No	Year	Cost Disburs (G, T & D)	Additional Infrastruct. Cost	Energy Generated MWh	Energy Sent−out MWh	Energy Sold MWh	Average Tariff RM/kwh	Average Revenue Million	Fixed O&M Million	Var O&M Million	Coal Prices $/Mil.Kcal	Fuel Cost Million	T, D & A Var Cost Million	Total Oper.Cost Million	Average Cashflow Million
−6	1994														
−5	1995						0.2003								
−4	1996						0.2003								($392)
−3	1997	$182	$210				0.2003								($1,261)
−2	1998	$911	$350				0.2003								($1,234)
−1	1999	$1,094	$140				0.2003								($729)
0	2000	$729					0.2003								($729)
1	2001	$729		6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	18.353	$255	$92	$396	$632
2	2002			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	19.184	$266	$92	$408	$620
3	2003			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.053	$278	$92	$420	$608
4	2004			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.181	$280	$92	$421	$607
5	2005			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.310	$282	$92	$423	$605
6	2006			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.439	$284	$92	$425	$603
7	2007			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.570	$285	$92	$427	$601
8	2008			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.701	$287	$92	$429	$599
9	2009			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.844	$289	$92	$431	$597
10	2010			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.988	$291	$92	$433	$595
11	2011			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.133	$293	$92	$435	$593
12	2012			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.278	$295	$92	$437	$591
13	2013			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.425	$297	$92	$439	$589
14	2014			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.573	$299	$92	$441	$587
15	2015			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.722	$301	$92	$443	$585
16	2016			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.872	$303	$92	$445	$583
17	2017			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.023	$306	$92	$447	$581
18	2018			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.175	$308	$92	$449	$579
19	2019			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.328	$310	$92	$451	$577
20	2020			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.482	$312	$92	$453	$575
21	2021			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.637	$314	$92	$455	$573
22	2022			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.794	$316	$92	$458	$570
23	2023			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.951	$318	$92	$460	$568
24	2024			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	23.109	$321	$92	$462	$566
25	2025			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	23.269	$323	$92	$464	$564
NPV		**$1,983**	**$444**					**$3,843**						**$1,589**	

Benefit/Cost Ratio = 0.93

IRR = 10%

APPENDIX 1

APPENDIX 1

WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP)

The Wien Automatic System Planning Package (WASP) was developed by the Tenessee Valley Authority (TVA) and the Cak Ridge National Laboratory (ORNL) of the United States of America to meet the needs of the International Atomic Energy Agency (IAEA) "Market Survey for Nuclear Power in developing Countries" conducted by the Agency in the period 1972 - 1973. Based on the experienced gained many improvements were made which led to the WASPII version in 1976. later the need to incorporate the study on interconnection of electrical grids led to a joint effort to develop WASPIII version.

WASPIII was designed to to find the economically optimal generation expansion policy for an electric utility system within user specified constraints. It utilises probabalistic estimation of system production costs, unserved energy cost, and reliability and the dynamic method of optimisation for comparing the costs of alternative system expansion policies. The modular structure of WASPIII permits the user to monitor intermediate results, avoiding waste of large amounts of computer time due to input data errors.

The computer time requirement to carry out a generation planning study using WASPIII depend on:

(a) the complexity of the system under study

(b) The number of hydrological conditions considered

(c) The number of periods into which the year is divided.

(d) the total number of years considered

(e) the accuracy required for simulating the system operations

(f) the total number of configurations generated during the study

WASPIII permits finding the optimal expansion plan for the power generating system over a period of over thirty years, within constraints given by the planner. the optimum is evaluated in terms of minimum discounted total cost.

Each possible sequence of power units added to the system meeting the constraints is evaluated by means of cost function (the objective function) which is composed of:

- Capital investment cost
- Salvage value of investment cost
- Fuel cost
- Fuel inventory cost
- Non-fuel operations and maintenance cost
- Cost of energy not served.

thus

Bj =

Where Bj is the objective function attached to the expansion plan

- t is the time in years
- T is the length of the study period

The reliability of the system configuration is evaluated by WASPIII in terms of the Loss-of-Load Probability Index (LOLP). this index is calculated by the code fpor each period and each condition.

