ENTRO

EASTERN NILE POWER TRADE PROGRAM STUDY

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ENERGY SECTOR PROFILE & PROJECTIONS

VOL 4 - SUDAN

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with participation of:

- EPS (Egypt)
- Tropics (Ethiopia)
- YAM (Sudan)

FINAL MAIN REPORT

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PHYSICAL UNITS AND CONVERSION FACTORS

bbl	barrel	(1t = 7.3 bbl)
cal	calorie	(1 cal = 4.1868 J)
Gcal	Giga calorie	
GWh	Gigawatt-hour	
h	hour	
km	kilometer	
km^2	square kilometer	
kW	kilo Watt	
kWh	kilo Watt hour	(1 kWh = 3.6 MJ)
MBtu	Million British Thermal Units	(= 1 055 MJ = 252 kCal)
	one cubic foot of natural gas produces approximately 1,000 BTU	
MJ	Million Joule	(= $0{,}948.10^{-3}$ MBtu = 238.8 kcal)
MW	Mega Watt	
m	meter	
m^3/d	cubic meter per day	
mm	millimeter	
mm^3	million cubic meter	
Nm^3	Normal cubic meter, i.e. measured under normal conditions, i.e. 0°C and 1013 mbar	
	(1 Nm^3 = 1.057 m^3 measured under standard conditions, i.e. 15°C and 1013 mbar)	
t	ton	
toe	tons of oil equivalent	
tcf	ton cubic feet	
°C	Degrees Celsius	

General Conversion Factors for Energy

To:	TJ	Gcal	Mtoe	MBtu	GWh
From:	multiply by:				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3412	1

ABBREVIATIONS AND ACRONYMS

ADB	African Development Bank
ADF	African Development Fund
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CIDA	Canadian International Development Agency
CT	Combustion Turbine
DANIDA	Danish Development Assistance
DFID	Department for International Development (UK)
DIDC	Department for International Development Cooperation (GoF)
DSA	Daily Subsistence Allowance
EEHC	Egyptian Electricity Holding Company
EEPCO	Ethiopian Electric Power Corporation
EHV	Extra Large Voltage
EHVAC	Extra High Voltage Alternating Current
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EN	Eastern Nile
ENCOM	Eastern Nile Council of Ministers
ENSAP	Eastern Nile Subsidiary Action Program
ENSAPT	Eastern Nile Subsidiary Action Program Team
ENTRO	Eastern Nile Technical Regional Office
ENTRO PCU	Eastern Nile Technical Regional Office Power Coordination Unit
FIRR	Financial Internal Rate of Return
GEP	Generation Expansion Plan
GTZ	German Technical Co-operation
HPP	Hydro Power Plant
HFO	Heavy fuel oil
HV	High Voltage
HVDC	High Voltage Direct Current
ICCON	International Consortium for Cooperation on the Nile
ICS	Interconnected System
IDEN	Integrated Development of the Eastern Nile
IDO	Industrial Diesel Oil
IMF	International Monetary Fund
JICA	Japanese International Co-operation Agency
JMP	Joint Multipurpose Project
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LPG	Liquefied Petroleum Gas

LRFO	Light Residuel Fuel Oil
MENA	Middle East, North Africa Countries
MIWR	Ministry of Irrigation & Water Resources (Sudan)
MWR	Ministry of Water Resources (Ethiopia)
MWRI	Ministry of Water Resources and Irrigation (Egypt)
MSD	Medium Speed Diesel (TPP)
NBI	Nile Basin Initiative
NEC	National Electricity Corporation (Sudan)
NECC	National Electricity Control Centre (Egypt)
NELCOM	Nile Equatorial Lake Council of Ministers
NELSAP	Nile Equatorial Lake Subsidiary Action Program
NG	Natural Gas
NGO	Non Governmental Organization
NORAD	Norwegian Aid Development
NPV	Net Present Value
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
OPEC	Organization of the Petroleum Exporting Countries
PBP	Pay Back Period
PHRD	Policy & Human Resource Development Fund
PIU	Project Implementation Unit
PRSP	Poverty Reduction Strategy Paper
RCC	Regional Electricity Control Centre (Egypt)
RE	Rural Electrification
SAPP	Southern Africa Power Pool
SIDA	Swedish International Development Agency
SSD	Slow speed diesel (TPP)
STPP	Steam Turbine Power Plant
STS	Senior Technical Specialist
TAF	Technical Assistant Fund
TPP	Thermal Power Plant
UA	Unit of Account
UNDP	United Nations Development Program
WB	World Bank

1. OVERVIEW

1.1 DEMAND FORECAST

The demand forecast study has formed the basic input data to Sudan Long Term Power Plan Study 2006 (LTPPS).

For the present Power Trade Study, in order to remain consistent with the NEC 2006 Long Term Power System Planning Study, the Consultant will keep the same assumptions of demand forecast and the same scenarios: Base, High and Low.

The main assumption for the base case demand forecast are the following:

	2006	2010	2030
Population annual growth rate		2.5%	1.7%
GDP annual growth rate		8.6%	3.6%
Electrification ratio	18%	52%	83%
Power losses	25%		12.5%
Load factor	65%	70%	70%

Table 1.1-1 - Main assumptions for the base case demand projection for Sudan

The total customer sales forecast is the summation of the individual sector forecasts. Overall electricity sales are forecast to increase to about 75 TWh by 2030 at an average annual growth rate of 10.8%. The influence of the industrial sector in the medium-term sees its share increase to over 40% in 2010 (overtaking the domestic sector which drops to 37% in that year). In the long-term the commercial sector share of total sales increases to over 20% by 2026.

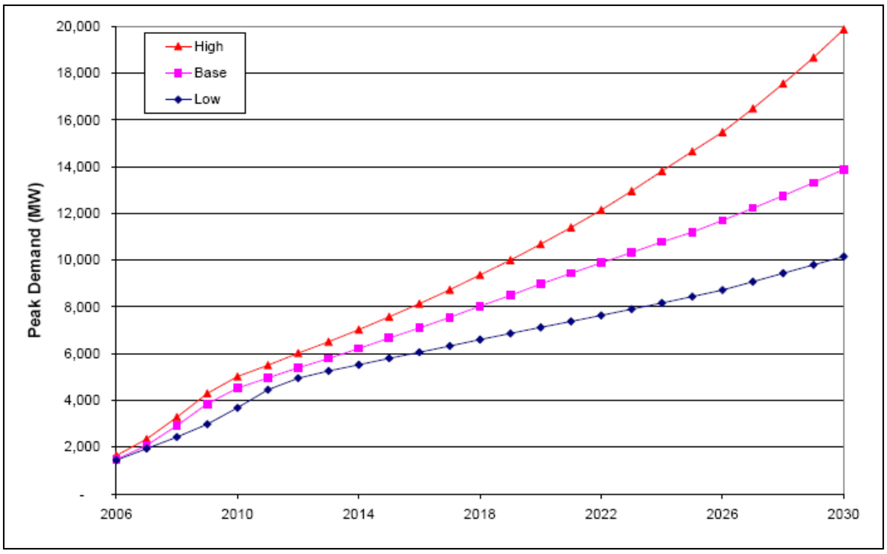

Figure 1.1-1 - Peak demand projection for Sudan (2006-2030)

	Peak forecast (MW)					
	2006	2010	2015	2020	2025	2030
High case	1 475	4 731	7 199	10 191	14 023	19 184
Base case	1 475	4 550	6 693	8 995	11 205	13 883
Low case	1 475	3 987	5 513	6 800	8 086	9 808

Table 1.1-2 - Main characteristics of the demand projection for Sudan

1.2 POWER TRADE OPPORTUNITIES

The present Study assumes that the only power trade opportunities for the next 25 years will be with Egyptian and Ethiopian power systems.

Considering the Feasibility study results of the interconnection between Ethiopia and Sudan, the Consultant assumes a commissioning date of this interconnection in 2010 with a maximum transfer capacity of 200 MW.

The simulation and economic analysis carried out in Module 6 will evaluate the potential of economic power trade between Egypt, Ethiopia and Sudan, and the economic opportunity of reinforcement of the Ethiopia – Sudan power connection (i.e. capacity > 200 MW).

1.3 GENERATION OPTIONS

The generation candidates are one of the key elements of the "Power Trade Study", as for the implementation of the domestic electricity master plan accomplished in Sudan LTPPS 2006.

For the present Power Trade Study, and to remain homogenous with the NEC master plan, we will keep the same assumptions of generation candidates.

1.3.1 THERMAL CANDIDATES

In line with Sudan Long Term Power Plan Study 2006 study, the following thermal candidates will be considered in the economic study (Module 6):

- coal-fired steam power plant for base-load generation:
  - 150 MW circulating fluidised bed combustion technology (CFB) STPP,
  - 400 and 600 MW Pulverised Fuel technology (PF) STPP.
- crude oil-fired steam turbine for base-load generation (150 MW, 250 MW, 500 MW),
- gas oil-fired CCGT for semi-base generation (200 MW, 350 MW and 450 MW),
- gas oil-fired OCGT for peak-load generation (41 MW to 268 MW),
- 40 MW Low Speed Diesel.

<u>Environmental preservation</u>:

Emissions control is an important aspect of all types of PF coal-fired steam plant. For the purposes of this study, we assume that the design will incorporate the following features:

- Moderate sulphur coal (blending coals so that the sulphur content is less than 2% by mass) in order to take advantage of the seawater flue gas desulphurisation process, which avoids the additional cost of sorbent such as lime or limestone;
- Low NOx combustion system, with allowance in the boiler design for selective catalytic reduction (SCR) equipment to be fitted at a later date;
- Use of bag filters to control the emission of particulates.

With these design features, a new PF plant, be it subcritical, supercritical or advanced supercritical, will meet the environmental emissions targets such as those set by the World bank or the even more stringent requirements of the Large Combustion Plant Directive (LCPD) in Europe.

Fluidised bed combustion technologies have some inherent environmental benefits over conventional PF type plants:

- Combustion temperatures are generally lower than those found in typical PF plant. In this regard, lower NOx emissions are achievable without the need for special combustion systems.
- The need for expensive flue gas desulphurisation equipment can be avoided by injecting sorbent (e.g. limestone) directly into the fluidised bed boiler. This has the added benefit of fuel flexibility to burn coals with a wide range of sulphur content.

In this study we consider the circulating fluidised bed combustion (CFB) technology as being the most suitable plant type owing to its suitability for use with coal.

Coal CFB is a well-proven technology suitable for medium size (less than 300 MW) coal-fired plants located inland, i.e. it does not require the availability of seawater for flue gas desulphurisation. For the purposes of this study, we assume that the design of a CFB steam plant will be optimised to incorporate the following features:

- Injection of sorbent into the boiler to control sulphur emissions, with sorbent recirculation from the bag filter to enhance utilisation;
- Use of bag filters to control the emission of particulates and enhance sulphur capture.

1.3.2 HYDRO POWER CANDIDATES

The list of hydro candidates to be considered in the economic evaluation (Module 6) are presented in the table below.

Project	River	Level of Study	Installed capacity MW	Total cost MUSD2006	Average generation GWh/year	Comments
Rumela	Atbara river	M&M/Gibb 1979	30	193	82	Irrigation pupose
Sabakola	Main Nile	Acers 1993	120	596	691	Might flood Khartoum
Shereiq	Main Nile	F (1990)	315	1 190	1 546	Prioritary
Dagash	Main Nile	Acers 1993	285	1 048	1 476	
Kajbar	Main Nile	F (Hydroproject 1997)	300	1 125	1 400	
Dal Low	Main Nile	On going PF	340	1 118	1 944	cost currently updated in PF
	Sub Total		1 360			
Fula Alt 1	Barh el jebel	Acers 1993	720	1 319	4 119	limited information
Shukoli	Barh el jebel	Acers 1993	210	420	1 422	available
Lakki	Barh el jebel	Acers 1993	210	429	1 415	comm. date > 2020
Bedden	Barh el jebel	Acers 1993	400	880	2 761	(Pre-Feasibility : starting in 2007)
	Sub Total		1 540			

Table 1.3-1 - List of hydro candidates for Sudan

The figures relative to Dal project will be updated in the course of the Feasibility Study carried out in Module 5.

1.4 REVIEW OF THE GENERATION EXPANSION PLAN

The last least cost generation plan was determined by Sudan Long Term Power Plan Study 2006 in November 2006.

For the base case, the main hypothesis are:

- planning period from 2006 to 2030,
- discount rate: 12%,
- base case demand scenario,
- 3% LOLP decreasing to 1% from 2009 to 2026,
- chosen alternative of High Dal (instead of Low Dal + Kajbar).

The commissioning of short construction duration units (low speed Diesel and gas oil-fired gas turbine) in 2009 boats the installed capacity to a level compatible of a good reliability of the power supply. This is demonstrated by the margin ratio which jumps to 30% in 2009.

The development of cost effective coal-fired capacity at Port Sudan being limited by the Grid capability, gas oil-fired CCGT, while being more expensive, become significant contributors to the generation mix (first commissioning in 2014).

Finally, all identified HPP candidates are included in the generation expansion plan by 2026.

1.5 REVIEW OF THE TRANSMISSION MASTER PLAN

The master plan provided a detailed planning of new equipments up to 2009. The planned elements over the next 3 years will triple the total length of the VHV network, due to a major extension of the 220 kV network to Port-Sudan, along the White Nile, to the Kordofan area, to the Gedaref area, and downstream Merowe along the Nile. A new voltage level - 500 kV - is to be commissioned within the next couple of years, for the evacuation of the generation of Merowe hydro power plant. The interconnection project with Ethiopia is not mentioned. The 2015 load-flow display indicate mainly a 500 kV reinforcement from Port-Sudan to Khartoum, and a VHV reinforcement in the Korfdofan and Darfur areas.

2. ORGANISATION OF THE REPORT

Module 3 deals with the future evolution of the demand and identification of supply and interconnection options. The findings of this Module will constitute the base on which the regional investment plan will be determinate.

This Module is organized in five Volumes:

- Volume 1: Executive summary of Module M3
- Volume 2: Energy Sector Profile & Projections for Egypt
  - Review and update of previous demand forecast.
  - Potential trade opportunities.
  - Review of the existing Generation Expansion Plan.
  - Identification of generation supply options.
  - Review of existing transmission master plan.
- Volume 3: Energy Sector Profile & Projections for Ethiopia
  - Review and update of previous demand forecast.
  - Potential trade opportunities.
  - Review of the existing Generation Expansion Plan.
  - Identification of generation supply options.
  - Review of existing transmission master plan.
- Volume 4: Energy Sector Profile & Projections for Sudan
  - Review and update of previous demand forecast.
  - Potential trade opportunities.
  - Review of the existing Generation Expansion Plan.
  - Identification of generation supply options.
  - Review of existing transmission master plan.
- Volume 5:
  - Fuel prices Projections.
  - Interconnection options.
  - First evaluation of economic profitability of exports from Sudan-Ethiopia.

The present Volume 4 is focussed on the Energy and Sector Profile & Projections in Sudan.

3. REVIEW AND UPDATE OF DEMAND FORECAST

The review and update of the demand forecast is organized along the following items:

- Review of the past evolution of demand (energy and annual peak demand, by economic sectors, correlation with the GDP growth rate, demographic evolution, etc).
- Identification of demand characteristics (load factor, daily and seasonal variations and demand diversities, annual load duration curve).
- Review of the existing consumptions patterns and tariff.
- Review and update of the more recent demand forecast available.

3.1 REVIEW OF DEMAND PAST EVOLUTION

3.1.1 ENERGY DEMAND

The main figures relating the historical evolution of the supply and the demand of electricity on the national grid up to 2005 are presented in the following chart (Source NEC).

Year	Energy	Energy growth (%)	Sales	Sales growth	Losses	Losses (%)
1997	2 150.5		1 344		806.5	38
1998	2 160	0.4	1 338	-0.4	822	38
1999	2 423	12.2	1 438	7.5	985	41
2000	2 429	0.2	1 565	8.8	864	36
2001	2 838.5	16.9	1 604	2.5	1 234.5	43
2002	3 093.5	9.0	1 758	9.6	1 335.5	43
2003	3 353.5	8.4	2 010	14.3	1 343.5	40
2004	3 452.79	3.0	2 294.39	14.1	1 158.4	34
2005	3 789.65	9.8	2 730	19.0	1 059.65	28

Table 3.1-1 - Demand past evolution

Over this period the energy generated increased from 2 150 GWh in 1997 to 3 768 GWh in 2005, an annual compound growth of 7.3% per year.

The evolution of each characteristic is presented on the graph here after:

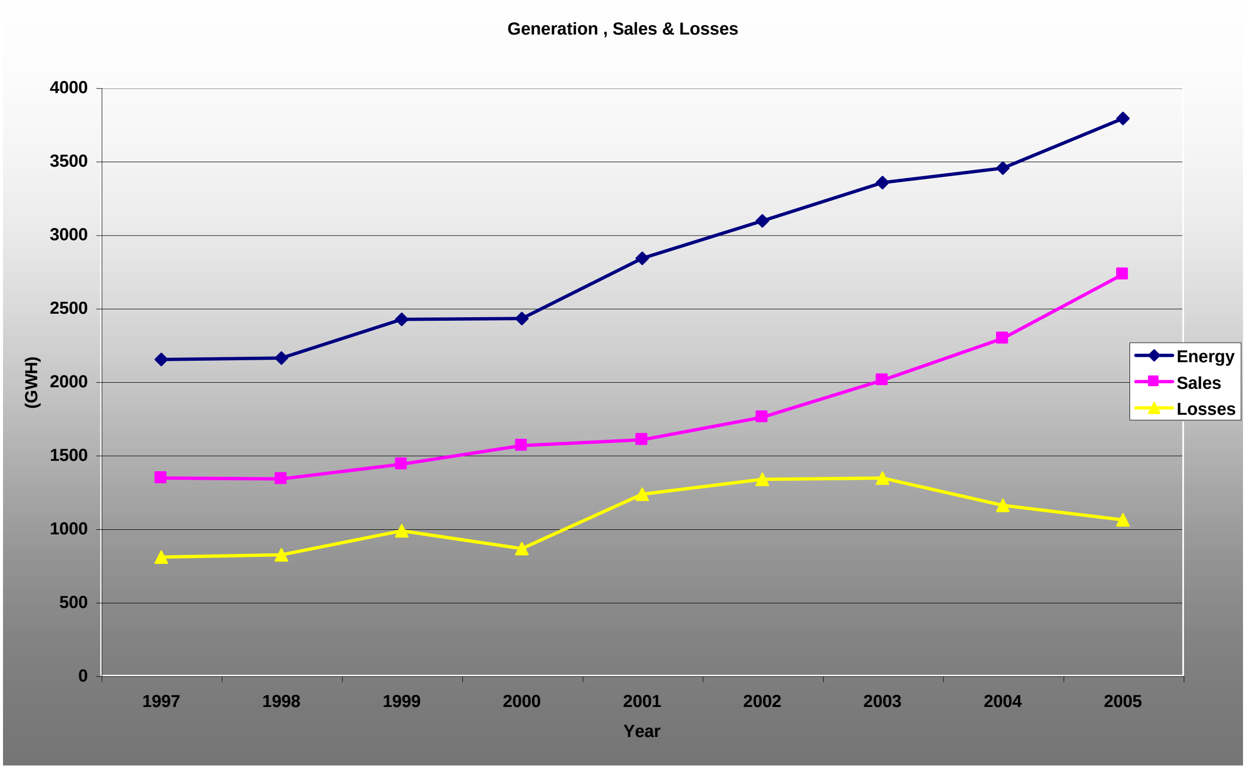

Figure 3.1-1 - Demand past evolution (Energy, sales, losses)

3.1.2 LOAD SHEDDING

Sudan suffered from significant load shedding in the past years due a lack of generation capacity. The situation improved with the commissioning of Garri thermal power plant. Nevertheless, more power capacity is still needed in order to reach a good level of reliability of the power supply:

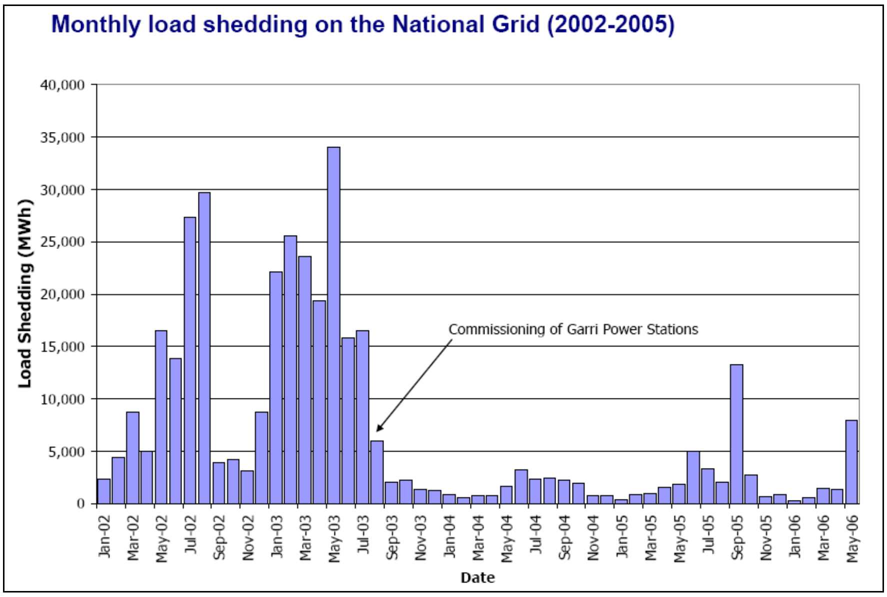

Figure 3.1-2 - Load shedding (2002-2005)

3.1.3 ENERGY CONSUMPTION PER SECTOR

In the National Grid, the total electrical energy consumption increased during the last decade (from 1 326 GWh in 1995 to 2 731 GWh in 2005).

