UNITED REPUBLIC OF TANZANIA

MINISTRY OF ENERGY

POWER SYSTEM MASTER PLAN 2024 UPDATE

TABLE OF CONTENTS

FOREWORD 13
PREFACE 14
DEFINITION OF TERMS 15
List of Abbreviations 18
CHAPTER ONE 23
INTRODUCTION 23
1.1 Background 23
CHAPTER TWO 25
IMPLEMENTATION STATUS OF 2020 PSMP UPDATE 25
2.1 Introduction 25
2.2 Load Forecast 25
2.2.1 Projected versus Actual Power Demand 25
2.2.2 Energy Losses 25
2.2.3 Rate of Electrification 26
2.3 Generation Plan 26
2.3.1 Review of Generation Projects (2020 to 2024) 26
2.4 Transmission Plan Update 27
2.4.1 Transmission Lines Implementation Status 27
2.4.2 Substations Implementation Status 29
2.5 Conclusion 32
CHAPTER THREE 33
LOAD FORECAST 33
3.1 Introduction 33
3.2 Approach and Methodology 33
3.2.1 Approach for the Forecast 33
3.2.2 Methodology 34
3.2.3 Key Assumptions 34
3.3 Factors considered in the demand Forecast 35
3.3.1 Electricity Consumption 35
3.3.2 Maximum Demand 36
3.3.3 Rate of Electrification 36
3.3.4 Interconnection of Isolated Systems 37
3.3.5 Persons Per Household 37
3.3.6 System Load Factor 37

3.3.7 Unserved Energy 37
3.3.8 Energy Losses 38
3.4 Power Requirements from Emerging Issues 38
3.4.1 Liquefied Natural Gas Project 38
3.4.2 Standard Gauge Railway Electric Train 38
3.4.3 E-Mobility 39
3.4.4 Adoption of Electricity for Clean Cooking 40
3.4.5 Net Metering Framework 41
3.4.6 Communications Towers 42
3.4.7 Surveyed Future Load 43
3.5 Forecast Results from Trend Analysis- Base Case 44
3.5.1 Demand Forecast Scenarion Results 44
3.5.2 The Base Case Demand Forecast Results 46
3.5.2.1 Forecasted Demand 46
3.5.2.2 Forecasted Customers 48
3.5.2.3 Forecasted Energy Consumption by Customers Category 49
3.6 Forecasts Results from Econometric Analysis 52
3.6.1 Background 52
3.6.2 Observed Relationship in Econometric 52
3.6.3 Scenario Considered for Econometric Forecast 58
3.7 Conclusion 59
CHAPTER FOUR 61
POWER GENERATION PLANNING 61
4.1 Introduction 61
4.2 Objective 61
4.3 Approach and Methodology 62
4.3.1 Data Collection and Review 62
4.3.2 Planning Criteria and Scenario Development 62
4.3.3 Generation Mix Optimization 62
4.3.4 Hydrological and Environmental Assessment 62
4.3.5 Project Ranking and Selection 62
4.3.6 Results Validation and Sensitivity Analysis 63
4.4 Factors Considered in the Generation Plan 63
4.4.1 Existing Power Generation System 63

4.4.1.1Existing Hydro Power Plants 65
4.4.1.2Characteristics of Existing Hydropower Plants 65
4.4.1.3Characteristics of Thermal Power Plants 67
4.4.1.4Biomass Power Plants 69
4.4.1.5Captive Power Plants 69
4.4.1.6Existing Capacity Retirement 70
4.4.2 Energy Resources for Power Generation 71
4.4.2.1Hydro 72
4.4.2.1.1 Hydrological System 72
4.4.2.1.2Hydrological Characteristics Assessment 72
4.4.2.1.3Strategic Location for Development of Hydropower 75
4.4.2.2Natural Gas Resources 75
4.4.2.3Geothermal 78
4.4.2.4Solar 78
4.4.2.5Wind 78
4.4.2.6Uranium 79
4.4.2.7Coal 79
4.4.2.8Hydrogen 79
4.4.3 Generation Planning Criteria 80
4.4.3.1Plant Life Span 80
4.4.3.2Reserve Margin 80
4.4.3.3Plant availability and energy generation 81
4.4.3.4Generation Mix 81
4.4.3.5Outage rates 81
4.4.3.6Unit capital cost 81
4.4.3.7Operation and Maintenance Cost (O&M) 81
4.4.3.8Lead Times 81
4.4.3.9Cross-Border Power Trading 81
4.4.4 Candidate Projects for Power Generation 82
4.4.4.1Hydro Power Projects 82
4.4.4.1.1Characteristics of hydropower Project candidate 83
4.4.4.2Thermal Power Projects 85
4.4.4.3Solar Power Projects 90

4.4.4.4 Wind Power Projects 90
4.4.4.5 Geothermal Power Projects 91
4.4.4.6 Power Project Development Costs 92
4.4.4.7 Thermal Power Plant Fuel Cost 99
4.4.4.8 Screening of Candidate Power Projects 101
4.5 Results of Generation Expansion Plans 105
4.5.1 Short Term Generation Expansion Plan (2024-2028) 106
4.5.1.1 Capacity expansion plan 106
4.5.1.2 Energy Generation 107
4.5.2 Medium Term Generation Expansion Plan (2029-2038) 109
4.5.2.1 Capacity expansion plan. 109
4.5.2.2 Energy Generation 110
4.5.3 Long Term Generation Expansion Plan (2039-2050) 112
4.5.3.1 Capacity expansion plan 112
4.5.3.2 Energy Generation 113
4.5.4 Generation Expansion Scenarios 113
4.5.5 Capital Cost for Base-Case Generation Expansion 114
4.6 Conclusion 115
CHAPTER FIVE 116
TRANSMISSION LINE NETWORK EXPANSION 116
5.1 Introduction 116
5.2 Objective 116
5.3 Approach and Methodology 117
5.3.1 Reliability Criteria 117
5.3.2 Normal Operating Conditions (N-0) 117
5.3.3 Contingency Operating Conditions (N-1) 117
5.3.4 System Voltage Criteria 118
5.3.5 Equipment Thermal Loading Criteria 118
5.3.6 Substation Planning Criteria 118
5.3.7 Transmission System Parameters 119
5.3.8 Grid Substation Demand 119
5.3.9 Load Flow Analysis 119
5.4 Assessment of Existing Grid System 120
5.5 Factors Considered in Transmission Planning 127

5.5.1 Reinforcement of Grid Security 127
5.5.2 Demand Growth 127
5.5.3 Grid Expansion to Explore Generation Resources 127
5.5.4 Grid Expansion to Underserved and Isolated Areas 128
5.5.5 Development of New Interconnectors 128
5.6 Results of Load Flow Analysis 129
5.6.1 Grid Substation Demand 129
5.6.1.1 Grid Substation Demand for Short-Term (2024-2028) 129
5.6.1.2 Grid Substation Demand for Medium-Term (2029-2038) 130
5.6.1.3 Grid Substation Demand for Long-Term (2039-2050) 131
5.6.2 Transmission System Addition - Least Cost Expansion Plan 132
5.6.2.1 Short term (2024-2028) 133
5.6.2.2 Medium Term (2029-2038) 139
5.6.2.3 Long Term (Year 2039-2050) 145
5.6.2.4 Reactive Compensation 148
5.6.2.5 Substation Additions 148
5.6.2.6 Short Circuit Study 148
5.7 Transmission and Substation Costs 160
5.7.1 Transmission Unit Costs 160
5.7.2 Transmission System Project Costs 161
5.8 Conclusion 181
CHAPTER SIX 182
ECONOMIC AND FINANCIAL ANALYSIS 182
6.1 Introduction 182
6.2 Objective 182
6.3 Approach and Methodology 182
6.4 Factors considered in Economic and Financial Analysis 183
6.4.1 Project Economic Life and Depreciation 183
6.4.2 Project Construction Schedules 183
6.4.3 Project Cost Estimates 184
6.4.4 Inflation Rate on Capital Cost 184
6.4.5 Discount and Interest Rates 185
6.4.6 Debt-Equity Ratio and Loan Tenure 185
6.4.7 Interest During Construction (IDC) 185

6.4.8 Foreign Exchange Rate 185
6.4.9 Income Tax 186
6.4.10 Return On Equity 186
6.5 Results of Economic and Financial Analysis 186
6.5.1 Economic Analysis 186
6.5.1.1 Short Term Funding Requirement 186
6.5.1.2 Medium Term Funding Requirement 188
6.5.1.3 Long Term Funding Requirement 189
6.5.2 Financial Analysis 189
6.5.2.1 Interest During Construction and Inflation 190
6.5.3 Projected Unit Cost of Power Supply over the Investment Plan 191
6.5.4 Results of Long-Run Marginal Costs 192
6.6 Conclusion 192
CHAPTER SEVEN 193
IMPLEMENTATION STRATEGY 193
7.1 Introduction 193
7.2 Institutional Structure of the Electricity Supply Industry 193
7.3 Government Commitment 194
7.3.1 Rehabilitate and Expand Energy Infrastructure at Competitive Costs 194
7.3.2 Leverage Benefits of Increased Regional Integration 195
7.3.3 Embrace Distributed Renewable Energy (DRE) and Clean Cooking Solutions as Critical Elements of the Access Agenda. 195
7.3.4 Incentivize Private-Sector Participation to Unlock Additional Resources and Develop Local Capacity. 196
7.3.5 Advanced Financially Viable Utilities That Ensure Energy Security and Provide Reliable and Affordable Services 197
7.4 Targets And Timelines 197
7.5 Implementation Strategies 198
7.5.1 Implementing Planned Generation Projects 198
7.5.2 Implementing Planned Electricity Transmission Projects 199
7.5.3 Implementing Critical Interconnection Investments 200
7.5.4 Adopting The Framework for the Independent Power Transmission Project 200
7.5.5 Establishing A Renewable Energy Independent Power Producer (IPP) Procurement Program 201

7.5.6 Developing And Operationalizing a Competitive Procurement Framework for Power Projects 202
7.5.7 Updating the Net Metering Rules for Renewable Energy 203
7.5.8 Revising The Small Power Projects (SPP) Framework to Establish Cost-Reflective Tariffs 205
7.5.9 Publication of Strategic Areas for Small Power Project Developments 206
7.5.10 Private Sector Participation in Financing the Construction of The Electric Supply Line 206
7.5.11 Establishment of Infrastructure Development Investment Funds 208
7.5.12 Establishing An Appropriately Resourced Trading Unit Within TANESCO 209
7.5.13 Harmonizing The Regulatory Framework to Facilitate Power Exchanges 209
7.5.14 Promoting The Development Of Indigenous Energy Resources 210
7.5.15 Updating A Comprehensive Least-Cost Power System Master Plan Periodically 211
7.5.16 Monitoring and Evaluation of PSMP Implementation 212
7.6 Conclusion 213
APPENDICES 214
Appendix-A: Detailed Generation Expansion Plan from 2024 to 2050 214

LIST OF TABLES

No table of figures entries found.
Table 2-1: Projected Versus Actual Power Demand 25
Table 2-2: Energy Losses 26
Table 2-3: Power Generation Project Implementation Status 26
Table 2-4: Transmission Lines Implementation Status 27
Table 2-5: Other Constructed Transmission Lines 29
Table 2-6: Planned substation performance in the PSMP 2020 plan 30
Table 2-7: Other Implemented Substations 32

Table 3-1: Key Assumptions for the Forecast 35
Table 3-2: Actual Energy Consumption - GWh 35
Table 3-3: Actual Suppressed Maximum Demand from 2012 to 2023 36
Table 3-4: Electrification Targets 36
Table 3-5: Actual System Load Factor 37
Table 3-6: Actual Unserved Energy From 2012 – 2023 37
Table 3-7: Actual Energy Losses From 2012 to 2023 38
Table 3-8: Power Demand for Electric Train 39
Table 3-9: Expected Energy Consumption E-mobility 40
Table 3-10: Household Energy for Clean Cooking in 2020 41
Table 3-11: Electricity from Distribution Generation 41
Table 3-12: Status Construction of Ongoing Communication 42
Table 3-13: Surveyed Loads(MW) by region from 2024 to 2028 43
Table 3-14: Surveyed Loads (MW) 2024-2028 44
Table 3-15: Demand Forecast Scenarion Results 45
Table 3-16: The Base Case Demand Forecast Results 46
Table 3-17: Total (bussiness as usual and With M-300) 48
Table 3-18: Forecasted Energy Consumption by Customers Category 49
Table 3-19: Emerging Issues Forecasted Demand 50

Table 4-1: Existing Hydro Power Plants 65
Table 4-2: Large Hydropower Plants 66
Table 4-3: Small Hydropower Plants 67
Table 4-4: Thermal Power Plants 68
Table 4-5: Biomass Power Plants 69
Table 4-6: Captive power plant 69
Table 4-7: Power Plant Retirements by 2030 71
Table 4-8: Hydropower Potential in Tanzania 72
Table 4-9: Hydrological Characteristics Assessment for existing Power Plants 73
Table 4-10: Details of the Gauging Stations for Hydrological Data Monitoring for Planned Power Plants 74
Table 4-11: Natural Gas Discoveries 76

Table 4-12: Natural Gas allocated for Power Generation from 2026-2045 77
Table 4-13: Geothermal Potential Sites in Tanzania 78
Table 4-14: Proven Solar Energy Potential Sites 78
Table 4-15: Uranium Resources in Tanzania 79
Table 4-16: Potential Sites with Coal Resources in Tanzania 79
Table 4-17: Power Plants Life Span 80
Table 4-18: Hydropower Project Candidates 82
Table 4-19: Characteristics of Candidate Hydropower Projects 84
Table 4-20: Characteristics of Thermal Power Projects 86
Table 4-21: Solar Power Projects 90
Table 4-22: Wind Power Projects 90
Table 4-23: Geothermal Power Projects 91
Table 4-24: Hydropower Project Construction Costs 94
Table 4-25: Thermal and Renewable Project Construction Costs 96
Table 4-26: Thermal Pricing Cost 99
Table 4-27: Screening of Thermal Projects 101
Table 4-28: Screening of Hydropower projects 102
Table 4-29: Screening of Renewable Projects 103
Table 4-30: Cumulative Installed Capacity by Technology 105
Table 4- 32: Cumulative Genaration by Technology 106
Table 4-33: Cumulative Capacity Additions (2024-2028) 106
Table 4- 34 Cumulative Energy Generation by Technology (2024-2028) 108
Table 4-35: Cumulative Capacity Additions (2029-2038) 109
Table 4- 36 Cumulative Energy Generation by Technology (2029-2038) 110
Table 4-37: Cumulative Capacity Additions (2039-2050) 112
Table 4- 38 Cumulative Energy Generation by Technology (2039-2050) 113
Table 4-39: Generation Expansion Scenarios (2024-2050) 114
Table 4-40: Summary Capital Cost requirement by Technology 115

Table 5-1: Acceptable Operating Voltage Range 118
Table 5-2: Thermal Loading Criteria 118
Table 5-3: Rated breaking current capability of switchgear 119
Table 5-4: Transmission Line Assumed Parameters 119
Table 5-5: Parameters of the Existing Transmission Line System 123
Table 5-6: Summarised Grid Substation Load Demand for Short Term (2024-2028) 130
Table 5-7: Summarised Grid substation Demand for Medium Term (2029-2038) 131
Table 5-8: Summarised Grid Substation Demand for long-Term (2039-2050) 132
Table 5-9: Summary of Transmission System Additions for 2024 – 2050 133
Table 5-10: Transmission System Additions for 2024 – 2028 136
Table 5-11: Transmission System Addition for 2029-2038 141
Table 5-12: Transmission System Addition for 2039-2050 147
Table 5-13: Short Circuit Results at 400kV Voltage Level at Year 2050 149
Table 5-14: Short Circuit Results at 330 kV Voltage Level at Year 2050 151
Table 5-15: Short Circuit Results at 220 kV Voltage Level at Year 2050 152
Table 5-16: Short Circuit Results at 132 kV Voltage Level at Year 2050 157

Table 5-17: Year 2050 Short Circuit Results at 66kV Voltage Level 159
Table 5-18: Unit Cost of Transmission Lines 160
Table 5-19: Unit Cost of Substation per Bay 160
Table 5-20: Unit cost of transformers and reactive compensation 161
Table 5-21: Total Transmission System Costs Estimates (2024-2050) 161
Table 5-22: Phased Transmission Lines Cost Estimates (2024-2028) 162
Table 5-23: Phased Transmission Lines Cost Estimates (2029 – 2038) 164
Table 5-24: Phased Transmission Lines Cost Estimates (2039 – 2050) 167
Table 5-25: Phased Transformer Cost Estimates (2024 – 2028) 168
Table 5-26: Phased Substation Transformer Cost Estimates (2029-2038) 171
Table 5-27: Phased Substation Transformer Cost Estimates (2039-2050) 173
Table 5-28: Phased Substation Switch Gear and Bays Cost Estimates (2024 – 2028) 174
Table 5-29: Phased Substation Switch Gear and Bays Cost Estimates (2029 -2038) 176
Table 5-30: Phased Substation Switch Gear and Bays Cost Estimates (2039 – 2050) 178
Table 5-31: Phased Substation Reactive Compensation Cost Estimate (2024-2050) 179

Table 6-1: Assumptions on Project Life Depreciation Rates 183
Table 6-2: Project Cost Disbursement Schedules 183
Table 6-3: Summary Cost Estimates for Power Projects 184
Table 6-4: Summary Investment Requirement 186
Table 6-5: Annual Investment Plan for Short Term 187
Table 6-6: Annual Investment Plan for Medium Term 188
Table 6-7: Annual Investment Plan for Long Term 189
Table 6-8: Breakdown of Cost for the Investment Plan 190
Table 6-9: System Unit Cost of Additional Power Supply 191
Table 6-10: Long-Run Marginal Cost: 2024-2050 192

LIST OF FIGURES

Figure 3-1 Approach for the Electricity Load Forecast....34
Figure 3-2: Average Contribution of Power Requirement from Emerging Issues....51
Figure 3-3: Forecast of Electricity for D1 and T1....54
Figure 3-4: Forecast of Electricity for T2....55
Figure 3-5: Forecast of Electricity for T3 and Zanzibar....57
Figure 3-6: Forecast of Total Electricity Consumption....58
Figure 3-7: Comparison of Econometric Forecast....59

Figure 4- 1: Grid Installed Capacity by Ownership 64
Figure 4- 2: Current Generation Mix 64
Figure 4- 3: Cumulative Capacity Additions (2024-2028) 107
Figure 4- 4: Cumulative Capacity Additions (2029-2038) 110
Figure 4- 5: Cumulative Capacity Additions (2039-2050) 112

Figure 5-1: Existing Grid System 122
Figure 5- 2: Transmission Plan-Year 2024-2028 135
Figure 5-3: Transmission Plan – Year 2038 140

Figure 5-4: Generation and Transmission Plan – Year 2050 146
Figure 5-5: *Breaker and Half Scheme* 148

Figure 6-1: Annual Investment Plan for Short Term 187
Figure 6-2: Annual Investment Plan for Medium Term 189
Figure 6-3: Annual Investment Plan for the long term 189

FOREWORD

It is with great appreciation and commitment that I present the Power System Master Plan (PSMP) 2024 Update. This strategic document serves as a critical roadmap for guiding Tanzania's power sector investments over the short, medium, and long term. The document outlines the vision, priorities, and investment pathways necessary to achieve reliable, affordable, and sustainable electricity supply across the country.

Over the years, Tanzania has made significant progress in expanding electricity access, improving generation capacity, and reinforcing the transmission and distribution networks. However, new challenges and opportunities ranging from rapid demand growth, regional integration, and technological innovation to climate change and the global clean energy transition necessitate regular updates to our planning frameworks.

The PSMP 2024 update incorporates some of these dynamics and aligns with national priorities, including the Vision 2050, the National Energy Policy, the Third Five-Year Development Plan (FYDP III), the National Energy Compact and our commitments under the Nationally Determined Contributions (NDCs). Importantly, the Plan reflects Tanzania's inclusive approach by integrating public and private sector participation and leveraging regional and international cooperation.

I therefore extend my sincere appreciation to all stakeholders who contributed to this effort, including government institutions, development partners, private sector actors, and civil society. Their insights, data, and commitment were instrumental in shaping this updated plan.

As we move forward, this Master Plan will serve as a compass for coordinated action, strategic investments, and policy reforms that will unlock Tanzania's full energy potential and accelerate socio-economic development for all.

Dr. Doto Mashaka Biteko (MP.)

DEPUTY PRIME MINISTER AND MINISTER FOR ENERGY

PREFACE

The Power System Master Plan (PSMP) 2024 Update represents a critical milestone in Tanzania's continued journey toward an inclusive, and sustainable energy future. It provides a strategic framework for guiding the development of power generation and transmission infrastructures to meet the growing energy demands of our nation and support broader socio-economic transformation.

As Tanzania works to achieve its development goals under Vision 2050, the Third Five-Year Development Plan (FYDP III), National Energy Compact and the National Energy Policy, access to reliable and modern energy remains central to accelerating industrialization, expanding public services, and improving livelihoods. The PSMP 2024 Update provides updated projections and policy directions to ensure energy planning is responsive to national priorities, regional dynamics, and global trends including the energy transition, digitalization, and climate change.

This Update has been informed by thorough analysis of electricity demand forecasts, resource availability, least-cost planning principles, and environmental considerations. It also integrates emerging priorities such as e-mobility, electricity cooking, energy efficiency, and regional power trade. In doing so, the PSMP 2024 update offers a balanced pathway that leverages both public and private investment to ensure affordability, reliability, and sustainability of electricity supply.

The preparation of the PSMP 2024 Update has been a collaborative process involving key government institutions, development partners, the private sector, and civil society. Their inputs and insights have enriched the planning process and reinforced our shared commitment to energy sector development.

I take this opportunity to thank all stakeholders who contributed to the development of this Plan, particularly the technical teams, ministries and institutions whose work was instrumental in completing this important update. Going forward, the successful implementation of this Plan will depend on strong coordination and resource mobilization.

The Ministry remains committed to ensuring that the PSMP serves as a living document through regular reviews and adaptes to support Tanzania's dynamic development landscape and evolving energy needs.

Eng. Felchesmi Jossen Mramba
PERMANENT SECRETARY

DEFINITION OF TERMS

The following terms has been used in the report

Access to Electricity	Means proportion or percentage of the population living within 600 meters from transformers.
Active power	Refer to real power or true power, is the actual power that performs work in an electrical circuit. It is the component of electric power that is converted into mechanical power, heat, light, or any other form of useful energy. Active power is measured in units of watts (W) or kilowatts (kW) or Megawatt (MW).
Connection Level	Means percentage of population (households) with metred electricity.
Cross-border electricity trade	Means trading in electricity between two states sharing a common border through an inter-connector power line, or between more than two states not sharing common border, but linked through a power pool which involves export or import of electric energy between the states.
Customer	Means an entity which receives electricity for its own use or sale.
D1	Means low usage tariff for domestic customers who on average consume less than 75kwh per month and are supplied at a low voltage single phase (230V).
Decommissioning	Means removal and/or disposal of structures.
Distribution	Means a system's network that carries electricity from the transmission system and deliver it to customers.
Energy Efficiency	Means a measure to use less energy to provide the same service.
Generation	Means the process of producing electric power from various sources of primary energy.
Geothermal	Means energy derived from the heat of the earth.
Grid Code	Means the technical and procedural rules and standards issued by the Authority on transmission and system operation; "high voltage" means ac or de voltage of the amount equal or abo.
Hydro	Means a resource for production of electric power through the use of falling or flowing water.
Liquefied Natural Gas (LNG)	Means a liquid form of natural gas, which has been cooled to about minus 162c (260f) at normal pressure . The liquefaction converts the gaseous phase into an

	easily transportable liquid whose volume is approximately 600 times less than the original volume of natural gas.
Liquefied Petroleum (LNG)	Means the light hydrocarbon material, gaseous at atmospheric temperature and pressure, held in the liquid state by pressure to facilitate storage, transport, and handling. Commercial Liquefied Petroleum Gas consists of either propane, butane, or a mixture of both.
Low voltage	Means AC or DC voltage less or equal to four hundred plus or minus five percent.
Medium voltage	Means AC or DC voltage between or above four hundred volts plus or minus ten percent and less than or equal to thirty-three thousand volts plus or minus ten percent.
Minister	Means the Minister responsible for electricity matters.
Natural Gas	This means fossil fuels naturally occur as a gaseous mixture of light hydrocarbons in sedimentary rocks. Natural gas's main constituents are methane, ethane, propane, butane, and pentane, with other non-hydrocarbon compounds including carbon dioxide, hydrogen, sulphide, nitrogen, and rare gases found in small quantities.
Power Losses	Means the electrical energy losses that occur on the transmission network equipment.
PSMP	Means a planning document prepared by the Minister and updated annually by the System Operator dealing with indicative medium and long-term plans for expansion of the transmission system to cater for expected generation and demand development.
Reactive power	Refers to the power which doesn't perform any work but is necessary for the operation of electrical equipment and maintaining voltage levels in the power system. It is measured in units called volt-ampere reactive (VARs).
Small Power Producer	Means a private or state enterprise that generates power with a capacity up to 10 MW from renewable energy resources such as wind, biomass, solar, and hydro, or from conventional sources such as natural gas, coal, oil, etc.
T1	This means the general usage tariff for customers, including residential, small commercial, and light industrial use, public lighting, and billboards supplied at low voltage single phase (230V) and three phases (400V).

