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A RELIABILITY TEST SYSTEM FOR EDUCATIONAL PURPOSES - BASIC DATA

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Abstract

The IEEE Reliability Test System RTS developed by the Application of Probability Method Subcommittee has been used to compare and test a wide range of generating capacity and composite system evaluation techniques and subsequent digital computer programs. The IEEE-RTS requires the utilization of computer programs to obtain indices and therefore is not entirely suited to the development of basic concepts and an appreciation of the assumptions associated with conducting practical system reliability studies.

This paper presents a basic reliability test system which has evolved from the reliability education and research programs conducted by the Power System Research Group at the University of Saskatchewan. The basic system data necessary for adequacy evaluation at the generation and composite generation and transmission system levels are presented together with the fundamental data required to conduct reliability cost/reliability worth evaluation.

Key words: Reliability test system, generation, transmission, educational studies.

INTRODUCTION

The IEEE Subcommittee on the Application of Probability Methods (APM) published the IEEE Reliability Test System (RTS) [1] in 1979. This system provides a consistent and generally acceptable set of data that can be used both in generation capacity and in composite system reliability evaluation [2,3]. The test system provides a basis for the comparison of results obtained by different people using different methods. Prior to its publication, there was no general agreement on either the system or the data that should be used to demonstrate or test various techniques developed to conduct reliability studies. Development of reliability assessment techniques and programs are very dependent on the intent behind the development as the experience of one power utility with their system may be quite different from that of another utility. The development and the utilization of a reliability program are, therefore, greatly influenced by the experience of a utility and the intent of the system manager, planner and designer conducting the reliability studies. The IEEE-RTS has proved to be extremely valuable in highlighting and comparing the capabilities (or incapabilities) of programs used in reliability studies, the differences in the perception of various power utilities and the differences in the solution techniques. An example of this is given in Reference 4 which compares the results obtained by two fundamentally different approaches to composite system adequacy assessment, namely the contingency enumeration method and the Monte Carlo simulation approach.

Another important contribution made by the creation of the IEEE-RTS is the provision of a starting point in regard to collecting the data required to conduct reliability studies. Data collection and the development of methodologies for reliability evaluation are complementary activities. Overall data and methodology development is an iterative process and with it comes an increased understanding of the importance of reliability in the design and operation of a power system.

The IEEE-RTS, since its creation in 1979, has been used extensively in a range of reliability studies conducted by utilities, consultants and universities [3,4,5]. Additional data have been proposed in order to enhance the applicability of the IEEE-RTS [3,6,7]. The IEEE-RTS contains a reasonably large power network which can be difficult to use for initial studies in an educational environment. The calculation of a simple index at the generation level (hierarchical level one (HLI) [3]) or at the composite generation and transmission level (HLII) for this system requires a computer and the development of suitable software. The direct utilization of a previously developed program may not give a student of reliability theory the appreciation required of the various steps required in modelling, the set of assumptions involved, the algorithmic development and the calculation process used to evaluate the reliability of the system. In order to achieve these objectives, it is therefore desirable to have a small test system which incorporates the basic data required in reliability evaluation at HLI and HLII. The objective of this paper is to provide such an educational reliability test system.

The main object in designing a reliability test system for educational purposes is to make it sufficiently small to permit the conduct of a large number of reliability studies with reasonable solution time but sufficiently detailed to reflect the actual complexities involved in a practical reliability analysis. The system presented in this paper has evolved from the reliability research activities conducted by the Power Systems Research Group at the University of Saskatchewan. These activities have been supervised by Professor R. Billinton. The overall approach used to teach power system reliability at the University of Saskatchewan is based on the philosophy that a technique, however elegant it may be, should first be applied to a small system which can be easily solved and appreciated by the student using hand calculations before being extended to computer development. This approach requires a thorough understanding in the mind of the student of the assumptions and approximations involved before engaging in the excessive calculations required in a practical system analysis. The system presented in this paper is an educational test system designated as the Roy Billinton Test System and abbreviated as the RBTS.