The main figures are presented in the following table:

Sector	*Sales (GWh)*	*Weight*
Agricultural	*125*	*4.6%*
Industrial	*479*	*17.5%*
Domestic	*1371*	*50.2%*
Commercial	*395*	*14.5%*
Governmental	*361*	*13.2%*
Total	***2731***	

Table 3.1-2 - Energy consumption per sector

- Households still represents the major consuming sector. It absorbed almost about 1 371 GWh, about 50% of the total electricity consumed in the grid.
- Industrial sector is the second consuming sector with 470 GWh (17.5%).
- Service sector, which composed of government and commercial business, is growing very fast compared to other sectors. The consumption of this sector reached 395 GWh representing 14% of the total electricity consumption.
- The consumption of the Agricultural sector share was consistently decreased during the last decade. It now represents around 5% of the total demand.

The weight of each sector in 2005 is presented on the graph here after:

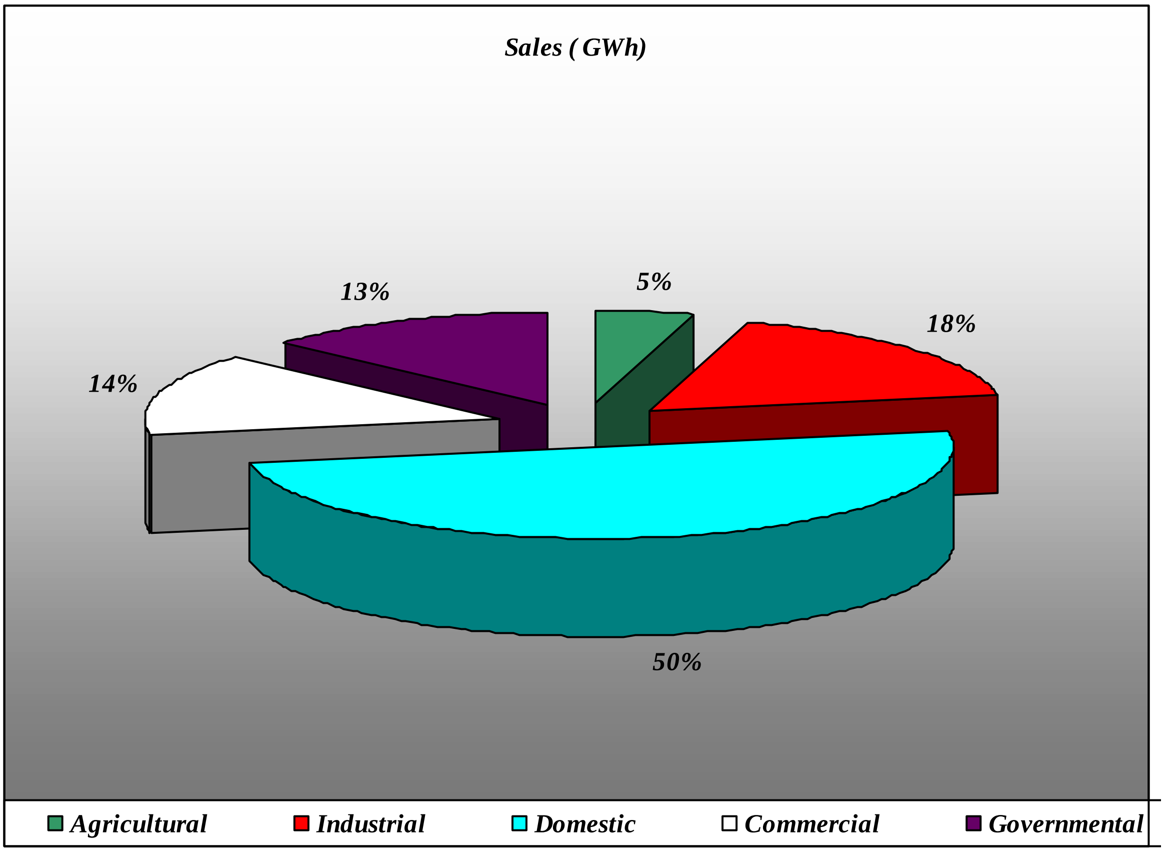

Figure 3.1-3 - Energy consumption per sector in 2005

The following table synthesizes the evolution of the consumption per sector since 1990 (Source NEC):

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Sales (GWh)																
Domestic (I/c staff)	729	669	736	648	684	764	764	722	580	572	677	722	916	942	1,262	1,371
Small Commercial & Industrial	63	73	75	62	64	64	79	89	115	129	124	127	178	260	375	395
Large Industry and Bulk Supplies	351	369	321	220	374	379	383	420	424	466	373	404	398	427	419	479
Small Agricultural	27	33	28	19	41	33	33	23	19	10	26	23	28	15	105	125
Govt. +SL + Inter Dept	88	99	87	61	96	86	121	90	200	210	209	213	238	284	335	361
Total NEC Grid Sales (GWh)	1,259	1,243	1,247	1,010	1,259	1,326	1,380	1,344	1,338	1,387	1,409	1,490	1,757	1,928	2,496	2,730
No of Grid Consumers																
Domestic (I/c staff)	322,767	330,054	333,457	340,180	342,691	368,937	352,242	339,973	*439,070*	346,261	356,165	388,865	473,615	502,206	551,124	585,560
Small Commercial & Industrial	15,210	12,509	13,448	14,585	15,510	10,874	27,848	43,435	*56,748*	55,852	60,463	57,805	68,037	72,175	80,027	83,012
Large Industry and Bulk Supplies	602	667	707	748	801	1,019	1,457	1,628	*1,726*	4,033	1,907	1,800	778	834	904	967
Small Agricultural	2,079	2,342	2,501	2,614	2,700	3,305	2,706	3,290	*6,003*	1,395	4,919	2,409	3,704	3,336	3,545	3,805
Govt. +SL + Inter Dept		4,908	5,569	5,825	6,005	6,400	6,867	8,964	*11,722*	9,712	9,105	9,240	11,902	12,608	12,700	12,742
Total	340,658	350,480	355,682	363,952	367,707	390,535	391,120	397,290	515,269	417,253	432,559	460,119	558,036	591,159	648,300	686,086
Sales per Connection (kWh)																
Domestic (I/c staff)	2,258	2,027	2,207	1,905	1,996	2,071	2,169	2,124	1,321	1,652	1,901	1,857	1,933	1,876	2,290	2,341
Small Commercial & Industrial	4,162	5,836	5,577	4,251	4,126	5,886	2,836	2,049	2,027	2,310	2,051	2,199	2,614	3,609	4,680	4,758
Large Industry and Bulk Supplies	583,555	553,223	454,031	294,118	466,916	371,933	262,872	257,985	245,655	115,547	195,543	224,278	511,049	511,972	463,642	495,069
Small Agricultural	12,987	14,091	11,196	7,269	15,185	9,985	12,038	6,991	3,165	7,168	5,235	9,672	7,635	4,442	29,684	32,726
Govt. +SL + Inter Dept		20,171	15,622	10,472	15,987	13,438	17,681	10,040	17,062	21,623	22,954	23,095	19,971	22,517	26,408	28,360
Total	3,695	3,547	3,506	2,775	3,424	3,395	3,528	3,383	2,597	3,324	3,257	3,238	3,149	3,262	3,850	3,980

Table 3.1-3 - Evolution of consumption per sector since 1990 (Source NEC)

3.1.4 POWER DEMAND AND LOSSES

Before the year 2003 demand exceeded supply at a certain time of the year (April – August), as a result the consumers subjected to long periods of power cuts which resulted in high economic losses especially in industrial and agricultural sectors.

At the times of capacity shortages NEC was forced to carry programmed and un-programmed power cuts. These cuts mainly carried in the summer season when the demand is at peak load and the hydro output is low.

In 2003 Gerri I and Gerri II combined cycle power generating facilities were commissioned. Adding to the grid about 386 MW generating capacity, the installed capacity exceeds the demand and the power cuts are mainly limited to failures in transmission and distribution.

The following chart synthesize the evolution of the peak demand and the associated load factor since 2000:

Description	***2000***	***2001***	***2002***	***2003***	***2004***	***2005***
Max. Load (MW)	**423**	**477**	**490**	**534**	**611**	**685**
Net Generation (GWh)	**2 442**	**2 704**	**2 982**	**3 238**	**3 749**	**3 768**
Load factor (%)	**66**	**65**	**69**	**69**	**70**	**63**
Energy Sold (GWh)	**1 408**	**1 489**	**1 757**	**1 928**	**2 496**	**2 730**
System Losses						
Losses (GWh)	1 034	1 215	1 225	1 310	1 253	1 038
Losses (%)	42	45	41	40	33	28

Table 3.1-4 - Historical load factor and losses

The peak demand increased significantly these last 2 years of 14% and 12% respectively.

The corresponding annual load factor (average power/maximum power) is about 63% in 2005, which is typical for a system whose largest component of load is residential demand.

3.1.5 ELECTRICITY TARIFF

3.1.5.1 Background

NEC Started designing its first specific tariff in 1958. Prior 1983 the criteria of tariff design were only to achieve financial objectives and flood-declining block applied to encourage consumption irrespective of day or season peak durations. During eighties hydro generation represented the major part of system generation so the prices were calculated on basis of investment (generating plants, transmission and distribution net work), operating costs and other costs associated with customer services. Due to the expansion in thermal generating plants to meet the growing demand, the associated costs reflected in the electricity price increase.

3.1.5.2 Pricing Policy

Normally the Electricity Tariff is determined according to the economical method known as the marginal cost, which comes from the analysis of the cost of production according to the development construction program to meet the demand. This method requires the following information:

- The forecast of the demand & types of consumption.
- The detail of development construction plan so as to meet the demand forecast.
- The cost & the expenditures needed to implement the plan.
- The type of consumption of each consumer (voltage, duration, load factor).

By analysing all the above data, the marginal cost covering the development cost of the generation mix and of the transmission/distribution system power, can be determined. Then the tariff by consumer type can be adjusted to cover financial requirements in the annual budget of the Utility.

For the present being, the tariffs of electricity are subsidised. The Ministry of Finance & National Economy (MOFNE) & Ministry of Energy & Mining revises the pricing policy annually to determine the tariff of Electricity consumption to the various sectors of consumers, in order to reduce the subsidy to electricity.

3.2 DEMAND VARIATION PATTERNS

3.2.1 TIME ZONE

Sudan is in the GMT + 3 h time zone, without any summer time due to its location near the equator.

3.2.2 DAILY LOAD VARIATION

The following graph shows the evolution of the daily demand in MWh from January to December for years 2004 and 2005.

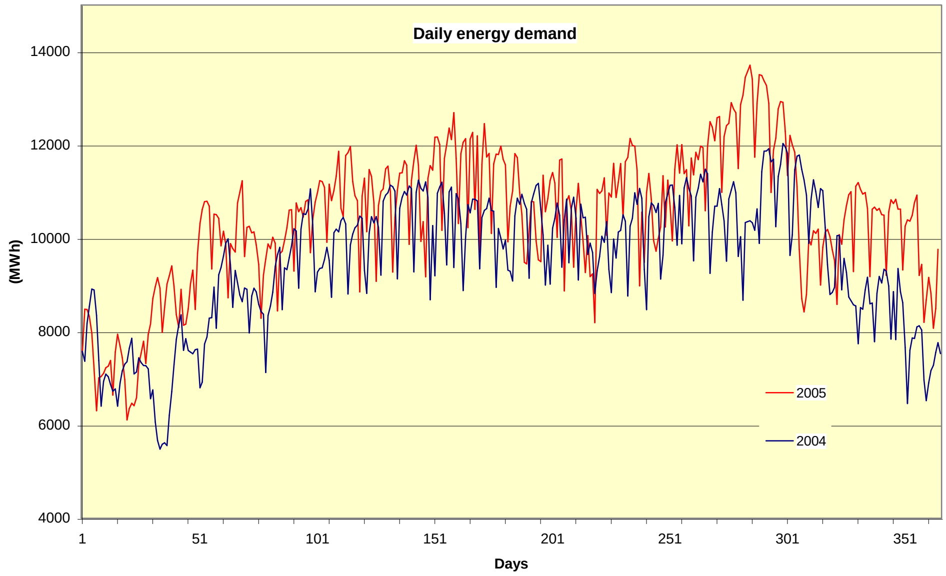

Figure 3.2-1 - Evolution of the demand during a typical week

A net increase in demand can be noticed from 2004 to 2005. It is marked by higher temperatures during the autumn (October, November), with rising influence of air conditioning use. The peak load occurred in October, during a week day: Tuesday in 2004 and Monday in 2005. In contrast with the other countries (Ethiopia and Egypt), the peak in October is during the lunch time (from 11 am to 1 pm) and in winter season (from December to March) during the evening (from 8 to 9 pm), characterizing a demand due mainly to residential sector. The following graphs show daily curves for two typical weeks during these two different seasons.

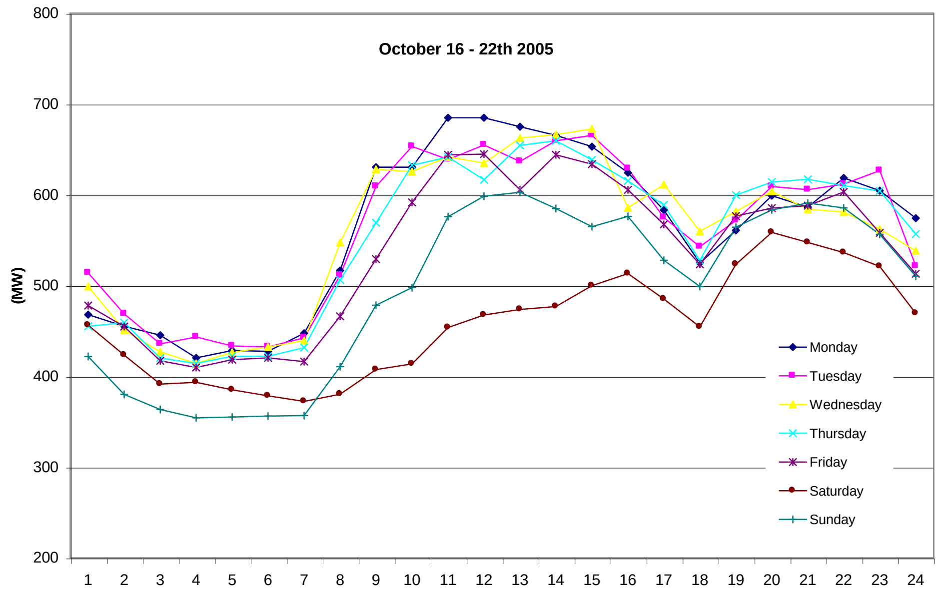

Figure 3.2-2 - Daily curves for two typical weeks in October

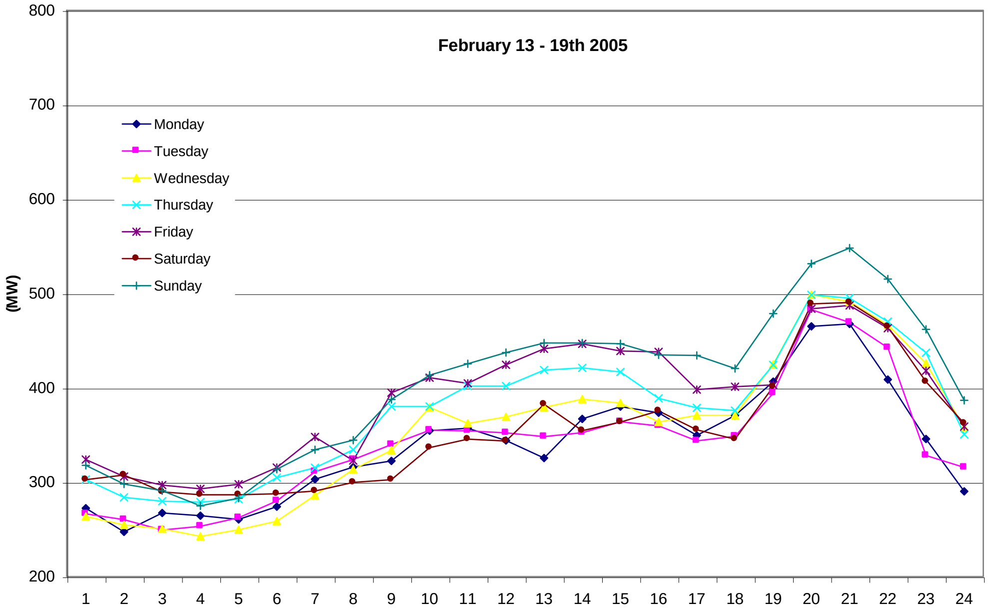

Figure 3.2-3 - Daily curves for two typical weeks in February

We can notice that the winter peak is transferred to a weekend day.

3.2.3 SEASONAL LOAD VARIATION

Due to Sudan geographical position close to the equator, the annual demand variation is relatively low, with January, February and December being the months with minimum demand.

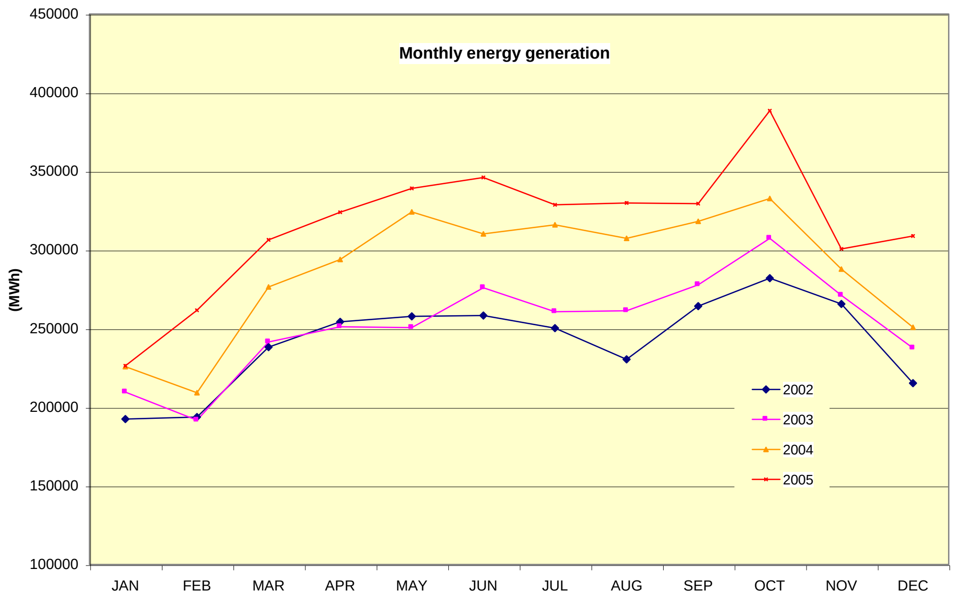

Figure 3.2-4 - Annual seasonal demand variation

In spite of this relatively flat annual demand, a pronounced peak can be observed in 2005 during the hot season (autumn). The air cooling use (in different customer sectors) associated with the fast economic development in Sudan might explain this peak increase.

3.2.4 ANNUAL LOAD DURATION CURVE FOR THE NATIONAL GRID

The annual load duration curve for the National Grid is shown in the following graph (source NEC) for the years 2002 and 2005. The shapes of the curves are as expected for a national electricity network. Compared to 2002, the load curve for 2005 has a more pronounced peak value which had the effect of reducing the load factor from 70% in 2002-2004 to 63% in 2005

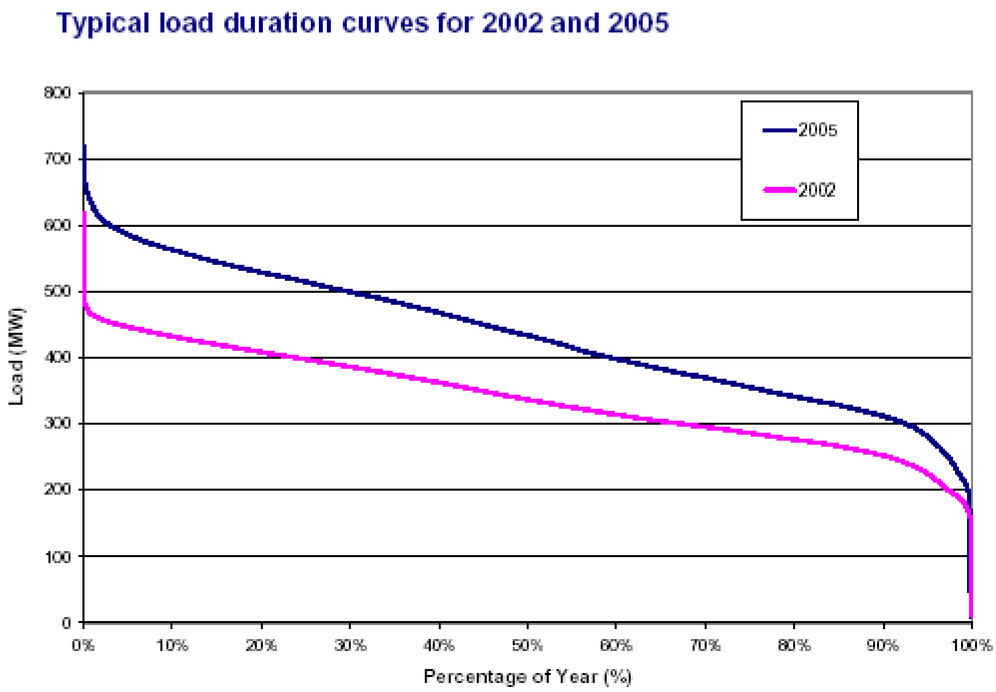

Figure 3.2-5 - Annual load duration curves for 2002 and 2005

3.3 TECHNICAL AND NON TECHNICAL LOSSES

The past evolution of technical and non technical losses is depicted in Figure 3.1-2- Demand past evolution (Energy, sales, losses).