The calculation of the various costs components in the expression is done in WASP in order to account for:

- Characteristic of the Load forecast
- Characteristic of thermal and nuclear plant
- Characteristic of hydroelectric plant
- Stochastic nature of the hydrology
- Cost of energy no served.

In WASPIII there are 7 modules to be executed in sequence,. The modules are:

LOADSY Processes information describing period peaks loads and load duration curves for the power system over the study period.

FIXSYS processes information describing the existing generation system and any predetermined additions or requirements

VARSYS processes information describing the various generating plans which are to be considered as candidate for expanding the generating system

CONGEN calculates all possible year to year combination of expansion candidate additions ehich satisfy certain input constraint and which in combination with the fixed system can satisfy the loads.

MERSIM considers all configurations put forward by CONGEN and uses probabalistic simulation of system operations to cvalculate the associated production costs, energy not served and system reliability for each configuration. the module also calculates plants loading orders if desired, and make use of all prevoiusly simulated configurations.

DYNPRO determines the optimum expansion plan based on previously derived operating costs along with input information on capital cost, energy not served cost and economic parameters and reliability criteria.

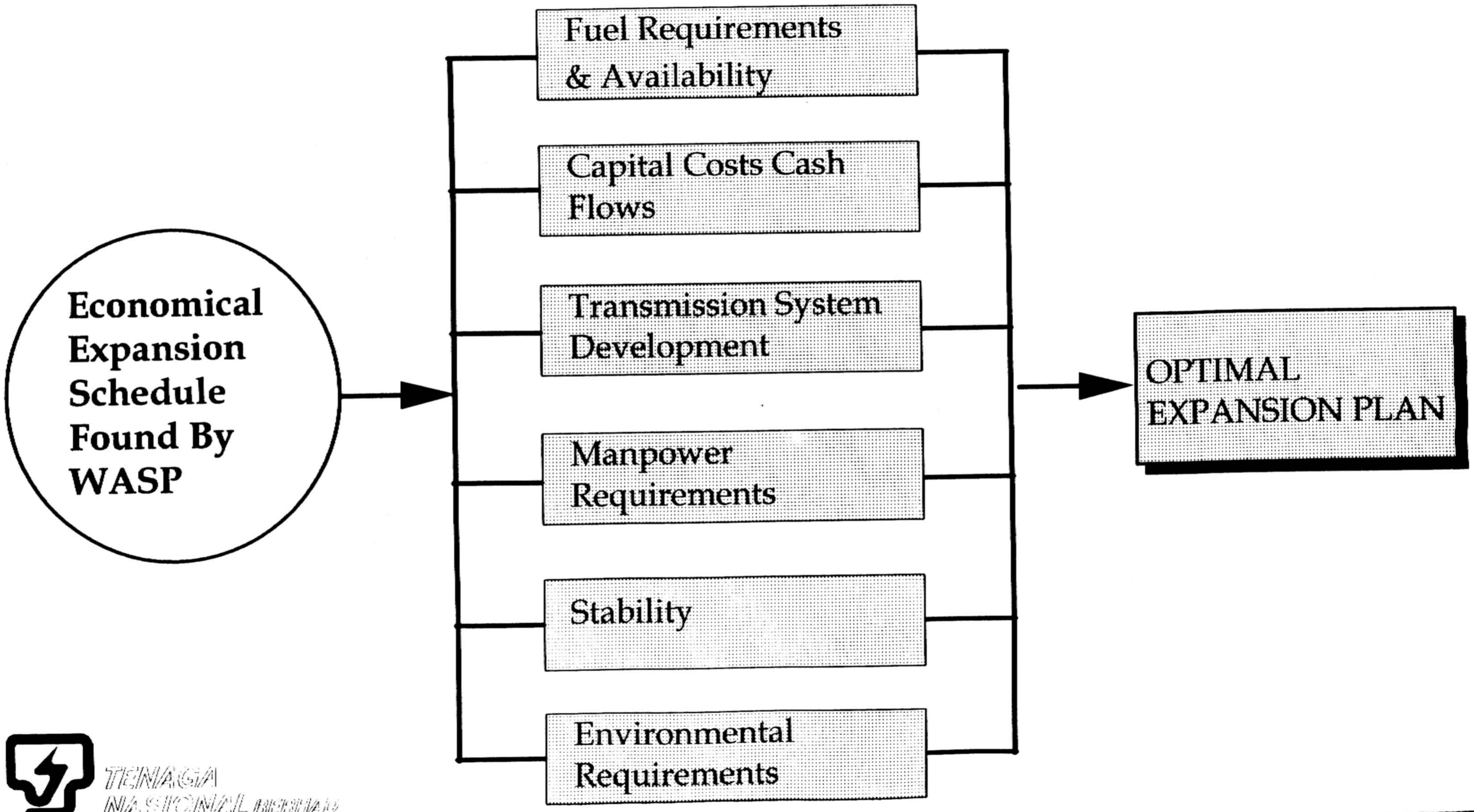
REPROBAT create a report summarising the total or partial results for the optimum or near optimum power system expansion plan and for fixed expansion schedules.

