.7	20.6	--	--
MECORE	14.7	0.20	52.9	16.4	1.1	0.5
ESCORT	13.1	--	93.4	15.4		--
COMPASS	15.7	0.12	75.3	16.8	0.8	0.2
RELACS	15.2	--	38.1	--	--	--
MEXICO	15.2	0.80	69.1	16.6	6.1	3.1
MAREL/ TPLAN	13.6	--	--	--	--	--
NB HL1	14.5	0.31	--	--	--	--

Table 2.3
Monthly Available Hydro Energies (GWh)

Month	Average	Adverse
January	144.3	62.9
February	122.1	41.5
March	158.2	44.1
April	389.1	44.8
May	502.7	392.8
June	245.1	151.5
July	169.1	79.1
August	151.8	46.2
September	151.2	43.2
October	190.8	52.4
November	218.0	76.4
December	210.3	62.4
Annual Total	2656.7	1371.3

2.4 Thermal Generation System

The total generating capacity is 4320 MW. This is made up of 13 conventional thermal units with a capacity of 2265 MW, one nuclear unit with a capacity of 635 MW and 7 combustion turbine peaking units with a capacity of 550 MW in addition to the 24 hydro units with a capacity of 870 MW. The thermal generation system capabilities are given in Table 2.4.

Table 2.4 Thermal Generating Station Capabilities

Plant	Unit	Fuel	Capacity (MW)	DAFOR	Location
Belledune	1	Coal	450.0	0.12	North coast on Bay of Chaleur
Chatham	2	Coal/Oil #6	20.0	0.10	East coast on Miramichi Bay
Coleson Cove	1	Oil #6	335.0	0.10	South coast on Atlantic Ocean
	2	Oil #6	335.0	0.10	
	3	Oil #6	335.0	0.10	
Courtenay Bay	1	Oil #6	44.5	0.10	South coast on Atlantic Ocean
	2	Oil #6	12.3	0.10	
	3	Oil #6	100.0	0.10	
	4	Oil #6	97.0	0.10	
Dalhousie	1	Oil #6	103.0	0.10	North coast on Bay of Chaleur
	2	Coal/Oil #6	203.0	0.12	
Grand Lake	8	Coal	60.0	0.12	Center of Province near coal fields
	9	Coal	170.0	0.12	
Grand Manan	10	Oil #2	25.0	0.10	Island, off south westerly area of Province
Moncton	1	Oil #2	25.0	0.10	South eastern area
Millbank	1	Oil #2	100.0	0.10	East Coast on Miramichi Bay
	2	Oil #2	100.0	0.10	
	3	Oil #2	100.0	0.10	
	4	Oil #2	100.0	0.10	
Point Lepreau	1	Nuclear	635.0	0.12	South coast on Atlantic Ocean
Ste Rose	1	Oil #2	100.0	0.10	East Coast on Miramichi Bay
			3449.8		

SECTION A - INTRODUCTION

(a) A RELIABILITY OVERVIEW in Chapter 1.0 provides an overview of the reliability methodologies.

(b) DESCRIPTION OF THE NEW BRUNSWICK POWER SYSTEM in Chapter 2.0 addresses the characteristic nature of the NB Power system as it has been defined for this comparison exercise.

1.0 A RELIABILITY OVERVIEW

1.1 Background

In the flow of events sense, and also in the flow of power sense, there is a logic to the patterns which take place in a power system. Power is generated in generators, it is transmitted in bulk over transmission lines, it is distributed in somewhat smaller blocks over the electrical distribution system, and it is utilized in even smaller blocks by individual customers (the GTDU pattern).

The same patterns apply in reliability analysis, and these patterns have been given names.

(a) When the reliability analysis includes only generation, it is called Hierarchical Level 1 (HL1).

(b) When the reliability analysis includes generation and transmission, it is called composite system reliability and also Hierarchical Level 2 (HL2).

(c) When the reliability analysis includes generation, transmission and distribution, it is called Hierarchical Level 3 (HL3).

CIGRE Working Group 38-03, in 1987, published a document entitled Power System Reliability Analysis Application Guide (hereafter referred to as the Application Guide). This comprehensive document, which focused primarily on HL1 and HL2 reliability, covered many aspects of power system reliability including:

(a) Concepts, principles, objectives and criteria
(b) Reliability indices
(c) Methodologies
(d) Generation equipment outage data collection and processing
(e) Transmission equipment outage data collection and processing
(f) Dependency concepts
(g) Weather modelling
(h) Substation modelling

The objective of this present document is to apply the various methodologies with sample calculations for an operating power system. The Application Guide outlines four fundamental methodologies which can be applied for HL1 and HL2 reliability evaluations.

(a) A deterministic generation method called Reserve Margin (HL1).

(b) A deterministic generation and/or transmission method called the Selected Base and Incidents method (HL2).

(c) A probabilistic generation and/or transmission method called State Enumeration (HL1 and HL2).

(d) A probabilistic generation and/or transmission system method called Monte Carlo Simulation (HL1 and HL2).

Based on material taken from the Application Guide, a flow sheet has been prepared which shows the important features of the methodologies. They are contained in Chapter 3 of the Application Guide and given here as Figure 1.1.

1.2 Reliability Concepts

Reliability is a general term which can be applied to any physical system. Often it can be used in a very crisp sense, such as stating the probability that a certain combination of generators and lines is available. Other times it needs added definition, such as saying how stable a power system is given that a specific combination of generators and lines is available. The latter is particularly important in power systems for a number of very good reasons. These include the physical distances involved in transmission lines, the electrical strength of the transmission lines, the rotational nature of the generators, the usual operating limitations on devices, and finally the vast number of acceptable combinations of generator outputs for any given load depending on the

RELIABILITY METHODS

- **Deterministic**
  - **Generation**
    - Method called Reserve Margin. It is a simple definition, but difficult to apply on systems with sales and purchases (Interconnections).
      - See Table 3.1 of the Application Guide entitled, "Criteria for generating system (reserve margin) used by different utilities".
  - **Generation and Transmission (with emphasis on transmission)**
    - Unnamed but it will be called Selected Base and Incidents methods.
      1. Select one or several base cases.
      2. Subject each base case to a series of generation and transmission incidents.
      3. Incidents are either one level (N-1) or two levels (N-2).
      - See Table 3.2 of the Application Guide entitled "Reliability criteria for the planning of the transmission and interconnection networks".
- **Probabilistic**
  - **Generation or Generation and Transmission**
    - Analytical technique called State Enumeration where every system state and its probability are enumerated. Often the number of states is reduced by allowing outages of up to G generators and up to L transmission lines. This is called Contingency Enumeration.
      - See Figure 3.2 of the Application Guide entitled "Basic structure of enumeration approach".
    - Method called Monte Carlo simulation. The heart of this method involves random number generation for each power system item under probabilistic control including generators, transmission lines, weather conditions and hydrological conditions.
      - See Figure 3.3 of the Application guide entitled "Schematic comparison of Monte Carlo and enumeration methods".

Figure 1.1 - Reliability Application Guide Methodologies

emphasis placed on cost, stability, security or other like factors.

As a result, and keeping in mind that it has taken tens of years of research and development to get there, it has become standard practice to use three terms to properly establish the reliability concepts associated with an electric power system. These are reliability, adequacy, and security. The definitions of these terms very closely follows those given in the Application Guide.

Reliability is a general term encompassing all the measures of the ability of the system, generally given as numerical indices, to deliver electric energy to all points of utilization within acceptable standards and in the amounts desired.

It is necessary to put the reliability work in a historical context. It has evolved over a period of more than forty years. With the evolution of the theory, and more particularly with the availability of the computational power to carry out the studies, it became clear that it was necessary to describe two attributes of power system reliability. These are adequacy and security. It is not unnatural, because of the evolutionary development process, that the indices which were historically referred to as reliability indices now became known as adequacy indices and that, using the now available computer power, security indices would be additionally defined and computed.

1.3. Adequacy

Adequacy is a measure of the ability of the power system to supply the electric power and energy requirements of the customers within component ratings and voltage limits, taking account of planned and unplanned outages of system components. Adequacy measures the capability of the power system to supply the load in all the steady states in which the power system may exist.

The state of a power system is one combination of loads, available generators, and available transmission lines. The first step in any adequacy evaluation is to produce the states of the power system one at a time. This can be done by a simple, exhaustive listing of states as in the State Enumeration method, or the states can be listed by a process which is weighted or controlled by the statistics of their availability as in the Monte Carlo method. It is worth emphasizing that the states of the power system which have been produced are steady states.

The load flow is the basic study which is carried out in the steady state. An adequacy evaluation based on the load flow normally consists of the following three steps.

(a) For each state of the power system run a load flow, or equivalent such as a d-c load flow or transportation solution. (This means running as many load flows as there are states produced, often in the thousands).

(b) If a given state of the power system is not able to supply the load power and energy, or if some transmission lines are overloaded, invoke a Load Curtailment Philosophy and re-run the load flow.

(c) After all the states have been produced, determine adequacy indices such as Loss of Load Expectation, Expected Energy Not Served, frequency of line overloads, frequency of low voltage occurrences, and the like.

1.4 Security

Security is a measure of the electric power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components (together with consideration of operating constraints).

Security means taking the power system in each of the states for which an adequacy evaluation has been carried out, and evaluating how successfully and securely it might have got to that state, how successfully and securely it might move to another state, and how successfully it might withstand sudden disturbances such as electric short circuits.

For immediate illustrative purposes consider briefly a small power system which has three generators and two transmission lines. Assume that an adequacy evaluation has been carried out for the following state of the power system:

G1 - available
G2 - available
G3 - unavailable
L1 - available
L2 - unavailable

(a) It is possible to get to this state from an N ± 1 state by one of the following:
- Adding G1
- Adding G2
- Losing G3
- Adding L1
- Losing L2

(b) It is possible to move away from this state to an N ± 1 state by one of the following:
- Losing G1
- Losing G2
- Adding G3
- Losing L1
- Adding L2

On the generally true assumption that the addition of a component will make the system more secure, the security of moving to and from a state for which an adequacy examination has been carried out can be satisfactorily evaluated by looking at the loss of available generators and lines one at a time.

As discussed earlier, adequacy examines the performance of the power system one state at a time. Security takes the system in each of the adequacy states, and looks at its behaviour upon the loss of one component.

(This, of course, means running potentially thousands of load flows for each of the potentially thousands of states for which adequacy has been evaluated).

This work is in the development state. A concise example of one process for various Test Systems is given in a paper by Billinton and Khan entitled "Security Considerations in Composite Power System Reliability Evaluation" and appearing in IEE Conference Proceedings No. 338 Probabilistic Methods Applied to Electric Power Systems (PMAPS), July 1991. Simply put, this method defines five classes of states in which the power system can exist namely Normal, Alert, Restorative, Emergency and Extreme Emergencies, and it counts the number of times that the power system lies in each class thus establishing a relative frequency or probability for each class.

For each of the adequacy states, it is useful to arrive at a measure of the system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components. This can be done by starting with the power system in each of the adequacy states and seeing how it survives the loss of any one component. (This, of course, means running potentially thousands of stability runs for each of the potentially thousands of states for which adequacy has been evaluated). Simply put, such a process is the exhaustive version of the Selected Base and Incidents method and might appropriately be called the Exhaustive Base and Incidents method.

1.5 Calculation Methods and Modelling Issues

As the report evolves, it will be clear that a distinction must be made between calculation methods and modelling issues. Figure 1.1 shows that the probabilistic calculation methods are State Enumeration and Monte Carlo simulation. In applying either of the calculation methods it is necessary to address many specific modelling issues such as load and hydro system representation. These modelling issues are often considered in very different ways in different software packages and may influence the resulting reliability indices.

A consequence of this is the virtual impossibility of making valid comparisons of the adequcy standards of different countries simply by comparing their reliability indices.

All of the calculations of this work apply specifically to the NB Power system and great care has been taken to provide consistent models so that the results of the different software packages may be as comparable as possible.

1.6 Scope of This Study

The output of this study will be the adequacy risk indices which describe the ability of the system to supply energy under various contingencies. It should be noted that the methodologies used involve only adequacy considerations: they do not verify the ability of the system to pass from one state to another nor do they assess the security of the new state. Evidently any security assessment would involve load flow and stability and would limit the population of contingencies to be considered and thus the whole probabilistic approach. Nevertheless it is expected that one day we will be able to include this aspect so as to complete the reliability story.

2.0 DESCRIPTION OF THE NEW BRUNSWICK POWER SYSTEM

This section provides a general technical overview of the NB Power system. An attempt has been made to make it both introductory, and complementary, to the Input Data which is required for the various reliability methodologies.

The NB Power system is a useful one for study for different reasons.

(a) For its size, it has relatively large generating units.

(b) It is small and computationally manageable, yet it has an interesting blend of hydro, conventional thermal, nuclear, and combustion turbine generation.

(c) While it is small, its geographical location has allowed it to serve in a power broker capacity. It is interconnected with six utilities within Canada and the United States.

(d) It has successfully adopted developing technologies including the first solid state High Voltage Direct Current link in Canada, a large Candu nuclear plant, and a Static Var Compensator on a major 345 kV interconnection to the USA.

2.1 Geography Overview

The Province of New Brunswick is located in eastern Canada as shown in Figure 2.1. It has a population of 725,000 people, an area of 100,000 square kilometres. At the south-east, it is connected to the Province of Nova Scotia which is served by the provincially owned Nova Scotia Power Corporation. Offshore to the east, Prince Edward Island is served by a privately owned utility called Maritime Electric Company Limited. At the north the Province of Quebec is served by the provincially owned Hydro Quebec. To the west the state of Maine in the United States is served by four privately owned utilities.

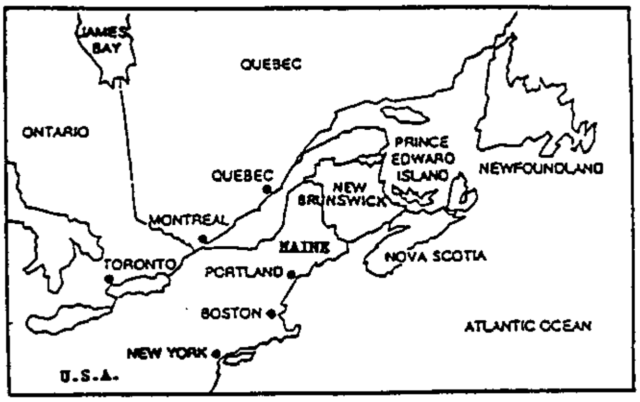


Figure 2.1
Geographical Location

2.2 In-Province Loads

The in-Province peak load including losses for the study system is projected to be 3156 MW with a total consumption of 16035 GWh. Included in this total is 52 MW of load which is normally supplied at high load factors, but which can be interrupted when needed by the utility for firm customers.

Because of the relative severity of the winters, and the amount of electric heating in homes, the peak load occurs during the cold winter months; December, January or February (which are also, unfortunately, periods of low hydro flow). Quantitatively, the peak demand for July is about 60% of the peak demand for January. Energy consumption for January and July proportionally have the same relationship.

The electrical demand for New Brunswick is made up of a number of sectors. The industrial sector is the largest single component of load making up about 25% of the peak demand and 40% of the total energy consumption. Of this, the forest industry is the largest and mining is second. These power intensive industries account for a higher proportion of the NB Power total load than is the case for most utilities.

Combining the effects of winter electric heat and industrial base load we can say that:

(a) The daily load factor for the system is quite high (80 - 90%).
(b) The annual load factor for the system is much lower (60%).

Table 2.1 provides a forecast of the monthly peak loads and energy requirements for the study system.

Table 2.1
Study System Load Forecast

Month	Energy Requirements (GWh)	Peak Load (MW)
April	1341	2432
May	1206	2209
June	1095	1942
July	1021	1767
August	1062	1854
September	1074	1962
October	1233	2199
November	1424	2550
December	1631	2913
January	1754	3156
February	1590	2960
March	1605	2887

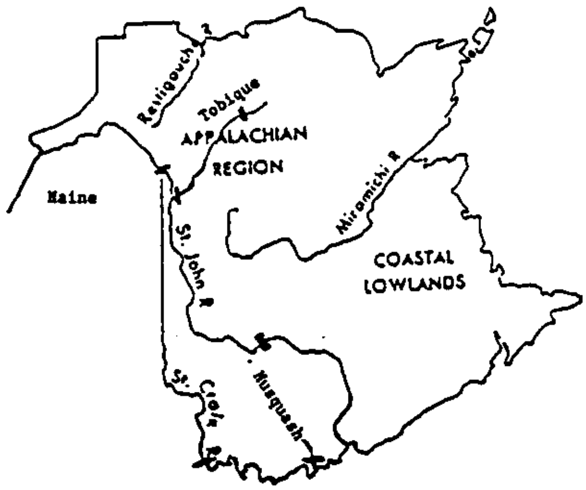


Figure 2.2
River Systems of New Brunswick

2.3 River Systems and Hydro Generation

The major river in the Province is the Saint John. It is approximately 400 km long. It has its source in the United States and in the upper reaches, occurring in the north western part of the Province, it forms the border between New Brunswick and the state of Maine. Following this section, the river generally flows from north to south. At about the 200 km point, the river turns in a somewhat easterly direction and it empties into the Atlantic Ocean at about the mid point of the southern end of the Province. At about the 125 km point, a river called the Tobique flows into the east side of the Saint John river. The Tobique river in turn has a feeder river called the Sisson.

There are two other small rivers which are also involved in hydro generation. The Saint Croix river forms the boundary between New Brunswick and Maine at the south-western end of the Province. Approximately halfway between the Saint John and the Saint Croix is a short river called the Musquash. Figure 2.2 shows these river systems within the Province.

The hydro generation system experiences low flows in winter and summer with very high flows during the spring snow melt season. These flows are also subject to variation in each month dependent on weather impacts. Most analysis can be conducted by using long term average hydro generation energies. Extreme low energy production under adverse conditions can be used to define the lower limit of the hydro system.

The monthly low available hydro energy is based on 95% available flow, that is low values of flows which will be available 95% or more of the time. These monthly energies are determined from analysis of historical records.

A summary of hydro station capabilities and energies are provided in Table 2.2 and Table 2.3.

Table 2.2
Hydro Generating Station Capabilities

			Annual Energy	
Plant	Unit	Capacity (MW)	Average (GWh)	Adverse (GWh)
Grand Falls	1	15.2	437	260
	2	15.2		
	3	15.2		
	4	15.2		
Beechwood	1	36.0	478	257
	2	36.0		
	3	40.0		
Mactaquac	1	110.0	1597	770
	2	110.0		
	3	110.0		
	4	110.0		
	5	110.0		
	6	110.0		
Tobique	1	10.0	94	54
	2	10.0		
Sisson	1	8.4	19	9
Musquash	1	5.2	16	11
Milltown	1-7	3.6	17	10
TOTAL HYDRO		870.1	2657	1371

Table 2.3
Monthly Available Hydro Energies (GWh)

Month	Average	Adverse
January	144.3	62.9
February	122.1	41.5
March	158.2	44.1
April	389.1	44.8
May	502.7	392.8
June	245.1	151.5
July	169.1	79.1
August	151.8	46.2
September	151.2	43.2
October	190.8	52.4
November	218.0	76.4
December	210.3	62.4
Annual Total	2656.7	1371.3

2.4 Thermal Generation System

The total generating capacity is 4320 MW. This is made up of 13 conventional thermal units with a capacity of 2265 MW, one nuclear unit with a capacity of 635 MW and 7 combustion turbine peaking units with a capacity of 550 MW in addition to the 24 hydro units with a capacity of 870 MW. The thermal generation system capabilities are given in Table 2.4.

Table 2.4 Thermal Generating Station Capabilities

Plant	Unit	Fuel	Capacity (MW)	DAFOR	Location
Belledune	1	Coal	450.0	0.12	North coast on Bay of Chaleur
Chatham	2	Coal/Oil #6	20.0	0.10	East coast on Miramichi Bay
Coleson Cove	1	Oil #6	335.0	0.10	South coast on Atlantic Ocean
	2	Oil #6	335.0	0.10	
	3	Oil #6	335.0	0.10	
Courtenay Bay	1	Oil #6	44.5	0.10	South coast on Atlantic Ocean
	2	Oil #6	12.3	0.10	
	3	Oil #6	100.0	0.10	
	4	Oil #6	97.0	0.10	
Dalhousie	1	Oil #6	103.0	0.10	North coast on Bay of Chaleur
	2	Coal/Oil #6	203.0	0.12	
Grand Lake	8	Coal	60.0	0.12	Center of Province near coal fields
	9	Coal	170.0	0.12	
Grand Manan	10	Oil #2	25.0	0.10	Island, off south westerly area of Province
Moncton	1	Oil #2	25.0	0.10	South eastern area
Millbank	1	Oil #2	100.0	0.10	East Coast on Miramichi Bay
	2	Oil #2	100.0	0.10	
	3	Oil #2	100.0	0.10	
	4	Oil #2	100.0	0.10	
Point Lepreau	1	Nuclear	635.0	0.12	South coast on Atlantic Ocean
Ste Rose	1	Oil #2	100.0	0.10	East Coast on Miramichi Bay
			3449.8		

2.5 Maintenance Scheduling

NB Power takes advantage of low summer loads to do most of its maintenance. This leaves the entire generation system available to meet the winter peak which is expected in January.

For the study system the maintenance schedule employed is given in Table 2.5.

Table 2.5
Maintenance Schedule

Units	Outage Length	Months
Nuclear/Thermal		
Lepreau 1	4 weeks	May
Coleson	7 weeks/unit	June-October
Dalhousie 1	5 weeks	April
Dalhousie 2	4 weeks	June
Courtenay Bay 3/4	6 weeks/unit	April-June
Courtenay Bay 1	6 weeks/unit	March-April
Grand Lake 8	4 weeks	April
Grand Lake 9	4 weeks	August
Belledune	4 weeks	July
Tracadie	4 weeks	May
Millbank	4 weeks/unit	June-Sept.

Units	Outage Length	Months
Hydro		
Grand Falls	1 week/unit	Feb.- March
Tobique	1 week/unit	March
Mactaquac	2 weeks/unit	June-August
Beechwood	1½ week/unit	August

2.6 Interconnections and Contracts

NB Power has interconnections with Canadian and United States utilities as shown in Figure 2.3. The power flows across these interconnections influence the operation and reliability of the NB Power system. These flows may generally be categorized as a contractual transfer, interruptible economy energy interchange and emergency interconnection support. For analysis purposes of system reliability the economy interchange may be ignored, but both contractual transfers and emergency interconnection support must be included.

2.6.1 Contractual Transfers

NB Power has contractual transfers which may be described as participation and/or joint ownership contracts. In this type contract, NB Power sells all or part of the output of a unit to an industry or to a neighbouring utility. If the unit is available the sale is made, but if the unit is not available the sale is interrupted. A summary of the contracts assumed to be in place for the test system is provided in Table 2.6.

Table 2.6
Contractual Power Transfers

Purchaser	Units	Capacity MW	Expected Capacity Factor
New England	Pt. Lepreau	230	80%
Prince Edward Island	Dalhousie #2	20	80%
	Belledune	40	80%
Hydro Quebec	Millbank #1-4	400	6%
	Total	690	

These contracts totalling 690 MW constitute 16% of the total NB Power generation capacity of 4320 MW. All the contracts are base load and tied specifically to their respective generating unit except for the Hydro Quebec 400 MW. In this contract when the Millbank units are not required by Hydro Quebec they are available for NB Power. Conversely if a Millbank unit is not available NB Power will still supply the contract from the rest of the system and interrupt only prior to not supplying in-Province customer firm load.

2.6.2 Interconnected System Support

The support available from an external interconnected system depends upon the availability of surplus generation resources in that system and upon the transmission delivery capability within the external system and through the interconnection. Since in most cases it is not possible or practical to include the total external system in the calculations, it is then necessary to develop some equivalent model for each external system. This is a complex issue which is discussed in

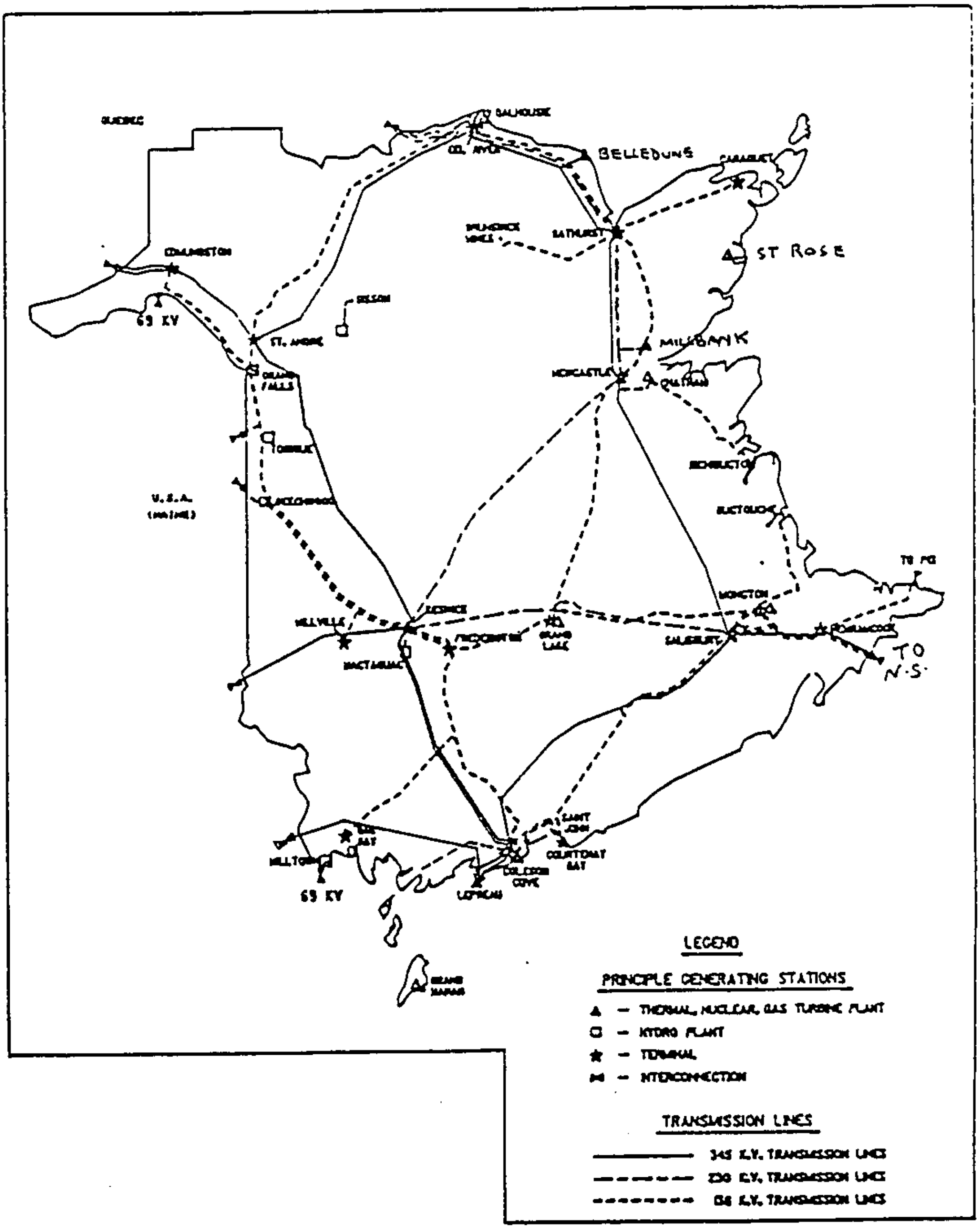


Figure 2.3 - Major Transmission Lines

more detail in Chapter 5.0. However at this stage, Table 2.7 defines the different interconnected systems and estimates the amount of capacity support available to NB Power.

Table 2.7
Interconnection Support in MW

External System	Transmission Maximum	Possible Support
Nova Scotia	700	400
Prince Edward Island	150	20
Hydro Quebec	1000	500
Maine Public Service	100	20
New England Pool	1000	400

2.7 Transmission System

There are 7000 km of transmission circuits. Figure 2.3 geographically shows that the basic transmission voltage level of 138 kV makes three loops within the Province with radial feeds to some areas. This is overlaid by a tree of 230 kV lines, which is contained within a grid or ring of 345 kV lines around the perimeter of the Province. The 69 kV system is basically a distribution network but in some cases closes a loop between otherwise radial 138 kV lines.

The objective of this work is to illustrate the application of reliability methods to an operating power system. To do this, some adjustments to the transmission system can make the problem much more manageable with little impact on the final result. Three simplifications have been made to the actual NB Power system to produce a study system for evaluation purposes.

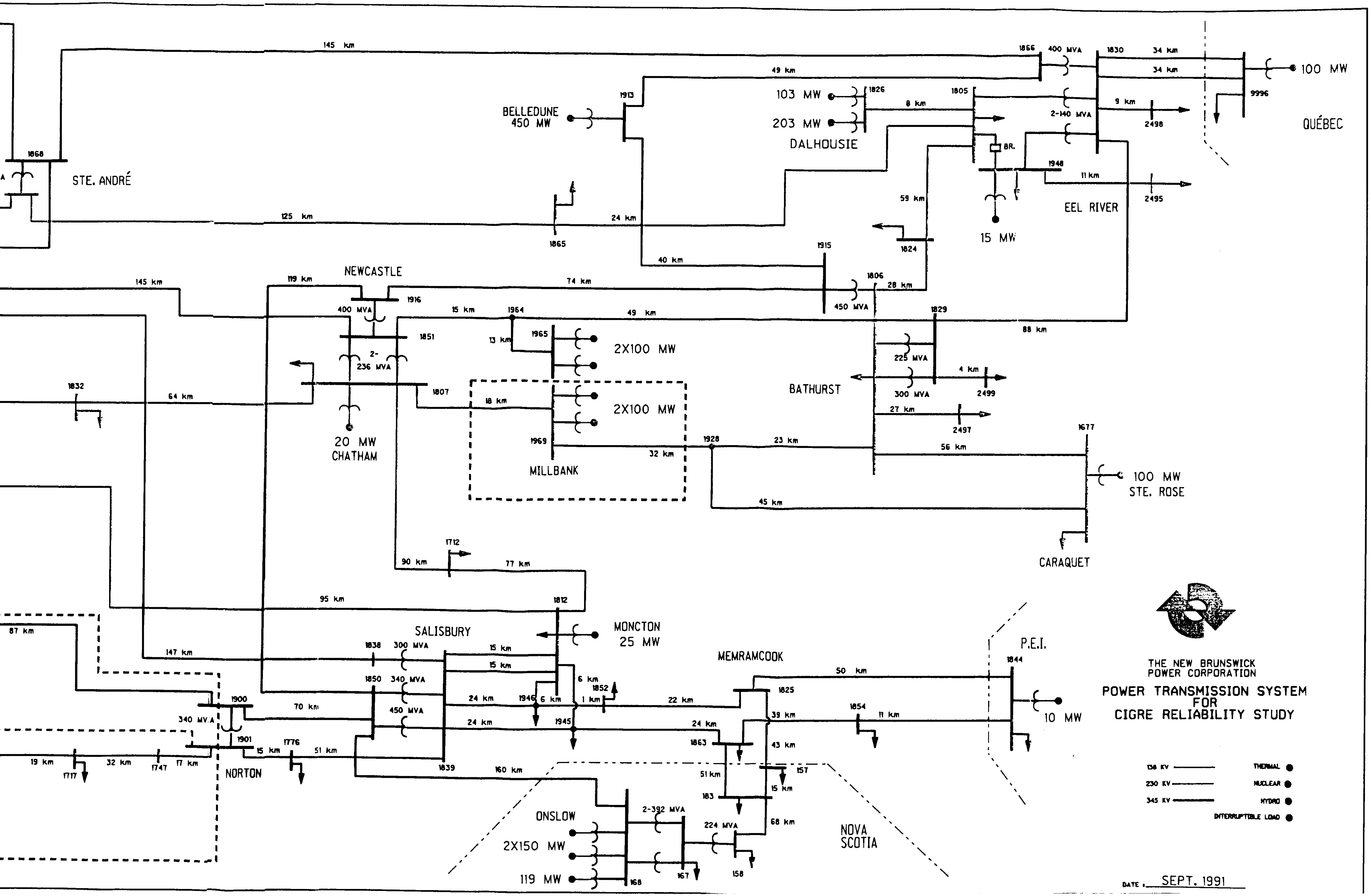
(1) The system configuration has been simplified somewhat. The 69 kV system has been dropped and all loads and generators moved to appropriate 138 kV nodes. Also distributed loads tapped from 138 kV lines have been lumped together. These changes make the system computationally more manageable.

(2) A phase shifting transformer at the Norton 138 kV node has been removed. This will ease the modelling requirements, and more importantly provide a network weakness in the Coleson Cove-Courtenay Bay - Norton area that can be detected by the reliability analysis.

(3) The Newcastle - Millbank 138 kV transmission line is rated at the nominal 138 kV rating of 140 MVA. This is insufficient capacity for certain contingency situations and so provides a second weakness to be detected in the analysis.

Figure 2.4 is a one line diagram of the complete NB Power base study system configuration. As shown in the lower right, the diagram is color coded according to voltage level and generation type. Included on the diagram are transmission line lengths, transformer ratings and the interconnection system support generation. Detailed system data, for the base study system including transmission and transformer data, is given in Appendix I.

The dashed boxes indicate the areas of transmission weakness. They are discussed in detail in Sections 4 and 10 along with proposed transmission improvements.



THE NEW BRUNSWICK POWER CORPORATION
POWER TRANSMISSION SYSTEM FOR CIGRE RELIABILITY STUDY
138 KV
230 KV
345 KV
THERMAL
NUCLEAR
HYDRO
INTERRUPTIBLE LOAD
DATE : SEPT. 1991
QUÉBEC
100 MW
STE. ANDRÉ
BELLEDUNE 450 MW
103 MW
203 MW
DALHOUSIE
EEL RIVER
15 MW
NEWCASTLE
2X100 MW
2X100 MW
MILLBANK
BATHURST
20 MW CHATHAM
100 MW STE. ROSE
CARAQUET
MONCTON 25 MW
SALISBURY
MEMRAMCOOK
P.E.I.
10 MW
NORTON
ONSLOW
2X150 MW
119 MW
NOVA SCOTIA

SECTION B - DETERMINISTIC METHODOLOGIES

(a) <u>RESERVE MARGIN METHOD</u> appearing in Chapter 3.0 inherently handles only generation.

(b) <u>SELECTED BASE AND INCIDENTS METHOD</u> appearing in Chapter 4.0 allows any incident to occur although the major emphasis is on transmission.

3.0 RESERVE MARGIN METHOD

The load on a power system normally grows according to some regularly shaped trend line. Generation, on the other hand, is installed on a system in megawatt blocks. The result of this is that just after the installation of new generation the installed generation greatly exceeds the system load. As time passes, the two quantities move closer together.

One criterion which specifies the limit of how close the load should be allowed to come toward installed capacity is the reserve margin. The reserve margin is equal to the ratio of the installed or available capacity to the maximum annual load, minus one.

Another way of expressing the criterion based on reserve margin is through a power inequality expression:

CAPACITY - LOAD $\geq$ RESERVE MEGAWATTS

The criterion based on reserve margin can be established and developed by asking four simple questions about this inequality expression.

1. In what time interval(s) should this power inequality expression be checked, and be required to hold? As a first response, if the maintenance patterns were always perfectly uniform then possibly it should be checked only once a year.

2. What is in the definition of the term "reserve megawatts", and what should be its numerical value? As a first response, Table 3.1 of the Application Guide shows that in 1987 Finland used a numerical value of 17% of load while the United Kingdom used a numerical value of 23% of load.

3. What components go together to make up the system load? As a first response, it might be only the in-Province or in-country load if the interconnections are interruptible by terms of a contract.

4. What components go together to make up the system capacity? As a first response, a conservative approach would be to ignore any capacity benefits from interconnections.

In the remainder of this section, we will examine the approach which New Brunswick Power has taken in answering these questions for an operating power system.

3.1 Time Interval of Application

The time interval over which the power inequality expression is applied in developing capacity installation patterns depends exclusively on the future period for which a utility has an acceptable level of confidence in its load forecasting capabilities. NB Power employs a 15 year period.

The time interval in which the power inequality expression is applied depends largely on three factors.

(a) The variability of hydro unit capability with time interval. A month with a high load demand might not be a cause of concern with respect to reserve megawatts if there is high hydro energy and capacity available to met the high load demand. Unfortunately, this is not the case in New Brunswick.

(b) The required timing for, and duration of, units on maintenance, and the size of the units on maintenance. In New Brunswick the 635 MW Point Lepreau nuclear unit requires an annual maintenance period of one month, and this can only logically be done during the high river flow months of April and May.

(c) Any variation in interconnection contracts (either purchases or sales) by time interval.

For these reasons, New Brunswick Power has chosen to evaluate the power inequality expression in intervals of one month.

3.2 Reserve Margin or Reserve Megawatts

NB Power has chosen to define reserve megawatts according to two criteria. These are a Criterion for Peak Capability and a Criterion for Sustained Capability. The most restrictive condition possible is chosen in that both criteria must be met in any month in order for any proposed capacity installation pattern to be considered satisfactory.

3.2.1 Reserve Criterion for Peak Capability

For this criterion, generating capacity is determined as the sum of hydro and thermal generation with 100% availability at rated capacity, and no reliance is placed on interconnections.

The numerical value of reserve megawatts is the capacity of the largest unit used on the system or 20% of the firm load, whichever is greater.

3.2.2 Reserve Criterion for Sustained Capability

For this criterion, the thermal generation is taken with 100% availability at rated capacity. The hydro is taken as the maximum capacity the total hydro generating units can supply when the total available hydro energy at 95% probable conditions (that is, low flows) is fitted under the load duration curve for each month. (This is a process called peak shaving with hydro, and it is discussed in more detail in the later section on generating capacity.)

The numerical value of reserve megawatts is more complicated in the criterion for sustained capability. This is an energy based criterion which requires that the so-called Maritime system, consisting of New Brunswick, Nova Scotia and Prince Edward Island, be able jointly to withstand the sustained loss of the larger of 10% of the interconnected system load or the largest unit on the interconnected system under conditions of historically low available hydro energy (that is, 95% probability conditions on the flow) on the NB Power system.

The above value of reserve megawatts is for the systems jointly. It is necessary to specify the proportion of the reserve megawatts which each system must meet.

(a) If the size of the largest unit is less than or equal to 10% of the interconnected system load, then each individual utility maintains 10% of their forecast load as the reserve requirement.

(b) If the size of the largest unit is greater than 10% of the interconnected load, each utility maintains a reserve equal to 10% of their forecast load with the utility owning the largest unit being responsible for the remainder.

There is one more factor. Because NB Power has strong interconnections to Quebec and the New England states, it relies on these interconnections for 25% of the total sustained reserve requirements.

3.2.3 Reserve Megawatts Calculations

We are going to illustrate these calculations for the study system as described in Chapter 2. With the Participation Sales included, the quantity of 230 MW generated at Point Lepreau goes directly as a sale. It nets to zero, and leaves the effective maximum capacity of Point Lepreau at 635 - 230 = 405 MW. This makes Belledune the largest unit with a capacity of 450 - 40 = 410 MW after its sale to PEI is subtracted.

(a) Reserve Criterion for Peak Capability

Largest generating unit on NB Power System	410 MW
20% of N.B. firm load 0.2 x 3104	621 MW
Greater of these two:	
Peak Capability Reserve	621 MW

(b) Reserve Criterion for Sustained Capability

N.B. forecast firm peak demand	3104 MW
N.S. forecast firm peak demand	2188 MW
P.E.I. forecast firm peak demand	150 MW
Total Maritime interconnected firm load	5442 MW
10% of total Maritime Firm Load	544 MW
Largest generating unit on NB Power	410 MW
Because 10% of the Maritime load is larger than the largest unit the rule is proportional sharing.	
Maritime interconnected reserve	544 MW
N.B. share of interconnected system reserve $\frac{3104}{5442} \times 544$	310 MW

Less 25% contribution from Quebec and New England (0.25 x 544)	- 136 MW
Sustained Capability Reserve	174 MW

3.3 System Load

The load for which a reserve margin is needed is the firm, in-Province load. This load is equal to the total forecast for each month less all interruptible load. The amount of interruptible load is 52 MW which, being associated with power intensive industries, is constant in all months. For the peak month of January:

N.B. forecast peak load	3156 MW
Interruptible load	52 MW
N.B. firm peak load	3104 MW

For the Peak Capability evaluation the only requirements are for the peak loads by month for the study year. For Sustained Capability evaluation, the peak loads by month are also required. However, in addition it is also necessary to take into account the energy and shape of each monthly load. This is given by means of the Load Duration Curves specified in 2% time intervals with 51 load points. The shape of the L.D.C. is adjusted to be consistent with the forecasted load energy for each month of the study period.

3.4 Generating Capacity

In evaluating the criterion for Peak Capability, the following factors are considered for determining the generation capacity available:

(a) The thermal generation is present with 100% availability at rated capacity. That is, no probability of forced outage is considered.

(b) The hydro generation is present with 100% availability at rated capacity. No consideration of energy limitations is included.

(c) No reliance is placed on interconnections except for inclusion of firm contract capacity which is netted from the generation.

(d) All hydro and thermal generating units are placed on maintenance according to the annual long term maintenance schedule.

In evaluating the criterion for Sustained Capability, the following factors are considered for determining the generation capacity available::

(a) The thermal generation is present with 100% availability at rated capacity. No forced outages are considered.

(b) For the hydro generation, the determination of available capacity is much more involved. The hydro energies are fitted under their respective load duration curves according to a process called peak shaving, in order to determine the hydro capacity credit. This process is illustrated in Figure 3.1. A certain amount of the monthly hydro energy must be run as base hydro, that is for 100% of the time. The remainder of the hydro energy is fitted into the peak of the Load Duration Curve.

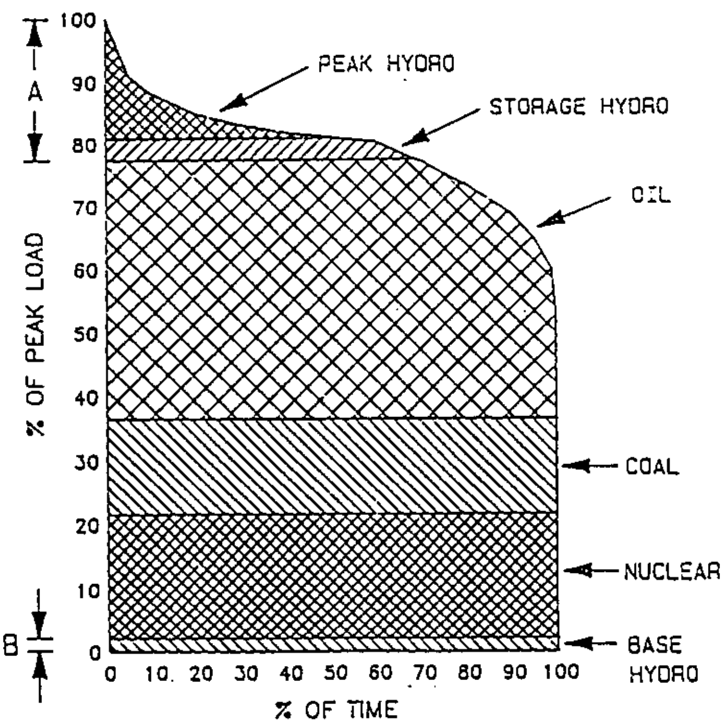


Figure 3.1
Peak Shaving the Load with Hydro Energies

(c) There is one additional effect present, and that is annual cycle storage hydro which is available in the Saint John river system. It is in fact just hydro energy which is controlled in a special way. This stored energy is released during the months of December - March, so that the storage will be empty to absorb as much as possible of the snow melt run off which begins in April. The stored energy is released in a manner which attempts to levelize the remaining thermal load across the four month period December - March. For simplification of the analysis, this storage energy has already been allocated and is included in the monthly hydro energies.

(d) All firm contracts are considered by netting the sale capacity from the generation. Interconnection support from Quebec and New England is included by reducing the reserve margin required by 25%.

(e) Maintenance of thermal units is included as scheduled. Hydro unit maintenance is not included. This is because the hydro system capacities are those derated values determined after consideration of energy limitations. Since hydro maintenance is scheduled in periods of low water the effect of the maintenance outages is already included in the energy limited hydro capacity.

3.5 Results

The results of the reserve margin analysis reflect the inequality:

CAPACITY - LOAD $\geq$ RESERVE MEGAWATTS

or

CAPACITY - LOAD - RESERVE MEGAWATTS ≥ 0

Results of the reserve margin analysis are given in Table 3.1 and Table 3.2 respectively for the Peak and Sustained Criteria. In addition to the reserve MW surplus or deficit values, calculation of the amount of percentage capacity reserve in excess of the firm load is included for the Peak Criterion.

TABLE 3.1
PEAK CAPABILITY CRITERIA

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
CAPACITY:												
1 HYDRO	870	870	870	870	870	870	870	870	870	870	870	870
2 NUCLEAR	635	635	635	635	635	635	635	635	635	635	635	635
3 THERMAL	2815	2815	2815	2815	2815	2815	2815	2815	2815	2815	2815	2815
4 LESS MAINTENANCE	305	835	845	995	750	435	435	0	0	0	7	34
5 PARTICIPATION	690	460	670	550	590	590	590	690	690	690	690	690
6 AVAILABLE CAPACITY (1+2+3-4-5)	3325	3025	2805	2775	2980	3295	3295	3630	3630	3630	3623	3596
LOAD:												
7 NB FORECAST LOAD	2432	2209	1942	1767	1854	1962	2199	2550	2913	3156	2960	2887
8 LESS: INTERRUPTIBLE	52	52	52	52	52	52	52	52	52	52	52	52
9 TOTAL FIRM LOAD (7-8)	2380	2157	1890	1715	1802	1910	2147	2498	2861	3104	2908	2835
RESERVE:												
10 NB RESERVE	621	621	621	621	621	621	621	621	621	621	621	621
11 SURPLUS/(DEFICIT): (6-9-10)	324	247	294	439	557	764	527	511	148	(95)	94	140
12 RESERVE MARGIN	40%	40%	48%	62%	65%	73%	53%	45%	27%	17%	25%	27%

TABLE 3.2
SUSTAINED CAPABILITY CRITERIA

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
CAPACITY:												
1 HYDRO	870	870	575	404	333	357	418	487	508	715	568	508
2 NUCLEAR	635	635	635	635	635	635	635	635	635	635	635	635
3 THERMAL	2815	2815	2815	2815	2815	2815	2815	2815	2815	2815	2815	2815
4 LESS MAINTENANCE	305	835	735	885	605	435	435	0	0	0	7	22
5 PARTICIPATION	690	460	670	550	590	590	590	690	690	690	690	690
6 AVAILABLE CAPACITY (1+2+3-4-5)	3325	3025	2620	2419	2588	2782	2843	3247	3268	3475	3321	3246
LOAD:												
7 NB FORECAST LOAD	2432	2209	1942	1767	1854	1962	2199	2550	2913	3156	2960	2887
8 LESS: INTERRUPTIBLE	52	52	52	52	52	52	52	52	52	52	52	52
9 TOTAL FIRM LOAD (7-8)	2380	2157	1890	1715	1802	1910	2147	2498	2861	3104	2908	2835
RESERVE:												
10 NB RESERVE	174	174	174	174	174	174	174	174	174	174	174	174
11 SURPLUS/(DEFICIT): (6-9-10)	771	694	556	530	612	698	522	575	233	197	239	237

Table 3.3
Comparison of Peak and Sustained Criteria
Surplus/(Deficit) in MW

Month	Peak	Sustained	Most Restrictive
April	324	771	Peak
May	247	694	Peak
June	294	556	Peak
July	439	530	Peak
August	557	612	Peak
September	764	698	Sustained
October	527	522	Sustained
November	511	575	Peak
December	148	233	Peak
January	(95)	197	Peak
February	94	239	Peak
March	140	237	Peak

Results show that the NB Power system is deficient under the Peak Criterion in the month of January by 95 MW. This coincides with a reserve margin of 17% which is below the desired 20%. There is sufficient capacity in all other months under the Peak Criterion. Under the Sustained Criterion, in Table 3.2,there is surplus capacity in all months. The amount of surplus is greater than the peak surplus in all months except September and October. This is shown in Table 3.3 which summarizes the results by month and indicates which criterion is the most restrictive.

3.6 Adequacy and Security in the Reserve Margin Method.

The Reserve Margin method is very weak in the examination of adequacy. It, in essence, has one generation schedule except that it examines the loads by month. Its principal short-coming is that it ignores any quantification of plant forced outages, so that, for example, there is no way to show the benefit of improved forced outage rates.

The Reserve Margin method attempts to do nothing in the examination of security.

4.0 SELECTED BASE AND INCIDENTS METHOD

Up to the present time many utilities, and particularly the interconnected utilities operating under Coordinating Councils, continue to use deterministic criteria to evaluate transmission system reliability. This is so because the use of probabilistic indices for the reliability evaluation of large transmission systems calls for sophisticated models, and powerful software packages together with the associated hardware.

4.1 General Procedure

The general procedure for the application of the deterministic Selected Base and Incidents methodology has two steps:

1. Select one or several base cases. These should correspond to operating conditions which are considered difficult based on the experience of planning and operating personnel.

2. Subject each case to a series of generation and or transmission incidents and examine how the system withstands the incidents from the following points of view:

   (a) Flows through system components kept within permissible limits.

   (b) Voltage changes at network nodes kept within permissible limits.

It is clear that the major analytical tool of the Selected Base and Incidents Method is the load flow.

4.2 N-1 Criterion

The N-1 criterion consists of the simulated loss of one network component such as a line, transformer, cable or even a reactive power component. The loss of a generator may also be considered, although few countries take into account generation outages.

4.3 Incidents

The starting point is the Base Study System under peak load conditions. This system was introduced in Section 2.7 and reference should also be made to modelling considerations discussed in Chapter 9, the One Line Diagram shown in Figure 2.4, the Generic System Data given in Appendix I, and the Base Case Load Flow Results given in Appendix III. Clearly the Base Case is one in which all line flows and all node voltages are normally within acceptable limits. There are two factors to be considered.

(a) The system is an operating system, and N-1 contingencies should not normally cause a problem on it.

(b) As described in Section 2.7, two transmission weaknesses have been built into the Generic Data set.

The system was subjected to a series of incidents, all of them being at the N-1 level and all of them involving the loss of a line or transformer. The following is a list of the element losses to which the system was subjected given in terms of bus terminations:

1. IRVREF-1681 to C.BAY1-1813
2. KESWK3-1803 to LEPRAU-1843
3. KESWK3-1803 to STAND3-1868
4. MACTQC-1809 to KESWK1-1827
5. C.COV3-1836 to C.COV1-1837
   (Loss of Transformer 2 of two parallel transformers)
6. C.COV3-1836 to NORTN3-1900
7. SALBR3-1850 to NORTN3-1900
8. BELDUN-1913 to BATHS3-1915
9. C.COV1-1837 to MILD47-1860

4.4 Results

The impact of the transmission incidents on the system is discussed in relation to the two areas of transmission weakness.

(a) Coleson Cove - Courtenay Bay - Norton area

This area as shown in Figure 4.1 is one which has received full study by NB Power. Without the phase shifting transformer between nodes 1836 and 1900, problems can arise. Four of the nine transmission incidents (#1, #6, #7 and #9) cause line overloads and/or voltage problems in the Coleson Cove - Norton area while incident #4 overloads line 1809-1861 out of the Mactaquac plant. The other incidents cause no problems.

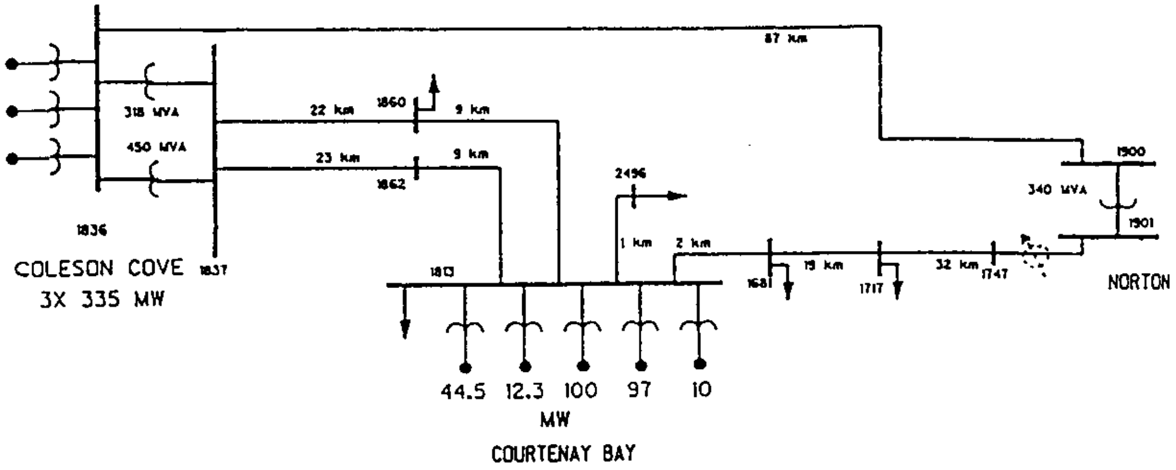


Figure 4.1 - Representation of the Coleson Cove - Courtenay Bay - Norton Area

It must be noted that problems caused by four of the five incidents can be overcome by altering the system dispatch. While this altered dispatch would incur an economic penalty it is still preferable to curtailing load. But incident #6, even after altered dispatch, incurs the voltage and line overload problems given in Table 4.1 and 4.2. Note that the low voltage at node 1712 already existed in the base case. This occurs because of the simplification of lumping distributed loads at this particular node. Note also that the overloaded lines in Table 4.2 also show up later in the composite reliability evaluation.

(b) Millbank - Newcastle area

The second area of potential transmission weakness as shown in Figure 4.2 is much more subtle. When generation conditions require dispatch of the 200 MW of combustion turbines at Millbank, then the resultant flow towards Newcastle would exceed the 140 MVA rating of the transmission line if line 1969-1928 were not available. Other transmission incidents could also influence those flows - but redispatch of Millbank to below 140 MVA would always avoid the problem.

No N-1 incidents on the Base Case Load flow cause any problems in this area. However double and triple contingencies could cause problems as detected later in the composite analysis.

Table 4.1
Buses With Voltage Out of Limits
(per unit)

Bus	Pre Event Voltage	Post Event Voltage
11356EQ-1712	0.935	0.917

Table 4.2
Lines Which Are Overloaded

From Bus	To Bus	Percent Overload
IRVREF-1681	LAKEWD-1717	103.2
IRVREF-1681	C.BAY4-1813	164.4
C.BAY1-1813	MILD47-1860	105.3
C.BAY1-1813	MILD65-1862	114.9
C.COV1-1837	MILD47-1860	123.3
C.COV1-1837	MILD65-1862	115.0

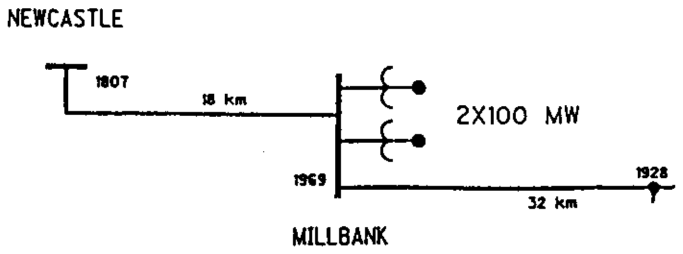


Figure 4.2 - Representation of the Millbank-Newcastle Area

4.5 Extensions Beyond the N-1 Criterion

NB Power is part of the Northeast Power Coordinating Council (NPCC) within North America. Power system planning within the Coordinating Councils may involve extensions to the N-1 criterion including:

(a) Examination of transient or dynamic stability during a fault or faults.