T3-MV	Means applicable customers connected to medium voltage.
Transmission	Means the transportation of electrical energy and power by means of high-voltage lines, facilities and associated meters, including the construction, operation. management and maintenance of such lines, facilities and meters.
Voltage profile	Refer to the variation of voltage magnitudes at different substations within the network.

List of Abbreviations

ARR	Annual Revenue Requirement
BCF	Billion Cubic Feet
Cap.	Chapter
CCGT	Combined Cycle Gas Turbine
CIT	Corporate Income Tax
COSTECH	Tanzania Commission For Science and Technology
DSM	Demand Side Management
EAC	East African Community
EACOP	East Africa Crude Oil Pipeline Project
EAPP	Eastern Africa Power Pool)
EIA	Environmental Impact Assessment
EIPC	Electricity Infrastructure Procurement Committee
EPC	Engineering, Procurement and Construction
ESI	Electricity Supply Industry
EWURA	Energy and Water Utilities Regulatory Authority
GDP	Gross Domestic Product
GIIP	Gas Initially In Place
GWh	Gigawatt-hours = 1,000,000,000 watt-hours
HPP	Hydropower Plant
HV	High Voltage
IAEA	International Atomic Energy Agency
IDC	Interest During Construction
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
IPT	Independent Power Transmission
JNHPP	Julius Nyerere Hydropower Project
km	Kilometer
kV	kilovolt
kW	Kilowatt = 1,000 watts
kWh	Kilowatt-hours = 1,000 watt-hours
LCOE	Levelized Cost of Electricity
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation.
LPG	Liquefied petroleum gas
LRMC	Long Run Marginal Cost
LV	Low Voltage
m.a.s.l	Metres Above Sea Level
m3/s	Cubic meters per second
MMSCFD	Million Standard Cubic Feet per Day
MoE	Ministry of Energy
MoF	Ministry of Finance
MoW	Ministry of Water
MV	Medium Voltage

MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Megawatt = 1,000,000 watts
MWh	Megawatt-hours = 1,000,000 watt-hours
MWp	Megawatt Peak
NBS	National Bureau of Statistics
NDC	National Development Corporation
NGUMP	Natural Gas Utilization Master Plan
OAG	Office of the Auditor General
p.a	Per Annum
PPP	Public Private Partnership
PPRA,	Public Procurement Regulatory Authority
PSMP	Power System Master Plan
PV	Photovoltaic
REA	Rural Energy Agency (REA)
RoE	Return on Equity
RPCL	Rusumo Power Company Limited
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SC	Simple Cycle
SGR	Standard Gauge Railway
SPP	Small Power Project
STAMICO	State Mining Corporation
TANESCO	Tanzania Electric Supply Company
TAZARA	Tanzania-Zambia Railway Authority
TBS	Tanzania Bureau of Standards
TCF	Trillion Cubic Feet
TIC	Tanzania Investment Centre
TPDC	Tanzania Petroleum Development Corporation
TPS	Traction Power Station
TR	Treasury Registrar
TTCL	Tanzania Telecommunications Corporation
TZS	Tanzania Shillings
US$	United States Dollar
USBLS	United States Bureau of Labor Statistics
USD	United States Dollar
WACC	Weighted Average Cost of Capital
WMA	Weights and Measures Agency
ZECO	Zanzibar Electricity Corporation

EXECUTIVE SUMMARY

The Power System Master Plan 2024 Update is a strategic document prepared by the Ministry of Energy aimed at guiding the evolution of the country's power sector over the years (2024-2050). This Update builds upon previous PSMP studies and aligns with key national policies, legislation, and development agendas, including the National Energy Policy 2015, Electricity Act Cap 131, Tanzania Development Vision 2050, National Energy Compact and Sustainable Development Goal 7. The goal of PSMP 2024 Update is to provide a reliable, sustainable, and cost-effective electricity supply fostering economic growth and social development accros three time frames: short - term (2025-2028), Medium - term (2028-2038) and Long - term (2039-2050) Terms.

Key highlights of the Power System Master Plan 2024 Update

A. Review of PSMP 2020 Implementation

The PSMP 2020 Update targeted the installation of 2,796MW of new power generation capacity between 2020 and 2024. By the end of this period the period, 1,741.5 MW (62.3%) of the planned generation projects were successfully implemented. Additionally, 3,925.8km (71.66%) of the planned 5,478.07km of transmission line projects, were completed; and 30 out of 55 substations (54.5%) were constructed. Electrification efforts achieved 46% connectivity rate by 2022.

B. Load Forecast

A multi-year load forecast from 2024 to 2050 has been developed, informed by historical electricity consumption patterns, economic factors (GDP, Population growth) performance, and electricity needs to support emerging demands. Key drivers of future power demand include adopting e-mobility, electricity cooking technologies, the Standard Gauge Railway (SGR) project, and the Liquefied Natural Gas (LNG) project development.

The Base-Case load forecast projects an increase in demand from 16,007.5 GWh in 2025 to 40,932.87 GWh in 2030. This forecast translates to an increase in per capita consumption from 243 kWh in 2025 to 528 kWh in 2030, with connectivity rates expected to rise from 50% in 2025 to 87% by 2030, as shown in the tabulation below: -.

Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Peak Demand -MW	2,507.80	3,203.54	4,415.27	5,256.01	5,856.96	6,571.09
Energy Demand-GWh	16,007.50	20,941.96	27,579.20	32,800.81	36,517.71	40,932.87
Number of Customer	6,647,233.00	8,017,787.00	9,388,341.00	10,758,895.00	12,129,449.00	13,500,000.00
Population	65,882,543.00	68,043,578.00	70,285,232.00	72,610,906.00	75,024,165.00	77,528,745.00
Household Population	13,176,508.60	13,608,715.60	14,057,046.40	14,522,181.20	15,004,833.00	15,505,749.00
Connectivity Rate	**50%**	**59%**	**67%**	**74%**	**81%**	**87%**
Per Capita Consumption-kWh	**243**	**308**	**392**	**452**	**487**	**528**

C. Power Generation Expansion Plan

To meet forecasted electricity demand, the total installed capacity is projected to grow from 3,191.71 MW in 2024 to 19,905.19 MW by 2050. The contribution of non-hydro renewable energy capacity is expected to increases from 1% to 52% of total renewable energy capacity during this period, as shown in the tabulation below. The corresponding energy increases is expected from 16,445.63 GWh in 2024 to 108,203.90 GWh in 2050.

Year	2024	2025	2028	2030	2038	2050
Installed Capacity-MW	3,191.71	4,181.71	8,735.09	11,822.39	15,638.19	19,905.19
Renewable	59%	69%	65%	62%	62%	57%
Non Renewable	41%	31%	35%	38%	38%	43%
Renewable non Hydro	1%	2%	46%	45%	44%	52%

D. Transmission Network Expansion

To evacuate power generated, a total of 16,552.16 km of new transmission lines will be constructed throughout the planning horizon, as shown in the table below. Thus, by the end of the planning horizon, a total transmission line will be 24,284.54 km. This expansion is expected to subsequent reducen transmission losses from 5.80% in 2024 to 2.85% by 2050.

S/N	Voltage Level	Transmission System Additions (km)			
		2024–2028	2029–2038	2039–2050	Total
1	400kV	1,922.00	2,558.33	880.22	5,360.55
2	220kV	2,663.58	5,769.72	1,098.00	9,531.30
3	132kV	1,299.01	175.7	108.6	1,583.31
	Total	**5,884.59**	**8,503.75**	**2,086.82**	**16,552.16**

E. Economic and Financial Analysis

The total investment requirement to support generation and transmission expansion plans is estimated at USD 39,951.90 million by 2050 equivalent to TZS 105.8 trillion. This includes USD 699.23 million to be fully financed by the government, with the remaining funding sourced through a 70%-debt and 30%-equity split as shown in the table below:-.

Description	Investment Requirement (USD) - Million			
	Short-Term	Medium-Term	Long-Term	Total
Generation	9,302.60	11,466.08	11,073.70	31,842.37
Transmission	3,632.02	3,472.41	1,005.10	8,109.53
Total Investments	**12,934.62**	**14,938.49**	**12,078.80**	**39,951.90**
Investments Based on Debt:Equity				
Govt Fully Financed Investments	666.11	33.12	0.00	**699.23**
Debt (70%)	8,587.96	10,433.76	8,455.16	**27,476.87**
Equity (30%)	3,680.55	4,471.61	3,623.64	**11,775.80**
Total	**12,934.62**	**14,938.49**	**12,078.80**	**39,951.90**

F. Implementation Strategy

To implement the PSMP 2024 Update,16 strategies and actions have been formulated, focusing on enhancing institutional capacity building, legal and regulatory framework, as well as investment and operational processes, while encouraging public and private participation. The successful execution of these initiatives will position Tanzania as a leader in sustainable development and socio-economic transformation that ensures clean energy access for all.

G. Conclusion

The government believes that the PSMP 2024 Update lays out a comprehensive plan to achieve short-term, medium-term and long-term targets while emphasizing the vital role of public and private sectors collaboration. Engaging both sectors is critical for the development of the electricity sub-sector and ensuring reliable, affordable, sustainable, inclusive, and clean energy access for everyone.

CHAPTER ONE

INTRODUCTION

1.1 Background

The Government, has been preparing Power System Master Plan Studies through TANESCO from 1985 to 2000s and through the ministry responsible for energy from 2008 to provide the country with a Road Map in guiding the development of the Country´s Power Sector over a 25-year planning horizon. A consulting firm, M/s ACRES International (Canada), with funding from the World Bank Technical Assistance, prepared the first comprehensive PSMP for Tanzania in 1985. Under the World Bank funding, M/s SNC – Lavalin Consultants of Canada developed another comprehensive PSMP for the Government of Tanzania through TANESCO in 2008.

Pursuant to part I of the Electricity Act Cap.131, the PSMP means a planning document prepared by the Minister and updated on an annual basis by the System Operator, dealing with indicative medium and long-term plans for expansion of the transmission system to cater for expected generation and demand.

The PSMP 2024 Update is in line with applicable policies, legislation, development agendas and strategies. These include National Energy Policy, Electricity Act Cap 131, Tanzania Development Vision 2050, Sustainable Development Goals No.7 (Affordable and clean energy), Electricity Supply Industry Reform Strategy and Roadmap 2014-2025, National Clean Cooking Strategy 2024-2034, National Renewable Energy Strategy and Roadmap 2024, and Rural Energy Master Plan 2022.

Considering the enhanced capacity of local experts following the knowledge transfer through the technical support during the preparation of the previous PSMP studies, the Government Technical Team, consisting of experts from MoE, MoF, TANESCO, EWURA, REA, TPDC, and NBS, completed four (4) updates of the Plan in 2009, 2012, 2016, and the recent 2020 PSMP update.

The PSMP 2024 Update emanates from the PSMP 2020 Update by adopting the approach and methodology for its preparation while accommodating fundamental changes and the government's outlook in guiding the development of the power sub-sector of Tanzania. The 2024 update accommodates the changing economic situation driven by Government policy, with consequential growth in electricity demand, thereby calling for additional power generation capacity and the associated need for transmission capacity additions for delivering electricity generation at a reasonable level of reliability to the load centres.

Specifically, the PSMP 2024 Update is in line with Government objectives under Section 3.1 of the Energy Policy 2015, which aims among others, to improve security of supply through effective use of energy resources and cross-border trading; enhancing power reliability and coverage of transmission and distribution networks; enhancing utilisation of renewable energy resources to increase its contribution in electricity generation mix; accelerating rural electrification to foster socio economic transformations; and increasing private sector participation in electricity supply industry.

Further, the PSMP 2024 Update addresses other Government targets, including the following:

i. Industrialization and sustaining Tanzania as a middle-income country;

ii. Aspiration to attain electricity per capita[1] of 490 kWh by 2025/26;

iii. Attaining 100% accessibility and 75% connectivity to electricity services by 2030

iv. Attaining 80% access to modern clean cooking technologies by 2034;

v. Accommodating power requirements for the adoption of E-mobility, and

vi. Providing a reliable power supply to strategic projects such as the Standard Gauge Railway, East Africa Crude Oil Pipeline Project (EACOP) from Hoima (Uganda) to Tanga (Tanzania), Liquefied Natural Gas (LNG)

Cognizant of the Government policy direction and the pertinent issues, the overall objective of the updated PSMP 2024 is to reassess Tanzania´s requirements for additional power generation and transmission capacities over the next 25-year planning horizon from 2024 to 2050.

The Plan study and its results are summarized in seven chapters as follows:

Consequently, Chapter One introduces the PSMP 2024 Update; Chapter Two reviews the implementation Status of PSMP 2020 Update; Chapter Three presents the Load Forecast; Chapter Four Power Generation Expansion Plan; Chapter Five describes the Transmission System Expansion Plan; Chapter Six appraises the Economic and Financial Analysis of the power system expansion plan; and Chapter Seven provides the conclusion and recommends the way forward for implementing the PSMP 2024 Update.

[1] *PSMP 2020 Update*

CHAPTER TWO

IMPLEMENTATION STATUS OF 2020 PSMP UPDATE

2.1 Introduction

The PSMP 2020 that has been earmarked for review hereunder was prepared considering the need to balance power requirement and associated transmission, and generation capacity for a sustainable Power System. It was therefore deemed prudent to assess the implementation status of the PSMP 2020 Update to underscore its performance for the period of 2020 to 2024. The performance assessment covers Load Forecast, Generation and Transmission Plans.

2.2 Load Forecast

2.2.1 Projected versus Actual Power Demand

Considering the growth in Grid Coincidental Peak, Imports, Isolated load and Captive Capacities, the actual peak between 2020 and 2024 has almost matched the projected coincidental peak demand with an average deviation of 0.11% as shown in **Table 2-1.**

Table 2-1: Projected Versus Actual Power Demand

YEAR	Projected-PSMP 2020 Update	Actual					Deviation (%)
	Coincidental Peak (MW)	Grid Coincidental Peak (MW)	Import Peak (MW)	Isolated Peak (MW)	Captive Peak (MW)	Total (MW)	
2020	1,425	1,180.53	27.10	25.69	238.72	1,472.04	3.30
2021	1,533	1,307.36	32.90	23.55	238.72	1,602.53	4.54
2022	1,702	1,354.61	36.60	25.62	251.22	1,668.05	-1.99
2023	1,914	1,482.80	40.83	18.47	251.22	1,793.32	-6.30
2024	2,189	1,888.72	46.03	25.15	251.22	2,211.12	1.01
Average deviation							**0.11**

2.2.2 Energy Losses

The projected energy losses in the National Grid were to decrease from 15.9% in 2020 to 13.3% in 2023 (PSMP 2020 Update, Table: 2-9, page 25), as indicated in Table 2-2. However, actual energy losses decreased from 15.18% in 2020 to 14.63% in 2023, which is higher than the projected targets. Hence, a study is needed to establish the reasons for such differences.

Table 2-2: Energy Losses

	Projected				Actual			
Years	**2020**	**2021**	**2022**	**2023**	**2020**	**2021**	**2022**	**2023**
Transmission	5.5	5.1	4.7	4.3	5.88	5.89	5.88	5.87
Distribution	10.4	10.0	9.50	9.0	9.30	9.10	8.65	8.76
Total	15.9	15.1	14.2	13.3	15.18	14.99	14.54	14.63

Source: PSMP 2020 & TANESCO 2024

2.2.3 Rate of Electrification

The actual electrification level in 2022[2] was 72%, and the target was to attain 100% in 2030.

2.3 Generation Plan

2.3.1 Review of Generation Projects (2020 to 2024)

The PSMP 2020 Update planned to install 2,796MW between 2020 to 2024. During the same period, the government constructed 1,741.5MW, equivalent to 62.3% of planned capacity, including 112.5MW constructed on an emergency basis to cater for power shortage. Another 1,054.5 MW are at different stages of development, as detailed in **Table 2-3**

Table 2-3: Power Generation Project Implementation Status

Project Type	Project Name	Planned Capacity (MW)	Planned Completion Year	Commissioned Capacity (MW) by 2024	Remarks
Hydropower Power Plants	Julius Nyerere HPP	2,115	2022	1,410	705MW to be completed by 2025
	Rusumo HPP (Shared)	81 (27 for Tanzania)	2021	27	Completed in 2023
	Murongo/Kikagati HPP	14 (7 for Tanzania)	2021	7	Completed in 2022
	Malagarasi HPP	49.5	2024	-	Under Construction
Thermal Power plants (Natural Gas)	Kinyerezi I Extension	185	2024	185	Completed in 2024
	Ubungo III[3]	112.5	2022	112.5	Procured in 2022
Renewable Energy	Dodoma Solar	55	2024	-	The project is still under study
	Singida Solar	150	2023	-	The project is still under study

[2] Energy Access Use Situation Report Survey II in Tanzania Mainland 2021/2022, REA & NBS

[3] Ubungo III was not in the 2020 PSMP but Government procured to cater for power shortage.

Project Type	Project Name	Planned Capacity (MW)	Planned Completion Year	Commissioned Capacity (MW) by 2024	Remarks
	Lake Ngozi Geothermal	30	2023	-	Under Resource confirmation
	Songwe Geothermal	5	2023	-	Under Resource confirmation
	Kiejo-Mbaka Geothermal	60	2024	-	Under Resource confirmation
Total		**2,796**		**1,741.5**	

2.4 Transmission Plan Update

2.4.1 Transmission Lines Implementation Status

According to the PSMP 2020 Update, 56 transmission lines with a total length of 5,478.07km had to be commissioned by 2024. The transmission lines include 3,253.57km of 400kV, 1,293.7km of 220kV and 930.8km of 132kV. However, twenty-nine (29) transmission lines with a total length of 3,925.8km, equivalent to 71.66%, were implemented, of which 29.2% are operational while others are at different stages of construction. The remaining 1,552.27km, which is equivalent to 28.3% of planned transmission projects, are at preparatory stages as shown in Table 2-4 below.

Table 2-4: Transmission Lines Implementation Status

From	To	Voltage [kV]	Length [km]	Planned Completion Year	Completion year	Remarks
Singida	Kisongo (Arusha)	400	300	2020	2024	Completed
Kisongo (Arusha)	Isinya (Kenya)	400	114	2020	2024	Completed
Morogoro	Mtibwa	220	88	2023	-	Project Preparation
Wind project (Kititimo)	Singida	220	10	2023	-	Project Preparation
Iringa	Kisada (TAZA)	400	106	2023	-	Under construction
Kisada	Mbeya (TAZA)	400	285	2023	-	Under construction
Mbeya	Tunduma (TAZA)	400	122	2023	-	Under construction
Tunduma	Sumbawanga (TAZA)	400	203	2023	-	Under construction
Solar I	Dodoma	220	10	2023	-	Under study
Wind project (Makambako)	Makambako	132	10	2023	-	Under study
JNHPP	Chalinze	400	160	2022	2024	Completed
Chalinze	Kinyerezi	400	93	2022	-	Under construction
Chalinze	Dodoma	400	345	2022	-	Under construction
Chalinze	Bagamoyo	220	60	2022	-	Fund solicitation

From	To	Voltage [kV]	Length [km]	Planned Completion Year	Completion year	Remarks
Mtwara	Lindi (Mahumbika)	400	60	2024	-	Fund solicitation
Lindi	Somanga	400	210	2024	-	Fund solicitation
Somanga	Kibiti	400	79.56	2024	-	Project under restructuring
Kibiti	Kinyerezi	400	110.56	2024	-	Project under restructuring
Narco (Kongwa)	Dumila	220	117	2024	-	Fund solicitation
Mtwara	Mozambique	400	100	2025	-	Under procurement of Consultant for study
Tabora	Ipole	132	127	2024	-	Under construction
Ipole	Inyonga	132	138	2024	-	Under construction
Inyonga	Mpanda	132	140	2024	-	Under construction
Tabora	Urambo	132	131	2024	-	Under construction
Urambo	Nguruka	132	185	2024	-	Under construction
Nguruka	Kigoma	132	79	2024	-	Fund solicitation
Bulyanhulu	Geita	220	55	2020	2020	Completed
Geita	Nyakanazi	220	144	2021	2021	Completed
Rusumo	Nyakanazi	220	94	2021	2023	Completed
Nyakanazi	Kigoma	400	280	2022	2024	Completed
Uyole	Kyela (Kasumulu)	400	80.66	2025	-	Fund solicitation
Kyela (Kasumulu)	Karonga (Malawi)	400	39.79	2023	-	Fund solicitation
Mbeya (Mwakibete)	Songwe (Mbalizi)	220	41	2024	-	Restructured
Songwe (Mbalizi)	Chunya (Mkwajuni)	220	73	2024	-	Restructured
Mkata	Handeni	132	46.8	2024	-	Under construction
Zuzu	Msalato	220	32	2023	-	Fund solicitation
Msalato	Ihumwa	220	12	2023	-	Fund solicitation
Ihumwa	Kikombo	220	52	2023	-	Fund solicitation
Kikombo	Zuzu	220	47	2023	-	Fund solicitation
Kikombo	Narco (Kongwa)	220	50	2023	-	Fund solicitation
Songea	Tunduru	400	230	2024	-	Under construction
Tunduru	Masasi	400	194	2024	-	Under construction
Masasi	Lindi (Mahumbika)	400	141	2024	-	Under construction
Masasi	Ruangwa	220	65	2024	-	Fund solicitation
Ifakara	Mahenge	220	68	2024	-	Fund solicitation
Shinyanga	Simiyu	220	113	2023	-	Under construction
Pugu (SGR)	Chanika	220	16	2024	-	Restructured, Under construction

From	To	Voltage [kV]	Length [km]	Planned Completion Year	Completion year	Remarks
Chanika	Mkuranga	220	60	2024	-	Restructured, Under construction
Kinyerezi (Kimara T-off)	Ubungo	220	17	2023	-	Under construction
Kinyerezi (Kimara T-off)	Mabibo	220	2	2023	-	Under construction
Zinga (Bagamoyo)	Bunju (Ununio)	220	18	2024	-	Fund solicitation
Bunju (Ununio)	Kunduchi	220	14	2024	-	Under Study
Kunduchi	Mbezi Beach	220	6	2024	-	Under Study
Mbezi Beach	Makumbusho	220	11	2024	-	Under Study
Mbezi Beach	Kawe	220	8.7	2024	-	Under Study
Malagarasi	Kigoma	132	74	2024	-	Under construction
Kishapu Solar	Shinyanga	220	10	2024	-	Restructured, under construction

From 2020 to 2024, the Government implemented other transmission lines and associated substations as shown in **Table 2-5.** The implemented transmission infrastructures aimed to address line overload, improve power reliability and meet additional power needs in the transport sector following the implementation of the Standard Gauge Railway(SGR) Project. Nine (9) transmission lines (220 kV and 132 kV) were constructed with a total length of 1039.34km. Among these, four (4) transmission lines equivalent to 595.61km were commissioned in 2024, and five (5) projects equivalent to 443.73km are in different stages of construction.

Table 2-5: Other Constructed Transmission Lines

From	To	Voltage [kV]	Length [km]	Planned Completion Year
Ilala	Kurasisni	132	7	2024
Kinyerezi	Morogoro (SGR)	220	172.61	2024
Morogoro	Ihumwa (SGR)	220	240	2024
Ihumwa	Kintinku (SGR)	220	176	2024
Mwanza	Isaka (SGR)	220	230	Under construction
Kiyungi	Rombo	132	61.31	Under construction
Kasiga	Lushoto	132	37	Under construction
Ubungo	Ununio	220	18.42	Under construction
Bunda	Ukerewe	132	97	Under construction

2.4.2 Substations Implementation Status

According to the PSMP 2020 Update, Fifty-Five (55) Substations with transformer ratings from 15MVA to 315MVA capacity were planned for construction by 2024. As shown in

Table 2-6 Thirty (30) Substations were implemented, which is equivalent to 54.5% of planned projects. About 30% of implemented substations are operational, while 70% are at different stages of construction. The remaining Twenty-Five (25), equivalent to 45.5% of planned substations, are at preparatory stages.