The chart overleaf denotes the flow chart for the processing of data. In order to determine the capacity addition to the TNB system, the reserach was carried out by first obtaining the base case for the least cost plant addition to the system. The least cost as indicated above will determine from the WASPIII model which has been adopted by TNB.

With the findings conclusions can be drawn on what is the least cost generation development for TNB. The base case is the additional plant required by the country between now to year 2005. This is the least cost option for the country.

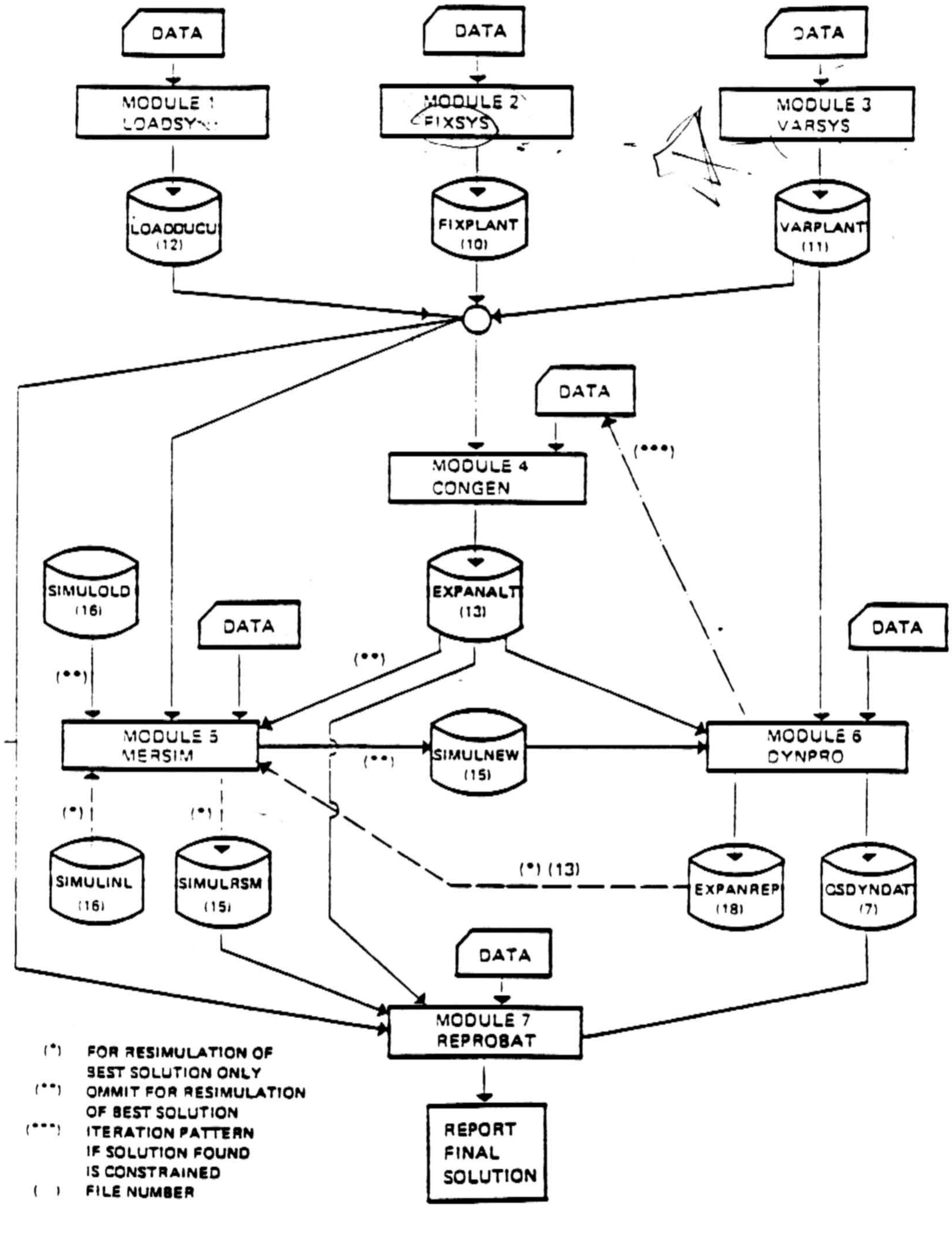
However, it may not be the least cost for the utility and the implementation of the actual projects need to be review annualy to assess variation in load demand which will determine a different planning scenario. However this paper will assumed that the base case for plant addition and look at the investment strategy if TNB decides to take up this projects.

