United Republic of Tanzania

POWER SYSTEM MASTER PLAN
2012 UPDATE

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LIST OF ABBREVIATIONS

AfDB	African Development Bank
BoT	Bank of Tanzania
CCM	Chama Cha Mapinduzi
COSS	Cost of Service Study
DSM	Demand-side Management
EAPMP	East Africa Power Master Plan
EEPCo	Ethiopia Electric Power Company
EPC	Engineering, Procurement and Construction Contract
ERT	Energizing Rural Transformation
ESKOM	Electricity Supply Company (RSA)
EWURA	Energy and Water Utilities Regulatory Authority
FYDP	Five Years Development Plan
GoT	Government of the United Republic of Tanzania
GWh	Gigawatt-hours = 1,000,000,000 watt-hours
GWh	Gigawatt-hours = 1,000,000,000 watt-hours
IDC	Interest During Construction
IPP	Independent Power Producer
IPTL	Independent Power Tanzania Limited
KPLC	Kenya Power and Lighting Company
kWh	Kilowatt-hours = 1,000 watt-hours
LTPP	Long Term Plan Perspective
MCA-T	Millennium Challenge Account Tanzania
MEM	Ministry of Energy and Minerals
MKUKUTA	Mkakati wa Kukuza Uchumi na Kupunguza Umasikini Tanzania
MKUZA	Mkakati wa Kukuza Uchumi Zanzibar
MoF	Ministry of Finance
MPEE	Ministry of Planning, Economy and Empowerment
MPIP	Medium-Term Public Investment Plan
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Megawatt = 1000,000 watts
MWh	Megawatt-hours = 1,000,000 watt-hours
NBS	National Bureau of Statistics
NDC	National Development Corporation
NGO	Non-Governmental Organisations
POPC	President’s Office Planning Commission
PPA	Power Purchase Agreement

PPP	Public Private Partnership
PSMP	Power System Master Plan
R&D	Research and Development
REA	Rural Energy Agency
REB	Rural Energy Board
REF	Rural Energy Fund
SADC	Southern African Development Community
SAPP	South African Power Pool
SEZ	Special Economic Zone
SME	Small and Medium Enterprises
SNC	SNC-Lavalin International Inc.
SPP	Small Power Producer
SVC	Static Var Compensator
TANESCO	Tanzania Electric Supply Company Limited
TANWAT	Tanzania Wattle Company
TEDAP	Tanzania Energy Development and Access Project
TPC	Tanzania Plantation Company
TPDC	Tanzania Petroleum Development Corporation
URT	United Republic of Tanzania
USD	United States Dollar
WVES	Way Leave Village Electrification Study
ZECO	Zanzibar Electricity Corporation
ZTK	Zambia – Tanzania – Kenya Interconnector

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ACKNOWLEDGEMENT

The 2012 PSMP update is a joint effort by intergovernmental institutions which spent six months working hard and tirelessly to come up with this review. The entire work was carried out by a team of experts from Ministry of Energy and Minerals (MEM), President's Office, Planning Commission (POPC), Ministry of Finance (MoF), National Bureau of Statistics (NBS), Rural Energy Agency (REA), Tanzania Electric Supply Company (TANESCO), Tanzania Petroleum Development Corporation (TPDC) and Energy and Water Utilities Regulatory Authority (EWURA). The work was carried out from September, 2012 to February, 2013. Technical Team and their institutions were:

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CHAPTER ONE

1 INTRODUCTION

1.1 Purpose and Scope

The 2012 Power System Master Plan (PSMP) reflects and accommodates recent development in the economy, including development in the gas sub sector as well as government policy guidelines. The policy guidelines include, among others the desire by the government to accelerate economic growth through the Vision 2025, MKUKUTA and the Five Year Development Plan (FYDP). The FYDP targets to improve key infrastructure networks, including power infrastructures to attain low cost energy service that will allow more inflow of foreign direct investment (FDIs) to Tanzania.

The FYDP targets to increase per capita electricity consumption from 81kWh in 2011/12 to 200kWh by 2015/16 through increased generation capacity alongside accelerated electrification program. This program has been formulated with the purpose of increasing electrification level from the current 18.4 percent to 30 percent by 2015/16. This implies connecting 250,000 new customers per annum for five years from 2013 to 2017.

The fundamental objective is also to attain stable power supply in order to achieve Economic Growth, Energy Security and Environmental Protection. The government of Tanzania set the maximum target to reduce poverty by achieving high economic growth, which could be achieved through a stable and efficient power system.

The overall objective of the Plan is to re-assess short-term (2013 – 2017), mid-term (2018 - 2023) and long term (2024 - 2035), generation, transmission plans requirements and the need for connecting presently off-grid regions, options for power exchanges with Ethiopia (through Kenya), Zambia, Uganda, Rwanda, Burundi and Mozambique, and increased supply of reliable power. While the short-term plan requires immediate decision and actions, the mid – to longer terms plan require coordinated planning, project development studies which ensures that future supply utilises the least cost projects, consistent with sound planning criteria and addresses national interests.

This report has been prepared drawing inference on specific data items or detailed procedures in the previous 2008 PSMP and the subsequent 2009 update studies. In 2008, a Power System Master Plan (PSMP) was developed by the consultant SNC-Lavalin of Canada for the Government of Tanzania, through TANESCO, to provide a fundamentally new plan to guide the development of the power system in Tanzania for the next 25 years. The study provided a detailed assessment of load demand projections, available options for meeting the demand and requirements for a new higher voltage backbone transmission system for the country.

The Plan was firstly updated in 2009 by MEM and TANESCO with the technical support from the SNC- Lavalin consultant which review the progress and challenges encountered during the first year of implementation. The 2012 update was conducted by technical staffs from MEM, TANESCO, President's Office - Planning Commission, Ministry of Finance, TPDC, EWURA, REA and NBS. The Plan has also incorporated comments from various stakeholders. The Update covers the following main components:

a) Revised load forecast based on the current situation and updated expectations;
b) Reassessment of the short-term, mid-term and long-term generation plan;
c) Update of the transmission plan to reflect the update in plans for connecting presently isolated regions and increased generation capacities; and
d) Economic and financial analysis

1.2 Scope of the work

The following five primary components underlie the 2012 update study:

a) Confirmation of planning criterion;
b) Load forecast update;
c) Generation plan update, including updating and confirming data on all generation sources, existing and future options;
d) Transmission plan update, including ongoing additions and reinforcement to the existing system, plans for interconnecting presently isolated areas, and options for import from neighbouring countries; and
e) Preparing a new PSMP Update report.

1.3 Information collected for the PSMP Update

The following information, was used for the 2012 Update study

Load forecast data

a) Historical to date peak demand at branch, sub-station, grid and national levels;
b) Historical to date energy sales by category of load and by region and substation; and
c) Historical to date level of losses, energy production, energy purchases and energy exports;
d) The information on the accelerated electrification scheme and its implementation status;
e) Current and recent electricity forecasts
f) Historical performance of the national economy up to year 2011; and
g) Information on expectations for the growth of the national economy and the individual sectors.

Hydrological data

a) Existing hydrological data from1940 to date reference hydrology from TANESCO;
b) Data on reservoirs and hydro plants from TANESCO;
c) All meteorological/synoptic records to date from The Tanzania Meteorological Agency;
d) All stream flow and reservoir water level records to date from Ministry of Water; and
e) Estimates/studies of water abstraction amounts – including information from the Ministry of Water.

System planning

a) Existing system operating and maintenance data;
b) Fuel types, prices, volume and characteristics;
c) Generation and transmission expansion planning criteria used in previous studies;
d) Inventory and characteristics of existing and committed units including hydro units, simple cycle gas turbine units, combined cycle units and others (solar, wind, etc.); Inventory and characteristics of transmission facilities including transmission lines and substations;
e) Transmission system current configuration and short- term plans; and
f) Previous study reports on identified new generation options and transmission.

The overall update program consisted of data update and validation, analyses and report writing. The detailed scope of work was as follows:

Load forecasts

a) Initial update of load forecast based on updated consumption data;
b) Review of updated load forecast;
c) Confirmation of schedule for interconnection of presently isolated regions; and
d) Adjustments and finalization of forecast study.

Generation planning

a) Review / update and finalize generation and planning criteria;
b) Update hydro generation study using updated hydrological records;
c) Review and update list of new generation candidates, and finalizes plant characteristics for use in the plan; and
d) Prepare preferred new generation plan, based on new base case forecast, short term generation commitments, retirement dates.

Transmission planning

a) To distribute regional load into respective substations;
b) Update PSS/E files of system configuration and characteristics for 2012 conditions;
c) For the new base case generation plan, the year 2015 and 2020 were considered for the mid-term and 2035 for long term; and
d) Prepare estimates of investment costs.

1.4 Factors considered in the Update plan

The update plan has taken into account a broad spectrum of new information and planning criteria. Primary factors affecting the results, as compared with the 2009 PSMP update, include:

Load forecast

a) The impact of current level of losses on the forecast;

b) Accelerated electrification program - 250,000 new customers annually for five years from 2013 to 2017 to reach the target of 30 percent connectivity by 2015/16;
c) The target of reaching 75 percent electrification of households by 2035;
d) Program for interconnection of remaining isolated systems;
e) Emerging of high demands of power (Mtwara corridor) and Mining activities; and
f) Average household size of 8 persons.

Generation options

a) Availability of resources to meet projected demand (eg. hydro, gas, coal, wind etc);
b) Lead time of projects (eg hydro projects have very long lead time);
c) Contracts/Retirement of project; and
d) Capital cost of the project

Transmission Plan

a) Concentrating on 220 and 400 kV backbone voltage; and
b) Developing transmission plans in every interval of five years, while focusing in introduction of 400 kV where necessary, instead of defining requirements for the whole horizon up to year 2035.

CHAPTER TWO

2 POWER DEMAND FORECAST

2.1 Background

This section provides estimate of the power demand in Tanzania over the study period from 2011 to 2035. The objectives of the load forecast activity were to provide set of forecasts for both short, mid and long terms for Tanzania Interconnected Power System, and the isolated systems. The forecast then forms the basis in the planning of generation and transmission facilities. This forecast study explicitly account for changed economic background, government development objectives in the power sector in addition to specific issues concerning the power demand.

2.2 Issues related to the load forecast

Current level of losses: the level of losses in 2010 was 25 percent, split as 5.3 percent for transmission while distribution losses (commercial or non-technical) were 19.7 percent. Plans to reduce these losses and how they are provided for in the forecast will affect the overall generation requirements both in the short, mid to longer term of the forecast.

New major loads in Tanzania: as for the previous forecast study, the mining and industrial loads growth continues to play a strong drive in the load growth in Tanzania. The development of mining and industries properties usually implies the sudden addition of major loads to the sector. A significant issue in planning is the combination of size, timing and uncertainty of these loads. The load forecast will identify the mining and industrial loads and assess the likely impact on the forecast of the uncertain additions.

Rate of electrification: There is a strong determination by the Government to accelerate electrification in Tanzania. The Government is targeting 30 percent connectivity by 2015, involving connection of 250,000 new customers per annum starting 2013 to 2017. The Rural Energy Policy, and the Tanzania Energy Development and Access Expansion Program (TEDAP) will serve to guide the levels of rural electrification. So far REA has been actively participating in rural electrification mainly in grid extension. Other rural electrification initiatives include; electrification of villages that will be affected by the 400kV Backbone transmission line, MCC funded electrification projects in seven regions (Morogoro, Iringa, Mwanza, Kigoma, Mbeya, Tanga and Dodoma) and electrification expansion program under ORIO project in Mpanda, Ngara and Biharamulo.

Interconnection of isolated systems: The update load forecast has assessed the possibility and timing for the interconnection of the isolated regions/systems into the main grid system. These efforts are well in line with the forecast to accelerate electrification in Tanzania by connecting the remaining six regions (Ruvuma Kigoma, Kagera, Rukwa, Lindi and Mtwara) by 2019. The prime drivers to interconnecting the isolated regions are mainly to provide adequate and reliable power, and relieve the country from costly diesel generation.

Number of persons per household: Household size is critical in load forecast as it is used to determine specific consumption and degree of electrification. This plan has used 8 persons per household. The choice of 8 persons is driven by the fact that the customers of electricity are counted basing on the number of houses connected with electricity meter. In most parts of Tanzania particularly in urban areas, it is common to observe one house being occupied by more than five households. It is also common to see a number of separate small houses (hut) in one compound each occupied by different household but all sharing one connection.

Tariffs: Economic theory suggests that the consumption of a good will decrease as the selling price of that good is increased. There are two practical difficulties in taking into account this concept: (i) the price elasticity of demand for electricity is not known for Tanzania and an estimate would need to be made based on experience elsewhere and (ii) the increase in tariffs is the purview of EWURA.

Sections 23(2) and 24(2) of the Electricity Act, 2008 directs EWURA to make amendments or review tariffs charged by a licensee once in every three years to allow price stability in the electricity sub sector in the determination of tariffs. EWURA based on those guiding factors is taking into account the Cost of Service Study to provide multi-year tariffs that are based on prudent costs.

EWURA has developed a Rate Setting Methodology that recommends principles to be adopted for the determination of tariffs in generation, transmission, distribution and supply segments of the electricity sub sector. In the generation and transmission segments, a forward looking approach is to be applied as opposed to historical cost approach as previously used. The recommended approach considers the determination of efficient costs necessary to meet the existing and future loads with the resulting capacity and energy charges linked to the efficient expansion of the network. Furthermore, the use of a forward looking approach in the determination of costs and relevant tariffs in the distribution and supply segment will be applied. The estimation of efficient capital expenditure will be based on the expansion path for the segment whilst efficient operating and maintenance expenditures will be estimated by the Reference Utility Model.

2.3 National economy

Highlights of the economy

The real GDP has recorded an average growth rate of 6.9 percent over the period of 2001 to 2011. Growth slowed down in 2009 to 6.0 percent, lower than 7.4 percent recorded in 2008, on account of the negative impacts of the global financial and economic crisis. However, the growth in real GDP bounced back to 7.0 percent in 2010 and slowed down again in 2011 to 6.4 percent following the impact of erratic power supply which affected particularly manufacturing and trade sub sectors as well as the spill over of the Euro Zone debt crisis. Consistent with rapid increase in mobile phone usage, the highest growth continued to be registered in the communication sub activity, which grew at 19.0 percent in 2011. Other sectors that recorded higher growth in 2011 were financial intermediation (10.7 percent); construction (9.0 percent); and trade (8.1 percent). The economy is however expected to pick up in the medium term following Government initiative to stabilise power supply and implement development projects as outlined under FYDP. The total GDP in 2011 at current market prices reached TSh 37,532,962 million or approximately equivalent to Tsh. 869,436.3 per capita income.

On sector by sector, the growth rate in agricultural, hunting and forestry economic activities was 3.6 percent in 2011 compared to 4.2 percent in 2010. The slowdown in growth was mainly due to unfavourable weather conditions during the 2009/10 season which affected crop production. Industry and construction economic activities grew by 6.9 percent in 2011 compared to 10.2 percent in 2010. The decline in growth rate was caused by the low growth in all sub activities due to lack of reliable power supply. In particular, the growth rate of electricity and gas sub activities decreased drastically to 1.5 percent in 2011 compared to 10.2 percent in 2010. The decrease was due to shortage of rain which led to decline in water levels in the main hydropower dams of Kihansi and Mtera; increase in human economic activities that are detrimental to the sources of water in the power generation dams; delapidated power plants; and temporary clossure of gas power plant for maintenance. The growth rate of services economic activities was 7.9 percent in 2011 compared to 8.2 percent in 2010. This was due to slowdown in growth in all sub activities except financial intermediation, administration and education sub-activities. The figure below summarises the GDP growth over the period 1999 – 2011.

Figure 2- 1: Historical Gross Domestic Product (GDP)

Inflation

Between 1999 and 2007, annual inflation has been at single digit averaging at 5.8 percent during that period. However, in 2008 and 2009, inflation reached double digits of 10.3 percent and 12.1 percent, respectively. These spikes of high inflation were due to global food and energy crises and drought in neighbouring countries. The overall annual average inflation rate eased to 5.5 percent in 2010 and picked up again to double digit of 12.7 percent in 2011 on account of food shortage in the Eastern Africa region; increase in electricity tariffs; increase in the cost of production associated with usage of expensive thermal energy; and continued increase of fuel price in the World Market.

Food is the main contributor to CPI, accounting for 47.8 percent of the total CPI basket, followed by transport (9.5 percent) and energy (9.2 percent.) This shows that food prices, fuel prices and energy are very significant in the determination of the inflation trend. The vagaries of weather and energy supply have a bearing on inflation. Given the fact that global demand for fossil fuel is expanding continuously, it is quite likely that inflationary pressures due to energy costs will continue to be felt. Domestic supply bottlenecks, particularly due to drought and poor infrastructure, also contribute to inflationary pressures.

Economic Outlook

The review of leading indicators of growth such as electricity generation, production and consumption based tax revenues, importation of industrial raw materials, and exports of manufactured, mineral and agricultural commodities have shown positive progress during the first half of 2012. Given such performance of those leading indicators, coupled with continued efforts to stabilize power supply and implementation of the FYDP I and other economic policies, the overall performance of the economy in 2012 and beyond is expected to remain buoyant. In the medium-term, growth is expected to pick up supported by prospects of increase in FDI particularly in oil and gas explorations, continued implementation of infrastructure projects, favourable weather conditions, and stability in power supply among others.

Long Term Perspective

Tanzania’s long-term growth potential is high, as the country begins to make full use of its resources and expands from a comparatively small market base. The availability of supporting infrastructure is a key factor to accelerating the pace of growth of modern sectors of the economy. It is however worth to note that much of Tanzania’s infrastructure, such as roads, water supply, power system and telecommunication facilities, requires considerable capital investment for rehabilitation and expansion to meet new demand.

The Tanzania long-term development plan is articulated in the “Tanzania Development Vision 2025”. The Vision 2025 projects a growth of 8 percent of the economy annually by 2025. The PSMP update has taken into consideration the “Vision 2025” and is aimed at increasing power capacity at a rate of 15 percent per annum in order to support the economic development envisaged in “Vision 2025”. Likewise in developing this forecast, the newly Tanzania Five Year Development Plan 2011/12 to 2015/16 has been considered. The key output/target of the FYDP is to increase electricity generation capacity from the current 1117 to 2,780MW and increase consumption from the current

81 kWh per capita (using current population of 42 million) to 200kWh (the minimum for Low Income Countries - LIC).

The government aims to transform agriculture to be the backbone of the economy, as it generates reasonably high incomes and ensures food security and food self-sufficiency. Currently, the sector depends mainly on rainfall and technology is characterized with low mechanization. Transformation of the sector is planned to be achieved through implementation of *Kilimo Kwanza* Resolution embarked in June 2009, SAGCOT and ASDP. However, dependence on agriculture will be reduced with an overall objective of having a diversified and semi-industrialized economy with a substantial industrial sector comparable to mid-income countries.

On the other hand, the Mini-Tiger Plan 2020 proposes to accelerate the economic growth to 8-10percent from the current 6-7 percent by adopting the Asian Economic Development Model. The Model is focusing on employment creation by attracting Foreign Direct Investment (FDI) and promoting exports by developing Special Economic Zone (SEZ). Specifically, it sets the following targets for 2020:

a) GDP to be growing at an average of 8-10 percent and reach $40 billion;
b) Exports to be expanded from $1.1 billion to $20 billion;
c) Per-Capita Income (PCI) to be increased from $280 to at least $1,000;
d) Creating 2-3 million new jobs by 2020; and
e) Develop at least 25-30 SEZs in the country and attracting FDI aggressively.

In keeping abreast with MKUKUTA and MKUZA initiatives, the government underscore the need to re-align and focus in its development agenda in terms of Government intervention into priority areas particularly investment in physical infrastructure, including power infrastructure. In this regard the government has prepared a Five Year Development Plan 2011/12 to 2015/16 that is aimed at fast-tracking realization of the Vision 2025 goals and objectives.

The FYDP recognizes the challenges on resource mobilization, and it has zeroed in on a few areas of prioritization, of which their implementation will unleash the country's growth potentials. These are in areas of agriculture, industry, transport, energy, ICT and human resources. According to this policy document, concerted and strategic measures will be taken to accelerate growth to between 12 percent and 15 percent per year in current prices and overall investment will be raised to more than 30 percent of GDP.

The FYDP document recognizes that there are a number of challenges, which need to be addressed to move Tanzania to a higher level of production. One of the key challenges is the development of low cost energy to make Tanzania a destination for producing efficient and competitive goods and services as well as a source for competitive energy supplies within the region. As such, Tanzania[1] is ranked low in terms of its competitiveness capable of attracting investment in the country.

[1] World Economic Forum: The Global Competitiveness Report, 2010-2011

The overall goal over the next five years in the implementation of the FYDP is to broaden the country's sources of economic growth. The main objectives of the plan are to improve infrastructure networks as well as to attain low cost energy service that allows more inflow of investments into the country. This will include the effective use of the country's mineral wealth and to leverage its gain for the development of infrastructure.

Population

Table 2-1 presents the population estimates by region for the last three censuses as well as projections of population to 2011 and then for the forecast period. The growth rates assumed for each region correspond to the growth between the census of 1988 and the census of 2002. No adjustments were made for the in and out migration between census periods as these are assumed part of the census exercise.

Table 2- 1: Regional Population Projections ('000')

S/n	Mainland	1978[i]	1988[i]	2002[i]	2008	2010	2015	2020	2025	2030	2035	2036
1	Arusha	926	744	1,293	1,570	1,665	1,896	2,123	2,350	2,582	2,817	2,865
2	Dar es Salaam	843	1,361	2,498	2,961	3,118	3,486	3,814	4,131	4,456	4,772	4,834
3	Dodoma	972	1,235	1,699	2,005	2,112	2,358	2,568	2,748	2,918	3,077	3,107
4	Iringa	925	1,193	1,495	1,680	1,737	1,858	1,950	2,019	2,074	2,115	2,121
5	Kagera	1,010	1,314	2,034	2,380	2,564	3,091	3,726	4,512	5,459	6,559	6,798
6	Kigoma	649	857	1,679	1,669	1,814	2,231	2,737	3,371	4,147	5,066	5,269
7	Kilimanjaro	902	1,105	1,381	1,569	1,636	1,799	1,949	2,083	2,206	2,319	2,340
8	Lindi	528	646	791	887	924	1,016	1,111	1,210	1,310	1,409	1,429
9	Manyara	na[iii]	604	1,040	1,288	1,388	1,680	2,038	2,484	3,022	3,652	3,789
10	Mara	724	946	1,369	1,692	1,823	2,194	2,635	3,174	3,819	4,562	4,723
11	Mbeya	1,080	1,476	2,070	2,502	2,662	3,063	3,485	3,974	4,519	5,102	5,222
12	Morogoro	939	1,221	1,760	2,022	2,115	2,350	2,581	2,819	3,065	3,308	3,356
13	Mtwara	772	889	1,128	1,272	1,324	1,451	1,580	1,725	1,879	2,033	2,064
14	Mwanza	1,443	1,877	2,942	3,364	3,566	4,077	4,564	5,020	5,469	5,916	6,005
15	Pwani	517	636	889	1,015	1,063	1,184	1,312	1,451	1,599	1,749	1,780
16	Rukwa	452	699	1,142	1,399	1,503	1,798	2,146	2,567	3,065	3,633	3,756
17	Ruvuma	562	780	1,117	1,303	1,375	1,567	1,778	2,014	2,273	2,548	2,605
18	Shinyanga	1,324	1,764	2,805	3,549	3,842	4,683	5,688	6,930	8,434	10,192	10,576
19	Singida	614	792	1,091	1,295	1,367	1,549	1,726	1,898	2,068	2,238	2,272
20	Tabora	818	1,036	1,718	2,171	2,349	2,849	3,442	4,181	5,079	6,127	6,356
21	Tanga	1,038	1,280	1,642	1,880	1,967	2,185	2,404	2,639	2,888	3,138	3,187
	MAINLAND TOTAL	**17,038**	**22,455**	**33,583**	**39,475**	**41,914**	**48,366**	**55,356**	**63,299**	**72,330**	**82,331**	**84,454**
	Zanzibar											
22	North Unguja	77	97	137	159	167	189	214	242	286	335	346
23	South Unguja	52	70	95	108	113	126	141	157	168	179	181
24	Urban West	142	209	391	511	559	699	875	1,094	1,193	1,291	1,311
25	North Pemba	106	137	186	212	222	247	276	307	376	457	475
26	South Pemba	99	128	176	202	211	237	265	297	366	449	467
	ZNZ TOTAL	**476**	**641**	**985**	**1,192**	**1,272**	**1,498**	**1,770**	**2,097**	**2,389**	**2,711**	**2,779**
	Country Total	**17,514**	**23,096**	**34,568**	**40,667**	**43,186**	**49,864**	**57,125**	**65,396**	**74,719**	**85,042**	**87,233**

NOTE:

I Actual Population Census Results were 1978, 1988 and 2002

II In 1988 Arusha region was split into 2 regions of Arusha and Manyara

III na' means Manyara is included in Arusha for that year

2.4 The Energy Sector

Institutional framework

The energy sector in Tanzania involves a number of stakeholders, both government and non-government institutions within and outside the country. The degree of their involvement in energy activities varies significantly, ranging from users of energy, production of energy equipment, financiers of energy projects, researchers, Non-Governmental organisations (NGOs), policy makers and regulator of energy sector. Key players, in the context of Tanzania's energy, include the Ministry of Energy and Minerals (MEM), Tanzania Electric Supply Company (TANESCO), Tanzania Petroleum Development Corporation (TPDC), the Rural Energy Agency (REA), the Energy and Water Utilities Regulatory Authority (EWURA), development partners and private sector

Legal framework of the Energy Sector

These are Electricity Act of 2008, Petroleum (Exploration and Development) Act of 1980, Petroleum (Supply) Act of 2008, EWURA Act of 2001 and REA Act of 2005. Currently the Ministry is in the process of preparing the Natural Gas Policy which will guide the preparation of Natural Gas Act and Natural Gas Utilisation Master Plan. The National Energy Policy , 2003 which is under review supports the institutional framework and specifically depicts the structural changes that occurred over the last decade in the economy, as well as the social and political transformations at national and international levels.

Electricity Sub-sector

The Tanzanian power system (interconnected grid) comprises of hydro and thermal generation units owned by TANESCO and IPP's (permanent and rental) with a total nameplate (installed) capacity of 1,466MW out of which 565MW hydro and 900.7MW thermal. Rental capacity of the IPPs constitutes 317 MW, equivalent to 21.7 percent of the total installed capacity. The isolated system is served by thermal generators with a total nominal capacity of 75 MW.

TANESCO has so far been the sole vertically integrated electricity supplier on the mainland and supplies bulk electricity to Zanzibar. TANESCO's monopoly position was ended in June 1992[2] to allow private sector participation in power trading. To date, there

[2]TANESCO was established in 1931 as the Tanganyika Electric Supply Company. At the time it was one of a number of power supply companies in the country. In 1957 all licences were revoked and a single licence issued to TANESCO under the Electricity Ordinance.

are independent power producers (IPPs) which supply power to the national utility: Independent Power Tanzania Ltd (IPTL) 100MW (diesel), Songas 189MW (natural gas), Symbion 225MW (60MW natural gas, 165MW Jet A1 and Diesel), Aggreko 100MW diesel, the other small (TPC 17 MW biogas, Mwenga 4MW hydro, TANWAT 2.7MW bio gas. Tanzania also imports electricity through cross-border interconnections of 9MW from Uganda, 5MW Zambia and 5MW from Kenya. Tanzania also exports up to One MW of power to Kenya through cross-border interconnection. However, distribution of electricity in Unguja (Zanzibar) and Pemba is a sole responsibility of the Zanzibar Electricity Corporation (ZECO).

The current power system

The administrative regions of TANESCO, generally follows political administrative region in Tanzania. The Dar es Salaam region however is composed of four TANESCO regions. There are two areas that are separated from the national grid: the western regions of Kagera, Kigoma and Rukwa and the south-eastern regions of Lindi, Mtwara and Ruvuma. There are also three main islands that are part of the United Republic of Tanzania. Of the three, Unguja and Pemba are connected to the system but Mafia is not.

Tanzania, along with the sub-Saharan African countries has experienced a prolonged drought (from 2003, 2006, 2009 and 2011). These dry spells have often depleted the entire hydropower reservoir system. The worst situation was in 2006 and in 2011 in such a way that the country was threatened by complete closure of Kidatu and Mtera hydropower plants, which accounted for an average of about 25 percent to the entire power system installed capacity.

The peak demand reached 828.99MW in 2011, for on grid customers. The total units generated in 2011 within TANESCO power system was 3,704GWh while imports from IPPs and neighbouring countries were 1,621MWh. The total units distributed in the country were approximately 4,076GWh, implying total system loss of 23.5 percent or 1,249GWh. Approximately, 2.1 percent of electricity generated in 2010 is taken to represent the level of suppressed demand in Tanzania.

Up to 2011, the transmission system in Tanzania operated at 220kV (2,732 km), 132kV (1,538km) including submarine cable to Zanzibar, and 66kV (546 km). The medium and low voltage lines are 33kV (12,603 km, including submarine cable to Pemba) and 11kV (6,392km**)** while the numerous distribution networks, 400/240V lines have a total length of approximately 26,565 km.

Inter-Connected Grid System Development

Up to 1979, TANESCO’s Interconnected System consisted of the Coastal System of Dar es Salaam, Tanga and Morogoro and the Northern System of Arusha and Moshi. Generation was based on the Pangani River System at Nyumba ya Mungu, Hale and Pangani Falls and the Great Ruaha River System at Kidatu, as well as thermal units at

Ubungo in Dar es Salaam. In 1981, the Mtera dam and the second phase of the Kidatu power station were completed and the Interconnected System was expanded to include deliveries to Zanzibar. In 1985 the grid was extended to the southwest through Iringa Municipal, Mufindi and ultimately to Mbeya and north from Iringa to Dodoma. Subsequently, the grid system was extended to Singida (1986), Shinyanga (1987), Mwanza (1988), Musoma (1989), Tabora (1989), Tukuyu (1993), Njombe (2007), and finally Pemba (2010).

In 1988, the Mtera Generating Station was added to the grid system. In 1994, the Pangani Falls Redevelopment Project was added, including a 132 kV transmission line to Tanga. A new second 220kV transmission line from Kidatu to Dar es Salaam was constructed in 1995. Another 220 kV transmission line from Singida to Arusha was also constructed in 1997. Two gas turbine units at Ubungo with a total installed capacity of 37MW were installed in 1994 and an additional two gas turbines with 75MW total installed capacity in 1995. In 2002, a 220 kV transmission line from Lower Kihansi to Iringa and Kidatu were added. In 2008 a gas plant with total installed capacity of 100MW was added at Ubungo while another 45MW gas plant at Tegeta Dar es Salaam was commissioned in October 2009. Two more generation plants, 100MW gas fired plant at Ubungo was commissioned in 2012 while 60MW HFO at Mwanza is expected to be commissioned in 2013.

Currently, the generation equipment in the isolated centres consists of nearly 90 diesel units with capacities of 1500 kW or less. Many of these units are out of service or in need of extensive repair. In recent years, about 20 diesel units were installed in Kigoma (6), Kasulu (2), Kibondo (2), Sumbawanga (4), Songea (1) and Loliondo (4) with a total capacity of about 15,750kW. The isolated system has suffered the same challenges on fuel and spare parts, as has the grid system, thus leading to power outages. The main objective to interconnecting the isolated regions into the main grid is therefore to relieve TANESCO from costly diesel generation and provide adequate and reliable power.

Table 2-2 summarises the country’s electricity sales and number of customers by regions for the year 2010. The table also shows the degree of electrification in each of the load centres considering that customers in tariff category T1 represent households with electricity connections in the country.

Table 2- 2: Electricity Sales and Number of Customers

Region Name		Arusha	Dar es Salaam	Dodoma	Iringa	Kagera	Kigoma	K'Manjaro	Lindi	Manyara	Mara	Morogoro	Mbeya	Mtwara	Mwanza	Pwani	Rukwa	Ruvuma	Singida	Shinyanga	Tabora	Tanga
Region Connected to Grid System?	Yes/No	Yes	Yes	Yes	Yes	NO	NO	Yes	NO	Yes	Yes	Yes	Yes	NO	Yes	Yes	NO	NO	Yes	Yes	Yes	Yes
Regions Connected to Main Grid	16																					
Regions in Isolated systems	7																					
Total Number of Regions	23																					
Energy Consumption per Tariff	kWh																					
Domestic Customers	D1	32.512.216	94.862.023	30.762.012	27.973.854	15.985.776	4.314.448	43.219.752	6.587.971	8.399.435	12.823.146	31.459.614	37.769.985	10.417.490	27.526.968	14.653.602	9.259.219	7.520.724	11.977.237	16.966.482	12.016.134	39.298.490
Residential Commercial Light Industry and Street Lighting	T1	119.784.022	877.035.789	40.690.928	12.382.625	14.844.783	4.326.653	57.051.561	6.237.760	13.510.219	17.935.852	62.256.499	55.052.425	13.335.434	81.093.884	26.489.160	6.783.666	10.115.104	13.365.545	30.575.402	21.970.844	42.961.019
Low Voltage Supply	T2	59.776.651	290.874.712	14.873.187	30.296.184	6.705.927	3.790.963	16.519.417	2.077.512	1.398.285	14.153.064	23.422.287	16.246.025	4.864.374	33.057.000	12.825.175	1.014.154	3.442.690	4.950.377	16.787.460	4.937.928	30.485.119
High Voltage Supply	T3	69.758.751	552.788.967	5.685.647	24.089.467	8.450.609	0	21.149.031	0	193.986	13.927.831	65.012.786	34.955.506	519.087	75.643.975	57.923.324	0	214.708	0	78.572.227	45.943.695	84.351.077
Bulk Supply - Zanzibar	T5	0	274.867.754	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Golden Pride Tanzania (T3)	T7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulyanhulu Gold Mine (T3)	T8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	144.000.000	0	0
Prepaid LUKU Meters(D1. or T1)	LUKU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NUWA	8																					
Total Regional		281,831,640	2,090,429,245	92,011,774	94,742,130	45,987,094	12,432,064	137,939,761	14,903,243	23,501,925	58,839,893	182,151,186	144,023,942	29,136,385	217,321,427	111,891,261	17,057,039	21,293,226	30,293,159	286,901,571	84,868,601	197,085,705
Residential Commercial Light Industry and Street Lighting	T1	152.296.238	971.897.812	71.452.940	40.356.479	30.830.559	8.641.102	100.271.313	12.825.731	21.909.654	30.758.998	93.716.113	92.822.410	23.752.924	108.620.452	41.142.762	16.042.885	17.635.828	25.342.782	47.541.884	33.986.978	82.249.510
Low Voltage Supply	T2	59.776.651	290.874.712	14.873.187	30.296.184	6.705.927	3.790.963	16.519.417	2.077.512	1.398.285	14.153.064	23.422.287	16.246.025	4.864.374	33.057.000	12.825.175	1.014.154	3.442.690	4.950.377	16.787.460	4.937.928	30.485.119
High voltage supply	T3	69.758.751	827.656.721	5.685.647	24.089.467	8.450.609	0	21.149.031	0	193.986	13.927.831	65.012.786	34.955.506	519.087	75.643.975	57.923.324	0	214.708	0	222.572.227	45.943.695	84.351.077
Total Regional		**281,831,640**	**2,090,429,245**	**92,011,774**	**94,742,130**	**45,987,094**	**12,432,064**	**137,939,761**	**14,903,243**	**23,501,925**	**58,839,893**	**182,151,186**	**144,023,942**	**29,136,385**	**217,321,427**	**111,891,261**	**17,057,039**	**21,293,226**	**30,293,159**	**286,901,571**	**84,868,601**	**197,085,705**
Tariff Share of Consumption	%																					
Domestic Customers	D1	11.5%	4.5%	33.4%	29.5%	34.8%	34.7%	31.3%	44.2%	0.0%	21.8%	17.3%	26.2%	35.8%	12.7%	13.1%	54.3%	35.3%	39.5%	5.9%	14.2%	19.9%
Residential Commercial Light Industry and Street Lighting	T1	42.5%	42.0%	44.2%	13.1%	32.3%	34.8%	41.4%	41.9%	0.0%	30.5%	34.2%	38.2%	45.8%	37.3%	23.7%	39.8%	47.5%	44.1%	10.7%	25.9%	21.8%
Low Voltage Supply	T2	21.2%	13.9%	16.2%	32.0%	14.6%	30.5%	12.0%	13.9%	0.0%	24.1%	12.9%	11.3%	16.7%	15.2%	11.5%	5.9%	16.2%	16.3%	5.9%	5.8%	15.5%
High Voltage Supply	T3	24.8%	26.4%	6.2%	25.4%	18.4%	0.0%	15.3%	0.0%	0.0%	23.7%	35.7%	24.3%	1.8%	34.8%	51.8%	0.0%	1.0%	0.0%	27.4%	54.1%	42.8%
Prepaid LUKU Meters(D1. or T1)	LUKU	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Regional Share of Total Consumption	%	**6.8%**	**50.1%**	**2.2%**	**2.3%**	**1.1%**	**0.3%**	**3.3%**	**0.4%**	**0.0%**	**1.4%**	**4.4%**	**3.4%**	**0.7%**	**5.2%**	**2.7%**	**0.4%**	**0.5%**	**0.7%**	**6.9%**	**2.0%**	**4.7%**
Number of Consumers																						
Domestic Customers	D1	27.399	121.465	24.473	17.782	16.339	5.963	46.730	6.048	4.724	8.162	26.644	31.889	8.960	15.871	4.987	7.835	7.808	7.831	14.083	13.584	22.284
Residential Commercial Light Industry and Street Lighting	T1	33.537	163.684	6.734	16.810	1.307	3.328	24.257	532	2.719	8.060	17.222	20.330	1.446	33.442	24.932	731	4.966	4.787	8.055	5.820	21.529
Low Voltage Supply	T2	170	916	70	67	25	13	57	13	4	32	73	48	24	99	80	5	17	17	48	17	85
High Voltage Supply	T3	26	147	11	11	3	0	14	0	2	8	15	9	2	27	7	1	2	1	8	4	15
Bulk Supply - Zanzibar	T5	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Auxilliary and own Use	T6	12	35	21	13	21	4	29	13	8	10	21	34	10	24	6	6	10	11	10	11	46
Golden Pride Tanzania (T3)	T7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulyanhulu Gold Mine (T3)	T8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Prepaid LUKU Meters(D1. or T1)	LUKU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		61,144	286,249	31,309	34,683	17,695	9,308	71,087	6,606	7,457	16,272	43,976	52,310	10,442	49,463	30,012	8,578	12,803	12,647	22,154	19,436	43,959
Residential Commercial Light Industry and Street Lighting	T1	60.948.0	285.184.0	31.228.0	34.605.0	17.667.0	9.295.0	71.016.0	6.593.0	7.451.0	16.232.0	43.887.0	52.253.0	10.416.0	49.337.0	29.925.0	8.572.0	12.784.0	12.629.0	22.098.0	19.415.0	43.859.0
Low Voltage Supply	T2	170.0	916.0	70.0	67.0	25.0	13.0	57.0	13.0	4.0	32.0	73.0	48.0	24.0	99.0	80.0	5.0	17.0	17.0	48.0	17.0	85.0
High voltage supply	T3	26.0	147.0	11.0	11.0	3.0	-	14.0	-	2.0	8.0	15.0	9.0	2.0	27.0	7.0	1.0	2.0	1.0	8.0	4.0	15.0
Total Regional		**61,144**	**286,247**	**31,309**	**34,683**	**17,695**	**9,308**	**71,087**	**6,606**	**7,457**	**16,272**	**43,976**	**52,310**	**10,442**	**49,463**	**30,012**	**8,578**	**12,803**	**12,647**	**22,154**	**19,436**	**43,959**
Customer Percentage of Total																						
Domestic Customers	D1	44.81%	42.43%	78.17%	51.27%	92.34%	64.06%	65.74%	91.55%	0.00%	50.16%	60.59%	60.96%	85.81%	32.09%	16.62%	91.34%	60.99%	61.92%	63.34%	69.89%	50.69%
Residential Commercial Light Industry and Street Lighting	T1	54.85%	57.18%	21.51%	48.47%	7.39%	35.75%	34.12%	8.05%	0.00%	49.53%	39.16%	38.86%	13.85%	67.61%	83.07%	8.52%	38.79%	37.85%	36.36%	29.94%	48.98%
Low Voltage Supply	T2	0.28%	0.32%	0.22%	0.19%	0.14%	0.14%	0.08%	0.20%	0.00%	0.20%	0.17%	0.09%	0.23%	0.20%	0.27%	0.06%	0.13%	0.13%	0.22%	0.09%	0.19%
High Voltage Supply	T3	0.04%	0.05%	0.04%	0.03%	0.02%	0.00%	0.02%	0.00%	0.00%	0.05%	0.03%	0.02%	0.02%	0.05%	0.02%	0.01%	0.02%	0.01%	0.04%	0.02%	0.03%
Prepaid LUKU Meters(D1. or T1)	LUKU	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Regional Share of Total Customers	%	**7.21%**	**33.77%**	**3.69%**	**4.09%**	**2.09%**	**1.10%**	**8.39%**	**0.78%**	**0.88%**	**1.92%**	**5.19%**	**6.17%**	**1.23%**	**5.84%**	**3.54%**	**1.01%**	**1.51%**	**1.49%**	**2.61%**	**2.29%**	**5.19%**
Specific Consumption	kWh/Cust																					
Residential Commercial Light Industry and Street Lighting	T1	2.499	3.408	2.288	1.166	1.745	930	1.412	1.945	2.940	1.895	2.135	1.776	2.280	2.202	1.375	1.872	1.380	2.007	2.151	1.751	1.875
Low Voltage Supply	T2	351.627	317.549	212.474	452.182	268.237	291.613	289.814	159.809	349.571	442.283	320.853	338.459	202.682	333.909	160.315	202.831	202.511	291.199	349.739	290.466	358.648
High voltage supply	T3	2.683.029	5.630.318	516.877	2.189.952	2.816.870	0	1.510.645	0	96.993	1.740.979	4.334.186	3.883.945	259.544	2.801.629	8.274.761	0	107.354	0	27.821.528	11.485.924	5.623.405
Total Regional		**4,609**	**7,303**	**2,939**	**2,732**	**2,599**	**1,336**	**1,940**	**2,256**	**3,152**	**3,616**	**4,142**	**2,753**	**2,790**	**4,394**	**3,728**	**1,988**	**1,663**	**2,395**	**12,950**	**4,367**	**4,483**
Population ('000) - 2009		1,618	3,040	2,059	1,709	2,470	1,740	1,603	905	1,337	1,756	2,068	2,582	1,298	3,466	1,039	1,450	1,339	1,331	3,693	2,259	1,923
Average Size of House Hold		4.5	4.2	4.5	4.3	5.2	6.9	4.6	4.1	5.2	5.6	4.6	4.2	3.8	5.9	4.4	5.1	4.8	6.3	5.0	5.9	4.6
Number of House Holds		359.0	726.0	456.0	397.0	479.0	251.0	345.0	218.0	257.0	316.0	450.0	615.0	338.0	583.0	235.0	283.0	278.0	211.0	736.0	383.0	418.0
Degree of electrification - 2008		**17%**	**39%**	**7%**	**9%**	**4%**	**4%**	**21%**	**3%**	**3%**	**5%**	**10%**	**9%**	**3%**	**8%**	**13%**	**3%**	**5%**	**6%**	**3%**	**5%**	**10%**

Recent Development in the Power Sector

The following are some of the main developments that have been implemented or under implementation on the power systems:

a) Grid reinforcement and extension of the grid to mines in the northwest (Buzwagi and North Mara),

b) Formulation of emergence power plan to address severe draught whereby the government had to acquire rental power plants of 205MW (Aggreko 100 MW and Symbion 55MW in Dodoma and 50MW in Arusha) capacities.

c) Installation of a permanent 100MW gas power plant at Ubungo in 2012.

d) Extension of the gas pipeline to fuel a 45MW gas plant at Tegeta, Dar es Salaam in 2009.

e) Implementation of rural electrification program – under the Tanzania Energy Development Access Project (TEDAP).

f) Several Small Power Producers (SPPs) agreements – such as TPC, Mwenga and TANWATT were implemented.

g) Initiative to construct a Backborne Transmission Investment Project (BTIP – 400kV) as part of reinforce the grid system from Iringa to Shinyanga is underway.

h) Construction of a Gas pipeline from Mtwara to Dar es Salaam, and implementation of Wayleave Village Electrification Scheme (WVES)

Other developments in the power sector include:

a) Upgrading and rehabilitation of the distribution networks in Tanga, Iringa, Mbeya, Morogoro, Mwanza and Dodoma, and development of the second submarine cable from Dar es Salaam to Zanzibar 132-kV.

b) The laying of a 33 kV submarine cable from Tanga to Pemba.

c) Natural gas discoveries: Songo Songo, Mnazi Bay, Mkuranga, Kiliwani, Ntorya and Deep Sea eight discoveries (Chaza, Jodari, Zafarani, Pweza, Mzia, Chewa, Papa 1 and Lavani 1).

d) Development of coal production at Ngaka area. Reinforcement of the Northeast grid from Dar es Salaam to Arusha via Chalinze Tanga and Same (400kV transmission line) project.

e) Extension of grid system to the Northwest regions of Kigoma, Rukwa and Kagera (220kV line).

f) Development of two wind farms of 50MW each.100MW wind farms in Singida.

