GENERATION RESERVE OPTIMISATION MODEL INCORPORATING DEMAND MARKET PARTICIPATION

By

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SUMMARY

Title: Generation reserve optimisation model incorporating Demand Market Participation
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The basic function of a power system is to supply customers, both large and small, with electrical energy as economically as possible and with an accepted degree of reliability and quality. The objective of this study is to determine the optimal operating reserve to be scheduled by the national control room for the South African supply industry on a day-ahead basis. The different methods used to determine the optimal reserve was studied. Comparisons were made and the best method was identified. The South African reserve market was studied and a model was constructed using the reliability cost-worth method to determine the optimal operating reserve. The reserve market included thermal generation, pumped storage, demand market participation (DMP) and interruptible load (IL). The DMP and IL customers were modelled as dummy generators and the cost to supply reserve by the utility is compared to the cost of unserved energy to the economy. The total minimal cost to the economy and utility is used as the optimal reserve level. The contribution to this field of study is to:

- Determine the optimal operating reserve level for the South African supply industry;
- Model DMP and IL customers as dummy generators; and
- Include DMP and IL in the reserve optimisation using the reliability cost-worth method.

Keywords: Reserve optimisation, Reliability cost-worth method, Demand Market Participation. Interruptible Load and Dummy generator.

OPSOMMING

Titel: Generation reserve optimisation model incorporating Demand Market Participation
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Die basiese funksie van 'n kragstelsel is om elektriese energie aan die verbruikers te verskaf so goedkoop as moontlik en met 'n aanvaarbare betroubaarheidvlak en kwaliteit. Die doel van die studie is om die optimale reserwe vir die Suid Afrikaanse elektrisiteits bedryf te bepaal. Verskillende metodes was bestudeer en die beste metode vir die Suid Afrikaanse reserwe mark gekies. Die betroubare koste-waarde metode is gebruik om 'n model te bou vir die Suid Afrikaanse reserwe mark. Die reserwe mark bevat thermiese generasie, gestoorde-hidro generasie, aanvraag mark deelname en afgooibare las. Die twee laas genoemde verbruikers word gemoddeleer as fiktiewe generators en in die betroubare koste-waarde metode gebruik om die optimale reserwe te bepaal. Die koste om ekstra reserwe beskikbaar te stel word afgespeel teen die koste om die reserwe nie beskikbaar te he nie. Die totale koste word gebruik om die optimale reserwe te bepaal. Die bydra tot die studieveld is:

- Om die optimale reserwe te bepaal vir die Suid Afrikaanse elektrisiteits bedryfs;
- Die aanvraag mark deelname en afgooibare las kliente te modelleer as fiktiewe generators; en
- Hulle in die model in te sluit wanneer die optimale reserwe bepaal word met behulp van die betroubare koste-waarde metode.

Kernwoorde: Optimale reserwe, betroubare koste-waarde metode, die aanvraag mark deelname, afgooibare las en fiktiewe generators.

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LIST OF ABBREVIATIONS

ACE – Area Control Error
AGC – Automatic Governor Control
CAISO – California ISO
COPT – Capacity outage probability table
DCS1 – Disturbance Control Standard
DMP – Demand market participation
DPLVC – Daily peak load variation curve
DSM – Demand side management
EENS – Expected energy not supplied
EIR – Energy index of reliability
F.C. – Fixed cost
F&D – Frequency and Duration
FOR – Forced outage rate
GROM – Generation Reserve Optimisation Model
GUI – Graphical User Interface
GUIDE – Graphical User Interface Development Environment
HLI – Hierarchical level I
HLII – Hierarchical level II
HVDC – High Voltage Direct Current
IEAR - Interruptible energy assessment rate
IL – Interruptible load
JIT – Just in time
LDC – Load duration curve
LOLE – Loss of Load Expected
LOEE – Loss of Expected Energy
LOLH – Loss of load hours
LOLP – Loss of Load Probability
MCR – Maximum capacity rating
MW – Mega Watt
MWh – Mega Watt hour
NERC – North American Electric Reliability Council

NYPP	–	New York Power Pool
ORR	–	Outage Replacement Rate
RTP	–	Real time pricing
SAPP	–	Southern African Power Pool
SMP	–	System Marginal Price
TOU	–	Time of use
UE	–	Unserved energy
V.C	–	Variable cost

CHAPTER 1

INTRODUCTION

1.1 Back ground and introduction

The basic function of a power system is to supply customers with electrical energy as economically as possible and with an acceptable degree of reliability and quality. Power system reliability is defined as the overall probability of a power system to perform its function [1]. Reliability is made up of power system security and power system adequacy. This is represented in Figure 1. Security is the ability of the power system to respond to disturbances arising within the system. Adequacy is the existence of sufficient facilities within the power system to satisfy the customer's load demand or the system's operational constraints.

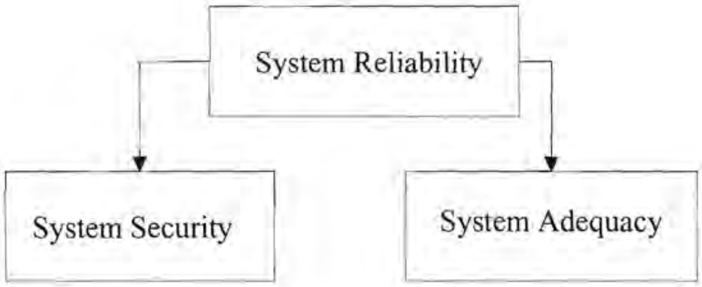


Figure 1: Subdivision of system reliability.

The following two techniques are used to determine the reliability of a power system:

- Deterministic technique,
- Probabilistic technique,

Deterministic techniques are more widely used in power systems. Following a major contingency, the power system will still satisfy the minimum operational conditions. Deterministic techniques cater for the loss of the largest generation plant on the system or they schedule reserve to between 4% to 8% of the maximum expected peak load.

These techniques do not take into consideration the possibility of losing the largest unit or the possibility of losing 4% to 8% of the expected peak load's generating capacity.

Probabilistic techniques evaluate the severity of a capacity outage state or an event and its impact on the system behaviour and operation. These methods also take the probability of the occurrence of capacity outages into account.

Most of the probabilistic techniques available for reliability assessment are in the adequacy domain. Probabilistic load flow and probabilistic transient stability are categorised in the adequacy domain together with the techniques for quantifying unit commitment and response risk. The ability to access security is limited. The indices collected as part of a fault reporting scheme include all system faults and failures irrespective of cause and therefore include the effects of insecurity as well as those due to inadequacy.

The basic techniques for adequacy assessment can be categorised in terms of their application to segments of the complete power system [1]. Figure 2 shows the different segments of a complete power system. Figure 3 shows how these segments are combined to form the different hierarchical levels which are to be used in the adequacy assessment. Hierarchical Level I (HLI) is only concerned with the generation facilities; Hierarchical Level II (HLII) includes generation and transmission facilities and Hierarchical Level III includes all three functional zones in an assessment of consumer load point adequacy.

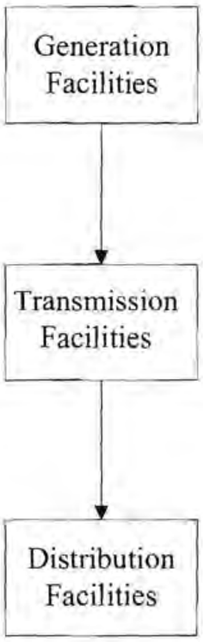


Figure 2: Basic functional zones.

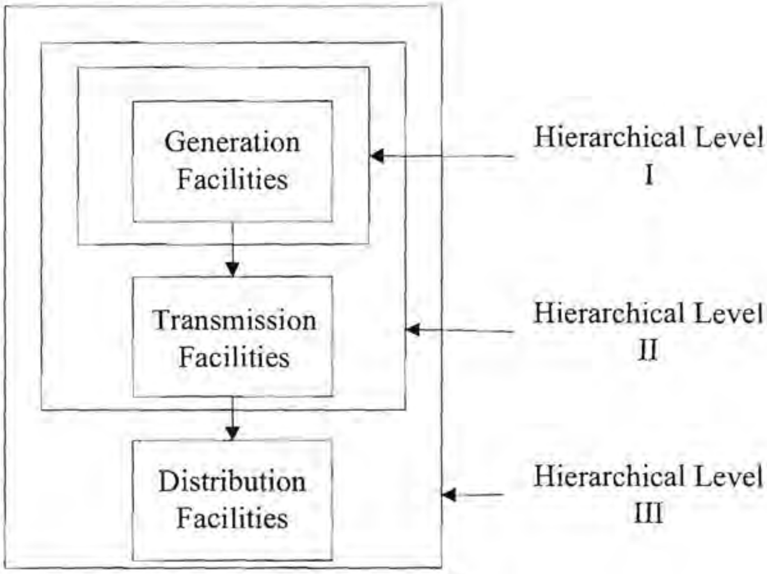


Figure 3: Hierarchical levels.

1.2 Adequacy evaluation

For HLI studies, the total system generation is examined to determine its ability to meet the total system load requirement. The transmission system and its ability to move power to the consumer load point are ignored [1]. The main objective of this study is to determine the necessary capacity to satisfy load demand. Another objective is to perform preventive and corrective maintenance on the network. The deterministic methods used to assess the adequacy of the power system is the percentage load method.

Reserve is the amount of generating plant scheduled in excess of the expected load. The reserve is equal to the loss of the largest unit. The percentage method sets the reserve equal to a percentage of the peak load forecast. This is usually 4% to 8% of the maximum peak load demand. These deterministic techniques are being replaced by probabilistic methods. The Loss of Load Expected (LOLE) or Loss of Expected Energy (LOEE) and Frequency and Duration (F&D) are commonly used risk indices which determine the condition of a power system. The LOLE determines the number of days or hours in which the load is expected to exceed the installed generating capacity. This method only provides the number of occurrences of which the load will exceed the installed capacity. It does not show the severity and duration of the energy not supplied. The LOEE is the Expected Energy Not Supplied (EENS) to the load. This method shows the severity as well as the duration of the energy not supplied to the consumer. It also shows that a power system is an energy supply system and can be used to compare it with, for example alternative energy sources. The energy supplied by the power system divided by the total energy demand gives the Energy Index of Reliability (EIR). The EIR is used to compare the adequacy of power systems that differs in size. The F&D method is an extension of the LOLE method. It determines the number of times that the expected load will exceed the installed generating capacity. It also determines the expected duration of the deficiency.

The indices described are calculated using direct analytical techniques. Monte Carlo simulation is sometimes used [1]. The analytical techniques represent the system with a mathematical model and evaluates the indices from the model using mathematical solutions. The Monte Carlo simulation method estimates the reliability indices by simulating the actual process and the random behaviour of the system. It treats the problem as a series of real experiments. The Monte Carlo simulation usually requires a large amount of computing time and is seldom used if analytical methods are available.

The modelling approach for an HLI study is given in Figure 4 [1]. The generation model or capacity model is formed by constructing a capacity outage probability table. This table represents the capacity outage states of the generating system together with the probability of each occurring state. The load model can be represented by either the Daily Peak Load Variation Curve (DPLVC) or by the Load Duration Curve (LDC). The DPLVC is the peak loads for each day of the study period and the LDC shows the hourly variation in load forecast for the day. The DPLVC is used to evaluate the LOLE indices and the LDC is used to evaluate the indices of the LDC.

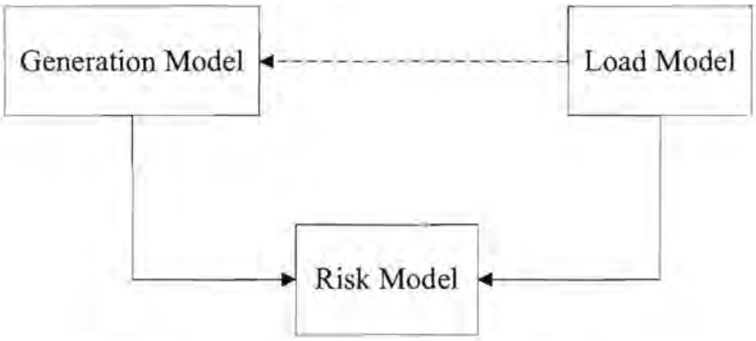


Figure 4: Conceptual tasks for HL I evaluation.

To be able to determine the optimal reserve, the reliability of the power system needs to be assessed.

1.3 Research questions and objectives

The objective of the research is to establish the best method with which to determine the reserve level for the South African supply industry. The following research questions have to be answered for the research objective to be achieved.

1 What are the different reserve optimisation techniques that are used internationally?
2 What is the optimal technique for the South African energy market?
3 Can Demand Market Participation (DMP) and Interruptible Load (IL) be incorporated into the optimal model identified?
4 How is the model validated?
5 Can the model be optimised for improved simulation time and ease of use?

Questions one and two have been answered in chapter two, by comparing the different techniques used to determine the reserve for the different utilities. It can be seen from this chapter that the optimisation techniques can be divided into two groups: deterministic and probabilistic techniques. Deterministic techniques do not take into consideration the reliability of the units used to schedule reserve as with probabilistic techniques. Therefore in order to more accurately determine the optimal reserve for the South African supply industry it would be better to use a probabilistic technique. In chapter three the South African energy market is presented and it is seen that the market comprises of DMP and IL customers. The reserve optimisation techniques studied in chapter two does not include DMP and IL customers, therefore a new model had to be developed to include DMP and IL customers. Question three is answered in chapter three, where it can be seen that a new model is presented that incorporates DMP and IL customers. The fourth question is answered in chapter four where the model is validated by comparing the model to two other models and it can be seen that the optimal reserve determined for the three different models are approximately the same. In chapters five and six the different methods used to optimise the new model are presented. A Graphical User Interface (GUI) was developed to improve the ease of program use. Please refer to chapter six and addendum A3 for more information.

1.4 Original contribution

The study identifies different methods used to determine the optimal generator reserve. It includes an analysis of the reserve market implemented in South Africa. This market is very unique in terms of the mix of generation, DMP and IL used. The contribution to this field of study is that a reserve optimisation model was developed specifically for the South African energy market. This model expanded the reliability cost-worth method to include DMP and IL customers. These customers are modelled as dummy generators each with a forced outage rate, available capacity as well as fixed and variable costs all of which are included in the reliability cost-worth method. The application of this model is not limited to the South African system, but can also be applied to any power system which does not have enough installed capacity to perform routine maintenance and supply the load demand. By introducing DMP in the form of IL, generation capacity is made available when no excess capacity is available or when the cost of energy is high.

1.5 Outline of the thesis

This thesis is broadly organised as follows: chapter one serves as an introduction and explains that power system adequacy determines whether sufficient facilities within the power system exists to satisfy customer load demand or system operational constraints. Chapter two focuses on the different techniques used by other utilities to determine the reserve and identify what research has been done in this field of study. In chapter three current the South African energy market is presented and a model is presented that incorporates DMP and IL customers. This model is theoretically tested in chapter three. In chapter four this model is validated and compared to two other models presented in [3] and [7]. In chapter five different techniques are used to reduce the execution time of the model. In the second part of the chapter a sensitivity analysis is carried out to determine how sensitive the model is to a change in the capacity step size, the Forced Outage Rate (FOR) and the Interruptible Energy Assessment Rate (IEAR). The third part of chapter five compares this model to the model previously used by Eskom (Electricity Supply Commission). A GUI was developed to increase the ease of use. The GUI is presented in chapter six and supplemented in addendum A3. The thesis is concluded in chapter seven, where the contribution to the field of research is discussed and future research is identified.

CHAPTER 2

METHODS FOR DETERMINING THE OPTIMAL GENERATOR RESERVE

2.1 Reserve levels used by different utilities

In [2] a study was undertaken to determine how the reserve levels are calculated by different utilities. The aim of this study is to determine whether the reserve levels as implemented by Eskom are in line with the reserve levels implemented by other utilities. The aim of this study is also to determine whether the principles adopted to determine the reserve levels are similar. The definitions for spinning reserve and operating reserve are similar for most utilities. The North American Electric Reliability Council (NERC) defines operating and spinning reserve as:

- Operating reserve is a plant (on- or off-line) available within 10 minutes to be connected to the grid, and
- Spinning reserve is an unloaded synchronised plant also available within 10 minutes to be connected to the grid.

NERC uses 10 minutes to achieve the NERC Disturbance Control Standard (DCS1) criterion of returning the Area Control Error (ACE) to zero within 10 minutes. Other countries' utilities and pools were also examined, but few reserve levels were found. Most utilities outside the United States of America (USA) do not use the term "operating and spinning reserve".

2.1.1 Eskom

Since mid 1999, the optimum operating reserve has been calculated on a daily basis by Eskom to minimise the cost of carrying reserve in addition to the cost of emergency resource usage and unmet demand. The spinning reserve target of 716 MW is based on a deterministic calculation of instantaneous reserve to meet a trip, less 390 MW, plus a regulating reserve of 600 MW. The Eskom target meets the requirements for the Southern African Power Pool (SAPP).

The new reserve market was introduced in 2001. The definitions for reserve have since changed. Spinning reserve was replaced by instantaneous and regulating reserve targets while operating reserve was replaced by the 10 minute and supplementary reserves.

2.1.2 SAPP

In 1996 operating guidelines were developed for the SAPP. It was decided to follow the method as used by the NERC regional council for the Mid Continent Area Power Pool (MAPP). The pool target operating reserve was 150% of the largest generating unit in the SAPP, with Koeberg at 920 MW. The spinning reserve was 50% of the operating reserve. Reserve was spread amongst the utilities based on a one third weighting of the largest unit and two thirds of the annual peak load.

2.1.3 New York Power Pool (NYPP)

For the NYPP the operating reserve consists of a spinning reserve and a non-spinning 10 and 30 minute reserve. Spinning reserve consists of the unloaded capacity of synchronised units. The operating reserve requirement is 150% of the largest contingency, that is 1800 MW. This is approximately 6% of the peak load of 30 GW. Spinning reserve of 600 MW is approximately one third of the operating reserve.

2.1.4 California Independent System Operator (CAISO)

For CAISO the operating reserve is comprised of spinning reserve and non-spinning reserve, both available in 10 minutes. Spinning reserve is defined as unloaded on-line generation. The requirement for operating reserve for CAISO is the maximum of the largest contingency or the sum of 5% hydro generation load and 7% thermal generation load. If CAISO is 50% thermal then the average is 6% of the peak of 45 GW. Spinning reserve is a half of the operating reserve.

2.1.5 PJM Pool

For this utility, the operating reserve is spinning plus supplemental reserve. Spinning reserve is defined as the on-line generation units that are loaded below the maximum capacity. It is available immediately. Supplemental reserve is quick to start plant and interruptible load. The required quantity of reserve is not given.

2.1.6 MAIN

This is both a NERC tool and a power pool. The operating reserve is defined as the spinning and non-spinning reserve and is available in 10 minutes. For MAIN the operating reserve target is 100% of the largest unit, that is 1 230 MW. Spinning reserve is a half of the operating reserve.

2.1.7 Ontario Hydro (Canada)

This utility has both a 10 minute and a 30 minute operating reserve. The regulation reserve is a synchronised plant that is available in 10 minutes. The 10 minute reserve is a 100% of the largest contingency. The 30 minute operating reserve is 50% of the second largest contingency. Spinning reserve is also called regulation reserve.

2.1.8 England and Wales (National Grid Co.)

This utility refers to operating and spinning reserve as scheduled as well as standing and contingency reserve. Scheduled reserve is similar to spinning reserve that is the sum of partly loaded generation plant and interconnections.

Standing reserve is hydro, pump storage plant, gas turbine and demand modification. It is available in 20 minutes. Contingency reserve is the off-line plant that is hot standby and it is available to replace standing and scheduled reserve that have been used. The amount of each of these contracted by the market is not known.

2.1.9 NORDEL (Scandinavian Pool)

This utility has three reserve categories: instantaneous (or frequency control) reserve, kept on spinning units (and available within 30 seconds), instantaneous disturbance reserve and interruptible load. The instantaneous reserve is 600 MW. This reserve is replaced by an instantaneous disturbance reserve which uses on- or off-line hydro plus emergency power over the High Voltage Direct Current (HVDC) connection. If no reserve is available then load is interrupted. The required reserve is calculated based on the largest unit connected to the system, for example 1 200 MW minus 200 MW, a fixed value, to give 1 000 MW reserve.

2.1.10 Australia and New Zealand

It is difficult to compare the reserve levels used by the utilities presented in this section to the reserve levels used by the Australian and New Zealand utilities. The Australian and New Zealand utilities refer to the reserve levels as "frequency control services". The "frequency control services" use various time frames, which makes it difficult to compare to the terms operating and spinning reserve.

2.2 Overview of the current literature

This literature review presents the research done to date on reserve optimisation techniques. This section presents the contribution to the body of knowledge for each research paper. In table 36 a table will be found that compares [4-10] i.t.o.

- the reserve optimisation method used.
- the indices used in calculating the optimal reserve.
- the limitations of the method.
- the advantages and disadvantages of the method.
- the different plant considered.
- the assumptions made by the method, and
- the result obtained.

It is proposed that a power system must operate at an acceptable level of risk while maintaining the economic benefits associated with it in [1]. A method for scheduling generation in order to meet a given risk index was proposed in [3]. The optimal value of the risk index was found by comparing the cost of carrying the reserve with the expected cost of not serving the reserve. This method does not consider the reliability of the individual generating units and therefore a large unreliable unit will increase the reserve requirement. Consequently it is better to reduce the loading on the unreliable units. A method was proposed that considers the reliability of each generating unit and as a result a market for reserve was proposed in [4]. In this market discreet decisions are made to select a unit to provide reserve. A penalty is paid if a unit is curtailed, causing generating companies to provide accurate Forced Outage Probabilities (FOP). The FOP is used to schedule the generating units. The cost of dispatching a system while providing reserve to cover each of the largest units was calculated and presented in [5]. If the cost of reserve for a particular unit exceeded the cost of load shedding, reserve would not be provided for that unit.

The balance between reserve and reliability cost is addressed in [6]. The variation in system marginal price over the scheduling period was not considered. A model for an operating reserve market is proposed to determine the optimal reserve capacity and simultaneously clear the operating reserve market in [7]. A method to deal with the combined problem of achieving economic operation, spin reserve and load shedding is presented in [8]. This is used to determine the critical compensation for the system and minimise the composed cost of the compensation.

A hybrid spin reserve allocation method, based on the Risk-Based Spin Reserve Allocation Method (RBSRAM) and the Cost-Based Spin Reserve Allocation Method (CBSRAM), is proposed to minimise total system cost in [9]. A new method is proposed to allocate and optimally price spin reserve in a power system in [10]. A modified security constrained economic dispatch is formulated, available reserve is optimally allocated to participants and the effect of reserve allocation on generation scheduling and locational pricing is analyzed. A method is developed for calculating the optimum reserve level for day-ahead scheduling in [11]. A minimum cost philosophy is used to calculate the optimum reserve for the utility. This method was used at Eskom on a daily basis for two years (1999 and 2000). After the reserve market was implemented at Eskom in January 2001, it was found to be more practical to maintain a fixed reserve requirement for each reserve category throughout the year.

The overall operating reserve requirement for the year is still calculated using the method presented in Addendum A2. The detailed specifications for the reserve optimisation program in [11] are presented in [12].

2.3 Comparing the reliability cost/reliability worth method

The methods proposed in [1], [3] and [11] are different applications of the reliability cost/reliability worth method to determine the adequacy of a power system. Table 37 in addendum A1 contains a comparison of these methods.

2.4 Unit Commitment (UC)

The unit commitment problem is a problem of scheduling the generation units which are to be operated and the output power of the units during a specified time period [13]. The generating units should meet the demand for electricity at each point in time and at the lowest total production cost without violating technical constraints. The unit commitment problem must be modelled in some mathematical form in order to be solved. The modelling of the unit commitment problem typically covers a 24 or 48 hour time span with one hour steps. Various numerical optimisation techniques have been employed to address UC problems. Specifically, there are methods like priority list [14]-[15], integer programming [16]-[17], dynamic programming [18]-[23], mixed-integer programming [24], branch-and-bound [25], and Lagrangian relaxation [26]-[27]. Apart from the methods listed, there are other classes of numerical techniques that can be applied to the UC problem. Specifically, there are artificially neural networks [28]-[29], Simulated Annealing (SA) [30] and Genetic Algorithms (GAs) [31-34]. These methods have claimed to accommodate more complicated constraints and present an improved solution.

The global requirements of the unit commitment problem are:

1. the system needs,
2. generation unit capabilities,
3. generation unit constraints, and
4. the costs to be minimised.

The system needs are:

1. electricity demand (to be satisfied at each time step);
2. the operating reserve (to meet generation mismatch or loss of unit during a contingency);
3. emission constraints; and
4. heat demand (in case of cogeneration).

The generation unit capabilities and constraints include:

- fuel consumption,
- efficiency,
- maximum ramping rates, and
- minimum up and down time.

Costs that are to be minimised are fuel costs for thermal units and the value (implicit cost) of water discharged from reservoirs.

The optimal reserve as determined by the proposed method in the next chapter will be used in the unit commitment problem to optimally schedule the generating units. Unit commitment is a complex problem which cannot be solved by elementary optimisation methods like linear programming or dynamic programming. This problem is solved within complex processes by which the problem is replaced by a sequence of simpler problems (each one being solved by an elementary method). These complex solution processes are called high-level methods. The elementary methods are basic building blocks of high-level methods. A comparison of the elementary methods is given in Table 38 and a comparison of the high level methods is given in Table 39.

2.5 Concluding remarks

The aim of the first part of this chapter was to identify the how reserve of the different utilities and power pools are determined and how the reserve is defined. It is evident that most of the utilities use deterministic techniques to calculate the amount of reserve that is to be scheduled. A literature review was undertaken and the different probabilistic methods which are used to determine the optimal reserve were studied.

All the identified methods use reliability and risk indicators to determine the optimal reserve. The reliability cost/worth method is used by [1],[3] and [11] in order to determine reserve. A comparison between the references were made and the reliability cost/worth method was identified as the best method to be used to determine the optimal reserve for the South African electricity supply industry.

The focus of the next chapter is to determine how the reliability cost/worth method can be applied to the South African reserve market.

CHAPTER 3

THE GENERATOR RESERVE OPTIMISATION MODEL

The basic techniques for adequacy assessment can be categorised in terms of their application to segments of the complete power system [1]. Figure 2 shows the different segments of a power system, while Figure 3 shows how these segments are combined to form the different hierarchical levels that are to be used in the adequacy assessment. HLI is concerned only with the generation facilities, while HLII includes generation and transmission facilities and HLIII includes all three functional zones in an assessment of consumer load point adequacy.

The models presented in this chapter assess the adequacy of a given generation configuration and determines the optimal generation or operating reserve for that system using the reliability cost/worth method.

There is a wide range of techniques available and in use for assessing the adequacy of a generation system. The most popular technique is the Loss of Load Expectation (LOLE) approach in which the system's inadequacy is given in either days per year or hours per year [1].

The basic approach to evaluating the adequacy of a particular generation system is fundamentally the same. The approach consists of the following three parts:

- the generation model
- the load model
- the risk model

The generation and load models as shown in Figure 5 are combined to form an appropriate risk model. The indices calculated do not normally include transmission constraints or transmission reliabilities. A conventional model is shown in Figure 6.

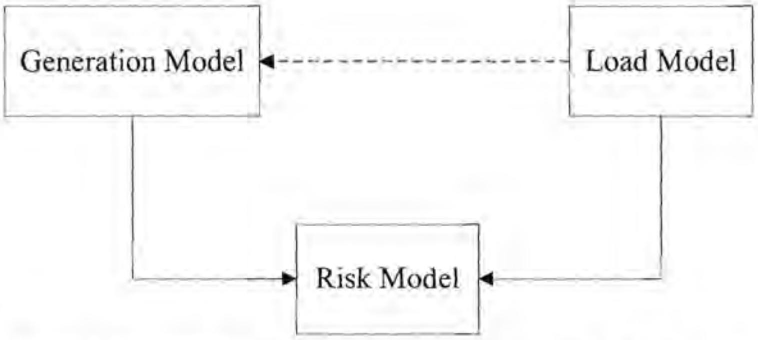


Figure 5: Conceptual tasks in generating capacity reliability evaluation

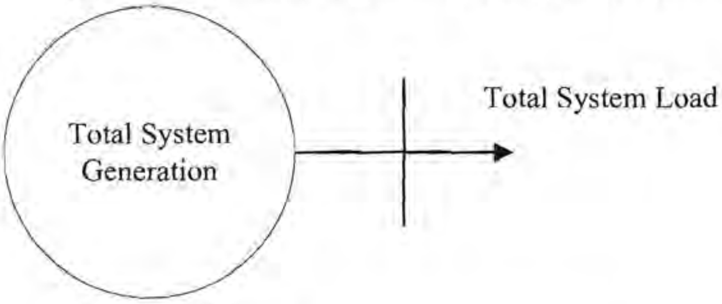


Figure 6: The conventional system model

The basic generating unit parameter used in the static capacity evaluation is the probability of finding a unit on forced outage at some time in the future. This probability is defined as the unit's unavailability or the unit's forced outage rate FOR.

Unavailability (FOR)

$$\begin{aligned} FOR &= \frac{\lambda}{\lambda+\mu} \\ &= \frac{\sum(down\_time)}{\sum(down\_time)+\sum(up\_time)} \end{aligned} \tag{3.1}$$

Availability (A)

$$\begin{aligned} A &= \frac{\mu}{\lambda+\mu} \\ &= \frac{\sum(up\_time)}{\sum(down\_time)+\sum(up\_time)} \end{aligned} \tag{3.2}$$

where, λ = expected failure rate and μ = expected repair rate.

Availability and unavailability are associated with a simple two-state model as shown in Figure 7. This model is applicable to a generating unit, which is either operating or forced out of service. Other methods can be used to model generating units in its de-rated capacity states.

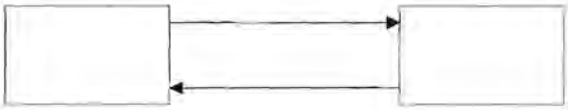


Figure 7: The basic two-state model.

3.1 The Generating Capacity Model

The generation model required in the loss-of-load approach is known as a Capacity Outage Probability Table (COPT). COPT is a simple array of the possible capacity states and the probability of that state occurring. If all the units in the system are identical, COPT can be obtained using the binominal distribution. In practice it is very unlikely that all the units will be identical and therefore the binominal distribution is very limited in its application. The units can be combined using basic probability concepts and this approach can be extended to a simple but powerful recursive technique in which units are added sequentially to produce the final model. These concepts are illustrated by a simple numerical example. The test system is shown in Table 1.

Table 1: The three-unit test system.

Unit (MW)	FOR (failures/year)
3	0.02
3	0.02
5	0.02

The test system consists of two 3 MW units and one 5 MW unit. A FOR of 0.02 is used. The two 3 MW units can be combined to give the COPT in Table 2.

Table 2: The COPT for the two 3 MW-units.

Capacity out of service		Probability
0 MW	(0.98)(0.98)	0.9604
3 MW	2(098)(0.02)	0.0392
6 MW	(0.02)(0.02)	0.0004
		1.0000

The 5 MW units can be added to this table considering that it exists in two states. It can be in service with a probability of 1 – 0.02 = 0.98 or it can be out of service with a probability of 0.02. Table 2 is extended to include the 5 MW unit in service in Table 3 and in Table 4 the 5 MW units are out of service.

Table 3: The COPT for the 5 MW unit in service.

Capacity out		**Probability**
0 + 0 = 0 MW	(0.9604)(0.98)	0.941192
3 + 0 = 3 MW	(0.0392)(0.98)	0.038416
6 + 0 = 6 MW	(0.0004)(0.98)	0.000392
		0.98

Table 4: The COPT for the 5 MW unit out of service.

Capacity out		**Probability**
0 + 5 = 5 MW	(0.9604)(0.02)	0.019208
3 + 5 = 8 MW	(0.0392)(0.02)	0.000784
6 + 5 = 11 MW	(0.0004)(0.02)	0.000008
		0.02

Tables 3 and 4 can be combined and re-ordered to construct Table 5. The probability value in this Table is the probability of finding a quantity of capacity on outage equal to or greater than the indicated amount. The cumulative probability value decreases as the capacity outage increases.

Table 5: The capacity outage probability table for the three units system.

Capacity out of service	**Individual probability**	**Cumulative probability**
0 MW	0.941192	1
3 MW	0.038416	0.058808
5 MW	0.019208	0.020392
6 MW	0.000392	0.001184
8 MW	0.000784	0.000792
11 MW	0.000008	0.000008
	1.000000	

In a practical system, the probability of having a large quantity of capacity forced out of service is usually quite small because the condition requires the outage of several units.

The capacity model can be created by using the simple algorithm as shown in (3.3).

$$P(X) = (1-U)P'(X) + (U)P'(X-C) \tag{3.3}$$

The cumulative probability of a particular capacity outage state of *X* MW after a unit of capacity *C* MW and forced outage rate *U* is given by (3.3). *P'(X)* and *P(X)* are the cumulative probabilities of the capacity outage state of *X* MW before and after the unit is added. The equation is initialised by setting *P'(X)* = 1.0 for X < 0 and *P'(X)* = 0 otherwise.

3.2 Loss of load indices

3.2.1 Loss of Load Expected (LOLE)

The illustrated generation system model can be convolved with an appropriate load model to produce a system risk index. There are a number of possible load models that can be used, and consequently a number of risk indices can be produced [1]. The simplest load model that can be used represents each day's peak load and the year's daily peak loads. They are arranged in a descending order. This is known as the Daily Peak Load Variation Curve (DPLVC). The individual daily peak loads can be used in conjunction with the COPT to obtain the expected number of days in the specified period in which the daily peak load will exceed the available capacity. The index in this case is designated as LOLE it is also known as the Loss of Load Probability (LOLP) as given in (3.4).

$$LOLP = \sum_{i=1}^{n} P_i(C_i - L_i) \tag{3.4}$$

Where C_i = available capacity on day *i*,

L_i = Forecast peak load on day *i*,

$P_i(C_i - L_i)$ = Probability of loss-of-load on day *i*.