ADDITIONAL ANALYSIS ARE REQUIRED



TENAGA NASIONAL BERHAD

Figure 1.1 : Flow Chart of WASP Programme



APPENDIX 2

APPENDIX 2

SCREENING CURVES

The screening curve method is a simplified approach for quick analysis of economic competitiveness. Basically the screening curve separates the technology costs into fixed and vbariable costs. this is followed by constructing the cost curve for each technology which is a plot of cost($/kW-yr) vs capacity factor. the least cost alternative will be determined as a function of utilisation. this approach have numerous limitations and it cannot be used as a substitude for through analysis as in WASPIII.

Total fixed cost

The total fixed costs are independant of the energy kWh generated by the unit. it can be represented by:

Annualised fixed cost =

Total capital cost x Levelised annual fixed charge rate + Fixed O&M cost

where the levelised annual fixed charge rate = capital recovery factor

Total variable cost

The variable cost on the other hand included cost that are proportioal to kWh generated and can be represented as:

Variable cost = Annual average heat rate x Fixed cost + Variable O&M cost

The fuel and operation and maintenance cost should be levelised if real escalation is assumed.

Total Cost

The total cost will thus be =

Annualised fixed cost + variable cost x capacity factor x 8760 and will produce the chart below.

Constraints of the Screening curve

The screening curve approach does not allow for many important factors in capacity planning. This will be discussed in turns as follows.