Table 2-6: Planned substation performance in the PSMP 2020 plan

S/N	Substation	Region	HV/LV (kV)	Rating (MVA)	No. of Transformer	Planned Completion Year	Completion year	Remarks
1	Bulyanhulu	Shinyanga	220/33	120	1	2020	2024	completed
2	Geita	Geita	220/33	50	2	2020	2020	Completed
3	Lemugur (Kisongo)	Arusha	400/220	250	2	2020	2024	Completed
		Arusha	220/33	125	2	2020	2024	Completed
4	Iringa	Iringa	400/220/33	250/250/85	2	2021	-	Under construction
		Iringa	220/33	125/125/37.5	2	2021	-	Under construction
5	Dodoma	Dodoma	400/220/33	250/250/85	2	2020	2022	Completed
		Dodoma	220/33	125/125/37.5	2	2020	2022	Completed
6	Singida	Singida	400/220/33	250/250/85	2	2020	2022	Completed
		Singida	220/33	125/125/37.5	2	2020	2022	Completed
7	Shinyanga	Shinyanga	400/220/33	315/315/105	2	2021	-	Under construction
		Shinyanga	220/33	125/125/37.5	2	2021	-	Under construction
8	Rusumo (BENACO)	Kagera	220/33	30	2	2021	-	Fund solicitation
9	Nyakanazi	Kagera	400/220/33	120/120/45	2	2021	-	Under construction
10	Kigoma	Kigoma	400/132/33	120/70/50	2	2021	-	Under construction
11	Mburahati (Mabibo)	Dar es Salaam	220/132/33	200/200/45	2	2022	-	Under construction
12	Buzwagi	Shinyanga	220/33	30	1	2022	2022	Completed
13	Zegereni	Dar es Salaam	220/33	200	2	2022	-	Under construction
14	Chalinze	Pwani	400/220/33	250/250/85	4	2022	2024	Completed
15	Kinyerezi	Dar es Salaam	400/220/33	250/250/85	4	2022	-	Under construction
16	Bagamoyo	Pwani	220/33	125	2	2022	-	Fund solicitation
17	Msalato	Dodoma	220/33	50	2	2023	-	Fund solicitation
18	Kikombo	Dodoma	220/33	100	2	2023	-	Fund solicitation
19	Ihumwa	Dodoma	220/33	30	2	2023	-	Fund solicitation
20	NARCO	Dodoma	220/33	45	2	2023	-	Fund solicitation
21	Simiyu	Simiyu	220/33	45	2	2023	-	Under construction
22	Luguruni	Dar es Salaam	220/33	90	2	2023	2022	Completed
23	Chanika	Dar es Salaam	220/33	45	2	2024	-	Restructured

S/N	Substation	Region	HV/LV (kV)	Rating (MVA)	No. of Transformer	Planned Completion Year	Completion year	Remarks
24	Mkuranga	Pwani	220/33	120	2	2024	-	Restructured, under construction
25	Mtibwa	Morogoro	220/33	45	2	2023	-	Fund solicitation
26	Mbeya (Iganjo)	Mbeya	400/220/33	200/200/70	2	2023	-	Under construction
27	Tunduma	Mbeya	400/330/33	250/250/85	2	2023	-	Under construction
28	Kisada	Iringa	400/220/33	150/150/45	2	2023	-	Under construction
29	Sumbawanga	Rukwa	400/66/33	100/100/35	2	2023	-	Under construction
30	Somanga	Lindi	400/220	125	2	2024	-	Fund solicitation
		Lindi	220/33	85	2	2024	-	Fund solicitation
31	Kibiti	Lindi	400/220	125	2	2024	-	Fund solicitation
		Lindi	220/33	85	2	2024	-	Fund solicitation
32	Ipole	Tabora	132/33	15	1	2024	-	Under construction
33	Inyonga	Tabora	132/33	15	1	2024	-	Under construction
34	Mpanda	Katavi	132/33	35	1	2024	-	Under construction
35	Urambo	Tabora	132/33	35	1	2024	-	Under construction
36	Nguruka	Tabora	132/33	15	1	2024	-	Under construction
37	Dumila	Dodoma	220/33	30	2	2024	-	Fund solicitation
38	Mtwara	Mtwara	400/132	100	3	2024	-	Fund solicitation
		Mtwara	400/220	125	2	2024	-	Fund solicitation
		Mtwara	220/33	85	2	2024	-	Fund solicitation
39	Lindi	Lindi	400/132	100	2	2024	-	Fund solicitation
40	Mkata	Tanga	132/33	30	2	2024	-	Under construction
41	Handeni	Tanga	132/33	30	2	2024	-	Under construction
42	Songwe	Songwe	220/33	45	2	2024	-	Fund solicitation
43	Makongolos (Chunya)	Mbeya	220/33	45	2	2024	-	Fund solicitation
44	Masasi	Mtwara	400/33	45	2	2024	-	Restructured
45	Tunduru	Ruvuma	400/33	45	2	2024	-	Restructured
46	Ruangwa	Lindi	400/33	30	2	2024	-	Restructured
47	Songea	Ruvuma	400/33	125	2	2024	-	Restructured
48	Ifakara	Morogoro	220/33	20	2	2024	2024	Completed
49	Mahenge	Morogoro	220/33	60	2	2024	-	Fund solicitation
50	Makumbusho	Dar es Salaam	220/132	150	2	2024	-	Under study
51	Mbezi Beach (Bunju)	Dar es Salaam	220/33	50	2	2024	-	Under study
52	Kunduchi	Dar es Salaam	220/33	60	1	2024	-	Under study

S/N	Substation	Region	HV/LV (kV)	Rating (MVA)	No. of Transformer	Planned Completion Year	Completion year	Remarks
53	Kawe	Dar es Salaam	220/33	50	2	2024	-	Under study
54	Malagarasi	Kigoma	11/132	60	2	2024	-	Under construction
55	Loliondo	Arusha	66/33	25	1	2024	-	Under study

From 2020 to 2024, the Government implemented other substations as shown in **Table 2-7**. The implemented substations infrastructures aimed to address transformer overload, improve power reliability and meet additional power needs in the transport sector following the implementation of the Standard Gauge Railway(SGR) Project. Six (6) Substations with a total rating capacity of 410 MVA were implemented, of which two (2) substations are in operation, while others are in different stages of construction.

Table 2-7: Other Implemented Substations

S/N.	Substation	Region	HV/LV (kV)	Rating (MVA)	No. of Transformer	Completion year	Remarks
1	Rombo	Kilimanjaro	132/33	60	2	-	Under construction
2	Lushoto	Tanga	132/33	45	2	-	Under construction
3	Ukerewe	Mara	132/33	45	2	-	Under construction
4	Chalinze	Pwani	220/132/33	250/250/65	2	2024	Completed
5	Ununio	Dar es salaam	220/33	120	2	-	Under construction
6	Mwanga	Kilimanjaro	132/33	10	2	2024	Completed

2.5 Conclusion

A review of the background growth of electricity peak demand signifies a positive trajectory in economic activities in the country. Subsequently, the Government, with the support of Local and Foreign Development Partners, implemented a number of projects for power generation, transmission lines and associated substations, aiming at improving reliability, security and quality of power supply.

In the period 2020 to 2024, the government implemented 62.3% of the planned generation capacity, 71.66% of the transmission lines route length, and 54.5% of the planned transformer capacities.

Despite this considerable achievement in implementing the earmarked power projects in the PSMP 2020 Update, the Government experienced funding constraints to implement all planned projects for the period up to 2024. Additionally, some power projects were not implemented due to a change in global climate policies and appetite towards funding certain technologies in power projects.

CHAPTER THREE

LOAD FORECAST

3.1 Introduction

The Load forecast presents the energy consumption and its respective peak demand of the country from 2024 to 2050. The forecast informs the generation and transmission expansion planning studies. It includes approaches and methodologies, factors considered, forecast results and conclusion.

3.2 Approach and Methodology

3.2.1 Approach for the Forecast

A general approach used for deriving forecasts of electricity is two-fold. Firstly, a review of the historical electricity consumption records and the corresponding number of connected customers. Secondly, a review of key aspects under emerging issues that are expected to define the evolution and transformation of electricity consumption in Tanzania.

A top-down approach was used to collect, review and analyse historical data on total electricity consumption and the number of customers disaggregated in tariff categories[4]. The inference from the review of historical records, and an appropriate methodology were used to prepare load forecasts for the period 2024-2050.

The aggregate electricity sales forecasts were summed up with the identified additional future electricity needs emanating from emerging issues such as clean cooking using electricity, Liquified Natural Gas Projects, telecommunication towers, and industrial surveys and ongoing development projects in the transport sector, such as Standard Gauge Railway (SGR) and electromobility (E-mobility). The power requirements from emerging issues will define the future pattern, profile, and structure of electricity consumption in Tanzania.

An account of electricity distribution of transmission losses, station/auxiliary and unserved energy (load shedding, planned and unplanned system outages) was added to ensure that electricity customers/loads are supplied with electricity that meets their future requirements. The overall approach for the forecast is summarized in **Figure 3-1.**

[4] *D1: Low usage Tariff for Domestic Customers who on average consume less than 75kWh per month and are supplied at a low voltage single phase (230V). T1: General Usage Tariff for customers including residential, small commercial and light industrial use, public lighting and billboards supplied at low voltage single phase (230V) and three phases (400V). T2: Applicable to general use customers where power is metered at 400V with an average consumption >7,500kWh per meter reading period and demand ≤500kVA per meter reading period. T3-MV: Applicable customers connected to Medium Voltage. T3-HV: Applicable customers connected to High Voltage including ZECO, Bulyanhulu and Twiga cement.*

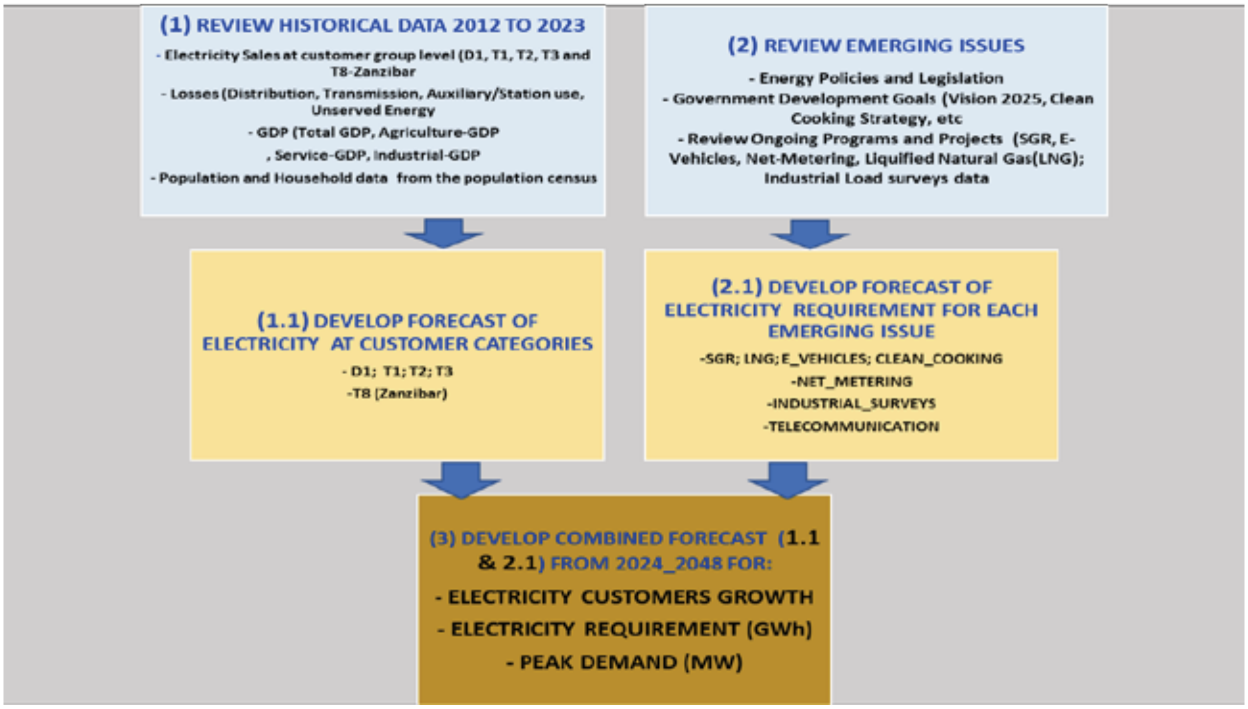

Figure 3-1 Approach for the Electricity Load Forecast

3.2.2 Methodology

The trend-based method of analysis was used to study the trend of the historical data set from 2012-2023 and use the information to prepare load forecasts for the period 2024 to 2050. Each historical data set was smoothed to flatten out the plotted data (Data stationarity). The established trend was used to determine a Simple Linear Regression (SLR) model for forecasting the respective data set.

An econometric approach was also used to underline and confirm the nexus and causality between the growth of electricity consumption and growth in Gross Domestic Product (GDP), and their implication in defining future power consumption in Tanzania.

The forecast emanating from emerging issues was summed up with the forecast from the trend-based analysis of the historical data to obtain the total country´s forecast of electricity requirement from 2024 to 2050.

3.2.3 Key Assumptions

Key assumptions used in developing scenarios considered for the electricity forecast, namely, Scenario-1 (Base Case), Scenario-2 (Low Case) and Scenario-3 (High Case), are indicated in **Table 3-1.**

Table 3-1: Key Assumptions for the Forecast

Assumption	Scenario-1 (Base Case)	Scenario-2 (LowCase)	Scenario-3 (High Case)
Forecast Period	2024 to 2050	2024 to 2050	2024 to 2050
Auxiliary/Station Use	1% of Total Generation, over the forecast period	1% of Total Generation, over the forecast period	1% of Total Generation, over the forecast period
Distribution Losses	8.7% (2023) to 6% (2050)	8.7% (2023) to 6% (2050)	8.7% (2023) to 6% (2050)
Transmission Losses	5.9% (2023) to 4% (2050)	5.9% (2023) to 4% (2050)	5.9% (2023) to 4% (2050)
Un-Served Energy (Load Shedding)	5.9% (2023) to 1% (2050)	5.9% (2023) to 1% (2050)	5.9% (2023) to 1% (2050)
Power Requirement Due to Emerging Issues	100% of Identified Power Requirements from Emerging Issues	80% of Identified Power Requirements from Emerging Issues	120% of Identified Power Requirements from Emerging Issues
GDP Growth Rates	(a) 6.0%-2024; 6.4% - 2025; 8%-2026; and 7%-2027 (b) 6.3% from 2028 to 2050	(a) 6.0%-2024; 6.4% - 2025; 8%-2026; and 7%-2027 *(b) 5.3% from 2028 to 2050*	(a) 6.0%-2024; 6.4% - 2025; 8%-2026; and 7%-2027 *(b) 7.3% from 2028 to 2050*

3.3 Factors considered in the demand Forecast

The load forecast considered factors described in subsections **3.3.1** to **3.3.8.**

3.3.1 Electricity Consumption

The National Grid's actual energy consumption from 2012 to 2023 is indicated in

Table 3-2**.** It increased from 4,299.54 GWh in 2012 to 7,926.58 GWh in 2023. The same was used to forecast the consumption and required generation for the planning horizon (2024 – 2050).

Table 3-2: Actual Energy Consumption - GWh

Year	D1	T1	T2	T3 -Mainland	Zanzibar	Total
2012	320.84	1,523.28	549.45	1,581.76	324.22	4,299.54
2013	279.75	1,768.16	562.91	1,663.53	378.58	4,652.93
2014	217.33	1,934.45	580.69	1,832.41	376.11	4,941.01
2015	246.07	2,207.54	632.81	2,077.81	375.63	5,539.86
2016	345.77	2,276.83	629.96	2,109.80	410.31	5,772.68
2017	309.27	2,487.27	620.14	2,332.99	425.75	6,175.41
2018	319.52	2,501.69	613.91	2,406.61	451.21	6,292.94
2019	307.18	2,664.21	630.20	2,510.73	501.83	6,614.15
2020	313.95	2,632.80	613.73	2,537.34	507.45	6,605.28
2021	339.77	2,783.59	623.75	2,627.50	492.96	6,867.57
2022	351.03	3,063.10	683.90	2,892.10	559.06	7,549.20

Year	D1	T1	T2	T3 -Mainland	Zanzibar	Total
2023	394.84	3,273.79	690.62	2,979.23	588.10	7,926.58

3.3.2 Maximum Demand

The actual demand in the National Grid from 2012 to 2023 is indicated in *Table 3-3***.** It increased from 851.35 MW in 2012 to 1,482.80 MW in 2023.

Table 3-3: Actual Suppressed Maximum Demand from 2012 to 2023

Year	Demand (MW)
2012	851.35
2013	898.72
2014	934.62
2015	988.27
2016	1,041.63
2017	1,051.27
2018	1,116.58
2019	1,120.12
2020	1,180.53
2021	1,307.36
2022	1,354.61
2023	1,482.80

Source*: TANESCO*

3.3.3 Rate of Electrification

Electricity accessibility in the country increased from 67.55% in 2017 to 78.4% in 2020 where as connectivity[5] increased from 32.8% to 37.7% in the same period as indicated in **Table 3-4** The Government through Energy Compact Program commits to increase connectivity to 75% by 2030. The program will contribute 8.5 million addition customers implying connectiong 1.7 million new customers annually up to 2030. These efforts will drive an increase in electricity consumption.

Table 3-4: Electrification Targets

Year	Electricity Accessibility			Electricity Connectivity		
	Urban (%)	Rural (%)	Overall (%)	Urban (%)	Rural (%)	Overall (%)
2016/17	99.6	49.3	67.5	65.3	16.9	32.8
2019/20	97.3	69.8	78.4	73.2	24.5	37.7

Source*: PSMP 2020*

[5] *The Energy Access Use Situation Report Survey II in Tanzania Mainland 2019/2020, REA&NBS*

3.3.4 Interconnection of Isolated Systems

Twenty-two (22) regions of mainland Tanzania are connected to the National Grid. The Government is implementing several projects to connect fully the remaining regions of Katavi, Kagera, Lindi and Mtwara to the National Grid by 2027. The power requirement by the unconnected regions has been considered in the demand forecast from 2024 to 2050.

3.3.5 Persons Per Household

The household size is critical in the load forecast as it determines specific consumption and the degree of electrification. The Plan has adopted eight (8) persons per household in line with the 2022 National Census report.

3.3.6 System Load Factor

The actual system load factor from 2012 to 2023 is indicated in **Table 3-5**Error! Reference source not found. The system recorded a slight increase and decrease between 74.3% in 2012 to 77.8% in 2023. The same is used in this PSMP 2024 with a projection of 70% load factor as was considered in the PSMP 2020 update.

Table 3-5: Actual System Load Factor

Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Load factor (%)	74.3	72.8	73.7	71.4	74.5	73.8	72.2	77.4	74.2	73	77.7	77.8

Source: *TANESCO*

3.3.7 Unserved Energy

The actual unserved energy in the National Grid is indicated in **Table 3-6** It increased from 148,415,030.0 kWh in 2012 to 675,331,734.2 kWh in 2023. The recorded unserved energy in 2023 was included in the demand forecast from 2024 to 2050 to represent part of the demand that would have been supplied.

Table 3-6: Actual Unserved Energy From 2012 – 2023

Years	**Load Shedding (kWh)**	**Faults (kWh)**	**Maintenance (kWh)**	**Total (Kwh)**
2012	66,339,867.2	39,659,717.9	42,415,444.9	148,415,030.0
2013	75,062,978.7	51,871,703.2	32,904,597.7	159,839,279.6
2014	57,791,439.9	43,009,166.8	36,013,408.3	136,814,015.0
2015	273,018,416.3	45,099,293.8	51,826,748.4	369,944,458.5
2016	17,801,583.6	29,599,091.4	62,006,317.9	109,406,992.8
2017	60,654,043.0	37,380,125.6	36,096,847.4	134,131,016.1
2018	15,618,410.8	37,186,275.5	75,867,961.8	128,672,648.1
2019	10,716,868.3	34,949,882.9	28,646,817.1	74,313,568.3
2020	16,113,342.9	32,105,606.7	33,982,132.8	82,201,082.4

Years	Load Shedding (kWh)	Faults (kWh)	Maintenance (kWh)	Total (Kwh)
2021	52,077,144.7	38,690,846.3	37,872,430.7	128,640,421.8
2022	301,569,020.1	71,229,741.2	50,142,887.7	422,941,649.0
2023	575,925,853.8	41,585,818.0	57,820,062.4	675,331,734.2

***Source**: TANESCO*

3.3.8 Energy Losses

The actual energy losses in the National Grid decreased from 20.07% in 2012 to 14.63% in 2023, as indicated in **Table 3-7**. These losses were used to forecast the demand from 2024 to 2050.

Table 3-7: Actual Energy Losses From 2012 to 2023

Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Transmission	6.11	6.20	6.13	6.20	6.14	6.12	5.88	5.88	5.88	5.89	5.88	5.87
Distribution	13.96	13.14	12.29	11.27	10.50	10.54	10.12	10.31	9.30	9.10	8.65	8.76
Total	**20.07**	**19.33**	**18.42**	**17.47**	**16.64**	**16.66**	**16.00**	**16.19**	**15.18**	**14.99**	**14.54**	**14.63**

***Source:** TANESCO*

3.4 Power Requirements from Emerging Issues

Several emerging issues were considered in the demand forecast from 2024 to 2050, as they will impact future power consumption in the country. These include the development of the Liquefied Natural Gas Project; adoption of e-mobility technology, development of the standard railway project (SGR), adoption of distribution generation (net-metering), and adoption of electricity cooking (e-cooking) as part of modern cooking technology. A detailed discussion of each emerging issue follows:

3.4.1 Liquefied Natural Gas Project

The Liquefied Natural Gas (LNG) project is planned to be constructed in the Lindi Region and is projected to commence its construction by 2027 with its full operation in 2030. The LNG project will require a cumulative power of up to 850MW by 2030. The power Demand for the Liquified Natural Gas Project is staggered as 70MW (2027), 140MW (2028), 210MW (2029), and 297.5MW (2030). This power requirement has been considered in the load forecast.

3.4.2 Standard Gauge Railway Electric Train

The forecast considered the power requirement for the Standard Gauge Railway (SGR) project. The project has seven (7) lots to be constructed along the central corridor, as indicated in **Table 3-8** Likewise, the project includes the Mtwara corridor (Southern corridor), Tanga Musoma corridor (Northern corridor), and TAZARA (upgraded to electrified SGR) projects. Upon completion of all proposed scope of construction works and full operational of the SGR project, a total of 2,374.40 MW will be needed to efficiently power the electric train and associated infrastructure. Lots 1 and 2 of the project have been operational since July 2024. Other lots are expected to be commissioned within 5-7 years.

Table 3-8: Power Demand for Electric Train

Lot. No.	Distance (km)	Traction Power Station(TPS)		Total Capacity		Utilization Factor (70%)	Projected Commissioning Date
		Quantity(No.)	Capacity(MW)	MVA	MW		
Lot 1 (DSM-Morogoro)	≈200	4	2x20	160	128	89.6	2024
Lot 2 (Morogoro – Makutopola)	≈350	7	2x20	280	224	156.8	2024
Lot 3 (Makutopola - Tabora)	≈300	6	2x20	240	192	134.4	2029
Lot 4 (Tabora – Isaka)	≈150	3	2x20	120	96	67.2	2029
Lot 5 (Isaka – Mwanza)	≈250	5	2x20	200	160	112	2029
Lot 6 (Tabora – Kigoma)	≈400	8	2x20	320	256	179.2	2029
Lot 7 (Uvinza – Msongati)	≈150	3	2x20	120	96	67.2	2029
Total 1		**36**		**1,440**	**1,152**	**806.4**	
Mtwara corridor (southern corridor)	≈1,500	30	2x20	1200	960	672	2031
Tanga Musoma (Northern corridor)	≈1000	20	2x20	800	640	448	2031
TAZARA (upgraded to electrified SGR)	≈1,000	20	2x20	800	640	448	2039
Total 2		**70**				**1568**	
Total						**2,374.40**	

Source: *TRC*

3.4.3 E-Mobility

The adoption of electromobility (E-mobility) technology in the country is rapidly gaining pace. Its respective policies and regulatory framework are underway. According to COSTEC report 2023, the vehicle stock in the country increased from 1.9 million in 2015 to 4.3 million in 2021 and it is projected to increase to 8 million in 2030 with 2-wheel contributing 45%, private passenger vehicles/cars 27.4%, light passenger vehicle/minibus 17.25%, and 3-wheeler at 3.15%. Likewise, 2&3-wheeler electric vehicles were 10,000 in 2020 with a projected growth of 3,000 annually, as indicated in **Table 3-9** Also, there were 30 four-wheel electric vehicles with a projected growth of 2 (two) annually[6]. Thus, the consumption of electricity due to electric cars in 2020 is estimated to be 43,058,320 kWh, equivalent to 4.92 MW. Given the expected rapid transformation of the transport sector, power requirements to support the E-Mobility aspect have been considered in the forecast.

Table 3-9: Expected Energy Consumption E-mobility

S/N	Description	Quantity (No.)	Battery Capacity (kW)	Charging Time (Hours)	Energy Consumption (kWh)	Frequency Of Charging Annually	Total Consumption Annually
1.	2 – 2-wheel and 3-wheel vehicles	13,000	3	3	117,000	365	42,705,000
2.	4-wheel vehicle - Light Duty Vehicles (LDV)	32	4	4	128	365	46,720
3.	Busses	1	120	7	840	365	306,600
Total (kWh)							**43,058,320**
Total (kW)							**4,915.33**

***Sourc**e: COSTEC 2023*

3.4.4 Adoption of Electricity for Clean Cooking

Electricity as a source of clean energy for cooking is a key agenda in the government[7]. To that effect, the clean cooking strategy was prepared and launched in April 2024. This is promoted by the introduction of more energy-efficient equipment as well as an increase in accessibility and connectivity of electricity. Electricity accessibility increased from 67.5% in 2017 to 78.4% in 2020. Likewise, connectivity increased from 32.8% in 2017 to 37.7% in 2020.