The RBTS data presented in this paper is divided into six basic sections. The first section provides a brief description of the RBTS which is followed by a load model, generation system, transmission network, station configuration, interconnections with other systems and cost of interruption data.

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BRIEF DESCRIPTION OF THE RBTS

The single line diagram of the test system is shown in Figure 1. The system has 2 generator (PV) buses, 4 load (PQ) buses, 9 transmission lines and 11 generating units. The minimum and the maximum ratings of the generating units are 5 MW and 40 MW respectively. The voltage level of the transmission system is 230 kV and the voltage limits for the system buses are assumed to be 1.05 p.u. and 0.97 p.u. The system peak load is 185 MW and the total installed generating capacity is 240 MW. The transmission system contains single lines and lines on a common right of way and/or on a common tower.

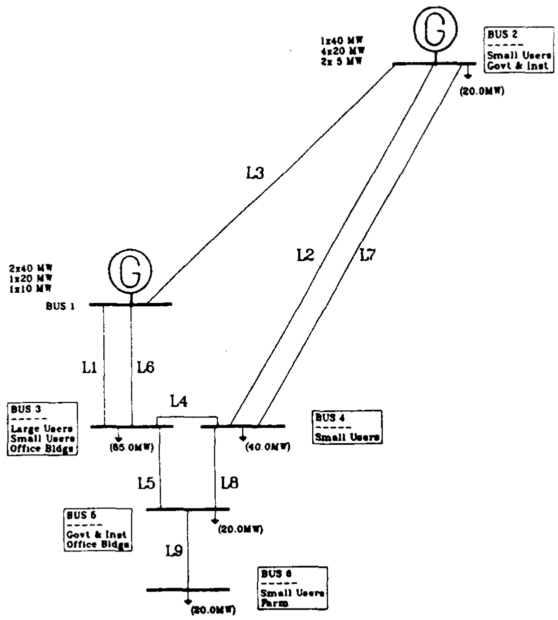
The transmission network shown in Figure 1 has been drawn to give a geographical representation. The line lengths are shown in proportion to their actual lengths. The geographic representation of the system gives the configuration a more physical appeal and can be used to consider various segments of the system in terms of the actual customer classes connected to those regions.

LOAD MODEL

The annual peak load for the system is 185 MW. The data on weekly peak loads in percent of the annual peak load, daily peak load in percent of the weekly peak, and hourly peak load in percent of the daily peak are the same as that given in Tables 1, 2 and 3 of the IEEE Reliability Test System [1]. These data are not given in this paper and can be obtained from Reference 1. The total number of data points required to define the daily peak load curve is 364. In the case of the hourly peak load curve or the load duration curve, 8736 points are required. A load duration curve described by 100 data points is shown in Figure 2. A discrete step load model is also shown. The actual data points are given in Table I.

GENERATING SYSTEM

The generating unit ratings and reliability data for the RBTS are shown in Table II.



All load points have residential customers.

Figure 1. Single line diagram of the RBTS.

Table II. Generating unit reliability data.

Unit size (MW)	Type	No. of units	Forced outage rate	MTTF (hr)	Failure rate per year	MTTR (hr)	Repair rate per year	Scheduled maintenance wk/yr
5	hydro	2	0.010	4380	2.0	45	198.0	2
10	thermal	1	0.020	2190	4.0	45	196.0	2
20	hydro	4	0.015	3650	2.4	55	157.6	2
20	thermal	1	0.025	1752	5.0	45	195.0	2
40	hydro	1	0.020	2920	3.0	60	147.0	2
40	thermal	2	0.030	1460	6.0	45	194.0	2

Table I. 100 Points Load Data for the RBTS.