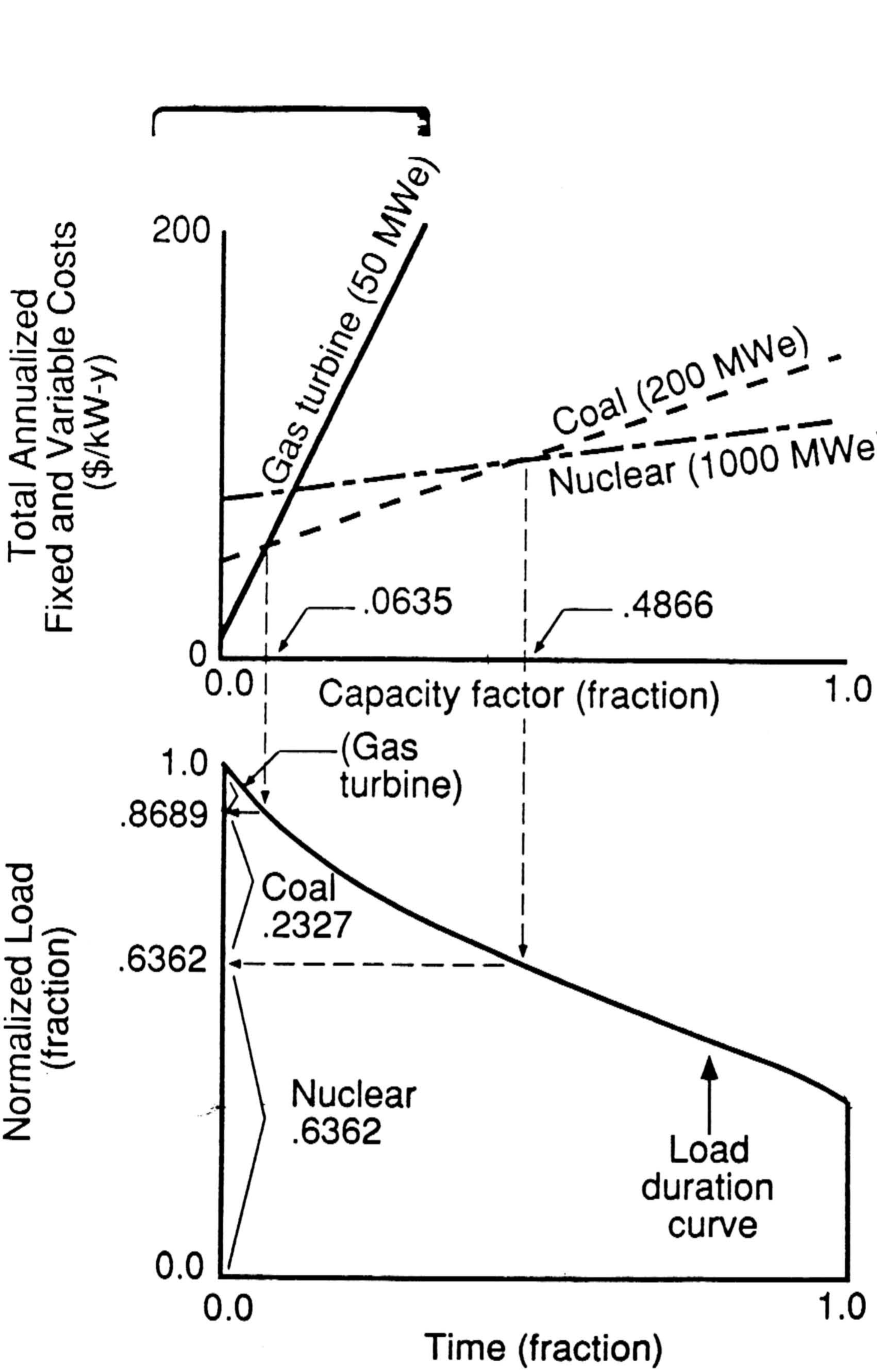
Firstly, the unit availability is not accounted for. Hence the forced outage rate and maintenanace frequency are not represented in the curve.