Therefore the LOLE or LOLP can be calculated by the summation of the probabilities for each day *i* where the peak load is expected to exceed the available capacity. This probability is given in COPT. The Load Duration Curve (LDC) can be used to determine the LOLE or LOLP for each hour. Therefore *i* in (3.4) is the load hour and not the peak load for the day. The LDC is the expected load for each hour. It is arranged in descending order from the peak load hour for the day to the lowest load hour.

3.2.2 Loss of Expected Energy (LOEE)

The LOLE approach utilizes the daily peak load variation curve or the individual peak loads to calculate the expected number of days the peak load will exceed the available capacity. The LOLE index can also be calculated using the LDC or the individual hourly values. The area under the LDC represents the energy requirement for the specified time interval and can be used to calculate the Expected Energy Not Supplied (EENS) due to insufficient installed capacity. The probabilities of having varying amounts of capacity unavailable are combined with the system load as shown in Figure 8. These values are obtained from the COPT. Any outage of generating capacity exceeding the reserve will result in a curtailment of system load energy.

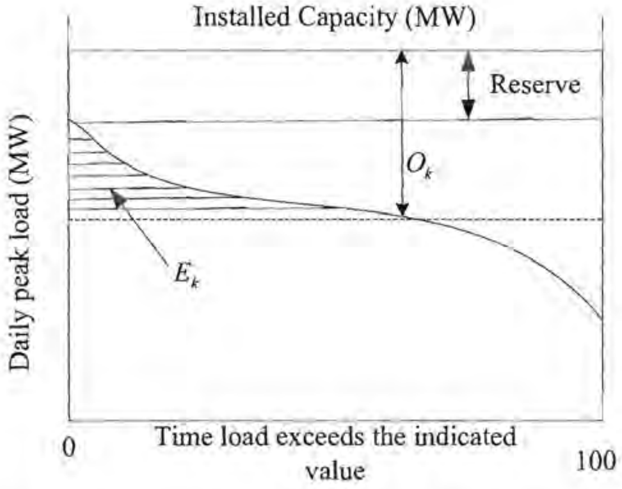


Figure 8: The energy curtailment due to a given capacity outage condition.

Where:

O_k = Magnitude of the capacity outage,

P_k = Probability of a capacity outage equal to O_k, and

E_k = Energy curtailment due to outage O_k.

The energy curtailment is given by the shaded area in Figure 8. The probable energy that is curtailed is $E_k P_k$. The sum of these products is the total expected energy curtailment or EENS for the period under study. EENS is also known as LOEE.

$$LOEE = \sum_{k=1}^{n} E_k P_k \tag{3.5}$$

The LOEE can be used in conjunction with the cost of un-served energy to provide a means of comparing the reliability worth to reliability cost [1]. The cost of un-served energy is the cost to the customer for not having the energy available.

3.3 Reliability cost and reliability worth

Adequacy studies of a system are only part of the required overall assessment. The economics of the alternative facilities play a major role in the decision-making process. In order to make a comparison between economics and reliability, it is necessary to compare the adequacy cost with adequacy worth. Adequacy cost is the investment cost needed to provide a certain level of adequacy, while adequacy worth is a benefit derived by the utility, consumer and society for a certain level of adequacy. Figure 9 shows that the cost to the utility will increase with an increase in reliability [1]. The consumer cost associated with supply interruptions will decrease with an increase in reliability. The total cost to the society will therefore be the sum of these two individual costs. The total cost exhibits a minimum and consequently an optimum for reliability is achieved. The difficulties with this assessment approach are that the calculated indices are from the adequacy assessment and there are problems in assessing the consumer perceptions of outage costs. The disparity between the calculated indices and the monetary costs associated with supply interruptions is shown in Figure 10.

The left-hand side of Figure 10 shows the calculated indices at the different hierarchical levels. The right-hand side shows the interruption cost data as obtained from user studies. From Figure 10 it can be seen that it becomes increasingly more difficult to correctly determine the cost to the customer for a power interruption at generating points as compared to user load points. This is because the users can more accurately determine its direct cost at load due to a decrease in reliability as compared to the cost to the economy at generation level due to a decrease in reliability.

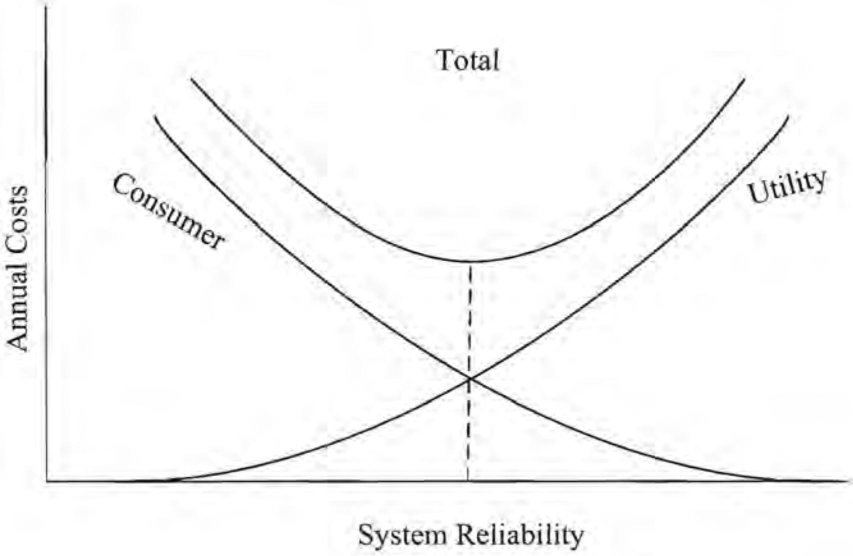


Figure 9: Reliability costs.

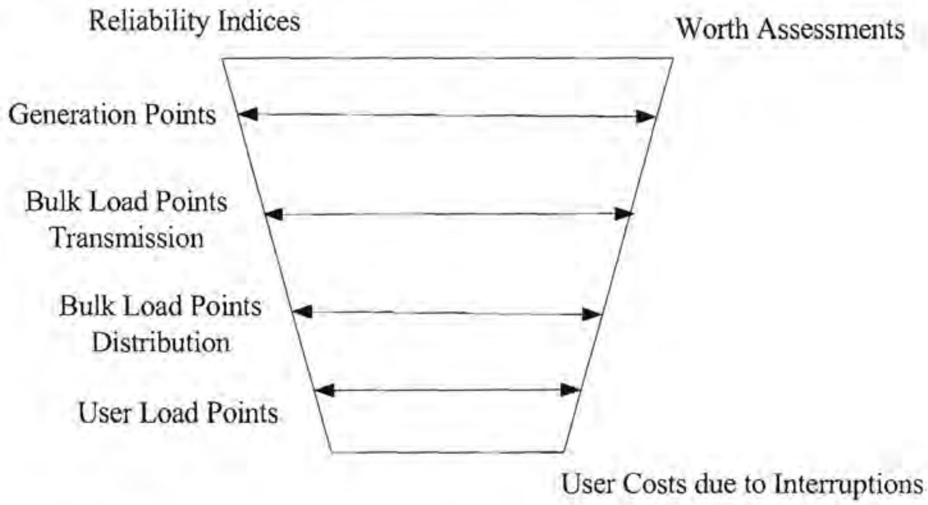


Figure 10: Disparity between indices and worth at different hierarchical levels.

3.4 Model I

A model has been constructed that combines the generation model with the load model and determines the risk indices for an 11-unit generating system. Risk indices are used to calculate the reliability cost and reliability worth of the 11-unit system. A block diagram of the model is shown in Figure 11.

The expected peak load for the day is used to calculate the optimal generator reserve on a day-ahead basis. A two-state Markov model is assumed for the generating units. It is assumed that the unit has two capacity states, meaning the unit is providing full power when available or no power when not connected to the power system. The model commits generating units until generation exceeds the expected demand. After each unit has been committed, COPT and the risk indices are updated. A multi-state Markov model is used to model the last unit committed to the load. This means that the generating unit will have more than two capacity states. This unit can be off, supply the load and/or supply reserve in the capacity steps entered by the user.

The reserve units are modelled as a multi-state Markov model and the user selects the capacity step size used to model these units. After each capacity step is committed as reserve, COPT and the risk indices are updated. The cost to the utility to provide this reserve for each unit is then determined using (3.6). The fixed cost of the generator is denoted as F.C. This is the cost to construct the generating plant. It is usually calculated over a 40-year payback period and is given in Rand or Rand per MWh. The variable cost (V.C.) is the cost of fuel for this generating plant. This cost is given in Rand per MWh. The energy supplied by the generating plant is the amount of power supplied over a certain time period and is given in MWh.

By committing reserve to the system, the system's reliability is increased which leads to a reduction in the cost to the customer due to a decrease in loss of production and a loss in credit card sales, to name but a few examples. The decrease in cost to the customer for an improvement in the power system reliability is calculated using (3.7). EENS is obtained from (3.5) and is given in MWh. The Interruptible Energy Assessment Rate (IEAR) is the cost to the customer for not having energy available. This is usually determined through a survey.

The different customer types that complete this survey and the average cost for not having the energy available are calculated. The IEAR is also known as the composite customer damage function. For this model the customer is the South African economy and it is mostly comprised of industrial, commercial and residential consumers.

$$Utility\ Cost = F.C. + (Energy)(V.C.) \tag{3.6}$$

$$Customer\ Cost = EENS \times IEAR \tag{3.7}$$

From Figure 9 it can be seen that by increasing the reliability of the system, the cost to the utility increases due to an increase in the fuel cost. The cost to the customer decreases as the reserve increases due to an increase in power system reliability. The total cost is obtained by adding these two graphs together. The optimal reserve is where the total cost is a minimum indicated by the dashed line in Figure 19.

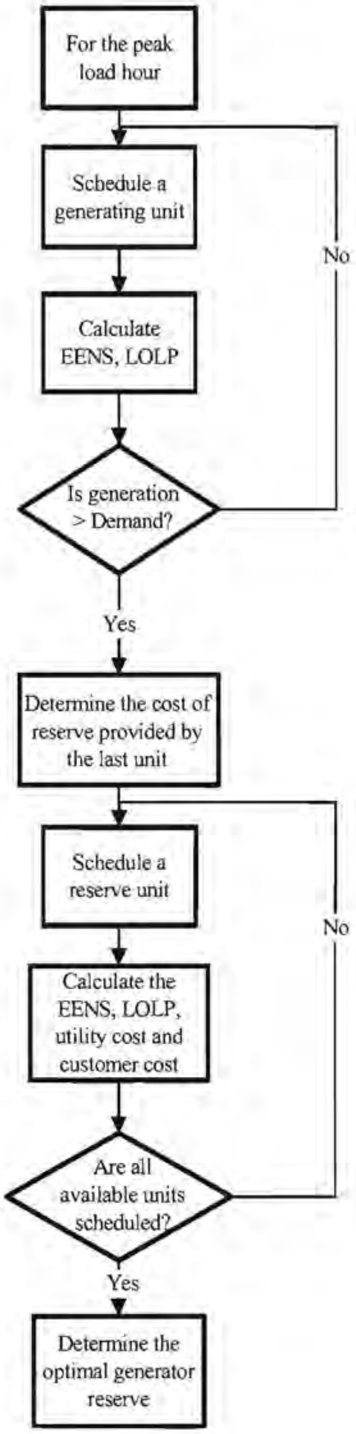


Figure 11: The block model of Model I.

3.4.1 Theoretical testing of the model

Before testing the model against a test system, the functional units of the system must be tested. The generation model will be tested using the three-unit test system. The risk indices will be verified using the results from the three-unit test system.

3.4.1.1 Generation model

The generation model is tested using a three-unit test system of two 25 MW units and a 50 MW unit, each with a FOR of 0.02 failures per year as shown in Table 6. COPT is constructed from (3.3).

Table 6: The three-unit test system.

Unit (MW)	FOR
25	0.02
25	0.02
50	0.02

Applying (3.3), the following results are obtained. The equation is initialised by setting $P'(X) = 1.0$ for $X < 0$ and $P'(X) = 0$ otherwise. The results obtained in step 1 are used in step 2 and the results from step 2 are used in step 3.

Step 1. Add the first unit and calculate the probability

$$P(0) = (1 - 0.02)(1.0) + (0.02)(1.0) = 1.0$$
$$P(25) = (1 - 0.02)(0) + (0.02)(1.0) = 0.02$$

Step 2. Add the second unit and calculate the possible capacity states and probabilities.

$$P(0) = (1 - 0.02)(1.0) + (0.02)(1.0) = 1.0$$
$$P(25) = (1 - 0.02)(0.02) + (0.02)(1.0) = 0.0396$$
$$P(50) = (1 - 0.02)(0) + (0.02)(0.02) = 0.0004$$

Step 3. Add the third unit and calculate the capacity states and probabilities.

$$P(0) = (1 - 0.02)(1.0) + (0.02)(1.0) = 1.0$$
$$P(25) = (1 - 0.02)(0.0396) + (0.02)(1.0) = 0.058808$$
$$P(50) = (1 - 0.02)(0.0004) + (0.02)(1.0) = 0.020392$$
$$P(75) = (1 - 0.02)(0) + (0.02)(0.0396) = 0.000792$$
$$P(100) = (1 - 0.02)(0) + (0.02)(0.0004) = 0.000008$$

The model was constructed in MATLAB™ version 7.0.4. The capacity states (after a unit has been added to COPT) are given by the CSA matrix and the probability of that capacity state occurring is given by the Pold matrix. Table 7 shows the generation model after the first unit has been added.

Table 7: The generation model after adding the first unit.

Capacity state after adding the unit (CSA)	**Probability of capacity outage occurring (Pold)**
0	1
25	0.02

Table 8 shows the generation model after the third unit has been added.

Table 8: The generation model after the third unit has been added.

Capacity State after adding the unit (CSA)	**Probability of capacity outage occurring (Pold)**
0	1.000000
25	0.058808
50	0.020392
75	0.000792
100	0.000008

Comparing Table 7 with step 1 of the calculation and Table 8 with step 3 on the previous page it can be seen that the model calculates the generation model correctly.

3.4.1.2 The risk model

The previous test system that is used to evaluate the generation model will be used to test the risk model. LOLE for the day is calculated using (3.4), with C_i the available capacity for the day and L_i the expected load for hour *i*. LOEE is calculated using (3.5), with $E_k P_k$ the expected energy curtailed for hour *k*.

The test system load data:

Table 9: The expected load data for the day.

Hourly load (MW)	57	52	46	41	34
No. of occurrences	3	4	6	3	8

Calculate LOLE

$$LOLE = \sum_{i=1}^{n} P_i(C_i - L_i)$$

$$\begin{aligned} LOLE &= 3(100-57) + 4(100-52) + 6(100-46) + 3(100-41) + 8(100-34) \\ &= 3(0.020392) + 4(0.020392) + 6(0.000792) + 3(0.000792) + 8(0.000792) \\ &= 0.156208\_\mathit{hours/day}. \end{aligned}$$

Calculate LOEE

$$LOEE = \sum_{k=1}^{n} E_k P_k$$

$$\begin{aligned} LOEE &= 7(0.020392) + 22(0.000792) + 6(0.000008) + 2(0.020392) + 27(0.000792) + 57(0.000008) \\ &+ 16(0.000792) + 41(0.000008) + 21(0.000792) + 46(0.000008) + 9(0.000792) + 34(0.000008) \\ &= 0.268528\_\mathit{MWh/day} \end{aligned}$$

Using the model constructed in MATLAB™ $LOLE = 0.156208\_hours/day$ and the $LOEE = 0.268528\_MWh/day$. The calculated values for LOLE and LOEE and the determined values for LOLE and LOEE using the program are the same. This validates the risk model.

It has been shown that the generation and risk models correctly update COPT and the risk indices. The next step is to test Model I, shown in Figure 11, against an 11-unit generating system.

3.4.2 The 11 unit generating system

The 11-unit generating system's data is shown in Table 10. The load data is shown in Table 11. IEAR is assumed to be linear with a cost of R 3.85/KWh.

Table 10: The 11 unit generating system.

Unit size (MW)	**Number of units**	**Loading order No. 1**	**Loading order No. 2**	**FOR**	**Variable cost (R/MWh)**	**Fixed cost (R/kW)/year**
40 (hydro)	1	1	1	0.02	0.5	2.5
20 (hydro)	2	2-3	2-3	0.015	0.5	2.5
40 (lignite)	2	8-9	4-5	0.03	12	19.75
20 (lignite)	1	10	6	0.025	12.25	34
10 (lignite)	1	11	7	0.02	12.5	60
20 (hydro)	2	4-5	8-9	0.015	0.5	2.5
5 (hydro)	2	6-7	10-11	0.01	0.5	2.5

Table 11: The load profile for the day

Hour	Load	Hour	Load
1	144	13	167
2	133	14	167
3	125	15	163
4	122	16	168
5	118	17	174
6	120	18	185
7	122	19	183
8	130	20	180
9	148	21	174
10	163	22	170
11	167	23	161
12	166	24	150

The results given in Figure 12 and 13 are for the two loading orders. The model is very sensitive to the reliability of the units scheduled and the order in which the units are scheduled. EENS for the day using loading order 1 is 5.58 MWh after the scheduled units are committed. Once the reserve unit is scheduled, EENS is reduced. The cost to the customer for energy not supplied and the cost to the utility for energy supplied are calculated. The cost to the utility and customer is shown in Figure 12. The optimal reserve is determined based on the minimum total cost. This is shown in Figure 13.

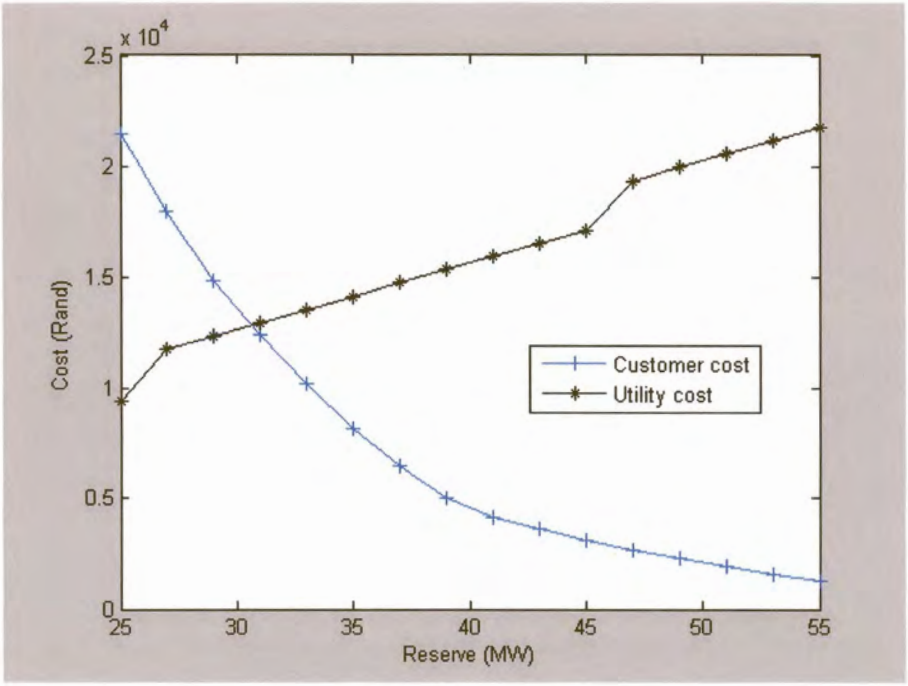


Figure 12: The cost to the utility and customer for loading order 1.

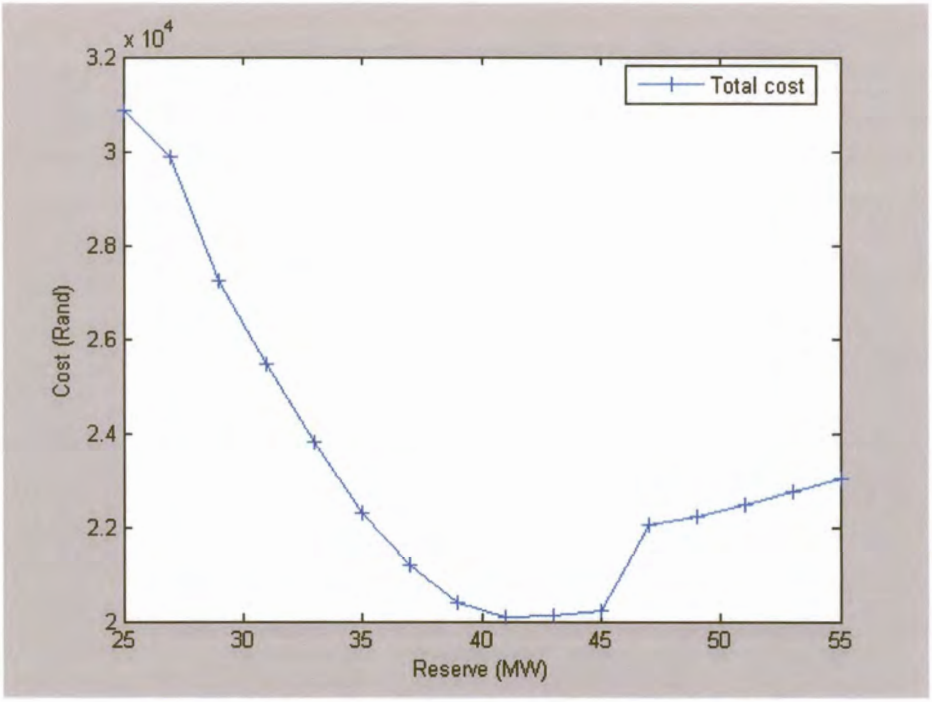


Figure 13: The total cost of providing reserve for loading order 1.

EENS using loading order 2 is 24.2 MWh for the day. The cost of reserve for a loading order of two is given in Figure 15, with the total cost given in Figure 16. The optimal generator reserve is determined based on the minimum total cost.

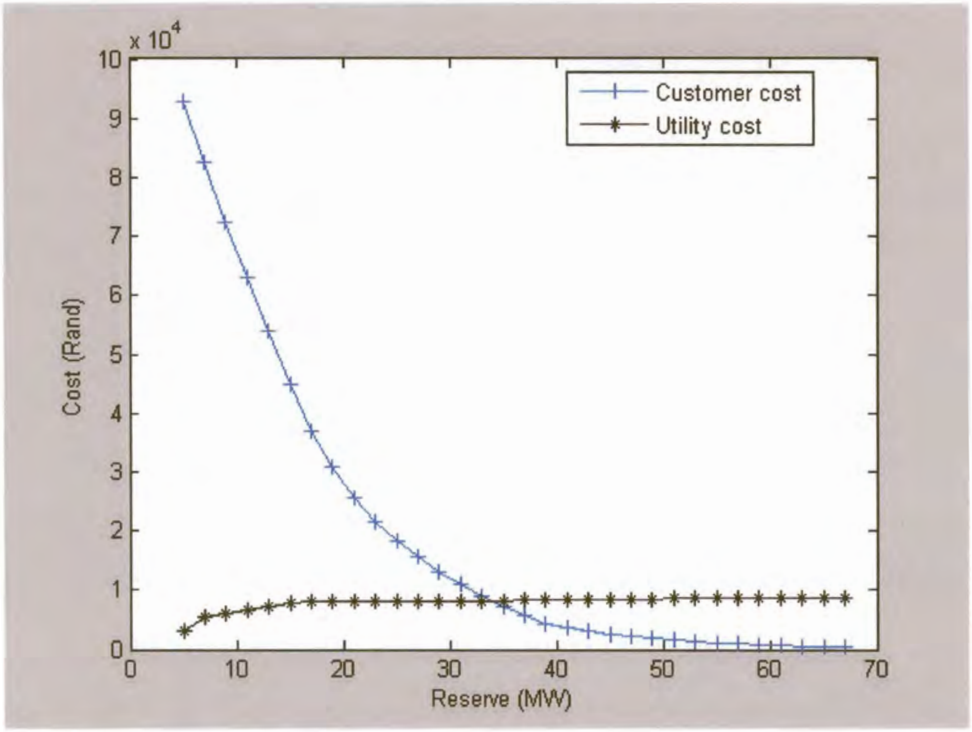


Figure 14: The cost to the utility and customer for loading order 2.

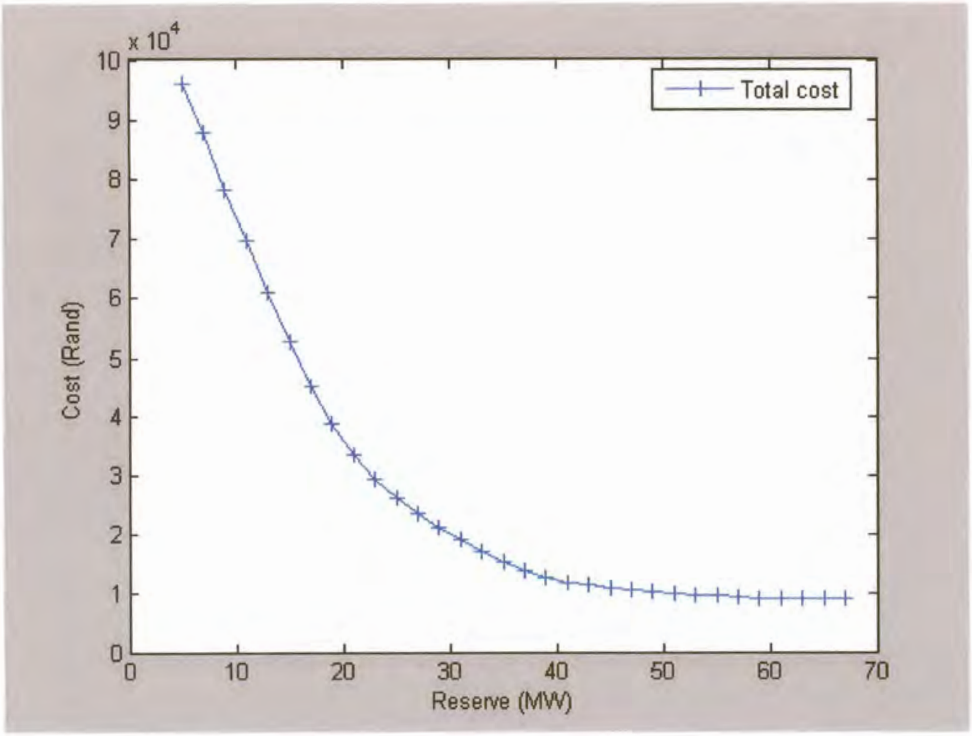


Figure 15: The total cost of providing reserve for loading order 2.

The optimal generation reserve using loading order 1 is 43 MW, while the optimal generation reserve using loading order 2 is 67 MW. The units in loading order 1 are more reliable than the units used in loading order 2.

Model I determines the optimal generator reserve for the 11-unit generating system presented in Table 10, with the load given in Table 11. The results of the system for the different loading orders are given in Figures 12 to 15. The results of this model shows that the system is very sensitive to:

- the reliability of the units used to cover the load;
- the reliability of the units used to provide reserve, and
- the order in which these units are scheduled.

The functional units of the model have been tested and verified. The system as a whole has also been tested. The model was expanded to be applicable to the South African electricity supply industry. The South African reserve market is presented in the following section.

3.5 The South African reserve market

The South African reserve market is divided into the following reserve categories [14].

- instantaneous reserve,
- regulating reserve,
- 10-minute reserve,
- supplemental reserve, and
- emergency reserve.

The instantaneous reserve is comprised of generation plant and DMP customers. The reserve in this category must be available within 10 seconds and for a maximum of 10 minutes to respond to an under frequency (49.8 Hz) event. The regulating reserve is made up of only generation and is used for frequency regulation. The 10 minute reserve is generating capacity (synchronised or not) and DMP customers that can respond within 10-minutes. The purpose of this reserve is to restore the instantaneous reserve to the required level after an incident. It must be available for at least two hours. Supplementary reserve is contracted on an annual basis (capacity) and replaces the 10-minute reserve. It is responsible for keeping the demand requirement off from the time the incident occurred until the time that the new generation shift starts (typically at 00h00). Emergency reserve is comprised of generation and IL. Some generating units can be operated at 1% of its Maximum Capacity Rating (MCR). If the units are operated at 1% of its MCR the next step will be to interrupt the IL customer and as a last resort start the expensive gas units.

3.5.1 DMP

While Real Time Pricing (RTP) has been used for some time, the Demand Side Management (DSM) benefits are uncertain as the load shift is not deemed sustainable or predictable. In response to these concerns, DMP was introduced. As with RTP, DMP encourages customers to purchase additional energy when the System Marginal Price (SMP) or market price is low. However, in addition the real-time system constraint signals are also incorporated through the reserve market mechanism. Coupled with the customer's Time of Use (TOU) base load purchases, which provide the long-term marginal cost signals, it was believed that the optimal (and reliable) DSM-based response would be achieved. The results of the 2003 winter were excellent. Over 100 MW of "optimal" load shifting was achieved with just two major participating customers [14].

The model presented in the following section is based on Model I. It is extended to include DMP, IL and emergency reserve customers in the optimisation. Therefore Model II is applicable to the South African reserve market.

3.6 Model II

This model determines the optimal operating reserve for the system presented. Model I determined the optimal generator reserve using the reliability cost/worth method. Model II is an extension of Model I. It includes generation, DMP, IL and emergency reserve. The DMP, IL and emergency reserve customers are modelled as dummy generators each with a fixed capacity, FOR as well as fixed and variable cost. The block diagram of the system model is given in Figure 16.

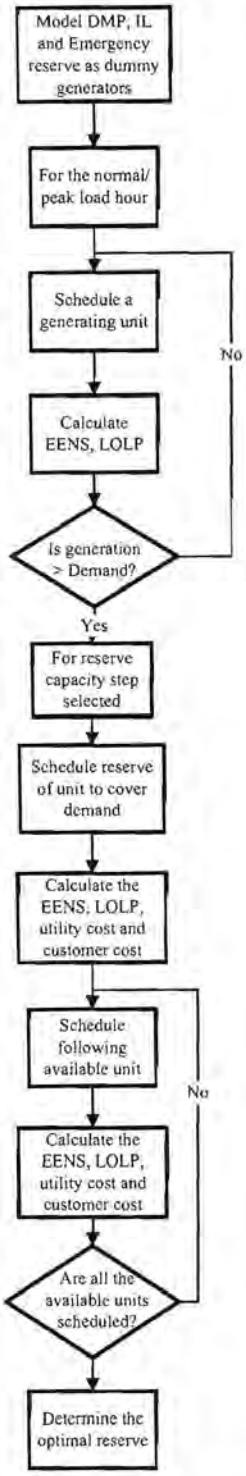


Figure 16: The block diagram of Model II.

The loading order of these generators is based on the bidding price received from the different generators and the experience of the system operator. The reserve was determined for the peak, off-peak and normal loading conditions. Model II determines the reserve using the same method as Model I. The model commits generating units until the generation exceeds the expected demand. After each unit has been committed, COPT and risk indices are updated. The reserve units are modelled by a multi-state Markov model. The user selects the capacity step size used to model these units. Once each capacity step is committed as reserve, COPT and the risk indices are updated. The cost to the utility and the costumer is determined using (3.6) and (3.7). Model II is tested using the 66-unit test system as shown below.

3.6.1 The test system

This test system comprises of a 66-unit generation system, with six DMP customers and IL. The reserve market presented is based on the reserve market used in South Africa with five reserve categories. Customers can participate in reserve levels I and III.

- **Reserve Level I**

  This consists of the generating plant and DMP. It must be available in 10 seconds and be able to provide energy for up to 10 minutes.
- **Reserve Level II**

  This consists of the generating plant only and is used for frequency regulation.
- **Reserve Level III**

  This consists of the generating plant and DMP. It must be available in 10 minutes and provide energy for up to two hours.
- **Reserve Level IV**

  This consists of emergency reserve and IL.
- **Reserve Level V**

  This consists of gas generating plant.

The generating system is given in Table 12, the DMP customers in Table 13 and the emergency reserve in Table 14. The expected load forecast for the day is given in Table 15.

Table 12: The 66 unit generating system.

Unit size (MW)	Number of units	Loading order	FOR	V.C. (R/MWh)	F.C. (R/MWh)
900	2	1	0.04	10	55
250	4	2	0.04	0	20
100	4	3	0.04	0	23
120	2	4	0.04	0	25
620	6	5	0.04	29	18
580	6	6	0.04	24	20
580	6	7	0.04	31	19
480	6	8	0.04	28	27
620	6	9	0.04	39	20
600	6	10	0.04	32	25
300	6	11	0.04	35	32
200	10	12	0.04	25	45
580	6	13	0.04	53	26
640	6	14	0.04	57	28

Table 13: The DMP customers for reserve levels I and III.

Customer	Capacity	FOR	V.C. (R/MWh)	F.C. (R/MWh)
A	120	0.01	800	10
B	100	0.01	800	10
C	80	0.01	1 000	10
D	80	0.01	1 000	10
E	60	0.01	1 500	10
F	60	0.01	1 500	10

Table 14: The emergency reserve.

Customer	Capacity (MW)	FOR	V.C. (R/MWh)	F.C. (R/MWh)
1% above MCR	500	0.06	35	30
Interruptible load	1 500	0.01	50 000	0

Table 15: The expected load forecast for the day.