The increase in non-technical losses followed large increases in all NEC tariff categories in local currency terms from 1992 to 2001. The non-technical losses were such that overall losses reached 45% of energy generated in 2001, with sales only amounting to 1 490 GWh as compared to 2 704 GWh generated. Assuming technical losses of 14%, non-technical losses amounted to over 30% of energy generated, or put another way, over 55% of the actual sales. Since 2001, however, energy losses have fallen back to 27% in 2005. It is interesting to note that whilst sales increased by about 20% between 2004 and 2005, the corresponding increase in generation was only 0.5%. This suggests that the increase in sales had more to do with improved operations by NEC rather than any strong change in consumption patterns by consumers. This observation is confirmed by the fact that the additional 34 000 domestic consumers added in 2005 had very little impact on total generation requirements.

3.4 DEMAND FORECAST

3.4.1 OVERVIEW

The demand forecast study has formed the basic input data to Sudan LTPSPS (July 2006). For the present interconnection study, and to remain homogenous with the national electricity master plan of Sudan, we will keep the same assumptions of demand forecast and the same scenarios.

A synthesis of the previous analysis of demand forecast is presented here after.

3.4.2 METHODOLOGY

The Sudan Long Term Power Plan Study demand forecast is based on a classic and reliable methodology:

- Review of energy consumption, market survey results and historical sales.
- Estimation of the unsuppressed demand.
- Forecast of the customers sales per sector (in GWh) according to the forecasted evolution of GDP and population, electrification programs and committed projects.
- Evaluation of energy losses (transmission and distribution network).
- Generation level forecast (in GWh).
- Peak demand forecast in MW according to load factor par sector and diversity factor.

The Consultant considers this demand forecast reliable and up to date and recommend to use it for the present Study.

3.4.3 DEMAND FORECAST – KEY POINTS

In the Demand Forecast report of Sudan Long Term Power Plan Study, three cases were considered. These were the Base, High and Low cases and the corresponding peak demand levels over the planning period.

The demand on the NEC system in any year will also depend on the extent to which the transmission system has grown. To remain homogeneous with the domestic electricity master plan, the present study will consider the same national interconnection (same technical characteristics and same commissioning date).

Note: Not all of the states will be connected to the grid in the earlier years of the study, and therefore the grid forecast will be somewhat lower than the overall demand forecast.

The following table lists the key assumptions of the three demand forecasts:

Summary of key assumption changes

Parameter	2010	2015	2020	2025	2030
Population Forecasts					
High	2.7%	2.6%	2.4%	2.2%	2.1%
Base	2.5%	2.4%	2.1%	1.8%	1.7%
Low	2.4%	2.2%	1.9%	1.6%	1.5%
GDP Forecasts					
High	8.8%	7.6%	6.7%	6.2%	5.4%
Base	8.6%	7.1%	5.7%	3.8%	3.4%
Low	7.4%	5.4%	3.7%	2.6%	2.3%
Firm Commercial and Industrial Projects					
High	100%				
Base	100%				
Low	75% (plus 1 year delay to anticipated date of connection)				
Industrial Electricity intensity					
High	0.090	0.076	0.068	0.063	0.060
Base	0.090	0.070	0.056	0.046	0.040
Low	0.063	0.053	0.042	0.035	0.030
Commercial Sector Consumption Elasticity					
High	1.2				
Base	1.2				
Low	1.0				
Irrigation Schemes					
High	Ministry of Irrigation Long-Term Plan plus 2m feddans in Northern State				
Base	Ministry of Irrigation Long-Term Plan				
Low	Ministry of Irrigation Long-Term Plan				

Table 3.4-1 - Demand forecasts - Key assumptions

The following table and figure depict the evolution of the electrification rates. The target level for the whole country being 83% in 2030:

Year	2006	2010	2015	2020	2025	2030
Khartoum	47%	62%	75%	85%	92%	96%
Gazeerah	30%	45%	61%	73%	81%	85%
White Nile	13%	42%	59%	72%	82%	87%
Sennar	5%	27%	49%	66%	78%	85%
Kassala	18%	51%	64%	74%	81%	85%
Gadareff	9%	47%	61%	72%	80%	85%
Blue Nile	7%	36%	62%	73%	80%	85%
River Nile	26%	52%	62%	70%	75%	78%
Northern State	23%	77%	77%	76%	76%	76%
Red Sea	22%	73%	82%	86%	91%	96%
North Kordofan	11%	74%	77%	76%	76%	76%
South Kordofan	4%	75%	83%	82%	82%	81%
Northern Darfour	5%	41%	69%	72%	74%	75%
South Darfour	6%	75%	76%	76%	76%	75%
West Darfour	4%	75%	76%	76%	75%	75%
Bahr El Gazal	4%	23%	43%	58%	69%	75%
Equatoria	5%	23%	43%	59%	69%	75%
Upper Nile	4%	23%	43%	58%	69%	75%
Whole Country	17%	52%	66%	74%	80%	83%

Table 3.4-2 - Evolution of electrification rates

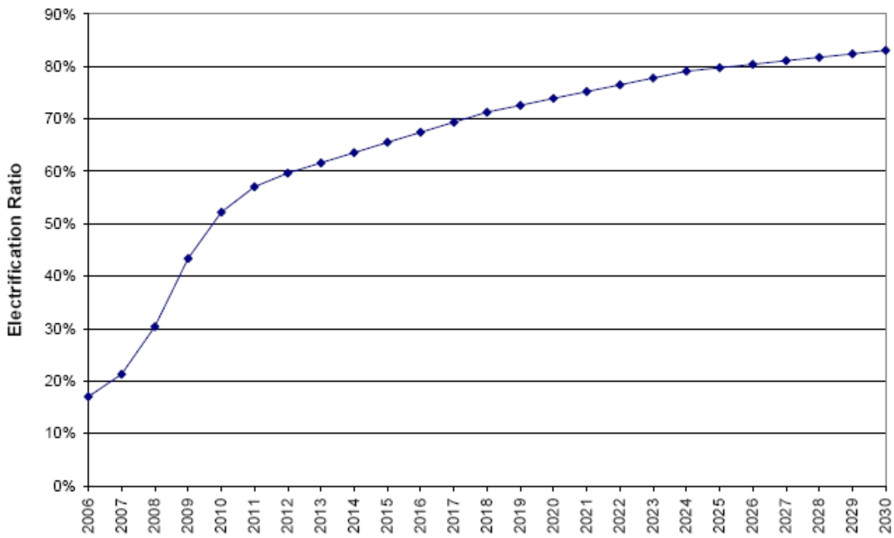

Figure 3.4-1 - Evolution of global electrification rate

3.4.4 DEMAND FORECAST FOR THE BASE CASE

This chapter presents the base case electricity forecasts for total generation (GWh) and peak demand (MW) at the sent-out generation level. These are derived from the total sector sales forecasts presented in Section 7 of Sudan Long Term Power Plan Study demand Report and the forecasts of energy and power losses and CADLFs presented in Section 8 of demand report.

The detailed values for peak demand, annual energy and load factor are give in appendix "Demand forecast".

3.4.4.1 Generation forecast

The total customer sales forecast is the summation of the individual sector forecasts. Overall electricity sales are forecasted to increase to about 75 TWh by 2030 at an average annual growth rate of 10.8%. The increasing influence of the industrial sector in the medium-term sees its share increase to over 40% in 2010 (overtaking the domestic sector which drops to 37% in that year). In the long-term the commercial sector share of total sales increases to over 20% by 2026.

The following figure illustrates the total generation forecast (GWh sent-out) which is seen to reach about 85 TWh by 2030, equivalent to an annual growth rate of 10%. Owing to the influence of the committed electrification projects and firm commercial and industrial projects, the shape of the generation curve is not exponential, as is often seen in forecasts of this type, but has a higher rate of growth in the early years to about 2012.

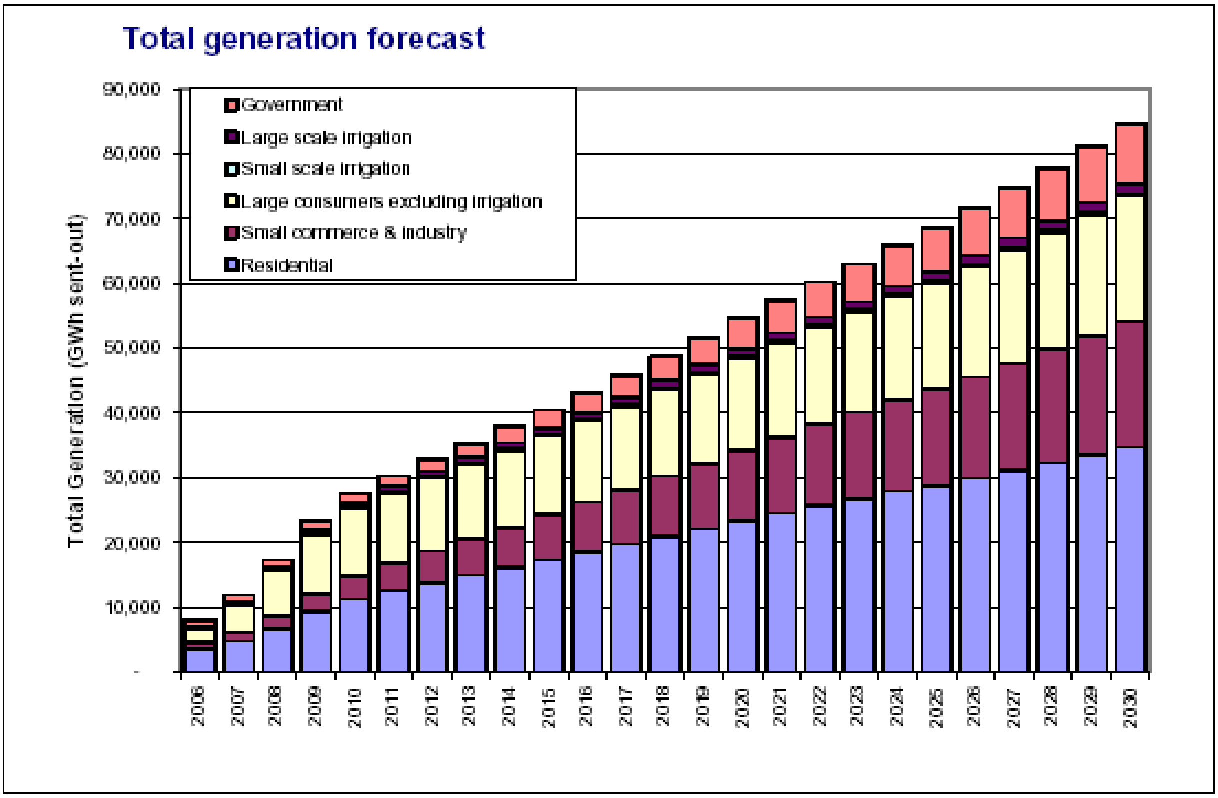

Figure 3.4-2 - Energy demand forecast – Base case

3.4.4.2 Derived sales forecast

Derived macro-economic sales forecast

Year	Domestic (l/c staff)	Small Commercial & Industrial	Large Industry & Bulk Supplies	Small Agricultural	Government + SL + Inter Dept.	NEC Total
2006	1618	505	471	153	403	3151
2007	1898	600	471	175	450	3595
2008	2261	712	465	200	502	4140
2009	2760	845	456	227	561	4848
2010	3436	1003	441	256	626	5762
2011	3965	1228	518	266	691	6667
2012	4640	1504	608	275	762	7789
2013	5512	1841	714	284	842	9194
2014	6659	2255	838	294	930	10976
2015	8194	2761	984	304	1028	13271
2016	9406	3277	1130	312	1136	15260
2017	10882	3889	1297	319	1256	17644
2018	12696	4616	1490	327	1389	20517
2019	14943	5478	1710	335	1537	24003
2020	17750	6502	1964	343	1702	28261
2021	19562	7541	2264	354	1869	31590
2022	21603	8747	2609	366	2053	35379
2023	23907	10146	3007	377	2257	39694
2024	26510	11769	3466	389	2481	44615
2025	29454	13651	3995	401	2730	50231
2026	30050	15541	4535	413	2975	53515
2027	30535	17694	5149	426	3244	57048
2028	30894	20144	5846	439	3538	60861
2029	31110	22933	6637	452	3861	64993
2030	31166	26109	7535	466	4215	69490

Table 3.4-3 - Derived macro-economic sales forecast

3.4.4.3 Peak generation forecast

The following figure shows the evolution of the Sudanese peak demand (interconnected and isolated systems) up to 2030. By 2030, total peak demand (MW sent-out) is forecast to reach just under 14,000 MW at an equivalent average annual growth rate of 9.8%.

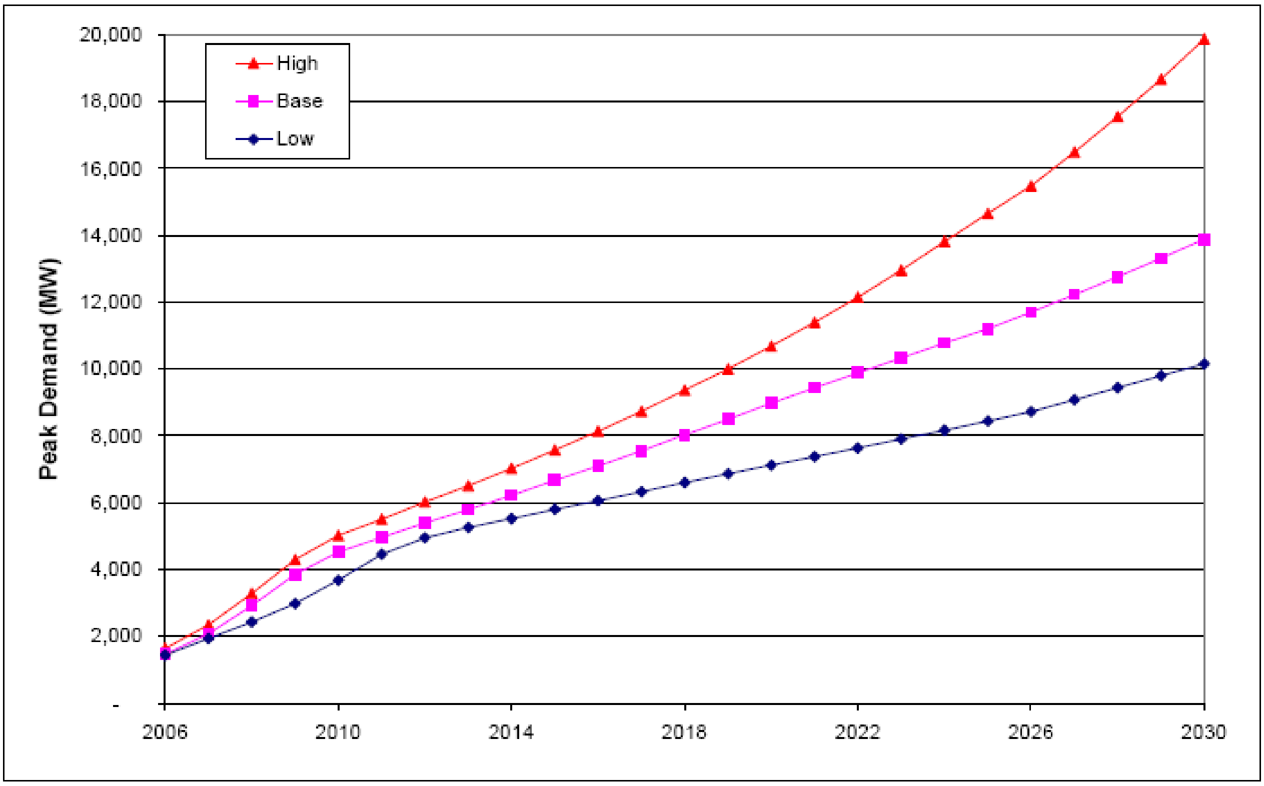

Figure 3.4-3 - Peak demand forecast for high, base and low cases

3.4.4.4 Load factor forecast

Historically the system load factor for the National Grid in Sudan has fluctuated between about 56% and 70% since 1990.

- A lower value would reflect a system heavily dominated by domestic loads and is thus more appropriate for the current off-grid areas than for the national grid.
- A higher value would suggest either a system dominated by industrial sector consumption or that demand has historically been suppressed by the availability of generation capacity.

The following figure shows the evolution of the system load factor derived from the forecast. The impact of the committed (energy intensive) industrial projects is to increase the load factor from 63% to about 70% by 2009. Thereafter, the balance between the respective sector shares of total sales and the reduction in losses, sees the system load factor fluctuate around the 70% level.

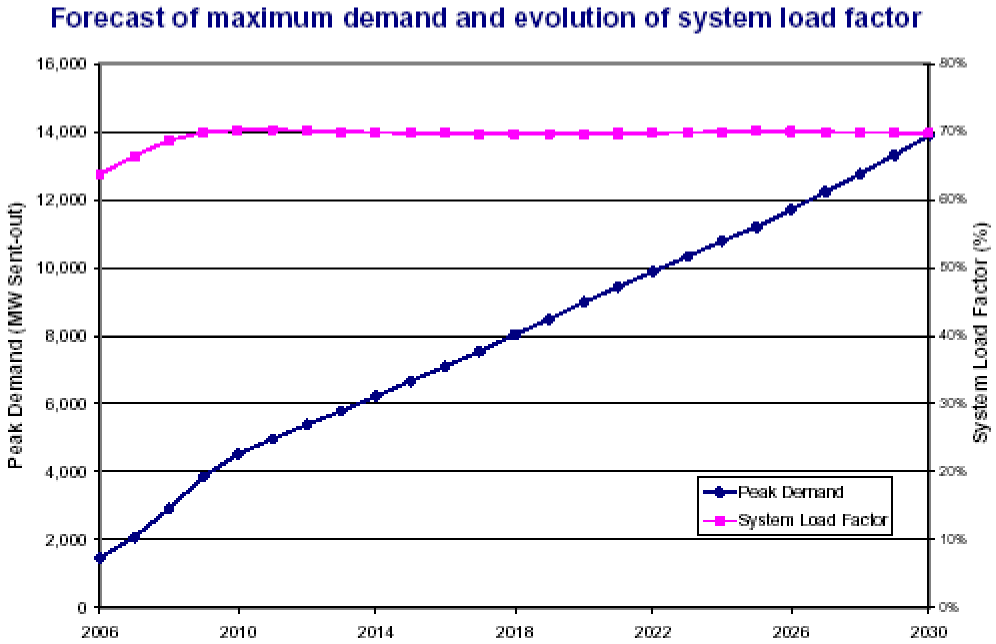

Figure 3.4-4 - Forecast of peak demand and load factor

3.4.4.5 Total energy losses

Total energy losses have fluctuated between 17% in 1990 and 45% in 2001. The values in 2005 was about 28%. At the very high loss levels it is apparent that these must consist both of technical and non-technical (or commercial losses).

As commercial losses are a direct drain on the revenues of the utility, NEC would expect measures to be taken such that they do not exceed 0.5% of sent-out generation.

NEC objective is to reduce the losses to values typical of an efficient network:

- to say not to exceed about 3% for the transmission network,
- 9% for the sub-transmission and distribution networks.

Accordingly target for NEC of total energy losses is 12.5% (about 50% of their 2005 level) in 2025.

According to the here before objective, the reduction path has been assumed as follows:

- losses reduce by 1% per year to 2011,
- then at 0.5% per year until the target value is achieved by in 2025.

3.4.4.6 Forecasted peak demand per state

The table below summarises the evolution of the global peak demand (MW) per state.

Year	2006	2010	2015	2020	2025	2030
Khartoum	659	1478	2101	2839	3576	4481
Gazeerah	248	580	980	1413	1821	2306
White Nile	76	235	368	515	650	806
Sennar	137	320	439	579	711	855
Blue Nile	9	39	77	110	142	181
Gadareff	34	200	286	387	482	600
Kassala	40	131	198	268	333	414
River Nile	44	146	195	246	296	355
Red Sea	79	314	365	426	487	565
Northern State	29	90	110	133	152	175
North Kordofan	37	184	222	265	308	369
South Kordofan	21	220	281	339	386	456
Northern Darfour	8	73	148	191	228	277
South Darfour	18	242	324	416	501	622
West Darfour	5	123	151	180	207	245
Bahr El Gazal	9	64	181	297	418	549
Equatoria	8	38	102	152	203	259
Upper Nile	15	73	166	236	303	369
Whole Country	**1475**	**4550**	**6693**	**8995**	**11205**	**13883**
Average Annual Growth		33%	8%	6%	4%	4%

Table 3.4-4 - Forecasted peak demand (MW) per state – Base case

3.4.5 DEMAND PROJECTIONS FOR THE INTERCONNECTED SYSTEM

The following figures display the evolution of the peak demand and of the annual demand for the interconnected system.

