DAMS AND HYDROELECTRIC PROJECTS

Key technical data on the dams and hydroelectric projects are given in Table 3.

Mbokazi Dam

In its lower reaches, the Umzimvubu river has cut down through the general plateau of Transkei producing a deep valley flowing along incised meanders with banks formed mainly within the in situ bedrock. Habitations are concentrated traditionally on the higher ground away from the river so only about 20 small settlements would be affected by the reservoir.

The dam site has been selected because of many advantageous natural features including control of as much as possible of the catchment where the valley is narrow so that the volume of the dam structure is not excessive. Immediately downstream of the dam site the river bends sharply to the right through more than a right angle and the short path through the spur can be utilised for locating ancillary structures such as the spillway, power system and diversion conduits.

The size of the proposed dam (200 m high) and reservoir (6 000 x 10^6 m^3 total volume) was based on consideration of the topography, geology, hydrology, dam costs and benefits.

The dam alignment was selected after studying 5 options for embankment dams and 2 for concrete dams. A rockfill dam was chosen because one could be constructed safely from locally available material more economically than a concrete dam.

The rockfill dam layout is shown in Figure 8. The diversion tunnels spillway and power systems are all on the right bank with intake structures upstream of the right abutment of the dam. Most of the upstream cofferdam is incorporated in the upstream shoulder of the main embankment.

The dam has three major zones (see Figure 9). The core, which forms the water barrier, is placed centrally with a slight inclination. The core is supported upstream and downstream by rockfill shoulders with a riprap protecting layer on the upstream face in the normal reservoir operating range. A chimney filter and drain system on the downstream side of the core collect and discharge seepage into the blanket drain placed on the foundation beneath the downstream shoulder. Borrow areas for all construction materials have been identified within reasonable haul distances.

Mbokazi dam falls into the very large category of dams by world standards and the highest degree of safety is required to avoid failure and the risk of a catastrophic uncontrolled release of water. The spillway design flood has been selected to be equal to the probable maximum flood (PMF). Not only is the incoming flood very large but the head difference between reservoir level and tail water is also high at over 200 m.

The reinforced concrete spillway consists of three parts: the gated overflow headworks; the chute; and the flip bucket for energy dissipation (Figure 10). The principle of a spillway controlled by gates was accepted because Mbokazi includes a large power station which will require skilled professional staff full time who will be on hand to maintain and operate spillway gates. A concrete lined chute carries the discharge to a flip bucket set on the right bank of the river about 60 m above river level. The chute is split into three channels. Modest floods would be discharged through one channel only so that the unit discharge is high enough to flip properly at the bucket and to be thrown clear of the structure.

The diversion system passes the 1 in 100 year flood through two ungated 12 m diameter concrete lined tunnels on the right bank. One tunnel is converted to a permanent low level outlet and the other will be plugged.

The power system is located on the right bank (Figure 11). The tunnels pass through the spur forming the river meander with the power station well downstream of the dam. The power intakes would be located immediately upstream of the dam on the right bank and set about 20 m below minimum operatiing level. From the power intakes, concrete lined tunnels about 650 m long lead to vertical shafts extending upwards as surge shafts which, to satisfy hydraulic transient conditions and to minimise the length of costly steel tunnel linings, are located as close as possible to the power station having regard to the topography. The switchyard would be located on the left side of the river.

The power intakes would be of the upstream sloping gate type avoiding the need for a separate vertical gate shaft and allowing the whole length of the tunnels up to the intake to be dewatered for inspection. The power tunnels and shafts would be concrete lined except at the downstream ends where rock cover is less than about half of the static head and steel liners would have to be used.

The Mbokazi surface power station for a six unit 1 600 MW installation is shown on Figures 12 and 13. The layout is conventional and provides for the control room, offices and workshop to be housed in a two-storey building as an annex to the loading bay. The floor levels of the loading bay and downstream deck provide a margin above the estimated maximum flood level.