Peak Load (p.u.)	Study Period (p.u.)	Peak Load (p.u.)	Study Period (p.u.)	Peak Load (p.u.)	Study Period (p.u.)	Peak Load (p.u.)	Study Period (p.u.)
1.0000	0.0000	0.9933	0.0002	0.9866	0.0003	0.9800	0.0004
0.9733	0.0006	0.9666	0.0008	0.9599	0.0010	0.9532	0.0015
0.9466	0.0024	0.9399	0.0034	0.9332	0.0040	0.9265	0.0058
0.9199	0.0076	0.9132	0.0081	0.9065	0.0100	0.8998	0.0137
0.8931	0.0160	0.8865	0.0189	0.8798	0.0239	0.8731	0.0290
0.8664	0.0333	0.8597	0.0401	0.8531	0.0464	0.8464	0.0517
0.8397	0.0614	0.8330	0.0718	0.8264	0.0823	0.8197	0.0906
0.8130	0.1004	0.8063	0.1122	0.7996	0.1254	0.7960	0.1353
0.7863	0.1452	0.7796	0.1574	0.7729	0.1704	0.7662	0.1823
0.7596	0.1918	0.7529	0.2005	0.7462	0.2114	0.7395	0.2232
0.7329	0.2339	0.7262	0.2436	0.7195	0.2561	0.7128	0.2670
0.7061	0.2773	0.6995	0.2909	0.6928	0.3030	0.6861	0.3163
0.6794	0.3300	0.6727	0.3448	0.6661	0.3616	0.6594	0.3769
0.6527	0.3934	0.6460	0.4094	0.6394	0.4260	0.6327	0.4420
0.6260	0.4591	0.6193	0.4771	0.6126	0.4932	0.6060	0.5089
0.5993	0.5242	0.5926	0.5390	0.5859	0.5501	0.5792	0.5625
0.5726	0.5742	0.5659	0.5869	0.5592	0.5592	0.5525	0.6134
0.5459	0.6265	0.5692	0.6415	0.5325	0.6544	0.5259	0.6706
0.5191	0.6881	0.5125	0.7043	0.5058	0.7218	0.4991	0.7410
0.1924	0.7603	0.4857	0.7810	0.4791	0.7992	0.4724	0.8158
0.4657	0.8302	0.4590	0.8473	0.4523	0.8599	0.4457	0.8758
0.4390	0.8880	0.4323	0.9029	0.4256	0.9159	0.4190	0.9293
0.4123	0.9420	0.4056	0.9549	0.3989	0.9347	0.3922	0.9721
0.3856	0.9783	0.3789	0.9827	0.3722	0.9867	0.3655	0.9905
0.3588	0.9949	0.3522	0.9977	0.3455	0.9991	0.3388	1.0000

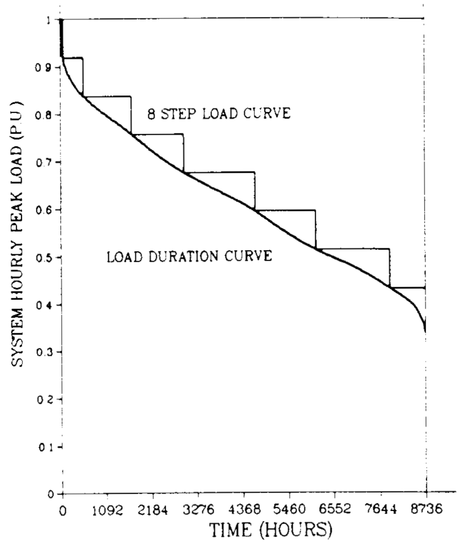


Figure 2. Load duration curve for the RBTS.

In order to recognize that large thermal units can operate in one or more derated states, the two 40 MW thermal units have been given an optional three state representation. The derated model is shown in Figure 3. It has been assumed that there are no transitions between the derated state and the down state. The state probabilities and transition rates of the derated model are such that the derating-adjusted two-state model data is identical to that given in Table II [7]. The two-state model is shown in Figure 3.