(b) Performance under extreme contingencies.

(c) Operation of Special Protection Systems.

The N-2 criterion is not used directly by NB Power in system planning. However it is included in some of the extreme contingencies referred to above. Clearly if an N-2 criterion were used there are weaknesses in other areas which would appear, and the situation in the Coleson Cove - Courtenay Bay area, as described in Section 4.3.2, would be exacerbated.

4.6 Adequacy and Security in the Selected Base and Incidents Method

The Selected Base and Incidents method is relatively weak in the examination of adequacy. This is so because there is normally a relatively small number of Selected Base Cases. Further, the Base Cases are selected deterministically usually based on planning and operational experience. In addition all of the Selected Base Cases are assumed to be equally likely events, since no probabilities are assigned to any of them. As will be seen later, this is in contrast to the State Enumeration process which exhaustively selects states (or Base Cases) while at the same time calculating the probability associated with being in that state. It is also in contrast to the Monte Carlo simulation which selects the states (or Base Cases) on a probabilistic basis thus capturing the ones which are most likely to occur.

The Selected Base and Incidents method is, on the other hand, relatively strong in the examination of security. This is inherent in the definition of the method, since it attempts to look at the effects of Incidents of specific sudden disturbances such as electric short circuits or unanticipated loss of system components. It is strong in the security area from two points of view. First, the state resulting from an unanticipated event such as a short circuit on a major bus is examined in the steady state by means of the load flow to detect voltage and line overload problems. Second, a transient stability analysis might also be carried out to see if the power system can securely transiently arrive at the state resulting from an unanticipated event such as a short circuit on a major bus.

SECTION C - PROBABILISTIC METHODS FOR GENERATION (HL1)

The two probabilistic methods of State Enumeration and Monte Carlo Simulation are, in this section, applied to the generation system by itself (HL1 analysis). The intent is to provide a comparison base for the later composite system reliability analysis.

5.0 DATA AND MODELLING FOR PROBABILISTIC ANALYSIS OF GENERATION

The major issue for probabilistic modelling of generation (the HL1 analysis) is the handling of generator unavailabilities, especially forced unavailabilities. In addition, stochastic treatement of loads and of hydro energy is also possible. Indeed, the calculation method utilized to handle the stochastic treatment defines the two probabilistic methodologies:

(a) State Enumeration
(b) Monte Carlo

But before they are considered in detail, it is necessary to look at the system to be studied and describe it in some manner that can be analyzed by application of either method. This requires the reduction of the actual system to a series of manageable models. There are many areas which must be considered, and different approaches which can be taken in each.

5.1 Modelling Issues

The following modelling issues need to be addressed:

1. Unit Forced Unavailabilities
   - Single State (*)
   - Multi State

2. Load Models
   - Load Period
     - annual
     - seasonal
     - monthly (*)
     - weekly
   - Load Shape
     - chronological
     - load duration curve (*)
   - Load Forecast Uncertainty

3. Hydro Generation Energy Limitations
   - peak shaving (*)
   - equivalent thermal
   - energy availability

4. Contractual Interconnection Transfers
   - net from generation (*)
   - add as load

5. Interconnection Support
   - equivalent 100% available generator
   - multi state system equivalent
   - multi unit equivalent (*)

6. Interruptible Load
   - reduce to firm load
   - add 100% available generator(*)

7. Maintenance
   - include in the forced outage rate
   - pre-scheduled outages or derations (*)

The modelling approaches marked by an asterisk (*) are the preferred ones utilized by NB Power engineers for the analysis of their system. However they are not necessarily available within all reliability software packages.

5.2 The Concept of the Peak Load Analysis

The objective of the CIGRE work is to demonstrate the various probabilistic methodologies on an operating power system. As visualized from the outset, the final stage of the work was to use the New Brunswick Power data as input to various international software packages for probabilistic composite system analysis (HL2). As the work progressed, it became evident that all software packages contained the same fundamental probabilistic base structures. However there were differences in handling various components of the power system such as load models and interconnections, largely based on varied but clearly understood corporate objectives for the various software packages when they were being developed and written. These variations in models could cause variations in results.

It is true that it might be possible to reconcile the results from the various international software packages by detailed qualitative arguments. However, this is difficult to do because of the large number of programs used and modelling variations present.

A decision was collectively made by the Working Group to initially constrain the New Brunswick Power operating conditions to a peak load analysis. This hopefully would facilitate clear quantitative comparisons from the various probabilistic methodologies, before proceeding to a more detailed complete year analysis of the NB Power system. The specific modelling details of the complete system are presented in Section 5.3 followed by the simplifications required for the constrained peak load system in Section 5.4.

5.3 Complete Year HL1 Modelling Details

Most of the modelling issues outlined in Section 5.1 are examined in more detail.

5.3.1 Unit Forced Unavailabilities

The forced unavailabilities of the thermal units have been given in Table 2.4. These are deration adjusted equivalent unavailabilities that provide for a simple two state model of generation availability.

5.3.2 Load Models

The load model is based on monthly load duration curves. Table 2.1 shows the peak load in MW by month and the energy which must be fitted into the load duration curve. The data to define the shape of the monthly load duration curves is given in Appendix II.

5.3.3 Hydro Generation Energy Limitations

The hydro units, as such, are assumed to be 100% available. However, the MW production level for each time interval under the energy limitations is determined by the peak shaving process. The peak shaving process has already been introduced in the discussion of the Reserve Margin methodology, and it is illustrated in Figure 3.1.

The states, represented by MW production levels, of the hydro generation are basically those determined when using the Sustained Capability Criterion of the Reserve Margin methodology, except that here the monthly available hydro energies are based on average or 50% availability flows rather than the low or 95% availability flows.

5.3.4 Contractual Interconnection Transfers

The manner in which contract transfers are modelled can greatly alter the results of the reliability calculations. This is especially true for NB Power because the 690 MW total amount of transfer as previously defined in Table 2.6 is large compared to the system size. Because contract transfers are tied specifically to particular generating units the best way to handle them is to net each from their respective generation.

This is easily done for generation only analysis. But when the transmission system is included it is necessary to include the contracts at their proper load point in order to maintain realistic transmission line power flows. This is properly done in load flow studies, but for reliability studies it requires that the load be interrupted when the respective generation is not available. This modelling feature is not available with the large composite system reliability software packages, but it has been done in the in-house programs written for State Enumeration and Monte Carlo methodologies for consideration of the generation system only.

To illustrate the importance of this modelling issue the generation only calculations are being presented both with the contracts netted out from generation and with the contracts included as load.

5.3.5 Interconnection System Support

Table 2.7 shows an estimate of the capacity support to NB Power over the interconnections. Detailed models are now developed for each of the interconnections.

The Nova Scotia Power system is considered in detail to determine the support available to NB Power for the critical month of January. The monthly available hydro energies within the Nova Scotia system are used to peak shave the Nova Scotia in-Province load. This leaves a thermal equivalent load for the Nova Scotia system. A capacity outage table is created for the thermal units on the Nova Scotia system. Any of the capacity states which are greater than the peak of the thermal equivalent load are available to contribute to the NB Power system. When the peak of the thermal equivalent load is subtracted from each state, a new capacity table for supply to the New Brunswick system is created.

The next step is to handle the interconnection transmission flow limit. In the new capacity table for supply to the New Brunswick system referred to above, any capacity state which is greater than the assumed 400 MW interconnection capacity is assigned a capacity value equal to the interconnection capacity limit and all the associated probabilities are added together. This then provides a final capacity availability and probability table for Nova Scotia as a support over the interconnection to New Brunswick. This support for January is assumed constant in all months. This is given as Table 5.1.

Many modelling programs do not have the capability to handle an interconnection equivalent in such detail. To overcome this problem, a further simplification was made by building a two-generator equivalent system which provides a simplified capacity availability in place of the detailed representation of Table 5.1. This two-unit equivalent is given Table 5.2.

Table 5.1
Nova Scotia System Representation

Assisting Capacity (MW)	Probability	Cumulative Probability
400	.16165	.16165
350	.20883	.37048
300	.13649	.50697
250	.14397	.65094
200	.13381	.78475
150	.10651	.89126
100	.06898	.95024
50	.03206	.98230
0	.00770	1.00000

Table 5.2
Nova Scotia Two-Unit Equivalent

Unit	Capacity (MW)	Probability Available
NS #1	150	0.90
NS #2	150	0.90

New Brunswick also has interconnections east to Prince Edward Island, north-west to Quebec and south-west to the New England states of the United States. Table 5.3 shows the two-unit equivalents for the four separate systems involved in these interconnections. These representations are not based on any detailed evaluation of these systems. Rather they are a simple estimate.

Table 5.3
New England, Quebec and Prince Edward Island Representation

	Unit	Capacity (MW)	Probability Available
New England	NE #1	250	0.90
	NE #2	250	0.90
Maine Public Service	MP #1	10	0.90
Hydro Quebec	HQ #1	300	0.95
	HQ #2	100	0.95
Prince Edward Island	PE #1	10	0.90

5.3.6 Interruptible Load

If a load can be interrupted at any time, then this is equivalent on the system to having the same amount of generation available. As a result the interruptible loads are modelled as 100% available generators.

5.3.7 Maintenance

Table 2.5 shows the maintenance schedule for both the hydro generators and the thermal generators. Thermal generator maintenance is modelled in each month as scheduled. When a unit is on maintenance for a portion of a month, it is placed on maintenance for the entire month but at an equivalent derated capacity.

Hydro maintenance is not included because it is scheduled in the low flow months when the limited hydro energy peak shaving makes it redundant.

5.4 Peak Load HL1 Modelling Details

The idea was introduced in Section 5.2 of defining a constrained peak load system such that the results could be obtained and compared in order to establish the equivalency of the fundamental probabilistic processes, but without the encumbrances of any one specific planning objective being structured into the software.

The constrained peak load system HL1 analysis was based on the complete year system modelling details described in Section 5.3, with three additional constraints.

(a) The load at each bus was assumed to exist at the peak level for each of the 8760 hours of the year.

(b) The hydro was prescheduled at a power value corresponding to the available hydro energy for the year. In essence, the hydro units were treated as 100% available thermal units at a capacity of 650 MW.

(c) Maintenance was not considered.

Since most of the international participants utilized a full composite system reliability software package for the HL1 analysis, they also utilized the full composite system data with some minor adjustments to reduce it to HL1 requirements. The loads and generation resources used are summarized in Section 9.1.5. Finally it is perhaps useful to state an additional obvious constraint. An HL1 analysis is achieved in a composite software package by making all transmission components have 100% availability, and setting their transmission capacity limits to very high values. A summary of conditions of the two HL1 cases studied is given in Table 5.4.

Table 5.4
Summary of Generation Only HL1 Cases Studied

System Condition or Variable	Peak Load Analysis (done by International Participants)	Complete Year Analysis (done by NB Power)
Thermal unit forced unavailabilities	Two state deration adjusted	Two state deration adjusted
Load conditions	Peak load for 8760 hours	Monthly Load Duration Curves
Hydro production	Prespecified at constant 650 MW	Actual production determined by monthly peak shaving
Generating unit maintenance	No	Yes
Interruptible load	Yes	Yes
Contract transfers	Firm loads	Modelled both as firm loads and as unit specific loads
Interconnection support	Yes	Yes
Arising from HL1		
Transmission line availability	100%	Not present
Transmission line capacity	System peak load	Not present

6.0 STATE ENUMERATION

For an HL1 evaluation the transmission system is considered 100% available with no flow limitations. Consequently, we will only look at all the states in which the generation can exist, and at all the states in which the load can exist.

6.1 Complete Year HL1 Analysis by NB Power

The HL1 analysis carried out by NB Power was done with a generation only software package which was written in house. The methods employed and results obtained are described in detail.

6.1.1 Capacity Availability Table

Based on the probabilities of unavailability, one can proceed to develop a capacity availability or capacity outage table. In developing a capacity availability or capacity outage table, there are two points to note.

(a) There must be a logical way to identify all possible states, and this is done with the usual recursive relationship.

(b) To prevent the number of states from becoming too large, especially when small units are involved, capacity rounding is used. This is shown to be a valid approach in the technical literature. NB Power chose a capacity increment of 20 MW.

Table 6.1 shows sample results of enumerating all of the states in which the thermal generating units can exist (with parts of the table left out).

Table 6.1
Results of State Enumeration

Capacity Available (MW)	Probability	Cumulative Probability
2920	0.14054	0.14054
2900	0.08017	0.22071
2880	0.04020	0.26091
----	-------	-------
1620	0.00107	-------
1600	0.00104	-------
----	-------	-------
20	0.00000	1.00000
0	0.00000	1.00000

(NOTE: In the computer, probability values are carried out to 10 places after the decimal).

6.1.2 Reliability Indices Used

Four reliability indices are used to express the state of the reliability of the NB Power system.

1. Loss of Load Expectation (LOLE) in Hours for each month, and a total for the year.

2. Expected Energy Not Served (EENS) in GWh

3. Average Megawatts of Dependence (AMD) which is the EENS in MWh divided by the LOLE in Hours.

4. System Minutes which is the EENS in MWh divided by the Peak Load for the Year and then expressing the resultant hours in minutes.

6.1.3 Consideration of Contracts and Interconnection Support

Contract obligations to external systems are as significant to NB Power as the emergency support which the external system can provide. They influence reliability both for a theoretically isolated system evaluation and for an interconnected system evaluation. For evaluation of the NB Power system by itself in an isolated state, there are two possible interpretations:

Case 1: Contract obligations are made by netting out the sales from the proper generators and no interconnection support is considered available. This is the theoretical worst case system.

Case 2: The interconnections are all opened so that no external support is available, but the contracted capacity cannot be delivered so it is available within New Brunswick. This is a case that could potentially happen.

Results are shown in Table 6.2 for the NB Power system under the assumption that it is an isolated system with no interconnection

Table 6.2
Results of Reliability Indices For Isolated
NB Power System

Month	Case 1 LOLE (Hours)	Case 1 EENS (GWh)	Case 2 LOLE (Hours)	Case 2 EENS (GWh)
April	0.2	0.02	0.1	0.01
May	0.3	0.03	0.2	0.02
June	0.6	0.05	0.5	0.05
July	0.8	0.06	0.6	0.05
August	0.2	0.02	0.2	0.02
September	0.1	0.01	0.1	0.01
October	0.2	0.02	0.2	0.02
November	0.5	0.06	0.4	0.04
December	30.2	4.86	2.2	0.33
January	104.2	22.27	10.5	1.91
February	87.8	16.92	9.0	1.41
March	46.1	7.56	3.4	0.54
Total	271.2	51.87	27.4	4.40
AMD in MW =		191		161
System Minutes =		985		84

Table 6.3
Reliability Indices Including Capability
Of All Interconnections

Month	Case 3 LOLE (Hours)	Case 3 EENS (GWh)	Case 4 LOLE (Hours)	Case 4 EENS (GWh)
April	0.00	0.00	0.00	0.00
May	0.00	0.00	0.00	0.00
June	0.00	0.00	0.00	0.00
July	0.00	0.00	0.00	0.00
August	0.00	0.00	0.00	0.00
September	0.00	0.00	0.00	0.00
October	0.00	0.00	0.00	0.00
November	0.00	0.00	0.00	0.00
December	0.02	0.00	0.16	0.02
January	0.23	0.03	0.63	0.15
February	0.25	0.02	0.23	0.11
March	0.04	0.00	0.02	0.03
Total	0.44	0.05	2.23	0.31
AMD in MW =		114		139
System Minutes =		1		6

support. With interconnections the contracts could be considered in two different ways:

Case 3: Contract obligations are made by netting out the sales from the proper generator and interconnection support is included by adding the interconnection equivalent generators to the calculation. This case represents the truest indication of the reliability of the system.

Case 4: Contract obligations are considered by adding firm load to the system load to be met by the combined total of NB Power and interconnection resources. This case is slightly pessimistic because the contract load must be met even when its respective generator is unavailable.

The results of the reliability evaluations for the NB Power system including interconnection support are shown in Table 6.3.

6.1.4 NB Power Complete Year State Enumeration Results

Table 6.4 summarizes the results of all of these cases.

Table 6.4
Comparison of Results

Reliability Index	NB Power Isolated Case 1	NB Power Isolated Case 2	Interconnections Case 3	Interconnections Case 4
LOLE (Hours)	271.2	27.4	0.44	2.23
EENS (GWh)	51.87	4.40	0.05	0.31
AMD (MW)	191	161	114	139
System Minutes	985	84	1	6

As expected the results show that the NB Power system is much more reliable when its large interconnections are included than it is when considered an isolated system. This is generally true for almost all utilities but not usually to the degree illustrated here. Results are also influenced significantly by the method employed to consider NB Power's external contracts. While arguments can be presented to consider each case as a valid measure of the NB Power system, Case 3 provides the truest measure from the NB Power point of view.

6.2 Constrained Peak Load HL1 Analysis by International Participants

As described in Section 5.4., this analysis assumes that the peak load level exists for each of the 8760 hours of the year, hydro is predispatched at 650 MW and no maintenance is considered. Although Case 3 provides the truest reliability measure of the NB Power system, not all international software packages possess the required capability to model the contract sales properly for this case. Therefore the contract obligations and the capacity interconnection benefits for this constrained system analysis are those of Case 4 from the NB Power complete year analysis.

The results of the State Enumeration methodology for the constrained peak load HL1 analysis are given in Table 6.5. For ease of comparison, only LOLE and EENS indices are reported. Note that for the UMIST evaluation RELACS #1 includes up to 7 generators on outage while #2 includes up to 11.

Table 6.5
State Enumeration Results by International Participants

Participant	Program	Reliability Index LOLE (Hours)	Reliability Index EENS (GWh)
USask (Canada)	F&D	--	14.7
	SEGMENTATION	--	16.2
UMIST (UK)	RELACS #1	73	11.0
	RELACS #2	88	15.2
	HL1	86	16.2
PTI (USA)	MAREL	81	13.6
NB Power (Canada)	NB HL1-S	82	14.5

7.0 MONTE CARLO

The Monte Carlo simulation is based on the idea that the decision as to whether a unit is, or is not, operating can in the simulation be determined by a uniform random number generator.

A random number is generated for each element in the simulated system that is subject to random unavailability. Any element whose number falls in its unavailability range is disconnected from the system for that particular simulation. This process is repeated many times to determine the true operation of the system.

7.1 Complete Year HL1 Analysis by NB Power

The HL1 analysis using Monte Carlo was carried out by NB Power similarly to that for State Enumeration. The program was written in house to incorporate the same modelling features as the NB Power State Enumeration program.

The many modelling issues discussed in Chapter 5 apply to both the State Enumeration and Monte Carlo methodologies. To eliminate potential errors in the results because of modelling decisions, the system data and modelling approach for the Monte Carlo simulations were made identical to that used for the State Enumeration analysis.

The same hydro generation schedules determined by the peak shaving process in the State Enumeration were applied to the load duration curves. This schedule was assumed 100% available and after dispatch produced a remaining load curve which had to be supplied by the thermal system. The Monte Carlo calculations were applied to this same thermal equivalent system as were the State Enumeration calculations.

The load time interval for Monte Carlo simulation was set equal to the load step size (50 intervals per month) used to define the load duration curves. The same monthly maintenance schedule was applied, which uses the deration principle for capacity on maintenance for only part of a month.

By modelling the system as described, only the probabilistic calculation methodologies applied to the unavailabilities of thermal generators were different. For such a calculation, theoretically the Monte Carlo results should be identical to the State Enumeration results.

The impact of interconnection modelling on the reliability of the NB Power system is clearly illustrated in Chapter 6. This analysis was repeated for the Monte Carlo methodology with similar results as given in Table 7.1.

Table 7.1
Monte Carlo Evaluations by NB Power

	Case 1		Case 2		Case 3		Case 4	
	LOLE (HOURS)	EENS (GWH)	LOLE (HOURS)	EENS (GWH)	LOLE (HOURS)	EENS (GWH)	LOLE (HOURS)	EENS (GWH)
April	0.2	0.03	0.2	0.03	0.0	0.00	0.0	.00
May	0.2	0.03	0.2	0.02	0.0	0.00	0.0	.00
June	0.5	0.06	0.5	0.05	0.0	0.00	0.0	.00
July	0.7	0.05	0.5	0.04	0.0	0.00	0.0	.00
August	0.1	0.02	0.1	0.02	0.0	0.00	0.0	.00
September	0.1	0.01	0.1	0.01	0.0	0.00	0.0	.00
October	0.1	0.01	0.1	0.01	0.0	0.00	0.0	.00
November	0.4	0.06	0.4	0.04	0.0	0.00	0.0	.00
December	30.5	4.97	2.4	0.34	.01	0.00	0.2	.02
January	103.8	22.16	11.3	1.98	.31	0.04	1.0	0.18
February	91.4	18.51	8.7	1.47	.17	0.02	0.8	.12
March	45.0	7.57	3.9	0.54	.03	0.01	0.3	.03
Total	273.2	53.49	28.5	4.55	0.53	0.07	2.3	0.35

7.2 Constrained Peak Load HL1 Analysis by International Participants

The NB Power system conditions used are the same as those for the State Enumeration methodology as described in Section 6.2. The results of the constrained peak load evaluation are shown in Table 7.2.

Table 7.2
Monte Carlo Results by Participants

Participant	Program	Reliability Index LOLE (Hours)	EENS (GWh)
ENEL (Italy)	SICRET	92	15.5
EDP(Portugal)	ZANZIBAR	--	15.5
UMIST (UK)	COMPASS	93	15.7
NGC (UK)	ESCORT	--	13.1
EDF(France)	MEXICO	95	15.2
USsask (Canada)	MECORE	85	14.7
NB Power (Canada)	NB HL1-M	86	14.5

7.3 Simulation Parameters

In conducting a Monte Carlo evaluation, there are two parameters which can influence the results of the calculation:

(a) Random number generator seed value
(b) Number of simulations conducted

To illustrate this variation, the constrained peak load HL1 evaluation was carried out using the three different seed values of 1,5 and 21 applied for 1000, 3000 and 10,000 simulations. The results are shown in Table 7.3.

Table 7.3
Results for Different Simulation Parameters

(a) LOLE in hours

Number of Simulations	Seed Value 1	5	21	Average
1000	35	79	79	64
3000	61	94	90	81
10000	78	96	83	86

(b) EENS in GWh

Number of Simulations	Seed Value 1	5	21	Average
1000	8.8	14.7	17.5	13.0
3000	9.6	17.8	18.7	15.4
10000	12.6	16.9	14.1	14.5

The results are in agreement with the classical theory for random variable simulations upon which the Monte Carlo approach is based. Results vary for different seed values and the amount of variance decreases as the number of simulations increases.

8.0 DISCUSSION AND COMPARISON OF PROBABILISTIC GENERATION RESULTS

Similar indices are available from both the state enumeration and Monte Carlo methods. The indices chosen for this general comparison of analyses are LOLE in hours and EENS in GWh.

Probabilistic evaluation of generation only or HL1 reliability was conducted from two approaches. NB Power did detailed complete year reliability evaluations for four different considerations of interconnection support and contract obligations. This was followed by a constrained peak load HL1 evaluation case carried out by all participating parties for only the Case 4 interconnection model.

8.1 Comparison of Probabilistic Generation Results

Summary results of the NB Power detailed evaluation are given in Table 8.1 for both Monte Carlo and State Enumeration methodologies.

Table 8.1
Summary of NB Power Complete Year HL1 Results

Method: Reliability Index	NB Power Case 1	Isolated Case 2	With Interconnections Case 3	Case 4
State Enumeration:				
LOLE (Hours)	271.2	27.4	0.44	2.23
EENS (GWh)	51.9	4.4	0.05	0.31
Monte Carlo:				
LOLE (Hours)	273.2	28.5	0.53	2.30
EENS (GWh)	53.5	4.5	0.07	0.35

The results from each of the two methods compare extremely well. This suggests that the final reliability result is not influenced by the probabilistic calculation method. However, the widely varying results that occur by changing the interconnection modelling indicates that this is not true for different modelling approaches.

This raises concern for the composite system reliability evaluation because many different modelling approaches exist in the various international software packages. To assist in isolating potential differences a peak load HL1 evaluation with data constraints was conducted. Results given in Table 8.2 show excellent agreement by all participants at this level of evaluation.

8.2 Discussion of Results by Methodology

These results for the generation only case have been obtained by running the NB Power data on the full software packages of the participants which employ either State Enumeration or Monte Carlo methods.

Table 8.2
Peak Load HL1 Evaluation (Case 4)

Participant	Program	Reliability Index: LOLE (Hours)	EENS (GWh)
State Enumeration:			
USask (Canada)	F & D	--	14.7
	SEGMENTATION	--	16.2
UMIST (UK)	RELACS #1	73	11.0*
	RELACS #2	88	15.2**
	HL1	86	16.2
PTI (USA)	MAREL	81	13.6
NB Power (Canada)	NB HL1-S	82	14.5
Monte Carlo:			
ENEL (Italy)	SICRET	92	15.5
EDP (Portugal)	ZANZIBAR	--	15.5
UMIST (UK)	COMPASS	93	15.7
NGC (UK)	ESCORT	--	13.1
EDF (France)	MEXICO	95	15.2
USask (Canada)	MECORE	85	14.7
NB Power (Canada)	NB HL1-M	86	14.5

* Going 7 states down in contingency selection
** Going 11 states down in contingency selection

The State Enumeration method exhaustively lists each possible state of available generators and available transmission lines, and calculates the probability of having each state. The Monte Carlo method lists the states of the power system based on a process which is weighted or controlled by the availability statistics of the generators and transmission lines. Consequently in theory both methodologies should give the same reliability results.

The results of Table 8.2 conclusively prove this theoretical expectation. The results are independent of methodology. Aside from modelling differences, there are only two factors which can make the results of the State Enumeration method and the Monte Carlo method differ. These are:

(a) A failure to go far enough down in selecting possible outage states in the State Enumeration method. This means that some states, which can significantly affect the reliability indices, may get left out.

(b) A failure to use a large enough sample size in the Monte Carlo method. This can result in a standard deviation in the reliability indices which is too large.

SECTION D - PROBABILISTIC METHODS FOR COMPOSITE SYSTEM RELIABILITY

The addition of the transmission system to the generation system is of much significance. A number of international software packages have been made available for composite system reliability evaluation.

9.0 INPUT DATA AND MODELLING ISSUES FOR COMPOSITE RELIABILITY STUDIES

We are going to discuss composite input data and modelling issues from three points of view:

(i) Detailed Complete Year specifics of the NB Power system
(ii) Simplifications for the constrained Peak Load evaluation
(iii) Data Preparation for the various software packages

9.1 Complete Year HL2 Modelling Details

Great effort has been expended so that NB Power system map, the peak load flow analysis and the composite system data set are consistent. But because of the nature of the composite problem, more detailed explanation of modelling issues behind the data is required and is addressed in this section. In following this discussion, reference on the part of the reader is necessary to the system one line diagram in Figure 2.4, the load flow in Appendix III and the Generic System Data set in Appendix I.

9.1.1 Network Configuration

1. Load flow inconsistencies:

   In the load flow, all generators are connected to a unit node and then through the unit transformer to the high voltage terminal. In the system data set, the generators are connected directly to the terminal and the unit transformer is not included.

2. Caraquet-Tracadie area and 69 kV system:

   System Operations procedures allow for immediate start up and dispatch of the Tracadie (St. Rose) gas turbine which can supply the area load. Taking this into account, the most appropriate 138 kV equivalent for the area is to join the Caraquet (1677) and Tracadie (1963) nodes together at Caraquet and ignore the 69 kV system. All load in the area and the Tracadie (St. Rose) generator is placed at node 1677 and node 1963 disappears.

3. Iroquois Terminal and 69 kV System:

   All load and losses in the northwest 69 kV system are brought back to the two Iroquois 138 kV nodes (1910) and (1909). This includes the load netted out by generation from Grand Falls (69 kV Station) and Tobique. To correct this, an equivalent generator for Grand Falls and Tobique (GF.TOB.6) is placed at node 1910.

4. Lancaster - Courtenay Bay 69 kV:

   The 69 kV has been deleted with all loads and generation moved to 138 kV nodes at Lancaster (1679) and Courtenay Bay (1813).

5. Marysville - Grand Lake 69 kV:

   The 69 kV has been deleted with all flows to 69 kV considered as loads.

9.1.2 Interconnection Equivalents:

6. External Sales:

   The 230 MW Point Lepreau participation sale to New England and the 60 MW of sales to Prince Edward Island are modelled as base loads at node numbers 700 and 1844. This approach is consistent with the Case 4 sales models described in detail in section 6.1.4 which were employed for both the General and Constrained HL1 evaluations.

   The 400 MW peaking sale to Hydro Quebec is modelled as a shaped load (type 4) split between the two Hydro Quebec interconnection points at node numbers 1869 and 9996. The HVDC stations are ignored.

   Transmission lines linking these loads to the NB Power main system are assumed available at 100%, so that unserved energy associated with interconnection outages are not included with NB Power EENS.

7. External Generation Support:

The ability of external systems to provide emergency support to NB Power is modelled by means of equivalent generators at the interconnection. The availabilities of these generators have been selected to approximate a multi-state capacity availability table determined by either detailed analysis or approximation of the total system behind the interconnection. The models employed are consistent with those used for HL1 evaluations presented earlier in section 5.3.5.

8. Nova Scotia Transmission System:

The Nova Scotia Transmission system is modelled in detail back to the ONSLOW 345 kV bus (168). Fixed loads are placed on nodes 157, 158, 167, and 183 which are offset by a 100% available generator at 168. These loads maintain flows on the Nova Scotia lines which are assumed available at 100%. This will limit the support available over the 138 kV circuits to their transmission limits.

9. US Equivalent at Tinker:

Line 1126 (14 km) shown on the system diagram connects to Tinker (1986) through the Maine Public Service system. For the reliability equivalent its effective length has been lengthened to 44 km.

9.1.3 Load Modelling Issues

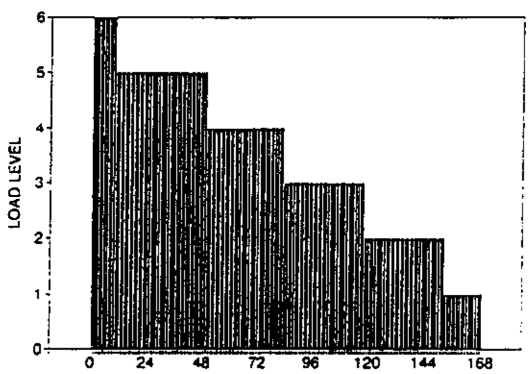
10. Space/time Load Allocations:

A major problem with composite modelling is the allocation of load throughout the network to the proper node where it is located and still account for the time distribution of each load throughout the year. To this end three models were developed to provide some flexibility to TF 38.03.10 participants for the inputting of load data to their computer models.

Load Model I is a detailed model based on weekly load duration curves, allowing one of four possible different load types to be used at any node. Each of the four load types is defined by twelve separate weekly distributions. The general weekly load duration shape used to develop each distribution is shown in Figure 9.1. While all weekly distributions employ this same generic shape, unique load models were generated by changing the value of load levels for each week for each load type. As well a month is assumed to consist of an integer number of weeks, essentially making the twelve weekly load duration curves become monthly load duration curves.

Load Model II is a simplified seasonal load model set to only five different variable load levels for the entire year.

LOAD DURATION MODEL



CHRONOLOGICAL LOAD MODEL

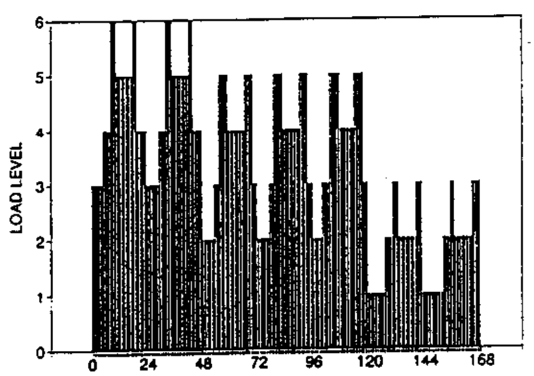


Figure 9.1
Load Duration and Chronological Load Models

In this model, only base load (100% Load factor) and peak load at each node are defined. The difference between these values is the variable portion of the load which follows the five level load distribution.

Load Model III is an extension of Load Model I. It provides a general weekly sequential load shape which is consistent with the general load duration shape of Load Model I. The sequential shape is given in Figure 9.1. Application of this general shape to the six load levels for each month of each load type will translate each load duration distribution to a sequential distribution. This actual translation was left to individual participants to perform.

If none of these load models fit a particular composite computer package it was necessary that the participant adjust a model as required. Generally most participants used Load Model I or II but model III was available for sequential analysis if desired.

11. Lepreau Station Service:

The Point Lepreau nuclear station is rated at 635 MW net, but has a station service load of 22 MW when shutdown. To model this the unit MW rating is set at 657 MW with a fixed 100% available load of 22 MW at the Lepreau (1843) node.

12. Interruptible Loads:

NB Power has 52 MW of load that is interruptible. Most of this is to large industrial customers and is constant all year.

To model this situation, the interruptible load has been included as firm load which will be netted out by an equivalent 100% available generator to simulate the interruption. The interruptible generators are assigned costs so they will be dispatched after all regular NB Power generation but before interconnection generators.

These interruptible load generators are specified at the following nodes:

Bus	Name	MW
1813	INTLOAD1	10
1847	INTLOAD2	12
1910	INTLOAD3	15
1948	INTLOAD4	15

13. Transmission Losses:

Generation only (HLI) reliability evaluation is done with the losses included in the loads which is forecast for the test system to be 3156 MW. Composite modelling requires that the losses be calculated from the load flow associated with a particular evaluation state. For composite models which do not calculate losses, they must be included in some equivalent manner so that results will be on a comparable basis. This problem was left for individual participants to solve as they best know their own software package.

9.1.4 Common Mode, Hydro and Weather Models

14. Common Mode Failures (Tapped Loads):

NB Power has many 138 kV lines which are tapped to 69 kV radial supplies but without breakers and primary protection on each side of the tap. When any portion of the line is faulted the entire line is cleared and the radial 69 kV load from the tap is interrupted.

In the load flow these tap points are considered as a node with a load. For reliability it is necessary that unavailability of one portion of the line to the tap also result in unavailability of the other portion of the line as well. That is, the conditional probability of a common mode fault is 100% given that any fault occurs.

A list of the common mode pairs of lines is given in the data set along with the probability of the common outage.

15. Hydro Generating Plant Models:

The hydro generators on the NB Power system all have some, but limited, storage. This fact is expressed in two ways.

(i) Each plant has a capacity factor less than one (usually significantly less than one).

(ii) We say that the plant and generators are energy limited.

Hydro generators therefore become a special problem in composite system reliability evaluation. The usual way in which they have been handled is as follows:

(i) The total system load has been established.

(ii) The hydro generators have been assumed to have a zero forced outage rate.

(iii) The hydro capacity has been dispatched to utilize the limited hydro energies to shave off the peak part of the system load.

Two hydro models are supplied and participants may be able to utilize either directly or make adjustments as appropriate.

Model I, which is consistent with Load Model I, is a detailed schedule for each month which simulates peak shaving of the total system load by the hydro plants. The area under each plant schedule is equal to the monthly average hydro energy available.

Model II does not attempt to preschedule the hydro. It simply provides the total energy available for each plant and the percentage allocation of this total to each season. This data can be used to model the hydro plants as energy limited thermal units. If a participant's composite computer model does not have this energy limited capability it may be necessary to determine by trial and error a thermal equivalent cost which will dispatch the hydro correctly. To assist in this matter seasonal dispatch costs were provided for a reasonable hydro dispatch.

16. Adverse/Normal Weather Affects:

The FOR data supplied for each transmission line is the annual average forced outage rate. As such, it does not include the concentration of outages in the relatively short duration of adverse weather in which most transmission outages occur. Additional data is supplied which can be used to model this effect. It was hoped that participants would do calculations with and without weather modelling to try to quantify its impact.

9.1.5 Modelling Summary

As a result of the above modelling decisions, the final system to be evaluated is summarized under peak load conditions as follows. All values are MW.

System Loads:	
NB Power forecast load (Table 2.1)	3156
Less system transmission losses	(82)
Plus Lepreau station service load	22
NB Power total connected load	3096
NS load to model transmission limits	119
Interconnection contract loads	690
Total connected load	3905
Transmission losses	82
Total load seen by generation	3987 MW

Generation Resources:	
NB Power thermal generation (Table 2.4)	3450 MW
Lepreau station service adjustment	22
Thermal generation subtotal	3472
NB Power hydro generation (Table 2.2)	870
Less energy limited deration on peak	220
Scheduled hydro generation	650
Interruptible load generators	52
NS generation for transmission limit	119
Interconnection support generators	1220
Total generation resources	5513 MW

9.2 Constrained Peak Load Modelling Details for HL2

As with the HL1 evaluations, a peak load analysis for composite system reliability (HL2) was also conducted. Data constraints were applied to simplify the general case HL2 data described in detail in section 9.1.

The data constraints employed were identical to those used for the peak load HL1 analysis plus some additional ones concerning the transmission system. For completeness all of these constraints are reported below:

(a) The load at each bus was assumed to exist at the peak level for each of the 8760 hours of the year.

(b) The hydro was prescheduled at a power value corresponding to the available hydro energy for the year. In essence, the hydro units were treated as 100% available thermal units at a capacity of 650 MW. Individual capacities are Mactaquac 500 MW, Beechwood 80 MW, Grand Falls #1 30 MW and the combined Grand Falls/Tobique at 40 MW.

(c) Maintenance was not considered.

(d) Common mode modelling of transmission outages was not considered.

(e) Weather related transmission outage modelling was not considered.

9.3 Data Preparation

In the initial stages of this project, data was prepared according to specific formats for four programs - the SICRET program of ENEL (Italy), the ZANZIBAR program of EDP (Portugal), the ESCORT program of NGC (United Kingdom) and the COMREL program of the University of Saskatchewan (Canada). Subsequent to this the number of participants grew and a set of Generic Data was provided, which in overall structure quite closely resembled the SICRET form. Some data changes were required in November 1990, and these data changes were made to the Generic Data set only. In this way, the Generic Data set came to be used by all participants.

Clearly to satisfy the data input requirements for the software packages of all participants, the Generic Data set had to include equivalent data in different forms. It is useful to look at two of these circumstances.

(a) Concerning line availabilities, one program requires line unavailability per 100 kilometers, another asks for the unavailability rate, while another asks for the failure rate of the line in failures/year together with the repair duration of the line in years/repair.

(b) Concerning line electrical modelling, one program requires the series impedance in ohms per kilometer together with the line length in kilometers, while other programs ask for the series impedance in per unit on the chosen system MVA base. Relative to this data item, it should be noted that the Generic Data set provided may have introduced some minor discrepancies. The fundamental data set which NB Power has in its data base is series resistance and reactance in per unit, as required for load flow and stability studies. An exact conversion of this data to series impedance in ohms per kilometer was not done for all lines, but rather typical impedance values in ohms per kilometer were provided for each of the lines according to the three voltage levels. This should not have introduced any appreciable error.

9.4 Generation Dispatch and Load Curtailment Philosophy

As part of the system data, NB Power provided the fuel cost functions for each of the thermal generators. Available generation is generally dispatched on a cost basis, although it is possible to dispatch the generation on a cost and reliability basis. In addition, there are a variety of load curtailment philosophies including curtailment at a major bus, curtailment in the area of overloaded transmission lines, and curtailment by an equal percentage at every bus of the system. For details of the generation dispatch approach and of the load curtailment philosophy for each of the international participants, reference should be made to Appendices IV-X where the international participants have outlined their software packages.

10.0 COMPOSITE SYSTEM RELIABILITY RESULTS

There is a wealth of information available from the composite system reliability results.

The first set of indices might be called System Indices. One example is the very familiar Expected Energy Not Served (EENS in GWh). Now however, the EENS can be assigned partly to generation and partly to transmission. Further the transmission component can be broken up into reasons such as line capability exceeded, partial system separation, and node isolation. Another example is the specification of the most frequently overloaded transmission lines, thus indicating potential weaknesses in the transmission system.

The second set of indices might be called Load Point Indices. One example is the frequency of load interruptions at one or more buses. Another example is the frequency of occurrence of low voltages at selected buses.

Finally it should be kept in mind that, since each of the international software packages were written for specific system planning purposes, the results which are output may not be in exactly, or even nearly, comparable form.

10.1 Brief Summary of HL2 Cases

The composite system reliability evaluation packages were run for four different sets of NB Power system data.

1. Base System Peak Load HL2 Case

The Base System peak load HL2 case represents the operating NB Power system as explained in detail in Section 9.1, but with the modelling constraints as described in Section 9.2 and summarized in Table 10.1.

It should be remembered that the constraints are present, not because they are necessary for system operation but, because they allow comparisons of results by different methodologies unencumbered by software differences.

2. Improved System Peak Load HL2 Case

As stated in Section 2.7 the NB Power system includes a phase shifting transformer in the south central part of the province to control active power flow in the Coleson Cove-Courtenay Bay - Norton area. This transformer was removed from the Base System to provide a transmission weakness that could be detected by the reliability analysis. It was originally intended that it be returned to the system for this improved case.

In the early stages of the work it became clear that few of the reliability software packages had the capability to model phase shifting transformers as such. Despite the best efforts of the Task Force, it was not possible to come up with an equivalent generator - load representation. Consequently an attempt was made to duplicate most of the effects of the phase shifting transformer by the addition of two transmission lines to the system and the upgrading of a transformer and a short transmission line. This improved transmission system is illustrated in detail in Figure 10.1.

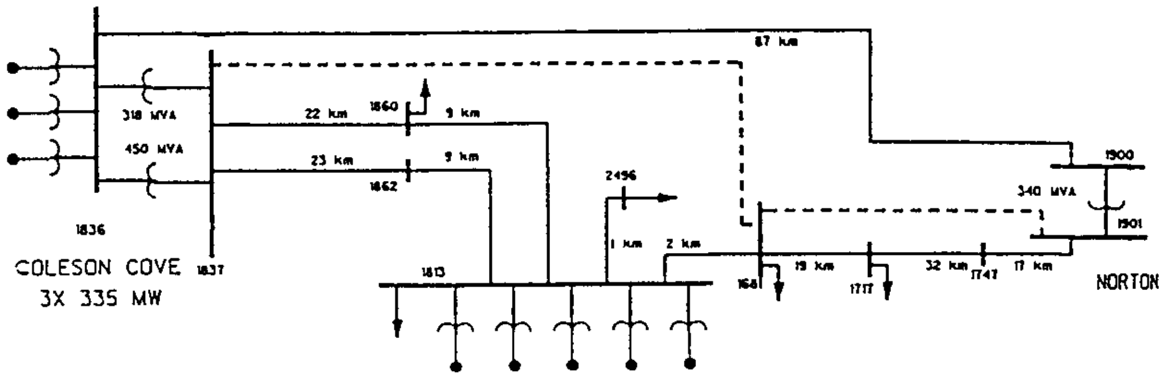


Figure 10.1
Transmission Improvements in the Coleson Cove - Courtenay Bay - Norton Area

As before the constraints on the data are those given in Section 9.2, and summarized in Table 10.1.

3. Base System Complete Year HL2 Case

This is the Base System in the normal operating mode, but without the constraints of Section 9.2. It includes all of the general modelling details of Section 9.1 to provide the most reasonable representation of the base NB Power study system possible over the complete year. Also each international software package is free to employ its full modelling capability to best analyze this case. The conditions for this case are summarized in Table 10.1.

Table 10.1

Summary of Composite System HL2 Case Studies

System Condition or Variable	Base Peak Load Analysis	Base Complete Year Analysis	Improved Peak Load Analysis	Improved Complete Year Analysis
Transmission State	Base	Base	Improved	Improved
Transmission line maintenance	None	None	None	None
Load conditions	Peak load for 8760 hours	Annual load variation	Peak Load for 8760 hours	Actual weekly load diagrams diagrams
Common mode failure	No	Yes	No	Yes
Generating unit maintenance	No	Yes	No	Yes
Weather Conditions	Same all year	Vary	Same all year	Vary
Hydro production variation	Prespecified at 650 MW	Average GWh monthly peak-shave	Prespecified at 650 MW	Average load
Interruptible load	Yes	Yes	Yes	Yes
Contract transfers	Firm load	Firm load	Firm load	Firm load
Interconnection support	Yes	Yes	Yes	Yes

4. Improved System Complete Year HL2 Case

With the two line transmission improvement in place of the existing phase shifting transfomer, and without the data constraints, this case is very close to the actual operating condition of the NB Power System. It utilizes all of the data supplied in Appendix I (including transmission upgrade) and employs the full modelling capability of each international software package. The conditions for this case are summarized in Table 10.1.

10.2 Composite System Reliability Indices

The state of a power system is one combination of loads, available generators, and available transmission lines. If the loads are assumed known at deterministic values for any time frame, then the state of the power system is any one combination of available generators and available transmission lines.

The State Enumeration method simply exhaustively lists, or enumerates, each possible combination or state of available generators and available transmission lines, and calculates the probability of having each combination. On the other hand, the Monte Carlo method comes up with the combinations or states of available generators and available transmission lines by a process which is weighted or controlled by the statistics of their availability.

Which ever method is used, the states of a power system are produced one at a time. For any state of a power system, there are three major studies which can be carried out on it. These are the load flow, transient stability runs and mode analysis studies.

Simply put, and it can be simply put, reliability indices are any information open to the imagination perceived as being available from load flow, stability and mode analysis studies.

10.2.1 Overview of Indices

With reference to Section 1.3 on reliability concepts, it is possible to structure indices according to three groups.

(a) Adequacy Indices

Indices available from load flow studies done on each of the states of the power system. At this point in time, these are the only indices which are regularly computed.

(b) Security Constrained Adequacy Indices

Indices available from load flow studies done when any component may be lost from an adequacy evaluated state.

(c) Security Indices

Indices available from transient stability studies during the loss of a component when in an adequacy evaluated state. While not yet available, these are best obtained from direct stability analysis methods based on energy functions.

10.2.2 Adequacy Indices Based on the Load Flow

Before proceeding to summarize these indices it is useful to point out that the formulation of indices is still in a continual state of development and it is useful to give a contemporary example of this fact. Chapter 2 of the Application Guide is on the subject of Reliability Indices and it gives a comprehensive overview, along with detailed definitions, of a large number of indices. However four of the international participants of the Task Force provided an index which was not in the Application Guide. This is the Marginal EENS Gain for Overloaded Lines in MWh per MW.

The following two indices may be considered as fundamental ones.

1. Loss of Load Expectation (LOLE), which is most easily illustrated in the Monte Carlo method, is simply the number of hours in which the load is not able to be served during a month or during a year.

2. Expected Energy Not Served (EENS), again most easily illustrated in the Monte Carlo method, is the summation over all the instances in which it happens of unserved load multiplied by the length of time that it is unserved.

The next two indices can be derived from the two above.

3. Average Megawatts of Dependence (AMD) is the Expected Energy Not Served in MWh

divided by the LOLE in hours.

4. System Minutes (SM) is the Expected Energy Not Served in MWh divided by the Peak Load for the year, with the resultant hour value converted to minutes.

Many additional indices have been defined, most of which are set out in Reliability Evaluation of Power Systems by Billinton and Allan. These can best be described when classified into groups.

A paper also being presented at the CIGRE Montreal Symposium, entitled "Composite Reliability Assessment Studies in the Greek Interconnected Power System" and written by authors at the National Technical University at Athens, classifies indices into two sets, with each set then subdivided into three types.

(A) Load Point Indices

(a) Basic Indices.

5. Probability of failure
6. Expected frequency of failure in occurrences per year.
7. Expected frequency of voltage violations in occurrences per year.
8. Expected frequency of load curtailments in occurrences per year.
9. Expected load curtailed in MW.
10. Expected duration of load curtailment in hours.
11. Expected energy not supplied in MWh.

(b) Maximum Indices

12. Maximum load curtailed in MW per curtailment.
13. Maximum energy not supplied in MWh.
14. Maximum duration of load curtailment in hours.

(c) Average Indices

15. Average load curtailed in MW per curtailment.
16. Average energy not supplied in MWh.
17. Average duration of load curtailment in hours.

(B) System Indices

(a) Basic Indices

18. Bulk power interruption index in MW per MW-year.
19. Bulk power supply average curtailment in MW per disturbances.
20. Bulk power energy curtailment index in MW-minutes per MW-year.
21. Modified bulk power curtailment index.
22. System minutes in MWh per MW-yr converted to minutes.

(b) Maximum indices

23. Maximum system load curtailed in MW.
24. Maximum system energy not supplied in MWh.

(c) Average indices

25. Average number of curtailments per load point.
26. Average load curtailed per load point in MW.
27. Average energy curtailed per load point in MWh.
28. Average duration of load curtailed per load point in hours.
29. Average number of voltage violations per load point.

In the preparation of results for this Task Force, Billinton prepared a list of indices some of which are included above. Those not included are:

(B) System Indices

30. Expected number of load curtailments in events per year.
31. Expected duration of load curtailments in hours per year.

Finally as already indicated, four of the international participants of the Task Force calculated an additional index.

32. Marginal EENS gain for overloaded lines in MWh per MW.

10.3 System Wide Reliability Measures

Indices used to indicate the reliability of the system as a whole are EENS and LOLE. The contributions from the generation and the network are provided as well as the system total in Table 10.2 for EENS, and in Table 10.3 for LOLE. Results for all HL2 study cases are given.

For the peak load analysis the generation components of outage are nearly identical. This is consistent with the HL1 results discussed in Section 8. There is greater variation in the network component of outage but the results clearly show the reliability improvement gained through the transmission reinforcement.

As expected there is greater variation in the results of the complete year analysis because of the varied modelling approaches taken. For example the network component for MEXICO is higher than others most likely because it utilizes a security constrained dispatch algorithm, while the COMPASS results are lower most likely because of its sequential load model. TPLAN network results are given in the PTI report but are not shown here because they are not available on a comparable basis to the other models. Regardless of these types of variations, all the models show the relative impact of the transmission reinforcement.

Table 10.2
HL2 Analysis EENS Results
(GWh)

Peak Load Analysis

		Base System			Improved System		
Participant	Program	Generation	Network	HL2	Generation	Network	HL2
ENEL (Italy)	SICRET #1	20.9	73.0	93.9*	20.9	2.7	23.6*
	SICRET #2	15.5	56.9	72.4	15.5	2.2	17.7
EDP (Portugal)	ZANZIBAR	15.1	35.7	50.8	14.6	2.8	17.4
EDF (France)	MEXICO	15.2	53.9	69.1	15.2	1.3	16.6
UMIST (UK)	COMPASS	15.7	59.6	75.3	15.7	1.1	16.8
	RELACS	--	--	38.1	--	--	--
NGC (UK)	ESCORT	13.1	80.3	93.4	13.0	2.4	15.4
PTI (USA)	MAREL/TPLAN	13.6	--	--	13.6	--	--
USask (Canada)	MECORE	14.7	38.3	52.9	14.7	1.7	16.4
	COMREL	--	--	46.7	--	--	20.6
NB Power (Canada)	NB HL1	14.5	--	--	14.5	--	--

Complete Year Analysis

		Base System			Improved System		
Participant	Program	Generation	Network	HL2	Generation	Network	HL2
ENEL (Italy)	SICRET #1	0.41	4.1	4.5*	0.41	1.6	2.0*
	SICRET #2	0.28	3.2	3.5	0.28	1.6	1.9
EDP (Portugal)	ZANZIBAR	1.50	3.9	5.4	1.50	0.6	2.1
EDF (France)	MEXICO	0.80	5.3	6.1	0.80	2.3	3.1
UMIST (UK)	COMPASS	0.12	0.7	0.8	0.12	0.05	0.17
NGC (UK)	ESCORT	0.11	0.2	0.3**	0.11	0.2	0.3**
PTI (USA)	MAREL/TPLAN						
USask (Canada)	MECORE	0.20	0.9	1.1	0.20	0.3	0.5
NB Power (Canada)	NB HL1	0.31	--	--	0.31	--	--

* SICRET #1 includes 52 MW Interruptible Load as firm load
** Based on insufficient simulations for convergence

Table 10.3
HL2 Analysis LOLE Results
(hours/year)

Peak Load Analysis

Participant	Program	Base System Generation	Base System Network	Base System HL2	Improved System Generation	Improved System Network	Improved System HL2
ENEL (Italy)	SICRET #1	114	1790	--	114	96	--
	SICRET #2	92	1750	--	92	79	--
EDP (Portugal)	ZANZIBAR						
EDF (France)	MEXICO	95	1762	1842	95	43	128
UMIST (UK)	COMPASS	93	2000	2048	93	193	253
NGC (UK)	ESCORT						
PTI (USA)	TPLAN						
USask (Canada)	MECORE	85	--	1565	85	--	110
NB Power (Canada)	NB HL1	82	--	--	82	--	--

Complete Year Analysis

Participant	Program	Base System Generation	Base System Network	Base System HL2	Improved System Generation	Improved System Network	Improved System HL2
ENEL (Italy)	SICRET #1	2.8	135		2.8	41	
	SICRET #2	2.1	105		2.8	41	
EDP (Portugal)	ZANZIBAR						
EDF (France)	MEXICO	--	1.6	--	--	0.6	--
UMIST (UK)	COMPASS	0.8	56	57	0.8	5.8	6.5
NGC (UK)	ESCORT						
PTI (USA)	TPLAN						
USask (Canada)	MECORE	1.3	--	35	1.3	--	11.0
NB Power (Canada)	NB HL1	2.2	--	--	2.2	--	--

10.4 Overloaded Transmission Lines

Many of the composite software packages identify the most severely overloaded transmission lines or transformers by various measures. Some determine the frequency of overloads and/or the average amount of overload. Others use this data to determine the reduction in overload that could be gained by a 1 MW increase in the capability of the transmission line. While this is often expressed in different forms in different programs, a common index is delta EENS reduction per delta MW capacity. Where possible the results of all programs have been translated to this index for comparison purposes as given in Table 10.4 for the two most commonly overloaded lines. In addition this index or an alternate is used to rank the transmission lines in decreasing order of overload.

Results show that all models identify the transmission line from C.COVE-1837 to MILD47-1860 as being the most critically overloaded before the transmission reinforcement. All models also show a significant improvement in this line loading after the transmission reinforcement.

Table 10.4
Marginal EENS Gain and Ranking For Overloaded Lines
MWh / MW (Rank)

From:	C.Cove-1837	NEWCA1-18007
To:	MILD47-1860	MILBK1-1969

Peak Load Analysis

Participant	Program	Base System	Improved System	Base System	Improved System
ENEL (Italy)	SICRET #1	2919 ( )	78 ( )	760 ( )	179 ( )
	SICRET #2	2850 ( )	55 ( )	419 ( )	28 ( )
EDP (Portugal)	ZANZIBAR	8760 (1)	109 (2)	190 (3)	27 (5)
EDF (France)	MEXICO	3234 (1)	30 (1)	60 (2)	13(2)
UMIST (UK)	COMPASS	--	--	--	--
NGC (UK)	ESCORT	3483 (1)	144 (2)	159 (2)	159 (1)
PTI (USA)	TPLAN	(1)	(2)		
USASK (Canada)	MECORE	--	--	--	--
	COMREL	--	--	--	--

Complete Year Analysis

Participant	Program	Base System	Improved System	Base System	Improved System
ENEL (Italy)	SICRET #1	155 ( )	0.4 (2)	15 (3)	0.4 (1)
	SICRET #2	106 ( )	0.3 ( )	11 ( )	0.7 ( )
EDP (Portugal)	ZANZIBAR	2059 (1)	0.0 (5)	17 (3)	1.0 (4)
EDF (France)	MEXICO	184 (1)	3.7 (2)	2.6 (5)	0.6 (3)
UMIST (UK)	COMPASS	--	--	--	--
NGC (UK)	ESCORT				
PTI (USA)	TPLAN				
USASK (Canada)	MECORE	--	--	--	--
	COMREL	--	--	--	--

10.5 Load Point Indices

There are different indices that measure the reliability of a specific load point including frequency of curtailment, MWH of curtailment and frequency of low voltage. It is impossible to report all results in all indices.

