CHAPTER 8
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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. $SMP < VOLL\ FOP \frac{C_{m}}{R_{m}}$	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:

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

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.

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

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.

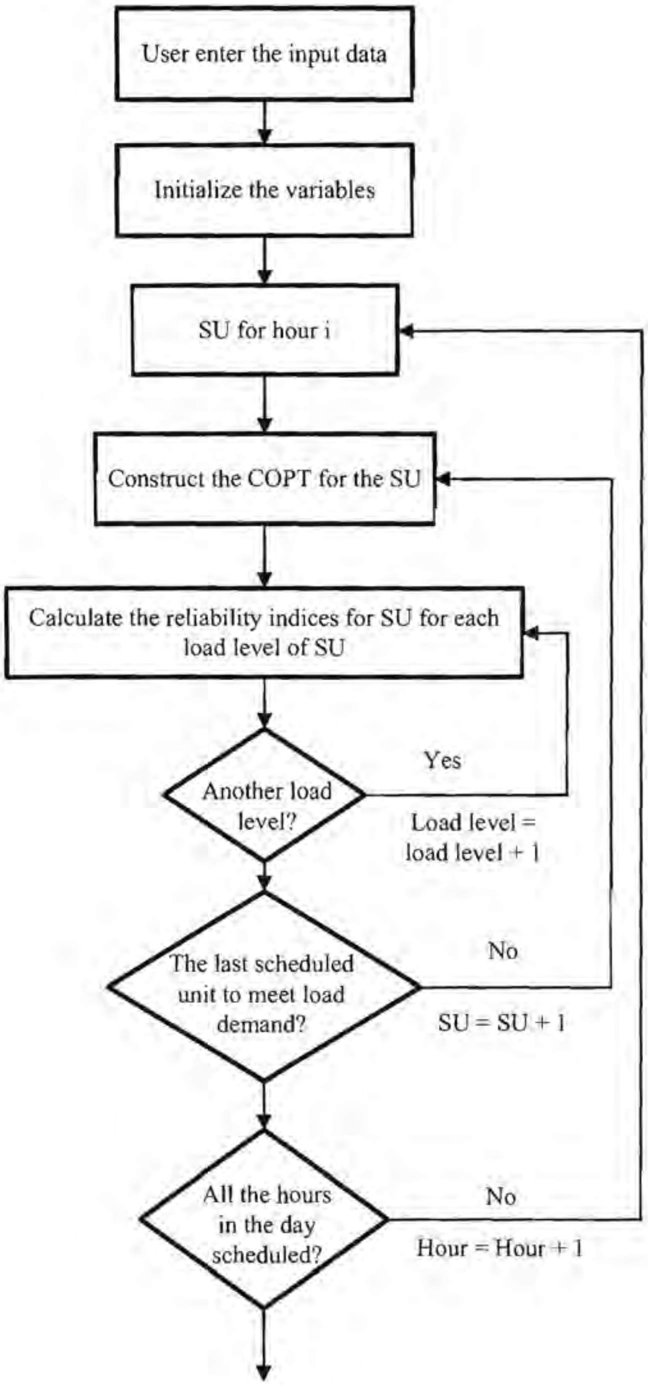
In this model the replacement of units by a cold reserve set is treated as an increase in the repair rate, M by 1/T. This model is not used for the RS but the first model is used instead.