The connection of the Southern states to the main grid in 2020 is clearly visible on these curves.

The detailed figures are provided in the appendix Module 3 Vol 4.

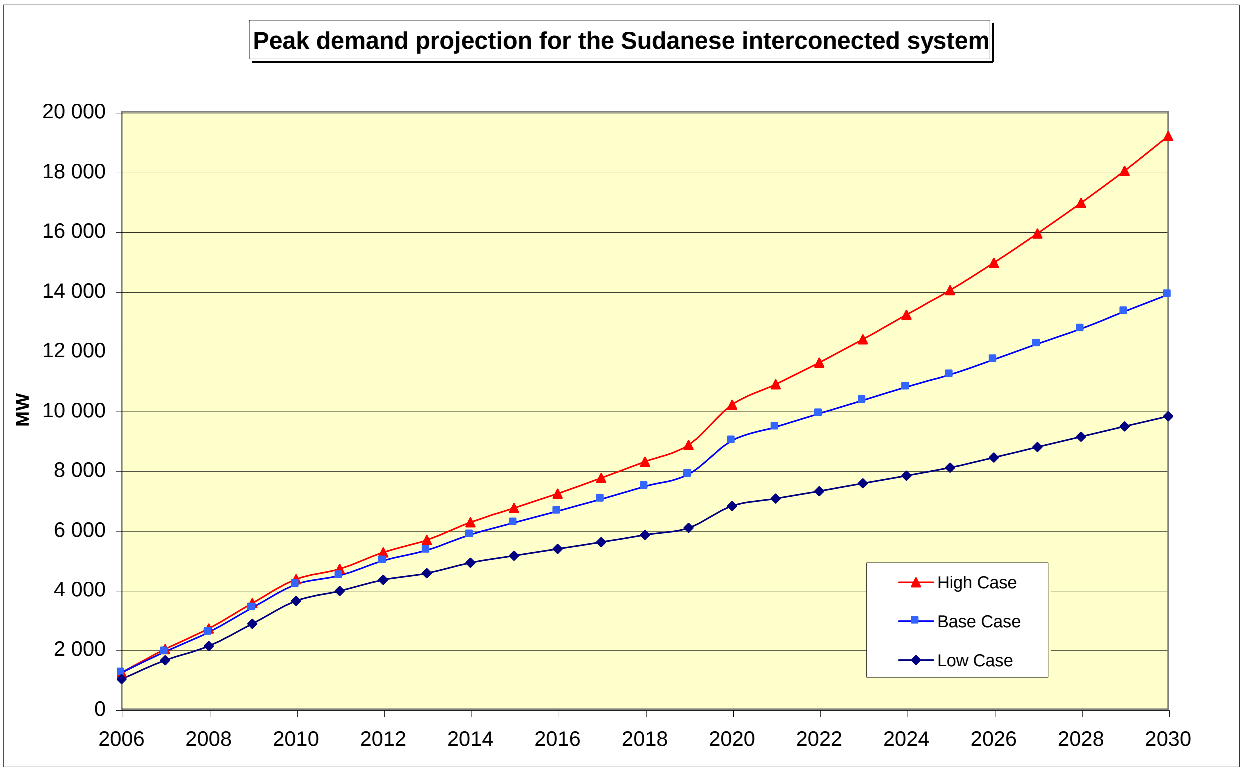

Figure 3.4-5 - Peak demand projections for the interconnected system

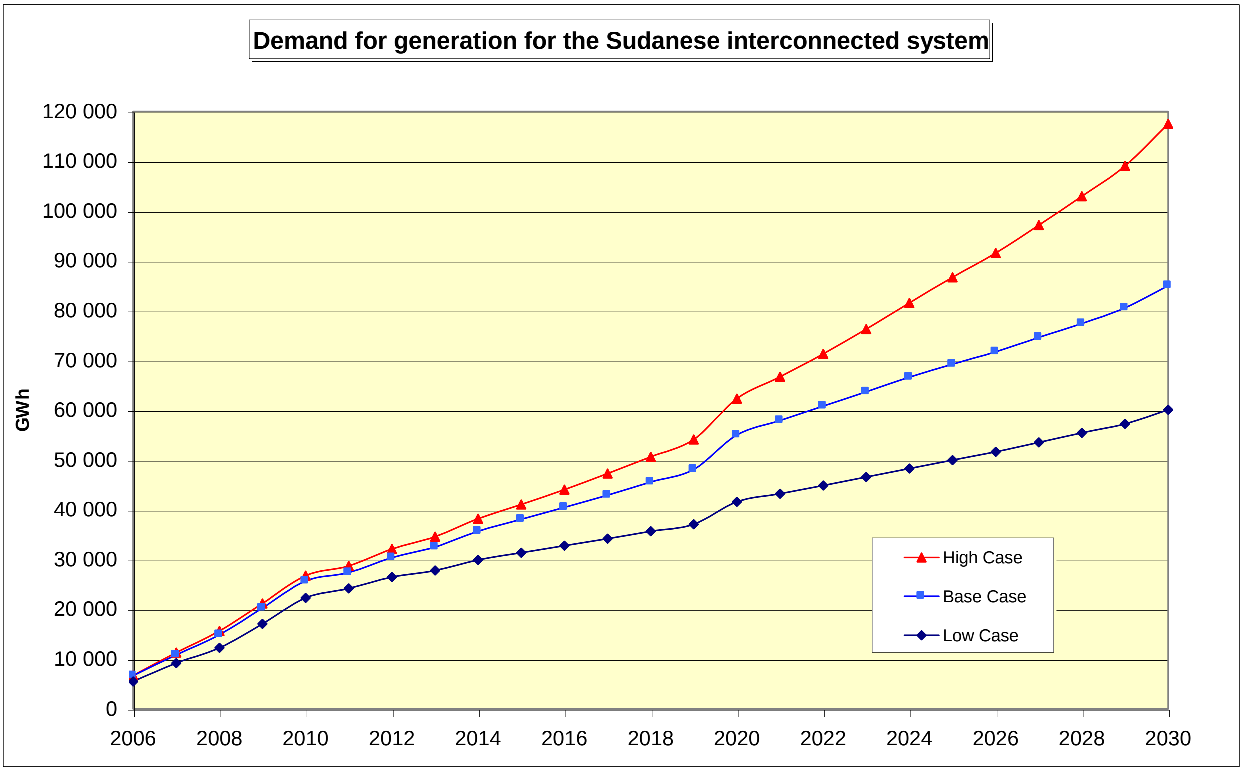

Figure 3.4-6 - Demand for generation projections for the interconnected system

4. POTENTIAL TRADE OPPORTUNITIES

The purpose of this paragraph is to analyse the potential power trade opportunities between Sudan and the neighbouring countries. Nevertheless, it should be emphasized that the potential for economic power trades between Egypt, Ethiopia and Sudan will be assessed on the basis of the simulations and analysis carried out in Module 6.

4.1 OVERVIEW

Interconnection of national electricity systems between neighbouring countries can provide significant benefits to both parties in the form of improved reliability of supply and cost reduction. Benefits of such interconnections include:

1. reducing the need for new generating capacity through the sharing of spare capacity,
2. reduced operational costs through the use of spare hydro energy and use of the lowest cost generating units,
3. improving system stability (frequency and voltage support).

4.2 ETHIOPIAN MARKET

The Ethiopia-Sudan Power System Interconnection Project's long-term development objective is to promote regional power trade through coordinated planning and development of power generation and power interconnections of multi-purpose water resources development.

The immediate objective is to facilitate cross-border trade between the two countries to optimise utilization of existing and planned generation capacity. The expected output is a high-voltage transmission line connecting the two countries.

The Project is a part of the Strategic Action Program under the Nile Basin Initiative established to promote poverty alleviation, growth and improved environmental management.

The four main Project components have been identified:

- Construction of transmission interconnection between Ethiopia and Sudan: a 230 kV line, complete with terminal substations, a fibre optic telecommunications system and supervisory control and data acquisition (SCADA) – the subject of this RAP.
- An Environmental Management Plan: that will be designed in accordance with recommendations made by the ESIA.
- Institutional Strengthening and Capacity Building: the establishment of operating rules for the interconnected system and the training of personnel in power system and design, and interconnected system operation and regulation.
- Establishment of a Coordinated Unit for Power Trade: transformation of the coordination unit established for the regional investment study into a regional power trade coordination unit.

The Ethiopia-Sudan Transmission Interconnection Project is being implemented under the Nile Basin Initiative under the supervision of the Eastern Nile Technical Regional Office (ENTRO) representing the Eastern Nile countries of Ethiopia, Egypt and Sudan. The Project forms part of the Program on Integrated Development of the Eastern Nile.

The Project involves the construction of a high voltage transmission line from Ethiopia to Sudan to utilise surplus hydropower from Ethiopia to replace oil-based thermal generation in Sudan. The interconnection would also provide benefits of common reserves in emergency cases (electricity could be transferred from Sudan to Ethiopia under severe hydrological conditions in Ethiopia) and achieve considerable savings in timing of power plants in the long run. Three alternative routes are being investigated. These routes pass through the Amhara, Oromiya and Benishangul-Gumuz Regions of Ethiopia, and the Al Qadarif (El Gedaref) and An-Nil al-Azraq (Blue Nile) States of Sudan.

The recommended route (Option C) is approximately 446 km in length, starting from Bahir Dar in Ethiopia and connecting to the El Gedaref Substation in Sudan via the border towns of Metema and Gallabat. This has been considered by the Project’s Feasibility Study as the most cost effective of the three Options. Option C route includes construction of a new single circuit line between Bahir Dar and Gonder (Azezo) running parallel to an existing single circuit line, construction of a second circuit using the same towers under construction by EEPCO for a single circuit line between Gonder and Shehedi, construction of a new double circuit 230 kV line from Shehedi to Metema/Gallabat and on to Gedaref in Sudan.

4.3 EGYPTIAN MARKET

The potential and economic viability of power trade between Sudan and Egypt will be evaluated in Module 6 of the present Study.

4.4 HYPOTHESIS CONSIDERED IN THE STUDY

The Feasibility Study Update of the "Ethiopia-Sudan Power systems interconnection Project" was completed by Hifab Oy and SOGREAH Consultants in 2006 in conjunction with EEPCO and NEC Utilities.

At the date of redaction of the present report (January 2007) it appears that no definite decision has been taken regarding the route of the interconnection.

The project is ready to go ahead as soon as financial backing is guaranteed. Funds are being put in place for the project's Ethiopian phases. Sudan declared that it will finance its part from its own resources.

Considering the Feasibility study results, the Consultant assumes the following hypothesis for the present study:

- commissioning date of the interconnection: 2010

- maximum transfer capacity of the interconnection: 200 MW

The Consultant will examine in Module 6 the possible economic benefits which would result from a re-enforcement of the interconnection between Ethiopia and Sudan (i.e. > 200 MW).

The amount of potential trade with Egypt will be assessed in the course of the Module 6 of the present Study.

No other interconnection between Sudan and other country is assumed in the present Study.

5. FUEL PRICES

5.1 PETROLEUM PRODUCTS

Commercial quantities of oil began to be produced in the last quarter of 1999 and are transported via a new 1 600 km pipeline from Bentiu to a new export terminal just south of Port Sudan. This pipeline also supplies a new 50,000 US barrels per day (bbl/d) refinery at Geili, about 50 km north of Khartoum, saving Sudan abut $100 million per year in imported petroleum products.

Crude oil production averaged 227,500 barrels per day (bbl/d) during 2002, a figure that has been rising steadily since the completion of the export pipeline in July 1999.

In 2005, oil production averaged 470,700 bbl/d, an increase of 63% on the 2004 production levels of 287,988 bbl/d. Oil production is set to increase by 15% to 540,000 bbl/d by the end of 2006 and is forecast to reach 710,000 bbl/d by the end of 2008.

According to the Energy Information Administration, Sudanese oil consumption increased 15% between 2004 and 2005 to 82,000 bbl/d.

In 2005, 70% of Sudan's total export revenues came from oil exports.

About 20% of the country's requirement for oil products is transported by pipeline.

Road transport (trucks) is the main mode of transport used contributing some 70% of the movements. About 9% of the bulk transport is transported by rail. Bulk transportation by river barge has had a limited application.

About 89% of the total power station fuel requirement is transported by road and the balance is transported by rail.

All future power station will be supplied directly from the crude pipeline, except the most remote.

The economic cost of fuel is affected by the Sudan being a net importer or net exporter of oil products. The derivation of the economic cost of fuel to be used in the LTPSPS starts with the international price of crude oil and oil products expressed either in terms of international carriage-insurance-freight (cif) or freight-on-board (fob) prices. It is then adjusted for the cost of delivering fuel to the power stations. Furthermore, in the Sudan, fuel can be transported by pipeline, road, rail or barge. The intention of NEC is to locate the Power Stations as near as possible to the fuel source (crude pipeline) to minimise the cost of transport and assure continuity of supply (for example the Kosti and El Fula power stations) by connecting to the crude oil source via the NEC owned pipeline.

The primary purpose of this Sub-section is to draw upon existing data on the oil and gas sector in the Sudan and develop fuel price assumptions to serve as the basis for assessing the economic viability of using oil as a fuel for power generation when compared to other resources such as hydro.

The transportation costs are available in Module 2 Volume 4 report (see table 4.4).

5.2 COAL

No significant coal reserve is available in Sudan. All the coal which will be used in the generation of electricity would be need to be shipped into Sudan from South Africa, the Far East or Australia.

Accordingly, Port Sudan is the favoured location for potential new coal-fired steam power plant in order to reduce transport and handling cost.

5.3 NATURAL GAS

There exits possibility that gas reserves in the Read Sea area could be of a sufficient level to allow them to be economically recoverable. Estimates of the total natural gas reserves in the Bashayer and Suakin in the Red Sea are quoted by Acres and the Energy Information Administration as about 3 tcf. If this were the case then electricity generation could be one of the major uses of natural gas.

Considering these uncertainties, the time for exploration of the resource and the development of the necessary infrastructure, the Consultant assumes for the present Study that no Natural Gas is available in sufficient quantity for power generation in thermal plant.

6. GENERATION SUPPLY OPTIONS

6.1 OVERVIEW

The purpose of this section is the identify the potential generation candidates to be considered in Module 6 economic study. The ranking and screening of this candidates will be carry out in Module M4 (for large HPP) and Module 6 (for TPP).

The generation candidates are one of the key elements of the present interconnection study, as for the implementation of the domestic electricity master plan accomplished in Sudan LTPPS 2006.

For the present interconnection study, and to remain homogenous with the national electricity master plan of Sudan, the Consultant will keep the same assumptions of generation candidates. Indeed the interconnection won't be commissioned before 2012 (in the best case), the Consultant will have then to consider the commissioning of new generation power plants not only after but before the interconnection.

A synthesis of the previous choices of candidates is presented here after.

6.2 THERMAL CANDIDATES

6.2.1 CANDIDATES THERMAL PLANTS

A candidate thermal plant is a generic power plant of a type and size that can be repeatedly added to the system over the period of the study with no practical restriction imposed on the number of units required or availability of fuel. The purpose of adding such plant is to add firm capacity to the existing system such that the planning criteria can be met.

According to Sudan LTPPS (October 2006[1]), 6 types of thermal candidates have been identified:

- Gas oil-fired gas turbines (for peak load generation);

[1] Long Term Power System Planning Study - Generation Book Data – October 2006 – PB Power

- Crude oil-fired low speed diesel units (for peak load generation);
- Gas oil-fired combined cycle gas turbines (for base load generation);
- Crude oil-fired steam units (for base load generation);
- Coal-fired steam turbine plant at Port Sudan (for base load generation);
- HFO-fired steam turbine plant at Port Sudan (for base load generation).

Note:

After having reviewed Sudan LTPPS 2006 data, the Consultant proposes to use the same data set because of their consistency and reliability. These data are described hereafter.

6.2.2 GAS OIL-FIRED GAS TURBINES

Gas oil-fired Gas turbines are cost effective for peak-load generation.

Plant Name	Plant Type	Installed capacity (MW)	Site Rating Capacity (MW)	Capacity Sent Out (MW)	Build Period (Years)	F.O.R. (%)	P.O.R. (Days/Yr)	Availability (%)	Life of Plant (Years)
PG 6581 (B)	OCGT	41	35	34	2.0	2.0%	25	91.3%	25
PG 6101 (FA)	OCGT	74	61	60	2.0	2.0%	25	91.3%	25
PG 9171 (E)	OCGT	127	111	109	2.0	2.0%	25	91.3%	25
PG 9231 (EC)	OCGT	180	153	150	2.0	2.0%	25	91.3%	25
PG 9351 (FA)	OCGT	268	231	226	2.0	2.0%	25	91.3%	25

Plant Name	Fuel Type	Capital Cost ($/kW)	Heat Rate (KJ/kWh)	Efficiency (%)	Fuel Cost (USc/kWh)	Variable O&M Cost (USc/kWh)
PG 6581 (B)	Gas Oil	864	12040	29.9%	19.69	1.49
PG 6101 (FA)	Gas Oil	791	11987	30.0%	15.63	1.36
PG 9171 (E)	Gas Oil	692	11917	30.2%	15.54	1.19
PG 9231 (EC)	Gas Oil	671	11626	31.0%	15.16	1.16
PG 9351 (FA)	Gas Oil	625	11132	32.3%	14.51	1.08

Table 6.2-1 - Characteristics of gas oil-fired OCGT candidates

6.2.3 CRUDE OIL-FIRED LOW SPEED DIESEL UNITS

Crude oil-fired low speed Diesel have been identified with a set size of 40 MW. They are modelled as 7 unit power stations with a total capacity of 280 MW (272 MW send out):

Plant Name	Fuel Type	Capital Cost ($/kW)	Heat Rate (KJ/kWh)	Efficiency (%)	Fuel Cost (USc/kWh)	Variable O&M Cost (USc/kWh)
LSD unit	Crude	1679	8372	43.0%	7.31	1.10

Plant Name	Plant Type	Site Rating Capacity (MW)	Capacity Sent Out (MW)	Build Period (Years)	F.O.R. (%)	P.O.R. (Days/Yr)	Availability (%)	Life of Plant (Years)
LSD unit	Diesel	280.0	271.6	3.0	4.0%	35	86.8%	30

Table 6.2-2 - Characteristics of Low Speed Diesel candidates

6.2.4 GAS OIL-FIRED COMBINED CYCLE GAS TURBINES

Gas oil-fired CCGT may be located adjacent to any of the four existing refineries.

Plant Name	Plant Type	Installed capacity (MW)	Site Rating Capacity (MW)	Capacity Sent Out (MW)	Build Period (Years)	F.O.R. (%)	P.O.R. (Days/Yr)	Availability (%)	Life of Plant (Years)
PG 6101 (FA) based CCGT	CCGT	238	214	208	3.0	3.0%	30	89.0%	30
PG 9171 (E) based CCGT	CCGT	391	352	342	3.0	3.0%	30	89.0%	30
PG 9231 (EC) based CCGT	CCGT	523	470	456	3.0	3.0%	30	89.0%	30
PG 9351 (FA) based CCGT	CCGT	787	708	687	3.0	3.0%	30	89.0%	30

Plant Name	Fuel Type	Capital Cost ($/kW)	Heat Rate (KJ/kWh)	Efficiency (%)	Fuel Cost (USc/kWh)	Variable O&M Cost (USc/kWh)
PG 6101 (FA) based CCGT	Gas Oil	885	6780	53.1%	8.84	0.81
PG 9171 (E) based CCGT	Gas Oil	821	7059	51.0%	9.20	0.76
PG 9231 (EC) based CCGT	Gas Oil	787	6867	52.4%	8.95	0.72
PG 9351 (FA) based CCGT	Gas Oil	740	6594	54.6%	8.60	0.68

Table 6.2-3 - Characteristics of Gas oil-fired CCGT candidates

6.2.5 CRUDE OIL-FIRED STEAM UNITS

Crude oil-fired steam units may be located along one of the three existing crude pipeline in Sudan.