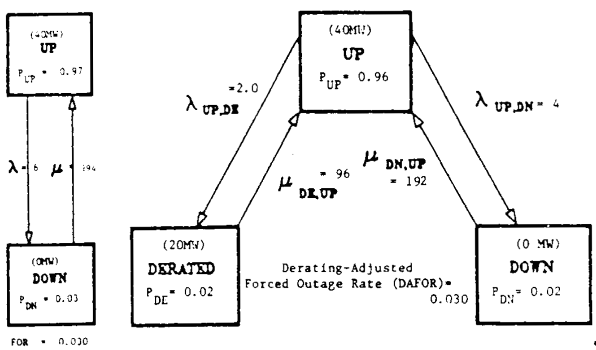


Figure 3. Two and three-state models for a 40 MW thermal unit generating unit.

The generation mix is shown in Table III.

Table III. Generation mix.

	MW	%
Thermal (lignite)	110	46
Hydro	130	54

The cost data, fuel cost, operating cost, fixed costs and capital cost are shown in Table IV. The total variable operating and maintenance (O&M) cost figure ($/MWh) is the sum of the total costs ($/MWh) and operating costs ($/MWh) of each unit as shown in the table. The variable costs include payment for materials, supplies, power etc.. The major component of the variable costs is the fuel costs, i.e. costs directly associated with energy production. The fuel cost for a hydro unit includes water rental charges. The fixed costs include the annual charges which continue as long as capital is tied up in the enterprise and whether or not the equipment is operating. These charges comprise interest, depreciation, rent, taxes, insurance and any other expenditure that is based upon the magnitude of capital investment and not on the degree of use to which the equipment is put during the year. The capital cost is the total cost to install a generating unit.

Two loading orders are given in Table IV. The first loading order is on a purely economic basis. The operating costs for hydro units are relatively low and therefore these units are loaded prior to the thermal units. The second loading order allocates some hydro units as peaking units which could reflect limited energy considerations. This loading order may be more realistic though not as economical as the first one. Either of the loading orders can be selected depending upon the operating philosophy in conducting reliability studies.

Additional Generating Units

Additional gas turbines can be used with the RBTS in order to satisfy a risk criterion such as the Loss of Load Expectation (LOLE) or the Loss of Energy Expectation (LOEE) value under condition of load growth, increased generating units FOR due to aging etc.. The generation, outage and cost data pertaining to these gas turbines are given in Table V.

TRANSMISSION SYSTEM

The transmission network consists of 6 buses and 9 transmission lines. The transmission voltage level is 230 kV. The locations of the generating units are shown in Table VI.

Table VII gives data on generating unit Mvar capacity for use in basic load flow calculations.

Table IV. Generating unit cost data.

Unit size (MW)	Number of units	Loading order 1st	Loading order 2nd	F.O.R.	Variable costs, $/MWh Fuel cost	Operat. cost	Total cost	Fixed costs $/yr $/kW	Total	Capital cost ($)
40 (hydro)	1	1	1	0.020	0.45	0.05	0.50	2.50	100,000	160×10^6
20 (hydro)	2	2-3	2-3	0.015	0.45	0.05	0.50	2.50	50,000	80×10^6
40 (lignite)	2	8-9	4-5	0.030	9.50	2.50	12.00	--	790,000	80×10^6
20 (lignite)	1	10	6	0.025	9.75	2.50	12.25	--	680,000	60×10^6
10 (lignite)	1	11	7	0.020	10.00	2.50	12.50	--	600,000	40×10^6
20 (hydro)	2	4-5	8-9	0.015	0.45	0.05	0.50	2.50	50,000	80×10^6
5 (hydro)	2	6-7	10-11	0.01	0.45	0.05	0.50	2.50	12,500	40×10^6

Table V. Generation, outage and cost data for additional gas turbines.

				Variable cost			
Capacity (MW)	FOR	MTTF hour	MTTR hour	Fuel cost ($/MWh)	Operating cost ($/MWh)	Fixed cost ($/yr)	Capital cost ($)
10	0.12	550	75	52.0	4.50	40,000	5×10^6

Table VI. Generating unit locations.