Hour	Load	Hour	Load
1	27 300	13	31 500
2	25 200	14	30 800
3	23 800	15	30 450
4	23 100	16	30 450
5	22 400	17	31 850
6	22 750	18	35 000
7	23 100	19	35 650
8	24 500	20	33 950
9	28 000	21	32 900
10	30 800	22	32 200
11	31 500	23	30 450
12	31 850	24	28 350

The results given below are for the test system as shown with the DMP customers, IL and emergency reserve. The optimal reserve is determined for the power system operating under normal conditions with an expected load of 30 000 MW. It has been assumed that one 900 MW and two 640 MW units are on a forced outage and one unit of 620 MW is undergoing maintenance. It is further assumed that the two peaking stations are also not available (1 000 MW and 400 MW). The cost to the utility and the cost to the customer are shown in Figure 17. The total cost is shown in Figure 18. The cost to the customer for reserve provided decreases as the available reserve increases. This is because with an increase in the reserve, the power system reliability increases and the expected loss of revenue decreases. The cost to the utility increases as the reserve level increases due to the increase in fuel cost as more units are needed to provide reserve. The optimal reserve is determined based on the minimal total cost. It can be seen from Figure 18 that the optimal reserve of the power system under the operating conditions proposed above is 2 240 MW.

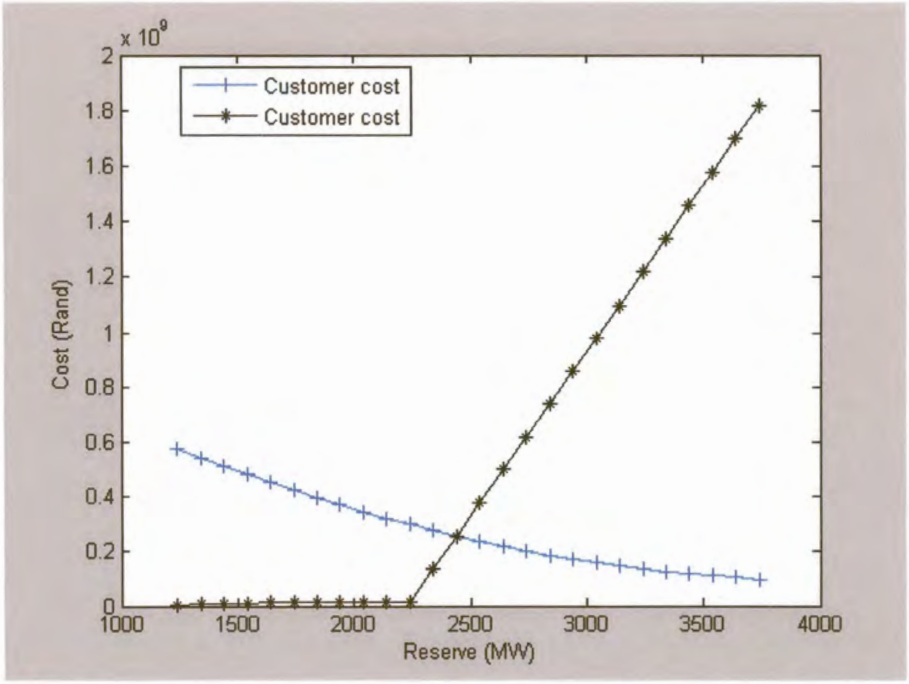


Figure 17: The cost to the utility and the customer for reserve supplied for an expected load of 30 000 MW.

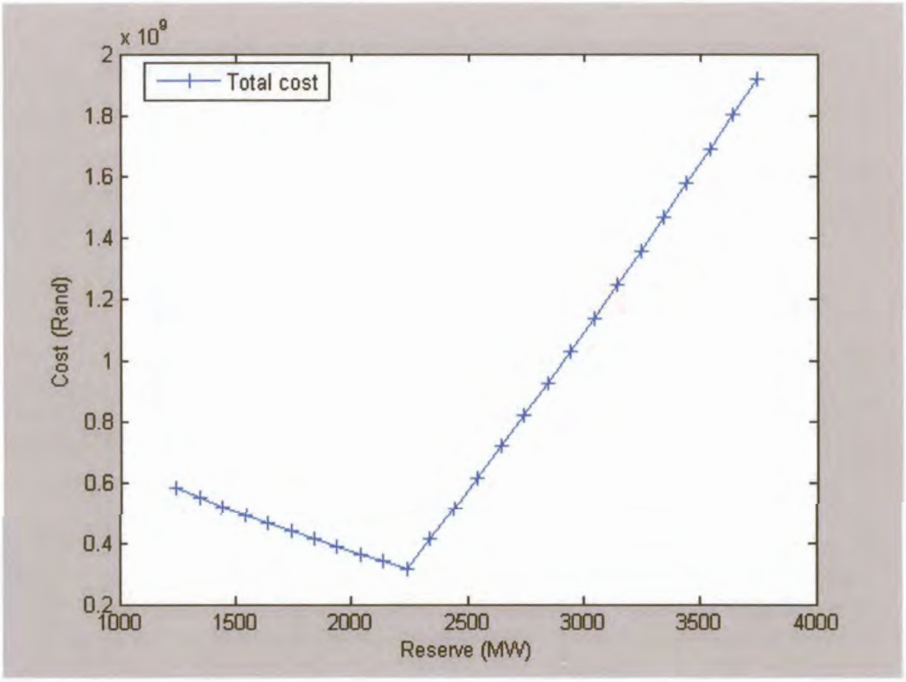


Figure 18: The total cost of reserve supplied for an expected load of 30 000 MW.

An example is presented where it is assumed that all the units are available and the expected peak load is 35 000 MW. The total cost to the customer and utility is shown in Figure 19. The optimal reserve is 1 440 MW. The reserve capacity step was chosen to be 100 MW in each case. The reserve capacity step can be chosen to be smaller, but this will increase in computation time.

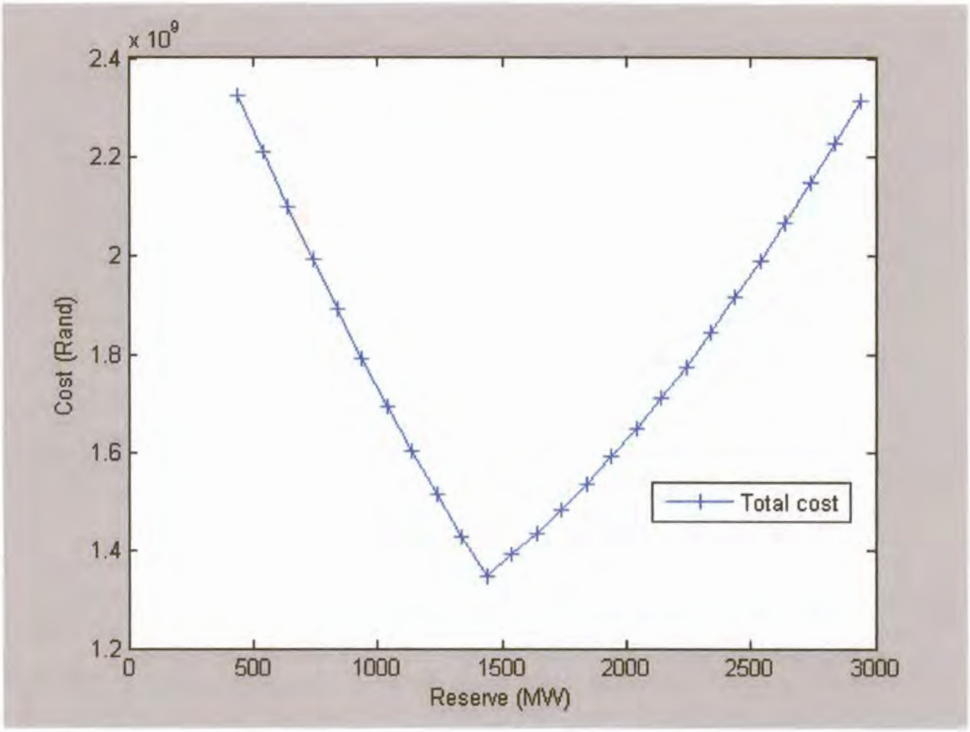


Figure 19: The total cost of reserve supplied for peak of 35 000 MW.

Model II has been tested by using the Eskom test data. The optimal reserve determined using this model compared well with the reserve as scheduled by Eskom. However the test system cannot be displayed due to a confidentiality agreement with Eskom.

3.7 Concluding remarks

The focus of the first part of this chapter was to present the reliability cost/worth method. It was seen that the generation model was convolved with the load model to obtain the risk model. The risk model was then used to determine the optimal reserve based on the cost/worth of the reserve provided. The total minimal cost to the utility and the customer is the optimal reserve.

The second part of this chapter focussed on expanding the reliability cost/worth method to the South African reserve market. The South African reserve market consists of generation, DMP, IL and emergency reserve. The contribution to the field of study was to expand the reliability cost/worth method to include DMP, IL and emergency reserve by modelling it as dummy generators. From this new model it is possible to determine the optimal reserve for the South African reserve market. The remaining part of this chapter focussed on validating and testing the model to verify if it correctly determines the optimal operating reserve.

The next chapter will focus on further validating the model and comparing the model to other models that also determine optimal reserve.

CHAPTER 4

MODEL VALIDATION AND COMPARISON

This chapter provides a basic validation of the model that was presented in chapter 3, the Generator Reserve Optimisation Model (GROM). This validation determined if the model correctly constructs COPT and calculates the risk indices. The risk indices are calculated from COPT and are used to determine the cost to the customer and the optimal reserve. A validation is required to test if the GROM correctly determines the optimal reserve. This is done by comparing the model in [3] and [7] to theGROM. If the optimal reserve as determined by the three models is approximately the same, then it can be concluded that the three models determine the optimal reserve correctly.

4.1 The test system

The IEEE Reliability Test System (RTS) of 1996 was developed in order to provide a common test system. This is used for comparing the results obtained by different methods [1]. The generating unit data is used to validate the models. The generating units modelled in the IEEE RTS are comprised of coal, oil, hydro and a nuclear generating plant. The model was expanded to include DMP and IL customers. The daily load profile for [3] and [7] is given in section 4.2 and 4.4. For a detailed study of the IEEE RTS of 1996, please refer to [35].

The unit data for the IEEE RTS of 1996 for one area is presented in Table 16. It is assumed the unit data for all three supply areas is the same. The amount of units available, scheduled in Table 16, is multiplied by three for a three-area system.

Table 16: The generating unit data for IEEE RTS of 1996.

Unit size (MW)	Amount of units	FOR	Selected capacity (MW)	Reserve capacity (MW)	Ramp rate (MW/min)
12	5	0.02	2	10	1
20	4	0.1	15	5	3
50	6	0.01	40	10	5
76	4	0.02	15	61	2
100	3	0.01	25	75	7
155	4	0.04	93	62	3
197	3	0.05	68	129	3
350	1	0.08	140	210	4
400	2	0.12	400	0	20

4.2 Validation method

The GROM is validated by firstly comparing this model to the models presented in [3] and [7]. The purpose of this comparison is to identify the differences in the models. To be able to compare the models to each other, the IEEE RTS of 1996 will be applied to the models and the results will be compared. If the shape of the optimal reserve curve over a 24 hour period looks the same and the error in the optimal reserve is relatively small, it can be assumed that the three models correctly determines the optimal reserve. The difference in the calculated optimal reserve between the three models can be due to the differences in the models.

4.3 Comparing the model with [7]

The model presented in [7] is compared to the reliability cost/worth method presented in the previous Chapter. The model presented in [7] proposes a novel method for determining the optimal spin reserve. This model uses a cost benefit study to determine the optimal reserve. If the cost of purchasing reserve C_{Rj} is higher than the cost of an interruption L_{Rl}, no extra reserve will be purchased as shown in Figure 20. The cost of reserve C_{Rj} is given in (4.1) and the cost of the interruption L_{Rj} is given in (4.2).

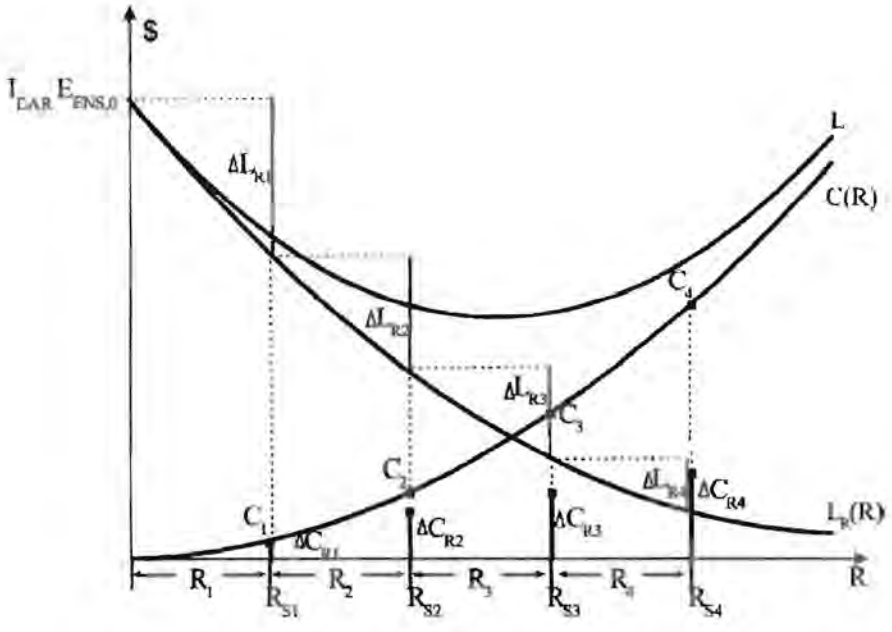


Figure 20: Determined optimal reserve presented in [7] by Wang et al see Fig 1.

$$C_{Ru} = \sum_{j=1}^{n} P_j \times R_j \tag{4.1}$$

$$L_{Ru} = I_{EAR} \times E_{ENS} \tag{4.2}$$

Where P_j is the cost of reserve (R/MWh) for unit j, R_j the amount of reserve (MW) provided by unit j, I_{EAR} the interruptible energy assessment rate (R/MWh) and E_{ENS} the expected energy not supplied (MWh). The model is presented in Figure 21.

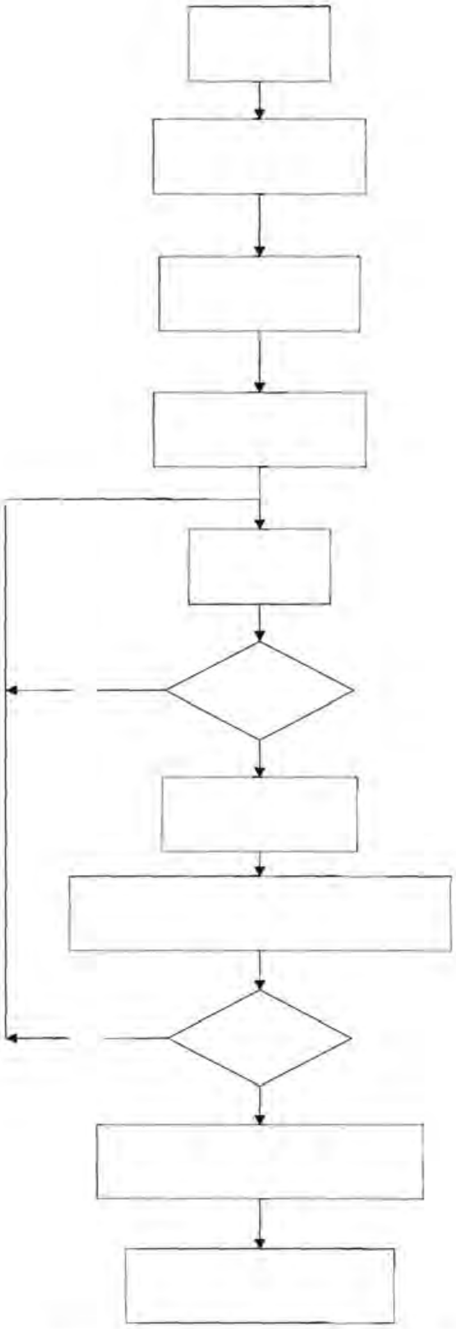


Figure 21: The reserve optimisation model presented in [7] by Wang et al see Fig 2.

Equations (5) and (6) of Figure 21 consider whether the unit used to provide reserve complies with its minimum and maximum reserve levels and ramping rates. Equation (10) determines if the incremental cost of reserve is less than the incremental cost of an interruption. If this is the case then reserve is purchased. The model continues to purchase reserve until the cost of reserve is higher than the cost of an interruption.

Both models use the reliability cost/worth method to determine the optimal reserve. EENS is used to determine the cost to the customer and the cost of dispatching the unit is the cost to the utility. The optimal reserve is determined based on a cost to the customer (or benefit derived) for buying reserve. If the cost of reserve is less than the cost of an interruption, reserve will be purchased.

The difference between the two models is that the GROM schedules the units based on cost or how the operator selects the loading order. It is assumed that the total capacity of a unit is available to be scheduled to cover the load. The cost to the utility is calculated for all the units available to be scheduled. After each unit has been scheduled, the reliability of the power system is recalculated and the cost to the customer is calculated for an interruption. The total minimal cost to the utility and customer is selected as the optimal reserve. The GROM determines the optimal reserve and assumes the operator divide the reserve between the units. The units are usually operated at 95% of its maximum capacity rating and the remaining 5% is used to provide reserve when needed. The reserve is divided between the units because the ramping rates of the units are fixed. If a reserve of 500 MW must be provided to the grid and only three units are used to provide the reserve, each with a ramping rate of 20 (MW/min) it will take approximately 8 minutes and 20 seconds for the 3 units to provide the 500 MW. If 10 units were used to provide the reserve each with the same ramping rate the 500 MW will be provided within 2 minutes and 30 seconds. Therefore it is advantageous to not operate a few units at each rated capacity.

The IEEE RTS of 1996 was used to test the model in chapter 3 with [7]. The optimal reserve is determined for three supply areas; therefore the amount of units available in Table 16 must be multiplied by three. The load profile is given in Figure 22. The optimal reserve determined is given in Figures 23 to 25.

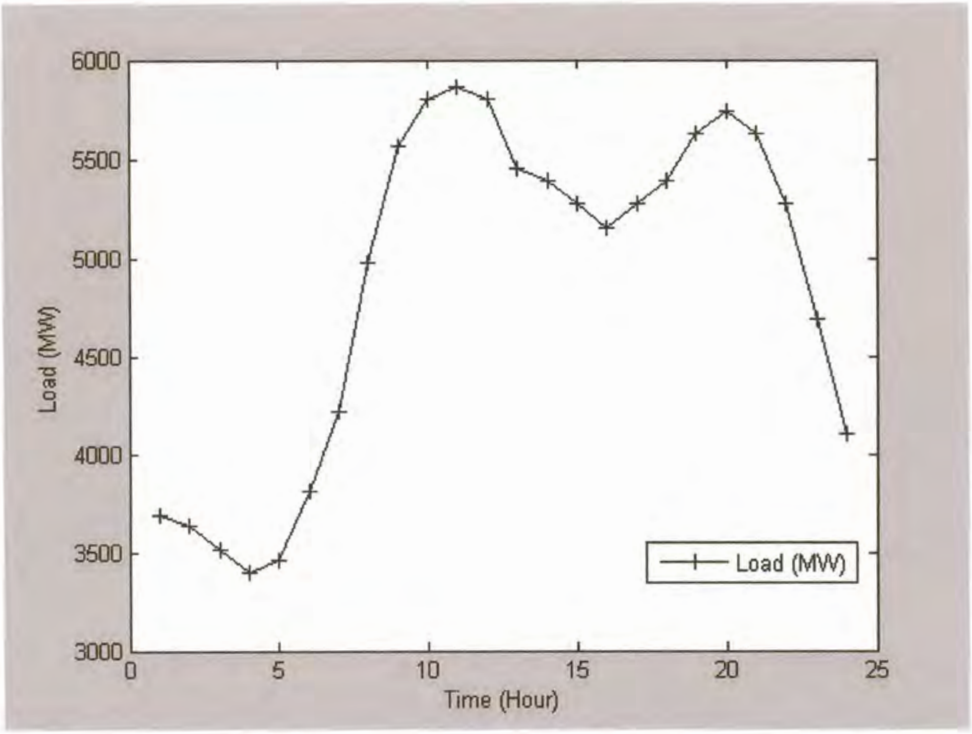


Figure 22: The load profile for the day

The optimal reserve calculated using the GROM for the load profile is given in Figure 23 and the optimal reserve using the model presented in [7] is presented in Figure 24. The optimal spin reserve using the pay as bid mode from Figure 24 is compared with the spin reserve from Figure 23. For the peak load of 5 860 MW, the reserve calculated using the model in [7] was 1 400 MW and the optimal reserve calculated using the model presented in chapter 3 was 922 MW. The model in [7] used a percentage of the unit capacity available to cover the load and the remaining capacity as reserve, therefore more expensive units can be used to cover the load, and less expensive units can provide reserve. The result of choosing the generating units to operate in this manner is that more reserve is required to operate the power system at a total minimal cost.

The model presented in [7] is more suited to a power system with an excess of capacity available, but in practical terms a utility cannot afford to keep 50% of a base load generating unit available for reserve. The GROM is more suited for a power system with a limited installed capacity and introduces DMP and IL as a means to have more capacity available when the price of reserve is high.

The GROM was modified to schedule the units as in [7] with the optimal reserve presented in Figure 25. It can be seen from Figure 24 and Figure 25 that the two reserve graphs have approximately the same reserve for the load duration curve. The optimal reserve for the peak-loading hour from Figure 25 is approximately 1300 MW compared to the 1400 MW from Figure 24. The difference in the reserve is due to the difference in how the two models determine the optimal reserve. The difference in the optimal reserve is, to a lesser extent due to the rounding used by the GROM when constructing COPT and possibly also due to rounding used by the model presented in [7].

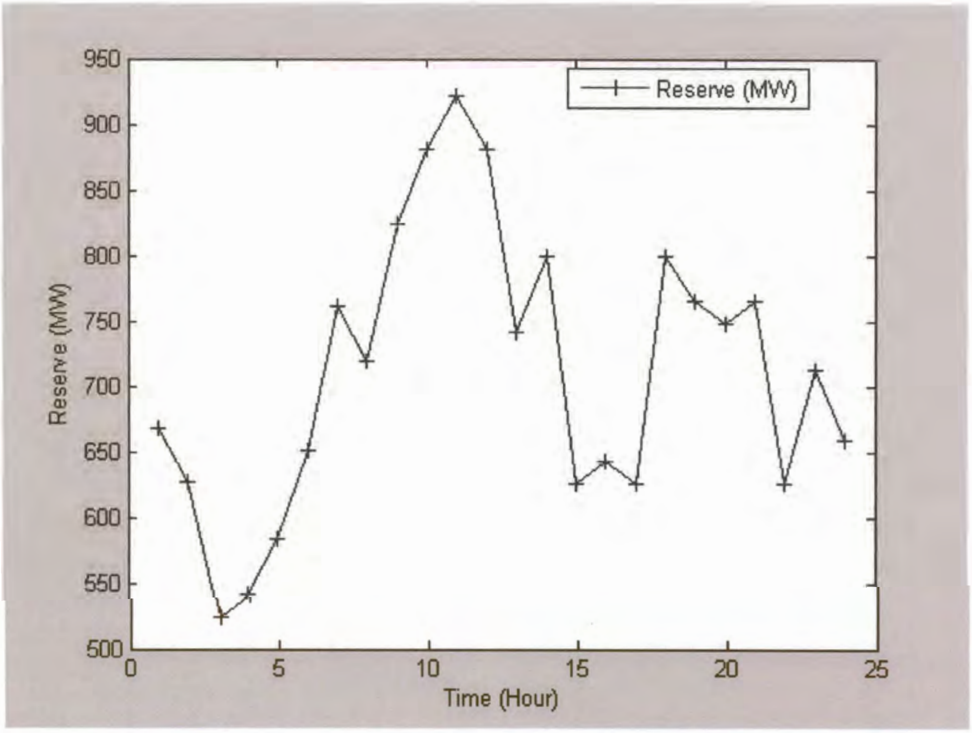


Figure 23: Reserve for each hour of the day using IEEE RTS 1996.

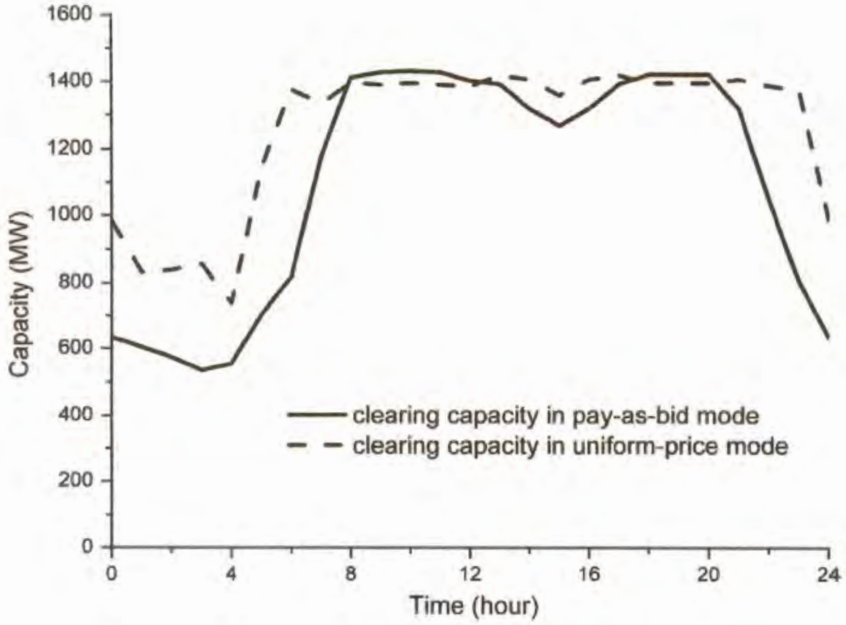


Figure 24: The optimal spin reserve determined by the model presented in [7] by Wang et al see Fig 4.

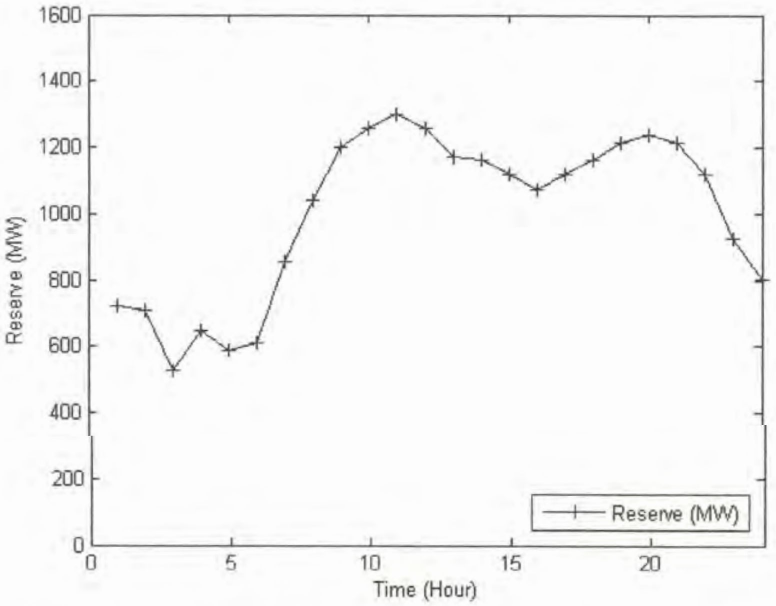


Figure 25: The reserve calculated by GROM after committing part of the unit as load.

To conclude the comparison of the two models presented one may say that the model in [7] is applicable to a power system with a large excess of generating capacity. This model schedules part of a generating unit to provide reserve, therefore more units will be used to match the load and provide reserve. This model focuses on minimising the cost to the customer or maximising the benefit. The GROM determines the optimal reserve from the utility's and the customer's perspective by selecting the total minimal cost of providing reserve. The GROM determines the optimal reserve and assumes the power system operator divides the reserve responsibility between the scheduled units. The GROM considered only the generating plant in its reserve calculation to make it possible to compare the two models. By comparing the results of the two models, it can be seen that the optimal reserve determined by the two models for the IEEE RTS of 1996 is relatively the same. The difference in the reserve is due to the difference in how the models determine the optimal reserve and the fact that rounding was introduced.

In the next section, GROM will be validated by using the model presented in [3].

4.4 Comparing the GROM with [3]

The model presented in [3] selects the optimal reserve based on a trade-off between the total scheduled cost obtained from the UC problem and the cost of EENS. This model determines the optimal reserve based on achieving a specified risk index selected by management. The model is presented in Figure 26 and Figure 27.

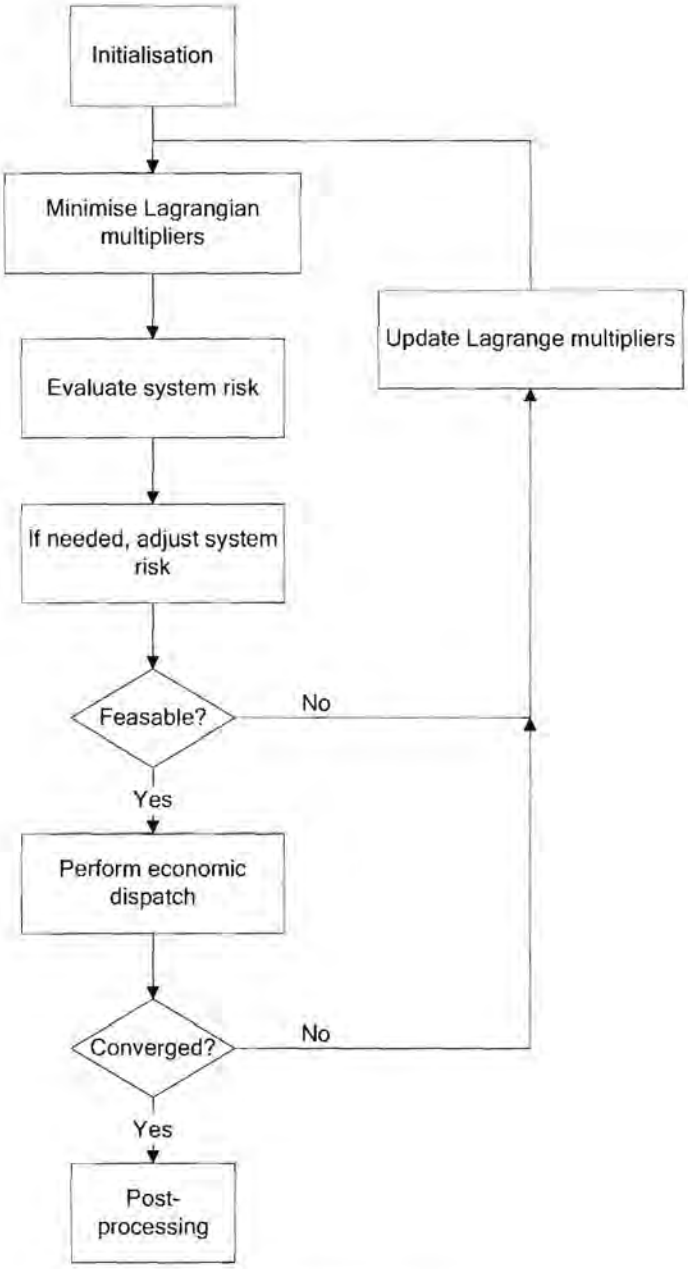


Figure 26: The unit commitment with probabilistic reserve assessment presented in [3], see Fig 1. by Gooi et al.

The GROM assumes that the units' UC problem has been carried out and that the operator has selected the order in which the units must be scheduled (taking into consideration minimum up/down times, starting cost, etc.). The model then determines the optimal amount of reserve for this selection.

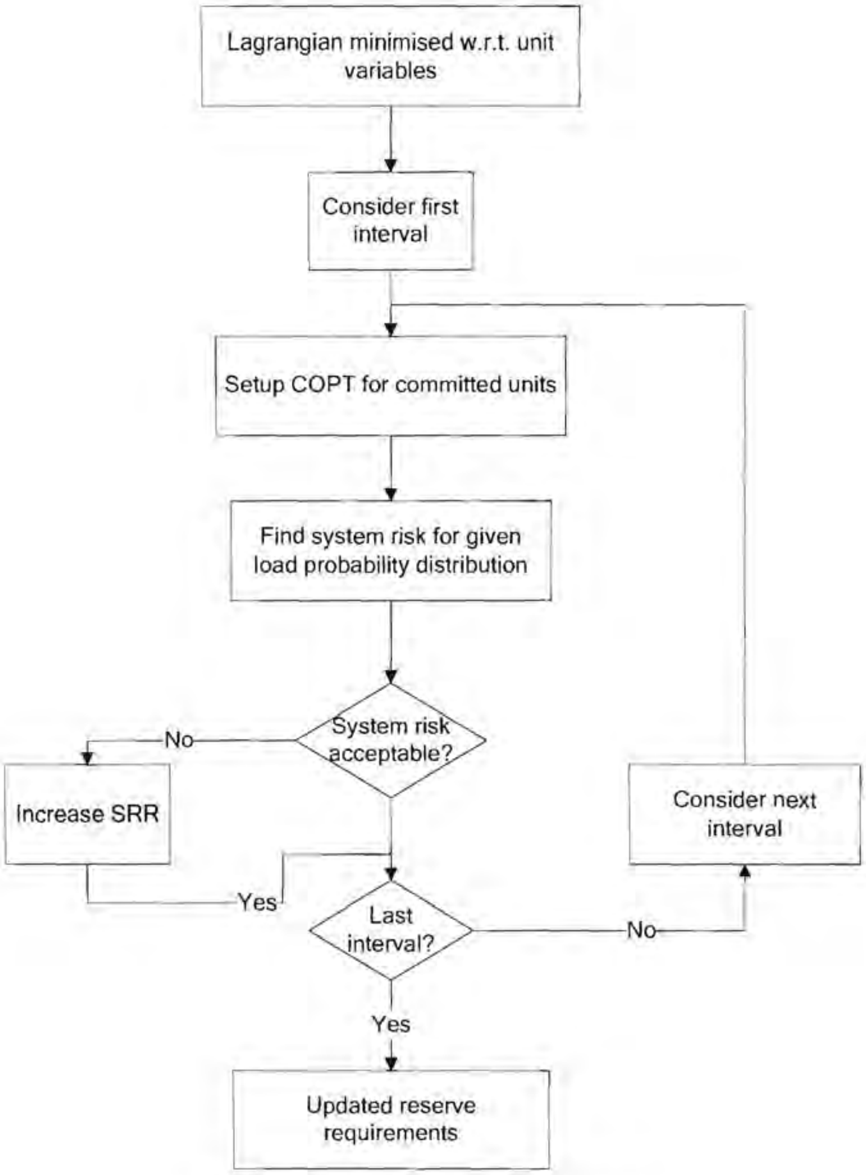


Figure 27: Probabilistic reserve assessment .