Plant Name	Plant Type	Site Rating Capacity (MW)	Capacity Sent Out (MW)	Build Period (Years)	F.O.R. (%)	P.O.R. (Days/Yr)	Availability (%)	Life of Plant (Years)
Crude Oil Fired Steam Plant (150MW)	Steam	150.0	142.5	4.0	4.0%	40	85.5%	30
Crude Oil Fired Steam Plant (250MW)	Steam	250.0	237.5	4.0	4.0%	40	85.5%	30
Crude Oil Fired Steam Plant (500MW)	Steam	500.0	475.0	4.0	4.0%	40	85.5%	30

Plant Name	Fuel Type	Capital Cost ($/kW)	Heat Rate (KJ/kWh)	Efficiency (%)	Fuel Cost (USc/kWh)	Variable O&M Cost (USc/kWh)
Crude Oil Fired Steam Plant (150MW)	Crude	1475	10235	35.2%	8.94	0.51
Crude Oil Fired Steam Plant (250MW)	Crude	1438	9979	36.1%	8.71	0.50
Crude Oil Fired Steam Plant (500MW)	Crude	1402	9730	37.0%	8.50	0.49

Table 6.2-4 - Characteristics of crude oil-fired STTP candidates

6.2.6 COAL-FIRED STEAM TURBINE PLANT AT PORT SUDAN

6.2.6.1 Technical and economical characteristics

Coal-fired STPP is the least cost generation option for base load. However, due to the lack of significant coal resources in Sudan, these plants would have to be located at Port Sudan in order to minimise transport cost (coal imported from Far East, South Africa or Australia). The capital cost given in the table below include a 50 to 100 USD/kW additional cost for additional port / jetty facilities at Port Sudan to accommodate larger vessels transporting coal.

Plant Name	Plant Type	Site Rating Capacity (MW)	Capacity Sent Out (MW)	Build Period (Years)	F.O.R. (%)	P.O.R. (Days/Yr)	Availability (%)	Life of Plant (Years)
150 MW Coal-fired Steam	Coal	150	143	4	4.0%	40	85.5%	30
400 MW Coal-fired Steam	Coal	400	380	4	4.0%	40	85.5%	30
600 MW Coal-fired Steam	Coal	600	570	4	4.0%	40	85.5%	30

Plant Name	Fuel Type	Capital Cost ($/kW)	Heat Rate (KJ/kWh)	Efficiency (%)	Fuel Cost (USc/kWh)	Variable O&M Cost (USc/kWh)
150 MW Coal-fired Steam	Coal	1325	9500	38.0%	1.48	0.93
400 MW Coal-fired Steam	Coal	1478	9474	38.0%	1.47	0.59
600 MW Coal-fired Steam	Coal	1391	9474	38.0%	1.47	0.56

Table 6.2-5 - Characteristics of coal-fired STPP candidates

Furthermore, the distance between Port Sudan and the main load centres sets some limits on the power evacuation from Port Sudan to be compatible with the Grid capabilities.

6.2.6.2 Environment preservation

Two technology types have been identified in the Sudan LTPPS 2006: pulverised fuel technology (400 and 600 MW) and circulating fluidised bed technology (150 MW).

Pulverised Fuel technology

Conventional pulverised fuel (PF) combustion is a common form of proven generation technology found throughout the world. Finely ground particles of coal are blown into a boiler where they are burned. The heat released is collected through the water walls of the boiler and a series of subsequent heat exchangers, producing high-pressure steam. This steam is passed through a steam turbine that in turn drives an electric generator.

Although PF plants can be built over a wide range of sizes, for the purposes of this study, PF steam plant is considered in large-scale (greater than 300 MW) schemes where coal is the primary fuel used for generation.

The key design features of a conventional PF plant are the pressure and temperature at which steam is generated. Many existing coal-fired plants operate at subcritical steam conditions. Advanced supercritical boilers, however, are becoming the technology of choice and it is expected that they may be more attractive to utilities and developers owing to their greater thermal efficiency.

Emissions control is an important aspect of all types of PF steam plant. These costs can be minimised with prior consideration of the location for the power plant and the specification of the fuel to be burned. For the purposes of this study, we assume that the design of a PF steam plant will optimised to incorporate the following features:

- Moderate sulphur coal (blending coals so that the sulphur content is less than 2% by mass) in order to take advantage of the seawater flue gas desulphurisation process, which avoids the additional cost of sorbent such as lime or limestone;
- Low NOx combustion system, with allowance in the boiler design for selective catalytic reduction (SCR) equipment to be fitted at a later date;
- Use of bag filters to control the emission of particulates.

With these design features, a new PF plant, be it subcritical, supercritical or advanced supercritical, will meet the environmental emissions targets such as those set by the World bank or the even more stringent requirements of the Large Combustion Plant Directive (LCPD) in Europe.

Circulating Fluidised Bed technology

Fluidised bed combustion technologies have some inherent environmental benefits over conventional PF type plants:

- Combustion temperatures are generally lower than those found in typical PF plant. In this regard, lower NOx emissions are achievable without the need for special combustion systems.
- The need for expensive flue gas desulphurisation equipment can be avoided by injecting sorbent (e.g. limestone) directly into the fluidised bed boiler. This has the added benefit of fuel flexibility to burn coals with a wide range of sulphur content.

In this study we consider the circulating fluidised bed combustion (CFB) technology as being the most suitable plant type owing to its suitability for use with coal.

Coal CFB is a well-proven technology suitable for medium size (less than 300 MW) coal-fired plants located inland, i.e. it does not require the availability of seawater for flue gas desulphurisation. For the purposes of this study, we assume that the design of a CFB steam plant will be optimised to incorporate the following features:

- Injection of sorbent into the boiler to control sulphur emissions, with sorbent recirculation from the bag filter to enhance utilisation;
- Use of bag filters to control the emission of particulates and enhance sulphur capture.

6.2.7 HFO-FIRED STEAM UNITS AT PORT SUDAN

It was noted that the existing consumption of HFO at Khartoum North and Fao power stations, plus some consumption in the industrial sector for raising steam, is about equal to the total annual production from the Sudanese refineries. NEC confirmed that it is unlikely that HFO will be used in future generation. It was also confirmed that the Kilo X low speed diesel power station would now be fired on crude oil, rather than the original intention to use HFO as the primary fuel.

It was therefore suggested that the only candidate HFO-fired plant options that would be considered in the LTPSPS 2006 would include the general assumption that the plants would be located at Port Sudan and be fired on imported HFO.

Furthermore, EDF/Scott Wilson observes that HFO-fired units based at Port Sudan would face the same limit of power evacuation to Khartoum area set by the Grid capability, and would come in competition for power export with lower cost coal-fired STPP. Accordingly, the Consultant will not consider the HFO-fired STTP in the evaluation of the Generation Expansion Plan.

6.2.8 PROJECT CASH FLOWS AND EARLIEST COMMISSIONING DATE

The following table gives typical disbursement schedule for the different technologies, and based on construction duration and time to arrange finance, the earliest commissioning dates for the different TPP candidates are listed in the following table:

Plant type	Disbursement Y-2	Disbursement Y-1	Disbursement Y-0	Earliest commissioning date
Gas oil-fired GT	0	50%	50%	2009
Crude oil-fired Low Speed Diesel	0	50%	50%	2009
Gas-oil fired CCGT	30%	40%	30%	2010
Coal-fired STPP	25%	25%	25%	2011
Crude oil-fired STPP	25%	25%	25%	2011

Table 6.2-6 - Earliest commissioning date for TPP candidates

6.3 HYDROPOWER PLANT CANDIDATES

6.3.1 CONTEXT

Based upon available reports, a review was carried out by for the Sudan LTPPS to determine the most likely hydroelectric schemes to be considered as candidates for power system expansion over the next 20 years. The principal selection criteria for such review can be summarised as:

- current state of project preparedness, e.g. whether a previously identified scheme has yet been studied to pre-feasibility, feasibility or full project specification level,
- availability of the data required to form the basis of capital-cost estimates and as necessary for simulation purposes and,
- location and prospective capacity of the scheme in relation to local electricity demand or transmission distance (and hence cost) for connection to the National Grid,
- previously reported economic and financial ranking of the scheme in relation to competing alternatives.

Committed Hydro Plants:

In the Sudan Long Term Power Plan Study master plan, the following hydroelectric power plants were considered to be committed:

- Merowe hydroelectric power plant,
- Sennar extension,
- Roseires heightening with Dinder.

The characteristics of these HPP are presented in Module 2 Vol 4.

6.3.2 GEOGRAPHICAL LOCATION OF THE HYDROPOWER PLANT CANDIDATES

The hydro power projects candidates identified in Sudan Long Term Power Plan Study are located on three rivers:

- Atbara river to the North East of the country (Rumela HPP),
- Nile river downstream from Khartoum (Shereiq, Dagash, Kajbar, low or high Dal I HPP),
- Bahr el Jebel river, in the south of the country (Fula, Shukoli, Lakki and Bedden HPP).

The HPP projects located downstream from Khartoum are relatively close to the main centres of demand of Sudan.

The projects located on Bahr el Jebel, which are relatively close from each other but some 1 000 to 1 500 km from Khartoum and main load centres, will need the extension of the main grid to be connected to the main centres of demand (probably not before 2020).

The following figure gives the schematic location of existing and candidate HPP.

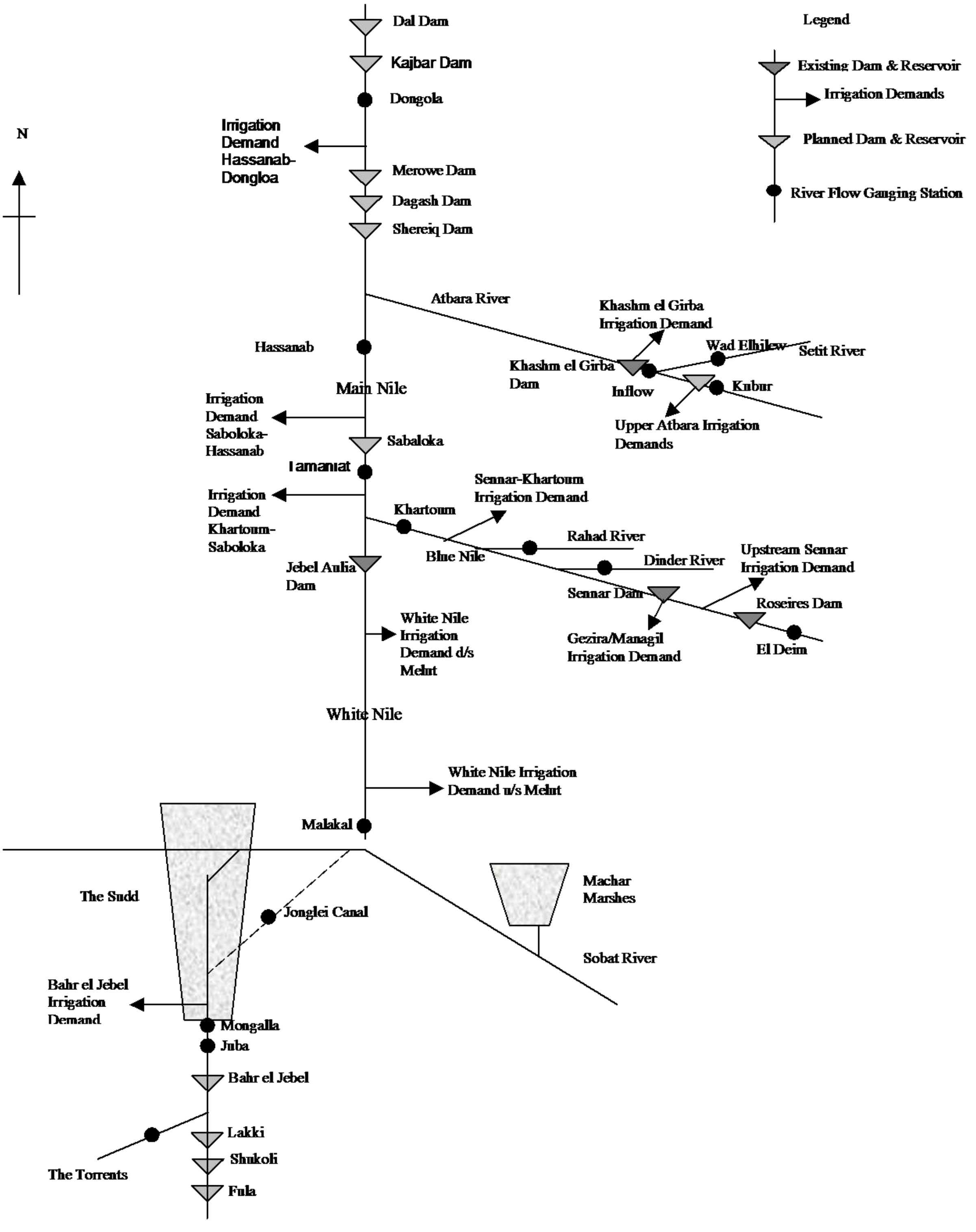

Figure 6.3-1 - Geographical location of existing and candidates HPP

6.3.3 CONSTRUCTION COST, TRANSMISSION COST AND GENERATION COST

Update of construction costs:

The main source of information for the construction cost of the different HPP projects are found in the original studies (Feasibility studies, Acres study in 1993, M/M&Gibb study in 1979). These construction costs have been reviewed and updated in two successive steps:

- In Power System Planning Study, Hydrology and hydroelectric power plant April 2003, for the Bahr el Jebel HPP projects. The costs were given in USD_{2001}.
- In Long Term Power System Planning Study, October 2006 for Blue Nile HPP projects. The costs were given in USD_{2006}.

The USD_{2001} costs given in 2003 Sudan Long Term Power Plan Study for Bahr el Jebel HPP projects are updated in USD_{2006} in the present Study on the basis of USD escalation between 2001 and 2006.

Cost of transmission expansion associated with HPP candidates:

The costs of the transmission reinforcement necessary for the connection of the new HPP to the Grid have been determined in Long Term Power System Planning Study (October 2006). It was found that, compared to the uncertainties in the construction costs, the transmission reinforcement costs are not a significant part of the total HPP cost (< 4%, except Kajbar with 12%).

a. For the Main River Nile schemes, these costs are given from paragraph 6.3.4.
b. For the Bahr El Jebel schemes, the Consultant decides not to incorporate the cost of a transmission link to Khartoum area in the economic study (Module M6) for the same reasons as in Sudan Long Term Power Plan Study:

The four major hydroelectric schemes on the Bahr El Jebel river (south of Juba) are Fula, Shukoli, Lakki and Bedden. Together they have an estimated total installed capacity of 1 540 MW.

The Bahr El Jebel schemes are relatively close to each other but some 1 500 km away from the main load centres in and around Khartoum. Hence, the capital cost estimates for Lakki, Bedden and Shukoli were adjusted to include the cost of AC transmission lines to a common point near Fula (the largest scheme). The capital cost for AC transmission was estimated at US$ 32.8 m, US$ 11.9 m and US$ 10m for Bedden, Lakki and Shukoli respectively.

If the output from these projects were to supply load solely in the main load centres in Khartoum and Gezeira states then it would be appropriate to include the cost of providing a transmission link capable of transmitting the total MW capacity of the 4 schemes to the Khartoum area. The magnitude of the unsuppressed load in the southern states of Sudan is forecast to be sufficient, however, to absorb the majority of the output from the plants once they have been commissioned. Any future interconnection between the southern states and the National Grid in the northern states will be to deliver any spare hydro energy northwards in times of surplus and thermal energy southwards during times when demand in the south exceeds the available capacity and energy from the hydro schemes.

Under these circumstances it is inappropriate to burden the candidate hydroelectric schemes with the costs of setting up a national grid in the southern states when comparing these with thermal plant options in the north. Recognising the large distances between the forecast major load centres in the south (predominantly in and around the towns of Wau, Juba and Malakal), it is likely that a 500 KV network will be required to ensure the output from the Bahr El Jebel Schemes can be absorbed in the South. Whilst the cost of constructing this southern grid will be incorporated in the Investment Plan Report, Accordingly, the cost of constructing this southern grid is not considered further in the economic Study (Module 6).

Generation cost per MWh:

The generation cost per MWh (also called economic cost or levelized cost of generation) which is given in the following paragraphs for each project, could be understood as the average generation cost per MWh all over the economic life of the investment, considering all costs (investment cost and O&M cost) and the discount rate[2]. The generation costs given in the following paragraph are given for a 12% discount rate, which is consistent with Sudan Long Term Power Plan Study 2006. The annual O&M costs are estimated to 1% of the construction cost. The investment cost are calculated on the base of the Net Present Value of the estimated cash flow during construction (see 6.3.14).

6.3.4 SABALOKA HPP PROJECT ON THE MAIN NILE RIVER

The Sabaloka site has been identified at the Sabaloka gorge about 90 km downstream of the Blue and White Nile confluence, however, the possible height of the structure and hence head of water is restricted by the possible flooding of Khartoum from the impounded reservoir water level. The possible full supply level would be fixed at 374 masl giving a gross rated head of approximately 8 m.

Earlier studies identified an installation of 4 x 30 MW Kaplan units, but Acres (Long Term Power System Planning Study – March 1993) later preference for 6 x 15 MW bulb units is retained for this study. The powerhouse and spillway would be located on the two branches of the Nile at the upstream end of Miskit island. The spillway would consist of 12 x 14.5 m high x 15 m wide gates. It was concluded that only modest non overspill dam sections will be required on either flank to complete the damming of the Nile River. The dam will have a gross head of 11.5 m, a rated head of 8 m and the minimum head at which power generation would be possible is assumed to be 5 m.

[2] More information on the definition and the calculation of the economic cost is given in Module 3 Vol 5 report

Sabaloka HPP	Main Features
River	Nile river
Gross / rated / minimum head	11.5 m / 98 m / 5 m
Total installed capacity	6 x 15 MW = 90 MW
Number of units	6
Maximum discharge	1 711 m^3/s (ACRES 1993 Table D7)
95% Firm energy	678 GWh
Average energy	691 GWh
Construction duration	6 years
Project costs	596 MUSD $_{2006}$ (unit costs updated in 2003 LTPPS)
Generation cost	129 USD_{2006}/MWh
Level of study	LTSP Study Acres 1993

Table 6.3-1 - Sabaloka HPP characteristics

Origin of data: LTPPS – NEC Data Book Vol 1 – April 2003

Complementary data are presented in appendix M3 Vol4.

Other issues:

Owing to concerns that tail waters from the Sabaloka hydroelectric scheme may induce additional flooding in the Khartoum area, this scheme is not offered as a candidate plant option.

6.3.5 SHEREIQ HPP PROJECT ON THE MAIN NILE RIVER

The proposed Shereiq Dam is to be sited approximately 400 km downstream of the White Nile – Blue Nile confluence close to the Shereiq railway station. The site would take advantage of the Umm Hugier island for easier diversion and construction methodology.

The Feasibility Report (Shereiq HPP-Feasibility report, Book1, Hydroproject and Dar Consult 1999) proposes the construction of a low head dam of about 27 m in height with an overall length of approximately 3 615 m for a full supply level of 343 masl. The concrete dam section located on the right bank is approximately 360 m long and contains the gated spillways and low level sluices. The combined right and left bank clay core earth-rock section of the dam is to be about 3 070 m in length.

The surface power station of about 185 m in length would be located on the right bank and is designed to house 6 x 52.5 MW Kaplan turbines for a FSL 343 m.

Shereiq HPP	Main Features
River	Nile river
Total installed capacity	6 x 52.5 MW = 315 MW
Number of units	6
Maximum discharge	1 942 m^3/s (IHP 1999)
Reservoir FSL	343 m (IHP 1999)
Reservoir MOL	340 m (IHP 1999)
Dead volume	1 293 hm^3
Active volume	909 hm^3
95% Firm energy	1 936 GWh
Average energy	1 536 GWh
Construction duration	6 years
Project costs	1 189 $MUSD_{2006}$
of which transmission cost	7 $MUSD_{2006}$ (unit costs updated in 2006 LTPPS)
Generation cost	122 USD_{2006}/MWh
Level of study	Feasibility 1990

Table 6.3-2 - Shereiq HPP characteristics

Origin of data: LTPPS – NEC Data Book Vol 1 – April 2003
except costs from LTPPS – NEC – Generation Plan Report – 18 nov 2006

Complementary data are presented in appendix M3 Vol4.

Other issues:

Shereiq project is considered as first priority by the Dams Implementation Unit of Sudan.

6.3.6 DAGASH HPP PROJECT ON THE MAIN NILE RIVER

The Dagash site is proposed in order to develop the potential head between the Shereiq site and the upstream end of Mograt island. The powerhouse containing 8 x 35.6 MW bulb turbines and the spillway with 12 x 14.5 m high x 15 m wide gates would be located on the main branch of the Nile.

Overall the embankment dams are designed slightly smaller than those of Shereiq. The dam would have a gross head of 16 m, a rated head of 15.8 m and a minimum head of 9.5 m. The creation of the reservoir would require the relocation of approximately 65 km of railway line running between Abu Hamed and Abu Hasmin.

Dagash HPP	Main Features
River	Nile river
Gross / net / minimum head	16 m / 15.8 m / 9.5 m
Total installed capacity	8 x 35.6 MW = 285 MW
Number of units	8
Maximum discharge	2 100 m^3/s (Acres 1993 Table D7)
Active volume	100 hm^3
95% Firm energy	1 427 GWh
Average energy	1 476 GWh
Construction duration	6 years
Project costs	1 048 $MUSD_{2006}$ (unit costs updated in 2006 LTPPS)
of which transmission cost	6 $MUSD_{2006}$
Generation cost	109 USD_{2006}/MWh
Level of study	LTSP Study Acres 1993

Table 6.3-3 - Dagash HPP characteristics

Origin of data: LTPPS – NEC Data Book Vol 1 – April 2003
except costs from LTPPS – NEC – Generation Plan Report – November 2006

Complementary data are presented in appendix M3 Vol4.

Other issues:

The creation of the reservoir would require the relocation of approximately 65 km of railway line running between Abu Hamed and Abu Hasmi.