Load Characteristics, Tariffs, Electrification and Losses

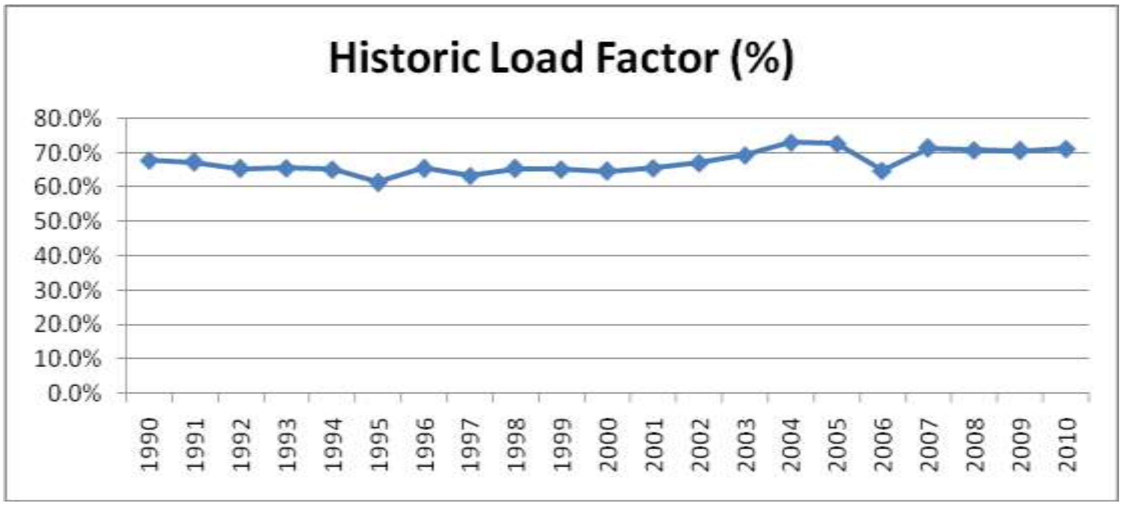
Daily load patterns: The hourly generation data collected for the years 1991 to 2011 and investigated to reveal load characteristics in Tanzania. A sample of 24 daily load curves were examined throughout that period: a typical weekday, a Saturday and a Sunday in April and in October of the years 1991 (before load shedding), 1994 (an early period of severe load shedding), 2004 with virtually no load shedding and 2006 with severe load shedding as well as on 2009 and 2010 to 2011.

The daily load pattern, with the exception of that for Sunday, displays a fairly constant load during the day with an evening peak. The Sunday pattern has both a morning and an evening peak and is typically at a lower demand level than for the other days of the week.

Seasonality: There is virtually no seasonality in the load on the Tanzania's power system.

System load factor: The graph in Figure 2-2 presents the records of load factors from 1990 to 2011. This graph suggests that the load factor has been quite steady from 1990 to about 2001. During that period the load factor averaged about 65.2 percent with variation between 61.4 percent and 67.8 percent. For the most recent five years the average load factor rose to about 69.7 percent and if the amount of energy not served is added with no change in peak demand, the average would be about 70.8 percent. For the 2010, adding the load shedding to the electricity generated while keeping the same peak, the load factor would increase to 62.43 percent which is used in the forecast with a target gradual increase to 71.78 percent in 2035. The level of electricity not delivered to customers (load shedding) was taken to represent the supply system constraints. An alternative scenario is to project demand without adding back the amount of load shed which will give unrealistic forecast of electricity.

Figure 2- 2: Historical Load Factor (%)



Tariff structure: A review of the tariff structures in Tanzania shows that there have been several major changes in structure during that period:

a) From 1980 to 1987 there were residential, small commercial, light industry, low voltage supply, high voltage supply, street lighting and Zanzibar;

b) In 1987, agriculture, energy intensive and the National Urban Water Authority (NUWA) were added; however, it is not clear how the previous categories were split in order to obtain the new ones;

c) In 1990 the structure remained the same but the definition of the prior categories was changed slightly;

d) In 1995, the structure was changed significantly;

e) The new Tariff T1 (General Use) grouped the loads from the previous residential, small commercial and light industrial;

f) The new T2 (Low Voltage Supply) appears the same as the previous low voltage supply;

g) The new T3 (High Voltage Supply) grouped the categories High Voltage Supply and High Intensive Supply Energy;

h) Those Agriculture and the NUWA accounts customers that are served at 11 kV or higher would become T3 customers and the others would be either T1 or T2, depending upon the size of the monthly bills. Given the size and type of customers, it has been assumed that all of these customers are served at 11 kV or above and therefore would become T3 customers;

i) Public lighting remains as before except that places of worship were added;

j) Zanzibar remains as before;

k) In 2003 another tariff structure change occurred and remains in effect to date;

l) Tariff T1 was split into D1 (domestic low usage) and T1 (general use) and added public lighting; and

m) In 2008 only the tariff rates changed but maintained the tariff structure as it was in 2003, which remains in effect to date.

Accelerated electrification

There is a program of accelerated electrification for Tanzania as a whole that is being implemented by TANESCO and the Government with support from development partners. The policy is to:

a) complete backlog on electricity connection applications in urban, peri-urban and rural areas[9];

b) Electrify agro-based industries such as ginneries and tea plantations to add value to the agriculture process;

c) Electrify development centres along the route of transmission lines; and

d) Implement REA funded projects.

In 2007, TANESCO set a target of connecting 100,000 customers per year. In 2011, the company managed to connect 75461 new customers, equivalent to 75.5 percent of the annual target. Connections against the target have been increasing continuously from 56 percent in 2008 to 59 percent in 2009 and further up to 66 percent in 2010. However, lack of funds to procure service line materials were among the limitations to reach the set target. In 2012 the Government set a new target of connecting 250,000 urban, peri-urban and rural customers per year. This new target aims at achieving the National objective of ensuring that 30 percent of the population has access to electricity by 2015 from the current level of 18 percent. The new targets of electrification will be achieved through concerted efforts by all key stakeholders like REA, TANESCO, private developers, and the recent government strategy to reduce connection fees as an incentive to attract many electricity customers.

System losses

An estimate of losses was taken from the COSS projections for the period 2011 – 2015 inclusive. The losses are split into transmission and distribution losses respectively for the same period and shown below.

Table 2- 3: System Losses

	2010	2011	2012	2013	2014	2015	2035
Transmission	5.3%	5.3%	5.6%	5.5%	5.5%	5.4%	4.8%
Distribution	19.7%	19.7%	17.8%	16.4%	15.1%	15.1%	11.0%
Total Losses	**25.0%**	**25.1%**	**23.4%**	**22.0%**	**20.6%**	**20.5%**	**15.8%**

The projections of loss values compares well with values derived using generation records for the year 2010 with the sales records for the same period.

2.5 Forecast Approach and Methodology

General

The update load forecast uses similar approach and methodology as was developed and used for the 2008 forecast (2008 PSMP) and its Update forecasts of 2009 and 2011 to project sales, energy requirements and peak demand for Tanzania. The methodologies used were:-

a) Trend line analysis for regional forecasts to arrive at total country forecasts; and
b) Econometric analysis as an overall check on the reasonableness of the results obtained using trend-line approach.

Load forecast strategy

The basic premise taken in this forecast is that it will provide an estimate of the needs of the customers and NOT an estimate of what can be supplied to the customer. This implies that:

The base year of the forecast will be adjusted to the level of demand estimated under an unconstrained system; Gross Domestic Product and its components will grow at higher than the average rates experienced in the past to reflect the removal of the constraints on growth in the economy that was caused by the lack of plentiful and reliable electric power; Population growth will follow the trend observed in the Tanzania's Population and Housing Census projections (2002). The forecast of unconstrained sales is equal to the forecast of sales for each category taking into account the underlying trends in each category plus the estimated impact of the shortages of capacity.

Approach used for forecasts

In arriving at national forecasts, individual regional forecasts were carried out based on the following steps:

a) Derive a forecast of sales for the regional load using a trend-line approach in which the trends in number of customers and the unit consumption in each category of load are studied and projected;
b) Assess the impact of the issues specific to the load forecast in the country;
c) Estimate the load factors that would apply in an unconstrained system,
d) Forecast the underlying trend in unconstrained sales for specific categories;
e) Estimate the losses, both transmission, distribution-categorised as technical as well as non-technical losses and derive the energy required;
f) Derive a forecast of the unconstrained energy and peak demand for the sector; and
g) Estimate the transition in energy and peak demand between the current constrained situation and the unconstrained forecast.

The forecast approach also do take into account , development agenda, as articulated in the Tanzania Development Vision 2025, Long Term Plan Perspective (LTPP-2010-

2025), Five Year Development Plan(2011/12 – 2015/2016) MKUKUTA (2010 – 2015), and CCM Election Manifesto, as a basis of judgement in applying future growth rates to the unit consumption of electricity. Furthermore, the approach accounts explicitly for the expected new industries as obtained from the recent industrial surveys, special program to accelerate electricity connection by 2015/16, emerging of gas economy as well as increase level of rural electrification.

Data validation

Validation of data was undertaken through tracing historic changes in a given data set. Graphs of the basic input data (e.g customers and unit consumption) are prepared for each region and these graphs are analysed for establishing historical trends. This examination permitted the selection of a historic time period for projection.

Assumptions

There are two group of assumptions used in this forecast- general and specific. The general assumptions are summarised in the **Table 2-6** and are applicable to all cases while specific ones apply to a given region only. The demand forecast assesses only the domestic demand although the future regional power trade has been considered under the generation plan section.

General Assumptions

a) The base year for the forecast is the calendar year 2010. The forecast is provided for the period 2011 to 2035.

b) **Customer categories retained:** In order to carry out the analysis of historic trends for use in projecting future trends, it is necessary to have a database covering a long period of time that has a consistent definition. The tariffs definitions are as follows:-

- T1 (general use) plus D1 (domestic low usage tariff) taken together, which includes the prior categories of residential, light commercial, light industrial, and public lighting;
- T2 (low voltage demand), which includes the prior categories of low voltage supply;
- T3 (High voltage usage tariff)[3], which includes the prior categories High Voltage Supply, High Intensive Supply Energy, Agriculture and NUWA;

c) **Historic period retained:** Based on the review of the tariff structures and their changing definitions, the historic period retained is from 1986 to 2010 inclusive[4].

d) The Tariff increases substantially higher than inflation can be expected to have an impact on consumer behaviour, depending upon the price elasticity of their

[3] Variations in this tariff have been applied to specific mining loads

[4] It would be preferable to have a longer historic period; however, the earlier data are not consistent and the 25 years of historic data (1986 to 2010) are sufficient for a forecast of 20 to 25 years.

consumption. The increase of electricity tariffs in Tanzania does not portray the behaviour of normal demand and supply curves because of the following:

- There is low level of electrification; and
- There is currently a high level of suppressed energy; by the time that adequate supplies of energy become available, the impact of the expected high increase will have dissipated.

e) Projections of economic and demographic parameters: It is assumed that the forecast period is split into three periods: the shorter term of 2012 to 2017 with relatively high growth during which 1.25million customers will be connected, the medium term period covering 2018 to 2025 with moderate growth rate responding to Tanzania Development Vision 2025 and LTPP. The longer term, that is 2026 to 2036 responding to characteristics of middle income countries.

An assessment of historical GDP growth over the past 14 years reveals that, the growth rate has been stable in all period. The historical analysis of growth rate was conducted by dividing time horizon into four categories. The results are summarized in **Table 2-4** below.

Table 2- 4: GDP Growth Analysis

Period of Analysis	High Case	Base Case	Low Case
Four-year growth	7.0%	6.8%	6.6%
Eight-year growth	7.2%	6.9%	6.3%
Ten-year growth	7.3%	7.1%	6.7%
Fourteen-year growth	7.8%	6.6%	4.8%

f) **Impact of Demand-Side Management:** a special program to connect new customers as outlined above will go in tandem with demand side management program. The following assumptions have been used in the forecast as they relate to demand-side management:

- For customers in the T1, T2 and T3 categories, special programs will be implemented during 2013 to 2017 and their impact will be felt from 2018 to the end of planning horizon;
- The estimates of consumption in the new major customers such as mining and other loads are assumed to have taken into account demand side management in their programs.

g) **Estimates of load shed:** It is assumed that the demand for energy and peak capacity in 2010 was 2.1percent greater than actual sales in the T1, T2 and T3 categories.

h) **Additional electrification:** In implementing a five-year program of connecting 250,000 new customers per year, two approaches were considered: (i) allocating new customers on a pro-rata basis across all regions and (ii) assuming more weight to regions other than Dar es Salaam. Given relatively high level of electrification in Dar es Salaam, the second approach is used. After end of the five-year program, historical growth rates were used to project forward up to 2035.

i) **Loads from Extraction of Natural Resources and others:** It is estimated that Tanzania has some 140.2 million tons of gold reserves, 535.8MT of coal, 33.04TCF of gas and abundant reserves of other minerals. In the wake of the liberalization of the economy, the government has been heavily promoting private investment in the natural resource extraction sector. Considerable development are expected in the growth of mining/extraction activities and the position of natural resources in the economy, and it is likely for the trend to intensify over the forecast period.

The development of mining activities in a specific region impacts directly on the future power needs in the region, and finally future power needs for the country. The new identified mining loads, their expected power needs, and respective locations are shown in **Table 2-5**. In the current update forecast study, these have been treated explicitly and are included as a set of specific assumptions in addition to other identified loads for each regional forecast.

Table 2- 5: Selection of Anticipated Major Loads in Tanzania

Mine	Capacity (MW)	Location	Expected Online
Kabanga – Nickel	32	Kagera	2016
Mibongo – Gold	20	Kigoma	2016
Ntaka Hill – Nickel	30	Lindi	2018
Dangote Cement plant	40	Mtwara	2015
Panda Hill – Gold	5	Mbeya	2016
Buckreef – Gold	8	Geita	2015
Geita – Gold	30	Geita	2015
Mchuchuma – Iron Smelter	100	Iringa	2018
Golden Ridge - Gold	7	Shinyanga	2015
Dutwa – Nickel	10	Shinyanga	2015
Bulyanhulu – Gold	20	Shinyanga	2013
Textile Mill	30	Shinyanga	2014
Williamson Diamond	10	Shinyanga	2013
Williamson Diamond	12	Shinyanga	2014
Williamson Diamond	3	Shinyanga	2015
Liquidified Natural Gas Power plant(LNG)	100	Lindi	2018
Expansion of Makonde Plateau Water Supply and Sanitation Authority	6	Mtwara	2017
Ikwiriri Sugar factory	4	Lindi	2014
Fertilizer Factory	30	Lindi	2017
Dawasa- Ruvu pumping Expansion	12	Coast	2015
Hong Yu Steel (T) Ltd – Expansion	34	Coast	2015
Eagle Cement Co. Ltd	20	Coast	2015

j) **Losses:** The estimate of losses for the forecast period is based on the losses in 2010 and is amounted to 25.0 percent including transmission loss of 5.3 and distribution losses of 19.7 percent as per Cost of Service Study (COSS, 2010). For the update forecast, the COSS projects reduction of losses up to 21.6 percent by 2015. Thereafter, the projection is assumed a rate of 0.2 percent deduction up to the end of plan. A reasonable and achievable target for reduction of losses would be to achieve a level of about 15.8 percent by 2035. A number of projects are ongoing like grid reinforcement project which includes TEDAP, Dar–Tanga-Arusha distribution grid upgrade and reinforcement, selected MCC distribution reinforcement and installation of smart meters to curb electricity theft and ensure revenue protection with the TANESCO grid system.

k) **Load factor:** The data available indicates a load factor of 55.31 percent for 2010. If the amount of load shed in 2010 is added to the energy generated and the peak is kept the same, the load factor would increase to 62.43 percent with a gradual increase to 71.78 percent in 2035. The level of electricity not delivered to customers (load shedding) was taken to represent the supply system constraints. An alternative scenario is to project demand without adding back the amount of load shed which will give unrealistic forecast of electricity.

l) Specific assumptions used in the forecast for each region have been adopted for the following factors:
   i. Population growth
   ii. Number of people per household
   iii. Rate of increase in customers under the electrification program (applied to T1 customers)
   iv. Rate of increase in customers in T2 and T3 as well as in T1 beyond the electrification program
   v. Unit consumption for all three categories
   vi. Amount and timing of new industrial loads
   vii. Amount and timing of major expansions of existing T3 customers.

Table 2- 6: Summarised General Assumption

High Case – Assumptions	**Base Case - Assumptions**	**Low Case - Assumptions**
Base Year Data - 2010	Base Year Data - 2010	Base Year Data - 2010
Target – Achieve 100% of the 250,000 new customers per annum for 5years.	Target – Achieve 85% of the High Case target (212,500)	Target – Achieve 75% of the High Case target (187,500)
Household size – 8 people	Household size – 8 people	Household size – 8 people
Emerging of high demands of electricity (industrial survey, open up of economy – Mtwara corridor and mining activities)	Emerging of high demands of electricity (industrial survey, open up of economy – Mtwara corridor and mining activities): Assuming structural breaks – delays and shift of projects	Historical growth rates
By 2025 Tanzania is assumed to be a middle income Country according to the TDV 2025 • FYDP-I requires 2780 MW by 2015/16 • Requires >6700 MW by 2035	By 2025 Tanzania is assumed to be a middle income Country according to the TDV 2025 • FYDP-I requires 2780 MW by 2015/16 • Requires >6700 MW by 2035	Business as usual, following historical trends

2.6 Regional forecast

Description of models used

Several models and databases are used in the derivation of the regional forecasts. Databases, from which the models draw their input data, include:

a) Sales and numbers of customers for each tariff category (T1, T2 and T3)

b) Population (historical and projected) and household size for each region

c) GDP values, historical as well as projected as categorised by economic sectors of Agriculture, Industries and Service sectors.

d) Industrial survey data, involving new plans and rehabilitation/Expansion programs evolution in a given region

e) Historical peak demand and diversity factors for each region

f) A model for the derivation of the sales and peak demand of each region (there is a separate, similarly structured model for each region);

g) A model to aggregate the regional forecasts to represent the interconnected grid; and isolated grid

These forecasts extend from 2011 to 2035; they combine the short to medium term forecast with the long-term forecast.

2.6.2 Interconnected grid

The description provided earlier implies that by year 2019 all the remaining isolated load centres would have been connected into the main grid system. The forecasts of sales for each region in the interconnected grid are presented in summary form in **Table 2-3**; the detailed forecasts by tariff category, by region and by year are contained in internal work files. The table also presents the losses, recovered load shedding, generation requirements, the sum of the non-coincident peak demand as well as the coincident peak demand for the overall grid; including the isolated loads as they are integrated into the main (these amounts for each of the twenty-one regions are included in the forecast model. It includes, in alphabetical order:

Arusha (including Manyara)	Lindi	Rukwa
Dar es Salaam (including Pwani)	Mara (Musoma)	Ruvuma
Dodoma	Mbeya	Shinyanga
Iringa	Morogoro	Singida
Kagera	Mtwara	Tabora
Kigoma	Mwanza	Tanga
Kilimanjaro	Pemba	Unguja

T**able 2-7** summarizes the results. It should be noted that there is a strong increase of annual demand growth starting 2013 to 2015 largely due to identified additional power demands from existing customers and a special electrification program which tallies with government's policy statement of connecting 30% of population by 2015.

Table 2-8 provides the corresponding peaks and evolution of the interconnected grid system - to include all the isolated regions, while **Table 2-9** presents' peak and generation requirements. **Figures 2-3** to **2-5** visualize the sales, demand and generation forecasts for the three cases considered. The forecast is based on actual data for 2010 and data for 2011 and 2012 were estimates. Furthermore the estimates were based on unconstrained demand consumption.

Table 2- 7: Detailed Forecast Results

Sales, Generation and Peak Forecast - Total Country **Base Case**

Region	Unit	*Actual* 2010	*Unconstrained* 2010	2011	2012	2013	2014	2015	2020	2025	2030	2035
Arusha	GWh	305.3	305.3	322.7	343.5	488.2	685.2	853.7	1,608.8	2,472.8	3,179.9	4,091.6
Dar es Salaam	GWh	2,202.3	2,202.3	2,261.5	2,349.0	2,713.0	3,360.3	3,936.6	5,792.4	6,936.6	8,332.3	10,070.5
Dodoma	GWh	92.0	92.0	96.5	102.2	186.9	301.7	373.9	572.6	818.5	1,179.6	1,492.3
Iringa	GWh	94.7	94.7	98.1	101.6	118.8	149.4	201.3	325.5	522.5	795.1	949.8
Kagera	GWh	46.0	46.0	51.1	56.6	83.5	111.1	176.6	479.2	734.2	1,191.8	2,036.7
Kigoma	GWh	12.4	12.4	14.3	15.0	18.6	33.6	55.5	459.8	583.1	749.0	980.8
Kilimanjaro	GWh	137.9	137.9	141.7	146.9	172.0	196.8	223.2	375.8	440.4	505.4	571.0
Lindi	GWh	14.9	14.9	15.8	16.8	28.2	40.5	76.9	432.4	568.5	739.5	953.7
Manyara (*Included in Arusha*)				-	-	-	-	-				
Mara	GWh	58.8	58.8	67.3	77.5	87.7	98.6	109.6	181.8	304.9	521.3	916.5
Mbeya	GWh	144.0	144.0	151.8	160.6	179.8	207.2	232.2	463.3	746.3	1,159.2	1,697.7
Morogoro	GWh	182.2	182.2	188.8	196.5	216.0	241.4	268.3	476.3	792.0	1,203.2	1,577.6
Mtwara	GWh	29.1	29.1	33.3	36.0	73.4	167.4	289.5	731.1	954.9	1,226.8	1,554.2
Mwanza	GWh	217.3	217.3	223.9	231.6	358.0	465.9	543.9	933.7	1,489.8	2,065.2	2,376.1
Rukwa	GWh	17.5	17.5	18.4	19.5	30.7	41.4	61.6	174.6	282.9	450.0	710.9
Ruvuma	GWh	21.3	21.3	20.4	19.8	26.8	33.3	39.1	125.3	186.1	278.9	400.5
Shinyanga	GWh	286.9	286.9	322.2	359.3	391.7	538.3	730.5	1,368.1	2,390.6	3,776.4	5,622.8
Singida	GWh	30.3	30.3	32.3	34.6	48.4	56.6	65.4	112.3	183.4	298.5	485.1
Tabora	GWh	84.9	84.9	98.1	111.6	152.7	163.5	174.4	305.1	572.8	940.5	1,439.8
Tanga	GWh	197.1	197.1	206.8	218.0	276.6	341.3	461.5	903.3	1,263.0	1,732.6	2,155.4
Total Sales	GWh	***4,175.0***	***4,175.1***	***4,364.9***	***4,596.7***	***5,651.1***	***7,233.4***	***8,873.8***	***15,821.4***	***22,243.5***	***30,324.9***	***40,083.0***
Annual Growth Rate	*%*		*0.0%*	*4.5%*	*5.3%*	*22.9%*	*28.0%*	*22.7%*	*7.4%*	*6.6%*	*6.0%*	*5.5%*
T1	GWh	2,024.1	2,024.1	2,126.2	2,258.4	2,661.1	3,094.3	3,548.7	6,016.5	9,318.0	13,642.0	18,827.5
T2	GWh	592.5	592.5	598.1	606.6	896.3	1,234.0	1,576.0	2,713.1	3,600.5	4,763.2	6,313.8
T3	GWh	1,558.5	1,558.5	1,640.6	1,731.7	2,093.7	2,905.1	3,749.1	7,091.7	9,325.0	11,919.7	14,941.8
LESS *New loads*	*GWh*	-	-	-	-	*(459.0)*	*(1,412.4)*	*(2,400.3)*	*(5,445.1)*	*(6,599.3)*	*(8,000.9)*	*(9,703.3)*
Total Sales	GWh	***4,175.0***	***4,175.1***	***4,364.9***	***4,596.7***	***5,651.1***	***7,233.4***	***8,873.8***	***15,821.4***	***22,243.5***	***30,324.9***	***40,083.0***
Distribution Losses			*1,027.3*	*1,074.0*	*992.7*	*1,111.0*	*1,286.5*	*1,575.8*	*2,588.8*	*3,338.5*	*4,147.7*	*4,960.9*
Distribution Loss rate	*%*		*19.7%*	*19.7%*	*17.8%*	*16.4%*	*15.1%*	*15.1%*	*14.1%*	*13.1%*	*12.0%*	*11.0%*
Generation required at S/S	GWh	***4,175.0***	***5,202.3***	***5,439.0***	***5,589.4***	***6,762.2***	***8,520.0***	***10,449.6***	***18,410.1***	***25,582.0***	***34,472.6***	***45,044.0***
Recovered Loadshedding	GWh		*98.0*	*98.0*	*98.0*	*98.0*	*98.0*	*98.0*	*98.0*	*98.0*	*98.0*	*98.0*
Transmission Losses	GWh		*290.8*	*305.9*	*331.0*	*391.1*	*480.8*	*574.6*	*882.7*	*1,160.3*	*1,570.7*	*2,056.7*
Transmission Loss rate	*%*			*5.2%*	*5.4%*	*5.3%*	*5.2%*	*5.1%*	*4.5%*	*4.3%*	*4.3%*	*4.3%*
Net Generation	GWh	***4,175.0***	***5,591.2***	***5,842.9***	***6,018.5***	***7,251.3***	***9,098.8***	***11,122.2***	***19,390.9***	***26,840.3***	***36,141.3***	***47,198.7***
Station Use	*GWh*		*62.19*	*64.99*	*66.94*	*80.65*	*101.20*	*123.71*	*215.67*	*298.53*	*401.98*	*524.96*
Fraction of Station Use	*%*		*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*
Gross Generation	GWh	***4,175.0***	***5,653.4***	***5,907.9***	***6,085.4***	***7,331.9***	***9,200.0***	***11,245.9***	***19,606.6***	***27,138.8***	***36,543.3***	***47,723.6***
Annual Growth Rate				*4.5%*	*3.0%*	*20.5%*	*25.5%*	*22.2%*	*7.0%*	*6.4%*	*5.7%*	*5.2%*
Sum of Peak Demands (MW)	MW		***1,061.9***	***1,117.0***	***1,138.9***	***1,364.6***	***1,704.1***	***2,088.5***	***3,573.3***	***4,724.3***	***6,084.6***	***7,644.8***
Coincident Peak (MW)	MW	***832.6***	***1,054.2***	***1,108.9***	***1,130.7***	***1,354.7***	***1,691.8***	***2,073.3***	***3,547.3***	***4,690.0***	***6,040.5***	***7,589.4***
Annual Growth Rate	*%*			*33.2%*	*2.0%*	*19.8%*	*24.9%*	*22.6%*	*5.9%*	*5.4%*	*4.8%*	*4.9%*
Overal Electrification Levels	***%***		***14.0%***	***14.0%***	***15.0%***	***18.0%***	***21.0%***	***24.0%***	***37.0%***	***51.0%***	***66.0%***	***78.0%***

Table 2- 8: Regional Peak Demand Forecast

Non-coincident Peak Demand Forecast - Interconnected Grid **Base Case**

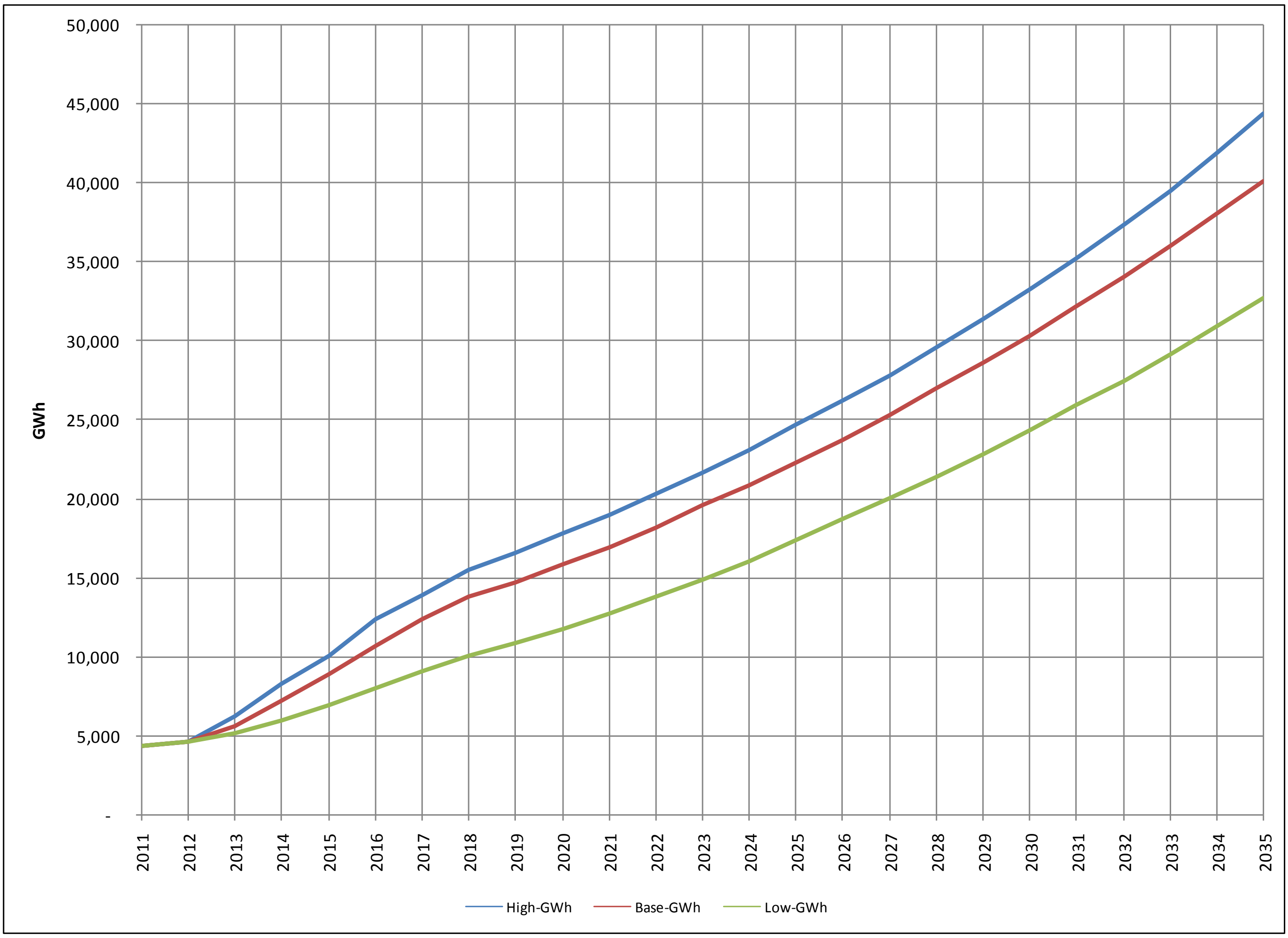
MW	Actual 2010	Unconstrained 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035
Arusha	53.83	68	72	74	103	142	176	204	231	259	289	322	481	603	751
Dar es Salaam	373	472.61	485.09	490.14	554.38	672.2	783.66	921.33	1023.86	1054.58	1086.46	1119.53	1304.8	1526.05	1801.61
Dodoma	18.07	23	24	25	44	69	85	97	104	111	118	125	173	240	295
Iringa	22.6	29	30	30	34	41	55	59	64	69	75	81	121	171	188
Kagera	12	15.95	16.91	17.86	25.09	32.03	49.55	78.05	99.34	108.98	114.27	121.37	170.47	255.08	402.64
Kigoma	5.69	7.65	8.70	8.92	10.04	16.42	25.25	78.11	140.36	165.09	158.77	158.6	162.83	175.06	193.79
K'Manjaro	35.76	45.31	46.52	46.15	52.01	57.37	63.72	69.85	75.8	82.45	89.24	96.46	102.74	107.88	114.98
Lindi	1.28	1.72	3.71	3.84	6.18	8.63	16.17	25.51	34.58	82.11	83.99	88.63	115.09	147.89	188.49
Manyara															
Mara	20.2	25.6	29.24	31.5	33.78	36.01	38.63	41.19	43.65	46.87	50.3	53.97	78.01	116.88	183.93
Mbeya	30	38.01	40.04	40.86	44.48	49.83	55.17	65.66	75.13	85.52	93.9	102.79	155.58	227.75	320.79
Morogoro	39.07	49.5	51.29	51.31	54.65	59.16	64.73	69.99	74.67	84.76	94.99	105.47	162.14	228.91	281.7
Mtwara	10.71	14.41	15.24	15.33	28.44	60.12	99.12	146.31	179.45	202.85	200.7	204.72	226.07	250.84	285.3
Mwanza	42	53	55	55	83	106	123	139	155	170	187	205	318	428	477
Rukwa	6.08	6.688	8.08	8.04	11.73	14.86	21.15	30.18	35.55	45.25	47.62	50.19	70.32	98.32	140.61
Ruvuma	5.77	7.77	7.87	8.58	10.86	12.71	14.41	16.66	27.33	36.42	37.09	38.66	50.17	66.6	79.41
Shinyanga	74.3	94.14	105.52	112.6	118.34	156.46	207.75	243.18	255.5	286.75	318.28	350.13	555.74	803.17	1128.12
Singida	7	9.37	9.98	10.17	13.74	15.62	17.8	19.92	22.02	23.97	26.09	28.39	43.29	66	97.35
Tabora	19.61	25	29	31	42	43	46	48	50	58	66	74	130	201	289
Tanga	59.3	75.14	78.79	78.61	94.92	111.72	146.38	169.5	206.48	231.17	236.98	247.34	304.02	371.18	426.12
System Peak Demand	**832.6**	**1,054.17**	**1,108.88**	**1,130.65**	**1,354.75**	**1,691.78**	**2,073.35**	**2,504.15**	**2,876.71**	**3,180.54**	**3,349.22**	**3,547.34**	**4,690.02**	**6,040.50**	**7,589.41**
Growth			*33.2%*	*2.0%*	*19.8%*	*24.9%*	*22.6%*	*20.8%*	*14.9%*	*10.6%*	*5.3%*	*5.9%*	*5.4%*	*4.8%*	*4.9%*
Overall Electrification Rate		**13.75%**	**14.46%**	**15.23%**	**18.31%**	**21.28%**	**24.14%**	**26.91%**	**29.59%**	**32.05%**	**34.63%**	**37.34%**	**50.75%**	**65.78%**	**78.17%**

Table 2- 9: Peak Demand and Generation Forecasts

Year	Sum of Peak MW	Coincidental Peak MW	Gross Generation GWh
2010-Unconstrained	1,061.9	1054.17	5,653
2011	1,117.0	1108.88	5,908
2012	1,138.9	1130.65	6,085
2013	1,364.6	1354.75	7,332
2014	1,704.1	1691.78	9,200
2015	2,088.5	2073.35	11,246
2016	2,522.4	2504.15	13,520
2017	2,897.7	2876.71	15,494
2018	3,203.8	3180.54	17,194
2019	3,373.7	3349.22	18,322
2020	3,573.3	3547.34	19,607
2021	3,780.7	3753.31	20,943
2022	4,008.7	3979.63	22,424
2023	4,252.9	4222.11	24,000
2024	4,482.8	4450.34	25,514
2025	4,724.3	4690.02	27,139
2026	4,979.2	4943.10	28,860
2027	5,247.6	5209.56	30,689
2028	5,531.0	5490.90	32,635
2029	5,806.0	5763.93	34,560
2030	6,084.6	6040.50	36,543
2031	6,377.5	6331.25	38,646
2032	6,678.8	6630.38	40,836
2033	6,978.6	6927.98	43,030
2034	7,290.2	7237.37	45,359
2035	7,644.8	7589.41	47,724

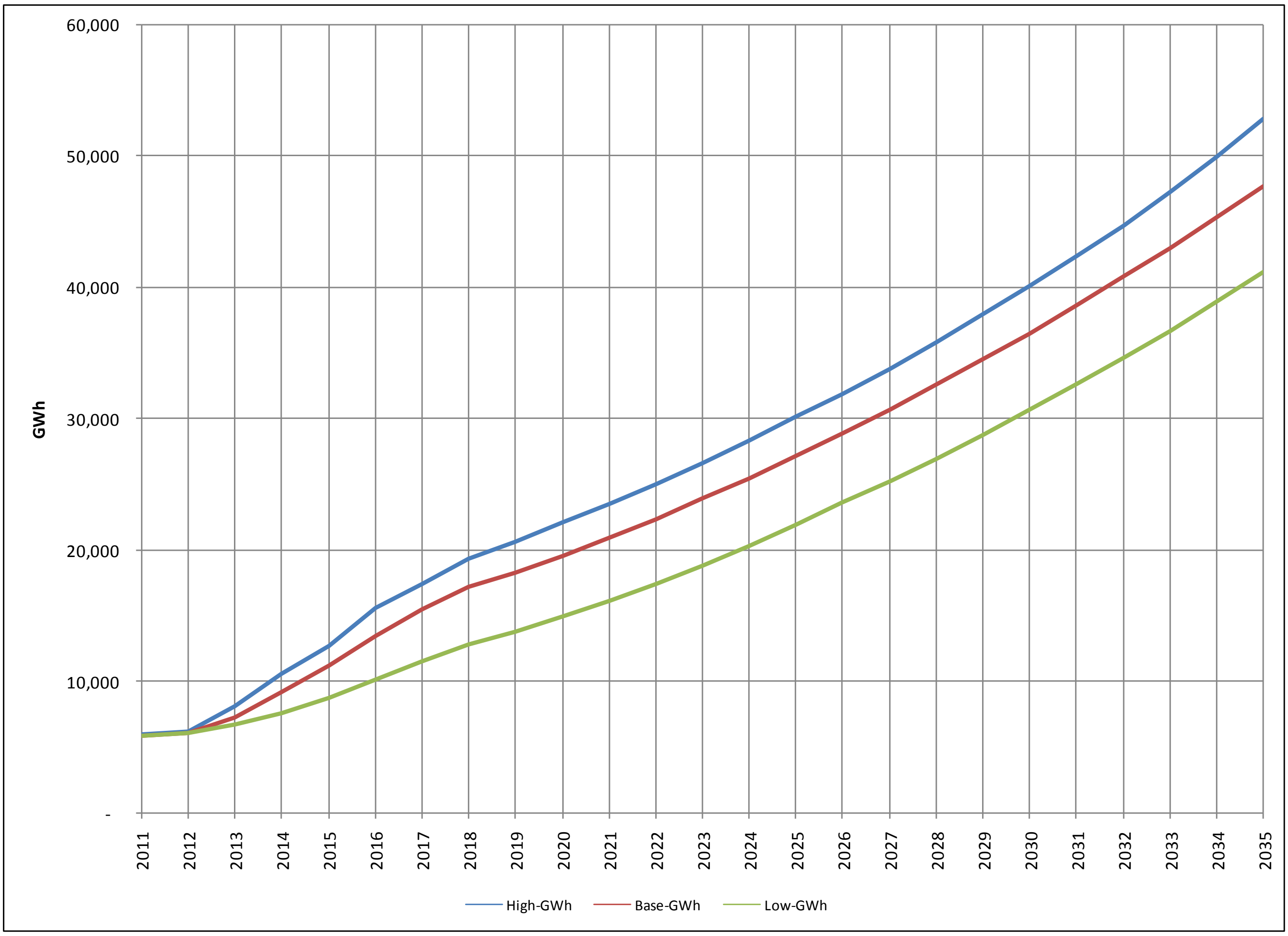
Source: Team Compilation

Figure 2- 3: Electricity Sales Forecast: 2011 - 2035



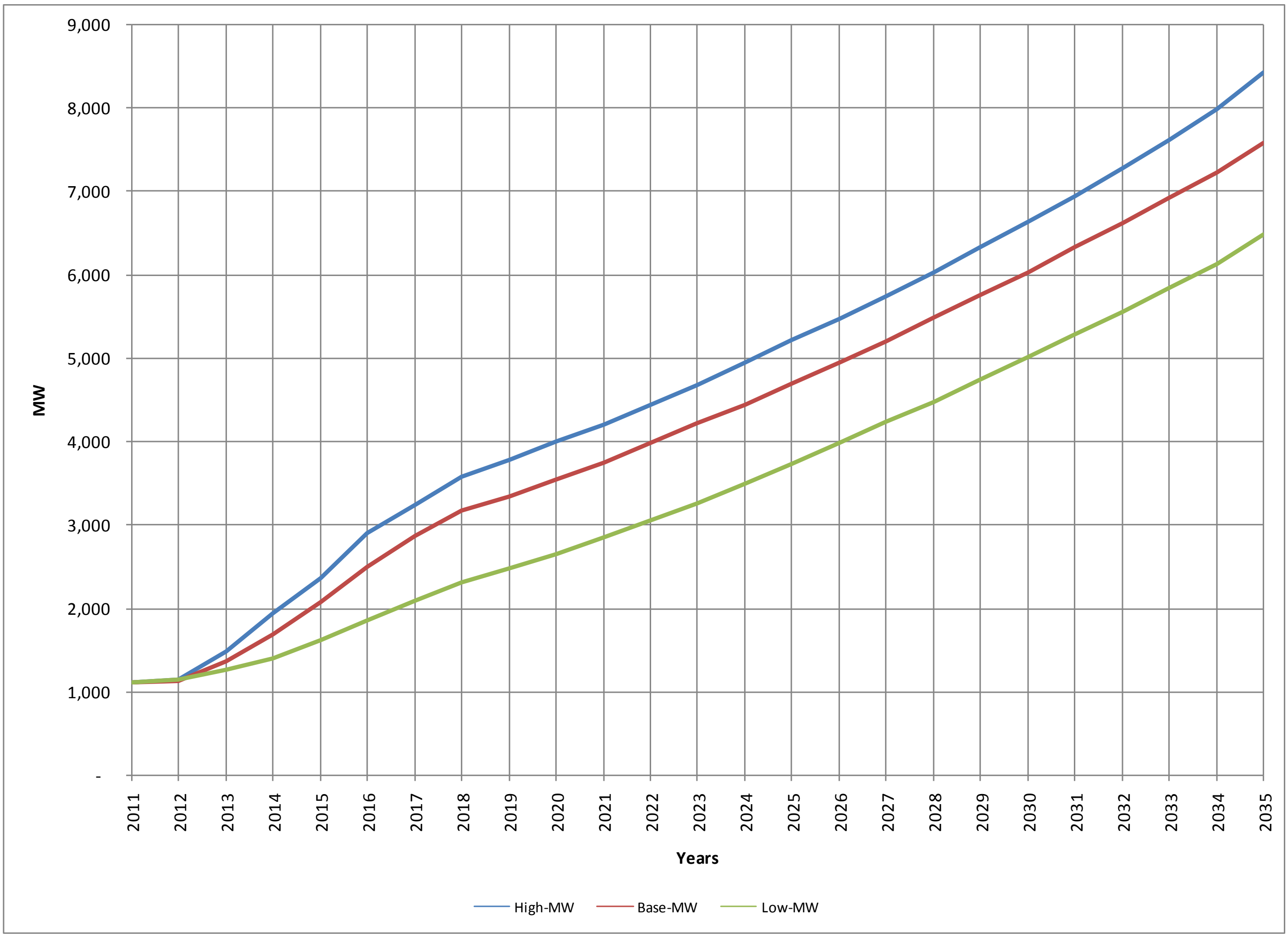
Source: Team Compilation

Figure 2- 4: Gross Generation Forecast: 2011 - 2035



Source Source: Team Compilation

Figure 2- 5: Peak Demand Forecast: 2011 - 2035



Source: Team Compilation

2.7 Derivation of global energy sales forecast

Introduction

This sub-section derives forecasts of electricity at the national level using econometric principles as opposed to the trend analysis approach used in the previous section. The two approaches are then compared.