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

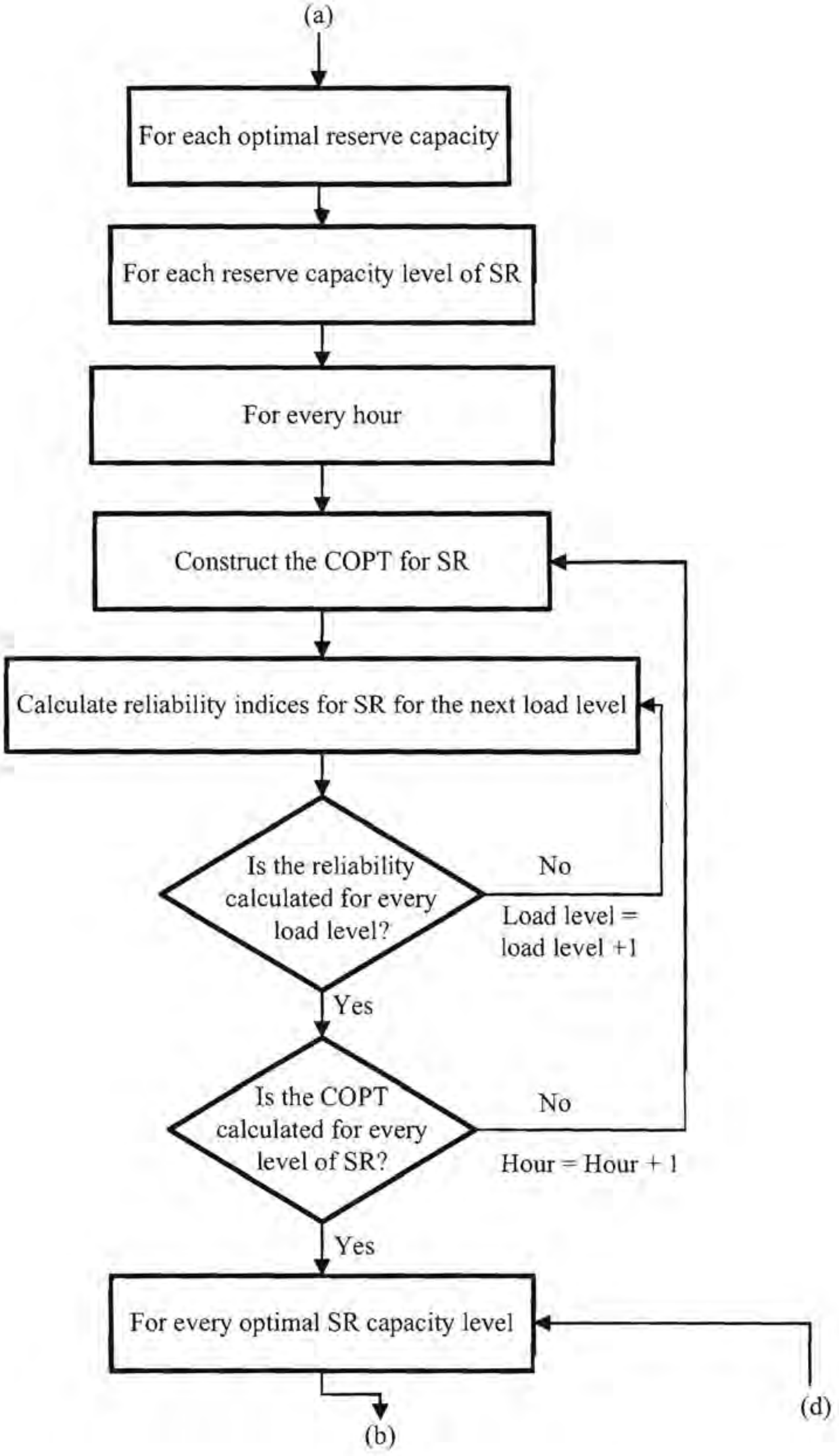
This model is very similar to the previous model. The only difference is the replacement rule algorithm. In the previous model, the replacement of a unit by an identical unit takes place after a fixed replacement time T = RLMTRP (lead time) after failure. Before and after T, the replacement rate is nil. 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).