Unit No.	Bus	Rating	Type
1	1	40	thermal
2	1	40	thermal
3	1	10	thermal
4	1	20	thermal
5	2	5	hydro
6	2	5	hydro
7	2	40	hydro
8	2	20	hydro
9	2	20	hydro
10	2	20	hydro
11	2	20	hydro

Table VII. Generating unit Mvar capability.

	Mvar	
Size MW	Maximum	Minimum
5	5	0
10	7	0
20	12	-7
40	17	-15

Bus load data at the time of system peak in MW and in percentage of the total system load are shown in Table VIII. It has been assumed that the power factor at each bus is unity. If power factor is of importance, a value of 0.98 lagging should be used. At 0.98 power factor, the reactive load Mvar requirements at each bus is 20% of the corresponding MW load.

Table VIII. Bus load data.

Bus	Load (MW)	Bus load in % of system load
2	20.0	10.81
3	85.0	45.95
4	40.0	21.62
5	20.0	10.81
6	20.0	10.81
Total	185.0	100.00

The annual load growth (LG) might reasonably be considered to lie between 2.5 and 7.5 percent. A basic value of 5% is therefore suggested. The load is assumed to be forecasted with an uncertainty represented by a normal distribution having a standard deviation (SD) of 4%. This is equivalent to 7.4 MW at the system peak load of 185 MW. The normal distribution with the system peak load of 185 MW as its mean can be approximated by 7 discrete intervals [2] as shown in Table IX.

Table X shows the basic transmission line reliability data.

The permanent outage rate of a given transmission line is obtained using a value of 0.02 outages per year per kilometer. The transient forced outage rates are calculated using a value of 0.05 outages per year per kilometer. The outage duration of a transient outage is assumed to be less than one minute and is, therefore, not included in Table X. Outages of substation components which are not switched as a part of a line are not included in the outage data given in Table X.

Table IX. Load forecast uncertainty data.

SD from mean	Load level MW	Probability
-3	162.8	0.006
-2	170.2	0.061
-1	177.6	0.242
0	185.0	0.382
1	192.4	0.242
2	199.8	0.061
3	207.2	0.006
	Total	1.000

Table X. Transmission line length and outage data.

Line	Buses From	Buses To	Length KM	Permanent outage rate (per year)	Outage duration (hours)	Transient outage rate (per year)
1	1	3	75	1.5	10.0	3.75
2	2	4	250	5.0	10.0	12.50
3	1	2	200	4.0	10.0	10.00
4	3	4	50	1.0	10.0	2.50
5	3	5	50	1.0	10.0	2.50
6	1	3	75	1.5	10.0	3.75
7	2	4	250	5.0	10.0	12.50
8	4	5	50	1.0	10.0	2.50
9	5	6	50	1.0	10.0	2.50

The substation configurations for the load and generation buses are given in the extended single line diagram shown in Figure 4.

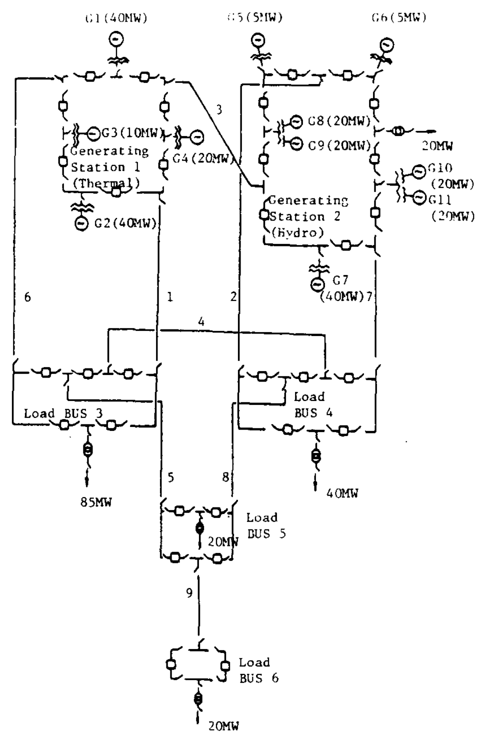


Figure 4. Extended single line diagram of the RBTS.