The econometric method consists of estimating causal relationships between energy sales or consumption (the dependent variable) and factors influencing consumption (the independent variables). From a conceptual point of view, there are three issues in a load forecast that need particular care:

Both sides of the equation need to be compatible. As mentioned earlier, it is inappropriate to consider variables reflecting conditions in an entire nation with a variable reflecting only a part of the nation (e.g., sales for a region compared to GDP of the country as a whole);

An econometric analysis is only appropriate on large "populations." It should <u>not</u> be used on consumer categories where there are a relatively small number of customers, each with a very high consumption. In such a case, decisions by a small number of consumers can have a significant impact on the utility load. Econometric analyses are not equipped to handle such situations.

It should be noted that this approach implicitly assumes that conditions in the past will continue in the future. Significant changes such as accelerated electrification and rapid expansion of the mining, industries, and other identified loads must therefore be considered as additions to this method.

Econometric method

The econometric method consists of two steps.

<u>Step 1</u>: Plot the Sales vs. economic and/or demographic indicators, i.e. fit – via a regression analysis – an equation of the form:

Sales (t) = $\alpha + \beta \cdot$ (demographic indicators, t) + $\gamma \cdot$ (economic indicators, t)

Where at time t:

Sale = Sales in GWh (Sales could be T1 Sales, T2 Sales, T3 Sales or Country Sales),

Demographic indicators = Population, housing, etc.

Economic indicators = GDP, or subset thereof,

and α = constant, β and γ are the (estimated) coefficients.

Step 2: It consists of:

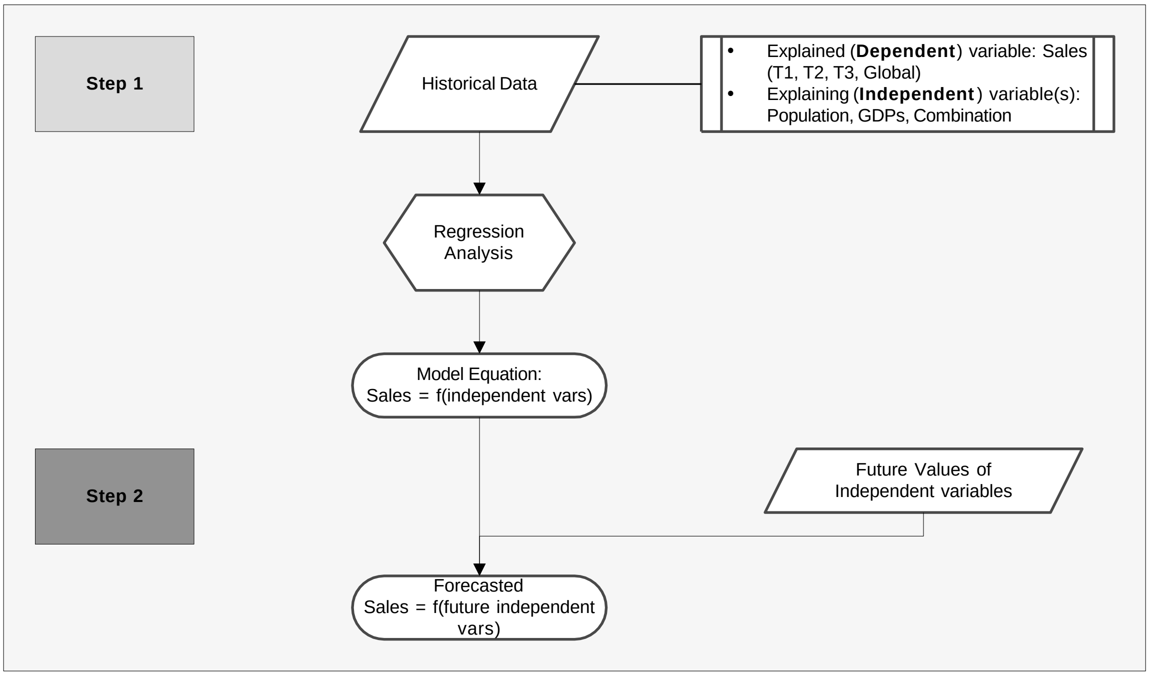
Assuming that, in time, the relationship established in Step 1 between Sales and the other variables --demographic, economic-- will hold true; and

On the basis of reasonable assumptions as to the evolution in the future of these (independent[5]) variables, which evolution is usually measured in terms of growth rates[6] (in percent), obtaining the forecast values of the Sales, at a future time t, by substituting the forecast values of the independent variables into the equation obtained in step 1.

The available historical data consists of: GDP components (Agriculture, Industry, and Services sectors) and Demography (Population). These variables or a Combination of them are the explaining or independent variables of the model. The explained or dependent variable is Sales (global sales or sales by customer category).

Its process is illustrated below.

Figure 2- 6: Econometric Modelling Forecast



A key element of the econometric process is the selection of the independent variables or combination of independent variables to be used in the equation "to explain" the dependent variables. A certain number of criteria are generally used to select the combination of independent variables. These selection criteria are:

[5] The term "independent" variable is used to designate an explanatory factor as opposed to "explained" or forecasted variable —in this case, Sales or Consumption— which is also termed as the "dependent" variable.

[6] By way of Population and Economic forecasts

Eligibility: if a combination yields a fitted coefficient –other than the *Intercept*– that is negative, it is ineligible. It is absurd to consider that, for example, the Sales would decrease when a predictor (e.g. Industry GDP or the Services GDP) increases.

Economic Argument: Between eligible combinations, the next applied criterion is economic and/or common sense. For example, to explain T1, Agriculture GDP was found to be eligible. However, T1 customers — that include residential, commercial, light industry and street lighting— straddle the three GDP sectors (Agriculture, Industries, and Services). Besides, the low electrification rate of the population whose majority lives off agricultural livelihood does not designate the Agriculture GDP alone as a prime independent variable to 'explain' the T1 sales.

Statistical Goodness of Fit: the statistical test criteria seek to answer two questions: (1) do the variables included in the equation belong there? and (2) is the relationship as a whole using these variables valid?

Two test statistics are usually retained: the Student t-statistic and the correlation coefficient R^2. The two statistics are provided by Stata package in its output. To be acceptable the t-statistic should be at least one in value and R^2, which is between 0 and 1, and it should be at least 0.6. Moreover, to break a "tie" between two or more equally good combinations of predictors, one also uses the F-statistic in conjunction with the t-statistic and R^2. More details on these statistical criteria are provided in footnote[7].

In line with this method, T1, T2, T3 and the Global Sales were, each, plotted against a series of combinations of independent variables or predictors. The ensuing results obtained after applying the above criteria are as follows:

Forecast for Category T1

Category T1 is composed of residential, commercial, light industry and street lighting customers. A series of relationships between sales to T1 customers and a number of

[7] The first test, using the *Student's t-statistic*, is calculated by Stata package, to test if a coefficient is zero (that is, if the variable does not belong in the equation). If the t-statistic exceeds one in magnitude, it is at least two thirds likely that the true value of the coefficient is not zero. If the t-statistic exceeds two in magnitude it is at least 95percent likely that the coefficient is not zero. Thus, a t-statistic greater than 2 indicates strongly that the variable used does belong in the relationship.

For testing the validity of the relationship, the *R-squared* **(R^2)** ratio is used. The R-squared measures the success of the equation in predicting the values of the dependent variable (sales of energy). The R-squared is unity if the equation provides a perfect fit and zero if it fits no better than the simple mean of the dependent variable. Usually, to be meaningful, R-squared is required to be at least 60percent, depending on the homogeneity of the historical data.

The *F Value* or F ratio is the test statistic used to decide whether the model as a whole has statistically significant predictive capability, that is, whether the regression SS is big enough, considering the number of variables needed to achieve it. F is the ratio of the Model Mean Square to the Error Mean Square.

The F-value can be used in conjunction with R2 and t-statistics as another criterion when one has to decide between several combinations of variables as predictors. Larger values of F tend to support better predictive capability.

combinations of various economic and demographic parameters were examined. The regression equation is given by:

T1 Sales as function of Total GDP

The details of this relationship are as follows:

```
. regress t1 gdp

      Source |       SS       df       MS              Number of obs =      32
-------------+------------------------------           F(  1,    30) =  115.14
       Model |  5613662.24     1  5613662.24           Prob > F      =  0.0000
    Residual |  1462701.61    30  48756.7205           R-squared     =  0.7933
-------------+------------------------------           Adj R-squared =  0.7864
       Total |  7076363.85    31  228269.802           Root MSE      =  220.81

------------------------------------------------------------------------------
          t1 |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
         gdp |    .000118    .000011    10.73   0.000     .0000955    .0001404
       _cons |    16.9954   96.33279     0.18   0.861    -179.7424    213.7332
------------------------------------------------------------------------------
```

That is:

T1 = 16.9954 + 0.000118 x GDP

Where T1 is expressed in GWh and the Total GDP is in TSh million (constant 2001 prices).

Forecast for Category T2

Category T2 includes low voltage commercial, service and industrial supply. A series of relationships between sales to T2 customers and a number of combinations of various economic and demographic parameters were examined. The equation is given by:

T2 Sales as a function of the sum of industry and services GDPs

The details of this relationship are as follows:

```
. regress t2 indservices

      Source |       SS       df       MS              Number of obs =      32
-------------+------------------------------           F(  1,    30) =   41.30
       Model |    297313.7     1    297313.7           Prob > F      =  0.0000
    Residual |  215966.801    30  7198.89336           R-squared     =  0.5792
-------------+------------------------------           Adj R-squared =  0.5652
       Total |  513280.501    31  16557.4355           Root MSE      =  84.846

------------------------------------------------------------------------------
          t2 |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
 indservices |   .0000271   4.21e-06     6.43   0.000      .0000185    .0000357
       _cons |   191.2547   24.27003     7.88   0.000      141.6887    240.8207
------------------------------------------------------------------------------
```

That is:

T2 Sales = 191.2547 + 0.0000271 x (Industry +Services GDPs)

Where T2 is expressed in GWh and the Industry **Plus** Services GDP is in TSh million (constant 2001 prices).

Forecast for Category T3

Category T3 includes high voltage supply, agricultural and National Urban Water Authority (NUWA) and mining load customers. A series of relationships between sales to T3 customers and a number of combinations of various economic and demographic parameters were examined.

The best relationship found was:

Sales to T3 customers as a function of sum of Agriculture and Industry GDPs alone

The details of this relationship are as follows:

```
. regress t3 agrindust

      Source |       SS       df       MS              Number of obs =      32
-------------+------------------------------           F(  1,    30) =  287.25
       Model |  6389607.16     1  6389607.16           Prob > F      =  0.0000
    Residual |  667314.806    30  22243.8269           R-squared     =  0.9054
-------------+------------------------------           Adj R-squared =  0.9023
       Total |  7056921.97    31  227642.644           Root MSE      =  149.14

------------------------------------------------------------------------------
          t3 |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
   agrindust |    .000251   .0000148    16.95   0.000      .0002208    .0002813
       _cons |  -422.0447   65.23152    -6.47   0.000     -555.2652   -288.8241
------------------------------------------------------------------------------
```

That is:

T3 Sales = -422.0447+0.000251 x (Agric + Industry GDPs)

Where T3 is expressed in GWh and the Agriculture **plus** Industry GDP is in TSh million (constant 2001 prices).

Forecast of total sales using a global equation

The Total Sales can be derived by taking the sum of the sales to the individual categories or by directly regressing it by the socioeconomic variables. As in the preceding section, the (direct) fitting of the Total (or Global) Sales is carried out by examining a series of relationships between Total Sales and various economic and demographic variables.

Hence, the best relationship found was:

Total sales as a function of total GDP

The details of this relationship are as follows:

```
. regress eneconsp gdp

      Source |       SS       df       MS              Number of obs =      32
-------------+------------------------------           F(  1,    30) =  398.27
       Model |  29235888.7     1  29235888.7           Prob > F      =  0.0000
    Residual |  2202212.23    30  73407.0744           R-squared     =  0.9300
-------------+------------------------------           Adj R-squared =  0.9276
       Total |  31438100.9    31  1014132.29           Root MSE      =  270.94

------------------------------------------------------------------------------
    eneconsp |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
         gdp |   .0002692   .0000135    19.96   0.000     .0002416    .0002967
       _cons |   -291.516   118.2023    -2.47   0.020    -532.9173   -50.11476
------------------------------------------------------------------------------
```

That is:

Global Sales = -291.516 + 0.00026928 x GDP

Where Total Sales is expressed in GWh and the Total GDP is in TSh million (constant 2001 prices).

2.7.1 Forecast Results

Figure 2-7 provides a forecast of the loads for each of the categories described above for the sum of the three Categories and for the global forecast (supporting data table is also provided below in Table 2-10). The figure indicates a close agreement between the sum of the three categories and the global forecast

Figure 2- 7: Econometric Forecast – Sum of Three Categories versus Global

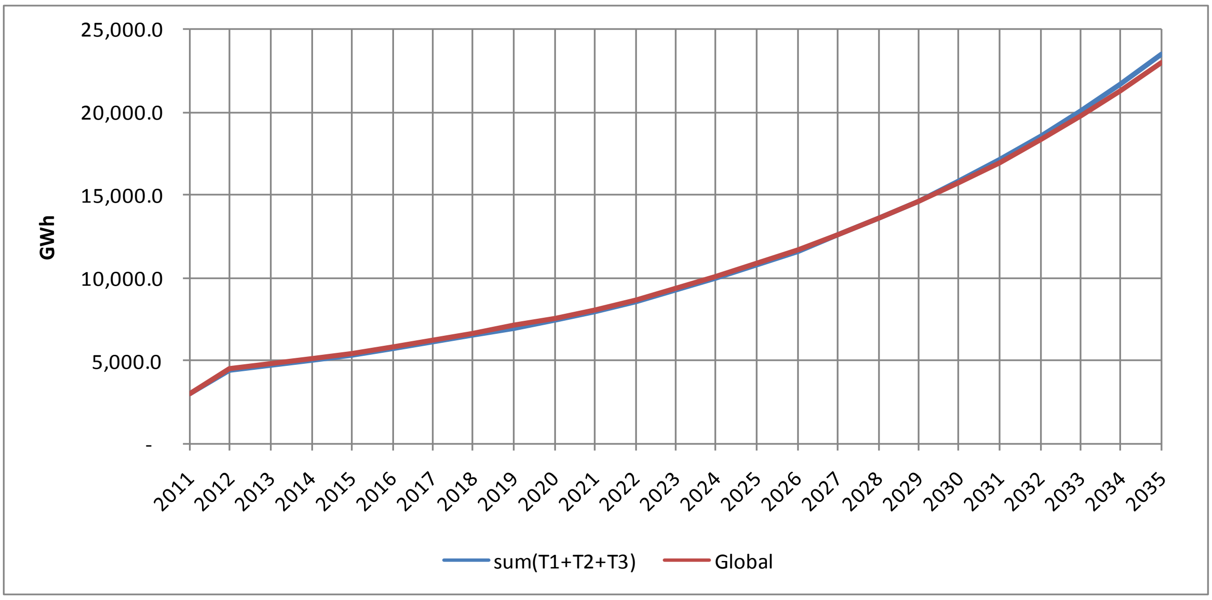


Table 2- 10: Sales Forecast (GWh) by Econometric Method

YEAR	T1	T2	T3	T1+T2+T3	Global
2010	2,187.0	599.8	1,604.4	4,391.2	4,391.2
2011	**1,444.4**	**413.7**	**1,192.7**	**3,050.8**	**3,050.8**
2012	2,140.1	560.5	1,736.7	4,437.3	4,552.1
2013	2,272.2	586.1	1,876.1	4,734.5	4,853.4
2014	2,413.1	613.5	2,026.0	5,052.6	5,174.9
2015	2,563.6	643.0	2,187.0	5,393.5	5,518.1
2016	2,725.3	674.5	2,362.5	5,762.3	5,887.0
2017	2,896.8	708.4	2,548.9	6,154.1	6,278.4
2018	3,080.1	744.7	2,749.4	6,574.2	6,696.5
2019	3,276.0	783.7	2,965.4	7,025.0	7,143.3
2020	3,485.3	825.5	3,198.0	7,508.8	7,620.9
2021	3,709.1	870.4	3,448.7	8,028.2	8,131.5
2022	3,978.1	925.4	3,741.9	8,645.4	8,745.1
2023	4,268.2	985.0	4,060.8	9,314.0	9,407.0
2024	4,581.3	1,049.7	4,407.6	10,038.6	10,121.4
2025	4,919.3	1,119.7	4,785.1	10,824.1	10,892.5
2026	5,284.4	1,195.6	5,196.1	11,676.1	11,725.2
2027	5,678.7	1,278.0	5,643.8	12,600.4	12,624.8
2028	6,104.8	1,367.3	6,131.7	13,603.7	13,596.8
2029	6,565.3	1,464.2	6,663.6	14,693.1	14,647.5
2030	7,063.3	1,569.3	7,243.9	15,876.4	15,783.6
2031	7,601.9	1,683.4	7,877.0	17,162.2	17,012.3
2032	8,184.6	1,807.2	8,568.0	18,559.8	18,341.7
2033	8,815.2	1,941.7	9,322.6	20,079.6	19,780.4
2034	9,498.0	2,087.6	10,147.0	21,732.6	21,337.9
2035	10,237.3	2,246.2	11,047.7	23,531.2	23,024.6

Source: Team Compilation

Trend of Electricity Share per Customer Tariff Category Looking at the trend of share categories as illustrated in **Table 2-12**, it is apparent that projections of tariff aimed at facilitating Tanzania to become a middle income country characterised by semi-industrial activities. Notwithstanding, a large contribution of T1 category in overall sales, its share is gradually declining reaching 43.5% in 2035 from a highest share observed in 2012. Similarly, T2 share is declining slowly reflecting graduation of T2 category into T3 category (agriculture and Industry). Comparably, T3 categories despite of their lower share in the early years of projections, their trend is increasing from 39.1% in 2011 to 46.9% surpassing T1 category mainly on account of expected increase and expansion of industrial and mining activities.

Table 2- 11: **Trend of Electricity Share per Customer Tariff Category**

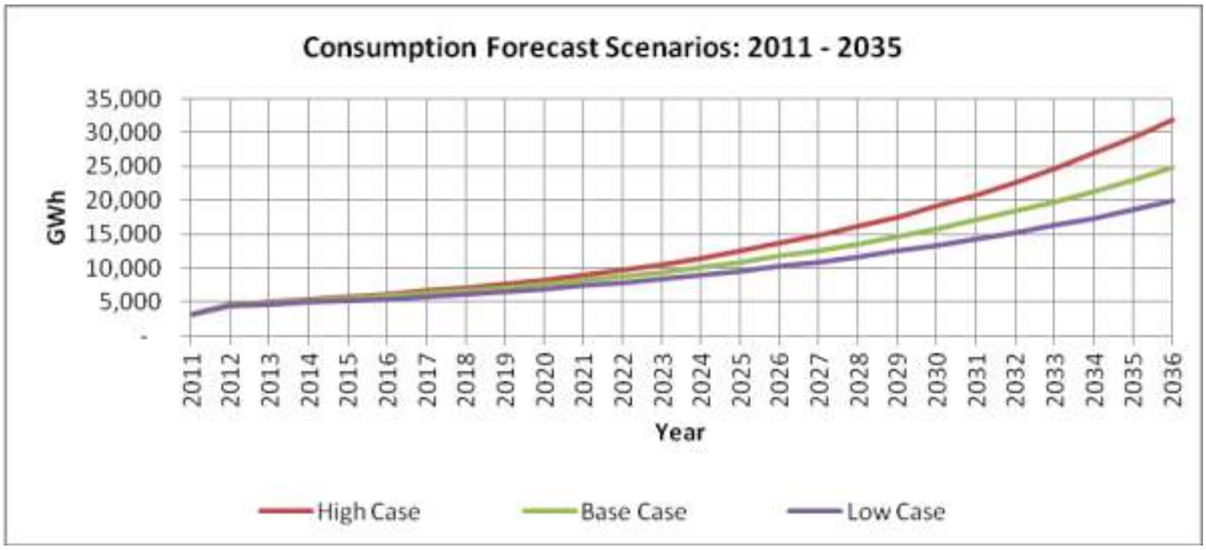
T1	T1	T2	T3
2011	47.3%	13.6%	39.1%
2012	48.2%	12.6%	39.1%
2013	48.0%	12.4%	39.6%
2014	47.8%	12.1%	40.1%
2015	47.5%	11.9%	40.5%
2016	47.3%	11.7%	41.0%
2017	47.1%	11.5%	41.4%
2018	46.9%	11.3%	41.8%
2019	46.6%	11.2%	42.2%
2020	46.4%	11.0%	42.6%
2021	46.2%	10.8%	43.0%
2022	46.0%	10.7%	43.3%
2023	45.8%	10.6%	43.6%
2024	45.6%	10.5%	43.9%
2025	45.4%	10.3%	44.2%
2026	45.3%	10.2%	44.5%
2027	45.1%	10.1%	44.8%
2028	44.9%	10.1%	45.1%
2029	44.7%	10.0%	45.4%
2030	44.5%	9.9%	45.6%
2031	44.3%	9.8%	45.9%
2032	44.1%	9.7%	46.2%
2033	43.9%	9.7%	46.4%
2034	43.7%	9.6%	46.7%
2035	43.5%	9.5%	46.9%

Source: Team Compilation

2.8 Sensitivity

Because of the uncertainties inherent in forecasting, the load forecast should be considered as a band of probable loads above and below a base forecast as opposed to a single value for each year. A range of values for various components of GDP have been used to forecast band using econometric principles. **Figure 2-8** illustrates the load forecasts for each set of assumptions. The graphs suggest that the low scenario grows about one percentage points less on average than the base case. Conversely, the high scenario grows at 1.1 percentage point faster than the base case.

Figure 2- 8: Econometrics Forecast Scenarios



Source: Team Compilation

2.9 Comparison of Trend Analysis and Econometric Analysis

Table 2-13 provides a comparison of the econometric results with the trend line results. The econometric relationship applied to Global Sales was used for this comparison as it was, by far, the strongest econometric relationship. As seen in the table, the difference between the forecast using the two approaches reveal that trend analysis approach provide higher estimates (taking into account assumptions of programs etc) than econometric approach. In this context and in the absence of policy interventions[8], the two approaches to the forecast energy would essentially derive comparable forecast results

Table 2- 12: Forecast Comparison: Econometric–Global vs Trend -Total in GWh

Year	Global - Econometric	Trend Forecast_ Total	Difference: with Global	Difference: (percent)
2012	4,552.1	4,596.7	44.6	1.0%
2015	5,518.1	8,873.8	3,355.7	60.8%
2020	7,620.9	15,821.4	8,200.4	107.6%
2025	10,892.5	22,243.5	11,351.0	104.2%
2030	15,783.6	30,324.9	14,541.3	92.1%
2035	23,024.6	40,083.0	17,058.5	74.1%

Source: Team Compilation

[8] *The policy intervention means special program initiated by the government to be implemented such as special rural electrification program which results in strong demand growth in the early years of the forecast.*

The difference of the forecast in terms of average growth rate over the planning horizon remains large as the trend approach reveals more GWh compared to econometric methods. The reason is mainly attributable to the connection of 1.25 million customers under electrification program in early years of the forecast. Thereafter, the growth rates of trend approach grow at a sustainable rate necessary to achieve overall objective of electrifying 75% of population by 2036. As such the growth using the trend line averages 9.7 percent while the growth using the econometric approach averages 7,5 percent.

CHAPTER THREE

3 GENERATION

Generation plan presents an assessment of generation sequencing that meet demand for the forecast period. A number of generation technologies have been evaluated to attain the recommended plans for development of power sector in the country. In identifying new power projects, the plan evaluate new power generation technologies, including a review of capital investment, project lead time, fuel costs and their availability, both locally and imported. In addition, confirmatory studies such as environmental assessment and project financing arrangement are key elements of the projects preparations and signals on the possibility of success for the identified projects. The generation plan considers the following power sources namely hydro, gas, coal, wind, geothermal, among others.

3.1 Existing Generation Plants

Table 3-1: Existing Hydro Plant Characteristics

	Mtera	Kidatu	Nyumba ya Mungu	Hale	New Pangani Falls	Lower Kihansi	Mwenga
Max. supply level (m.a.s.l.)	698.50	450.00	688.91	342.44	177.50	1146.00	1127
Min. supply level (m.a.s.l.)	690.00	433.00	679.15	342.44	176.00	1141.00	1126
Recommended min. operational level (m.a.s.l.)	690.00	437.00	683.76	N/A	176.50	1143.00	1126
Storage vol. at max. level (mill. m^3)	3750.00	167.00	1118.11	0.00	1.31	1.62	0.0024
Storage vol. at min. level (mill. m^3)	563.00	40.00	246.71	0.00	0.50	0.62	0.0019
Active storage volume (mill. m^3)	3187.00	127.00	871.40	0.00	0.81	1.00	N/A - Run of River
Surface area at max. vol. (km^2)	604.96	9.62	148.52	0.00	0.75	0.27	0.003
Gross head at max. level (m)	101.0 (Francis)	175.0 (Francis)	25.2 (Francis)	70.0 (Francis)	169.7 (Francis)	852.75 (Pelton)	62 (Francis)
Gross head at min. level (m)	92.00	160.00	20.60	70.00	168.00	847.75	58.5
Energy equivalent (kWH/m^3)	0.23	0.42	0.05	0.13	0.42	2.06	N/A - Run of River
Firm energy generation GWh							6 GWh per annum
Average energy GWh	363.00	964.00	35.00	88.00	323.00	662.00	24 per annum
Avg. generation for each m^3/s (MW/(m^3/s)	0.846	1.5	0.2	0.5	1.5	7.4	0.5
Rated turbine discharge (total plant) (m^3/s)	97.50	132.00	42.50	45.00	45.00	23.76	8

Kidatu storage level restrictions (control curve) :-
During wet periods January to May level is supposed to be maintained =or<445.0 m.a.s.l
During dry periods June to December level is supposed to be maintained =or>449.5 m.a.s.l

Thermal plants

The interconnected grid system is composed of several power plants, among those seven are gas fired plants, three are Heavy Fuel Oil (HFO) plants, two are Biomass plants, two are Diesel and one Industrial Diesel Oil.

Thermal power plants on average have an economic life span of twenty (20) years however; the life span can be extended by proper maintenance and interim replacement of major parts. Characteristics of the existing thermal power plants are shown in table **3-2.**

Table 3- 2: Existing Thermal Plants

Plant	Fuel	Units	Installed Capacity MW	Available Capacity MW	Station service %	Net Available Capacity MW	FOR %	Combined Outage Rate %	Maximum Plant Factor %	Available Energy GWh	Year Installad (Jan)	Nominal Service Life Years	Retirement Year (Dec)
IPP UNITS													
Songas 1	Gas	2	42.00	38.30	1.60	37.69	5	13	80	251	2004	20	2023
Songas 2	Gas	3	120.00	110.00	1.60	108.24	5	13	80	721	2005	20	2024
Songas 3	Gas	1	40.00	37.00	1.60	36.41	5	13	80	242	2006	20	2025
Tegeta IPTL	HFO	10	103.00	100.00	1.60	98.40	8	18	75	595	2002	20	2021
TPC	Biomass		17.00	17.00	1.60	16.73	5	13	50	70	2011	20	2030
TANWAT	Biomass		2.70	2.40	1.60	2.36	5	13	50	10	2010	20	2029
Subtotal			**324.70**	**304.70**		**299.82**				**1888**			
TANESCO													
Ubungo I	Gas	12	102.00	100.00	1.60	98.40	5	13	80	655	2007	20	2026
Tegeta GT	Gas	5	45.00	43.00	1.60	42.31	5	13	80	282	2009	20	2028
Ubungo II	Gas	3	105.00	100.00	1.60	98.40	5	13	80	655	2012	20	2031
Zuzu D	IDO	1	7	5.00	1.60	4.92	5	18	75	31			2014
Subtotal			**259.00**	**248.00**		**244.03**				**1623**			
RENTAL UNITS (IPP's)													
Symbion Ubungo	Gas/Jet A1	5	120	113.79	1.60	112.00	5	13	80	746	2011	2	2013
Aggreko (Ubungo)	GO		50	50	1.60	50.00	8	18	85	674	2011	1	2012
Aggreko (Tegeta)	GO		50	50	1.60	50.00	8	18	85				
Symbion Dodoma	HFO		55	55.00	1.60	54.12	8	18	85	371	2012	2	2014
Symbion Arusha	HFO		50	50.00	1.60	49.20	8	18	85	337	2012	2	2014
Subtotal			**325**	**318.79**		**315.32**				**2127**			
TOTAL			**908.70**	**871.49**		**859.18**				**5638.23**			

Available energy (MWh) = Available capacity (MW) * 8.76*(100-FOR)*max plant factor/100

Small diesels assumed to stay in service to December 2012 as reserve

FOR = Forced outage rate

Retirement of Existing Plant

In the scheduling of new generation, existing generating units were assumed to be retired at the end of their normal "economic" service life except for hydroelectric plants which were assumed to remain in service. Assumed retirement dates are shown in **Table 3-3.**

Table 3- 3: Existing Plant Retirement Dates (Interconnected System)

Plant name	Nominal Capacity MW	Normal service life – years	Installation year January	Retirement year December
HYDRO				
Mtera	80	50	1988	2038
Kidatu	204	50	1975	2025
Hale	21	50	1967	2017
Kihansi	180	50	2000	2050
Pangani Falls	68	50	1995	2045
Nyumba Ya Mungu	8	50	1968	2018
Mwenga	4	15*	2012	2017
THERMAL				
SONGAS I (2 units)	40	20	2004	2024
SONGAS II (3 units)	120	20	2005	2025
SONGAS III (1 units)	40	20	2006	2026
Tegeta IPTL	100	25	2002	2027
Tegeta GT	45	20	2009	2029
Ubungo I	100	20	2010	2030
Symbion 112	112.5	2*	2011	2013
Symbion Dodoma	55	2*	2011	2013
Symbion Arusha	50	2*	2012	2014
Ubungo II	105	20	2012	2032
Tanwat	2.7	20	2010	2029
Zuzu Diesel	7.44	20**	1980	2014
TPC	17	20	2011	2030

Source: TANESCO

*Contractual period

** Rehabilitated

3.2 Future Generation Options

3.2.1 Hydroelectric power

3.2.1.1 Hydrology and Hydro System Capability

The availability of reliable generation sequences at each candidate hydroelectric project is of major importance. It is important that updated hydrologic data is used for each PSMP update, and that the simulations reflect the optimum use of hydroelectric resources, taking into account the use of reservoirs in a mixed hydro-thermal system. In this Power System Master Plan Update, the energy generation of all new candidate hydroelectric projects, and existing plants, was re-estimated using revised and updated flow records. The re-estimate of generation values was made in two steps, updated hydrology and new generation simulations.

3.2.1.2 Hydrological Data Update

The Tanzania Power System Master Plan requires consideration of existing and potential power development options. Since many of these options are hydropower projects, a clear assessment of the hydrology and hydropower system capability is unavoidable. Hydropower generation capability is determined by simulating generation from historical flows over a sufficient long period. The period should be long enough to cover observed natural variations and should include most recent data to reflect new developments.

Therefore, availability of representative sample (reference hydrology) of river flows is the key to reliable assessment of the generation potential of hydroelectric system. A reference hydrology consists of complete set of recorded or estimated stream flows during a specified period of time.

Observed historical stream flows has always been the favoured source of representative time series for hydropower simulation. River flow data collection is the responsibility of Ministry of Water and its integrity of dataset has always been subject to budgetary and other constraints. Uninterrupted datasets spanning many years are difficult to find thus reconstitution of historical flow records has always been a prerequisite to hydropower generation simulations.

This study employed datasets developed during preparation of 2008 Power System Master Plan and later updated in 2009 when intensive analysis was carried out. TANESCO is currently working with Ministry of Water to update relevant datasets for future analyses. The data will also indicate recent trends.

3.2.1.3 Hydro generation simulations

The simulation model is used to determine the generation capability of new hydro options. This study utilised simulation results as implemented during 2009 update following establishment of new set of reference hydrology.

3.2.1.4 Existing Hydroelectric Power Plants

The interconnected grid system is composed of several power plants, among those seven hydro power plants have a capacity of more than 1MW connected to the grid.

Table 3- 4: Existing Hydroelectric Power Plants

Plant name	Capacity MW	Average energy GWh	Firm energy GWh	Installation year	Age in 2012 (years)
Mtera	80	429	195	1988	25
Kidatu	204	1111	601	1975	38
Hale	21	93	55	1967	46
Kihansi	180	694	492	2000	13
Pangani Falls	68	341	201	1995	18
Nyumba Ya Mungu	8	36	20	1968	45
Mwenga	4	28.51	0	2012	1
TOTAL	**565**	**2,820.5**	**1,564**		

Hydro power plants on average have an economic life span of fifty (50) years however; the life span can be extended by proper maintenance and interim replacement of major parts. This PSMP Update assumes that existing hydro plants remains operational during the period of this plan. Characteristics of the existing hydro power plant are shown in **Table 3.4**

Plan Strategies

There are three major development strategies for generation planning. This update borrows some strategies used in the preparation of the 2008 Master Plan, and subsequent 2009 Update study. The Plan is guided by Overall Power Development Strategy which is explained in **Table 3-5**. The specific strategies are illustrated more in **Tables 3.7**.

Table 3- 5: Overall Power Development Strategy

Element	Why?
Base case load forecast	To take account of all identified new industrial loads, including background load growth, and to target a 75% electrification rate by 2035.
Interconnect isolated regions	To the extent that it is economic and feasible to do so, in order to promote social and economic development
Install all new generation options that are feasible in the short term regardless of unit cost	To eliminate risk of load shedding in early years of the plan
Use judicious mix of hydro and non-hydro generation options	To avoid over-reliance on hydro with attendant risk of power shortages during dry periods
Accept limited amounts of firm imports/exports	To balance low cost of power and energy self-sufficiency
Schedule new generation so that sufficient reserve margin is provided to allow for future pool power trading	To improve the economics of system expansion by developing revenue potential, while also providing improved security of energy supply

Short-Term Power Development Strategy

a) The generation projects shown in **Table 3.6** forms the short-term plan (2013 – 2017) for both public and private sector. The projects are either under construction, committed stage, and/or they have short lead time and can be developed under a fast-track arrangement. Aggreko and Dowans power plants are expected to retire following end of contract periods. In addition, there are private sector companies which have shown up an interest to invest in short term projects as outlined in the table below. The projects include 200 ± 25MW Gas based Combined Cycle Power Project (Zinga - Bagamoyo) for the purpose of facilitating development of industrial area (EPZ). The captive power requirement within the EPZ is estimated to be 75MW while the surplus power will be supplied to the grid. Other projects are Mkuranga 250MW, Mtwara 400MW and Somanga Fungu 320MW (phase I & II).

Table 3- 6: Power Generation Projects for Short – Term Expansion Plan

Project Description	Reasons	Date On-line
a) Mwanza 60MW, Diesel fired	a. They are committed plants, b. Meet background growth in demand in Tanzania, c. These are the only resources identified as capable of being ready at this short time.	Early 2013
a) Kinyerezi I, 150MW GTs plant	i. Meet background growth in demand ii. They are the only resources identified as capable of being ready at this time	Early 2014
b) Somanga Fungu (TANESCO) 8MW c) Somanga Fungu 210MW d) Kinyerezi II, 240MW GTs plant e) 200 ± 25MW Gas based Combined Cycle Power Project (Zinga - Bagamoyo) f) Mkuranga 250MW g) Renewable - Cogen (Mufindi) 30MW h) Renewable – Cogen (Sao Hill) 10MW	i. Meet background growth in demand ii. Generation mix, to include renewable wind power iii. They are the only resources identified as capable of being ready at this time	Early 2015
a) Kinyerezi III, 300MW GTs plant b) Kinyerezi IV, 300MW GTs Plant c) Mtwara (18), 400MW d) Kiwira I 200MW Coal fired, Mbeya e) Somanga Fungu, 110MW f) Wind I, 50MW g) Solar I, 60MW h) Import (Kenya/Ethiopia), 200MW	i. Meet background growth in demand ii. They are the only resources identified as capable of being ready in the short time iii. Generation mix, to include more renewable wind power iv. Build base for possible power trading	Early 2016
a) Wind II, 50MW, b) Ngaka-I 200MW, coal fired Ruvuma c) Hale, 11MW d) Interconnector	i. Meet background growth in demand ii. Import from Ethiopia through Tanzania – Kenya interconnector.	Early 2017

Source: Team Compilation

Mid to Long-Term Power Development Strategy

Strategies shown in **Table 3.7** were considered in the preparation of the mid to long-term plan (2018 – 2035). It is assumed that most of the projects are committed while others are in feasibility study or at early preparatory stages.

Table 3- 7: Mid to Long-Term Strategies

Element	Why?
Work with IPPs/PPPs to Identify and study additional sites for renewable power generation	It is a renewable energy whose costs are being lowered through ongoing research world-wide
Implement the Demand Side Management Program as per energy efficiency study report.	It is cheaper to implement energy efficiency program than building a new plant
Work with the Ministry of Energy and Minerals, and the private sector to continue studies to prove up additional quantities of natural gas	It is a relatively low-cost indigenous fuel with relatively few negative environmental and social impacts
The government to harmonize the acceleration of coal usage for power generation	It is a relatively low-cost indigenous fuel although it has significant negative environmental and social impacts. With new technology can be considered as base load resource.
Develop and implement a program of project preparation studies, including environmental and social assessments, for all hydro sites included in this PSMP generation plan.	Hydro is of key importance as an indigenous resource, and indicative costs are lower than thermal power. Adequate basic information is required to encourage private investors to submit proposals for project implementation
Work with the Ministry of Energy and Minerals to develop a long term policy on possible use of nuclear power, and support studies to prove the availability and capacity of uranium resources and study the opportunities for the development of nuclear generation	It may be a relatively low-cost indigenous fuel that has few immediate environmental and social impacts.
Complete studies on Stiegler's Gorge hydro development to the point where a decision can be made on whether or not it can be implemented	On the one hand, it is a relatively low cost power development with few negative environmental and social impacts. On the other hand, it is located in a Game Reserve which makes it difficult to obtain international financing
Jointly with Malawi, carry out further studies on Songwe hydro cascade development to the point where a decision can be made on the optimum development of the river from the points of view of all potential users in both affected countries	On the one hand, it is a relatively low cost power development with few negative environmental and social impacts. On the other hand, it is located in a river bordering Tanzania and Malawi and it has been studied more from the point of view of uses other than hydro power

Interconnection strategies

Apart from development strategies that are aimed at utilizing local sources of generation, the PSMP extend more strategy that includes export and import of power to and from neighbouring countries. Based on the recent climatic change it is risky to depend on the internal sources of power generation implying the need for countries moving immediately towards interconnecting their Grid systems. **Table 3-8** shows expected interconnection projects.

Table 3 - 8: Interconnection Projects

Countries	Generation	Why?	When?
Ethiopia via Kenya	Inter-connector	To improve energy security with power purchases	From 2016
Zambia and Kenya,		- do –	
Tanzania and Mozambique		- do –	mid – term
The rest of EAC countries.		- do –	
Comments: Interconnection would facilitate integrated power resource planning that have environmental and social risks and would strengthen the transmission networks of each country.			

Generation Planning Criteria

The 2012 PSMP update use the following criteria:-

Reserve Margin: This study update assumes a reserve margin of 15 to 40 percent of the system installed capacity.

Generation Mix: This study update assumes a hydro to thermal generation mix of 40:60 of the system installed capacity.

Loss of Load Expectation: The plan maintains the use of a maximum loss of load expectation (LOLE) of 5 days per year as established in the 2008 PSMP. The LOLE values are based on a hydropower during a low flow period with a return period of 1: 30 years, or 97percent probability of exceedance.

Outage rates: The plan assumes that there will be planned and forced outages at the generating plants. The Combined Outage Rates per year is a result of scheduled maintenance and forced outages. **Table 3-9** below outlines the selected outage rates based on different technologies.

Table 3 - 9: Selected Outage Rates for Generation Planning in PSMP

Generation type	Scheduled maintenance in weeks per year	Forced outage in percent of time per year	Combined outage rate percent
Coal steam thermal	6	8	20
Oil steam thermal	4	7	15
Gas turbine	4	5	13
Combined cycle gas turbine	3	5	11
Medium speed diesel	5	8	18
Cogeneration steam plant	4	7	15
Hydroelectric	4	0	8

Plant service lives: The following service lives were used in determining average unit generation costs for preliminary comparisons, and for determining retirement dates for existing and future plants in the development of generation plans:

Table 3- 10: Plant service lives

Generation type	Normal service life – years
Gas turbines	20
Combined cycle gas turbines	20
Medium speed diesel	20
Low speed diesel	25
Coal and oil steam plants	25
Hydroelectric plant	50 *

* Normally extended by major equipment replacement and maintenance

Operation and maintenance and other costs: Unit generation costs include allowances for operation and maintenance, interim replacement, and insurance. For thermal plants, the operation and maintenance cost is separated into fixed and variable costs, while for hydroelectric plants, O&M cost is considered as fixed cost. Interim replacement is an annual allowance to cover periodic replacement of major equipment items that have a shorter service life than the overall project, such as turbines in a hydroelectric project.

For the 2012 PSMP update, the allowances used by the Tanzania system are as shown in **Table 3-11**.

Table 3- 11: Selected operation and maintenance, and other annual costs

Plant type	Unit size MW	Fixed O&M US$/kW/yr	Variable O&M US$/kWh	Interim Replacement percent	Insurance percent
Coal steam thermal	100	62	0.0075	0.35	0.25
Coal steam thermal	50	87	0.0075	0.35	0.25
Oil steam thermal	100	44	0.0063	0.35	0.25
Oil steam thermal	50	44	0.0063	0.35	0.25
Gas turbine	60	9	0.0056	0.35	0.25
Combined cycle gas turbine	3x60	7	0.003	0.35	0.25
Medium speed diesel	50	29	0.0150	0.35	0.25
Cogeneration steam	40	43	0.00642	0.35	0.25
Hydroelectric	All	16	0	0.25	0.10

Notes:

a) The O&M values are from the TANESCO 2003 PSMP update + 25 percent to adjust to 2012 price levels.

b) The interim replacement rates and insurance are normal industry practice and are expressed as a percent of the capital cost.