The capability of the composite software packages to identify the weak delivery points in the network is illustrated using only one index in Table 10.5. The MWh of curtailment is given for MILD47-1860 and C.BAY1-1813 which are the load points that are most improved by the additional transmission. This illustrates the general ability of the software packages to quantify specific load point improvements.

It must be noted that load point curtailment is an area that is greatly influenced by the load curtailment philosophy built into the model. In all systems, this is dependent on operator interaction and so becomes very difficult to model in a generic sense. Results show reasonable agreement between the models for the base system which has a clear transmission deficiency, but after transmission reinforcement where there is no clear weakness the results are much more varied.

Table 10.5
Load Point Energy of Curtailment and Ranking
GWh (Rank)

Peak Load Analysis

Participant	Program	MILD47-1860 Base System	MILD47-1860 Improved System	C.BAY1-1813 Base System	C.BAY1-1813 Improved System
ENEL (Italy)	SICRET #1	41.3 (1)	.6 (14)	11.6 (3)	1.5 (5)
	SICRET #2	--	--	--	--
EDP (Portugal)	ZANZIBAR	23 (1)	.1 (17)	9.5 (2)	1.3 (3)
EDF (France)	MEXICO	40 (1)	1.4 (1)	16.6 (2)	0.0 (-)
UMIST (UK)	COMPASS	30.7 (1)	.16(32)	27.2 (2)	1.0 (3)
NGC (UK)	ESCORT	--	--	--	--
PTI (USA)	TPLAN	--	--	--	--
USask (Canada)	MECORE	7.3 (3)	.22(21)	16.2 (1)	.40(20)
	COMREL	25.4 (1)	.03(15)	19.7 (2)	.10(7)

Complete Year Analysis

Participant	Program	MILD47-1860 Base System	MILD47-1860 Improved System	C.BAY1-1813 Base System	C.BAY1-1813 Improved System
ENEL (Italy)	SICRET #1	1.4 (1)	.002 (42)	0.5 (2)	.04 (13)
	SICRET #2	--	--	--	--
EDP (Portugal)	ZANZIBAR	1.6 (1)	.0 (27)	1.5 (2)	.18 (3)
EDF (France)	MEXICO	--	--	--	--
UMIST (UK)	COMPASS	.32 (1)	.001 (30)	.29 (2)	.009 (2)
NGC (UK)	ESCORT	--	--	--	--
PTI (USA)	TPLAN	--	--	--	--
USask (Canada)	MECORE	.11 (4)	.002 (21)	.29 (1)	.003 (20)

10.6 Additional Results

Most of the models are capable of providing additional information which is valid to the power system planning process. Some participants utilized these capabilities for this project and have documented their results in individual reports included in the Appendices. Some of the additional results and capabilities are:

(a) MEXICO and ESCORT have evaluated the impact of properly tying the availability of contracted participation sales to the availability of the generating units from which the sales are made.

(b) The reliability benefits of the 52 MW of interruptible load are considered by ENEL using SICRET.

(c) A cost-benefit analysis of the transmission reinforcement considering the benefits of reduced customer outage costs and reduced system fuel costs is proposed in the ENEL and National Grid reports.

(d) UMIST has reported statistical parameters such as standard deviation and confidence limits for the main system reliability indices.

(e) Histograms of transmission line flows are available from many of the models. Actual reported examples are included for TPLAN and ESCORT.

(f) While the focus of this work has centered on HL2 adequacy, the MEXICO and ESCORT models include some security considerations through the use of a security constrained dispatch algorithm.

(g) Hydro generation is an integral part of the NB Power system that must be integrated properly with the thermal generation. ZANZIBAR includes a probabilistic model to account for varying river flows and resulting hydro generation.

(h) TPLAN and COMREL both include full AC load flow capability which provides for an analysis of voltage problems as presented in the Power Technologies Inc. report.

(i) USask results report the complete set of output reliability indices.

10.7 Future Considerations

Composite generation and transmission reliability evaluation models are not yet in wide use in the utility industry. They are continually evolving such that the various reliability models have certain relative features and strengths compared to each other. From the evaluations done in this project, the following features are recommended for future incorporation into all models:

(a) capability to handle phase shifting transformers
(b) capability to handle contract sales of various types especially those tied to the availability of specific generating units.
(c) consistent approaches to load curtailment which provide some flexibility to incorporate system operating procedures.
(d) voltage considerations
(e) security constraints and their impact on generation dispatch
(f) capability to model the varying availabilities of system components because of adverse weather conditions
(g) standard output indices
(h) common mode failures
(i) limited energy unit capabilities
(j) flexible hydro plant modelling
(k) consideration of system losses

While none of the models include all of the above features, each model has shown that it can make a significant contribution to the system planning process.

APPENDIX I

GENERIC SYSTEM DATA

```
C          NB POWER COMPOSITE SYSTEM DATA FOR RELIABILITY EVALUATION
C          ---------------------------------------------------------
C                              Prepared by
C                    CIGRE Task Force 38.03.10 at NB Power
C                             November 1990
C                          (Updated August 1991)
C
C***  General Information  ***
C-----------------------------------------------------------------------
C   Col.  4- 5 : number of nodes
C   Col.  9-10 : number of transmission lines
C   Col. 14-15 : number of transformers
C   Col. 19-20 : number of generators
C   Col. 24-25 : number of nodes with load
C   Col.    30 : number of voltage levels
C   Col.    35 : number of meteorological zones
C   Col.    40 : number of weekly cumulative distributions for
C                     each type of load
C   Col.    45 : number of load diagram configurations
C   Col. 49-50 : number of nodes with generating units
C   Col.   54  : number of simulated generating stations from
C                     interchange areas
C-----------------------------------------------------------------------
C
   85   98   24   39   49    3    1    4    6   21    6
C
C
C
C***  Node informtion  ***
C-----------------------------------------------------------------------
C  col.  3- 6 : node identification number
C   "       11 : number of lines connected to node
C   "       16 : number of transformers connected to node
C   "    21-23 : voltage level at node
C   "    28-33 : generating power in MW for peak load
C   "    38-42 : peak active load in MW at this node
C   "    44-49 : peak reactive load in MVAR at this node
C   "       52 : type of cumulative distribution of the load (see monthly
C                      load model I)
C   "    55-60 : name of node
C   "    65-69 : base (100% Load Factor) load in MW (see seasonal
C                      load model II)
C   "    74-77 : static shunt capacitors in MVAR at rated voltage at this node
C-----------------------------------------------------------------------
C
C 1. Inter-change Generating Nodes
C
   168    1    2   345   119.10     0.0    0.0  1  ONSLO3
   700    2    0   345     0.00   230.0   54.0  3  ORRING    230.0
  1844    2    0   138     0.00    60.0  -20.0  3  MURRCR     60.0
  1869    1    0   345     0.00   200.0   40.0  4  MADHYQ
  1896    2    0   138     0.00     0.0    0.0  1  TINKER
  9996    2    0   230     0.00   200.0   40.0  4  EELHYQ
  9997    2    0   345     0.00     0.0    0.0  1  CHESTR
```

```
C 2. NB Power Hydro Generating Nodes
C
  1800   4   0   138     80.00     39.1   20.0  2  BEECHW     15.0
  1802   2   0   138     30.00      0.0    0.0  1  GRFALL
  1809   3   0   138    500.00     20.7    5.0  1  MACTQC
C
C 3. NB Power Thermal Generating Nodes
C
  1677   2   0   138    100.00    135.7   24.0  1  CARAQT
  1807   3   2   138     20.00    191.0   74.0  2  NEWCA1     30.0      70.0
  1811   3   0   138    230.00     46.2   30.0  1  GRLAKE
  1812   6   0   138      0.00    350.6   87.5  1  MONCTN     17.0      55.0
  1813   4   0   138    253.80    245.6   50.4  2  C.BAY1     40.0      20.0
  1826   1   0   138    306.00      0.0    0.0  1  DALHOU
  1836   3   2   345   1005.00      0.0    0.0  1  C.COV3
  1843   3   0   345    657.00     22.0   10.0  3  LEPRAU     22.0
  1847   2   0   138      0.00     55.0   14.8  2  112572     20.0
  1910   1   0   138     40.00    153.9   33.6  2  IROQUB     60.0
  1913   2   0   345    450.00      0.0    0.0  1  BELDUN
  1948   2   1   138      0.00    108.8   43.4  1  EELRA1               20.0
  1965   1   0   230    100.00      0.0    0.0  1  MILBK2
  1969   2   0   138     90.00      0.0    0.0  1  MILBK1
  1971   1   0   138      0.00     58.7   18.6  1  PENFLD               10.0
C
C 4. Non-Generating Nodes
C
   157   2   0   138      0.00     12.6    5.1  3  MACCAN     12.6
   158   1   1   138      0.00     50.1   90.5  3  ONSLO1     50.1      50.0
   167   0   3   230      0.00     31.4  112.7  3  ONSLO2     31.4
   183   3   0   138      0.00     23.6    7.1  3  SPRNGH     23.6
  1679   1   0   138      0.00    101.5   42.0  1  LANCST
  1681   2   0   138      0.00     32.9    8.3  3  IRVREF     32.9
  1712   2   0   138      0.00    149.2   31.0  2  RICHBT     40.0
  1717   2   0   138      0.00    129.2   31.4  2  114963     23.4
  1747   2   0   138      0.00      0.0    0.0  1  NORPSR
  1776   2   0   138      0.00     46.2   13.5  2  114981     19.1
  1803   4   3   345      0.00      0.0    0.0  1  KESWK3
  1804   2   0   138      0.00     14.9    3.7  1  117562
  1805   4   1   138      0.00     15.9    2.0  3  EELRV1     15.9
  1806   4   3   138      0.00    130.5   53.0  1  BATHS1               40.0
  1810   4   0   138      0.00    159.6   41.0  1  MARYSV
  1817   3   0   138      0.00      0.0    0.0  1  111144
  1824   2   0   138      0.00     46.6   14.5  2  111528     27.0
  1825   3   0   138      0.00      0.0    0.0  1  MEMCOK
  1827   6   2   138      0.00      0.0    0.0  1  KESWK1
  1828   2   1   230      0.00      0.0    0.0  1  KESWK2
  1829   3   2   230      0.00      0.0    0.0  1  BATHS2
  1830   4   3   230      0.00      0.0    0.0  1  EELRV2
  1832   2   0   138      0.00     15.5    8.0  2  110553      5.5
  1834   1   0   138      0.00     60.2   24.8  1  OAKBAY               30.0
  1835   2   0   138      0.00      0.0    0.0  1  110421
  1837   5   2   138      0.00      0.0    0.0  1  C.COV1
  1838   1   1   230      0.00      0.0    0.0  1  SALBR2
  1839   5   3   138      0.00      0.0    0.0  1  SALBR1
  1845   2   0   138      0.00     20.9    5.3  1  NASH03
  1846   2   0   138      0.00     20.9    5.3  1  NASH12
  1849   2   1   138      0.00      0.0    0.0  1  STAND1
  1850   3   2   345      0.00      0.0    0.0  1  SALBR3               16.0
  1851   2   3   230      0.00      0.0    0.0  1  NEWCA2
  1852   2   0   138      0.00     21.9    5.5  1  110871
  1854   2   0   138      0.00      4.8    1.2  1  HARDRD
```

```
  1860   2   0    138     0.00     26.0    6.6  1  MILD47
  1861   2   0    138     0.00    119.2   30.0  1  DOAKST
  1862   2   0    138     0.00      0.0    0.0  1  MILD65
  1863   3   0    138     0.00     65.8   34.1  1  119042
  1865   2   0    138     0.00      2.1    0.5  3  111036        2.1
  1866   2   1    345     0.00      0.0    0.0  1  EELRV3
  1867   2   2    345     0.00      0.0    0.0  1  EDMST3
  1868   3   1    345     0.00      0.0    0.0  1  STAND3
  1900   2   1    345     0.00      0.0    0.0  1  NORTN3
  1901   2   1    138     0.00      0.0    0.0  1  NORTN1
  1907   2   2    138     0.00      0.0    0.0  1  EDMST1
  1908   2   0    138     0.00      0.0    0.0  1  114084
  1909   1   0    138     0.00    122.7   37.0  1  IROQUA                 30.0
  1915   2   1    345     0.00      0.0    0.0  1  BATHS3
  1916   2   1    345     0.00      0.0    0.0  1  NEWCA3
  1928   3   0    138     0.00      0.0    0.0  1  110684
  1930   2   0    138     0.00     50.3   20.8  1  1126MP
  1945   3   0    138     0.00      6.6    1.5  1  119024
  1946   3   0    138     0.00      6.6    1.5  1  112408
  1964   3   0    230     0.00      0.0    0.0  1  MBNKTP
  2495   1   0    138     0.00     29.7    7.5  3  NBIPC1      29.7
  2496   1   0    138     0.00     89.1   22.3  3  ROTHPR      89.1
  2497   1   0    138     0.00     52.0   13.1  3  BRMINE      52.0
  2498   1   0    230     0.00     68.9   17.3  3  NBIPC2      68.9
  2499   1   0    230     0.00     60.0   16.4  3  CONSBH      60.0
C
C
C
C ***  Transmission Line Information  ***
C
C -----------------------------------------------------------------------
C There are two data lines for each transmission line.
C Data Line 1:
C   Col.  2- 3 : progressive number of line
C   Col.  5- 8 : identification number of node at 1st extreme end of line
C   Col. 10-13 : identification number of node at 2nd extreme end of line
C   Col.    15 : indication of weather zone to which line belongs
C   Col. 17-18 : week line maintenance begins
C   Col. 20-21 : week line maintenance ends
C   Col. 23-28 : length of line in km
C   Col. 32-39 : probable unavailability for 100 km of line
C                   (including terminal related forced outages)
C   Col. 44-50 : failure rate in failures per year
C   Col. 54-60 : repair duration in hours per repair
C Data Line 2:
C   Col. 13-18 : resistance in ohms/ km of line
C   Col. 20-25 : reactance in ohms/ km of line
C   Col. 27-29 : voltage level in line (kV)
C   Col. 32-36 : emergency transmission capability of line in MW
C   Col. 39-43 : normal transmission capability of line in MW
C   Col. 46-52 : resistance of line in pu
C   Col. 54-60 : reactance of line in pu
C   Col. 63-69 : total line charging capacitive
C                   susceptance/admittance in pu
C-----------------------------------------------------------------------
C
  1  157  183 1  0  0  15.00   0.000000    0.00000       0.00
          0.1200 0.4963 138  220.0  140.0  0.00880 0.03940  0.00000
  2  157 1825 1  0  0  43.20   0.000477    0.37412       4.83
          0.1200 0.4963 138  220.0  140.0  0.02518 0.11266  0.00000
```

3	158	183	1	0	0	68.00	0.000000	0.00000	0.00	
			0.1200	0.4963	138	220.0	140.0	0.03710	0.17170	0.04360
4	168	1850	1	0	0	159.74	0.000957	0.49888	26.88	
			0.0390	0.4270	345	400.0	400.0	0.00504	0.05727	0.00000
5	183	1863	1	0	0	51.30	0.000477	0.44421	4.83	
			0.1200	0.4800	138	220.0	140.0	0.03052	0.12998	0.00000
6	700	1843	1	0	0	210.00	0.000000	0.00000	0.00	
			0.0390	0.3723	345	900.0	700.0	0.00670	0.07020	1.19620
7	700	9997	1	0	0	76.04	0.000000	0.00000	0.00	
			0.0468	0.3710	345	900.0	700.0	0.00299	0.02370	0.00000
8	1677	1806	1	0	0	56.00	0.000477	0.48492	4.83	
			0.1200	0.4520	138	220.0	140.0	0.03400	0.13290	0.03920
9	1677	1928	1	0	0	45.00	0.000477	0.38965	4.83	
			0.1200	0.4520	138	220.0	140.0	0.04778	0.18992	0.00000
10	1679	1837	1	0	0	12.97	0.000477	0.11229	4.83	
			0.1200	0.4669	138	220.0	190.0	0.00550	0.03180	0.00870
11	1681	1717	1	0	0	19.41	0.000477	0.16805	4.83	
			0.1295	0.5897	138	220.0	190.0	0.01320	0.06010	0.00000
12	1681	1813	1	0	0	1.84	0.000477	0.01593	4.83	
			0.1200	0.4852	138	220.0	140.0	0.00110	0.00470	0.00120
13	1712	1807	1	0	0	89.99	0.000477	0.77938	4.83	
			0.1071	0.4954	138	220.0	140.0	0.05059	0.23408	0.00000
14	1712	1812	1	0	0	77.01	0.000477	0.66692	4.83	
			0.1118	0.4953	138	220.0	140.0	0.04520	0.20030	0.00000
15	1717	1747	1	0	0	31.59	0.000477	0.27352	4.83	
			0.1302	0.5895	138	220.0	190.0	0.02160	0.09779	0.00000
16	1747	1901	1	0	0	16.75	0.000000	0.00000	0.00	
			0.0171	0.5895	138	220.0	190.0	0.00150	0.05185	0.00000
17	1776	1839	1	0	0	51.26	0.000477	0.44387	4.83	
			0.1048	0.4480	138	220.0	140.0	0.02820	0.12059	0.00000
18	1776	1901	1	0	0	15.47	0.000477	0.13393	4.83	
			0.1059	0.4481	138	220.0	140.0	0.00860	0.03640	0.00000
19	1800	1817	1	0	0	34.76	0.000477	0.30097	4.83	
			0.1200	0.4640	138	220.0	140.0	0.02120	0.08470	0.02360
20	1800	1847	1	0	0	65.21	0.000477	0.56470	4.83	
			0.1200	0.4667	138	220.0	140.0	0.03970	0.15890	0.04430
21	1800	1896	1	0	0	44.00	0.000477	0.38099	4.83	
			0.1200	0.4667	138	220.0	140.0	0.12681	0.47602	0.00000
22	1800	1930	1	0	0	32.18	0.000477	0.27862	4.83	
			0.1200	0.4801	138	220.0	140.0	0.01962	0.08113	0.02122
23	1802	1804	1	0	0	0.62	0.000477	0.00538	4.83	
			0.1200	0.5221	138	220.0	190.0	0.00050	0.00170	0.00040
24	1802	1817	1	0	0	23.49	0.000477	0.20338	4.83	
			0.1200	0.4645	138	220.0	140.0	0.01430	0.05730	0.01600
25	1803	1836	1	0	0	116.83	0.000957	0.36472	26.88	
			0.0390	0.3943	345	900.0	700.0	0.00410	0.03870	0.58410
26	1803	1843	1	0	0	135.01	0.000957	0.42154	26.88	
			0.0390	0.3941	345	900.0	700.0	0.00470	0.04470	0.67500
27	1803	1868	1	0	0	146.12	0.000957	0.45628	26.88	
			0.0390	0.3943	345	900.0	700.0	0.00510	0.04840	0.73040
28	1803	9997	1	0	0	164.70	0.000000	0.00000	0.00	
			0.0358	0.3710	345	900.0	700.0	0.00496	0.05133	0.00000
29	1804	1849	1	0	0	13.30	0.000477	0.11515	4.83	
			0.1200	0.4940	138	220.0	190.0	0.00940	0.03450	0.00850
30	1805	1824	1	0	0	58.75	0.000477	0.50874	4.83	
			0.0536	0.4779	138	220.0	140.0	0.03577	0.14744	0.00000
31	1805	1826	1	0	0	7.50	0.000477	0.06493	4.83	
			0.1200	0.4698	138	400.0	310.0	0.00210	0.01860	0.00510
32	1805	1865	1	0	0	23.77	0.000477	0.20580	4.83	
			0.1200	0.4935	138	220.0	140.0	0.01650	0.06160	0.01520

33	1805	1948	1	0	0	0.01	0.000000	0.00000	0.00
		0.1200	0.4935	138	900.0	700.0	0.00000	0.00010	0.00000
34	1806	1824	1	0	0	27.53	0.000477	0.23836	4.83
		0.1148	0.4779	138	220.0	140.0	0.01659	0.06909	0.00000
35	1806	1928	1	0	0	22.53	0.000477	0.19506	4.83
		0.1200	0.4820	138	220.0	140.0	0.01378	0.05702	0.01490
36	1806	2497	1	0	0	27.00	0.000000	0.00000	0.00
		0.1200	0.4820	138	220.0	140.0	0.01620	0.06540	0.01800
37	1807	1832	1	0	0	64.31	0.000477	0.55690	4.83
		0.1153	0.4959	138	220.0	140.0	0.03894	0.16747	0.00000
38	1807	1969	1	0	0	18.37	0.000477	0.15904	4.83
		0.1200	0.4969	138	220.0	140.0	0.00870	0.03610	0.00000
39	1809	1827	1	0	0	11.60	0.000477	0.10043	4.83
		0.1200	0.4695	138	320.0	280.0	0.00330	0.02860	0.00780
40	1809	1827	1	0	0	11.60	0.000477	0.10043	4.83
		0.1200	0.4695	138	320.0	280.0	0.00330	0.02880	0.00790
41	1809	1861	1	0	0	15.71	0.000477	0.13601	4.83
		0.0897	0.4606	138	240.0	190.0	0.00740	0.03800	0.00000
42	1810	1811	1	0	0	49.08	0.000477	0.42498	4.83
		0.1200	0.4800	138	230.0	140.0	0.02990	0.12370	0.03230
43	1810	1845	1	0	0	5.31	0.000477	0.04597	4.83
		0.1200	0.4806	138	220.0	140.0	0.00320	0.01340	0.00350
44	1810	1846	1	0	0	5.23	0.000477	0.04528	4.83
		0.1200	0.4624	138	220.0	140.0	0.00320	0.01270	0.00360
45	1810	1861	1	0	0	13.68	0.000477	0.11844	4.83
		0.1239	0.4608	138	220.0	140.0	0.00890	0.03310	0.00000
46	1811	1812	1	0	0	95.25	0.000477	0.82495	4.83
		0.1200	0.4826	138	220.0	140.0	0.05780	0.24140	0.06200
47	1811	1832	1	0	0	52.19	0.000477	0.45192	4.83
		0.1170	0.4960	138	220.0	140.0	0.03206	0.13592	0.00000
48	1812	1839	1	0	0	14.91	0.000477	0.12908	4.83
		0.1200	0.4803	138	240.0	190.0	0.00910	0.03760	0.00980
49	1812	1839	1	0	0	14.91	0.000477	0.12908	4.83
		0.1200	0.4803	138	240.0	190.0	0.00910	0.03760	0.00980
50	1812	1945	1	0	0	6.00	0.000477	0.05194	4.83
		0.1200	0.4803	138	220.0	140.0	0.00529	0.02001	0.00000
51	1812	1946	1	0	0	6.00	0.000477	0.05194	4.83
		0.1200	0.4803	138	220.0	140.0	0.00529	0.02001	0.00000
52	1813	1860	1	0	0	9.43	0.000477	0.08164	4.83
		0.1200	0.4827	138	220.0	140.0	0.00580	0.02390	0.00610
53	1813	1862	1	0	0	9.43	0.000477	0.08164	4.83
		0.1200	0.4827	138	220.0	140.0	0.00580	0.02390	0.00610
54	1813	2496	1	0	0	0.60	0.000000	0.00000	0.00
		0.1200	0.4827	138	220.0	140.0	0.00040	0.00170	0.00040
55	1817	1896	1	0	0	7.02	0.000477	0.06077	4.83
		0.1200	0.4801	138	220.0	140.0	0.00430	0.01780	0.00470
56	1825	1844	1	0	0	50.21	0.000000	0.00000	0.00
		0.1200	0.4798	138	220.0	140.0	0.03060	0.12650	0.03110
57	1825	1852	1	0	0	22.42	0.000477	0.19411	4.83
		0.1200	0.4986	138	220.0	140.0	0.01460	0.05870	0.01420
58	1827	1845	1	0	0	17.20	0.000477	0.14891	4.83
		0.1200	0.4805	138	220.0	140.0	0.01050	0.04340	0.01130
59	1827	1846	1	0	0	17.20	0.000477	0.14891	4.83
		0.1200	0.4805	138	220.0	140.0	0.01050	0.04200	0.01170
60	1827	1847	1	0	0	23.29	0.000477	0.20164	4.83
		0.1200	0.4644	138	220.0	140.0	0.01420	0.05680	0.01580
61	1827	1930	1	0	0	56.40	0.000477	0.48839	4.83
		0.1200	0.4801	138	220.0	140.0	0.03438	0.14217	0.03718
62	1828	1838	1	0	0	146.89	0.000780	1.50532	6.68
		0.0780	0.4837	230	480.0	350.0	0.02280	0.13430	0.26720

63 1828 1851 1 0 0 145.46			0.000780		1.49065		6.68			
	0.0780	0.4670	230	480.0	350.0	0.02240	0.12840		0.43560	
64 1829 1830 1 0 0 88.34			0.000780		0.90489		6.68			
	0.0780	0.4838	230	480.0	350.0	0.00690	0.06590		0.19660	
65 1829 1964 1 0 0 49.19			0.000780		0.50371		6.68			
	0.0780	0.4673	230	480.0	350.0	0.00820	0.04680		0.09980	
66 1829 2499 1 0 0 4.00			0.000000		0.00000		0.00			
	0.0780	0.4673	230	480.0	350.0	0.00060	0.00330		0.00740	
67 1830 2498 1 0 0 9.00			0.000000		0.00000		0.00			
	0.0780	0.4673	230	480.0	350.0	0.00140	0.00850		0.01710	
68 1830 9996 1 0 0 34.00			0.000000		0.00000		0.00			
	0.0780	0.4673	230	480.0	350.0	0.00170	0.00990		0.00000	
69 1830 9996 1 0 0 34.00			0.000000		0.00000		0.00			
	0.0780	0.4673	230	480.0	350.0	0.00170	0.00990		0.00000	
70 1834 1835 1 0 0 65.56			0.000477		0.56773		4.83			
	0.1200	0.4802	138	220.0	140.0	0.03989	0.16517		0.00000	
71 1835 1837 1 0 0 71.91			0.000477		0.62274		4.83			
	0.1200	0.4907	138	220.0	140.0	0.04090	0.18530		0.04640	
72 1836 1843 1 0 0 28.80			0.000957		0.08983		26.88			
	0.0390	0.3968	345	900.0	900.0	0.00100	0.00960		0.14400	
73 1836 1900 1 0 0 87.00			0.000957		0.27152		26.88			
	0.0390	0.3937	345	900.0	700.0	0.00340	0.03270		0.49310	
74 1837 1860 1 0 0 22.48			0.000477		0.19463		4.83			
	0.1200	0.4736	138	220.0	140.0	0.01120	0.05590		0.01510	
75 1837 1862 1 0 0 23.43			0.000477		0.20286		4.83			
	0.1200	0.4698	138	220.0	140.0	0.01240	0.05780		0.01580	
76 1837 1971 1 0 0 50.70			0.000477		0.43902		4.83			
	0.1200	0.4527	138	220.0	140.0	0.02931	0.11457		0.01809	
77 1839 1945 1 0 0 24.00			0.000477		0.20779		4.83			
	0.1200	0.4748	138	220.0	140.0	0.01000	0.04010		0.01130	
78 1839 1946 1 0 0 24.00			0.000477		0.20779		4.83			
	0.1200	0.4748	138	220.0	140.0	0.01000	0.04010		0.01130	
79 1844 1854 1 0 0 11.47			0.000000		0.00000		0.00			
	0.1200	0.4798	138	220.0	140.0	0.00700	0.02890		0.00760	
80 1849 1865 1 0 0 124.62			0.000477		1.07948		4.83			
	0.1200	0.4938	138	220.0	140.0	0.08830	0.32310		0.07950	
81 1850 1900 1 0 0 69.82			0.000957		0.21786		26.88			
	0.0390	0.3938	345	900.0	700.0	0.00230	0.02210		0.33390	
82 1850 1916 1 0 0 119.09			0.000957		0.37178		26.88			
	0.0390	0.3938	345	900.0	700.0	0.00410	0.03940		0.59530	
83 1851 1964 1 0 0 15.00			0.000780		0.15356		6.68			
	0.0780	0.4673	230	480.0	350.0	0.00170	0.00990		0.02130	
84 1852 1946 1 0 0 0.80			0.000477		0.00693		4.83			
	0.1200	0.4690	138	220.0	140.0	0.00040	0.00200		0.00040	
85 1854 1863 1 0 0 38.73			0.000477		0.33535		4.83			
	0.1200	0.4799	138	220.0	140.0	0.02360	0.09760		0.02550	
86 1863 1945 1 0 0 23.63			0.000477		0.20459		4.83			
	0.1200	0.4748	138	220.0	140.0	0.01500	0.05890		0.05890	
87 1866 1868 1 0 0 144.51			0.000957		0.45125		26.88			
	0.0390	0.3937	345	900.0	700.0	0.00500	0.04780		0.72230	
88 1866 1913 1 0 0 49.00			0.000957		0.15287		26.88			
	0.0390	0.3939	345	900.0	700.0	0.00190	0.01790		0.27030	
89 1867 1868 1 0 0 49.08			0.000957		0.15312		26.88			
	0.0390	0.3929	345	900.0	700.0	0.00170	0.01620		0.24530	
90 1867 1869 1 0 0 25.00			0.000957		0.07798		26.88			
	0.0428	0.3904	345	400.0	400.0	0.00090	0.00820		0.12390	
91 1907 1908 1 0 0 5.68			0.000477		0.04917		4.83			
	0.1200	0.4660	138	220.0	140.0	0.00240	0.01390		0.00390	
92 1907 1910 1 0 0 6.19			0.000477		0.05359		4.83			
	0.1200	0.4676	138	220.0	140.0	0.00270	0.01520		0.00420	

```
 93 1908 1909 1  0  0   0.72   0.000477    0.00623      4.83
           0.1200 0.5026 138  220.0  140.0  0.00050 0.00190  0.00050
 94 1913 1915 1  0  0  40.00   0.000957    0.12478     26.88
           0.0390 0.3928 345  900.0  700.0  0.00160 0.01510  0.22800
 95 1915 1916 1  0  0  74.02   0.000957    0.23098     26.88
           0.0390 0.3940 345  900.0  700.0  0.00260 0.02450  0.37000
 96 1928 1969 1  0  0  32.00   0.000477    0.27707      4.83
           0.1200 0.4820 138  220.0  140.0  0.02572 0.10658  0.02790
 97 1948 2495 1  0  0  11.00   0.000000    0.00000      0.00
           0.1200 0.4935 138  220.0  140.0  0.00760 0.02920  0.00750
 98 1964 1965 1  0  0  13.00   0.000780    0.13308      6.68
           0.0780 0.4673 230  480.0  350.0  0.00200 0.01140  0.02430
C
C
C
C
C*****************************************************************************
C*****************************************************************************
C*****************************************************************************
C    The following items of Transmission Line data are to be used for the
C  Transmission Improvement Case.
C (a)  Add the following two transmission lines.
C
 99 1681 1837 1  0  0  34.00   0.000477    0.29439      4.83
           0.1014 0.4750 138  220.0  140.0  0.01810 0.08480  0.02250
100 1681 1901 1  0  0  51.00   0.000477    0.44162      4.83
           0.1143 0.4724 138  220.0  140.0  0.03060 0.12650  0.31100
C
C (b)  Increase the MW ratings of Transmission Line 12 by replacing it
C  with the following.
C
 12 1681 1813 1  0  0   1.84   0.000477    0.01593      4.83
           0.1200 0.4852 138  320.0  280.0  0.00110 0.00470  0.00120
C
C*****************************************************************************
C*****************************************************************************
C*****************************************************************************
C
C
C ***  Transformer Information  ***
C-----------------------------------------------------------------------------
C There are two data lines for each transformer.
C Data Line 1:
C   Col.  2- 3 : progressive number of transformer
C   Col.  6- 9 : identification number for 1st node to which transformer
C                   is connected
C   Col. 12-15 : identification number for 2nd node connection
C   Col.    18 : identification of weather zone to which transformer belongs
C   Col.    21 : week transformer maintenance begins
C   Col.    24 : week transformer maintenance ends
C   Col. 32-37 : probablity of transformer unavailability
C   Col. 43-49 : failure rate in failures per year
C   Col. 54-59 : repair duration in hours per repair
C Data Line 2:
C   Col. 18-24 : transformer resistance in pu
C   Col. 28-34 : transformer reactance in pu
C   Col. 37-43 : maximum transformer transmission  rating in MW
C                 (short term overload)
C   Col. 46-52 : transformer rated capacity in MVA
C   Col. 56-61 : transformer resistance in per cent
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```
C   Col. 64-70 : transformer reactance in per cent
C------------------------------------------------------------------------
C
  1   158   167  1  0  0      0.0000    0.00000     0.00
                 0.00300  0.04510  252.00  224.00  0.3000  4.5100
  2   167   168  1  0  0      0.0000    0.00000     0.00
                 0.00200  0.03050  443.00  392.00  0.2000  3.0500
  3   167   168  1  0  0      0.0000    0.00000     0.00
                 0.00100  0.03050  443.00  392.00  0.1000  3.0500
  4  1803  1827  1  0  0      0.0011    0.05006   192.72
                 0.00030  0.02940  570.00  504.00  0.0300  2.9400
  5  1803  1827  1  0  0      0.0011    0.05006   192.72
                 0.00030  0.02940  570.00  504.00  0.0300  2.9400
  6  1803  1828  1  0  0      0.0011    0.05006   192.72
                 0.00030  0.01390  570.00  504.00  0.0300  1.3900
  7  1805  1830  1  0  0      0.0011    0.05006   192.72
                 0.00190  0.09520  158.00  140.00  0.1900  9.5200
  8  1806  1829  1  0  0      0.0011    0.05006   192.72
                 0.00090  0.03500  252.00  225.00  0.0900  3.5000
  9  1806  1829  1  0  0      0.0011    0.05006   192.72
                 0.00090  0.02356  338.00  300.00  0.0900  2.3560
 10  1806  1915  1  0  0      0.0011    0.05006   192.72
                 0.00040  0.03300  509.00  450.00  0.0400  3.3000
 11  1807  1851  1  0  0      0.0011    0.05006   192.72
                 0.00090  0.03520  267.00  236.00  0.0900  3.5200
 12  1807  1851  1  0  0      0.0011    0.05006   192.72
                 0.00090  0.03520  267.00  236.00  0.0900  3.5200
 13  1830  1866  1  0  0      0.0011    0.05006   192.72
                 0.00029  0.01360  452.00  400.00  0.0290  1.3600
 14  1830  1948  1  0  0      0.0011    0.05006   192.72
                 0.00240  0.09620  158.00  140.00  0.2400  9.6200
 15  1836  1837  1  0  0      0.0011    0.05006   192.72
                 0.00090  0.06010  359.00  318.00  0.0900  6.0100
 16  1836  1837  1  0  0      0.0011    0.05006   192.72
                 0.00050  0.03340  509.00  450.00  0.0500  3.3400
 17  1838  1839  1  0  0      0.0011    0.05006   192.72
                 0.00090  0.02356  338.00  300.00  0.0900  2.3560
 18  1839  1850  1  0  0      0.0011    0.05006   192.72
                 0.00040  0.03300  509.C0  450.00  0.0400  3.3000
 19  1839  1850  1  0  0      0.0011    0.05006   192.72
                 0.00100  0.04330  340.00  340.00  0.1000  4.3300
 20  1849  1868  1  0  0      0.0011    0.05006   192.72
                 0.00041  0.03160  331.00  293.00  0.0410  3.1600
 21  1851  1916  1  0  0      0.0011    0.05006   192.72
                 0.00240  0.06000  452.00  400.00  0.2400  6.0000
 22  1867  1907  1  0  0      0.0011    0.05006   192.72
                 0.00050  0.03070  331.00  293.00  0.0500  3.0700
 23  1867  1907  1  0  0      0.0011    0.05006   192.72
                 0.00050  0.03070  331.00  293.00  0.0500  3.0700
 24  1900  1901  1  0  0      0.0011    0.05006   192.72
                 0.00100  0.04330  338.00  340.00  0.1000  4.3300
C
C
C*****************************************************************************
C*****************************************************************************
C*****************************************************************************
```

```
C
C    The following item of Transformer data is to be used for the
C  Transmission Improvement Case.
C    Replace Transformer 15 (318 MVA) with the 450 MVA one below, which has a
C  different impedance  and a higher rating ( the one below being identical
C  to Transformer 16.)
C
 15  1836  1837  1  0  0        0.0011     0.05006     192.72
                 0.00050   0.03340   509.00   450.00   0.0500   3.3400
C
C*****************************************************************************
C*****************************************************************************
C*****************************************************************************
C
C***  Generating Unit Information  ***
C-----------------------------------------------------------------------------
C   Col.  3- 6 : identification number of node to which generator
C                    is connected
C   Col.  9-10 : week generator maintenance begins
C   Col. 13-14 : week generator maintenance ends
C   Col. 16-20 : minimum generator capacity in MW
C   Col. 23-28 : maximum generator capacity in MW
C   Col. 30-35 : minimum generator reactive capability in MVAR
C   Col. 37-41 : maximum generator reactive capability in MVAR
C   Col. 44-47 : probable unavailability of generator in pu
C   Col. 50-55 : failure rate in failures per year
C   Col. 57-62 : repair duration in hours per repair
C   Col. 64-68 : cost of generation in $/MWh
C   Col. 71-78 : name of generator
C-----------------------------------------------------------------------------
C
C 1. NB Power Resources
C
  1677  14  18   0.0   100.0  -66.0  66.0  0.10   9.733 100.00  65.0  ST.ROSE1
  1800   0   0   5.0   120.0  -80.0  38.0  0.00   0.000   0.00  35.0  BEECHWOO
  1802   0   0  20.0    30.0  -35.0  15.5  0.00   0.000   0.00  33.0  GR.FALL1
  1809   0   0   0.0   660.0 -610.0 316.0  0.00   0.000   0.00  35.5  MACTAQUC
  1807   0   0   0.0    20.0  -28.2  18.0  0.12  29.864  40.00  50.0  CHATMCFB
  1811  15  18   0.0    60.0  -56.9  51.7  0.12  29.864  40.00  40.0  GRLAKE08
  1811  31  34   0.0   170.0 -100.0  80.0  0.12  29.864  40.00  30.0  GRLAKE09
  1812   0   0   0.0    25.0  -12.0  18.0  0.10   9.733 100.00  75.0  MONCTNGT
  1813  10  15   0.0    44.5  -18.0  31.5  0.10  24.333  40.00  45.0  CT.BAY01
  1813   0   0  10.0    12.3   -7.7   8.3  0.10  24.333  40.00  25.0  CT.BAY02
  1813  19  24   0.0   100.0  -66.0  66.0  0.10  24.333  40.00  34.0  CT.BAY03
  1813  25  30   0.0    97.0  -66.0  66.0  0.10  24.333  40.00  40.0  CT.BAY04
  1813   0   0   0.0    10.0   -5.0   5.0  0.00   0.000   0.00  80.0  INTLOAD1
  1826  14  18   0.0   103.0  -66.0  66.0  0.10  24.333  40.00  37.0  DALHOU01
  1826  23  27   0.0   203.0 -130.0 100.0  0.12  29.864  40.00  30.0  DALHOU02
  1836  23  29   0.0   335.0 -125.0 160.0  0.10  24.333  40.00  37.0  C.COVE01
  1836  30  36   0.0   335.0 -125.0 160.0  0.10  24.333  40.00  32.0  C.COVE02
  1836  37  43   0.0   335.0 -125.0 160.0  0.10  24.333  40.00  34.0  C.COVE03
  1843  19  22   0.0   657.0 -450.0 415.0  0.12  11.946 100.00   5.0  LEPRAU01
  1847   0   0   0.0    12.0   -6.0   6.0  0.00   0.000   0.00  80.0  INTLOAD2
  1910   0   0   0.0    40.0  -40.0  20.0  0.00   0.000   0.00   0.0  GF.TOB.6
  1910   0   0   0.0    15.0   -7.0   7.0  0.00   0.000   0.00  80.0  INTLOAD3
  1913  27  30   0.0   450.0 -250.0 220.0  0.12  29.864  40.00  28.0  BELDUN01
  1948   0   0   0.0    15.0   -7.0   7.0  0.00   0.000   0.00  80.0  INTLOAD4
  1965  19  23   0.0   100.0  -66.0  66.0  0.10   9.733 100.00  65.0  MILBNK01
  1965  24  28   0.0   100.0  -66.0  66.0  0.10   9.733 100.00  65.0  MILBNK02
  1969  29  33   0.0   100.0  -66.0  66.0  0.10   9.733 100.00  65.0  MILBNK03
  1969  34  38   0.0   100.0  -66.0  66.0  0.10   9.733 100.00  65.0  MILBNK04
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  1971   0   0   0.0    25.0  -12.0  18.0  0.10   9.733 100.00  75.0  GRMANAGT
C
C
C Three of the NB Power Resources listed above are hydro generating stations.
C It is necessary to give the value of available energy for each of these
C stations.
C
C  Col. 3-6 : identification number of node to which generator
C                 is connected (as above)
C  Col. 9-12: energy limit of hydro-generators in GWH per year
C  Col.16-23: name of generator.
C
  1800   478    BEECHWOO
  1802   210    GR.FALL1
  1809  1609    MACTAQUC

C
C 2. Inter-change System Supporting Resources
C
   168   0   0   0.0   150.0  -25.0  40.0  0.10  24.333  40.00  90.0  NS.SYS01
   168   0   0   0.0   150.0  -25.0  40.0  0.10  24.333  40.00  90.0  NS.SYS02
   168   0   0   0.0   119.0 -100.0 100.0  0.00   0.000   0.00   0.0  NS.SYS04
   700   0   0   0.0   250.0  -75.0  75.0  0.10  24.333  40.00 100.0  NE.SYS01
   700   0   0   0.0   250.0  -75.0  75.0  0.10  24.333  40.00 100.0  NE.SYS02
  1844   0   0   0.0    10.0    0.0  20.0  0.10  24.333  40.00 100.0  PE.SYS01
  1869   0   0   0.0   300.0  -50.0 100.0  0.05  11.526  40.00 120.0  HQ.SYS01
  1896   0   0   0.0    10.0   -5.0   5.0  0.10  24.333  40.00 100.0  MP.SYS01
  9996   0   0   0.0   100.0  -50.0  50.0  0.05  11.526  40.00 120.0  HQ.SYS02
  9997   0   0   0.0     0.0 -125.0 425.0  0.00   0.000   0.00   0.0  CHES.SVC
C
C
C
C*** Typical Grouping of Weeks into Monthly Periods
C-----------------------------------------------------------------------------
   Jan  Feb  Mar  Apr  May  June  July  Aug  Sept  Oct  Nov  Dec
    5    4    4    4    5    4     5     4    4     5    4    4
C-----------------------------------------------------------------------------
C
C
C
C***  Load Model Information  ***
C Three kinds of Load Models are given in this section.
C The load diagrams given in sub-section I are 6 step load duration
C curves for 4 different types of load for each month. They provide
C a reasonably detailed load model for evaluation. Alternatively
C a more simplified model is presented in sub-section II. It is a
C fixed 5 load-level probability distribution of loads for three seasons.
C Subsection III provides a generic chronological weekly load shape
C which can be applied to the actual load data of Model I to produce
C detailed chronological load models for each month of each load type.
C The building of these chronological models is left to the user.
C
C I. Monthly Load Diagrams
C-----------------------------------------------------------------------------
C   First Line :  Period in hours for a typical week.
C   Line 2-13  :  Monthly Load in per unit of annual peak for each period.
C-----------------------------------------------------------------------------
C
C TYPE 1  (100% variable loads)
C
```

	0-10	10-49	49-83	83-117	117-151	151-168
Jan.	1.000	0.850	0.730	0.580	0.450	0.300
Feb.	0.930	0.850	0.730	0.580	0.450	0.300
Mar.	0.885	0.770	0.650	0.510	0.400	0.260
Apr.	0.745	0.660	0.560	0.450	0.341	0.227
May	0.660	0.561	0.476	0.383	0.290	0.193
June	0.570	0.520	0.460	0.350	0.260	0.173
July	0.510	0.452	0.384	0.305	0.236	0.158
Aug.	0.540	0.470	0.420	0.330	0.250	0.165
Sep.	0.570	0.520	0.460	0.350	0.260	0.173
Oct.	0.665	0.590	0.500	0.383	0.290	0.193
Nov.	0.760	0.680	0.612	0.486	0.378	0.251
Dec.	0.890	0.780	0.673	0.534	0.415	0.276

C
C
C TYPE 2 (mixed variable & base loads)
C

	0-10	10-49	49-83	83-117	117-151	151-168
Jan.	1.000	0.910	0.867	0.802	0.727	0.660
Feb.	0.930	0.910	0.867	0.802	0.727	0.660
Mar.	0.885	0.830	0.770	0.710	0.650	0.590
Apr.	0.745	0.700	0.656	0.607	0.550	0.500
May	0.660	0.595	0.558	0.516	0.468	0.425
June	0.570	0.540	0.500	0.463	0.420	0.381
July	0.510	0.483	0.456	0.421	0.382	0.347
Aug.	0.540	0.500	0.456	0.421	0.382	0.347
Sep.	0.570	0.540	0.500	0.463	0.420	0.381
Oct.	0.660	0.620	0.570	0.516	0.468	0.425
Nov.	0.760	0.720	0.690	0.650	0.610	0.553
Dec.	0.890	0.848	0.799	0.739	0.670	0.608

C
C
C TYPE 3 (base loads)
C

	0-10	10-49	49-83	83-117	117-151	151-168
Jan.	1.000	1.000	1.000	1.000	1.000	1.000
Feb.	1.000	1.000	1.000	1.000	1.000	1.000
Mar.	1.000	1.000	1.000	1.000	1.000	1.000
Apr.	1.000	1.000	1.000	1.000	1.000	1.000
May	1.000	1.000	1.000	1.000	1.000	1.000
June	1.000	1.000	1.000	1.000	1.000	1.000
July	1.000	1.000	1.000	1.000	1.000	1.000
Aug.	1.000	1.000	1.000	1.000	1.000	1.000
Sep.	1.000	1.000	1.000	1.000	1.000	1.000
Oct.	1.000	1.000	1.000	1.000	1.000	1.000
Nov.	1.000	1.000	1.000	1.000	1.000	1.000
Dec.	1.000	1.000	1.000	1.000	1.000	1.000

C
C
C TYPE 4 (HQ contract)
C

	0-10	10-49	49-83	83-117	117-151	151-168
Jan.	1.000	0.850	0.400	0.000	0.000	0.000
Feb.	1.000	0.850	0.400	0.000	0.000	0.000
Mar.	0.000	0.000	0.000	0.000	0.000	0.000
Apr.	0.000	0.000	0.000	0.000	0.000	0.000
May	0.000	0.000	0.000	0.000	0.000	0.000
June	0.000	0.000	0.000	0.000	0.000	0.000
July	0.000	0.000	0.000	0.000	0.000	0.000
Aug.	0.000	0.000	0.000	0.000	0.000	0.000

```
Sep.   0.000   0.000   0.000   0.000    0.000    0.000
Oct.   0.000   0.000   0.000   0.000    0.000    0.000
Nov.   0.000   0.000   0.000   0.000    0.000    0.000
Dec.   0.000   0.000   0.000   0.000    0.000    0.000
C
C
C II. Seasonal Load Model
C
C     The following seasonal distribution of loads by load level applies
C only to the variable portion of the load at each node. This variable
C load at each node is defined as the difference between the peak load
C (col. 38-42) and the base load (col. 65-70) specified with the node
C information.
C
C    First Line : Season of the year.
C    Second Line : Duration of each season in years.
C    Lines 3-7 :
C        Col. 10-20 : Variable load level in per unit.
C        Col. 21-30 : Summer probability of variable load level.
C        Col. 31-40 : Intermediate probability of variable load level.
C        Col. 41-50 : Winter probability of variable load level.
C
                    Summer  Intermediate  Winter
                     .3342      .3342      .3315
          .9         .0000      .0000      .1300
          .7         .0000      .0900      .4200
          .5         .1400      .6300      .3600
          .3         .8100      .2800      .0900
          .1         .0500      .0000      .0000
C
C
C  III Chronological load model
C
C  Load level:                  6      5      4      3       2       1
C  Matching Load Model I hours  0-10   10-49  49-83  83-117  117-151 151-168
C
   Weekly Chronological Model expressed in terms of load levels

     Hour:  1   2   3   4   5   6   7   8   9   10  11  12

Day 1       3   3   3   3   3   4   4   4   6   6   6   5
            5   5   5   5   5   5   6   6   4   4   4   4
Day 2       3   3   3   3   3   4   4   4   6   6   6   5
            5   5   5   5   5   5   6   6   4   4   4   4
Day 3       2   2   2   2   2   3   3   5   5   5   5   4
            4   4   4   4   4   4   5   5   5   5   3   3
Day 4       2   2   2   2   2   3   3   5   5   5   5   4
            4   4   4   4   4   4   5   5   5   5   3   3
Day 5       2   2   2   2   3   3   3   5   5   5   5   5
            4   4   4   4   4   4   5   5   5   5   3   3
Day 6       1   1   1   1   1   1   1   1   2   2   2   3
            3   3   2   2   2   2   2   2   2   3   3   3
Day 7       1   1   1   1   1   1   1   1   1   2   2   2
            3   3   2   2   2   2   2   2   2   3   3   3
C
C
C
C
C***  Hydro Generating Unit Modeling  ***
C
```

```
C     Two different hydro models are provided in this section.  Hydro Model I
C is consistent with Load Model I while Hydro Model II is consistent with Load
C Model II.
C
C-----------------------------------------------------------------------
C
C I.  Prescheduled peak shaving load adjustment model by month.
C
C   First Line :  Period in hours for a typical week.
C   Lines 2-13  :  Monthly Modeling Diagrams.
C                  Scheduled hydro generation in per unit of the rated
C                  capacity for the station.
C-----------------------------------------------------------------------
C
C 1. Beechwood Hydro Station
C
```

	0-10	10-49	49-83	83-117	117-151	151-168
Jan.	0.66667	0.52940	0.32350	0.05880	0.02940	0.02940
Feb.	0.67650	0.47060	0.41180	0.05880	0.02940	0.02940
Mar.	0.81180	0.50000	0.41180	0.08820	0.02940	0.02940
Apr.	1.00000	0.94120	0.79410	0.70590	0.52940	0.35290
May	1.00000	1.00000	1.00000	0.85290	0.64710	0.52940
June	0.82350	0.64710	0.58820	0.41180	0.20590	0.02940
July	0.64710	0.54710	0.41180	0.17650	0.02940	0.02940
Aug.	0.61760	0.50000	0.38230	0.17650	0.02940	0.02940
Sep.	0.70590	0.52940	0.29410	0.11760	0.02940	0.02940
Oct.	0.70590	0.52940	0.47060	0.35290	0.02940	0.02940
Nov.	0.79410	0.67650	0.50000	0.29410	0.08820	0.02940
Dec.	0.85290	0.76470	0.41180	0.29410	0.02940	0.02940

```
C
C
C 2. Grand Falls 138 Hydro Station
C
```

	0-10	10-49	49-83	83-117	117-151	151-168
Jan.	1.00000	1.00000	1.00000	0.66667	0.33333	0.33333
Feb.	1.00000	1.00000	1.00000	1.00000	0.33333	0.33333
Mar.	1.00000	1.00000	1.00000	1.00000	0.33333	0.33333
Apr.	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
May	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
June	1.00000	1.00000	1.00000	1.00000	1.00000	0.83333
July	1.00000	1.00000	1.00000	1.00000	0.83333	0.33333
Aug.	1.00000	1.00000	1.00000	1.00000	0.33333	0.16666
Sep.	1.00000	1.00000	1.00000	1.00000	0.83333	0.50000
Oct.	1.00000	1.00000	1.00000	1.00000	1.00000	0.33333
Nov.	1.00000	1.00000	1.00000	1.00000	1.00000	0.50000
Dec.	1.00000	1.00000	1.00000	1.00000	0.66667	0.33333

```
C
C
C 3. Mactaquac Hydro Station
C
```

	0-10	10-49	49-83	83-117	117-151	151-168
Jan.	0.75760	0.46970	0.16670	0.00000	0.00000	0.00000
Feb.	0.60610	0.32580	0.21210	0.02270	0.00000	0.00000
Mar.	0.72730	0.45610	0.21210	0.03790	0.00000	0.00000
Apr.	1.00000	0.84090	0.68180	0.50760	0.32580	0.11360
May	1.00000	1.00000	1.00000	0.76520	0.49240	0.30300
June	0.76520	0.62120	0.46970	0.28790	0.05030	0.00000
July	0.60610	0.43940	0.32270	0.14390	0.00000	0.00000
Aug.	0.50450	0.38180	0.28030	0.13640	0.00000	0.00000
Sep.	0.52270	0.37880	0.27270	0.11360	0.00000	0.00000

```
Oct.   0.65910   0.44700   0.35610   0.18940   0.00000   0.00000
Nov.   0.74240   0.54550   0.41670   0.26520   0.00000   0.00000
Dec.   0.90910   0.56820   0.32580   0.08330   0.00000   0.00000
C
C
C
C II. Seasonal Thermal-Equivalent Hydro Model
C
C    Col.  1- 6 : Hydro Plant Name.
C    Col.  9-12 : Node location identification number.
C    Col. 13-20 : Annual energy production in GWh.
C    Col. 21-26 : Summer energy in per unit of annual total.
C    Col. 27-32 : Intermediate energy in per unit of annual total.
C    Col. 33-38 : Winter energy in per unit of annual total.
C    Col. 39-44 : Maximum equivalent thermal cost for dispatch.
C    Col. 45-50 : Summer cost in per unit of maximum cost.
C    Col. 51-56 : Intermediate cost in per unit of maximum cost.
C    Col. 57-62 : Winter cost in per unit of maximum cost.
C
C
BEECHW  1800     478 .313  .449  .238  35.0  .87   .87   .99
GRFALL  1802     210 .358  .354  .288  33.0  .87   .87   .99
MACTQC  1809    1609 .264  .345  .391  35.5  .87   .87   .99
C
C
C
C
C***  Common Mode Pairs of Lines  ***
C---------------------------------------------------------------------------
C   Col.  4-12 : nodes making up first line subject to common mode failure
C   Col. 19-27 : nodes making up second line subject to common mode failure
C   Col. 35-44 : probability of one line being out of service
C   Col. 55-64 : probability of both lines being out of service
C---------------------------------------------------------------------------
C
   1681-1717      1717-1747      0.00000000          0.00024327
   1776-1839      1776-1901      0.00000000          0.00031959
   1805-1824      1806-1824      0.00000000          0.00041022
   1807-1832      1811-1832      0.00000000          0.00055332
   1712-1807      1712-1812      0.00000000          0.00079659
   1800-1930      1827-1930      0.00000000          0.00042453
   1809-1861      1810-1861      0.00000000          0.00014072
   1825-1852      1852-1946      0.00000000          0.00022514
   1844-1854      1854-1863      0.00000000          0.00023850
   1800-1817      1802-1817      0.00000000          0.00031005
   1806-1928      1677-1928      0.00000000          0.00047462
   1802-1804      1804-1849      0.00000000          0.00006678
   1839-1945      1863-1945      0.00000000          0.00022514
   1800-1847      1827-1847      0.00000000          0.00042220
   1829-1964      1851-1964      0.00000000          0.00060220
C
C
C
C
C
C
C
C
C
C
```

```
C
C
C
C***  Weather Condition Modelling Information  ***
C------------------------------------------------------------------------------
C    Number of geographic zones  =  1
C
C    Number of weather seasons   =  2
C                     Winter : December - March, 4 months
C                 Non-winter : April - November, 8 months
C
C    Duration of adverse weather
C                     winter : 15%
C                 non-winter :  5%
C
C    Percentage of outages occuring in adverse weather  = 90%
C        for both seasons
C
C    Forced outage rates (FOR) applicable for different weather.
C      adverse weather = 5.4 * annual average FOR as specified in
C                        Transmission data.
C      normal weather  = 0.6 * annual average FOR as specified in
C                        Transmission data.
C------------------------------------------------------------------------------
```