In 2020, 63.5% of households used firewood as a main source of energy for cooking, 26.2% charcoal, 5.1% liquefied Petroleum Gas (LPG), 3% electricity, and 2.2% other energy sources[8] as indicated in **Table 3-10.**

[6] *Tanzania Commission for Science and Technology, 2024*

[7] *The National Clean Cooking Strategy 2024*

[8] *The Energy Access Use Situation Report Survey II in Tanzania Mainland 2019/2020, REA&NBS, 2020*

As per the National Clean Cooking Strategy, the Government envisages having 80% of the population using clean energy for cooking from natural gas, LPG, and electricity by 2034. Thus, the plan has used the percentage contribution of clean energy for cooking in 2020 to get the percentage distribution by source for 2034 as indicated in **Table 3-10**. Likewise, the plan has assumed the same percentage increase in forecasting the use of electricity for cooking from 3% in 2020 to 23% in 2034.

The National Clean Cooking Strategy 2024 implies that there will be strategies aimed at increasing the use of electricity for cooking at the household level. Such strategies may include tariff incentives, tax incentives for cooking equipment, and provide subsidies on the prices of clean cooking equipment. Considering the expected impact of rolled-out strategies and the observed specific consumption of electricity of D1 and T1 Tariff categories in 2023, the Clean-Cooking Strategy has been translated into additional electricity consumption in D1 and T1 and included in the electricity forecast from 2024 to 2050.

Table 3-10: Household Energy for Clean Cooking in 2020

Years	Fire Wood	Charcoal	LPG	Electricity	Others
2020	63.50%	26.20%	5.10%	3.00%	2.20%
2048	20%		40%	23%	17%

Source: *MoE, REA & NBS*

3.4.5 Net Metering Framework

The forecast considered a net metering framework. This is a billing mechanism that credits solar (renewable) energy system owners for the electricity they add to the grid. The legislation allows net metering[9] capacity of up to 5% of the highest peak load during the previous calendar year based on first-in first-out. The net effect of this framework is to reduce electricity generation from public power plants, thereby allowing the private sector to contribute power supply and peak demand into the grid system. The realization of this emerging issue is a gradual process requiring strategies to support it. The forecast includes the impact of net metering based on projected demand and a capacity factor of ≤23% based on solar projects[10]. **Table 3-11** shows the potential of the load reduction due to distributed generation from 2012 to 2024.

Table 3-11: Electricity from Distribution Generation

Year	Demand (MW)	Distributed Generation 5% (MW)	Capacity Factor (23%)
2012	851.35	42.57	9.79
2013	898.72	44.94	10.34
2014	934.62	46.73	10.75

[9] *The Electricity (Net-Metering) Rules, 2018*

[10] *The Electricity (Standardized Small Power Projects Tariff) Order, 2019*

Year	Demand (MW)	Distributed Generation 5% (MW)	Capacity Factor (23%)
2015	988.27	49.41	11.37
2016	1041.63	52.08	11.98
2017	1051.27	52.56	12.09
2018	1116.58	55.83	12.84
2019	1120.12	56.01	12.88
2020	1180.53	59.03	13.58
2021	1307.36	65.37	15.03
2022	1354.61	67.73	15.58
2023	1482.80	74.14	17.05

Source: *TANESCO*

3.4.6 Communications Towers

The Government has been implementing a strategy that aims to increase public access to communication services by supplying reliable electricity to the communication towers through REA.

Table 3-12 shows operating communication towers not connected to the national grid, instead, they are powered by diesel generators or connected with solar panels. The forecast considered a unit load ranging from 26kW to 36kW for powering a single communication tower. The forecast considered an average of 28kW as the power requirement for powering each communication tower to be constructed in the next two years.

Table 3-12: Status Construction of Ongoing Communication

S/N	Ownership of Communication Towers	Existing Communication Towers	Towers under Construction 2023/2024	Towers to start Construction 2024/2025
1.	Helios Towers (HTT)	430		
2.	TanzaniaTowers Company	238		
3.	Halotel	596		
4.	Tigo	135		
5.	Airtel	7		
6.	Vodacom Company	49		
7.	TTCL Corporation	377		
Total		**1,832**	**758**	**636**
Power requirement (kW)		**51,296**	**21,224**	**17,808**

3.4.7 Surveyed Future Load

As indicated in **Table 3-13** the site survey identified types of load with capacity above 500kW to be constructed between 2024 and 2028. A summary of identified loads by sector is shown in **Table 3-14**. The data has been used in the forecast.

Table 3-13: Surveyed Loads(MW) by region from 2024 to 2028

No	Region	2024	2025	2026	2027	2028
1	Rukwa	5.0	4.8	2.7	2.5	1.8
2	Songwe	16.7	16.7	44.6	2.5	2.2
3	Mbeya	2.4	2.5	3.5	2.5	0.5
4	Njombe	0.8	8.0	5.0	7.0	3.5
5	Iringa	10.6	15.2	5.6	1.2	1.8
6	Mara	19.3	2.7	4.0	-	-
7	Simiyu	9.0	8.5	2.5	2.0	3.5
8	Mwanza	13.7	31.2	36.0	18.0	6.0
9	Geita	43.3	15.5	1.5	12.7	0.8
10	Kagera	9.5	24.9	31.5	14.5	17.8
11	Tanga	39.3	38.8	14.5	7.7	6.5
12	Kilimanjaro	5.2	6.0	6.4	2.0	4.6
13	Manyara	3.8	6.5	-	0.7	3.7
14	Arusha	19.0	16.8	27.5	14.1	1.5
15	Mtwara	7.9	1.5	-	-	-
16	Lindi	7.7	12.6	22.5	7.8	2.5
17	Ruvuma	5.0	9.5	25.5	-	-
18	Dodoma	20.2	25.7	51.9	50.0	66.1
19	Singida	3.5	28.2	14.3	5.0	0.8
20	Morogoro	43.2	74.2	63.3	30.2	38.0
21	Tabora	3.5	2.0	-	0.7	0.5
22	Shinyanga	3.2	7.8	6.0	4.0	40.5
23	Katavi	33.2	20.0	0.5	-	-
24	Kigoma	28.0	4.3	-	-	-
25	Dar es Salaam	81.1	71.4	-	-	-
26	Pwani	370.7	191.8	130.0	155.0	-
	TOTAL	**804.8**	**647.1**	**499.2**	**340.1**	**202.6**

Table 3-14: Surveyed Loads (MW) 2024-2028

Type of loads	2024	2025	2026	2027	2028	Total
Mining	131.33	122.58	205.46	108.20	48.50	**616.07**
Agriculture	51.82	49.10	26.38	19.80	10.70	**157.80**
Water Sectors	32.04	26.94	34.80	45.30	8.50	**147.58**
Health	4.53	1.50	0.50	1.20	-	**7.73**
Port	1.00	4.00	-	-	-	**5.00**
Industries	541.94	343.18	194.89	176.30	30.20	**1,286.52**
Education Sector	5.11	5.11	1.10	-	-	**11.32**
EACOP	3.50	46.50	5.00	10.00	-	**65.00**
Fishing Industry	0.40	8.00	3.00	-	-	**11.40**
Business	1.00	12.10	6.68	4.00	4.00	**27.78**
Airport	-	2.00	-	-	-	**2.00**
SGR Station	2.25	1.50	0.50	-	-	**4.25**
Oil& Gas Exploration	-	-	-	5.50	1.50	**7.00**
Government Institutions	27.63	9.90	20.90	20.80	65.50	**144.73**

Source: *Survey Data.*

3.5 Forecast Results from Trend Analysis- Base Case

3.5.1 Demand Forecast Scenarion Results

In line with the forecast approach, methodology, and key assumptions, four scenarios were considered based on the expectation of growth of power requirements emanating from emerging issues. The scenarions are; Bussines As Usual (BU), BU+80% Emerging issue+ M300, BU+100% Emerging issue+ M300, BU+120% Emerging issue+ M300. The forecast results are shown in **Table 3-15.**

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Table 3-15: Demand Forecast Scenarion Results

	Forecast of Electricity Generation Requirement - GWh				Forecast of PEAK DEMAND Requirement - MW			
Year	**Bussines As Usual (BU)**	**BU+80% Emerging issue+ M300**	**BU+100% Emerging issue+ M300**	**BU+120% Emerging issue+ M300**	**Bussines As Usual (BU)**	**BU+80% Emerging issue+ M300**	**BU+100% Emerging issue+ M300**	**BU+120% Emerging issue+ M300**
2022	9,640.67	9,640.67	9,640.67	9,640.67	1,411.30	1,411.30	1,411.30	1,411.30
2023	10,674.23	10,674.23	10,674.23	10,674.23	1,568.60	1,568.60	1,568.60	1,568.60
2024	12,260.08	13,274.16	13,527.68	13,781.20	1,957.42	2,119.32	2,159.80	2,200.28
2025	14,458.62	17,191.62	17,874.87	18,558.12	2,310.53	2,747.27	2,507.80	2,965.64
2026	16,543.89	21,542.35	22,791.96	24,041.58	2,646.17	3,445.67	3,203.54	3,845.41
2027	18,541.04	25,771.57	27,579.20	29,386.83	2,968.32	4,125.88	4,415.27	4,704.66
2028	20,460.82	30,332.81	32,800.81	35,268.81	3,278.65	4,860.54	5,256.01	5,651.49
2029	22,314.37	33,677.04	36,517.71	39,358.38	3,578.93	5,401.35	5,856.96	6,312.56
2030	24,113.88	37,569.07	40,932.87	44,296.66	3,871.08	6,031.09	6,571.09	7,111.09
2031	24,304.93	39,109.61	42,810.79	46,511.96	3,905.32	6,284.14	6,878.85	7,473.55
2032	24,509.32	40,032.91	43,913.80	47,794.70	3,941.77	6,438.39	7,062.54	7,686.70
2033	24,720.36	40,818.70	44,843.28	48,867.86	3,979.35	6,570.78	7,218.64	7,866.49
2034	24,941.34	41,587.45	45,748.98	49,910.51	4,018.61	6,700.67	7,371.19	8,041.70
2035	25,166.71	42,365.22	46,664.84	50,964.47	4,058.65	6,832.26	7,525.66	8,219.06
2036	25,399.74	43,110.68	47,538.42	51,966.15	4,099.99	6,958.87	7,673.59	8,388.31
2037	25,637.62	43,907.33	48,474.76	53,042.19	4,142.20	7,093.98	7,831.93	8,569.87
2038	25,877.56	44,663.38	49,359.84	54,056.29	4,184.81	7,222.78	7,982.27	8,741.76
2039	26,122.96	46,298.80	51,342.76	56,386.73	4,228.39	7,494.15	8,310.59	9,127.03
2040	26,371.29	47,163.38	52,361.40	57,559.42	4,272.52	7,641.14	8,483.29	9,325.45
2041	26,622.11	48,028.99	53,380.71	58,732.43	4,317.14	7,788.57	8,656.42	9,524.28
2042	26,873.35	48,836.14	54,326.84	59,817.54	4,361.91	7,926.78	8,817.99	9,709.21
2043	27,128.11	49,728.89	55,379.09	61,029.28	4,407.34	8,079.15	8,997.10	9,915.05
2044	27,384.36	50,561.26	56,355.49	62,149.71	4,453.09	8,221.99	9,164.21	10,106.43
2045	27,641.95	51,489.48	57,451.36	63,413.24	4,499.14	8,380.69	9,351.07	10,321.46
2046	27,900.43	52,354.44	58,467.94	64,581.45	4,545.43	8,529.38	9,525.36	10,521.35
2047	28,159.81	53,329.74	59,622.22	65,914.71	4,591.94	8,696.34	9,722.43	10,748.53
2048	28,593.46	54,549.02	61,037.91	67,526.80	4,662.99	8,895.80	9,954.00	11,012.20
2049	29,050.70	55,006.26	61,495.15	67,984.03	4,737.56	8,970.36	10,028.56	11,086.76
2050	29,521.18	55,476.73	61,965.62	68,454.51	4,814.28	9,047.09	10,105.29	11,163.49

3.5.2 The Base Case Demand Forecast Results

3.5.2.1 Forecasted Demand

The BU+100% Emerging issue+ M300 was considered as Base-Case forecast scenario. Under this Case generation requirement is projected to grow from 13,527 GWh in 2024 to 61,965.62 GWh in 2050. The corresponding peak demand is expected to grow from 2,159.80 MW to 10,105.29 MW as detailed in **Table 3-16.** This growth in demand signifies requirement for additional generation and transmission capacities.

Table 3-16: The Base Case Demand Forecast Results

Year	(A) Total Sales Forecast Business as Usual - MWh	(B) Total Required for Emerging (Base-Case) - MWh	Total Expected Sales - MWh	At Distribution Level - MWh	At Transmission Level - MWh	Station Use/Auxilliary - MWh	Generation Requirement - MWh	Peak - MW
2022	8,337,932.26	0.00	8,337,932.26	643,222.85	563,111.74	96,406.74	9,640,673.59	1,411.30
2023	9,081,369.10	0.00	9,081,369.10	862,632.83	623,481.52	106,742.26	10,674,225.72	1,568.60
2024	9,606,673.99	2,396,548.92	11,509,020.46	1,093,233.72	790,151.96	135,276.83	13,527,682.98	2,159.80
2025	9,932,905.42	6,159,646.55	15,241,723.92	1,425,610.35	1,028,788.21	178,748.71	17,874,871.19	2,507.80
2026	10,258,954.23	10,769,032.02	19,478,161.43	1,793,576.08	1,292,304.21	227,919.61	22,791,961.33	3,203.54
2027	10,584,820.60	14,923,204.16	23,622,283.82	2,140,963.52	1,540,160.41	275,792.00	27,579,199.75	4,415.27
2028	10,910,504.70	19,556,711.00	28,157,729.42	2,511,356.36	1,803,716.57	328,008.10	32,800,810.45	5,256.01
2029	11,236,006.72	21,644,485.04	31,418,708.22	2,756,940.31	1,976,886.34	365,177.12	36,517,711.99	5,856.96
2030	11,561,326.85	24,685,804.54	35,296,164.48	3,046,470.46	2,180,903.14	409,328.67	40,932,866.75	6,571.09
2031	11,886,465.24	26,200,389.73	36,997,981.67	3,140,342.03	2,244,355.51	428,107.87	42,810,787.08	6,878.85
2032	12,211,422.10	26,537,684.90	38,035,946.75	3,174,084.37	2,264,634.87	439,138.04	43,913,804.04	7,062.54
2033	12,536,197.58	26,618,407.63	38,927,613.08	3,193,006.81	2,274,226.93	448,432.80	44,843,279.61	7,218.64
2034	12,860,791.88	26,654,649.77	39,802,280.46	3,208,166.31	2,281,044.18	457,489.81	45,748,980.76	7,371.19
2035	13,185,205.18	26,699,528.15	40,689,408.28	3,221,977.31	2,286,810.72	466,648.45	46,664,844.76	7,525.66
2036	13,509,437.64	26,685,119.44	41,543,223.27	3,230,836.34	2,288,974.86	475,384.19	47,538,418.64	7,673.59
2037	13,833,489.44	26,742,800.90	42,455,500.87	3,241,901.58	2,292,613.97	484,747.64	48,474,764.06	7,831.93
2038	14,157,360.77	26,739,899.55	43,326,508.77	3,247,459.92	2,292,270.87	493,598.38	49,359,837.94	7,982.27
2039	14,481,051.80	27,951,078.79	45,166,852.44	3,322,024.61	2,340,459.93	513,427.65	51,342,764.62	8,310.59
2040	14,804,562.71	28,058,435.55	46,164,841.93	3,330,820.43	2,342,125.51	523,614.02	52,361,401.88	8,483.29

Year	(A) Total Sales Forecast Business as Usual - MWh	(B) Total Required for Emerging (Base-Case) - MWh	Total Expected Sales - MWh	At Distribution Level - MWh	At Transmission Level - MWh	Station Use/Auxilliary - MWh	Generation Requirement - MWh	Peak - MW
2041	15,127,893.67	28,161,650.74	47,167,497.29	3,337,324.92	2,342,078.56	533,807.08	53,380,707.85	8,656.42
2042	15,451,044.87	28,187,353.54	48,109,437.23	3,336,993.82	2,337,140.66	543,268.40	54,326,840.11	8,817.99
2043	15,774,016.47	28,317,686.37	49,149,358.70	3,340,877.52	2,335,059.17	553,790.86	55,379,086.26	8,997.10
2044	16,096,808.65	28,369,214.05	50,126,043.38	3,337,843.08	2,328,045.15	563,554.86	56,355,486.46	9,164.21
2045	16,419,421.59	28,534,372.49	51,213,164.08	3,339,487.85	2,324,194.78	574,513.60	57,451,360.31	9,351.07
2046	16,741,855.46	28,620,037.71	52,233,857.36	3,334,076.00	2,315,330.56	584,679.43	58,467,943.35	9,525.36
2047	17,064,110.44	28,830,134.76	53,381,940.33	3,333,997.25	2,310,063.02	596,222.23	59,622,222.84	9,722.43
2048	17,429,855.37	28,985,086.00	54,529,801.24	3,480,625.61	2,417,101.12	610,379.07	61,037,907.04	9,954.00
2049	17,872,480.11	28,985,086.00	54,938,287.86	3,506,699.23	2,435,207.80	614,951.46	61,495,146.34	10,028.56
2050	18,326,674.22	28,985,086.00	55,358,595.68	3,533,527.38	2,453,838.46	619,656.18	61,965,617.70	10,105.29

3.5.2.2 Forecasted Customers

The plan indicates forecasted customer growth from 5,276,679 in 2024 to 21,007,203.05 in 2050 as indictaed in **Table 3-17**. The growth includes the additional 8.5 million customer by 2030 which reflect the government efforts to accelarete electricity connectivity under various programs including -300 (Energy Compact Program).

Table 3-17: Total (bussiness as usual and With M-300)

Year	D1	T1	T2	T3	Total
2022	1,251,887.00	2,916,465.00	3,744.00	1,034.00	4,173,131.00
2023	1,359,346.00	3,292,401.00	3,964.00	1,110.00	4,656,822.00
2024	1,590,891.00	3,680,026.00	4,489.00	1,272.00	5,276,679.00
2025	1,996,393.00	4,643,789.00	5,477.00	1,573.00	6,647,233.00
2026	2,399,975.00	5,609,523.00	6,421.00	1,866.00	8,017,787.00
2027	2,802,004.00	6,576,852.00	7,330.00	2,154.00	9,388,341.00
2028	3,202,756.00	7,545,493.00	8,210.00	2,435.00	10,758,895.00
2029	3,602,449.00	8,515,221.00	9,065.00	2,713.00	12,129,449.00
2030	4,001,250.00	9,485,862.00	9,900.00	2,986.00	13,500,000.00
2031	4,107,536.00	9,751,629.00	10,080.00	3,053.00	13,872,300.00
2032	4,213,770.00	10,017,266.00	10,260.00	3,119.00	14,244,417.00
2033	4,319,952.00	10,282,772.00	10,439.00	3,186.00	14,616,351.00
2034	4,426,082.00	10,548,147.00	10,619.00	3,252.00	14,988,102.00
2035	4,532,159.00	10,813,392.00	10,798.00	3,319.00	15,359,670.00
2036	4,638,184.00	11,078,507.00	10,978.00	3,385.00	15,731,056.00
2037	4,744,158.00	11,343,491.00	11,157.00	3,451.00	16,102,259.00
2038	4,850,079.00	11,608,346.00	11,336.00	3,518.00	16,473,281.00
2039	4,955,948.00	11,873,070.00	11,515.00	3,584.00	16,844,119.00
2040	5,061,765.00	12,137,665.00	11,694.00	3,650.00	17,214,776.00
2041	5,167,531.00	12,402,130.00	11,873.00	3,716.00	17,585,252.00
2042	5,273,244.00	12,666,465.00	12,052.00	3,783.00	17,955,546.00
2043	5,378,906.00	12,930,671.00	12,231.00	3,849.00	18,325,659.00
2044	5,484,517.00	13,194,748.00	12,410.00	3,915.00	18,695,592.00
2045	5,590,075.00	13,458,696.00	12,588.00	3,981.00	19,065,342.00
2046	5,695,582.00	13,722,514.00	12,767.00	4,047.00	19,434,912.00
2047	5,801,037.00	13,986,204.00	12,945.00	4,113.00	19,804,301.00
2048	5,906,441.00	14,249,765.00	13,123.00	4,179.00	20,173,510.00
2049	6,025,980.95	14,540,577.89	13,374.04	4,261.35	20,584,196.23
2050	6,149,107.10	14,840,115.17	13,632.61	4,346.17	21,007,203.05

3.5.2.3 Forecasted Energy Consumption by Customers Category

The plan indicates Forecasted Energy Consumption by Customers Category growth from 12,260,078.20MWh in 2024 to 29,521,175.50 MWh in 2050 as indicated in .
Table 3-18. The growth implies demand forecast from 1,957.42 in 2024 to 4,814.28 MW in 2050.

Table 3-18: Forecasted Energy Consumption by Customers Category

Year	D1- MWh	T1- MWh	T2- MWh	T3- MWh	Total- MWh	Losses at Distribution Level - MWh	Losses at Transmission Level - MWh	Station Auxilliary - MWh	Requirement - MWh	MW
2022	351,033.48	3,063,101.77	683,898.93	4,239,898.08	8,337,932.26	643,222.85	563,111.74	96,406.74	9,640,673.59	1,476.06
2023	394,841.00	3,273,793.27	690,620.04	4,722,114.79	9,081,369.10	862,632.83	623,481.52	106,742.26	10,674,225.72	1,656.03
2024	447,272.50	3,889,299.42	801,358.47	5,292,643.05	10,430,573.45	990,792.80	716,111.17	122,600.78	12,260,078.20	1,957.42
2025	549,963.47	4,749,033.93	973,740.01	6,055,986.99	12,328,724.40	1,153,147.59	832,166.12	144,586.24	14,458,624.35	2,310.53
2026	649,299.58	5,571,325.15	1,137,250.62	6,780,641.03	14,138,516.38	1,301,894.17	938,038.44	165,438.88	16,543,887.88	2,646.17
2027	745,919.07	6,363,301.87	1,293,678.19	7,477,972.52	15,880,871.66	1,439,334.45	1,035,424.43	185,410.41	18,541,040.95	2,968.32
2028	840,308.97	7,130,394.92	1,444,232.81	8,149,574.26	17,564,510.96	1,566,559.07	1,125,140.42	204,608.19	20,460,818.63	3,278.65
2029	932,845.90	7,876,807.73	1,589,739.06	8,799,200.01	19,198,592.70	1,684,645.14	1,207,988.42	223,143.70	22,314,369.96	3,578.93
2030	1,023,825.64	8,605,845.61	1,731,171.55	9,432,411.51	20,793,254.31	1,794,700.24	1,284,787.58	241,138.81	24,113,880.94	3,871.08
2031	1,039,639.52	8,691,234.75	1,757,871.39	9,516,081.45	21,004,827.11	1,782,863.24	1,274,185.71	243,049.25	24,304,925.31	3,905.32
2032	1,055,939.08	8,783,657.05	1,784,692.00	9,604,458.18	21,228,746.31	1,771,530.29	1,263,945.38	245,093.15	24,509,315.14	3,941.77
2033	1,072,658.11	8,882,119.31	1,811,765.76	9,692,739.89	21,459,283.07	1,760,180.80	1,253,693.09	247,203.61	24,720,360.56	3,979.35
2034	1,089,741.66	8,985,804.57	1,838,786.31	9,784,998.28	21,699,330.83	1,749,021.95	1,243,575.29	249,413.41	24,941,341.47	4,018.61
2035	1,107,143.98	9,094,034.53	1,866,029.98	9,876,906.08	21,944,114.56	1,737,637.44	1,233,294.82	251,667.14	25,166,713.96	4,058.65
2036	1,124,826.12	9,206,242.44	1,893,211.87	9,972,231.25	22,196,511.67	1,726,233.32	1,222,997.47	253,997.40	25,399,739.87	4,099.99
2037	1,142,755.05	9,321,951.14	1,920,592.45	10,068,815.72	22,454,114.36	1,714,595.93	1,212,531.12	256,376.18	25,637,617.59	4,142.20
2038	1,160,903.02	9,440,754.03	1,948,029.52	10,164,816.30	22,714,502.87	1,702,524.38	1,201,753.73	258,775.57	25,877,556.54	4,184.81
2039	1,179,245.72	9,562,305.77	1,975,517.48	10,263,614.69	22,980,683.65	1,690,230.61	1,190,815.08	261,229.59	26,122,958.93	4,228.39
2040	1,197,762.28	9,686,307.63	2,003,051.32	10,363,331.66	23,250,452.90	1,677,533.82	1,179,587.68	263,712.87	26,371,287.27	4,272.52
2041	1,216,434.46	9,812,502.84	2,030,626.55	10,463,880.85	23,523,444.69	1,664,395.67	1,168,044.92	266,221.06	26,622,106.34	4,317.14
2042	1,235,246.71	9,940,667.92	2,058,239.08	10,563,691.10	23,797,844.80	1,650,679.48	1,156,091.49	268,733.49	26,873,349.26	4,361.91
2043	1,254,184.89	10,070,607.37	2,085,885.26	10,665,729.71	24,076,407.23	1,636,569.22	1,143,856.95	271,281.15	27,128,114.55	4,407.34
2044	1,273,236.82	10,202,150.22	2,113,561.76	10,768,391.81	24,357,340.62	1,621,930.94	1,131,248.05	273,843.63	27,384,363.24	4,453.09
2045	1,292,391.95	10,335,145.94	2,141,368.81	10,871,622.99	24,640,529.70	1,606,749.97	1,118,255.27	276,419.54	27,641,954.48	4,499.14
2046	1,311,640.47	10,469,461.86	2,169,094.72	10,975,374.32	24,925,571.38	1,590,993.92	1,104,856.89	279,004.26	27,900,426.45	4,545.43
2047	1,330,973.98	10,604,979.19	2,196,941.30	11,079,601.70	25,212,496.17	1,574,659.75	1,091,051.67	281,598.06	28,159,805.64	4,591.94
2048	1,350,384.76	10,741,593.22	2,224,803.30	11,227,933.96	25,544,715.24	1,630,513.74	1,132,301.21	285,934.65	28,593,464.83	4,662.99
2049	1,370,759.62	10,960,810.43	2,248,872.16	11,372,759.64	25,953,201.86	1,656,587.35	1,150,407.88	290,507.04	29,050,704.14	4,737.56
2050	1,391,706.00	11,186,604.16	2,273,656.54	11,521,542.99	26,373,509.68	1,683,415.51	1,169,038.55	295,211.75	29,521,175.50	4,814.28

Emerging Issues Forecasted Demand Error! Reference source not found.The forecasted demand grows from 382.63MW in 2024 to 4,726.86 MW in 2050. This corresponds to respective energy consumption ranging from 2,396,548.92 MWh to 28,985,086.00 MWh as indicated in **Table 3-19**. The average percentage contribution for each emerging issue is presented in **Figure 3-2**.