Lead times: A critical issue in determining the possible scheduling of new projects is the minimum lead-time that would be required to complete the project implementation process up to commercial operation date. A major consideration in the estimate of minimum lead-time is the level of preparation of the project (Pre-feasibility, feasibility, bankable document etc.).

The following guidelines are to be used to assist in the definition of an appropriate minimum lead-time. Earliest on-power dates for the current update were based on lead time after January 2013.

Table 3-12 below shows the generic times for each of the individual activities leading up to implementation and on-power may be used to assess an appropriate minimum lead time.

Table 3- 12: Plant overall implementation schedule

Activity	**Time in months**
Prefeasibility study, following a reconnaissance level project identification	6-12
Feasibility study (including consultant selection)	12-24
Feasibility study update (where required)	6-12
Environmental study and approval	12
Preparation of IPP process and tendering (where applicable)	12
Project financing (IPP or public ownership)	12
Final design (including consultant selection) – depending on size/complexity	12-18
Tendering	6-12
Construction (depending on size/complexity)	36-72

Actual times will vary considerably, depending on environmental approval process, private or public ownership, commitment of the government, financially feasibility, size and complexity of the project, and the extent to which activities may be fast tracked (i.e., carried out in parallel, such as final design and preparation of the EIA).

Lead times for hydroelectric

Overall implementation times used in this assessment for each hydroelectric candidate are based on the following minimum timeframes, expressed in years.

Table 3- 13: Minimum on-power lead times for hydroelectric plants (years)

Present project status	Project preparation	Tender/Construct	Total
Reconnaissance/ Preliminary			
less than 70 MW	3	4	7
70 to 150 MW	4	5	9
More than 150 MW	4	6	10
Prefeasibility			
less than 70 MW	2	4	6
70 to 150 MW	3	5	8
More than 150 MW	3	6	9
Feasibility			
less than 70 MW	2	4	6
70 to 150 MW	2	5	7
More than 150 MW	2	6	8
Design/tender documents			
less than 70 MW	1	4	5
70 to 150 MW	1	5	6
More than 150 MW	1	6	7

Source: Team Compilation

These values allow no margin for delays between successive development stages. They also do not provide for additional delays for approval and financing activities. At least one year should be added to the above values for any project that is not being fast tracked.

Lead times for thermal plants
Overall implementation times used in this assessment for each thermal plant candidate are based on the following minimum timeframes, expressed in years.

Table 3- 14: Minimum On-Power Lead Times (Years) for Thermal Plants

Technology	Project preparation	Tender/Construct	Total
Coal steam	3	3	6
Oil steam	3	3	6
Conventional diesel	1	1	2
Gas fired engines	2	1	3
Combined cycle gas turbine	2	2	4

Generation Candidates

Hydropower Resources

The new hydroelectric options considered in this PSMP update and their generation capabilities are listed in **Table 3-15**.

Table 3- 15: New Hydro Options and Generation

Plant/site	Installation	Average energy	Firm energy GWh	River
	MW	GWh		
Kakono	53	404	335	Kagera
Mpanga	144	955	646	Rufiji
Masigira	118	664	492	Ruhuhu
Ruhudji	358	1928	1333	Ruhudji
Rumakali	520	1475	2520	Rumakali
Rusumo (80MW) – 26.7 for Tanzania (1)	26.7	148	129	Kagera
Songwe (3 plants)	340 (170 Tanzania)	1669	1045	Songwe
Steiglers Gorge	1200 (to Phase 3)	5259	3247	Rufiji
Ikondo	340	1832	1316	Mnyera
Taveta	145	850	622	Mnyera
Malagarasi Stage (Igamba III) - (2)	44.8	186.7	21.44	Malagarasi

(1) Capacity and energy values are 33 % of the total, ie Tanzania portion

(2) Igamba III values from current studies

The detailed plant characteristics for new hydro projects are shown in **Table 3-16.**

Table 3- 16: New Hydro Plant Characteristics

	Songwe Bipugu	Songwe Sofre	Songwe Manolo	Kakono	Rusumo	Ruhudji	Rumakali	Masigira	Mpanga	Kihansi	Malagarasi	Stieglers 1	Stieglers 2	Stieglers 3	Ikondo	Taveta
Generation																
Installed capacity MW	34	157	149	53	30	358	520	118	144	248	45	300	600	300	340	145
Average energy GWH	153	736	780	404	148	1928	1475	664	955	69	187	2230	1506	1523	1,842	850
Firm energy GWH	101	456	488	335	129	1333	2520	492	646	99	21	1908	855	464	1,316	622
Powerhouse																
Number of units	3	3	3	3	3	4	3	2	2	2	3	4	4	3	4	2
Gross head at max. level (m)	80	315	253	26	35	765	1295	238	374		846.5	100	100	128	405	155
Gross head at min. level (m)	55	285	173	24	30	765	1265	237	350		832.5	99	99	99	400	150
Tailwater level (m.a.s.l)	1165	825	527	1156	1290							59	59	59		
Rated turbine discharge(total) (m3/s)	50	59	69	240	207	54.4	19.1	57.0	45.0			353	706	277	100	125
MW/(m^3/s) based on calc Qmax	0.67	2.66	2.13	0.22	0.30	6.6	11.7	2.1	3.2		7.14	0.84	0.84	1.08	3.4	1.16
Reservoir																
Max. supply level (m.a.s.l.)	1245	1140	780	1182	1325	1478	2055	938	734			159	159	187	1070	
Min. supply level (m.a.s.l.)	1230	1110	700	1180	1320	1440	2025	937	710			158	158	158	1030	
Full supply level (m.a.s.l)	1245	1140	780	1182	1325	1478	2055	938	734			174	187	187	1070	
Recommended min. operational level (m.a.s.l.)	1230	1110	700	1180	1320	1367	2025	937	710		843	158	158	158	1030	
Storage vol. at max. level (mill. m^3)	350	440	260	27	1250	300	280	24	75		457,000	13000	13000	34000	800	475
Storage vol. at min. level (mill. m^3)	100	80	0	0	0	31.3	24	23	7		427,000	12000	12000	12000	20	470
Active storage volume (mill. m^3)	250	360	260	27	1250	269.3	256	2	68		457,000	1000	1000	22000	780	5
Surface area at max. vol. (km^2)	30	15	11	14	390	14	13	3	2.5		169,000	1250	1250	N/A	38	

Rusumo energy values are 1/3 of the total, as project will be shared with Burundi and Rwanda

Kihansi is Upper Kihansi storage + addition of 2 x 60 MW units at Lower Kihansi. Cost is for storage dam + E/M for Lower Kihansi addition

Songwe based on package 4 ie - 3 dams with powerhouses, priority for power, storage for flood control at Sofwe and Manolo

Stieglers capital costs are increments for each phase.

Q= MW*1000/9.81/0.866/Gross Head

Thermal resources

There are three categories of conventional new thermal options:

a) Identified /evaluated specific projects using indigenous fuel like natural gas, coal and biomass.
b) Generic projects/technologies using indigenous fuel.
c) Generic project/technologies using imported fuel.

Other potential sources such as nuclear and geothermal are covered in this chapter.

The list of identified projects will change with each master plan update. For example the possibility of gas-fired generation at Mnazi Bay appeared in the 2008 PSMP for the first time. However the situation has changed and now this generation will be at Kinyerezi after construction of a natural gas pipeline from Mtwara to Dar es Salaam.

Similarly the availability of indigenous fuel will change with time as more reserves are identified, evaluated and reserves confirmed. This is the case for the current update, which reflects identified large coal resources in the south-west part of the country.

The 2012 update Study includes more thermal plants based on Tanzanian fuels (gas ,Coal etc.) to meet the forecast load demands up to the end of the planning period (i.e. 2035).

The initial step in the planning process is to develop or update a catalogue of candidate thermal new power options, covering the above three categories. In this case, the first step is to refer to previous PSMPs, which have already considered known options (specific projects and generic), and update this with current information.

Specific and committed thermal projects

Except for changed timing for the on-line dates for these resources, the current PSMP update has retained the committed and identified future specific projects using indigenous fuels that were considered in the previous study as per **Table 3-17.**

Table 3- 17: New Thermal Options

Plant/site	Installation Capacity (MW)	Technology	Fuel source
COAL FIRED PLANT			
Coast Coal	500	Steam	Local Coal
Kiwira I	200	Steam	Local Site Coal
Kiwira II	200	Steam	Local Site Coal
Local Coal I	100	Steam	Local Site Coal
Local Coal II	200	Steam	Local Site Coal
Local Coal III	400	Steam	Local Site Coal
Local Coal IV	400	Steam	Local Site Coal
Local Coal V	400	Steam	Local Site Coal
Mchuchuma I	300	Steam	Local Site Coal
Mchuchuma II	400	Steam	Local Site Coal
Mchuchuma III	300	Steam	Local Site Coal
Ngaka I	200	Steam	Local Site Coal
Ngaka II	200	Steam	Local Site Coal
SUB TOTAL I	***3800***		
GAS/HFO PLANT			
Kinyerezi I	150	GTs - Gas	Local Gas
Kinyerezi II	240	CCGT	Local Gas
Kinyerezi III	300	CCGT	Local Gas
Kinyerezi IV	300	GT	Local Gas
Mkuranga 250	250	CCGT	Local Gas
Mtwara 400	400	CCGT	Local Gas
Mwanza MS Diesel	60	MSD HFO/Dual	Imported/Local Gas
Somanga Fungu 320	320	CCGT	Local Gas
Somanga TANESCO	8	GT	Local Gas
Zinga 200	200	CCGT	Local Gas
TOTAL	**2228**		

Source: Team Compilation

It is worth noting that the current plan for plants using natural gas (existing and future plants) have assumed a total proven reserve of about 880 billion cubic feet from Songosongo and 262 BCF from Mnazi bay respectively.

Renewable Projects

Renewable power projects are among the sources of power generation plan. Currently, there are potential sources with capacity of generating 260MW in the country. Renewable power projects include biomass, solar and wind. **Table 3-18** identifies the following power projects that can be developed in the short term.

Table 3- 18: Candidates Renewable Projects

Plant/site	Installation Capacity (MW)	Technology	Fuel source
Mufindi (Cogen)	30	Steam	Local Biomass
Sao Hill (Cogen)	10	Steam	Local Biomass
Solar I	60	Solar	Local
Solar II	60	Solar	Local
Wind I	50	Wind	Local
Wind II	50	Wind	Local
TOTAL	**260**		

Source: Team Compilation

Indigenous Fuels

Coal

The 2012 PSMP update has assumed that 3,800MW of new local coal would be developed from presently proven reserves from Lake Nyasa area (that includes the Mchuchuma, Katewaka, Ngaka and Kiwira coal fields).**Table 3-19** shows the usage of coal reserve in the country.

The 400 MW Ngaka coal fired plant being proposed by TANCOAL, has a quoted coal price of US$ 65.00/ton as proposed by TANCOAL Depending on the coal calorific value, the corresponding fuel cost would be in the order of US$ 2.5/GJ, or 2.5c/ kWh. Proven reserve on this site is estimated to be 251 million metric tonnes with Calorific value of 6200 kcal/Kg.

The Mchuchuma project is now considered as multipurpose project (Colliery, power plant and Smelter), the power plant component has two phases; Phase one of the project to supply the smelter, and a second phase is planned to power supply to TANESCO grid. No coal prices (or PPA sales prices) have been proposed. However, the proposed coal price for the Mchuchuma site of US$ 55.00/t as proposed by the NDC and the Chinese developer. Depending on the coal calorific value, the corresponding fuel cost would be in the order of US$ 2.6/GJ. It is estimated that the site has a total reserve amounting to 445 million metric tonnes out of which, the proven reserve is 125 million metric tonnes and indicative reserve is 328 million metric tonnes. The corresponding Calorific value is 5200kcal/kg.

The **Kiwira coal fired plant** has also been committed for 200 MW installations, with a possible further addition of 200 MW. The project has now been restructured with government stepping in to split the project where the colliery will be transferred to STAMICO while the responsibility of developing a power plant has been transferred to TANESCO. The site has total reserve of about 86.31 million metric tonnes with calorific value of 4200 kcal/kg.

Table 3- 19: Coal Resources Utilization for future generation

	Coal Resources			**Proven (MT)**	**Reserve (MT)**		
	NGAKA			251.00			
	MCHUCHUMA			125.30	454.10		
	KIWIRA			86.31			
	KATEWAKA			33.50	81.70		
			Total	**496.11**			
YEAR	**PLANT**		**INSTALLED CAPACITY [MW]**	**SPECIFIC CONSUMPTION [GJ/MWh]**	**CONSUMPTION PER YEAR [MT]**	**PLANT LIFE TIME [YEARS]**	**TOTAL COAL CONSUMPTION [MT]**
2016	Kiwira I		200	9.24	0.72	25	18.00
2017	Coastal Coal		300	9.73	0.80	25	19.90
2017	Ngaka I	IPP	200	9.73	0.53	25	13.27
2018	Mchuchuma I	IPP	300	8.99	0.74	25	18.48
2018	Kiwira II	IPP	200	9.24	0.72	25	18.00
2019	Ngaka II	IPP	200	9.73	0.72	25	18.00
2021-2024	Mchuchuma II	IPP	400	8.99	1.13	25	28.29
2026-2028	Mchuchuma III	IPP	300	8.99	0.85	25	21.22
2029	Local Coal I		200	9.73	0.05	25	1.33
2030	Local Coal II		400	9.73	1.33	25	33.17
2031	Local Coal III		400	9.73	1.33	25	33.17
2033	Local Coal IV		400	9.73	1.06	25	26.53
2034	Local Coal V		300	9.73	0.80	25	19.90
TOTAL			**3800**				**222.81**

Source: Team Compilation

Natural Gas

Tanzania has eleven natural gas discoveries namely: Songo Songo, Mnazi Bay, Mkuranga, Kiliwani, Ntorya and Deep Sea eight discoveries (Chaza, Jodari, Zafarani, Pweza, Mzia, Chewa, Papa 1 and Lavani1). Among the discoveries, Songo Songo and Mnazi Bay have proven commercial quantities of gas and are operational while others still have to undergo commercial appraisal.

In ensuring there is enough gas for power generation, the government through TPDC is constructing a pipeline from Mtwara to Dar es Salaam. The project will involve the construction of two expandable Natural Gas Processing Plants at Mtwara 210 mmscfd and Songo Songo 140 mmscfd together with a 36” Pipeline from Mtwara to Dar es Salaam with a 24” subsea spur line from Songo Songo to tie in at Somanga Fungu, Kilwa Region. Upon completion, the pipeline infrastructure will have a capacity to transport up to 784 mmscfd of natural gas without compression. However, this capacity will be reached gradually from 181 mmscfd in 2014 to 724 mmscfd in 2024 and up to 1002 mmscfd in 2030 as shown in the table below. Assuming 70 percent of amount of delivery gas is used for power generation this translates into 2744 MW in 2024.

Table 3- 20: Expected Gas Delivered and Power Generation as per Mtwara – Dar es Salaam Pipeline

Year	Amount of Gas Delivered (mmscfd)	70 percent of the Amount (mmscfd)	Possibe Power Generation MW
2014	181	127	634
2015	306	214	1071
2016	470	329	1645
2017	475	333	1663
2018	500	350	1750
2019	669	468	2342
2020	769	538	2692
2021 - 2025	784	549	2744
2026 - 2028	914	640	3199
2029 - 2030	958	671	3353
2031	1002	701	3507

Source: TPDC and TANESCO

The **SongoSongo gas** field with estimated reserve of 880 TC is a primary source for natural gas for power generation in Dar es Salaam. The reserve would be equivalent to about 15,513 MW-years of generation at 70percent CF, and the upper value of about 1000 Tcf would be equivalent to about 17,000 MW-years. This in turn corresponds approximately to 500 MW of generation over 20 years (the assumed economic life of a gas turbine or combined cycle plant).

For this plan the cost of natural gas is estimated to be as shown below:

a) US$ 0.68/GJ for protected gas supply to Ubungo

b) 3.18 US$/GJ for additional gas

The availability of Songo Songo gas depends on the delivery infrastructure, which consists of the wells, the gas processing facilities on Songo Songo Island (SSI), and the pipeline to Ubungo. The current pipeline capacity is 105 mmscfd which has been related from initial capacity of 90mmscfd.

The **Mnazi Bay gas** with estimated proven reserve of 262TCF primary source for natural gas for power generation in Dar es Salaam, equivalent to about 4506.4 MW-years of generation at 70percent CF. This in turn corresponds approximately to 365 MW of generation over 20 years (the assumed economic life of a gas turbine or combined cycle plant). For this plan the cost of natural gas is estimated to be at price of US$ 4.74/GJ.

The assumed use of available gas resource for existing plants and future projects in the 2012 PSMP is shown in **table 3-21 below**. This table indicates an inadequate gas supply to meet the present gas plants until 2014 when the Mtwara to Dar es Salaam pipeline will be available. It is assumed that all the available gas resource is confined for use in power generation implying that industrial gas needs remains at current level.

Table 3- 21: Use of Natural Gas (SS, M-Bay, Mkuranga, Deep Sea) – Existing/committed Thermal

Generation assumed at average plant factor for 70 %	Proven (BCF)	Reserve (BCF)			
PAE(T) contract 245 MW x 16 years =			3920	MW-YEAR	70 %PF
SONGO SONGO	880	2000	15136	MW-YEAR	70 %PF
MNAZI BAY	262	5000	4506.4	MW-YEAR	70 %PF
MKURANGA		20	0	MW-YEAR	70 %PF
KILWANI		7	0	MW-YEAR	70 %PF
NTORYA		17	0	MW-YEAR	70 %PF
DEEP SEA		26000	0	MW-YEAR	70 %PF
1 bcf equivalent to		17.2 MW-years at 70 % CF			

YEAR	PLANT		GAS ADDED MW	IFO MW	GAS ON LINE MW	END YEAR	GAS YEARS (After Jan 2014)	MW-YEARS 70% PF COMMITTED
2002	Tegeta IPTL			100		2014		
2004	Songas 1	IPP	42		42	2024	11	462
2005	Songas 2	IPP	120		162	2025	12	1440
2006	Songas 3	IPP	40		202	2026	13	520
2007	Ubungo I		100		302	2026	13	1300
2008	Mtwara	IPP	18		320	2027	14	252
2009	Tegeta new		45		365	2029	16	720
2012	Ubungo II		105		470	2032	19	1995
2013	Kinyerezi I		150		620	2033	20	3000
2013	Symbion 205	IPP	100		720	2014	1	100
2014	Kinyerezi II		160		880	2034	20	3200
2014	Somanga	IPP	210		1090	2034	20	4200
2015	Kinyerezi III		300		1390	2035	20	6000
2015	Zinga-Bagamoyo	IPP	225		1615	2035	20	4500
2015	Mkuranga		250		1865	2035	20	5000
2014	Tegeta IPTL		100		1965	2022	9	900
2016	Mtwara	IPP	400		2365	2036	20	8000
TOTAL			2365					41589

Source: Team Compilation

In addition it is assumed that more indigenous coal and gas will be identified in the long term, as noted above.

3.3 Development costs

Capital costs for all candidate power plants are based on benchmarking of generic plants around the world, original capital costs from the 2008 PSMP study, and proposed developers' prices. These costs were then escalated from original sources to obtain costs on a common basis. Schedules of costs during construction, including pre-construction costs, and estimated lead times for project preparation and construction for both hydro and thermal are summarized in **Table 3-22** and **Table 3-23** respectively.

Table 3- 22: Schedule of construction costs for hydroelectric projects

PLANT	Units	Capital cost $M no IDC / 2011	Construction (months)	Pre const-ruction	Annual expenditure as % of total capital cost										TOTAL
					1	2	3	4	5	6	7	8	9	10	
Ruhudji	1	*1220	66	4.00	7.00	8.00	20.00	30.00	20.00	10.00	1.00				100.00
Rumakali	1	*740	84	4.00	7.00	8.00	11.00	15.00	24.00	20.00	8.00	2.00	1.00		100.00
Masigira	1	224.41	54	4.00	6.00	16.00	35.00	23.00	14.00	2.00					100.00
Mpanga	1	267.73	63	4.00	8.00	9.00	20.00	30.00	18.00	10.00	1.00				100.00
Upper Kihansi	1	116.71	45	4.00	14.00	30.00	37.00	14.00	1.00						100.00
Stieglers Phase 1	1	938.49	108	4.00	7.00	4.00	7.00	7.00	11.00	18.00	16.00	12.00	9.00	5.00	100.00
Stieglers Phase 2 Addition	1	334.36	36	3.00	38.00	40.00	8.00	8.00	3.00						100.00
Stieglers Phase 3 Addition	1	274.09	24	3.00	30.00	60.00	5.00	1.00	1.00						100.00
Kakono	2	96.86	36	5.00	25.00	40.00	30.00	0.00							100.00
Malagarasi (Igamba III)	2	153.24	40	5.00	25.00	40.00	30.00	0.00							100.00
Rusumo	2	**339	36	5.00	25.00	40.00	30.00	0.00							100.00
Songwe Bipugu	2	90.41	36	5.00	25.00	40.00	30.00	0.00							100.00
Songwe Sofre	2	274.28	60	5.00	10.00	20.00	20.00	35.00	10.00						100.00
Songwe Manolo	2	278.88	48	5.00	20.00	30.00	30.00	15.00	0.00						100.00
Ikondo	2	665.84	72	5.00	7.00	8.00	20.00	30.00	20.00	10.00	0.00				100.00
Taveta	2	251.13	60	5.00	10.00	25.00	25.00	35.00	0.00						100.00

After on-power 1 Schedule of costs from the EAPMP 2005

2 Schedule of costs from planning criteria

* Developer's price

** Cost to be equally shared by three countries

Table 3- 23: Schedule of construction costs for thermal projects

PLANT	MW (net)	Capital cost $M no IDC / 2011	Annual expenditure as % of total capital cost					TOTAL
			1	2	3	4	5	
COAL FIRED PLANT								
Coastal coal	500	1,150.00	15	30	30	25		100
Kiwira I	200	413.80	15	30	30	25		100
Kiwira II	200	413.80	15	30	30	25		100
Local Coal I	100	287.00	15	30	30	25		100
Local Coal II	200	574.00	15	30	30	25		100
Local Coal III	400	1,148.00	15	30	30	25		100
Local Coal IV	400	1,148.00	15	30	30	25		100
Local Coal V	400	1,148.00	15	30	30	25		100
Local Coal VI	300	861.00	15	30	30	25		100
Mchuchuma I	300	366.58	15	30	30	25		100
Mchuchuma II	300	366.58	15	30	30	25		100
Mchuchuma III	300	366.58	15	30	30	25		100
Ngaka I	200	620.60	15	30	30	25		100
Ngaka II	400	868.80	15	30	30	25		100
GAS/HFO PLANT								
Kinyerezi I	150	207.00	40	60				100
Kinyerezi II	240	331.00	40	60				100
Kinyerezi III	300	330.00	40	60				100
Kinyerezi IV	300	200.00	15	50	35			100
Mkuranga 250	250	200.00	40	60				100
Mtwara	400	551.67	15	50	35			100
Mwanza MS Diesel	60	51.00	30	45	25			100
Somanga Fungu IPP	320	365.00	15	50	35			100
Somanga Fungu TANESCO	320	365.00	15	50	35			100
Zinga 200	200	276.20	40	60				100

NB: This table of cost excludes cost of mine development and transmission

Costs were escalated by applying the ratio of the index for January 2010 and that for the year of the last estimate.

3.3.1 Generation Costs

Hydro and Thermal Generation Unit Costs

For the purpose of comparing alternative new generation options for initial screening, the unit capacity (US$/kW) and energy costs are estimated. The capital cost includes interest during construction, which is a function of the scheduling of capital expenditures during construction, the length of the construction period and the discount rate. The unit cost of capacity is estimated from the capital cost, including interest during construction, and the nominal plant installed capacity. Note that the firm capacity of the plant, especially for run-of-the-river hydroelectric projects may be significantly low.

Unit energy costs (US$/kWh) are calculated from capital charges and variable operation and maintenance costs, and fuel costs. For hydroelectric projects, unit costs are calculated for both estimated average annual and firm energy. The calculation of energy costs takes into account the service lives attributable to each technology.

The total cost of energy generation is a function of plant capacity factor and combines the fixed annual capacity component (US$/kW-year/hours of operation) with the variable energy component (US$/kWh). In the case of the hydroelectric option the plant capacity factor, and thus average hours of operation, is defined.

The calculations of the unit generation costs for candidate new hydroelectric and thermal options are shown in **Table 3 -24 and Table 3 -25** respectively

Table 3- 24: New hydro Costs

			Songwe Bipugu	Songwe Sofre	Songwe Manolo	Kakono	Rusumo	Ruhudji	Rumakali	Masigira	Mpanga	Upper Kihansi	Stieglers 1	Stieglers 2	Stieglers 3	Ikondo 1	Taveta 3	Malagarasi
Installed capacity MW			34	157	149	53	80	358	520	118	144	*120*	300	600	300	340	145	44.8
Average annual energy GWH			153	736	780	404	477	1928	1475	664	955	124	2230	1506	1523	1,842	850	186.7
Firm energy GWh			101	456	488	335	413	1333	908	492	646	11	1908	855	464	1,316	622	21.44
Capital costs																		
Latest capital cost $ Million			59.00	179.00	182.00	67.50	92.00	384.00	351.00	157.00	191.00	81.20	654.00	233.00	191.00	464	175	149.5
Year of estimate			2002	2002	2002	2004	2004	2004	2004	2004	2004	2004	2004	2004	2004	1984	1984	2011
Source			Norplan	Norplan	Norplan	SSEA	SSEA	EAPMP	EAPMP	EAPMP	EAPMP	EAPMP	EAPMP	EAPMP	EAPMP	Norconsult	Norconsult	ESBI
Multipurpose use cost factor			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Additional mitigation costs $ Million			2.95	8.95	9.10	3.38	4.60	19.20	17.55	7.85	9.55	4.06	32.70	11.65	9.55	23.20	8.75	7.48
Adjusted cost $ Million			61.95	187.95	191.10	70.88	96.60	403.20	368.55	164.85	200.55	85.26	686.70	244.65	200.55	487.20	183.75	156.98
Cost index estimate year			236	236	236	252	252	252	252	252	252	252	252	252	252	252	252	252
Escalated cost (2011) I	344		90.41	274.28	278.88	96.86	339.00	1220.00	740.00	225.30	274.09	116.52	938.49	334.36	274.09	665.84	251.13	153.24
IDC calculation																		
% cost year -10	9.5	2.473											0.04					
% cost year -9	8.5	2.248							0.04				0.07					
% cost year -8	7.5	2.044							0.07				0.04					
% cost year -7	6.5	1.858						0.04	0.08		0.04		0.07					
% cost year -6	5.5	1.689						0.07	0.11	0.04	0.08		0.07	0.00		0.04		
% cost year -5	4.5	1.536		0.05	0.05	0.00	0.00	0.08	0.15	0.06	0.09	0.04	0.11	0.03	0.03	0.06		
% cost year -4	3.5	1.396	0.05	0.10	0.20	0.05	0.05	0.20	0.24	0.16	0.20	0.14	0.18	0.38	0.30	0.16		0.05
% cost year -3	2.5	1.269	0.25	0.20	0.30	0.25	0.25	0.30	0.20	0.35	0.30	0.30	0.16	0.40	0.60	0.35	0.25	0.25
% cost year -2	1.5	1.154	0.40	0.20	0.30	0.40	0.40	0.20	0.08	0.23	0.18	0.37	0.12	0.08	0.05	0.23	0.40	0.40
% cost year -1	0.5	1.049	0.30	0.35	0.15	0.30	0.30	0.10	0.02	0.14	0.10	0.14	0.09	0.08	0.01	0.14	0.30	0.30
%cost on/power year			0.00	0.10	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.01	0.05	0.03	0.01	0.02	0.05	0.00
Total			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Cost with IDC			105.16	292.93	345.84	112.67	394.32	1364.42	703.50	262.75	304.41	141.14	803.41	421.41	354.79	776.54	274.58	178.25
Cost $/kW			3093	1866	2321	2126	4929	3811	1353	2227	2114	1176	2678	702	1183	2284	1894	3979
Fixed annual cost																		
Fixed annual cost (capital + interest UAP)			11.16	31.07	36.69	11.95	41.83	144.74	74.63	27.87	32.29	14.97	85.23	44.70	37.64	82.37	29.13	18.91
Interim replacement an	0.35 %		0.32	0.96	0.98	0.34	1.19	4.27	2.59	0.79	0.96	0.41	3.28	1.17	0.96	2.33	0.88	0.54
Fixed O and M $M	10		0.34	1.57	1.49	0.53	0.80	3.58	5.20	1.18	1.44	1.20	3.00	6.00	3.00	3.40	1.45	0.45
Total fixed annual cost			11.81	33.60	39.15	12.82	43.82	152.59	82.42	29.84	34.69	16.58	91.51	51.87	41.60	88.11	31.46	19.89
Unit cost of energy																		
Average energy $/kWh			0.0772	0.0457	0.0502	0.0317	0.0919	0.0791	0.0559	0.0449	0.0363	0.1337	0.0410	0.0344	0.0273	0.0478	0.0370	0.1065
Firm energy $/kWh			0.1169	0.0737	0.0802	0.0383	0.1061	0.1145	0.0908	0.0607	0.0537	1.5073	0.0480	0.0607	0.0896	0.0670	0.0506	0.9278

Upper Kihansi Consists of storage dam plus 2 units addition at lower Kihansi
Songwe based on package 4 ie - 3 dams with powerhouses, priority for power, storage for flood control at Sofwe and Manolo
Stieglers capacity and energy values from EAPMP / Generation after addition of Phase 4 units not known
Stieglers capital costs are increments for each phase. Cost for Phase 4 addition is not known
Rusumo energy and capital costs from LNC LAVALIN report (Sept. 2011). These costs are to be equally shared with Tanzania, Burundi and Rwanda
Ikondo and Taveta project costs re-estimated for this PSMP update

Table 3- 25: Thermal generation alternatives for Tanzania and screening

`	10.0%	Mchuchuma Stage I 3x100 MW	Mchuchuma Stage II 4x100 MW	Mchuchuma Stage III 3x100 MW	Kiwira I 4x50 MW	Kiwira II 4x50 MW	Ngaka I 4x100 MW	Ngaka II 4x100 MW	Coastal Coal-Steam 3x100 MW	Local I Coal-Steam 2x100 MW	Local II Coal-Steam 4x100 MW	Local III Coal-Steam 4x100 MW	Local IV Coal-Steam 4x100 MW	Local V Coal-Steam 3x100 MW
Installed capacity	MW	324	432	324	216	216	216	216	324	216	432	432	432	324
Station service	%	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Net capacity	MW	300	400	300	200	200	200	200	300	200	400	400	400	300
Unit availability														
Scheduled maintenance	wks per unit	6	6	6	6	6	6	6	6	6	6	6	6	6
Forced outage rate	%	8	8	8	8	8	8	8	8	8	8	8	8	8
Combined outage rate	%	20	20	20	20	20	20	20	20	20	20	20	20	20
Net capacity available (after derating for outage)	MW	244	326	244	163	163	163	163	244	163	326	326	326	244
Earliest on-power date	Yr	2033	2034	2018	2019	2017	2019	2019	2016	2026	2029	2030	2031	2033
Service life	Yrs	25	25	25	25	25	25	25	25	25	25	25	25	25
O & M														
Fixed O & M	$/kW	50	50	50	70	70	50	50	50	50	50	50	50	50
Variable O & M	$/kWh	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Interim replacement	% of capital	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Insurance	% of capital	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total capital cost with IDC														
Unit capital cost	US $/kW	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0
Capital costs Stage 1	US $ x 10^6	645.8	861.0	645.8	430.5	430.5	430.5	430.5	645.8	430.5	861.0	861.0	861.0	645.8
Capital cost Stage 2	US $ x 10^6													
Transmission	US $ x 10^6	0.0	0.0	0.0	0.0	0.0	200.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital cost	US $ x 10^6	645.8	861.0	645.8	430.5	430.5	630.5	630.5	645.8	430.5	861.0	861.0	861.0	645.8
Avg capital cost per available capacity	$/kW avail	2644.8	2644.8	2644.8	2644.8	2644.8	3873.6	3873.6	2644.8	2644.8	2644.8	2644.8	2644.8	2644.8
Annual fixed cost	$/kW avail	71.4	71.4	71.4	95.9	95.9	76.0	76.0	71.4	71.4	71.4	71.4	71.4	71.4
Cashflow in year prior to on-power														
-5	% of capital													
-4	% of capital	15	15	15	15	15	15	15	15	15	15	15	15	15
-3	% of capital	30	30	30	30	30	30	30	30	30	30	30	30	30
-2	% of capital	30	30	30	30	30	30	30	30	30	30	30	30	30
-1	% of capital	25	25	25	25	25	25	25	25	25	25	25	25	25
0	% of capital	0	0	0	0	0	0	0	0	0	0	0	0	0
Avg total cost at on-power	$/kW avail	3022.1	3022.1	3022.1	3022.1	3022.1	4426.1	4426.1	3022.1	3022.1	3022.1	3022.1	3022.1	3022.1
Annuity over economic life (year-end)	$/kW avail	332.9	332.9	332.9	332.9	332.9	487.6	487.6	332.9	332.9	332.9	332.9	332.9	332.9
Total annual fixed cost	$/kW avail	404.3	404.3	404.3	428.9	428.9	563.6	563.6	404.3	404.3	404.3	404.3	404.3	404.3
Fuel cost calculation														
Fuel type		Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal
Fuel price	$/GJ	3.31	3.40	3.40	3.82	3.82	3.48	3.31	5.02	5.02	5.02	5.02	5.02	5.02
Heat rate	kJ/kWh	9,730	9,730	9,730	9,243	9,243	9,730	9,730	9,730	9,730	9,730	9,730	9,730	9,730
Fuel cost	$/kWh	0.03225	0.03306	0.03306	0.03535	0.03535	0.03386	0.03223	0.04883	0.04883	0.04883	0.04883	0.04883	0.04883
Total fixed cost	$/kW avail.	404.3	404.3	404.3	428.9	428.9	563.6	563.6	404.3	404.3	404.3	404.3	404.3	404.3
Total variable cost	$/kWh avail.	0.03825	0.03906	0.03906	0.04135	0.04135	0.03986	0.03823	0.05483	0.05483	0.05483	0.05483	0.05483	0.05483

`	10.0%	Somanga CCGT (Gas) 2x115 1x110	MTWARA Gas 4x100 MW	Kinyerezi I GT(Gas) 3x50 MW	Kinyerezi II CCGT (Gas) 2x60 2x60	Kinyerezi III Gas 3x100 MW	Kinyerezi IV Gas 3x100 MW	Zinga Gas 2x100 MW	Mkuranga Gas 5x50 MW	Mufindi Cogen 30 MW	Sao Hill Cogen 10 MW	Solar 60 MW	Wind 50 MW
Installed capacity	MW	328	406	152	179	305	305	203	254	31	10	61	51
Station service	%	2.35	1.60	1.60	2.35	1.60	1.60	1.60	1.60	2.4	2.40	2.4	2.40
Net capacity	MW	320	400	150	240	300	300	200	250	30.0	10	60.0	50
Unit availability													
Scheduled maintenance	wks per unit	4	4	4	3	4	4	4	4	3	3	3	3
Forced outage rate	%	5	7	5	5	5	5	5	5	5	5	5	5
Combined outage rate	%	11	15	13	11	13	13	13	13	11	11	11	11
Net capacity available (after derating for outage)	MW	281	343	132	215	263	263	175	219	20	10	20	10
Earliest on-power date	Yr	2015	2016	2014	2016	2017	0	2015	2015	2016	2016	2016	2016
Service life	Yrs	20	25	20	20	20	20	20	20	20	20	20	20
O & M													
Fixed O & M	$/kW	7.5	7.5	7.5	6	7.5	7.5	7.5	7.5	40	40	40	40
Variable O & M	$/kWh	0.0025	0.0050	0.0045	0.0030	0.0045	0.0045	0.0045	0.0045	0.0030	0.0030	0.0030	0.0030
Interim replacement	% of capital	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Insurance	% of capital	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total capital cost with IDC													
Unit capital cost	US $/kW	1141.0	1220.0	1220.0	1808.3	1808.3	1808.3	1808.3	1808.3	3860	3860	4692	2438
Capital costs Stage 1	US $ x 10^6	374.2	500.2	187.6	444.8	556.1	556.1	370.7	463.4	118.7	39.6	288.6	124.9
Capital cost Stage 2	US $ x 10^6	141.0											
Transmission	US $ x 10^6	85.0	100.0	0.0	0.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0
Capital cost	US $ x 10^6	365.0	600.2	187.6	444.8	557.1	557.1	371.7	464.4	118.7	39.6	288.6	124.9
Avg capital cost per available capacity	$/kW avail	1300.7	1747.9	1426.0	2070.5	2117.5	2117.5	2119.4	2118.2	5934.8	3956.5	14427.9	12494.8
Annual fixed cost	$/kW avail	13.4	15.3	13.9	14.5	16.5	16.5	16.5	16.5	82.3	54.8	174.1	246.9
Cashflow in year prior to on-power													
-5	% of capital												
-4	% of capital												
-3	% of capital	15			15					15	15	15	15
-2	% of capital	50	40	40	50	40	40	40	40	50	50	50	50
-1	% of capital	35	60	60	35	60	60	60	60	35	35	35	35
0	% of capital	0	0	0	0	0	0	0	0	0	0	0	0
Avg total cost at on-power	$/kW avail	1406.7	1817.8	1483.0	2239.3	2202.1	2202.1	2204.1	2202.9	6418.4	4279.0	15603.8	13513.1
Annuity over economic life (year-end)	$/kW avail	165.2	200.3	174.2	263.0	258.7	258.7	258.9	258.8	753.9	502.6	1832.8	1587.2
Total annual fixed cost	$/kW avail	178.7	215.6	188.1	277.5	275.2	275.2	275.4	275.3	836.2	557.4	2006.9	1834.1
Fuel cost calculation													
Fuel type		Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Biomass	Biomass	Solar	Wind
Fuel price	$/GJ	4.74	4.74	4.74	4.74	4.74	4.74	4.74	4.74	1.03	1.03	N/A	N/A
Heat rate	kJ/kWh	7,800	7,840	10,900	7,840	10,900	10,900	10,900	10,900	11500	11500	N/A	N/A
Fuel cost	$/kWh	0.03697	0.03716	0.05167	0.03716	0.05167	0.05167	0.05167	0.05167	0.01185	0.01185	N/A	N/A
Total fixed cost	$/kW avail.	178.7	215.6	188.1	277.5	275.2	275.2	275.4	275.3	836.2	557.4	2006.9	1834.1
Total variable cost	$/kWh avail.	0.03947	0.04216	0.05617	0.04016	0.05617	0.05617	0.05617	0.05617	0.01485	0.01485	0.22000	0.13000

Source: Team Compilation

Fuel costs

The assumption of fuel prices for planning study comparisons is of critical importance, except for projects being evaluated under a PPA tariff arrangement.

Indigenous fuel Costs

Cost information related to indigenous fuel resources were obtained from potential developers/suppliers. Thus, for the 2012 PSMP, fuel prices for Songo Songo, Mnazibay, Mchuchuma, Ngaka and Kiwira were available. Songo Songo supply costs are at a contractual level, while the coal prices can only be considered as indicative. Fuels prices are considered at the plant, i.e., include delivery charges.

Imported fuel costs

For the imported fuels such as HFO, LNG and coal, market information on offshore (FOB) prices is available from sources such as Platts Oil and Gas Journal, US Department of Energy etc. From such sources representative long-term average constant dollar prices have been estimated. HFO prices are based on the reference-selected cost for crude oil. Fuel prices have to be adjusted to take into account handling and delivery charges.**Table 3-26** outlines the basis for the fuel prices for fuel oil as proposed for this 2012 PSMP update.

Table 3- 26: Proposed Fuel Oil Costs

Fuel type	bbl/Mt	Price at US$ 110 /bbl
Heavy fuel oil (No. 6)	6.45	749.03 US$/Mt
Heavy fuel oil (No.6)		17.51 US$/GJ
Industrial diesel industrial diesel (No. 2)	7.46	838.73 US$/Mt
Industrial diesel (No. 2)		21.22 US$/GJ

Source: Team computation

3.4 Plant Data and Operating Costs

To complete the catalogue of thermal new power options it is necessary to prepare a data base of plant data or characteristics, schedules of disbursement for the calculation of IDC, and plant operating costs. The two tables overleaf summarize the planning data that has been updated from the 2009 PSMP update report. **Table 3-27** provides the basic information on each candidate plant, including ratings, station service, outage rates, service lives and minimum lead time to on-power. **Table 3-28** provides fuel costs, fixed and variable operation and maintenance costs, interim replacement and insurance.

Table 3- 27 New thermal plants earliest time

Plant	Fuel	Installed Capacity MW	Station service %	Net Available Capacity MW (after station use)	FOR %	Combined Outage Rate %	Maximum Plant Factor %	Available Energy GWh	Nominal Service Life Years	Minimum lead time years	Earliest on power year (Jan)
COAL FIRED PLANT											
Coast Coal	Coal	500	8.00	460	8	20	80	2966	25	6	2019
Kiwira I *	Coal	200	8.00	184	8	20	80	1186	25	6	2017
Kiwira II *	Coal	200	8.00	184	8	20	80	1186	25	6	2019
Local Coal I	Coal	100	8.00	92	8	20	80	593	25	6	2026
Local Coal II	Coal	200	8.00	184	8	20	80	1186	25	6	2029
Local Coal III	Coal	400	8.00	368	8	20	80	2373	25	6	2030
Local Coal IV	Coal	400	8.00	368	8	20	80	2373	25	6	2031
Local Coal V	Coal	400	8.00	368	8	20	80	2373	25	6	2033
Local Coal VI	Coal	300	8.00	276	8	20	80	1779	25	6	2034
Mchuchuma I	Coal	300	8.00	276	8	20	80	1779	25	5	2018
Mchuchuma II	Coal	300	8.00	276	8	20	80	1779	25	6	2019
Mchuchuma III	Coal	300	8.00	276	8	20	80	1779	25	6	2019
Ngaka I	Coal	200	8.00	184	8	20	80	1186	25	6	2019
Ngaka II	Coal	400	8.00	368	8	20	80	2373	25	6	2019
HFO/Gas/IDO FIRED PLANT											
Kinyerezi I	GTs - Gas	150	2.35	146	4	11	80	1051	20	1	2014
Kinyerezi II	CCGT	240	2.35	234	4	11	80	1682	20	3	2016
Kinyerezi III	CCGT	300	2.35	293	4	11	80	2102	20	4	2017
Kinyerezi IV	GTs - Gas	300	2.35	293	4	11	80	2102	20	4	2017
Mkuranga 250	CCGT	250	3.00	243	4	11	75	1643	20	4	2015
Mtwara 400	CCGT	400	3.00	388	4	11	75	2628	20	4	2016
Mwanza MS Diesel	MSD	60	2.00	59	8	18	75	394	20	1	2014
Somanga Fungu	CCGT	320	2.00	314	4	11	75	2102	20	3	2016
Zinga 200	CCGT	200	3.00	194	4	11	75	1314	20	4	2015
TOTAL		**6420**		**6028**				**39932**			

* Project may come earlier as some of preparatory activities are done in advance

Table 3- 28: New Thermal Plant Operating Costs

Plant	Fuel	Units	Installed Capacity MW	Fuel price $/GJ	Plant heat rate kJ/kWh	Fuel cost $/kWh	Fixed operating cost /kW-year	Variable operating cost $/kWh	Interim replace - ment %	Insurance %
COAL FIRED PLANT										
Coastal coal	Coal	3	300	5.019	9730	0.0488	50	0.0060	0.350	0.025
Kiwira I	Coal	3	200	3.824	9243	0.0353	70	0.0060	0.350	0.025
Kiwira II	Coal	2	200	3.824	9243	0.0353	70	0.0060	0.350	0.025
Local Coal I	Coal	1	100	5.019	9730	0.0488	50	0.0060	0.350	0.025
Local Coal II	Coal	2	200	5.019	9730	0.0488	50	0.0060	0.350	0.025
Local Coal III	Coal	4	400	5.019	9730	0.0488	50	0.0060	0.350	0.025
Local Coal IV	Coal	4	400	5.019	9730	0.0488	50	0.0060	0.350	0.025
Local Coal V	Coal	4	400	5.019	9730	0.0488	50	0.0060	0.350	0.025
Local Coal VI	Coal	3	300	5.019	9730	0.0488	50	0.0060	0.350	0.025
Mchuchuma I	Coal	3	300	3.315	9730	0.0323	50	0.0060	0.350	0.025
Mchuchuma II	Coal	3	300	3.398	9730	0.0331	50	0.0060	0.350	0.025
Mchuchuma III	Coal	3	300	3.398	9730	0.0331	50	0.0060	0.350	0.025
Ngaka I	Coal	2	200	3.480	9243	0.0322	50	0.0060	0.350	0.025
Ngaka II	Coal	2	200	3.824	9243	0.0353	50	0.0060	0.350	0.025
GAS/HFO PLANT										
Kinyerezi I	GTs - Gas	1	150	4.740	10900	0.0517	7.5	0.0045	0.350	0.025
Kinyerezi II	CCGT	4	240	4.740	7840	0.0372	6	0.0030	0.350	0.025
Kinyerezi III	CCGT	3	300	4.740	10900	0.0517	7.5	0.0045	0.350	0.025
Kinyerezi IV	CCGT	3	300	4.740	10900	0.0517	7.5	0.0045	0.350	0.025
Mtwara	CCGT	4	400	4.740	7840	0.0372	7.5	0.0050	0.350	0.025
Zinga 200	CCGT	2	200	4.740	7840	0.0372	7.5	0.0050	0.350	0.025
Mkuranga 250	CCGT	4	250	4.740	7840	0.0372	7.5	0.0050	0.350	0.025
Mwanza MS Diesel	MSD HFO/Dual	1	60	21.220	8216	0.1743	8	0.0050	0.350	0.025
Somanga Fungu IPP	CCGT	3	320	4.740	7800	0.0370	7.5	0.0025	0.350	0.025

3.5 Import Options - The Zambia-Tanzania-K Inter-connector

The 2008 PSMP and the subsequent 2009 Update included the options of power imports from Zambia via the proposed Zambia-Tanzania-Kenya inter-connector, and from Ethiopia via Kenya. In both cases an import amount of 200MWs at 85 percent load factor was assumed for the generation plans. Both these options would be take or pay, i.e. with a fixed charge corresponding to an energy tariff, with supply of 200MW at 85 percent load factor.