The GROM incorporates DMP and emergency reserve in the optimal reserve calculation. A heuristic method is proposed that illustrates how DMP and IL are modelled and the optimal reserve is taken to be the total minimum cost to the utility and the customer. To be able to compare the two models, only the generation units will be included in the model.

The model presented in [3] was tested using the IEEE RTS of 1996 (presented in Table 16), but only one supply area was considered in this study. The comparison made between the models presented in chapter 3 and in [7] considered three supply areas. Please refer to [35] for more information on this test system.

The load profile of the test system is presented in Figure 28. The expected peak load is 2 650 MW and the generation unit data is presented in Table 17.

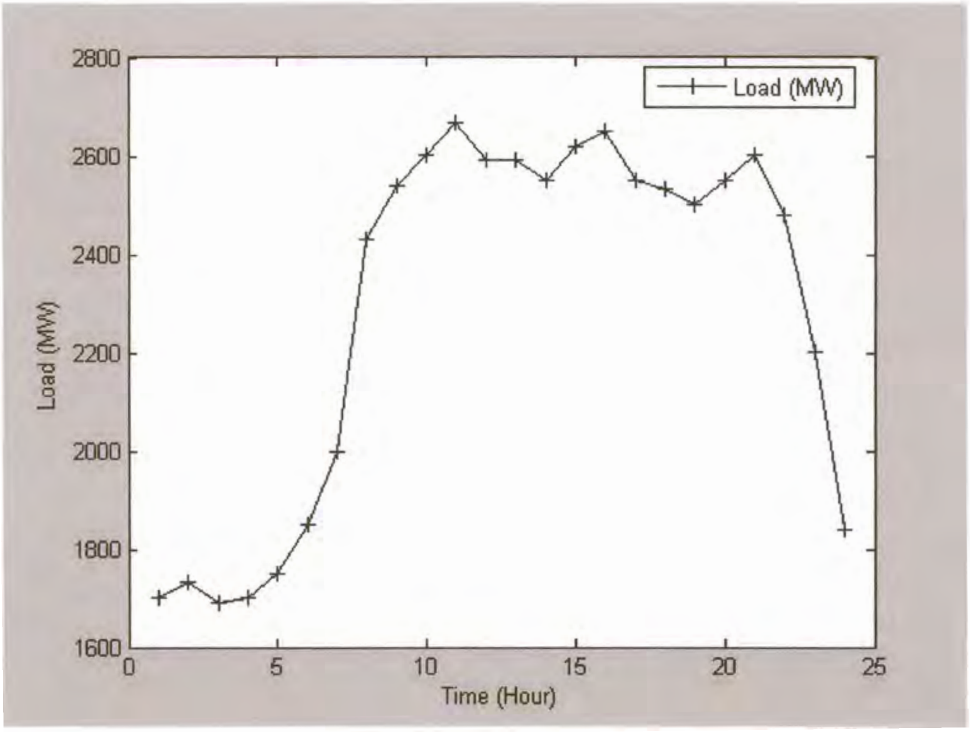


Figure 28: The load profile for the day.

Table 17: The generating unit data for the IEEE RTS without the 50 MW units.

Unit size (MW)	**Amount of units**	**FOR**	**Ramp rate (MW/min)**
12	5	0.02	1
20	4	0.1	3
76	4	0.02	2
100	3	0.01	7
155	4	0.04	3
197	3	0.05	3
350	1	0.08	4
400	2	0.12	20

Please note when comparing Table 17 with Table 16 that the 50 MW units were not available to be scheduled and therefore the 32-unit test system has been reduced to a 26-unit test system.

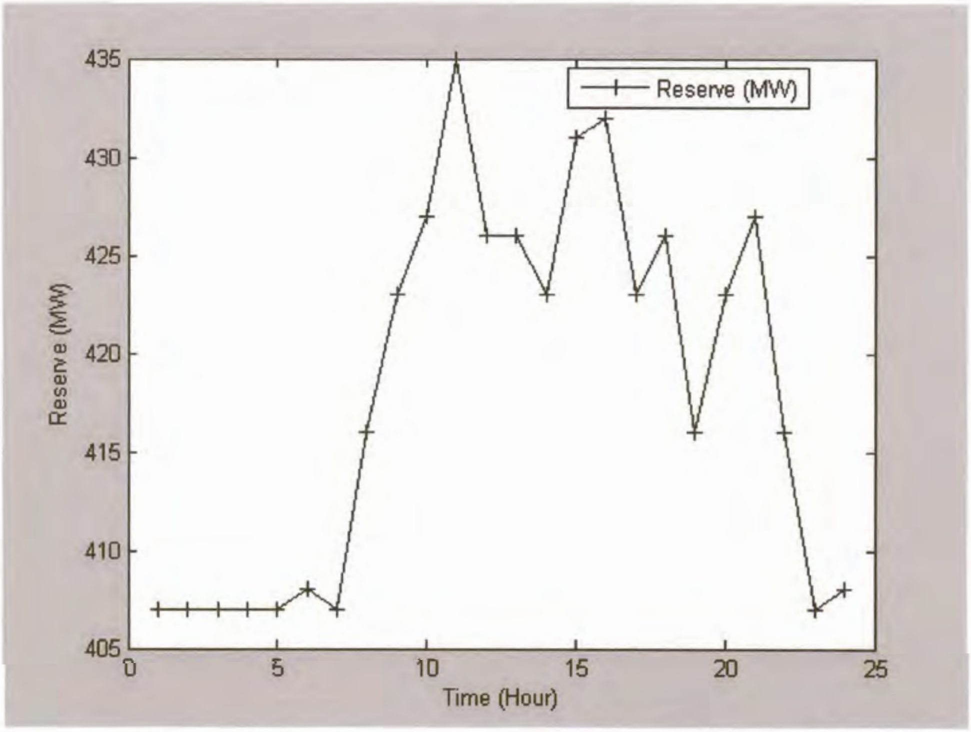


Figure 29: The optimal reserve determined using the model presented in [3].

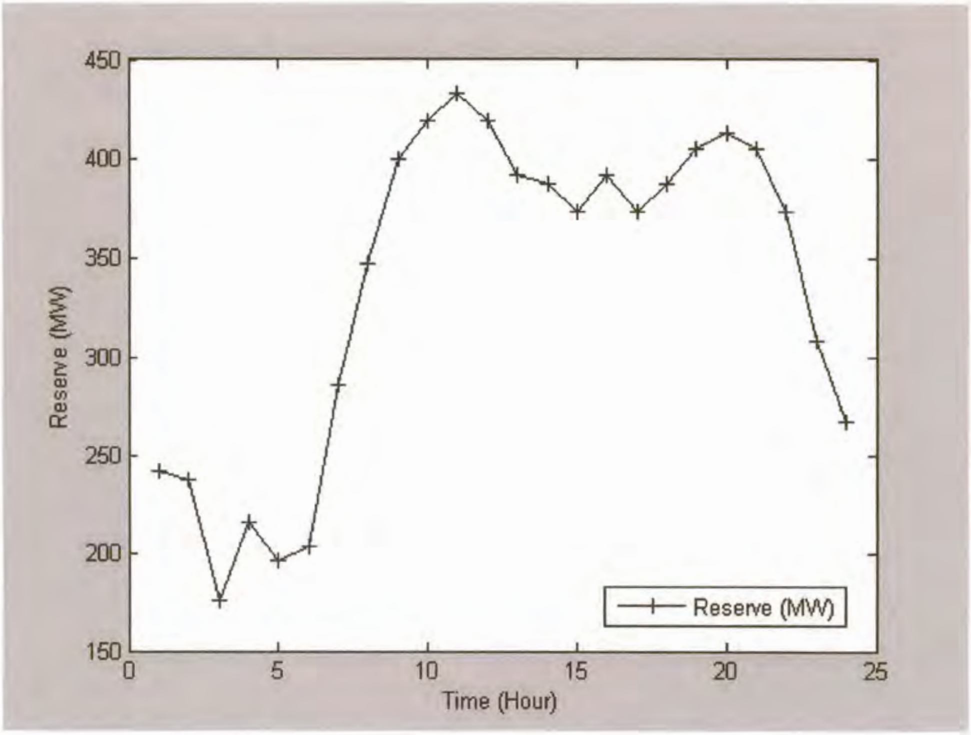


Figure 30: The optimal reserve determined using the GROM for the test system presented.

The reserve for each loading hour determined by [3] is presented in Figure 29 and the reserve using the GROM in Figure 30. The reserve in Figure 30 is lower compared to the reserve of Figure 29. The model presented in [3] commits reserve until the system risk exceeds the specified minimum risk (as also seen in Figure 26 and Figure 27). An economic dispatch is carried out to determine if the cost function converges. If it does not converge, the Lagrangian multipliers are updated and recalculated.

The GROM determines the optimal reserve based on the cost to the customer, which is based on the system risk (3.6) and the cost of providing the reserve (3.7). The reserve determined during loading hours 00:00 to 06:00 is much lower than the reserve determined by the model presented in [3]. This is because the cost of the unit used to provide the reserve is much higher in comparison to the reduction in cost for improving system reliability. During the peak and normal loading hours the amount of reserve scheduled by the two models compares well.

The GROM is very sensitive to a change in load demand where the reserve has increased from 200 MW to 400 MW between the hours of 06:00 and 09:00. In comparison the reserve determined by the model presented in [3] has increased from 407 MW to 423 MW. A sensitivity analysis is carried out in Chapter 5 to determine the influence of customer cost and unit reliability on determining the optimal reserve. The GROM truncates COPT by adding the probabilities of a certain capacity outage until it exceeds a threshold value of 10^{-6}. A small error is made by truncating COPT when calculating the risk indices. This leads to a small error in calculating the cost to the customer for the power system reliability and optimal reserve. This is done to increase the program execution time, but this issue will also be addressed in the next chapter.

4.5 Concluding remarks

This chapter has focussed on comparing the GROM with two other models. The model presented in [7] uses a cost-benefit approach to determine the optimal reserve, whereas the model presented in [3] uses Lagrangian relaxation based on the UC and a predefined risk index to determine the optimal reserve. Models [3] and [7] were tested using the IEEE RTS of 1996 and the optimal reserve determined compared with the reserve determined by the GROM. The results compared well and a small error was calculated when the optimal reserves determined by the different models were compared in Figures 24, 25, 29 and 30. The same test data was used on two different models, [3] and [7], and approximately the same optimal reserve was determined in each study using GROM. Therefore it can be concluded that the GROM correctly determines the optimal generating reserve.

The next Chapter will focus on the performance assessment of the GROM.

CHAPTER 5

PERFORMANCE ASSESMENT OF THE GENERATOR RESERVE OPTIMISATION MODEL

The aim of this Chapter is to assess the performance of the GROM. The first part of this chapter analyses different techniques used to improve the execution time of the model and investigate what the influence is on the optimal reserve. The second part of this chapter investigates how sensitive the model is to a change in IEAR, capacity step size and the FOR of the units. The third part of this chapter compares the GROM to the old Eskom model and identifies the benefits of incorporating DMP, IL and emergency reserve in the GROM.

5.1 Analysis of optimisation techniques on the model

The GROM is used to determine the optimal operating reserve for the South African Energy market. Two of the most important factors which affect the user's perception of the program are:

- the program execution time, and
- the accuracy of the program.

The GROM, will be used as the base case scenario. Small changes will be made to the model and the performance will be analysed. The model is analysed using the test system shown in Table 18 to Table 21.

Table 18: The 66-unit generating system.

Unit Size (MW)	Number of units	Loading order	FOR.	V.C. (R/MWh)	F.C. (R/MWh)
900	2	1	0.04	10	55
250	4	2	0.04	0	20
100	4	3	0.04	0	23
120	2	4	0.04	0	25
620	6	5	0.04	29	18
580	6	6	0.04	24	20
580	6	7	0.04	31	19
480	6	8	0.04	28	27
620	6	9	0.04	39	20
600	6	10	0.04	32	25
300	6	11	0.04	35	32
200	10	12	0.04	25	45
580	6	13	0.04	53	26
640	6	14	0.04	57	28

Table 19: The DMP customers for reserve level I and III.

Customer	Capacity	FOR	V.C. (R/MWh)	F.C. (R/MWh)
A	120	0.01	800	10
B	100	0.01	800	10
C	80	0.01	1000	10
D	80	0.01	1000	10
E	60	0.01	1500	10
F	60	0.01	1500	10

Table 20: The emergency reserve.

Customer	Capacity (MW)	FOR	V.C. (R/MWh)	F.C. (R/MWh)
1% above MCR	500	0.06	35	30
Interruptible load	1500	0.01	50000	0

Table 21: The expected load forecast for the day.

Hour	Load	Hour	Load
1	27300	13	31500
2	25200	14	30800
3	23800	15	30450
4	23100	16	30450
5	22400	17	31850
6	22750	18	35000
7	23100	19	35650
8	24500	20	33950
9	28000	21	32900
10	30800	22	32200
11	31500	23	30450
12	31850	24	28350

The peak demand is 35 000 MW, the IEAR is R 40 000 per MWh and the reserve is calculated in steps of 300 MW. The total cost to provide reserve using the test system is presented in Figure 31. The optimal reserve determined is 1 440 MW.

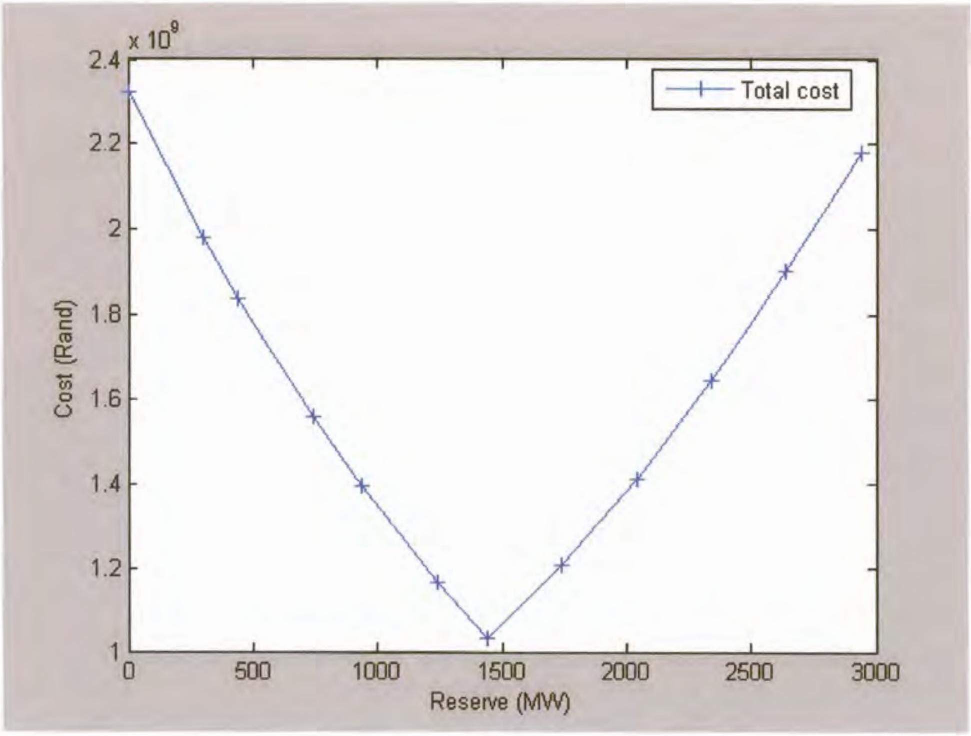


Figure 31: The results for the base case presented.

The model takes 11 minutes and 8 seconds to determine the optimal reserve for the system presented.

The profiling function in Matlab™ was used to identify the lines in the code that takes the longest to execute. Profiling is a way of measuring where a program spends its time. The profiler identifies the lines in the code that consumes the most time and it is established shat these functions are called and how to optimise or minimise their use. The profiler helps by:

- avoiding unnecessary computation, which can arise from oversight;
- changing the algorithms to avoid costly functions; and
- avoiding re-computation by storing results for future use.

The results of the profiling function are given in Table 22 to Table 24.

5.1.1 The base case

Table 22: The summary of the profiling done on the base case.

Function name	**Calls to function**	**Total time (s)**	**Self execution time (s)**
EskomB	1	6585.56	196.78
ProbabilityOld	396 245	3187.23	3187.23
ProbabilityOldMinusC	396 245	3187.23	3187.23

The total execution time of the model is 11 minutes and 8 seconds without the profiler enabled and 109 minutes and 46 seconds with the profiler enabled. The most time-consuming functions are presented in Table 22. The number of times the function is called and the execution time are presented. The main program takes 196 seconds to execute with ProbabilityOld and 3 187 seconds with ProbabilityOldMinusC. By reducing the execution time of these two functions, the total program execution time will decrease. A summary of the performance of these functions is given in Table 23 and Table 24.

Table 23: The summery of function ProbabilityOld for the base case.

Line number	**Code**	**Calls to function**	**Total time (s)**
14	If-function	3.83×10^9	144.56
16	counter	3.83×10^9	20.12
18	end	3.83×10^9	62.14
Other lines and overhead			3182

Table 24: The summery of function ProbabilityOldMinusC for the base case.

Line number	**Code**	**Calls to function**	**Total time (s)**
13	If-function	3.83×10^9	181.55
16	counter	3.83×10^9	21.185
17	End	3.83×10^9	69.122
Other lines and overhead			2953.493

ProbabilityOld and ProbabilityOldMinusC have a total execution time of 53 minutes and 53 minutes and 16 seconds respectively. Both functions spend more than 92% of the total execution time on 'other lines and overhead'. This is the time used by the profiler to do calculations on the functions. The actual execution time of ProbabilityOld for 396 245 calls is 3 minutes and 49 seconds with the profiler disabled. In Table 23 the number of times the different lines are called is shown with the total execution time. The lines of code where the execution time is close to zero were not included in the table. The comparator function in lines 14 to 18 takes longest to execute because it is called 3.83×10^9 times. The execution time of the ProbabilityOldMinusC function for 396 245 calls is 4 minutes and 2 seconds. The comparator function in lines 14 to 17 is called 3.83×10^9 times and takes the longest to execute. To reduce the execution time the number of calls to the function must be reduced.

The total execution time is 11 minutes and 8 seconds. The main program takes 3 minutes and 17 seconds to execute (29.5% of the total execution time). ProbabilityOld takes 3 minutes and 49 seconds to execute (34.1% of the total execution time) and ProbabilityOldMinusC takes 4 minutes and 2 seconds to execute (36.3% of the total time to execute). If the execution time of ProbabililtyOld and ProbabilityOldMinusC is reduced then the program will execute faster.

Different methods were investigated to reduce the execution time of the program. The following case studies are presented.

5.1.2 Case 1. Use matrix-indexing techniques.

ProbabililtyOld and ProbabilityOldMinusC are used to update COPT using (3.3). ProbabilityOld uses a counter and a logic function to determine if the capacity state in the matrix is a new state or an existing state If the capacity state is new then the probability of the initialised value is returned. For an existing capacity state the probability of that state occurring is returned. The indexing method presented in this section does not index each capacity state in the matrix sequentially. This method determines the size of the matrix and places an upper and lower boundary in the matrix. This method also searches for the possible capacity states between these boundaries. This comparison is made on only the data included between the boundaries. The improvement in the indexing technique will reduce the data that is being compared in the logical functions, but the amount of logical functions has increased to accommodate this indexing technique.

The same data is used as in the base case with the only changes in the functions ProbabilityOld and ProbabilityOldMinusC. The results are given in Figure 32 and in Tables 25 to 27.

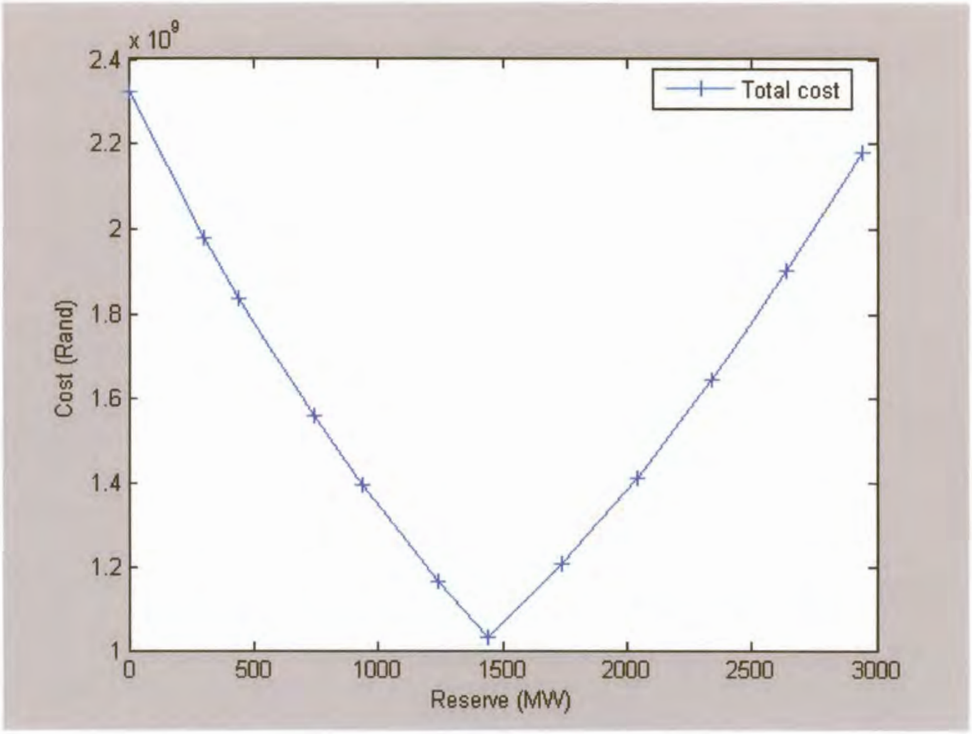


Figure 32: The optimal reserve determined for Case 1.

Table 25: The profiling results of EskomB for Case 1.

Line number	**Call to line**	**Total execution time (s)**
894	195 542	758.661
1 132	150 015	588.060
388	19 503	59.776
626	14 185	43.473
822	178 202	40.606
Other lines and overhead		124.541
Total		1615.122

Table 26: The results of ProbabilityOld for Case 1.

Line number	**Code**	**Calls to function**	**Total time (s)**
37	If-function	16 841 163	177.157
25	If-function	16 841 163	168.5
48	End	16 841 163	118.16
46	End	16 841 163	17
Other lines and overhead			101.43
Total			668.43

Table 27: The results of ProbabilityOldMinusC for Case 1.

Line number	**Code**	**Calls to function**	**Total time (s)**
43	If-function	16 617 139	237.895
31	If-function	16 617 139	205.88
54	End	16 617 139	119.702
52	End	16 617 139	16.994
Other lines and overhead			189.701
Total			778.019

The GROM takes 26 minutes and 55 seconds to execute using the profiling function and 20 minutes and 20 seconds without the profiling function enabled. The reduction in the profiling time is due to a reduction in the 'other lines and overheads'. This is because the total calls in the functions have decreased. The execution time of the model has decreased within the main code from 3 minutes and 17 and seconds to 2 minutes and 25 seconds, while the execution time of the model increased in the main functions for ProbabilityOld from 3 minutes and 49 seconds to 8 minutes and 7 seconds and for ProbabilityOldMinusC from 4 minutes and 2 seconds to 9 minutes and 48 seconds. The increase in the execution time is because the indexing technique uses more logical functions compared to the base case and these logical functions takes longer to execute than indexing the whole capacity state matrix sequentially.

5.1.3 Case 2. Incorporate reserve provided by the last unit when the reserve unit is scheduled

In this section the GROM is the same as in its base case, the only difference is that the total reserve provided by the last unit committed to the load is considered in one capacity step. The capacity steps for the reserve units are the same as in the base case, namely 300 MW. The results obtained using the profiling functions are given in Figure 33 and Table 28 to Table 30.

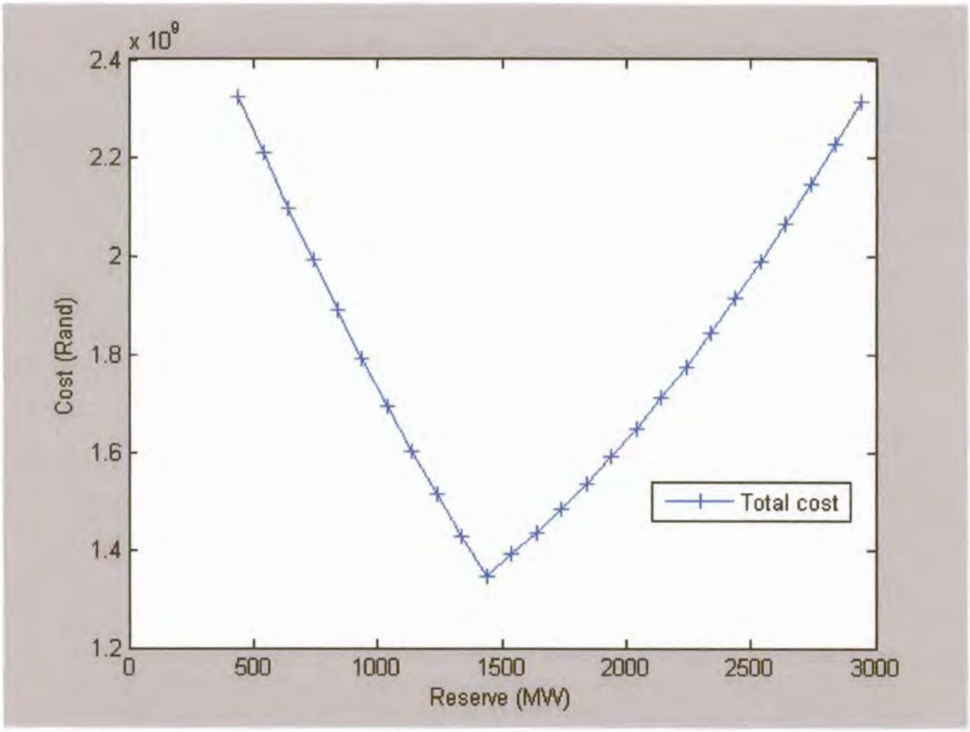


Figure 33: The optimal reserve determined for Case 2.

Table 28: The summery of Case 2.

Function name	**Calls to function**	**Total execution time (s)**	**Function execution time (s)**
EskomG	1	2 511.591	74.417
ProbabilityOldMinusC	231 063	1 222.918	1 222.918
ProbabilityOld	231 063	1 211.011	1 211.011

Table 29: The results of ProbabilityOld for Case 2.

Line number	**Code**	**Calls to function**	**Total time (s)**
14	If-function	3.077×10^9	56.612
18	End	3.077×10^9	25.736
17	counter	3.077×10^9	10.159
28	End	3.077×10^9	5.024
Other lines and overhead			1 117.392
Total			1 211.011

Table 30: The results of ProbabilityOldMinusC for Case 2.

Line number	**Code**	**Calls to function**	**Total time (s)**
13	If-function	3.077×10^9	59.927
17	End	3.077×10^9	29.250
16	counter	3.077×10^9	9.092
28	End	3.077×10^9	0.0541
Other lines and overhead			1 123.65
Total			1 222.918

The GROM takes 41 minutes and 52 seconds to execute using the profiling function and 4 minutes and 27 seconds without the profiling function enabled. The reduction in profiling time is due to a decrease in the size of the capacity state matrix. This in turn leads to a decrease in the amount of calls to ProbabilityOld and ProbabilityOldMinusC. The total execution time was reduced by removing unnecessary code. The execution time of the main part of the model has decreased from 3 minutes and 17 seconds to 1 minute and 14 seconds, while decreasing in the function ProbabilityOld from 3 minutes and 49 seconds to 1 minute and 33 seconds and decreasing in the function ProbabilityOldMinusC from 4 minutes and 2 seconds to 1 minute and 39 seconds.

5.1.4 Case 3. Increase the reserve capacity step

In this section it will be illustrated that by increasing the reserve capacity step size, the GROM execution time decreases, and the data points available for the total-cost optimisation will decrease. Consider the base case with a reserve capacity step of 300 MW given in Figure 31. The GROM takes 11 minutes and 8 seconds to execute. Consider an increase in the reserve capacity step from 300 MW to 500 MW. The model takes 7 minutes and 35 seconds with an optimal reserve of 1 440 MW. For a reserve capacity step of 800 MW the model takes 6 minutes and 43 seconds to determine the optimal reserve of 1 440 MW. The decrease in the execution time is due to a decrease in the size of COPT. If the size of COPT decreases the time taken to calculate the energy indices decreases, which leads to a decrease in the total execution time.

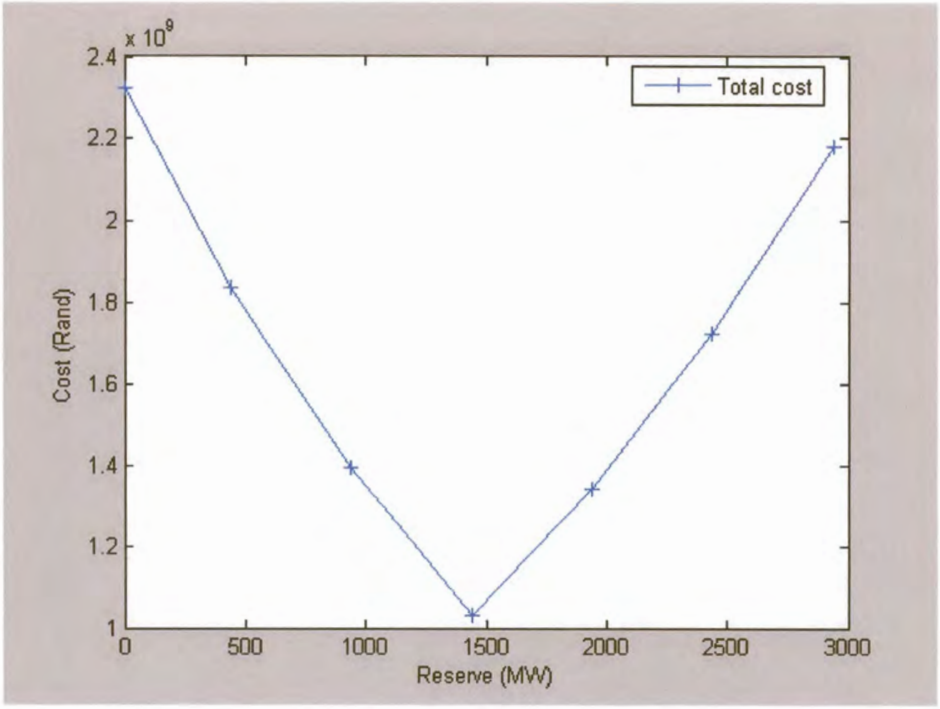


Figure 34: The optimal reserve for a reserve capacity step of 500 MW.

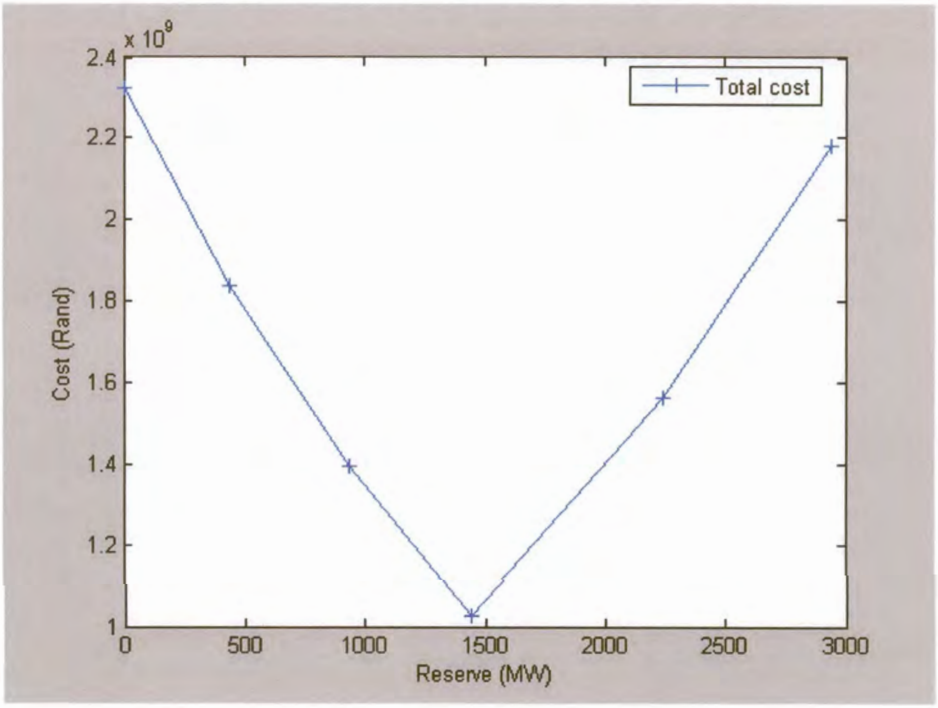


Figure 35: The optimal reserve for a reserve capacity step of 800 MW.