Table 3-19: Emerging Issues Forecasted Demand

Year	SGR Operation - MW	E-Mobility - MW	Commun-Towers (REA) - MW	Net-Metering - MW	Clean Cooking Strategy - MW	LNG Operation - MW	Survey Data - MW	Export - MW	Total MW	Total MWh
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	101.25	9.74	0.00	(3.76)	9.82	0.00	265.58	0.00	382.63	2,396,548.92
2025	156.48	10.94	14.86	(6.88)	14.24	0.00	744.69	50.00	984.33	6,159,646.55
2026	184.09	12.14	22.43	(10.10)	17.32	0.00	1,396.60	100.00	1,722.49	10,769,032.02
2027	230.11	13.35	22.43	(13.94)	23.58	70.00	1,893.60	150.00	2,389.12	14,923,204.16
2028	303.75	15.33	22.43	(17.44)	27.28	140.00	2,242.43	400.00	3,133.77	19,556,711.00
2029	331.36	17.61	22.43	(21.88)	35.73	210.00	2,426.24	450.00	3,471.49	21,644,485.04
2030	607.50	20.22	22.43	(22.10)	40.02	297.50	2,497.34	500.00	3,962.89	24,685,804.54
2031	791.59	23.20	22.43	(23.25)	51.08	297.50	2,497.34	550.00	4,209.88	26,200,389.73
2032	791.59	26.62	22.43	(23.44)	55.95	297.50	2,497.34	600.00	4,267.99	26,537,684.90
2033	791.59	30.55	22.43	(24.62)	70.11	297.50	2,497.34	600.00	4,284.89	26,618,407.63
2034	791.59	35.05	22.43	(24.76)	75.52	297.50	2,497.34	600.00	4,294.66	26,654,649.77
2035	791.59	40.21	22.43	(25.97)	82.75	297.50	2,497.34	600.00	4,305.84	26,699,528.15
2036	791.59	46.14	22.43	(26.08)	78.57	297.50	2,497.34	600.00	4,307.48	26,685,119.44
2037	791.59	52.94	22.43	(27.33)	86.29	297.50	2,497.34	600.00	4,320.76	26,742,800.90
2038	791.59	60.76	22.43	(27.39)	82.05	297.50	2,497.34	600.00	4,324.27	26,739,899.55
2039	975.68	69.73	22.43	(28.67)	90.30	297.50	2,497.34	600.00	4,524.30	27,951,078.79
2040	975.68	80.04	22.43	(28.70)	101.58	297.50	2,497.34	600.00	4,545.87	28,058,435.55
2041	975.68	91.89	22.43	(30.01)	111.98	297.50	2,497.34	600.00	4,566.80	28,161,650.74
2042	975.68	105.49	22.43	(30.00)	106.76	297.50	2,497.34	600.00	4,575.19	28,187,353.54
2043	975.68	121.13	22.43	(31.34)	117.86	297.50	2,497.34	600.00	4,600.60	28,317,686.37
2044	975.68	139.11	22.43	(31.29)	112.48	297.50	2,497.34	600.00	4,613.24	28,369,214.05
2045	975.68	159.76	22.43	(32.66)	124.35	297.50	2,497.34	600.00	4,644.40	28,534,372.49
2046	975.68	183.51	22.43	(32.58)	118.79	297.50	2,497.34	600.00	4,662.66	28,620,037.71
2047	975.68	210.81	22.43	(33.98)	131.49	297.50	2,497.34	600.00	4,701.25	28,830,134.76
2048	975.68	242.18	22.43	(33.98)	125.71	297.50	2,497.34	600.00	4,726.86	28,985,086.00
2049	975.68	242.18	22.43	(33.98)	125.71	297.50	2,497.34	600.00	4,726.86	28,985,086.00
2050	975.68	242.18	22.43	(33.98)	125.71	297.50	2,497.34	600.00	4,726.86	28,985,086.00

SGR Operation - MW	E-Mobility - MW	Commun-Towers (REA) - MW	Net-Metering - MW	Clean Cooking Strategy - MW	LNG Operation - MW	Survey Data - MW	Export - MW	Total MW
18.3%	1.8%	0.6%	-0.6%	1.9%	5.6%	60.7%	11.8%	100.0%

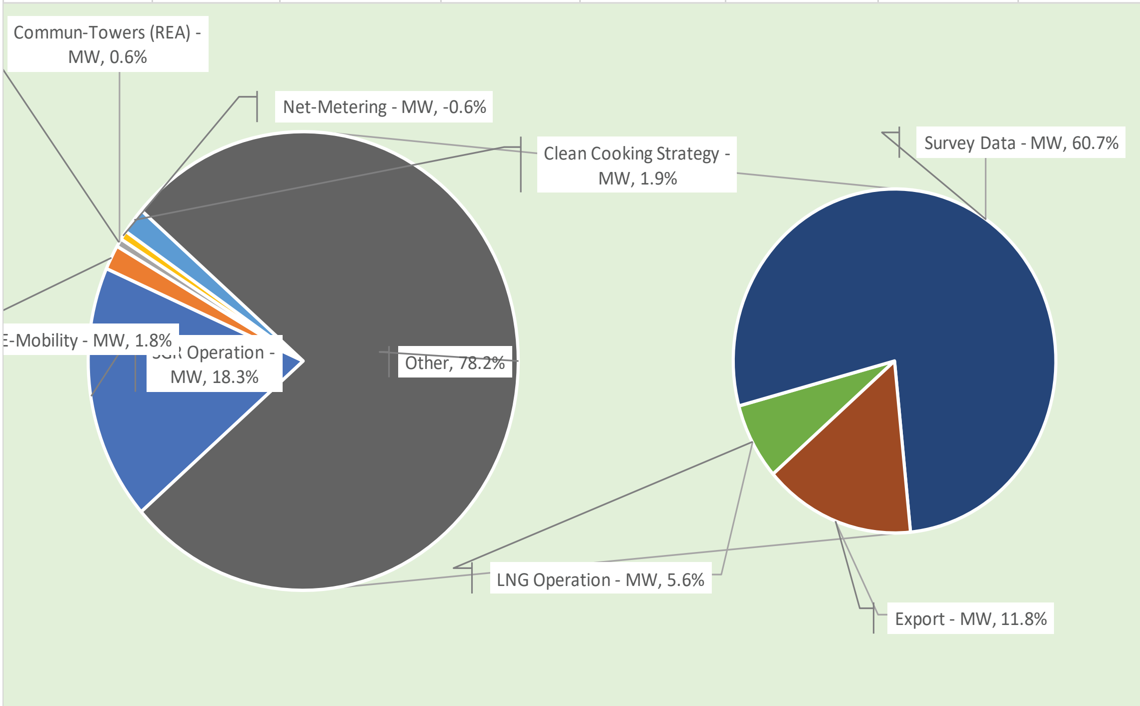

Figure 3-2: Average Contribution of Power Requirement from Emerging Issues

3.6 Forecasts Results from Econometric Analysis

3.6.1 Background

A forecast of electricity consumption at the national level using an econometric approach was derived. The results from this approach were then compared with the forecast results obtained from the trend section. The forecast of electricity under this approach must observe the following issues:

i. *Both sides of the equation need to be compatible*: 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);

ii. *The use of an econometric approach is only appropriate for large "populations".* It should not be used in consumer categories where there are a relatively small number of customers, each with very high consumption. In such a case, decisions by a small number of consumers can have a significant impact on the utility load. Econometric analysis is not equipped to handle such situations, and

iii. *The past trend will continue in the future:* It should be noted that this approach typically involves using statistical models to analyse historical data and make predictions. Significant changes such as accelerated electrification and rapid expansion of the mining activities, industries, and other identified loads must, therefore, be considered as additions to this method.

3.6.2 Observed Relationship in Econometric

The relationship between selected electricity consumption variables and the growth in economic activities was studied using the following general model:-

Equation: Sales (t) = $\alpha + \beta 1 \cdot$ (demographic indicators, t) + $\beta 2 \cdot$ (economic indicators, t)

Where at time t:

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

Demographic indicators = Population,

Economic indicators = GDP, or a subset thereof, and α = constant, $\beta 1$, and $\beta 2$ are the (estimated) coefficients.

Using historical data, the behaviour of the dependent variable, i.e., electricity sales (global sales or sales by customer category) against the explanatory variable, i.e., GDP and

Population, four equations were formulated. The equations include: D1 & T1 against Population, T2 against GDP (Agriculture + Services), T3 & Zanzibar against GDP (Industry), and Total Consumption (kWh) against Total GDP.

The obtained parameters from the equations below were used to forecast electricity consumption for each tariff category and aggregated as a national forecast.

i). **Forecast for Category D1 and T1**

Customers category, i.e., D1&T1, are composed of residential, commercial, light industry, and street lighting customers. There is common economic intuition and empirical evidence that population growth tends to drive up energy demand, hence, a relationship between sales of D1 and T1 customers and demographic parameters (population) was examined. The regression equation is given by:

D1 & T1 Sales as a function of Total Population.

That is:

D1&T1 Sales = -1,997,586,230 + 90.83 x Population

where D1 & T1 are expressed in kWh, and the Total Population is in million (Census 2022).

The details of this relationship are as follows:

Regression Statistics								
Multiple R	0.982567391							
R Square	0.965438678							
Adjusted R Square	0.961982546							
Standard Error	106685567.6							
Observations	12							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	1	3.1794E+18	3.18E+18	279.3	1.23141E-08			
Residual	10	1.13818E+17	1.14E+16					
Total	11	3.29322E+18						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1997586230	285037992.4	-7.00814	4E-05	-2632690455	-1362482005	-2632690455	-1362482005
Population	90.834488	5.434800407	16.71349	1E-08	78.72499806	102.9439779	78.72499806	102.9439779

An *R-Square* value of 96% suggests that there is a robust and highly significant relationship between population growth and energy consumption within these specific customer categories. In other words, as the total population of the country increases, there is a substantial and proportional increase in energy consumption among customers falling into categories D1 and T1. The obtained forecast of electricity consumption is shown in **Figure 3-3.**

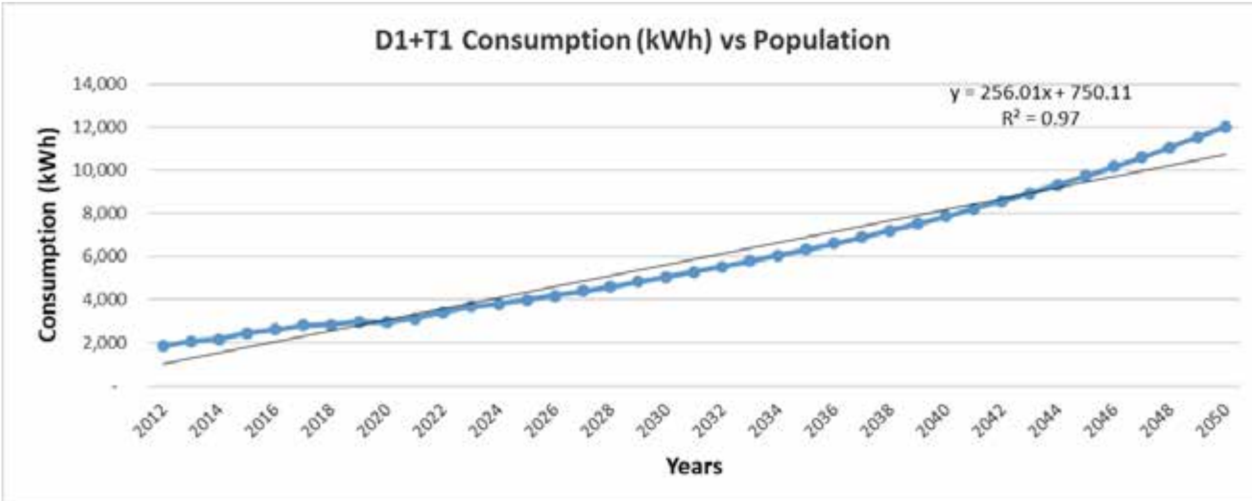

Figure 3-3: Forecast of Electricity for D1 and T1

ii). **Forecast for Category T2**

Electricity customer category T2 comprises low voltage commercial, service and industrial supply. Analysing the relationships between sales to T2 customers and economic/demographic parameters in the country can offer insights into the dynamics of this market segment within the country.

To determine how GDP components of the Agriculture and Service sector affect energy consumption, a relationship between sales to T2 customers and a combination of various economic parameters, i.e., agriculture and service, was examined. The equation is given by:

T2 Sales as a function of the sum of Agriculture and Services GDPs

That is:

T2 Sales = 441,003,587 + 2.42 x (Agriculture + Services GDPs)

Where T2 is expressed in kWh, and the Agriculture plus Services GDP is in TZS Billion (constant 2015 prices).

The details of this relationship are as follows:

Regression Statistics								
Multiple R	0.863276577							
R Square	0.745246449							
Adjusted R Square	0.719771093							
Standard Error	22176257							
Observations	12							
ANOVA								
	df	SS	MS	F	Significance F			
Regression	1	1.43865E+16	1.43865E+16	29.25	0.000297745			
Residual	10	4.91786E+15	4.91786E+14					
Total	11	1.93044E+16						
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	441003587	33587681.38	13.12992052	1E-07	366165569.1	5.16E+08	366165569.1	5.16E+08
Agri+Services	2.421462821	0.447700904	5.408661899	3E-04	1.423923043	3.419003	1.423923043	3.419003

Overall, the findings suggest that the growth in the agriculture and service sectors tends to correlate with increased electricity demand, driven by the expansion of industrial and commercial activities, urbanization, technological advancements, and government policies.

To anticipate and meet the evolving electricity needs of these sectors is essential to understand these dynamics. The obtained forecast of electricity consumption for T2 is shown in **Figure 3-4.**

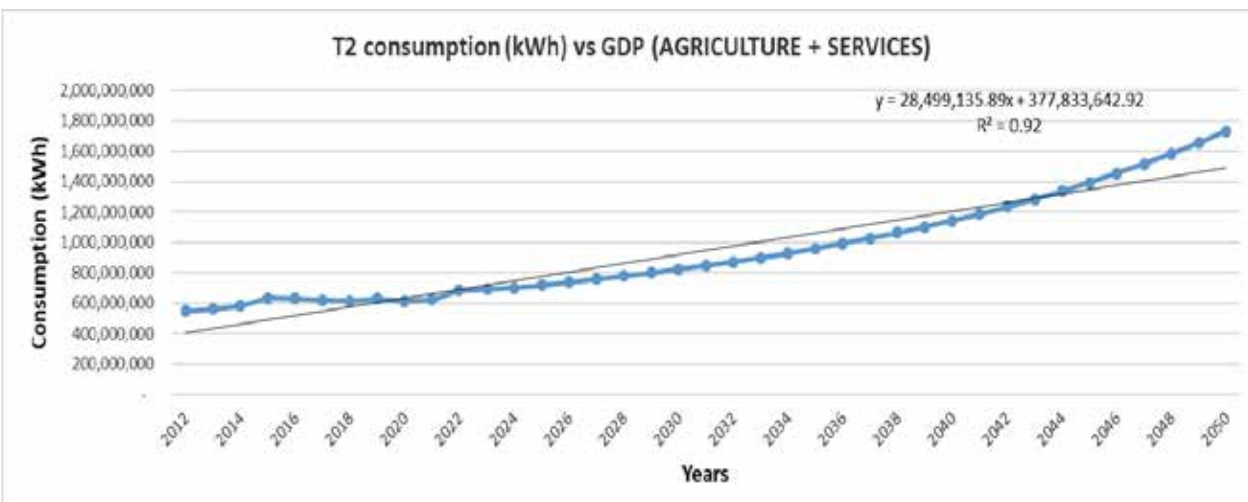

Figure 3-4: Forecast of Electricity for T2

iii). Forecast for Category T3 and Zanzibar

The T3 electricity customer category in the country typically comprises larger industrial consumers, including heavy manufacturing, processing, mining, and other energy-intensive industries. These industries have substantial electricity demand and play a significant role in shaping the energy landscape of the country.

Understanding the interplay between industries and T3 electricity customers is crucial for energy planning, infrastructure development, and policy formulation in the country.

Thus, a relationship between sales to T3 customers and economic parameters i.e., Industry and Construction GDPs, was examined.

The best relationship found was:

Sales to T3 customers as a function of Industry and Construction GDPs alone.

That is:

T3 Sales = 915,279,479.1 + 61.27 x (Industry GDPs + Construction)

Where T3 is expressed in GWh and the Industry and Construction GDP is in TZS Billion (constant 2015 prices).

The details of this relationship are as follows:

Regression Statistics								
Multiple R	0.953200273							
R Square	0.90859076							
Adjusted R Square	0.899449836							
Standard Error	168651287.3							
Observations	12							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	1	2.82721E+18	2.82721E+18	99.4	1.63413E-06			
Residual	10	2.84433E+17	2.84433E+16					
Total	11	3.11164E+18						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Ipper 95.0%*
Intercept	915279479.1	189897448.9	4.8198619	7E-04	492161595.2	1.34E+09	492161595.2	1.34E+09
Industry and Construction	61.27553367	6.146076961	9.969861111	2E-06	47.58122081	74.96985	47.58122081	74.96985

An *R-Square* value of 90.8% suggests that there is a robust and highly significant relationship between Industry and construction growth and energy consumption. In other words, Industrial development often necessitates the expansion and upgrading of electricity infrastructure to meet the growing demand from T3 customers.

The electricity demand forecasts for T3 customers as illustrated in **Figure 3-5** reflect the scale and diversity of industrial activities, impacting employment levels, income distribution, and socio-economic indicators.

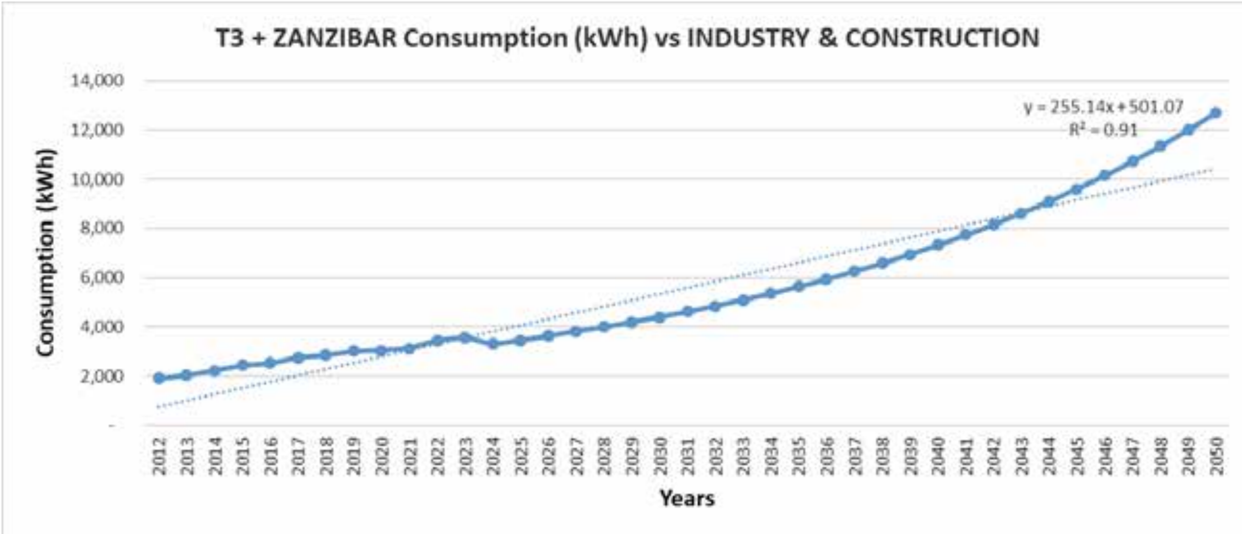

Figure 3-5: Forecast of Electricity for T3 and Zanzibar

iv). **Forecast for Total Consumption (kWh)**

Electricity consumption is closely tied to economic activity, and GDP growth often correlates with increased demand for electricity as industries expand and households consume more energy.

As in the preceding section, a regression analysis is carried out to identify the strength and direction of the relationship, as well as quantify the impact of GDP growth on electricity consumption.

Hence, the best relationship found was:

Total Sales (D1, T1, T2 & T3) as a function of total GDP.

That is:

Global/Total Sales = 1,128,676,488+ 48.05 x GDP

where Total Sales is expressed in GWh and the Total GDP is in TZS Billion (constant 2015 prices). The details of this relationship are as follows:

Regression Statistics									
Multiple R	0.983242117								
R Square	0.96676506								
Adjusted R Square	0.963441566								
Standard Error	213288497.1								
Observations	12								
ANOVA									
	df	*SS*	*MS*	*F*	*Significance F*				
Regression	1	1.32331E+19	1.32331E+19	290.9	1.01199E-08				
Residual	10	4.5492E+17	4.5492E+16						
Total	11	1.3688E+19							
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*	
Intercept	1128676488	298089714	3.786365095	0.004	464491215	1.79E+09	464491215	1.79E+09	
Total GDP All Activities	48.05645995	2.817661077	17.05544373	1E-08	41.77831983	54.3346	41.77831983	54.3346	

These findings suggest that electricity consumption in the country is indeed influenced by changes in GDP, with economic growth driving increased demand for electricity. Such insights can be valuable for policymakers, energy planners, and businesses in understanding the dynamics of energy usage and planning for future infrastructure development.

Figure 3-6 visualizes the positive relationship between electricity demand and GDP growth, meaning that as GDP grows, so does the electricity demand.

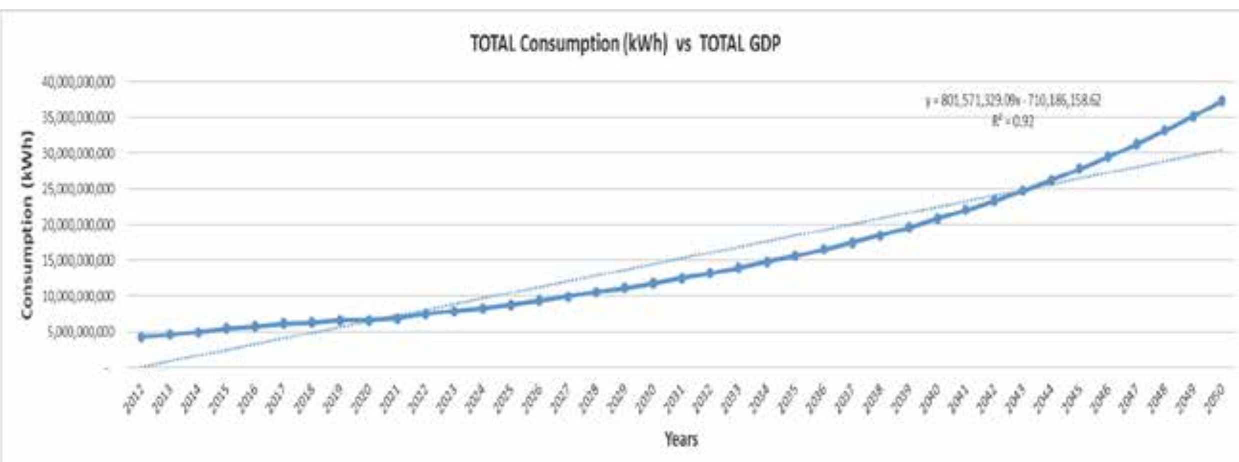

Figure 3-6: Forecast of Total Electricity Consumption

3.6.3 Scenario Considered for Econometric Forecast

There is indeed empirical evidence suggesting that GDP is one of the significant factors determining electricity consumption patterns. Therefore, an assessment of future GDP growth reveals that the economic growth rate will be stable in all periods.