The switchyard configuration will be a standard double busbar arrangement which is consistent with the ESCOM 400 kV philosophy with gas insulated switchgear. Two overhead line entries will be required at each end of the substation.

Integration of the project into the ESCOM transmission system is proposed at two locations, namely Mersey (near Pietermaritzburg) and Neptune (near East London). Four transmission lines of 275 km are required, and this configuration will be sufficient for a station output between 1 200 and 2 000 MW. Because of the levels of power transfer involved and the relatively long route lengths, Quad Zebra configuration has been chosen.

For the six unit 1 600 MW scheme the generators and transformers would be rated at 2 000 MW and generation at this output would be possible at reservoir levels above 210 m. 1 600 MW will be generated at the minimum reservoir operating level of 180 m.

The turbines will be vertical shaft Francis turbines with butterfly inlet valves. The runners will be approximately 5 m in diameter.

The turbines will be directly coupled to conventional air cooled umbrella type generators with static excitation and a thrust bearing mounted below the rotor. The generators will be rated 390 MVA at 0,85 power factor.

Nkwalini Dam

A reregulation dam is proposed downstream of Mbokazi to even out the fluctuating discharges from the power station. The size of the reregulation reservoir is sufficient to store the weekday releases from Mbokazi over 5 week days and to generate over seven days. The full supply level (FSL) is at the normal operating tailwater level (TWL) for Mbokazi dam, i.e. 43 masl and minimum drawdown would be 37 masl.

The dam structure is a conventional overflow concrete gravity dam incorporating a 16 000 m^3/s spillway to handle the discharge from Mbokazi plus a 3 unit 50 MW power station on the right bank to generate electricity for the TESCOR system (see Figure 14).

The turbines would be vertical shaft Kaplan type operating at a rated speed of 200 rpm with concrete spiral casings. The runner will be approximately 3,3 m in diameter.

The turbines will be directly coupled to conventional air cooled umbrella type generators with static excitation and thrust bearing mounted below the rotor. The generators will be rated 20,6 MVA at 0,85 power factor with a rated voltage of 11 kV. The transformers would be three phase units rated at 20 MVA, 11/132 kV. The 132 kV switchyard located on the right bank adjacent to the power station will be of the conventional outdoor type in single busbar formation. Three 132 kV outgoing feeders are foreseen comprising a double circuit line to Zimbane and a single circuit line to Magwa.

ROLE OF POWER STATIONS

Mbokazi

The current (mid 1986) ESCOM forecast is for 5% p.a. increase in maximum demand and 5,5% p.a. increase in energy demand over the period to 1996. The difference between these two rates represents the effect of demand side management (DSM) i.e. tariffs to discourage use of peak electricity.

After 1996 there is no formal ESCOM forecast, but others expect growth in both maximum demand and energy demand of 4,55% p.a. (Table 4).

The approximate shape of the annual load duration curve (LDC) in 1985 was estimated from hourly system demand data in each calendar month. This estimated LDC is shown in Figure 15. It can be seen that generating plants supplying the top 10% of the demand would have an average plant factor of less than 5% and a maximum plant factor of 10%. On this basis, therefore, there would appear to be a role for at least 1 800 MW of low plant factor peaking plant in 1985. This compares with an actual capacity of 882 MW of hydroelectric and gas turbine units. The above simplified assessment underestimates the potential for peaking capacity (operating at plant factors of less than 10%) due to the substantial reserve capacity requirements and the total amount of such plant might be expected to be in the order of 10% of the total capacity (i.e. 2 500 MW in 1985) rather than 10% of the maximum demand.

ESCOM expect that, due to the implementation of demand side management, the annual system load factor will increase to 79,5% by 1997 with consequent changes to the peak load region of the LDC. A preliminary estimate of the shape of the 1997 annual LDC is also shown in Figure 15. This indicates a potential for peaking plant up to 10% plant factor of over 3 000 MW in that year. With respect to the need for additional peaking capacity, it may be noted that the existing ESCOM hydro stations (540 MW) are not actually very low plant factor schemes since they have an average plant factor of approximately 20%. Also the existing gas turbine units (342 MW) will be reaching the end of their useful lives by that time. On the other hand, the pumped storage plant (1 400MW) could change to lower plant factor operation as the proportion of high efficiency plant increases.

