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THE IEEE RELIABILITY TEST SYSTEM - EXTENSIONS TO AND EVALUATION OF THE GENERATING SYSTEM

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Abstract - This paper outlines some of the restrictions which currently exist in the generation data of the IEEE Reliability Test System (RTS). The paper extends the RTS by including more factors and system conditions which may be included in the reliability evaluation of generating systems. These extensions create a wider set of consistent data. The paper also includes generation reliability indices for the base and extended RTS. These indices have been evaluated without any approximations in the evaluation process and therefore provide a set of exact indices against which the results from alternative and approximate methods can be compared.

INTRODUCTION

Reliability is one of the most important criteria which must be taken into account during the design and planning phases of a power system. This need has resulted in the development of comprehensive reliability evaluation and modelling techniques [1,2]. One particularly frustrating aspect associated with the wide range of material published [3-5] on this subject is that, until 1979, there was no general agreement of either the system or the data that should be used to demonstrate or test proposed techniques. Consequently it was not easy, and often impossible, to compare and/or substantiate the results obtained from various proposed methods.

This problem was recognized by the IEEE Subcommittee on the Application of Probability Methods (APM) which, in 1979, published [6] the IEEE Reliability Test System (RTS). This is a reasonably comprehensive system containing generation data, transmission data and load data. It was intended to provide a consistent and generally acceptable set of data that could be used both in generation capacity and in composite system reliability evaluation. This would enable results obtained by different people using different methods to be compared.

This primary objective has been satisfied in most respects but, from experience, it has become evident that certain particular limitations exist. These are discussed in the next section. The purpose of the present paper is to address and reduce these limitations for the generating system and thus make the RTS more useful in assessing reliability models and evaluation techniques.

LIMITATIONS OF EXISTING RTS DATA

System Input Data

The original RTS was developed in order to provide system data that was perceived to be sufficient at that time. Experience has shown that certain additional data in both the generation system and the transmission system would be desirable. This has become evident because of developments that have taken place subsequently in both modelling and evaluation and also because of the type and scope of more recently published analyses. This particular paper is concerned with expanding the information relating to the generation system.

Although the system input data is already comprehensive, several important aspects are omitted. These include unit derated (partial output) states, load forecast uncertainty, unit scheduled maintenance and the effect of interconnections. It is desirable for these factors to be specified for the RTS in order that users of the RTS may all consider the same data and therefore evaluate results which can easily be compared. This additional data is specified in Appendix 1. There are many other aspects which could also be considered including start-up failures and outage postponability. Inclusion of these, however, requires additional modelling assumptions which are outside the scope of the present RTS and therefore, should be included only when the RTS is revised.

System Reliability Indices

Although the original RTS paper [6] included the input data, no information was included concerning the system reliability indices. Experience has shown that this was an important omission which should be rectified. The main reason is that most practical evaluation techniques include approximations and modelling assumptions regarding the generating capacity model, the load model and/or the evaluation algorithm.

Consider first the generating capacity model. This has 1872 states if no rounding is used and the model is truncated at a cumulative probability of 1×10^{-8}. In practice, rounding and higher truncation values of cumulative probability are frequently used. Also, other approximate methods, such as the cumulant method [7] have been developed. All of these aspects introduce approximations.

Consider now the load model. The specified RTS load model has 364 levels if only the daily peak loads are used and 8736 levels if the hourly loads are used. In many practical applications, the load model is usually represented, not by the actual daily or hourly levels, but by a smoothed curve depicted by a restricted number of coordinate points. These practical models are known [2] as the daily peak load variation curve (DPLVC) in the case of daily peak loads and the load duration curve (LDC) in the case of hourly loads. These two curves (DPLVC and LDC) for the RTS are shown in Figure 1. This modelling aspect also leads to approximations.