According to the report on Macroeconomic Developments and Projections by the Ministry of Finance and Planning in 2023, it states that as for the future, medium-term projections indicate a real GDP growth rate of 6.3 per cent. This growth is fueled by the ongoing implementation of significant infrastructure projects, particularly in the transportation and energy sectors, governmental efforts to enhance mining activities, improved efficiency in revenue collection and expenditure management, and recent initiatives aimed at bolstering the agricultural sector through investments in irrigation schemes.

The Base Case forecast, which assumed annual GDP[11] the growth rate of 6.3 per cent was tested using a low GDP growth rate of 5.2 per cent, and a high GDP growth rate of 7.1 per cent.

Figure 3-7 illustrates the future electricity consumption patterns in the Base, High, and Low Cases scenarios.

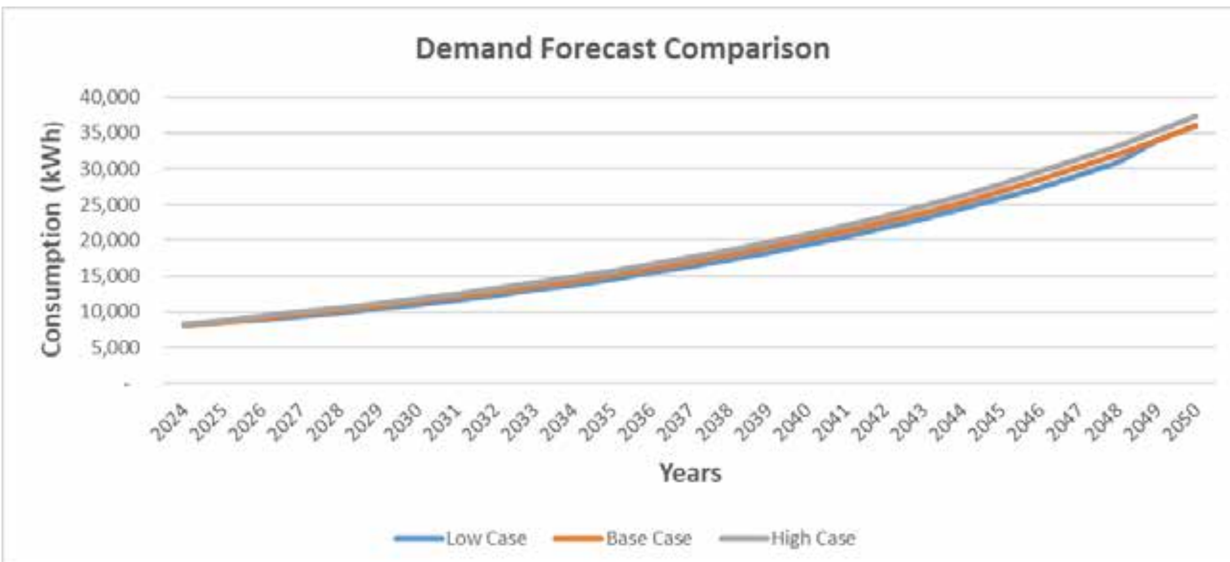

Figure 3-7: Comparison of Econometric Forecast

3.7 Conclusion

The derived forecast of electrical energy and peak power demand covers the period 2024 to 2050. The forecast consists of two components, namely, a forecast based on the historical pattern of electricity consumption for each tariff category and a forecast deriving from emerging issues that cannot be captured by historical profiles of energy and peak demand. A forecast using the Econometric method was developed to confirm the relationship between electricity consumption and economic variables. A forecast using trend analysis method gave the growth pattern of future growth of forecast results. The

[11] *Ministry of Finance and Planning*

power demand from emerging issues and Energy Compact Program (M300) complemented the demand forecast

The result indicates that generation requirement is projected to grow from 13,527 GWh in 2024 to 61,965,617.70 GWh in 2050. The corresponding peak demand is expected to grow from 2,159.80 MW to 10,105.29 MW as detailed in **Table 3-16.** This growth in demand signifies requirement for additional generation and transmission capacities.

CHAPTER FOUR

POWER GENERATION PLANNING

4.1 Introduction

The Plan presents the generation infrastructure expansion requirement to cater for the country's load forecast. The planning horizon is from 2024 to 2050, and it is divided into Short-Term (2024-2028), Medium-Term (2029-2038), and Long-Term (2039-2050). The chapter comprises the objective, methodologies, factors considered, results, and conclusion.

The generation expansion plan reviewed the existing power generation capabilities to meet projected demand growth from 2024 to 2050. The Plan determined the retirement schedule for power plants and evaluated the available energy resources to support future power generation needs. The candidates for power expansion were evaluated based on cost per capacity to be installed and electricity generation cost per unit, to ensure optimal sequencing of power generation over the planning horizon. After assessing Low, Base, and High case expansion scenarios, a Base-Case Generation was selected as the optimal pathway for power development up to 2050.

The generation plan results (Base-Case) indicate the cumulative total capacity to be **18,905.19 MW,** consisting of an additional **15,813.48 MW** by the end of the planning horizon in 2050. These additions have cost estimates of **USD 32,684.40** million**.** A total of **USD 6,379.60** million is required in the short term, **USD 13,935.60** million in the medium term, and **USD 12,369.20** million in the long term.

4.2 Objective

The generation expansion plan aims to ensure sufficient power generation capacity to meet the forecasted demand in the planning horizon. The Plan intends:

i. To identify a definitive short, medium and long-term power generation plan.
ii. To ensure a reliable, sustainable and affordable supply of electrical energy to serve the forecasted demand and support economic development and environmental protection.
iii. To improve energy security, optimize resource utilization, diversify the generation mix and foster cross-border power trade.
iv. To estimate the capital cost requirement.

4.3 Approach and Methodology

The generation plan follows a structured and data-driven approach to ensure accuracy, reliability, and comprehensiveness in the planning process. The methodology involved the following steps:

4.3.1 Data Collection and Review

i. Historical power generation and forecasted demand,
ii. Previous Power System Master Plans (2008, 2012, 2016, and 2020 Updates).
iii. Reports from national and international organizations, such as the International Atomic Energy Agency (IAEA) and the U.S. Energy Information Administration (EIA), were used to benchmark costs and technical parameters.
iv. Feasibility study of various candidate projects.

4.3.2 Planning Criteria and Scenario Development

i. The study adopted key generation planning criteria, including reserve margins, unit capital costs, fuel availability, environmental considerations, and lead times for project development.
ii. Demand scenarios (Low, Base and High) were assessed to evaluate the optimal generation expansion plan.

4.3.3 Generation Mix Optimization

i. Screening of power generation candidates was done based on economic feasibility, environmental sustainability, and implementation readiness
ii. A diversified energy mix was considered, including Hydropower, Natural Gas, Geothermal, Wind, Solar, Hydrogen and Uranium energy sources.

4.3.4 Hydrological and Environmental Assessment

i. A hydrological analysis was conducted to evaluate water availability for hydropower projects, ensuring resilience to climate variability.
ii. Environmental and social impact assessments were considered to ensure sustainability and compliance with regulatory frameworks.

4.3.5 Project Ranking and Selection

i. Candidate power projects were ranked based on cost-effectiveness, energy security, and project readiness.

ii. The plan prioritized projects that support Tanzania's participation in regional power trading within the Southern African Power Pool (SAPP) and the East African Power Pool (EAPP).

4.3.6 Results Validation and Sensitivity Analysis

i. The proposed generation expansion plan was tested under different load growth scenarios and economic conditions to ensure its flexibility and reliability.
ii. Sensitivity analyses were performed to assess the impact of changes in fuel prices, investment costs, and demand growth on the power system.

4.4 Factors Considered in the Generation Plan

4.4.1 Existing Power Generation System

The total installed generation capacity in the country stands at 3,111.90 MW, comprising the interconnected Grid System (3,091.71 MW) and the Isolated Grid System (20.19 MW). As of December 2024, the National Grid System consists of hydro and thermal power plants owned by TANESCO and Independent Power Producers (IPPs), as illustrated in **Figure 1**. The current generation mix includes hydro, natural gas, liquid fuel, and biomass sources, as detailed in **Figure 2**. The System Maximum Demand was 1,888.72 MW recorded on 26th November 2024.

In 2024, the electricity generated was 11,628.83GWh compared to generation in 2023 of 10,079.47GWh, whereby 2,707.54 GWh and 7,369.93 GWh were generated by hydro and thermal, respectively. Electricity generated was complemented by imports of 197.36 GWh from Uganda and Zambia.

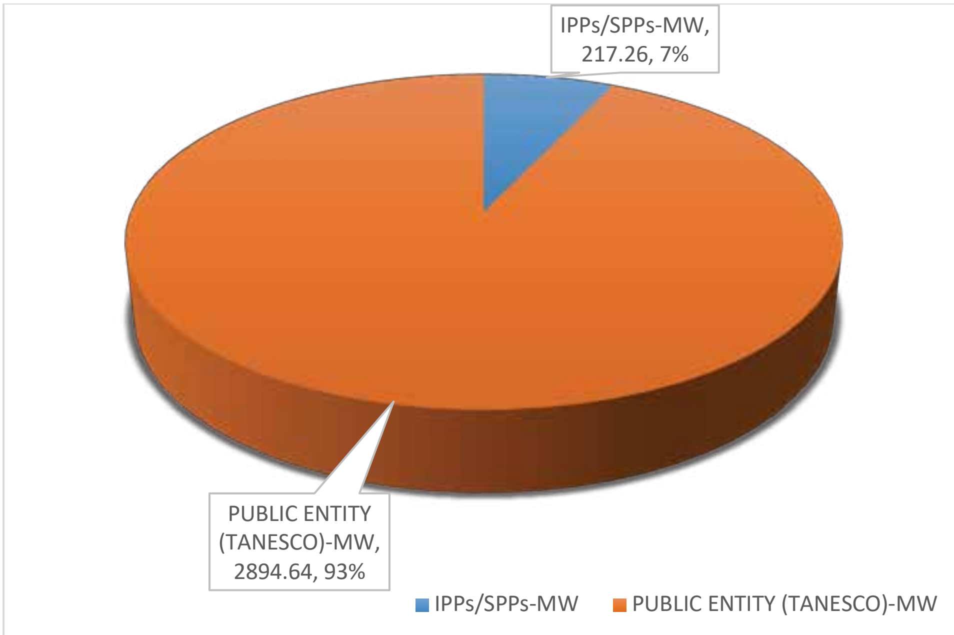

Figure 4- 1: *Grid Installed Capacity by Ownership*

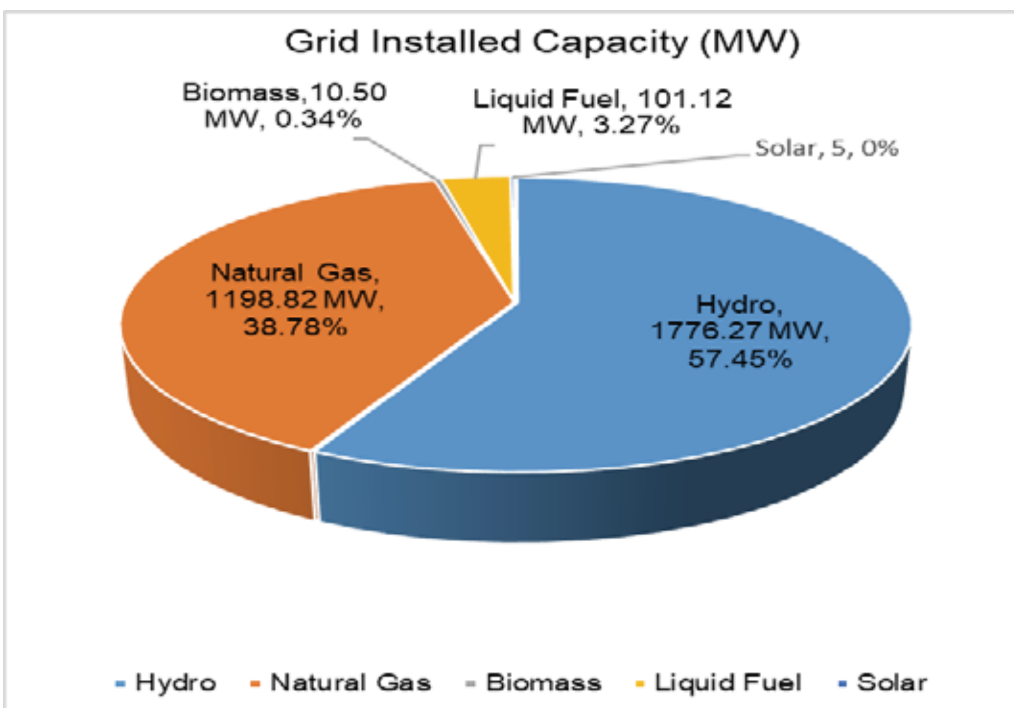

Figure 4- 2: *Current Generation Mix*

4.4.1.1 Existing Hydro Power Plants

As of 2024, the hydro generation system consists of 16 hydropower plants connected to the National Grid Network with a total installed capacity of 1,776.27 MW. The plants comprise seven (7) large and nine (9) small hydro (below 10MW), as shown in **Table 4-1**. The large hydropower plants and two (2) small hydropower plants are owned by the government through TANESCO, while seven (7) small power plants are owned by the private sector (SPPs).

Table 4-1: Existing Hydro Power Plants

S/N	Plant Name	Installed Capacity (MW)	Annual Average Energy (GWh)	Annual Minimum Energy (GWh)	Year Installed	Retirement Year	Age in 2024
1	Mtera	80	368.1	166.68	1988	2038	36
2	Kidatu	204	963	558.34	1975	2025	49
3	JNHPP	1175	7420	5920	2023	2074	1
4	Rusumo	26.67	84.7	43	2023	2073	1
5	Hale	21	93	55	1967	2017	57
6	Kihansi	180	779.8	501.11	2000	2050	24
7	NewPangani Falls	68	248.3	119.31	1995	2045	29
8	Nyumba ya Mungu	8	35.1	20.1	1968	2018	56
9	Uwemba	0.84	7.3	2.3	1991	2041	33
10	Mwenga	4	24	6	2012	2027	12
11	Luponde	0.9	5.85	3.14	2021	2041	3
12	Yovi	0.95	8.3	8.3	2012	2031	12
13	Matembwe	0.59	0.4	0.57	2015	2026	9
14	Darakuta	0.32	0.2	0.32	2013	2033	11
15	Andoya	1	5.2	5.91	2015	2025	9
16	Tulila	5	30	6.176	2015	2035	9
TOTAL		**1,776.27**	**10,073.25**	**7,416.26**			

4.4.1.2 Characteristics of Existing Hydropower Plants

Table 4-2 and **Table 4-3** present the characteristics of large and small hydropower plants, including their firm and average energy as defined by the volume of water and respective plant heads. Furthermore, they provide an overview of the factors that were considered before constructing the plant. The average economic life of a hydropower plant is 50 years.

Table 4-2: Large Hydropower Plants

Project Name	**Mtera**	**Kidatu**	**Nyumba Ya Mungu**	**Hale**	**New Pangani Falls**	**Lower Kihansi**	**JNHPP**	**Rusumo**
Owner	TANESCO	TANESCO	TANESCO	TANESCO	TANESCO	TANESCO	TANESCO	RPCL
Location	Iringa	Morogoro	Kilimanjaro	Tanga	Tanga	Morogoro	Morogoro	Kagera
Type	Reservoir	Reservoir	Reservoir	Run-off river	Run-off river	Run-off river	Reservoir	Run-off river
Max. Dam level (m.a.s.l.)	698.5	450	688.91	342.44	177.5	1,146.00	184	1320.5
Min. Dam level (m.a.s.l.)	690	433	679.15	342.44	176	1,141.00	163	1317.0
Recommended min. operational level (m.a.s.l.)	690	437	683.76	N/A	176.5	1,143.00	163	1317.0
Storage vol. at max. level (mill. m3)	3,750.00	167	1,118.11	0	1.31	1.62	32,782	
Storage vol. at min. level (mill. m3)	563	40	246.71	0	0.5	0.62	13,410	
Active storage volume (mill. m3)	3,200.00	125	600	0	0.8	1	19,372	
Surface area at max. vol. (km2)	604.96	9.62	148.52	0	0.75	0.27	1,194.40	
Gross head at max. level (m)	101.0 (Francis)	175.0 (Francis)	25.2 (Francis)	70.0 (Francis)	169.7 (Francis)	852.7 (Pelton)	117.24 (Francis)	29
Gross head at min. level (m)	92	160	20.6	70	168	847.75	78.13	27
Energy equivalent (kWh/m3)	0.23	0.42	0.05	0.13	0.42	2.06	0.29	
Firm energy generation (GWh)	166.68	558.34	20.1	55	119.31	501.11	5,920	
Average energy (GWh)	429	1,111.00	35	93	341	694	6307	166.67
Avg. generation for each m3/s (MW/(m3/s)	0.85	1.5	0.2	0.5	1.5	7.4	1.026	
Rated turbine discharge (total plant) (m3/s)	96	140	42.5	45	45	23.76	229	120

Table 4-3: Small Hydropower Plants

Project Name & Characteristics	Mwenga	Tulila	Andoya	Darakuta	YOVI	Matembwe	Uwemba	Luponde
Owner	IPP	IPP	IPP	IPP	IPP	IPP	TANESCO	IPP
Location	Iringa	Ruvuma	Ruvuma	Manyara	Morogoro	Njombe	Njombe	Njombe
Type	Run-off river	Run-off river	Run-off river	Run-off river	Run-off river		Run-off River	Run-off river
Max. supply level (m.a.s.l.)	1,127.00	747.5	N/A	N/A	1,225.01	1,489.50	N/A	N/A
Min. supply level (m.a.s.l.)	1,127.00	746.5	N/A	N/A	1,224.30	1,480.00	N/A	N/A
Recommended min. operational level (m.a.s.l.)	1,127.00	746.5	N/A	N/A	N/A	N/A	N/A	N/A
Storage vol. at max. level (mill. m3)	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Storage vol. at min. level (mill. m3)	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Active storage volume (mill. m3)	N/A - Run of River	0.6	N/A	N/A	N/A	N/A	N/A	N/A
Surface area at max. vol. (km2)	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gross head at max. level (m)	62	7.5 (Kaplan)	36 (Francis)	N/A	357.3	N/A	N/A	N/A
Gross head at min. level (m)	58.5	22.5	36	N/A	357.3	10	N/A	N/A
Energy equivalent (kWh/m3)	N/A - Run of River	N/A	N/A	N/A	2,763.00	N/A	N/A	N/A
Firm energy generation (GWh)	6	6.18	5.91	0.32	8.3	0.57	N/A	N/A
Average energy (GWh)	24	30	5.25	0.2	8.3	0.4	7.3	N/A
Avg. generation for each m3/s (MW/(m3/s)	0.5	0.19	0.28	N/A	2.76	N/A	N/A	N/A
Rated turbine discharge (total plant) (m3/s)	8	26.6	3.6	N/A	0.36	N/A	N/A	N/A

4.4.1.3 Characteristics of Thermal Power Plants

The thermal generation system consists of 27 power plants connected to the National Grid Network with a total installed capacity of 1,291.18 MW and 29.35 MW connected to an isolated system, as shown in **Table 4-4**. The average economic life of thermal power plants is twenty-five (25) years. Through proper maintenance and interim replacement of major parts, the plant's economic life may reach about 30 years.

4.4.4.3 Solar Power Projects

The power expansion plan considered solar sites with a proven p
1,674MWp to be candidates for generating 3,666.06 GWh as shown

Table 4-21: Solar Power Projects

Table 4-4: Thermal Power Plants

Plant	Technology	Fuel	Units	Installed Capacity (MW)	Available Capacity (MW)	Station Service (%)	Net Available Capacity (MW)	FOR (%)	Combined Outage Rate (%)	Maximum Plant Factor (%)	Annual Available Energy (GWh)	Year Installed	Nominal Service Life Years	Retirement Year
IPP UNITS														
TANWAT	STG	Bagasse	1.00	1.50	1.00	2.00	0.97	5.00	13.00	50.00	4.04	2010	20	2030
TPC	STG	Bagasse	1.00	9.00	7.00	2.00	6.82	5.00	13.00	50.00	28.38	2011	20	2031
Subtotal				**10.50**	**8.00**	2.00	**7.79**				**32.41**			
TANESCO UNITS														
Ubungo I	GE	Gas	10.00	102.00	55.00	2.00	52.96	5.00	13.00	80.00	352.59	2007	20	2027
Songas	GT	Gas	6.00	189.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2006	20	2026
Ubungo II	GT	Gas	3.00	129.00	124.00	2.00	121.42	5.00	13.00	80.00	808.37	2011	25	2036
Ubungo III	GT	Gas	4.00	92.50	85.00	2.00	83.15	5.00	13.00	80.00	553.58	2008	25	2033
Kinyerezi I	GT	Gas	8.00	335.00	300.00	2.00	293.30	5.00	13.00	80.00	1952.67	2015	25	2040
Kinyerezi II	GT	Gas	8.00	248.22	220.00	2.00	215.04	5.00	13.00	80.00	1431.62	2018	25	2043
Tegeta	GE	Gas	5.00	45.00	40.00	2.00	39.10	5.00	13.00	80.00	260.31	2009	20	2029
Mtwara I	GE	Gas	9.00	30.60	19.00	2.00	18.39	5.00	13.00	80.00	122.42	2007	20	2027
Mtwara II	GE	Gas	2.00	20.00	16.00	2.00	15.60	5.00	13.00	80.00	103.86	2008	25	2033
Somanga	GE	Gas	3.00	7.50	1.00	2.00	0.85	5.00	13.00	80.00	5.66	2010	20	2030
Subtotal				**1198.82**	**860.00**		**839.80**				**5591.08**			
TANESCO Reserve Capacity - Grid Connected														
Biharamulo	DG	Diesel	5.00	2.72		2.00	-	8.00	18.00	75.00	-	2015	20	2035
Zuzu	DG	Diesel	3.00	7.44	5.00	2.00	4.85	8.00	18.00	75.00	29.32	1980	20	2000
Nyakato	DG	HFO	10.00	63.00	29.00	2.00	27.74	8.00	18.00	75.00	167.67	2013	20	2033
Songea	DG	Diesel	3.00	5.74	-	2.00	0.00	8.00	18.00	75.00	-	2005	20	2025
Ludewa	DG	Diesel	3.00	1.27	-	2.00	0.00	8.00	18.00	75.00	-	2010	20	2030
Mbinga	DG	Diesel	2.00	1.00	-	2.00	0.00	8.00	18.00	75.00	-	2007	20	2027
Madaba	DG	Diesel	1.00	0.00	-	2.00	0.00	8.00	18.00	75.00	-	2010	20	2030
Namtumbo	DG	Diesel	1.00	0.00	-	2.00	0.00	8.00	18.00	75.00	-	2012	20	2032
Ngara	DG	Diesel	2.00	1.25	-	2.00	0.00	8.00	18.00	75.00	-	2015	20	2035
Liwale	DG	Diesel	2.00	0.85	-	2.00	0.00	8.00	18.00	75.00	-	2013	20	2033
Tunduru	DG	Diesel	4.00	2.06	-	2.00	0.00	8.00	18.00	75.00	-	1991	20	2011
Kigoma	DG	Diesel	7.00	8.75	8.75	2.00	8.58	8.00	18.00	75.00	36.78	2010	20	2030
Kasulu	DG	Diesel	2.00	2.50	2.50	2.00	2.45	8.00	18.00	75.00	14.81	2011	20	2031
Kibondo	DG	Diesel	2.00	2.50	2.50	2.00	2.45	8.00	18.00	75.00	14.81	2011	20	2031
Loliondo	DG	Diesel	4.00	3.75	2.50	2.00	2.43	8.00	18.00	75.00	14.66	2012	20	2032
Subtotal				**102.83**	**50.25**		**48.49**				**278.05**			
TOTAL ON GRID				**1312.15**	**918.25**		**896.08**				**5901.54**			
Off-Grid														
Mafia	DG	Diesel	4.00	3.00	2.40	2.00	2.34	8.00	18.00	75.00	14.14	1970	20	1990
Mpanda	DG	Diesel	5.00	5.41	3.75	2.00	3.64	8.00	18.00	75.00	22.01	1992	20	2012
Inyonga	DG	Diesel	3.00	1.64	1.64	2.00	1.61	8.00	18.00	75.00	9.72	2015	20	2035
Kasulu	DG	Diesel	2.00	2.50	2.50	2.00	2.45	8.00	18.00	75.00	14.81	2011	20	2031
Bukoba	DG	Diesel	4.00	2.56	2.20	2.00	2.15	8.00	18.00	75.00	12.99	1991	20	2011
Sumbawanga	DG	Diesel	4.00	5.00	5.00	2.00	4.90	8.00	18.00	75.00	29.62	2011	20	2031
Liwale	DG	Diesel	2.00	0.85	-	2.00	0.00	8.00	18.00	75.00	-	2013	20	2033
Kibondo	DG	Diesel	2.00	2.50	2.50	2.00	2.45	8.00	18.00	75.00	14.81	2010	20	2030
Subtotal (off grid)				**23.45**			**19.54**				**118.10**			
Grand Total				**1335.60**			**915.62**				**6019.64**			
Available energy =		Available capacity * (8760*100-FOR*max plant factor)												
FOR = Forced outage rate														

ential capacity of

Table 4-21.