ESCOM have a generation development programme which they estimate will meet demand increases up to the year 1997, provided that the maximum demand increase rate is 5% per year. In 1997, with the present development plan almost entirely consisting of coal fired thermal stations, there should be a total installed net capacity on the integrated ESCOM system of 42 321 MW to meet a forecast demand of 32 474 MW, i.e. a reserve margin of 30,3%. This capacity will comprise 28 000 MW of large coal-fired units (600/660 MW units size), about 10 000 MW of other coal-fired plant, one 1 840 MW nuclear station and peaking capacity comprising gas turbines (342 MW) hydro (540 MW) and pumped storage (1 400 MW). Thus, in 1997 the gas turbine and hydroelectric units will represent 2,7% of the demand and the pumped storage plant 4,3%.

By the year 2000 there will be a requirement for a total of some 48 250 MW of capacity on the ESCOM system. Figure 16 shows typical and peak winter weekday load curves for the ESCOM system in 2000. These were constructed based on similar curves for 1985. The possible operating role of a 2 000 MW peaking hydro station occupying the top of the peak is also shown. This could represent Mbokazi with an installed capacity of 1 600 MW, since this is capable of 2 000 MW much of the time. For both the peak day and the typical day the station would operate twice a day, but the energy generated during the evening peak is much less than that generated during the morning. The approximate energy required in 7,4 GWh for the peak day, and 5,3 GWh during the average winter weekday.

The average energy output of Mbokazi for the 290 m, 250 m and 230 m FSL are 1 579 GWh, 1 192 GWh and 985 GWh per annum, i.e. 4,6 GWh for every weekday on average for 250 m FSL. If the output for Mbokazi is 1 600 MW the approximate energy that could be generated subject to the constraints of the load curve falls to 5,4 GWh for the peak winter day and 2,6 GWh for the typical winter weekday. All three alternative dam heights would provide sufficient energy for the typical weekday, and the 290 m option would provide more energy than is necessary for the peak day. A scheme based on 1 600 MW installed capacity would therefore operate in a marginally less peaking role in order to fully utilise all available energy.

The role of Mbokazi power station in expected to change with time as the demand increases and also to differ between winter and summer.

Nkwalini

Since the formation of TESCOR in August 1979 the maximum demand on its interconnected system has increased steadily, the 1985 level being approximately 41,3 MW. The average rate of increase in demand has been 10% per year over this period. The energy demand (generation plus purchase) has increased from 122,1 GWh in 1981 to 198,4 GWh in 1985, an increase rate of 13% per year. The annual system load factor has varied between 51,6% and 54,8% over the latter period on a calendar year basis. Load forecasts have been prepared by various advisers to TESCOR and we have adopted a maximum demand increase at 8,5% per year up to 1993/94, with increases thereafter constant at 8,0% per year. The load forecast is shown in Table 5.

Over the period to 1995, TESCOR plan to commission a fourth 14 MW unit at Collywobbles and to build a 60 MW power station at Qalweni or equivalent alternatives.

It can be demonstrated that the Nkwalini power station can make a useful contribution to the TESCOR system but the exact role will depend on the other stations completed before Nkwalini, the pattern of water releases required downstream of Nkwalini and the amount of storage available in the small reservoirs serving other power stations.

CAPITAL COSTS OF DAMS AND POWER DEVELOPMENT

Capital cost estimates were prepared for nine alternative Mbokazi options embracing the range of dam heights from 290 m to 230 m FSL and a range of installed capacities between 1 000 and 2 000 MW, together with three options for Nkwalini of 40, 50 and 60 MW installed capacity. All costs are based on September 1986 price levels. Where appropriate foreign exchange rates have been assumed of 3,2 Rand equals 1 Pound Sterling and 2,2 Rand equals US$ 1. Physical contingencies and engineering have been included in the costs.