These potential future import options are still expected to be available. The supply from Ethiopia is considered to be more advanced, as Ethiopia Electric Power Co (EEPCo) has signed Power Purchase Agreement with Kenya Power and Lighting Co (KPLC) on supplies to Kenya, while Tanzania Electric Supply Company Limited (TANESCO) is in direct discussion with EEPCo which are taking into account possible supplies to Tanzania at Arusha. It is assumed that supply from Ethiopia could be available as of January 2016.

Information on the ZTK interconnector is provided in the Project Information Memorandum[9] that has been prepared for the Governments of Zambia, Tanzania and Kenya to solicit funding for the development of the longest part of the proposed 1,600 km HVAC power interconnector which will start in Serenje, Zambia and end in Nairobi, Kenya.

Currently, the line is divided into three development parts under the umbrella of ZTK Interconnector Project, namely Zambia (Kasama) – Tanzania (Mbeya); reinforcement of Tanzania transmission backbone (Iringa – Singida); and Tanzania (Singida-Arusha) – Kenya (Nairobi) interconnection.

Construction of Tanzania Backbone transmission line Project (Iringa – Shinyanga via Dodoma and Singida) to start early 2013, feasibility study for Tanzania – Kenya interconnector has been completed, feasibility study for Iringa – Mbeya has been concluded and NBI through NELSAP has secured funds from Norway to carry out feasibility study for Mbeya (Tanzania) to Kasama (Zambia).

[9] Zambia Tanzania Kenya Power Transmission, May 2007, Fieldstone and Scott Wilson

The proposed ZTK interconnector scheme will have to be modified if further supply to Kenya is displaced by the Ethiopia supply to Kenya. This supply from Zambia is assumed to be available before 2021. Information on these options is summarized below. This information is unchanged from that included in the 2008 PSMP, and is included for reference purposes. Ethiopia has extensive hydro resources with more than 1100MW currently under construction (Takese - 300MW, Gilgel II - 420MW Anabeles – 460MW) [10]. A further committed and under construction project is Gilgel III, 1870MW. This project was to be the source for exports to Kenya in 2012, however construction is delayed and current planning is to provide export power from Gilgel II.[11] Information on

HYDROELECTRIC RESOURCES IN ETHIOPIA

A: EXISTING HYDRO	MW
Tis Abbay	80
Finchaa IV	34
Gilgel I	184
Total	**298**

B: COMMITTED HYDRO	MW	Year
Takese	300	
Gilgel II	420	2009
Anabeles	460	2009
Gilgel III	1870	2013
Total	**3050**	

C: LIST OF ETHIOPIA HYDRO PROJECTS IN NBI PRELIMINARY BASIN STUDY DATA BASE

	Installation MW	Average energy GWh	Firm energy GWh
Halele Worabesa	422	2,245	2,030
Chemoga-Yeda	280	*1,348*	1,348
Aleltu East	186	800	780
Aleltu West	265	1,050	983
Baro 1 and 2 + Genji	900	4,409	2,857
Geba 1 and 2	372	1,788	*1,788*
Gojeb	153	520	364
Genale 3 and 4	514	2,210	2,439
Awash 4	38	160	144
Karadobi	1,600	9,700	9,300
Mabil	1,200	5,300	*5,300*
Mandaya (option 1)	2,000	12,300	11,600
Total	**7,930**	**41,830**	**38,933**

future potential hydro sites suggests that there may be a further 8000MW or hydro that could be developed in Ethiopia[12]. The available current committed and identified hydro resources are summarized in the table below:

[10] Hydropower projects to generate megawatts and foreign currency in Ethiopia - www.globalinsight.com, July 2007

[11] Authority plans power export to Kenya from Gibe II, www.addisfortune.com, July 6, 2008

[12] SNC-Lavalin Preliminary Basin Wide Study, May 2008, for NBI Regional Power Trade Project

At this time it is clear that Ethiopia will have large surplus of hydro capability, with project implementation only being limited by financing and off-take agreements. Present information suggests that the cost delivered to Nairobi would be in the order of 7 US cents/kWh, to which the cost of wheeling power to Arusha has to be added, however, actual prices will be determined by the PPA. A possible delivery date is now 2016. It is worth noting that the interconnection will be used for trading within both the SAPP and EAPP power pools.

3.6 Security of supply from Zambia through ZTK interconnector

A key issue that could affect either the on-power date, or supply during the commercial life of the interconnector is the availability of supply from Zambia or SAPP. The PIM notes that Zambia is predicting a deficit in generation capacity in the years 2010-2012, ie during the commissioning of the first phase of the project[13]. The PIM then states that ZESCO is considering the construction of additional hydro such as Lower Kafue Gorge, Kalungwishi, and Itezhi Tezhi. Current information published by ZESCO[14] refers to the following initiatives:

Itehzi Tezhi – 120 MW : This would be the addition of a powerhouse to an existing storage dam. An MOU has been signed with TATA, and investigations are underway. Such a project would take 4 years to implement including an EPC contracting period.

Lower Kafue Gorge - 750 MW: This is a major project, to be constructed downstream of the existing Kafue Gorge hydro plant (900 MW). This project is still at the planning stage and would have minimum lead-time to on-power in the order of 6 years. It may be noted that there has been discussion about these projects for at least 15 years, without significant change to their status or level of preparedness. Reference is also made to the addition of two units at Kariba North - 360 MW, however this would not add any energy, as there is virtually no spillage at Kariba.

Rehabilitation also includes Victoria Falls (108 MW completed), and Kafue Gorge – additional 90 MW. However presumably these will not add any firm energy to the Zambian capability. The supply situation in the area (SAPP) is improving with the ZESCO Zaire interconnection, the full operation of Caborra Bassa (2000 MW) which is supplying to ESKOM etc. However it is noted that in the short term ESKOM is not supplying to other countries.

However security of supply from Zambian system will carry some risk until Lower Kafue is constructed, unless ZESCO has firm supplies from other SAPP members.

[13] The ZESCO profile on their web site indicates a 200-300 MW deficit by 2012.

[14] www.zesco.co.zm

The total hydro generation capability in Zambia (2004), as taken from the Scott Wilson report, was as follows:

Installed capacity	1646	MW
Average energy	11141	GWh
Firm energy	9375	GWh

No firm information is available to estimate a probable Zambia supply cost. Zambia has suggested a price of 10 cents/kWh. A more probable value would be in the order of 6 cents/kWh.

3.7 Other power interchanges

Present cross border interconnection between Tanzania and neighbouring countries are limited to:

With Uganda:

Supply from Uganda into the Kagera area in North West Tanzania (10 MW), which is presently not connected to the main grid.

With Zambia:

Interconnection between Mbala in Zambia to Sumbawanga in Tanzania at 66 kV (5 MW), to supply the presently isolated system in the Rukwa area Interconnection from Nakonde to the TANESCO grid at Mbozi at 33 kV (7 MW)

With Kenya:

Interconnection between Tanga in Tanzania and Lungalunga in Kenya at 33 kV and Interconnection between Namanga in Kenya and Namanga in Tanzania at 33kV.

Reference has also been made to potential power inter-connector projects, which include:

Tanzania – Kenya (400 kV) – feasibility study has just been completed.

Tanzania – Uganda (220 kV) - feasibility study has just been completed.

Mozambique-Tanzania (220 kV), of up to 45MW of power from Tanzanian.

3.8 Renewable

The information on other supply options for 2012 PSMP Update is still based on 2008 PSMP; however, additional renewable sources have been included as supply sources in the development of generation plans as shown in **Table 3-29** and **Table 3-30** below.

Table 3- 29: New Renewable Plants Earliest Time

Plant	Fuel	Installed Capacity MW	Nominal Service Life Years	Minimum lead time years	Earliest on power year (Jan)
RENEWABLES					
Mufindi (Cogen)	Biomass	30	20	3	2015
Sao Hill (Cogen)	Biomass	10	20	3	2015
Solar I	Solar	60	20	3	2016
Solar II	Solar	60	20	3	2017
Wind I	Wind	50	20	3	2016
Wind II	Wind	50	20	3	2017
	TOTAL	**260**			

Source: TANESCO

Table 3- 30: New Renewable Plant Operating Costs

Plant	Fuel	Units	Installed Capacity MW	Fuel price $/GJ	Plant heat rate kJ/kWh	Fuel cost $/kWh	Fixed operating cost /kW-year	Variable operating cost $/kWh	Interim replace - ment %	Insurance %
RENEWABLES										
Mufindi (Cogen)	Biomass	-	30.00	1	10900	0	40	0.01	0	0.025
Sao Hill (Cogen)	Biomass	-	10.00	1	7000	0	40	0.01	0	0.025
Solar I	Solar	-	60.00	N/A	N/A	0	40	0.01	0	0.025
Solar II	Solar	-	60.00	N/A	N/A	0	40	0.01	0	0.025
Wind I	Wind	-	50.00	N/A	N/A	0	40	0.00	0	0.025
Wind II	Wind	-	50.00	N/A	N/A	0	40	0.00	0	0.025

Source: TANESCO

Biomass

Limited information is available on significant biomass operations in the country; including sugar mills which generates up to 12 MW, and delivering several MW of power to TANESCO. Potential fuel quantities also exist from sources such as wood waste from barking operations (resulting in waste of 70,000 t/year), palm oil, coconut and other waster or residue sources.

However, the rural electrification study[15] has identified a number of major potential biomass sources in Mufindi area. These include the Sao Hill Plantation/Sawmill, the Mufindi Wood poles Plant and Timber Ltd, and the Southern Paper Mill. The report refers to a total potential in the order of 75-100 MW, assuming significant future developments in the sawmill plants. By 2015 Sawmill plants are expected to generate 30MW from Mufindi and 10MW from Sao Hill. However, such development would require significant additional electricity supplies, which would use some of the potential generation addition. The report also notes the complexity in planning and developing such integrated timber industry and generation projects. It should be noted that electricity generation is not the core objective of the timber industries. To be able to generate electricity requires massive investment for these industries to be able to generate enough by-products on a sustainable basis without jeopardising the environment. The study therefore proposed further feasibility studies to explore the possibility of taking advantages of these potentials.

Wind Energy Conversion Systems

Wind energy is now being recognized as a potential new power option in the East Africa Region. Wind speed has to be greater than 4 meters per second (m/s) to start producing energy, but a more acceptable amount of energy is produced when the wind speed is greater than 6 m/s. Most economic operation requires wind velocities in the order of 15 m/s. Economic viability of a wind generator also depends on wind distribution with time. Normally a plant has to be able to generate at a plant factor of 25 percent to 30 percent to be viable, and many wind farms are located where plant capacity factors of 35 percent to 40 percent can be achieved.

In Tanzania, studies have been under way for a number of years including the following:

a) An investigation program, sponsored by the Ministry of Energy and Minerals, TANESCO, Tanzania Traditional Energy Development and Environment Organization (TaTEDO) with technical and financial support from Denmark National Laboratory (RISO), and DANIDA. This program resulted in a final report issued in 2003[16].

b) The rural electrification master plan study 2005: As part of this study, three sites were selected for measurement programs, and measurements were initiated in 2005. There were Makambako Town, Iringa region; Mgagau Village, Mwanga district, Kilimanjaro region and Singida, near Singida town.

When the study report was issued, measurements had been taken for on high wind season. The results were very promising for Makambako and Singida, with average wind speeds of 10-11 m/s.

Wind Power Projects

[15] Tanzania Rural Electrification Study, Draft Feasibility Studies and other Tasks of Phase 2, summary Report - Decon and SWECO, African Development Bank Group, November 2005

[16] Danida. RISO (Denmark) – Wind Measurements and Wind Power Feasibility at Selected Sites in Tanzania – 2000-2003 – Final Report

Currently, there are two potential Wind power projects capable to generate between 50 and 100MW at Singida. These projects compliment the government efforts to accelerate the usage of renewable energy. The 2012 PSMP assumed two separate 50 MW wind projects.

Geothermal

Geothermal is another potential source of power in the country. Currently, there are about 50 geothermal potential sites in the country, with an estimated geothermal potential of more than 650MW. There are three most promising sites proposed for more detailed investigations. The sites are:

a) Lake Natron in Arusha region
b) Songwe river basin in Mbeya region
c) Luhoi Spring site, with potential of 50 – 100MW located in Lower Rufiji Valley, Utete district.

There is insufficient information to consider geothermal option in the generation expansion plan under the current PSMP review. However, given the importance of using Tanzanian resources, the coming comprehensive PSMP update could include up to 100MW geothermal plant as a candidate starting 2025 in anticipation that confirmatory studies will have been completed.

Energy Efficiency

Due to generation shortages in the region, a number of countries have taken or are planning Demand Side Management (DSM) initiatives to reduce demand and thus generation requirements. Over the recent years, TANESCO has embarked on a number of initiatives to address the issue of energy efficiency, which includes a Demand Side Management program. A study by TANESCO to improve capacity factors in industrial plants came up with proposals to reduce power demand in Tanzania. **Table 3-31** shows the potential reduction in energy and power for each component of the program.

Table 3- 31: Energy Efficiency Program - Energy and Peak Reduction

Program Description		2011	2012	2013	2014
CFL	GWh	0	19.4	38.2	38.2
Motors and VSD	GWh	0	9.5	22.6	39.5
Awareness	GWh	0	80	120	140
AC	GWh	0	0	2.3	5.8
Beverage Vending Machines	GWh	0	0	0	1.1
Power Factor Correction	GWh	0	0	0	0
Refrigerators	GWh	0	0	0	2
Industrial	GWh	0	0	28.7	57.4
Total	**GWh**	**0**	**108.9**	**211.8**	**284**
CFL	MW	0	12.4	24.4	24.4
Industrial Motors, Variable Speed Drive	MW	0	0.9	2.2	3.8
Awareness, Information dissemination	MW	0	14	21.1	24.6
Commercial, Inst. Air Conditioner	MW	0	0	1.8	4.7
Refrigerators, Beverage Vending Machines	MW	0	0	0	0.1
Audit Incentives (Power Factor Correction)	MW	0	0	0.5	1.4
Refrigerators	MW	0	0	0	0.3
Industrial	MW	0	0	5	10
Total	**GWh**	**0**	**27.3**	**55**	**69.3**

Source: Team Compilation

Though the above programs were set to begin on January 2012, their implementation has not started; as a result, this PSMP has not taken into consideration the DSM programs.

In the context of the Tanzania PSMP, and particularly taking into account the present supply deficit, the impacts of DSM initiatives was not considered for the 2012 PSMP update as a realistic option, at least in the medium term to get the benefits of reduced capacity needs i.e. to displace about 20 to 30 MW. The program has significant impact not only in Tanzania but even in other neighbouring countries. Kenya has taken similar initiatives which provide an opportunity for TANESCO to borrow such experiences when the project materialise and eventually affect the supply-demand balance in Tanzania. Another option to reduce power demand is to reduce technical losses (reduction in non-technical losses will not reduce demand). Investment in loss reduction may be more economic. Losses in Tanzania are moderately high, at about 12 percent, and this suggests that a loss reduction program could provide benefits. However the potential benefits were not considered sufficient to include this option in the 2012 PSMP update.

3.8.1 Nuclear

The potential for uranium deposits in Tanzania was identified in a countrywide airborne geophysical survey in the 1970´s. Further exploration between 1978 and 1982 resulted in the identification of surface mineralization and recognition of the potential for uranium deposits in Tanzania. Currently, there are about 20 companies engaged in exploration for uranium in Tanzania. Significant mineralization or deposits have been identified in the Dodoma area at Handa and Bahi North (Mantra Resources), in the Ruhuhu area near

Lake Nyasa (Uranium Hunter, Atomic Minerals, and Western Metals). Nuclear generation could become an option, particularly when other indigenous resources are fully committed.

This technology has not been considered in this PSMP update because it is considered that nuclear generation could only be selected when:

a. The Government has finalized the policies on uranium and nuclear generation.
b. Human Capacity building on nuclear technology and other related matters.

It is considered that this resource would have been developed in Tanzania and available for power generation by 2030s subject to further studies and familiarization with this technology.

3.8.2 Solar Photo Voltaic (PV)

Contemporary solar PV technology is done at small scale level. Application of solar power technology in Tanzania at large scale is not well established. However, in this update solar power was considered, with a potential to undertake pilot project before engaging many players.

3.9 Generation Plan Results

Development of Comparative Expansion Plans

The development of alternative expansion generation plans covered the three scenarios following three cases of load forecast. The scheduling of projects in each plan (high, base and low case) observes a reserve margin on firm capacity in the order of 15 - 40 percent, hydro thermal mix of 40:60 and export/import of not more than 25 percent of total available capacity. The purpose of these relatively high reserve margins is to have a robust generation capability in the event of failures and the possibility for power trading with the neighbouring countries.

The 2012 Update generation expansion plan retains the base case scenario as a recommended power generation expansion plan for the country. The plan reflects the most likely growth of power demand. Overall and as shown in **Table 3-32,** the "Base Case Plan" has a total installed capacity of 8990MW by 2035 consisting of 3304 MW hydro, 995MW gas-fired generation, 3800MW-Coal, 100MW-Solar, 120MW-Wind, 40MW- Biomass/Cogen, and some export limited to 250MW of total available generation. This plan fulfills all assumptions and results which were assumed and obtained in the load forecast respectively.

Table 3- 32: Generation Plan – Base Case

EXPANSION PLAN
LOAD FORECAST CASE BASE

Retirements January 1
On power January
Thermal additions are net MW

YEAR	PLANT	FUEL	TYPE	ADDITION MW	ADDITION GWH FIRM	TOTAL SUPPLY MW	TOTAL SUPPLY GWH FIRM	DEMAND MW	DEMAND GWH	SURPLUS (DEFICIT) MW	SURPLUS (DEFICIT) GWH	Reserve Margin Capacity %	Reserve Margin Energy %	Generation Mix % HYDRO Capacity	Generation Mix % HYDRO Energy	Power Pool Trading MW	Power Pool Trading GWH
2011	All existing plants			1103	5310	1103	5310	833	4485	270	825	32	18	33	55	(145)	(152)
				-	-	1103	5310										
2012	Aggreko (Ubungo)	FUEL	GO	50	242	1153	5551										
	Aggreko (Ubungo)	FUEL	GO	(50)	-81	1103	5471										
	Symbion 112	GAS	GT	(75)	-161	1028	5310										
	Symbion 112	GAS	GT	75	484	1103	5793										
	Symbion 112	FUEL	Jet- A1	(37)	-80	1066	5714										
	Symbion 112	FUEL	Jet- A1	37	239	1103	5952										
	Ubungo II	Gas	GT	105	338	1208	6291										
	Aggreko (Tegeta)	FUEL	GO	50	242	1258	6532										
	Aggreko (Tegeta)	FUEL	GO	(50)	-81	1208	6452										
	Mwenga Hydro	Hydro	Hydro	4	2	1212	6453										
	Symbion 205 DODOMA	FUEL	GO	55	355	1267	6808										
	Symbion 205 ARUSHA	FUEL	GO	50	215	1317	7023	1139	6085	178	937	16	15	28	42	(7)	(25)
2013	Mwanza MS diesel	FUEL	Diesel	60	290	1377	7313										
	Ubungo II	Gas	GT	105	677	1482	7990										
	Ubungo II	Gas	GT	(105)	(338)	1377	7651										
	Aggreko (Ubungo)	FUEL	GO	(50)	(242)	1327	7410										
	Aggreko (Tegeta)	FUEL	GO	(50)	(242)	1277	7168										
	Symbion 205 DSM	FUEL	GO	100	645	1377	7813										
	Mwenga Hydro	Hydro	Hydro	4	6	1381	7819										
	Mwenga Hydro	Hydro	Hydro	(4)	-2	1377	7817										
	Symbion 112	FUEL	Jet- A1	75	242	1452	8059										
	Symbion 112	FUEL	Jet- A1	37	119	1489	8178										
	Symbion 112	FUEL	Jet- A1	(112)	(722)	1377	7456										
				-	-	1377	7456	1365	7332	12	124	1	2	27	40	192	976
2014						1377	7456										
	Somanga Tanesco	Gas	GE	8	48	1385	7504										
	Symbion 205 ARUSHA	FUEL	GT	50	215	1435	7719										
	Symbion 205 ARUSHA	FUEL	GT	(50)	(355)	1385	7365										
	Retire Symbion 205 DODOMA	FUEL	GT	(55)	(355)	1330	7010										
	Kinyerezi I	Gas	GT	150	967	1480	7977										
	Somanga Fungu (320)	Gas	GT	210	677	1690	8654										
	Mwanza MS diesel	Fuel	Diesel	(60)	(315)	1630	8339										
	Mwanza MS diesel	FUEL	Diesel	60	387	1690	8726										
	Retire Symbion 112	FUEL	Jet- A1	(112)	(361)	1578	8365	1704	9200	(127)	(835)	(7)	-9	23	35	382	2,215
2015	Kinyerezi II	Gas	CCGT	240	1682	1818	10047										
	Retire Symbion 205 ARUSHA	FUEL	GO	(50)	(215)	1768	9832										
	Retire Symbion 205 DSM	FUEL	GO	(100)	(645)	1668	9187										
	Somanga Fungu (320)	Gas	GT	(210)	(677)	1458	8510										
	Zinga 200MW	Gas	CCGT	200	1,289	1658	9799										
	Somanga Fungu (320)	Gas	GT	210	1,354	1868	11153										
	Mkuranga 250MW	Gas	CCGT	250	1,612	2118	12765										
	Renewable - Cogen (Sao Hill)	Biomass	Cogen	10	84	2128	12849										
	Renewable - Cogen (Mfindi)	Biomass	Cogen	30	210	2158	13059	2088	11246	69	1813	3	16	22	23	244	(126)
2016	Kinyerezi III	Gas	GT	300	1934	2458	14993										-
	Somanga Fungu (320)	Gas	CC	110	709	2568	15703										
	Interconnector (Ethiopia/Kenya)	Import	Import	200	1,402	2768	17104										
	Kiwira I	Coal	Steam	200	1,402	2968	18506										
	Mtwara 400MW	Gas	CCGT	400	2,579	3368	21085										
					-	3368	21085										
	Solar I	Solar	Solar	60	210	3428	21295										
	Renewable - Wind I	Wind	Wind	50	201	3478	21496	2522	13520	955	7976	38	59	12	14	(577)	(5,948)
				-	-	3478	21496									-	-
2017	Renewable - Wind II	Wind	Wind	50	175	3528	21672										
	Ngaka I	Coal	Steam	200	1,289	3728	22961										
					-	3728	22961										
	Hale	Hydro	Hydro	11	28	3738	22989										
	Coastal Coal	Coal	Steam	300	1,934	4038	24923										
					-	4038	24923	2898	15494	1140	9429	39	61	11	12	(706)	(7,105)
2018	Rusumo Falls	Hydro	Hydro	27	148	4065	25071									-	-
	Mchuchuma I	Coal	Steam	300	1,934	4365	27005										
	Kiwira II	Coal	Steam	200	1,289	4565	28295										
	Solar II	Solar	Solar	60	210	4625	28505										
	Interconnector - Rwanda/Burundi	export	export	(50)	(350)	4575	28154										
	Interconnector - Mozambique	export	export	(100)	-645	4475	27510										
	Interconnector - I (Zambia)	export	export	(100)	(701)	4375	26809	3204	17194	1171	9614	37	56	10	11	(690)	(7,035)
2019						4375	26809									-	-
	Kakono	Hydro	Hydro	53	335	4428	27144										
	Ngaka II	Coal	Steam	200	1,402	4628	28545										
					-	4628	28545	3374	18322	1254	10223	37	56	11	10	(748)	(7,475)
2020						4628	28545									-	-
	Mchuchuma II-1	Coal	Steam	100	701	4728	29246										
	Malagarasi	Hydro	Hydro	45	187	4773	29433	3573	19607	1199	9827	34	50	11	11	(663)	(6,886)
2021	Ruhudji	Hydro	Hydro	358	1,333	5131	30766									-	-
					-	5131	30766										
						5131	30766	3781	20943	1350	9823	36	47	18	10	(783)	(6,682)
2022	Mpanga	Hydro	Hydro	144	646	5275	31412									-	-
						5275	31412										
	Mchuchuma II-2	Coal	Steam	100	701	5375	32113										
				-	-	5375	32113	4009	22424	1366	9689	34	43	20	9	(765)	(6,325)
2023	Retire Tegeta IPTL	Fuel	HFO	(100)	(701)	5275	31412									-	-
	Stieglers Gorge I	Hydro	Hydro	300	1908	5575	33320										
	Songwe Bupigu	Hydro	Hydro	34	101	5609	33421										
					-	5609	33421										
						5609	33421	4253	24000	1356	9422	32	39	26	9	(718)	(5,822)
2024	Masigira	Hydro	Hydro	118	492	5727	33913									-	-
	Mchuchuma II-3	Coal	Steam	200	1,402	5927	35315										
						5927	35315	4483	25514	1444	9801	32	38	27	8	(771)	(5,974)
2025	Rumakali	Hydro	Hydro	520	2,520	6447	37835									-	-
						6447	37835										
					-	6447	37835										
	Retire Songas 1+2+3	Gas	GT	(187)	(1,310)	6260	36524										
					-	6260	36524										
					-	6260	36524	4724	27139	1535	9386	33	35	34	8	(827)	(5,315)
2026						6260	36524									-	-
	Songwe Sofre	Hydro	Hydro	157	456	6417	36980										
						6417	36980										
	Mchuchuma III-1	Coal	Steam	100	701	6517	37681	4979	28860	1537	8821	31	31	35	8	(791)	(4,492)
2027						6517	37681									-	-
					-	6517	37681										
	Ikondo - Mnyera	Hydro	Hydro	340	1,316	6857	38997	5248	30689	1609	8308	31	27	33	11	(822)	(3,705)
2028						6857	38997									-	-
	Mchuchuma III-2	Coal	Steam	200	1402	7057	40399										
	Songwe Manolo	Hydro	Hydro	149	488	7206	40887	5531	32635	1675	8252	30	25	37	8	(845)	(3,357)
2029	Taveta - Mnyera	Hydro	Hydro	145	622	7351	41509									-	-
	Local Coal I	Coal	Steam	200	1402	7551	42910	5806	34560	1745	8351	30	24	39	7	(874)	(3,167)
2030	Retire Ubungo GT	Gas	GT	(100)	(701)	7451	42210									-	-
					-	7451	42210										
	Local Coal II	Coal	Steam	400	2803	7851	45013										
					0	7851	45013	6085	36543	1766	8469	29	23	37	7	(853)	(2,988)
2031	Retire Tegeta GT	Gas	GT	(41)	(287)	7810	44725									-	-
				-	-	7810	44725										
	Local Coal III	Coal	Steam	400	2803	8210	47529										
						8210	47529										
				-	-	8210	47529	6377	38646	1832	8883	29	23	36	6	(876)	(3,086)
2032	Retire Mwanza Ms Diesel	Fuel	Diesel	(60)	(420)	8150	47108									-	-
	Retire Ubungo EPP	Gas	GT	(100)	(701)	8050	46407										
	Retire Cogen	Biomass	Steam	(40)	(280)	8010	46127										
				-	-	8010	46127										
				-	-	8010	46127										
	Stieglers Gorge II	Hydro	Hydro	600	855	8610	46982										
					0	8610	46982	6679	40836	1931	6146	29	15	41	6	(929)	(21)
2033	Local Coal IV	Coal	Steam	400	2,579	9010	49561									-	-
					-	9010	49561										
					-	9010	49561										
				-	-	9010	49561										
						9010	49561										
					-	9010	49561	6979	43030	2031	6531	29	15	39	6	(984)	(77)
2034				-	-	9010	49561									-	-
				-	-	9010	49561										
	Local Coal V	Coal	Steam	300	1,934	9310	51495										
						9310	51495										
					-	9310	51495	7290	45359	2019	6136	28	14	38	6	(926)	668
2035	Stieglers Gorge III	Hydro	Hydro	300	464	9610	51959	7645	47724	1965	4236	26	9	37	7	(818)	2,923
						9610	51959										
	TOTAL ADDITIONS 2011-2035			9610	51959	19219	103918										

3.10 Ranking on costs of new power options

The previous sections provided information and procedures on the cost and availability of new power options. The ordering of projects for the generation plan was based in part on a ranking of projects based on cost and availability.

3.11 Basic technical screening

Conventionally, in selecting candidate new power options, an initial screening is made to exclude projects not to be considered in the generation planning program. A project may be excluded during screening process due to the following reasons:

a. Insufficient data for analysis: projects without pre-feasibility studies. (although some such sites may be recommended for further study);
b. Socially or environmentally unacceptable: sites with significant social or environmental risk which cannot be mitigated;
c. Too expensive: sites with indicated unit energy cost above 10 USD cents/kWh for firm energy, as this threshold is significantly above available thermal options; and
d. Too small: sites with identified capacities less than 20MW, because they would have no impact on the planning process. However, such size of plants have been considered if are developed by private investors for instance Mwenga 4MW hydro power project.

3.12 Project Ranking and Availability

The ranking of projects to be included in generation expansion plan is based on unit cost of production. For thermal plants unit costs are based on 75 percent annual capacity factor. The ranking of hydro plants is based on cost of firm energy generation. Overall, the availability of a given plant is based on present level of preparation, project size, and consequent minimum lead times as shown in **Table 3-33**.

Table 3- 33: Ranking of hydro and thermal options

Name	TOTAL COST $ MILLION	INSTAL. CAP (MW)	ENERGY AV (GWh)	ENERGY FIRM (GWH)	GENERATION COST Average $/kWh	GENERATION COST Firm $/kWh	GENERATION COST $/kW	Tech.	STATUS	Earliest installation date (January)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sao Hill (Cogen)	39.57	10	66	-	0.0148	0.0148	3,956.50	Thermo	Committed	2016					10																			
Mufindi (Cogen)	118.70	30	197	-	0.0148	0.0148	3,956.50	Thermo	Committed	2016					30																			
Mchuchuma Coal I	645.75	300	1,971	1,971	0.0383	0.0383	2,152.50	Thermo	Committed	2018							300																	
Kakono (High)	96.86	53	404	335	0.0317	0.0383	1,827.55	Hydro	Candidate	2018							53																	
Mchuchuma Coal II	861.00	400	2,628	2,628	0.0391	0.0391	2,152.50	Thermo	Candidate	2019								400																
Mchuchuma Coal III	645.75	300	1,971	1,971	0.0391	0.0391	2,152.50	Thermo	Candidate	2019								300																
Somanga Fungu(210+120), CC	365.00	320	2,102	2,102	0.0395	0.0395	1,140.63	Thermo	Committed	2015					320																			
Ngaka coal I	630.50	200	1,314	1,314	0.0399	0.0399	3,152.50	Thermo	Committed	2019								200																
Kinyerezi II	444.84	240	1,577	1,577	0.0402	0.0402	1,853.51	Thermo	Committed	2016					240																			
Kiwira I - coal steam	430.50	200	1,314	1,314	0.0413	0.0413	2,152.50	Thermo	Committed	2017								200																
Kiwira II - coal steam	430.50	200	1,314	1,314	0.0413	0.0413	2,152.50	Thermo	Committed	2019								200																
Ngaka coal II	630.50	200	1,314	1,314	0.0413	0.0413	3,152.50	Thermo	Committed	2019								200																
Mtwara	600.20	400	2,628	2,628	0.0422	0.0422	1,500.50	Thermo	Committed	2015				400																				
Stiegler Gorge Phase 1	938.49	300	2,230	1,908	0.0410	0.0480	3,128.30	Hydro	Candidate	2022											300													
Taveta	251.13	145	850	622	0.0370	0.0506	1,731.90	Hydro	Candidate	2021										145														
Mpanga	274.09	144	955	646	0.0363	0.0537	1,903.37	Hydro	Candidate	2021										144														
Coastal coal	645.75	500	3,285	3,285	0.0548	0.0548	1,291.50	Thermo	Candidate	2019								500																
Local Coal I	430.50	100	657	657	0.0548	0.0548	4,305.00	Thermo	Candidate	2026															100									
Local Coal II	861.00	200	1,314	1,314	0.0548	0.0548	4,305.00	Thermo	Candidate	2029																		200						
Local Coal III	861.00	400	2,628	2,628	0.0548	0.0548	2,152.50	Thermo	Candidate	2030																			400					
Local Coal IV	861.00	400	2,628	2,628	0.0548	0.0548	2,152.50	Thermo	Candidate	2031																				400				
Local Coal V	645.75	400	2,628	2,628	0.0548	0.0548	1,614.38	Thermo	Candidate	2033																						400		
Kinyerezi I	187.58	150	986	986	0.0562	0.0562	1,250.50	Thermo	Committed	2014			150																					
Kinyerezi III	557.05	300	1,971	1,971	0.0562	0.0562	1,856.84	Thermo	Committed	2017						300																		
Zinga	276.20	200	1,314	1,314	0.0562	0.0562	1,381.00	Thermo	Committed	2015			200																					
Mkuranga	200.00	250	1,643	1,643	0.0562	0.0562	800.00	Thermo	Committed	2015			250																					
Masigira	225.30	118	664	492	0.0449	0.0607	1,909.28	Hydro	Candidate	2021										118														
Stiegler Gorge Phase 2 addition	334.36	600	1,506	855	0.0344	0.0607	557.26	Hydro	Candidate	2022											600													
Ikondo	665.84	340	1,842	1,316	0.0478	0.0670	1,958.35	Hydro	Candidate	2021										340														
Songwe Sofre	274.28	157	736	456	0.0457	0.0737	1,747.00	Hydro	Candidate	2022											157													
Songwe Manolo	278.88	149	780	488	0.0502	0.0802	1,871.65	Hydro	Candidate	2021										149														
Stiegler Gorge Phase 3 addition	274.09	300	464	464	0.0273	0.0896	913.62	Hydro	Candidate	2022											300													
Rumakali	740.00	520	1,475	908	0.0559	0.0908	1,423.08	Hydro	Committed	2020									520															
Rusumo Falls (Full) 33% Tanzania	339.20	27	148	129	0.0919	0.1061	12,720.00	Hydro	Committed	2018							27																	
Ruhudji	1,220.00	358	1,928	1,333	0.0791	0.1145	3,407.82	Hydro	Committed	2019								358																
Songwe Bipigu	90.41	34	153	101	0.0772	0.1169	2,658.97	Hydro	Candidate	2019								34																
Wind	272.00	100	408	-	0.1300	0.1300	2,720.00	Wind	Committed	2016					100																			
Solar	288.56	300	1,971	-	0.2200	0.2200	961.86	Thermo	Candidate	2016					300																			
Malagarasi (Igamba III)	153.24	45	187	21	0.1065	0.9278	3,420.54	Hydro	Committed	2018							45																	
Upper Kihansi	116.52	120	69	99	0.1337	1.5073	971.02	Hydro	Candidate	2020									120															

Source: Team Compilation

3.13 Detailed Generation Costs and Screening Tables

The development of alternative generation plans and their comparisons use comparative costs for alternative technologies. These are presented in a screening table showing generation cost as a function of plant capacity factor.

The unit cost of generation is based on:

a. Fixed annual cost
b. Amortization of capitalized amount
c. Interim replacement
d. Insurance
e. Fixed operation and maintenance

Annual cost is split into:

a. Fuel cost
b. Variable operation and maintenance

The screening tables that compare unit generation costs as a function of plant factor are shown in **Table 3-34**.