It is evident from the above reasoning that a result obtained from a particular analysis, in which one or more of the above approximations are incorporated, will not be exact. The degree of error however is unknown unless the result can be compared against an exact value. Therefore it was decided that a series of results should be evaluated for the RTS in which no approximations in the evaluation process and no assumptions, additional to those already associated

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with the RTS, were made. These indices could then form base values against which results from alternative and approximate methods can be compared. All the results in the following sections, except those showing the effect of rounding, are therefore exact (for the given data) since no approximations have been made in either the capacity model or the load model. They are therefore reproducible within the precision limitations of a particular computer. The methods used to ensure the exactness are described in the relevant section that follows.

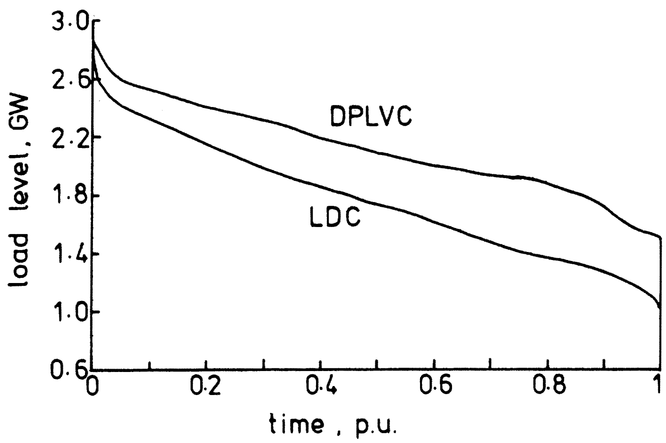

Figure 1. Load Models

LOLE ANALYSIS OF BASE CASE

The base case is considered to be the system as published in the original RTS [6]. In order to evaluate the exact loss of load expectation (LOLE) indices, the complete capacity model was developed with no rounding and truncated at a cumulative probability of 1×10^{-8}, i.e. it consisted of 1872 states. It was assumed that there were no energy or capacity limitations associated with the hydro units. The load model was represented by all 364 daily peak loads in order to evaluate the exact LOLE in day/yr and by all 8736 hourly peak loads in order to evaluate the exact LOLE in hr/yr. The LOLE indices were evaluated by deducing the risk for each of these load levels and summing over all load levels, i.e.:

$$\text{LOLE} = \sum_{i=1}^{n} P(C < L_i) \qquad (1)$$

where $P(C < L_i)$ = probability of loss of load on day i or during hour i. This value is given directly by the capacity model.

n = 364 or 8736 as appropriate.

Using this technique, the exact LOLE indices are:

LOLE = 1.36886 day/yr using daily peak loads
LOLE = 9.39418 hr/yr using hourly loads

These two values must be considered as two fundamental indices. They can be used to compare results obtained using the DPLVC and the LDC respectively. Any deviation from these values will be due to precision (or lack of it) in the computer system.

EFFECT OF ROUNDING

If the generation model and/or load model is rounded, the values of LOLE will differ from those given in the previous section. This effect is illustrated in this section in which both the generation model and the load model have been rounded separately and concurrently.

The generation model was rounded in steps between 20 and 100 MW using conventional techniques [2]. In practice, rounding is normally done during the development of the model. However the results are then dependent on the order of adding units and how frequently rounding is performed. In order to ensure a set of consistent and reproducible results, the table was rounded after the complete capacity model was evaluated. The results then become independent of the order of adding units to the model.

The load model was rounded by first dividing the load into n equally spaced load levels. The number of days that each of these load levels is exceeded was deduced. This process created n coordinate points for the DPLVC, which was used with the capacity model to give the value of LOLE in day/yr using conventional techniques [2]. If a capacity level existed between two sets of coordinate points, interpolation was used to find the number of corresponding days.

The results are shown in Table I for the cases of rounded generation/exact load, exact generation/rounded load and rounded generation/rounded load. It is seen that, as severity of rounding is increased, the values of LOLE tend to increase. It should be noted that the 364 point rounded load model is represented by 364 equally spaced load levels which is not the same as the exact 364 individual daily peaks.