APPENDIX II

MONTHLY LOAD DURATION CURVE DATA

NB Power - CIGRE Reliability Test System Load Duration Curves

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
0	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2	94.09	93.85	95.30	95.46	97.50	97.76	95.19	93.82	94.25	93.81	94.01	94.99
4	92.52	92.19	93.32	93.09	94.71	95.34	93.79	92.79	93.19	92.32	92.59	93.39
6	91.43	91.46	92.03	91.87	92.46	94.05	92.93	91.73	92.29	90.79	91.39	92.03
8	90.19	90.44	90.69	90.37	91.04	92.87	91.99	90.99	91.57	89.99	90.79	91.14
10	89.29	89.39	89.45	89.59	90.39	91.89	91.25	90.49	90.29	89.19	89.89	90.09
12	88.06	88.56	88.39	88.79	89.59	91.29	90.39	89.76	89.49	88.69	89.25	88.96
14	87.49	87.39	87.47	88.19	88.69	90.81	89.89	89.29	88.89	87.97	88.69	88.07
16	86.38	86.79	86.77	87.59	87.98	90.19	89.29	88.69	88.29	87.09	88.19	87.38
18	85.39	85.89	86.29	86.87	87.19	89.43	88.79	88.29	87.89	86.69	87.69	86.49
20	84.40	85.39	85.69	85.89	86.39	88.79	88.21	87.89	87.49	85.99	87.29	85.81
22	83.42	84.78	84.92	85.49	85.72	88.19	87.32	87.32	86.99	85.42	86.69	85.12
24	82.68	84.26	84.18	85.09	85.23	87.69	86.83	86.59	86.61	84.88	86.29	84.43
26	82.18	83.78	83.54	84.58	84.68	87.17	86.34	86.09	86.19	84.54	85.87	83.58
28	81.65	83.28	82.72	84.18	84.08	86.59	85.79	85.55	85.79	83.98	85.49	83.15
30	80.78	82.68	81.98	83.58	83.18	85.99	84.98	85.09	84.88	83.69	84.98	82.38
32	80.17	82.08	81.27	82.98	82.58	85.45	84.48	84.68	84.58	83.18	84.74	81.77
34	79.18	81.58	80.48	82.60	82.18	84.68	83.98	84.18	83.88	82.88	84.40	81.28
36	78.48	80.98	79.68	82.28	81.48	84.16	83.50	83.88	83.18	82.58	83.98	80.88
38	77.91	80.58	79.08	81.82	81.18	83.38	82.88	83.28	82.88	82.08	83.62	80.04
40	77.48	80.10	78.58	81.48	80.68	82.68	82.52	82.78	81.98	81.68	83.18	79.48
42	76.98	79.76	78.08	80.74	80.38	81.64	81.88	82.13	81.48	81.08	82.78	78.68
44	76.48	79.38	77.38	80.38	79.78	80.98	81.38	81.58	80.80	80.74	82.18	78.08
46	75.85	78.88	76.78	79.76	79.36	80.26	80.56	81.03	80.26	80.28	81.78	77.35
48	75.28	78.68	76.28	79.28	78.87	79.78	79.57	80.58	79.28	79.97	81.22	76.78
50	74.47	78.08	75.48	78.78	77.98	78.88	79.08	79.68	78.68	79.28	80.58	75.88
52	73.99	77.73	74.67	78.18	77.38	78.38	78.08	78.99	77.68	78.98	80.14	75.00
54	73.37	76.99	74.37	77.58	76.68	77.38	77.10	78.58	76.78	78.08	79.40	74.27
56	72.71	76.38	73.61	77.08	76.01	76.26	76.28	77.68	76.18	77.41	78.88	73.27
58	71.92	75.70	73.17	76.48	75.02	75.52	75.32	76.98	75.32	76.62	77.98	72.57
60	71.09	75.16	72.43	75.88	74.13	75.18	74.47	75.88	74.17	75.94	77.28	71.99
62	70.44	74.41	71.87	74.77	72.72	74.27	73.62	75.35	73.37	75.08	76.38	71.12
64	69.32	74.07	71.47	74.09	71.46	73.39	72.47	74.26	72.19	74.16	75.50	70.65
66	68.56	73.42	70.77	73.47	70.07	71.87	70.17	72.57	71.27	72.87	74.15	69.87
68	67.58	72.88	70.28	72.61	69.07	70.81	68.09	70.48	70.11	71.78	73.37	68.88
70	66.87	72.19	69.67	71.57	68.27	69.37	66.77	69.13	69.27	70.79	72.07	68.17
72	65.50	71.67	69.23	70.49	66.90	67.83	65.50	68.13	68.13	69.50	71.07	67.67
74	64.61	71.27	68.31	69.79	65.80	66.77	64.75	67.37	67.17	68.27	70.49	66.91
76	63.92	70.87	67.67	69.07	64.76	66.05	63.32	66.57	66.35	67.22	69.57	65.97
78	62.53	70.15	66.93	68.37	63.43	65.31	62.26	65.97	65.81	66.57	68.65	65.47
80	61.66	69.27	66.35	67.87	62.74	64.66	61.66	65.25	65.17	65.47	67.67	64.84
82	60.85	68.67	65.67	67.33	61.25	64.16	61.16	64.76	64.22	65.07	66.73	63.36
84	59.76	68.27	65.07	66.87	60.16	63.00	60.66	64.36	63.48	64.66	65.99	62.76
86	59.18	67.68	64.38	66.27	59.38	62.36	60.16	63.96	62.96	63.88	65.45	61.36
88	58.19	66.93	63.22	65.77	58.96	61.26	59.69	63.46	62.40	63.36	64.76	60.02
90	57.00	65.69	62.00	65.27	57.96	60.26	59.10	62.96	61.26	62.64	64.16	58.56
92	56.01	65.07	60.76	64.62	56.86	59.86	58.51	62.51	59.98	61.86	63.12	56.41
94	54.27	63.40	59.56	63.98	55.76	59.08	57.62	62.03	58.98	60.49	62.28	54.42
96	49.88	61.85	55.99	62.18	55.06	57.34	56.93	60.86	57.04	59.54	61.26	52.85
98	47.12	59.90	52.84	59.80	54.14	55.64	53.14	58.98	51.39	57.83	60.48	51.52
100	39.34	56.16	43.74	55.26	52.45	51.15	48.05	41.44	40.94	54.85	55.46	47.05
Peak Load in MW	3156	2960	2887	2432	2209	1942	1767	1854	1962	2199	2550	2913

APPENDIX III

BASE CASE LOAD FLOW RESULTS

PTI INTERACTIVE POWER SYSTEM SIMULATOR—PSS/E FRI, AUG 30 1991 16:05
CIGRE RELIABILITY STUDY : NB POWER TEST SYSTEM
PEAK JAN/1997; FILE : PSSE.SAV.CIGRE.RELI.BASECASE.PEAKLOAD

OUTPUT FOR AREA 1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1677	CARAQT 138	1	1.020	-9.6	100.0	135.7	0.0										
		8	140.8		8.1R	24.0	0.0	1806	BATHST 8 138	1	1	-30.9	-14.6			24	140
								1928	110694 138	99	1	-4.8	-1.3			3	140
1679	LANCST 4 138	1	1.005	1.2	0.0	101.5	0.0										
		4	138.8		0.0	42.0	0.0	1837	C.COVE 4 138	1	1	-101.5	-42.0			57	190
1681	IRVREF 4 138	1	0.993	-2.6	0.0	32.9	0.0										
		21	137.0		0.0	8.3	0.0	1717	LAKEWDEQ 138	99	1	96.7	7.0			51	190
								1813	C. BAY 4 138	1	1	-129.6	-15.3			94	140
1712	111856EQ 138	1	0.939	-18.4	0.0	149.2	0.0										
		5	129.6		0.0	31.0	0.0	1807	NEWCST 138	99	1	-83.5	-14.6			65	140
								1812	MONCTN 5 138	99	1	-65.7	-16.4			51	140
1717	LAKEWDEQ 138	1	0.978	-6.0	0.0	129.2	0.0										
		4	134.9		0.0	31.4	0.0	1681	IRVREF 4 138	99	1	-95.4	-1.3			51	190
								1747	PHSFLO 138	99	1	-33.8	-30.1			24	190
1747	PHSFLO 138	1	1.016	-4.4	0.0	0.0	0.0										
		4	140.1		0.0	0.0	0.0	1717	LAKEWDEQ 138	99	1	34.3	32.2			24	190
								1901	NORTN1 138	1	1	-34.3	-32.2			24	190
1776	1149-EQL 138	1	1.027	-5.3	0.0	46.2	0.0										
		4	141.7		0.0	13.5	0.0	1839	SALBRY 5 138	99	1	43.4	-19.9			33	140
								1901	NORTN1 138	99	1	-89.6	6.4			62	140
1800	BEECHW 138	1	1.033	-0.4	0.0	39.1	0.0										
		1	142.6		0.0	20.0	0.0	1817	111144 1 138	1	1	40.6	-15.1			30	140
								1847	112572 1 138	1	1	-12.7	7.6			10	140
								1890	BEEG12 113.8	1	1	-40.0	-18.1	0.971UN			
								1891	BEEG3 113.8	1	1	-40.0	-9.0	0.971UN			
								1896	TINKER61 138	99	6	7.0	-2.5			5	140
								1930	1126MP 138	1	1	5.9	17.1			13	140
1802	GRFALL 138	1	1.039	-4.0	0.0	0.0	0.0										
		1	143.4		0.0	0.0	0.0	1804	117562 138	1	1	76.9	-10.7			39	190
								1817	111144 1 138	1	1	-46.9	15.8			34	140
								1888	GR.FGH 16.60	1	1	-30.0	-5.1	0.970UN			
1803	KESWIC 2 345	1	1.031	2.5	0.0	0.0	0.0										
		2	355.6		0.0	0.0	0.0	1827	KESWIC 2 138	1	1	-30.3	13.4	0.993RG		6	504
								1827	KESWIC 2 138	2	1	-30.3	13.4	0.993RG		6	504
								1828	KESWIC 2 230	1	1	207.4	-24.3	1.000RG		40	504
								1836	C.COVE 4 345	1	1	-255.5	13.4			35	700
								1843	LEPRAU 345	1	1	-258.5	-0.5			36	700
								1868	STANDR 345	1	1	335.3	-24.3			47	700
								9997	CHSTER30 345	99	3	32.0	8.9			5	700
1804	117562 138	1	1.039	-4.0	0.0	14.9	0.0										
		1	143.4		0.0	3.7	0.0	1802	GRFALL 138	1	1	-76.9	10.8			39	190
								1849	STANDR 138	1	1	62.0	-14.4			32	190
1805	EELRVR 9 138	1	1.038	-4.1	0.0	15.9	0.0										
		22	143.3		0.0	2.0	0.0	1824	TETGCHEQ 138	99	1	42.6	-4.6			29	140
								1826	DALHOU 9 138	1	1	-304.2	4.6			95	310
								1830	EELRVR 9 230	1	1	50.3	-4.6	0.992UN		35	140
								1865	111036 9 138	1	1	6.8	-5.9			6	140
								1948	EELRAD11 138	1	1	188.6	8.5			26	700

PTI INTERACTIVE POWER SYSTEM SIMULATOR—PSS/E   FRI, AUG 30 1991   16:05
CIGRE RELIABILITY STUDY : NB POWER TEST SYSTEM
PEAK JAN/1997: FILE : PSSE.SAV.CIGRE.RELI.BASECASE.PEAKLOAD

OUTPUT FOR AREA   1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1806	BATHST 8 138	1	1.047	-7.6	0.0	130.5	0.0										
		22	144.5		0.0	53.0	-43.9	1677	CARAQT 138	1	1	31.3	11.8			23	140
								1824	TETGCHEQ 138	99	1	4.7	21.9			15	140
								1829	BATHST 8 230	1	1	-13.3	-31.3	0.953UN		14	225
								1829	BATHST 8 230	2	1	-20.3	-46.2	0.953UN		16	300
								1915	BATHST 8 345	1	1	-169.1	18.6	0.988UN		36	450
								1928	110694 138	1	1	-16.2	3.3			11	140
								2497	BMSMEL 138	1	1	52.4	12.9			37	140
1807	NEWCST 138	1	1.040	-7.3	0.0	191.0	0.0										
		22	143.5		0.0	74.0	-75.7	1712	111856EQ 138	99	1	87.7	33.7			65	140
								1832	NBCOALEQ 138	99	1	-47.1	28.0			38	140
								1851	NEWCST 6 230	1	1	-76.7	-28.6	0.987UN		33	236
								1851	NEWCST 6 230	2	1	-76.7	-28.6	0.987UN		33	236
								1969	MLLBNK 138	99	1	-78.3	-2.9			40	190
1809	MACTQC 2 138	1	1.044	5.3	0.0	20.7	0.0										
		2	144.0		0.0	5.0	0.0	1827	KESWIC 2 138	1	1	156.6	19.5			54	280
								1827	KESWIC 2 138	2	1	155.5	19.5			54	280
								1861	RAINSLEQ 138	99	1	167.2	42.9			87	190
								1870	MACTG1 213.8	1	1	-100.0	-17.1	0.945UN			
								1871	MACTG2 213.8	1	1	-100.0	-17.3	0.945UN			
								1872	MACTG3 213.8	1	1	-100.0	-17.1	0.945UN			
								1873	MACTG4 213.8	1	1	-100.0	-18.1	0.945UN			
								1874	MACTG5 213.8	1	1	-100.0	-17.4	0.945UN			
								1875	MACTG6 213.8	1	1	0.0	0.0	0.945UN			
1810	MARYSV 2 138	1	1.013	1.2	0.0	159.6	0.0										
		2	139.8		0.0	41.0	0.0	1811	GRLAKE 2 138	1	1	-20.4	-1.8			14	140
								1845	NASH03 2 138	1	1	-45.6	-18.6			35	140
								1846	NASH12 2 138	1	1	-47.9	-18.8			36	140
								1861	RAINSLEQ 138	99	1	-45.8	-1.8			32	140
1811	GRLAKE 2 138	1	1.020	2.6	0.0	46.2	0.0										
		2	140.7		0.0	30.0	0.0	1810	MARYSV 2 138	1	1	20.5	-1.0			14	140
								1812	MONCTN 5 138	1	1	98.2	-12.5			69	140
								1832	NBCOALEQ 138	99	1	65.0	-9.7			46	140
								1887	GRLKGN 213.8	1	1	-60.0	-1.9	0.975UN			
								1921	GRLKU9 19.0	1	1	-169.9	-4.8	1.025LK			
1812	MONCTN 5 138	1	1.014	-10.9	0.0	350.6	0.0										
		22	140.0		0.0	87.5	-46.3	1712	111856EQ 138	99	1	68.0	26.8			51	140
								1811	GRLAKE 2 138	1	1	-92.8	28.7			68	140
								1839	SALBRY 5 138	1	1	-133.1	-34.4			71	190
								1839	SALBRY 5 138	2	1	-133.1	-34.4			71	190
								1945	119024 138	99	1	-26.1	-9.9			20	140
								1946	112408 138	99	1	-33.6	-18.1			27	140
								1947	MONCTA 569.0	1	1	0.0	0.0	0.980RG		0	134.

OUTPUT FOR AREA 1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1832	NBCOALEQ 138	1	1.016	-2.5	0.0	15.5	0.0										
		6	140.2		0.0	8.0	0.0	1807	NEWCST 138	99	1	48.2	-23.4			38	140
								1811	GRLAKE 2 138	99	1	-63.7	15.4			46	140
1834	OAKBAY 3 138	1	0.966	-9.6	0.0	60.2	0.0										
		3	133.3		0.0	24.8	-28.0	1835	110421 138	99	1	-60.2	3.2			45	140
1835	110421 138	1	0.991	-3.6	0.0	0.0	0.0										
		2	136.7		0.0	0.0	0.0	1834	OAKBAY 3 138	99	1	61.8	3.2			45	140
								1837	C.COVE 4 138	1	1	-61.8	-3.2			45	140
1836	C.COVE 4 345	1	1.029	7.9	0.0	0.0	0.0										
		4	355.0		0.0	0.0	0.0	1803	KESWIC 2 345	1	1	258.1	-50.8			37	700
								1837	C.COVE 4 138	1	1	283.8	74.3	0.984RG		90	318
								1837	C.COVE 4 138	2	1	157.7	41.3	0.984RG		35	450
								1843	LEPRAU 345	1	1	-171.3	-37.6			19	900
								1877	C.CVG1 419.0	1	1	-335.0	-35.4	1.050LK			
								1878	C.CVG2 419.0	1	1	-335.0	-35.4	1.050LK			
								1879	C.CVG3 419.0	1	1	-335.0	-35.4	1.050LK			
								1900	NORTN3 345	1	1	476.7	79.2			67	700
1837	C.COVE 4 138	1	1.025	2.9	0.0	0.0	0.0										
		4	141.4		0.0	0.0	0.0	1679	LANCST 4 138	1	1	102.2	44.9			57	190
								1835	110421 138	1	1	63.3	5.7			44	140
								1836	C.COVE 4 345	1	1	-283.4	-48.0	0.984UN		88	318
								1836	C.COVE 4 345	2	1	-157.5	-26.7	0.984UN		35	450
								1860	MILD47 4 138	1	1	126.0	19.5			89	140
								1862	MILD65 4 138	1	1	115.3	15.1			81	140
								1971	PENFLD 138	1	1	34.0	-10.5			25	140
1838	SALBRY 5 230	1	0.992	-7.1	0.0	0.0	0.0										
		5	228.2		0.0	0.0	0.0	1828	KESWIC 2 230	1	1	-107.3	-18.2			31	350
								1839	SALBRY 5 138	1	1	107.3	18.2	0.950LK		37	300
1839	SALBRY 5 138	1	1.040	-8.4	0.0	0.0	0.0										
		5	143.5		0.0	0.0	0.0	1776	1149-EQL 138	99	1	-42.7	22.5			33	140
								1812	MONCTN 5 138	1	1	134.7	40.2			71	190
								1812	MONCTN 5 138	2	1	134.7	40.2			71	190
								1838	SALBRY 5 230	1	1	-107.2	-15.6	0.950UN		35	300
								1850	SALBRY 5 345	1	1	-192.9	-68.8	0.919UN		44	450
								1850	SALBRY 5 345	2	1	-149.6	-75.6	0.910UN		47	340
								1945	119024 138	1	1	113.3	30.8			81	140
								1946	112408 138	1	1	109.7	26.4			77	140
1843	LEPRAU 345	1	1.034	8.8	0.0	22.0	0.0										
		25	356.6		0.0	10.0	0.0	700	ORRING30 345	1	3	200.6	-59.4			29	700
								1803	KESWIC 2 345	1	1	261.6	-42.8			37	700
								1836	C.COVE 4 345	1	1	171.6	25.0			19	900
								1876	LEPRG1 426.0	1	1	-655.8	67.1	1.010LK			
1845	NASH03 2 138	1	1.017	1.5	0.0	20.9	0.0										
		2	140.4		0.0	5.3	0.0	1810	MARYSV 2 138	1	1	45.6	18.5			35	140
								1827	KESWIC 2 138	1	1	-66.5	-23.8			50	140
1846	NASH12 2 138	1	1.017	1.5	0.0	20.9	0.0										
		2	140.4		0.0	5.3	0.0	1810	MARYSV 2 138	1	1	48.0	18.8			36	140
								1827	KESWIC 2 138	1	1	-68.9	-24.1			51	140

OUTPUT FOR AREA 1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1847	112572 1 138	1	1.023	0.9	0.0	55.0	0.0										
		1	141.2		0.0	14.8	0.0										
								1800	BEECHW 138	1	1	12.8	-11.9			12	140
								1827	KESWIC 2 138	1	1	-67.8	-3.0			47	140
1849	STANDR 138	1	1.038	-5.2	0.0	0.0	0.0										
		1	143.3		0.0	0.0	0.0										
								1804	117562 138	1	1	-61.6	14.8			32	190
								1865	111036 9 138	1	1	-4.7	-3.7			4	140
								1868	STANDR 345	1	1	66.3	-11.1	0.979UN		22	293
1850	SALBRY 5 345	1	0.978	-5.1	0.0	0.0	0.0										
		5	337.4		0.0	0.0	-15.3										
								168	ONSLOW 345	99	5	7.1	-38.4			10	400
								1839	SALBRY 5 138	1	1	193.1	81.6	0.919RG		48	450
								1839	SALBRY 5 138	2	1	149.8	86.9	0.910RG		52	340
								1900	NORTN3 345	1	1	-341.6	-24.9			50	700
								1916	NEWCAS 6 345	1	1	-8.4	-89.8			13	700
1851	NEWCST 6 230	1	1.037	-5.9	0.0	0.0	0.0										
		6	238.4		0.0	0.0	0.0										
								1807	NEWCST 138	1	1	76.7	30.7	0.987RG		34	236
								1807	NEWCST 138	2	1	76.7	30.7	0.987RG		34	236
								1828	KESWIC 2 230	1	1	-95.3	1.4			26	350
								1916	NEWCAS 6 345	1	1	-31.8	-90.3	0.920UN		23	400
								1964	MBNKTP 230	1	1	-26.3	27.4			10	350
1852	110871 5 138	1	1.019	-10.7	0.0	21.9	0.0										
		5	140.7		0.0	5.5	0.0										
								1825	MEMCOK 5 138	1	1	46.3	-2.2			32	140
								1946	112408 138	1	1	-68.2	-3.3			48	140
1854	HARDRD 5 138	1	1.006	-14.8	0.0	4.8	0.0										
		5	138.9		0.0	1.2	0.0										
								1844	MURRCR 5 138	1	2	20.1	-15.2			18	140
								1863	119042 138	1	1	-24.9	14.0			20	140
1860	MILD47 4 138	1	1.002	-0.9	0.0	26.0	0.0										
		23	138.3		0.0	6.6	0.0										
								1813	C. BAY 4 138	1	1	98.2	5.7			70	140
								1837	C.COVE 4 138	1	1	-124.2	-12.3			89	140
1861	RAINSLEQ 138	1	1.018	2.1	0.0	119.2	0.0										
		2	140.5		0.0	30.0	0.0										
								1809	MACTQC 2 138	99	1	-165.2	-32.5			87	190
								1810	MARYSV 2 138	99	1	46.0	2.5			32	140
1862	MILD65 4 138	1	1.004	-0.7	0.0	0.0	0.0										
		4	138.5		0.0	0.0	0.0										
								1813	C. BAY 4 138	1	1	113.7	9.3			81	140
								1837	C.COVE 4 138	1	1	-113.7	-9.3			81	140
1863	119042 138	1	0.998	-13.2	0.0	65.8	0.0										
		5	137.7		0.0	34.1	0.0										
								183	SPRNGHIL 138	99	5	-12.5	-5.2			10	140
								1854	HARDRD 5 138	1	1	25.1	-15.8			21	140
								1945	119024 138	1	1	-78.4	-13.1			57	140
1865	111036 9 138	1	1.040	-4.4	0.0	2.1	0.0										
		9	143.6		0.0	0.5	0.0										
								1805	EELRVR 9 138	1	1	-6.8	4.3			6	140
								1849	STANDR 138	1	1	4.7	-4.8			5	140
1866	EELRVR 9 345	1	1.037	-5.3	0.0	0.0	0.0										
		9	357.9		0.0	0.0	0.0										
								1830	EELRVR 9 230	1	1	192.5	32.8	1.001UN		47	400
								1868	STANDR 345	1	1	45.1	-4.4			6	700
								1913	BELDUN 9 345	1	1	-237.6	-28.4			33	700
1867	EDMSTN 1 345	1	1.003	-10.3	0.0	0.0	0.0										
		1	346.1		0.0	0.0	0.0										
								1868	STANDR 345	1	1	-437.9	-53.2			63	700
								1869	MADHYQ 345	1	4	200.4	12.0			50	400
								1907	EDMSTN12 138	1	1	118.8	20.6	0.967RG		41	293
								1907	EDMSTN12 138	2	1	118.8	20.6	0.967RG		41	293

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PEAK JAN/1997; FILE : PSSE.SAV.CIGRE.RELI.BASECASE.PEAKLOAD

OUTPUT FOR AREA 1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1868	STANDR 345	1	1.020	-6.4	0.0	0.0	0.0										
		1	351.8		0.0	0.0	0.0	1803	KESWIC 2 345	1	1	-329.9	-1.1			46	700
								1849	STANDR 138	1	1	-66.3	12.4	0.979RG		23	293
								1866	EELRVR 9 345	1	1	-44.9	-70.6			12	700
								1867	EDMSTN 1 345	1	1	441.1	59.3			62	700
1870	MACTG1 213.8	1	1.000	9.1	100.0	0.0	0.0										
		2	13.80		24.1R	0.0	0.0	1809	MACTQC 2 138	1	1	100.0	24.1	0.945LK			
1871	MACTG2 213.8	1	1.000	9.1	100.0	0.0	0.0										
		2	13.80		24.2R	0.0	0.0	1809	MACTQC 2 138	1	1	100.0	24.2	0.945LK			
1872	MACTG3 213.8	1	1.000	9.1	100.0	0.0	0.0										
		2	13.80		24.1R	0.0	0.0	1809	MACTQC 2 138	1	1	100.0	24.1	0.945LK			
1873	MACTG4 213.8	1	1.000	9.0	100.0	0.0	0.0										
		2	13.80		24.8R	0.0	0.0	1809	MACTQC 2 138	1	1	100.0	24.8	0.945LK			
1874	MACTG5 213.8	1	1.000	9.1	100.0	0.0	0.0										
		2	13.80		24.2R	0.0	0.0	1809	MACTQC 2 138	1	1	100.0	24.2	0.945LK			
1875	MACTG6 213.8	1	0.986	5.3	0.0	0.0	0.0										
		2	13.61		0.0	0.0	0.0	1809	MACTQC 2 138	1	1	0.0	0.0	0.945LK			
1876	LEPRG1 426.0	1	1.020	15.2	657.0	0.0	0.0										
		25	26.52		5.8R	0.0	0.0	1843	LEPRAU 345	1	1	657.0	5.8	1.010UN			
1877	C.CVG1 419.0	1	1.000	14.8	335.0	0.0	0.0										
		4	19.00		77.0R	0.0	0.0	1836	C.COVE 4 345	1	1	335.0	77.0	1.050UN			
1878	C.CVG2 419.0	1	1.000	14.8	335.0	0.0	0.0										
		4	19.00		77.0R	0.0	0.0	1836	C.COVE 4 345	1	1	335.0	77.0	1.050UN			
1879	C.CVG3 419.0	1	1.000	14.8	335.0	0.0	0.0										
		4	19.00		77.0R	0.0	0.0	1836	C.COVE 4 345	1	1	335.0	77.0	1.050UN			
1880	DALHG1 913.8	1	1.000	4.9	103.0	0.0	0.0										
		9	13.80		12.4R	0.0	0.0	1826	DALHOU 9 138	1	1	103.0	12.4	0.950LK			
1881	DALHG2 919.0	1	1.000	3.6	203.0	0.0	0.0										
		9	19.00		26.0R	0.0	0.0	1826	DALHOU 9 138	1	1	203.0	26.0	0.950LK			
1883	C.BYG1 413.8	1	1.000	1.8	44.5	0.0	0.0										
		4	13.80		4.6R	0.0	0.0	1813	C. BAY 4 138	1	1	44.5	4.6	1.000LK			
1884	C.BYG2 46.90	1	1.000	-0.4	12.3	0.0	0.0										
		4	6.90		3.6R	0.0	0.0	1813	C. BAY 4 138	98	1	19.9	3.4	1.000UN			
								1885	C.BYG3 413.8	99	1	-7.6	0.3				
1885	C.BYG3 413.8	1	1.000	6.3	100.0	0.0	0.0										
		4	13.80		10.6R	0.0	0.0	1813	C. BAY 4 138	98	1	92.4	9.9	1.000UN			
								1884	C.BYG2 46.90	99	1	7.6	0.6				

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OUTPUT FOR AREA 1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1886	C.BYG4 413.8	1	1.035	1.3	97.0	0.0	0.0										
		4	14.29		66.0H	0.0	0.0	1813	C. BAY 4 138	1	1	97.0	66.0	1.000LK			
1887	GRLKGN 213.8	1	1.000	7.2	60.0	0.0	0.0										
		2	13.80		6.8R	0.0	0.0	1811	GRLAKE 2 138	1	1	60.0	6.8	0.975LK			
1888	GR.FGH 16.60	1	1.023	0.1	30.0	0.0	0.0										
		1	6.75		7.4R	0.0	0.0	1802	GRFALL 138	1	1	30.0	7.4	0.970LK			
1890	BEEG12 113.8	1	1.022	1.8	40.0	0.0	0.0										
		1	14.10		20.0R	0.0	0.0	1800	BEECHW 138	1	1	40.0	20.0	0.971LK			
1891	BEEG3 113.8	1	1.022	3.6	40.0	0.0	0.0										
		1	14.10		12.0R	0.0	0.0	1800	BEECHW 138	1	1	40.0	12.0	0.971LK			
1900	NORTN3 345	1	0.991	-0.7	0.0	0.0	0.0										
		4	341.9		0.0	0.0	0.0	1836	C.COVE 4 345	1	1	-469.1	-55.9			68	700
								1850	SALBRY 5 345	1	1	344.4	19.6			50	700
								1901	NORTN1 138	1	1	124.7	36.4	0.946RG		39	340
1901	NORTN1 138	1	1.033	-3.5	0.0	0.0	0.0										
		4	142.5		0.0	0.0	0.0	1747	PHSFLO 138	1	1	34.3	33.3			24	190
								1776	1149-EQL 138	99	1	90.2	-3.6			62	140
								1900	NORTN3 345	1	1	-124.5	-29.7	0.946UN		36	340
1907	EDMSTN12 138	1	1.032	-12.2	0.0	0.0	0.0										
		12	142.4		0.0	0.0	0.0	1867	EDMSTN 1 345	1	1	-118.7	-16.5	0.967UN		40	293
								1867	EDMSTN 1 345	2	1	-118.7	-16.5	0.967UN		40	293
								1908	114084 138	1	1	123.1	7.2			85	140
								1910	IROQUB 138	1	1	114.2	25.8			81	140
1908	114084 138	1	1.028	-13.2	0.0	0.0	0.0										
		12	141.9		0.0	0.0	0.0	1907	EDMSTN12 138	1	1	-122.8	-5.6			85	140
								1909	IROQUA 138	1	1	122.8	5.6			85	140
1909	IROQUA 138	1	1.027	-13.3	0.0	122.7	0.0										
		22	141.8		0.0	37.0	-31.7	1908	114084 138	1	1	-122.7	-5.4			85	140
1910	IROQUB 138	1	1.025	-13.1	40.0	153.9	0.0										
		12	141.4		9.3R	33.6	0.0	1907	EDMSTN12 138	1	1	-113.9	-24.3			81	140
1913	BELDUN 9 345	1	1.045	-3.0	0.0	0.0	0.0										
		9	360.5		0.0	0.0	0.0	1866	EELRVR 9 345	1	1	238.6	8.5			33	700
								1914	BELGEN 19.0	1	1	-449.4	-74.6	0.975UN		58	756
								1915	BATHST 8 345	1	1	210.8	66.1			30	700
1914	BELGEN 19.0	1	1.035	1.0	450.0	0.0	0.0										
		9	19.66		108.0R	0.0	0.0	1913	BELDUN 9 345	1	1	450.0	108.0	0.975LK		59	756
1915	BATHST 8 345	1	1.031	-4.7	0.0	0.0	0.0										
		8	355.6		0.0	0.0	0.0	1806	BATHST 8 138	1	1	169.2	-9.8	0.988RG		37	450
								1913	BELDUN 9 345	1	1	-210.1	-83.7			31	700
								1916	NEWCAS 6 345	1	1	40.9	93.5			14	7006

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OUTPUT FOR AREA 1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING %I	RATING A MVA
1916	NEWCAS 6 345	1	1.003	-5.1	0.0	0.0	0.0										
		6	346.0		0.0	0.0	0.0	1850	SALBRY 5 345	1	1	8.6	33.0			5	700
								1851	NEWCST 6 230	1	1	32.0	95.4	0.920RG		25	400
								1915	BATHST 8 345	1	1	-40.6	-128.4			19	700
1921	GRLKU9 19.0	1	1.000	6.8	170.0	0.0	0.0										
		2	19.00		17.1R	0.0	0.0	1811	GRLAKE 2 138	1	1	170.0	17.1	1.025UN			
1928	110694 138	1	1.047	-7.1	0.0	0.0	0.0										
		8	144.5		0.0	0.0	0.0	1677	CARAQT 138	99	1	4.8	1.6			3	140
								1806	BATHST 8 138	1	1	16.3	-4.7			12	140
								1969	MLLBNK 138	1	1	-21.1	3.2			15	140
1930	1126MP 138	1	1.018	-0.5	0.0	50.3	0.0										
		1	140.4		0.0	20.8	0.0	1800	BEECHW 138	1	1	-5.9	-19.1			14	140
								1827	KESWIC 2 138	1	1	-44.4	-1.7			31	140
1945	119024 138	1	1.018	-10.7	0.0	6.6	0.0										
		5	140.4		0.0	1.5	0.0	1812	MONCTN 5 138	99	1	26.1	10.1			20	140
								1839	SALBRY 5 138	1	1	-112.0	-26.9			81	140
								1863	119042 138	1	1	79.3	15.3			57	140
1946	112408 138	1	1.020	-10.6	0.0	6.6	0.0										
		5	140.7		0.0	1.5	0.0	1812	MONCTN 5 138	99	1	33.7	18.4			27	140
								1839	SALBRY 5 138	1	1	-108.5	-22.8			78	140
								1852	110871 5 138	1	1	68.2	3.0			48	140
1947	MONCTA 569.0	1	1.035	-10.9	0.0	0.0	0.0										
		5	71.44		0.0	0.0	0.0	1812	MONCTN 5 138	1	1	0.0	0.0	0.980UN		0	134
1948	EELRAD11 138	1	1.038	-4.1	0.0	108.8	0.0										
		11	143.3		0.0	43.4	-21.6	1805	EELRVR 9 138	1	1	-188.6	-8.5			26	700
								1830	EELRVR 9 230	1	1	50.0	-20.3	0.978UN		37	140
								2495	NBIPC 11 138	1	1	29.8	7.0			21	140
1964	MBNKTP 230	1	1.034	-5.8	0.0	0.0	0.0										
		8	237.9		0.0	0.0	0.0	1829	BATHST 8 230	1	1	71.0	40.2			23	350
								1851	NEWCST 6 230	1	1	26.4	-29.5			11	350
								1965	MLLBNK 230	1	1	-97.3	-10.7			27	350
1965	MLLBNK 230	1	1.037	-5.2	0.0	0.0	0.0										
		8	238.6		0.0	0.0	0.0	1964	MBNKTP 230	1	1	97.5	9.1			27	350
								1986	MBKGT1 13.8	1	1	-97.5	-9.1	0.950UN		76	125
								1987	MBKGT2 13.8	1	1	0.0	0.0	0.950UN		0	125
1969	MLLBNK 138	1	1.048	-5.9	0.0	0.0	0.0										
		8	144.6		0.0	0.0	0.0	1807	NEWCST 138	99	1	78.8	4.9			40	190
								1928	110694 138	1	1	21.2	-5.8			15	140
								1988	MBKGT3 13.8	1	1	-100.0	0.9	0.950UN		76	125
								1989	MBKGT4 13.8	1	1	0.0	0.0	0.950UN		0	125
1971	PENFLD 138	1	1.026	0.6	25.0	58.7	0.0										
		3	141.6		18.0L	18.6	-10.5	1837	C.COVE 4 138	1	1	-33.7	9.9			24	140
1986	MBKGT1 13.8	1	1.000	0.5	97.5	0.0	0.0										
		8	13.80		19.0R	0.0	0.0	1965	MLLBNK 230	1	1	97.5	19.0	0.950LK		80	125
1987	MBKGT2 13.8	1	0.985	-5.2	0.0	0.0	0.0										
		8	13.60		0.0	0.0	0.0	1965	MLLBNK 230	1	1	0.0	0.0	0.950LK		0	125

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OUTPUT FOR AREA 1 {N.B. POW}

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1988	MBKGT3 13.8	1	1.000	0.0	100.0	0.0	0.0										
		8	13.80		9.3R	0.0	0.0	1969	MLLBNK 138	1	1	100.0	9.3	0.950LK		80	125
1989	MBKGT4 13.8	1	0.996	-5.9	0.0	0.0	0.0										
		8	13.74		0.0	0.0	0.0	1969	MLLBNK 138	1	1	0.0	0.0	0.950LK		0	125
2495	NBIPC 11 138	1	1.034	-4.6	0.0	29.7	0.0										
		21	142.7		0.0	7.5	0.0	1948	EELRAD11 138	1	1	-29.7	-7.5			21	140
2496	ROTHPR 138	1	0.994	-2.3	0.0	89.1	0.0										
		21	137.2		0.0	22.3	0.0	1813	C. BAY 4 138	1	1	-89.1	-22.3			66	140
2497	BMSMEL 138	1	1.031	-9.3	0.0	52.0	0.0										
		21	142.3		0.0	13.1	0.0	1806	BATHST 8 138	1	1	-52.0	-13.1			37	140
2498	NBIPC 11 230	1	1.032	-7.0	0.0	68.9	0.0										
		21	237.3		0.0	17.3	0.0	1830	EELRVR 9 230	1	1	-68.9	-17.3			20	350
2499	CONSBH 8 230	1	1.008	-7.5	0.0	60.0	0.0										
		21	231.8		0.0	16.4	0.0	1829	BATHST 8 230	1	1	-60.0	-16.4			18	350

OUTPUT FOR AREA 2 { }

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1844	MURRCR 5 138	2	1.009	-15.2	0.0	60.0	0.0										
		5	139.3		0.0	-20.0	0.0	1825	MEMCOK 5 138	1	1	-39.9	5.4			29	140
								1854	HARDRD 5 138	1	1	-20.1	14.6			18	140E

OUTPUT FOR AREA 3 { }

BUS DATA								LINE DATA									
FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
700	ORRING30 345	3	1.027	1.2	0.0	230.0	0.0										
		30	354.2		0.0	54.0	0.0	1843	LEPRAU 345	1	1	-198.1	-41.1			28	700
								9997	CHSTER30 345	1	3	-31.9	-12.9			5	700
9997	CHSTER30 345	3	1.025	1.6	0.0	0.0	0.0										
		30	353.6		-42.7R	0.0	0.0	700	ORRING30 345	1	3	31.9	-34.3			7	700
								1803	KESWIC 2 345	99	1	-31.9	-8.4			5	700L

OUTPUT FOR AREA 4 { }

FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1869	MADHYQ 345	4	1.000	-11.2	0.0	200.0	0.0										
		1	345.0		18.8R	40.0	0.0	1867	EDMSTN 1 345	1	1	-200.0	-21.2			50	400
9996	EELHYQ 230	4	1.032	-7.2	0.0	200.0	0.0										
		9	237.5		38.8R	40.0	0.0	1830	EELRVR 9 230	99	1	-200.0	-1.2			55	350

OUTPUT FOR AREA 5 { }

FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
157	MACCAN 138	5	1.007	-12.5	0.0	12.6	0.0										
		36	139.0		0.0	5.1	0.0	183	SPRNGHIL 138	99	5	-7.1	-0.6			5	140
								1825	MEMCOK 5 138	99	1	-5.5	-4.5			5	140
158	ONSLOW 138	5	1.045	-8.5	0.0	50.1	0.0										
		36	144.2		0.0	90.5	-54.6	167	ONSLOW 230	1	5	-94.1	-47.8	0.950UN		45	224
								183	SPRNGHIL 138	1	5	44.0	11.9			31	140
167	ONSLOW 230	5	1.016	-6.4	0.0	31.4	0.0										
		36	233.6		0.0	112.7	0.0	158	ONSLOW 138	1	5	94.4	52.4	0.950LK		47	224
								168	ONSLOW 345	1	5	-64.2	-81.5	0.960UN		26	392
								168	ONSLOW 345	2	5	-61.6	-83.6	0.960UN		26	392
168	ONSLOW 345	5	1.000	-5.5	119.1	0.0	0.0										
		36	345.0		210.8R	0.0	0.0	167	ONSLOW 230	1	5	64.4	84.6	0.960LK		27	392
								167	ONSLOW 230	2	5	61.7	86.8	0.960LK		27	392
								1850	SALBRY 5 345	99	1	-7.0	39.3			10	400
183	SPRNGHIL 138	5	1.008	-12.4	0.0	23.6	0.0										
		36	139.1		0.0	7.1	0.0	157	MACCAN 138	99	5	7.1	0.6			5	140
								158	ONSLOW 138	1	5	-43.2	-13.2			32	140
								1863	119042 138	99	1	12.6	5.4			10	140

OUTPUT FOR AREA 6 { }

FROM BUS	NAME	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS	NAME	CKT	AREA	MW	MVAR	TRANSFORMER RATIO	TRANSFORMER ANGLE	RATING A %I	RATING A MVA
1896	TINKER61 138	6	1.037	-2.3	0.0	0.0	0.0										
		10	143.1		0.0	0.0	0.0	1800	BEECHW 138	99	1	-7.0	2.7			5	140
								1817	111144 1 138	1	1	7.0	-2.7			5	140E

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GENERATOR SUMMARY:

BUS	NAME	BSVLT	#MAC	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
168	ONSLOW	345	4	2	119.1	210.8	450.0	-150.0	1.0000	1.0000	
700	ORRING30	345	3	-2	0.0	0.0	0.0	0.0	1.0000	1.0265	
1677	CARAQT	138	1	2	100.0	8.1	60.0	-40.0	1.0200	1.0200	
1844	MURRCR 5	138	1	-2	0.0	0.0	0.0	0.0	1.0000	1.0091	
1869	MADHYQ	345	1	2	0.0	18.8	210.0	-100.0	1.0000	1.0000	
1870	MACTG1	213.8	1	2	100.0	24.1	52.0	-52.0	1.0000	1.0000	
1871	MACTG2	213.8	1	2	100.0	24.2	52.0	-52.0	1.0000	1.0000	
1872	MACTG3	213.8	1	2	100.0	24.1	52.0	-52.0	1.0000	1.0000	
1873	MACTG4	213.8	1	2	100.0	24.8	52.0	-52.0	1.0000	1.0000	
1874	MACTG5	213.8	1	2	100.0	24.2	54.0	-54.0	1.0000	1.0000	
1875	MACTG6	213.8	1	-2	0.0	0.0	0.0	0.0	1.0000	0.9864	
1876	LEPRG1	426.0	1	2	657.0	5.8	415.0	-230.0	1.0200	1.0200	
1877	C.CVG1	419.0	1	2	335.0	77.0	160.0	-98.0	1.0000	1.0000	
1878	C.CVG2	419.0	1	2	335.0	77.0	160.0	-98.0	1.0000	1.0000	
1879	C.CVG3	419.0	1	2	335.0	77.0	160.0	-98.0	1.0000	1.0000	
1880	DALHG1	913.8	1	2	103.0	12.4	66.0	-20.0	1.0000	1.0000	
1881	DALHG2	919.0	1	2	203.0	26.0	100.0	-60.0	1.0000	1.0000	
1883	C.BYG1	413.8	1	2	44.5	4.6	31.5	-12.0	1.0000	1.0000	
1884	C.BYG2	46.90	1	2	12.3	3.6	8.3	-5.5	1.0000	1.0000	
1885	C.BYG3	413.8	1	2	100.0	10.6	66.0	-46.0	1.0000	1.0000	
1886	C.BYG4	413.8	1	-2	97.0	66.0	66.0	-46.0	1.0100	0.9951	1813
1887	GRLKGN	213.8	1	2	60.0	6.8	37.0	-15.0	1.0000	1.0000	
1888	GR.FGH	16.60	1	2	30.0	7.4	15.4	-15.4	1.0227	1.0227	
1890	BEEG12	113.8	1	2	40.0	20.0	35.2	-36.0	1.0217	1.0217	
1891	BEEG3	113.8	1	2	40.0	12.0	20.0	-20.0	1.0217	1.0217	
1896	TINKER61	138	2	-2	0.0	0.0	0.0	0.0	1.0000	1.0366	
1910	IROQUB	138	1	2	40.0	9.3	30.0	-30.0	1.0250	1.0250	
1914	BELGEN	19.0	1	2	450.0	108.0	320.0	-250.0	1.0450	1.0450	1913
1921	GRLKU9	19.0	1	2	170.0	17.1	83.0	-40.0	1.0000	1.0000	
1947	MONCTA	569.0	1	-2	0.0	0.0	0.0	0.0	1.0000	1.0353	
1971	PENFLD	138	1	-2	25.0	18.0	-12.0	18.0	1.0150	1.0263	
1986	MBKGT1	13.8	1	3	97.5	19.0	66.0	-20.0	1.0000	1.0000	
1987	MBKGT2	13.8	1	-2	0.0	0.0	0.0	0.0	1.0000	0.9855	
1988	MBKGT3	13.8	1	2	100.0	9.3	66.0	-20.0	1.0000	1.0000	
1989	MBKGT4	13.8	1	-2	0.0	0.0	0.0	0.0	1.0000	0.9955	
9996	EELHYQ	230	1	2	0.0	38.8	50.0	-50.0	1.0325	1.0325	
9997	CHSTER30	345	1	2	0.0	-42.7	425.0	-125.0	1.0250	1.0250	
SUBSYSTEM TOTALS					3993.4	942.3	3350.4	-1868.9	MVABASE=		5864.6

PTI INTERACTIVE POWER SYSTEM SIMULATOR—PSS/E FRI, AUG 30 1991 16:05
CIGRE RELIABILITY STUDY : NB POWER TEST SYSTEM
PEAK JAN/1997; FILE : PSSE.SAV.CIGRE.RELI.BASECASE.PEAKLOAD

BUSES WITH VOLTAGE GREATER THAN 1.0500:

X——— BUS ———X	AREA	V(PU)	V(KV)	X——— BUS ———X	AREA	V(PU)	V(KV)

* NONE *

BUSES WITH VOLTAGE LESS THAN 0.9500:

X——— BUS ———X	AREA	V(PU)	V(KV)	X——— BUS ———X	AREA	V(PU)	V(KV)
1712 111856EQ 138	1	0.9391	129.60				

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI, AUG 30 1991 16:10
CIGRE RELIABILITY STUDY : NB POWER TEST SYSTEM AREA TIE LINE
PEAK JAN/1997; FILE : PSSE.SAV.CIGRE.RELI.BASECASE.PEAKLOAD INTERCHANGE

FROM AREA 1 N.B. POW

TO AREA 2

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
1825 MEMCOK 5 138	1844* MURRCR 5 138	1	39.9	-5.4		
1854 HARDRD 5 138	1844* MURRCR 5 138	1	20.1	-14.6		
TOTAL FROM AREA 1 TO AREA 2					60.0	-20.0

TO AREA 3

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
1803 KESWIC 2 345	9997* CHSTER30 345	99	31.9	8.4		
1843* LEPRAU 345	700 ORRING30 345	1	200.6	-59.4		
TOTAL FROM AREA 1 TO AREA 3					232.6	-51.0

TO AREA 4

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
1830 EELRVR 9 230	9996* EELHYQ 230	99	200.0	1.2		
1867 EDMSTN 1 345	1869* MADHYQ 345	1	200.0	21.2		
TOTAL FROM AREA 1 TO AREA 4					400.0	22.4

TO AREA 5

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
1825 MEMCOK 5 138	157* MACCAN 138	99	5.5	4.5		
1850 SALBRY 5 345	168* ONSLOW 345	99	7.0	-39.3		
1863 119042 138	183* SPRNGHIL 138	99	-12.6	-5.4		
TOTAL FROM AREA 1 TO AREA 5					0.0	-40.3

TO AREA 6

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
1800 BEECHW 138	1896* TINKER61 138	99	7.0	-2.7		
1817 111144 1 138	1896* TINKER61 138	1	-7.0	2.7		
TOTAL FROM AREA 1 TO AREA 6					0.0	0.0

TOTAL FROM AREA 1 692.5 -88.9

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI, AUG 30 1991 16:05
CIGRE RELIABILITY STUDY : NB POWER TEST SYSTEM AREA TOTALS
PEAK JAN/1997; FILE : PSSE.SAV.CIGRE.RELI.BASECASE.PEAKLOAD IN MW/MVAR

AREA	FROM GENERATION	TO LOAD	TO BUS SHUNT	TO LINE SHUNT	FROM CHARGING	TO NET INT	LOSSES	DESIRED NET INT
1	3874.3	3097.0	0.0	0.0	0.0	692.5	84.8	690.0
N.B. POW	716.6	910.0	-340.9	0.0	768.3	-88.9	1004.8	
2	0.0	60.0	0.0	0.0	0.0	-60.0	0.0	0.0
	0.0	-20.0	0.0	0.0	0.0	20.0	0.0	
3	0.0	230.0	0.0	0.0	0.0	-232.6	2.6	0.0
	-42.7	54.0	0.0	0.0	174.4	51.0	26.7	
4	0.0	400.0	0.0	0.0	0.0	-400.0	0.0	0.0
	57.6	80.0	0.0	0.0	0.0	-22.4	0.0	
5	119.1	117.7	0.0	0.0	0.0	0.0	1.3	0.0
	210.8	215.4	-54.6	0.0	4.6	40.3	14.3	
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
TOTALS	3993.4	3904.7	0.0	0.0	0.0	0.0	88.7	690.0
	942.3	1239.4	-395.5	0.0	947.2	0.0	1045.9	

APPENDIX IV

ENEL REPORT

The Computing Program SICRET
for
Adequacy Evaluation of a Composite Power System

1. FOREWORD

In planning studies of composite power systems (generation plus transmission) simulation methods based on the Monte-Carlo technique allow the system adequacy to be quantitatively evaluated even in the most complex cases.

The numerical adequacy indices can be quantified and introduced into the overall economic optimization of the system.

The SICRET program is intended for the study of a system including thermal and hydraulic generation and a transmission network of the meshed type.

It is mainly used during planning of transmission systems in order to verify their overall adequacy and the convenience of reinforcing some particular part of the network. It can be also used for the determination of the basic characteristics of the main transmission system components, such as overhead lines carrying capacity, substation layout, etc.

2. METHODOLOGY

The quantitative evaluation of the power system reliability in steady-state conditions (adequacy) is obtained through a "risk index" which expresses, in a probabilistic way, the comparison at given time between the steady-state generated and transmitted capacity with the components available at the time, and the load to be supplied. This index does not take into account the transients of the system when forced outages occur.

The static index obtained by the program is the yearly Expected Energy Not Supplied (EENS in MWh/Year) due to deficiency of the generation and/or transmission system, and takes into account the active power system constraints.

As to the "how", the system risk is broken down according to the main primal causes as follows:
- lack of total available generations capacity (risk due to lack of power);
- insufficient capability of lines and/or transformers (risk due to network overloading);
- insufficient local generating capacity in isolated areas or nodes due to line outages (risk due to network splitting or to node isolation).

All the above quoted indices can be obtained for the system as a whole and for each load bus, "where" the deficiency occurs.

The results may also be subdivided according to the metereological conditions ("when") in which the load shedding occurs.

In order to evaluate the composite power system adequacy, the Monte-Carlo simulation method is applied according to the followings:

a) the reference period of time (one calendar year), during which the system behaviour is examined, is divided into elementary intervals, each lasting one hour. The assumption is made that the state of the system is constant during such intervals and that all its changes occur at the beginning of the interval;

b) the power system state is characterized in each hour by the following elements:
   i. the load of each network node;
   ii. the availability of the system components (generators, lines, etc.) (1);
   iii. the operation policies (unit committment, load shedding, network connection, etc.)

c) the changes in the system state are caused by:
   i. the events that are generally random, and thus unpredictable by the operation staff, which cause variations of component availability and of the load demand;
   ii. the dispatching actions in order to match the system state with the above mentioned changes. Such actions are carried out in order to obtain the best service quality (pure adequacy policies) or the best compromise between service quality and economy (mixed adequacy and economy policies).

The Monte-Carlo simulation is carried out considering a sufficiently wide number of time intervals ("sampled hours"). In each hour:

- a possible system configuration is randomly determined starting from the probabilistic availability distribution of each system component (generating units, lines, transformers, D.C.-A.C. conversion stations, etc.), and from the load diagrams;

- the action of the Dispatching Center is simulated by means of the more or less complex selected policies;

- the variables of interest in planning or designing stages (energy curtailements, frequency and amount of load-shedding, statistics of power flows in the lines, etc...) are evaluated using the linear formulation of the network equations (d.c. load-flow);

----

(1) As far as the availability of the overhead lines is concerned, it is possible to model the outage concentration due to the occurrence of adverse weather conditions and the common mode outages.

The total number of hours considered (sample size) must be representative of the reference period, usually fixed in a "calendar year", during which the system composition is assumed to remain constant, and so extended that the results of the Monte-Carlo simulation will have the required confidence.

The system situations and the order of their examination are obtained by random sampling of the hours of constitute the calendar year. This type of Monte-Carlo approach is usually called "non sequential" as compared to a "sequential approach" by which the hours of the year are exhamined in cronological order.

The "non sequential approach" is applicable when the power system, with thermal or hydraulic generation, is such that the primary energy sources (fuel or water) may be considered always available. On these assumptions, in fact, the system state in each hour does not depend on the occurences and on the system operation in the preceding ones.

3. LOAD SHEDDING POLICIES

3.1 Lack of generation capacity

If the system is modelled as a "one area system" the load amount to be shed, in order to match demand and generation availability, is broken down among all load busses proportionally to their load.

If the system is subdivided in two or more areas (or subsystems), the total load to be shed is shared among areas proportionally to the relevant generation power unavailability; for each area the actual load shedding is done proportionally to the load of each bus.

3.2 Lack of transmission capacity

Should line or transformer overloads occur for a given system situation, remedial actions (redispatching and load-shedding) are modelled by taking into account both the fuel cost variation of each unit (in respect of the optimum dispatching) and the cost of the load curtailements necessary to eliminate such overloads.

In this case load shedding is performed accordingly to node-branch sensitivity coefficients, consistent with d.c. load-flow model, by using a linear programming technique.

4. OUTPUT OF THE PROGRAM

SICRET program supplies both System and local Adequacy Indices as follows.