The terminal station equipment data are as follows:

Circuit Breaker

Active failure rate = 0.0066 failures per year
Passive failure rate = 0.0005 failures per year
Average outage duration = 72 hours
Maintenance outage rate = 0.2 outages per year
Maintenance time = 108 hours
Switching time = 1 hour

Bus Section

Failure rate = 0.22 failures per year
Outage duration = 10 hours

Station Transformer

Failure rate = 0.02 failures per year
Outage duration = 768 hours
Maintenance outage rate = 0.2 outages per year
Maintenance time = 72 hours
Switching time = 1 hour

Four transmission lines are assumed to be on a common right-of-way or common tower for their entire length. The common mode data for these lines are given in Table XI.

Table XI. Common mode data for the circuits on a common right-of-way or a common tower.

Buses From	Buses To	Line	Common length km	Outage rate per year	Outage duration (hours)
1	3	1	75	0.150	16.0
1	3	6	75		
2	4	2	250	0.500	16.0
2	4	7	250		

Two basic models which can be used to represent common mode failures in a two-component system are shown in Figure 5. The independent failure rates for the two components are given by λ_1 and λ_2 and the independent repair rates by μ_1 and μ_2. The common mode failure rate and repair rate are given by λ_c and μ_c. The difference between these two models is that one has a single down state (Figure 5a) and the other has two separate down states: one associated with the independent failures, the other associated with common mode failures (Figure 5b). Either model can be used.

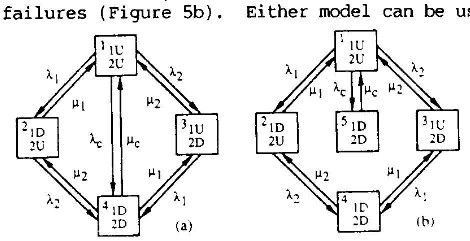


Figure 5. Common mode models for a two-component system.

The load flow data (impedance and current capacity data) for the transmission lines are given in Table XII.

The additional bus data required to conduct reliability studies using an ac load flow method is given in Table XIII. Bus 1 is assumed to be the slack bus under normal circumstances. If Bus 1 is isolated, Bus 2 acts as the slack bus. The load at each bus can be classified into two categories:

(a) firm load,
(b) curtailable load.

Table XII. Line data.

Line	Buses From	Buses To	Impedance (p.u.) R	X	B/2	Current rating (p.u.)
1, 6	1	3	0.0342	0.180	0.0106	0.85
2, 7	2	4	0.1140	0.600	0.0352	0.71
3	1	2	0.0912	0.480	0.0282	0.71
4	3	4	0.0228	0.120	0.0071	0.71
5	3	5	0.0228	0.120	0.0071	0.71
8	4	5	0.0228	0.120	0.0071	0.71
9	5	6	0.0228	0.120	0.0071	0.71

100 MVA base
230 kV base

Table XIII. Bus data.

Bus	Load (p.u.) P	Q	Scheduled generation (p.u.)	Q_{max}	Q_{min}	V_{int}	V_{max}	V_{min}
1	0.00	0.00	1.0	0.50	-0.40	1.05	1.05	0.97
2	0.20	0.00	1.2	0.75	-0.40	1.05	1.05	0.97
3	0.85	0.00	0.0	0.00	0.00	1.00	1.05	0.97
4	0.40	0.00	0.0	0.00	0.00	1.00	1.05	0.97
5	0.20	0.00	0.0	0.00	0.00	1.00	1.05	0.97
6	0.20	0.00	0.0	0.00	0.00	1.00	1.05	0.97

100 MVA base
230 kV base

The curtailable load can be designated as some percentage of the total load at the bus based on individual load point requirements. A value of 20% of the total bus load is designated as curtailable load in the RBTS. In the case of a system problem requiring load curtailment, curtailable load is interrupted first, followed by the curtailment of firm load, if necessary. An appropriate load curtailment algorithm, depending upon the operation philosophy, should be used when conducting reliability studies at HLII.