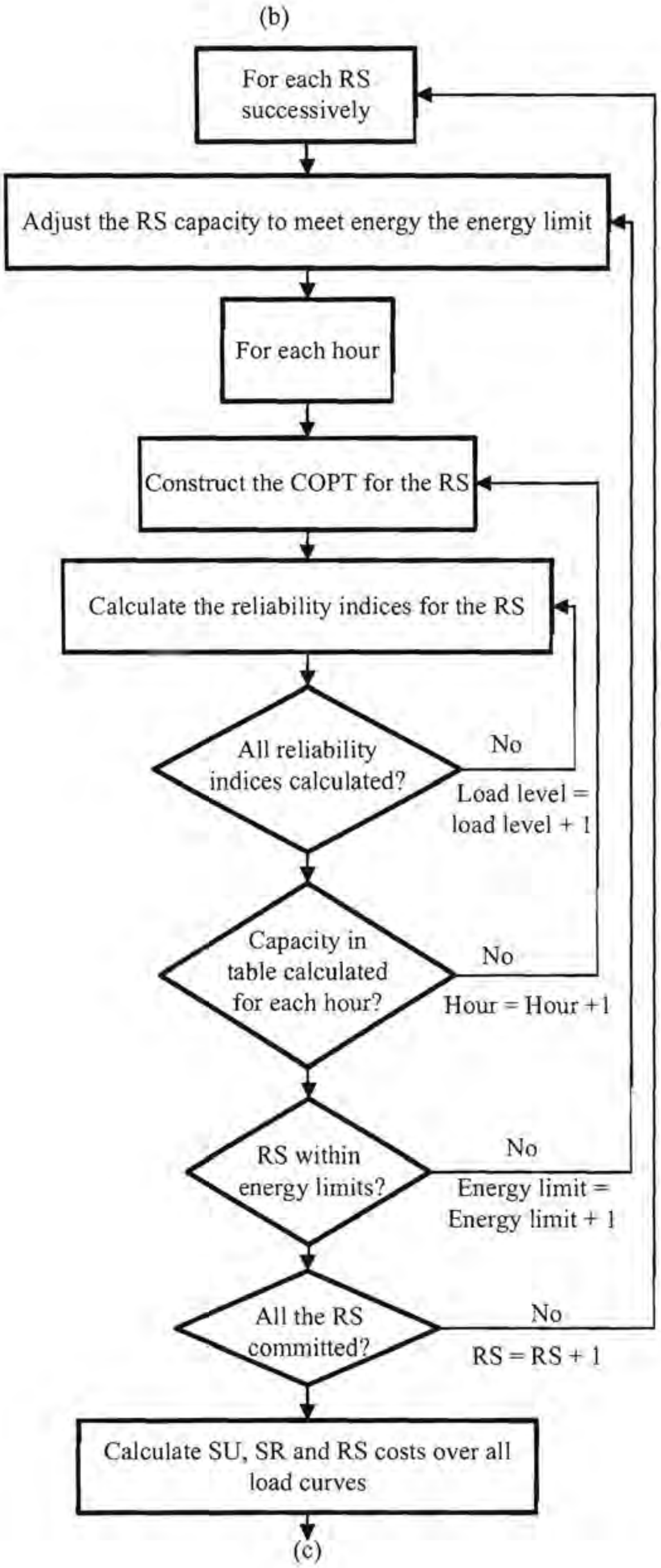
The assumption that T has an exponential distribution is quite arbitrary. An analysis of the available statistics may be necessary to corroborate this assumption. Overall this model is more optimistic than the previous since a unit may be replaced at any time after failure, instead of after time T. It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