A summary of the results is presented in Table 31 for the different case studies. From this table it can be seen that Case 2 gives the best results for a reserve capacity step size of 300 MW. The effect of increasing the reserve capacity step reduces the model execution time as can be seen in Case 3. The optimal reserve calculated for the different scenarios is the same. The execution time for Case 2 will reduce as a result of an increase in the reserve step size.

Table 31: Summery of the results presented for Cases 1 to 3.

	Reserve step size	**Optimization method**	**Profiling time (min:sec)**	**Actual time**	**Optimal reserve (MW)**
Base Case	300	Model II	109:46	11:08	1440
Case 1	300	Matrix indexing	26:55	20:20	1440
Case 2	300	Reserve reduction	41:52	4:27	1440
Case 3a	300	Model II	109:46	11:08	1440
Case 3b	500	Model II	66:46	7:35	1440
Case 3c	800	Model II	57:04	6:43	1440

5.1.5 Case 4. Reducing the size of COPT

In a practical system, the probability of having a large quantity of capacity forced out of service is usually quite small as this requires several units to be out of service. COPT incorporates all the possible system capacity states. Table 31 can be truncated by omitting all the capacity states for which the cumulative probability is less than 10^{-6}. This results in a considerable saving in computing time as the table is truncated progressively with each additional unit. The capacity outage probabilities can be calculated as the units are added or calculated directly as cumulative values, with little error made [1].

In the GROM using this technique the probability of a capacity state occurring is compared to a threshold value, if the probability of that state occurring is less than the threshold value, the value is added to the following capacity state. The capacity outage state in the matrix increases as the model progresses through the matrix and the optimisation will show the system to be less reliable than it actually is (Table 32).

Table 32: A comparison between the base case, Case 2 and Case 4.

Case	LOEE error (MWh)	Capacity states	Execution time (Minutes)
Base	0	31335	11:08
Case 2	0	28975	4:27
Case 4	0.3	5262	0:25

Comparing Case 2 with Case 4, it can be seen that both studies determined the optimal reserve to be 1 440 MW. In Case 2 COPT has 28 975 capacity states with a total execution time of 4 minutes and 27 seconds. In Case 4 the capacity states have been reduced to 5 262 states with a total execution time of 25 seconds. A trade-off is made between accuracy of and the speed of execution time. Using the profiling function, Case 4 took 3 minutes and 28 seconds to execute with the results given in Figure 36 and Table 33 to Table 35.

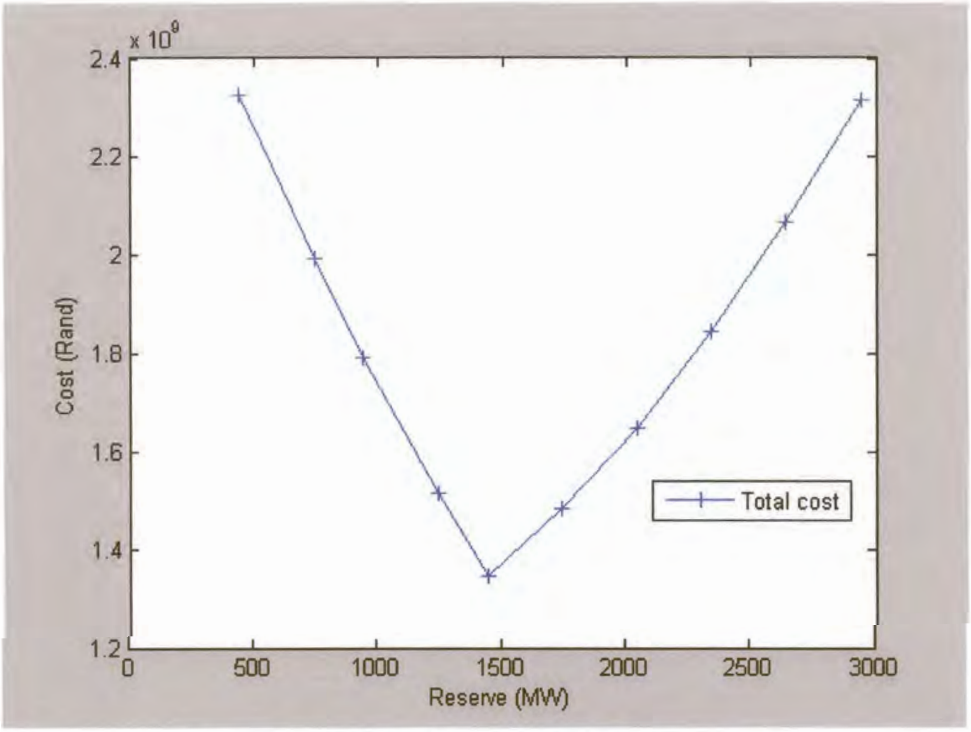


Figure 36: The optimal reserve calculated using case 4.

Table 33: The summary provided by the profiling function for Case 4.

Function name	Calls to function	Total execution time (s)	Function execution time (s)
EskomH	1	208.62	17.80
ProbabilityOldMinusC	79 400	98.31	98.31
ProbabilityOld	79 400	97.51	97.51

Analysing Table 34, one can conclude that 94.3% of the total execution time is spent in functions ProbabilityOld and ProbabilityOldMinusC. Studying Table 34 and Table 35, it will be seen that approximately 93% of the total execution time is spent in 'other lines and overheads'. Consequently the actual execution time is approximately 7 seconds in each function, which amounts to 7% of the total execution time. It is in calling these functions where the greatest time saving is made when compared to the other case studies.

Table 34: The summary provided by the profiling function for function ProbabilityOld.

Line number	**Code**	**Calls to function**	**Total time (s)**
14	If-function	246 698 897	4.327
18	End	246 698 897	1.892
17	counter	246 698 897	0.667
28	End	246 698 897	0.050
Other lines and overhead			90.612
Total			97.51

Table 35: The summary provided by the profiling function for function ProbabilityOldMinusC.

Line number	**Code**	**Calls to function**	**Total time (s)**
13	If-function	246 698 897	4.514
17	End	246 698 897	2.080
16	counter	246 698 897	0.651
28	End	246 698 897	0.006
Other lines and overhead			91.137
Total			98.391

The first part of this Chapter has focussed on execution speed of the GROM. Four different techniques were used to improve the execution speed of the model. The first technique used a matrix indexing technique. This technique used a searching technique, which determined an upper and lower limit when searching for a specific capacity state. The search techniques correctly located the required capacity state but the logical functions took longer to execute if compared to when the program iterates through COPT in a sequential way. Therefore this was not a suitable improvement.

The second technique reduced the execution time by considering the total reserve provided by the last unit committed to the load in one capacity step. If the amount of reserve provided by the last unit was greater than the selected reserve capacity step, the execution speed of the program will increase. By using this method a small saving in the execution speed was gained.

The third technique reduced the execution time by increasing the reserve capacity step. By increasing the reserve capacity step, less data points are available to determine the optimal reserve. Caution must be exercised when increasing the reserve capacity step because the model may incorrectly calculate the optimal reserve if the cost to the customer and utility is approximately the same over a wide range of capacity steps. Therefore it is important to keep a balance between the capacity step and the execution time.

The fourth technique presented the truncated the COPT for a threshold value of less than 10^{-6}. By reducing the amount of capacity states LOEE and LOLP can be calculated faster, which decreases the program execution time. This technique has reduced the program execution time the most with little error made when calculating LOEE.

5.2 Sensitivity Analysis

The aim of this section is to determine how sensitive the GROM is to a change in IEAR, change in the capacity step size and the influence of FOR on the optimal reserve.

The test system presented section 3.6.1 will be used as the base case and the different variables will be compared to this model. The optimal reserve for the base case is presented in Figure 37. The optimal reserve in this figure is for GROM without truncating COPT. COPT is truncated for probabilities of less than 10^{-6} to increase execution speed. If the probability of a certain capacity state occurring is less than 10^{-6} in order the probability of that capacity state is added to the next capacity state until the threshold value is exceeded. By adding the cumulative probabilities the power system is determined to be less reliable than it actually is, but the error made is small and the optimal reserve is the same as when COPT is not calculated.

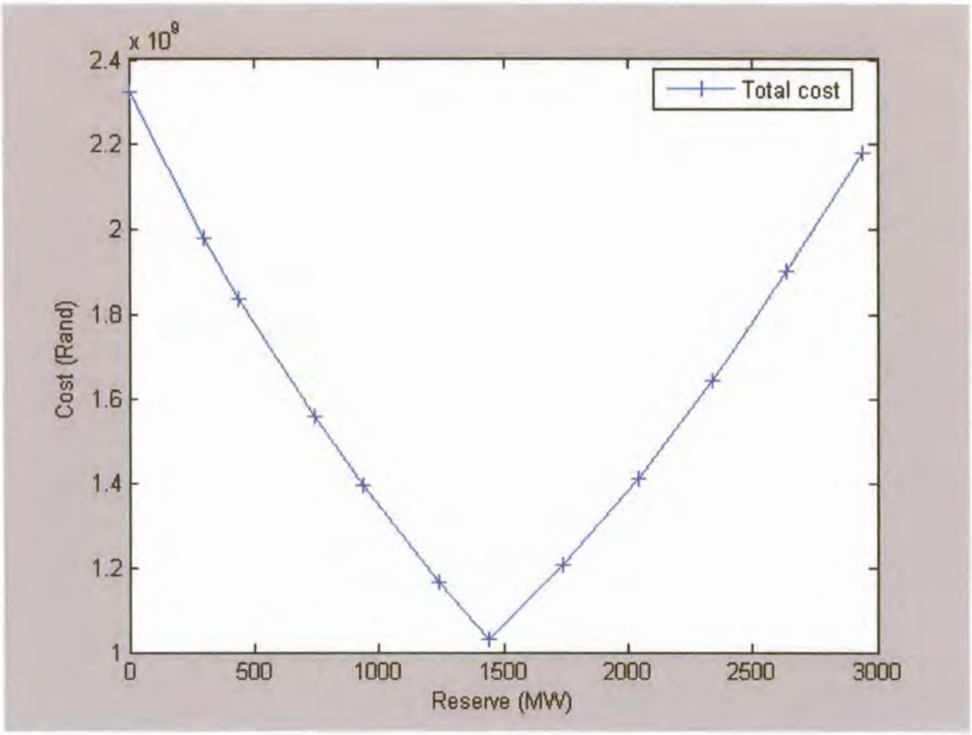


Figure 37: The optimal reserve calculated without truncating the COPT.

The optimal reserve given in Figure 31 is for the GROM with the test data presented in section 3.6.1. The model truncates COPT for a capacity state of probability less than 10^{-6}. It can be seen by comparing Figure 31 (truncating COPT) with Figure 38 (not truncating COPT) that no error is made when determining the optimal reserve. In both studies the optimal reserve is 1 440 MW. The error is made when calculating LOEE and therefore the cost to the customer for reserve.

The next section will focus on determining how sensitive the GROM is to a change in IEAR. This will be followed by a study focussed on determining how sensitive the GROM is to a change in the reserve capacity step when determining LOEE. In this study it will be illustrated that the error made is very small and as a result it will be shown that the model is not sensitive to a change in the load capacity step size when determining the optimal reserve. The last study presented will determine how sensitive the model is to a change in FOR of the generating units.

5.2.1 Sensitivity to a change in IEAR

The aim of this section is to determine how sensitive the GROM is to a change in IEAR when calculating the optimal reserve.

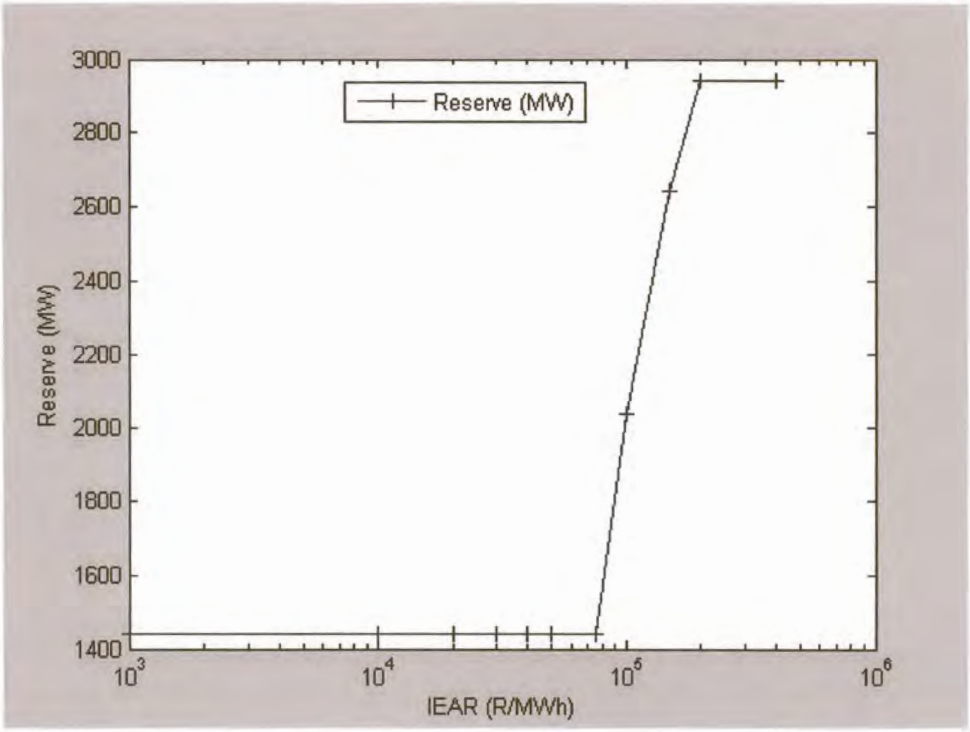


Figure 38: The influence of IEAR on determining the optimal reserve.

The optimal reserve determined is based on the cost to the customer and the utility. The total minimal cost is used as the optimal reserve. (3.7) illustrates the cost to the customer for a change in LOEE. LOEE is kept constant in this study and IEAR is the only variable that is changed. It can be seen from Figure 38 that the optimal reserve determined is constant at 1 440 MW for a change of IEAR from (R 1 000/MWh) to R 75 000/MWh. By increasing IEAR to R 100 000/MWh the optimal reserve is determined to be 2 640 MW and by increasing IEAR to R 200 000/MWh the optimal reserve is 2940 MW.

In conclusion to this part of the study, it can be seen from Figure 38 that the optimal reserve determined is fairly insensitive for a change in IEAR. IEAR is a measure of what it costs the customer (the South African economy) for a MWh of energy not available as reserve. In reality, when IEAR increases, the cost to the utility to dispatch these reserve units will also increase. The utility must replace the old generating units with new units. This leads an increase in to the fixed cost of supplying energy and reserve as well as an increase in the cost of fuel which is used to generate power.

5.2.2 Sensitivity to change in the capacity step size

The aim of this section is to investigate how sensitive the GROM is to a change in the capacity step size. The test system is used to investigate the sensitivity.

The optimal reserve calculated for the different capacity step sizes is 1 440 MW for capacity step sizes of 50, 100, 200, 300 and 500 MW. The optimal reserve calculated by truncating COPT is 1 440 MW for the different capacity step sizes, therefore no error is made in the calculation of the optimal reserve.

An error is made when calculating LOEE and the influence of the reserve capacity step size on LOEE calculated is presented in Figure 39. COPT is truncated by adding the probabilities of a certain capacity outage until it exceeds a threshold value of 10^{-6}. The value of the accumulated capacity state is then given as the probability of losing that capacity. By changing the threshold value from 10^{-6} to 10^{-8} no error is made when calculating LOEE.

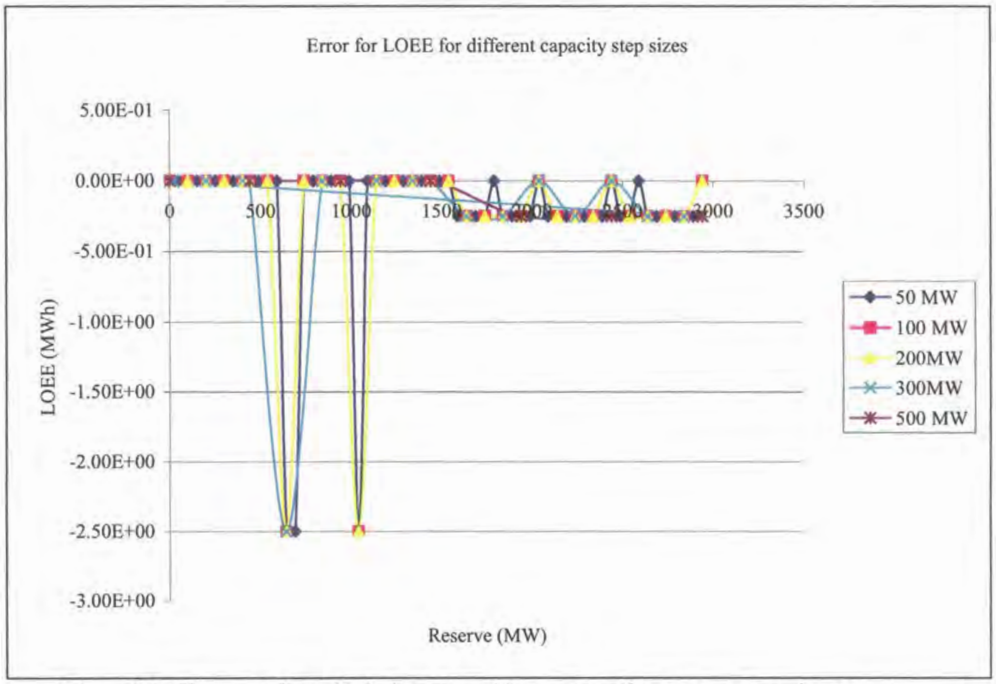


Figure 39: The error for calculating altered by varying the reserve capacity step size.

It can be seen from Figure 39 that the error made when calculating LOEE is small. The maximum error is 2.5 MWh for the day, in the next capacity step the cumulative probability is zero and the probability is added until the threshold value of 10^{-6} is exceeded. Figure 40 shows the error made for a reserve capacity step of 300 MW when the threshold value is changed.

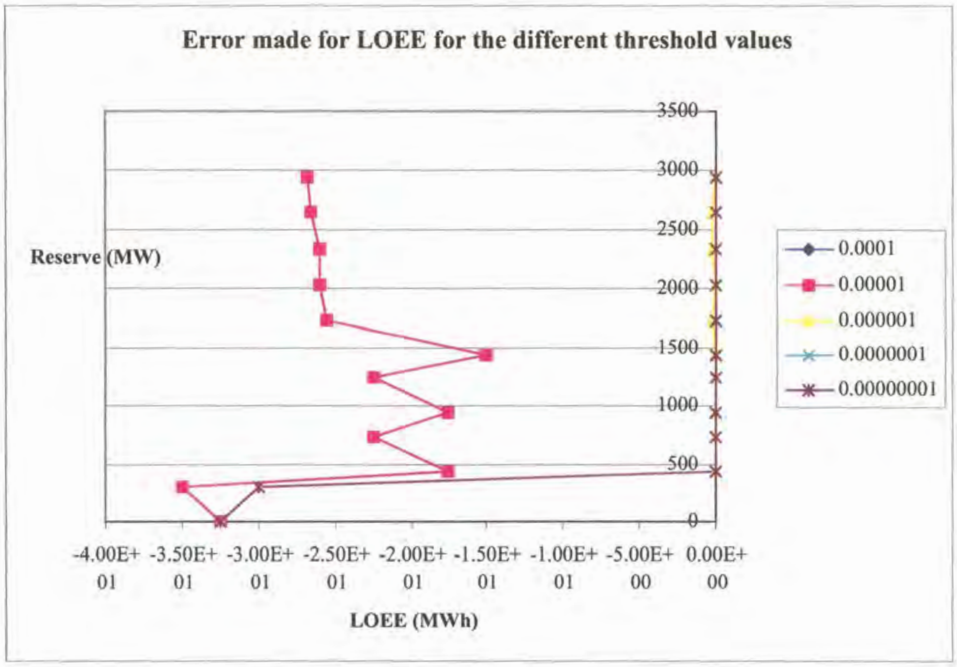


Figure 40: The error made for the different threshold values when truncating COPT.

It can be seen in Figure 40 that the error made when LOEE is calculated is reduced if the threshold value is reduced. The largest error is made when the threshold value is 10^{-3} and the smallest error is made when the threshold value is 10^{-7}. It is recommended that the threshold value must be smaller than 10^{-6} [1].

5.2.3 Sensitivity to a change in FOR

The aim of this section is to investigate the influence of FOR on determining the optimal reserve using the GROM and the test system in section 5.1.1.

The reliability of a power system is increased by reducing the FOR of the generating units. With the increased reliability, LOEE will decrease which will lead to a reduction in the cost to the customer given in (3.6). The same is true for reducing the reliability on the units: the cost to the customer will increase because LOEE will increase, which in turn will lead to an increase in the optimal reserve.

Figure 40 illustrates how sensitive the model is to a change in FOR.

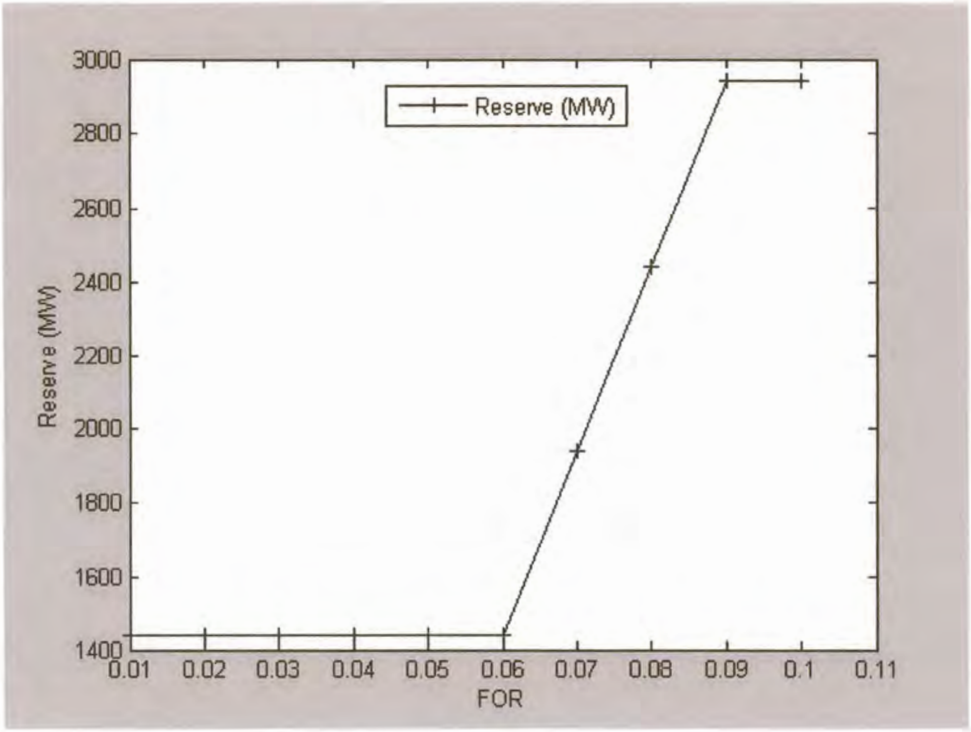


Figure 41: The optimal reserve determined as a function of FOR.

It can be seen from Figure 41 that the model determines the optimal reserve to be 1 440 MW for a change in FOR from 0.01 to 0.06 for the base case scenario. The reserve increases as FOR of the generating units increases, this was expected because with an increase in FOR, LOEE will increase which in turn will increase the required reserve.

The aim of the second part of this chapter was to identify how sensitive the GROM is to changes in IEAR, the reserve capacity step size and FOR of the generating units. By changing IEAR the optimal reserve determined was 1 440 MW for an IEAR of R 1 000/MWh to R 75 000/MWh. By increasing IEAR to R 100 000/MWh the optimal reserve is determined to be 2 640 MW and if IEAR is increased to R 200 000/MWh the optimal reserve is 2 940 MW.

This study shows that the model is not as sensitive to a change in IEAR for values below R 1000/MWh. By truncating COPT a small error is made when calculating the optimal reserve. By decreasing the threshold value of truncation during the construction of COPT, the error made when calculating LOEE decreases. Finally it was found that by increasing FOR the reserve requirement increased. The model is not sensitive for FOR of below 0.06 and increases linearly with an increase in FOR as can be seen from Figure 41.

5.3 Comparing the model with the old Eskom model

The model previously used by Eskom is presented in appendix 2. The model in appendix 2 is compared to GROM. The model presented in appendix 2 is comprised of generation units only while the GROM is based on the energy market currently used by Eskom. This model is comprised of generation units, DMP, IL and emergency reserve. Because of a lack of generating reserve capacity and an ever-increasing power demand, Eskom has introduced DMP. The GROM will be validated against the model in Appendix 2. The benefits of incorporating DMP (in the form of IL) and emergency reserve in the reliability cost/worth method will be investigated.

The model in Appendix 2 will be tested using the test data presented in chapter 3 in section 3.6.1. The load profile in Table 15 is presented in Figure 42. Three case studies will be used to test the two models.

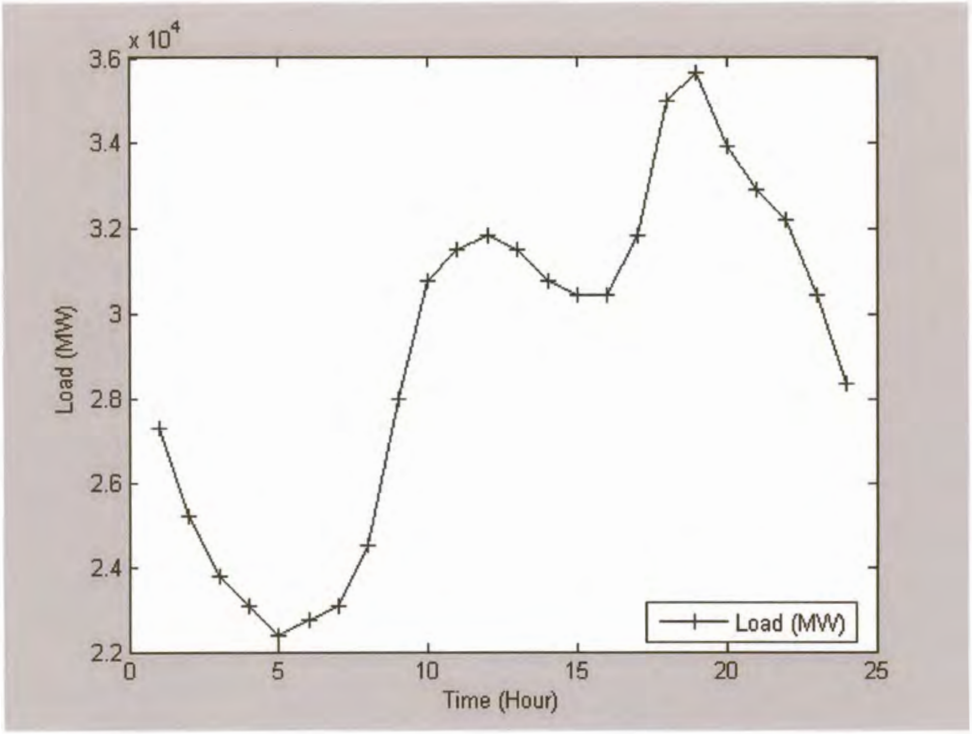
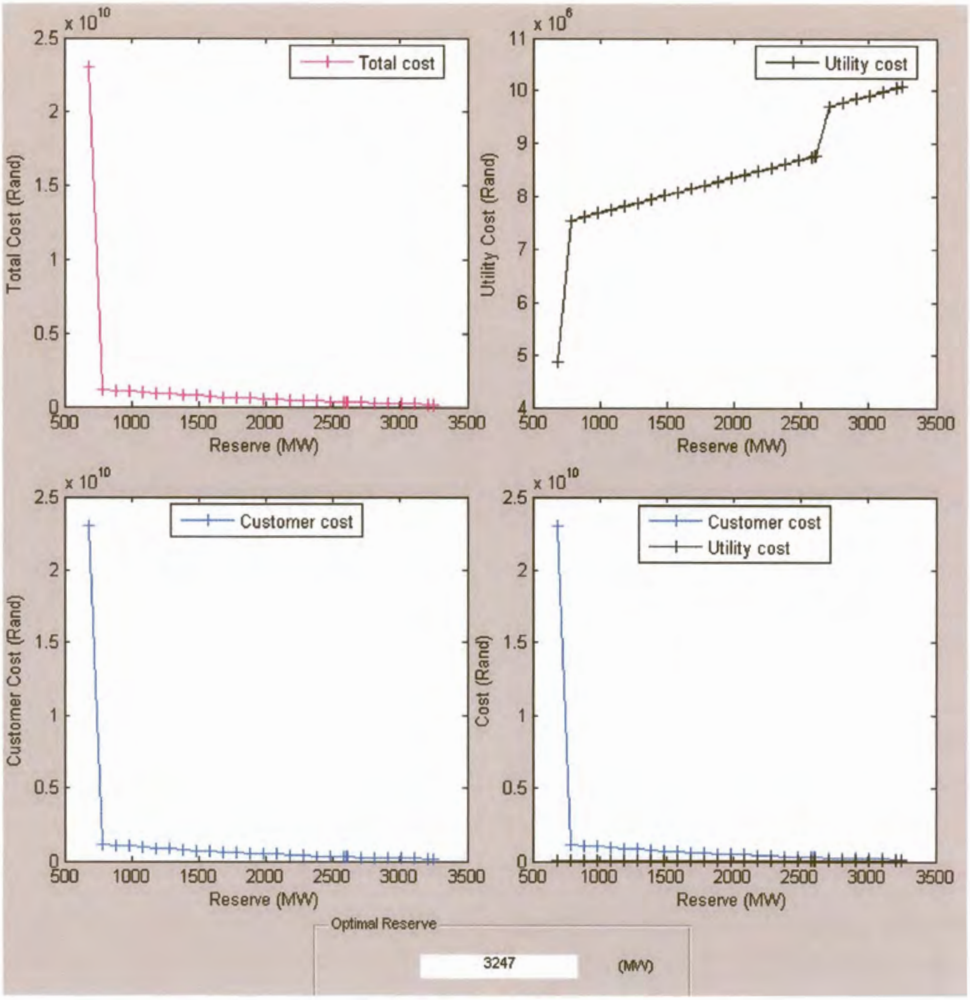


Figure 42: The load profile for the data presented in Table 15.

5.3.1 Case 1: Off-peak scenario

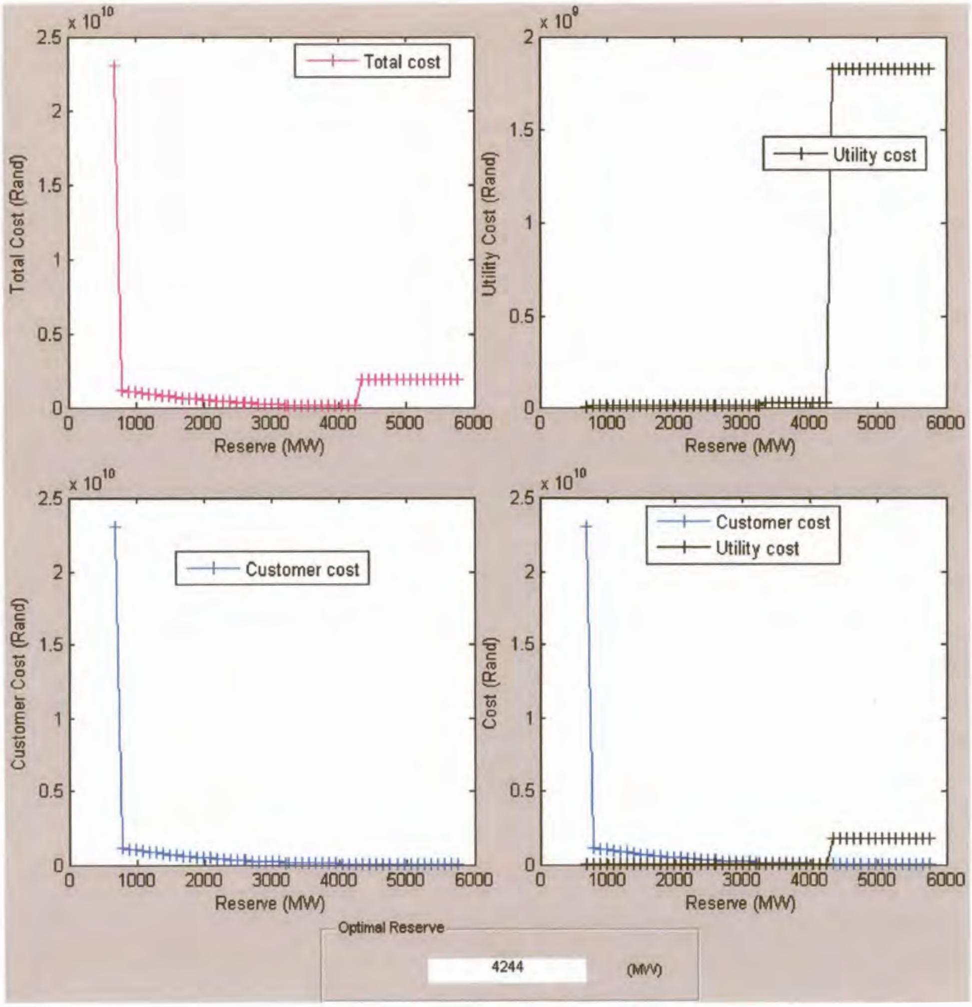
It has been assumed that one 900 MW and two 640 MW units are on a forced outage and one unit of 620 MW is undergoing maintenance. The two peaking stations are also not available (1 000 and 400 MW). The expected load is 28 000 MW.