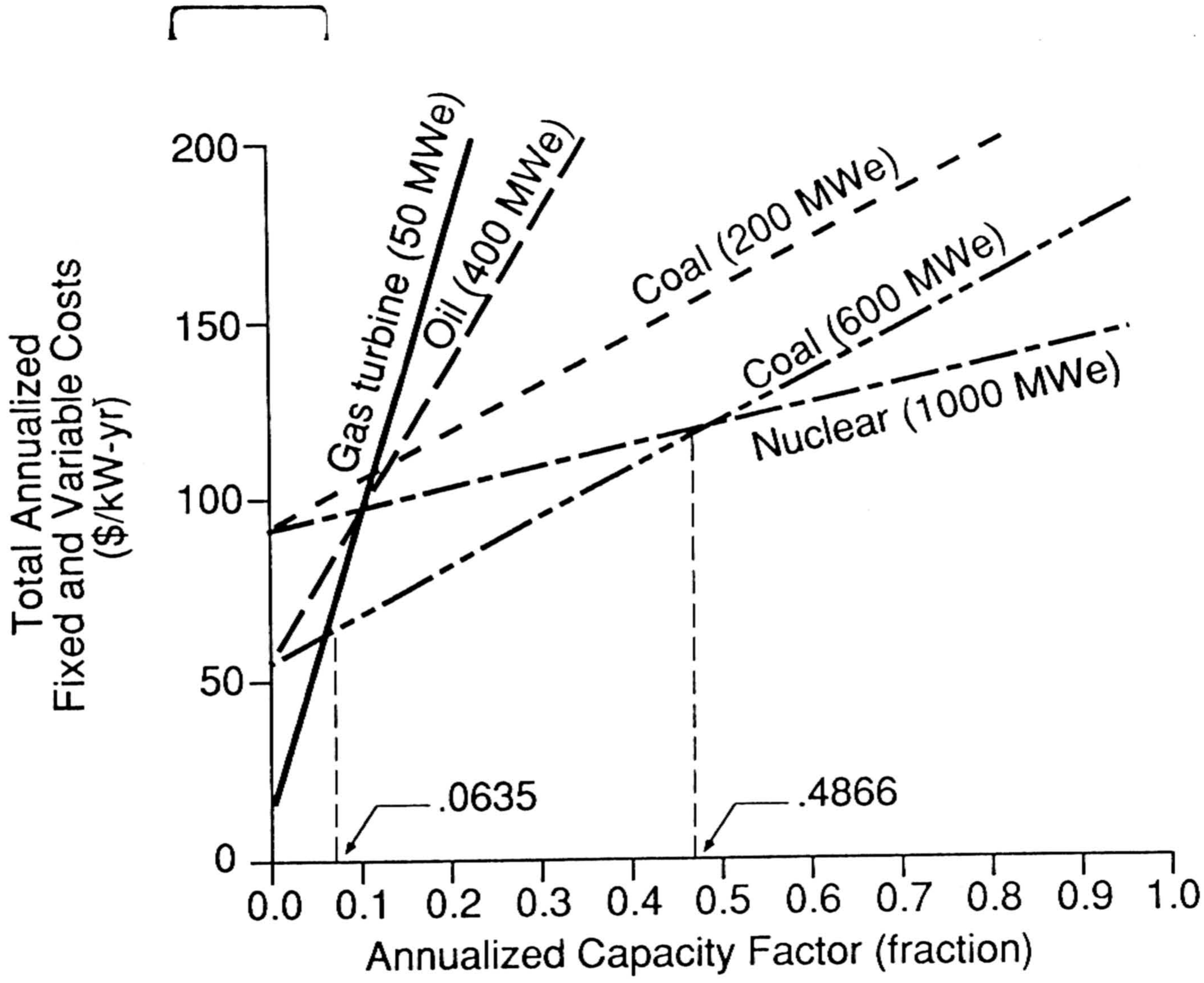
Secondly, it does not include the role of existing plant in the system. therefore the performance of existing units are not fairly treated.

Thirdly, the screening curve is not able to incorporate the dispatching role of the candidate plants. this means the minimum load capability, the spinning reserve contribution and startup cost are not taken into consideration.

Fourthly, the reliability criteria is not imposed or included. As in WASPIII and discussed int he text, reliability criteria is an important input to planning.