Interconnected Systems

Reliability studies of interconnected systems can be conducted by joining two or more than two identical RBTS with one or more tie lines. The tie line data are given in Table XIV.

Table XIV. Tie line data.

Rating MW	Permanent outage rate per year	Duration hour	FOR	Transient outage rate per year
30	1	8.77	0.001	2.50

RELIABILITY COST/RELIABILITY WORTH

A major element in the justification of new expansion facilities and in the determination of an appropriate operating reliability level is reliability cost (the investment cost needed to achieve a certain level of reliability) and reliability worth (the benefit derived by the utility, consumer and society) assessment of a power system. Conceptually, this implies that the benefit of having increased levels of electric supply reliability can be related to the costs of providing that service at the increased reliability levels. This is shown in Figure 6.

Figure 6 shows that the utility cost will generally increase as consumers are provided with higher reliability and that the consumer costs associated with supply interruptions will generally decrease as the reliability increases. The total costs to society will, therefore, be the sum of these two individual costs. In order to achieve an optimum level of reliability, the sum of the costs accrued to

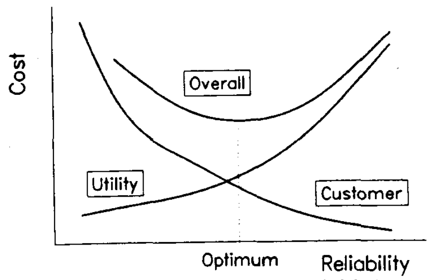


Figure 6. Cost as a function of reliability.

a utility for system enhancements and costs to customers resulting from the power outages should be minimized.

The data presented in this paper can be used to calculate reliability indices and reliability costs at HLI and HLII. In order to assess the reliability worth, additional data are required which are related to the actual or perceived costs of power interruptions and/or outages to a consumer. One of the most commonly used methods to gather this data is to survey electrical consumers, sector by sector, to determine the costs or losses resulting from supply interruptions. The cost of interruption at a single customer load point is dependent entirely on the cost characteristics of that customer. As the supply point in question moves away from the actual customer load point, the consequences of an outage of the supply point involves an increasing number of customers. As the supply point becomes the generating system, i.e. HLI, potentially all system customers are involved. The customer cost associated with a particular outage at a specific point in the system involves an amalgamation of the costs associated with the customers affected by interruptions at that point in the system. This amalgamation or consolidation of costs is known as a composite customer damage function (CCDF).

Composite Customer Damage Function (CCDF)

Conceptually, the CCDF for a particular service area is an estimate of the cost associated with power supply interruptions as a function of the interruption duration for the customer mix in the service area. Each customer or type of customer has a different cost for a particular outage duration and the method for combining the individual costs is to perform a weighted average according to the annual peak demand or energy consumption of the individual customers or customer group. Weighting by annual peak demand is used for short duration interruptions and weighting by the energy consumptions is used for interruptions longer than one-half hour [3].

Table XV gives cost of interruption data by sector using a 1987 Cdn $ base. As shown in the table, the costs can be a simple average ($/r respondent) or can be normalized by the annual consumption of electricity ($/kWh) or by the annual peak demand ($/kW). The seven sectors used in the RBTS for allocating cost of interruption data are as follows:

1. Large users (peak demand above 5 MW).
2. Industrial users (peak demand less than 5 MW).
3. Commercial (retail trade and services).
4. Agriculture and farms.
5. Residential.
6. Government and institution.
7. Office space (office building owners and their tenants).

Cost of interruptions in $/kW are used to generate a CCDF. The load composition by both energy consumption and peak demand for the service areas is shown in Table XVI. The data presented in Tables XV and XVI were obtained from studies conducted by the Power

Table XV. Cost of interruption data.