Optimal Reserve

3247 (MW)

Figure 43: The optimal reserve using the model presented in appendix 2.



Optimal Reserve
4244 (MW)

Figure 44: The optimal reserve GROM for Case 1.

By comparing Figure 43 with Figure 44 it can be seen that by using DMP and emergency reserve, the available reserve has increased from 3 247 MW to 4 244 MW. In both models the units used to cover the load have a relatively high FOR, therefore the cost of reserve not available to the customer is much higher than the cost to the utility to provide the reserve. The benefit of adding DMP and emergency reserve to the model presented in appendix 2 is that the total cost to the customers and the utility for the optimal reserve has been reduced from R 314.57 million to R 173.39 million.

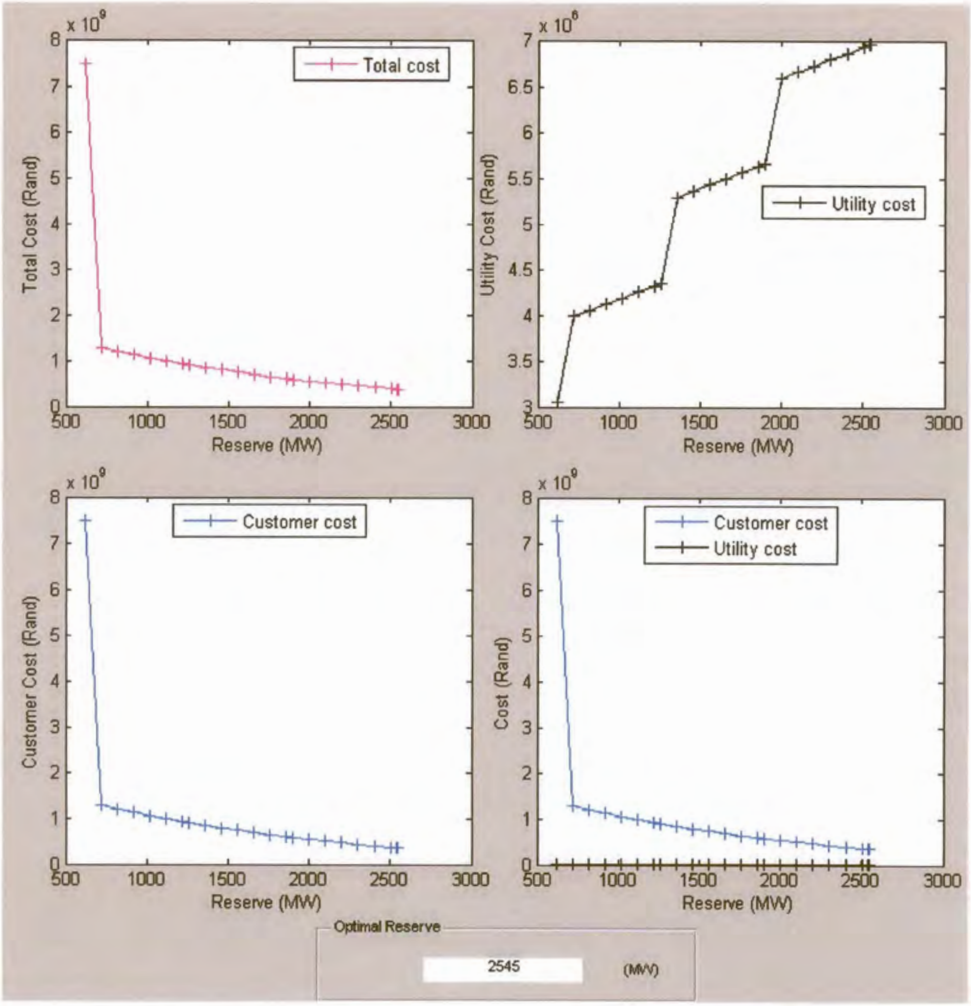
By implementing DMP the power system stability is improved: if a customer is affected by load shedding the capacity by which the customer is affected is available to meet the load demand. In conjunction with the other reserve, units are able to supply the required demand much faster. The example used to illustrate this point in chapter 3 can be used here. If a reserve of 500 MW must be provided and DMP customers A and B are used: 200 MW of capacity is instantly available if ten units, each with a ramping rate of 20 MW/min, are used to provide the required reserve. The reserve capacity will be replaced within 90 seconds, while if the two DMP customers were not used it would have taken 210 seconds to provide the 500 MW capacity. It must also be taken into account that during this time the power system stability is at risk.

The GROM can be used as a tool to investigate the influence of maintenance on the generating units. By improving the reliability of the different units the cost to the customer can be reduced by reducing LOLP and LOEE. The important units on which maintenance must be done can be identified and a maintenance schedule can be constructed. The second case study is presented in the next section. It evaluates the performance of the two models under a normal power system load.

Please note that the two models presented in chapter 3 and appendix 2 uses the HLI study to determine the optimal reserve for the South African electricity supply industry. The cost to the customer referred to in the text is actually the cost to the economy for reserve provided.

5.3.2 Case 2: Normal load scenario

It is assumed that all the generating units are available except for the two peaking stations of 1000 MW and 400 MW. The load is 31 500 MW.



Optimal Reserve
2545 (MW)

Figure 45: The optimal reserve using the old Eskom for Case 2.

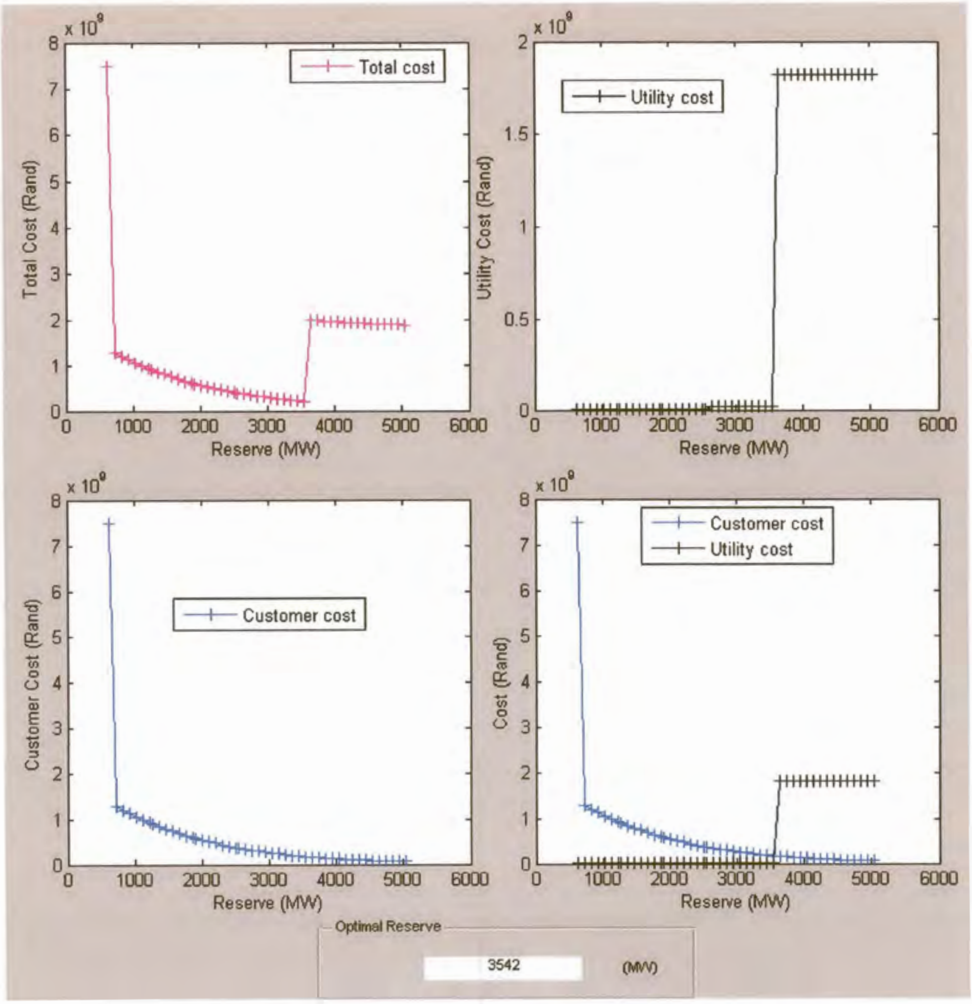


Figure 46: The optimal reserve for the GROM for Case 2.

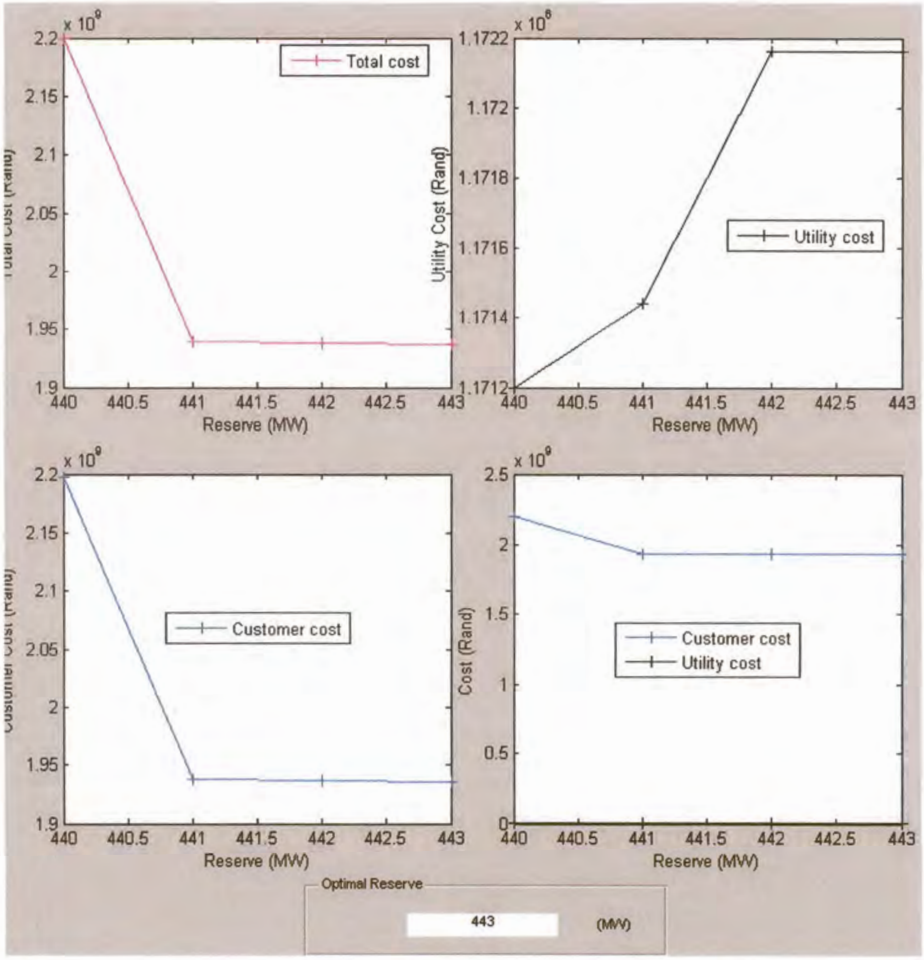
The loading order for the three case studies is the same. When comparing this case study to Case 1 it can be seen that more units are available to meet the demand, but the load demand has increased to 31 500 MW. For both models the cost to the customer for not having the reserve available is much higher than the cost to the utility for dispatching the reserve units. The cost of optimal reserve using the old Eskom model is R 421.09 million and by using DMP and emergency reserve the cost of the optimal reserve has decreased to R 227.74 million. Comparing the cost of optimal reserve from Case 1 to Case 2, the increase in the cost of the optimal reserve is due to an increase in the demand. Some of the reserve capacity used in Case 1 is used to meet the load demand in Case 2.

Therefore the system will be less reliable compared to Case Study 1 and the cost to the customer will be higher for unsupplied energy. More units are scheduled and as a result the total cost of reserve to the utility has increased.

In Case 3 the system will be operating under peak load conditions with the peak stations available to be scheduled.

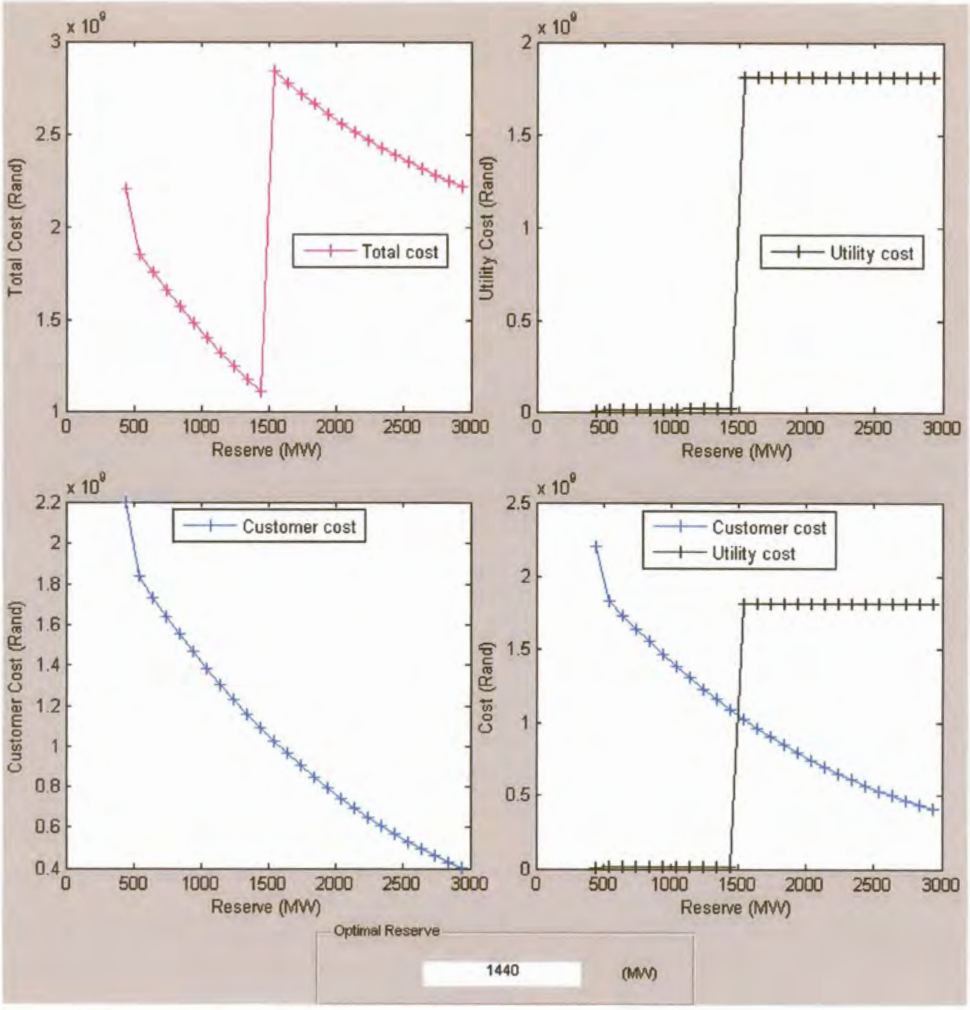
5.3.3 Case 3: Peak load scenario

It is assumed all the units are available to be scheduled. The expected load is 35 000 MW.



Optimal Reserve
443 (MW)

Figure 47: The optimal reserve using the old Eskom model for Case 3.



Optimal Reserve

1440 (MW)

Figure 48: The optimal reserve for the GROM for Case 3.

The optimal reserve for the two models is presented in Figure 47 and Figure 48. The optimal reserve for the old Eskom model is 443 MW. This is all the available spare capacity. The total cost of reserve is R 2 110.1 million. By using the GROM, the optimal reserve is determined to be 1 440 MW with a total cost of R 1 210.4 million. Once again an enormous saving is made by implementing DMP and emergency reserve while improving power system stability.

5.4 Concluding remarks

The reliability cost/worth method is used to determine the optimal reserve for a power system based on the benefits derived from the reserve of the customer and the utility. Three case studies were presented and it can be seen that the GROM is better suited to the energy market currently used by Eskom than the model previously used by Eskom (presented in appendix 2). The benefits of using GROM over the model presented in appendix 2 is that:

- DMP, IL and emergency reserve serve to increase the available reserve capacity when the cost of energy is high.
- It reduces the total cost of optimal reserve for the utility and the customer.
- It helps stabilise the power system after a disturbance has occurred by replacing the power demand faster when compared to not having DMP available.

Therefore by including DMP, IL and emergency reserve in the reserve optimisation, the optimal reserve can correctly be determined for the South African energy market. The old Eskom model does not take DMP, IL and emergency reserve into consideration when determining the optimal reserve. The financial benefit of incorporating DMP, IL and emergency reserve into the reserve optimisation can be calculated by using the GROM.

This chapter was divided into three sections. In the first section, four techniques were presented to improve the execution time of the GROM. By truncating COPT for a threshold value of less than 10^{-6}, LOEE and LOLP can be calculated faster, which decreases the program execution time. This technique has reduced the program execution time the most with the least error made when calculating LOEE. The second part of this chapter investigated the influence of IEAR, capacity step size and FOR on determining the optimal reserve. This study shows that the GROM is not that sensitive to a change in IEAR for values below R 1000/MWh. By truncating COPT a small error is made when calculating the optimal reserve and the model is not sensitive for FOR of below 0.06. The optimal reserve increases linearly with an increase in FOR. The third part of this Chapter compared the GROM with the old Eskom model.

It was seen that large savings are made when including DMP, IL and emergency reserve in the South African energy market and the GROM correctly determined the optimal reserve and resulting savings for this market.

The focus of the next chapter is to explain how the GUI was constructed and what the requirement was from the power system operator.

CHAPTER 6

THE GRAPHICAL USER INTERFACE (GUI) FOR THE RESERVE OPTIMISATION MODEL

Power system operators from Eskom are currently using the reserve optimisation model to determine the optimal reserve for the South African reserve market. The operator does not want to change the variables of the reserve optimisation model in the Matlab™ code, therefore the need exists for a GUI. A GUI must:

- be user friendly and easy to use,
- not contain too much information, and
- contain input and output information.

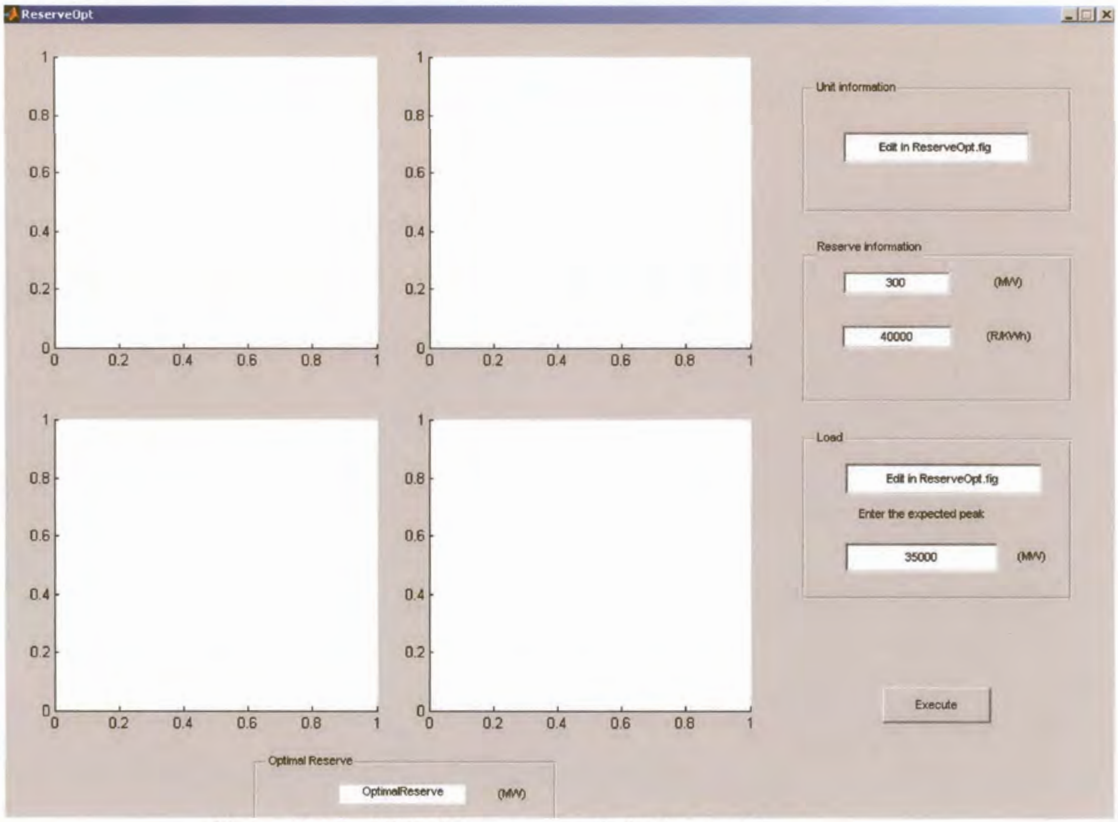
The input variables are entered in the GUI and the GUI automatically updates the variables in the Matlab™ code. The Graphical User Interface Development Environment (GUIDE) has been used to construct the GUI.

In the following section the layout and orientation, entering of variables and the execution of the model will be discussed.

6.1 The model layout, entering variables and the execution of the model

The layout of the GUI is given in Figure 49. It was requested that the model return four graphs:

- the total cost to the customer and utility,
- the cost to the customer and utility on one graph,
- the cost to the customer, and
- the cost to the utility.



Unit information: Edit in ReserveOpt.fig

Reserve information: 300 (MW); 40000 (R/KWh)

Load: Edit in ReserveOpt.fig

Enter the expected peak: 35000 (MW)

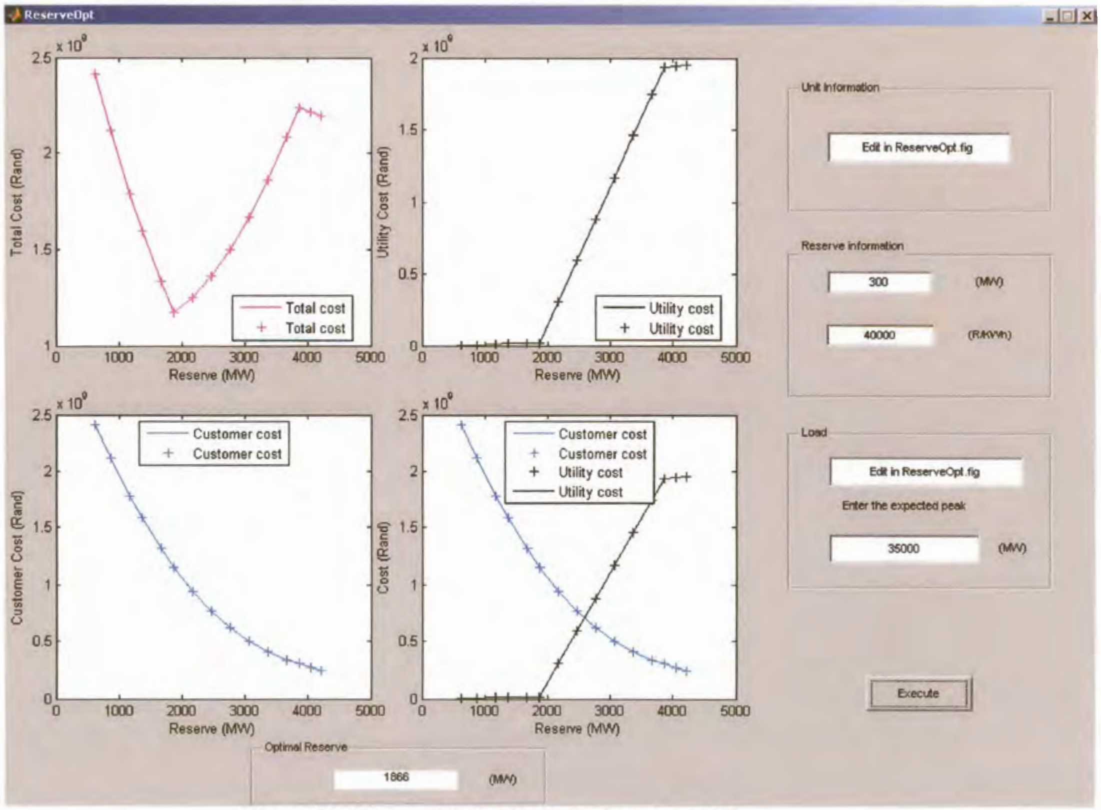
Optimal Reserve: OptimalReserve (MW)

Figure 49: The GUI of the reserve optimisation model.

The user interface is divided into three areas:

- input variables,
- graphs, and
- execution of the model.

The input variables are located at the right hand-side of the user interface. The unit information contains the unit size, FOR and the fixed and variable costs. In the reserve information panel the reserve step size and IEAR are edited. In the load panel the load profile for the day and the expected peak load are edited. After the model has executed, the graphs are displayed on the four axes shown in Figure 49 and the optimal reserve is returned to the optimal reserve panel. The results for the model using the data as used in chapter 5 are given in Figure 50.



Unit Information: Edit in ReserveOpt.fig

Reserve information:
300 (MW)
40000 (R/kWh)

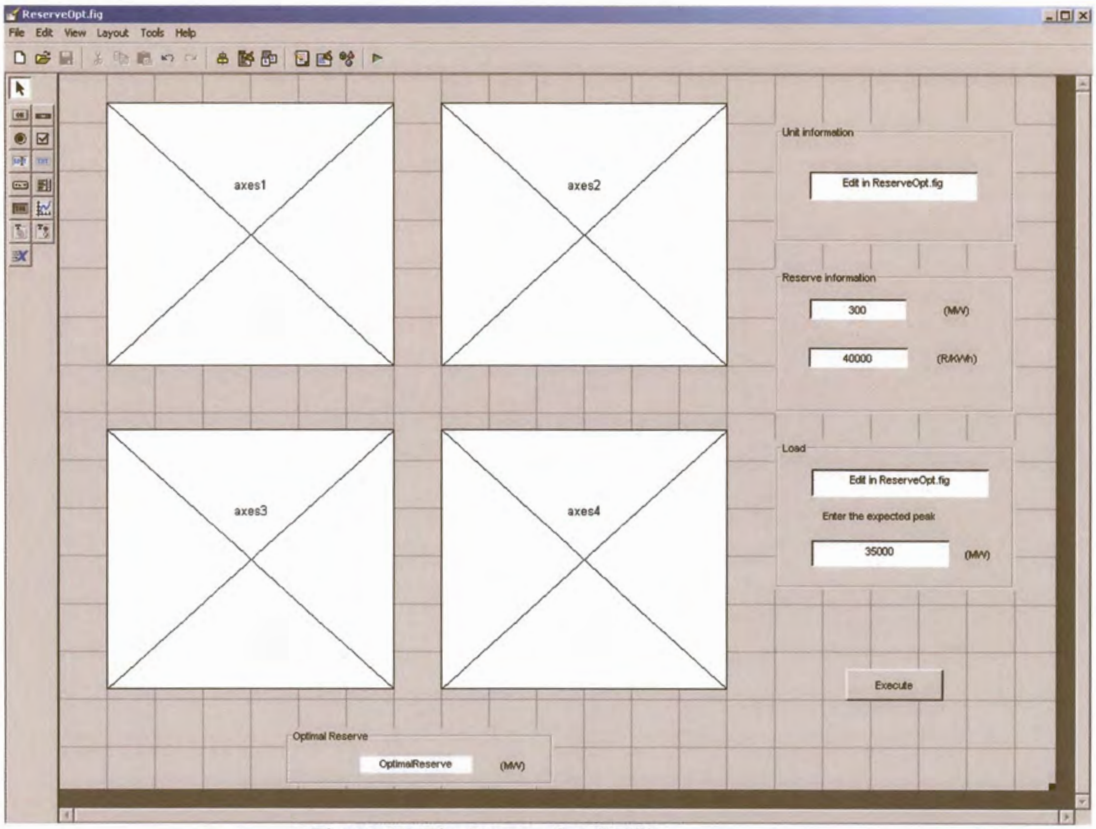
Load: Edit in ReserveOpt.fig
Enter the expected peak: 35000 (MW)

Optimal Reserve: 1866 (MW)

Figure 50: The results for the base case scenario.

The unit information and the load data are edited in ReserveOpt.fig file because the variable matrix has more than one row and one column. The ReserveOpt.fig file is given in Figure 51. To edit the unit information and load profile the "Edit in ReserveOpt.fig" box has to be double clicked. The property inspector will open and the unit information can be edited in the CData matrix as seen in Figure 52. The same method has to be followed to edit the load data matrix.

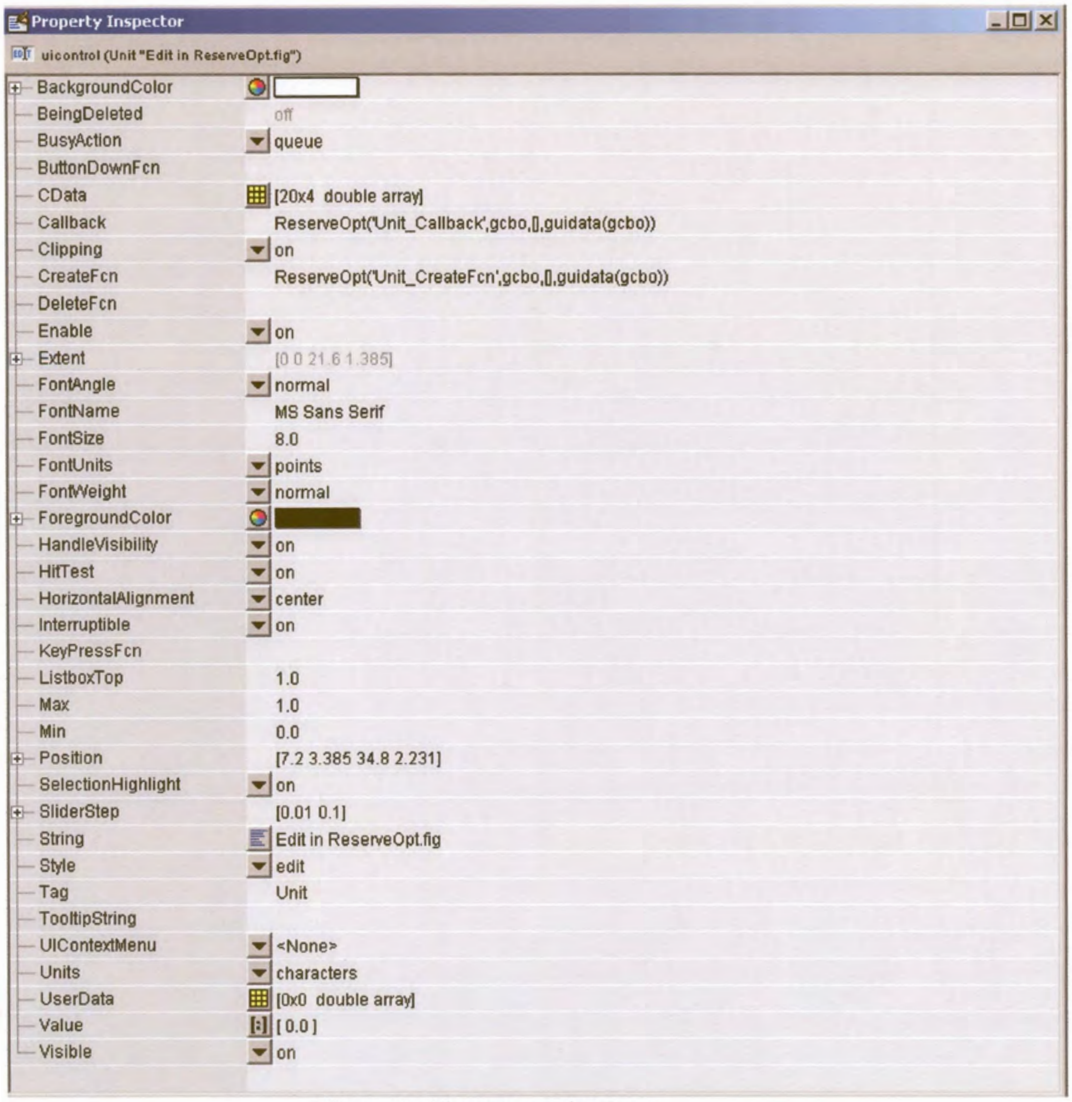
Before the model can execute the ReserveOpt.fig file has to be run. This can be done by clicking the 'Run' button in the taskbar, or by clicking 'Run' in the 'Tools' dropdown menu. Figure 49 will be displayed and after editing and pressing the 'Execute' button Figure 49 will change to Figure 50.



Reserve information
300 (MW)
40000 (R/kWh)

Enter the expected peak
35000 (MW)

Figure 51: The ReserveOpt.fig file.