TABLE I
Effect of Rounding

Capacity Model Rounding Interval (MW)	Load Model (no. of points)	LOLE d/yr.
20	exact	1.38587
40	exact	1.37978
60	exact	1.39806
80	exact	1.37687
100	exact	1.41622
exact	10	1.74649
exact	100	1.42843
exact	200	1.38993
exact	364	1.37256
20	100	1.43919
20	200	1.39869
20	364	1.38967
40	100	1.45041
40	200	1.41514
40	364	1.39415

EFFECT OF DERATED STATES

Derated or partial output states can have a significant effect on the LOLE, particularly units of large capacity. There are various ways in which such units can be included in the analysis; the only exact way being to represent the unit by all its states and to add the unit into the capacity model as a multi-state unit. An EFOR (equivalent forced outage rate) representation is not an equivalent and gives pessimistic values of LOLE [2]. It is not normally necessary however to include more than one or possibly two derated states [2] to obtain a reasonably exact value of LOLE.

For these reasons, the 400 MW and 350 MW units of the RTS have been given a 50% derated state. The number of service hours (SH), derated hours (DH) and forced outage hours (FOH) are shown in Appendix 1 and were chosen so that the EFOR [8] of the units are identical to the FOR specified in the original RTS [6]. Using the evaluation concepts of Reference 8:

400 MW unit: SH = 1100 hr, DH = 100 hr, FOH = 100 hr, derated capacity = 200 MW

$$EH = \frac{200}{400} DH = 50 \text{ hr}$$

$$\therefore \text{EFOR} = \frac{\text{DH+EH}}{\text{SH+DH+EH}} = \frac{100+50}{1100+100+50} = 0.12$$

350 MW unit: SH = 1150 hr, DH = 60 hr, FOH = 70 hr, derated capacity = 175 MW

$$EH = \frac{175}{350} DH = 30 \text{ hr}$$

$$\text{and EFOR} = \frac{70+30}{1150+70+30} = 0.08$$

These values of state hours give the limiting state probabilities [1] shown in Table II.

TABLE II
Limiting State Probabilities

Unit	State Probability		
	Up	Derated	Down
400 MW	0.846154	0.076923	0.076923
350 MW	0.898438	0.046875	0.054687

The LOLE was evaluated using the exact generating capacity and load models i.e. no rounding, for three cases; when one 400 MW unit, when both 400 MW units and when both the 400 units and the 350 MW unit was represented by 3 states. The results are shown in Table III.

TABLE III
Effect of Derated States

Units Derated	LOLE d/yr.
1 x 400 MW	1.16124
2 x 400 MW	0.96986
2 x 400 + 1 x 350 MW	0.88258

These results show that the value of LOLE decreases significantly when derated states are modelled. This clearly demonstrates the inaccuracies that can be created if EFOR values are used, particularly for the larger units.

EFFECTS OF LOAD FORECAST UNCERTAINTY

Load forecast uncertainty was modelled using a normal distribution divided into seven discrete intervals [2]. The probabilities associated with each interval can be evaluated [1] as the area under the density function and these are shown in Appendix 1. It is suggested that a load forecast uncertainty having a standard deviation of 5% should be associated with the RTS. This is the value specified in Appendix 1. In the present analysis however, standard deviations from 2-15% have been considered. The results using the exact capacity and load models are shown in Table IV.

TABLE IV
Effect of Load Forecast Uncertainty

Uncertainty %	LOLE d/yr.
2	1.45110
5	1.91130
10	3.99763
15	9.50630

These results clearly show the very significant increase in LOLE as the degree of uncertainty is increased.

EFFECT OF SCHEDULED MAINTENANCE

There are two main aspects relating to scheduled maintenance. The first is to ascertain or deduce the schedule. The second is its effect on LOLE. The value of LOLE will increase when maintenance is considered because of the reduced and variable reserve at different times of the year.

The schedule selected is Plan 1 of Reference 9. This complies with the maintenance rate and duration of the original RTS [6], and was derived using a levelized risk criteria. The schedule is shown in Appendix 1.