A) SYSTEM INDICES

* EENS (Expected Energy not Supplied)
  LOLP (Loss of Load Probability for the weekly peak hours)
  LOLE (Loss of Load Expectation in hours/year)

  each subdivided by:

  - main primal causes
    Lack of generation capacity
    Lack of transmission capacity
    Node isolation or Network splitting

  - weather conditions

* YEARLY EXPECTED FUEL COSTS
  For the total generation system and for each type of generating unit

B) LOCAL INDICES

* EENS for each load bus and subdivided by primal causes

* LINE CAPACITY MARGINAL GAIN (MWh/MW)

* STATISTICS OF LINE AND TRANSFORMER POWER FLOWS
  - according to the economic power dispatching
  - after redispatching actions

4.1 Characteritics, size and computing resources

PROGRAM LIMITS:
500 busses
800 links
300 generators

COMPILER:
FORTRAN IV OR FORTRAN V - FORTRAN 77

COMPUTER:
IBM 3081/K
APOLLO DN-3000

CPU TIME

For analysing a composite system of 400 Nodes, 550 branches, 140 generating units, by 1000 randomly sampled system situations:

60 min. on APOLLO DN 3000 Work-station (1 MIPS machine)
3 min. on IBM 3081/K.

ADEQUACY EVALUATION: AN APPLICATION OF ENEL's SICRET PROGRAM TO THE NEW BRUNSWICK POWER SYSTEM (*)

by

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ABSTRACT
The New Brunswick Power system was examined with the ENEL's Monte Carlo based program for composite system analysis. Several results are produced which are usable for planning purposes.
The effect of Interruptible Loads on system adequacy in the framework of Demand Side Management is studied with a view to evaluating them appropriately when adopting special tariffs for such industrial consumers.
The authors believe that the paper represents an example of real planning.

1. INTRODUCTION

The paper deals with the application of the SICRET program, set up by ENEL for its planning practice in the early seventies [1.2.3.4], to the evaluation of the adequacy of the New Brunswick Power (NBP) system in a given year of its future development.

The paper's framework is the activity of CIGRE W.G. 38.03 (T.F. 38.03.10) whose principal activity was the carrying out of a test case with different computing tools. In the paper, no discussion is made on the relative merits-demerits of Monte Carlo simulation and Contingency Selection methods since the subject has been debated in various previous papers. The reader may find an application, and the related comparisons, of these two approaches to IEEE RTS system in [5]. The papers [6-7] deal extensively with the features of the various computer programs available for composite-system adequacy evaluation and with the cautions with which the results should be interpreted.
The system data were assigned by NBP, after a cross discussion with ENEL experts.

Two system structures have been examined:
i) "Reference system";
ii) "Improved System", corresponding to the reinforcement of the Reference system.

In order to compare the results obtained by the WG Members, for each of the two system structures two modelling situations have been proposed and examined:
i) Complete real system yearly behaviour, that is with various load levels, forced and planned outages of the generating units etc: this situation will be referred to as "Unconstrained";
ii) Simplified behaviour under a set of technical prescriptions (only one load level, no maintenance etc..): this situation will be referred to as "Constrained".

Beginning with the existence of Interruptible Loads (ILs) in the NBP system, a methodology for their evaluation in the framework of Demand Side Management (DSM) has been introduced.

2. SYSTEM MODELLING

2.1 - Demand

Three types of loads have been considered:

- "Normal" loads, for a total of	: 3045 MW
- Interruptible Loads (ILs) for a total of:	52 MW
- External sales (Es), with obligation to supply	: 808 MW
- Total	: 3905 MW

To obtain the total load (PL) to be supplied, the transmission system losses (83 MW) were added.
As a result, the total system load, ILs included, is PL = 3988 MW

By assigning to the transmission system losses an approximate load factor, the total energy demand (EL) comes to 20209 GWh.

(*) Already published as Paper WG 38.03/1 in the Volume of the CIGRE Symposium on Power System Reliability (Montreal September 16-18, 1991)

2.2 - Generation system

The NBP system is mixed; its capability at the winter peak load is as follows:

- Thermal Pgit = 3472 MW
- Hydro Pgih = 650 MW
- Total internal Pgi = 4122 MW
- External resources Pgex = 1338 MW
- Total capability Pg = 5460 MW

The hydro capability is lower than the hydro installed capacity, due to the energy limitations at the winter peak.
The total installed capacity is 5660 MW.

In addition, NB Power suggested to consider 4 fictitious units, for a total of 52 MW, in order to net the Interruptible Loads (ILs). Such units, 100% available, should be dispatched after the internal units but before the recourse to the external resources obtained through the interconnections. The impact of ILs on the risk index will be emphasized later.

2.3 - Reserve margin

The reserve margin (capability at winter peak-winter peak load), is internationally recognized as a parameter to make comparisons among various systems.
In our case, two reserve margins can be evaluated, according to the different modelling of the ILs:

- by taking into account just the capability Pg : r= (Pg/PL-1)x100 = 36.9%;
- by taking into account also the contribution of the fictitious generators (PgIL), netting the ILs (Pg* = Pg + PgIL) : r*=(Pg*/PL-1) x 100 = 38.2%.

In both cases, the reserve margin is well higher than internationally found in the "normal practice".

2.4 - The effect of the Interruptible Loads

It is worthwhile to discuss the relationship between the system adequacy and the possibility offered to the system planner by the Interupptible Loads (ILs). In fact, the ILs option is increasingly promoted by utilities in the general framework of Demand Side Management (DSM). Customers sign contracts in which they agree to reduce, when asked, their demand to a predetermined level. Utilities/customers mutual needs and advantages should take into account on one side the generation (and trasmission) constraints of the utility, on the other side the production constraints of the consumers.

Because of the nature of industrial processes, the mean duration and the frequency of the load curtailments, as well as their yearly duration and seasonal allocation, are key issues for ILs evaluation. The sequential Monte Carlo [2-6], by which the behaviour of each generating unit and the load are simulated hour by hour chronologically, is needed.

When planning, two situations having the desired adequacy can be compared: the first one obtained with the ILs option, the second one with the traditional installation of peaking combustion turbines (CTs). The "value" of the ILs for the Utility can be obtained by the expenses (capital and fuel) of the CTs that can be deferred.

In the present application, the non sequential Monte Carlo was used, so that only the expected yearly duration of the generation system difficulties can be investigated and not their frequency and duration.

Despite this limitation, two cases have been run for the unconstrained situation, which can be assumed to represent the following planning policies:

i) NBP is satisfied with the system adequacy corresponding to Pg and PL and does not consider any special tariff and the "potential" ILs are shed after the recourse to the imports;

ii) NPB would consider to improve the system adequacy and has the option of installing CTs dispatched before the imports, or of agreeing special tariffs for the ILs consumers.

This methodology is general and can be applied when financial or siting constraints affect the expansion of generating system.

2.5 - Transmission system

The complete NBP system has been simulated with three voltage levels 345-230-138 kV, by a suitable equivalent of the loads (and losses) of the 69 kV network.

The total MW losses mentioned in par. 2.1 (83 MW), have been proportionally shared among the busses with loads higher than 100 MW and added to them.

The total number of busses with load is 53, out of the 88 simulated. Moreover, each load has been subdivided in 1 MW elementary loads so that the simulated loads are about 4000.

Two capability limits, "normal" and "emergency", have been assigned by NBP for the transmission lines. In our evaluations, the "normal" limits have been adopted. The most frequent values are 700/350/140 MW for 345/230/138 kV lines respectively.

2.6 - Failure bunching effect

The forced outage probability of NBP transmission lines during adverse weather has been assumed to be 9 times higher than in normal weather.
The occurrence of the adverse weather is uniformly distributed all along the year, without distinction among the seasons, for 730 hrs out of the total 8736 simulated.

2.7 - "Constrained" situation

The following simplifications were suggested by the Task Force in order to make easier the comparison of results obtained by using very differing methologies:
- Load: only the yearly peak load, lasting 8736 hrs, examined. Annualized parameters, in particular risk indices, are obtained;
- Outages: no planned maintenance of the generating units is taken into account. Furthermore, no common mode outages for the pairs of 138 kV lines feeding the directly tapped loads are considered.
- **Failure bunching:** the relative duration of the adverse weather is supposed higher (15% of the year) than the above mentioned 730/8736= 8.4%, that is coincident with the winter period.
- **Hydro dispatching:** a simplified situation was assumed.

The above mentioned assumptions have contrasting effects on composite system adequacy.

In general the **constrained** situation does not provide any real help to a planning process based on a cost vs benefit approach.

3. RESULTS

3.1 - Unconstrained situation

3.1.1 - Risk indices and fuel costs

Adequacy risk indices and fuel costs have been obtained for the two system structures, as shown in Table I. The values in the table refer to the case when the ILs are considered "normal" loads, that is without any tariff reduction, and are shed after recourse to the imports.

Table I - Unconstrained situation (Energy Demand EL = 20209 GWh/yr): Risk Indices & Fuel Costs

	System structure	
	Reference	**Improved**
EENS (MWh/yr)	4458	1911
(p.u. EL)	2.2×10^{-4}	9×10^{-5}
- lack of G capacity	411	411
- lack of T capacity	2479	12
- node isolation	1288	1288
- network splitting	280	280
Fuel Costs (M$/yr)		
- Internal NBP	403.8	404.7
- NBP+Imports	415.6	412.2

The following comments can be made:

i) In contrast with the presumption drawn by the high reserve margin, the contribution of the lack of capacity (HL1) to the total EENS is low but not excessively so. Its value (411 MWh/yr) corresponds to about $2x10^{-5}$ EL, which is a reasonable parameter for many systems having far lower reserve margins (roughly 22-25%) than the present one. This could be due to the fact that about 53% of the total capability is carried by only 8 unit having sizes of 6-16% of the total generating capability;

ii) The overall adequacy of the NBP composite system (HL2) is largely dictated by the effect of the transmission system, which increases the risk index by about one-half an order of magnitude compared to the values for the busbar system (HL1). Since the SICRET program utilizes d.c. load-flow, it is reasonable to expect that the system could also have some voltage problems and that the risk indices could be even higher than those calculated.

iii) Local reinforcement, namely the addition of two lines, the upgrading of another and the substitution of one transformer in the Courtenay Bay Area, provides considerable benefit, corresponding to a decrease of 2240(*) MWh/yr in the EENS. This figure could be used for a cost vs benefit comparison. At an average **"unit risk cost"** of **2 $/kWh**, it corresponds to a benefit of about US $ 4.4 million/yr, that is, about US $ 31 million. The fuel benefits correspond to US $ 24 million. The resulting total amount of money represents the potential benefit that should be compared with the capital expenses necessary for the network improvements. This comparison was not possible since NBP did not supply the line costs.

iv) The system reinforcement has no effect on the EENS due to node isolation and network splitting since the improvements take place in busses not contributing to such phenomena.

3.1.2 - Interruptible Loads

Fig.1 shows the Load and Generation Duration Curves (LDC & GDC) without and with the fictitious units.

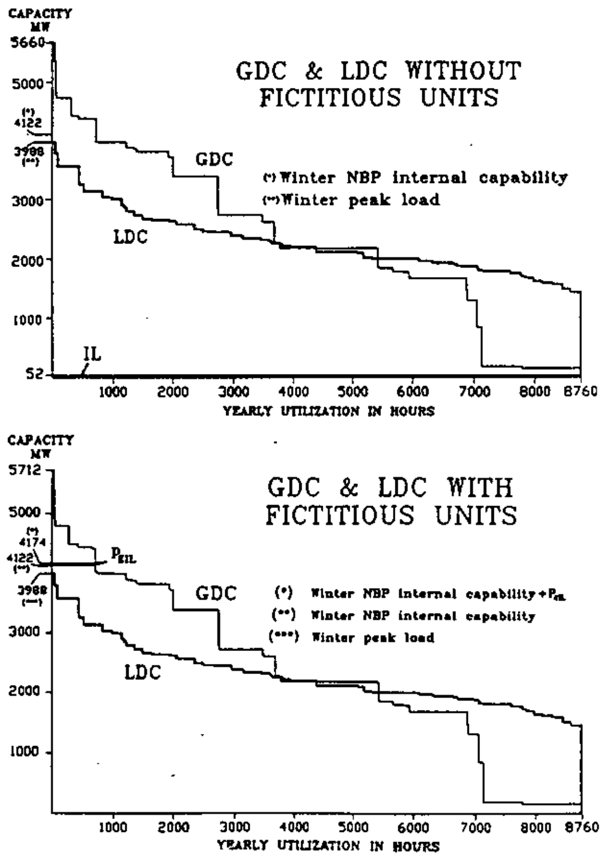

Fig. 1 - Load and Generation Duration Curves

Table II gives the main results concerning the ILs behaviour when applying the two said planning policies. When the special tariff option is not present ("No") the MWh/yr gives the contribution of the industrial consumers to the system risk index; when the tariff option is applied ("Yes") the MWh/yr represents the amount of energy that the industrial consumers are requested to disconnect in order to allow the utility to keep the planned adequacy.

Table II - Effect of DSM Clause on ILs supply (ILs demand: 454 GWh/yr)

	System structure			
	Reference		Improved	
	Tariff option		Tariff option	
EENS (MWh/yr) by DSM clause	No	Yes	No	Yes
- lack of G cap.	132	17160	132	17160
- lack of T capacity	227	22080	2	2430
- Total	359	39240	134	19590

The impact on the ILs is higher in the Reference structure, the less adequate one, than for the Improved structure; the time of recourse to the ILs clause increases from 371 hrs to 745 hrs respectively.

For the Reference system, the existence of special tariffs for the industrial consumers, subjected to yearly curtailments of 326 hrs (in the case of a busbar system) and of 745 hrs (when network constraints are taken into account), would allow NPB to spare the capital cost and the fuel cost of 52 MW of CTs. It would also improve the generation system (HL1) adequacy since the relevant EENS will decrease from 411 to 279 MWh/yr.

The duration (745 hrs) of the yearly curtailments appears to be in rather good accord with current DSM practice. Using this result, some cost-benefit comparison could be attempted in order to make the appropriate agreements with the industrial consumers interested in such DSM strategy.

3.1.3 - G & T systems Interaction

To obtain a better idea of the influence of the network on the total composite system adequacy (HL2), the portion of EENS due to lack of transmission capacity in sound network situations has been obtained as follows:

Table III - Effect of Transmission System Capacity Constraints

	System structure	
EENS (MWh/yr)	Reference	Improved
- lack of G capacity	411	411
- lack of T capacity	2479	12
(out of which in sound network situations)	1435	2

In the case of network sound and all generating units available, the load flow does not show any overlaod. Consequently, the above mentioned EENS due to overloads (1435 MWh/yr for the Reference system) are clearly due to interference between the generator outages and local problems arising from insufficient trasmission capacity.

3.1.4 - Other output

Table IV shows the contributions to the risk of the various buses, in decreasing order.

Table IV - Load point risk Indices: EENS (MWh/yr) due to lack of transmission capacity

BUS	System structure: Reference EENS	%	Improved EENS
1860 MILD47	1364	55	-
1813 C.BAY1	470(*)	19	2
2496 ROTHPR	450	18	-
1807 NEWCA1	115	5	-
1681 IRVREF	36	1.5	-
....	....	....	....
Total	2479	100	12

(*) Out of which 227 relevant to the ILS

Table V presents the index "Capability Marginal Gain" (CMG) of the transmission lines. CMG is defined as the potential decrease in load shedding, due to overloading of each line, obtained by increasing the capability limit of the concerned line by 1 MW.

Table V - Line marginal gains (MWh/MW)

Line: from BUS to BUS	System structure: Reference	Improved
1807(NEWCA1)-1969(MILBK1)	15	0.4
1831(C.BAY1) -1860(MILD47)	20	-
1837(C.COV1) -1860(MILD47)	155	0.2

The contents of Tables IV and V confirm that the reinforced system was obtained with appropriate action.

Fig. 2 shows the distribution of the power flows, as resulting by the probabilistic combination of load levels, generation and network component availability and operation policies in one of the most loaded lines of the system. Reference [8] explains how such output may be used for system planning and component design studies.

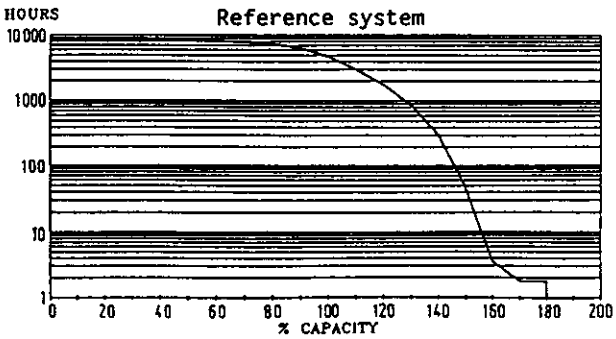

Fig. 2 - Power flow duration curve on the line from Bus C.COV1 to Bus MILD47 (rating = 140 MW, power flow in normal situation = 131 MW)

3.1.5 - Computing resources
The Montecarlo Simulation has been carried out by means of groups of 1200 sampled hours each.

The statistical analysis of the EENS relevant to HL1 and HL2, obtained for each group, shows that the correlation is not so good (r = 0.65).
Consequently, one could not profit from the generalized regression techniques [9] aimed at improving the confidence limit of the results. Sufficient accurracy (standard deviation of 0.1 p.u.) has been reached with a sample size of 12.000 hours (10 groups).

CPU time requested (IBM 3090): **2 min.** for adequcy indices evaluation, and further **1.5 min.** for fuel costs and power flows statistics.

3.2 Constrained situation
Paragraph 2.7 indicated the reasons why the results of the constrained situation are not of great significance.
Nevertheless, the **annualized** indices obtained for the constrained situation are given in Table VI.

Table VI - Constrained situation: Risk Indices

	System structure	
	Reference	**Improved**
EENS (MWh/yr)	93879	23555
- lack of G capacity	20874	20874
- lack of T capacity	71486	1162
- node isolation	569	569
- network splitting	950	950
LOLE (G system)(hrs/yr)	114	114

LOLE index has been computed by excluding fictitious generators and assuming that the load has standard deviation of 0.

The contribution to EENS of "node isolation" is lower than for the **unconstrained** system since the loads making the prevailing contribution are tapped directly on 138 kV lines. In the **unconstrained** situation common-mode failures are assumed for the two sections of such lines, while in the unconstrained situation this is not the case.

4. CONCLUSIONS

4.1 The ENEL's Monte Carlo based SICRET program, was applied to NBP system but no attempt was made to compare Monte Carlo with contingency evaluation methods since this subject has been covered many times.

4.2 After discussions with NPB to assess the proper system input data, the NBP was examined. The system under its actual behaviour, **Unconstrained** situation, has been investigated as in a real planning study. In particular the load diagram, generating unit forced and planned outages, overhead lines outages, weather effect were carefully modelled.

4.3 A **constrained situation**, involving simplified modelling of the system was also considered so as to allow comparison with the results obtained by other tools. It is felt that the corresponding **annualized** results cannot be profitably used for real system planning.

4.4 In view of the increasing attention being given by many utilities to Demand Side Management, the possibilities offered by the **Interruptible Loads** (ILs) has been presented. The power of the **sequential** Monte Carlo simulation and associated methodology used to determine the real "value" of the ILs option to the utility and to the consumers has been demonstrated. Some results, obtained with the **non sequential** Monte Carlo for NBP have been also discussed and the caution to be exercised when no frequency and duration parameters are obtained has been outlined.

4.5 The effects of the various models on the risk indices have been discussed. Various output, besides the adequacy risk indices and fuel costs, have been produced and their utilization for system plannig and component design have been discussed.

4.6 The study is offered for discussions. In particular the authors would appreciate a feedback from NBP concerning the applicability of the presented methodology to the real planning of its system.

5. ACKNOLEDGMENTS
The authors are indebted to Mr E.Giampieri and Mr. C. Tagliabue for their helpful contribution.

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*                 *
*  SICRET PROGRAM *
*                 *
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RELIABILITY STUDY ON

NEW BRUNSWICK POWER SYSTEM

BASE CASE - NOVEMBER 1990 - "Unconstrained Generalized Analysis"

COMMON MODE OUTAGES - ACTUAL LOAD DIAGRAMS - YEARLY ADVERSE WEATHER

HIGHER PRIORITY LEVEL FOR INTERRUPTIBLE LOADS IN CASE OF LOAD SHEDDING

TOTAL INSTALLED CAPACITY = 5659. MW

PEAK POWER DEMAND = 3988. MW

RESERVE MARGIN (at winter peak) = 36.9 %

MONTECARLO SIMULATION CARRIED OUT BY MEANS OF 1 SAMPLE OF:

10000 TESTS IN NORMAL WEATHER CONDITIONS

2000 TESTS IN ADVERSE WEATHER

RISK INDICES

WEATHER CONDITION	LACK OF POWER		ISOLATED NODE		NETWORK SPLITTING		LINE OVERLOAD	
	LOLE	LOLP	LOLE	LOLP	LOLE	LOLP	LOLE	LOLP
NORMAL	2.6	0.0015	19.0	0.0024	2.6	0.0004	87.6	0.0539
BAD	0.2	0.0015	17.3	0.0240	1.7	0.0025	6.9	0.0535
STORMY	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000

CURTAILED ENERGY (MWH/YEAR)

" WHEN "		" WHY "				
WEATHER CONDITIONS	HOURS/YEAR	LACK OF POWER	ISOLATED NODE	NETWORK SPLITTING	LINE OVERLOAD	TOTAL
NORMAL	8036.0	389.8	649.9	242.1	2290.2	3572.0
BAD	724.0	21.7	637.9	48.4	188.8	896.8
TOTAL		411.4	1287.9	290.4	2479.1	4468.8

CURTAILED ENERGY (MWH/YEAR)

" WHERE "			" WHY "					
		NODE	LACK OF POWER	ISOLATED NODE	NETWORK SPLITTING	LINE OVERLOAD	TOTAL	TOTAL WEIGHTED
1	169	NSFICT	0.0	0.0	0.0	0.0	0.0	0.0
2	1843	LEPRAU	3.5	0.0	0.0	0.0	3.5	7.0
3	1913	BELDUN	0.0	0.0	0.0	0.0	0.0	0.0
4	1800	BEECHW	5.9	0.0	0.0	0.0	5.9	11.7
5	1802	GRFALL	0.0	0.0	0.0	0.0	0.0	0.0
6	1809	MACTQC	3.0	0.0	0.0	0.0	3.0	5.9
7	1677	CARAQT	6.1	0.0	0.0	0.0	6.1	12.1
8	1807	NEWCA1	8.9	0.0	0.0	114.5	123.4	246.8
9	1811	GRLAKE	1.5	0.0	0.0	0.0	1.5	2.9
10	1813	C.BAY1	8.1	0.0	0.0	243.6	251.7	503.4
11	1826	DALHOU	0.0	0.0	0.0	0.0	0.0	0.0
12	1836	C.COV3	0.0	0.0	0.0	0.0	0.0	0.0
13	1910	IROQUB	9.4	28.7	48.0	0.0	86.0	172.0
14	1965	MILBK2	0.0	0.0	0.0	0.0	0.0	0.0
15	1969	MILBK1	0.0	0.0	0.0	0.0	0.0	0.0
16	1812	MONCTN	11.5	0.0	0.0	0.8	12.2	24.5
17	1971	PENFLD	8.4	7.3	0.0	0.0	15.8	31.5
18	168	ONSLO3	0.0	0.0	0.0	0.0	0.0	0.0
19	700	ORRING	38.1	0.0	0.0	0.0	38.1	76.1
20	1844	MURRCR	2.1	0.0	0.0	1.2	3.4	6.7
21	1869	MADHYQ	13.0	0.0	0.3	0.0	13.3	26.6
22	1896	TINKER	0.0	0.0	0.0	0.0	0.0	0.0
23	9996	EELHYQ	13.0	0.0	0.0	0.0	13.0	26.0
24	1948	EELRA1	6.1	0.0	0.0	0.0	6.1	12.2
25	1847	112572	6.4	113.0	0.0	0.0	119.5	238.9
26	157	MACCAN	0.5	0.0	0.0	0.0	0.5	0.9
27	158	ONSLO1	1.8	0.0	0.0	0.0	1.8	3.6
28	167	ONSLO2	1.1	0.0	0.0	0.0	1.1	2.2
29	183	SPRNGH	0.8	0.0	0.0	0.0	0.8	1.7
30	1679	LANCST	15.1	72.5	0.0	2.3	89.9	179.9
31	1681	IRVREF	1.2	0.0	0.0	35.7	36.8	73.7
32	1712	RICHBT	6.7	582.9	0.0	0.0	589.6	1179.2
33	1717	114963	4.3	58.7	0.0	21.2	84.2	168.5
34	1776	114981	1.5	17.9	0.0	1.0	20.5	41.0
35	1804	117562	0.9	12.1	0.0	0.0	13.0	26.0
36	1805	EELRV1	1.1	0.0	0.0	0.0	1.1	2.2
37	1806	BATHS1	5.8	0.0	0.0	0.0	5.8	11.7
38	1810	MARYSV	23.8	0.0	0.0	0.2	24.0	48.0
39	1817	111144	0.0	0.0	0.0	0.0	0.0	0.0
40	1824	111528	2.1	138.9	0.0	0.0	140.9	281.9
41	1825	MEMCOK	0.0	0.0	0.0	0.0	0.0	0.0
42	1827	KESWK1	0.0	0.0	0.0	0.0	0.0	0.0
43	1828	KESWK2	0.0	0.0	0.0	0.0	0.0	0.0
44	1829	BATHS2	0.0	0.0	0.0	0.0	0.0	0.0
45	1830	EELRV2	0.0	0.0	0.0	0.0	0.0	0.0
46	1832	110553	0.5	33.7	0.0	0.0	34.2	68.4
47	1834	OAKBAY	8.6	94.2	26.4	16.3	145.5	291.1
48	1835	110421	0.0	0.0	0.0	0.0	0.0	0.0
49	1837	C.COV1	0.0	0.0	0.0	0.0	0.0	0.0
50	1838	SALBR2	0.0	0.0	0.0	0.0	0.0	0.0
51	1839	SALBR1	0.0	0.0	0.0	0.0	0.0	0.0
52	1845	NASH03	3.0	0.0	0.0	0.5	3.4	6.9
53	1846	NASH12	3.0	0.0	0.0	0.0	3.0	6.0
54	1849	STAND1	0.0	0.0	0.0	0.0	0.0	0.0
55	1850	SALBR3	0.0	0.0	0.0	0.0	0.0	0.0
56	1851	NEWCA2	0.0	0.0	0.0	0.0	0.0	0.0
57	1852	110871	0.7	39.6	0.0	0.5	40.7	81.4
58	1854	HARDRD	0.2	5.6	0.0	0.0	5.8	11.5
59	1860	MILD47	0.8	0.0	0.0	1363.6	1364.4	2728.9
60	1861	DOAKST	17.1	0.0	75.9	0.0	93.0	186.0
61	1862	MILD65	0.0	0.0	0.0	0.0	0.0	0.0
62	1863	119042	2.1	0.0	0.0	0.0	2.1	4.2
63	1865	111036	0.1	0.0	0.0	0.0	0.1	0.3
64	1866	EELRV3	0.0	0.0	0.0	0.0	0.0	0.0
65	1867	EDMST3	0.0	0.0	0.0	0.0	0.0	0.0
66	1868	STAND3	0.0	0.0	0.0	0.0	0.0	0.0
67	1900	NORTN3	0.0	0.0	0.0	0.0	0.0	0.0
68	1901	NORTN1	0.0	0.0	0.0	0.0	0.0	0.0
69	1907	EDMST1	0.0	0.0	0.0	0.0	0.0	0.0
70	1908	114084	0.0	0.0	0.0	0.0	0.0	0.0
71	1909	IROQUA	7.9	0.0	113.5	0.0	121.5	242.9
72	1915	BATHS3	0.0	0.0	0.0	0.0	0.0	0.0
73	1916	NEWCA3	0.0	0.0	0.0	0.0	0.0	0.0
74	1928	110684	0.0	0.0	0.0	0.0	0.0	0.0
75	1930	1126MP	7.2	82.7	0.0	0.0	89.9	179.9
76	1945	119024	0.2	0.0	0.0	0.1	0.4	0.7
77	1946	112408	0.2	0.0	0.0	0.1	0.4	0.7
78	1964	MBNKTP	0.0	0.0	0.0	0.0	0.0	0.0
79	2495	NBIPC1	2.0	0.0	0.0	0.0	2.0	4.1
80	2496	ROTHPR	3.2	0.0	0.0	450.1	453.3	906.5
81	2497	BRMINE	2.5	0.0	0.0	0.0	2.5	5.0
82	2498	NBIPC2	4.7	0.0	0.0	0.0	4.7	9.4
83	2499	CONSBH	2.9	0.0	0.0	0.0	2.9	5.7
84	91813	INTER1	25.5	0.0	0.0	227.4	252.9	252.9
85	91847	INTER2	30.6	0.0	0.0	0.0	30.6	30.6
86	91910	INTER3	38.3	0.0	26.4	0.0	64.7	64.7
87	91948	INTER4	38.3	0.0	0.0	0.0	38.3	38.3
88	1803	KESWK3	0.0	0.0	0.0	0.0	0.0	0.0
		TOTAL	411.4	1287.9	290.4	2479.1	4468.8	8551.0

APPENDIX V

ELECTRICIDADE DE PORTUGAL REPORT

THE NEW BRUNSWICK SYSTEM SIMULATION
EXERCISE OF CIGRE WG 38.03.10

Contribution of Electricidade
de Portugal with the ZANZIBAR model

by

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Keywords: System and network planning - Composite models-New Brunswick system-ZANZIBAR model.

Abstract - This paper resumes the results obtained with Zanzibar model on the WG 38.03.10 exercise of simulation of the New Brunswick system with several composite simulation models. The paper also gives a broad idea of the model simulation capabilities.

1 - Introduction

1.1 - The present document is the final report of the NB system simulation exercise carried out at Electricidade de Portugal, S.A., using the ZANZIBAR model. This report describes the main lines of the model, the input/output facilities of the program and the results obtained for the NB system for HL1 and HL2 cases.

1.2 - Aknowledgments are in order for several people who helped me in this work. The first goes to Dr. Paulo Bárcia, the author of ZANZIBAR in the ate 70's (first results in 79), early 80's first upgrade in 82). Dr. Paulo Bárcia made all necessary code changes to support special load types in this particular exercise.

The second goes toEngº Jorge Morais who helped in the early stages of the study, and to Mrs. Isabel Ferrão and Ana Valeriano who typed all the sucessive versions of this report.

And last, but not the least, aknowledgents are also due to WG 38.03.10, and, in special, to Bill Marshall, who prepared the first set of data end has been always ready to answer our questions about data and modeling details.

I also am indebted to my family, who lost several weekends because of "the damned work for CIGRE".

2 - THE ZANZIBAR model - A short functional discription.

2.1 - Zanzibar is a computer program for the assessment of power system adequacy. It has been designed and implemented at Electricidade de Portugal, EDP in the early 80's, by Dr. Paulo Bárcia to be used as a transport network planning tool. Some improvements have been made so far, enhancing its capabilities.

In the following lines, we present a summary of the present features of this program.

2.2 - Zanzibar is a composite model, simulating both the power generators as well as the transport network. Monte Carlo technique is employed to produce a non-sequencial simulation of one year of system operation.

As for generation, different types of power stations can be represented. Special emphasis has been given to the simulation of the hydro component, wich, in Portugal, accounts for more than 45% of total generated energy. Hydro power stations are simulated as follows:

. Three hydrologic situations are possible: wet, intermediate and dry. Each one has its own given probability of occurrence.

. Three year seasons are possible: winter, intermediate and summer. For our climate, their probability is 0,5, 0,25 and 0,25, by the same order.

. Each hydro power stations has a maximum given energy cost: for each combination of hydro

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situation/season, a multiplier 1<<0 affects that cost to define its effective cost. Therefore, each hydro power station has nine equivalent production costs, one of each is chosen for each Monte Carlo case.

. In each study, a complete year is simulated. Each power station has a maximum possible productible energy. In pratice, a ±10% deviation is accepted.

Several different generators can be simulated at each node. Maximum and minimum power output limits can be specified. Total unavailability can be broken down into two components, non-programmed, and programmed. The last one can be made to occur only in favourable conditions regarding year season and/or load diagram step and/or hydrologic situation. One only rule can be specified for all generators and another to network elements: different percentages of total unavailability can be assigned as non-programmed for generators and network elements.

Thermal generators can be simulated in a similar way in respect to unavalability. Their cost function can be any linear piecewise convex function.

Loads are represented either as constant loads or as variable loads. The variable ones are defined by a 5 step diagram. The probability of occurrence of each diagram step is conditional to the year season, ie, a matrix of 15 conditional probabilities (5 load steps x 3 year seasons) is defined for all variable loads. The curtailment cost function can be given for any load, as a specific linear piecewise concave function.

Network elements (lines, transformers, etc.) are represented in the usual way. As was said, distinction can be made between programmed and non-programmed unavailability with the same facilities as for generating units. Common failures can be considered, defining groups of lines/transformers that will be put down should any other element in the same group became unavailable.

A global overview of how the program operates can be given as follows:

a - Data reading and preliminary calculations- -dynamic ordering and factorization of admittance matrix, stratification, calculations, etc. All network data handling uses sparsity techniques.

b - In each Monte Carlo case:

. Year season and hydrologic situation are sampled. Load diagram step is also sampled, conditional to the year season. Cost of each hydro power station can then be calculated, according with year season, hydrologic situation and accumulated v.s. maximum year producible energy.

. Availability situation of each power station and network element, including loads, is assessed.

. Productions in power stations are defined with an optimisation procedure, minimising production and network "losses" plus cost of curtailed energy, taking into consideration MW limits of all elements. A DC approach is used, but real losses are simulated changing slightly loads in adjacent busbars of each line. The program can take into consideration any given set of lines or transformers to add contingency restrictions.

The optimisation problem is solved using the dual problem with limited variables and also a technique of relaxion, using an iterative constraint search.

2.3 - Outputs of all Monte Carlo simulations are stored. At the end, several outputs and statistics are available.

The program can also be used to perform other studies as DC load flows and optimal productions plans taking into consideration network MW restrictions.

A list of some possible outputs of Zanzibar is given:

- For each load: average, standard deviation (SD) and frequency of load curtailment.

- For each generator: average and SD of output; effective unavailability in Monte Carlo simulations; total (1 year) generated energy.

- For network branches: average and frequency of power flow in each direction (sending -> receiving and receiving -> sending); average marginal deficiency, ie, in how much total MW curtailment would have been reduced, if MW rating of each branch was increased by 1 MW.

- For each area and for the whole system: reserve margin, average and SD of "losses", average, SD and frequency of EENS, both total values and partial values due to failures of network and generating capacity.

These are standard printouts. More detailed information is available on request:

- Histograms of generators, loads, flows, load curtailment (in individual loads or global) and branch "losses".

- Detailed outputs of particular Monte Carlo case namely those where load curtailments have occurred or those which the model was unable to solve.

  It is possible to go back to each of those cases, analyse it in detail to see what actually has been responsible for the load curtailment and make further analysis. Interface is provided for AC load flow.

- A companion program, Zangraf, can produce geographic outputs of load flow.

- Special outputs are possible such as admittance matrices, initial load flow solutions, simplex tableaux, simplex and stratification related data, etc.

3 - The ZANZIBAR model: load-curtailment philosophy

For each Monte-Carlo case, the program solves a linear programming (LP) problem which consists of minimising the total production cost in power stations plus the total load curtailment cost subject to:

- Network equations in linear (DC) approximation.

- Bounds on power station output.

- Bounds on load curtailment at each node.

- Bounds on branch flows.

So, the load curtailment philosophy is the one imposed by the solution of the above optimisation problem.

Note that, in order to avoid degeneracies in the LP, costs are perturbed with small noise, so that costs will be all slightly different, even if some of them are given of equal value.

This perturbation changes from one Monte-Carlo case to another.

Origin classification of curtailed energy between generation and network follows a very simple criterium.

For each Monte-Carlo simulation let PA be the total production capacity available and LD be the total load demand; the curtailment due to generation is defined as CG = LD - PA.

The total curtailment, CT, is the sum of the load curtailed at each busbar. Then the curtailment due to the transmission network, CN, is defined as CN = CT - CG.

Of course this is only meaningful for the whole system and not for each area individually.

4 - Simulation of the New Brunswick case with ZANZIBAR. Some details in system representation.

In other parts of this paper we describe, in detail, both the simulation and representation facilities of ZANZIBAR. This gives a detailed overview of the program in general functional terms.

Here, we address some general representation and simulation details regarding the NB case. Taking, as reference, the degree of system representation subjacent to the "November data set", some approximations had to be done, since ZANZIBAR, at its present state, is not able to cope, in some aspects, with such representation level.

4.1 - Zanzibar does not perform a sequencial one year simulation. It uses a non-sequential approach.

4.2 - Zanzibar does not use AC representation, although losses are approximated by changing loads in a inner iteration with DC optimal flow, for each Monte Carlo case, according with calculated losses from DC branch flows.

4.3 - As a consequence of 4.1, it is not possible to assign scheduled unavailabilities to exact weeks along the year. Also, it is not possible to simulate the "weather condition modelling" changing non-programmed unavailability according with year season.

Recalling that ZANZIBAR considers three year seasons, three hydrologic year conditions and 5 load diagram steps, what has actually been done is:

. To specify a percentage of total unavailability programmed:

50% for generators

0% for lines and transformers.

. To allow thermal programmed maintenance only in summer and not in the highest load diagram step.

. Unavailability is equally distributed all over the year for lines and transformers.

4.4 - All variable loads are simulated according with the "type II seasonal load model" - page 11/14 of "November data set". One only model is possible for all loads. Neverthless, to simulate more closely the two 200 MW "type 4 - HQ contract" at 1869 and 9996 busbars, Dr. Bárcia changed the code to cope with these situations. The loads are active with 200 MW only in winter and at the two higher load diagram steps and in half of the Monte Carlo cases.

All constant loads of constant part of variable loads are correctly simulated.

4.5 - Hydro power stations are simulated as "seasonal thermal-equivalent hydro model" of page 13/14 of "November data set".

4.6 - In all other aspects, data is exactly the one referred in the "November data set". All details treated in various telexes between Mr. William Marshall and us were considered. We emphasise the fact normal MVA rating have been considered for lines and transformers.

4.7 - It is worth nothing that the DC load-flow or the optimisation procedure do fail to solve some Monte Carlo cases. This happens for fifty cases, more or less, in a study of 5 thousand. The final results for the study is therefore affected by these "forgotten" cases which would make those results worse.

5 - New Brunswick system simulations with ZANZIBAR The HL1 equivalent case

In this case, the HL2 "Constrained Base Case" was run with the modifications suggested by Mr. William Marshall so that all network elements (lines and transformers) are 100% available with a very high MVA rating. This last value was set to 9000 MVA throughout for both lines and transformers.

Also, the MW powers of the hydro power stations have been corrected.

Two runs have been made, one with 4000 and the other with 8000 Monte Carlo simulations. The results show only small differences, as expected, since lines and transformers - the elements with small probability of failure - are 100% available. The figures of the 8000 case will be considered in this documented.

Main results are the following:

* Total generated energy	: 34894.4 GW.h
" consumped	: 34190.8

Total consumped + curtailed : 34206.3

Total curtailed energy : 15,5 GW.h

Equivalent interr. time : 3h 57m 41s

All curtailed energy is due to generation failure

* Mean load curtailment

* Average defficiency : 1,766 MW

Standard dev. of estimator : 0,286 MW

Frequency of curtailment : 0,925%

These figures are for the whole system, including alien (non NB) busbars.

* Installed power : 5513 MW

Peak load : 3904 MW

% reserve : 41,2%

"Losses" in transmission

Average : 80,3 MW

SDE : 0,88 MW

These figures are for the whole system.

(Remember that in ZANZIBAR, "losses" are simulated with a DC approach, ie, are not the real losses, but fall bellow the true value).

Please note:

1 - Since all branches in the network have "infinite" MVA rating, it is meaningless to present values of curtailment at the individual busbars.

2 - Since the network elements are not at stake, both from the point of view of reliability and in what concerns rating limitations, the optimization was always successfully completed in all 8000 simulations. There is not any "dropped situation", as in inevitable whenever important network limitations make optimization LP impossible to solve.

6 - New Brunswick system simulation with ZANZIBAR. The HL2 constrained case.

We remember that in the constrained case:

Load is constant at all busbars.

No modelling of maintenance is done.

The hydro power stations are always at top power: Mactaquac 500 MW, Beechwood 80 MW and Grand Falls 30 MW.

No scheduled maintenance is considered.

Common mode failures are not considered.

Main results obtained with ZANZIBAR running 32 000 Monte Carlo simulations follow. We start with the system global indices, then figures regarding expected curtailment at busbars and last we show what network elements are imposing restrictions. This last item is given, for each branch, by the "average marginal deficiency" (AMD) value, i.e. the number of watts by which load curtailment would have been reduced, should the rating of the network element had been increased by 1 megawatt.

Both base case and improved case results are presented.

6.1 - Global system load curtailment values

Situations:	Base	Network improvement
Total		
Average (MW)	5,67	1,99
STD (MW)	0,157	0,140
Frequency (%)	20,4	1,80
EENS (GW.h)	50,8	17,4
Due to generation		
Average	1,69	1,67
STD	0,136	0,135
Frequency	0,937	0,924
EENS	15,1	14,6
Due to network		
Average	3,98	0,316
STD	0,085	0,039
Frequency	19,5	0,887
EENS	35,7	2,8

Notes:

* STD - Standard deviation of average estimator.

* The rationale for splitting EENS down to "due to generation" and "due to network" explained elsewhere in this report.

* Figures are for the whole represented system, which includes the external (non NB) equivalents.

6.2 - Busbar curtailment data

All busbars having at least one situation of load reduction imposed by system failure are listed on Table I. On the top of the list come the busbars which better improved with network reinforcement.

Situation at busbars 1860, 1813, 1910, 1717, 1946, and 1679 show sharp improvement. Nevertheless, some others have high values of curtailment frequency.

TABLE I

HL2 CONSTRAINED CASE

BUSBAR LOAD CURTAILMENT

	Base Case			Netw. Imp.		
	AVC (MW)	STD (MW)	FRQ (%)	AVC (MW)	STD (MW)	FRQ (%)
Busbars						
MILD47-1860	13,8	4,0	19	14,9	4,6	0,085
C.BAY1-1813	33,8	17	3,3	179	32	0,085
IROQUB-1910	104	33	0,11	No curtailment		
PENFLD-1971	35,6	9,8	0,038	32,9	4,1	0,019
114963-1717	45,2	26	0,17	67,4	27	0,010
112408-1946	4,93	0,26	0,35	6,58	0,14	0,29
114981-1776	17,1	4,5	0,18	18,6	5,5	0,11
OAKBAY-1834	55,4	8,4	0,24	56,9	7,6	0,19
LANCST-1679	61	27	0,10	69	23	0,088
110871-1852	21,9	0	0,006	21,9	0	0,006
110553-1832	8,9	2,1	0,10	9,1	2,1	0,10
1126MP-1930	48,2	13	0,19	35,8	13	0,17
117562-1804	14,9	-	0,003	14,9	-	0,003
111528-1824	18,4	3,5	0,063	No curtailment		
119042-1863	28,8	15	0,26	38,2	15	0,27
119024-1945	6,01	0,089	0,013	6,6	0	0,025
BATHSI-1806	103	46	0,25	107	43	0,25
DOAKST-1861	4,4	1,8	0,54	4,5	1,8	0,55
BEECHW-1800	23,7	2,1	0,091	23,4	3,3	0,11
CARAQT-1677	91,5	44	0,13	88,0	45	0,13
HARDRD-1854	4,5	1,2	0,022	4,8	-	0,003
IROQUA-1909	104	33	0,11	107	33	0,10
MARYSV-1810	124	56	0,038	124	56	0,038
MACTQC-1809	20,7	0	0,013	20,7	0	0,013
MONCTN-1812	157	81	0,40	150	81	0,43
NASH03-1845	12,6	2,0	0,11	19,1	1,8	0,091
NEWCA1-1807	36,8	40	0,069	35,7	41	0,072
RICHTB-1712	34,9	16	0,088	33,4	14	0,091
EELRAI-1948	No curtailment			93	25	0,078

Notes:

AVC - Average curtailment (whenever curtailment does occur), in MW.

STD - Standard deviation of AVC estimator in MW.

FRQ - Curtailment frequency, in percent.

6.3 - Lines imposing load curtailment

Network elements that impose load curtailments by their low MW rating, in any of the Monte Carlo simulations, are listed below. Their AMD is also given. All network branches in this situation are lines.

AMD (W/MW)

Branch	Base Case	Improved Networ
C.COV1-1837/MILD47-1860	>1000	11,7
NEWCA1-1807/MILBK1-1969	21,7	3,14
114981-1776/NORTN1-1901	12,3	4,87
NORPSR-1747/NORTN1-1901	7,21	0
IRVREF-1681/C.BAY1-1813	5,99	0
C.COV1-1837/MILD65-1862	0,858	0
110684-1928/MILBK1-1969	0,055	0
MACTQC-1809/DOAKST-1861	104	105
RICHBT-1712/MONCTN-1812	2,43	2,50
RICHBT-1712/NEWCA1-1807	1,76	1,77
GRLAKE-1811/MONCTN-1812	0,915	1,22
SALBR1-1839/119024-1945	0,605	0,605
SALBR1-1839/112408-1946	0,280	0,280
IRVREF-1681/NORTN1-1901	0	10,0

The exact AMD value for the first line in the base case is not known because the printout field has only room for three integer digits. We know, for shure, that it is greater then 1000 W/MW.

The situation of the first 5 lines has a clear improvement with the network reinforcement. The first two lines are heavily loaded in the base case. Even with the network improvement, average load is still high. Note that the new line addition 1681/1901 has a considerable load from busbar 1681 to 1901.

Last, we note that the line, 1809/1861 is also heavily loaded and has a very high AMD. This situation is not improved with the proposed network addition.

As a last comment, we refer that the total EENS in the base case is lower that the one mentioned in the New York meeting. Only two changes have been made in the data: maximum MW power in hydrostations (Beechwood - 1800 and Mactaquac - 1809) have been reduced to 80 MW and 500 MW and transformer ratings were set to "normal rating" instead of "short overload values". We recall that these changes were suggested by Mr. William Marshall for the constrained case.

The second change is meaningless in what EENS is concerned, since, even with reduced MW ratings (for instance, 0,93 x normal MVA rating) no transformer is responsible for any additional EENS.

As a matter of fact, the reduction of rated power of those hydro stations do account for a reduction of EENS in this constrained case. The justification must come from the fact that as hydro power is mobilised in areas near the loads, therefore, with better chances to reach loads, in spite of the heavy transmission problems faced.

TABLE II

HL2 CONSTRAINED CASE

Branch Flows

Busbar I J	Rating MW	— Base Case — AV MW I —> J	FRQ %	AV MW J <— I	FRQ %	— Improved Network — AV MW I —> J	FRQ %	AV MW J <— I	FRQ %
1837/1860	140	124	99,96	15,9	0,04	96	99,94	63,4	0,06
1807/1969	140	10,9	0,54	111	99,46	8,9	0,73	93,3	99,27
1776/1901	140	23,2	0,15	77,5	99,85	0	0	86,3	100
1809/1861	190	168	100	0	0	169	100	0	0
1681/1901	140	— Not considered —				14	71,2	10	28,8

Notes:

AV - Average flow, in MW.

FRQ - Frequency in %.

—> Flow from busbar I to busbar J, in MW.

<— Flow from busbar J to busbar I, in MW.

7 - New Brunswick system simulation with ZANZIBAR. The HL2 unconstrained case.

As for the HL2 constrained case, 32 000 Monte Carlo simulations were run to reach the results that follow. From those, more or less 140 simulations have been dropped due to optimization problems.

7.1 - Global system data

Installed capacity	5713 MW
Peak load	3879 MW
Reserve margin	47,3
"Losses" Average	38,3 MW
STD	0,42 MW
Number of hydrologic situations considered	1 (intermediate)
Probability of each year season	1/3

Load diagram:

Conditional probabilities

Steps	Summer	Interm.	Winter
0,90	0	0	0,13
0,70	0	0,09	0,42
0,50	0,14	0,63	0,36
0,30	0,81	0,28	0,09
0,10	0,05	0	0

Scheduled maintenance for generators

- forbided in the 0,9 load step
- alowed in Summer but not in intermediate and Winter and seasons.

See point 2.3 of "The ZANZIBAR model" for the definition of "losses" within a DC approach.

7.2 - Global system load curtailment values

Situations:	Base	Network improvement
Total		
Average (MW)	0,611	0,237
STD (MW)	0,056	0,048
Frequency (%)	1,48	0,292
EENS (GW.h)	5,4	2,1
Due to generation		
Average	0,171	0,170
STD	0,054	0,054
Frequency	0,079	0,079
EENS	1,5	1,5
Due to network		
Average	0,440	0,067
STD	0,030	0,012
Frequency	1,41	0,217
EENS	3,9	0,6

Notes:

* STD - Standard deviation of average curtailment estimator

* The rationale for splitting total EENS down to "due to generation" and "due to network" is explained elsewhere in this report (see "The ZANZIBAR model: load curtailment philosophy).

* Figures are for the whole represented system, which includes the external (non NB) equivalents.

7.3 - Busbar curtailment data

Busbars having at least one situation of load curtailment in the 32 000 Monte Carlo situations are listed in Table III. The first busbars are those whose situation improved after the network reinforcement.

TABLE III

HL2 UNCONSTRAINED CASE

BUSBAR LOAD CURTAILMENT

	Base Case			Netw. Imp.		
	AVC (MW)	STD (MW)	FRQ (%)	AVC (MW)	STD (MW)	FRQ (%)
Busbars						
MILD47-1860	15,5	3,7	1,2	-	no curtailment	-
114963-1717	35,9	18	0,035	-	no curtailment	-
C.BAY1-1813	33,6	13	0,55	57,0	11	0,035
LANCST-1679	49,5	9,2	0,032	29,2	0	0,013
HARDRD-1854	0,48	0	0,032	0,48	0	0,025
BATHS1-1806	54,2	25	0,028	100	13	0,019
OAKBAY-1834	24,1	6,4	0,116	27,4	6,0	0,091
PENFLD-1971	21,6	13	0,025	21,6	14	0,019
110871-1852	12,4	0	0,013	95	-	0,003
110553-1832	1,0	0	0,022	1,0	0	0,025
117562-1804	6,5	1,0	0,013	6,5	1,0	0,013
1126MP-1930	29,8	6,4	0,041	29,8	6,4	0,041
112572-1847	24,5	-	0,003	24,5	-	0,003
119042-1863	57,0	4,6	0,013	57,0	4,6	0,013
119024-1945	0,66	0	0,010	0,66	0	0,010
BEECHW-1800	19,1	1,9	0,019	18,7	2,0	0,019
EELRA1-1948	59,6	12	0,022	72	12	0,022
IROQUA-1909	72,5	16	0,019	72	16	0,019
MARYSV-1810	82,5	48	0,013	89,3	42	0,013
NASH03-1845	11,6	5,1	0,016	10,9	5,9	0,016
NEWCA1-1807	132	22	0,022	161	22	0,022
RICHBT-1712	98,3	-	0,003	98,3	-	0,003
DOAKST-1861	34,0	26	0,028	26,3	22	0,035
114981-1776	14	0	0,010	24,4	0	0,013
MONCTN-1812	138	56	0,032	113	59	0,041
112408-1946	-	no curtailment	-	0,66	0	0,013
MACTQC-1809	-	no curtailment	-	17,3	2,0	0,010
MILD65-1862	-	no curtailment	-	10,4	2,6	0,006

Notes:

AVC - Average curtailment (whenever curtailment does occur), in MW.

STD - Standard deviation of AVC estimator in MW.

FRQ - Curtailment frequency, in percent.

The global situation, in the base case, is much better than in the constrained case, since loads, although with the same peak MW, are now modulated taking lower MW values most of the time.

Busbars that most benefit from network reinforcement are MILD47-1860 and C.BAY-1813. From curtailment frequencies of 1, 2% and 0,55%, reinforcement reduces those values to 0% and 0,035%. Other busbars like 1679, 1717, 1854, 1806, 1834, 1971 and 1852 show also some improvements.

Some other busbars (see end of list) exhibit higher curtailment frequencies, but with low absolute values.

7.4 - Lines imposing load curtailment

A few lines exhibit positive AMD. Only one has a triple digit AMD value in the base case, C.COV1-1837/MILD47-1860, indicating that this line is the cause for significant load curtailment. This situation is solved by the proposed network reinforcement, turning the AMD value of 235W/MW to zero.

Lines with non zero AMD are the following:

Branch	AMD (W/MW) Base Case	Improved Network
C.COV1-1837/MILD47-1860	235	0
NORPSR-1747/NORTN1-1901	4,4	0
MARYSV-1810/GRLAKE-1811	0,1	0
114981-1776/NORTN1-1901	0,44	0
NEWCA1-1807/MILBK1-1969	1,9	0,12
MACTQC-1809/DOAKST-1861	1,3	1,9
114981-1776/SALBR1-1839	0,31	0,31
IRVREF-1681/NORTN1-1901	not considered	5,54

The new line 1681/1991 is imposing some load curtailment, although the network reinforcement clearly improves the situation. Probably it won't be sound, on an economic point of view, to make further reinforcements for the simulated load situation.

APPENDIX VI

ÉLECTRICITÉ DE FRANCE REPORT

STUDY OF NEW BRUNSWICK POWER SYSTEM with the MEXICO MODEL

Final report

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Abstract

Within the framework of CIGRE WG 38-03, the purpose is to evaluate the reliability of a composite (generation and transmission) systems using several models.

This final report reviews the study of the New Brunswick system's reliability carried out by EDF with the help of the MEXICO model. It gives the approach and the final results of the study.

Keywords: network reliability, simulation, CIGRE, MEXICO.

CONTENTS

1. PRESENTATION OF THE STUDY - HISTORICAL BACKGROUND

1.1. Introduction

This study is the contribution of Eléctricité de France to the work of the CIGRE 38-03-10 Task Force. This task force was assigned the comparison of probabilistic models for adequacy evaluation of composite, generation and transmission, electric power systems.

In the first place, the main methods used to define the system reliability were described and collected in a book called "Power System Reliability Analysis Application Guide" published in 1987.

It was then decided to test the methods presented on the basis of a precise example so as to make an in-depth comparison of these methods. A system of a size sufficient though not excessive and incorporating all the generation types contemplated was used for observational comparison purposes: it is the New Brunswick (a relatively small Canadian province) system.

Data corresponding to this system were consequently supplied by the New Brunswick Power (N.B.P.) to all contractors or research institutes willing to test and compare the model(s) in their possession. The final aim of the working group is to demonstrate that these models give comparable results - though they sometimes may differ - to evaluate the system reliability.

The first runs of the models showed some difficulty in comparing the results; each programme having its own way to model the system. In order to make the comparison of the models easier, the group decided to revise the data and to define a graduate sequence of exercises with standard modelization of the New Brunswick Power electrical system.

The present report describes the results obtained by Electricité de France on the basis of the revised exercises definition.

These results are to be presented during the CIGRE symposium of Montréal on power system reliability in September 1991.

1.2. Tools used by EDF to carry out CIGRE exercises

1.2.1. EDF probabilistic tools for system planning

For transmission expansion planning EDF has developed and uses 3 probabilistic models, which cover specific scopes:

MERIDA, to evaluate expected yearly operation costs
MEXICO, to evaluate system adequacy.
ANASEC, to investigate systems failures.
Other tools including the CAST programme are available for in-depth evaluation of MEXICO results.

MEXICO was the most suitable program for the CIGRE comparison and was selected by EDF for this purpose. It is a general simulation software programme designed to carry out network reliability studies.