The costs of the civil works are based on the outline designs. Quantities have been estimated for the main construction activities such as excavation, embankment fill, tunnel construction, adits with grout and drainage curtains, and concrete in the spillway and power station. Unit rates for construction were derived. The major cost item is Mbokazi dam structure at 40% of the total. Unmeasured items and physical contingencies have been taken as 15% at this stage. In addition engineering and administration charges have been added at 8% of the total construction costs.

The basis for the cost estimates for electrical and mechanical plant was a combination of actual contract costs for similar plant under international competitive tendering and manufacturers' budgetary estimates. These costs include generators, turbines, valves, electrical and mechanical auxiliaries and powerhouse cranes. Physical contingencies and engineering are included at a combined rate of 20%.

Switchyard costs include a 400 kV switchyard and generator transformers on the basis of a GIS installation. Physical contingencies and engineering are included at a combined rate of 15%.

Costs have been added for four 275 km long 400 kV Quad Zebra overhead lines to interconnect Mbokazi into the ESCOM system including compensation and integration costs to the ESCOM substations. Physical contingencies and engineering are included at a combined rate of 15%.

Since the role of Nkwalini is to reregulate the flow of water down the Umzimvubu river to an acceptable regime, a portion of the civil costs of Nkwalini dam and spillway should be included in the costs of Mbokazi. This portion has been taken to be 80% for the purposes of this study, i.e. a cost of R70,33 million. Physical contingencies and engineering have been included for at rates of 20% and 8% respectively because of greater uncertainties in foundation conditions.

The total cost assumptions for all options are summarised in Table 6. The range of specific capital costs for these options varies between Rand 1 125 per kilowatt for the 250 m 2 000 MW option to Rand 1 794 per kilowatt for the 290 m 1 200 MW option.

Cost estimates for the power development at Nkwalini have been prepared using the same general approach as for Mbokazi (Table 7).

ECONOMIC EVALUATION OF POWER BENEFITS

The Mbokazi and Nkwalini schemes have been separately considered within the context of the ESCOM and TESCOR systems respectively, and the integration of the schemes into the power systems has been examined over a 10 year period.

All costs of the dams, power stations and transmission lines have been included although if the water transfer scheme proceeds some of these features assist both projects and costs should be shared. Any sharing will improve the economics of the hydroelectric project.

The evaluation of the Mbokazi scheme has been carried out in quasi-economic terms as a project serving Southern Africa. Local market prices have been used for coal, for example, which do not necessarily correspond to economic prices. SACU rebates on the capital costs have also been excluded. No shadow prices have been applied to any of the capital cost elements. The rationale for this approach is that at this stage a comparison has to be made between a number of competing schemes, both within and outside RSA.

Only base-load coal-fired steam stations are being considered for installation on the ESCOM system up to the late 1990's. The main economic comparisons have been made on the assumption that the Mbokazi scheme would replace or delay the construction of further plant of the same type after the presently scheduled power stations have been completed. Alternative generation planting programmes were drawn up, each of which met the ESCOM security criterion. The programmes cover a ten year period, starting in 1997 (the first year in which it was assumed the Mbokazi plant could be commissioned).

The nine programmes were based on the alternative options for Mbokazi covering 290 m to 230 m dam heights, with variation in installed capacity. In addition to these programmes an all-thermal programme was developed as a datum against which to measure the Mbokazi based programmes.

The estimated cost of the coal-fired power station assumed in the evaluation is R1 200/kW at September 1986 price levels. This represents the cost of the power station, plus the switchyard and necessary transmission to interconnect it to the main ESCOM system. This cost excludes GST.

The capital and operating costs of each programme were determined on an annual basis over the ten year period using a probabilistic type computer program. This simulates system operation subject to the constraints of the load duration curve, plant availabilities, merit order, etc. The costs in the final year of simulation were run out over the life of the hydro scheme, thereby avoiding any calculation of significant residual values. The capital costs of any thermal plants commissioned during the simulation period were reintroduced into the cost stream as appropriate at the end of their economic lives.