Fifthly, dynamic factors such as load growth and economic trends are not considered. therefore the curve are instantaneous information. this also means that the the curve is not able to be used for interpreting long term sequence of the short term results.


Total Annualized
Fixed and Variable Costs
($/kW-y)
200
0
Gas turbine (50 MWe)
Coal (200 MWe)
Nuclear (1000 MWe)
.0635
.4866
0.0
Capacity factor (fraction)
1.0
1.0
.8689
.6362
0.0
(Gas
turbine)
Coal
.2327
Nuclear
.6362
Load
duration
curve
Normalized Load
(fraction)
0.0
1.0
Time (fraction)


Total Annualized
Fixed and Variable Costs
($/kW-yr)
200
150
100
50
0
Gas turbine (50 MWe)
Oil (400 MWe)
Coal (200 MWe)
Coal (600 MWe)
Nuclear (1000 MWe)
.0635
.4866
0.0 0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8 0.9 1.0
Annualized Capacity Factor (fraction)

APPENDIX 3

Capacity	*1000 MW*	*Efficiency =*	*38%*		*Heat Rates =*	*2,263 kcal/kwh*	
Aux.Cons =	7%	T&D Loss =	10%		Cap.factor=	70%	
Cap. Cost =	$2,741 RM/kw	Fix O&M =	35.04 RM/kw/year		Var O&M =	2.34 RM/MWh	
IDC =	23.78%	T&D Cost=	33% of Definite Works		T&D Var O&	1.5 sen/kwh	
Total Cost =	$2,741 Million			Definite Works Disbursement			
Infras.Cost =	$700 Million		Year−1	Year−2	Year−3	Year−4	Year−5	Total
Disc.Rate =	10%		5%	25%	30%	20%	20%	100%
			$137	$685	$822	$548	$548	$2,741

No	Year	Disburs (G, T & D)	Infrastruct. Cost	Generated MWh	Sent−out MWh	Sold MWh	Tariff RM/kwh	Revenue Million	O&M Million	O&M Million	Prices $/Mil.Kcal	Cost Million	Var Cost Million	Oper.Cost Million	Cashflow Million
−6	1994														
−5	1995						0.2003								
−4	1996						0.2003								($392)
−3	1997	$182	$210				0.2003								($1,261)
−2	1998	$911	$350				0.2003								($1,234)
−1	1999	$1,094	$140				0.2003								($729)
0	2000	$729					0.2003								($729)
1	2001	$729		6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	18.353	$255	$92	$396	$632
2	2002			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	19.184	$266	$92	$408	$620
3	2003			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.053	$278	$92	$420	$608
4	2004			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.181	$280	$92	$421	$607
5	2005			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.310	$282	$92	$423	$605
6	2006			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.439	$284	$92	$425	$603
7	2007			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.570	$285	$92	$427	$601
8	2008			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.701	$287	$92	$429	$599
9	2009			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.844	$289	$92	$431	$597
10	2010			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	20.988	$291	$92	$433	$595
11	2011			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.133	$293	$92	$435	$593
12	2012			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.278	$295	$92	$437	$591
13	2013			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.425	$297	$92	$439	$589
14	2014			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.573	$299	$92	$441	$587
15	2015			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.722	$301	$92	$443	$585
16	2016			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	21.872	$303	$92	$445	$583
17	2017			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.023	$306	$92	$447	$581
18	2018			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.175	$308	$92	$449	$579
19	2019			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.328	$310	$92	$451	$577
20	2020			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.482	$312	$92	$453	$575
21	2021			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.637	$314	$92	$455	$573
22	2022			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.794	$316	$92	$458	$570
23	2023			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	22.951	$318	$92	$460	$568
24	2024			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	23.109	$321	$92	$462	$566
25	2025			6,132,000	5,702,760	5,132,484	0.2003	$1,028	$35	$14	23.269	$323	$92	$464	$564
NPV		**$2,224**	**$484**					**$5,267**						**$2,189**	