4.4.1.4 Biomass Power Plants

The existing biomass power plants connected to the National Grid with an installed capacity of 10.5 MW are detailed in **Table 4-5.** The average economic life of a biomass power plant is 15 years. Through proper maintenance and interim replacement of major equipment, the plant's economic life may be extended beyond 15 years.

Table 4-5: Biomass Power Plants

Plant	Technology	Fuel	Installed Capacity (MW)	Year Installed	Retirement Year	Status
TANWAT	STG	Bagasse	1.5	2010	2030	Grid Connected
TPC	STG	Bagasse	9.0	2011	2031	Grid Connected
Subtotal			**10.5**			

4.4.1.5 Captive Power Plants

The existing captive power plants with an installed capacity of 303.583 MW are detailed in **Table 4-6**. Depending on the type of fuel and generation technology, the average economic life ranges from 15 to 25 years. The captive generation is largely used for meeting its power requirements at the respective facilities.

Table 4-6: Captive power plant

S/N	Name of Licensee	Project Area	Energy Source	Capacity (MW)	Duration (Years)	License No.	Date of Issue	Date of Expiry
1	Lake Cement Limited	Kimbiji Village, Temeke	Coal	15.4	15	BEGL-2016-001	29-Mar-16	28-Mar-31
2	Tanga Cement Public Limited Co.	Tanga	Diesel	11.48	15	SEGL-2016-001	10-Apr-16	10-Mar-31
3	Kilombero Sugar Company Ltd.	Kidatu - Morogoro	Biomass	12.552	15	BEGL-2017-001	18-Apr-17	17-Apr-32
4	Shanta Mine Co. Ltd	Songwe	Diesel	8.2	15	BEGL-2018-001	2-Feb-18	2-Jan-33
5	Kilombero Plantations Limited	Morogoro	Biomass	1.692	15	EGL-2018-001	30/2/2018	29-Aug-33
6	Geita Gold Mining Limited	Geita	Diesel	40	25	BEGL-2018-002	12-Mar-99	12-Feb-24
7	Tanzania Cigarette Public Ltd. Co.	Dar es Salaam	Natural Gas	4.7	5	EGOWL-2024-001	1/Nov/24	31/Oct/29

S/N	Name of Licensee	Project Area	Energy Source	Capacity (MW)	Duration (Years)	License No.	Date of Issue	Date of Expiry
8	Stamigold Co. Ltd.	Biharamulo	Diesel	7	15	BEGL-2019-002	22-Mar-19	21-Mar-34
9	ALAF Ltd.	Dar es Salaam	Natural Gas	4	5	BEGL-2020-001	30-Jan-20	29-Jan-25
10	North Mara Goldmine Ltd	Tarime	Heavy Fuel Oil	18	5	EGOWL-2020-001	27-Nov-20	26-Nov-25
11	Bulyanhulu Goldmine Ltd	Kahama	Heavy Fuel Oil	39.1	5	EGOWL-2020-002	27-Nov-20	26-Nov-25
12	Dangote Cement Limited	Mtwara	Natural Gas	50	5	EGOWL-2021-001	28-Jun-20	27-Jun-26
13	Maweni Limestone Ltd.	Tanga	Coal	7.5	5	EGOWL-2022-002	29-Sep-22	28-Sep-27
14	Bagamoyo Sugar Ltd.	Bagamoyo	Biomass	5	5	EGOWL-2022-001	9-Sep-22	8-Sep-27
15	Kagera Sugar Ltd.	Kagera	Diesel, Biomass	27.5	15	EGOWL-2022-003	27-Oct-22	17-April-32
16	Mufindi Paper Mills Limited	Mufindi	Biomass	10.4	5	EGOWL-2024-002	29/Nov/24	28/Nov/29
17	Mtibwa Sugar Estates Limited	Turiani	Biomass	15	5	EGOWL-2024-003	29/Nov/24	28/Nov/29
18	Kioo Limited	Dar es Salaam	Natural Gas	12.2	5	EGOWL-2025-001	31/Jan/25	30/Jan/30
19	Gas Company T LTD - GASCO	Songosongo	Natural Gas	10.7	5	EGOWL-2025-002	31/Jan/25	30/Jan/30
20	Gas Company T LTD - GASCO	Madimba	Natural Gas	3.159	5	EGOWL-2025-003	31/Jan/25	30/Jan/30
Total				**303.583**				

4.4.1.6 Existing Capacity Retirement

A review of the existing generation system indicates that 13 power plants are due for retirement by 2030, as shown in **Table 4-7.** The best industrial practice suggests that power plants, upon reaching useful economic life, should be retired. About 29MW of hydro (Hale 21MW and Nyumba ya Mungu 8MW) should have been retired by 2018. Hale power plant is undergoing major rehabilitation, while Nyumba ya Mungu is still in operation, while major efforts for rehabilitation is ongoing. Additionally, a total of 606.39 MW (209.59 MW of Hydro and 396.8 MW of thermal) are expected to retire by 2030. Considering the importance and ongoing rehabilitation efforts, the power plants are still accounted for in future generations to meet power requirements.

The retirement of privately owned power plants that are connected to the grid system is based on the expected expiry of respective Power Purchase Agreements (PPAs) and Standardised Power Purchase Agreements (SPPAs). In the event of the expiry of Agreements, such plants are not considered in future generation power planning.

Table 4-7: Power Plant Retirements by 2030

S/N	Plant Name	Installed Capacity(MW)	Normal Service Life (years)	Year Installed	Retirement Year
A	**HYDRO**				
1	Hale	21	50	1967	2017
2	Nyumba ya Mungu	8	50	1968	2018
3	Kidatu	204	50	1975	2025
4	Andoya	1	10	2015	2025
5	Matembwe	0.59	10	2016	2026
6	Mwenga	4	15	2012	2027
B	**THERMAL**				
1	Songas	189	20[12]	2004	2024
2	Mtwara I	30.6	20	2007	2027
3	Ubungo I	102	20	2008	2028
4	Tegeta Gas Engine	45	20	2009	2029
5	Mtwara II	20	20	2010	2030
6	Somanga	7.5	20	2010	2030
7	TANWAT	2.7	20	2010	2030

4.4.2 Energy Resources for Power Generation

Tanzania has abundant indigenous energy resources, including Hydro, estimated to generate around 7,491.2MW, Natural gas with proven reserves of 57.54 TCF, where 47.13 TCF are offshore and 10.406 TCF onshore, and The solar resources in Tanzania are generally very good, with solar irradiation levels ranging from 1800 to 2400 kWh per square meter per year. Other resources include Wind with more than 7,000MW at an average speed of 10m/s, Coal reserves with a potential of 5 billion tonnes of which 0.4

[12] The Power Purchase Agreement expired on 31st July 2024, unless it is renewed

billion tonnes are proven, Uranium 58,500 tons, Geothermal potential of 5,000MW, and abundant Biomass resources.

4.4.2.1 Hydro

The hydropower potential consists of 7,491.2MW, with only 36 per cent equivalent to 2,716.27MW currently harnessed for power generation. **Table 4-8** presents several potential sites with varying capacities. It is considered that the remaining hydro potentials will be developed and therefore will form part of a future power generation expansion plan.

Table 4-8: Hydropower Potential in Tanzania

S/N.	Range of Capacity (MW)	Total Capacity (MW)	Percentage%	Number of Potential Sites
1	0−9	602.31	8.0	450
2	10−49	396.6	5.3	22
3	50−199	2,453.30	32.7	21
4	200 −500	1,924.00	25.7	7
5	Over 500	2115	28.2	1
	Total	**7491.2**	**100**	**501**

Source: *2020 PSMP Update. Renewable Energy Resource Mapping: Small Hydro-Tanzania 2018*

4.4.2.1.1 Hydrological System

Hydrology is one of the significant risk events that could lead to an energy supply shortage. To effectively evaluate potential hydroelectric power development options, it is crucial to undertake a comprehensive assessment of the hydrological systems and the operational capabilities of existing and prospective hydroelectric power infrastructures. Reliable historical river flow records, ideally extending for at least 30 years, are fundamental for accurately determining the power generation capacity of any hydroelectric system.

This plan integrates insights from ongoing hydroelectric projects and leverages datasets developed during previous iterations of the Power System Master Plan. The analysis is underpinned by an intensive review of existing hydrological datasets.

4.4.2.1.2 Hydrological Characteristics Assessment

The hydrological characteristics of rivers that feed into reservoirs of both existing and potential large-scale hydropower plants are presented in **Table 4-9** and **Table** 4-10**.** These tables detail the specific gauging stations utilized for the collection of hydrological data, ensuring a robust framework for data-driven decision-making in hydropower planning.

Table 4-9: Hydrological Characteristics Assessment for existing Power Plants

PLANT	GAUGING STATION(s)	PERIOD (Year)	FLOW (m^3/s) Max	Min	Mean	REMARKS
Nyumba ya Mungu	Kikuletwa River at TPC (1DD1)	2010 -2024	163.72	7.90	22.87	During wet seasons, when both rivers experience high flows, the plant can maximize power output. Managing reservoir levels and flow rates during dry seasons becomes critical to ensure continuous power supply.
	Ruvu River at Kifaru (1DC2A)	2010 -2024	58.10	1.40	6.02	
Hale/sPangani	Pangani River at Korogwe(1D14)	2010 - 2024	161.45	1.72	17.14	Flow variability presents challenges, but it also offers opportunities for maximizing hydropower output, especially if integrated management strategies are employed across these river systems.
	Pangani River at Mnyuzi (1D17A)	2010 - 2024	107.90	1.57	14.13	
	Luengera River at Korogwe(1DA1)					
Mtera	Kizigo River at Chinugulu	1980 - 2023	1805	0.00	34.33	For Kizigo and Great Ruaha, with frequent high peaks and significant under-average flows, the reservoir must be resilient against floods and equipped to conserve water during droughts. This might involve advanced forecasting tools, flexible turbine operations, and spillage. Little Ruaha, has relatively moderate flow variability.
	Little Ruaha River at Mawande(1KA31)	1989 - 2023	92.26	0.18	21.65	
	Great Ruaha River at Msembe (1KA59)	1980 - 2023	1397	0.00	42.6	
Kidatu	Great Ruaha River at Msosa (1KA5)	1990 - 2023	379.09	26.16	88.91	During years or seasons of low flow, the plant might need to operate below capacity, necessitating the use of alternative energy sources
	Yovi River at Confluence (1KA38A)					
	Lukose River at Mtandika (1KA37)	1958 -2023	37.84	12.72	61.2	
Kihansi	Kihansi River at Lutaki (1KB32)	2006 - 2024	51.28	3.97	15.57	Supplementary power sources might be necessary during lower flow periods to ensure a stable power supply. Long-term sustainability practices, such as watershed management and possibly weather forecasting integration, are crucial. These practices help anticipate changes in water availability and plan accordingly.
JNHPP	Rufiji River at Stielers Gorge	1959 - 2022	7144.00	40.61	931.51	Effective management of flow variability is crucial. It involves using reservoirs to regulate river flow, ensuring that there is enough water during dry spells and mitigating flood risks during periods of high discharge.

PLANT	GAUGING STATION(s)	PERIOD (Year)	FLOW (m^3/s)			REMARKS
			Max	Min	Mean	
						The operation of the hydropower plant must be adaptable, with the ability to scale generation up or down based on real-time water availability. This adaptive management helps optimize power output while protecting the hydraulic infrastructure.

Table 4-10: Details of the Gauging Stations for Hydrological Data Monitoring for Planned Power Plants

PROJECT	GAUGING STATION(s)	PERIOD (Year)	Flow (m^3/s)			REMARKS
			Max	Min	Mean	
Malagarasi	Malagarasi River at Mbelagure(4A9)	1977-2023	800	17.20	135.40	To handle high flows and store excess water during peak periods, potentially using it during dry seasons. Adjustable turbine operations to optimize electricity production throughout varying flow conditions.
Kakono	Kagera River at Pumping Station	2014-2023	564.20	138.65	213.00	To account for the impact of low-flow periods, the hydropower project may need to incorporate a storage reservoir
Ruhudji	Ruhudji River at Itipula (NC2)	2008-2023	171.91	3.00	30.93	A reservoir or regulated release facility might be needed to buffer against low-flow periods and store water during peak flows.
Rumakali	Rumakali River at Mwakauta(1RC1 1A)	1981-2023	101.70	1.58	14.38	Flow variability necessitates the development of a flexible operational strategy that can adjust to changing water levels without compromising efficiency and economic viability.
Masigira	Ruhuhu River at Masigira(1RB2)	2010 -2020	228.10	5.28	31.90	Operational flexibility, including quickly adjusting power production based on water availability, will be crucial.
Kikonge	Kikonge (1RB3)	1971-2023	1332.00	22.60	178.10	To mitigate the impact of flow variability, the dam design might include a large reservoir

PROJECT	GAUGING STATION(s)	PERIOD (Year)	Flow (m^3/s)			REMARKS
			Max	Min	Mean	
						to regulate water flow, ensuring water availability during dry periods and the ability to manage flood risks during high flow periods.
Mpanga	Mpanga River at Mpanga Mission(1KB8)	2010-2020	92.45	9.56	30.60	Operational strategies need to be developed to maximize power output during high flow periods while maintaining sufficient reservoir levels during the dry season to ensure continuous power generation

Source: *River basin flow reports, TANESCO/basin authorities.*

4.4.2.1.3 Strategic Location for Development of Hydropower

The existing large hydroelectric power plants (2,579MW), including JNHPP, Kidatu, Kihansi, and Mtera, are located within the Rufiji Water Basin. There is a risk associated with poor hydrology if one water basin is affected, with consequent loss of power generation capacity. Diversification of hydropower plants to different water basins will mitigate hydrological risk and alleviate water usage stress, among other factors.

It is therefore recommended that priority should be given to developing future hydropower projects that are located in other basins, such as those in the Nyasa Basin. Special emphasis should be placed on advancing projects such as the 321 MW Kikonge Multipurpose Dam and the 222 MW Rumakali Hydropower Project, both located in the Lake Nyasa Basin. These projects offer significant potential and can serve as a strategic counterbalance to the existing concentration of hydropower facilities in the Rufiji Basin.

Projects such as the Ruhudji, Mpanga, and Mnyera Hydropower Projects should be re-evaluated, considering the cumulative impact and existing hydroelectric saturation in the basin.

4.4.2.2 Natural Gas Resources

Tanzania has a significant amount of natural gas resources of 57.54 TCF, out of which, approximately 7.5 TCF, representing 13% of Gas Initially in Place (GIIP) has been developed. By 2023, the total daily gas production reached 233 mmscfd, whereby 81%, equivalent to 189.51 mmscfd was allocated for power generation. The trend of natural gas consumption in power generation from 2004 to 2023 has increased from 14.5BCF to

67.8BCF. The Natural Gas Utilization Master Plan (NGUMP) forecasts that from 2024 to 2050 the electricity sub-sector will be a significant gas user.

The TPDC Business Plan projects that gas production will rise to 353 million standard cubic feet per day (mmscfd) between 2028 and 2050, peaking at 527 mmscfd in 2032 following the commencement of production from the Tanzania LNG (TLNG) project. The primary sources will be the Songo Songo and Mnazi Bay fields, with Mnazi Bay expected to add 45 mmscfd in 2026. Additionally, new production is anticipated from the Ntorya Gas Field in 2026 (60 mmscfd) and the TLNG project in 2032 (168 mmscfd). **Table 4-11** outlines the natural gas discoveries up to 2015. The amount of gas allocated for power generation is as shown in **Table 4-12**.

Table 4-11: Natural Gas Discoveries

S/N	Discovery Block/ Location	Year Discovered	Gas Reserve December 2023 (Tcf)	Resource -GIIP (Tcf)
1	Songosongo	1974	0.5983	2.5
2	Mnazi Bay	1982	0.4362	5
3	Kiliwani North	2008	Under study	0.07
4	Mkuranga	2007	Under study	0.2
5	Ntorya	2012	0.306	0.466
6	Mambakofi	2015	Under study	2.17
Total Gas Onshore				**10.406**
7	Block 1	2011	Under study	0.47
		2012	Under study	3.53
		2012	Under study	8.5
		2013	Under study	0.6
		2014	Under study	1.1
	Block 2 &	2013	Under study	6.0
		2012	Under study	3.6
		2013	Under study	1.4
8	Block 3	2013	Under study	5.4
		2014	Under study	2.5
		2014	Under study	3.0
		2015	Under study	1.7
		2015	Under study	1.8
		2012	Under study	2
	Block 4	2010	Under study	1.8
9				
		2010	Under study	1.9
		2013	Under study	0.8
		2014	Under study	1.03
Total Gas Deep Sea				**47.13**

S/N	Discovery Block/ Location	Year Discovered	Gas Reserve December 2023 (Tcf)	Resource -GIIP (Tcf)
Total Gas in Deep Sea and Onshore				**57.536**

Source: *TPDC*

Table 4-12: Natural Gas allocated for Power Generation from 2026-2045

Year	Additional Gas Power Plant-MW	Cummulative Gas Installed Capacity- MW	TANESCO gas requirement MMSCFD	TPDC Prod Forecast MMSCFD	Gas allocation to TANESCO (MMSCFD)	Equivalent Power- MW from allocated Gas	Gas Defficient (mmscfd)	Equivalent Power Defficient from Gas (MW)
2023	1198	1,198.0	189.51	233.35	189.51	913.44	0.00	0.00
2024	0	1,198.0	157.01	193.33	157.01	756.78	0.00	0.00
2025	0	1,198.0	159.76	196.72	159.76	770.05	0.00	0.00
2026	630	1,828.0	303.40	299.00	242.83	1170.42	-60.58	291.98
2027	200	2,028.0	336.60	314.00	255.01	1229.14	-81.59	393.26
2028	370	2,398.0	398.01	353.30	286.92	1382.98	-111.08	535.42
2029	985	3,383.0	561.49	356.37	289.42	1395.00	-272.07	1311.40
2030	-27.5	3,355.5	556.93	354.39	287.81	1387.24	-269.12	1297.16
2031	414	3,769.5	625.64	357.94	290.70	1401.15	-334.95	1614.45
2032	11.5	3,781.0	627.55	526.70	427.75	2061.75	-199.80	963.05
2033	0	3,781.0	627.55	531.84	431.92	2081.86	-195.63	942.94
2034	200	3,981.0	660.75	514.46	417.81	2013.84	-242.94	1170.96
2035	200	4,181.0	693.94	493.55	400.83	1931.98	-293.12	1412.82
2036	0	4,181.0	693.94	472.18	383.47	1848.34	-310.47	1496.46
2037	0	4,181.0	693.94	452.98	367.88	1773.16	-326.07	1571.64
2038	200	4,381.0	727.14	435.28	353.51	1703.90	-373.63	1800.90
2039	200	4,581.0	760.33	419.50	340.69	1642.11	-419.64	2022.69
2040	413	4,994.0	828.88	404.75	328.71	1584.37	-500.17	2410.83
2041	0	4,994.0	828.88	506.69	411.50	1983.41	-417.38	2011.79
2042	0	4,994.0	828.88	506.38	411.24	1982.19	-417.64	2013.01
2043	313	5,307.0	880.83	493.36	400.67	1931.23	-480.16	2314.37
2044	212	5,519.0	916.02	462.50	375.61	1810.43	-540.41	2604.77
2045	212	5,731.0	951.20	432.70	351.41	1693.80	-599.79	2891.00

Source: *TPDC and PSMP Team*

4.4.2.3 Geothermal

The available geothermal potential is 5,000MW, with only 22.2%, equivalent to 1,110MW are planned to be developed from 2028 to 2050. **Table 4-13** highlights geothermal sites with varying capacities**.**

Table 4-13: Geothermal Potential Sites in Tanzania

S/N.	Site Location	Region	Capacity (MW)
1	Ngozi	Mbeya	220
2	Kiejo Mbaka	Mbeya	225
3	Songwe	Songwe	60
4	Luhoi	Coast	45
5	Natron	Arusha	210
6	Meru	Arusha	145
7	Kisaki	Morogoro	145
8	Ibadakuli	Shinyanga	60
Total Capacity (MW)			**1,110**

4.4.2.4 Solar

Solar resource potential ranges from 4.5 to 6.0 kWh per square meter per day for about 10 hours from 0800 hours to 1700 hours as indicated in **Table 4-14**. This indicates that the solar potential is estimated to be more than 4,700MWp, whereby3,666.06 GWh (1,674 MWp) is proven resources from different sites

Table 4-14: Proven Solar Energy Potential Sites

S/N.	Region	District	Capacity (MWp)
1	Shinyanga	Kishapu	300
2	Singida	Manyoni	450
3	Dodoma	Zuzu	130
		Udom	150
	Kilimanajro	Same	100
4	Iringa	Iringa District	394
5	Njombe	Makambako	150
Total Capacity Solar Per year (MWp)			**1674**

4.4.2.5 Wind

The wind resources in Tanzania are generally good, with average wind speeds above 7 m/s at 100m height above ground level in many parts of the country. High elevations in the nation's central and western regions have good wind resources, with some areas experiencing wind speeds of more than 10m/s. The wind resources in Tanzania are particularly strong during the dry season, which runs from June to October. During this time, the air is generally dry and stable, which leads to strong and consistent wind speeds. The identified sites have a potential capacity of about 7,500MW, which can inject 26,413GWh into the Grid at an assumed plant factor of 40%.

4.4.2.6 Uranium

The National Energy Policy of 2015 and the Mineral Policy of Tanzania of 2009 acknowledge the availability of uranium resources in the country. Tanzania is confirmed to have Uranium resources of 58,500 tonnes discovered along the Mkuju River at the Namtumbo district. **Table 4-15** shows regions with prospects of uranium in Tanzania. The plan has considered 480 MW to be produced from uranium resources in 2050.

Table 4-15: Uranium Resources in Tanzania

S/N	Name	Region	Size (ton)/Status
1	Mkuju	Ruvuma	58,500
2	Kianju Mbuga	Singida	The study is ongoing
3	Ndala Mbuga	Tabora	The study is ongoing
4	Bahi Swamp	Dodoma	The study is ongoing

4.4.2.7 Coal

Tanzania has potential coal reserves of approximately 5 billion tonnes. 1,208 million tonnes are proven reserves that can be used for power generation. **Table 4-16** shows potential sites with coal reserves. Depending on the coal calorific value, and the assumption that one metric ton of coal can generate about 2200 kilowatt hours (kWh) of electricity, the available coal reserves can generate about 2.66 x 10^6 GWh of coal-fired.

Table 4-16: Potential Sites with Coal Resources in Tanzania

S/N	Coal Projects	Reserve (Million tone)	Equivalent (10^6)GWh
1	Mchuchuma	428	0.94
2	Ketewaka	100	0.22
3	Ngaka	423	0.93
4	Kiwira (Ivogo Ridge)	90	0.20
5	Mbeya	109	0.24
6	Rukwa	58	0.13
Total		**1,208**	**2.66**

4.4.2.8 Hydrogen

Hydrogen has recently emerged on the global market as a clean fuel capable of powering thermal plants. Some thermal power plant manufacturers have developed future facilities to use a combination of natural gas and synthetic fuels like hydrogen. Hydrogen is produced by electrolysis or by splitting natural gas through steam methane reforming (SMR). SMR requires carbon capture and storage (CCS) technologies to be in place, as CO_2 is produced during the process.

Hydrogen production costs vary depending on the source of energy used during the production process. In future, utilizing renewable energy to produce hydrogen through electrolysis will be cost-effective as it is proven as the cleanest method of producing hydrogen. Other hydrogen production technologies have emerged, compromising the cost of production with CO_2 emissions during production. However, the production cost of Hydrogen is expected to decrease with the global trends on clean energy and associated decarbonization goals. The Plan has considered hydrogen as one of the resources for power generation.

4.4.3 Generation Planning Criteria

Planning criteria for electricity generation expansion are crucial for a reliable and resilient power supply. The criteria guide in optimizing energy sources, maintaining capacity and operational reserves, as well as ensuring robust infrastructure and operational stability. The respective criteria are presented in this section.

4.4.3.1 Plant Life Span

The Plan considered life span as one of the criteria. **Table 4-17** shows the expected plant economic life spans for typical generation technology. The economic life has been used to determine the retirement of candidate power generation projects.

Table 4-17: Power Plants Life Span

S/N	Technology Type	Normal Service life (years)
1	Gas Turbines	25
2	Combined Cycle Gas Turbine	25
3	Medium Speed Diesel	20
4	Low-Speed Diesel	25
5	Coal	35
6	Hydroelectric Plant	50
7	Renewable (Wind, Solar, Geothermal)	25

4.4.3.2 Reserve Margin

The Plan considered surplus capacity to ensure sufficient supply to meet forecasted demand due to an increase in demand or an unexpected generation failure. The Plan assumes a reserve margin of 15 to 40 per cent of the system installed capacity.

4.4.3.3 Plant availability and energy generation

The Plan considered the availability of power generation plants, taking into account scheduled maintenance, forced outages, fuel availability, and renewable power plants intermittent nature.

4.4.3.4 Generation Mix

The plan considers the share of all resources, i.e., renewable, hydropower, and gas-fired power plants, to reduce reliance on a single source.

4.4.3.5 Outage rates

Both scheduled and forced outages were considered in the generation plan.
Table 4-27 and **Table 4-28** outline all outage rates based on different power generation technologies.