Throughout the analysis costs common to all alternative generation planting programmes have been ignored. No retirements of existing generating plant have been made.

The evaluation of Nkwalini is essentially similar to that for Mbokazi, with a calculation of total system costs. Alternative generation planting programmes were derived based upon the 40, 50 and 60 MW alternatives for Nkwalini, with a fourth case based on no Nkwalini development. It was assumed that growth in electricity demand would be met by either:

(a) input from ESCOM, based on the costs of large coal-fired generating plant, or

(b) import from ESCOM, costed on the basis of the ESCOM tariff, before and after allowance for SACU rebate.

These alternatives represent consideration of the Nkwalini scheme in a Southern African and Transkei context respectively.

Due to the very marked seasonality in the outputs and operating regime of the hydro plants in Transkei, all modelling has been done on a seasonal basis with different load duration curves for the summer and winter seasons.

In the context of methodology adopted for this study it was decided to adopt a test discount rate of 6% p.a. This rate corresponds closely to the rate used by ESCOM of 5,5% p.a. It is understood that DBSA use a lower rate of 3% in the analysis of projects in the agricultural sector. However, it was decided to use a range of discount rates from 3% to 12%.

Table 8 shows the comparative benefits for the nine alternative Mbokazi options considered at the test discount rate of 6%. The least cost development is seen to be that based on a 2 000 MW scheme with a 250 m FSL. Also given is the Equalising Discount Rate (EDR) i.e. the rate at which hydro and thermal options are equally economic. If the test discount rate is less than the EDR, Mbokazi is favoured. The results indicate increasing economic viability for Mbokazi with increasing installed capacity for each dam height. Increasing the size of Mbokazi power station, however, decreases its load factor since at any dam height the energy output is virtually fixed.

The economic analysis carried out shows that on the assumptions made, a development of 2 000 MW output with a FSL of 250 m represents the most attractive alternative when compared with the developments based on coal fired thermal power stations. This conclusion was found to be the most robust when subject to changes in basic assumptions including capital costs of Mbokazi and the coal fired thermal alternative, fuel prices and the shape of the load duration curve (see Table 8 for effects on the 1 600 MW, 250 masl scheme).

In practice a development with a 1 600 MW installed capacity has a potential output 2 000 MW for reservoir levels higher than 210 masl. The value of this additional power output has not been quantified in the analysis but it would be available for 90% of the time. It will increase the flexibility of operation of Mbokazi both in terms of peaking and for system reserve. This additional benefit should be examined in a detailed economic appraisal.

The most attractive development at Nkwalini was shown to be that based on schemes between 40 and 50 MW (Table 9). These offered a lower cost than importation from ESCOM if imports are based on the ESCOM tariff, either with or without the SACU rebate. If viewed from a Southern African context the total costs of development assuming imports are costed at direct ESCOM costs of are lower than the equivalent costs with Nkwalini. This result, however, is very sensitive to the assumptions made regarding the cost allocation of Nkwalini dam civil works between Mbokazi and Nkwalini (Table 10).

PROGRAMME FOR DEVELOPMENT

Study and design

Multipurpose development of the Umzimvubu basin is recommended with the main elements being the hydroelectric scheme at Mbokazi and the water utilisation schemes within Transkei and RSA. The most beneficial use of the river would include both aspects which are interdependent in that both require the dam at Mbokazi. However, separate development programmes are presented to show clearly the steps required for realisation of each element and the time that they will take. It is emphasised that such large projects take many years to come to fruition and that the next stages in this process should follow directly on from this report if the schemes are to be ready when required near the end of this century.

(a) Hydroelectric project

The rate of increase in electrical demand and development plans of both ESCOM and TESCOR point to commissioning the first units in early 1998. This fits well with award of the main civil contract for the Mbokazi project dams and power stations, etc at the end of 1990 with a seven year contruction programme. A programme of activities for the dam and hydro power development between now and start of construction is set out in Figure 17. This programme is based on the assumption that the civil works construction would be carried out by a large consortium of national and international companies who have constructed similar schemes already.