Table 3- 34: Thermal generation alternatives for Tanzania and screening tables (Sheet 1 of 2)

Thermal generation alternatives for Tanzania and screening tables

`	10.0%	Mchuchuma Stage I 3x100 MW	Mchuchuma Stage II 4x100 MW	Mchuchuma Stage III 3x100 MW	Kiwira I 4x50 MW	Kiwira II 4x50 MW	Ngaka I 4x100 MW	Ngaka II 4x100 MW	Coastal Coal-Steam 3x100 MW	Local I Coal-Steam 2x100 MW	Local II Coal-Steam 4x100 MW	Local III Coal-Steam 4x100 MW	Local IV Coal-Steam 4x100 MW	Local V Coal-Steam 3x100 MW
Installed capacity	MW	324	432	324	216	216	216	216	324	216	432	432	432	324
Station service	%	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Net capacity	MW	300	400	300	200	200	200	200	300	200	400	400	400	300
Unit availability														
Scheduled maintenance	wks per unit	6	6	6	6	6	6	6	6	6	6	6	6	6
Forced outage rate	%	8	8	8	8	8	8	8	8	8	8	8	8	8
Combined outage rate	%	20	20	20	20	20	20	20	20	20	20	20	20	20
Net capacity available (after derating for outage)	MW	244	326	244	163	163	163	163	244	163	326	326	326	244
Earliest on-power date	Yr	2033	2034	2018	2019	2017	2019	2019	2016	2026	2029	2030	2031	2033
Service life	Yrs	25	25	25	25	25	25	25	25	25	25	25	25	25
O & M														
Fixed O & M	$/kW	50	50	50	70	70	50	50	50	50	50	50	50	50
Variable O & M	$/kWh	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Interim replacement	% of capital	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Insurance	% of capital	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total capital cost with IDC														
Unit capital cost	US $/kW	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0
Capital costs Stage 1	US $ x 10^6	645.8	861.0	645.8	430.5	430.5	430.5	430.5	645.8	430.5	861.0	861.0	861.0	645.8
Capital cost Stage 2	US $ x 10^6													
Transmission	US $ x 10^6	0.0	0.0	0.0	0.0	0.0	200.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital cost	US $ x 10^6	645.8	861.0	645.8	430.5	430.5	630.5	630.5	645.8	430.5	861.0	861.0	861.0	645.8
Avg capital cost per available capacity	$/kW avail	2644.8	2644.8	2644.8	2644.8	2644.8	3873.6	3873.6	2644.8	2644.8	2644.8	2644.8	2644.8	2644.8
Annual fixed cost	$/kW avail	71.4	71.4	71.4	95.9	95.9	76.0	76.0	71.4	71.4	71.4	71.4	71.4	71.4
Cashflow in year prior to on-power														
-5	% of capital													
-4	% of capital	15	15	15	15	15	15	15	15	15	15	15	15	15
-3	% of capital	30	30	30	30	30	30	30	30	30	30	30	30	30
-2	% of capital	30	30	30	30	30	30	30	30	30	30	30	30	30
-1	% of capital	25	25	25	25	25	25	25	25	25	25	25	25	25
0	% of capital	0	0	0	0	0	0	0	0	0	0	0	0	0
Avg total cost at on-power	$/kW avail	3022.1	3022.1	3022.1	3022.1	3022.1	4426.1	4426.1	3022.1	3022.1	3022.1	3022.1	3022.1	3022.1
Annuity over economic life (year-end)	$/kW avail	332.9	332.9	332.9	332.9	332.9	487.6	487.6	332.9	332.9	332.9	332.9	332.9	332.9
Total annual fixed cost	$/kW avail	404.3	404.3	404.3	428.9	428.9	563.6	563.6	404.3	404.3	404.3	404.3	404.3	404.3
Fuel cost calculation														
Fuel type		Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal
Fuel price	$/GJ	3.31	3.40	3.40	3.82	3.82	3.48	3.31	5.02	5.02	5.02	5.02	5.02	5.02
Heat rate	kJ/kWh	9,730	9,730	9,730	9,243	9,243	9,730	9,730	9,730	9,730	9,730	9,730	9,730	9,730
Fuel cost	$/kWh	0.03225	0.03306	0.03306	0.03535	0.03535	0.03386	0.03223	0.04883	0.04883	0.04883	0.04883	0.04883	0.04883
Total fixed cost	$/kW avail.	404.3	404.3	404.3	428.9	428.9	563.6	563.6	404.3	404.3	404.3	404.3	404.3	404.3
Total variable cost	$/kWh avail.	0.03825	0.03906	0.03906	0.04135	0.04135	0.03986	0.03823	0.05483	0.05483	0.05483	0.05483	0.05483	0.05483

				183	438								
				1.22	1.825								
`	10.0%	Somanga CCGT (Gas) 2x115 1x110	MTWARA Gas 4x100 MW	Kinyerezi I GT(Gas) 3x50 MW	Kinyerezi II CCGT (Gas) 2x60 2x60	Kinyerezi III Gas 3x100 MW	Kinyerezi IV Gas 3x100 MW	Zinga Gas 2x100 MW	Mkuranga Gas 5x50 MW	Mufindi Cogen 30 MW	Sao Hill Cogen 10 MW	Solar 60 MW	Wind 50 MW
Installed capacity	MW	328	406	152	179	305	305	203	254	31	10	61	51
Station service	%	2.35	1.60	1.60	2.35	1.60	1.60	1.60	1.60	2.4	2.40	2.4	2.40
Net capacity	MW	320	400	150	240	300	300	200	250	30.0	10	60.0	50
Unit availability													
Scheduled maintenance	wks per unit	4	4	4	3	4	4	4	4	3	3	3	3
Forced outage rate	%	5	7	5	5	5	5	5	5	5	5	5	5
Combined outage rate	%	11	15	13	11	13	13	13	13	11	11	11	11
Net capacity available (after derating for outage)	MW	281	343	132	215	263	263	175	219	20	10	20	10
Earliest on-power date	Yr	2015	2016	2014	2016	2017	0	2015	2015	2016	2016	2016	2016
Service life	Yrs	20	25	20	20	20	20	20	20	20	20	20	20
O & M													
Fixed O & M	$/kW	7.5	7.5	7.5	6	7.5	7.5	7.5	7.5	40	40	40	40
Variable O & M	$/kWh	0.0025	0.0050	0.0045	0.0030	0.0045	0.0045	0.0045	0.0045	0.0030	0.0030	0.0030	0.0030
Interim replacement	% of capital	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Insurance	% of capital	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total capital cost with IDC													
Unit capital cost	US $/kW	1141.0	1220.0	1220.0	1808.3	1808.3	1808.3	1347.5	1808.3	3860	3860	4692	2438
Capital costs Stage 1	US $ x 10^6	374.2	500.2	187.6	444.8	556.1	556.1	276.2	463.4	118.7	39.6	288.6	124.9
Capital cost Stage 2	US $ x 10^6	141.0											
Transmission	US $ x 10^6	85.0	100.0	0.0	0.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0
Capital cost	US $ x 10^6	365.0	600.2	187.6	444.8	557.1	557.1	277.2	464.4	118.7	39.6	288.6	124.9
Avg capital cost per available capacity	$/kW avail	1300.7	1747.9	1426.0	2070.5	2117.5	2117.5	1580.7	2118.2	5934.8	3956.5	14427.9	12494.8
Annual fixed cost	$/kW avail	13.4	15.3	13.9	14.5	16.5	16.5	14.5	16.5	82.3	54.8	174.1	246.9
Cashflow in year prior to on-power													
-5	% of capital												
-4	% of capital												
-3	% of capital	15			15					15	15	15	15
-2	% of capital	50	40	40	50	40	40	40	40	50	50	50	50
-1	% of capital	35	60	60	35	60	60	60	60	35	35	35	35
0	% of capital	0	0	0	0	0	0	0	0	0	0	0	0
Avg total cost at on-power	$/kW avail	1406.7	1817.8	1483.0	2239.3	2202.1	2202.1	1644.0	2202.9	6418.4	4279.0	15603.8	13513.1
Annuity over economic life (year-end)	$/kW avail	165.2	200.3	174.2	263.0	258.7	258.7	193.1	258.8	753.9	502.6	1832.8	1587.2
Total annual fixed cost	$/kW avail	178.7	215.6	188.1	277.5	275.2	275.2	207.6	275.3	836.2	557.4	2006.9	1834.1
Fuel cost calculation													
Fuel type		Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Biomass	Biomass	Solar	Wind
Fuel price	$/GJ	4.74	4.74	4.74	4.74	4.74	4.74	4.74	4.74	1.03	1.03	N/A	N/A
Heat rate	kJ/kWh	7,800	7,840	10,900	7,840	10,900	10,900	10,900	10,900	11500	11500	N/A	N/A
Fuel cost	$/kWh	0.03697	0.03716	0.05167	0.03716	0.05167	0.05167	0.05167	0.05167	0.01185	0.01185	N/A	N/A
Total fixed cost	$/kW avail.	178.7	215.6	188.1	277.5	275.2	275.2	207.6	275.3	836.2	557.4	2006.9	1834.1
Total variable cost	$/kWh avail.	0.03947	0.04216	0.05617	0.04016	0.05617	0.05617	0.05617	0.05617	0.01485	0.01485	0.22000	0.13000

Table 3- 34: Screening tables - Unit energy costs ($/MWh) for thermal generation alternatives

Plant Factor	Mchuchuma Stage I 3x100 MW	Mchuchuma Stage II 4x100 MW	Mchuchuma Stage III 3x100 MW	Kiwira I - 4x50 MW	Kiwira II - 4x50 MW	Ngaka - 4x100 MW	Ngaka - 4x100 MW	Coastal Coal-Steam 3x100 MW	Local I Coal-Steam 2x100 MW	Local II Coal-Steam 4x100 MW	Local III Coal-Steam 4x100 MW	Local IV Coal-Steam 4x100 MW	Local V Coal-Steam 3x100 MW	Somanga CCGT (Gas) 2x115 1x110	MTWARA Gas 4x100 MW	Kinyerezi I GT(Gas) 3x50 MW	Kinyerezi II CCGT (Gas) 2x60 2x60	Kinyerezi III Gas 3x100 MW	Kinyerezi IV Gas 3x100 MW	Zinga Gas 2x100 MW	Mkuranga Gas 5x50 MW	Mufindi Cogen 30 MW	Sao Hill Cogen 10 MW	Solar - 60 MW	Wind - 50 MW
5.0%	961.3	962.1	962.1	1020.5	1020.5	1326.6	1324.9	977.9	977.9	977.9	977.9	977.9	977.9	447.4	534.3	485.6	673.7	684.4	684.4	530.1	684.6	1923.9	1287.5	4802.0	4317.4
10.0%	499.8	500.6	500.6	530.9	530.9	683.2	681.6	516.4	516.4	516.4	516.4	516.4	516.4	243.4	288.2	270.9	356.9	370.3	370.3	293.1	370.4	969.4	651.2	2511.0	2223.7
15.0%	345.9	346.7	346.7	367.7	367.7	468.8	467.1	362.5	362.5	362.5	362.5	362.5	362.5	175.4	206.2	199.3	251.3	265.6	265.6	214.1	265.6	651.2	439.1	1747.3	1525.8
20.0%	269.0	269.8	269.8	286.1	286.1	361.5	359.9	285.6	285.6	285.6	285.6	285.6	285.6	141.4	165.2	163.5	198.5	213.2	213.2	174.6	213.3	492.1	333.0	1365.5	1176.9
25.0%	222.9	223.7	223.7	237.2	237.2	297.2	295.6	239.4	239.4	239.4	239.4	239.4	239.4	121.1	140.6	142.1	166.9	181.8	181.8	151.0	181.9	396.7	269.4	1136.4	967.5
30.0%	192.1	192.9	192.9	204.5	204.5	254.3	252.7	208.7	208.7	208.7	208.7	208.7	208.7	107.5	124.2	127.7	145.8	160.9	160.9	135.2	160.9	333.0	227.0	983.7	827.9
35.0%	170.1	170.9	170.9	181.2	181.2	223.7	222.0	186.7	186.7	186.7	186.7	186.7	186.7	97.7	112.5	117.5	130.7	145.9	145.9	123.9	145.9	287.6	196.7	874.6	728.2
40.0%	153.6	154.4	154.4	163.7	163.7	200.7	199.1	170.2	170.2	170.2	170.2	170.2	170.2	90.5	103.7	109.8	119.4	134.7	134.7	115.4	134.7	253.5	173.9	792.8	653.4
45.0%	140.8	141.6	141.6	150.1	150.1	182.8	181.2	157.4	157.4	157.4	157.4	157.4	157.4	84.8	96.8	103.9	110.6	126.0	126.0	108.8	126.0	227.0	156.3	729.1	595.3
50.0%	130.6	131.4	131.4	139.3	139.3	168.5	166.9	147.1	147.1	147.1	147.1	147.1	147.1	80.3	91.4	99.1	103.5	119.0	119.0	103.6	119.0	205.7	142.1	678.2	548.7
55.0%	122.2	123.0	123.0	130.4	130.4	156.8	155.2	138.7	138.7	138.7	138.7	138.7	138.7	76.6	86.9	95.2	97.8	113.3	113.3	99.3	113.3	188.4	130.5	636.5	510.7
60.0%	115.2	116.0	116.0	122.9	122.9	147.1	145.5	131.8	131.8	131.8	131.8	131.8	131.8	73.5	83.2	92.0	93.0	108.5	108.5	95.7	108.5	173.9	120.9	601.8	479.0
65.0%	109.3	110.1	110.1	116.7	116.7	138.8	137.2	125.8	125.8	125.8	125.8	125.8	125.8	70.8	80.0	89.2	88.9	104.5	104.5	92.6	104.5	161.7	112.7	572.5	452.1
70.0%	104.2	105.0	105.0	111.3	111.3	131.8	130.1	120.8	120.8	120.8	120.8	120.8	120.8	68.6	77.3	86.8	85.4	101.0	101.0	90.0	101.1	151.2	105.8	547.3	429.1
75.0%	99.8	100.6	100.6	106.6	106.6	125.6	124.0	116.4	116.4	116.4	116.4	116.4	116.4	66.7	75.0	84.8	82.4	98.0	98.0	87.8	98.1	142.1	99.7	525.5	409.2
80.0%	95.9	96.7	96.7	102.5	102.5	120.3	118.6	112.5	112.5	112.5	112.5	112.5	112.5	65.0	72.9	83.0	79.8	95.4	95.4	85.8	95.4	134.2	94.4	506.4	391.7
85.0%	92.5	93.4	93.4	98.9	98.9	115.5	113.9	109.1	109.1	109.1	109.1	109.1	109.1	63.5	71.1	81.4	77.4	93.1	93.1	84.0	93.1	127.1	89.7	489.5	376.3
90.0%	89.5	90.3	90.3	95.7	95.7	111.3	109.7	106.1	106.1	106.1	106.1	106.1	106.1	62.1	69.5	80.0	75.4	91.1	91.1	82.5	91.1	120.9	85.6	474.6	362.6

Sources: Team Compilations

3.14 Environmental and Social Impact Assessment

Environmental and social issues

There are two components to the planning process that take into account environmental and social aspects.

Project environmental and social analysis: The system planning function provides the mechanism to include environmental and social mitigation costs in the cost estimates for candidate new power option, as these are a real project costs. Additionally, this task will provide an assessment of the acceptability of new generation options on a project-by-project basis.

Cumulative environmental and social analysis: This provides for an assessment of potential impacts on a cumulative basis, referenced to a generation plan, and thus combination of projects.

The procedures for making a combined assessment of project economic and environmental/social parameters are described in **Table 3-35.** The table provides a list of the parameters that are combined in the evaluation model for Multiple Criteria Analysis.

Table 3- 35: Criteria and indicators used for comparison of power options

Criteria	Indicators
Category: Cost	
Economic Viability	Unit cost of firm energy per kWh over the projected life of the facility (US¢/kWh), taking into account: - Direct investment – plant - Engineering and owners costs - Interest during construction - Operating and maintenance costs - Environmental and social mitigation costs (included in the civil works contingency amount) - Multi-purpose benefits (irrigation, fisheries) – treated by cost sharing for the dam (unless a specific allowance has been included in the estimates, in which case that estimate is used) - Contingency allowance for uncertainties (e.g. technical, financial and geological risks)
Category: Socio-economic	
Impacts Due to Population Displacement	Number of persons affected by project infrastructure and ancillary facilities (People/GWh)
Promotion of Rural Electrification	Number of rural persons living in a 10 km radius of the power station and in a 10 km wide corridor along the transmission line between the option and the main transmission grid (People/GWh)
Socio-economic Impacts on the Downstream Reaches	Number of persons living in a 1 km corridor along the river stretch with altered flow downstream of the dam (People/GWh)
Land Issues	Area required for project infrastructure, including reservoir and transmission facilities (ha/GWh)
Category: Environment	
Impact on Resource Depletion	Energy payback ratio: ratio of energy produced during the normal life span of the option divided by the energy required to build, maintain and fuel the generation equipment. This indicator is a measure of the global pressure of an option on the environment
Impacts of Greenhouse Gas Emissions	Net CO_2 equivalent emissions over the life cycle of the project (t/GWh)
Impacts of Air Pollutant Emissions on Biophysical Environment	SO_2 equivalent emissions over the life cycle of the project (t/GWh)
Land requirements	Area required for project infrastructure, including reservoir and transmission facilities (ha/GWh)
Waste Disposal	Land area required for ash disposal (ha/GWh)
Environmental Impacts on the Downstream Reaches	Length of river with altered flow downstream of the dam (km/GWh)

3.15 Status of environmental assessments

A review of the status of Environmental Impact Assessment (EIA) reporting of power options was carried out as part of the East African Power Master Plan Study[17]. This review indicated that EIAs are available only for a limited number of projects in the EAC region:

a) Preliminary EIAs exist for Ruhudji and Rumakali (produced in 1998). Environmental impact studies of the Stiegler's Gorge Project were carried out in the late 1970s and early 1980s but they do not meet current national and international environmental and funding requirements.
b) A first EIA of the Mchuchuma Project was produced in 1997 by the National Development Corporation of Tanzania (NDC) and it is believed that its report conforms to Tanzania government and World Bank standards

In most cases, screening of projects with regards to environmental aspects and the evaluation of the environmental performance of power options against criteria will be on the basis of the following:

a) Environmental impacts known to occur in similar projects;
b) Information from government sources on environmental and socio-economic characteristics at country, province or district levels; and
c) Information on technical characteristics of project components from reports.

There is no change in the status of the above EIA assessments.

3.16 Project Assessments in the Current PSMP

The current update on project assessment borrows information available from the 2009 PSMP Update report, except for 400kV transmission lines (Iringa – Shinyanga, Iringa – Mbeya, and Nairobi – Arusha - Singida), and 220kV Masaka – Mwanza.

Adjustments for mitigation measures

Mitigation, compensation and enhancement measures are normally developed as part of environmental impact assessment studies, socio-economic impact assessment studies and resettlement plans. However, studies of this nature have been carried out on only some of the considered options. In the cases where these measures and associated costs are known, the exact figure and proposed mitigating measures may be used. In other cases, it is assumed that internationally recognized standard mitigation measures that have proven to be effective over the years would be applied in the implementation of the project, with consequent additional project costs.

[17] BKS Acres, 2003. East African Power Master Plan Study. Appendix H – Review of Environmental Assessment and Environmental Costs of Candidate Power and Transmission Line Projects

CHAPTER FOUR

4 TRANSMISSION EXPANSION PLAN

4.1 Introduction

This section provides the update to the transmission plan based upon the load forecast and the generation expansion plan presented in the previous chapters. Practically, the overall logical planning process that was used for conceptual primary transmission system planning update doesn't differ from that which was used in preparing the Power System Master Plan of 2009.

An assessment of major power flows was conducted across widely separated geographical areas over the planning period up to the year 2035 in order to plan for reinforcement and new transmission lines. The assessment was done by calculating the ranges of major interface flows for critical system conditions, at discrete intervals of five years – (including year 2010) throughout the study period for the base and for alternative generation plans. These ranges of major interface power flows between geographic subsystems are based on a generation planning sequence, grid station load forecast, ranges of load levels and known operating constraints. This information led to a conceptual update design of the transmission additions or changes where it appeared necessary. Likewise, the information will help provide an early feedback of transmission costs associated with the least cost generation update option.

After the simulation of load flow using generation data as an input to transmission plan, the results provided detail information for transmission system expansion/additions. Simulations were carried by an interval of 5 years starting from year 2010 as a base year to 2035.

Objectives

The main objective of this process is to identify a definitive near to mid-term plan (to year 2020) and an indicative long-range plan (to year 2035) for the transmission system expansion update. More specifically, transmission expansion plan objectives are:

a) Ensuring security of supply in the short term by coordinating electricity supply and demand;
b) Ensuring security of supply in the medium and long term by developing the National Grid;
c) Ensuring accessible transmission and distribution routes by means of good maintenance practices;
d) Determining the location, capacity, and type of the required power transmission development and upgrades over the planning horizon 2035;
e) Establishing the timing of the transmission upgrades across years 2015, 2020 and 2035; and
f) Estimating the capital cost and investment plan associated with the transmission line development and system upgrades.

In the context of a master plan, the transmission expansion determines the system upgrades that will allow the planned generation to serve the forecasted load. Additionally, a corresponding investment plan is developed to estimate the cost of the transmission expansion plan associated to the generation and sub-transmission/distribution plans which provide the basic input to financial and economic analysis.

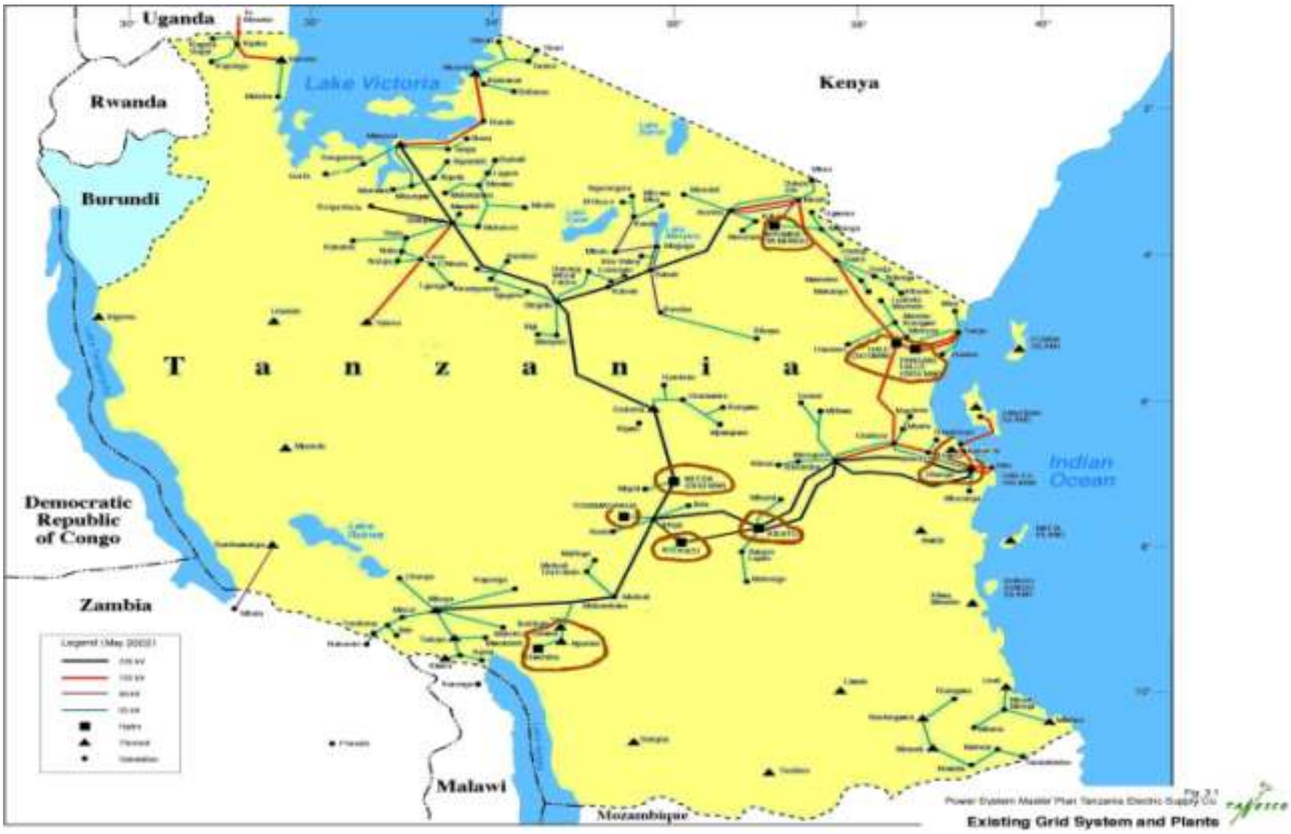
The transmission plan chooses the system additions that are most economical, while satisfying a pre-defined set of technical criteria. Such criteria composed a set of rules that measure the system performance and compare several scenarios on a common technical basis, ensure the adequate operation of the power system under both normal and emergency conditions, once the infrastructure has been built.

Existing Grid System

TANESCO owns transmission and distribution lines of different voltage capacities all over the country. The transmission system is comprised of 2,732 km of 220 kV, 1,538 km of 132kV and 546 km of 66kV. The isolated centres away from the grid are served by generating units with an aggregate nominal capacity of 81.5 MW. TANESCO imports power from Uganda via 132kV and from Zambia through 66 and 33kV lines.

Simulation of the existing power system under peak load conditions revealed that the following portions of line, the Iringa – Dodoma – Singida 220kV line, the Chalinze – Hale – Arusha 132kV line and Ubungo – Kunduchi – Ras Kilomoni 132kV line and 132kV marine cable from Ras Kilomoni (Mainland) to Ras Fumba (Zanzibar) had exceeded their thermal limits therefore they could not transfer all the respective demanded power. This has resulted in the introduction of the 400kV Iringa – Shinyanga backbone project, the 400kV Dar es Salaam – Tanga – Arusha and the reinforcement of 132kV line to Ras Kilomoni and 132kV marine cable to Zanzibar projects. All these projects have been committed. The proposed increase of power generation in Mbeya, Iringa and Dar es Salaam regions has necessitated the reinforcement of the 220kV lines to these areas so that power can be evacuated to the load centres. To this effect, 400kV lines from Dar es Salaam – Morogoro – Dodoma, Dar es Salaam – Chalinze – Tanga – Arusha and Iringa – Makambako – Mbeya are planned for construction.

Figure 4- 1: Existing Grid System



Source: TANESCO

Table 4- 1: Parameters of the Existing Transmission Line System

LINE	VOLTAGE (KV)	ROUTE (KM)	TYPE OF CONDUCTOR	OVERALL AREA (mm2)	YEAR COMMISSIONED	LINE CAPACITY (Amps)	LINE CAPACITY (MW at 0.8 pf)	LINE CAPACITY (MW at 1.0 pf)
MOROGORO - UBUNGO	220	172	BLUEJAY	604.39	1975	1165	355	444
MOROGORO - UBUNGO	220	179	BLUEJAY	604.39	1995	1165	355	444
KIDATU - MOROGORO 1	220	116	BLUEJAY	604.39	1975	1165	355	444
KIDATU - MOROGORO 2	220	130	BLUEJAY	604.39	1993	1165	355	444
KIDATU - IRINGA	220	160	BISON	481.18	1985	812	248	309
IRINGA - MUFINDI	220	130	BISON	481.18	1985	812	248	309
IRINGA - MTERA	220	107	BISON	481.18	1985	812	248	309
MTERA - DODOMA	220	130	BISON	481.18	1985	812	248	309
DODOMA - SINGIDA	220	210	BISON	481.18	1988	812	248	309
SINGIDA - SHINYANGA	220	200	BISON	481.18	1988	812	248	309
SHINYANGA - MWANZA	220	140	BISON	481.18	1988	812	248	309
SHINYANGA - BULYANHU	220	129.46	BISON	481.18	2000	812	248	309
MUFINDI - MBEYA	220	220	BISON	481.18	1985	812	248	309
UBUNGO - CHALINZE	132	97	WOLF	194.94	1963	405	74	93
CHALINZE - MOROGORO	132	82	WOLF	194.94	1967	405	74	93
CHALINZE - HALE	132	175	WOLF	194.94	1963	405	74	93
HALE - TANGA	132	60	WOLF	194.94	1971	405	74	93
HALE - SAME	132	173	WOLF	194.94	1975	405	74	93
SAME - KIYUNGI	132	102	WOLF	194.94	1975	405	74	93
UBUNGO - ILALA 1ST	132	11	WOLF	194.94	1963	405	74	93
UBUNGO - TEGETA	132	41	WOLF	194.94	1980	405	74	93
TEGETA - ZANZIBAR	132	38	CABLE	95 (CU)	1980	286	52	65
MWANZA - MUSOMA	132	210	WOLF	194.94	1989	405	74	93
SHINYANGA - TABORA	132	203	WOLF	194.94	1989	405	74	93
KIYUNGI - ARUSHA	132	70	WOLF	194.94	1983	405	74	93
NYUMBA YA MUNGU - KI	66	53	RABBIT	61.70	1968	190	17	22
KIYUNGI - ARUSHA	66	78	RABBIT	61.70	1967	190	17	22
BABATI - KONDOA	66	85	WOLF	194.94	1999	405	37	46
BABATI - MBULU	66	85	WOLF	194.94	1999	405	37	46
MBULU - KARATU	66	65	WOLF	194.94	1999	405	37	46
KIHANSI - IRINGA	220	95.23	BLUEJAY	604.39	1998	1165	355	444
KIHANSI - KIDATU	220	180	BLUEJAY	604.39	1999*	1165	355	444
UBUNGO - ILALA 2ND	132	11	HAWK	280.80	1999	583	107	133
UBUNGO - KIPAWA	132	16	WOLF	194.94	2000	405	74	93
PANGANI FALLS - HALE	132	8.5	HAWK	281.13	1995	583	107	133
HALE - TANGA	132	60	HAWK	281.13	1994	583	107	133
SINGIDA - BABATI	220	150	RAIL	517.39	1996	1050	320	400
BABATI - ARUSHA	220	162	RAIL	517.39	1996	1050	320	400
MTUKULA - KYAKA	132	30	TIGER	161.85	1992	296	54	68
KYAKA - BUKOBA	132	54	TIGER	161.85	1992	296	54	68
MBALA - SUMBAWANGA	66	120	WOLF	194.94	2001	405	37	46
SHINYANGA - BUZWAGI	220	100	BISON	481.18	2000	812	248	309
MUSOMA - NYAMONGO	132	100	WOLF	194.94	1989	405	74	93

Source: TANESCO

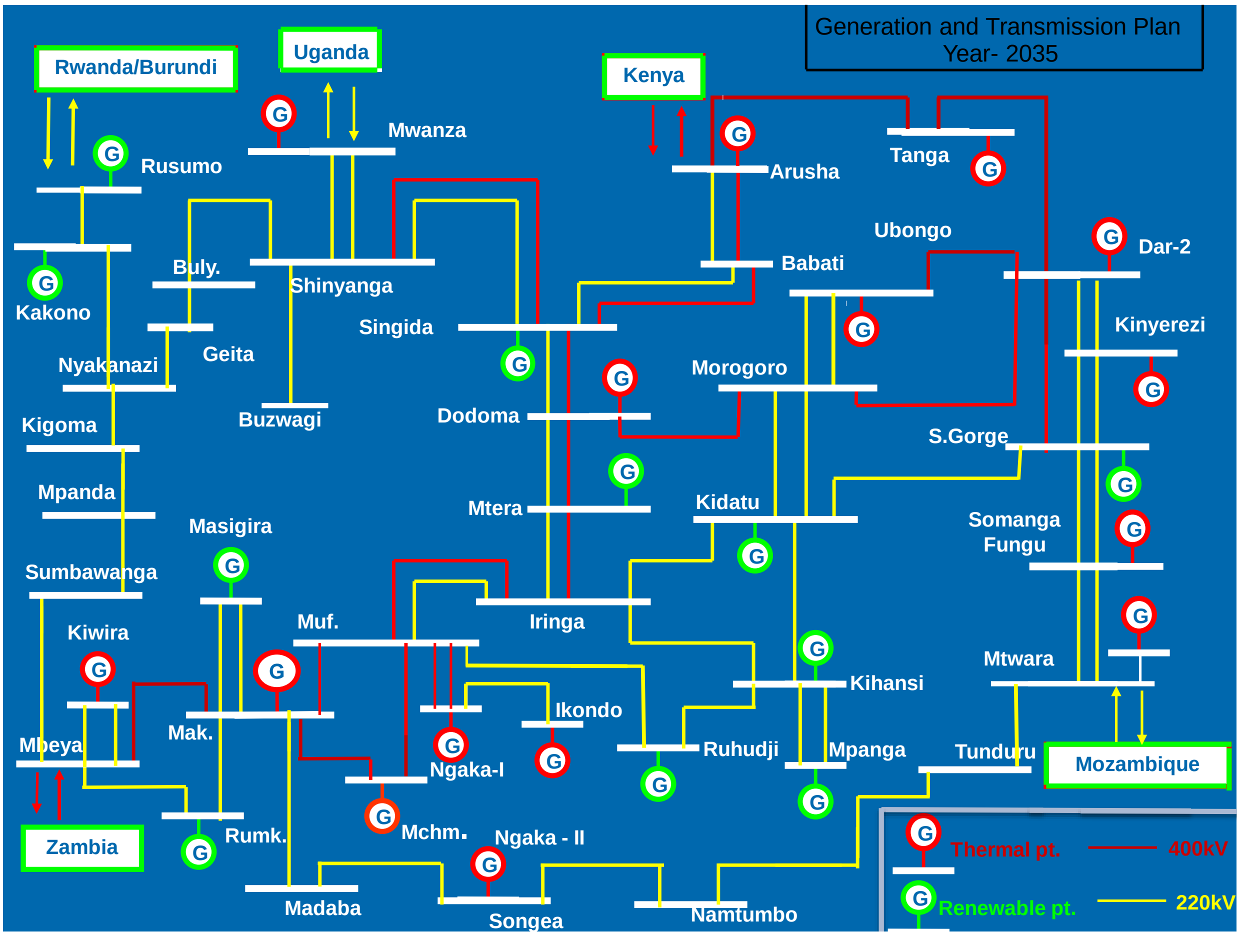
Development of New Interconnectors

Transmission capacity to other countries is an integrated and important part of a main grid that facilitates new renewable power generation and ensures security of supply domestically. It is necessary to increase the exchange capacity with other countries, both to ensure access through power trading.

The results from the operational experience in recent years lead to necessary adjustments of the plans for establishing new interconnectors in the coming ten-year period. The countries project portfolio for interconnectors comprising of six projects: The new 400kV interconnector to Kenya, currently undergoing preparation phase, is scheduled for entering into operation in 2016. The connection point in the Grid is Singida. Tanzania is planning another connection to Zambia at 400kV which is currently under preparation phase, scheduled to enter into operation in 2016 and the connection point in the Grid is Mbeya. Uganda and Tanzania are planning for the 220kV Masaka (Uganda) - Mwanza (Tanzania) interconnector, it is scheduled for operation by 2015.

Tanzania is also planning a new connection to Mozambique with a capacity of 220kV; currently efforts to initiate discussions with the Mozambican counterparts are underway. Tanzania, Rwanda and Burundi are planning a 63MW hydro power plant project at Rusumo border with Rwanda and Burundi, the project will enable the National grids of the three countries be interconnected through 220kV transmission line by 2016. The last one involves Tanzania and Malawi, a total of 340MW hydro power plant project at Songwe border is planned, the project will enable the National grids of the two countries be interconnected through 220kV transmission line by 2021. By year 2035, the Grid network (400kV and 220kV lines in red and yellow colours respectively) will look as shown below;

Figure 4- 2: Generation and Transmission Plan – Year 2035



Drivers for grid development:

(1) Security of supply is our top priority,

The Western, Northern and Lake Zones need new transmission capacity to secure a satisfactory supply, the South-West and Dar es Salaam areas also need transmission capacity to evacuate excess generated power to other load centers. In 2010, the government initiated preparations for the 400kV transmission projects namely the backbone project, South-West transmission project, Dar es Salaam – Tanga – Arusha and Dar es Salaam – Morogoro - Dodoma transmission projects and the 220kV transmission projects namely the North-West Grid, Makambaku – Songea, Dar es Salaam – Somanga – Mtwara and Songea - Mtwara.

Lengthy preparation procedures have forced the government to increase focus on preparedness in recent years, and in some cases have found it necessary to implement special short-term preparedness measures in certain areas.

(2) Renewable energy requires more grid capacity,

The government is determined to achieve its goals regarding new renewable generation in the most social economic efficient way. The government aims to contribute to at least

260MW of new renewable power generation being connected to the Tanzanian grid by 2016.

Since the potential for renewable in the country is great, it is important that all these developments are balanced, so that new generation is harmonized and adjusted to the implemented grid development plans as well as changes in consumption patterns. This applies both nationally and regionally and that is why the plans for a reinforced main grid include both domestic implementation measures and interconnector capacity to other countries. An increase in the generation of renewable energy will further increase variations in the grid power system between years with low precipitation and years with high precipitation; this requires an increase in the exchange capacity between Tanzania and other countries, both to secure access to energy in dry years, and ability to export surplus power during wet years.

(3) Reliable grid creates value,

The government will facilitate value creation by securing the necessary transmission capacity domestically, delivering power to the growing number of newly established enterprises, as well as facilitating increased power exchange internationally. Generally, in the entire country, the load forecast show that there will be high growth of power demand mainly due to increase of industrial activities and in addition to that, the gas and coal discoveries made in recent years, will lead to higher levels of energy consumption, for example, the Mtwara EPZ alone will require not less than 200MW by 2016. It is anticipated that the next generation main grid will comprise stronger connections between all regions, and contribute to more uniform electricity prices across the country during normal situations. This will provide producers and consumers alike with improved predictability, and facilitate value creation all over Tanzania.

(4) The future of Tanzania is electric,

The government's policy is to attain electrification rate of 78% of its people by year 2035. In addition to that, the expectation in the long term is that the transport sector will be extensively electrified and industrial sector will grow up, in order to be able to facilitate these objectives; sufficient grid capacity must be developed.

Transmission Planning Criteria

Planning methodologies and criteria used in the Power System Master Plan Update Studies of 2009 were reviewed as appropriate and generally the same have been used in this update study. The planning of the transmission grid considers the operation of a power system under two possible situations, that is:

Normal operating conditions (N-0);

The transmission infrastructure is entirely available (no equipment has been forced out of service).

Contingency operating conditions (N-1);

The main principal is that the main grid will be operated and scheduled based on the so called **N-1 criterion.** This means that under normal system conditions a fault in one single component (line, transformer or VAr compensator) will have no influence on the general power supply. This criterion establishes security of supply as a stronger driving force in grid development. In this chapter, the study has set as target to rectify all known breaches of the planning criteria by 2035. The deadline has been predetermined to ensure that we also have the capacity to carry out investment projects related to additional priorities, therefore only outages of equipment rated at 220 kV or above will be considered under the N-1 criteria. For each of these two operating conditions, the following criteria are applied to the analyses.

System Voltage Criteria

The acceptable voltage range for operating the system based on factors such as equipment limitations and motor operation under normal and contingency conditions is as follows:

Condition	Acceptable Voltage Range
Normal System Conditions	95% - 105%
Contingency Conditions	90% - 110%

It is important to note that from an operational standpoint, healthy systems usually target a minimum voltage close to 1.0 per unit (pu) in the bulk system.

Equipment Thermal Loading Criteria

The transmission system shall be planned/designed to allow all transmission lines and equipment to operate within the following limits for the following defined conditions:

Condition	Thermal Loading Limit
Normal System Conditions	Defined Normal Load Capacity
System Design Contingencies of Long Duration (i.e. an outage involving the failure of a transformer)	Defined Normal Load Capacity
System Design Contingencies of Short Duration (i.e. not involving a transformer)	Defined Emergency Load Capacity (120% of normal rating for 10 hours per year)

Transmission and Substation Costs

Transmission voltage options

It is expected that the present 132kV and 220kV system voltage levels and the proposed 400kV line will be the main transmission technology of choice for the internal transmission expansion. Should a Direct Current (DC) voltage level be required, the range of 330kV to 500kV voltage standard used in other African countries is the next voltage above the 220kV voltage standard that will be considered in future. Series and shunt capacitors and static variance compensators were used to improve the receiving end voltages on long and heavily loaded lines. These devices are still considered to delay or replace the need for new transmission lines where they appeared to be economical and practical.

Transmission Unit Costs

Transmission line and substation costs have been derived from data compiled by a NSC Lavalin International (CANADA) 2008, for recent planning studies and from actual transmission line projects in a number of countries, including Canada, Ethiopia, Tanzania, Kenya, Ghana, Thailand, Pakistan and Bangladesh. These costs are based on international competitive bidding. Table 4-2 lists the updated transmission line unit costs that were used in this update study. Unit costs for various substation components are summarised in Table 4-3 Costs for new switching substations include circuit breakers, disconnectors, switches, current and voltage transformers relay buildings, structures and site preparation.

Table 4- 2: Unit Cost of Transmission Lines

	Transmission Line Cost KUSD/km		
	Single	Double	Triple
132 KV	200.00		
220 KV	220.00	245.85	
400 KV	294.18	378.23	472.78

Table 4- 3: Unit cost of substation per bay[18]

Substation Cost MUSD/bay		
132kV	220 kV	400 Kv
-	5.25	6.83

[18] One bay consists of three circuit breakers (1 1/2 arrangement).

Grid Station Load Forecast

The grid substation load forecast updates are shown in **Table 4-4**. Individual existing and future grid substations were modelled in the load flow simulations in particular intervals of periods so that the corresponding total updated load forecasts in all regions were used as one of the inputs.

Table 4- 4: Grid Substation Load forecast

AREA	Substation Load Distribution along 2015/2020/2035				
	Bus no	Bus Name	2015	2020	2035
Arusha	5203	Arush33	38.08	50.22	41.47
	5582	Arush2	73.07	126.90	536.23
	5580	Babat2	14.48	30.45	142.03
	5581	Babat66	7.24	4.35	3.59
	5601	Mbulu	2.84	3.74	3.09
	5602	Karatu	3.29	4.35	3.59
Dar es Salaam	5189	Ubung2	-	321.32	646.36
	5190	Ubung1	248.51	175.41	188.91
	5205	Chlnz33	4.34	6.50	7.01
	5207	Ilala33	75.49	113.22	121.93
	5210	Mtoni	20.24	30.36	32.70
	5217	Mlndz33	13.45	20.17	21.72
	5218	Ubung33	62.04	93.05	100.20
	5247	Fzone1	124.74	51.40	55.36
	5248	Fzone2	94.21	38.82	41.81
	5250	Fzone3	32.36	13.34	14.37
	5294	Kndch33	91.34	37.63	40.53
	5709	Dar-2		126.53	436.55
	5709	Dar-2		68.31	115.73
Dodoma	5181	Dodom2	64.45	105.99	324.03
	5206	Dodom33	22.44	36.41	21.02
	5600	Kondoa	16.11	8.60	4.96
Iringa	5173	Madaba	1.30	1.21	0.39
	5183	Iring2	6.72	8.18	26.16
	5184	Mufnd2	25.18	20.52	65.43
	5193	Makambako	44.76	85.12	109.03
	5208	Iring33	3.35	6.06	3.03
	5211	Mufnd33	15.69	25.90	12.96
Kagera	5703	Nyakanazi	62.93	105.52	254.11
	5706	Rusumo		0.42	
	5717	Kyaka		1.66	1.53
Kigoma	7019	Kigoma	22.14	137.10	179.58
	7020	Kibondo	17.71	34.27	35.92
K'Manjaro	5201	Kiyng33	44.35	67.94	83.81
	5213	Same33	8.94	13.69	16.89
	5290	Kiyng11	10.92	16.73	20.64
Lindi			11.91	24.23	59.63
Mara	174	Nyamongo	17.12	28.43	49.72
	5212	Musom33	10.21	16.96	68.85
	5241	Bunda33	3.41	5.65	9.89
Mbeya	5185	Mbeya2	33.29	66.23	311.46
	5209	Mbeya33	23.49	41.28	31.94
Morogoro	5186	Kidat2	11.96	14.97	54.48
	5187	Morgr2	31.90	60.17	218.17
	5188	Morgr1	15.95	29.73	26.28
	5223	Kidat33	5.50	8.36	7.40
Mtwara	5630	Mtwara	93.71	153.90	216.36
Mwanza	5176	Mwanz2	81.70	98.18	316.10
	5204	Mwanz1	23.30	35.19	105.73
	5702	Geita		18.63	21.17
Rukwa	7020	Mpanda	6.86	15.02	33.36
	7021	Sumbawanga	12.13	26.54	58.95
Ruvuma	5172	Songea	10.98	42.89	70.17
Shinyanga	5177	Shnyn2	149.08	243.61	1,104.90
	5178	Shnyn1	41.73	51.18	68.00
	5589	Bulyanhu	14.71	64.92	45.37
	5701	Buzwagi	10.16	8.44	14.13
Singida	5180	Singd2	8.34	28.36	114.84
	5214	Singd33	14.89	6.39	4.24
Tabora	5215	Tabor33	68.00	146.00	384.00
Tanga	5197	Tanga1	90.89	188.29	118.12
	5216	Tanga33	45.45	55.92	35.09
	5292	Songa33	5.04	6.94	4.36
	5718	Tanga			357.49

Power Transfer Requirements

In order that transmission schemes could be devised, the range of power flows that would be experienced between distant centres (of load or generation) was calculated using the load forecast update and the updated generation expansion plan. The power flows across the transmission network of the Grid system was simulated to see whether or not; the generation dispatched in accordance to the generation expansion plan can overload (stress) any part of the transmission system. Six major long-distance transmission paths are identified as follows:

i. Iringa – Singida – Shinyanga;
ii. Singida -Arusha;
iii. Mbeya – Makambako – Iringa;
iv. Kidatu – Morogoro – Ubungo;
v. Chalinze – Tanga – Arusha;
vi. Dar – Morogoro – Dodoma

i. Iringa – Singida – Shinyanga;

This transmission path identifies the flows from the Southwest zone into the central and northwest zone. This flow is positive (central bound into Mtera). Power transfer from Iringa to Mtera is 177.3 MW in year 2010 and 17 MW in year 2015, 20 MW in year 2020 and 243 MW in year 2035. This flow pattern does not necessitate an additional transmission line between Iringa and Mtera during the whole planning period.

The flow from Mtera to Dodoma increases with load growth in the West, Lake and North Zones. Power transfer increases to 241.8MW in year 2010 and 53MW in year 2015, 90 MW in year 2020 and 303MW in year 2035.

The 220kV transmission line between Mtera and Dodoma has a thermal rating of about 220 MVA, (equivalent to 178 MW) but the transfer capability is much below this, because of the technical difficulty of loading this line higher than about 125MW. Beyond this level of power flow, additional 400kV line is proposed between Iringa, Mtera, Dodoma, Singida and Shinyanga. This new line will be required before the year 2015 under this scenario.

ii. 220kV Kidatu – Morogoro – Ubungo line

The generation output from Kidatu is being supplied westward to support the generation output from Kihansi and Mtera in supplying the load west of Kidatu and to the North. The addition of Ruhudji plant in year 2025 reverses the direction of power flow.

Power in the order of 77MW flows westwards from Kidatu to Iringa in year 2012, it then reduced to 38MW in year 2015 following the introduction of 400kV Dar es Salaam – Morogoro – Dodoma line. It then increases to 52MW in year 2020 following the introduction of Nairobi 100MW export from Arusha. In 2035, the direction of power flow is reversed following the introduction of Ruhudji with a total of 80MW flow westward to Kidatu. In year 2012, power flow from Morogoro to Kidatu is 48.6MW, in year 2015 the flow pattern is reversed towards the direction of Morogoro with a power flow of 46MW, it then increases to 111MW in year 2020 and 445MW in year 2035.

In year 2012, the flow of power between Ubungo and Morogoro is 230MW flowing in the direction of Morogoro, in 2015 the flow from Ubungo to Morogoro is 58MW, in 2020 the flow pattern is reversed, it now flows from Morogoro towards Ubungo and the power flow is 18MW and in 2035 due to increase of demand in Coastal Zone, the power flow increases to 50MW.

iii. 400kV Dar es Salaam – Morogoro – Dodoma line

The power flow from Dar es Salaam to Morogoro and further to Dodoma is 373 MW in 2015, in 2020 the flow pattern is reversed following the increase of demand in the Coastal Zone, it now flows from Dodoma towards Ubungo and the power flow is 34MW. In year 2035 the power flow pattern is reversed again, this time 430MW flow is from Coastal Zone to Morogoro and further to Dodoma where it joins the 400kV backbone line

iv. 132kV Dar es Salaam – Chalinze – Morogoro line

In year 2012 the power flow from Dar es Salaam and Morogoro of 119.2MW and 27.5MW respectively flow through 132kV line towards Chalinze and 93.2MW further to Hale. The thermal limit of this line is 74MW, additional 400kV line is proposed between Dar es Salaam, Chalinze, Tanga, and Arusha. This new line will be required before the year 2015 under this scenario. In year 2015, 40.2MW flow from Dar es Salaam through Mlandizi to Chalinze where a total of 25.7MW is received. Here the power flow between Chalinze and Morogoro is reversed and 10.3MW flow towards Morogoro while the flow towards Hale is reduced to 10.7MW following the introduction of 400kV Dar es Salaam – Chalinze – Tanga – Arusha line.

v. 400kV Chalinze – Tanga – Arusha line

The power flow from Dar es Salaam to Chalinze and further to Tanga and Arusha is 358MW in 2015, in 2020 the flow pattern is reduced to 100MW and it increases to 1366MW in year 2035 following the increase of demand in the North Zone and increase of generation in the Coastal Zone.

vi. 220kV Mbeya – Makambako - Iringa

The flow from Iringa to Mbeya in year 2012 is 53MW; it then increases to 161MW in year 2015. In 2020 the flow pattern is reversed following the increase of generation in the South-West Zone after the commissioning of Kiwira, Masigira and Rumakali power plants, it now flows from Mbeya towards Iringa and the power flow is 97MW. In year 2035 the flow increases to 279MW.

vii. 400kV Mbeya – Makambako – Iringa

In year 2020, the power flow is flowing from Mbeya towards Iringa; the transfer of power from the West to Iringa through this line is 502MW. It then increases to 1,712MW in year 2035.

viii. 400kV Singida to Arusha

The flow from Singida to Arusha through the 400 kV line is 95MW, it then decreases to 58MW in year 2035 due to increases in power generation in the Coastal Zone.