1.2.2. The simulation software programme MEXICO

MEXICO enables simulations of the composite system operation for the purpose of evaluating the reliability. It uses the Monte-Carlo method and runs as follows:

a) a great number of situations existing on the system are chosen at random regarding generation and transmission equipment availability rates,

b) in each situation and for a given preset consumption level, a linear programme determines the generation scheme which minimizes the sum of operating and failure costs in full respect of the network electrical equations (in the D.C. approximation) and the allowable flows in dipoles,

c) the results achieved over all the situations analyzed are averaged out. The mathematical expectancy of power not served for a given consumption level, and, then, by integrating the result according to a load duration curve, the mathematical expectancy of energy not served over a given time period can thus be deduced (usually one year). This gives the E.E.N.S. ("Expected Energy Not Served") and other global and local indices,

d) one value is given for the unavailability of each component. This value is to represent forced and planned outages. The dates of planned outages are assumed to be unknown 5 or 15 years ahead of time when the expansion planning process takes place,

correlation of unavailabilities: the unavailability of several equipments may be defined as correlated, positively or negatively. This option has been developed to cope with specific cases as common mode failure of pairs of lines.

e) one value of load for each bus and a linear stepwise load duration curve are given for the whole system to cover the study period. A Gaussian distribution of load uncertainty is introduced to represent climatic and conjunctural uncertainty. This representation of the loads allows the use of a very efficient analytical way to cope with load variations.

MEXICO, which is written in FORTRAN, allows large-size networks - up to 500 buses, 1,000 thermal units, 1,200 dipoles - to be studied.

As regards the New Brunswick system, a run of MEXICO with the analysis of 5000 situations (which affords reliable results) needs a calculation time of about 5 minutes on a CRAY-YMP.

1.2.3. The results given by MEXICO

A simulation using MEXICO gives global results covering the whole selected study period and detailed information upon a well-defined consumption level, in general peak consumption.

The detailed inventory of results is the following:

Results covering the duration of the study:

- Total value of the global failure (E.E.N.S. in MWh), with the part due to network deficiencies and that due to the lack of generation means;

- Failure expectancy and probability for each stage of the demand duration curve, which permits an easy access to the L.O.L.E. value (Loss Of Load Expectation, in hours) globally and stagewise;

- The value of marginal gains on line reinforcements in case of failure (in MWh/MW) for lines under constraint.

Results covering an hour point:

- Mean value of the generation per region, cost bracket and generation unit for the demand under consideration,

- Mean value and standard deviation of the failure per region,

- Mean management cost per region and cost bracket,

- Histograms of the failure resulting from the lack of generation and network deficiencies,

- Mean generation, consumption and failure for each network bus,

- Mean flows and frequency of constraint for each line,

- Analog (though deterministic) results for the worst failure occurrence due to the network.

1.3. List of study cases run by Mexico

1.3.1. CASE 1: HL1 Equivalent

Simplified study case; November 90 data set is used and the following assumptions and changes are applied:

(a) The peak load for each bus is assumed to occur over the entire year.

(b) The maintenance of generators is ignored

(c) Concept of "common mode" pair of lines is ignored.

(d) Hydro generation capacities are set constant all year long:

Matacquac	500 MW
Beechwood	80 MW
Grand falls	30 MW

(e) Network improvements are ignored.

(f) Rating capacity of lines are defined infinite, ie:

unvailability = 0
flow limit = 6000 M

(g) Exportations are set constant during all year and do not stop when NBP shared generators are not available.

1.3.2. CASE 2: Peak load analysis - reference case

Study case 2 is similar to the previous except that the simplification (f) is now rejected:

Lines and transformers are given their flow limits and unavailability rates as specified in the reference set of data dated November 1990.

1.3.3. CASE 3: Peak load analysis with network improvements

Study case 3 is similar to case 2 except that the network is slightly modified according to "Network Improvements":

- 318 MVA transformer 1836-1837 is replaced with a 4590 MVA transformer,
- A new line 1681-1837 is added,
- A new line 1681-1901 is added,
- Rating of line 1681-1813 is increased up to 280 MW.

1.3.4. CASE 4: Complete year analysis without network improvements

Up to case 3 the study was limited to the peak hour. Cases 4 to 6 on the contrary are dealing with a full year.

In the study case number 4, the conditions of the reference case 2 are retained as a basis. The following modifications are brought

The year is split in three periods: Summer (4 months) Intermediate (4 months) and Winter (4 months) in order to base the study on the 3 seasons load model, It also allows to take into account different rates of unavailability for lines and transformers according to the season.

Availability rates of lines and transformers is adapted according to the period: slightly increased in winter and slightly reduced in the summer and intermediate seasons.

Capacity of thermal units are derated in order to include maintenance outages.

1.3.5. CASE 5: Complete year analysis with network improvements

Study Case 5 is similar to 4 except that network improvements are taken into account.

1.3.6. CASE 6: Special case with correlation of exports

This study case six is strictly identical to five, except that a correlation is introduced between exported shares of generation and corresponding generators. This simulation is described in the paragraph 2.5.2.

Export contracts link export to generation. Each exportation corresponds to a share of a specific generator. When the shared generator is not available, the export should be interrupted. In the standard exercises export is never interrupted. Not interrupting export when corresponding generators are not available exposes NBP system to very severe situations. Situations were a shared generator is unavailable are severe for two reasons:

- NBP has to meet usual demand with reduced generation capacities.
- NBP still has to meet export requirements when there is a lack of generation.

Neglecting to interrupt the export of a shared generator when unavailable will very likely induce an over estimation of the failure expectation.

2. MODELLING THE N.B.P. SYSTEM WITH THE MEXICO PROGRAM

An interface program has been developed in order to provide data appropriate to MEXICO from the generic data supplied by NBP. The interface program is based on the following modelling principles:

2.1. Demand

Whilst MEXICO considers only one category of load, the generic system data of NBP power system consider a full variety of loads:

- fixed consumptions, constant throughout the year,
- season-related consumptions,
- mixed consumptions: a fixed part and a variable part,
- time-related consumption (assistance to foreign consumers),
- interruptible loads which are constant throughout the year but may be switched off in case of emergency.

MEXICO does not enable direct acknowledgement of several types of demands: the total consumption is modulated by applying the load duration curve principle but consumption at buses will vary accordingly and automatically. However there is one way to define a constant load: forcing negative generation. Generation can be imposed, and a negative generation is equivalent to a consumption.

Only 2 types of demand are discriminated by the MEXICO interface: loads connected at NBP buses and loads connected at external buses representing neighbouring companies.

- Loads connected at internal NBP buses are all considered as common load; they regroup all kinds of loads of the given data. These common loads follow the modulation of the load duration curve. This modelization induces 2 side upshots:

  . Loads defined as fixed in the given set of data will vary and follow the variation of the load curve, loads initially defined as variable will still vary but within a narrower range. The global distortion may induce a small increase or decrease of the network failure. The (+ or -) sign of the global impact is unpredictable but the magnitude is certainly very small.

  . Interruptible loads will also follow the load curve. The fictitious generators included in the generic data will simulate the interruptions. However there will be a minor bias due to the fact that the rating of the fictitious generators will not follow the load curve and thus may produce more power then necessary to compensate the interrupted load. This distortion may slightly reduce the global network failure.

- Loads connected at external buses correspond to export contracts; the level of these loads is kept constant throughout the year. These loads for MEXICO are described by the means of generators with forced negative output.

2.2. Load curve

The yearly assessment of the adequacy of an electric system with MEXICO is usually performed with a one year simulation, based on a one year load curve. This approach is valid as long as the stochastic parameters of the system are constant throughout the year. Several parameters which should be considered as constant according to usual the EDF planning practices are not constant throughout the year in the reliability CIGRE exercises. The maintenance of generators varies with the season according to a fixed plan. Forced outage rate of transmission equipment varies with adverse weather which itself is correlated with seasons. These considerations lead to the decision to split the year in several periods and to compute the global yearly results by adding the relevant results of the different periods.

A major issue is the definition of an average solution regarding the time span so that it permits the acknowledgement of a sufficient number of data varying with time while enabling easy aggregation of the results per year.

For increased accuracy, the use of a one-week time span would be ideal. But, unfortunately, this is not feasible since it would require 52 weekly simulations to be made for a single yearly result which would make the computation time too costly (not to mention the working out of 52 sets of data).

Another modelling possibility in which data were aggregated for three typical seasons (summer, off-season and winter) provides easy access to yearly results while taking account of most changes met with the diverse parameters.

This is the retained solution for MEXICO runs. The load model number II of the generic data, with 3 seasons: summer, intermediate and winter, is selected. However the load model II is modified for MEXICO, a correction is brought to incorporate fixed loads in the load duration curve.

2.3. Unavailabilities

2.3.1. Unavailabilty of transmission lines

In this respect, "normal" and "bad" weathers are the key parameters since the dipole failure probability is much higher in the case of bad weather. This factor cannot be directly taken into account within MEXICO since stochastic parameters cannot be modified as the simulation progresses. The ratio of adverse versus normal weather being given for each season, transmission failure rate are averaged for each season. In this way, the availability rate of transmission equipment is considered constant during each season.

2.3.2. Availability of generators

The data supplied by the CIGRE working group state that generator maintenance is strictly planned on an annual basis.

The simulations with MEXICO could not take these forced shut-downs into account as the characteristics of generating units do not include a maintenance plan. However the impact of unavailability of each generator during the period of maintenance had to be taken into account in the simulation. Therefore the solution retained is the following: the maximum capacity of each generator is derated in proportion to the duration of maintenance. This calculation is performed for NBP generators as well as for external generators. The computation of derating is performed for each of the 3 seasons.

2.4. Hydro generation

EDF and NBP do not approach the management of hydro resources in the same manner. A satisfactory compromise therefore had to be found for the hydro plant model.

The data supplied on hydroelectricity do not address output modulation. An estimate of the total annual generation in GWh is provided for each facility together with monthly output duration curves.

MEXICO processes hydro generation in a completely different manner. So-called "zero-cost" hydro generation, which is based on global generation estimates, is performed automatically and remains unchanged throughout the simulation period. A cost will be allocated to any additional hydro generation.

For the MEXICO runs, an adaptation was made on the basis of the "thermal equivalent hydro model" of the exercises's generic data and also of the hydro generation power proposed for the peak analysis. The principle is to modulate the power level of peak analysis according to the seasons and to split it in two shares:

- "base zero cost" power,
- "modulation" power.

The hydro modulation is given the cost provided with the thermal equivalent.

2.5. Exchanges with neighbouring COMPANIES

2.5.1. Exports: Standards study cases

The levels of export are set constant and established according to the figures of the contracts. Within study cases 1 to 5, an export is not interrupted when the corresponding shared generator happens to be unavailable.

2.5.2. Correlating exports and shared generators: study case 6

A more accurate modelization of export is possible with MEXICO. Fictitious generators are attached at the boundary buses. This modelization is selected for the special study case, number 6.

A fictitious generator is associated to each export, it is given the same power level as the corresponding export. The following table gives the list of these fictitious generators:

Fictitious Generator	Purchaser	Facility	Power purchased (MW)	Power generated (MW)
A	New England	Pt Lepreau	210	427
B	New England	Belledune	20	410
C	P.E. Island	Dalhousie 02	20	183
D	P.E. Island	Pt Lepreau	20	427
E	P.E. Island	Belledune	20	410

The availability of such fictitious generators is exactly opposite to the one of the corresponding shared generator. When a shared generator happens to be available in one situation, as a result of the random drawing, then the related fictitious generators are unavailable. On the opposite if a shared generator is drawn unavailable, then the related fictitious generators are then available and cover directly the exports which are to be met at the same buses.

Thus, actually, with the help of these anticorrelated fictitious generators, when during a random situation, one of the following generators is unavailable: Pt LEPREAU, BELLEDUNE or DALHOUSIE2, the exported shares of generation are automatically stopped.

2.6. Value of failure cost

A number of parameters required by MEXICO for simulation were not provided by New Brunswick. The values selected had to be as accurate as possible.

One of the most important is the cost of failure. In order to solve the MEXICO linear program, a cost must be allocated to failure. The exact value is of little importance but the order of magnitude must be far higher than total generation costs.

The value selected is $1,200/MWh, which corresponds to approximately FFr5/kWh, an average value often selected in France. In comparison, the most costly generation resources total $120/MWh.

2.7. Dividing the country into regions

MEXICO allows discrimination of up to 8 regions within the network studied. Local results can then be obtained especially for generation, failures and management costs. It should however be noted that the management of the whole network by MEXICO will in no case be modified.

This possibility has been extensively used in our example so as to delineate the problems more easily. The idea was primarily to consider these regions as identical with the countries under consideration ie: New Brunswick and the neighbouring regions.

Since this gave only 6 regions, New Brunswick has been divided into 3 characteristic portions. In conclusion, the following eight regions have been established:

[1] the middle of New Brunswick

[2] New Scotland

[3] Prince Edward Island

[4] The Province of Quebec

[5] The Maine (public service only)

[6] The Maine (private companies)

[7] New Brunswick South, in the vicinity of St John, Coleson Cove, Point Lepreau and Courtenay Bay plants

[8] New Brunswick North, in the vicinity of Bathurst and Eel River, Belledune, Dahlousie and Cowans Creeks plants.

3. THE SIMULATION RESULTS

3.1. Tables of result

Six study cases were performed:

Case 1: HL1 equivalent
one run of 8000 situations

Case 2: Peak load analysis - reference case
one run of 8000 situations

Case 3: Peak load analysis - with network improvements
one run of 8000 situations

Case 4: Complete year analysis
without network improvements
3 runs of 5000 situations, one for each season

Case 5: Complete year analysis - with network improvements
3 runs of 5000 situations, one for each season

Case 6: Complete year analysis
special case with correlation of export
3 runs of 5000 situations, one for each season

The results are regrouped according to their types. They are displayed in the four following tables:

- Expected Energy Not Served
- Loss Of Load Expectation
- Marginal Gain on Overloaded Lines
- Load Point Curtailment on buses

Remarks
Load point curtailment is edited by MEXICO, only in the studies dealing with particular hour points. Therefore they were not available for study cases 4,5 and 6.

CIGRE TASK FORCE 38.03.10
Results of MEXICO runs

Expected Energy Not Served

Items	HL1	Peak Load Analysis		Year Analysis		Year Anal
		without Net Imprv	with Net Imprv	without Net Imprv	with Net Imprv	with correlati Expor-Gen
Case no	1	2	3	4	5	6
EPNS (MW) Generatio	1.7	1.7	1.7			
EPNS (MW) Network	0.0	6.2	0.2			
EENS (GHh) Generatio	15.2	15.2	15.2	0.8	0.8	0.2
EENS (GWh) Network	0.0	53.9	1.3	5.4	2.3	2.5
EENS (GWh) total	15.2	69.1	16.6	6.1	3.1	2.7

CIGRE TASK FORCE 38.03.10
Results of MEXICO runs

LOSS OF LOAD EXPECTATION
in hours per year

Items	HL1	Peak Load Analysis		Year Analysis		Year Anal with correlati Expor-Gen
		without Net Imprv	with Net Imprv	without Net Imprv	with Net Imprv	
Case no	1	2	3	4	5	6
LOLE due generation						
Freq %	1.08	1.08	1.08	NOT MENTIONNED IN MEXICO PRINTOUTS FOR A ONE YEAR STUDY		
LOLE	95	95	95			
LOLE due to network						
Level 1				0.622	0.117	0.116
Level 2				0.409	0.072	0.069
Level 3				0.283	0.258	0.257
Level 4				0.265	0.131	0.136
Level 5				0.006	0.005	0.006
Freq %	0.000	20.110	0.490	0.018	0.007	0.007
LOLE	0.0	1761.6	42.9	1.6	0.6	0.6
Global LOLE						
Freq %	1.08	21.03	1.46	NOT MENTIONNED IN MEXICO PRINTOUTS FOR A ONE YEAR STUDY		
LOLE	94.6	1842.2	127.9			

NOTE

For year analysis LOLE is computed for each level of the load curve.

CIGRE TASK FORCE 38.03.10
Results of MEXICO runs

Marginal EENS gain and ranking for overloaded lines

Items	Peak Load Analysis		Year Analysis		Year Anal with correlati Expor-Gen
	without Net Imprv	with Net Imprv	without Net Imprv	with Net Imprv	
Case no	2	3	4	5	6
LINE 1837-1860 from C.COV1 to MILD47					
Gain MWh/MW	3234.2	29.8	183.7	3.7	3.7
rank	1	1	1	2	2
LINE 1807-1969 from NEWCA1 to MILBK1					
Gain MWh/MW	59.6	13.1	2.6	0.6	0.2
rank	2	2	5	3	3

CIGRE TASK FORCE 38.03.10
Results of MEXICO runs

Load Point Energy of Curtailment and ranking

Items	Peak Load Analysis	
	without Net Imprv	with Net Imprv
Case no	2	3
bus 1860 : MILD47		
EENS GWh	36	1
rank	1	1
bus 1813 : C.BAY1		
EENS GWh	17	0
rank	2	

NOTE

Bus load curtailment is computed only for peak analysis.

3.2. Comments on the results

The reliability of the New Brunswick Power system is high. The study identifies a significant level of failure in one area only. This area is located where the actual existing phase shifter transformer should be included. The transformer is missing from the generic data.

Modelisation for Peak load exercises, study cases 1 to 3, are specified in such a way that they are applicable to MEXICO without distortion. Results may be directly compared with other model results.

On the contrary, the modelization of the system for the complete year analysis brought particular challenges. The options selected to cope with the modelization peculiarities may explain some distortion in the results.

4. CONCLUSIONS OF THE STUDY

This study of the New Brunswick generation-transmission system reliability was an opportunity for the MEXICO software programme to be tested on a foreign network.

All the simulations provided consistent results which we briefly recall:

- The yearly failure is low and due mainly to transmission. Generation failure is very low around 200 MWH with an accurate modelling of export, ie: if the contractual exports are stopped when shared generators are unavailable.

- The study of lines under constraint shows that most of the problems are due to a very reduced number of lines.

- In all cases, system interconnection with neighbouring countries are particularly advantageous for New Brunswick electric system adequacy as evidenced by a comparison of the failure values.

To get a better estimate of the adequacy of the network NBP needs a model including an accurate modelling of phase shifter transformers.

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APPENDIX VII

UNIVERSITY OF MANCHESTER REPORT

Studies of the New Brunswick Power System using UMIST's COMPASS and RELACS Programs

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1. INTRODUCTION

The reliability of the electric power system is becoming an increasingly important issue for utility planners because of the recent increase in load demand growth and the limited amount of new generation that is currently planned. The primary function of an electric utility is to provide energy to satisfy the system load demand as economically as possible while maintaining a reasonable level of reliability. This assessment can be made, in part, by the use of reliability evaluation techniques. There are two basic reliability evaluation methods; the analytical approach and the stochastic simulation approach. Both approaches are used at UMIST and a brief description of the programs (COMPASS and RELACS) are described in this Appendix. Simulation techniques, often known as Monte Carlo simulation because they involve random numbers, can themselves be divided into two categories; nonsequential (or random) and sequential. A nonsequential simulation process considers each hour to be independent of every other hour. Consequently, nonsequential simulation cannot model issues that involve time correlations. The sequential approach which examines each basic interval of the simulated period in chronological order can take into account virtually all contingencies inherent in the system.

2. COMPASS

2.1 General

The COMPosite system Assessment using Sequential Simulation (COMPASS) program is based on a sequential Monte Carlo simulation technique. Although the NBP system does not contain hydro units, COMPASS can simulate efficiently mixed hydro-thermal systems with special reference to the operating policy, management of water and randomness associated with reservoir water. Models associated with hydro systems are not described in this report.

2.2 Simulation Procedure

The concepts of Monte Carlo simulation used in COMPASS are based on:

(a) the multiplicative congruent method for generating pseudo-random numbers
(b) the inverse transform method for converting these to the relevant probability distribution
(c) the sequential simulation approach in order to represent the time dependent process and to obtain the density estimates associated with each indices.

The system operation is simulated over a long period of time which is subdivided into reference periods of one year. Each year is divided into basic time intervals during which the state of the system is assumed to be constant. The present model works on an hourly basis which means that changes in the system are assumed to occur at the beginning of every hour. In this sequential simulation procedure the power system reliability evaluations are performed as follows:

- for every simulated hour the availability state of all system elements, such as generating units and lines, are checked
- times to fail or repair are produced by sampling the appropriate probability distributions
- other random conditions, such as uncertainty of the load, are also modelled by random variates sampled from their associated probability functions
- components and their operations are represented by mathematical models
- the combined operation of the power system is then assessed. Deficiencies are recorded in magnitude and frequency. Each deficiency is stored as an independent sample. These deficiencies are also grouped by simulated years
- indices are obtained from the above records together with their frequency distributions

- the simulation is performed for a period of simulated time long enough to include most of the events of interest.

2.3 Availability Model

The model used to represent the forced outages and repair states is the same for generating units, transmission lines and transformers. This assumes that the time between forced outages and the outage duration are independent and exponentially distributed. A forced outage of a generating unit causes the total loss of the unit, the forced outage of a line causes the loss of the corresponding capacity, repair is undertaken as soon as an element fails. Repair time is independent of any other repairs or failures and repair is always successful and restores the component to as good as new states.

2.4 Operating Policy

The operating policy model recognises the factors affecting the actual dispatch of generating units, e.g. fuel costs, and it classifies the thermal generation into four different types:

(a) THA: Base generation

(b) THB: Economic generation

(c) THC: Expensive generation

(d) THD: Peaking generation

The actual dispatch is performed in the following order:

(a) G1: THA (Base generation) (all THA units)

(b) G2: THB (Economic generation) (all THB units plus G1)

(c) G3: THC (Expensive generation) (all THC units plus G2)

(d) G4: THD (Peaking generation) (all THD units plus G3)

Each thermal unit is type-specified and dispatched according to a merit order list within each type. For the NBP system all the 38 generating units are grouped together within a type and dispatched according to their increasing incremental fuel cost.

2.5 Sequential Load Flow

A load flow is performed for every simulated hour of the operation of the system. The flow through the lines are calculated and corrective actions are performed if a transmission constraint is violated. A linearised load flow is used to represent the transmission system. This classical representation only takes into account active power flows and change of bus voltages are not considered. Load flow is performed using the impedance matrix and line flows are obtained by multiplying the distribution factor matrix by the vector of load and generation injections.

Generation is allocated for every simulated hour according to demand, available generating units and a merit order list. Demand changes proportionally with time at all load buses, therefore, the contribution of the loads to the line flows are recalculated at every hour. Whenever there is a change of generation of any unit, the contribution of generation to the line flows are calculated again.

2.6 Overload Relief Procedures

The simulation of a composite system must include models for relieving transmission overloads. The methods implemented in COMPASS are based on the sensitivity of global system overload to busbar injections. The basic concepts and algorithms are outlined in what follows. In the case of an overload, generation redispatch is attempted first then, if necessary, load is shed at the most sensitive bus and a new redispatch is attempted if the overload persists. This process, redispatch/load shedding, is repeated until the overload has finally been eliminated.

2.7 Sensitivity Of Overloads To Busbar Injections

Each bus of the system in a linearised representation contributes to the flow in a line proportionally to its distribution factor and its net power injection. Similarly, if a line is overloaded, each bus contributes to that overload proportionally to its distribution factor and its net power injection. Therefore, the contribution to the system overload by bus n is:

$$C_n = \sum_l D_{nl}(-1)^k$$

where:

$k=0$ if $F_l>0$ or $=1$ if $F_l<0$

F_l = power flow through line l

D_{nl} = distribution factor of bus n for line l

C_n = unitary contribution of bus n to global system overload

The summation is extended only to overloaded lines.

If C is positive, positive injections at bus n create overloads in the system and vice versa. However, if C is negative, positive injections reduce the overload of the system and vice versa. Therefore, there will be buses where a generation decrease will reduce the overload and others where an increase will produce the same effect. The reverse occurs in the case of loads. Therefore, the value of C can be used to select the most sensitive buses for generation redispatch or load shedding. A line is considered to be overloaded when its power flow is larger than its capacity limit. On the other hand, a certain margin (tolerance) of overload can be tolerated in each line. The NBP system is simulated without any tolerance for the transmission lines.

2.8 Redispatch For Overload Relief

During the simulation of each simulated hour, a generation dispatch is performed according to the demand, available generating units and finally a merit order list. This dispatch is done before any restrictions from the transmission system are considered. Therefore, overloaded lines may appear when the load flow is performed.

The overload may be reduced by modifying the original generation dispatch. It is not always possible to reduce the overload of the system by redispatch, so it is important to know whether a redispatch will reduce the overload or not. The first condition for a redispatch is the existence of generation reserve, the second condition is that the generation reserve must exist at buses where an increase of generation will produce a reduction of the system overload.

The method implemented consists of successively selecting pairs of buses according to their unitary contribution to the global system overload. The bus K_{re} with the largest positive contribution and positive injection, and the bus K_{in} with the largest negative contribution and positive generation reserve are selected. If the difference between the contribution of bus K_{ini} and bus K_{re} is positive, then it is not possible to reduce the system overload by means of generation redispatch. If the difference is negative, then an increase of generation at K_{in} and a reduction at K_{re} will reduce the system overload.

If a redispatch is beneficial, the amount of generation to be exchanged is calculated. The maximum amount of generation exchanged between a pair of buses is given by the minimum value among the generation at bus K_{re} (for generation reduction), the reserve available at bus K_{in} (for generation increase) and the quantity that makes at least one line change its overloaded status, i.e.:

$$GE = \min(G_{Kre}, GR_{Kin}, d)$$

where

GE = amount of generation to be exchanged

G_{Kre} = amount of generation at bus K_{re}

GR_{Kin} = generation reserve available at bus K_{in}

d = quantity that overcomes overload of a line.

All lines must be checked to select d and this should be the minimum value found.

For every exchange of generation that is performed, the unitary contribution of buses must be calculated, a pair of buses selected, the feasibility of the redispatch checked, the amount of generation exchanged chosen and the new flows through the lines computed. This procedure continues until the system overload has been eliminated or the redispatch becomes infeasible.

2.9 Load Shedding For Overload Relief

Load shedding procedures can be applied, in a similar manner to redispatch. The K_{re} bus will reduce its generation while the K_{in} bus (which is now a load bus) will reduce its load (a reduction of load is equivalent to an increase of generation). The amount of load to be shed is chosen so that only one line at a time changes its overload status, ensuring minimum load shed. Load shedding procedures are always possible and certainly eliminate the overload of the system.

During the redispatch and load shedding procedures only the bus generations are reassigned in order to eliminate line overflows. To obtain the individual unit energy production and hence the cost of energy generation these bus generations are reallocated to specific generating units.

2.10 Indices Evaluated

A wide range of system and load point indices are evaluated representing measures of a reliability and energy production. These consist of expected values, standard deviations, confidence limits and the complete frequency (probability) distributions.

The indices include:

FOI: frequency of interruption (int/yr)
- FOI_g: frequency of interruption due to insufficient generation
- FOI_t: frequency of interruption due to transmission inadequacies

LOEE: loss of energy expectation (MWh/yr)
- $LOEE_g$: loss of energy expectation due to insufficient generation
- $LOEE_t$: loss of energy expectation due to transmission inadequacies

LOLE: loss of load expectation (h/yr)
- $LOLE_g$: loss of load expectation due to insufficient generation
- $LOLE_t$: loss of load expectation due to transmission inadequacies

EIR: energy index of reliability
AWE: average water used to produce electric energy (Hm^3/yr)
EAWE: average energy produced from AWE (GWh/yr)
AWS: average water spilled (Hm^3/yr)
EAWS: average energy production lost due to water spillage (GWh/yr)
AWP: average water pumped (Hm^3/yr)
EAWP: average energy used to pump water (GWh/yr)
AEHG: average energy produced by all hydro plants (GWh/yr)
FEHG: fraction of total energy demand supplied by hydro generation (%)

3. RELACS

3.1 Introduction

RELACS is based on the analytical approach and has been developed to perform Reliability Analysis of Composite (generation and transmission) systems. This is achieved by considering generating units and circuit outages and assessing their impact on the power system operation subjected to predetermined load levels. The system operation can either be modelled by linear or by non-linear load flow equations. The impact, in turn, is quantitatively measured by the probability of encountering the system in a certain condition, either a failure or a non-failure state, or in a state where remedial action is required in order to maintain a satisfactory operation. The techniques embedded in RELACS are based on those described in References [1] and [2].

3.2 State Enumeration

The number of states analysed by RELACS is established by choosing one of two available state selection methods.

(a) Probability Truncation - allows a state to be analysed only if its probability of occurrence is higher than a specified value (probability tolerance).

(b) Component Combination - where it is possible to prespecify the maximum number of generators, of lines and of components(generators and lines, together) that will be considered on outage.

3.3 Component Outages

The program simulates three different outage modes. These are independent, common mode and station originated outages.

It is important to note that, irrespective of their failure modes, a state is analysed only once. The probability of occurrence is, however, altered accordingly.

3.4 Generation Dispatch

For reliability studies the generation dispatch algorithm needs to be reasonably realistic but not very exact nor time consuming. Therefore, two very straightforward routines are implemented in the program. The first, based on the merit order rule, allocates the required active generation accordingly in order to achieve minimum generating costs. The second distributes the generation requirements among every generator available observing an equal percentage reserve.

3.5 Load Characteristic

The program can either assume a peak load value (1.0 pu) throughout the period of study or adopt a variable load. In this case, the load consists of a set of different levels and is simulated by the frequency and duration method.

3.6 Load Flow

RELACS contains the necessary algorithms for using AC (Fast Decoupled Method) and DC load flows.

3.7 Insufficient Generation

An algorithm detects states without enough generation to meet the load. Such a condition can be caused by generator or line outages. One of two load shedding routines can be used to overcome this system malfunction. These two different routines are called distributed and geographical depending on the method of selecting busbars at which load is to be interrupted. In the distributed routine the load to be shed is distributed among every load busbar on an equal percentage. The geographical routine sheds the load at appropriate busbars near to where the disturbance occurs.

3.8 Overloaded Lines

After the load flow simulation, every circuit flow is compared against its maximum rating. If there is an overload, generation redispatch routines can be employed in an attempt to alleviate it. If the overload condition persists, one of five different load shedding algorithms can be selected to completely overcome the malfunction. These five algorithms are called, depending on the procedure for selecting busbars at which load is to be shed and on the method for evaluating this load:

- optimum
- closest-busbar
- proportional
- generalised
- localised.

(i) Optimum Load Shedding

This procedure seeks to curtail load at the minimum number of busbars in the system. It also seeks to shed the minimum load. Load curtailment is not the only problem involved in alleviating an overload. Generation must also be reduced when load is shed. Therefore, generation and load busbars are affected. Distribution factors are used as measures of the sensitivity or impact a change of load in a given busbar has on the receiving end busbar of the overloaded line. They also measure the effect a change in injected power at a generation busbar has on the sending end busbar of the overloaded line. Therefore, they can be used to near-optimise the load curtailment.

(ii) Closest Busbar Load Shedding

This load shedding procedure also curtails load and reduces generation at the minimum number of busbars in the system but, this time, tries to constrain the effect to busbars in the immediate neighbourhood of the overloaded line. The concept of distribution factors is still used to estimate the amount of load and generation to be shed. However, the busbars at which load curtailment takes place are the closest technically to the malfunction.

(iii) Proportional Load Shedding

This routine selects the load busbar in a similar way to the one used in the closest-busba, i..e. the nearest technically possible. The load to be shed is determined using proportional factors.

The generalised and localised load shedding techniques are dependent on the definition of geographical areas. These are defined as follows:

(a) AREA 1 is the set of busbars comprising the receiving end of the overloaded line and those busbars lying one line away from it.

(b) AREA 2 is the set of busbars including AREA 1 and those busbars lying one line away from it.

(c) AREA 3 is the set of busbars including AREA 2 and those busbars lying one line away from it.

The simulation of geographical areas can be adapted to suit the characteristics of the system under study for load shedding purposes. Load shedding can be simulated progressively starting in AREA 1. A wider area is affected when insufficient load exists in the previous area. Flexibility is introduced in defining the size of the first area in which load shedding is applied. This can start in AREA 1, AREA 2 or AREA 3, thus creating Geographical Divisions of the system where:

(a) Division 1 - when load shedding starts in AREA 1
(b) Division 2 - when load shedding starts in AREA 2
(c) Division 3 - when load shedding starts in AREA 3

Therefore, three different divisions can be adopted. Characteristics of the system will dictate their use. This will enable the simulation of the effect of load shedding in diffferent size of geographical areas.

(iv) Localised Load Shedding Technique

The principle of the load shedding technique is as follows. Load is shed proportionately at all the busbars of the pre-specified geographical area with direct influence on the overloaded line. It first sheds only the curtailable load in the area. Firm load, in the same area, is then shed if there is insufficient curtailable load, however, in the event of insufficient total load in this geographical area, load shedding is continued using the same pattern at the additional busbars of the next size of geographical area. If necessary, this process continues until it affects all of the system. The total amount of load to be curtailed is evaluated using the concepts of distribution factors.

(v) Generalised Load Shedding Technique

The generalised load shedding technique is a slight modification of the previous localised shedding one. The procedure allows a variation in the policy of load curtailment carried out by utilities. The principle involved is that the curtailable load is shed, area by area as required, in the whole of the system before starting to shed any firm load. This differs from the localised load shedding technique in which all load is shed in each area before any loa dis shed in the next area. The simulation and philosophy of load shedding is carried out using the same concepts developed for the localised load shedding technique.

The last two routines shed load by geographical areas. Areas closer to the malfunction are first affected.

3.9 Voltage Profiles

This feature is only applicable to non-linear assessment. This uses a full AC load flow model allowing common power system components, such as LTC transformers, reactors or shunt capacitors, to be easily represented. An identification of voltage violations and MVAR out-of-limit conditions is performed. A straightforward load shedding routine is used for voltage problems and MVAR violations are alleviated by setting new voltage levels at the controlled busbars.

3.10 Busbar Isolation

Line outages can split the power network into two or more areas of different sizes. for these events, the system is assumed to be divided into a main section and one or more subsections. Each are is analysed separately.

3.11 Reliability Indices

RELACS produces a complete set ofload point, line and system reliability indices. All these indices represent valuable information about the system under study. An important complement to these figures are a set of maximum and expected values which are presented together with annualised system indices. Both groups of indices give an overall picture of the system reliability.

An alternative to the above indices, is to evaluate probability bounds instead of exact calculation of the probability of system failure as given by the reliability indices. It avoids the need of having to analyse every single state and, thus, it may reduce the overall computational effort. These probability bounds (upper and lower) are the second optional output of RELACS.

4. ANALYSIS OF NEW BRUNSWICK POWER SYSTEM

4.1 General

A summary of results obtained from COMPASS and RELACS are given in the main body of this report. The following information represents additional results obtained from COMPASS which, in particular, highlights the large values of standard deviation associated with the reliability indices and the wide ranges observed in the confidence intervals.

The indices quoted in these results are:

LOEE - loss of energy expectation
LOLE - loss of load expectation
LCY - load curtailed per year
FOI - frequency of interruptions

4.2 Data and Results

In all cases, a period of 200 years was simulated each made up of 8736 (= 52 x 7 x 24) hours.

The data used is that defined for the NBPS. In addition, a modified annual load model was used because the sequential / chronological relationship of load was needed. This load model is shown in Tables 1 and 2.

The results are shown in Tables 3 to 10 in which:

Tables 3/4: fixed peak load without transmission improvement

Tables 5/6: fixed peak load with transmission improvement

Tables 7/8: with load model without transmission improvement

Tables 9/10: with load model with transmission improvement

5. REFERENCES

[1] Billinton, R. and Allan, R.N. "Reliability Evaluation of Power Systems". Plenum Publishing, New York, 1984.

[2] Billinton, R. and Allan, R.N. "Reliability Assessment of Large Electric Power Systems". Kluwer Academic Publishers, Boston, 1988.

Table 1 - NBP Load Model Used In COMPASS

month	peak load (MW)	number of weeks
JAN	3986.7	5
FEB	3787.1	4
MAR	3712.7	4
APR	3249.2	4
MAY	3022.1	5
JUN	2750.1	4
JUL	2571.9	5
AUG	2660.5	4
SEP	2770.5	4
OCT	3011.9	5
NOV	3369.4	4
DEC	3739.2	4

These peak loads include system loads, support to neighbouring systems and system losses.

Table 2 - Chronological Weekly Load Model

hr	day number						
	1	2	3	4	5	6	7
1	3.0	3.0	2.0	2.0	2.0	1.0	1.0
2	3.0	3.0	2.0	2.0	2.0	1.0	1.0
3	3.0	3.0	2.0	2.0	2.0	1.0	1.0
4	3.0	3.0	2.0	2.0	2.0	1.0	1.0
5	3.0	3.0	2.0	2.0	3.0	1.0	1.0
6	4.0	4.0	3.0	3.0	3.0	1.0	1.0
7	4.0	4.0	3.0	3.0	3.0	1.0	1.0
8	4.0	4.0	5.0	5.0	5.0	1.0	1.0
9	6.0	6.0	5.0	5.0	5.0	2.0	1.0
10	6.0	6.0	5.0	5.0	5.0	2.0	2.0
11	6.0	6.0	5.0	5.0	5.0	2.0	2.0
12	5.0	5.0	4.0	4.0	5.0	3.0	2.0
13	5.0	5.0	4.0	4.0	4.0	3.0	3.0
14	5.0	5.0	4.0	4.0	4.0	3.0	3.0
15	5.0	5.0	4.0	4.0	4.0	2.0	2.0
16	5.0	5.0	4.0	4.0	4.0	2.0	2.0
17	5.0	5.0	4.0	4.0	4.0	2.0	2.0
18	5.0	5.0	4.0	4.0	4.0	2.0	2.0
19	6.0	6.0	5.0	5.0	5.0	2.0	2.0
20	6.0	6.0	5.0	5.0	5.0	2.0	2.0
21	4.0	4.0	5.0	5.0	5.0	2.0	2.0
22	4.0	4.0	5.0	5.0	5.0	3.0	3.0
23	4.0	4.0	3.0	3.0	3.0	3.0	3.0
24	4.0	4.0	3.0	3.0	3.0	3.0	3.0

Table 3 Fixed Peak Load - Without Transmission Improvement

(a) global results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	75320		2048		29.88		63.92	
std deviation	22050		326		44.87		7.38	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	72270	78380	2002	2093	29.10	30.65	62.90	64.93
99%	71300	79350	1988	2107	28.85	30.90	62.57	65.27

(b) generation system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	15690		92.77		128.7		6.77	
std deviation	14810		64.15		104.8		3.46	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	13640	17740	83.87	101.7	123.1	134.3	6.29	7.25
99%	12990	18390	81.06	104.5	121.3	138.1	6.14	7.40

(c) transmission system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	59630		2000		21.07		61.84	
std deviation	16440		323		19.95		7.41	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	57350	61910	1955	2045	20.71	21.42	60.81	62.86
99%	56630	62630	1941	2059	20.60	21.53	60.48	63.19

Table 4 Fixed Peak Load - Without Transmission Improvement

Bus number	ENSB (MWh/yr)
1860	30730.35
1813	27247.16
1812	1468.37
1807	1147.07
1971	1132.32
1679	1089.29
0700	923.97
9996	804.29
1869	803.47
1712	696.28
1810	643.30
1861	640.60
1910	624.39
1717	584.03
1677	546.04
1806	524.27
1909	492.92
1681	448.42
1948	437.08
2496	357.94
2498	276.79
1863	275.01
1834	253.32
1844	253.27
2499	241.04
1847	220.95
1776	212.40
2497	208.90
1930	202.07
0158	201.26
1824	187.20
1811	185.60
1800	157.08
0167	126.49
2495	119.32
0183	108.00
1852	99.75
1843	88.38
1846	88.30
1845	87.88
1809	83.16
1805	63.88
1832	62.71
1804	61.87
0157	56.78
1945	30.29
1946	30.17
1854	19.85
1865	8.44

Table 5 Fixed Peak Load - With Transmission Improvement

Bus number	ENSB (MWh/yr)
1812	1459.49
1807	1116.36
1813	1021.28
0700	924.24
1869	803.70
9996	803.70
1712	704.37
1810	642.96
1910	624.57
1677	546.20
1717	535.09
1806	524.42
1909	493.07
1861	483.19
1948	437.21
1679	422.33
2496	358.05
1971	313.83
2498	276.87
1863	275.35
1844	247.27
1834	246.51
2499	241.11
1847	221.02
1776	212.81
2497	208.96
1930	202.13
0158	201.32
1824	187.26
1811	185.65
1800	157.13
1860	156.73
1681	132.31
0167	126.18
2495	119.35
0183	108.68
1852	98.80
1843	88.41
1846	87.67
1845	87.11
1809	83.18
1805	63.89
1832	62.98
1804	61.76
0157	55.98
1946	29.99
1945	29.89
1854	19.48
1865	8.44

Table 6 Fixed Peak Load - With Transmission Improvement

(a) global results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	16770		253.4		44.78		20.14	
std deviation	15220		96.51		84.20		5.29	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	14660	18880	240.1	266.8	42.19	47.38	19.41	20.87
99%	13990	19550	235.8	271.0	41.37	48.20	19.17	21.11

(b) generation system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	15690		92.77		128.7		6.77	
std deviation	14810		64.15		104.8		3.46	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	13640	17740	83.87	101.7	123.1	134.3	6.29	7.25
99%	12990	18390	81.06	104.5	121.3	136.1	6.14	7.40

(c) transmission system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	1079		192.7		4.94		16.35	
std deviation	2321		83.15		10.53		5.10	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	757.4	1400	181.2	204.2	4.58	5.30	15.64	17.06
99%	655.6	1502	177.5	207.9	4.47	5.42	15.42	17.28

Table 7 With Load Model - Without Transmission Improvement

(a) global results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	794.0		56.85		12.24		19.85	
std deviation	1075		21.96		30.23		6.39	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	645	943	53.80	59.89	11.30	13.18	18.96	20.74
99%	597	990	52.84	60.85	11.00	13.48	18.68	21.02

(b) generation system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	121		0.84		135.4		0.38	
std deviation	384		2.03		143.4		0.88	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	68	174	0.56	1.12	103.1	167.6	0.26	0.50
99%	51	192	0.47	1.21	92.96	177.8	0.22	0.54

(c) transmission system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	672		56.29		9.86		19.62	
std deviation	936		21.82		16.08		6.30	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	542	802	53.26	59.31	9.35	10.36	18.74	20.48
99%	501	843	52.31	60.27	9.19	10.52	18.47	20.77

Table 8 With Load Model - Without Transmission Improvement

Bus number	ENSB (MWh/yr)
1860	323.70
1813	286.44
1812	28.18
1971	16.30
1679	14.07
1807	10.65
1776	8.13
0700	7.07
1681	6.92
1717	6.84
9996	6.20
1869	6.15
1712	6.01
1810	4.91
1910	4.75
1834	4.31
1677	4.17
1861	4.15
1806	4.01
1909	3.77
1948	3.35
2496	2.74
1863	2.48
2498	2.12
1844	1.95
2499	1.85
1847	1.69
2497	1.60
1930	1.55
0158	1.54
0183	1.45
1824	1.43
1811	1.42
1852	1.34
1800	1.20
0167	0.97
2495	0.91
0157	0.84
1846	0.70
1843	0.68
1845	0.68
1809	0.64
1946	0.55
1805	0.49
1804	0.48
1832	0.48
1945	0.45
1854	0.15
1865	0.06

Table 9 With Load Model - With Transmission Improvement

Bus number	ENSB (MWh/yr)
1812	27.92
1807	11.41
1813	9.76
1776	9.33
1679	7.27
0700	7.16
9996	6.27
1869	6.23
1717	5.58
1971	5.08
1712	5.07
1810	4.97
1910	4.80
1677	4.23
1834	4.10
1806	4.06
1861	3.83
1909	3.82
1948	3.39
2496	2.78
1863	2.13
2498	2.15
1844	1.87
2499	1.87
1860	1.77
1847	1.71
2497	1.62
1681	1.58
1930	1.57
0158	1.56
0183	1.45
1824	1.45
1811	1.44
1800	1.22
0167	0.98
2495	0.93
1852	0.90
1846	0.71
1843	0.69
1845	0.68
1809	0.64
0157	0.62
1805	0.50
1804	0.49
1832	0.48
1946	0.45
1945	0.29
1854	0.15
1865	0.07

Table 10 With Load Model - With Transmission Improvement

(a) global results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	169		6.46		23.77		2.39	
std deviation	752		8.69		75.73		2.28	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	65	273	5.26	7.67	16.98	30.56	2.07	2.71
99%	32	306	4.87	8.05	14.83	32.71	1.97	2.81

(b) generation system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	121		0.84		135.4		0.38	
std deviation	384		2.03		143.4		0.88	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	68	175	0.56	1.12	103.2	167.6	0.26	0.50
99%	51	192	0.47	1.21	92.96	177.8	0.22	0.54

(c) transmission system results

	LOEE (MWh/yr)		LOLE (h/yr)		LCI (MW/int)		FOI (int/yr)	
average value	47		5.81		3.13		2.13	
std deviation	572		8.31		19.18		2.12	
confidence intervals								
level	lower	upper	lower	upper	lower	upper	lower	upper
95%	0	127	4.70	7.01	1.31	4.96	1.83	2.42
99%	0	152	4.34	7.37	0.73	5.53	1.74	2.51

APPENDIX VIII

NATIONAL GRID COMPANY REPORT

THE ANALYSIS OF THE NEW BRUNSWICK POWER SYSTEM USING ESCORT

-by-

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1. Introduction

This paper describes an analysis of the New Brunswick Power System using NGC's software ESCORT (1),(2),(3). This is part of the CIGRE WG 38.03 exercise on comparative software for Power System analysis.

2. Adequacy and security

Most reliability software undertakes what is termed an adequacy analysis (4). This allows generators and circuits to undergo random breakdown, but does not cover the operational requirement for the system to be secure. This operational requirement is for the system to be robust against certain defined faults. In effect an adequacy analysis assumes that, in the event of a fault, redispatch of generation (or, in extremis, load shedding) can be undertaken before cascade failure occurs.

A security analysis takes into account the requirement for the system to be robust against these defined failures.

3. The ESCORT program

ESCORT is a piece of software designed to model a Power System. It has been specifically designed to undertake a security analysis, i.e. the Power System is modelled with security constraints. The usual forms of these constraints can be expressed as "No single circuit outage must result in any other transmission circuit being overloaded". ESCORT has been designed as a planning tool rather than an operational one, and hence does not include any dynamic aspects, e.g. the requirement to have sufficient reserve on the system.

As such ESCORT is more powerful than the majority of pieces of software considered in this comparative exercise. Nevertheless, by giving ESCORT (as data) no contingency constraints, the effect of an adequacy analysis can be mimicked.

The analysis of the New Brunswick system did not require any software modifications to be made to ESCORT.

3.1 Limitations of ESCORT

The major limitations of ESCORT are two-fold:-

i) It only undertakes a d.c. load flow analysis. Accordingly problems associated with reactive power shortfalls are not addressed.

ii) No allowance is made for possible post-fault action (e.g. switching)

4. Modelling of the New Brunswick system

ESCORT requires 7 input files of data. Appendix 1 shows part of each of these input files; full details are not provided due to space limitations. These files are discussed below.

4.1 Network data.

The Network data file contains all transmission elements (irrespective of voltage level, or whether they are lines, transformers or cables.) The parameters are R and X (measured in % on 100MVA base), together with their rating (which can vary by season). In addition, the terminal end-points of each line are required, together with a unique alphanumeric identifier (for the New Brunswick system the code of L for line and X for transformer has been adopted).

For the New Brunswick exercise, the data supplied gave two transmission ratings. It has been assumed that the lower rating is used in the adequacy analysis (i.e. that which assumes immediate post-fault redispatch of generation) and the higher rating has been used in the security analysis. In other words, the low rating reflects normal operation, but in emergency conditions, i.e. immediately after a transmission fault, a higher or emergency rating can be accepted.

ESCORT was written to give a comparison between two different networks (generally before and after reinforcement). This is done in the Network file by having most circuits of type C (for constant), but a few circuits are type V (for Variable). Variable circuits are present in a network if there is a T (for True); absent if they are F (False). This has the great advantage that identical sets of random outages can be applied to each network, so that one is genuinely examining the effect of a reinforcement (and there is less danger of statistical freaks making it difficult to calculate the benefit of a reinforcement).

4.2 Generator data.

ESCORT allows generation to be modelled in two different ways. The first way is as a simple probabilistic generator, with certain probabilities of being available - similar to the treatment used in most other software. The second way is as a deterministic generator - i.e. its running regime can be pre-specified. This can be particularly relevant to energy-constrained hydro plants, for example, where ESCORT would allow them to be scheduled during the day but not the night.

The generator data is as supplied by New Brunswick Power, with the exception of Point Lepreau. In order to deal with the participation sale, Point Lepreau and its associated American load, has been modelled as a deterministic generator. For 21.12 hours a day (i.e. 88% of the time) Point Lepreau generates 657MW with a 230MW load at the appropriate USA busbar; for 2.88 hours/day (i.e. 12% of the time) there is no generation at Point Lepreau and no load at the USA busbar.

For certain analyses, discussed below, this was modified so that the 230MW load was present for 100% of the time.

Each generator has the usual parameters - name, node, production cost, breakdown rate, etc. Note in particular that each generator has an overhaul pattern (this can be used to downrate generators in the overhaul season if a specific maintenance schedule is not used) and a fuel type. This latter is purely for ease of tabulating output (e.g. ESCORT will give details of how much energy is supplied from each different fuel).

4.2.1 Phantom Generators

If the generation is insufficient to supply the demand then the software will label the case as infeasible (i.e. there is no feasible solution). In order to correctly analyse this case, a number of 'phantom' generators were placed on the system at strategic places. These generators were all given fuel type "Disconnection" and a very high cost, so that they would only be scheduled if there was no real plant which could supply the load. The expected energy not supplied is then equal to the total energy produced by these phantom generators.

In a similar fashion, curtailable load was also modelled as a generator (of type IL, for Interruptible Load) at an appropriate price.

4.3 Demand Data

The nodal demand data was as provided by New Brunswick Power. Loads were split into three categories :-

i) NB Industrial loads which would be constant throughout the year (Area N.B.IND)

ii) NB ordinary loads which would vary by season (Area N.B.Power)

iii) Four other areas representing Hydro-Quebec, Nova Scotia, Maine Power and Prince Edward Island

The way in which the load varies throughout the year is given in the Period data (see below)

4.4 Period Data

The year was split into 5 periods, as follows:-

i) Peak period
ii) Winter
iii) Spring/Fall
iv) Summer
v) Point Lepreau maintenance period.

The Point Lepreau maintenance period was modelled separately in order to correctly model the effect of the participation sale.

Each period was then divided into a number of demand levels, each lasting for a specified time, in order to model the New Brunswick load curve. A total of 28 demand levels were used to model the whole year.

The nodal demands (see 3.3 above) were scaled separately in each demand block. New Brunswick industrial loads (see section 4.3 above) were not scaled, while other NB demands were scaled by the appropriate factor to give the correct overall load shape.

4.5 Outage Data

This file contains the probabilistic line outage data for the transmission circuits. Each circuit is referred to by its unique code (see Network data). It is possible here to define multiple (common-mode) outages.

4.6 Contingencies

This file lists all the contingencies which ESCORT (in its security-constrained form) will consider. For the New Brunswick system all single circuit outages that did not split the system were considered to be credible contingencies, with the exception of the circuit at Eel River connecting busbars 1805 and 1948. ESCORT has the capability to have multiple circuit contingencies, although this facility was not utilised in this exercise.

4.7 Maintenance data

In this file a maintenance schedule is given. ESCORT can maintain both circuits and generators, although for this exercise only generator maintenance has been included.

5. Modelling issues

There are three important aspects whereby ESCORT has to make assumptions about how the system will be operated in practice. These areas are :

- How energy-limited hydro plant is modelled
- How a system split is modelled
- How post-fault operator action is modelled.
- How load-point indices are calculated

These are each considered in turn.

5.1 Modelling of energy limited hydro plant.

There are two ways in which energy-limited hydro plant can be modelled. The first (and the commonest method in reliability software) is to pre-determine the output schedule. The hydro plant is modelled as, for example, at 100% output during the day, 80% output during the evening and 20% output during the night. This method ensures that the energy constraint is satisfied; however, it is rather pessimistic as it does not allow any freedom for the operator. In particular it will not allow the operator to use hydro plant as reserve, and may come to the stage where demand is modelled as being disconnected when in practice there is unused hydro capacity available.

The second way is to model the hydro plant as if it were thermal plant, but to put in a cost which will ensure that it is only scheduled during part of the day. In New Brunswick this will probably mean allocating a 'cost' midway between coal and oil. Provided the cost is correctly determined, the energy constraints will be met while the pessimism of method one above is eliminated.

For the New Brunswick system the hydro plant was allocated the costs given in Table 1. These differ from the costs given in the data, which were not found to give the correct overall energy supplied. The resultant energy utilisation is also shown in table 1 (as the ESCORT utilisation value), where it may be compared with the actual energy deemed available; it can be seen that the figures used actually gave a total over-utilisation of approximately 4%

Table 1 Costs allocated to Hydro Plants (in $Cdn/MWhr)

				Utilisation	
	Winter	Spr/Fall	Summer	NB Value	ESCORT
Beechwood	35.7	32.3	32.3	478	580
Grand Falls	32.5	32.5	32.5	210	225
Mactaquac	37.5	34.5	34.5	1609	1592
			Total	2297	2397

5.2 System Splits

There are a number of outages that split the system. Sometimes these are cases where a load is connected by a single circuit only; clearly loss of that circuit will result in the load being isolated. Secondly, there are a number of cases where a larger scale system split can occur (e.g. loss of the circuit from Edmunston to St. Andre).

In common with much other reliability software, the treatment of system splits need to be handled carefully. ESCORT makes the following assumptions:-

1) If an outage splits the system then it is logged as an infeasible case and the simulation is ignored.

2) If a contingency would split the system, then it is ignored.

These assumptions would give rise to a considerable optimism in the New Brunswick case, which is poorly interconnected. (ESCORT was designed for a more closely meshed system, where system splits are much less likely). Accordingly two measures were taken to ensure that ESCORT did not give optimistic results:-

1) In cases where line outages were likely to give rise to a system split, a dummy line with a high reactance and low capability was put in parallel with the real line. This dummy line was given 100% reliability. This meant that, if the relevant line was outaged, the network would still be connected.

2) In addition, a phantom ('disconnection') generator was placed at the node likely to be disconnected. In the event that the critical outage occurred, this phantom generator would be run and give rise to energy not supplied.

This modelling is shown in Figure 1.

5.3 Post-fault Operator Action

The New Brunswick system contains a number of normally open circuit breakers which can be closed in an emergency. Typically this would happen in the event of certain outages. ESCORT, in common with most other software, can only handle this in clearly defined circumstances (e.g. if there is a very simple rule of the sort "close circuit breaker X if generator G is unavailable).

5.4 Load Point Indices

This report does not give load point indices (i.e. identifying individual buses where load is curtailed).

The reason for this is part of the philosophy of ESCORT. Because ESCORT is an optimising program, it will optimise (i.e. minimise) costs. The way that ESCORT operates mean that the implicit load-curtailment strategy adopted will be to curtail load at the most effective bus-bars; as ESCORT takes losses into account this will be included within the strategy as a second order effect. In particular, therefore, if there is a shortfall in generation then load will be curtailed at the bus-bar which minimises system losses, and not uniformly (as would normally be assumed).

Because this load-curtailment strategy is unrealistic (in practice the load to be curtailed will normally be evenly spread so that every load point suffers equally) load point indices are not published.