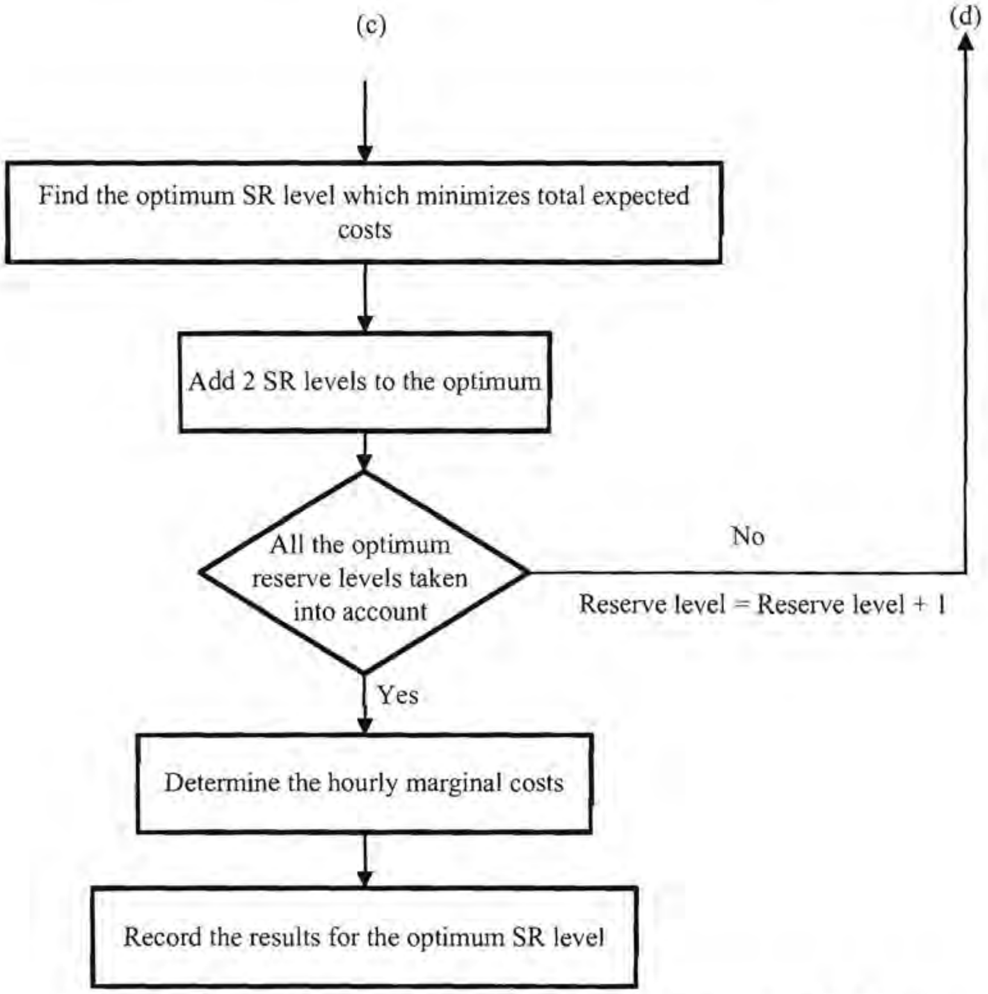


Figure 54: The logical diagram of the reserve optimization program used by Eskom.

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)

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

- 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.

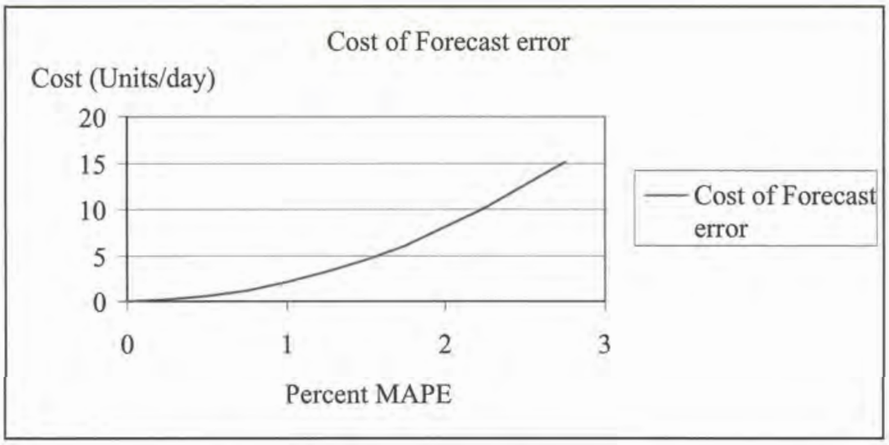


Figure 55: The effect of load forecast error.