6.3.7 KAJBAR HPP PROJECT ON THE MAIN NILE RIVER

The proposed Kajbar Dam scheme is to be located on the Main Nile River approximately 1 200 km north of Khartoum above the Kaibar cataract. The feasibility design (Kajbar Hydropower Project, Detailed Project Report, Hydroproject, 1997) proposes the construction of a low head dam of about 18 m in height with an overall length of approximately 1 600 m. The dam would consist of a concrete gated (286 m), ungated (400 m) spillway gravity section and a nonoverspill gravity section on the left bank of 900 m. The surface power station is designed for 6 x 18.1 MW Kaplan turbines and is to be located on the right bank.

It was proposed in Sudan LTPPS 2003 study to build the scheme in two phases:

PHASE I:

- Stage I: the design FSL is 209 masl with the dam wall built to a crest height of 213 masl. The power station would comprise four turbines rated for the final Phase II raised crest height of 218.5 masl.
- Stage II: to be implemented about three years after the commissioning of the last of Stage I turbines. The FSL 209 masl would remain with two further turbines installed, bringing the number of turbines up to six in total.

PHASE II: raising the dam to a FSL 213 masl, which in turn increases the generating head.

Recently, alternate projects are being considered by NEC with an installed capacity in the range of 200 to 300 MW in conjunction with the development of Dal I Low.

The LTPPS 2006 (November version) consider a 300 MW scheme which will be also considered in the present Study.

Kajbar HPP	Main Features
River	Nile river
Total installed capacity	6 x 50 MW = 300 MW
Number of units	6
Average energy	1 400 GWh
Construction duration	7 years
Project costs	1 125 $MUSD_{2006}$ (unit costs updated in 2006 LTPPS)
of which transmission cost	20 $MUSD_{2006}$
Generation cost	130 USD_{2006}/MWh
Level of study	Feasibility Hydroproject 1997

Table 6.3-4 - Kajbar HPP characteristics

Origin of data: LTPPS – NEC Data Book Vol 1 – April 2003
except costs from LTPPS – NEC – Generation Plan Report – October 2006

Complementary data are presented in appendix M3 Vol4.

Other issues:

- Final design will depend on the choice and decision relative to the development of Dal I project.
- The Hydroproject Institute report drew attention to the potential impact of sediment on the Kajbar development with an estimate that 80% of the reservoir storage would be lost within the first 7 – 8 years of operation.
- Non energetic uses: irrigation.

6.3.8 DAL HPP PROJECT ON THE MAIN NILE RIVER

The pre-feasibility study of Dal HPP project is currently conducted within Module 5 of the present Study.

Two options have been considered in the past for development of the Dal-Kajbar-Dongola reach of the Nile. These comprise:

- a high dam option at Dal with full supply level of El. 218 m which would flood upstream as far as Dongola or
- a cascade of two lower reservoirs at Dal and Kajbar which would operate as run-of-river projects.

Various full supply levels have been considered for Kajbar. In feasibility studies carried by Hydroproject Institut of Moscow in 1997 a first stage development with FSL of 209 m was proposed with installed capacity of 108 MW.

A second stage of development would raise the FSL by 4 metres to El. 213 m. Other studies (Acres, 1993 and Sudan LTPPS, 2003-2006) have proposed an FSL of El. 218 m, similar to the high Dal option and with an installed capacity of 300 MW. Local objections resulted in the planned development of Kajbar being deferred.

Long term power development plan studies by Acres (1993) and Sudan LTPPS (2003 and 2006) both recommended the High Dal option rather than the Low Dal plus Kajbar alternative based on the lower engineering costs for the single project rather than cascade development. However, both of these studies were based on desk-top analysis alone, without field visits to the project area and did not take account of environmental and social costs.

The Hydroproject Institute report drew attention to the potential impact of sediment on the Kajbar development with an estimate that 80% of the reservoir storage would be lost within the first 7 – 8 years of operation. With the construction of Merowe taking place upstream it is anticipated that this will no longer be the case and that following impounding of Merowe in 2008, the majority of sediment will be deposited within the Merowe reservoir and future that sediment concentrations at Dal and Kajbar will be much lower than current levels although some sediment can still be expected to arise from degradation of the river bed downstream of Merowe.

It is clear from the site visit that development of a high dam at Dal would lead to significant population displacement and social upheaval. In addition it would appear that the Dal reservoir would be extensive but relatively shallow potentially leading to excessive losses due to evaporation. Having regard to both of these factors it is considered that the most appropriate development of the Dal reach would comprise two low head run-of-river projects at Dal and Kajbar.

Low Dal HPP	Main Features
River	Nile river
Mean natural inflow	2 055 m^3/s
Total installed capacity	340 MW
Number of units	8 x 42.5 MW
Maximum discharge	2 099 m^3/s
Reservoir FSL	201 m (ACRES 1993 Table D7)
Reservoir MOL	289 m (ACRES 1993 Table D7)
Active volume	2 471 hm^3
95% Firm energy	to be determined in PF study (Module 5)
Average energy	1 944 GWh without Mandaya (2 190 GWh with Mandaya)
Project costs	1 118 $MUSD_{2006}$ (without mitigation cost to be determined in PF study - Module 5)
of which transmission cost	22 $MUSD_{2006}$, to be updated in PF study (Module 5)
Generation cost	to be determined in PF study (Module 5)
Level of study	Ongoing Pre feasibility study (Module M5)

Table 6.3-5 - Dal HPP characteristics

Complementary data are presented in appendix M3 Vol4.

6.3.9 FULA I HPP PROJECT ON THE BAHR EL JEBEL RIVER

The proposed site was identified approximately 34 km downstream of Nimule, in an asymmetrical valley with a narrow riverbed area about 160 m wide with a 200 m wide flood plain located on the left bank.

Scheme I comprises a powerhouse containing the 8 x 90 MW Francis units which would be located on the right bank section, the central riverbed section which would have 4 x 12 m wide bays with 13.5 m high radial gates and a non-overflow earth or rock fill embankment 1 000 m long on the left bank. The dam will have a gross head of 62 m, a rated head of 59 m and a minimum head of 49 m.

The Acres study mentions that there may be a difficulty with the diversion works and when the next study is undertaken consideration should be given to moving the proposed position of the structure.

Scheme II is similar in layout to that described above, however, the powerhouse would be designed to contain only 6 x 90 MW units.

According to NEC, the retained option for the long term master plan is scheme I with the proposed reservoir and 8 x 90 MW power station.

Fula HPP (scheme1)	Main Features
River	Bahr el Jebel
Reservoir surface area	18 km^2
Gross / rated / minimum head	62 m / 59 m / 49 m
Total installed capacity	8 x 90 MW = 720 MW
Number of units	8
Maximum discharge	1 400 m^3/s
Reservoir FSL	622 m (Bonifica 1983 Fig 4.15)
Reservoir MOL	616 m (Bonifica 1983 Fig 4.15)
Dead storage	510 hm^3 (Bonifica 1983 Fig 4.15)
Active storage	220 hm^3 (Bonifica 1983 Fig 4.15)
95% Firm energy	2 300 GWh
Average energy	4 119 GWh
Construction duration	6 years
Project costs	1 319 $MUSD_{2006}$
Generation cost	49.1 USD_{2006}/MWh
Level of study	Acers study LTPSPS March 1993 (unit costs updated in 2003 LTPPS)

Table 6.3-6 - Fula HPP characteristics

Origin of the data: LTPPS – NEC Data Book Vol 1 – April 2003
except transmission costs from LTPPS – NEC – Generation Plan Report – October 2006

Complementary data are presented in appendix M3 Vol4.

Other issues:

Difficulties with siltation for the Bahr el Jebel schemes are expected to be negligible such that is no need for any seasonal drawdown to be enforced.

Not expected to be built before 2020, when grid extension will allow, like other Bahr el Jebel HPP projects.

6.3.10 SHUKOLI HPP PROJECT ON THE BAHR EL JEBEL RIVER

The proposed site was identified approximately 48 km downstream of Nimule, 14 km downstream from Fula in a relatively narrow site with a riverbed about 200 m wide. The powerhouse containing the 4 x 52.5 MW Kaplan units would be located on the left bank, the central riverbed section would have 4 x 12m wide bays with 13.5 m high radial gates and a non-overflow concrete non overspill section 230 m long on the right bank. The dam would have a gross head of 25 m, a rated head of 23.3 m and a minimum head of 12 m, and once again the selection of the dam site should be reviewed in future studies.

Shukoli HPP	Main Features
River	Bahr el Jebel
Reservoir surface area	10 km^2
Gross / rated / minimum head	25 m / 23.3 m / 12 m
Total installed capacity	4 x 52.5 MW = 210 MW
Number of units	4
Maximum discharge	1 043 m^3/s
Reservoir FSL	560 m (Bonifica 1983 Fig 4.17)
Reservoir MOL	557.9 m (Bonifica 1983 Fig 4.17)
Reservoir dead storage	92.9 hm^3 (Bonifica 1983 Fig 4.17)
Reservoir active storage	19.6 hm^3 (Bonifica 1983 Fig 4.17)
95% Firm energy	914 GWh
Average energy	1 420 GWh
Construction duration	6 years
Project costs	420 $MUSD_{2006}$
of which transmission cost	10 $MUSD_{2006}$
Generation cost	45.2 USD_{2006}/MWh
Level of study	Acers study LTPSPS March 1993 (unit costs updated in 2003 LTPPS)

Table 6.3-7 - Shuloki HPP characteristics

Origin of the data: LTPPS – NEC Data Book Vol 1 – April 2003
except transmission costs from LTPPS – NEC – Generation Plan Report – October 2006

Complementary data are presented in appendix M3 Vol4.

Other issues:

Difficulties with siltation for the Bahr el Jebel schemes are expected to be negligible such that is no need for any seasonal drawdown to be enforced.

Not expected to be built before 2020, when grid extension will allow, like other Bahr el Jebel HPP projects

6.3.11 LAKKI HPP PROJECT ON THE BAHR EL JEBEL RIVER

The proposed site was identified approximately 72 km downstream of Nimule, 24 km downstream from Shukoli in a relatively wide site with a 250 m wide shoulder on the left bank. The powerhouse (4 x 52.5 MW units) and spillway size, arrangement and layout are similar to that of the Shukoli site, however, there would be an earth/rock fill embankment constructed through the riverbed area and on the right bank. The dam would have a gross head of 25 m, a rated head of 23.3 m and a minimum head of 12.5 m.

Lakki HPP	Main Features
River	Bahr el Jebel
Reservoir surface area	17 km^2
Gross / rated / minimum head	25 m / 23.3 m / 12.5 m
Total installed capacity	4 x 52.5 MW = 210 MW
Maximum discharge	1 043 m^3/s
Reservoir FSL	532.9 m (Bonifica 1983 Fig 4.19)
Reservoir MOL	535 m (Bonifica 1983 Fig 4.19)
Dead storage	114.9 hm^3 (Bonifica 1983 Fig 4.19)
Active storage	3.6 hm^3 (Bonifica 1983 Fig 4.19)
95% Firm energy	912 GWh
Average energy	1 422 GWh
Construction duration	6 years
Project costs	429 $MUSD_{2006}$
of which transmission cost	11.9 $MUSD_{200}$
Generation cost	46.5 USD_{2006}/MWh
Level of study	Acers study LTPSPS March 1993 (unit costs updated in 2003 LTPPS)

Table 6.3-8 - Lakki HPP characteristics

Origin of the data: LTPPS – NEC Data Book Vol 1 – April 2003
except transmission costs from LTPPS – NEC – Generation Plan Report – October 2006

Complementary data are presented in appendix M3 Vol4.

Other issues:

Difficulties with siltation for the Bahr el Jebel schemes are expected to be negligible such that is no need for any seasonal drawdown to be enforced.

Not expected to be built before 2020, when grid extension will allow, like other Bahr el Jebel HPP projects

6.3.12 BEDDEN HPP PROJECT ON THE BAHR EL JEBEL RIVER

The proposed site was identified approximately 138 km downstream of Nimule, 66 km downstream from Lakki. The site is located where the Bedden Island divides the main flows with the main flow passing in the right channel of the island. The powerhouse located in the left channel of the river is expected to contain 4 x 100 MW Kaplan units, the spillway designed to be constructed on the island, would house 4 x 12 m wide bays with 13.5 m high radial gates. The non-overspill section of the dam would be constructed of fill embankments, 680 m long for the right bank and about 100 m long for the left bank. The dam would have a gross head of 44.4 m, a rated head of 39 m and a minimum head of 30 m (with downstream irrigation demand).

Bedden HPP	Main Features
River	Bahr el Jebel
Reservoir surface area	100 km^2
Gross / rated / minimum	44.4 m / 30 m / 30 m
Number of units	4 x 100 MW = 400 MW
Maximum discharge	1 166 m^3/s
Reservoir FLS	503.9 m (Bonifica 1983 Fig 4.21)
Reservoir MOL	510 m (Bonifica 1983 Fig 4.21)
Dead storage	1 774 hm^3 (Bonifica 1983 Fig 4.21)
Active storage	748 hm^3 (Bonifica 1983 Fig 4.21°
95% Firm energy	1 850 GWh
Average energy	2 761 GWh
Construction duration	6 years
Project costs	880 $MUSD_{2006}$
of which transmission cost	32.8 $MUSD_{2006}$
Generation cost	48.8 USD_{2006}/MWh
Level of study	Acers study LTPSPS March 1993 (unit costs updated in 2003 LTPPS)

Table 6.3-9 - Bedden HPP characteristics

Origin of the data: LTPPS – NEC Data Book Vol 1 – April 2003
except transmission costs from LTPPS – NEC – Generation Plan Report – October 2006

Complementary data are presented in appendix M3 Vol4.

Other issues:

Difficulties with siltation for the Bahr el Jebel schemes are expected to be negligible such that is no need for any seasonal drawdown to be enforced.

Not expected to be built before 2020, when grid extension will allow, like other Bahr el Jebel HPP projects.

Non energetic uses: irrigation.

6.3.13 RUMELA HPP PROJECT ON THE ATBARA RIVER

The Rumela dam would be located approximately 15 km upstream of the confluence with the Setit River (named Tekeze in Ethiopia). The primary function of the dam would be to create seasonal regulation of the flows for irrigation purposes, with the potential to include 3 x 10 MW Francis units, rated for a head of about 40 m. The dam size is expected to be approximately 52 m high with a full supply level of 520 masl and an overall length of approximately 8 100 m. The spillway needs to be sized to pass a flood of 6 000 m^3/s.

Rumela HPP	Main Features
River	Atbara river
Rated head	40 m
Total installed capacity	3 x 10 MW
Reservoir FLS	517.5 m (SOGREAH 1982 pA1.5)
Reservoir MOL	508.4 m (SOGREAH 1982 pA1.5)
Dead storage	729 hm^3 (SOGREAH 1982 pA1.5)
Active storage	931 hm^3 (SOGREAH 1982 pA1.5)
95% Firm energy	35 GWh
Average energy	82 GWh
Project costs	193 $MUSD_{2006}$
of which transmission cost	12 $MUSD_{2006}$
Generation cost	341 USD_{2006}/MWh
Level of study	1979 Merz&McLellan&Gibb LTPP report (unit costs updated in 2003 LTPPS)

Table 6.3-10 - Bedden HPP characteristics

Origin of the data: LTPPS – NEC Data Book Vol 1 – April 2003

Complementary data are presented in appendix M3 Vol4.

Other issues:

Provides seasonal regulation for irrigation purpose. Project identified having a high priority.

6.3.14 HPP PROJECT ESTIMATED CASH FLOW

The following table summarizes the estimated cash flow during construction of each HPP project up to the commissioning date. The origin of information is the Sudan LTPPS 2003.

HPP Project cash flow during construction - $MUSD_{2006}$

	Year - 5	Year - 4	Year - 3	Year - 2	Year - 1	Com.	Total
Rumela		19.3	28.8	67.4	57.8	19.3	192.5
Sabakola	11.9	95.4	143.1	196.7	113.3	35.8	596.1
Shereiq	114.3	216.5	330.6	415.7	235.1	15.9	1 328.0
Dagash	21.0	167.7	251.7	345.6	199.1	62.9	1 048.0
Kajbar	11.4	91.4	137.1	188.3	108.5	34.3	571.0
Fula Alt 1	26.3	211.0	316.5	435.0	250.7	79.1	1 318.6
Shukoli	8.4	67.0	100.5	138.4	79.7	25.2	419.3
Lakki	8.6	68.6	102.9	141.6	81.5	25.8	429.0
Bedden	17.6	140.7	211.1	290.1	167.2	52.8	879.5

Table 6.3-11 - HPP project estimated cash flow during construction

6.3.15 EVAPORATION

Data for monthly evaporation are presented in appendix M3 Vol 4.

6.3.16 IRRIGATION DEMAND

The following figure illustrate the evolution of the extension of irrigation demand in Sudan:

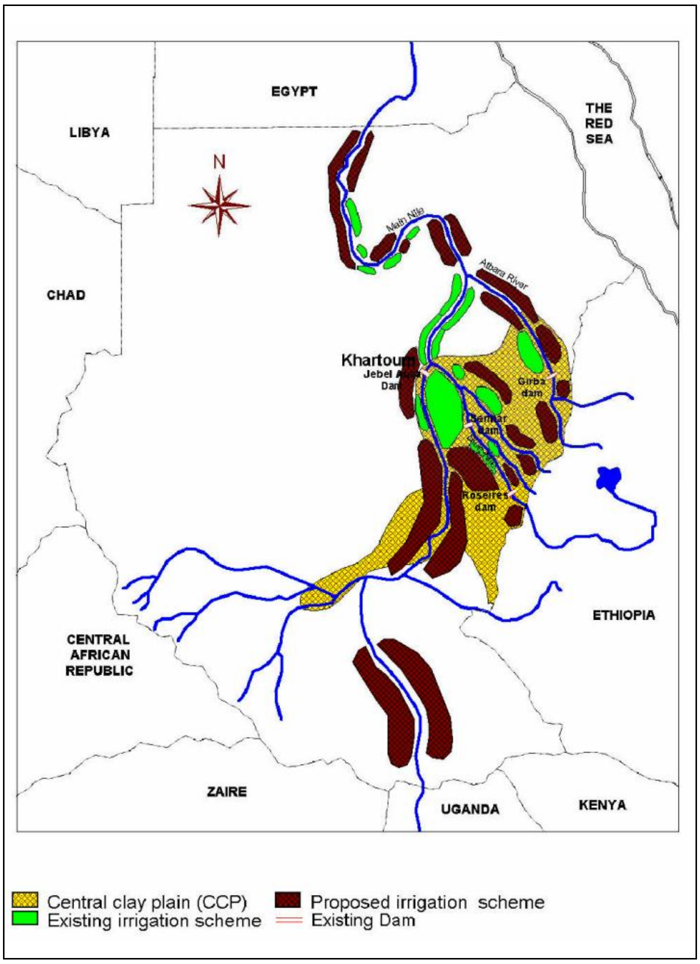

Figure 6.3-2 - Schematic map of existing and potential dams, reservoirs and irrigation demand

Origin: ENTRO – Inventory report on water resource – Related data and information – Sudan – Prof D.R Abdalla Abdelsalam Ahmed – 2006

<u>Total irrigation water requirements</u>:

The present Study will be based on the same water irrigation requirement as the LTPPS 2003: In total the existing irrigation demand adopted for this study is an average of 13.7 G m^3 per annum (excluding evaporation for reservoirs). This is similar to 1997-99 total irrigation estimates provided by the MoI and slightly lower than the often quoted irrigation demand of around 18.5 G m^3 in The Water Resources of Sudan (1977).

The average irrigation demand is projected to increase to 20.5 G m^3 and 26.8 G m^3 by 2012 and 2027 respectively. Short- and medium-term plans could see the area of irrigated land increase and irrigation demand grow by 1.47 G m^3 from the Atbara river, 4.9 G m^3 from the Blue Nile, 5.2 G m^3 from the White Nile and 1.7 G m^3 from the Main Nile.

A summary of projected water requirements for the Sudan 2006 - 2027 is given in the following table:

Nile Tributary	Cultivated area (1000 Feddans)			Water requirement G m^3		
	2002	2012	2027	2002	2012	2027
The Blue Nile[1]	2 112	3 186	4 279	9 050	11 481	13 941
The White Nile	480	1 067	1 556	2 050	4 968	7 280
Atbara River[2]	282	572	792	1 270	2 123	2 740
The Main Nile	311	571	860	1 300	1 903	2 867
Total	**3 185**	**5 396**	**7 487**	**13 670**	**20 475**	**26 828**

Note :

1 : Irrigated areas in 2002 to 2007 are based on assuming the completion of the heigtening of Roseires

2 : Irrigated areas in 2002 to 2007 are based on assuming the completion of Upper Atbara Dam

3 : The increase in requirement in 2012 can be met following the completation of the water conservation projects at Jonglei I an d Machar

4 : The increase in requirement in 2027 can be met following the completation of the water conservation projects at Jonglei II and Bahr El Gazal

Table 6.3-12 - Irrigation water requirements

Source: Long-Term Agricultural Strategy (2002-2027)

6.3.17 HPP SEQUENCING

Under normal circumstances, the HPP commissioning schedule adopted in a least cost generation expansion plan would be based on the scheme lifetime generation cost (USD/MWh), such that the hydroelectric scheme with the lowest generation cost would be 'offered' as the first hydroelectric candidate plant and the scheme with the second lowest lifetime cost would be offered second and so on.