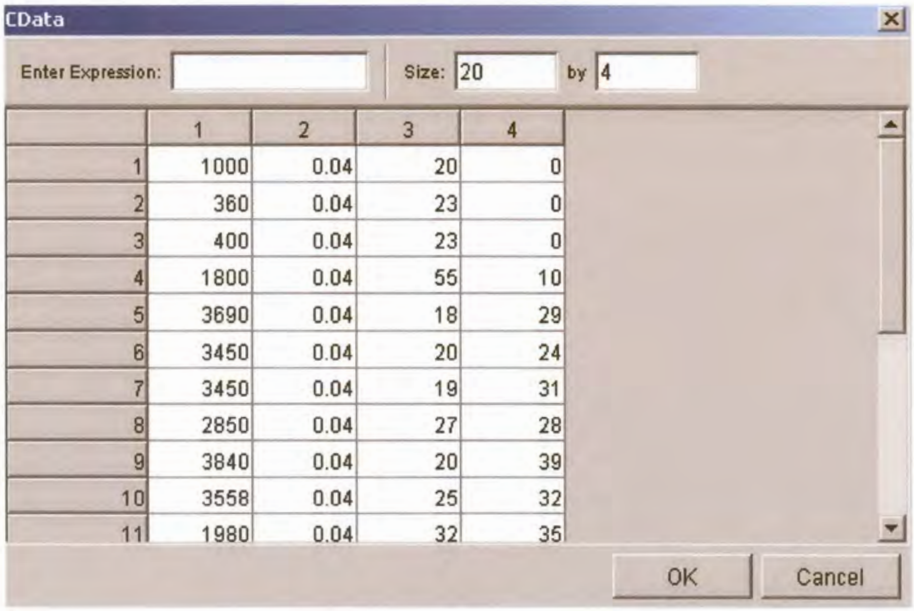


Property Inspector

uicontrol (Unit "Edit in ReserveOpt.fig")

BackgroundColor	⬜
BeingDeleted	off
BusyAction	queue
ButtonDownFcn	
CData	[20x4 double array]
Callback	ReserveOpt('Unit_Callback',gcbo,[],guidata(gcbo))
Clipping	on
CreateFcn	ReserveOpt('Unit_CreateFcn',gcbo,[],guidata(gcbo))
DeleteFcn	
Enable	on
Extent	[0 0 21.6 1.385]
FontAngle	normal
FontName	MS Sans Serif
FontSize	8.0
FontUnits	points
FontWeight	normal
ForegroundColor	⬛
HandleVisibility	on
HitTest	on
HorizontalAlignment	center
Interruptible	on
KeyPressFcn	
ListboxTop	1.0
Max	1.0
Min	0.0
Position	[7.2 3.385 34.8 2.231]
SelectionHighlight	on
SliderStep	[0.01 0.1]
String	Edit in ReserveOpt.fig
Style	edit
Tag	Unit
TooltipString	
UIContextMenu	<None>
Units	characters
UserData	[0x0 double array]
Value	[0.0]
Visible	on

Figure 52: The property inspector.



Enter Expression:

Size: 20 by 4

	1	2	3	4
1	1000	0.04	20	0
2	360	0.04	23	0
3	400	0.04	23	0
4	1800	0.04	55	10
5	3690	0.04	18	29
6	3450	0.04	20	24
7	3450	0.04	19	31
8	2850	0.04	27	28
9	3840	0.04	20	39
10	3558	0.04	25	32
11	1980	0.04	32	35

Figure 53: The CData matrix for the unit data.

By including a GUI the power system operator can change the variables of the model in the user interface, increasing program execution time and reducing the probability of making an error when calculating the optimal reserve. Another benefit of using the GUI is that all the graphs are available and the operator can see how the cost to the customer and utility influences the reserve calculation.

6.2 Concluding remarks

This chapter explained how the GUI was laid out. It was requested that the four graphs in Figure 50 be available to determine how big the influence of the cost to the customer and utility is when determining the optimal reserve. Before the user enters the input variables the default screen is displayed. After the 'Execute' button is pressed, the optimal reserve calculated is returned to the optimal reserve panel and the four graphs are displayed. The rest of the chapter explained how the operator can change the variables. For more information on how to use the model and the GUI, please refer to appendix 3.

The next chapter concludes the six chapters presented.

CHAPTER 7

SUMMARY AND CONCLUSIONS

The aim of this chapter is to conclude on the work covered by this research. This chapter is subdivided into three sections. The three sections conclude the extent of the work covered in each chapter they discuss the contribution made to the field of research and they suggest further research.

7.1 Work presented

In the first chapter deterministic and probabilistic techniques were defined as the two groups of methods used to determine the amount of reserve to be scheduled for a power system. Deterministic techniques do not take into consideration the reliability of the units used to schedule reserve as with probabilistic techniques. Therefore, to more accurately determine the optimal reserve for the South African electricity supply, industry it would be better to use a probabilistic technique.

The focus of the second chapter was to identify how reserve for the different utilities and power pools is determined, and how the reserve are defined. It was seen that most of these utilities use deterministic techniques to determine the amount of reserve to be scheduled. A literature review was undertaken which studied the different probabilistic methods used to determine the optimal reserve. All the identified methods use reliability and risk indicators to determine the optimal reserve. A comparison between the references was made and the reliability cost/worth method was identified as the best method to be used to determine the optimal reserve for the South African electricity supply industry.

In the third chapter the reliability cost/worth method was presented. The generation model is convolved with the load model to obtain the risk model. The risk model was then used to determine the optimal reserve based on the cost/worth of the reserve provided. The total minimal cost to the utility and the customer is identified as the optimal reserve. The remainder of the chapter was devoted to expand the reliability cost/worth method to be more applicable to the South African reserve market. The reliability cost/worth method was expanded to include DMP, IL and emergency reserve.

The fourth chapter focussed on validating and comparing the GROM. The GROM was compared to two other models. The model presented in [7] uses a cost-benefit approach to determine the optimal reserve, whereas the model presented in [3] uses Lagrangian relaxation based on the UC and a predefined risk index to determine the optimal reserve. The IEEE RTS of 1996 was used to compare the optimal reserve of [3] and [7] with the optimal reserve of the GROM. By comparing the optimal reserve of [3] and [7] with the optimal reserve of the GROM, it was seen that there is a small difference and can be concluded that the GROM correctly determines the optimal reserve.

The fifth chapter assessed the performance of the GROM. In the first part of the fifth Chapter different techniques were investigated to reduce the execution time of the model. The most effective method identified truncates COPT. The capacity state with a probability of less than 10^{-6} is removed from the capacity states table and the probability is added to the next capacity state's probability until the threshold value of 10^{-6} is exceeded. By reducing the amount of capacity states, LOEE and LOLP can be calculated faster, which decreases the program execution time. This technique has reduced the program execution time the most with little error made when calculating LOEE. The second part of the fifth chapter investigated how sensitive the model is to a change in IEAR, a change in reserve capacity step size and a change in the units' FOR. It was seen that the model is relatively insensitive to a change in these variables. The third part of chapter 5 investigated what the influence is of incorporating DMP, IL and emergency reserve in the reserve optimisation model. It was concluded that by incorporating DMP and IL in the reserve optimisation model, the financial saving made by DMP can be verified and the optimal reserve can be calculated more accurately. Therefore, by including DMP, IL and emergency reserve, the optimal operating reserve can be determined for the South African energy market.

The layout and construction of the GUI is explained in chapter 6. This chapter must be read together with appendix 3 to use the reserve optimisation program correctly.

7.2 Original contribution

The contribution to this field of study is that the reserve optimisation model was developed specifically for the South African energy market. This model expanded the reliability cost/worth method to include DMP and IL customers. These customers were modelled as dummy generators, each with a forced outage rate, available capacity, and fixed and variable costs (which are included in the reliability cost/worth method). The research questions presented in chapter 1 is answered in this research:

1. A survey is presented in chapter 2 which identifies the different methods used globally to determine the reserve margins for the different utilities.
2. A reserve optimisation model is presented in chapter 3 which determines the optimal reserve for the South African energy market.
3. DMP and IL are modelled as dummy generators, each with a forced outage rate, available capacity, fixed and variable costs, and scheduled together with the thermal units to determine the optimal operating reserve. Please refer to the model in chapter 3.
4. The model presented in chapter 3 (GROM) is validated in chapter four by comparing the results for three different models using the same test system.
5. Different optimisation techniques are presented in chapter 5 to improve model execution time.

The application of this model is not limited to the South African energy system, but can be applied to any power system which does not have enough installed capacity to perform routine maintenance and supply the load demand. By introducing DMP in the form of IL, generation capacity is made available when no excess capacity is available or when the cost of energy is high.

7.3 Future research

Eskom is using this model to determine the optimal operating reserve for the South African energy market and is satisfied that the model correctly determines the optimal operating reserve. It was proposed that the model commits the units using a two-state loading model. The first segment commits the unit from 0 MW to minimum loading and the second segment commits the unit from minimum loading to maximum loading. The model currently commits the units based on the capacity step size as entered by the operator and the minimum loading cost is included in the variable cost of the units. By using this two-state loading model, the variable cost for minimum loading can be specified. The optimal reserve determined must be the same before and after the two-state loading model has been implemented, because the variable cost used by the GROM assumes the minimum load cost is included in the variable cost component of the unit.

The model presented in Chapter 3 determines the optimal operating reserve. This model can be improved by determining the optimal mixture of generation, DMP and IL for the optimal operating reserve. This can help the power system operator to identify which DMP customer to use with the generating units to compensate for the unit's ramping rate. This will increase power system stability and help identify the frequency and duration of which the DMP customer is interrupted. The model presented in Chapter 3 assumes the power system operator will select the optimal mixture of DMP and generating units used to provide reserve. A study can be undertaken to determine how practical it will be to implement this function.

CHAPTER 8

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ADDENDUM A1

ADDENDUM A1

Table 36:Comparing the different methods used optimize the generator reserve.

	[4]	[5]	[6]	[7]	[8]	[9]	R Ferrero et al [10]
How is the reserve optimised	Price for reserve is used along with unit reliability to find the balance between the cost of reserve and risk of not providing for it. $SMP < VOLL\,FOP\frac{C_{m}}{R_{i}}$	For small isolated power systems After loss of unit economic dispatch is done to determine minimum reserve to prevent under frequency load shedding	Reserve minimization is part of the objective function and the reserve is not explicitly optimised.	Reserve is optimised w.r.t. cost-benefit analysis. Cost to provide reserve is compared to the cost of not supplying reserve.	The power system is dived into 4 areas, the amount of reserve and load shedding for that area are determined. If generation is lost the reserve and load shedding must compensate for gen.	Look at cost and risk when allocating reserve in a power system.	The spin reserve are optimally allocated and priced using this method.
What indices are used in the optimization	IEAR SMP	PPLL (what is costs the utility)	Not stated	IEAR EENS	Not stated	CBSRAM RBSRAM	Not stated.
Is UC considered	Yes	Yes	Yes	No	No	Yes	Yes.
What method are used for the optimization	Augmented Lagranain dual function with recurrent Neural Network from Hopefield type	Heuristic method (see the paper for details)	Mix integer linear programming coordinated over time by dynamic programming	Heuristic method (see paper)	Bender's Decomposition. System response is simulated using Runga-Kutta, Newton Rhapson for load flow.	Heuristic method is used to allocate spin reserve in the power system.	Lagrianian Relaxation.
What constraints are used in the UC problem	Min up and down time Min and Max MW values Unit FOP	Min and Max MW Demand constraint Emissions	Min and Max MW Max reserve Min up and down time Time off Cooling time Unit failure rates	N/A	N/A	Cost of spin reserve. Risk of allocating reserve at a specific bus.	Reserve at each bus. Line flow constraints. Gen power must be equal to demand, local and export reserve.
For UC is the Cost function linear, quadratic, ect.	Non linear	Not stated	Piece wise linear	N/A	N/A	Not stated.	Not stated.
What makes the paper unique	Determines only to supply reserve or not, doesn't optimise reserve	Method for small isolated power systems	Balance between reliability and cost but didn't include SMP	Model is used for Pay-as-bid and uniform price model	Specific for the Northern Chilean supply industry.	Allocate reserve based on cost and risk.	Looks at line losses, local and export reserve.
What different plants are considered	Thermal but it can be applied to other as well	Not stated	Not stated	Not stated	Not stated. But applicable to any plant.	Not stated.	Not stated.
Disadvantages	Determines only to supply reserve or not, optimise reserve w.r.t. cost of interruption to the utility	Determines only to supply reserve or not, optimise reserve w.r.t. cost of interruption to utility Small power systems Doesn't look at dynamic characteristics of Gen response	Determines only to supply reserve or not, optimise reserve w.r.t. cost of interruption to utility. Medium size power system. Fixed emergency requirement.	Not stated	Not stated	Not stated.	Not stated.
Assumptions	Lossless system without transmission constraints.	Not stated	Not stated	Not stated	Not stated	Not stated.	Not stated.
Is this method practically implemented	Test system of 17 Thermal units	17 Bus system, but has not been implemented	17 Bus test system.	IEEE RTS96	Yes, North Chilean supply industry (1300-1600 MW)	IEEE RTS96	3-Bus system is used.

ADDENDUM A1

Table 37: The reliability cost/ reliability worth methods.

	Billington et al [1]	Gooi et al [3]	Pabot [12]
How is the reserve optimized	Reliability cost/ reliability worth method	Risk index =(Product of 7 COPT) + (Demand Probability) Combines Lagrangian Relaxation with UC to determine the optimal reserve based on a predefined risk index and cost of EENS.	Reliability cost/ reliability worth method
How is the generation model modelled	COPT with Unit capacity Forced outage rates Failure rates Repair rates	COPT with Min up and down time Initial conditions Unit availability Must run and duration schedules	COPT with Unit capacity Forced outage rates Failure rates Repair rates
How is the load model modelled	The exact-state type load model is used to represent the sequence of discreet load levels.	Load forecast is normally distributed with a 7-step probability level model for the expected demand.	Load uncertainty is represented with load curves and associated probabilities up to 9 load curves.
How is the cost model modelled	The cost of interruption with their distribution of energy and peak for the service area or the CCDF.	Cost of EENS vs. Risk of supplying reserve.	The CCDF were obtained by a survey conducted for each consumer group.
What different plants are considered	Coal, Hydro, Nuclear, Oil and Gas	Not stated	Coal, Hydro, Nuclear, Gas and Pumped storage
Disadvantages	Not stated	Doesn't consider reliability of individual units	Doesn't consider the increase in reliability after a forced outage.
Assumptions	The probability distribution for a unit for a month is the same for a whole study period. The running costs for a unit will rise in a linear form.	Unit failures are exponential Load forecast uncertainties are nominal distributed	A 2 state Markov model. There is no limit on the number of units which can be replaced. The failed units can only be replaced at the end of the day.
Is this method practically implemented	RTS96.	26 Generator system.	Eskom network.

ADDENDUM A1

Table 38: A comparison of the elementary methods used in the unit commitment problem.

	Linear Programming	Network Flow	Dynamic Programming	Quadratic Programming
Objective Function	Linear / Linearized	Linear/ Linearized	Separable (decomposable into "step"-decisions)	Quadratic.
Constraints	Linear	Linear/ Linearized, variable coefficients only (0,-1,1)	Almost any	Linear/ Linearized.
Variables	Continuous	Continuous (or quasi-continuous integer)	Discreet/ discretized.	Continuous.
Usage	Single or with MIP, SLP	Single or with MIP, SLP	Single or with LR,SDP	Single or with LP, B&B
Advantages	Give a fast solution. Solve big problems that cannot be solved by other algorithms.	Much faster than LP-algorithms. Losses in flow can be modelled. Capable to deal with side constraints like load balance.	Any problem, which can be, stated as separable state transitions can be optimized.	High accuracy if load dispatch is required.
Disadvantages	Not stated.	Not stated.	Has to be customized for each problem. Number of independent discreet variables is limited-determining system states- is very low, because the number of states is determined by full enumeration of all variables. Therefore only a small system can be optimized. To solve larger system heuristic methods are used to reduce the number of state transitions.	Because only continuous variables are used, this method is not used in UC but in load dispatch.
Computational Time	Linear w.r.t. number of constraints. Dependant on the application and LP-formulation.	Less than quadratic w.r.t. problem size. 100 times faster than LP for Network problems.	Exponential w.r.t. number of system states. Linear w.r.t. number of transitions. Decreasing w.r.t. number of constraints.	Dependent on the problem.

ADDENDUM A1

Table 39: A comparison of the high level methods used in the unit commitment problem.

	Mixed integer (Linear) Programming	Branch and Bound	Lagrangian Relaxation	Successive Linear Programming	Successive Dynamic Programming	Benders decomposition	Simulated Annealing	Genetic Algorithm
Type			Mathematical decomposition (no optimization)		Decomposition/ Optimization.	Decomposition / Optimization	Heuristic Optimization	Heuristic Optimization
Objective Function	Linear, piece wise linear, non convex	Almost any.		Unimodal	Separable		Almost any	Almost any
Constraints	Linear, piece wise linear and discrete variables	Almost any.		Convex solution space.	Almost any		Almost any	Almost any
Variables	Continuous, Boolean, discrete, piece-wise continuous.	Boolean, discrete, integer.		Continuous	Discreet/ discretized		Discreet or continuous.	Discreet or continuous.
Usage	Single or with Heuristics	In combination with LP, QP	Only with other methods, LP, DP, ect.	Single with LP or with B&B and LR.	Single or with LR	Only with other methods like LP, QP, ect.	Single or with other methods.	Single or with other methods.
Advantages	Find the optimal solution even for non-convex problems.	It has an upper limit for the difference between the solution for continuous and discreet variables. The search strategy can be optimized by choosing the order in which the variables are discretized.		Applied to non-linear problems with continuous variables.				
Disadvantages	Algorithm has to be cut off to decrease calculation time. The "so-far best" solution is accepted and maybe not the best one.	Not stated.		Only used on a unimodal cost function.	Optimization depends strongly on the decomposition of the problem. If a solution converges there is no proof that it is the optimal one.		No proof of optimality, because it is a heuristic method.	
Computational time	Exponential w.r.t. number of discreet variables. Strongly problem dependent. Decreasing with number of constraints for discreet variables.	Exponential w.r.t. number of variables. Decreasing with number of constraints.		Linear increasing w.r.t. number of iterations. Otherwise determined by the LP algorithm.	Dependent on the implementation and the problem.		Dependent on the implementation and the problem.	Dependent on the implementation and the problem.

Note: High-level methods are often rather a solution process than an optimization method. The UC problem is replaced by a sequence of simpler problems which can be solved by one or several of the elementary methods.

ADDENDUM A2: THE OLD ESKOM MODEL

A2.1 Introduction

The techniques used by Eskom prior to 1997 were based on providing sufficient reserve to achieve a target LOLP of 5% over peak [2]. From 1997 onward studies have been done on a daily basis to derive the optimum amount of reserve plant capacity to be committed above the expected peak load forecast. This reserve has been called synchronized reserve or surplus capacity on-line. If one adds the capacity of quick start plant off-line and of interruptible load one arrives at the total operating reserve.

The operating reserve at Eskom is the plant capacity that may be called upon within 10 minutes. This consists of spinning and non-spinning reserve. Spinning reserve is split into instantaneous reserve (units on governing which can respond in 10 seconds) and regulating reserve (units on Automatic Governor Control (AGC) which can pick up load automatically in 10 minutes) plus some 10-minute reserve, which is held on generating units synchronized to the network. The non-spinning reserve consists of quick start plant not connected to the grid but available in 10 minutes and interruptible load customers. The non-spinning reserve is classified as 10-minute or emergency reserve. The 10-minute reserve is typically used more than once a week, and is bid into the day-ahead market. The pump storage and hydro plant is catered for here. Quick start plant (gas turbines) and interruptible load are classified as emergency reserve since they are infrequently used. Eskom also has a supplemental reserve category which mainly consists of generating plant that can be synchronized within 6 hours.

The non-emergency operating reserve is equal to the sum of the instantaneous, regulating and 10 minute reserve capacity since the same capacity may not be used for more than one category. This is equal to the spinning reserve plus offline available hydro and pump storage capacity.

A2.2 The model assumptions

The following assumptions were made before constructing the optimisation model [11].

- The generating units scheduled to be on-line for the next day is available at the time the schedule is drawn up. It is assumed they are already on-line and at risk of failure. Units that have failed may be repaired or replaced with an identical cold reserve unit after the call-up time has elapsed.
- The units follow a two-state Markov model in which units are either fully available to run at maximum output, or not available. This implies that the probability of changing state in any time interval is independent of what happened previously.
- The reserve requirement is calculated for the following day. It takes into consideration the load forecast and the units known to be available at the time of the schedule and which will be committed for the next day.
- Off-line hydro is treated as equivalent to spinning thermal reserve, i.e. the capacity has the same cost of reserve.
- A constant failure rate (L) and repair rate (M) is assumed for each unit. This results in an exponential model for the reliability R(t), or probability of finding the unit on-line at time t. If the unit replacement is ignored [1], then the outage replacement rate, ORR(t), or probability of finding the unit in the unavailable state at time t is given by:

$$ORR(t) = 1 - R(t) = F[1 - e^{-[(L+M)\times(t+t_p)]}] \tag{A2.1}$$

Where:

F the forced outage rate, and
tp the advance planning time i.e. the number of hours the schedule was drawn up before the start of the day being studied.

It can be shown [1] that

$$F = \frac{L}{L+M} \tag{A2.2}$$

The forced outage rate is defined as the probability of finding a set of plant out of service due to unplanned outage at any time.

There are two conceptual models programmed in the Eskom model, the second one having two variants. All three may be used for the SU and SR units. Only the first one is used for the RS units. The program uses these three models to calculate the ORR(t). The user selects one of the three options when entering the input data.

Option 1. Non – Equilibrium with Replacement.

All units are scheduled to be on-line during the day to fail and then be repaired using constant failure and repair rates. At time T after a unit fails it may be replaced by another identical unit even if it is not yet repaired. The bulk of the generators connected to the grid are 600 MW coal-fired units, therefore this is not a bad assumption provided the replacement time (call-up time) is similar for all cold reserve sets. For the RS there is no replacement of the unit. The user may decide to use a constant unplanned F for all hours instead of a time dependent ORR when entering the input data. (A3.1) applies until time t >= T – tp after which ORR is constant and we have.

$$ORR(t) = F[1-e^{-(L+M)T}] \tag{A2.3}$$

The model has three variations depending on what the user selects.

First variant / assumption: units operational at time t = 0, RLAPTM = 0

At time t = 0, i.e. hour 1, all the units included in the model population (scheduled, synchronized reserve and reserve resources) are operational, i.e. in the in-state. Each scheduled unit is represented with a two state Markov model (L the failure and M the repair transitions rates), i.e. can fail and be repaired. The Markov model of each unit starts in a transient state, with a probability of being in the failed mode varying hourly, from 0 to F within a few days. Synchronized reserve and resources are represented by a derated capacity state. Between hour 1 and hour 24, there is no change in the population of units, no removal from service, no replacement of failed units. The probability of being in the out state is ORR(t), as given in section A2.2.1 above. At hour h = 25, the model is reset to time 0, i.e. hour 1.
The fundamental operational assumptions are the following:

- The units selected by the scheduler for the day are operational at time t = 0. If any unit fails before the start of the day, the scheduler takes whatever action is necessary to repair it or replace it at time t = 0. In effect, replacement of failed units takes place at times t = 0, 24, 48, etc., and there is no limit on the number of units which can be replaced at these times. This is an optimistic assumption, i.e. it overestimates the reliability of the system. But if the scheduler is unable to replace a unit at t = 0, there is still a few hours left before the first peak hour to take some corrective action. The units selected by the scheduler for the day can fail and be repaired during the day, but are never replaced, up to the end of the 24 hours day.
- This is a conservative, pessimistic assumption, i.e. it underestimates the reliability of the system, since the operator could possibly start one of the units in cold reserve. This model may be slightly conservative, and overestimate the optimal operating reserve.

Second variant / assumption: units operational at time t = 0 - RLAPTM, RLAPTM > 0

This is a variant of Model 1, where it is now assumed that the units selected by the Scheduler are operational at the advance planning time for example RLAPTM hours before the start of the day. The Markov state of each unit is initialised then. At the beginning of the 24 hours day cycle, at time t = 0, units may already be in a failed state since RLAPTM hours have elapsed since the beginning of the Markov cycle. There is no replacement of failed units between the advanced planning time and the end of the day cycle, over a 24 + RLAPTM hours period. But units may be repaired during this time. Both variants are equivalent if RLAPTM = 0

Third variant / assumption: units replaced at time t = RLMTRP - RLAPTM, RLAPTM > 0, RLMTRP > 0

This is a variant of Model 1, where it is now assumed that the units selected by the Scheduler are operational at the advance planning time t = 0 - RLAPTM, and are replaced after the mean time to repair RLMTRP after a failure. In effect the Markov model reaches equilibrium at time t = RLMTRP - RLAPTM. This places a cap on the maximum outage replacement rate: see the following section.

Option 2: Equilibrium Markov Model.

In this model plant has an equal probability of being on forced outage at all times. This model is not used for the RS but the first model is used instead. Here for all values of h (from hour 1 to 24) we have.

$$ORR(t) = F[1 - e^{-(L+M)T}] \tag{A2.4}$$

As in the previous model, each scheduled unit is represented with a two state Markov model i.e. can fail and be repaired. The main difference with the previous model is the assumption that each unit which fails at any hour, either before t = 0 or after can be either repaired, or replaced by a similar unit after a fixed replacement time T = RLMTRP (mean time to repair). T represents the time to bring back an off-line unit on-line when requested. This might be the time to warm up a cold unit, or the time to finish repairing an off-line unit (not scheduled) in unplanned outage. The assumption of a fixed replacement time is quite arbitrary. T could be the average replacement time derived from statistics.

In effect, all units reach an equilibrium state after T hours since any unit which would fail at hour h would be repaired or replaced before or at hour h + T. The probability of a unit to be out at hour h > T is ORR(t = T) as given by (A2.4). Since each unit is in an equilibrium, the scheduled units may not be operational at time t = 0, i.e. at hour h = 1 of the day which is a slightly pessimistic assumption. However the cap placed on ORR(t) for all hours is a very optimistic assumption. Whether 1, 2, 3,…N units fail, they will be replaced. This assumes that there is an infinite pool of replacement units available at all times. This is also a very optimistic assumption. The fundamental operational assumption is the following.

- Every time a unit fails, the operator makes a decision to both get it repaired and get it replaced, even if it is the first unit to fail, irrespective of the time of the day, irrespective of the remaining reserve. Overall this model is quite optimistic, and underestimates the optimal operating reserve.

Option 3: Equilibrium Markov Model with replacement at a constant rate.

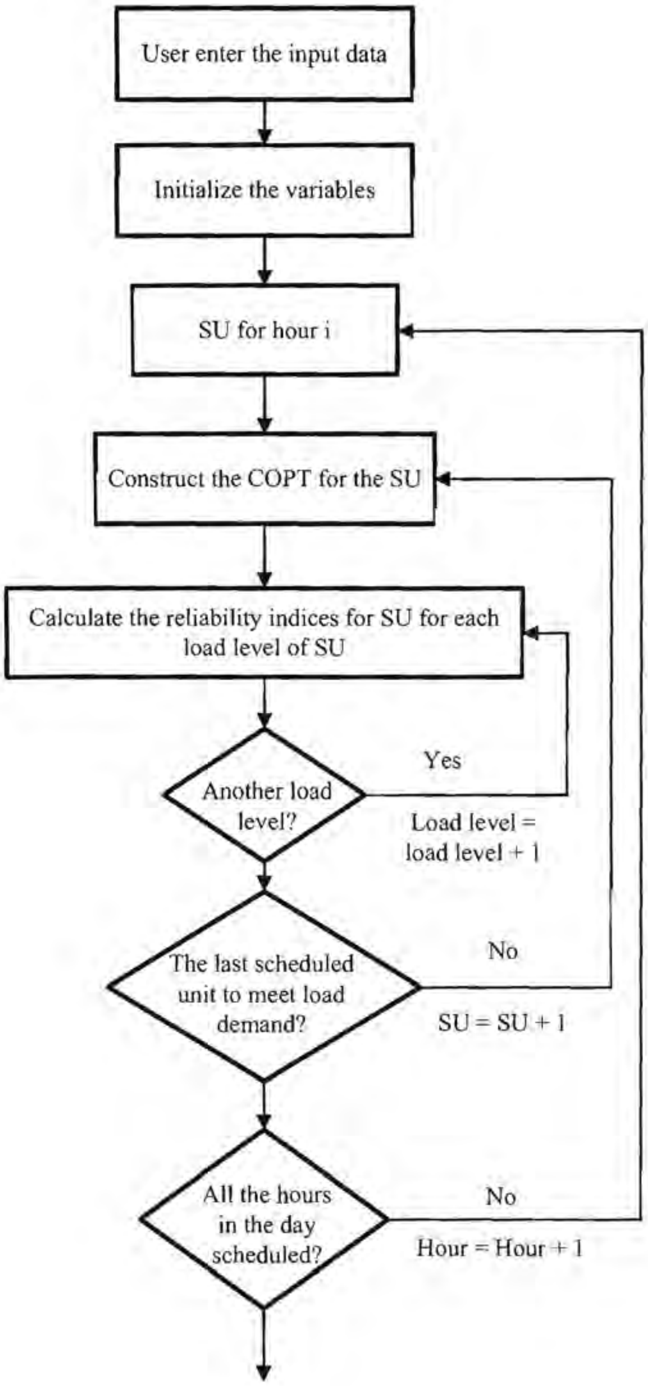
In this model the replacement of units by a cold reserve set is treated as an increase in the repair rate, M by 1/T. This model is not used for the RS but the first model is used instead.

$$ORR(t) = \frac{L}{L + M + \frac{1}{T}} \qquad (A2.5)$$

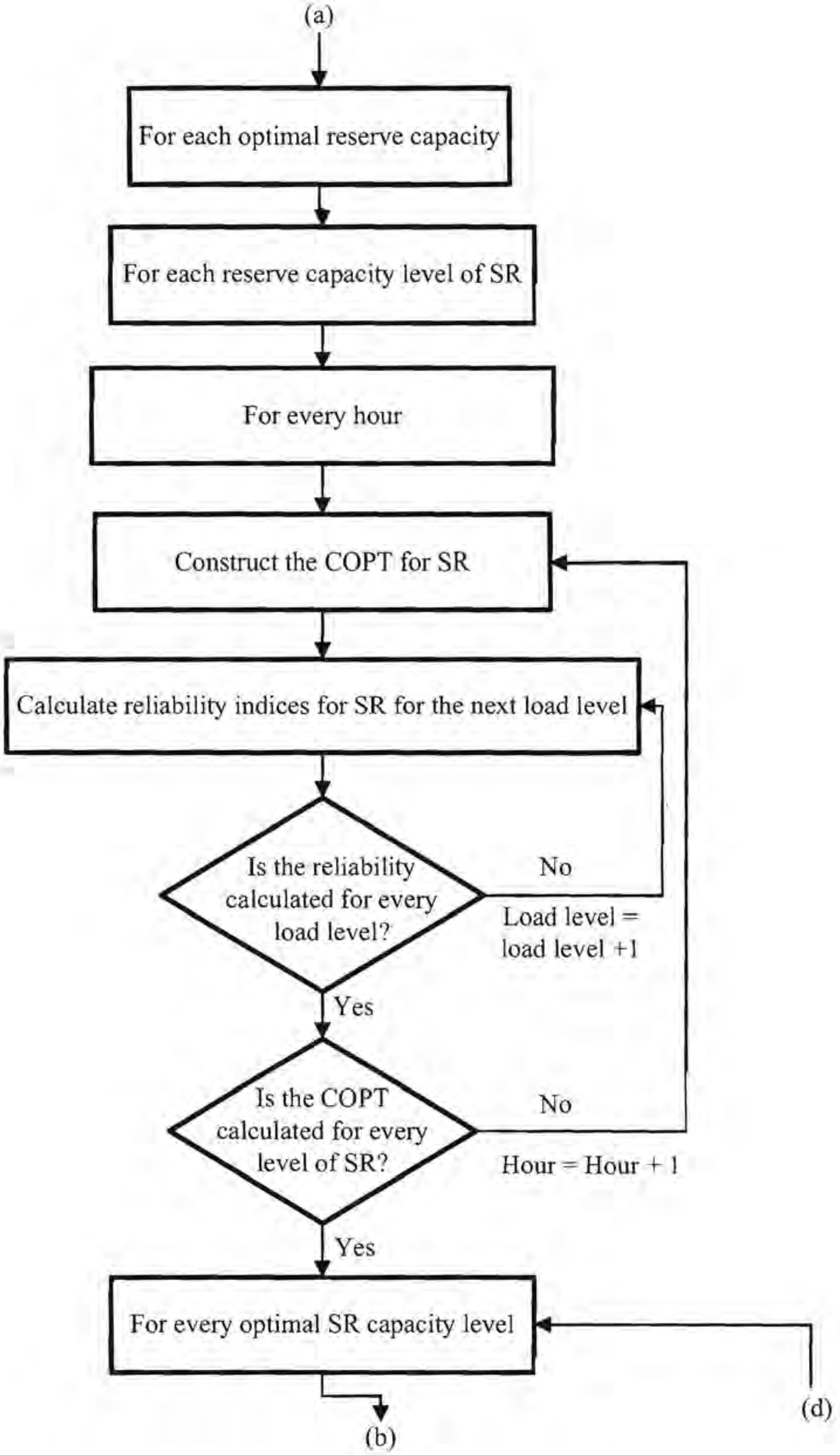
This model is very similar to the previous model. The only difference is the replacement rule algorithm. In the previous model, the replacement of a unit by an identical unit takes place after a fixed replacement time T = RLMTRP (lead time) after failure. Before and after T, the replacement rate is nil. In this model, an exponential distribution of the replacement time after failure is assumed with a mean time to replacement T = RLMTRP (lead time). Before and after T, the replacement rate is constant and is 1/T. The Markov model is modified, to reflect the dual transition mode from the failed out state to repaired in state, one with repair rate M and one with replacement rate 1/T. The Markov model is assumed to be at equilibrium, i.e. The ORR(t) is given by (A2.5).