The analysis proceeds by using the exact capacity model and the exact load model for each week of the year. The LOLE for each week is evaluated using Equation 1. The annual LOLE is deduced by summing all the weekly values. The details of this exercise is shown in Table V together with the overall annual LOLE. These results show that the risk is approximately doubled when this maintenance schedule is included.

EFFECT OF PEAK LOAD

One particular criticism levelled against the RTS is that the transmission system is too reliable compared with that of the generation system. This is because the generation is particularly unreliable: the LOLE is 1.36886 day/yr compared with a frequently quoted practical value of 0.1 day/yr. The reason for this high level of risk can be viewed as being due to a load level that is too great for the generating capacity or a generating capacity that is too small for the expected load.

The first of these reasons, i.e. the effect of the peak load on the LOLE, is considered in this section. Taking the RTS peak load of 2850 MW as 1 pu, a range of peak loads between 0.84 and 1.1 pu were studied. In each case, all 364 daily peak loads were multiplied by the same pu factor and the LOLE evaluated using Equation 1 and the exact capacity and load models. The results are plotted in Figure 2 and some are tabulated in Table VI. These results show that the peak load carrying capability, PLCC [2] for a risk level of 0.1 day/yr is 2483.5 MW which is 0.8714 pu of the specified [6] RTS peak load.

TABLE V
Effect of Scheduled Maintenance

Week Nos.	LOLE d/yr.
1,2,19,23-25,44-52	1.12026
3-5	0.11395
6,7	0.06801
8	0.07424
9	0.02122
10	0.04624
11	0.07223
12,13	0.04632
14	0.03701
15	0.04654
16,17	0.07203
18	0.04392
20	0.06214
21,22	0.07202
26	0.06483
27	0.02015
28	0.06718
29	0.03259
30	0.04878
31,32	0.08787
33	0.05896
34	0.02059
35	0.11809
36	0.02266
37	0.07039
38,39	0.05062
40	0.02819
41,42	0.03858
43	0.04098
Total LOLE	2.66659 d/yr.

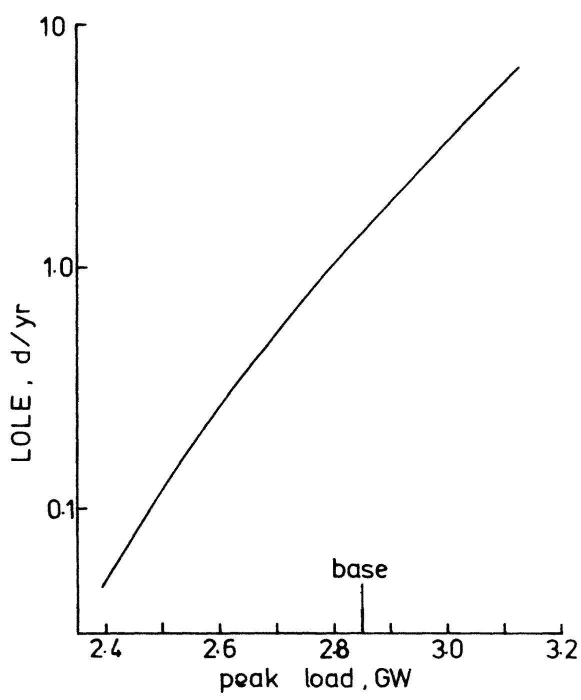

Figure 2. Effect of Peak Load

TABLE VI
Effect of Peak Load

Multiplying Factor p.u.	Peak Load MW	LOLE d/yr.
1.10	3135	6.68051
1.06	3021	3.77860
1.04	2964	2.67126
1.00	2850	1.36886
0.96	2736	0.65219
0.92	2622	0.29734
0.88	2508	0.12174
0.84	2394	0.04756

EFFECT OF ADDITIONAL GENERATION

The second reason mentioned in the previous section for the unreliable generating system can be alleviated by adding generating units to the system. This was achieved by adding a number of gas turbines each rated at 25 MW and having a FOR of 0.12.