Benefit/Cost Ratio = 1.14

IRR = 10%

Capacity =	1000 MW	Efficiency =	38%		Heat Rates =	2,263	kcal/kwh
Aux.Cons =	7%	T&D Loss =	10%		Cap.factor=	80%	
Cap. Cost =	$2,741 RM/kw	Fix O&M =	35.04	RM/kw/year	Var O&M =	2.34	RM/MWh
IDC =	23.78%	T&D Cost=	33%	of Definite Works	T&D Var O&	1.5	sen/kwh

Total Cost =	$2,741 Million	Definite Works Disbursement					
Infras.Cost =	$700 Million	Year−1	Year−2	Year−3	Year−4	Year−5	Total
Disc.Rate =	10%	5%	25%	30%	20%	20%	100%
		$137	$685	$822	$548	$548	$2,741

No	Year	Cost Disburs (G, T & D)	Additional Infrastruct. Cost	Energy Generated MWh	Energy Sent-out MWh	Energy Sold MWh	Average Tariff RM/kwh	Revenue Million	Fixed O&M Million	Var O&M Million	Coal Prices $/Mil.Kcal	Fuel Cost Million	T, D & A Var Cost Million	Total Oper.Cost Million	Average Cashflow Million
−6	1994														
−5	1995						0.2003								
−4	1996						0.2003								($392)
−3	1997	$182	$210				0.2003								($1,261)
−2	1998	$911	$350				0.2003								($1,234)
−1	1999	$1,094	$140				0.2003								($729)
0	2000	$729					0.2003								($729)
1	2001	$729		7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	18.353	$291	$105	$448	$727
2	2002			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	19.184	$304	$105	$461	$714
3	2003			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.053	$318	$105	$475	$700
4	2004			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.181	$320	$105	$477	$698
5	2005			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.310	$322	$105	$479	$696
6	2006			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.439	$324	$105	$481	$694
7	2007			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.570	$326	$105	$483	$692
8	2008			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.701	$328	$105	$485	$690
9	2009			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.844	$331	$105	$487	$688
10	2010			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	20.988	$333	$105	$489	$686
11	2011			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	21.133	$335	$105	$492	$683
12	2012			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	21.278	$337	$105	$494	$681
13	2013			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	21.425	$340	$105	$496	$679
14	2014			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	21.573	$342	$105	$499	$676
15	2015			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	21.722	$344	$105	$501	$674
16	2016			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	21.872	$347	$105	$503	$672
17	2017			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	22.023	$349	$105	$506	$669
18	2018			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	22.175	$352	$105	$508	$667
19	2019			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	22.328	$354	$105	$511	$664
20	2020			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	22.482	$357	$105	$513	$662
21	2021			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	22.637	$359	$105	$516	$659
22	2022			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	22.794	$361	$105	$518	$657
23	2023			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	22.951	$364	$105	$520	$654
24	2024			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	23.109	$366	$105	$523	$652
25	2025			7,008,000	6,517,440	5,865,696	0.2003	$1,175	$35	$16	23.269	$369	$105	$526	$649
NPV		**$2,224**	**$484**					**$6,020**						**$2,476**	

Benefit/Cost Ratio = 1.31

IRR = 12%

Capacity =	1000 MW	Efficiency =	38%		Heat Rates =	2,263	kcal/kwh
Aux.Cons =	7%	T&D Loss =	10%		Cap.factor=	70%	
Cap. Cost =	$2,741 RM/kw	Fix O&M =	35.04	RM/kw/year	Var O&M =	2.34	RM/MWh
IDC =	23.78%	T&D Cost=	33%	of Definite Works	T&D Var O&	1.5	sen/kwh

Total Cost =	$2,741 Million	Definite Works Disbursement					
Infras.Cost =	$700 Million	Year−1	Year−2	Year−3	Year−4	Year−5	Total
Disc.Rate =	13%	5%	25%	30%	20%	20%	100%
		$137	$685	$822	$548	$548	$2,741

APPENDICES