On this basis the economic order would be Dagash first, then Shereiq, Dal and Kajbar which have equivalent costs, then Rumela. For the Southern project, considering the limited available information, these projects could be considered economically equivalent.

However, this is complicated by:

- the priority status given to certain projects by Sudanese Authorities,
- the possible additional non energetic benefits of the projects (e.g. irrigation),
- the installed capacity of the schemes relative to the country power demand,
- the construction duration,
- the limited information available for the schemes on the Bahr El Jebel river in Southern Sudan.

Based on LTPPS 2006, the hydroelectric sequencing is to be based on the following information:

<u>Rumela and Shereiq HPP</u>:

The Dams Implementation Unit in Sudan is actively seeking to develop both the Rumela and Shereiq projects in the next 6 to 7 years.

Although the Rumela scheme on the Atbara River is the most expensive candidate scheme (and also the smallest at only 30 MW) in terms of unit lifetime cost of electricity, it also has strategic irrigation benefits that would benefit Sudan

<u>Bahr et Jebel HPP projects</u>:

The Fula, Shukoli, Lakki and Bedden schemes are the cheapest schemes to build and commission in terms of generation cost. Each of these schemes is located in the Southern states of Sudan. It has been assumed for the grid demand forecast for this generation planning study that the southern states would not be interconnected to the grid until about 2020. It is also assumed that it is very unlikely that any of these southern hydroelectric schemes would be able to be fully built prior to this date owing to the realistic timetable for implementation shown below:

- Pre feasibility, feasibility and design stage: 4.5 years;
- Tendering and financial close etc: 1.5 years
- Construction: 8 years

We have therefore assumed that the Fula, Shukoli, Lakki and Bedden and schemes can be built (in this least-cost order) from 2020 onwards.

It should be noted than Module 4 of the present Study will focus on the ranking of these projects considering multi-criteria analysis.

HPP Project	River	Construction duration	Earliest commissioning date
Rumela	Atbara	5	2011
Shereiq	Main Nile	6	2013
Kajbar	Main Nile	7	2015
Dal I	Main Nile	6 (to be confirmed in PF study Module 5)	2015
Dagash	Main Nile	6	2017
Fula – Shukoli – Lakki – Bedden	Bahr et Jebel	8	2020

Table 6.3-13 - Earliest commissioning date of HPP candidates

6.3.18 HPP CANDIDATES SUMMARY TABLE

The main technical and economic characteristics of the hydroelectric candidates are synthesized in the table below.

The following abbreviations are used to describe the level of study:

- R: Reconnaissance
- PF: Pre-feasibility study
- F: Feasibility study
- D: Design study

The quality and precision of the data is variable from one project to an another.

- 2 projects have been studied to the feasibility stage (Shereiq and Kajbar).
- Dal is currently studied to pre-feasibility level within Module 5 of the present Study.
- The Consultant was informed that pre-feasibility Studies of the four southern projects will be carried out in 2007.

For the purpose of information, the cost of generation (USD/MWh) is calculated for two discount rates (12% and 10%).

Project	River	Level of Study	Installed capacity MW	Total cost MUSD2006	Construction duration year	Earliest commissioning date	Average generation GWh/year	USD/MWh a = 12%	USD/MWh a = 10%	Comments
Rumela	Atbara river	M&M/Gibb 1979	30	193	5	2011	82	341	299	Irrigation pupose
Sabakola	Main Nile	Acers 1993	120	596	6	Not offered	691	132	115	Might flood Khartoum
Shereiq	Main Nile	F (1990)	315	1 190	6	2013	1 546	123	106	Prioritary
Dagash	Main Nile	Acers 1993	285	1 048	6	2017	1 476	109	95	
Kajbar	Main Nile	F (Hydroproject 1997)	300	1 125	7	2015	1 400	123	107	
Dal Low	Main Nile	On going PF	340	1 118	6	2015	1 944	83	72	cost currently updated in PF
	Sub Total		1 360							
Fula Alt 1	Barh el jebel	Acers 1993	720	1 319	8	2020	4 119	49.1	42.7	limited information
Shukoli	Barh el jebel	Acers 1993	210	420	8	2020	1 422	45.2	39.3	available
Lakki	Barh el jebel	Acers 1993	210	429	8	2020	1 415	46.5	40.4	comm. date > 2020
Bedden	Barh el jebel	Acers 1993	400	880	8	2020	2 761	48.8	42.4	(Pre-Feasibility : starting in 2007)
	Sub Total		1 540							

Table 6.3-14 - HPP candidates summary table

7. REVIEW OF THE EXISTING GENERATION EXPANSION PLAN

7.1 MAIN HYPOTHESIS

The least cost generation plan was determined in the Sudan LTPPS 2006 (October 2006) for the period 2006 to 2030.

The discount rate was 12%. Sensitivity analysis were carried out for 15% and 10% discount rate.

The GEP presented hereafter is related to:

- the base case demand scenario,
- a discount rate of 12%,
- a LOLP of 3% decreasing to 1% from 2009 to 2026,
- the chosen alternative of High Dal (instead of Low Dal + Kajbar).

7.2 GENERATION EXPANSION PLAN FOR THE BASE CASE DEMAND FORECAST

The results of the base case plan were proven to be robust to changes in demand forecast, fuel prices and discount rates.

The table here after illustrates the implementation schedule for the base case demand forecast.

Year	New GTs (gasoil)	New LSD Plant (Diesel oil)	New CGTs (gasoil)	New Crude-fired Steam	New Coal-fired Steam	New Hydro Plant	Total Added Capacity	Total Existing and Committed Capacity	Total Capacity	Demand	Reserve margin	Reserve Margin (%)
2006								871	871	1 223	-351	-29%
2007								1 187	1 187	1 927	-740	-38%
2008							250	1 377	1 627	2 577	-950	- 37%
2009	1 x 60 MW	1 x 272 MW					332	3 789	4 121	3 396	725	21%
2010							332	4 942	5 274	4 179	1 095	26%
2011					2 x 143 MW	Rumela	648	5 114	5 762	4 478	1 284	29%
2012					1 x 380 MW		1 028	5 274	6 302	4 969	1 333	27%
2013						Shereiq	1 343	5 274	6 617	5 322	1 295	24%
2014			1 x 208 MW				1 551	5 304	6 855	5 843	1 012	17%
2015					1 x 380 MW	Low Dal	2 271	5 215	7 486	6 244	1 242	20%
2016						Kajbar	2 571	5 215	7 786	6 629	1 157	17%
2017			1 x 208 MW	1 x 238 MW			3 017	5 215	8 232	7 029	1 203	17%
2018					1 x 380 MW		3 397	5 215	8 612	7 456	1 156	16%
2019			1 x 208 MW	1 x 238 MW		Dagash	4 128	5 215	9 343	7 868	1 474	19%
2020				2 x 475 MW		Fula I	5 798	5 316	11 114	8 995	2 119	24%
2021					1 x 570 MW		6 368	5 316	11 684	9 449	2 235	24%
2022						Shukoli	6 578	5 316	11 894	9 898	1 996	20%
2023			1 x 342 MW				6 920	5 214	12 134	10 337	1 797	17%
2024	1 x 60 MW					Lakki	7 190	5 214	12 404	10 786	1 619	15%
2025				1 x 475 MW			7 665	5 214	12 879	11 205	1 674	15%
2026			1 x 342 MW			Bedden	8 407	5 214	13 621	11 704	1 917	16%
2027			2 x 342 MW		1 x 570 MW		9 661	5 214	14 875	12 231	2 645	22%
2028							9 661	5 050	14 711	12 756	1 955	15%
2029			2 x 456 MW				10 573	5 050	15 623	13 315	2 308	17%
2030			2 x 456 MW				11 485	5 050	16 535	13 883	2 652	19%
Total	120	272	3,816	1,901	2,566	2,810	11 485	5,050	16 535			

Table 7.2-1 - Generation expansion plan for base case demand forecast

The following graph summarizes the implementation schedule for the various type of power plant.

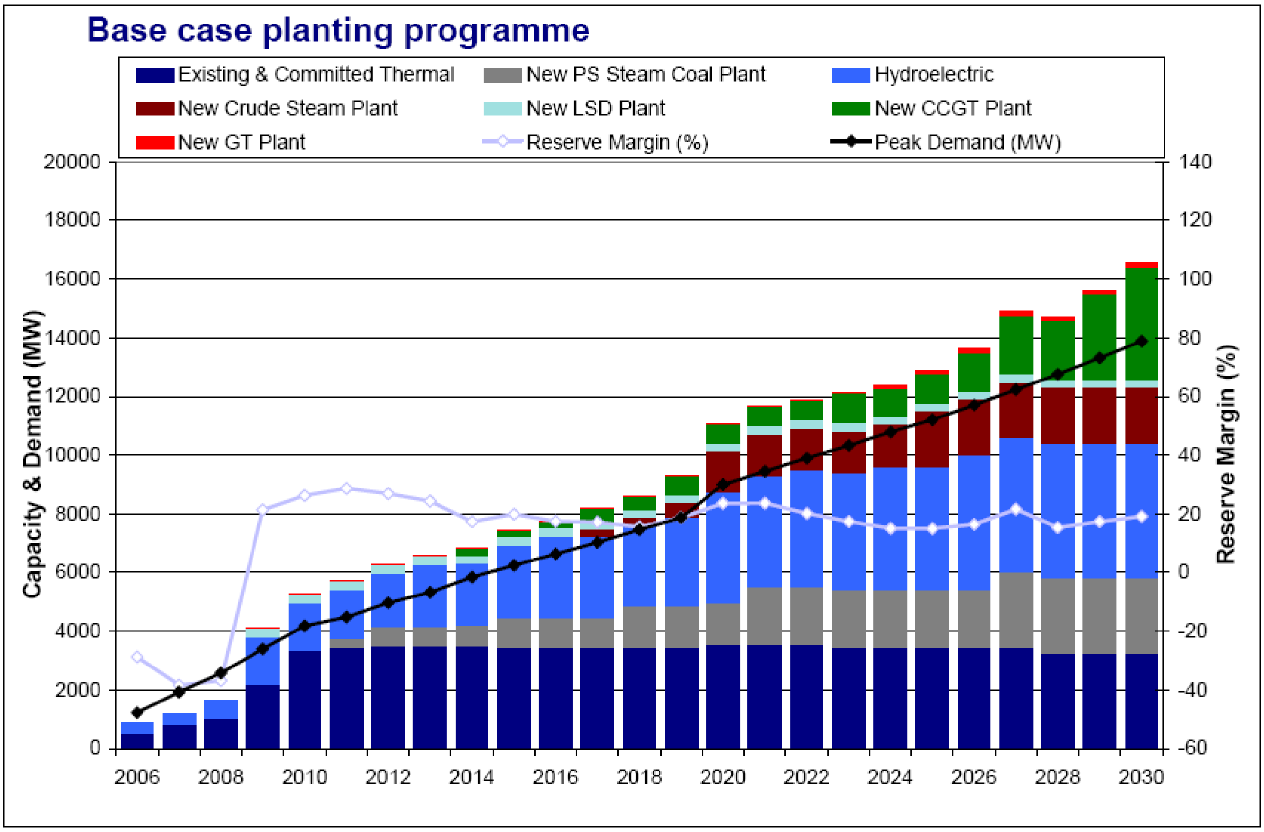

Figure 7.2-1 - Sudan Generation Expansion Plan

The commissioning of short construction duration units (LSD and GT) in 2009 boats the installed capacity to a level compatible of a good reliability of the power supply. This is demonstrated by the margin ratio which jumps to 30% in 2009.

The development of cost effective coal-fired capacity at Port Sudan being limited by the Grid capability, gas oil-fired CCGT, while being more expensive, become significant contributors to the generation mix (first commissioning in 2014).

Finally, all identified HPP candidates are included in the generation expansion plan by 2026.

8. REVIEW OF THE EXISTING TRANSMISSION MASTER PLAN

- Analysis of the existing Transmission Master Plan: See Long Term Power System planning study - Draft Transmission planning report - November 2006

Existing transmission system in 2006

The existing transmission system consists of 2003 km of transmission lines, of which 830 km are at 220 kV level, 880 km at 110 kV level, 293 km at 66 kV levels respectively. There are a total of 32 substations in the system, of which 9 are at 220 kV level, 22 include 110 kV level (9 around Khartoum), 7 include 66 kV level. Isolated networks are in distribution.

Committed Transmission Installations by 2007-2009

Connection of new dam

A new voltage level - 500 kV - is about to be implemented, with the commissioning of Merowe dam (1 250 MW), to evacuate its generation to the 220 kV network towards east (Atbara, north of the present 220 kV backbone) and south to the future 220 kV Khartoum ring (in Markhiat and Kabashi 500/220 kV substations).

Network reinforcement

The reinforcement by 2008/2009 of Khartoum 110 kV ring with a 220 kV double circuit loop closed by the 500 kV circuit from Markhiat to Kabashi, with 4 new 220/110 kV substations, and the corresponding 110 kV extension.

Network extension

The 220 kV system will be extended:

- to the north-east to Port-Sudan (450 km of 220 kV double circuit),
- along the White Nile, from Khartoum to Rank (220 kV double circuit, loop closed with the line Rank - Roseires),
- to the south-east, to the Ethiopian border, via Gedaref,
- to the north-west, along the Nile river, downstream Merowe.

The master plan report shows that between the year 2006-2009 the following will be constructed.

Voltage level	Length
110 kV	121 km
220 kV	3535 km
500 kV	611 km
Total	**4267 km**

Transmission master plan

(See **Table 7.2-1 - Transmission Master plan - 500 kV, Table 1.1-2 - Main characteristics of the demand** , **Figure 7.2-1 - Load Flow Results peak 2015)**.

The master plan does not provide a detailed planning of the new equipment commissioning after 2009, although load-flow results are displayed for years 2015, 2020 and 2030.

The main extensions appearing on the 2015 load-flow scheme are:

- A 500 kV double circuit transmission line from Port-Sudan (about 1 000 MW exportation to Khartoum from coal-fired steam plants) to Kabashi, via Atbara, doubling therefore the 220 kV double circuit from Port-Sudan to Khartoum, via Kabashi;
- A 500 kV double circuit line from Kabashi to Hasaheisa to supply the Gezirah area;
- A 500 kV single line from High Dal (750 MW) to Merowe;
- An “isolated” 500 kV line from Nyala (west of Fulah) to Rabak via Fulah (with a 500/220 kV substation in the last 2 towns) to evacuate the generation of the new Fulah power plant (450 MW of GT and ST), connected to the 220 kV system in Fulah and Rabak;
- Extension of the 220 kV network in Kordofan and in Darfur;
- Extension of the 220 kV network north of Atbara, from Atbara to Abu Hamed, along the Nile, to connect the hydro plant of Shereik;
- Extension of the 220 kV network in the north along the Nile to Wadi Hal, closed to the Egyptian border.

Khartoum area load still represents half of the system load.

Planned interconnection

The feasibility study for the interconnection project with Ethiopia (194 km of double 230 kV circuit, from Shehedi to Gedaref - maximum export of 200 MW) has been carried out. EEPCO and NEC agreed to complete their interconnection line by February 2008.

500 kV Circuits

	From	To	Length (km)	Number of Circuits	Rating/ct (MVA)	(A)	Conductor Type	Resistance (ohms/km)	Reactance (ohms/km)	Susceptance (nF/km)
Committed										
1	Merowe	Markhiat	363	2	1843	2128	4x280mm2 ACSR (Quad Dove)	0.028	0.276	13.083
2	Merowe	Atbara	210	1	1843	2128	4x280mm2 ACSR (Quad Dove)	0.028	0.276	13.083
3	Markhiat	Kabashi	38	1	1843	2128	4x280mm2 ACSR (Quad Dove)	0.028	0.276	13.083

Table 7.2-1 - Transmission Master plan - 500 kV

220 kV Circuits

From	To	Length (km)	Number of Circuits	Rating/ct (MVA)	(A)	Conductor Type	Resistance (ohms/km)	Reactance (ohms/km)	Susceptance (nF/km)
Existing									
1 Kilo X	Giad	43	2	256	673	400 mm^2 ACSR	0.076	0.403	9.02
3 Giad	Meringan	141	2	256	673	400 mm^2 ACSR	0.076	0.403	9.02
4 Meringan	Sennar	84	2	256	673	400 mm^2 ACSR	0.076	0.403	9.02
5 Sennar	Roseires	228	2	256	673	400 mm^2 ACSR	0.076	0.403	9.02
6 Garri	Eid Babiker	60	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
7 Eid Babiker	Kilo X	14	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
8 Garri	Shendi	120	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
9 Shendi	Atbara	140	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
Committed/Future									
2008 Atbara	Port Sudan	450	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Roseires	Rank	160	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Rank	Rabak	108	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Rabak	Mashkur	108	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Maskur	Jebel Aulia	100	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Jebel Aulia	Giad	36	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Rabak	UmRawaba	224	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 UmRawaba	EL Rahad	80	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 EL Rahad	Obeid	20	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Jebal Aulia	Gamoeia	38	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Gamoeia	Markhiyat	38	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Garri	Free Zone	5	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 Free Zone	kabbashi	26	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2008 kabbashi	Eid Babiker	30	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Singa	Hawata	90	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Hawata	Gedaref	110	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Gedaref	Girba	140	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Girba	Showak	70	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Girba	Kassala	66	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Girba	Halfa	58	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Kassala	Aroma	60	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Atbara	Barbar	36	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Barbar	Alghobosh	25	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Barbar	Shereik	84	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Shereik	Abu Hamad	104	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Merowe	Merowe Town	35	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Merowe Town	Debba	150	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Debba	Dongola	180	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Dongola	Merowe	310	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Dongola	Karma	52	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Karma	Wadi Halfa	275	1	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Obeid	Debebat	85	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Debebat	Abu Zabad	65	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06
2009 Abu Zabad	Fula	117	2	370	972	2 x 240 mm2 ACSR	0.067	0.302	13.06

Table 7.2-2 - Transmission Master Plan – 220 kV

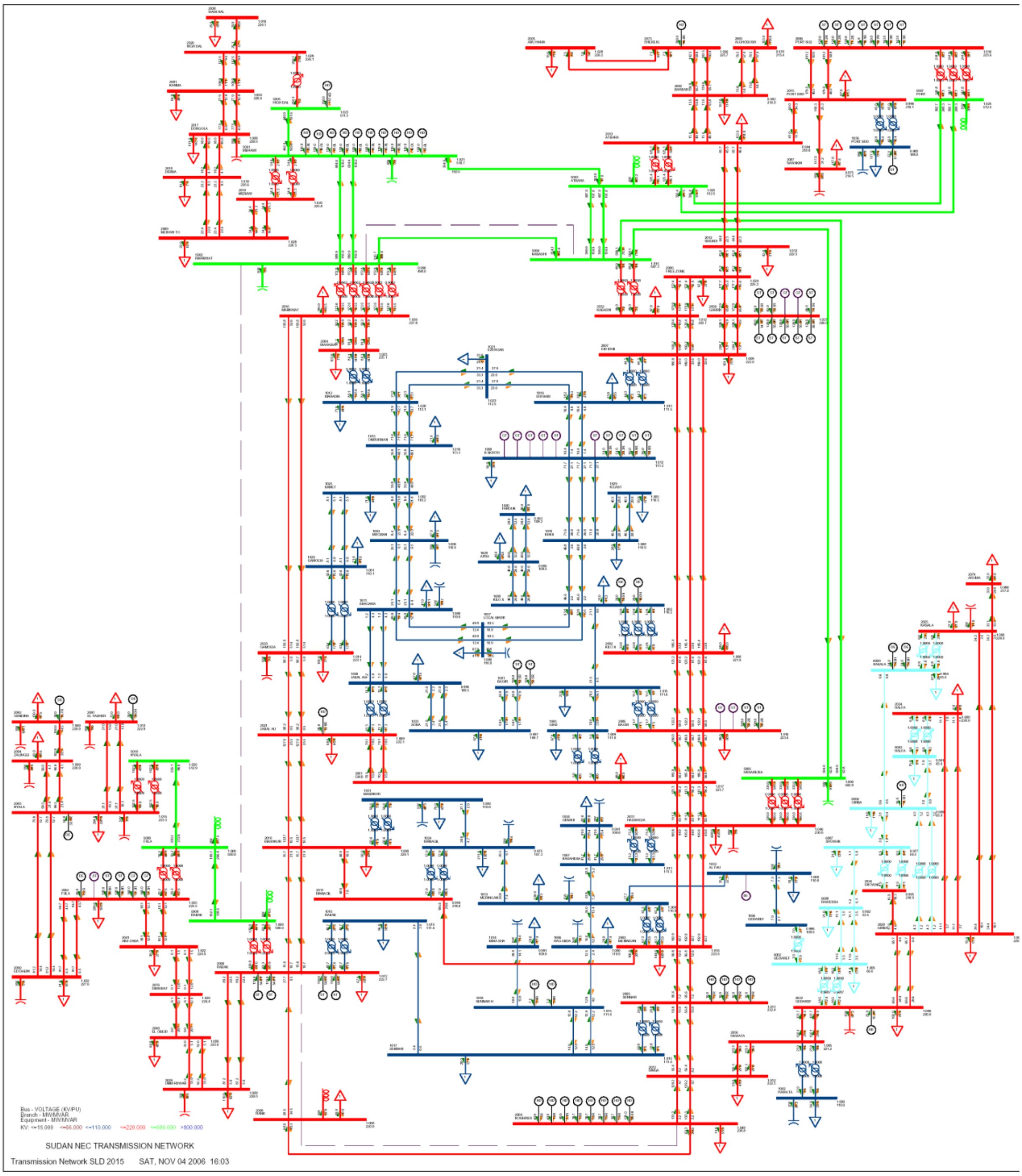

Figure 7.2-1 - Load Flow Results peak 2015

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with participation of:

- EPS (Egypt)
- Tropics (Ethiopia)
- YAM (Sudan)

ENERGY SECTOR PROFILE & PROJECTIONS

VOL 4 - SUDAN

FINAL APPENDIX

June 2007

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1. ISOLATED GRID

State	Date of interconnection to the main grid	Existing & comitted cities' plants	Installed capacity MW	Available capacity MW	Comissionnig date
Red sea	2007				
		Port Sudan station (B)	5.55	3.9	1998/2001
		Port Sudan station (C)	25.5	23.1	1985/2002
		Tokar	2	2	2006/2007
		Total	**33.05**	**29**	
Northern State	2009				
		Karima	9	8	1999/2000
		Dongola	5.6	4.8	1996/2002
		Wadi Halfa	1.8	1.8	1993/1997
		El dabba	6	6	2006
		Wadi Halfa	2	2	2006/2007
		Al Golid	2	2	2006/2007
		Total	**26.4**	**24.6**	
North & South Kordofan States	2009				
		El Obeid	9.5	8.2	1984/1987
		Um Ruwaba	3.2	2.8	1994/2004
		Kadogli	2	2	2004
		Dilling	2	2	2007
		Tendalti	2	2	2007
		Rahad	2	2	2007
		Al Fula	3	3	2007
		Nahood	4	4	2007
		Total	**27.7**	**26**	
South Darfur State	2010				
		Nayala	9.4	8	1985
		Ad Dein	2	2	2006
		Buram	2	2	2007
		Adila	2	2	2007
		Kass	2	2	2007
		Nayala	35	35	2007/2010
		Total	**52.4**	**51**	
Northern Darfur State	2012				
		El Fasher	9.2	6.4	2000
		El Fasher	18.4	18.4	2006/2010
		Total	**27.6**	**24.8**	
Western Darfur State	2014				
		El Geneina	3.1	2.4	1994/2002
		Zalinge	2	2	2006
		El Geneina	26	26	2006/2010
		Total	**31.1**	**30.4**	
Southern States	???				
- Bahr El Jebel State		Juba	5	3.8	1985/2002
		Juba	7	7	2007
- Bahr el Gazal State		Waw	3.6	2.4	1983/2002
		Waw	9	9	2007
- Upper Nile State		Malakal	2.6	2.2	1995/2002
		Malakal	6	6	2007
- Other southern subgrids		Maribi	6	6	2007
		Kangor	2	2	2007
		Nasir	3	3	2007
		Total	**44.2**	**41.4**	

2. DEMAND FORECAST FOR SUDAN – BASE CASE

Future Power & Energy Demand Forecast
Base Case

	Energy GWh	Peak Demand MW	LOAD FACTOR %
2006	8 061	1 475	62%
2007	11 002	1 955	64%
2008	15 015	2 590	66%
2009	20 490	3 433	68%
2010	27 961	4 550	70%
2011	30 063	4 915	70%
2012	32 454	5 309	70%
2013	35 035	5 735	70%
2014	37 820	6 195	70%
2015	40 834	6 693	70%
2016	43 347	7 101	70%
2017	46 013	7 533	70%
2018	48 843	7 992	70%
2019	51 846	8 478	70%
2020	55 012	8 995	70%
2021	57 625	9 399	70%
2022	60 362	9 821	70%
2023	63 227	10 262	70%
2024	66 227	10 723	71%
2025	69 259	11 205	71%
2026	71 674	11 696	70%
2027	74 498	12 208	70%
2028	77 433	12 742	69%
2029	80 484	13 300	69%
2030	85 031	13 883	70%

3. DEMAND FORECASTS FOR THE INTERCONNECTED GRID

	Interconnected Peak Demand				Annual Demand for generation		
Calendar Year	Low case	Base Case	High Case	Load factor	Low case	Base Case	High Case
Jan. to Dec.	MW	MW	MW		GWh	GWh	GWh
2006	1 010	1 223	1 228	62%	5 520	6 684	6 711
2007	1 636	1 927	2 007	64%	9 208	10 846	11 297
2008	2 116	2 577	2 699	66%	12 266	14 938	15 645
2009	2 860	3 396	3 549	68%	17 072	20 271	21 185
2010	3 629	4 179	4 354	70%	22 301	25 681	26 757
2011	3 959	4 478	4 694	70%	24 216	27 390	28 711
2012	4 330	4 969	5 252	70%	26 469	30 375	32 105
2013	4 548	5 322	5 665	70%	27 784	32 512	34 608
2014	4 903	5 843	6 258	70%	29 933	35 672	38 206
2015	5 141	6 244	6 734	70%	31 365	38 094	41 084
2016	5 367	6 629	7 218	70%	32 764	40 468	44 063
2017	5 597	7 029	7 741	70%	34 188	42 935	47 284
2018	5 838	7 456	8 286	70%	35 680	45 569	50 641
2019	6 067	7 868	8 849	70%	37 100	48 113	54 112
2020	6 800	8 995	10 191	70%	41 588	55 012	62 327
2021	7 052	9 449	10 878	70%	43 236	57 932	66 693
2022	7 300	9 898	11 601	70%	44 866	60 833	71 300
2023	7 559	10 337	12 380	70%	46 571	63 686	76 273
2024	7 816	10 786	13 205	71%	48 271	66 613	81 553
2025	8 086	11 205	14 023	71%	49 980	69 259	86 678
2026	8 427	11 704	14 943	70%	51 643	71 725	91 574
2027	8 775	12 231	15 923	70%	53 549	74 639	97 170
2028	9 121	12 736	16 948	69%	55 427	77 394	102 990
2029	9 465	13 315	18 024	69%	57 275	80 572	109 068
2030	9 808	13 883	19 184	70%	60 072	85 031	117 498

4. RESERVOIR CHARACTERISTICS

(Origin: RAPSO modelling)

Reservoir characteristics at Blue and White Nile Sudanese sites

Roseires (1)

	Level	2002		2012		2027		
	Level (m)	Volume (Mm^3)	Area (km^2)	Volume (Mm^3)	Area (km^2)	Volume (Mm^3)	Area (km^2)	Spill capacity (m^3/s)
Dead	465	0	9.1	0	5	0	0	0
	466	13	10.5	13	6	12	1	0
	467	30.1	14.4	28	10	26	4	0
Active	467.7	50.7	18.5	47	14	43	8	6808
	468	61.8	20.6	58	16	53	10	6942
	468.5	83.2	24.5	78	19	71	13	7219
	469	108.8	29	102	24	94	17	7497
	470	172.4	39.7	162	34	149	26	8168
	471	253.2	52.3	238	46	220	37	8788
	472	351.9	67.4	331	60	307	51	9575
	473	469	84.3	443	76	411	66	10253
	474	605	103.4	572	94	532	83	11098
	475	760.4	124.5	720	114	671	102	11892
	476	935.5	147.6	887	136	829	123	12688
	477	1130.8	172.7	1073	160	1004	145	13647
	478	1346.5	199.8	1279	186	1199	170	14558
	478.5	1462.1	214.1	1390	200	1303	183	15071
	479	1583	228.9	1506	214	1413	196	15583
	479.5	1709.2	244.2	1626	229	1527	210	16096
	480	1840.6	260	1752	244	1646	224	16609
	480.5	1877.5	276.3	1883	259	1771	239	17147
	481	2119.7	293	2020	274	1900	254	17685
Sources	HLC(MoI) 2002							

Heightened Roseires (1)

	Level	2002		2012		2027		
	Level (m)	Volume (Mm^3)	Area (km^2)	Volume (Mm^3)	Area (km^2)	Volume (Mm^3)	Area (km^2)	Spill capacity (m^3/s)
Dead	465	0	9.1	0	5	0	0	0
	466	13	10.5	12	6	11	1	0
	467	30.1	14.4	27	10	24	4	0
	467.7	50.7	18.5	46	13	40	7	6808
	468	61.8	20.6	56	15	49	9	6942
	468.5	83.2	24.5	75	19	66	12	7219
	469	108.8	29	98	23	86	16	7497
	470	172.4	39.7	156	33	138	24	8168
Active	471	253.2	52.3	230	44	204	35	8788
	472	351.9	67.4	321	58	286	47	9575
	473	469	84.3	429	74	383	61	10253
	474	605	103.4	555	92	497	78	11098
	475	760.4	124.5	699	111	629	95	11892
	476	935.5	147.6	862	133	777	115	12688
	477	1130.8	172.7	1044	156	943	136	13647
	478	1346.5	199.8	1246	181	1128	160	14558
	478.5	1462.1	214.1	1354	195	1227	172	15071
	479	1583	228.9	1467	209	1331	185	15583
	479.5	1709.2	244.2	1585	223	1439	198	16096
	480	1840.6	260	1708	238	1553	211	16609
	480.5	1877.5	276.3	1836	253	1671	226	17147
	481	2119.7	293	1970	269	1794	240	17685
	482	2458.3	327.7	2290	302	2092	271	17686
	483	2832.1	363.3	2645	335	2424	303	17688
	484	3241.2	398.6	3035	369	2792	335	17689
	485	3685.5	433.4	3461	403	3196	366	17690
	486	4163.2	465.7	3922	434	3636	396	17691
	487	4673.6	498.6	4415	466	4107	427	17692
	488	5217.3	532.2	4941	498	4612	458	17693
	489	5795.1	566.9	5500	532	5149	490	17694
	490	6408.3	603.0	6095	567	5719	524	17696
Sources	M&M97 (95 satlte) >481m, KEANE Feb 2003; MoI 2003							

Sennar (1)

	Level (m)	Volume (Mm^3)	Area (km^2)
Dead	411.9	0.84	0.89
	412	0.85	0.9
	412.3	1.07	1.4
	412.6	1.45	2.1
	413	2.3	3.2
	413.3	3.3	4.3
	413.6	4.6	5.7
	414	7	7.8
	414.3	9.5	9.6
	414.6	12.6	11.7
	415	17.6	15.6
	415.3	22.4	17.8
	415.6	27.9	20.8
	416	36.9	25.3
	416.3	44.8	28.9
	416.6	53.9	33
	417	67.9	38.8
Active	417.3	80.1	43.5
	417.6	93.7	48.6
	418	114.2	55.8
	418.3	131.7	61.7
	418.6	150.9	67.8
	419	179.5	76.6
	419.3	203.3	83.5
	419.6	229.3	96.9
	420	267.6	101.3
	420.3	299	109.4
	420.6	340	117.9
	421	382.5	129.9
	421.3	422.9	139.4
	421.7	481.2	152.6
Sources	HLC(MoI) 2002		

Jebel Aulia

	Level (m)	Volume (Mm^3)
Minimum	372.5	-
Maximum	377.4	3 890
Sources	M&M 1996-7	

Reservoir calculation based on separate filling and emptying characteristics (to allow for bank storage effects) as measured by rising or falling levels at Melut (just upstream of the reservoir)

Note: 1 Throughout the flood season each year reservoir drawn down to minimum level for flushing and then refilled on the back end of the flood.

Sudanese power plant principal characteristics on the Blue & White Niles

	Roseires				Sennar				Jebel Aulia	
	Existing		Heightened + Dinder		Existing		With extension			
Maximum capacity (MW)	7 x 40	280	7x40 + 3x45	415	2 x 7.5	15	2x7.5 + 4x12.5	65	40 x 0.72	28.8
Maximum discharge (m3/s)	1 032		1 538		117.0		524		692	
Level / Energy coefficient : -	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)
	467	5.9156	-	-	417	9.3971	417	10.4457	374.5	77.5466
	469	5.4526	-	-	418	8.7667	418	9.5947	375.5	40.9871
	471	5.0504	471	5.2245	419	8.2188	419	8.9045	376.5	29.1956
	473	4.6969	473	4.8317	420	7.7348	420	8.3236	377.4	24.0344
	475	4.3917	475	4.4955	421	7.3054	421	7.7819		
	477	4.1227	477	4.1823						
	479	3.8915	479	3.8883						
	481	3.6845	481	3.6452						
			483	3.4426						
			485	3.2808						
			487	3.1165						
			489	2.9581						
			490	2.8854						
Sources	NEC		M&M 1997		NEC		FROM Sep 2000		VATECH 2000	

Power plant characteristics at Main Nile Sudanese sites and High Aswan

	Sabaloka		Shereiq		Dagash		Merowe		Kajbar		Low Dal		High Aswan	
Maximum capacity (MW)	8 x 15	120	6 x 52.5	315	8 x 35.6	284.8	10 x 125	1 250	5 x 50	250	8 x 42.5	340	12 x 175	2 100
Maximum discharge (m3/s)	1711		1942		2100		3105		1824		2099		4211	
Level / Energy coefficient : -	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)
	371	21.4082	340	7.7555	323	7.3720	285	3.4243	208	12.8832	189	11.5687	147	3.4591
	372.5	16.8677	341	7.3879			288	3.1063	210	10.6896	193	8.5916	153	2.9887
	374	13.2936	342	7.0315			291	2.8594	212	9.1285	197	6.8027	159	2.5577
			343	6.6196			294	2.6539	213	8.5058	201	5.3348	165	2.2514
							297	2.5112					171	2.0476
							300	2.2945					177	1.8080
													183	1.6917
Sources	Acres 1993 Table D7		IHP 1999		Acres 1993 Table D7		LI 2001		Scott Wilson 2006, etc.		Acres 1993 Table D7		Scott Wilson 2006, etc.	

Reservoir characteristics at Main Nile Sudanese sites and High Aswan

Sabaloka		
Level (m)	Volume (Mm^3)	Area (km^2)
365.9	28.15	14.07
366	28.16	14.08
368	86.78	29.31
370	190	51.61
372	334.76	72.38
374	506.42	85.83
Source	MIHP 1974 p11	

Shereiq			
	Level (m)	Volume (Mm^3)	Area (km^2)
D	330	321.94	44.68
e	335	740.47	118.39
a	337	973.62	148.48
d	339	1292.8	181.16
A	340	1496.1	205.75
ct	341	1699.3	230.34
ive	343	2202.1	279.87
IHP Shereiq DPR 1999			

Dagash		
Level (m)	Volume (Mm^3)	Area (km^2)
323	100	250
Acres 1993 Table D7		

Merowe (1)							
		2002		2012		2027	
	Level (m)	Volume (Mm^3)	Area (km^2)	Volume (Mm^3)	Area (km^2)	Volume (Mm^3)	Area (km^2)
	240	0	0	0	0	0	0
	249.9	0	0	0	0	0	0
D	250	3	1	2	0.7	1	1
e	260	143	35	130	31.6	83	22
a	265	389	65	355	60.2	247	46
d	270	817	108	752	101.6	560	83
	275	1520	174	1413	166	1114	142
	280	2570	256	2438	246.6	2008	219
	284.9	4119	353	3903	343.3	3324	312
A	285	4120	354	3904	343.4	3325	312
c	290	6170	476	5915	464.9	5173	432
ti	295	8900	620	8588	609.7	7683	579
v	298	11050	724	10570	715.8	9576	691
e	300	12450	803	12087	803	11066	803
Hydroprojekt 99 Fig 3.1				From Lahmeyer International			

Kajbar		
Level (m)	Volume (Mm^3)	Area (km^2)
207.9	100	2
208.2	257	8
209	271.1	26.15
212	290	33
212.3	291	35
213	300	40
IHP 1997		

Low Dal		
Level (m)	Volume (Mm^3)	Area (km^2)
180	45	14
183	100	24
187	246	52
190	456	87
193	780	133
197	1420	195
200	2120	277
201	2471	306
Gibb 1978 Table 1.16		

High Aswan			
	Level (m)	Volume (Mm^3)	Area (km^2)
	120	5 200	450
D	125	7 800	600
e	130	11 300	749
a	135	15 600	988
d	140	21 200	1 242
	145	28 300	1 589
	147	31 860	1 738
A	150	37 200	1 962
c	155	48 100	2 414
t	160	61 500	2 950
i	165	77 900	3 581
v	170	97 600	4 308
e	175	121 300	5 168
	180	149 500	6 118
	183	169 420	6 752
FAO & Scott Wilson			

Note: 1 Throughout the flood season each year reservoir drawn down to minimum level for flushing and then refilled on the back end of the flood.

Reservoir characteristics at Bahr Jebel and Atbara Sudanese sites

Bahr Jebel												Atbara						
Fula (Alt I)			Shukoli			Lakki			Bedden			Rumela			Khashm el Girba [1]			
Level (m)	Volume (Mm^3)	Area (km^2)	Level (m)	Volume (Mm^3)	Area (km^2)	Level (m)	Volume (Mm^3)	Area (km^2)	Level (m)	Volume (Mm^3)	Area (km^2)	Level (m)	Volume (Mm^3)	Area (km^2)		Level (m)	Volume (Mm^3)	Area (km^2)
615.9	509.9	13.6	557.9	92.9	8.7	532.9	114.9	14.59	503.9	1774	12.3	508.4	729	29.9		440	0	1
616	510	13.7	558	93	8.8	533	115	14.6	504	1775	12	508.5	730	30		445	5	2
617	547	14.4	558.5	97.4	9.05	533.5	122.5	15	505	1957	13.3	509	770	33	D	450	12.5	2
618	587	14.9	559	102.9	9.3	534	135	15.75	506	2053	13.9	510	860	36	e	455	22.5	3
619	627	15.4	559.5	107	9.5	534.5	142.5	16.45	507	2168	14.5	511	950	39	a	460	37.5	4
620	660	15.9	560	112.5	9.85	535	147.5	17.15	508	2299	15	512	1050	42	d	461	42.5	6
621	700	16.4							509	2426	15.7	513	1150	46		462	50	7
622	730	16.8							510	2522	16.3	514	1250	50		463	60	8
												515	1350	54	A	463.5	65	9.4
												516	1500	58	c	464	70	10.8
												517	1600	62	t	465	90	19
												517.5	1660	66	i	467.5	165	35
															v	470	308	63
															e	473.6	580	95
																474	657	100
Source	Bonifica 1983 Fig 4.15		Bonifica 1983 Fig 4.17			Bonifica 1983 Fig 4.19			Bonifica 1983 Fig 4.21			Sogreah 1982 p A1.5			Acres(1993) Fig C2.4d			

Note: 1 Throughout the flood season each year reservoir drawn down to minimum level for flushing and then refilled on the back end of the flood.

Sudanese power plant principal characteristics on the Bahr Jebel & Atbara

	Fula (Alt I)		Shukoli		Lakki		Bedden	
Maximum capacity (MW)	8 x 90	720	4 x 52.5	210	4 x 52.5	210	4 x 100	400
Maximum discharge (m3/s)	1400		1043		1043		1166	
Level / Energy coefficient : -	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)
	616	2.0844	558	5.2885	533	5.2885	504	3.3560
	618	2.0120	559	5.0638	534	5.0638	506	3.1810
	620	1.9443	560	4.8371	535	4.8371	508	3.0232
	622	1.8780					510	2.8632
Sources	ACRES 1993 Table D7							

	Rumela		Khashm el Girba Kaplan		Khashm el Girba Pump	
Maximum capacity (MW)	3 x 10	30	2 x 5.3	10.6	3 x 2.54	7.6
Maximum discharge (m3/s)	86		32.2		116	
Level / Energy coefficient : -	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)	Level (m)	Coefficient (m^3/s/MW)
	509	3.5754	464	3.7419	468	39.8696
	513	3.1839	467	3.3525	470	25.6214
	517	2.8667	470	3.0418	472	19.4068
			474	2.7261	474	15.2504
Sources	M&M/Gibb 1979		Voith Riva 99			

5. EVAPORATION DATA

(Origin: RAPSO modelling)

Evaporation net loss (mm) at Sudanese reservoir sites

Site	Roseires	Jebel Aulia	Sabaloka	Kashm el Girba	Shereiq	Merowe		Kajbar	Low Dal
Elevation (masl)	481	377.4	374	474	343	300		212.3	201
Jan	180	189	226	174	174	174	197	174	137
Feb	185	235	241	204	179	179	222	179	167
Mar	227	233	313	242	233	233	295	233	267
Apr	221	222	330	248	255	255	331	255	319
May	189	229	326	258	295	295	365	295	380
Jun	63	225	306	238	291	291	340	291	405
Jul	-28	118	245	126	288	288	314	288	412
Aug	-26	115	189	81	285	285	303	285	408
Sep	20	135	216	162	270	270	317	270	347
Oct	125	152	264	183	251	251	307	251	278
Nov	157	174	252	188	198	198	231	198	401
Dec	167	171	220	183	167	167	199	167	158
Annual	1479	2197	3127	2286	2886	2886	3421	2886	3679
Source	M&M 1997	M&M 1997	MIHP 1974	Water resources of the Sudan 1977	IHP 1999	Monenco '93	Hookey '04	IHP 1999	Scott Wilson