Cost of interruption in $/respondent

Duration	Sector					
	Large users	Industrial	Commercial	Agriculture	Residential	Government
1 min.	23441	1011.9	26.2	1.84*	0.003*	1.19
20 min.	35178	2096.3	192.2	8.99	0.34	123.78
1 hr.	51895	4341.4	511.6	16.10	1.83	2042.48
4 hrs.	92536	8205.6	1818.0	48.00	18.45	18014.12
3 hrs.	192195	14766.5	4799.5	92.22	58.58*	39222.57

Cost of interruption in $/kW

Duration	Large users	Sector				Government	Office Space
		Industrial	Commercial	Agriculture	Residential		
1 min.	1.005	1.625	0.381	0.060*	0.001*	0.044	4.778
20 min.	1.508	3.868	2.969	0.343	0.093	0.369	9.878
1 hr.	2.225	9.085	8.552	0.649	0.482	1.492	21.065
4 hrs.	3.968	25.163	31.317	2.064	4.914	6.558	68.830
8 hrs.	8.240	55.808	83.008	4.120	15.690*	26.040	119.160

Cost of interruption in $/kWh

Duration	Large Users	Sector		Agriculture	Residential
		Industrial	Commercial		
1 min.	0.073	0.460	0.129	0.027*	0.0004*
20 min.	0.111	1.332	1.014	0.155	0.044
1 hr.	0.163	2.990	2.951	0.295	0.243
4 hrs.	0.291	8.899	10.922	1.027	2.235
8 hrs.	0.604	18.156	28.020	2.134	6.778*

Note: Values marked with * were obtained after extrapolation.

Systems Research Group at the University of Saskatchewan (U of S) and Ontario Hydro (OH), Canada. The composite customer damage function (CCDF) is given both in tabular form in Table XVII and in graphical form in Figure 7.

Table XVI. Distribution of energy consumption and peak demand.

Sector	Energy (%)	Peak demand (%)
Large users	31.0	30.0
Industrial	19.0	14.0
Commercial	9.0	10.0
Agriculture	2.5	4.0
Residential	31.0	34.0
Government	5.5	6.0
Office space	2.0	2.0
Total	100.0	100.0

Table XVII. Composite customer damage function.

Interruption duration	Interruption cost (1987 $/kW)
1 minute	0.67
20 minutes	1.56
1 hour	3.85
4 hours	12.14
8 hours	29.41

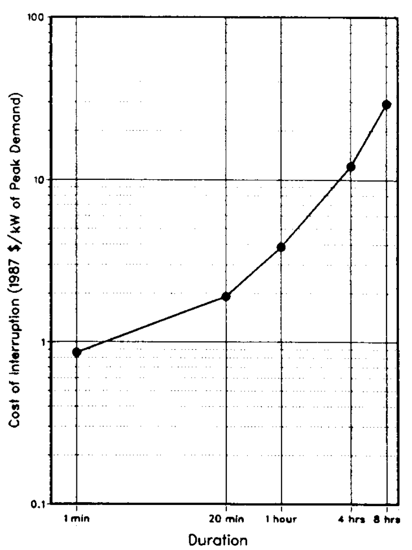


Figure 7. Composite customer damage function.

Despite the uncertainties affecting the development of a CCDF, it is the most suitable index available for determining monetary estimates of the reliability worth. The CCDF can be tailored to reflect the individual nature of the system, a region within it and in the limit, any particular customer.

CONCLUSIONS

This paper has presented an educational test system which includes all the basic data required for fundamental reliability studies at HLI and HLII. This system has evolved from the research and teaching program conducted at the University of Saskatchewan by Professor R. Billinton. The system provides the framework for conducting basic studies which can be largely conducted by hand calculation or simple computer programs without requiring excessive calculations. This approach permits the student to develop an appreciation for the assumptions and approximations required in practical studies. These requirements are often overlooked when the student utilizes predeveloped computer packages for reliability assessment without having examined the methodology and the development process.

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