Using the exact capacity and load models together with Equation 1 gives the results plotted in Figure 3 some of which are shown in Table VII. These results show that 15 such gas turbines are required in order to achieve a PLCC of 2850 MW with a LOLE of about 0.1 day/yr.

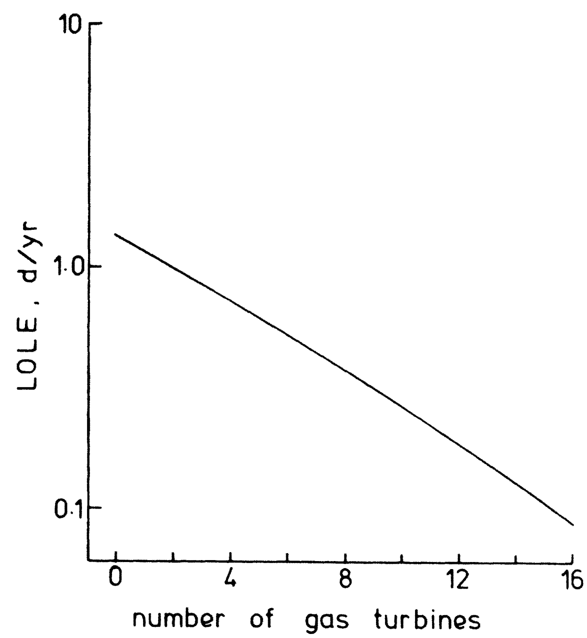

Figure 3. Effect of Added Generation

It is therefore suggested that the generating system of the RTS as originally specified [6] should be used as the base but that additional 25 MW gas turbines as specified in Appendix 1 should be included if a smaller risk index is required, e.g. in order to make transmission and generation more comparable or to achieve an LOLE that is nearer to frequently quoted practical values. In order to be consistent with the RTS and to conduct network analysis, it is necessary to specify the busbars to which additional generation must be attached. This requires a composite reliability study which is beyond the scope and objective of the present paper. This decision is, therefore, left to subsequent studies which will lead to revisions of the RTS.

TABLE VII
Effect of Adding Gas Turbines

No. of Gas Turbines	LOLE d/yr.
1	1.18298
3	0.86372
5	0.62699
8	0.38297
10	0.27035
12	0.18709
15	0.10674
16	0.08850

ENERGY BASED INDICES

The most popular generation reliability index is the Loss of Load Expectation (LOLE) as derived in the previous sections. Energy based indices are now receiving more attention particularly for systems that have energy limitations (e.g. pumped storage) or for studying replacement of thermal energy by novel forms of generation (e.g. solar, wind). It is useful therefore to evaluate relevant energy indices for the RTS, these include Loss of Energy Expectation (LOEE) and Energy Index of Reliability (EIR). An additional advantage given by energy based evaluation methods is that the energy generated by each unit can be evaluated [2]. This enables production costs to be found.

The principle used to evaluate exact values of energy not supplied in these studies was as follows. Each hourly load level is numerically equal to the energy demanded during that hour. Consequently the total energy demanded by the system is numerically given by the summation of all 8736 load levels. The energy not supplied can be found using a similar principle. For each state of the capacity model C_k, the energy not supplied E_k is given numerically by summing all positive values of (L_i-C_k) where L_i is the i-th load level and i=1 to 8736. The expected energy not supplied is then given by:

$$EENS = \sum_{k=1}^{n} E_k P_k \qquad (2)$$

where P_k = probability of capacity state C_k

and n = number of capacity states

This value of EENS can be evaluated after adding each unit into the system capacity model. Hence the expected energy produced by each unit is given [2] by the difference in EENS before and after adding the unit. The order of adding units is important and must follow the merit order. When all units have been added, the final value of EENS gives the system LOEE. Also the EIR is given by

$$EIR = 1 - LOEE/\text{energy demanded} \qquad (3)$$

Using the above principle, the expected energy produced by each unit is shown in Table VIII. The merit order was assumed to be that shown in the table. Also:

energy demanded = 15297.075 GWh

LOEE = 1.176 GWh

EIR = 0.999923

TABLE VIII
Energy Supplied by Each Unit

Merit Order	Type	Size MW	Energy Supplied GWh
1	hydro	50	432.432
2	hydro	50	432.432
3	hydro	50	432.432
4	hydro	50	432.432
5	hydro	50	432.432
6	hydro	50	432.432
7	nuclear	400	3075.072
8	nuclear	400	3067.682
9	coal 1	350	2521.737
10	coal 2	155	963.742
11	coal 2	155	833.633
12	coal 2	155	677.731
13	coal 2	155	527.295
14	coal 3	76	217.557
15	coal 3	76	186.101
16	coal 3	76	153.884
17	coal 3	76	122.912
18	oil 1	197	196.003
19	oil 1	197	96.639
20	oil 1	197	40.645
21	oil 2	100	9.859
22	oil 2	100	5.661
23	oil 2	100	3.119
24	oil 3	12	0.268
25	oil 3	12	0.248
26	oil 3	12	0.229
27	oil 3	12	0.210
28	oil 3	12	0.194
29	GT	20	0.265
30	GT	20	0.234
31	GT	20	0.205
32	GT	20	0.181

EFFECT OF INTERCONNECTION

The effect of interconnection is modelled using two identical RTS's joined with a single tie line. It is suggested that the tie line should have a rating of 300 MW, a length of 55 miles and be energized at 230 kV. The terminal busbars for the interconnections are required in order to be consistent with the RTS and to perform network studies. However, as in the case of the additional generators, this is beyond the present scope and objective and is, therefore, left to subsequent studies. Using the RTS data [6] means that the permanent outage rate is 0.477 f/yr. It is also suggested that it should have a repair rate of 364 repairs/yr (since the RTS has 364 days in its year, this repair rate is equivalent to an average repair time of one day or 24 hr). The unavailability of the tie line is therefore 0.00130873. These are the values specified in Appendix 1. In the present analysis tie line ratings from zero (no tie line) to 555 MW have been considered.

The evaluation technique used was the equivalent assisting unit approach [2]. This models the assisting system by a single multi-state unit which is moved through the tie line and added to the capacity model of the assisted system. The LOLE for the assisted system can then be found using Equation 1. No rounding was performed in the analysis and therefore exact models were used for the equivalent assisting unit and the capacity model of the assisted system. The results are, therefore, exact for the conditions stated below.

It was assumed that the assisting system would share its reserves but would not share the deficiencies of the assisted system. Consequently, the effective capacity of the equivalent assisting unit is equal to the reserve in the assisting system or the capacity of the tie line, whichever is smaller.

Two sensitivity analyses were performed. The first considered a single day only when the peak loads in each system were 2850 MW (the maximum value). The maximum reserve of the assisting system is therefore 555 MW.

The second analysis used the maximum peak load reserve approach [2]. This assumed that the load in the assisting system remained constant at 2850 MW whilst that in the assisted system was represented by the 364 daily peak loads. The equivalent assisting unit therefore remained a constant for a given tie line capacity.

The results for both analyses, assuming the tie line can and cannot fail, are shown in Table IX. It is seen that the values of LOLE decrease as the tie line capacity is increased to 555 MW above which no further change occurs. This is because no further benefit can be achieved from the assisting system. It is also seen that the effect of tie line reliability is very small; an effect often observed in practice.

TABLE IX
Effect of Interconnection

Tie Capacity MW	LOLE Tie Does Not Fail	LOLE Tie Can Fail
a) single peak load of 2850 MW (LOLE in day/day)		
0	0.08458	-
100	0.07007	0.07009
200	0.05928	0.05931
300	0.04483	0.04488
400	0.03578	0.03584
500	0.02477	0.02485
555	0.02104	0.02112
600	0.02104	0.02112
b) complete load model in assisted system (LOLE in day/yr)		
0	1.36886	-
100	1.09762	1.09798
200	0.85594	0.85661
300	0.64707	0.64802
400	0.51094	0.51206
500	0.34434	0.34571
550	0.27404	0.27547
600	0.27404	0.27547

CONCLUSIONS

This paper has extended the data and available information relating to the IEEE Reliability Test System. In so doing, it increases the value of the RTS in two important respects.