6. Results

6.1 Results of Winter Peak only analysis, adequacy analysis, participation sale ignored

The first task was to provide some comparisons between ESCORT and the other items of software. For this exercise, ESCORT was run in the following mode, with 4000 simulations:-

i) No contingencies

ii) The participation sale was not modelled; 230 MW of Maine Power demand was assumed constant whether Point Lepreau was available or not.

iii) Only winter peak demand level was considered; this demand level was assumed to last throughout the year.

Results for Energy not supplied are as follows:-

	Base Case	Improvement
Energy not supplied due to generation	13.1	13.0
Energy not supplied due to transmission	80.3	2.4
Total	93.4	15.4 (TWhrs)

ESCORT also gives, as output, details of the limiting circuits. The following circuits were limiting (i.e. if the circuit rating had been increased, then a more economic dispatch was available). Note that this does not mean that the Expected Energy Not Supplied would have decreased.

Limiting circuits (in decreasing order of activity, expressed as hours/year for which the circuit is limiting) are as follows:-

		Base Case	Improvement	
CC1837 to MI1860		1954	264	hours/year
NC1807	MB1969	1913	2037	hours/year
MQ1809	DO1861	101	99	hours/year
IR1681	CB1813	17	0	hours/year
CC1837	CC1836	10	0	hours/year
NO1901	TP1776	6	6	hours/year
TP1928	MB1969	2	2	hours/year
KE1827	NA1846	2	2	hours/year
RI1712	MN1812	2	2	hours/year
IR1681	NO1901	0	8	hours/year

It should be noted that the effect of the transmission improvement is to dramatically reduce the proportion of time for which the line from CC1837 to MI1860 is restrictive (although it has not completely eliminated the restriction). However, the transmission constraints on some other lines (e.g. from IR1681 to NO1901) now become active; previously they were hidden, but the transmission improvement has allowed them to become visible. Values of marginal gains (i.e. the benefit of increasing the circuit rating by 1 MW) are shown in Table 10.3 of the main document, and are not repeated here. It should be noted that the marginal gains are actually defined in ESCORT as the financial saving (in $Cdn) per extra MW of capacity. In the main report the assumption is made that the marginal gain is entirely due to a saving in energy not supplied (costed here at an arbitrary $500Cdn/MWhr) whereas in reality a component of the marginal gain may be due to a more economic dispatch (typically a saving of $30Cdn/MWhr). The effect of this assumption is not considered significant.

6.1.1 Effect of Participation Sale.

A subsidiary run was done to evaluate the effect of modelling the participation sale "properly". This gave the following results:-

	Base Case	Improvement
Energy not supplied due to generation	5	5
Energy not supplied due to transmission	82	3
Total	87	8 (TWhrs)

The two major restricting circuits displayed active restrictions for the following durations:-

		Base Case	Improvement	
NC1807	MB1969	2533	2221	hours/year
CC1837	MI1860	1137	59	hours/year

It can be seen that the effect of modelling the participation sale 'properly' is to reduce the EENS due to generation; a comparatively small effect on transmission is seen.

6.2 Effect of Transmission Contingencies

For this run, winter peak only again was studied, with the participation sale modelled 'correctly'. Only 50 simulations were used, which is inadequate for convergence; hence there is a degree of uncertainty in the figures below. Line limits were the higher values (see section 4.1). The following results for energy not supplied were obtained:-

	Base Case	Improvement
EENS due to generation	2.2	2.2
EENS due to transmission	187	1.2
Total	189	3.4 (TWhrs)

The following transmission outages were constraining the system. The figures show the proportion of time for which the constraint was active (expressed in hours/year):-

Failing circuit	Overloaded circuit			
CC1836 - NO1900	IR1681 - CB1813	(base case)	5296	hours/year
	IR1681 - CC1837	(improvement)	-	hours/year
NS168 - SA1850	NS158 - NS167	(base case)	3975	hours/year
		(improvement)	1951	hours/year
ER1805 - ER1948	ER1805 - ER1830	(base case)	6335	hours/year
		(improvement)	6685	hours/year
CC1836 - CC1837	CC1836 - CC1837	(base case)	7377	hours/year
		(improvement)	21	hours/year
ST1868 - ER1866	GF1802 - TP1804	(base case)	-	hours/year
		(improvement)	21	hours/year

Of these, the first and fourth outages represents the weakness that the transmission improvement is designed to rectify. The second is actually a weakness within the Nova Scotia system and might represent a modelling deficiency rather that a weakness in the system. The third outage (at Eel River) is a short line between two sub-stations that subsequent discussion indicates should not be considered a credible failure. The fifth overload occurred when the circuit KE1803-ST1868 was faulted.

The effectiveness of the transmission reinforcement in the 'improvement' case is self-evident.

6.3 All Year round analysis

This part of the document deals with the results when the system is modelled all year round. It should be noted that generator maintenance was included, but not transmission line maintenance; the circuit ratings given were assumed to apply all year round.

As part of the ESCORT output, a thorough analysis of demand and generation is provided. A summary of the New Brunswick energy balance is given below.

Energy Utilised

New Brunswick - Ordinary Loads	9.90 (TWhr)
New Brunswick - Industrial Loads	5.85
P.E.I.	0.52
Maine Power Corp.	2.02
Hydro-Quebec	0.17
Losses	0.33
Total	18.79

and this energy was supplied by the following fuels:-

Nuclear	4.68

Coal	5.88
Oil	5.34
Gas Turbines	0.08
Hydro	2.75
Imports	0.04
Interruptible load curtailed	0.01
Normal load curtailed	0.01
Total	18.79 TWhr

The Maine Power demand represents a continuous demand of 230MW, i.e. it assumes that the New Brunswick system is supplying 230MW to Maine whether Pt. Lepreau is available or not.

6.3.1 Financial Benefit of Transmission Improvement

The primary task of ESCORT is to determine the benefit of a proposed transmission reinforcement. The transmission improvement case here shows the following benefits:-

Reduction in energy not supplied :-	9.5 GWhrs/yr
Reduction in economic dispatch costs	$1.7M Cdn
Reduction in system losses	$0.5M Cdn

The reduction in economic dispatch costs is largely derived from the ability to run more generation at Coleson Cove, with a reduction in more expensive generation elsewhere on the system. The transmission system is preventing the generation from being dispatched economically while retaining system security.

At an effective cost of energy not supplied of $1000Cdn/MWhr this would give a total economic benefit of $12M Cdn per year, which would need to be compared with the capital cost of the transmission reinforcement. It should, however, be emphasised that this economic benefit is that as seen by the ESCORT model; in many cases the savings can be achieved by, for example, operational action without requiring extra capital expenditure.

6.3.2 System Losses

An often neglected part of system planning is the minimisation of transmission losses. In the New Brunswick system, ESCORT demonstrates that losses total 333 GWhrs per year. The following circuits have annual losses exceeding 10 GWhrs/year:-

		Base Case	Improvement Case	
US700 to	LP1843	16.3	16.4	GWhrs/yr
RI1712	NC1807	12.5	12.3	
KE1803	LP1843	10.8	11.1	
MN1812	GL1811	21.3	20.9	
CC1836	NO1900	21.4	21.1	
CC1837	MI1860	11.5	6.7	
CC1837	MI1862	11.3	6.4	

In some cases the losses represent high power flows, and in other cases they represent particularly long circuits; however this indicates the areas where the largest components of losses occur.

The largest value occurs on the 87 km long circuit between Coleson Cove and Norton. A histogram of the line flows on that circuit is shown in Figure 2. This shows the proportion of time the line flow lies within each 10% band (on an all-year-round basis).

7. Conclusions

ESCORT has been successfully been applied to the New Brunswick system. It has overcome a number of modelling problems inherent in that system, in particular the modelling of a participation sale and the dispatch of energy-limited hydro generation. The benefits of the transmission improvement case are quantified, although ESCORT cannot say if it is economic as the costs of the improvement are not known.

REFERENCES

1) Dunnett R.M. and Berry P.E., Contingency constrained economic dispatch algorithmn for transmission planning, Proc IEE Part C, Vol 136, No. 4 (1989)

2) Manning P.T. and Plumptre P.H., Reliability Modelling of the CEGB's Power system incorporates economic optimisation while remaining fault tolerant, Reliability '89, Brighton, U.K. (1989)

3) Dunnett R.M. and Macqueen J.F., Transmission Planning by Monte-Carlo optimisation. 10th Power Systems Computational Conference, Graz, Austria (1990)

4) Manning P.T. and Plumptre P.H., The practical use of reliability analysis in system planning, CIGRE symposium on electric power systems reliability, Montreal, Canada (1991)

Figure 1

MODELLING OF CIRCUITS WHICH COULD SPLIT THE SYSTEM

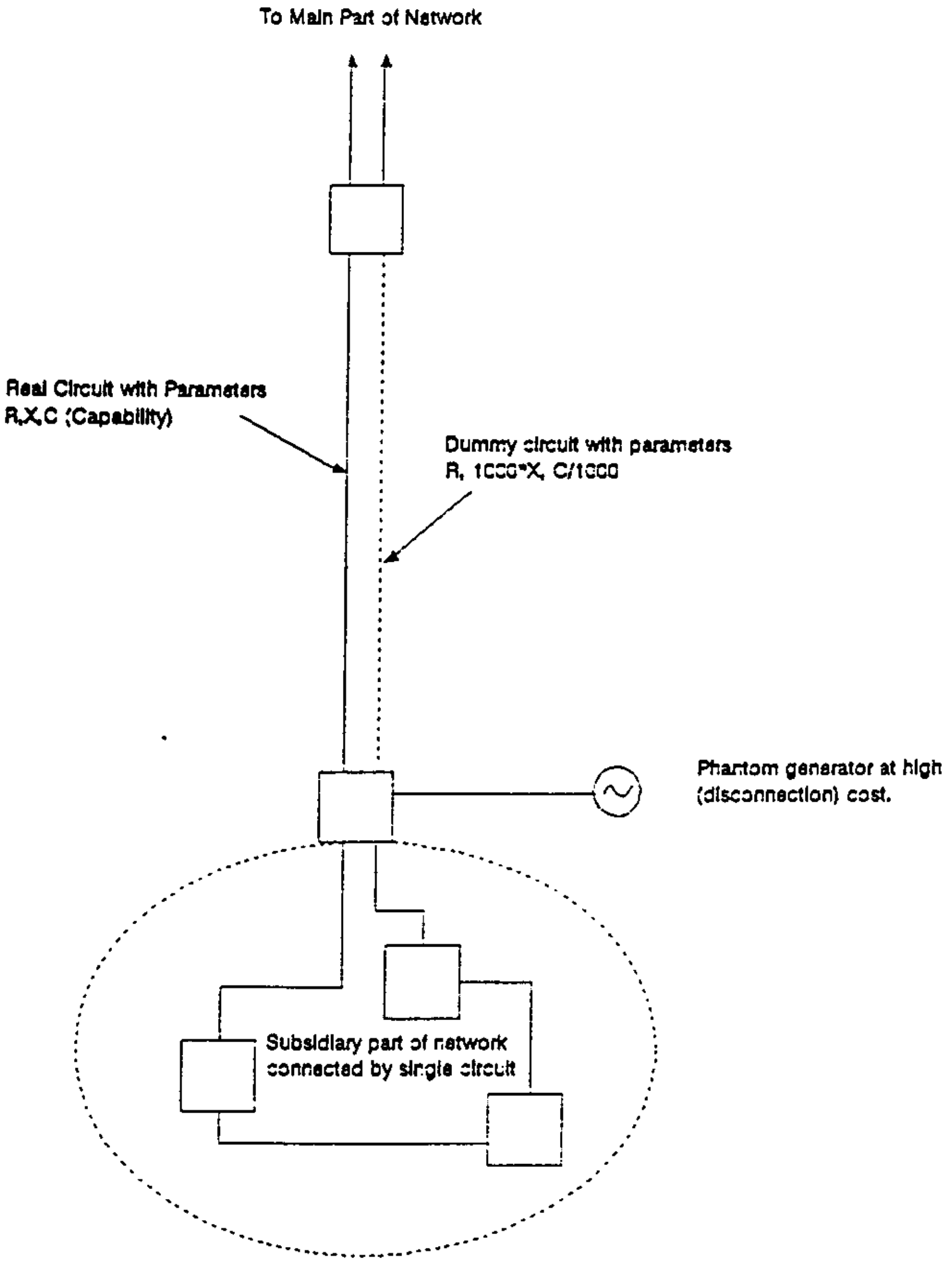
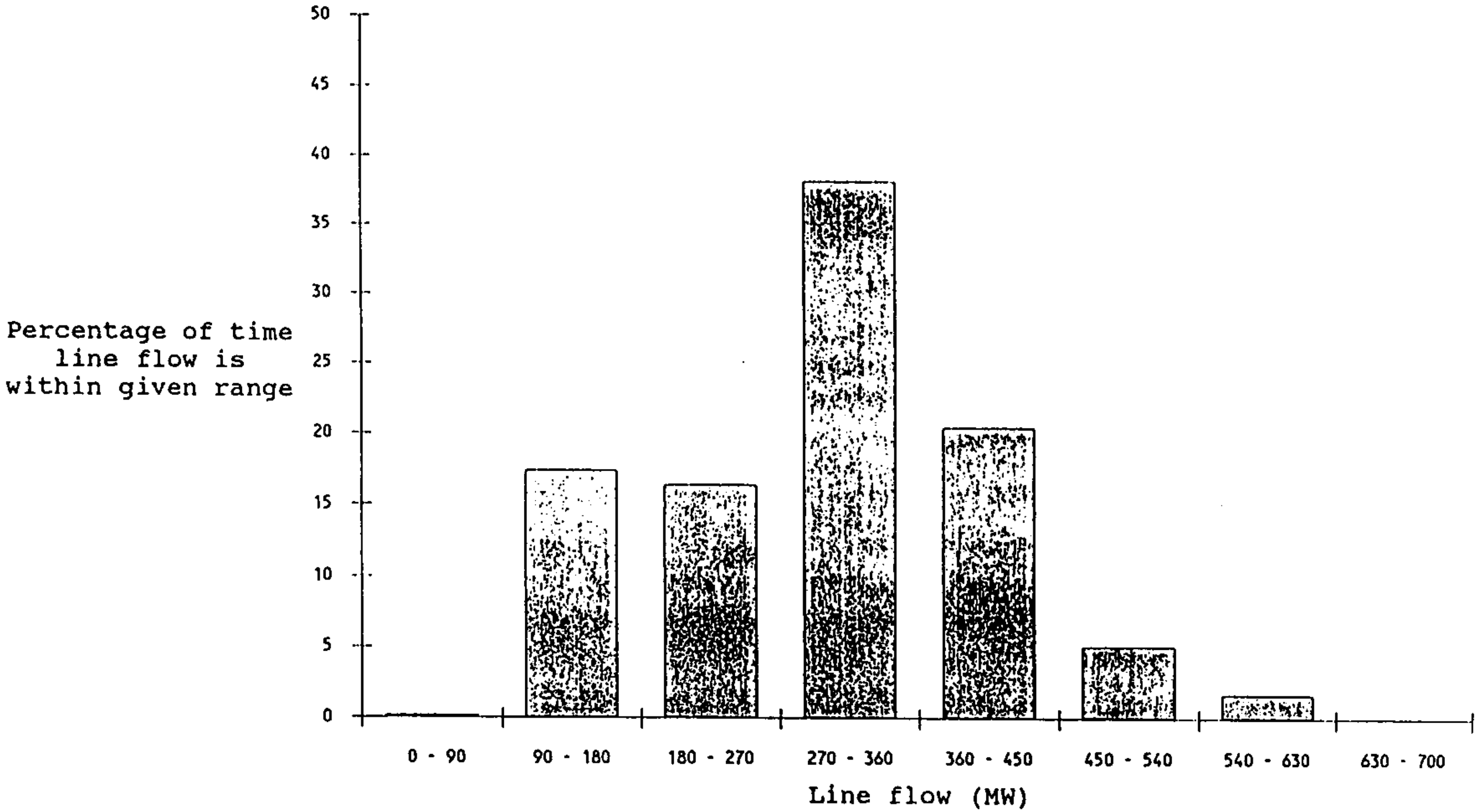


Figure 2: All year round line flows on the Coleson Cove - Norton circuit



APPENDIX 1

ESCORT Input Data for the New Brunswick System

This Appendix gives a partial listing of the input data for the New Brunswick system. Omitted is the file giving details of output controls, random number seeds, number of simulations and a number of other options; in addition, in the interests of space saving, only a partial listing is given of most of the data files. Full listings are available from the author.

FILE: APPENDIX NB A1 CMS RELEASE 5.0 FOR NATIONAL GRID COMPANY

```
******************************
*  FILE 1  NETWORK  DATA     *                    PAGE 00001
******************************
```

PROPOSALS
NEW BRUNSWICK
COLESON COVE

(L I N E D A T A (E S C O R T)
(
(

NETWORK					DJF	EFGH	PQRS	UVWX			
L1175A	GF1802	TP1804	000.05	000.17	230	230	230		I	C	
L1111B	GF1802	TP1817	001.43	005.73	230	230	230		I	C	
L2002	KE1803	CC1836	000.41	003.87	950	950	950		I	C	
L3003	KE1803	LP1843	000.47	004.47	950	950	950		I	C	
L3011	KE1803	ST1868	000.51	004.84	950	950	950		I	C	
L1175B	TP1804	ST1849	000.94	003.45	230	230	230		I	C	
L1115A	ER1805	TP1824	002.88	011.92	230	230	230		I	C	
L1107	ER1805	DA1826	0.21	1.86	478	478	478		I	C	
L1130A	ER1805	TP1865	1.65	6.16	230	230	230		I	C	
ERBUS	ER1805	ER1948	0.0000	000.01	280	280	280		I	C	
L1115B	BA1806	TP1824	002.36	009.74	230	230	230		I	C	
L1106A	BA1806	TP1928	001.38	005.70	230	230	230		I	C	
L1127	BA1806	BM2497	001.62	006.54	230	230	230		E	C	
L1105A	NC1807	TP1832	002.41	010.29	230	230	230		I	C	
L1106C	NC1807	MB1969	000.87	003.61	230	230	230		I	C	
L1133	MQ1809	KE1827	000.33	002.86	478	478	478		I	C	
L1134	MQ1809	KE1827	000.33	002.86	478	478	478		I	C	
L1174A	MQ1809	DO1861	001.11	005.19	478	478	478		I	C	
L1102	MV1810	GL1811	002.99	012.37	230	230	230		I	C	
L1103A	MV1810	NA1845	000.32	001.34	230	230	230		I	C	
L1112A	MV1810	NA1846	000.32	001.27	230	230	230		I	C	
L1174B	MV1810	DO1861	000.52	001.92	230	230	230		I	C	
L1101	GL1811	MN1812	005.78	024.14	230	230	230		I	C	
L1105B	GL1811	TP1832	004.69	020.06	230	230	230		I	C	
L1148	MN1812	SA1839	000.91	003.76	230	230	230		I	C	
L1151	MN1812	SA1839	000.91	003.76	230	230	230		I	C	
L1190C	MN1812	TP1945	000.53	002.00	230	230	230		I	C	
L1124B	MN1812	TP1946	000.53	002.00	230	230	230		I	C	
L1122	CB1813	RO2496	000.04	000.17	230	230	230		E	C	
L1147A	CB1813	MI1860	0.58	2.39	190	190	190		I	C	
L1165B	CB1813	MI1862	0.58	2.39	190	190	190		I	C	
TEST1	IR1681	CC1837	1.81	8.48	140	140	140		I	V	FT
TEST2	IR1681	NO1901	3.06	12.65	140	140	140		I	V	FT
L1144	TP1817	US1896	0.43	1.78	230	230	230		I	C	
L2130A	BA1829	MB1964	000.82	004.68	478	478	478		I	C	

```
********************************
*  FILE 2  GENERATOR  DATA     *
********************************
```

```
(
(            G E N E R A T O R   D A T A (E S C O R T)
GENERATORS
(
(                   NO     CAN  $    CAP    BK/DOWNO/H  FUEL
(NAME      NODE    UNITS  COST/MW   MW       %       PATT
(
GRLAKE8   GL1811    1      40.0     60      12.0  COP  COAL       E
GRLAKE9   GL1811    1      30.0    170      12.0  COP  COAL       E
MONCTN    MN1812    1      75.0     25      10.0  COP  Oil 2      E
C.BAY--1  CB1813    1      45.0     45      10.0  CO2  Oil        E
C.BAY--2  CB1813    1      25.0     12      10.0  CO2  Oil        E
C.BAY--3  CB1813    1      34.0    100      10.0  CO2  Oil        E
C.BAY--4  CB1813    1      40.0     97      10.0  CO2  Oil        E
INTLOD-1  CB1813    1      80.0     10       0.0  IL   INT.LOAD   E
DALHOU-1  DA1826    1      37.0    103      10.0  MAG  Oil        E
DALHOU-2  DA1826    1      30.0    203      12.0  MAG  COAL       E
C.COVE-1  CC1836    1      37.0    335      10.0  MAG  Oil        I

             ******************************
             *  FILE 3  DEMAND     DATA   *
             ******************************

(
(               DEMAND DATA
(               -----------
(
(  NODE  DEMAND  NODE  DEMAND  NODE  DEMAND  NODE  DEMAND  NODE  DEMAND
(
(2345678901234567890123456789012345678901234567890123456789012345678901
(-----------------------------------------------------------------------
AREA  N.B.IND
 IR1681    32.9 ER1805    15.9
 MN9911    17.0 LP1843    22.0
 TP1865     2.1
 IP2495    29.7 RO2496 89.1
 BM2497    52.0 IP2498    68.9
 CO2499 60.0
 BW9900    15.0 NC9901    30
 CB9902  40     TP9903    20
 IR9904  60     TP9905    23.4
 TP9906  19.1
 TP9907    27.0 TP9908   5.5
 RI9909    40.0
AREA  N.B.POWER
 CA1677   135.7 LA1679   101.5 RI1712   109.0 TP1717   106.0
 TP1776    27.1 BW1800    24.1
 GF1802     0.0 KE1803     0.0 TP1804    14.9 BA1806   130.5

            ******************************
            *  FILE 4  PERIOD     DATA   *
            ******************************
```

```
(
(   NATIONAL DEMANDS AND OTHER PERIOD DATA
(
(
 3274 MW - ACS DEMAND TO SCALE TO FOR WHOLE STUDY
 5, 6,  4   - NUMBER OF PERIODS, AREAS, OUTSIDE SOURCES
(  INDIVIDUAL PERIOD DATA FOLLOWS:
(
PEAK     PERIOD
(--------------
2      DAY TYPES
DJF    RATING PERIOD
(          NO.   BLKS
(          DAYS
(LEPR         1.76 1
LEPR         1    1
           PEAK
DURATION    21.12
OUTPUT       T
NATIONAL 100.0
N.B.POWER 2427
N.B.IND     669
N.S.POWER   118
P.E.I.      60
HYDRO QUE   0.1
M.P.S.      0.1
(
HYDRO-Q1   -200
HYDRO-Q2   -200
LEPREAU    657
US-PS     -230
(
--------------
NOLP         1       1
           PEAK
DURATION    2.88
OUTPUT       T
NATIONAL 100.0
N.B.POWER 2427
N.B.IND     669
N.S.POWER   118
P.E.I.      60
HYDRO QUE   0.1
M.P.S.      0.1
(
HYDRO-Q1   -200
HYDRO-Q2   -200
LEPREAU    0.0
US-PS      0.0
(
--------------------------
WINTER   PERIOD
(--------------
```

```
                    ******************************
                    *  FILE 5  OUTAGE     DATA   *
                    ******************************

(
(         1         2         3         4         5         6
(234567890123456789012345678901234567890123456789012345678901234567890
(----------------------------------------------------------------
CLASS : random          1
L1152                                    .027  0.0   0.0 0.0 0.0 0.0
L1116                                    .006  0.0   0.0 0.0 0.0 0.0
L1149A                                   .009  0.0   0.0 0.0 0.0 0.0
L1109   TEST9                            .0008 0.0   0.0 0.0 0.0 0.0
TEST1                                    .016  0.0   0.0 0.0 0.0 0.0
TEST2                                    .024  0.0   0.0 0.0 0.0 0.0
L1118                                    .043  0.0   0.0 0.0 0.0 0.0
L1114                                    .037  0.0   0.0 0.0 0.0 0.0
L1149B                                   .0    0.0   0.0 0.0 0.0  0.0
L1199B                                   .024  0.0   0.0 0.0 0.0 0.0
L1199A                                   .007  0.0   0.0 0.0 0.0 0.0
L1111A L1111B                            .03   0.0   0.0 0.0 0.0 0.0
L1125A                                   .031  0.0   0.0 0.0 0.0 0.0

                   ******************************
                   *  FILE 6  CONTINGENCY  DATA  *
                   ******************************

(
(
(                   CONTINGENCY OUTAGE LIST FOR SAMPLE PROBLEM
(         1         2         3         4         5         6
(2345678901234567890123456789012345678901234567890123456789012345678901234567890
SINGLE
(LNS2     LNS4     L3006   - Nova Scotia circuits not considered
 L3006    L3001    L3016    L1152    L1192    L1149A
 TEST1    TEST2    TEST3
 L1109    L1118    L1114    L1149B
 L1199A   L1199B   L1111A   L1125A   L1176    L1126A   L1175A
 L1111B   L2002    L3003    L3011
 L1175B   L1115A   L1130A   L1115B   L1106A
 L1105A   L1106C   L1133    L1134    L1174A   L1102
 L1103A   L1112A
 L1174B   L1101    L1105B   L1148

                  ******************************
                  *  FILE 7  MAINTENANCE  DATA  *
                  ******************************

(
(
(       MAINTENANCE SCHEDULE DATA
PERIOD DATA  (PER IN COL 1-3 INDICATES START OF THIS BLOCK)
```

```
FILE: APPENDIX NB       A1  CMS RELEASE 5.0 FOR NATIONAL GRID COMPANY

                                                          PAGE 00005
 52  WEEKS
( WEEK REFERENCE-            1         2         3         4         5
( ..............    1234567890123456789012345678901234567890123456789012
 PEAK               x
 WINTER              xxxxxxxxxxxx                                   xxxx
 SUMMER                                  xxxxxxxxxxxxxxxxx
 SPRFAL                          xxxxx                     xxxxxxxxx
 PLPRMAI                              xxxx
(
GENERATOR OUTAGES  (GEN IN COL 1-3 INDICATES START OF THIS BLOCK
 COWAN                           xxxxx
 GRLAKE8                          xxxx
 GRLAKE9                                          xxxx
 C.BAY--1                   xxxxxx
 C.BAY--3                            xxxxxx
 C.BAY--4                                  xxxxxx
 DALHOU-1             xxxxx
 DALHOU-2                                 xxxxx
 C.COVE-1                                 xxxxxxx
 C.COVE-2                                        xxxxxxx
 C.COVE-3                                               xxxxxxx
```

APPENDIX IX

UNIVERSITY OF SASKATCHEWAN REPORT

COMPOSITE SYSTEM RELIABILITY EVALUATION PROGRAM (COMREL)

COMREL was developed at the University of Saskatchewan as a result of extensive work done in the area of composite or bulk power system adequacy assessment. The program is based on a failure modes and effects analysis procedures provided through the contingency enumeration approach. Some important features of the program are as follows:

1. The program is suitable for evaluating the adequacy indices of moderately sized power systems. It calculates individual load point as well as system indices. A comprehensive list of the indices calculated is given in Reference [1].

2. The program considers simultaneous independent outages of generating units (up to 4th level), of transformers/transmission lines (up to 3rd level) and of generating units AND lines/transformers (up to 3rd level). Common mode outages of transmission lines/transformers and station-initiated outages can also be considered. Data for common mode outages is included in the same input file as that for generators/lines/transformers and buses, etc. Outage events due to station outages are evaluated using a separate computer program and are included in the form of a separate input data file while executing COMREL.

3. The program is equipped with three solution techniques, namely linear network flow method, DC load flow technique and fast decoupled AC load flow method. The network flow model can be used to examine the continuity of power supply at various load centers. The DC load flow technique is quite simple to apply and is fast and free of convergence problems but only provides an estimate of the line power flows without including any estimate of the bus voltages and the reactive power limits of the generating units, etc. If the quality of the power supply, i.e., proper voltage levels and generating units MVAr limits are an integral part of the adequacy criteria, then more accurate AC load flow methods such as the fast decoupled load flow method should be used. Any one of these three methods can be selected by the user for evaluating the system performance.

4. The base case load flow values are used as initial estimates for 1st level outages. Similarly the values for the load flow quantities at an outage level are used as the initial estimates for the next outage level contingencies. This procedure results in a faster convergence of the load flow for the outage events.

5. Computational time is reduced by:

   a. sorting identical generating unit contingencies such that the indices for only one identical unit are calculated.

   b. restricting the calculation of higher level outages (5th or more for generators and 4th or more for lines/transformers) by modifying the probability and the frequency of the highest level outages considered, and

   c. not solving those contingencies which have a frequency of occurrence less than a prespecified cut-off limit [2].

6. Any given set of selected generating unit and/or line contingencies can also be evaluated.

7. Load at each bus is classified into two categories, curtailable (some percentage of the total bus load) and firm (remaining load). In the case of a capacity deficiency, curtailable load is interrupted first followed by the interruption of firm load if necessary. The load curtailment philosophy utilized in COMREL in quite flexible. The load interruption may be localized in the neighbourhood of a disturbance or it can be distributed over a wider system area. This provision has been made in the load

curtailment algorithm by defining three load curtailment passes [3]. Proportional load is interrupted at those buses which are covered by the pass specified. Line overloads are alleviated by generation rescheduling and load shedding at appropriate buses which is governed by the number of load curtailment passes (1, 2 or 3) selected by the user.

8. If a generating unit outage at a generation bus results in capacity shortfall at that bus, then the generation at other generation buses having reserve capacity is increased to meet the deficiency. If, however, the system remains deficient even after supplying all the available system spinning reserve, then load is curtailed at the buses covered by the load curtailment pass specified.

9. Additional features associated with using the AC load flow through COMREL are:

   a. In case of bus isolation due to line(s) outages AC load flow is conducted for the remaining buses and lines in the system.

   b. In case of a line outage causing a split network condition, the network flow method is used to check the adequacy of the split networks.

   c. Voltage violation cases and non-convergent situations are corrected by injecting reactive power and rescheduling the generating units. Heuristic algorithms have been developed for solving such cases [4].

Methods/Philosophies Used for the N.B. System

Generating unit outages up to 4th level, transmission line/transformer outages up to 2nd level and combined generator and line/transformer outages up to 2nd level were considered. Sorting of identical generating units was done. Three load curtailment passes were used. Effects due to higher level unit and/or line outages were not considered. A frequency cut-off limit of 0.1E-09 was used. Curtailable load was selected as 5% and the remaining 95% was used as firm load. The base case load flow was conducted using the AC load flow method and the contingencies were solved using the DC load flow technique (unless otherwise specified). Common mode and/or station outages were not considered.

References

1. Billinton, R. and Allan, R.N., Reliability Evaluation of Power Systems, Pitman Books, New York and London, 1984.

2. Billinton, R. and Kumar, S., "Effects of Higher-Level Independent Generator Outages in Composite System Adequacy Evaluation", IEE Proceedings, Vol. 134, Part C, pp. 17-26, Aug., 1986.

3. Billinton, R. and Kumar., "Pertinent Factors in the Adequacy Assessment of a Composite Generation and Transmission System", Transactions of the Engineering & Operating Division, Canadian Electrical Association Vol. 25, Part 3, No. 86-SP-141, 1986.

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MECORE COMPUTER PROGRAM

MECORE is a computer program developed at the University of Saskatchewan for composite generation and transmission system adequacy assessment. This program is based on a combination of Monte Carlo simulation and the enumeration approach. A Monte Carlo simulation method is used to calculate the annualized indices and a hybrid method utilizing an enumeration approach for aggregated load states is used to calculate the annual indices. This program includes many system considerations such as generating unit derated states, transmission line common cause outages, regional weather effects and bus load uncertainty and correlation, etc. A brief description of the MECORE program is as follows [1-3]:

1. A multi-step load model is created which eliminates the chronology and aggregates the load states using hourly load records during one year. The number of load level steps depends on the sensitivities of the composite system adequacy indices to load variation. It is necessary to use many steps in the case of sensitive composite systems and fewer steps in the case of non-sensitive systems. Annualized indices are calculated first by using only the single peak load level and expressed on a base of one year. A set of ratios of generation-transmission adequacy indices can be obtained from the annualized indices based on the peak load level and used to judge sensitivities of composite systems to load variation. All load level steps are considered successively and the resulting indices for each load level are weighed by their probabilities to obtain the annual indices.

2. The system states at a particular load level are selected by using Monte Carlo simulation techniques. This procedure includes the following:

   a. Generating unit states are modeled using multi-state random variables. The MECORE program can therefore recognize multi-derated-states of generating units. A user has three options for a generating unit: (a) two-state model; (b) three-state model; and (c) four-state model.

   b. Transmission line states are modeled using two-state (up and down) random variables. The transmission line forced outage rates and repair times are determined using a method for recognizing regional weather effects. A uniformly distributed random number is sampled to select a transmission line state according to the calculated weather-related forced outage rates. Transmission line common causes outages are simulated by separate random numbers. A user has the following options: (a) no weather effect; (b) entire system in common weather; (c) recognition of regional weather; and (d) common cause outage plus (a) or (b) or (c).

   c. Bus load uncertainty and correlation are modeled using a correlative normal distribution random vector. A tabulating technique of normal distribution sampling and a correlation sampling technique are used to select bus load states. A user has three options: (a) independence between bus loads; (b) complete dependence between bus loads: and (c) different degrees of correlation between bus loads.

3. A direct analytical approach of system analysis, which is based on DC load flow relationship, is used to judge if a drawn system state definitely creates no load curtailment. A minimization model is solved only for the relatively few contingency states which may lead to load curtailment.

4. A linear programming model is used to reschedule generation, alleviate line overloads and avoid load curtailment if possible or to minimize total load curtailment if unavoidable. The load curtailment philosophy is incorporated in this minimization model to calculate realistic bus indices. Loads of each bus are divided into several parts according to importance. When load curtailment is unavoidable, the least important part is curtailed first, then the next least important and at last the most important part.

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2. Li Wenyuan and R. Billinton, "Effect of Bus Load Uncertainty and Correlation in Composite System Adequacy Evaluation", IEEE/PES 1991 Winter Meeting, 91 WM 175-0 PWRS, New York, Feb. 1991

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CIGRE EENS System Indices

HLI Evaluation

Segmentation Method EENS=16.215 GWh/yr

F&D Method EENS=14.661 GWh/yr

Monte Carlo Simulation Method EENS=15.522 GWh/yr

HLII Evaluation Using COMREL

Constrained Case: Base Case EENS=46.696 GWh/yr

Constrained Case: Trans. Improvement Case EENS=20.566 GWh/yr

Constrained Case: Base Case CUP Time 2 hrs, 48 min.

Constrained Case: Trans. Improvement case CPU time 2 hrs, 05 min.

HLII CONSTRAINED: BASE CASE STUDY RESULTS (ANNUALIZED)

S Y S T E M   I N D I C E S

NUMBER OF LOAD BUSSES INCLUDED IN INDICES= 49
TOTAL INSTALLED CAPACITY= 5512.800
TOTAL LOAD AT BUSSES INCLUDED IN INDICES= 3987.30
BULK POWER SUPPLY DISTURBANCES= 148.53984

PROBABILITY OF ALL ELEMENTS IN SERVICE = 0.043100125641534

IEEE INDICES

BULK POWER INTERRUPTION INDEX=	1.52687 MW/MW-YR
EXPECTED ENERGY NOT SUPPLIED=	46695.58984 MWH/YR
BULK POWER ENERGY CURTAILMENT INDEX=	11.71108 MWH/MW-YR
BULK POWER SUPPLY AVERAGE MW CURTAILMENT INDEX=	40.98633 MW/DISTURBANCE
SEVERITY INDEX=	702.665 SYSTEM-MINUTES
MODIFIED BULK POWER ENERGY CURTAILMENT INDEX=	0.00133688

SYSTEM INDICES: AVERAGE VALUES

AV. # OF LOAD CURTAILMENTS/LOAD PT./YEAR=	5.97625
AV. # OF VOLTAGE VIOLATIONS/LOAD PT./YEAR=	0.00000 BEFORE REACTIVE COMP. ADDED
AV. # OF VOLTAGE VIOLATIONS/LOAD PT./YEAR=	0.00000 AFTER REACTIVE COMP. ADDED
AV. LOAD CURTAILED/LOAD PT./YEAR=	124.24700 MW
AV. ENERGY CURTAILED/LOAD PT./YEAR=	952.97119 MWH
AV. # OF HRS OF LOAD CURTAILMENT/LOAD PT./YEAR=	46.37536 HRS

SYSTEM INDICES: MAXIMUMS

MAX. LOAD CURTAILED= 482.06 FOR CONTINGENCY NG1= 9 NG2= 0 NG3= 0 NG4= 0 LOUT1= 31 LOUT2= 0 LOUT3= 0 I_B1= 16
PROB.=0.00000017 FREQ 0.00045318
MAX. ENERGY CURTAILED= 3672.97 FOR CONTINGENCY NG1= 0 NG2= 0 NG3= 0 NG4= 0 LOUT1=113 LOUT2=114 LOUT3= 0 I_B1= 0
PROB.=0.00000005 FREQ 0.00003712

HLII CONSTRAINED: BASE CASE STUDY RESULTS (ANNUALIZED)

BUS INDICES

BUS	FAILURE PROB	FAILURE FREQ	#OF CURTAILMENTS (ANNUALIZED) TOTAL	#OF CURTAILMENTS (ANNUALIZED) ISOLATED	TOTAL LOAD SHED (ANNUALIZED) TOTAL MW	TOTAL LOAD SHED (ANNUALIZED) ISOLATED MW	TOTAL ENERGY CURTAILED (ANNUALIZED) TOTAL MWH	TOTAL ENERGY CURTAILED (ANNUALIZED) ISOLATED MWH	TOTAL DURATION (ANNUALIZED) TOTAL HRS	TOTAL DURATION (ANNUALIZED) ISOLATED HRS
2 ORRING	0.00028911	0.36648574	0.37	0.00	6.90	0.00	47.46	0.00	2.53	0.00
3 MURRCR	0.00000066	0.00149824	0.00	0.00	0.03	0.00	0.10	0.00	0.01	0.00
4 MABHYD	0.00024842	0.29766795	0.30	0.00	18.14	0.13	131.47	0.98	2.18	0.00
6 EELHYD	0.00001696	0.02208631	0.02	0.00	0.88	0.00	5.91	0.00	0.15	0.00
8 BEECHW	0.00000000	0.00000966	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11 CARAQT	0.00005550	0.06477308	0.06	0.00	1.81	0.00	13.55	0.00	0.49	0.00
12 NEWCA1	0.00108401	1.31074789	1.31	0.00	14.97	0.00	108.33	0.00	9.50	0.00
13 GRLAKE	0.00017244	0.21992309	0.22	0.00	0.46	0.00	3.20	0.00	1.51	0.00
14 MONCTN	0.00030047	0.38271755	0.38	0.00	16.47	0.00	125.72	0.00	2.63	0.00
15 C.BAY1	0.11523867	128.91679382	128.92	0.00	2612.18	0.00	19738.66	0.00	1009.51	0.00
18 LEPRAU	0.00112304	1.39901173	1.40	0.00	14.67	0.00	102.79	0.00	9.84	0.00
19 112572	0.00000009	0.00011891	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
20 IROQUB	0.00009308	0.10798372	0.11	0.01	5.56	1.44	38.51	4.91	0.82	0.05
22 EELRA1	0.00000665	0.01705279	0.02	0.00	1.45	0.00	4.95	0.00	0.06	0.00
25 PENFLD	0.00028051	0.31344974	0.31	0.12	13.92	4.10	122.27	14.00	2.46	0.39
26 MACCAN	0.00000067	0.00151190	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
27 ONSLO1	0.00018611	0.23769183	0.24	0.00	1.08	0.00	7.45	0.00	1.63	0.00
28 ONSLO2	0.00018611	0.23768899	0.24	0.00	3.00	0.00	20.59	0.00	1.63	0.00
29 SPRNGH	0.00011993	0.15053087	0.15	0.00	0.30	0.00	2.29	0.00	1.05	0.00
30 LANCST	0.00118807	1.40873206	1.41	0.03	29.76	3.05	211.35	10.44	10.41	0.18
31 IRVREF	0.00032725	0.36729273	0.37	0.00	7.21	0.00	64.71	0.00	2.87	0.00
32 RICHBT	0.00017964	0.41767627	0.42	0.00	9.92	0.00	34.24	0.01	1.57	0.00
33 114963	0.00028816	0.28609926	0.29	0.00	1.56	0.00	13.08	0.00	2.52	0.00
35 114981	0.00065842	0.82007390	0.82	0.00	3.00	0.00	20.96	0.00	5.77	0.00
37 117562	0.00000349	0.00429578	0.00	0.00	0.06	0.00	0.44	0.00	0.03	0.00
38 EELRV1	0.00019539	0.25710878	0.26	0.00	2.90	0.00	19.25	0.00	1.71	0.00
39 BATHS1	0.00087206	1.09827828	1.10	0.00	25.59	0.00	177.77	0.00	7.64	0.00
40 MARYSV	0.00017246	0.22001015	0.22	0.00	3.63	0.00	24.90	0.00	1.51	0.00
42 111528	0.00019680	0.25930604	0.26	0.00	2.37	0.00	14.01	0.00	1.72	0.00
48 110553	0.00017345	0.22224095	0.22	0.00	0.36	0.00	2.43	0.00	1.52	0.00
49 OAKBAY	0.00078051	1.13299990	1.13	0.15	23.14	9.17	93.00	31.32	6.84	0.31
54 NASH03	0.00083045	1.03713393	1.04	0.00	1.61	0.00	11.14	0.00	7.27	0.00
55 NASH12	0.00082997	1.03584972	1.04	0.00	1.59	0.00	11.06	0.00	7.27	0.00
59 110871	0.00006848	0.08740249	0.09	0.00	0.10	0.00	0.67	0.00	0.60	0.00
60 HARDRD	0.00000084	0.00195414	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.00
61 MILB47	0.12997670	145.99433899	145.99	0.00	3243.80	0.00	25391.99	0.00	1138.62	0.00
62 DOAKST	0.00000119	0.00315167	0.00	0.00	0.08	0.00	0.26	0.00	0.01	0.00
64 119042	0.00006849	0.08743503	0.09	0.00	0.29	0.00	2.02	0.00	0.60	0.00
65 111036	0.00000667	0.01711137	0.02	0.00	0.03	0.00	0.10	0.00	0.06	0.00
73 IROQUA	0.00009326	0.10844376	0.11	0.00	5.10	0.21	33.00	0.70	0.82	0.01
77 1126MP	0.00083061	1.03730455	1.04	0.00	3.83	0.00	26.70	0.00	7.28	0.00
78 119024	0.00022703	0.30763397	0.31	0.00	0.37	0.00	1.56	0.00	1.99	0.00
79 112408	0.00021084	0.26674733	0.27	0.00	0.10	0.00	0.61	0.00	1.85	0.00
81 NBIPC1	0.00017090	0.22562033	0.23	0.00	0.39	0.00	2.43	0.00	1.50	0.00
82 ROTHPR	0.00011243	0.15147554	0.15	0.00	1.84	0.00	11.96	0.00	0.98	0.00
83 BRNINE	0.00067537	0.84738412	0.85	0.00	2.92	0.00	20.33	0.00	5.92	0.00
84 NBIPC2	0.00072604	0.90424919	0.90	0.00	4.18	0.00	28.71	0.00	6.31	0.00
86 CONTBN	0.00013840	0.18070086	0.18	0.00	0.54	0.00	3.65	0.00	1.21	0.00

MLII CONSTRAINED: TRANSMISSION IMPROVEMENT CASE STUDY RESULTS (ANNUALIZED)

S Y S T E M   I N D I C E S

NUMBER OF LOAD BUSSES INCLUDED IN INDICES= 49
TOTAL INSTALLED CAPACITY= 5512.800
TOTAL LOAD AT BUSSES INCLUDED IN INDICES= 3987.30
BULK POWER SUPPLY DISTURBANCES= 225.23421

PROBABILITY OF ALL ELEMENTS IN SERVICE = 0.043082482580175

IEEE INDICES

BULK POWER INTERRUPTION INDEX=	0.44137 MW/MW-YR
EXPECTED ENERGY NOT SUPPLIED=	20566.43945 MWH/YR
BULK POWER ENERGY CURTAILMENT INDEX=	5.15799 MWH/MW-YR
BULK POWER SUPPLY AVERAGE MW CURTAILMENT INDEX=	11.35407 MW/DISTURBANCE
SEVERITY INDEX=	309.479 SYSTEM-MINUTES
MODIFIED BULK POWER ENERGY CURTAILMENT INDEX=	0.00058881

SYSTEM INDICES: AVERAGE VALUES

AV. # OF LOAD CURTAILMENTS/LOAD PT./YEAR=	4.94713
AV. # OF VOLTAGE VIOLATIONS/LOAD PT./YEAR=	0.00000 BEFORE REACTIVE COMP. ADDED
AV. # OF VOLTAGE VIOLATIONS/LOAD PT./YEAR=	0.00000 AFTER REACTIVE COMP. ADDED
AV. LOAD CURTAILED/LOAD PT./YEAR=	52.19077 MW
AV. ENERGY CURTAILED/LOAD PT./YEAR=	419.72327 MWH
AV. # OF HRS OF LOAD CURTAILMENT/LOAD PT./YEAR=	40.39619 HRS

SYSTEM INDICES: MAXIMUMS

MAX. LOAD CURTAILED= 431.70 FOR CONTINGENCY NB1= 34 NB2= 0 NB3= 0 NB4= 0 LOUT1= 89 LOUT2= 0 LOUT3= 0 I_B1= 0
PROB.=0.00000107 FREQ 0.00123439
MAX. ENERGY CURTAILED= 3284.29 FOR CONTINGENCY NB1= 34 NB2= 0 NB3= 0 NB4= 0 LOUT1= 89 LOUT2= 0 LOUT3= 0 I_B1= 0
PROB.=0.00000107 FREQ 0.00123439

MLII CONSTRAINED: TRANSMISSION IMPROVEMENT CASE (ANNUALIZED)

BUS INDICES

BUS	FAILURE PROB	FAILURE FREQ	#OF CURTAILMENTS (ANNUALIZED) TOTAL	ISOLATED	TOTAL LOAD SHED (ANNUALIZED) TOTAL MW	ISOLATED MW	TOTAL ENERGY CURTAILED (ANNUALIZED) TOTAL MWH	ISOLATED MWH	TOTAL DURATION (ANNUALIZED) TOTAL HRS	ISOLATED HRS
2 ORRING	0.00108468	1.35425067	1.35	0.00	20.87	0.00	145.54	0.00	9.52	0.00
3 MURRCR	0.00000000	0.00000008	0.00	0.00	0.00	0.00	9.00	0.00	0.00	0.00
4 MADHYD	0.00023367	0.27844304	0.28	0.00	14.20	0.13	118.04	0.98	2.05	0.00
6 EELHYD	0.00001462	0.02133407	0.02	0.00	0.46	0.00	3.11	0.00	0.15	0.00
11 CARAQT	0.00005021	0.07984671	0.08	0.00	3.09	0.00	14.63	0.00	0.44	0.00
12 NEWCAL	0.21095490	223.27947998	223.28	0.00	2355.42	0.00	19291.30	0.00	1847.93	0.00
13 GRLAKE	0.00015639	0.19790131	0.20	0.00	0.43	0.00	2.96	0.00	1.37	0.00
14 MONCTN	0.00018649	0.23266065	0.23	0.00	6.20	0.00	42.99	0.00	1.63	0.00
15 C.BAY1	0.00010529	0.13380705	0.13	0.00	14.50	0.00	100.06	0.00	0.92	0.00
18 LEPRAU	0.00108468	1.35425067	1.35	0.00	14.62	0.00	102.40	0.00	9.52	0.00
19 112572	0.00000000	0.00000915	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20 IROQUB	0.00009304	0.10800596	0.11	0.01	5.56	1.44	38.49	4.91	0.82	0.05
25 PENFLD	0.00007507	0.15003948	0.15	0.12	4.12	4.10	14.15	13.99	0.66	0.39
26 MACCAN	0.00001511	0.01735095	0.02	0.00	0.22	0.00	1.71	0.00	0.13	0.00
27 ONSLO1	0.00011055	0.14045547	0.14	0.00	0.60	0.00	4.16	0.00	0.97	0.00
28 ONSLO2	0.00018470	0.23472531	0.23	0.00	2.75	0.00	18.98	0.00	1.62	0.00
29 SPRNGH	0.00012571	0.15784356	0.16	0.00	0.59	0.00	4.36	0.00	1.10	0.00
30 LANCST	0.00081570	1.03203666	1.03	0.03	19.74	3.05	126.26	10.43	7.15	0.10
31 IRVREF	0.00083928	1.04713631	1.05	0.00	3.59	0.00	38.78	0.00	7.35	0.00
32 RICHBT	0.00017809	0.41440439	0.41	0.00	9.65	0.00	33.08	0.01	1.56	0.00
33 114963	0.00062816	0.78113323	0.78	0.00	5.15	0.00	36.30	0.00	5.50	0.00
35 114981	0.00062816	0.78113306	0.78	0.00	1.85	0.00	13.01	0.00	5.50	0.00
37 117562	0.00000000	0.00000003	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38 EELRV1	0.00018756	0.23773091	0.24	0.00	2.45	0.00	16.91	0.00	1.64	0.00
39 BATHS1	0.00066683	0.82704955	0.83	0.00	18.28	0.00	127.66	0.00	5.84	0.00
40 MARYSV	0.00015641	0.19795398	0.20	0.00	2.90	0.00	20.06	0.00	1.37	0.00
42 111528	0.00071148	0.88390905	0.88	0.00	2.78	0.00	19.55	0.00	6.23	0.00
48 110553	0.00015640	0.19771415	0.20	0.00	0.28	0.00	1.94	0.00	1.37	0.00
49 OAKBAY	0.00074046	2.08145797	1.08	0.15	21.59	9.17	82.33	31.31	6.49	0.51
54 NASH03	0.00078980	0.98411065	0.98	0.00	1.03	0.00	7.24	0.00	6.92	0.00
55 MAUH12	0.00078980	0.98411179	0.98	0.00	1.03	0.00	7.24	0.00	6.92	0.00
59 110871	0.00006784	0.08581577	0.09	0.00	0.08	0.00	0.53	0.00	0.59	0.00
60 HARDRD	0.00000034	0.00053448	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
61 MILB47	0.00083929	1.04716384	1.05	0.00	4.41	0.00	30.59	0.00	7.35	0.00
62 DOAKST	0.00000000	0.00000801	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
64 119042	0.00008295	0.10316657	0.10	0.00	0.37	0.00	2.60	0.00	0.73	0.00
65 111036	0.00016418	0.20840851	0.21	0.00	0.05	0.00	0.37	0.00	1.44	0.00
73 IROQUA	0.00009322	0.10848148	0.11	0.00	5.11	0.21	32.99	0.70	0.82	0.01
77 1124MP	0.00078980	0.98411316	0.98	0.00	2.49	0.00	17.48	0.00	6.92	0.00
78 119024	0.00020876	0.26149887	0.26	0.00	0.08	0.00	0.51	0.00	1.83	0.00
79 112408	0.00020842	0.26096377	0.26	0.00	0.07	0.00	0.49	0.00	1.83	0.00
81 NBIPC1	0.00014983	0.19019635	0.19	0.00	0.29	0.00	1.99	0.00	1.31	0.00
82 RGTHPR	0.00010529	0.13380705	0.13	0.00	0.88	0.00	3.10	0.00	0.92	0.00
83 BRMINE	0.00066683	0.82704610	0.83	0.00	2.15	0.00	15.20	0.00	5.84	0.00
84 NBIPC2	0.00069711	0.86550254	0.87	0.00	2.99	0.00	21.09	0.00	6.11	0.00
85 CONS3H	0.00012093	0.14193414	0.14	0.00	0.44	0.00	3.25	0.00	1.04	0.00

CIGRE EENS SYSTEM INDICES
(in GWh/year)

by using MECORE (Monte Carlo simulation program)

Basic System Evaluation

	HL1		HL2 Constrained			HL2 Unconstrained		
	Annualized	Annual	Gen.	Network	Total	Gen.	Network	Total
EENS	14.68	0.20	14.68	38.26	52.94	0.20	0.94	1.14
Coefficient of variation	0.056	0.048	0.053			0.035		
CPU time	31.0 sec.	4.9min.	16.4 min.			1 h 6 min.		
Number of Samples	80000	720000	8000			8000 x 10		

Note : 10 step model of annual load curve is used in HL2 unconstrained case.

Transmission Improvement Evaluation

	HL1		HL2 Constrained			HL2 Unconstrained		
	Annualized	Annual	Gen.	Network	Total	Gen.	Network	Total
EENS	14.68	0.20	14.68	1.68	16.36	0.20	0.30	0.50
Coefficient of variation	0.056	0.048	0.063			0.031		
CPU time	31.0 sec.	4.9min.	29.5 min.			4 h 6 min.		
Number of Samples	80000	720000	40000			40000 x 10		

Note : 10 step model of annual load curve is used in HL2 unconstrained case.