A2.12 Improvements to be made

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

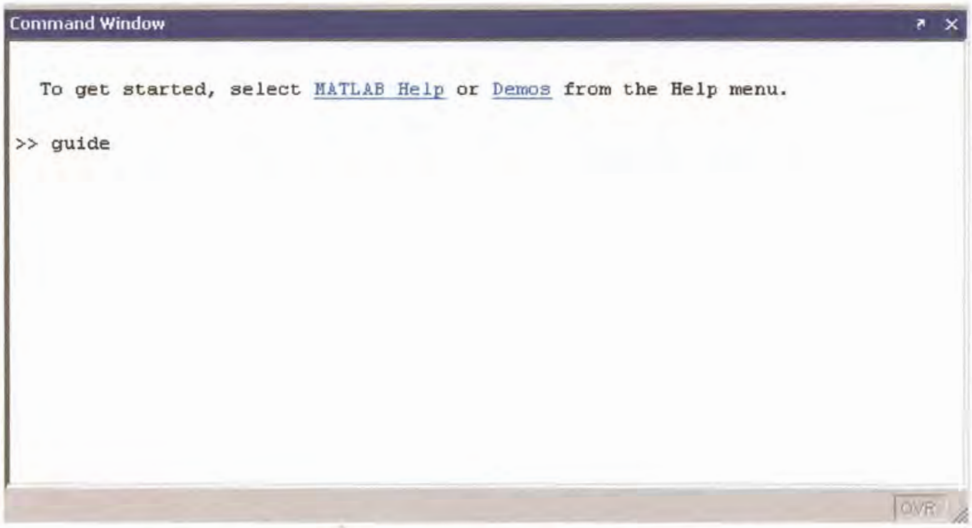
- Plant not yet committed on-line is not at any risk of failure. Units not committed at the time of scheduling should have their ORR calculated only from when they are committed. Since few (less than 5) thermal units are not already online the error is small. The hydro units are on for only a few hours 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



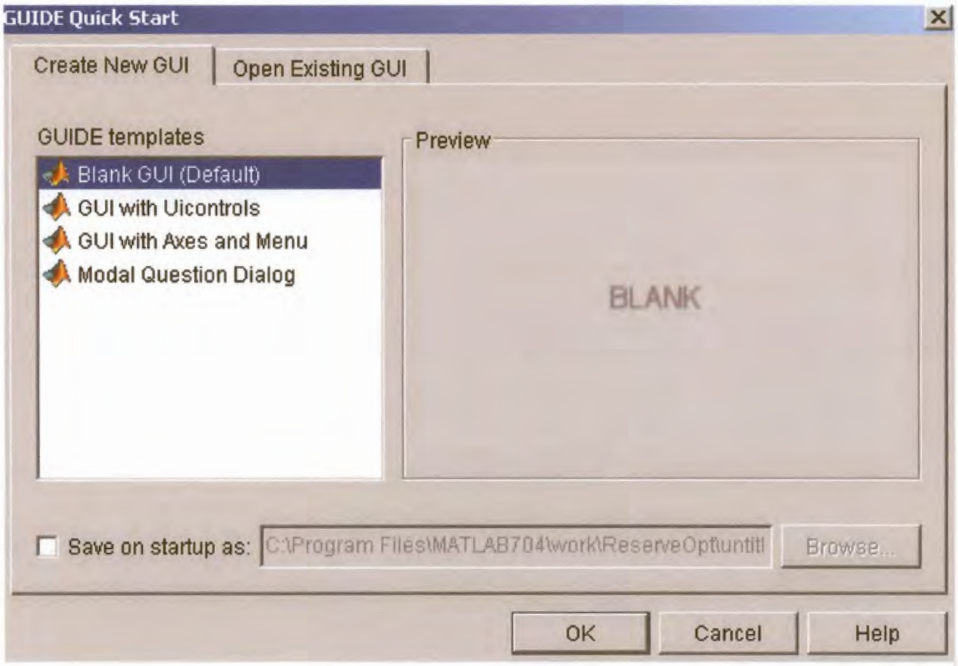
```
  To get started, select MATLAB Help or Demos from the Help menu.

>> 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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