The assumption that T has an exponential distribution is quite arbitrary. An analysis of the available statistics may be necessary to corroborate this assumption. Overall this model is more optimistic than the previous since a unit may be replaced at any time after failure, instead of after time T. It underestimates the optimal operating reserve even more than Model 2.

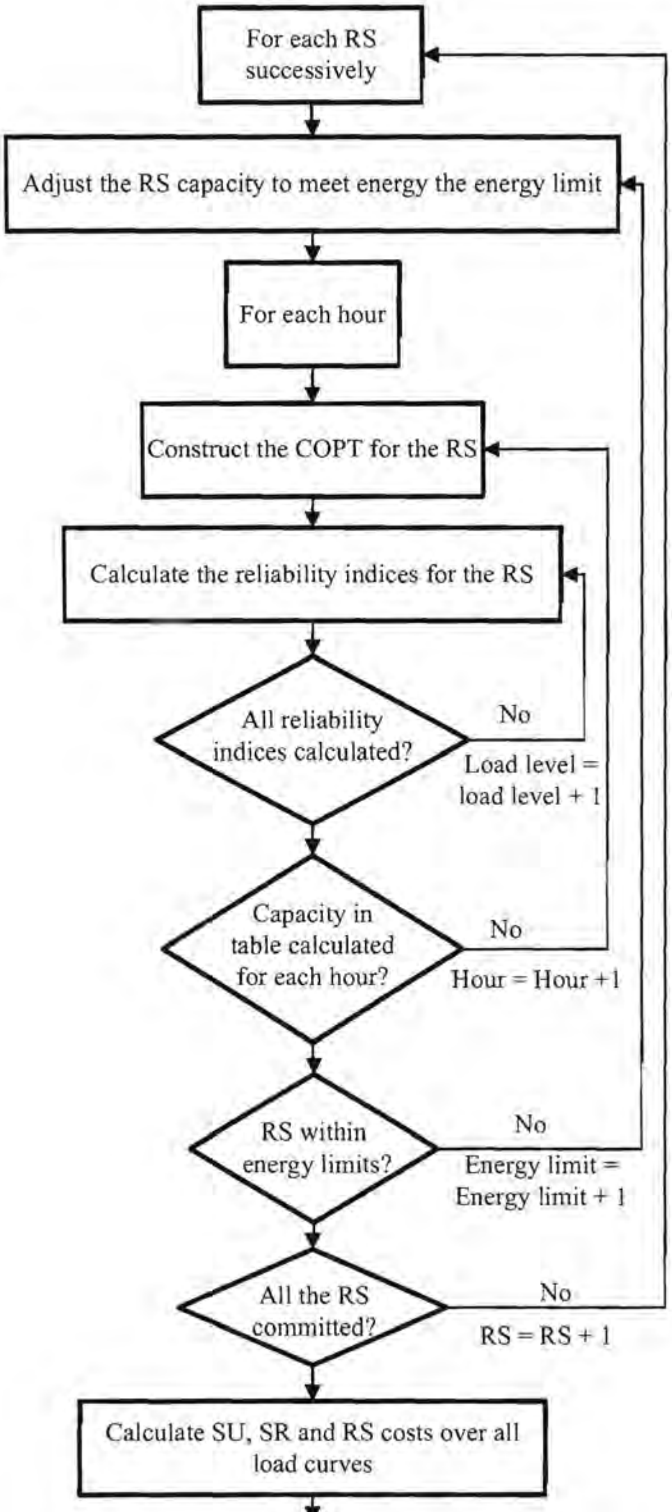
A2.3 The model



(a)


(a)
For each optimal reserve capacity
For each reserve capacity level of SR
For every hour
Construct the COPT for SR
Calculate reliability indices for SR for the next load level
Is the reliability calculated for every load level?
No
Load level = load level +1
Yes
Is the COPT calculated for every level of SR?
No
Hour = Hour + 1
Yes
For every optimal SR capacity level
(b)
(d)

(b)


For each RS successively
Adjust the RS capacity to meet energy the energy limit
For each hour
Construct the COPT for the RS
Calculate the reliability indices for the RS
All reliability indices calculated?
No
Load level = load level + 1
Capacity in table calculated for each hour?
No
Hour = Hour +1
RS within energy limits?
No
Energy limit = Energy limit + 1
All the RS committed?
No
RS = RS + 1
Calculate SU, SR and RS costs over all load curves

(c)

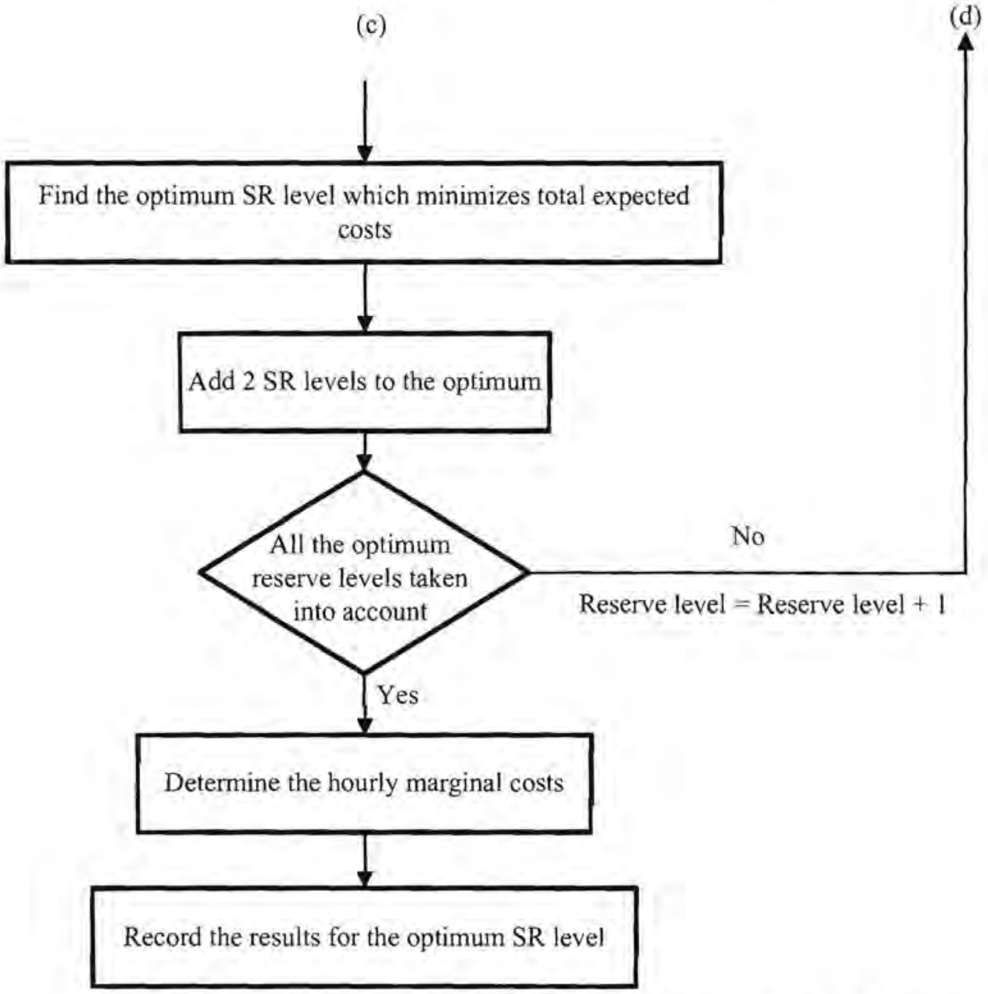


Figure 54: The logical diagram of the reserve optimization program used by Eskom.

A2.4 The model input data

The program [12] prompts the user to enter data for:

- The expected load
- The scheduled units input data
- The synchronized reserve input data
- The reserve resources input data
- The capacity-in table input data
- The reliability input data
- The program input data

The input data for the load is:

- The number of hours for which the load must be represented with a load curve the maximum number of hours is 24
- The load curves with its number, the maximum number of load curves are 9
- The probability of the load curve occurring
- The expected peak load of the day
- The expected hourly load

The input data for the scheduled units (SU) are:

- The number of stations, with a maximum of 200 stations
- The station identification name, with a maximum of 40 characters
- The number of units for the station
- The capacity of the station
- The variable cost for the station
- The fixed cost of the station
- The station's lambda failure rate and transitions per hour
- The station's mu repair rate and transitions per hour
- The station's unplanned outage rate (FOR).

The input data for the synchronized reserve:

- The number of capacity steps for the synchronized reserve. Here the user has an option to enter a fast optimal search. The default capacity step is 1 but a maximum of 50 can be entered
- The synchronized reserve total capacity
- The synchronized reserve capacity step
- The synchronized reserve fixed cost option. The default option is a linear SR fixed cost
- The other option is a non-linear SR cost. The non-linear SR fixed cost is calculated using (3.6)

$$SR\_FC = A + B \times (SU + SR) + C \times (SU + SR)^2 + D \times (SU + SR)^3 \qquad \text{(A2.6)}$$

- The fixed cost of synchronized reserve (if option 1 is taken)
- The variable cost of synchronized reserve
- The fixed cost coefficient A, of the synchronized reserve (if option 2 is chosen)
- The fixed cost coefficient B of the synchronized reserve. (if option 2 is chosen)
- The fixed cost coefficient C of the synchronized reserve. (If option 2 is chosen)
- The fixed cost coefficient D of the synchronized reserve. (If option 2 is chosen)
- The default values for the coefficients are A = 313.8; B = 5749.9; C = 7646.6 and D = 1364.6
- The lambda failure rate of the synchronized reserve and the transitions per hour
- The repair rate of the synchronized reserve and the transitions per hour
- The unplanned outage rate of the synchronized reserve
- The adjustment ratio of the synchronized reserve
- The adjustment option of the synchronized reserve option has 3 options:
  0 = no adjustment
  1 = adjustment upwards towards flat maximum SU capacity
  -1 = adjustment downwards towards load + constant reserve
- The unit capacity of the synchronized reserve
- The minimum spinning reserve for synchronized reserve the default is 716 MW

The input data for the reserve resources:

- The number of resources, with a maximum of 20
- The name of the resource, with a maximum 40 characters
- The type of resource

  0 = demand side, and

  1 = supply side.
- The maximum capacity of the resource
- The energy limit of the resource
- The fixed cost of the resource
- The Variable cost of the resource
- The lambda failure rate of the resource and the transitions per hour
- The repair rate of the resource and the transitions per hour
- The unplanned outage rate of the resource

The input data of the capacity-in table:

- The capacity step of the capacity-in table
- The scheduled units regrouping step option:

  0 = no regrouping, 0 = default value

  1 = regrouping after last SU unit is loaded

  k = regrouping after SU unit k is loaded, e.g k = 50
- The cumulative probability table option of the capacity-in table:

  0 = No, no derivation, (0 = default value)

  1 = Yes, derivation.
- The cumulative probability table option of the capacity-in table:

  0 = No,

  1 = Yes.
- The individual probability it is minimum for capacity-in table calculations

The reliability input data:

- The mean time to replacement
- The advanced planning time
- The reliability, outage rate option for SU and SR units:

1 = System not initially at equilibrium, with replacement
at time t = (mean time to replacement minus the advance planning time)
2 = System at short term equilibrium with replacement
at time t= (mean time to replacement)
3 = System at short term equilibrium with replacement
rate = 1 (mean time to replacement)

- The reliability calculation option, 0-1

0 = system reliability derived after loading all SU units
1 = system reliability derived after loading each SU unit

The program input data:

- Program title with a maximum of 80 characters
- The program output level log file
- The program unserved energy cost
- The hourly marginal cost (HMC) option
  0 = do not calculate HMC
  1 = calculate HMC
- Please note this option was only used for testing purposes

A2.5 The model variables

After the user has entered the input data the variables are initialized. The different variables used in the model are given below together with the symbols used in the program [12]. Please note a variable with the EP extension refers to the expected value of the variable over all load curves taking into account the curves probabilities, for example VARIABLE_EP. A variable with the MAX extension refers to the maximum value of the variable over the 24 hours of the day, for example VARIABLE_EP_MAX. A variable with the PLH extension refers to the value of the variable at the peak load hour of the day, for example VARIABLE_EP_PLH.

A2.6 The load variables

LDHLLD_MAX	Load, hourly load, maximum, MW
LDPLHR	Load, peak load hour
LDLRHR	Load, lowest reserve (capacity) hour
XLDLCSF (l)	Load, load curve scaling factor, p.u.
XLDHLSL(h)	Load, hourly load, scaled load, MW
XLDLCHL (h,l)	Load, load curve hourly load, MW
XLDLCED (l)	Load, Load curve, energy demand for a load curve, MWh/day
XLDENDM_EP	Load, energy demand, expected value, MWh/day

A2.7 The scheduled unit variables

ISUNBUN	Scheduled units, number of units (total number), max = 200
ISUSTNB(w)	Scheduled unit, station number
ISUSTUN(w)	Scheduled unit, station unit number
ISURDCP(h,w)	Scheduled unit, rounded capacity, MW

ISUTTCP(h)	Scheduled units, total capacity, MW
ISUTTCP_EP(h)	Scheduled units, expected total capacity, MW
ISURSCP(h)	Scheduled units, reserve capacity, MW
ISURSCP_EP(h)	Scheduled units, expected reserve capacity, MW
ISUTTCP_MAX	Scheduled units, total capacity, maximum over the day, MW
ISUTTCP_PLH	Scheduled units, total capacity, at peak hour, MW
ISURSCP_PLH	Scheduled units, reserve capacity, at peak hour, MW
ISURSCP_LRH	Scheduled units, reserve capacity, at lowest reserve hour, MW
STORRT(h,$)	Station, outage replacement rate, p.u.
STFORT(h,$)	Station, forced outage rate, p.u.
STTUCP(h)	Stations, total unrounded capacity, MW
STRSCP_PLH	Stations, reserve capacity, at peak hour, MW
STRSCP_LRH	Stations, reserve capacity, at lowest reserve hour, MW

A2.7.1 The capacity-in table variables

CISPFG(c)	Capacity in, step flag, logical, true if CIIDPB(c) not 0
CISPCP(c)	Capacity in, step capacity, MW (not used explicitely)
CIIDPB(c)	Capacity in, individual probability, p.u.
CICMPB(c)	Capacity in, cumulative probability, p.u.
ICIMXCP	Capacity in, maximum capacity in table, MW
ICINBCS	Capacity in, number of capacity states in table
ICIULCP	Capacity in, unit loaded, capacity MW
CIULOP	Capacity in, unit loaded, outage probability, p.u.

ICIGNSP	Capacity in, group number of steps, Integer should be > 2
ICIRLCS	Capacity in, regrouping lower capacity step
ICIRUCS	Capacity in, regrouping upper capacity step

A2.7.2 Scheduled unit capacity-in table variables

This is the hourly capacity-in table variables after loading all scheduled units

CISPFG_SU(c,h)	Capacity in, step flag, scheduled units, logical, true if CIIDPB_SU(c,h) not 0
CIIDPB_SU(c,h)	Capacity in, individual probability, scheduled units, p.u.
ICIMXCP_SU(h)	Capacity in, maximum capacity in table, scheduled units, MW
ICINBCS_SU(h)	Capacity in, number of capacity states in table, scheduled units

A2.8 Scheduled unit reliability variables

SULOLP_EP(h,w)	Scheduled unit, LOLP, expected value, p.u.
SULOLP_MAX_EP(w)	Scheduled unit, LOLP, maximum expected value, p.u.
SULOLH_EP(w)	Scheduled unit, LOLH, expected value, hours/day
SUUSEN_EP(w)	Scheduled unit, unserved energy, expected value, MWh/day

SUENGN_EP(w)	Scheduled unit, energy generated, expected value, MWh/day
SUENGN_EP_CUM	Scheduled unit, energy generated, cumulative expected value, MWh/day

A2.8.1 Scheduled unit cost result variables

SUFXCT_EP (w)	Scheduled unit, fixed cost,expected value, R/day
SUVRCT_EP (w)	Scheduled unit, variable cost, expected value, R/day
SUTTCT_EP (w)	Scheduled unit, total cost, expected value, R/day
SUVRCT_CUM	Scheduled unit, variable cost, cumulative over all SU units, R/day
SUFXCT_CUM	Scheduled unit, fixed cost, cumulative over all SU units, R/day
SUTTCT_CUM	Scheduled unit, total cost, cumulative over all SU units, R/day

A2.8.2 Synchronised reserve variables

ISRFSOT	Synchronised reserve, fast (optimal) search, 0 = no, 1 = yes
ISROSSS(s)	Synchronised reserve, optimal search, step status, 0-4 0 = not selected, 1-4 = selected at iteration
ISROSNI	Synchronised reserve, optimal search, number of iterations 1-4

SRORRT(h)	Synchronised reserve, outage replacement rate, p.u.
SRFORT	Synchronised reserve, forced outage rate, p.u.
SRDRCP(h,s)	Synchronised reserve, derated capacity, MW derated for outage
ISRTTCP_APL	Synchronised reserve, total capacity above peak load, MW
ISRAJCP(h)	Synchronised reserve, adjustment capacity, MW

A2.8.3 Synchronized reserve reliability variables

SRLOLP_EP(h,s)	Synchronised reserve, LOLP, expected value, p.u.
SRLOLP_MAX_EP(s)	Synchronised reserve, LOLP, expected value maximum value, p.u.
SRLOLH_EP(s)	Synchronised reserve, LOLH, expected value, hours/day
SRUSEN_EP(s)	Synchronised reserve, unserved energy, expected value, MWh/day
SRENGN_EP(s)	Synchronised reserve, energy generated, expected value, MWh/day

A2.8.4 Synchronized reserve cost result variables

SRFXCT_EP (s)	Synchronised reserve, fixed cost, expected value, R/day
SRVRCT_EP (s)	Synchronised reserve, variable cost, expected value, R/day
SRTTCT_EP (s)	Synchronised reserve, total cost, expected value, R/day

A2.8.5 Reserve resource variables

IRSNBRS_SS	Resource, number of resources, supply side
IRSNBRS_DS	Resource, number of resources, demand side
RSORRT(h,r)	Resource, outage replacement rate, p.u.
RSFORT(r)	Resource, forced outage rate, p.u.
RSTTCP	Resources total capacity, MW
RSTTCP_DS	Resources total capacity, demand side, MW
RSTTCP_SS	Resources total capacity, supply side, MW

A2.8.6 Reserve resource reliability variables

Many RS variables are function of the synchronised reserve capacity levels.

RSDRCP_TEMP	Resource, derated capacity for energy limit, MW (temporary variable during optimisation)
RSLOLP_EP(h,r,s)	Resource, LOLP, expected value, p.u.
RSLOLP_MAX_EP(r,s)	Resource, LOLP, maximum value, p.u.
RSLOLH_EP(r,s)	Resource, LOLH, expected value, hours/day
RSUSEN_EP(r,s)	Resource, unserved energy, expected value, MWh/day
RSENGN_EP(r,s)	Resource, energy generated, expected value, MWh/day

A2.8.7 Reserve resource cost result variables

RSDRCP(r,s)	Resource, derated capacity for energy limit, MW
RSVRCT_EL(r)	Resource, variable cost when energy limited, R/MWh
RSFXCT_EP(r)	Resource, fixed cost, expected value, R/day
RSVRCT_EP(r,s)	Resource, variable cost, expected value, R/day
RSTTCT_EP(r,s)	Resource, total cost, expected value, R/day
RSTTCT_CUM(s)	Resource, total cost, cumulative value over all resources, R/day

A2.8.8 Marginal reliability and marginal cost variables

SUPBMG_EP(h,w)	Scheduled unit, probability to be at the margin, expected value, p.u.
SUHRMG_EP(w)	Scheduled unit, hours at the margin, expected value, hours/day
SRPBMG_EP(h)	Synchronised reserve, probability to be at the margin, expected value, p.u.
SRHRMG_EP(s)	Synchronised reserve, hours at the margin, expected value, hours/day
RSPBMG_EP(h,r)	Resource, probability to be at the margin, expected value, p.u.
RSHRMG_EP(r,s)	Resource, hours at the margin, expected value, hours/day
SMHRMG_EP_CUM	System, hours at the margin, expected value, cumulative, hours/day
SMMGCT(h)	System marginal cost, R/MWh

SMMGCT_EL(h)	System marginal cost, with energy limits for RS units, R/MWh

A2.8.9 System result variables

SMTTCT(s)	System, total cost, R/day
SMMNCT	System minimum cost, R/day,
ISROTCP_ID	Synchronised reserve, optimal capacity step index
ISROTCP	Synchronised reserve, optimal capacity, MW
SMUECT(s)	System, unserved energy cost, R/day
ISMOTSR_PLH	System, optimal synchronised reserve at peak hour, MW
ISMOTSR_LRH	System, optimal synchronised reserve at lowest reserve hour, MW
ISMOTOR_PLH	System, optimal operating reserve (supply side) at peak hour, MW
ISMOTOR_LRH	System, optimal operating reserve (supply side) at lowest reserve hour, MW

A2.9 Scheduling the units and optimising the reserve

After the program has initialized the variables the SU, SR and RS energy capacity expectation are prepared. The expected load curves and the outage rate tables for the SU, SR and RS are prepared.

For every load curve the available scheduled units are committed for the day, for each hour after a scheduled unit is committed the COPT is updated and the reliability indices calculated.

The reliability indices calculated after each scheduled unit is committed are the:

- Loss of load probability (LOLP) for the hour
- The loss of load hours (LOLH) for the week
- The unserved energy (UE) and this is in hours per week

The program commits the scheduled units until generation equals demand.

The second part of the program determines the optimal amount of reserve to be committed for the specific load curve. For every reserve capacity level of synchronized reserve (entered by the user) and for every hour of the load curve, the COPT is constructed after the unit is committed. The reliability indices are calculated just as it was calculated for the SU and included in the COPT. The reserve resources are scheduled after the synchronized reserve resources. After each reserve resource is committed for the hour, the capacity of the reserve resource is adjusted to meet its energy limit. The COPT is constructed and the reliability indices calculated.

If all the synchronized reserve and reserve resources are committed, the accumulated costs are determined to commit the resources and to provide energy. These costs are compared to the costs to the consumer if the reserve is not supplied. The costs to Eskom are added to the costs to the consumer if reserve is not supplied to obtain the total expected costs to provide reserve. The minimum total expected cost is identified and two levels of SR capacity are added to the optimum value. The program determines if all the optimal reserve levels have been taken into consideration and compute the hourly marginal cost. These results are recorded for the optimum level of SR for all the load graphs.

Please note. When the program determines the optimal reserve capacity it takes the value of SR fast (optimal) option entered and the number of capacity steps specified by the user into account.

If option ISRNBCS = 0, the user wants a fast optimal search option, and ISRFSOT is set to 1, fast search, requiring cost calculations for about 11 SR steps to be selected during the search.

If option ISRNBCS > 0, the user wants a systematic optimal search option, and ISRFSOT is set to 0, systematic search, requiring cost calculations for all the SR steps over the range.

If option ISRNBCS = 0, the user selected the fast search option to find the optimum SR capacity level. Six steps are selected, with ISR = 7, 15, 23, 31, 39 and 47. The step status ISROSSS(s) is set to 1 for these steps.

If option ISRNBCS > 0, the user selected the standard systematic search option to find the optimum SR capacity level, by calculating the total cost for all steps over the range. All the steps are selected, and the step status ISROSSS(s) is set to 1 for each of the ISRNBCS steps.

A2.10 Sensitivity analysis

A2.10.1 Effect of changing the capacity of Emergency Resources

Table 40 shows that the optimum synchronized reserve increases as the amount of emergency resources (interruptible load capacity available) decreases. The increase is about two-thirds of the drop in resource capacity. The total daily cost also increases.

Table 40: The optimum reserve variation with capacity of interruptible load for 19 July 2001.

Run number	Case	Initial load capacity	Optimum spin reserve capacity (MW)	Total cost increase (units/day)	Increase
1	All available	1927	1341	38.7	0
2	Source 1 out	1627	1541	48.8	10.1
3	Source 2 out	1507	1641	51.0	12.3
4	Source 3 out	867	2041	74.1	35.4
5	All initial load out	0	2491	107.0	68.3

A2.10.2 The effect of load forecast error

Figure 55 on page 155 and Table 41 shows how daily cost increases due to load forecast error as a percentage of daily peak loads. Since the optimum reserve also increases this cost is the sum of the reserve cost and the emergency resource usage cost, both of which are increasing. This data may be used to estimate the cost of load forecast error.

Table 41: Variation of optimum reserve with load forecast error.

Standard deviation of percentage peak (%)	Optimum spinning reserve (MW)	Total cost (units/day)	Increase
0	1143	25.9	0
0.5	1143	26.6	0.7
1	1193	28.8	2.9
1.3	1243	30.8	4.9
1.6	1343	33.3	7.5
2	1393	37.6	11.8
2.4	1543	42.9	17.0

A2.10.2 Effect The effect of hourly load shape for daily variations

Table 42 shows results for a typical week in March 2003. Note how the reserve varies by a range of at least 200 MW. The highest reserves were obtained on days with relatively flat load profiles i.e. more hours with load close to daily peak.

This table also shows results if the call-up time is reduced from 24 hours to 6 hours. The reserve drops about 600 MW. This occurs because the plant that has failed in 6 hours is much less than at 24 hours.

Table 42:The variation of the optimum reserve with run date and call-up time.

Date	Day of week	24 Hour call-up optimal spinning reserve (MW)	6 Hour call-up optimal spinning reserve (MW)	Difference (MW)
2003/03/03	Monday	1600	1000	600
2003/03/04	Tuesday	1720	1060	660
2003/03/05	Wednesday	1800	1150	650
2003/03/06	Thursday	1700	1050	650
2003/03/07	Friday	1650	1050	600
2003/03/08	Saturday	1700	1100	600
2003/03/09	Sunday	1650	1100	550
Average		1689	1073	616

A2.10.3 The effect of reserve cost

If the linear reserve cost is doubled from 20000 R/ MW-day to 40000 R/ MW-day the reserve drops by 300 MW. Thus the reserve is not too sensitive to cost. For accuracy a non-linear cost curve is normally employed, since the cost increases exponentially with the amount of surplus capacity on-line.

A2.11 Cost savings incurred

- The reserve optimization program has been used since August 1999. The reserve levels are in fair agreement with what Eskom used previously based on reliability criteria, the amount of emergency resource usage and low frequency incidents which are acceptable. The use of the program during 2000 led to the required operating reserve varying each day. If the actual plant committed had been just sufficient to meet this reserve each day an estimated cost saving of R 445 000 could have been realized. However the actual reserve levels in 2000 were on average 800 MW higher than the optimum, so that these savings were not fully realized.

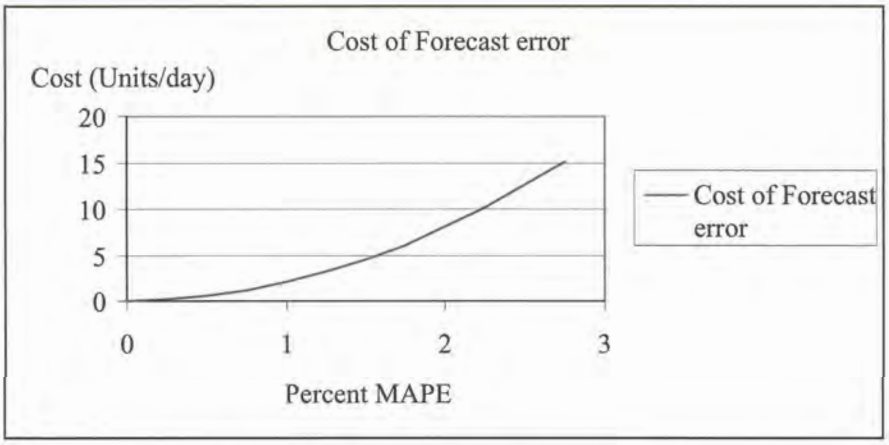


Figure 55: The effect of load forecast error.

A2.12 Improvements to be made

Several assumptions made in this model used for the program are incorrect [11]:

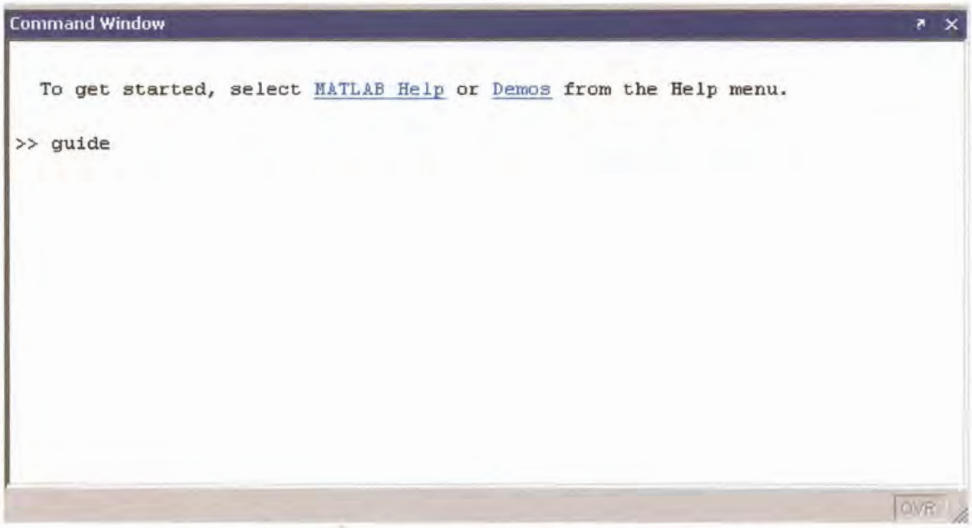
- Plant not yet committed on-line is not at any risk of failure. Units not committed at the time of scheduling should have their ORR calculated only from when they are committed. Since few (less than 5) thermal units are not already online the error is small. The hydro units are on for only a few hours per day but their outage rates is low (this program is usually run with hydro plant excluded, which is equivalent to having no outage rates).
- Any plant that fails can be replaced T hours after the failure. The amount of cold reserve differs from day to day and each has its own call-up time. An arrangement was made for one or two sets to be available on hot standby at 3 - 6 hours notice. The program cannot handle this since all sets are assumed to have the same call-up time. The cold reserve is only called up if the expected reserve over peak drops below a critical value (i.e. 500 MW).
- The model assumes the reliability of the units doesn't change after maintance operation has taken place.

ADDENDUM A3

A3.1 How to use the model

Step 1: Open Matlab™ by double clicking the icon.

Step 2: In the command window enter the command
>> guide
and press enter



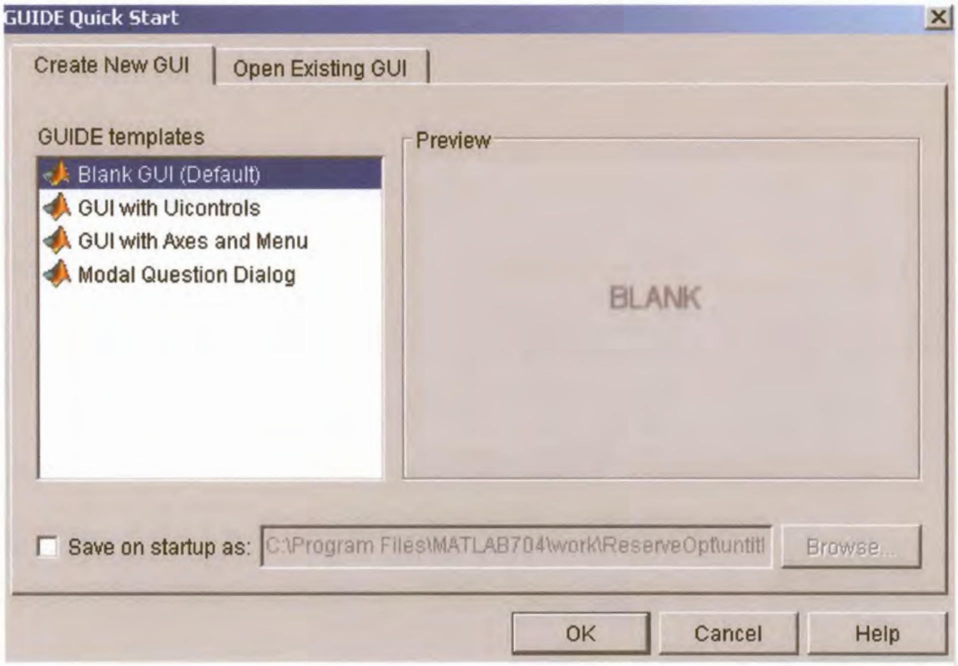
```
  To get started, select MATLAB Help or Demos from the Help menu.

>> guide
```

Figure 56: Enter the guide command in the command window.

The GUIDE quick start window will open.

Step 3: Select the "Open existing GUI" tab, and select the path where the ReserveOpt.fig file are stored, and press "OK"

ADDENDUM A3



☐ Save on startup as: C:\Program Files\MATLAB704\work\ReserveOpt\untitl

Figure 57: The GUIDE quick start window.

Figure 51 will be displayed.

Step 4: In the Unit Information panel, double click the "Edit in ReserveOpt.fig", the property inspector will open, and edit the unit data in variable "CData". (See Figure 51, 52 and 53)

In Figure 53 the size of the matrix is given by the amount of units to be scheduled. In this Figure 20 units are to be used in the reserve optimisation. Row 1 gives the information for unit 1 to be scheduled and row 2 the information for row 2, etc. Column 1 gives the unit size, column 2 the FOR, column 3 the fixed cost of the units and Column 4 the variable cost of the units.

ADDENDUM A3

Do the same with the load data.

Step 5: Press the run button in the toolbar and the ReserveOpt GUI opens, edit the reserve information and the peak load. (See Figure 51)

Step 6: Press the execute button, and the model will calculate the optimal reserve. (See Figure 49).

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