Apart from negotiations on interstate agreements further economic and financial studies, detailed site investigation, testing, hydraulic modelling and preparation of contract designs must be completed before tendering or negotiation of contracts. Award of the main civil contract would be at the end of 1990.

(b) Water transfer projects

The more detailed study of the agricultural potential and benefits that would accrue from large scale development within Transkei and RSA is a top priority. The benefits should be assessed in socio-economic terms to show the advantages of the project to the whole region. Taking into account the different organisations that would have an input to such a study, a period of two years should be allowed for comprehensive soil surveys, selecting suitable crops, market surveys and predictions, planning large farm developments and assessing demand for water on a seasonal basis region by region. The water requirements for rural, urban and industrial use should be derived from long term plans for Transkei. Socio-economic and financial analyses would demonstrate the viability of development and indicate the scope of the first stage.

Preparation of tender documents for such a long conduit through Transkei to RSA could take up to four years depending on the number of contracts and the extent of secondary and smaller offtake conduits included.

Award of the first contract for large water transfer conduit through Transkei could be in 1993.

Construction

(a) Mbokazi and Nkwalini dams

The programmes for construction of Mbokazi dam and Nkwalini dam are given in Figure 18. The first unit is commissioned after 7 years and the last in the ninth year. The civil works should be let as one contract because of the interaction between project features in the compact site. In particular economic earth moving will require careful programming of construction sequences. The mechanical and electrical equipment would be supplied under separate contracts. The critical path is through the construction of the diversion tunnels, the embankment and impounding to a high enough level to test and commission the first two units in January of year 8. Construction of the civil works for the power system and erection of the generating plant and transmission lines are not on the critical path for commissioning the project.

(b) Water transfer conduits

The construction programme for the water conduit system would depend mainly on the supply of pipes. It would be preferable if these were manufactured in a special factory established locally for this purpose. Construction of the conduit would probably be let in a number of contracts of the size that can be handled by contractors in Southern Africa but could possibly be arranged with one large contractor or consortium either acting as main contractor or as contract manager controlling sub-contracts.

A simplified construction programme for the western route is set out in Figure 19.

TWO YEAR STUDY WITH EMPHASIS ON WATER USES

Activities

1. **Management and engineering,** including

   - direction and coordination of study
   - liaison with coordinating committee
   - liaison with government departments in Transkei and RSA
   - liaison with the Development Bank of Southern Africa
   - preparation and circulation of regular progress reports on all aspects
   - estimating growth of domestic and industrial water requirements in study area
   - overall planning
   - engineering of water transfer, routes, systems, sizes, pumping rates, optimisation, access routes
   - selection of pumps, transmission lines
   - costing
   - meteorology, hydrology
   - detailed reservoir operation studies
   - review of land tenure aspects, shared water basin, shared benefits
   - implementation and construction programme including staged development
   - coordination and preparation of final report

2. **Geology**

   - mapping of routes for pipes, canals, tunnels with some seismic surveys
   - mapping of pumping station sites including drilling if necessary
   - identification of borrow areas

3. **Agriculture**

   - review reconnaissance study
   - identify areas suitable for irrigation (soils, slopes, settlements, present usage)
   - carry out detailed soil mapping including testing
   - identify possible crops (winter, summer and perennial)
   - establish marketability in Transkei, RSA and export as raw and processed products
   - prepare outline schemes for large scale commercial agriculture and local irrigation
   - assess overall economic (including social) benefits

4. **Electrical benefits**

   - review with ESCOM, role and integration of Mbokazi in their system
   - review with TESCOR, role and integration of Nkwalini with other alternatives in their system
   - optimisation of operations of both power stations and water transfer schemes

TABLE 1

SUMMARY OF CONDUIT FEATURES

Route	Pipeline and siphons km	Canals km	Total km	Pumping station no.	Total Static lift m	End point(s)
Western						
A	351	115	466	11	1750	Molteno Tarkastad
B	346	76	422	10	1750	Molteno Tarkastad
B1	282	0	282	9	1650	Dordrecht
E	377	0	377	9	1350	Tarkastad
Northern						
N	94	-	94	3	600	Umtamvuna