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Output Results of HL1 Evaluation
(by Monte Carlo simulation)

1. Annualized indices using annual peak load plus network loss

```
LOLE=       85.06680 (hour/year)
EENS=    14680.99512 (MWh/year)
```

VARIANCE COEFFICIENT OF EENS IS

0.05600

CPU TIME IS (in second):

31.00980

2. Annual indices using a 10 step model of the annual load curve

```
LOLE=      1.33753 (hour/year)
EENS=    199.75185 (MWh/year)
```

VARIANCE COEFFICIENT OF EDNS IS

0.04814

CPU TIME IS (in second):

291.60001

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Output Results of Basic System Evaluation
(HL2 Constrained Case)

SYSTEM INDICES

Expected number of load curtailments(1/year)
ENLC= 237.11395
Average duration of load curtailment (hrs/disturbance)
ADLC= 6.59953
Expected duration of load curtailment(hrs/year)
EDLC= 1564.83594
Probability of load curtailments
PLC = 0.17912
Expected demand not supplied(mw)
EDNS= 6.05994
Expected energy not supplied(mwh/year)
EENS= 52939.66797
Bulk Power-interruption Index(MW/MWyear)
BPII= 2.28647
Bulk Power/energy Curtailment Index(MWh/MWyear)
BECI= 13.27574
Bulk Power-supply average MW curtailment Index(MW/disturbance)
BPACI= 38.45306
Modified Bulk/energy curtailment Index
MBECI= 0.00152
Severity Index(system minutes)
SI= 796.54437

Variance coefficient of EDNS is:
0.0529576
Square root deviation of EDNS is:
0.3209199

CPU Time is (in seconds):
985.84003

THE LOAD BUS INDICES

No.Bus	PLC	ENLC	ELC	EDNS	EENS
2	0.00013	0.25254	11.86361	0.00587	51.29976
3	0.00088	1.56244	17.20669	0.00941	82.21280
4	0.00050	0.85554	27.19781	0.01659	144.91583
8	0.00013	0.25254	2.01681	0.00100	8.72096
10	0.00050	0.92701	3.91942	0.00211	18.46791
12	0.00200	3.43360	107.64028	0.06382	557.50836
13	0.00138	2.40610	22.70495	0.01298	113.35016
14	0.00200	3.59779	221.54387	0.12163	1062.58240
15	0.07337	100.85837	2589.63867	1.85132	16173.16797
18	0.00100	1.88067	8.45082	0.00449	39.25547
19	0.00113	2.08376	22.39705	0.01201	104.95868
20	0.00138	2.39193	77.03756	0.04454	389.09088
22	0.00100	1.78892	39.75444	0.02222	194.13614
25	0.00275	4.56423	67.86791	0.03643	318.24176
26	0.00213	3.99100	10.27109	0.00547	47.77569
27	0.00238	4.38958	40.32598	0.02145	187.39087
28	0.00225	4.18232	26.51571	0.01428	124.75204
29	0.00238	4.38958	21.15922	0.01145	100.01219
30	0.00325	5.43011	166.93770	0.08462	739.25995
31	0.01475	22.31729	145.41991	0.09587	837.55524
32	0.00450	8.32390	199.10399	0.11067	966.82251
33	0.01513	23.34126	561.38184	0.36446	3183.89380
35	0.00375	6.69767	62.01711	0.03496	305.41443
37	0.00288	4.93877	14.46786	0.00844	73.71017
38	0.00263	4.46094	14.48732	0.00852	74.47387
39	0.00275	4.81457	118.81192	0.06722	587.22522
40	0.00388	7.02958	204.66577	0.11381	994.23029
42	0.00313	5.40237	50.55440	0.02914	254.55632
48	0.00475	8.12010	25.09470	0.01466	128.07767
49	0.00512	8.64183	162.70244	0.08002	699.01532
54	0.00400	7.04252	30.06347	0.01708	149.17082
55	0.00412	7.41804	31.66651	0.01761	153.83241
59	0.00487	8.47429	37.90637	0.02181	190.50058
60	0.00462	8.06234	7.90436	0.00453	39.61233
61	0.17375	226.92542	1122.95081	0.83476	7292.44385
62	0.00412	6.94654	165.53589	0.09764	853.01825
64	0.00487	8.44379	113.48229	0.06552	572.37128
65	0.00350	5.78746	2.48240	0.00150	13.11490
73	0.00425	7.02869	166.41953	0.10081	880.71429
77	0.00425	7.03402	69.66682	0.04197	366.63129
78	0.00562	9.63862	12.99342	0.00758	66.24359
79	0.00562	9.63862	12.99342	0.00758	66.24359
81	0.00400	6.57034	39.85739	0.02427	211.97949
82	0.10337	144.43820	1983.50439	1.37862	12043.60645
83	0.00425	7.10674	71.48469	0.04278	373.68378
84	0.00500	8.03941	104.99180	0.06496	567.48322
85	0.00525	8.57673	100.69724	0.06146	536.88074

Note:
PLC-----probability of load curtailments
ENLC----expected number of load curtailments (1/year)
ELC-----expected load curtailed(mw/year)
EENS----expected energy not supplied(mwh/year)
EDNS----expected demand not supplied(mw)

```
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    Output Results of Basic System Evaluation
    (HL2 Unconstrained Case, 10 Step Load Model)


                    SYSTEM  INDICES
===========================================================
    Expected number of load curtailments(1/year)
          ENLC=     7.06903
    Average duration of load curtailment   (hrs/disturbance)
          ADLC=     4.93379
    Expected duration of load curtailment(hrs/year)
          EDLC=     34.87706
    Probability of load curtailments
          PLC =    0.00399
    Expected demand not supplied(mw)
          EDNS=     0.13029
    Expected energy not supplied(mwh/year)
          EENS=       1138.25696
    Bulk Power-interruption Index(MW/MWyear)
          BPII=    0.08204
    Bulk Power/energy Curtailment Index(MWh/MWyear)
          BECI=     0.34702
    Bulk Power-supply average MW curtailment Index(MW/disturbance)
          BPACI=   35.74510
    Modified Bulk/energy curtailment Index
          MBECI=  0.00004
    Severity Index(system minutes)
          SI=        20.82140
=======================================================


Variance coefficient of EDNS is:
 0.0352200
Square root deviation of EDNS is:
 0.0045890


CPU Time is (in seconds):
     3979.96997
```

THE LOAD BUS INDICES

No.Bus	PLC	ENLC	ELC	EDNS	EENS
2	0.00000	0.00144	0.06762	0.00003	0.29241
3	0.00001	0.02022	0.22453	0.00012	1.01539
4	0.00003	0.04133	1.35607	0.00083	7.28916
8	0.00000	0.00144	0.01150	0.00001	0.04971
10	0.00000	0.00528	0.02234	0.00001	0.10527
12	0.00006	0.10161	2.53897	0.00137	11.98174
13	0.00003	0.05602	0.49351	0.00027	2.33017
14	0.00003	0.06281	3.75514	0.00201	17.52470
15	0.00140	2.08554	51.66110	0.03354	292.97421
18	0.00001	0.01072	0.04817	0.00003	0.22376
19	0.00001	0.01188	0.12766	0.00007	0.59826
20	0.00007	0.10993	2.28221	0.00139	12.11508
22	0.00001	0.01020	0.22660	0.00013	1.10658
25	0.00030	0.73771	8.37626	0.00336	29.31237
26	0.00002	0.03287	0.08231	0.00004	0.38714
27	0.00002	0.03514	0.32434	0.00017	1.52469
28	0.00002	0.03396	0.21036	0.00011	0.99723
29	0.00002	0.03514	0.16511	0.00009	0.78514
30	0.00032	0.82510	47.76628	0.01695	148.10957
31	0.00020	0.34345	2.02091	0.00116	10.12976
32	0.00006	0.11055	2.69495	0.00146	12.75441
33	0.00021	0.40229	6.91416	0.00391	34.14355
35	0.00003	0.05911	0.45331	0.00025	2.21929
37	0.00002	0.03896	0.11246	0.00006	0.55593
38	0.00002	0.03623	0.11459	0.00007	0.56940
39	0.00002	0.03823	0.71503	0.00040	3.51858
40	0.00006	0.10345	2.46112	0.00133	11.58215
42	0.00004	0.07274	0.65228	0.00036	3.14963
48	0.00008	0.15158	0.42923	0.00024	2.05762
49	0.00049	1.36726	46.39380	0.01515	132.35974
54	0.00006	0.10288	0.41374	0.00023	1.98208
55	0.00006	0.10502	0.42287	0.00023	2.00865
59	0.00007	0.13313	0.56015	0.00031	2.67097
60	0.00007	0.13078	0.12047	0.00007	0.57321
61	0.00288	4.06247	17.60172	0.01205	105.23685
62	0.00006	0.10233	2.32590	0.00130	11.31731
64	0.00007	0.13295	1.68068	0.00092	8.02509
65	0.00004	0.07494	0.03056	0.00002	0.15130
73	0.00012	0.19261	3.22805	0.00193	16.87656
77	0.00006	0.09934	0.95220	0.00055	4.84010
78	0.00009	0.15706	0.19903	0.00011	0.97558
79	0.00009	0.15706	0.19903	0.00011	0.97558
81	0.00006	0.09669	0.55495	0.00032	2.83222
82	0.00179	2.68813	37.74915	0.02497	218.13657
83	0.00005	0.09139	0.89572	0.00051	4.47211
84	0.00007	0.12620	1.46343	0.00085	7.40192
85	0.00009	0.15671	1.58368	0.00092	8.01763

Note:

PLC-----probability of load curtailments
ENLC----expected number of load curtailments (1/year)
ELC-----expected load curtailed(mw/year)
EENS----expected energy not supplied(mwh/year)
EDNS----expected demand not supplied(mw)

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Output Results of Transmission Improvement Evaluation
(HL2 Constrained Case)

SYSTEM INDICES

Expected number of load curtailments(1/year)
ENLC= 22.87027
Average duration of load curtailment (hrs/disturbance)
ADLC= 4.85114
Expected duration of load curtailment(hrs/year)
EDLC= 110.94720
Probability of load curtailments
PLC = 0.01270
Expected demand not supplied(mw)
EDNS= 1.87239
Expected energy not supplied(mwh/year)
EENS= 16357.16309
Bulk Power-interruption Index(MW/MWyear)
BPII= 0.82623
Bulk Power/energy Curtailment Index(MWh/MWyear)
BECI= 4.10190
Bulk Power-supply average MW curtailment Index(MW/disturbance)
BPACI= 144.06377
Modified Bulk/energy curtailment Index
MBECI= 0.00047
Severity Index(system minutes)
SI= 246.11426

Variance coefficient of EDNS is:
0.0629750
Square root deviation of EDNS is:
0.1179134

CPU Time is (in seconds):
1771.15002

THE LOAD BUS INDICES

No.Bus	PLC	ENLC	ELC	EDNS	EENS
2	0.00015	0.28375	10.26350	0.00528	46.09577
3	0.00057	0.99713	10.96113	0.00625	54.62639
4	0.00045	0.69844	35.95407	0.02374	207.43051
6	0.00010	0.19407	6.16732	0.00307	26.82921
8	0.00015	0.29009	2.31672	0.00120	10.46515
10	0.00035	0.64064	2.70864	0.00148	12.92754
11	0.00012	0.23877	5.37357	0.00285	24.87575
12	0.00262	4.43286	132.45197	0.07920	691.90338
13	0.00165	2.86836	25.93822	0.01493	130.46472
14	0.00182	3.20725	179.65259	0.10069	879.63983
15	0.00115	2.15599	86.72340	0.04623	403.89148
18	0.00083	1.51080	6.56504	0.00357	31.22466
19	0.00088	1.60412	16.64309	0.00906	79.15885
20	0.00140	2.43202	83.97110	0.04720	412.36005
22	0.00105	1.87629	38.47542	0.02148	187.63023
25	0.00182	3.43938	52.82640	0.02533	221.26726
26	0.00182	3.25409	8.33113	0.00467	40.83748
27	0.00172	3.08098	30.73864	0.01716	149.86621
28	0.00170	3.01831	19.06242	0.01074	93.80314
29	0.00190	3.35239	16.15962	0.00916	80.00975
30	0.00210	3.75023	96.00852	0.04785	418.06104
31	0.00187	3.30341	21.38655	0.01213	105.97794
32	0.00445	8.04854	198.61523	0.11242	982.11646
33	0.00260	4.58407	114.85380	0.06522	569.73999
35	0.00290	5.11066	46.95619	0.02662	232.55841
37	0.00252	4.44349	13.44395	0.00764	66.75932
38	0.00225	3.95035	12.82913	0.00731	63.83477
39	0.00245	4.31254	99.87029	0.05666	494.97714
40	0.00402	7.11950	209.52969	0.11837	1034.08533
42	0.00305	5.30030	49.11213	0.02825	246.75798
48	0.00530	9.06989	28.61725	0.01673	146.16942
49	0.00467	8.83014	194.40474	0.08471	740.06934
54	0.00442	7.66599	32.48170	0.01874	163.69638
55	0.00450	7.79992	32.89318	0.01903	166.25279
59	0.00487	8.34146	36.86211	0.02154	188.17982
60	0.00477	8.18466	8.02430	0.00468	40.89706
61	0.00482	8.34096	42.80047	0.02476	216.32248
62	0.00530	9.08101	204.23892	0.11905	1039.99841
64	0.00557	9.47506	125.60114	0.07384	645.07275
65	0.00450	7.59694	3.25854	0.00193	16.86199
73	0.00535	8.91182	214.21382	0.12702	1109.66406
77	0.00540	9.04185	89.16653	0.05312	464.05984
78	0.00632	10.62685	14.29215	0.00850	74.28622
79	0.00637	10.71316	14.31985	0.00852	74.38862
81	0.00520	8.67923	52.40993	0.03139	274.19348
82	0.00660	11.10436	190.83932	0.11347	991.24261
83	0.00577	9.50011	95.93953	0.05803	506.97464
84	0.00690	11.28545	149.11086	0.09107	795.58563
85	0.00697	11.42495	131.41228	0.08048	703.07635

Note:

PLC-----probability of load curtailments
ENLC----expected number of load curtailments (1/year)
ELC-----expected load curtailed(mw/year)
EENS----expected energy not supplied(mwh/year)
EDNS----expected demand not supplied(mw)

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Output Results of Transmission Improvement Evaluation
(HL2 Unconstrained Case, 10 Step Load Model)

SYSTEM INDICES

```
Expected number of load curtailments(1/year)
      ENLC=     3.42331
Average duration of load curtailment  (hrs/disturbance)
      ADLC=     3.19986
Expected duration of load curtailment(hrs/year)
      EDLC=     10.95414
Probability of load curtailments
      PLC =    0.00125
Expected demand not supplied(mw)
      EDNS=     0.05733
Expected energy not supplied(mwh/year)
      EENS=       500.85321
Bulk Power-interruption Index(MW/MWyear)
      BPII=    0.05142
Bulk Power/energy Curtailment Index(MWh/MWyear)
      BECI=     0.17419
Bulk Power-supply average MW curtailment Index(MW/disturbance)
      BPACI=   41.20952
Modified Bulk/energy curtailment Index
      MBECI=  0.00002
Severity Index(system minutes)
      SI=       10.45123
```

Variance coefficient of EDNS is:
0.0311736
Square root deviation of EDNS is:
0.0017872

CPU Time is (in seconds):
14783.37988

THE LOAD BUS INDICES

No.Bus	PLC	ENLC	ELC	EDNS	EENS
2	0.00000	0.00162	0.05850	0.00003	0.26275
3	0.00001	0.01495	0.16478	0.00008	0.74250
4	0.00006	0.09370	2.95388	0.00207	18.08787
6	0.00000	0.00111	0.03515	0.00002	0.15293
8	0.00000	0.00165	0.01321	0.00001	0.05965
10	0.00001	0.01065	0.04201	0.00002	0.18470
11	0.00000	0.00136	0.03063	0.00002	0.14179
12	0.00004	0.07949	1.99883	0.00110	9.63147
13	0.00003	0.05105	0.41821	0.00023	1.99900
14	0.00003	0.05296	2.68312	0.00144	12.60460
15	0.00001	0.01686	0.70354	0.00037	3.19744
18	0.00001	0.01318	0.05066	0.00003	0.23662
19	0.00001	0.01122	0.11613	0.00006	0.55145
20	0.00012	0.22578	7.00566	0.00323	28.23071
22	0.00001	0.01699	0.30849	0.00017	1.48026
25	0.00021	0.61760	7.06122	0.00244	21.33429
26	0.00002	0.03606	0.08813	0.00005	0.41385
27	0.00002	0.03508	0.32811	0.00018	1.53252
28	0.00002	0.02814	0.17209	0.00009	0.81753
29	0.00002	0.03662	0.16823	0.00009	0.79521
30	0.00012	0.32977	19.42742	0.00661	57.78671
31	0.00002	0.03181	0.19387	0.00011	0.92971
32	0.00006	0.10682	2.56572	0.00141	12.28534
33	0.00003	0.05364	1.22735	0.00068	5.90497
35	0.00003	0.05911	0.49807	0.00027	2.37064
37	0.00003	0.04827	0.13978	0.00008	0.67613
38	0.00002	0.04341	0.13472	0.00007	0.65198
39	0.00002	0.04155	0.86737	0.00048	4.17193
40	0.00005	0.08489	2.36526	0.00129	11.29849
42	0.00003	0.05708	0.50957	0.00029	2.49336
48	0.00007	0.13144	0.38576	0.00021	1.87439
49	0.00070	2.03644	67.46552	0.02263	197.70990
54	0.00005	0.09375	0.37815	0.00021	1.83633
55	0.00006	0.10372	0.39759	0.00022	1.93463
59	0.00006	0.11385	0.46411	0.00026	2.26818
60	0.00006	0.11296	0.10444	0.00006	0.50954
61	0.00006	0.10297	0.50979	0.00029	2.49614
62	0.00006	0.11374	2.50324	0.00140	12.25708
64	0.00007	0.12476	1.55365	0.00087	7.60943
65	0.00005	0.09441	0.03853	0.00002	0.19148
73	0.00012	0.21838	5.48205	0.00270	23.56445
77	0.00007	0.11574	1.10462	0.00063	5.54715
78	0.00008	0.14469	0.18383	0.00010	0.91040
79	0.00008	0.14721	0.18491	0.00010	0.91544
81	0.00007	0.11640	0.65276	0.00037	3.26846
82	0.00009	0.15436	2.46547	0.00141	12.29553
83	0.00007	0.12069	1.17745	0.00068	5.93848
84	0.00009	0.15691	1.92970	0.00112	9.77015
85	0.00010	0.16431	1.76175	0.00102	8.92971

Note:
PLC-----probability of load curtailments
ENLC----expected number of load curtailments (1/year)
ELC-----expected load curtailed(mw/year)
EENS----expected energy not supplied(mwh/year)
EDNS----expected demand not supplied(mw)

APPENDIX X

POWER TECHNOLOGIES INC. REPORT

APPLICATION OF PTI'S MAREL AND TPLAN PROGRAM FOR THE ADEQUACY ASSESSMENT OF THE NEW BRUNSWICK POWER SYSTEM

by

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(U.S.A.)

1.0 INTRODUCTION

PTI's evaluation of the New Brunswick Power test system involved the application of two software packages. The HL1 evaluation was performed using our Multi-area Reliability Evaluation Program, MAREL. The HL2 evaluation was performed using our Interactive Transmission System Planning Program, TPLAN.

MAREL incorporates an analytical approach to calculate multi-area LOLE and related indices [1,2]. A linear flow network model is employed to represent transmission constraints and the max-flow/min-cut algorithm is used to efficiently categorize failure and success states. In this study only a single area representation of the New Brunswick system is reported. A more detailed description of the MAREL package is provided in Appendix A.

TPLAN provides both a.c and d.c load flow models for bulk power transmission system analysis. It also incorporates a set of interactive activities to perform comprehensive contingency testing through enumeration and to calculate bulk power system reliability indices. TPLAN was applied to both the Peak Load and Enhanced Transmission models of the New Brunswick System. A description of the TPLAN package is provided in Appendix B.

2.0 HL1 RESULTS

HL1 results were calculated using a conventional, single area model of the New Brunswick system. Indices calculated included LOLE (hours/year), Expected Energy Not Served (EENS-GWH) and average MW's of load loss per event. The peak load model assumed that the peak load level existed for 8760 hours per year. Other approximations applied to meet study specifications included:

- No scheduled outages for unit maintenance.
- Addition of 690 MW to the load to represent contractual power transfers.
- Modeling of interruptible load as a 100% available generating unit (52 MW).
- Modeling of Hydro capacity as a 100% available generating unit (650 MW).
- Modeling of Nova Scotia, New England, and Hydro Quebec as two-unit equivalents and Maine Public Service and Prince Edward Island as single unit equivalents.

This representation produced the model parameters summarized in Table 2.1.

Table 2.1

Summary of NB Peak Load Model for HL1 Evaluation

Installed Capacity	5374 MW
Peak Load	3846 MW
Installed Reserves	1528 MW
Reserves as Percent of Peak Load	39.73
Weighted Average Unit Forced Outage Rate	8.89

Application of the MAREL program to this system representation produced the results shown in Table 2.2.

Table 2.2

HL1 Results for NB Peak System

LOLE (hrs/yr)	EENS (GWH)	AV. MW
80.8215	13.63	168.75

A summary of computer output for this evaluation is presented in Appendix C.

3.0 HL2 EVALUATION

The TPLAN HL2 evaluation was performed utilizing an a.c load flow model of the New Brunswick System. As a result, both overload and voltage problem indices were generated. TPLAN incorporates a contingency enumeration approach in combination with ranking and screening techniques to efficiently capture those events which cause problems in the system.

Investigations were performed on both the base transmission system and enhanced transmission system using peak load conditions. These systems were modeled as described in "NB Power Composite System Data For Reliability Evaluation" Summary prepared by CIGRE Task Force 38.03.10 at NB Power and dated November 1990. In each case, contingencies were tested involving up to three levels of generating unit outages, two levels of circuit outages, or various combinations of the two. A probability threshold of 1.0 E-7 was used to screen low probability events. An automatic, inertial redispatching scheme was employed to balance generation and load after a loss of generation. No attempt was made to relieve system problems by generation dispatch or load curtailment.

Using the statistics provided for circuit and unit outages, base indices were computed for the following failure conditions:

- Branch overloads (MVA flows greater than 100% of the "A" rating)
- High and low voltages (greater than 1.1 pu or less than 0.9 pu of nominal)
- Islanding (involving 1 MW or more of load loss)
- Voltage collapse
- Voltage Depression (low voltage involving 4 or more buses with less than 0.9 p.u. voltage)

These results are summarized in Table 3.1 for the base system and the improved system.

The frequencies shown are upper bound frequencies calculated by simple summation of the frequencies of individual outage events. This is a good assumption as long as all events are low probability transmission events. However, the presence of a large number of single and multiple generation outages that contribute to the failure indices may produce excessively high frequencies through double counting of independent overlapping events. Since this is the case in this sample calculation, the computed frequencies will be overstated significantly for the most frequent events; i.e., branch overloads. On the other hand, this sample study did not include the specification of common mode and substation dependent events. Inclusion of such events would have increased the calculated frequencies of the more severe, less frequent, events. Studies performed with TPLAN are normally transmission system oriented with emphasis on representation of single and dependent (common mode and substation/protection failures) multiple outages [3,4]. Independent overlapping transmission outages are normally ignored except when adverse weather conditions (failure bunching) are modelled.

<u>Islanding Indices</u>
Loss of load is only recorded when it is associated with transmission outages resulting in islanding. This occurs due to generation deficiencies within some of the islands. The load loss indices associated with these events are shown in Tables 3.2 and 3.3.

Table 3.1

Reliability Indices from TPLAN Studies

	Base System		Enhanced System	
	Frequency Occ/Yr	Duration Hrs/Occ	Frequency Occ/Yr	Duration Hrs/Occ
Branch Overloads	906.8	19.9	265.4	16.9
Low Voltages	6.2	5.0	5.8	4.7
High Voltages	0	0	0	0
Islanding	2.1	6.5	2.1	6.5
Voltage Collapse	0.0014	20.1	0.1264E-2	13.4
Voltage Depression	0.007	10.7	0.007	8.4

Table 3.2

Exact and Cumulative Load Interruption Indices

***** SYSTEM LOSS OF LOAD INDEX *****

LOAD LOST (MW)	FREQUENCY (OC/YR)	DURATION (HR/OC)	POWER INTERRUPTED (MW/YR)	ENERGY CURTAILED (MWHR/YR)	CUM. FREQUENCY (OC/YR)	CUM. CURTAILED (MWHR/YR)
0 - 20	0.651	4.8	0.00	0.00	2.091	493.94
21 - 40	0.625	10.4	20.67	208.09	1.440	493.94
41 - 60	0.593	4.8	35.70	171.33	0.814	285.85
61 - 80	0.000	0.0	0.00	0.00	0.221	114.53
81 - 100	0.054	5.0	5.31	26.64	0.221	114.53
101 - 120	0.112	4.8	11.40	55.05	0.168	87.88
121 - 140	0.055	4.8	6.80	32.83	0.055	32.83
** TOTAL **	2.091	6.47	79.88	493.94		

Table 3.3

Load Interruption Indices by Bus

*** RELIABILITY INDICES FOR BUS LOAD LOSS ***

			TOTAL LOAD (MW)	FREQ. (OC/YR)	DUR (HR/OC)	POWER INTERPT. (MW/OCC)	ENERGY CURTAIL. (MWH/YR)	B.P.I. INDEX (1/YR)	B.E.C. INDEX (HR/YR)	# .OF FAIL. CONT.	WORST CONT. INDEX
** TOTAL **			3905	2.091	6.5	38.20	493.94	0.020	0.126	174	5440
AREA 1 : 138- 345 KV BUSES			3905	2.091	6.5	64.17	1069.49	0.034	0.274	174	6581
1869	MADHYQ	345	200	0.167	25.6	51.03	218.26	0.043	1.091	49	5350
1910	IROQUB	138	154	0.221	20.6	53.79	194.86	0.077	1.266	51	6581
1971	PENFLD	138	59	0.458	4.8	33.70	74.18	0.263	1.264	38	5312
1679	LANCST	138	102	0.112	4.8	101.50	55.05	0.112	0.542	1	5226
1834	OAKBAY	138	60	1.244	4.8	60.20	359.37	1.244	5.970	82	5228
1835	110421	138	0	0.651	4.8	0.00	0.00	0.000	0.000	42	5269
1867	EDMST3	345	0	0.167	25.6	0.00	0.00	0.000	0.000	49	5350
1907	EDMST1	138	0	0.167	25.7	0.00	0.00	0.000	0.000	50	5350
1908	114004	138	0	0.216	20.9	0.00	0.00	0.000	0.000	51	5350
1909	IROQUA	138	123	0.222	20.5	54.10	167.78	0.098	1.367	52	5440

Table 3.2 lists exact and cumulative indices by amount of load interrupted. Table 3.3 details load interruption by bus. The load interruption indices for the base system and the improved system are the same.

Overload Indices

Overload indices for the base system are displayed by branch in Table 3.4. The line reinforcements reduce the overload frequency on some of the most frequently overloaded lines by two orders of magnitude while other lines which are not directly paralleled by the reinforcements are less affected. A comparative summary of frequently overloaded lines is presented in Table 3.5.

The results above reveal that the transmission improvements of the enhanced system have a major effect in reducing the frequency and severity of overloads on the first three circuits which are paralleled by the reinforcements in the system. Figure 3.1 shows the cumulative frequency distributions of overload events as a function of degree of overload for the system and the C.Cov1-MILD47 circuit. These results were obtained by repeat application of TPLAN's reliability index activity to the results of the contingency analysis performed.

Bus Voltage Indices

Reliability indices for bus voltage violations in the Base System are shown in Table 3.6. Improvements obtained through the

Table 3.4

Reliability Indices for Overloads by Branch

RELIABILITY INDICES FOR BRANCH OVERLOADS

							RATING MVA 1.00*A	FREQ (OC/YR)	AVG DUR (HR)	AVG LOAD. (P.U.)	MAX LOAD. (P.U.)	# OF. FAIL. CONT.	WORST CONT. INDEX
TOTAL								906.762	19.9	1.19	2.53	3485	5475
AREA 1 : 138- 345 KV BUSES								906.762	19.9	1.19	2.53	3485	5475
158	ONSLO1	138	183	SPRNGH	138	1	140	0.076	21.2	1.14	1.14	1	5153
1677	CARAQT	138	1806	BATHS1	138	1	140	0.094	4.4	1.05	1.05	13	1416
1677	CARAQT	138	1928	110684	138	1	140	0.117	4.4	1.21	1.21	13	1291
1681	IRVREF	138	1717	114963	138	1	190	1.524	17.8	1.20	1.68	133	5475
1813	C.BAY1	138	1681	IRVREF	138	1	140	19.911	16.9	1.25	2.53	823	5475
1807	NEWCA1	138	1712	RICHBT	138	1	140	1.793	4.5	1.53	1.57	65	6971
1812	MONCTN	138	1712	RICHBT	138	1	140	3.503	4.4	1.57	1.67	145	5619
1717	114963	138	1747	NORPSR	138	1	190	0.040	4.6	1.08	1.11	15	2321
1747	NORPSR	138	1901	NORTN1	138	1	190	0.040	4.6	1.08	1.11	15	2321
1776	114981	138	1839	SALBR1	138	1	140	1.220	17.9	1.25	1.90	129	5608
1776	114981	138	1901	NORTN1	138	1	140	1.279	17.7	1.55	2.25	135	5616
1800	BEECHW	138	1817	111144	138	1	140	0.300	14.6	1.09	1.35	18	5535
1802	GRFALL	138	1804	117562	138	1	190	0.275	14.8	1.08	1.32	15	5535
1802	GRFALL	138	1817	111144	138	1	140	1.997	18.4	1.07	1.57	130	5535
1804	117562	138	1849	STAND1	138	1	190	0.094	16.1	1.12	1.24	5	5535
1826	DALHOU	138	1805	EELRV1	138	1	310	0.018	30.2	1.03	1.09	4	5535
1809	MACTOC	138	1827	KESWK1	138	1	280	0.135	4.3	1.05	1.17	40	1369
1809	MACTOC	138	1827	KESWK1	138	2	280	0.135	4.3	1.05	1.17	40	1356
1809	MACTOC	138	1861	DOAKST	138	1	190	292.170	19.6	1.04	1.19	680	1664
1811	GRLAKE	138	1810	MARYSV	138	1	140	0.001	8.1	1.19	1.30	3	5875
1810	MARYSV	138	1845	NASH03	138	1	140	0.021	4.3	1.09	1.16	2	1651
1810	MARYSV	138	1846	NASH12	138	1	140	0.053	4.2	1.05	1.21	11	1651
1811	GRLAKE	138	1812	MONCTN	138	1	140	1.366	18.2	1.06	1.46	130	5616
1812	MONCTN	138	1839	SALBR1	138	1	190	0.481	4.4	1.03	1.10	73	1658
1812	MONCTN	138	1839	SALBR1	138	2	190	0.481	4.4	1.03	1.10	73	1657
1813	C.BAY1	138	1860	MILD47	138	1	140	87.170	15.6	1.24	1.87	478	266
1813	C.BAY1	138	1862	MILD65	138	1	140	449.010	19.7	1.20	2.04	991	264
1827	KESWK1	138	1845	NASH03	138	1	140	0.629	4.4	1.07	1.32	100	1651
1827	KESWK1	138	1846	NASH12	138	1	140	0.629	4.4	1.11	1.37	100	1651
1847	112572	138	1827	KESWK1	138	1	140	0.004	11.8	1.10	1.24	6	5591
1836	C.COV3	345	1900	NORTN3	345	1	700	0.002	17.3	1.11	1.16	2	5536
1837	C.COV1	138	1860	MILD47	138	1	140	646.632	19.9	1.20	2.05	1497	266
1837	C.COV1	138	1862	MILD65	138	1	140	450.745	19.7	1.20	2.04	994	264
1839	SALBR1	138	1945	119024	138	1	140	1.699	4.4	1.05	1.13	231	1657
1839	SALBR1	138	1946	112408	138	1	140	1.028	4.4	1.04	1.10	153	5830
158	ONSLO1	138	167	ONSLO2	230	1	224	0.076	21.2	1.01	1.01	1	5153
1803	KESWK3	345	1828	KESWK2	230	1	504	0.001	13.4	1.19	1.31	2	5474
1830	EELRV2	230	1866	EELRV3	345	1	400	0.158	20.0	1.07	1.22	29	6011
1836	C.COV3	345	1837	C.COV1	138	1	318	0.463	52.6	1.26	1.65	91	5530
1836	C.COV3	345	1837	C.COV1	138	2	450	0.088	33.1	1.10	1.22	6	5528
1838	SALBR2	230	1839	SALBR1	138	1	300	0.001	13.4	1.10	1.10	2	5616
1839	SALBR1	138	1850	SALBR3	345	2	340	0.004	10.2	1.11	1.17	6	5832

Table 3.5

Most Frequently Overloaded Circuits

	Base System				Enhanced System			
Line	Frequency Occ/Year	Duration Hrs/Occ	Avg. Overload p.u	Max. Overload p.u	Frequency Occ/Year	Duration Hrs/Occ	Avg. Overload p.u	Max. Overload p.u
1837 C.Cov1 1860 MILD47	646.6	19.9	1.20	2.05	5.29	14.5	1.14	1.56
1837 C.Cov1 1862 MILD65	450.7	19.7	1.20	2.04	2.00	15.5	1.08	1.46
1813 C.BAY7 1862 MILD65	449.0	19.7	1.20	2.04	1.97	15.4	1.08	1.46
1809 MACTQC 1861 DOAKST	292.2	19.6	1.04	1.19	248.4	17.3	1.04	1.19

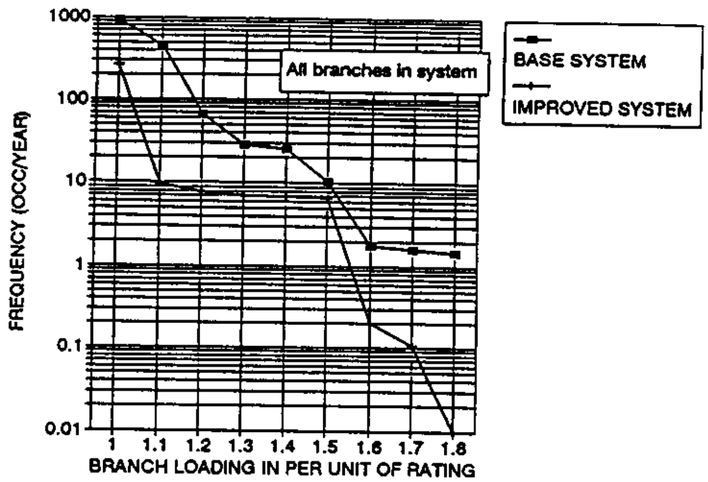

Figure 3.1.a
Cumulative Frequency Distribution of Overall Events for all Branches: Graph shows frequency of exceeding p.u. overloads indicated on X-axis.

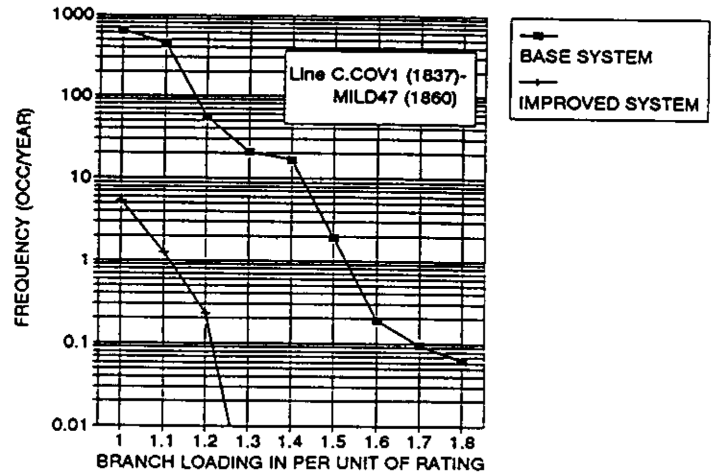

Figure 3.1.b
Cumulative Frequency Distribution of Overall Events for Line C.Cov1(1837) - MILD47(1860): Graph shows frequency of exceeding p.u. overloads indicated on X-axis.

Table 3.6

Reliability Indices for Bus Limit Violations for The Base System

*** RELIABILITY INDICES FOR BUS VOLTAGE VIOLATIONS ***

			VOLT LIMIT (PU)	FREQ. (OC/YR)	AVG. DUR. (HR)	AVG. VIO. (PU)	MAX. VIO. (PU)	# OF. FAIL. CONT.	WORST CONT. INDEX
TOTAL			LOW:	6.215	5.0	0.11	0.35	329	5619
			HIGH:	0.000	0.0	0.00	0.00	0	0
AREA 1 : 138- 345 KV BUSES									
			LOW:	6.215	5.0	0.11	0.35	329	5619
			HIGH:	0.000	0.0	0.00	0.00	0	0
LOW BUS VOLTAGES:									
168	ONSLO3	345	0.900	0.091	14.0	0.03	0.24	17	5616
1844	HURRCR	138	0.900	0.003	11.6	0.06	0.25	5	5616
1677	CARAQT	138	0.900	0.117	4.4	0.09	0.09	13	1291
1812	MONCTN	138	0.900	0.004	9.7	0.05	0.21	6	5616
157	MACCAN	138	0.900	0.005	10.3	0.06	0.26	7	5616
158	ONSLO1-	138	0.900	0.003	8.5	0.09	0.27	4	5616
167	ONSLO2	230	0.900	0.043	11.9	0.03	0.26	14	5616
183	SPRNGH	138	0.900	0.006	9.9	0.05	0.27	9	5616
1681	IRVREF	138	0.900	0.040	4.6	0.10	0.12	15	2321
1712	RICHBT	138	0.900	5.601	5.1	0.18	0.35	250	5619
1717	114963	138	0.900	0.449	4.5	0.03	0.11	54	2321
1747	NORPSR	138	0.900	0.002	8.6	0.01	0.01	2	5476
1776	114981	138	0.900	0.003	8.8	0.01	0.03	4	5616
1825	MEMCOK	138	0.900	0.003	11.6	0.07	0.24	5	5616
1838	SALBR2	230	0.900	0.323	15.2	0.02	0.23	49	5616
1839	SALBR1	138	0.900	0.001	16.2	0.07	0.19	3	5616
1850	SALBR3	345	0.900	0.007	9.2	0.05	0.25	9	5616
1852	110871	138	0.900	0.003	11.6	0.06	0.22	5	5616
1854	HARDRD	138	0.900	0.003	11.6	0.07	0.25	5	5616
1863	119042	138	0.900	0.043	5.0	0.03	0.26	15	5616
1900	NORTN3	345	0.900	0.003	11.7	0.02	0.04	5	5476
1901	NORTN1	138	0.900	0.002	8.6	0.00	0.00	2	5476
1945	119024	138	0.900	0.003	11.6	0.06	0.22	5	5616
1946	112400	138	0.900	0.003	11.6	0.06	0.21	5	5616

Table 3.7

Comparison of Bus Voltage Reliability Indices for the Base System and the Improved System for Selected Buses.

		Frequency Occ/Year	Duration Hrs/Occ	Average Violation p.u.	Worst Violation p.u.
<u>Base System</u>					
RICHBT	(1712)	5.601	5.1	0.18	0.35
CARCT	(1677)	0.117	4.4	0.09	0.09
114963	(1717)	0.449	4.5	0.03	0.11
SALBR2	(1838)	0.323	15.2	0.02	0.23
System		6.215	5.0	0.11	0.35
<u>Improved System</u>					
RICHBT	(1712)	5.585	4.6	0.20	0.35
CARCT	(1677)	0.122	4.4	0.09	0.09
114963	(1717)	0.021	4.3	0.02	0.11
SALBR2	(1838)	0.076	11.7	0.02	0.14
System		5.849	4.7	0.14	0.35

reinforcements are summarized for some of the buses in Table 3.7.

Using a non-diverging load flow solution technique, TPLAN also identifies contingencies for which there is no solution (Jacobian matrix is singular). These are classified as voltage collapse contingencies as indicated in Table 3.1. Table 3.8 shows details of one of the voltage collapse contingencies for the Base System: the loss of two 345 kV lines (St Andre-Eel River and St. Andre-Keswick). The output from the non-divergent load flow in Table 3.8 indicates the collapse of the portion of the system normally supplied from the 345 kV buses at St. Andre and Edmundston and the 138 kV bus at Keswick. The loss of the two 345 kV lines connected to St.Andre would most likely occur either by the loss of one line when the other is out on maintenance or the simultaneous loss of both line because of substation or protection trouble. The voltage collapse indices in Table 3.1 would be significantly higher if such events were included in the analysis.

Table 3.8

Details of Contingency Causing Voltage Collapse

```
                S U M M A R Y   O F   C O N T I N G E N C I E S
      ( OVLD>1.00 RATING-A  VOLT>1.10,  VOLT<0.90,  BUSES/ISLD>=   1 )
      ----------------------------------------------------------------

                        * * * * *  CONTINGENCY  5533 * * * * *
CONT #   SOLN       OVERLOADS   HIGH VOLTAGE    LOW VOLTAGE     SWING GEN   ITER MISMATCH
 5533    VC         0 - 0.00      0 - 0.00       20 - 0.00    ( 945, 363)    7       1032

OUTAGES   FROM BUS               TO BUS           ID  BASE CASE   RATING-A  P.U.-A
      1866 EELRV3     345   1868 STAND3     345 1         69        700     0.10
      1803 KESWK3     345   1868 STAND3     345 1        336        700     0.48
```

* AREA 1 *

VOLTAGE	BUS NAME		MAX.	MIN.	BASE	CONT	DEV.
	1869 MADHYQ	345	1.100	0.900	0.968	0.034	-0.934
	1896 TINKER	138	1.100	0.900	1.026	0.256	-0.770
	1800 BEECHW	138	1.100	0.900	1.022	0.327	-0.695
	1802 GRFALL	138	1.100	0.900	1.027	0.256	-0.771
	1847 112572	138	1.100	0.900	1.003	0.716	-0.287
	1910 IROQUB	138	1.100	0.900	1.030	0.034	-0.996
	1804 117562	138	1.100	0.900	1.027	0.001	-1.026
	1810 MARYSV	138	1.100	0.900	0.997	0.893	-0.104
	1817 111144	138	1.100	0.900	1.026	0.030	-0.996
	1827 KESWK1	138	1.100	0.900	1.014	0.889	-0.125
	1845 NASH03	138	1.100	0.900	1.000	0.891	-0.109
	1846 NASH12	138	1.100	0.900	1.000	0.891	-0.109
	1849 STAND1	138	1.100	0.900	1.024	0.016	-1.008
	1865 111036	138	1.100	0.900	1.041	0.706	-0.335
	1867 EDMST3	345	1.100	0.900	0.973	0.032	-0.941
	1868 STAND3	345	1.100	0.900	0.996	0.026	-0.970
	1907 EDMST1	138	1.100	0.900	1.039	0.033	-1.006
	1908 114084	138	1.100	0.900	1.036	0.033	-1.003
	1909 IROQUA	138	1.100	0.900	1.035	0.033	-1.002
	1930 1126MP	138	1.100	0.900	1.003	0.410	-0.593

VAR								GENERATORS ON VAR LIMIT
	1802 GRFALL	138	15.5	-35.0	7.8	3649.0	3641.2	++
	1826 DALHOU	138	166.0	-196.0	1.3	321.0	319.7	++
	1847 112572	138	6.0	-6.0	-6.0	-19.0	-13.0	--
	1913 BELDUN	345	220.0	-250.0	220.0	219.0	-1.0	+
	1948 EELRA1	138	7.0	-7.0	4.3	6.0	1.7	+
	168 ONSLO3	345	180.0	-150.0	180.0	180.0	0.0	+
	1844 MURRCR	138	20.0	0.0	0.0	0.0	0.0	-
	1896 TINKER	138	5.0	-5.0	1.9	307.0	305.1	++

Even when there is a solution to the load flow, there may be a high risk of voltage collapse indicated by a widespread low voltage condition. To capture such events, TPLAN includes a voltage depression failure criterion defined by N or more buses being below a specified voltage level. Figure 3.2 shows the frequency of such events for the Base System and the Improved System as a function of the number of buses (N) for a voltage limit of 0.9 per unit. Table 3.9 shows the frequency and duration of voltage depressions involving 4 or more buses for the base system. The table details reliability indices by bus affected by such events.

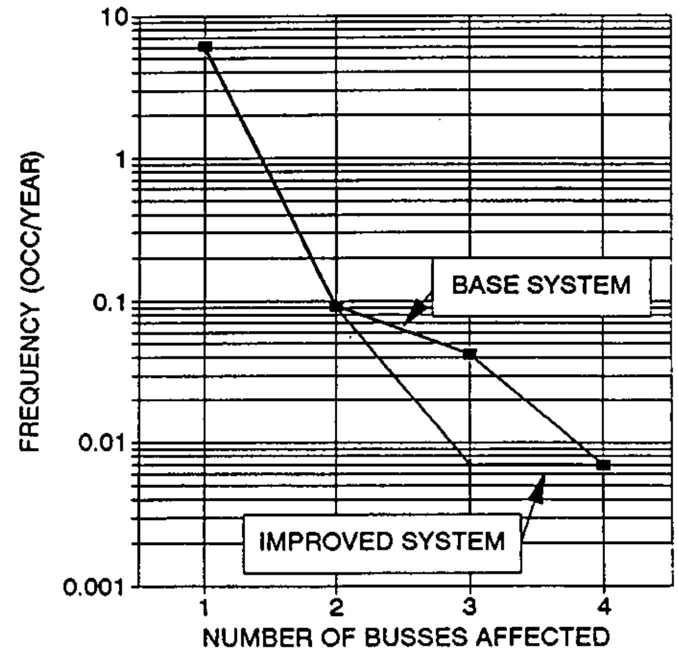

Figure 3.2

Cumulative Frequency for Voltage Depression Affecting N or more Buses

Table 3.9

Reliability Indices for Voltage Depression by Bus Affected

*** RELIABILITY INDICES FOR VOLTAGE DEPRESSION VIOLATIONS ***
CRITERION: (4) BUSES UNDER (0.900) P.U.

			FREQ. (OC/YR)	AVG. DUR. (HR)	AVG. VIO. (PU)	MAX. VIO. (PU)	# OF. FAIL. CONT.	WORST CONT. INDEX	V.COL. FREQ. (OC/YR)
TOTAL			0.007	10.7	0.06	0.35	11	5619	0.001
AREA 1 : 138- 345 KV BUSES			0.007	10.7	0.06	0.35	11	5619	0.001
BUSES:									
168	ONSLO3	345	0.007	9.2	0.05	0.24	9	5616	
1844	MURRCR	138	0.003	11.6	0.06	0.25	5	5616	
1812	MONCTN	138	0.004	9.7	0.05	0.21	6	5616	
157	MACCAN	138	0.005	10.3	0.06	0.26	7	5616	
158	ONSLO1	138	0.003	8.5	0.09	0.27	4	5616	
167	ONSLO2	230	0.006	8.4	0.05	0.26	8	5616	
183	SPRNGH	138	0.006	9.9	0.05	0.27	9	5616	
1712	RICHBT	138	0.007	10.6	0.12	0.35	10	5619	
1747	NORPSR	138	0.002	8.6	0.01	0.01	2	5476	
1776	114981	138	0.002	9.6	0.02	0.03	3	5616	
1825	MEMCOK	138	0.003	11.6	0.07	0.24	5	5616	
1838	SALBR2	230	0.006	9.3	0.07	0.23	8	5616	
1839	SALBR1	138	0.001	16.2	0.07	0.19	3	5616	
1850	SALBR3	345	0.007	9.2	0.05	0.25	9	5616	
1852	110871	138	0.003	11.6	0.06	0.22	5	5616	
1854	HARDRD	138	0.003	11.6	0.07	0.25	5	5616	
1863	119042	138	0.006	9.9	0.05	0.26	9	5616	
1900	NORTN3	345	0.003	11.5	0.03	0.04	4	5476	
1901	NORTN1	138	0.002	8.6	0.00	0.00	2	5476	
1945	119024	138	0.003	11.6	0.06	0.22	5	5616	
1946	112408	138	0.003	11.6	0.06	0.21	5	5616	

4.0 REFERENCES

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[2] Hosseini, H., S.B. Dhar, W.R. Puntel, "Interconnected California Power Systems Transfer Capability and Reliability Study," 1981 Reliability Conference for the Electric Power Industry, Portland, OR, April, 1981.

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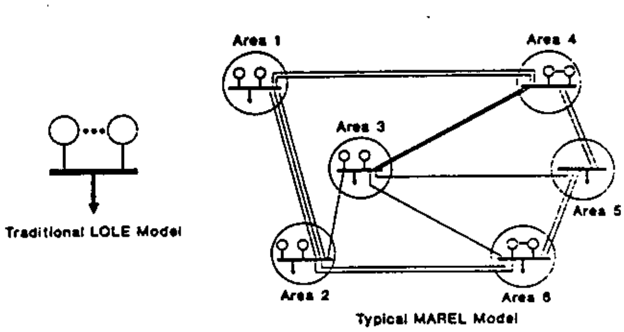
APPENDIX 1

MULTI-AREA RELIABILITY PROGRAM (MAREL) DESCRIPTION

A.1 INDUSTRY NEED

The loss-of-load expectation (LOLE) measure has gained widespread use in the electric utility industry for evaluating the adequacy of future generation additions. LOLE studies are traditionally based on single area models where generation and load are assumed connected to a single bus and where transmission effects are ignored.

In today's utility planning environment, generation additions are often evaluated on a regional basis, with several utilities interconnected and operating in a coordinated manner such as illustrated below.



In these situations, the reliability of the overall system and each utility area depends not only on area resources and load, but also on the ability of areas to share resources with one another over transmission ties.

System and area LOLE indices can differ significantly and are influenced by transmission limitations and reserve sharing policies. The proper evaluation of these interdependencies requires a technique that is more sophisticated than the traditional single-area approach.

A.2 PROGRAM CAPABILITIES

PTI's Multi-Area Reliability Evaluation Program, MAREL, provides the enhanced modeling capabilities needed to address today's more complicated reliability questions. It calculates both system and area LOLE indices for interconnected electric utility systems - fully recognizing the ability of areas to share reserves over transmission ties. MAREL's modeling capabilities provide a high degree of flexibility for the specification of system configurations and characteristics.

- Loads are modeled by area using distributions of daily peak loads. The chronological aspects of area load distributions can be retained so that the effects of load diversity among areas are fully incorporated in the study results.

- Generating units are specified by area and may be modeled with up to eight probabilistic outage states. Individual capacity/probability tables are constructed for each area to model the availability of generating capacity in that area.
- Planned maintenance outages are simulated by taking generating units out-of-service for specific maintenance periods. The outage periods may be specified by the user or scheduled automatically within MAREL by an algorithm designed to level available area generation reserves over the year. Maintenance period duration can be defined by the user depending on what is appropriate for the study.
- Transmission interconnections are represented by a linear flow network model which accommodates multi-state, probabilistic transfer limits between areas. This model places no restrictions on the network configuration or topology.
- Indices computed include system and area LOLE's, expected MW-days of load loss, average MW's of load loss, probability of limitations on transfer links and expected interchange between pairs of areas. In addition, four different policies for sharing reserves and load losses between areas are incorporated in the analysis. Indices are computed for each policy. LOLE and related indices are also calculated assuming that areas are not connected to one another. These "isolated" indices are useful for comparison and reference purposes.
- Program output reports include formatted summaries of study parameters, model inputs, and the results of the reliability analysis. These outputs are suitable for direct incorporation into study documents. The user may suppress the display of certain output summaries. Some samples are shown on page 4.
- Program controls may be set by the user to establish the fineness with which loads and capacity are represented and to save unnecessary computer effort and cost.

APPENDIX B

TPLAN DESCRIPTION

B.1 THE TPLAN PROGRAM

The TPLAN program, developed by Power Technologies, Inc. is an interactive computer program for long term planning and operations planning. The program is dimensioned for 4000 buses and has the following application functions:

1) Automatic contingency analysis using either AC or DC load flow models.
2) Probabilistic reliability assessment of power systems including transmission network effects and failures.
3) Parametric studies allowing the automatic determination of selected variables as a function of any systematic change in the network; e.g., automatic generation of curves that show voltage vs. power transfer to determine safe margin against voltage collapse.
4) Interactive transmission system expansion functions to help determine the most effective circuit additions for eliminating overload problems during base case and contingency conditions.
5) Corrective action function that determines generation redispatch and phase shifter action required to eliminate overloads on transmission circuits, with optional load shedding function.
6) Simulation of overload cascading events to help identify portions of the system that are vulnerable to islanding caused by overload cascading.
7) Power transfer limit determination based on circuit overloads during single and multiple contingencies.

These application functions all work on the same system data base and are mutually supportive. For example, the system created by the interactive expansion planning function can be tested with AC contingency analysis without any manual data preparation. A command language allows the automatic execution of complex studies without manual intervention.

The program provides two-way communication of load flow data with PTI's PSS/E program via formatted raw data files or binary save case files. Additional input data supports unit commitment/dispatch functions, ROW and line type data, outage statistics, etc.

B.2 RELIABILITY ANALYSIS WITH TPLAN

TPLAN provides the capability to compute reliability indices for specific system conditions. The computed indices are given in terms of frequencies and durations of the following system problems:

- Overload on transmission circuits
- Violation of bus voltage limits
- Voltage collapse conditions
- Isolation of individual buses or separation of a network into islands
- Indices expressing loss of load caused by interruptions of supply
- Indices expressing the severity of overloads and bus voltage violations
- Frequency deviations (computed based on generator droop settings) that exceed criterion high or low values when islands are formed

Indices can be computed by system, area, kV level, bus or branch as appropriate.

A TPLAN reliability study is carried out in the following steps (See Figure 1):

1) Prepare outage statistics for single generator and transmission units that may be tested either by themselves or as a part of

an independent multiple outage events.

2) Prepare outage data files that specifies and assigns outage statistics for the single and multiple dependent outages that shall be tested.

3) Perform contingency analysis using either an AC or a DC load flow model. All contingencies specified in (2) will be tested. In addition, the program will test single and independent overlapping generation and transmission unit outages guided by ranking and screening processes. The results of the contingency analysis will be stored in a contingency results file as shown in Figure 1.

4) Calculate reliability indices based on the outage statistics given in the outage data files prepared under (1) and (2) and the contingency results existing in the contingency results file. This step can be repeated with different but compatible outage data files without recalculation of the contingency results.

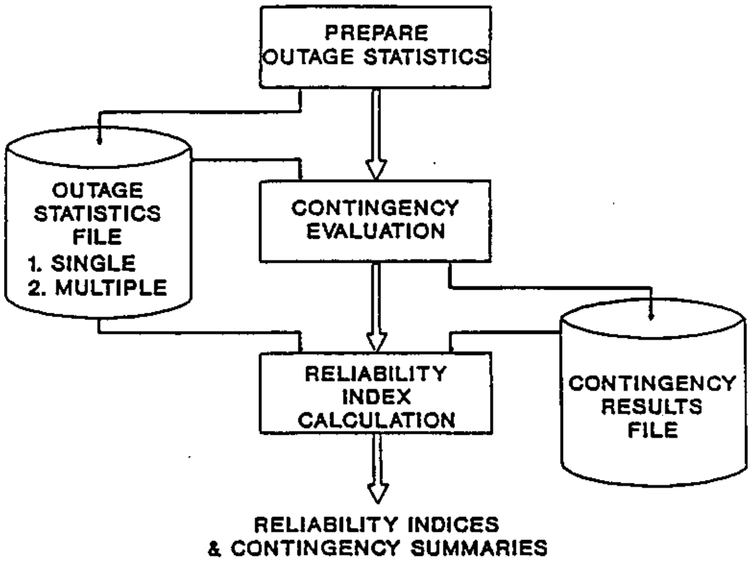


Figure 1
Reliability Assessment Using TPLAN

APPENDIX C

MAREL RESULTS FOR NB POWER SYSTEM HL1 EVALUATION

--- SUMMARY ON CAPACITY AND PEAK LOAD BY AREA :

AREA	AREA 1 NORTHE	AREA 2 SOUTHE
PEAK LOAD SEASON	1	1
INSTALLED CAPACITY (MW) AT ANNUAL PEAK	5374	5374
ANNUAL PEAK LOAD (MW)	3846	3846
INSTALLED RESERVES (MW)	1528	1528
RESERVES IN PERCENT OF ANNUAL PEAK LOAD	39.73	39.73
AREA WEIGHTED AVERAGE UNIT FOR (PERCENT)	8.89	8.89
AREA ANNUAL AVERAGE MAINTENANCE(PERCENT)	0.00	0.00

(Note: Two-Area System was Modeled to Satisfy MAREL Requirements. Single Area "isolated" indices were reported.)

--- SUMMARY : EXPECTED AREA DEFICIENCIES FOR DIFFERENT POLICIES ---

AREA		ISOLATED	WITH LLS	NO LLS	NEXT AREA	POOLING
	MW-DAY	15.57	15.57	15.57	15.50	0.00
1 NORTHE	DAYS	0.09	0.09	0.09	0.09	0.00
	AV.MW	168.75	168.75	168.75	168.00	0.00
	MW-DAY	15.57	15.57	15.57	15.50	0.00
2 SOUTHE	DAYS	0.09	0.09	0.09	0.09	0.00
	AV.MW	168.75	168.75	168.75	168.00	0.00

INTERCONNECTED SYSTEM LOLP (DAYS) - 0.183672

NOTE : LLS - LOAD LOSS SHARING

(Note: LOLE indices reflect results for 10 load levels. Values must be multiplied by 876.0 to produce annual hourly indices.)

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