The first is that an increased range of data is now available. This will enable users of the RTS to employ a consistent set of data even with extended techniques and ensure that comparison of results is much easier.

The second is that generically exact indices for a wide range of conditions have been evaluated. These will enable the results from alternative and approximate methods to be compared since the indices quoted should be reproducible within the precision limitations of the computers used.

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APPENDIX 1

ADDITIONAL DATA TO BE USED WITH THE RTS

Generating System

TABLE X
Generating Unit Derated State Data

Unit Size MW	Derated Capacity MW	SH(1) hr	DH(2) hr	FOH(3) hr	EFOR (4)
350	175	1150	60	70	0.08
400	200	1100	100	100	0.12

Notes: (1) SH = service hours
(2) DH = derated state hours
(3) FOH = forced outage hours
(4) EFOR = equivalent forced outage rate

See Reference [8] for more detail of these terms.

TABLE XI
Maintenance Schedule

Weeks	Units on Maintenance			
1,2	none			
3-5	76			
6,7	155			
8	197	155		
9	197	155	20	12
10	400	197	20	12
11	400	197	155	
12,13	400	155	20	20
14	400	155		
15	400	197	76	
16,17	197	76	50	
18	197			
19	none			
20	100			
21,22	100	50		
23-25	none			
26	155	12		
27	155	100	50	12
28	155	100	50	
29	155	100		
30	76			
31,32	350	76	50	
33	350	20	12	
34	350	76	20	12
35	400	350	76	
36	400	155	76	
37	400	155		
38,39	400	155	50	12
40	400	197		
41,42	197	100	50	12
43	197	100		
44-52	none			

Additional Generating Units

These additional gas turbines can be used with the RTS in order to reduce the LOLE of the system to a level frequently considered acceptable.

TABLE XII
Additional Gas Turbines

Unit Size MW	Forced Outage Rate	MTTF hr	MTTR hr
25	0.12	550	75

All other data may be assumed to be identical to the existing gas turbines of the RTS.

Load Forecast Uncertainty

The load levels are assumed to be forecasted with an uncertainty represented by a normal distribution having a standard deviation of 5%. This is equivalent to a load difference of 142.5 MW at the peak load of 2850 MW. Using a load model having 7 discrete intervals, the discretised peak loads are shown in Table XIII.

TABLE XIII
Data For Load Forecast Uncertainty

Std. Deviations from Mean	Load Level MW	Probability
-3	2422.5	0.006
-2	2565.0	0.061
-1	2707.5	0.242
0	2850.0	0.382
+1	2992.5	0.242
+2	3135.0	0.061
+3	3277.5	0.006
		1.000

Tie Line

The information shown in Table XIV should be used to connect two identical RTS.

TABLE XIV
Tie Line Data

Voltage kV	Rating MW	Length Miles	Permanent Outage Rate f/yr	Outage Duration hr	Unavailability
230	300	55	0.477	24	0.00130873

APPENDIX 2

SUMMARY OF RTS RESULTS

The following results were evaluated using the exact capacity and load models together with Equations 1, 2 and 3 as appropriate. They can therefore be considered exact and can be used to compare the results of approximate methods.

The details of each "case" can be found in the appropriate section of the main text.

LOLE Indices

base (as per RTS [6])	1.36886 day/yr [9.39418 hr/yr]
with derated states	0.88258 day/yr
with 5% load forecast uncertainty	1.91130 day/yr
with maintenance	2.66659 day/yr
with 15 x 25 MW gas turbines	0.10674 day/yr
with interconnection	0.64802 day/yr

Energy Indices for Base System

LOEE	1.176 GWh
EIR	0.999923