TABLE 2

SUMMARY OF WATER TRANSFER COSTS

Route	Capital cost $R \times 10^6$	Running Costs $R\times10^6$ p.a.			
		Pumping	Maintenance	Operation	Total
Western (20 m^3/s)					
A	2090	170	12,0	1,3	183
B	2000	168	11,4	1,2	181
B1	1540	158	9,0	0,9	168
E	2045	130	11,4	1,1	143
Northern (10 m^3/s)					
N	353	28	2,2	0,3	31

Notes : A - via Queenstown.
: B - via Dordrecht.
:B1- discharge to Orange but reach Fish through Orange/Fish tunnel.
: E - not to Orange.

TABLE 3

SUMMARY OF KEY TECHNICAL DATA OF DAMS AND HYDROELECTRIC PROJECTS

1. **Mbokazi**

Reservoir	
Catchment area	20 000 km^2
Mean annual runoff (MAR)	3 000 x 10^6 m^3
Full supply level (FSL)	250 masl
Reservoir area at FSL	85 km^2
Minimum operating level	180 masl
Total storage volume	5 950 x 10^6 m^3
Live storage volume	4 350 x 10^6 m^3
Dam Type	Rockfill with central earth core
Crest elevation	260 masl
Crest length	850 m
Maximum height above foundations	210 m
Volume of dam	47 x 10^6 m^3
Spillway Type	Gated crest overflow with flip bucket
Sill level	237 masl
Maximum discharge in PMF	27 400 m^3/s
Number and size of radial gates	9 - 15,56 m W, 14 m H
Diversion Conduits	
Number and diameter	2 - 12 m
Average length	1 675 m
Lining	Concrete
Power System	
Number of gates	4
Penstocks - number and diameter	2 - 11 m
- lining	Concrete
trifurcating to:	
- number and diameter	6 - 6,5 m
- lining	Concrete with steel encasement
Surge tanks - number and diameter	2 - 11 m
	(27 m above 270 masl)
Power station type	Surface, indoor
Installed capacity	1 600 MW
Number of units	6
Turbine type	Francis
Rated speed	136 rpm
Generator rating	390 MVA

2. **Nkwalini**

Reservoir	
Full supply level (FSL)	43 masl
Reservoir area at FSL	3,25 km^2
Minimum operating level	37 masl
Total storage volume	59 x 10^6 m^3
Live storage volume	19 x 10^6 m^3

Dam Type	Concrete, gravity
Crest elevation	53 masl
Crest length	375 m
Spillway Type	Gated overflow, roller bucket
Sill level	31 masl
Hydraulic design capacity	16 000 m^3/s
Number and size of radial gates	9 - 14,3 m W, 20 m H
Power Station Type	Integral, indoor
Installed capacity	50 MW
Number of units	3
Turbine type	Kaplan
Rated speed	200 rpm
Generator rating	20,6 MVA

TABLE 4

LOAD FORECAST FOR ESCOM

Year	Maximum Demand (MW)	Energy sent out (GWh)
1990	23 178	157 047
1995	29 582	205 254
1996	31 061	216 554
1997	32 474	226 397
1998	33 952	236 698
1999	35 496	247 468
2000	37 111	258 728
2001	38 800	270 500
2002	40 565	282 807
2003	42 411	295 675
2004	44 341	309 128
2005	46 358	323 194
2006	48 468	337 899
2007	50 673	353 273
2008	52 979	369 347
2009	55 389	386 153
2010	57 909	403 723
2011	60 544	422 092
2012	63 299	441 297
2013	66 179	461 376
2014	69 190	482 369
2015	72 338	504 317
2016	75 630	527 263

Notes :

1. Maximum demand forecast based on 5% pa increase to 1996 and 4,55% thereafter.
2. Energy forecast based on 5,5% pa increase to 1996 and 4,55% thereafter.