Transmission System Additions - Least Cost Expansion Plan

Table 4- 5: Transmission System Additions from 2012 to 2015

Year	Transmission System Additions	Distance In Km
2013	132KV Ubungo -Mtoni Interconnector	46
2014	220KV Somangafungu to Kinyerezi	198
2014	Ubungo - Kinyerezi	15
2015	400KV Iringa – Shinyanga	647
2015	132KV Makambako – Songea	250
2015	Geita - Nyakanazi	133
2015	220KV Nyakanazi – Kigoma	280
2015	220KV Masaka-Mwanza	250
2015	220kV Mkuranga A - Mkuranga B	10
2015	220kV Mlandizi - Zinga	48

Table 4- 6: Transmission System additions from 2016 to 2020

Year	Transmission System Additions	Distance In Km
2016	220KV Wind Project Singida	10
2016	220KV Mtwara to Power Plant	20
2016	400KV Tanzania -Kenya Interconnection (Tanzania Part)	414.4
2016	400KV Kiwira – Mbeya	100
2016	400KV Mbeya – Iringa	350
2016	220KV Solar I Project to Dodoma	10
2016	400KV Coastal Coal to Tanga	10
2016	400KV Dar es Salaam-Chalinze-Same - Tanga-Arusha	682
2016	132KV Factory Zone III to Factory Zone II	7.4
2016	132KV Factory Zone II to Mbagala	16.2
2016	132KV Mbagala to Kurasini	15.1
2016	132KV Kurasini to Ubungo	13
2017	220KV Nyakanazi to Mbeya	1148
2017	400KV Dar es Salaam-Morogoro-Dodoma	451
2017	400 KV Ngaka to Makambako	200
2017	220KV Somanga -Lindi_Mtwara	154
2018	220KV Nyakanazi – Rusumo	95
2018	220KV Solar II Project to Shinyanga	10
2018	220KV Kigoma to Sumbawanga	485
2018	330KV Pensulo – Mbeya	700
2018	400KV Mchuchuma – Mufindi	200
2019	220KV Masigira – Makambako	180
2020	400KV Rumakali – Mbeya	150

Table 4- 7: Transmission Additions from 2021 to 2035

Year	Transmission System Additions	Distance In Km
2021	220KV Mtwara to Songea	656
2022	220KV Kakono – Rusumo	150
2022	220KV Mpanga – Kihansi	40
2023	400KV Stiegler's Gorge – Dar es Salaam	200
2024	220KV Masigira – Makambako	180
2025	400KV Ruhudji – Mufindi	100
2025	400KV Ruhudji – Kihansi	150
2026	400 KV Local Coal to Dar es salaam	15
2027	220KV Ikondo (Mnyera) – Mufindi	150
2027	220KV Taveta (Mnyera) – Ikondo	5

Table 4- 8: 400kV and 220 kV Transmission line assumed parameters

Parameter	400kV	220KV	Comments
Conductor	ACCC: Flint	ACSR: Drake	
Size (MCM/mm^2)	714/375.4	795/468.6	
No. of Cond. Per phase	4	2	
Current/conductor (Amp.)	775	890	
R	0.001718	0.007360	Per unit on 100MVA base for 100km line
X	0.017723	0.072730	
B	0.542608	0.022544	
Normal Rating (MVA)	1720	540	80% of current rating
Emergency Rating (MVA)	2064	650	120% of normal rating

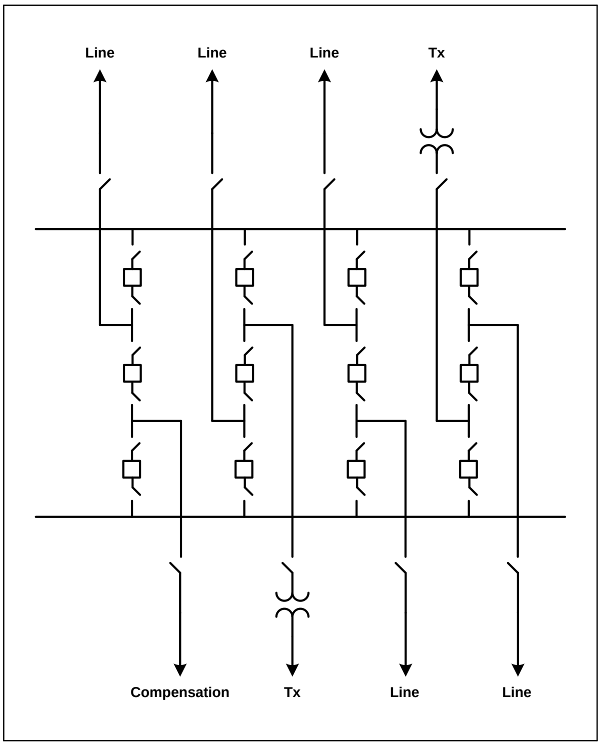
Reactive compensation

Fixed capacitor banks were sized to ensure the adequacy of the system operating conditions as given in the planning criteria. Static Var Compensators (SVCs) were standardized at +50/-50 MVAr, only the SVC at Singida was sized at 200/-50 MVAr. No bus shunt reactors were required.

Substation Arrangement

The number of circuit breakers for the 400 kV systems is based on the breaker and a half scheme, as shown below. Each bay is composed of three (3) breakers and provides two positions for transmission line, transformer or compensation equipment. Sub-transmission switchgear has not been considered as it depends greatly on how many positions will be needed, which in turn, depends on the local area planning.

Fig 4-3: Substation arrangement



4.2 Load flow analysis

The proposed Tanzania's transmission system is based on the load forecast and the new power plants as presented in the previous sections. Four study years were considered:

a. Y - 2012 existing peak load case;
b. Y-2015 peak load case;
c. Y-2020 peak load case; and
d. Y-2035 peak load case.

Each case has been analyzed under both normal (N-0) and contingency (N-1) conditions. System reinforcements including transmission lines, transformers and reactive power compensations were defined as appropriate.

4.2.1 Year-2012 case

In 2012, simulation of existing peak load revealed that the Iringa – Dodoma – Singida 220kV line, the Chalinze – Hale 132kV line and Kunduchi – Ras Fumba – Zanzibar 132kV line had exceeded thermal limits, and therefore could not conduct all the demanded power. These overloads have resulted in the introduction of the 400kV Iringa

– Shinyanga backbone project, the 400kV Dar es Salaam – Chalinze - Tanga – Arusha , the 400kV Dar es Salaam – Chalinze – Morogoro – Dodoma, 400kV Iringa – Mbeya, the reinforcement of 132kV line to Zanzibar projects and introduction of 132 kV line from Kinyerezi to Factory Zone II-Gongolamboto. All these projects have been committed. The overloaded lines are confirmed by the branch loading simulation results shown below;

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 25 2012 12:18

2010- PEAK LOAD - BASE CASE, TANZANIA

2011 LOAD FORECASTBASE CASE

BRANCH LOADINGS ABOVE 100.0 % OF RATING SET A:

X--------- FROM BUS	----------X			X---------- TO BUS	-----------X				CURRENT(MVA)		
BUS#	X-- NAME --X	BASKV	AREA	BUS#	X-- NAME --X	BASKV	AREA	CKT	LOADING	RATING	PERCENT
5174	KIBAHA	132.00	61	5190	UBUNG1	132.00*	61	1	123.7	85.0	145.6
5174	KIBAHA	132.00*	61	5289	MLNDZ1	132.00	61	1	123.7	85.0	145.5
5180	SINGD2	220.00	61	5181	DODOM2	220.00*	61	1	259.5	233.0	111.4
5181	DODOM2	220.00	61	5182	MTERA2	220.00*	61	1	236.4	233.0	101.5
5186	KIDAT2	220.00	61	5219	KIDATG1	11.000*	61	1	105.6	60.0	176.0
5189	UBUNG2	220.00*	61	5190	UBUNG1	132.00	61	1	309.3	300.0	103.1
5189	UBUNG2	220.00*	61	5190	UBUNG1	132.00	61	2	309.3	300.0	103.1
5189	UBUNG2	220.00*	61	5650	UBUNG0 II	11.000	61	1	308.2	150.0	205.5
5189	UBUNG2	220.00*	61	5651	AGGREK-UBUNG	11.000	61	1	294.1	100.0	294.1
5190	UBUNG1	132.00	61	5360	UBUNGOWATSIL	10.900*	61	1	103.0	100.0	103.0
5190	UBUNG1	132.00	61	5649	SYMBION-112	11.000*	61	1	242.6	200.0	121.3
5192	CHLNZ1	132.00*	61	5195	HALE1	132.00	61	1	96.4	85.0	113.4
5192	CHLNZ1	132.00*	61	5205	CHLNZ33	33.000	61	1	17.0	10.0	170.1
5192	CHLNZ1	132.00*	61	5205	CHLNZ33	33.000	61	2	8.5	5.0	170.1
5192	CHLNZ1	132.00	61	5289	MLNDZ1	132.00*	61	1	106.1	85.0	124.8
5200	KIYNG66	66.000*	61	5201	KIYNG33	33.000	61	1	11.4	10.0	114.0
5200	KIYNG66	66.000*	61	5201	KIYNG33	33.000	61	2	11.4	10.0	114.0
5217	MLNDZ33	33.000	61	5289	MLNDZ1	132.00*	61	1	8.0	5.0	160.8
5217	MLNDZ33	33.000	61	5289	MLNDZ1	132.00*	61	2	8.0	5.0	160.8
5217	MLNDZ33	33.000	61	5289	MLNDZ1	132.00*	61	3	11.0	10.0	110.5
5293	KNDCH1	132.00*	61	5295	RSFMB1	132.00	61	1	43.0	40.0	107.5
5293	KNDCH1	132.00*	61	5616	TEGETAWATSIL	33.000	61	1	173.0	100.0	173.0
5603	TEGETA	132.00	61	5604	TEGETA1	11.000*	61	1	17.4	15.0	116.0
5603	TEGETA	132.00	61	5605	TEGETA2	11.000*	61	1	17.4	15.0	116.0
5603	TEGETA	132.00	61	5606	TEGETA3	11.000*	61	1	17.4	15.0	116.0
5603	TEGETA	132.00	61	5607	TEGETA4	11.000*	61	1	17.4	15.0	116.0
5603	TEGETA	132.00	61	5608	TEGETA5	11.000*	61	1	17.4	15.0	116.0
5603	TEGETA	132.00	61	5609	TEGETA6	11.000*	61	1	17.4	15.0	116.0
5603	TEGETA	132.00	61	5610	TEGETA7	11.000*	61	1	17.4	15.0	116.0

```
  5603 TEGETA      132.00    61   5611 TEGETA8     11.000*   61  1     17.4    15.0   116.0
  5603 TEGETA      132.00    61   5612 TEGETA9     11.000*   61  1     17.4    15.0   116.0
```

4.2.2 Year-2015 case

The major additions by year 2016 consist in establishing two 400kV corridors. The first is composed of the Dar es Salaam-Tanga-Arusha single-circuit lines, and the second is composed of the Iringa-Dodoma-Singida-Shinyanga double-circuit lines.

For voltage considerations, one of the two 400kV circuits from Iringa to Shinyanga needs to be switched off. The amount of power generated at each plant was adjusted to maintain the load/generation balance. Under normal conditions (N-0), all bus voltages are within the limits (0.95 -1.05 pu), as defined in the planning criteria. No voltage violations are recorded in the bulk system (220 kV and above.). Transmission line power flows are also below the line normal capacity (rating A). A summary of (N-0) results is given below.

Year - 2015 (N-0)

```
--------------------------------------------------------------------------------

      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  12:30
 2015 - PEAK LOAD - BASE CASE, TANZANIA
 2011 LOAD FORECAST

 BUSES WITH VOLTAGE GREATER THAN 1.0500:

   BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)
    174 NYAMONGO    132.00   61 1.1076 146.21      5172 SONGEA      220.00   61 1.0610 233.42
   5173 MADABA      220.00   61 1.0567 232.47      5175 MUSOM1      132.00   61 1.1390 150.35
   5200 KIYNG66     66.000   61 1.0892 71.889      5201 KIYNG33     33.000   61 1.1436 37.740
   5203 ARUSH33     33.000   61 1.0897 35.960      5212 MUSOM33     33.000   61 1.0985 36.252
   5240 BUNDA132    132.00   61 1.0912 144.03      5241 BUNDA33     33.000   61 1.0853 35.814
   5288 NYUMB66     66.000   61 1.0571 69.767      5290 KIYNG11     11.000   61 1.1099 12.209
   5291 ARUSH66     66.000   61 1.0572 69.775
 BUSES WITH VOLTAGE LESS THAN 0.9500:

   BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)
   2177 SHNYANGA    220.00   61 0.9487 208.72      5177 SHNYN2      220.00   61 0.9487 208.72
   5178 SHNYN1      132.00   61 0.8543 112.76      5179 TABOR1      132.00   61 0.0000  0.000
   5215 TABOR33     33.000   61 0.0000  0.000      5581 BABAT66     66.000   61 0.8389 55.366
   5585 KONDOA      66.000   61 0.4356 28.749      5586 MBULU       66.000   61 0.8267 54.565
   5587 KARATU      66.000   61 0.8220 54.251      5600 KONDOA      33.000   61 0.0013  0.044
   5601 MBULU       33.000   61 0.8178 26.989      5602 KARATU      33.000   61 0.8192 27.033
```

Year - 2015 (On Rating A)

```
--------------------------------------------------------------------------------

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  12:31
 2015 - PEAK LOAD - BASE CASE, TANZANIA
 2011 LOAD FORECAST

 BRANCH LOADINGS ABOVE 100.0 % OF RATING SET A:
```

X--------- FROM BUS ----------X				X---------- TO BUS -----------X					CURRENT(MVA)		
BUS#	X-- NAME --X	BASKV	AREA	BUS#	X-- NAME --X	BASKV	AREA	CKT	LOADING	RATING	PERCENT
2177	SHNYANGA	220.00	61	5178	SHNYN1	132.00*	61	1	62.1	60.0	103.5
2177	SHNYANGA	220.00	61	5178	SHNYN1	132.00*	61	2	62.1	60.0	103.5
2177	SHNYANGA	220.00	61	5178	SHNYN1	132.00*	61	3	67.9	60.0	113.2
2190	UBONGO1	132.00	61	5293	KNDCH1	132.00*	61	1	91.2	85.0	107.3
2580	BABATI	220.00*	61	5581	BABAT66	66.000	61	1	22.4	20.0	112.0
2580	BABATI	220.00	61	5581	BABAT66	66.000*	61	2	26.9	20.0	134.4
5178	SHNYN1	132.00	61	5179	TABOR1	132.00*	61	1	155.2	85.0	182.6
5186	KIDAT2	220.00*	61	5219	KIDATG1	11.000	61	1	64.3	60.0	107.2
5196	NWPNG1	132.00*	61	5216	TANGA33	33.000	61	1	38.0	20.0	190.0
5197	TANGA1	132.00*	61	5216	TANGA33	33.000	61	2	31.2	20.0	156.1
5198	SAME1	132.00*	61	5213	SAME33	33.000	61	1	9.3	7.0	133.2
5199	KIYNG1	132.00*	61	5200	KIYNG66	66.000	61	1	28.3	20.0	141.3
5199	KIYNG1	132.00*	61	5200	KIYNG66	66.000	61	2	28.3	20.0	141.3
5200	KIYNG66	66.000*	61	5201	KIYNG33	33.000	61	1	14.9	10.0	149.3
5200	KIYNG66	66.000*	61	5201	KIYNG33	33.000	61	2	14.9	10.0	149.3
5226	NYUMBG1	11.000	61	5288	NYUMB66	66.000*	61	1	5.0	5.0	100.2
5227	NYUMBG2	11.000	61	5288	NYUMB66	66.000*	61	1	5.0	5.0	100.2
5585	KONDOA	66.000	61	5600	KONDOA	33.000*	61	1	21.8	5.0	435.1
5585	KONDOA	66.000	61	5600	KONDOA	33.000*	61	2	21.8	5.0	435.1
5624	SOMANGATANES	33.000	61	5635	SOMAFUNG	220.00*	61	1	75.3	50.0	150.5

The overloading at Kinyerezi-220kV Substation is negligible and can be overlooked now as it will be fixed after 2015 during additions of new generation plants at Kinyerezi Substation.

Contingency analysis (N-1) for this case was performed and no voltage or overloading problems were encountered in the bulk system. Under contingency conditions the voltage check was based on the (0.9-1.1 pu) limits and the loading was based of the transmission line/transformer emergency capacity (rating B). A summary of (N-1) results is given below.

Year – 2015 (N-1)

```
--------------------------------------------------------------------------------

      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  12:33
 2015 - PEAK LOAD - BASE CASE, TANZANIA
 2011 LOAD FORECAST

 BUSES WITH VOLTAGE GREATER THAN 1.1000:

   BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)
    174 NYAMONGO    132.00   61 1.1076 146.21      5175 MUSOM1      132.00   61 1.1390 150.35
   5201 KIYNG33     33.000   61 1.1436 37.740      5290 KIYNG11     11.000   61 1.1099 12.209
 BUSES WITH VOLTAGE LESS THAN 0.9000:

   BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)
   5178 SHNYN1      132.00   61 0.8543 112.76      5179 TABOR1      132.00   61 0.0000  0.000
   5215 TABOR33     33.000   61 0.0000  0.000      5581 BABAT66     66.000   61 0.8389 55.366
   5585 KONDOA      66.000   61 0.4356 28.749      5586 MBULU       66.000   61 0.8267 54.565
   5587 KARATU      66.000   61 0.8220 54.251      5600 KONDOA      33.000   61 0.0013  0.044
   5601 MBULU       33.000   61 0.8178 26.989      5602 KARATU      33.000   61 0.8192 27.033
```

Year – 2015 (On Rating B)

```
--------------------------------------------------------------------------------

      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  12:57
 2015 - PEAK LOAD - BASE CASE, TANZANIA
 2011 LOAD FORECAST

 BRANCH LOADINGS ABOVE 120.0 % OF RATING SET B:

 X--------- FROM BUS ----------X X---------- TO BUS -----------X       CURRENT(MVA)
   BUS# X-- NAME --X BASKV  AREA   BUS# X-- NAME --X BASKV  AREA CKT LOADING  RATING PERCENT
   5178 SHNYN1      132.00    61   5179 TABOR1      132.00*  61  1    155.2    85.0   182.6
   5196 NWPNG1      132.00*   61   5216 TANGA33     33.000   61  1     38.0    24.0   158.3
   5197 TANGA1      132.00*   61   5216 TANGA33     33.000   61  2     31.2    24.0   130.1
   5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000   61  1     14.9    12.0   124.4
   5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000   61  2     14.9    12.0   124.4
   5585 KONDOA      66.000    61   5600 KONDOA      33.000*  61  1     21.8     6.0   362.6
   5585 KONDOA      66.000    61   5600 KONDOA      33.000*  61  2     21.8     6.0   362.6
```

It should be noted that in most cases for this voltage class (220kV and above), the line thermal capability is not the main limiting factor for the amount of power transferred. Transfer limits are usually dictated by both steady state stability and voltage stability concerns.

4.2.3 Year-2020 case

The major addition by this year is the expansion of the 400kV network. The Iringa-Shinyanga corridor expanded south to include Mufindi, Makambako and Mbeya and North to join Arusha through Babati. Other additions include interconnectors of 400kV with Mozambique, Kenya, Zambia and Uganda. The 220 kV network has also expanded with the integration of the Rumakali, Kinyerezi I (150MW), Kinyerezi II (240MW), Kinyerezi III (300MW), Kinyerezi IV (300MW), Solar(120MW), Mchuchumas (600MW), Somanga Fungu (320MW), Mtwara (200MW), Rusumo Falls (27MW), Kiwira (200MW), Malagarasi(45MW), Ngaka (300MW), and Ruhudji (358MW) power plants .

Under normal conditions (N-0), all bus voltages are within limits (0.95 -1.05 pu), as defined in the planning criteria. No voltage violations are recorded in the bulk system (220 kV and above.). Transmission line power flows are also below the line normal capacity (rating A). A summary of (N-0) results is given below.

Year – 2020 (N – 0)

```
      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  12:47
 2020 - PEAK LOAD - BASE CASE, TANZANIA
 2009 LOAD FORECAST

 BUSES WITH VOLTAGE GREATER THAN 1.0500:

   BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)
   5172 SONGEA      220.00   61 1.0845 238.59      5173 MADABA      220.00   61 1.0815 237.93
   5223 KIDAT33     33.000   61 1.0677 35.235      5707 RUMAKALI    220.00   90 1.0500 231.00
   5717 KYAKA       220.00   90 1.0540 231.88


 BUSES WITH VOLTAGE LESS THAN 0.9500:

   BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)
    174 NYAMONGO    132.00   61 0.8669 114.43      5175 MUSOM1      132.00   61 0.9415 124.28
   5198 SAME1       132.00   61 0.7722 101.93      5199 KIYNG1      132.00   61 0.7300 96.359
   5200 KIYNG66     66.000   61 0.4769 31.474      5201 KIYNG33     33.000   61 0.0000  0.000
   5202 ARUSH1      132.00   61 0.8838 116.67      5203 ARUSH33     33.000   61 0.8259 27.255
   5212 MUSOM33     33.000   61 0.9321 30.759      5213 SAME33      33.000   61 0.6118 20.189
   5288 NYUMB66     66.000   61 0.7602 50.174      5290 KIYNG11     11.000   61 0.0000  0.000
   5291 ARUSH66     66.000   61 0.6894 45.497      5600 KONDOA      33.000   61 0.9303 30.700
```

Year -2020 (On Rating A)

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 25 2012 12:52

2020 - PEAK LOAD - BASE CASE, TANZANIA

2009 LOAD FORECAST

BRANCH LOADINGS ABOVE 100.0 % OF RATING SET A:

X--------- FROM BUS	----------X		X---------- TO BUS	-----------X				CURRENT(MVA)		
BUS# X-- NAME --X	BASKV	AREA	BUS# X-- NAME --X	BASKV	AREA	CKT	LOADING	RATING	PERCENT
5184 MUFND2	220.00	61	5619 COGEN	33.000*	61	1	68.9	50.0	137.8
5184 MUFND2	220.00	61	5626 MWENGA	33.000*	61	1	62.2	10.0	621.6
5186 KIDAT2	220.00	61	5219 KIDATG1	11.000*	61	1	153.4	60.0	255.6
5198 SAME1	132.00*	61	5213 SAME33	33.000	61	1	22.2	7.0	316.6
5199 KIYNG1	132.00*	61	5200 KIYNG66	66.000	61	1	62.0	20.0	309.8
5199 KIYNG1	132.00*	61	5200 KIYNG66	66.000	61	2	62.0	20.0	309.8
5199 KIYNG1	132.00*	61	5202 ARUSH1	132.00	61	1	89.7	85.0	105.5
5200 KIYNG66	66.000*	61	5201 KIYNG33	33.000	61	1	51.5	10.0	514.8
5200 KIYNG66	66.000*	61	5201 KIYNG33	33.000	61	2	51.5	10.0	514.8
5200 KIYNG66	66.000*	61	5201 KIYNG33	33.000	61	3	51.5	20.0	257.4
5200 KIYNG66	66.000*	61	5288 NYUMB66	66.000	61	1	52.9	23.0	230.2
5200 KIYNG66	66.000*	61	5290 KIYNG11	11.000	61	1	51.2	15.0	341.3
5200 KIYNG66	66.000*	61	5291 ARUSH66	66.000	61	1	29.6	23.0	128.9
5202 ARUSH1	132.00	61	5203 ARUSH33	33.000*	61	1	20.4	20.0	102.0
5202 ARUSH1	132.00	61	5203 ARUSH33	33.000*	61	2	20.4	20.0	102.0
5202 ARUSH1	132.00*	61	5203 ARUSH33	33.000	61	3	21.6	20.0	107.9
5203 ARUSH33	33.000*	61	5291 ARUSH66	66.000	61	1	14.7	10.0	147.5
5203 ARUSH33	33.000*	61	5291 ARUSH66	66.000	61	2	14.7	10.0	147.5
5217 MLNDZ33	33.000	61	5289 MLNDZ1	132.00*	61	1	6.6	5.0	132.7
5217 MLNDZ33	33.000	61	5289 MLNDZ1	132.00*	61	2	6.6	5.0	132.7
5217 MLNDZ33	33.000	61	5289 MLNDZ1	132.00*	61	3	10.3	10.0	102.8
5226 NYUMBG1	11.000	61	5288 NYUMB66	66.000*	61	1	26.3	5.0	525.6
5227 NYUMBG2	11.000	61	5288 NYUMB66	66.000*	61	1	26.3	5.0	525.6
5293 KNDCH1	132.00*	61	5295 RSFMB1	132.00	61	1	44.6	40.0	111.4
5625 MALAGALAS	220.00	61	7019 KIGOMA	220.00*	61	1	46.3	15.0	308.8

There are no buses with Voltages above 1.05.Contingency analysis (N-1) for this case was performed and no severe voltage or overloading problems were encountered in the bulk system. Under contingency conditions the voltage check was based on the (0.9-1.1 pu) limits and the loading was based of the transmission line/transformer emergency capacity (rating B). A summary of (N-1) results is given below.

Year - 2020 (N-1)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  12:54
2020 - PEAK LOAD - BASE CASE, TANZANIA
2009 LOAD FORECAST

BUSES WITH VOLTAGE GREATER THAN 1.1000:

  BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)

                                          * NONE *

BUSES WITH VOLTAGE LESS THAN 0.9000:

  BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)      BUS# X-- NAME --X BASKV AREA  V(PU)  V(KV)
   174 NYAMONGO    132.00   61 0.8669 114.43      5198 SAME1       132.00   61 0.7722 101.93
  5199 KIYNG1      132.00   61 0.7300 96.359      5200 KIYNG66     66.000   61 0.4769 31.474
  5201 KIYNG33     33.000   61 0.0000  0.000      5202 ARUSH1      132.00   61 0.8838 116.67
  5203 ARUSH33     33.000   61 0.8259 27.255      5213 SAME33      33.000   61 0.6118 20.189
  5288 NYUMB66     66.000   61 0.7602 50.174      5290 KIYNG11     11.000   61 0.0000  0.000
```

There are no buses with voltages less than 0.9 in the bulk system. The 132kV buses at Nyamongo and Tabora experience low voltage due to long distances.

Year 2020 (On Rating B)

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     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  12:54
2020 - PEAK LOAD - BASE CASE, TANZANIA
2009 LOAD FORECAST

BRANCH LOADINGS ABOVE 120.0 % OF RATING SET B:

X--------- FROM BUS ----------X X---------- TO BUS -----------X       CURRENT(MVA)
  BUS# X-- NAME --X BASKV  AREA   BUS# X-- NAME --X BASKV  AREA CKT LOADING  RATING PERCENT
  5184 MUFND2      220.00    61   5626 MWENGA      33.000*  61  1      62.2    13.0   478.2
  5186 KIDAT2      220.00    61   5219 KIDATG1     11.000*  61  1     153.4    60.0   255.6
  5197 TANGA1      132.00*   61   5216 TANGA33     33.000   61  2      15.6    10.0   156.1
  5198 SAME1       132.00*   61   5213 SAME33      33.000   61  1      22.2     7.0   316.6
  5199 KIYNG1      132.00*   61   5200 KIYNG66     66.000   61  1      62.0    20.0   309.8
  5199 KIYNG1      132.00*   61   5200 KIYNG66     66.000   61  2      62.0    20.0   309.8
  5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000   61  1      51.5    10.0   514.8
  5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000   61  2      51.5    10.0   514.8
  5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000   61  3      51.5    20.0   257.4
```

5200	KIYNG66	66.000*	61	5288	NYUMB66	66.000	61	1	52.9	23.0	230.2
5200	KIYNG66	66.000*	61	5290	KIYNG11	11.000	61	1	51.2	15.0	341.3
5200	KIYNG66	66.000*	61	5291	ARUSH66	66.000	61	1	29.6	23.0	128.9
5203	ARUSH33	33.000*	61	5291	ARUSH66	66.000	61	1	14.7	10.0	147.5
5203	ARUSH33	33.000*	61	5291	ARUSH66	66.000	61	2	14.7	10.0	147.5
5226	NYUMBG1	11.000	61	5288	NYUMB66	66.000*	61	1	26.3	5.0	525.6
5227	NYUMBG2	11.000	61	5288	NYUMB66	66.000*	61	1	26.3	5.0	525.6
5625	MALAGALAS	220.00	61	7019	KIGOMA	220.00*	61	1	46.3	18.0	257.3

There are no buses with loading outside the limit in the bulk system of 220kV and 400kV.

4.2.4 Year-2035 case

This case represents the ultimate load flow case for the Tanzania's power system. Generally, the importance of such a case is to plan the system in the early years (e.g. in Y-2015 and Y-2020) with an eye on the foreseen ultimate configuration.

Both the 400 kV and 220 kV networks were expanded as many power plants were considered. Since the generation is mostly concentrated in the South and coastal areas and there are substantial load centers at North, reactive power compensation played an important role in reaching satisfactory operating conditions for the system developed.

Under normal conditions (N-0), all bus voltages are within the limits (1.0-1.05 pu), as defined in the planning criteria. No voltage violations are recorded in the bulk system (220 kV and above.). Transmission line power flows are also below the line normal capacity (rating A). A summary of (N-0) results is given below.

Year – 2035 (N – 0)

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 25 2012 14:26

2033 - PEAK LOAD - BASE CASE, TANZANIA

2009 LOAD FORECAST

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
5202	ARUSH1	132.00	61	1.1171	147.46	5203	ARUSH33	33.000	61	1.1847	39.094
5708	RUHUDJI	220.00	90	1.0500	231.00	5717	KYAKA	220.00	90	1.0540	231.88

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
174	NYAMONGO	132.00	61	0.0000	0.000	2185	MBEYA	220.00	61	0.9471	208.36
5175	MUSOM1	132.00	61	0.0000	0.000	5185	MBEYA2	220.00	61	0.9471	208.36
5198	SAME1	132.00	61	0.9300	122.76	5199	KIYNG1	132.00	61	0.9254	122.15
5212	MUSOM33	33.000	61	0.0000	0.000	5213	SAME33	33.000	61	0.8587	28.337

```
  5240 BUNDA132    132.00   61 0.4864 64.207      5241 BUNDA33     33.000   61 0.4391 14.489
  5290 KIYNG11     11.000   61 0.9225 10.147      7020 MPANDA      220.00   61 0.7909 173.99
  7021 SUMBAWANGA  220.00   61 0.6561 144.34
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Year -2035 (On Rating A)

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     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 25 2012  14:28
 2033 - PEAK LOAD - BASE CASE, TANZANIA
 2009 LOAD FORECAST

 BRANCH LOADINGS ABOVE 100.0 % OF RATING SET A:

 X--------- FROM BUS ----------X X---------- TO BUS -----------X       CURRENT(MVA)
   BUS# X-- NAME --X BASKV  AREA   BUS# X-- NAME --X BASKV  AREA CKT LOADING  RATING PERCENT
   2176 MWANZA      220.00*   61   5204 MWANZ1      132.00    61  1    108.3    60.0   180.5
   2176 MWANZA      220.00*   61   5204 MWANZ1      132.00    61  2    108.3    60.0   180.5
   2582 ARUSHA      220.00*   61   5202 ARUSH1      132.00    61  1     78.7    75.0   104.9
   2582 ARUSHA      220.00*   61   5202 ARUSH1      132.00    61  2     78.7    75.0   104.9
   5175 MUSOM1      132.00*   61   5240 BUNDA132    132.00    61  1    170.9    85.0   201.1
   5182 MTERA2      220.00    61   5183 IRING2      220.00*   61  1    243.4   233.0   104.5
   5184 MUFND2      220.00    61   5619 COGEN       33.000*   61  1    101.6   100.0   101.6
   5189 UBUNG2      220.00*   61   5190 UBUNG1      132.00    61  1    223.8   150.0   149.2
   5189 UBUNG2      220.00*   61   5190 UBUNG1      132.00    61  2    223.8   150.0   149.2
   5198 SAME1       132.00*   61   5213 SAME33      33.000    61  1     21.3     7.0   304.6
   5199 KIYNG1      132.00*   61   5200 KIYNG66     66.000    61  1     58.0    20.0   290.0
   5199 KIYNG1      132.00*   61   5200 KIYNG66     66.000    61  2     58.0    20.0   290.0
   5199 KIYNG1      132.00*   61   5202 ARUSH1      132.00    61  1    102.1    85.0   120.1
   5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000    61  1     34.2    10.0   341.8
   5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000    61  2     34.2    10.0   341.8
   5200 KIYNG66     66.000*   61   5201 KIYNG33     33.000    61  3     34.2    20.0   170.9
   5200 KIYNG66     66.000*   61   5290 KIYNG11     11.000    61  1     24.8    15.0   165.5
   5202 ARUSH1      132.00    61   5203 ARUSH33     33.000*   61  3     20.1    20.0   100.4
   5204 MWANZ1      132.00    61   5240 BUNDA132    132.00*   61  1    178.0    85.0   209.4
   5217 MLNDZ33     33.000    61   5289 MLNDZ1      132.00*   61  1      8.8     5.0   175.9
   5217 MLNDZ33     33.000    61   5289 MLNDZ1      132.00*   61  2      8.8     5.0   175.9
   5217 MLNDZ33     33.000    61   5289 MLNDZ1      132.00*   61  3     11.3    10.0   113.2
   5240 BUNDA132    132.00    61   5241 BUNDA33     33.000*   61  1     16.8    15.0   112.3
   5293 KNDCH1      132.00*   61   5295 RSFMB1      132.00    61  1     42.4    40.0   105.9
```

Contingency analyses (N-1) for this case were performed and no voltage or overloading problems were encountered in the bulk system. Under contingency conditions the voltage check was based on the (0.9-1.1 pu) limits and the loading was based of the transmission line/transformer emergency capacity (rating B). A summary of (N-1) results is given below.

Year - 2035 (N-1)

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 25 2012 14:30

2033 - PEAK LOAD - BASE CASE, TANZANIA

2009 LOAD FORECAST

BUSES WITH VOLTAGE GREATER THAN 1.1000:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
5202	ARUSH1	132.00	61	1.1171	147.46	5203	ARUSH33	33.000	61	1.1847	39.094

BUSES WITH VOLTAGE LESS THAN 0.9000:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
174	NYAMONGO	132.00	61	0.0000	0.000	5175	MUSOM1	132.00	61	0.0000	0.000
5212	MUSOM33	33.000	61	0.0000	0.000	5213	SAME33	33.000	61	0.8587	28.337
5240	BUNDA132	132.00	61	0.4864	64.207	5241	BUNDA33	33.000	61	0.4391	14.489
7020	MPANDA	220.00	61	0.7909	173.99	7021	SUMBAWANGA	220.00	61	0.6561	144.34

Year 2035 (On Rating B)

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 25 2012 14:28

2033 - PEAK LOAD - BASE CASE, TANZANIA

2009 LOAD FORECAST

BRANCH LOADINGS ABOVE 120.0 % OF RATING SET B:

X--------- FROM BUS ----------X				X---------- TO BUS -----------X					CURRENT(MVA)		
BUS#	X-- NAME --X	BASKV	AREA	BUS#	X-- NAME --X	BASKV	AREA	CKT	LOADING	RATING	PERCENT
2176	MWANZA	220.00*	61	5204	MWANZ1	132.00	61	1	108.3	60.0	180.5
2176	MWANZA	220.00*	61	5204	MWANZ1	132.00	61	2	108.3	60.0	180.5
5175	MUSOM1	132.00*	61	5240	BUNDA132	132.00	61	1	170.9	85.0	201.1
5189	UBUNG2	220.00*	61	5190	UBUNG1	132.00	61	1	223.8	150.0	149.2
5189	UBUNG2	220.00*	61	5190	UBUNG1	132.00	61	2	223.8	150.0	149.2
5198	SAME1	132.00*	61	5213	SAME33	33.000	61	1	21.3	7.0	304.6
5199	KIYNG1	132.00*	61	5200	KIYNG66	66.000	61	1	58.0	20.0	290.0
5199	KIYNG1	132.00*	61	5200	KIYNG66	66.000	61	2	58.0	20.0	290.0
5199	KIYNG1	132.00*	61	5202	ARUSH1	132.00	61	1	102.1	85.0	120.1
5200	KIYNG66	66.000*	61	5201	KIYNG33	33.000	61	1	34.2	10.0	341.8
5200	KIYNG66	66.000*	61	5201	KIYNG33	33.000	61	2	34.2	10.0	341.8

5200	KIYNG66	66.000*	61	5201	KIYNG33	33.000	61	3	34.2	20.0	170.9
5200	KIYNG66	66.000*	61	5290	KIYNG11	11.000	61	1	24.8	15.0	165.5
5204	MWANZ1	132.00	61	5240	BUNDA132	132.00*	61	1	178.0	85.0	209.4

4.3 Transmission System Costs

The major 400kV and 220kV, transmission additions required for the above Least Cost Expansion Plan are illustrated in Figure 4.2, the costs of the transmission additions are listed in **Table 4-9.** The total transmission costs in the Least Cost Expansion Plan are US$ 2,653.57million.

Table 4- 9: Phased transmission lines cost estimates

From	To	Kv	No. of Circuits	Length (km)	Unit Cost k$/km	Total Cost M$	2012 -- 2015	2016 - 2020	2021 - 2035	Comments
Shinyanga	Singida	400	2	235.00	378.23	88.88	71.11	17.78	-	
Singida	Dodoma	400	2	245.00	378.23	92.67	37.07	55.60	-	
Dodoma	Iringa	400	2	175.00	378.23	66.19	26.48	39.71	-	
Dar es salaam	Tanga	400	2	283.50	378.23	107.23	32.17	75.06	-	
Arusha	Tanga	400	2	395.50	378.23	149.59	44.88	104.71	-	
Mlandizi	Zinga	220	1	48.00	220.00	10.56	10.56	-	-	
Mtwara S/S	200 Plant Station	220	1	20.00	220.00	4.40	3.30	1.10	-	
Mkuranga	Power Plant	220	1	10.00	220.00	2.20	2.20	-	-	
Kiwira	Mbeya	220	2	120.00	245.85	29.50	-	23.60	5.90	out of plant line
Kinyerezi	Ubungo	220	1	15.00	220.00	3.30	0.66	2.64	-	out of plant line
Somanga	Kinyerezi	220	1	198.00	220.00	43.56	34.85	8.71	-	
Babati	Arusha	400	2	162.00	378.23	61.27	30.64	30.64	-	
Singida	Babati	400	2	150.00	378.23	56.73	28.37	28.37	-	
Arusha	Kenya borders	400	2	113.30	378.23	42.85	21.43	21.43	-	
Iringa	Mufindi	400	1	175.00	294.18	51.48	-	25.74	25.74	
Mufindi	Makambako	400	1	73.00	294.18	21.48	-	10.74	10.74	
Ubungo	Stieglers	400	1	200.00	294.18	58.84		17.65	41.19	out of plant line
Mbeya	Rumakali	220	1	150.00	220.00	33.00	-	23.10	9.90	out of plant line
Makambako	Rumakali	200	1	200.00	220.00	44.00	-	30.80	13.20	out of plant line
Mufindi	Ruhudji	220	1	100.00	220.00	22.00	-	6.60	15.40	out of plant line
Kihansi	Ruhudji	220	1	150.00	220.00	33.00	-	9.90	23.10	out of plant line
Buly	Geita	220	1	150.00	220.00	33.00	9.90	16.50	6.60	
Nyakanazi	Kigoma	220	1	280.00	220.00	61.60	18.48	30.80	12.32	
Geita	Nyakanazi	220	2	133.00	245.23	32.62	9.78	16.31	6.52	
Nyakanazi	Rusumo	220	1	50.00	220.00	11.00	-	9.35	1.65	
Sumbawanga	Mbeya	220	1	260.80	220.00	57.38	17.21	28.69	11.48	
Mwanza	Shinyanga	400	2	140.00	378.23	52.95		37.07	15.89	
Mbeya	Makambako	400	1	147.00	294.18	43.24	-	30.27	12.97	
Makambako	Mchuchuma	400	1	200.00	294.18	58.84	-	41.19	17.65	out of plant line
Mufindi	Mchuchuma	400	1	220.00	294.18	64.72	-	45.30	19.42	out of plant line
Stieglers	Dar-2	400	1	160.00	294.18	47.07	-	-	47.07	out of plant line
Dar-2	Morogoro	400	2	179.00	378.23	67.70	-	54.16	13.54	
Makambako	Songea	220	1	250.00	220.00	55.00	33.00	22.00	-	
Ubungo	Dar-2	400	1	50.00	294.18	14.71	-	-	14.71	
Rusumo	Kakono	220	1	150.00	220.00	33.00	-	-	33.00	
Rusumo	Nyakanazi	220	1	168.00	220.00	36.96	-	-	36.96	
Masigira	Makambako	220	2	180.00	245.85	44.25	-	-	44.25	out of plant line
Taveta	ikondo	220	2	5.00	245.85	1.23	-	-	1.23	out of plant line
Ikondo	Mufindi	220	2	150.00	245.85	36.88	-	-	36.88	out of plant line
Kihansi	Mpanga	220	2	40.00	245.85	9.83	-	-	9.83	out of plant line
Masaka	Mwanza	220	1	250.00	220.00	55.00		44.00	11.00	
Arusha	Kenya borders	400	2	414.40	378.23	156.74	62.70	94.04	-	ZTK Interconnection
Zambia borders	Mbeya	400	2	120.00	378.23	45.39	-	-	45.39	
Wind Project	Singida	220	1	10.00	220.00	2.20	-	2.20	-	
Solar I Project	Dodoma	220	1	10.00	220.00	2.20	-	2.20	-	
Coastal Coal	Tanga	220	1	10.00	220.00	2.20	-	2.20	-	
Dar	Morogoro	400	1	192.00	294.18	56.48	-	33.89	22.59	
Morogoro	Dodoma	400	1	259.00	294.18	76.19	-	45.72	30.48	
Ngaka	Makambako	400	1	200.00	294.18	58.84	-	47.07	11.77	
Somanga	Lindi/Mtwara	220	1	353.00	220.00	77.66	-	38.83	38.83	
Kigoma	Sumbawanga	220	1	485.00	220.00	106.70	-	106.70	-	
Malagalasi	kigoma	220	1	20.00	220.00	4.40	-	3.52	0.88	
Solar II Project	Shinyanga	220	1	10.00	220.00	2.20	-	2.20	-	
Local Coal	Dar es salaam	400	1	15.00	220.00	3.30	-	-	3.30	
Mtwara	Songea	220	1	656.00	220.00	144.32	-	-	144.32	
						-				
Line upgrades						-				
Shinyanga	Bulyanhulu	220	2	180.00	240.00	43.20	-	43.20	-	
Dodoma	Mtera	220	1	180.00	197.00	35.46	-	35.46	-	
Iringa	Kihansi	220	1	180.00	197.00	35.46	-	-	35.46	
Mbeya	Makambako	220	1	180.00	197.00	35.46	-	-	35.46	
	TOTAL					**2,728.11**	**494.77**	**1,366.74**	**866.60**	

Table 4- 10: Phased transformers cost estimate

Substation	HV/LV (kV)	Rating MVA	No. of T.x	Total Cost M$	2012 - 2015	2016 - 2020	2021 - 2035
Shinyanga	400/220	250/332	4	13.97	6.99	5.59	1.40
Singida	400/220	100/133	2	2.84	1.14	1.70	
Dodoma	400/220	150	2	3.16	1.26	1.89	
Iringa	400/220	150/200	2	4.20	1.68	2.52	
Arusha	400/220	250/332	4	13.97	5.59	8.38	
Tanga	400/132	100	2	2.10	0.84	1.26	
Morogoro	400/220	150/200	2	4.11	1.64	2.47	
Kinyerezi	400/220	250/300	2	10.51	4.20	6.30	
Makambako	400/220	150/200	2	4.20	0.84	3.36	
Mufindi	400/220	150/200	3	6.30		5.04	1.26
Ubungo2	400/220	250/332	4	0.55		0.38	0.16
Somanga	200/33	100/130	2	2.84	2.27	0.57	
Mwanza	400/220	250/332	3	10.51		4.20	6.30
Mbeya	400/220	100/132	2	2.84		1.14	2.27
Tanga	400/220	150/200	4	8.41		2.52	5.88
Babati	400/220	100/132	2	2.84		0.57	2.27
Dar-2	400/132	250/132	4	13.97			13.97
Sumbawanga	220/33	45/60	2	2.84	0.85	1.99	
Mpanda	220/33	45/60	2	2.84	0.85	1.99	
Kigoma	220/33	45/60	2	2.84	0.85	1.99	
Nyakanazi	220/33	45/60	2	2.84	0.85	1.99	
Songea	220/33	45/60	2	2.84	1.99	0.85	
Namtumbo	220/33	45/60	2	2.84		0.85	1.99
Tunduru	220/33	45/60	2	2.84		0.85	1.99
Madaba	220/33	45/60	2	2.84	1.99	0.85	
Mtwara	220/33	100/132	2	2.84	0.85	1.99	
Mkuranga	220/33	250/200	2	2.84	2.84		
Zinga	220/33	250/200	2	2.84	2.84		
Mtwara	220/33	415/300	2	2.84	2.27	0.45	
			Total	141.38	42.64	61.70	37.50

(1) Generator step up transformers are not included

(2) Cost estimate is based on the transformer highest rating

Table 4- 11: Phased Substation Cost Estimate

Substation	Switchgear (kV)	No. of Positions	No. of Bays	Unit Cost M$/bay	Total Cost M$	2012-2015	2016-2020	2021-2035
Shinyanga	400	9	4 2/3	6.83	31.87	19.12	6.37	6.37
Singida	400	11	5 2/3	6.83	38.70	23.22	7.74	7.74
Dodoma	400	8	4	6.83	27.32	16.39	5.46	5.46
Iringa	400	9	4 2/3	6.83	31.87	19.12	6.37	6.37
Arusha	400	10	5	6.83	34.15	20.49	6.83	6.83
Tanga	400	12	6	6.83	40.98	24.59	8.20	8.20
Somanga	220	5	2 2/3	5.25	14.00	8.40	5.60	-
Makambako	400	5	2 2/3	6.83	18.21	7.29	9.11	1.82
Mufindi	400	8	4	6.83	27.32	-	21.86	5.46
Ubungo2	400	6	3	6.83	20.49	-	14.34	6.15
Babati	400	6	3	6.83	20.49	-	12.29	8.20
Geita	220	6	3	5.25	15.75	-	11.03	4.73
Nyakanazi	220	8	4	5.25	21.00	-	14.70	6.30
Rusumo	220	4	2	5.25	10.50	-	7.35	3.15
Kinyerezi	400	12	6	6.83	40.98	-	28.69	12.29
Mwanza	400	7	3 2/3	6.83	25.04	-	5.01	20.03
Mbeya	400	5	2 2/3	6.83	18.21	-	3.64	14.57
Dar-2	400	8	4	6.83	27.32	-	5.46	21.86
Mtwara	220	6	3	5.25	15.75	4.73	11.03	-
Sumbawanga	220	6	3	5.25	15.75	4.73	11.03	-
Mpanda	220	6	3	5.25	15.75	4.73	11.03	-
Kigoma	220	6	3	5.25	15.75	4.73	11.03	-
Nyakanazi	220	6	3	5.25	15.75	4.73	11.03	-
Songea	220	6	3	5.25	15.75	11.03	4.73	-
Namtumbo	220	6	3	5.25	15.75	-	4.73	11.03
Tunduru	220	6	3	5.25	15.75	-	4.73	11.03
Madaba	220	6	3	5.25	15.75	11.03	4.73	-
Zinga	220	6	3	5.25	15.75	15.75	-	-
Mtwara	220	6	3	5.25	15.75	13.39	2.36	-
Mkuranga	220	6	3	5.25	15.75	15.75	-	-
TOTAL					**653.22**	**229.19**	**256.44**	**167.59**

Source: Team Calculation

(1) Cost estimate is based on “a breaker and a half” scheme.
(2) Switchgear associated with the power plants is not included.
(3) Subs transmission or distribution switchgear is not included.
(4) Expansion of existing substation is not included.