TABLE 5

LOAD FORECAST FOR TESCOR

Year	Maximum Demand (MW)	Energy sent out (GWh)
1985	42,7(1)	209,5(2)
1986	46,3	227,1
1987	50,2	246,3
1988	54,5	267,4
1989	59,1	289,9
1990	64,2	314,4
1991	69,6	341,4
1992	75,4	369,9
1993	81,8	401,3
1994	88,3	433,2
1995	95,4	468,0
1996	103,0	505,3
1997	111,3	546,0
1998	120,1	589,2
1999	129,8	636,7
2000	140,2	687,8

Notes : 1. Financial year, i.e. 1985 is year ending 31 March 1986.

2. Actual figures for 1985/1986 were 41,7 MW and 207,8 GWh (system load factor 56,9%).

3. Maximum demands and energy demands after 2 000 assumed to increase at annual rate of 8%.

TABLE 6

TOTAL CAPITAL COSTS FOR ALTERNATIVE MBOKAZI SCHEMES

Rands x 10^6

FSL	Installed Capacity (m)	Civil Works (1) (MW)	Generation Plant (2)	Transmission	Total	Rand/ kW
290	2000	1666	492	330	2488	1244
	1600	1617	422	296	2335	1459
	1200	1570	313	268	2151	1792
250	2000	1395	524	330	2249	1125
	1600	1334	441	296	2071	1294
	1200	1284	335	268	1887	1572
230	1600	1235	443	296	1974	1234
	1200	1168	335	268	1771	1476
	1000	1145	293	230	1668	1668

Notes: 1. Including R70.33 x 10^6 for attributable cost for Nkwalini
2. Including substation costs

TABLE 7

TOTAL CAPITAL COSTS FOR ALTERNATIVE NKWALINI SCHEMES

Rands x 10^6

Installed Capacity MW	Civil Works	Generating Plant	Transmission	Total	Rand/kW
40	41	34	7	82	2 055
50	42	42	7	91	1 820
60	43	51	7	101	1 680

Notes: 1. Excluding R70,33 x 10^6 attributable to Mbokazi.
2. Including Nkwalini sub-station costs.

TABLE 8

MBOKAZI - COMPARATIVE SIMULATION COSTS

Base case

Dam FSL	Mbokazi installed capacity			
	1 000 MW	1 200 MW	1 600 MW	2 000 MW
(a) Savings in costs (R x 10^6) discounted to 1986 at 6% discount rate				
290 m		-38	161	507
250 m		42	290	610
230 m	141	84	321	
(b) Equalising Discount Rate (EDR)				
290 m		5,7%	8,8%	* 12%
250 m		7,1%	* 12%	* 12%
230 m	9,3%	8,2%	* 12%	

Note : * is greater than.

Sensitivity Checks

Present value of cost savings at 6% discount rate for 250 m 1 600 MW scheme with the following changes:

		Rand x 10^6
Coal-fired thermal costs	+ 20%	585
	- 20%	- 4
Mbokazi costs	+ 20%	37
	- 20%	543
Fuel costs	+ 20%	284
LDC shape as 1985		368

TABLE 9

NKWALINI - COMPARATIVE SIMULATION COSTS

Costs in Rands x 10^6 discounted to 1986 at 6% discount rate

Costing basis	60 MW	50 MW	40 MW
Tariff before SACU rebate	25	31	31
Tariff after SACU rebate	12	18	19
ESCOM costs	-11	- 5	- 4

TABLE 10

NKWALINI - COMPARATIVE SIMULATION COSTS

20% change to Nkwalini capital costs

Costs in Rands x 10^6 discounted to 1986 at 6% discount rate

Costing basis	60 MW		50 MW		40 MW	
	+20%	-20%	+20%	-20%	+20%	-20%
Tariff before SACU rebate	13	37	19	43	21	41
Tariff after SACU rebate	0	24	7	29	9	29
ESCOM costs	-24	1	-16	6	-14	6