Table 4- 12: Phased Reactive Compensation Cost Estimate

Substation	SVC		BSC	
	MVAr	Cost	MVAr	Cost
Shinyanga	50/-50	5.26	350	5.53
Iringa	50/-50	5.26		
Arusha	50/-50	5.26	350	5.53
Geita	50/-50	5.26	100	1.58
Mwanza	50/-50	5.26	400	6.32
Tanga	50/-50	5.26	250	3.95
Singida	50/-50	5.26	100	1.58
Nyakanazi	50/-50	5.26	150	2.37
Bulyahulu	50/-50	5.26		
Dodoma	50/-50	5.26	100	1.58
Ubungo	50/-50	5.26	400	6.32
Mtwara	25/-25	2.63	100	1.58
Songea	25/-25	2.63		
Kigoma	25/-25	2.63		
Madaba	25/-25	2.63		
Mpanda	25/-25	2.63		
Sumbawanga	25/-25	2.63		
	Total - SVC	73.57	Total - BSC	36.34
	Total	109.91	MUSD	

Resource: Team Calculation

4.3.1 Summary of cost estimate

The overall phased costs for the transmission lines, transformers, substation and reactive power compensation over the planning horizon (2012-2035) are summarized in **table 4.13 below**;

Table 4- 13: Cost Estimate Summary

Cost of	Option, MUSD			Total
	2012-2015	2016-2020	2020-2035	
Transmission Lines	494.77	1,366.74	866.60	2,728.11
Transformers	42.64	61.70	37.50	141.38
Substation	229.19	256.44	167.59	653.22
Compensation	27.48	27.48	54.96	109.91
Diatribution System Loss Remediation	75.70			75.70
Total	**869.77**	**1,712.36**	**1,126.65**	**3,708.32**
% of Each Phase	**23.45%**	**46.18%**	**30.38%**	**100%**

(1) Out of Hydro Power Plant Lines are NOT considered.

(2) Compensation is divided as 25% in the first two periods and 50% in the third.

DISTRIBUTION PLANNING

The Power System Master Plan objective seeks to promote efficient operation and investment in the electricity sector for the long term interest of consumers from the perspective of reliability, price, safety and quality of electricity services.

The electricity network infrastructure (both transmission and distribution) plays a critical role in delivering services to consumers and driving efficient and competitive outcomes in the wholesale (Zanzibar) and retail segments of the market. Unreliable infrastructure which does not meet the needs of the community will have significant adverse effects on the public and the economy. An appropriate planning process is essential to ensure ongoing efficient and reliable supply of electricity.

Existing Distribution System

The distribution system network voltages are 33kV and 11kV which serve as the distribution back-bone stepped-down by distribution transformers to 400/230 volts for residential, light commercial and light industrial supplies. Heavy industries are supplied at 11 kV and 33 kV. Until December 2012, there were more than 1,037,859 customers linked by these distribution lines in which 335,322 are in Domestic Low Usage Tariff (D1), 700,048 are in General usage Tariff (T1), 2,096 are in Low voltage maximum Demand (MD) usage tariff (T2), 391 are in High Voltage Maximum Demand (MD) usage tariff (T3), 1 as the Bulk sales to Zanzibar (T5), 1 as the Bulk Sales to Kahama Mining (T8).

The total length of the 33kV lines is 12,602 km, 11kV lines are 6,392 km and 400/230 Volts lines are 26,565 km. Total number of transformers in the distribution system is more than 12,000. All of these facilities were critically in poor condition, to date, distribution networks (including 33 & 11kV, LV lines and distribution substations) in Dar es Salaam, Kilimanjaro and Arusha are being rehabilitated and reinforced under the TEDAP project. In other regions, rehabilitation initiatives by Finland and AFDB’s Electricity V project are also playing a great role in minimizing the distribution system losses and new network extensions are also being carried out where it is appropriate. In other 7 regions the same activities are being carried out under the MCC project. On the other hand, though with its limited resources, TANESCO under its routine activity programs carries out planned and unplanned maintenance works on the distribution system.

System Losses

Despite the above efforts, there are still high energy losses in Transmission and Distribution Systems. This alarming situation called for a need to have a study to identify the problem areas and their causes so as to take the necessary remedies to minimize the losses. A study was commissioned in 2010 by Millennium Challenge Account – Tanzania to carry out a technical and commercial loss-reduction study of the transmission and distribution of TANESCO's electrical power system.

The objectives of the study were to:

a) Reduce the current total level of technical and non-technical losses to 18% by 2013 in TANESCO system from an estimated loss level of 25%
b) Establish the level of system losses and accurately allocate these losses into technical and non-technical, and also identify the main sources and causes of these losses.
c) Identify the cost benefit of reducing losses.

The Sales Gap is first determined in terms of the difference between the inputs to and outputs from the Transmission and Distribution (T&D) system. By performing load flow analysis on the individual levels in the T&D system, the technical loss rate for each such level was determined, in terms of the technical losses as a percentage of the input to that level. The loss rates derived are summarized in table below:

Table 4- 14: System Loss Rates

System Level	Losses
Transmission	5.3%
Distribution	8.1%
Total Technical Loss	13.4%
Commercial Loss	11.6%
Total Loss	**25.0%**

Source: COSS 2010

Applying the loss rates to the through flows for each level in the system makes it possible to derive the technical losses at each level. These technical losses are aggregated for the system. The technical losses are subtracted from the sales gap, defined by the difference between units sent out and actual sales. This residue comprises commercial losses. A separate analysis was performed for the condition of the system at peak time. This is significant because it determines the sizing or capacity (kVA) requirements in assigning costs to the various flows through the system. Applying these loss rates to the flows through the T&D system, the technical losses for each level in the system were calculated.

Technical Loss Reduction Program – 2011 to 2013

Specific Remedial Measures

The most efficient way to improve technical loss performance on both the transmission and distribution networks is to amend the processes for network development to build efficiency into the networks through normal network development. This takes time to produce results. To achieve significant technical loss reduction in the short term additionally requires a specific program of remedial measures targeting the most problematic network areas. These measures are summarized as follows:

i. **Transmission Network**

There are four transmission reinforcement projects proposed to be commissioned by year 2015 that will definitely improve the transmission technical losses to the allowable loss level. These projects include the 400 kV Grid Backbone (Iringa to Shinyanga), 400 Kv Dar es Salaam – Chalinze – Tanga – Arusha, 400 kV Iringa – Mbeya, and 400 kV Dar es Salaam – Morogoro – Dodoma. The higher voltage level of 400 kV will transfer more power with less losses compared to the existing 220kV network.

ii. **Distribution Network**

To achieve significant technical loss reduction in the short term additionally requires a specific program of remedial measures targeting the most problematic networks. The program is proposed to start from year 2013 to 2015 with an objective to minimize energy losses from a level of 20.65% to the acceptable level of 18%. These measures including the respective associated costs and loss savings (for distribution network) are summarized as follows:

a) **11kV Networks**
   - Power factor correction with capacitor installation.
   - 11to 33kV voltage conversion for heavily loaded 11kV lines.

b) **LV Networks**
   - New MV/LV transformers to relieve heavily loaded LV networks.
   - Reconductoring other heavily loaded LV feeders that do not qualify for a new transformer.

c) **Capacitors**

   Capacitor installation to improve network power factors provides very cost effective loss reduction. The overall system impact is relatively small but the costs are very attractive, saving MVA capacity, reducing losses and improving voltage. It is economical to correct power factors in excess of 0.95 up to about 0.98.

The proposed strategy is:

- To install fixed capacitors close to the middle of 11kV main feeders to fully compensate reactive power at minimum load.
- Within next 2 years target all 11kV lines with 2MVA or more of load and Power Factor of 0.88 or less
- In years 3 - 5 target 11kV lines with 2MVA or more of load and Power Factor of 0.90 or less
- To correct PF above 0.95 or towards 0.98 increasingly requires switched capacitors on 11kV bus bars in HV/MV substations but these can still be economical.

d) **11 to 33kV Voltage Conversion**

Capacitor installation yields a modest improvement in 11kV network loss performance at low cost. However it does not address the more seriously over loaded networks. These require more significant development.

The options for relieving heavily loaded MV networks include:

- New HV/MV substation out in the network and re-sectionalizing existing load onto the new substation.
- 11kV to 33kV voltage conversion.
- New 11kV feeder to relieve existing feeder or re-conductoring the heavier loaded sections of the feeder.
- 33kV voltage conversion yields more significant loss reduction benefit. Losses are reduced by some 90%. Conversion costs are also more predictable and will generally be lower than for the construction of a new substation. From a loss reduction perspective 33kV voltage conversion is a much more attractive option and is taken as the preferred major 11kV network development option.

e) **New MV/LV Transformers**

The major development option for overloaded LV networks is to install a new transformer out in the network near the centre of load congestion. Existing LV feeders are split and portions are connected to the new transformer to redistribute load between the available transformers. This provides significant LV load relief and approximately 75% loss reduction on the relieved feeder(s).

f) **Re-conductoring LV Networks:**

There are situations that do not justify such major development as a new transformer but can still benefit from a degree of re-conductoring. This is an additional development option. Approximately two thirds of the losses on a typical LV feeder with distributed load arise in the first one third of the main feeder length. Re-conductoring this first third section can reduce the overall feeder losses by about a third. The idea is to run a length of 4x95mm2 bundle conductor on the existing poles and re-distribute some of the existing load onto this.

To achieve significant technical loss reduction in the short term additionally requires a specific program of remedial measures targeting the most problematic network areas. The program is proposed to start from year 2013 to 2015 with an objective to minimize energy losses from a level of 20.65% to the acceptable level by then of 18%; this will be complemented by the reduction in transmission losses resulting from the introduction of 400 kV transmission lines in the system.

Table 4- 15: Calculation of Energy Loss Savings

Specific Loss Remediation	Units	2013	2014	2015	Total
		11kV Overhead Networks			
Convert to 33kV:					
11kV Line Length	km	200.00	250.00	315.00	765.00
Development Cost	US$M	10.80	14.00	17.00	41.80
Loss Saving - Energy	MWh	19,320.00	24,150.00	30,429.00	73,899.00
Loss Saving - Capitalized Value	US$M	47.00	59.00	74.00	180.00
Install Fixed 11kV Capacitors:					
No 11kV Feeders		66.00	66.00	66.00	198.00
Total Capacitors	MVAR	60.00	60.00	60.00	180.00
Development Cost	US$M	0.90	0.90	0.90	2.70
Loss Saving - Energy	MWh	2,977.00	2,977.00	2,977.00	8,931.00
Loss Saving - Capitalized Value	US$M	7.30	7.30	7.30	21.90
		LV Networks			
New MV/LV Substations:		86.00	100.00	100.00	286.00
Development Cost	US$M	3.40	4.00	4.00	11.40
Loss Saving - Energy	MWh	6,453.00	7,503.00	7,503.00	21,459.00
Loss Saving - Capitalized Value	US$M	15.50	18.10	18.10	51.70
Reconductor LV Feeders:					-
LV Feeder Length	km	500.00	700.00	780.00	1,980.00
Development Cost	US$M	5.00	7.00	7.80	19.80
Loss Saving - Energy	MWh	14,621.00	20,470.00	22,809.00	57,900.00
Loss Saving - Capitalized Value	US$M	23.92	33.49	37.32	94.72
		Totals			
Development Cost	US$M	20.10	25.50	29.80	75.70
Loss Saving - Energy	MWh	43,371.00	55,100.00	63,718.00	162,189.00
Loss Saving - Capitalized Value	US$M	93.82	117.69	136.82	348.32

These measures including the respective associated costs and loss savings (for distribution network) are summarized in **Table 4-16**.

Table 4- 16: System Loss Remedy Costs

No.	Problematic Areas	Remedies	Associated costs (US$ Million)	Loss Savings (US$ Million)
1	11kV Networks	➢ Power factor correction with capacitor installation. ➢ 11 to 33kV voltage conversion for heavily loaded 11kV lines ➢ Install fixed capacitors ➢ Construction of new feeders ➢ Construction of new substation	44.5	201.9
2	LV Networks	➢ New MV/LV transformers to relieve heavily loaded LV networks. ➢ Reconductoring the heavier loaded sections of the feeder.	31.2	146.4
3	Commercial losses	➢ Sensitize the community on electricity theft ➢ Give incentives to whistle blowers ➢ Enforce legal measures		
4	Vandalism	➢ Sensitize the community on electricity theft ➢ Give incentives to whistle blowers ➢ Enforce legal measures		
Total Costs for years 2013, 2014 and 2015			75.7	
Total Savings for years 2013, 2014 and 2015				348.3

Source: COSS

CHAPTER FIVE

5 ECONOMIC AND FINANCIAL ANALYSIS

This chapter presents economic and financial analysis of the proposed power investment plan. It identifies planning criteria used in the analysis which covers three major themes, namely:

a) An estimate of the long-run marginal cost of generation, transmission and distribution
b) An assessment of whether and when the isolated load centres should be connected to the main grid; and
c) A financial analysis of the proposed generation and transmission expansion plans

Furthermore, the chapter shows the costs involved in the implementation of the proposed plan so that the players can identify the projects to implement either independently or in partnership. The modality of implementing these projects can either be purely Government or purely private sector or in partnership (PPP). The Government's role in this respect will be two folds: to mobilise financial resources to implement some of the earmarked projects and to create conducive environment of attracting investors in the power sector. In additional, this chapter also analyse economics of interconnecting the isolated load centres as well as estimating long run marginal cost.

5.1 Main Assumptions

5.1.1 Discount rate

The discount rate may be considered as the time value of money, and is used to calculate the present value of a series of future costs. The selection of an appropriate discount rate value should reflect the opportunity cost of capital, and therefore it tends to be higher in regions where capital is relatively scarcer. The choice of discount rate is discretionary. Use of a higher discount rate will tend to favour thermal plants in cost comparisons with hydro due to their lower initial costs, but higher yearly operating costs, while lower interest rates would favour hydroelectric plants, where most of the expenditures are at the beginning of the project cycle. A real discount rate of 10 percent (i.e. excluding inflation) was used in converting capital costs into equivalent annual costs over the life of an asset and for comparisons of unit generation costs for initial screening of options.

5.1.2 Debt Equity Ratio

The debt equity ratio of 70:30 is a standard ratio preferred by most financiers/banks, and has been adopted in this study. Although somehow it may be difficult for the project developers (in this case, the Government and/or private sector) to raise such equity, it reflects their commitment towards implementation of the projects and its operations to be able to service the debt.

5.1.3 Interest Rate

Different source of finance have different cost of the loan to be offered. For the purpose of this assignment, an interest rate of 7 percent has been assumed which is considered to represent average cost of debt in Tanzania.

5.1.4 Interest During Construction (IDC).

This is interest incurred directly as the result of investment cost obtain as loan. This has impact on the overall project cost as it is added on the project cost by capitalizing them. A 7% per annum equivalent to the interest rate has been assumed in calculating IDC of projects by considering 70% of the projects cost will be secured in the form of loan.

5.1.5 Inflation Rate on Capital Cost

Most of the costs in electricity projects are based in US dollar. The analyses and comparisons made in this PSMP process are based on constant prices. However, it should be noted that since projects are implemented one after another during the plan horizon, it is obvious that inflation will have impact on the total cost of implementing this Plan. In this case, inflation rate of 2.5 percent per year has been assumed, which is in line with USA CPI index.

5.2 Financial Analysis

This section presents the approach and results of the financial analysis. It follows from the economic analysis and long run marginal costs. The financial analysis looks at the overall Tanzanian PSMP from the financial point of view and takes into consideration the financing for the plan, the total amount of required debt and equity, the interest during construction, and inflation. During the financial forecast period the annual interest costs, repayment of debt, and returns to equity investors and income taxes are presented.

5.2.1 Summary of Financial Analysis

The financing requirement to implement the PSMP in the short run (2013 – 2017) is about US$ 11.3 billion, the breakdown of which is indicated in **Table 5.1** and **5.2** below.

Table 5- 1: Term Financing Requirement (2013 – 2017) USD Million

Investments	Installed Capacity MW	Planned On-Line Year	2012	2013	2014	2015	2016	2017	Project Total
Mwanza MSD	60	2013	80						**80**
Kinyerezi I	150	2014		188					**188**
Somanga Fungu II (CC 320)	210&110	2014 &16		135	91	84	55		**365**
Mufindi Cogen	30	2015	21	14	6				**41**
Sao Hill Cogen	10	2015	2	8	6				**16**
Kinyerezi II	240	2015		259	173				**432**
ZINGA BAGAMOYO	225	2015		138	138				**276**
MKURANGA	250	2015		100	100				**200**
Kiwira - 1	200	2017		62	123	123	103		**410**
Coastal Coal - I	300	2017		215	431	431	359		**1,435**
Wind I	50	2016		19	62	44			**125**
Ngaka Coal - Phase I	200	2017		71	143	143	119		**476**
SOLAR- 1	60	2016		43	144	101			**289**
Stiegler's Phase-1	300	2023		38	66	38	66	66	**272**
Kinyerezi III	300	2016			214	143			**357**
Wind II	50	2017			19	62	44		**125**
Mchuchuma - I	300	2018			115	231	231	192	**769**
Kiwira II	200	2018			62	123	123	103	**410**
Rusumo Hydro	27	2018			6	28	45	34	**113**
Ruhuji Hydro	358	2021			49	85	98	244	**476**
Mtwara 400	400	2017				289	192		**481**
Mchuchuma II	400	2018				32	95	32	**159**
Mchuchuma III	400	2018				32	95	32	**159**
SOLAR- II	60	2018				43	144	101	**289**
Kakono Hydro	53	2019				5	24	39	**68**
Mpanga Hydro	144	2022				11	22	25	**58**
Ngaka Coal - Phase II	200	2019					71	143	**214**
Malagarasi	45	2020					8	38	**46**
Rumakali Hydro	520	2025					30	52	**81**
Generation Investments			**103**	**1,290**	**1,947**	**2,046**	**1,923**	**1,099**	**8,409**
Transmission Investments				**161**	**161**	**161**	**161**	**161**	**806**
Total Investments			**103**	**1,452**	**2,108**	**2,208**	**2,084**	**1,260**	**9,215**
Cum. Investments			**103**	**1,555**	**3,663**	**5,871**	**7,955**	**9,215**	**9,215**
Financing									
Debt		**70%**	**72**	**1,016**	**1,476**	**1,545**	**1,459**	**882**	**6,451**
Equity		**30%**	**31**	**435**	**633**	**662**	**625**	**378**	**2,765**

NB: [1] Total project costs marked with red colour are partial cost since construction of these projects goes beyond 2017

Table 5- 2: Summary of short term financing requirement (2013 -2017)

Investments	Installed Capacity MW	Planned On-Line Year	2012	2013	2014	2015	2016	2017	Total
Generation Investments			**103**	**1,290**	**1,947**	**2,046**	**1,923**	**1,099**	**8,409**
Transmission Investments				**161**	**161**	**161**	**161**	**161**	**806**
Distribution Investments			**25**	**348**	**506**	**530**	**500**	**302**	**2,212**
Total Investments			**128**	**1,800**	**2,615**	**2,737**	**2,584**	**1,563**	**11,427**
Cum. Investments			**128**	**1,928**	**4,542**	**7,280**	**9,864**	**11,427**	**11,427**
Financing									
Debt		**70%**	**89**	**1,260**	**1,830**	**1,916**	**1,809**	**1,094**	**7,999**
Equity		**30%**	**38**	**540**	**784**	**821**	**775**	**469**	**3,428**

The breakdown of the total capital expenditures, inflation and interest during construction for generation and transmission plan over the period 2011 to 2035 is given below in **Table 5.3.**

Table 5- 3: Breakdown of Capital Costs

Cost Item	(Mill. USD)	(Mill. USD)	(%)	(%)
1 Capital Costs without Inflation and IDC				
Generation	17,518		63.3	42.8
Transmission	3,708		13.4	9.1
Distribution	6,460		23.3	15.8
Total Capital Cost (excl. Inflation & IDC)	**27,687**		100.0	67.7
	(Mill. USD)	**(Mill. USD)**	**(Mill. USD)**	
2 Capital Costs with Inflation		*(Inflation)*		
Generation	17,518	*8,221*	25,740	
Transmission	3,708	*1,414*	5,122	
Distribution	6,460	*1,693*	8,153	
Inflation		***11,329***		27.7
Total Capital Cost (incl. Inflation)			***39,015***	
3) Capital Costs with Interest During Construction				
Interest During Construction			1,903	4.9
Total Capital Costs (incl Infl & IDC)			***40,919***	100.2

Inflation

The table shows that based on annual inflation of 2.5 %, the overall capital costs will increase by 11,329 million Dollars (accumulation), an increase of 40.9%.

Interest during construction

The Interest During Construction (IDC) for the generation, transmission and distribution over the period 2011 to 2035 amounts to 1,903 million USD, which increases the overall cost of the capital expenditures by 6.9%.

Impact of financing of capital expenditures

The financing of capital expenditures is given below and is based on the 70% debt and 30% equity financing of the draw-downs for capital expenditures. The IDC is based on the interest rate of 7% for new loans and the assumptions made on capitalizing the capital works in progress.

Table 5- 4: Breakdown of Overall Financing Requirements for Capital Costs

Capital Costs and Financing Items	(Mill. USD)	(%)
Total Capital Cost without IDC	39,015	
1 Drawdowns for Financing Capital Expenditures		
Debt financed	27,311	70.0
Equity financed	11,705	30.0
Total Financing without IDC	**39,015**	100.0
2) Overall Financing including IDC		
IDC	**1,903**	71.4
Total Debt (Drawdown +IDC)	29,214	28.6
Equity	11,705	100.0
Total Financing including IDC	**40,919**	

The IDC is added to the debt principal and results in increase in total debt. The increase in debt is marginal since this is the IDC over the study period. At the same time as the IDC is accumulating, the overall debt portion decreases during the study period since the principal including previous accumulated IDC is also being repaid.

Unit cost of supply of power

The unit cost of supply derived on a financial basis for the new power was calculated for each of the years of the study period by dividing the Annual Revenue Requirements (ARR) by the energy supplied. The financial cost of supply is derived on an accounting basis and includes the depreciation expense, financing costs, income taxes and net income for the company.

The Financial Unit Cost of Supply is obtained by dividing the ARR by the energy supplied for that year. The ARR, energy supplied and unit cost of supply for each year is presented below. The unit costs of supply start at 1.4 US$cents/kWh in 2013, and rise rapidly to 4.5 US$cents/kWh in 2014, and then with fluctuations but with overall increases to 17.9 US$cents/kWh in 2021 before falling back to 12.7 in 2029 and remaining in that range till 2035. It should be noted that the ARR considered in this analysis is to carter for the new investments only and not for the overall ARR of TANESCO.

Table 5- 5: Annual Revenue Requirements, Energy Supplied and Unit Cost of Supply

Year	ARR (Mill. USD)	Energy Supply (GWh)	Unit Cost of Supply (US c/kWh)
2013	82	5,888	1.4
2014	312	6,973	4.5
2015	621	8,473	7.3
2016	1,176	10,018	11.7
2017	1,804	11,395	15.8
2018	2,165	12,320	17.6
2019	2,343	13,195	17.8
2020	2,570	14,127	18.2
2021	2,700	15,092	17.9
2022	2,821	16,176	17.4
2023	2,902	17,352	16.7
2024	3,028	18,645	16.2
2025	3,094	20,087	15.4
2026	3,232	21,629	14.9
2027	3,338	23,328	14.3
2028	3,496	25,214	13.9
2029	3,707	27,217	13.6
2030	3,990	29,473	13.5
2031	4,267	31,896	13.4
2032	4,376	34,578	12.7
2033	4,603	37,533	12.3
2034	4,670	40,804	11.4
2035	4,494	44,470	10.1

5.3 Estimate of Long Run Marginal Costs

From an economic perspective, the long run marginal cost is the cost of supplying an incremental unit of electricity (kWh) to the system at a future date. In practice, such a cost cannot be determined directly mainly due to the fact that the investment required to meet the incremental kWh is “lumpy”. Adding to the complexity, it is the system as a whole that supplies the incremental kWh.

The rationale for using marginal costs as a basis for electricity pricing is to direct the customer, through the price charged for electricity, towards the most efficient use of resources available. Theoretically, if the price is equal to the marginal cost of supply, an optimal allocation of resources takes place and economic efficiency will result.

Marginal cost is one of many considerations used in the development of electricity tariffs. The long run marginal costs (LRMC) of electricity supply are computed to satisfy the criterion of economic efficiency. Marginal costs are usually adjusted to arrive at an appropriate tariff structure that meets various other goals and constraints, including, the financial viability of the electric power sector, social objectives, metering and billing constraints etc. This report focuses exclusively on the estimate of long-run marginal costs and does not address the financial viability or tariff structure issues.

Approach Used to Estimate Marginal Costs

Two broad categories of cost are considered: demand or capacity-related costs and energy-related costs. Marginal capacity costs (also referred to as marginal demand costs) are taken as the costs of investment in generation, transmission and distribution to supply additional kilowatts plus the fixed costs of operation and maintenance. To establish these demand costs the projected capital investment is required for the generation and transmission aspects. Marginal energy costs are the costs of fuel, energy purchases and the variable operating and maintenance costs needed to provide additional kilowatt-hours.

One issue that needs particular attention is the estimate of the capital costs for the expansion of the distribution system to meet the system needs at the end of this plan (2035). The mandate for the master plan considered only the expansion of the generation and transmission system. An estimate of the distribution investments is required, even though it was not part of the mandate for the study. Based on studies elsewhere, it is assumed that the distribution costs for the Tanzania’s system will amount to about twice the investment costs in transmission. For instance, SNC-Lavalin calculated the marginal costs for a specific system in India where Generation = 64% of the total, transmission = 11 to 13% and distribution = 23 to 25%. This study has adopted the same for purposes of calculating the LRMC with a loss of 20%.

5.3.1 Summary of Results

The long run marginal cost of power in Tanzania was calculated on a year-by-year basis by examining the incremental cost over the base year. This approach is closer to the strict definition of long run marginal cost.

The development of the capital and operating costs, average annual energy generated by the new plan additions and the energy transmitted is based on same approach as the original 2008 PSMP study and its subsequent 2009 Update study.

From the analyses, the unit cost of generation, transmission and distribution are calculated for each year. These are presented below.

Table 5- 6: Marginal cost ($ per kWh)

	Marginal cost Production	Marginal cost Transmission	Marginal cost Distribution	Marginal cost of supply
Period	**(US Cents/kWh)**	**(US Cents/kWh)**	**(US Cents/kWh)**	**(US Cents/kWh)**
2013 to 2020	14.6	1.3	2.8	18.1
2021 to2036	5.9	0.6	2.8	8.7
2013 to 2036	9.1	0.8	2.8	12.1

The marginal costs of production, transmission and distribution cannot simply be added to result in the overall cost of supply since there are transmission losses of 5 % as well as distribution losses of about 20%. The marginal cost of supply is higher than other marginal costs because the marginal costs of generation and transmission are applied across a much smaller amount of energy at the distribution level.

5.4 Economics of Connecting the Isolated Loads

In Tanzania there are 6 isolated load centres namely Kagera, Kigoma, Lindi, Mtwara, Ruvuma and Rukwa. The drive is to connect all isolated regions to the main grid system by 2019. The process of connecting Ruvuma to the national grid is at advanced stage and actual construction of the transmission lines will start soon. This analysis therefore is confined to the remaining five isolated load centres. Given the fact that, the power from the diesel generators is more expensive to generate than the power supply from the main grid, this Plan suggest when it is economical to connect the remaining centres to the grid.

5.4.1 Approach for Examining the Economics of Connecting the Isolated Loads

The approach undertaken for the economics of the isolated load centres is to compare the benefits with the cost of the interconnection. The benefits are the annual savings resulting from the difference in generation costs and supply from the isolated diesel generators as compared to the power supply from the main grid. The costs are the capital costs of 132kV or 220kV as initial voltage of the transmission lines to connect the load centres to the main grid, depending on the load growth of the respective centres. The costs of associated new substation and transformer from 132kV or 220kV to the distribution level are also considered. These capital costs of the interconnection are then annualised and compared to the annual benefits.

Assumptions for the isolated loads

The following are the key assumptions and parameters used in the model.

Load factor for isolated system:	60 %
Cost of Supply on isolated system:	190 $/MWh
Cost of Supply on grid:	10 $/MWh
Unit Savings	180 $/MWh
<u>Cost of Interconnection</u>	
Transmission line 132 kV Single Circuit	200,000 $/kM
Transmission line 220 kV Single Circuit	284,000 $/kM
Substation	
Bay and Switchgear at 132 kV	6.000,000 USD
Bay and Switchgear at 220 kV	8.000,000 USD
Substation and Transformer Cost 132 kV to 13.8/11kV	12,000,000 USD
Substation and Transformer Cost 220 kV to 13.8/11kV	20,000,000 USD
Total Switchgear and substation cost 132kV	18,000,000 USD
Total Switchgear and substation cost 220kV	28,000,000 USD
Discount Rate	10 %

5.4.2 Results for the Interconnection

The results from the economic analysis for varying loads and with distances of 200 to 500 km were analyzed via a model. The model was used to look at loads from 1 to 35 MW. These show that, to connect a 5MW load, the load should be within less than 100 km of the transmission system. This model was used for all isolated loads. Table**5-7:** presents isolated load centres, the distance from the grid, the minimum economic load in MW and the load in 2010. The table also presents the year in which the load would be of sufficient size to make it feasible for connecting to the main grid.

Table 5- 7: Isolated Load Centres and Feasibility of Connection to the Main Grid

Isolated Load Centre	Distance from grid (km)	Economic minimum load (MW)	Load in 2010 (MW)	Load in 2035 (MW)	Time for grid connection
Kagera	**220**	**10**	**11.4**	**383**	**Now**
Mtwara	**353**	**15**	**10.2**	**271**	**2013**
Rukwa	**340**	**15**	**5.8**	**134**	**2015**
Kigoma	**280**	**10**	**5.4**	**184**	**2014**
Lindi	**353**	**15**	**1.2**	**179**	**2013**

Source: Team Compilation

This analysis shows that the Government can initiate plans for the connection of all of these isolated load centres. In terms of priorities, the Kagera centres would provide the best economic return, followed by Mtwara. On economic point of view Lindi would be connected by 2015 but technically Mtwara and Lindi could be connected at the same time as early as 2013.

CHAPTER SIX

6 CONCLUSION AND RECOMMENDATIONS

6.1 Conclusion

Discovery of new mineral deposits such as natural gas in the southern part of Tanzania, initial development of coal resources (Mchuchuma, Ngaka) and uranium mining (Mkuju – Ruvuma); and mushrooming of economic activities (construction, processing industries, and others) are changing the structure of Tanzania's economy. All these pose pressure on the electricity demand in the country. Despite the endowment of enormous resources for power generation, some challenges exists including mobilization of adequate financial resources to implement the proposed power projects and inadequate requisite human resources skills and knowledge for developing the existing power resources.

Other general challenge especially in the preparations of this Plan is related to data issue. Some data and information was found to be inconsistency and outdated. Some of the identified projects have not been studied to feasibility level while others have outdated feasibility study reports, thus render it difficult to make meaningful decision on the project implementation. Furthermore, most generation resources are located in the south-west part of the country while huge loads are located in the north-west of the country, implying the need for long transmission lines.

The system expansion plan considered all energy resources available within the country which includes hydro, natural gas, coal, solar and wind as well as the importation of electric power from enamouring countries to ensure adequate, reliable power and security of supply over the planning horizon.

The development of alternative expansion generation plans covered the three scenarios following the three cases of load forecast. The 2012 PSMP Update study considers three plans, that the scheduling of projects in each plan (high, base and low case) respects a reserve margin on firm capacity in the order of 15percent - 20 percent, hydro – thermal mix of 40:60 percent and export/import of not more than 25 percent of total available capacity. The purpose of these reserve margins is to allow sufficient generation capability to meet local demand and the possibility for power trading with the neighbouring countries during average hydro supply.

The "Base Case Plan" was considered as the preferred plan for 2012 PSMP update study as it does not commit over-investment and meets national development goals and policy targets such as FYDP-I requires power generation of 2780 MW by 2015/16 and LTPP requires more than 6700 MW by 2025.

The "Preferred Base Case Plan" has a deficit of about 508 MW in the Short-term which is less than 50% of the deficit in the "High Case Plan". The "Base Case Plan" has a total installed capacity of 8960MW by 2035 consisting of 3304 MW hydro, 995MW gas-fired generation, 3800MW-Coal, 100MW-Solar, 120MW-Wind, 40MW- Biomass/Cogen, and some export limited to 250MW of total available generation throughout the planning horizon.

This Plan suggests countermeasures to address power shortage in the short, medium and long term. While the short-term plan requires immediate decision and actions, the mid – to longer terms plan require coordinated planning, project development studies to ensure that future electricity supply utilises the least cost projects, consistent with sound planning criteria and addresses national interests.

In view of the above, the country will need a total of 3,400MW in the medium term (2013-2017) and 8,990MW by 2035 that will require financing to the tune of USD 11.4 billion and UDS 27.7 billion in those two periods respectively. When inflation and interest during construction are added, total investment required rises to US$ 40.9 billion dollars in the long run. Of this amount, about two third of it is for generation.

6.2 General Recommendations

The following are recommendations for successful implementation of the PSMP 2012 updates.

i. For a sustainable development of power sector, there is a need to firm up project implementation schedule as proposed by PSMP particularly those which have element of PPP and IPP arrangements;

ii. There is a need to ensure that strategic power projects are studied to full feasibility level to reduce project implementation lead time and cost;

iii. To speed up feasibility studies for coal and geothermal power projects, there is need to enhance capacity of Geological Survey of Tanzania (GST) to carry out detailed geological exploration to identify location of all coal and geothermal resources;

iv. There is a need to create conducive environment for development of renewable power projects (Wind, geothermal, Solar, and Biomass) to supplement exhaustible resources;

v. Coal, Geothermal and Nuclear Policies should be prepared to guide the utilization of these resources for power generation;

vi. To ensure effective implementation of PSMP 2012 updates, the Government may need to establish a monitoring and evaluation unit; and

vii. Capacity building: In order to internalise and broaden up experts of formulating plan of this nature and improve local expertise, the government needs to maintain and retain the core team that involved in the preparation of this plan. More capacity is required to enhance the process of formulate/ review/update of PSMP. There is a need to have modern software, tools to improve the level of projections. This will include training of the core team, procuring of the modelling packages (Stata etc) and sharing leaf of experience with institutions involved in related to similar planning works.

6.3 Specific Recommendations

A. Load Forecast

i. The current level of energy losses is high; more efforts are needed to scale down energy loss from 25% to 15.8% as forecasted. The projected loss level by 2035 is synonymous to semi-industrialised countries.

ii. Implement Demand Side Management programmes to defer investment in additional generation.

iii. The share of T1 and T2 on electricity consumption kept on decreasing by 5.4 and 4.1 percentage points by 2035 respectively. This implies that, more energy will be used by customers under category T3 (Agriculture and industries). However, in the early years of projections, T1 share reach a maximum of 48% following introduction of special electrification program.

B. Generation

i. In order to avoid power shortages, projects earmarked for implementation in the short term (2013 – 2017) should be strictly adhered to as there is no room to manoeuvre.

ii. Two hydro options will require removal on significant obstacles before becoming firm candidates for implementation:

   a) **Songwe project** is a multipurpose project located on the border between Tanzania and Malawi, its development will involve trade-offs between two countries and various competing uses of the water resource. It is necessary to initiate joint discussions on the best way to develop the project.

   b) **The Stiegler's Gorge** option is located within the Selous Game Reserve; its development is constrained by the Algiers Conventions which defines the developments possibilities within national parks and game reserves. It is therefore important to redefine the game reserve borders.

iii. The results of the study indicated occurrence of shortage of power supply in the short term (2013 - 2017). Therefore there is an urgent need to arrange investment in generation infrastructure in order to avoid load shedding;

iv. Implementation of generation supply should be based on the base case forecast which has as a target the electrification of 75% of the households of Tanzania by the year 2035;

v. The isolated centres should be connected to the main grid as soon as it is feasible, ie., during the period 2013 to 2017;

vi. The generation additions should respect a need to have sufficient technological diversification that the risk of power shortages during drought periods is reduced by adhering to hydro-thermal mix ratio of 40:60;

vii. Development of renewable power resources (Wind, Solar, and Biomass); and

viii. Accept the import/export of firm power from outside the country (whether from, Ethiopia, Zambia, Mozambique or elsewhere) as they become economic.

C. Transmission requirements

i. Continue implementation of earmarked Transmission lines projects parallel with generation projects to ensure power evacuation.

ii. Reinforce distribution network to meet electrification targets.

iii. The current load factor in the Tanzania interconnected grid has been relatively constant at about 65 percent over most of the historic period and it is projected to reach 72 percent by 2035 reflecting emergence of economic activities such as mining loads

D. Financial and Economic Perspective

i. Implementation of this plan requires huge financial resources. Concerted efforts to be exercised in mobilizing required financing for both power generation, transmission and distribution;

ii. The Government should continue with efforts to invest in power infrastructure to meet long term power demand and at the same time create conducive environment to attract private investment in the power sector; and

iii. The isolated centres should be connected to the main grid as soon as it is feasible.

Short-term commitments

Except for rental power with contract lasting for 2 years, in the short term there are very few options available to meet the expected demand for power. All identified resources that can be implemented during that period should be committed as soon as possible.

Thermal options

a) Investigations of the gas reserves need to be pursued to ensure that as much of the gas reserves as possible are proven

b) Construction of the gas pipe-line from Mtwara – Dar es Salaam must be fast-tracked to allow its use for the proposed gas-fired power units

c) Investigations of the coal reserves need to be pursued to ensure that as much of the coal deposits are proven as possible.

Hydro development options

a) Very few of the identified hydro options have recent feasibility study reports; all of these options need to be studied to at least the feasibility level before decisions can be made to firmly commit the construction of these options. This information is also required by private investors if they are to bid on hydro projects

b) The options for the development of the Stiegler's Gorge option need to be studied to determine the feasibility of development of that resource; and

c) The options for the development of the Songwe River need to be studied to determine the optimum development scheme for this river basin. This includes negotiations with the Government of Malawi over the sharing of this resource.

Power imports/Exports

The possibility of imports/Export from Ethiopia via Kenya – Tanzania inter-connector needs to be pursued. Possible import of up to 200MW is anticipated by 2016.

Other options

It is recommended to implement the demand-side management program as proposed under the recently completed Energy Rationalisation and Demand Response Study by Ms Hatch of Canada.