4.4.3.6 Unit capital cost

The Unit Capital Cost expressed in US Dollars per kilowatt ($/kW) or per Megawatt ($/MW), reflects the cost of building a unit capacity of a power plant. It is influenced by factors such as the technology used, the size and scope of the project, its location, the regulatory environment, and prevailing market conditions. This metric was used for assessing the economic feasibility of projects, aiding in financial planning, and facilitating comparisons between different technologies and projects, thus guiding investment decisions.

4.4.3.7 Operation and Maintenance Cost (O&M)

The Plan considered operation and maintenance costs for power plants over the planning horizon.

4.4.3.8 Lead Times

The Plan considered the lead time for the development of power projects. Thus, several factors were considered in estimating a minimum lead time for the project. These include feasibility studies, financing, design, Environmental Impact Assessment (EIA) and construction period.

4.4.3.9 Cross-Border Power Trading

The Plan considered imports and reserves for export to enable cross-border power trading. This is based on the fact that Tanzania has bilateral agreements for power trading with neighbouring countries and its membership in EAPP and SAPP. Power Trading has potential for improving power supply security, sharing of power reserves, access to least-cost energy, and auxiliary services (e.g. reactive power, black start power).

4.4.4 Candidate Projects for Power Generation

4.4.4.1 Hydro Power Projects

The projects identified from different sites across water basins are shown in **Table 4-18.** Twenty-eight (28) sites with a potential capacity of 2,580.20 MW are available for development within the next 25 years to meet the forecasted demand. The capacities and firm energies from various project studies have been used in this Plan.

Table 4-18: Hydropower Project Candidates

S/N	Project Name	Capacity (MW)	Plant Factor (%)	Average energy (GWh)	Firm energy (GWh)	River	River Basin
1	Malagarasi HPP	49.5	0.42	181.00	21.44	Malagarasi	Lake Tanganyika
2	Kakono HPP	87.8	0.42	321.05	335	Kagera	Lake Victoria
3	Kidunda Morogoro DAWASA	20	0.50	87.60	87.6	Ruvu	Wami-Ruvu
4	Ruhudji	358	0.64	2,000.00	1,333	Ruhudji	Rufiji
5	Rumakali	222	0.68	1,322.00	1,075.90	Rumakali	Lake Nyasa
6	Masigira	118	0.64	664.00	492	Ruhuhu	Lake Nyasa
7	Songwe Manolo - lower	90	0.68	536.11	295.1	Songwe	Lake Nyasa
8	Kikonge	321	0.48	1,356.76	883.82	Ruhuhu	Lake Nyasa
9	Mpanga Iringa	160	0.54	756.86	717.8	Mpanga	Rufiji
10	Mnyera Kisingo	119.8	0.55	577.30	513.9	Mnyera	Rufiji
11	Mnyera Mnyera	137.4	0.55	662.30	589.4	Mnyera	Rufiji
12	Songwe Sofre - Middle	81.6	0.54	382.50		Songwe	Lake Nyasa
13	Mnyera Kwanini	143.9	0.55	693.80	617.3	Mnyera	Rufiji
14	Nsongezi (TZ-Portion)	12	0.50	52.56		Kagera	Lake Victoria
15	Upper Kihansi	120	0.60	628.24	99	Kihansi	Rufiji
16	Songwe Upper	29	0.60	151.82		Songwe	Lake Nyasa
17	Mnyera Pumbwe	122	0.55	587.86	527.2	Mnyera	Rufiji
18	Mnyera Taveta	83.9	0.55	404.23	622	Mnyera	Rufiji
19	Iringa Nginayo	52	0.58	264.20	223.1	Little Ruaha	Rufiji
20	Mbarali	39	0.42	142.61	107.9	Kimani Falls	Rufiji

S/N	Project Name	Capacity (MW)	Plant Factor (%)	Average energy (GWh)	Firm energy (GWh)	River	River Basin
21	Iringa Ibosa	36	0.59	186.06	106.9	Little Ruaha	Rufiji
22	Songwe Bupigu	17	0.51	75.95	50.5	Songwe	Lake Nyasa
23	Njombe	32	0.59	165.39	123.9	Ruhudji	Rufiji
24	Mhanga	27	0.50	118.26	74.6	Lukosi	Rufiji
25	Songea	15	0.42	54.85	82.41	Ruvuma	Ruvuma
26	Nakatuta (Liparamba)	15	0.50	65.70	29.7	Ruvuma	Ruvuma
27	Kikuletwa	11	0.50	48.18	30.8	kikuletwa	Pangani
28	Mnyera Ruaha	60.3	0.55	290.53	258.7	Mnyera	Rufiji
Total Capacity		**2,580.20**		**12,777.72**	**9,298.97**		

4.4.4.1.1 Characteristics of hydropower Project candidate

The hydroelectric power plants characteristics shown in **Table 4-19** that include plant capacity and firm energy, turbine discharge rates, and water storage capacities for plants with reservoirs have been used in this Plan.

Table 4-19: Characteristics of Candidate Hydropower Projects

Plant Name	Rumakali	Ruhudji	Ikondo Mnyera	Kikonge	Mpanga	Songwe Sofre (163.2 MW)*	Iringa Kilolo	Songwe Manolo (180.2 MW)*	Mnyera Taveta	Mnyera Kwanini	Mnyera Mnyera	Mnyera Pumbwe
Generation												
Installed capacity (MW)	222	358	340	300	160	81.6	150	90.1	145	143.9	137.4	122.9
Average energy (GWh)	1322	2000	1832	1268	1061.1	382.5	994.8	471.7	850	693.8	662.3	592.2
Firm energy (GWh)	1075.9	1333	1315.675	883.8	717.8	237	672.9	295.1	622.0444	617.3	589.3986	527.19862
Plant Factor	0.679789	0.637739	0.615095	0.482496	0.757063	0.535103	0.757078	0.597636	0.669186	0.550389	0.550255	0.550063
Power house												
Number of units	3	4	4	N.A	2	3	N.A	3	2	2	2	2
Gross head at max. level (m)	1294.5	765	405	N.A	374	315	N.A	253	155	N.A	N.A	N.A
Gross head at min. level (m)	1264.5	765	400	N.A	350	285	N.A	173	150	160	155	130
Tailwater level (m.a.s.l)	N.A	N.A	N.A	N.A	N.A	825	N.A	527	N.A	N.A	N.A	N.A
Rated turbine discharge (total) (m3/s)	19.1	54.4	100	N.A	51.56	58.66812	N.A	69.32324	125	105	103.2	111
MW/(m3/s) based on calc Qmax	11.65354	6.580882	3.4	N.A	3.2	2.657529	N.A	2.13446	1.16	N.A	N.A	N.A
Reservoir												
Max. supply level (m.a.s.l.)	2055	1478	1070	N.A	734	1140	N.A	780	490	805	960	645
Min. supply level (m.a.s.l.)	2025	1440	1030	N.A	710	1110	N.A	700	490	805	960	645
Full supply level (m.a.s.l)	2055	1478	1070	N.A	734	1140	N.A	780	490	805	960	645
Recommended min. operational level (m.a.s.l.)	2025	1367	1030	N.A	710	1110	N.A	700	N.A	N.A	N.A	N.A
Storage vol. at max. level (mill. m3)	280	300	800	N/A	75	440	N/A	260	N/A	N/A	N/A	N/A
Storage vol. at min. level (mill. m3)	24	31.3	20	N/A	7	80	N/A	0	N/A	N/A	N/A	N/A
Active storage volume (mill. m3)	256	269.3	780	N/A	68	360	N/A	260	N/A	N/A	N/A	N/A
Surface area at max. vol. (km2)	13.2	14	38	N.A	2.5	15	N.A	11	N.A	N.A	N.A	N.A

Plant Name	Upper Kihansi	Mnyera Kisingo	Masigira	Mnyera Ruaha	Kakono	Iringa (Nginayo)	Malagarasi	Mbarali	Iringa (Ibosa)	Songwe Bipugu (34 MW)*	Njombe	Mhanga	Nakatuta (Liparamb a)	Songea	Kikuletwa
Generation															
Installed capacity MW	120	119.8	118	60.3	87	52	49.5	38.522	36	17	32	26.637	15	15	11
Average energy GWH	69	577.3	664	290	573	262.8	181	199	186.1	76.5	165.4	250.1	140.8	140.8	103
Firm energy GWH	99	513.9	492	258.7	335	223.1	21.4	107.9	106.94	50.5	123.85	74.6	29.7	82.41176	30.80677
Plant Factor	0.065639269	0.550099	0.642365	0.549005	0.75185	0.5769231	0.4174162	0.589712	0.590119	0.513699	0.59004	1.071826	1.0715373	1.071537	1.068908
Powerhouse															
Number of units	2	2	2	2	3	2	3	N.A	2	3	N.A	N.A	N.A	N.A	N.A
Gross head at max. level (m)	853.5	N.A	238	N.A	26	N.A	846.5	N.A	N.A	80	N.A	N.A	N.A	N.A	N.A
Gross head at min. level (m)	N.A	105	237	110	24	195.9	832.5	N.A	150.6	55	N.A	N.A	N.A	N.A	N.A
Tailwater level (m.a.s.l)	N.A	N.A	N.A	N.A	1156	N.A	N.A	N.A	N.A	1165	N.A	N.A	N.A	N.A	N.A
Rated turbine discharge(total) (m3/s)	16.6	134	57	67	239.9472	30.47		N.A	27.85	50.02672	N.A	N.A	N.A	N.A	N.A
MW/(m3/s) based on calc Qmax	N.A	N.A	2.070175	N.A	0.219352	N.A	7.14	N.A	N.A	0.674928	N.A	N.A	N.A	N.A	N.A
Reservoir															
Max. supply level (m.a.s.l.)	1146	415	938	1070	1182	977	N.A	N.A	1212	1245	N.A	N.A	N.A	N.A	N.A
Min. supply level (m.a.s.l.)	1441	415	937	1060	1180	977	N.A	N.A	1212	1230	N.A	N.A	N.A	N.A	N.A
Full supply level (m.a.s.l)	1146	415	938	1070	1182	977	N.A	N.A	1212	1245	N.A	N.A	N.A	N.A	N.A
Recommended min. operational level (m.a.s.l.)	N.A	N.A	937	N.A	1180	N.A	843.2	N.A	N.A	1230	N.A	N.A	N.A	N.A	N.A
Storage vol. at max. level (mill. m3)	N.A	N/A	24	N/A	27	N/A	457000	N/A	N/A	350	N.A	N/A	N/A	N/A	N.A
Storage vol. at min. level (mill. m3)	N.A	N/A	22.5	N/A	0	N/A	427000	N/A	N/A	100	N.A	N/A	N/A	N/A	N.A
Active storage volume (mill. m3)	1	N/A	1.5	287.84	27	N/A	457000	N/A	N/A	250	N.A	N/A	N/A	N/A	N.A
Surface area at max. vol. (km2)	N.A	N.A	2.5	N.A	14	N.A	169000	N.A	N.A	30	N.A	N.A	N.A	N.A	N.A

4.4.4.2 Thermal Power Projects

The considered thermal power plants are Gas-fired plants with a total capacity of 6,708MW in simple and combined cycles configuration. It is estimated that 5,731MW of gas turbines (Simple Cycle operations) will be installed in the planning horizon, requiring a total of 951.20 mmscfd of gas by 2045 as shown in **Table 4-12.** The additional capacity complements the existing capacity of 1,198MW as of December 2024. The detailed characteristics of plants are shown in **Table 4-20**.

Table 4-20: Characteristics of Thermal Power Projects

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
GAS FIRED PLANTS					0.3										
Mtwara I	Natural Gas	CCGT	300	1128.4	338.52	24.00	36.00	2031	5.00	15	40	40	0	0	100.00
Kinyerezi III	Natural Gas	SC	1000	1124.0	1124.00	12.00	24.00	2027	5.00	50	45	0	0	0	100.00
Somanga Fungu Site II Phase I	Natural Gas	SC	400	1124.0	449.60	24.00	24.00	2028	5.00	55	40	0	0	0	100.00
Somanga Fungu Site II Phase II	Natural Gas	CCGT	200	1128.4	225.68	24.00	24.00	2029	5.00	65	30	0	0	0	100.00
Mtwara II	Natural Gas	CCGT	300	1128.4	338.52	24.00	24.00	2035	5.00	55	40	0	0	0	100.00
Ubungo I New	Natural Gas	CCGT	320	1128.4	361.09	24.00	24.00	2028	5.00	50	45	0	0	0	100.00
Ubungo II New	Natural Gas	CCGT	470	1128.4	530.35	24.00	24.00	2045	5.00	65	30	0	0	0	100.00
Somanga Fungu PPP	Natural Gas	CCGT	320	1128.4	361.09	24.00	36.00	2031	5.00	15	50	30	0	0	100.00
Dodoma	Natural Gas	CCGT	300	1128.4	338.52	24.00	36.00	2038	5.00	15	50	30	0	0	100.00
Somanga Mtama	Natural Gas	CCGT	318	1128.4	358.83	24.00	36.00	2028	5.00	15	50	30	0	0	100.00
Somanga Fungu site III	Natural Gas	CCGT	350	1128.4	394.94	24.00	36.00	2032	5.00	15	50	30	0	0	100.00
Mkuranga	Natural Gas	CCGT	320	1128.4	361.09	24.00	24.00	2040	5.00	55	40	0	0	0	100.00
Kinyerezi IV	Natural Gas	CCGT	1000	1128.4	1128.40	24.00	36.00	2030	5.00	15	50	30	0	0	100.00
Shinyanga Phase I	Natural Gas	CCGT	300	1128.4	338.52	24.00	36.00	2034	5.00	15	50	30	0	0	100.00
Tegeta New	Natural Gas	CCGT	320	1128.4	361.09	24.00	36.00	2044	5.00	15	50	30	0	0	100.00
Bagamoyo	Natural Gas	CCGT	300	1128.4	338.52	24.00	36.00	2039	5.00	15	50	30	0	0	100.00
Mtwara OCGT	Natural Gas	SC	30	1124.0	33.72	24.00	36.00	2035	5.00	15	50	30	0	0	100.00
Ubungo I OCGT	Natural Gas	SC	60	1124.0	67.44	24.00	36.00	2028	5.00	15	50	30	0	0	100.00
Tegeta OCGT	Natural Gas	SC	30	1124.0	33.72	24.00	36.00	2029	5.00	15	50	30	0	0	100.00
Ubungo II Conversion	Natural Gas	SC	70	1124.0	78.68	24.00	24.00	2027	5.00	15	50	30	0	0	100.00
COAL FIRED PLANTS															
Kiwira I	Coal	IGCC	200	2186.0	437.20	12.00	36.00	2030	5.00	35	40	20	0	0	100.00
Kiwira II	Coal	IGCC	400	2186.0	874.40	12.00	36.00	20228	5.00	35	40	20	0	0	100.00
Mchuchuma I	Coal	IGCC	300	2185.7	655.71	24.00	36.00	2029	5.00	35	40	20	0	0	100.00
Mchuchuma II	Coal	IGCC	400	2185.7	874.28	24.00	36.00	2032	5.00	35	40	20	0	0	100.00
Mchuchuma III	Coal	IGCC	300	2185.7	655.71	24.00	36.00	2024	5.00	35	40	20	0	0	100.00

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
Ngaka I	Coal	IGCC	200	2186.0	437.20	24.00	36.00	2031	5.00	35	40	20	0	0	100.00
Ngaka II	Coal	IGCC	400	2344.4	937.76	24.00	36.00	2028	5.00	35	40	20	0	0	100.00
Rukwa I	Coal	IGCC	300	2344.4	703.32	24.00	36.00	2040	5.00	35	40	20	0	0	100.00
Mbeya I	Coal	IGCC	300	2185.7	655.71	24.00	36.00	2037	5.00	35	40	20	0	0	100.00
Rungwe	Coal	IGCC	600	2185.7	1311.42	24.00	36.00	2044	5.00	35	40	20	0	0	100.00
Mbeya II	Coal	IGCC	600	2319.3	1391.58	24.00	36.00	2047	5.00	35	40	20	0	0	100.00
Mbeya III	Coal	IGCC	600	2347.1	1408.26	24.00	36.00	2037	5.00	35	40	20	0	0	100.00
Kiwira III	Coal	IGCC	300	2319.3	695.79	24.00	36.00	2033	5.00	35	30	30	0	0	100.00
Rukwa II	Coal	IGCC	600	2185.7	1311.42	24.00	36.00	2039	5.00	35	40	20	0	0	100.00
Mkuju Ruvuma	Nuclear	7x80MW Small Modular Reactor	560	8936.0	5004.16	12.00	60.00	2048	5.00	15	30	30	10	10	100.00
RENEWABLE PROJECTS															
A. SOLAR															
Kishapu Phase I	Solar	PV	50	1785.0	89.25	12.00	24.00	2026	5.00	55	40	0	0	0	100.00
Kishapu Phase II	Solar	PV	100	1785.0	178.50	12.00	24.00	2026	5.00	55	40	0	0	0	100.00
Zuzu Dodoma	Solar	PV	130	1706.9	221.90	12.00	24.00	2026	5.00	55	40	0	0	0	100.00
Manyoni Phase I	Solar	PV	150	1785.0	267.75	12.00	24.00	2026	5.00	55	40	0	0	0	100.00
Same Solar	Solar	PV	100	1785.0	178.50	12.00	24.00	2026	5.00	55	40	0	0	0	100.00
Manyoni Phase II	Solar	PV	150	1785.0	267.75	12.00	24.00	2027	5.00	55	40	0	0	0	100.00
Kitapilimwa Iringa	Solar	PV	100	1785.0	178.50	12.00	24.00	2026	5.00	55	40	0	0	0	100.00
Kisima Iringa	Solar	PV	144	780.7	112.42	12.00	24.00	2026	5.00	5	90	0	0	0	100.00
Shinyanga II	Solar	PV	150	1785.0	267.75	12.00	24.00	2027	5.00	55	40	0	0	0	100.00
Makambako Njombe II	Solar	PV	150	1785.0	267.75	12.00	24.00	2032	5.00	55	40	0	0	0	100.00
Ikungi solar Singida	Solar	PV	150	1785.0	267.75	12.00	24.00	2036	5.00	55	40	0	0	0	100.00
Kisima Dodoma Solar	Solar	PV	150	1785.0	267.75	12.00	24.00	2040	5.00	55	40	0	0	0	100.00
Iringa Solar	Solar	PV	150	1785.0	267.75	12.00	24.00	2044	5.00	55	40	0	0	0	100.00
B. WIND															

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
Kititimo Singida I	Wind	Wind	300	1530.0	459.00	24.00	12.00	2026	5.00	95	0	0	0	0	100.00
Same	Wind	Wind	50	1530.0	76.50	24.00	12.00	2027	5.00	55	40				100.00
Waging'ombe Njombe I	Wind	Wind	300	1530.0	459.00	24.00	12.00	2028	5.00	95	0	0	0	0	100.00
Ikungi Phase I	Wind	Wind	300	1530.0	459.00	24.00	12.00	2028	5.00	95	0	0	0	0	100.00
Singida II	Wind	Wind	300	1530.0	459.00	24.00	12.00	2027	5.00	95	0	0	0	0	100.00
Makambako Njombe I	Wind	Wind	300	1530.0	459.00	24.00	12.00	2029	5.00	95	0	0	0	0	100.00
Ikungi Phase II	Wind	Wind	300	1530.0	459.00	24.00	12.00	2030	5.00	95	0	0	0	0	100.00
Makambako Njombe II	Wind	Wind	300	1530.0	459.00	24.00	12.00	2034	5.00	95	0	0	0	0	100.00
Ikungi wind Singida	Wind	Wind	300	1530.0	459.00	24.00	12.00	2038	5.00	95	0	0	0	0	100.00
Kisima Wind Dodoma	Wind	Wind	300	1530.0	459.00	24.00	12.00	2042	5.00	95	0	0	0	0	100.00
Iringa wind	Wind	Wind	300	1530.0	459.00	24.00	12.00	2046	5.00	95	0	0	0	0	100.00
C. GEOTHERMAL															
Songwe Phase I	Geothermal	Geothermal	5	3963.0	19.82	12.00	36.00	2028	5.00	25	60	10	0	0	100.00
Ngozi phase I	Geothermal	Geothermal	60	3963.0	237.78	12.00	36.00	2028	5.00	25	60	10	0	0	100.00
Kiejo – Mbaka Phase I	Geothermal	Geothermal	70	3963.0	277.41	12.00	36.00	2028	5.00	25	60	10	0	0	100.00
Songwe Phase II	Geothermal	Geothermal	10	3963.0	39.63	12.00	36.00	2030	5.00	25	60	10	0	0	100.00
Natron Phase I	Geothermal	Geothermal	60	3963.0	237.78	12.00	36.00	2028	5.00	25	60	10	0	0	100.00
Ngozi phase II	Geothermal	Geothermal	40	3963.0	158.52	12.00	36.00	2030	5.00	25	60	10	0	0	100.00
Meru (Arusha) Phase II	Geothermal	Geothermal	30	3963.0	118.89	12.00	36.00	2031	5.00	25	60	10	0	0	100.00
Ibadakuli Shinyanga Phase I	Geothermal	Geothermal	5	3963.0	19.82	12.00	36.00	2031	5.00	25	60	10	0	0	100.00
Songwe Phase III	Geothermal	Geothermal	20	3963.0	79.26	12.00	36.00	2033	5.00	25	60	10	0	0	100.00
Kiejo Mbaka Phase II	Geothermal	Geothermal	30	3963.0	118.89	12.00	36.00	2033	5.00	25	60	10	0	0	100.00
Kisaki Morogoro	Geothermal	Geothermal	30	3963.0	118.89	12.00	36.00	2035	5.00	25	60	10	0	0	100.00
Natron Phase II	Geothermal	Geothermal	150	3963.0	594.45	12.00	36.00	2041	5.00	25	60	10	0	0	100.00
Kisaki Morogoro Phase II	Geothermal	Geothermal	115	3963.0	455.75	12.00	36.00	2042	5.00	25	60	10	0	0	100.00
Meru (Arusha) Phase II	Geothermal	Geothermal	115	3963.0	455.75	12.00	36.00	2043	5.00	25	60	10	0	0	100.00
Kioje Mbaka Phase III	Geothermal	Geothermal	125	3963.0	495.38	12.00	36.00	2044	5.00	25	60	10	0	0	100.00
Ngozi Phase III	Geothermal	Geothermal	30	3963.0	118.89	12.00	36.00	2045	5.00	25	60	10	0	0	100.00

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
Songwe Phase IV	Geothermal	Geothermal	25	3963.0	99.08	12.00	36.00	2045	5.00	25	60	10	0	0	100.00
Ngozi Phase IV	Geothermal	Geothermal	30	3963.0	118.89	12.00	36.00	2046	5.00	25	60	10	0	0	100.00
Ibadakuli Shinyanga Phase II	Geothermal	Geothermal	55	3963.0	217.97	12.00	36.00	2046	5.00	25	60	10	0	0	100.00
Ngozi Phase V	Geothermal	Geothermal	30	3963.0	118.89	12.00	36.00	2047	5.00	25	60	10	0	0	100.00
Luhoi	Geothermal	Geothermal	45	3963.0	178.34	12.00	36.00	2047	5.00	25	60	10	0	0	100.00
Ngozi Phase VI	Geothermal	Geothermal	30	3963.0	118.89	12.00	36.00	2048	5.00	25	60	10	0	0	100.00
Hydrogen	Hydrogen	Hydrogen	50	8,960.0	448.00	12.00	36.00	2048	5.00	25	60	10	0	0	100.00

s connected to the National Grid Network with a total installed
solated system, as shown in **Table 4-4**. The average economic
gh proper maintenance and interim replacement of major parts,

4.4.4.3 Solar Power Projects

67 The power expansion plan considered solar sites with a proven potential capacity of **1,674MWp** to be candidates for generating 3,666.06 GWh as shown in **Table 4-21.**

Table 4-21: Solar Power Projects

SN.	Plant Name/Location	Fuel Type	Capacity MW	Maximum Plant Factor	Available GWh	Nominal Service Life (Years)
1	Kishapu Phase I	Solar PV	50	0.25	110	25
2	Kishapu Phase II	Solar PV	100	0.25	219	25
3	Zuzu Dodoma	Solar PV	130	0.25	285	25
4	Manyoni Phase I	Solar PV	150	0.25	329	25
5	Same	Solar PV	100	0.25	219	25
6	Manyoni Phase II	Solar PV	150	0.25	329	25
7	Kitapilimwa Iringa	Solar PV	100	0.25	219	25
8	Kisima Dodoma	Solar PV	144	0.25	315	25
9	Shinyanga II	Solar PV	150	0.25	329	25
10	Makambako Njombe II	Solar PV	150	0.25	329	25
11	Ikungi Solar Singida	Solar PV	150	0.25	329	25
12	Kisima Iringa Solar	Solar PV	150	0.25	329	25
13	Iringa Solar	Solar PV	150	0.25	329	25
Total Capacity			**1,674**		**3,666**	

4.4.4.4 Wind Power Projects

The expansion plan considered wind sites with a proven potential capacity of 3,050 MW to be candidates for generating 10,687.20 GWh as shown in **Table 4-22.**

Table 4-22: Wind Power Projects

S/N	Plant Name/Location	Fuel Type	Capacity (MW)	Maximum Plant Factor (%)	Available Energy (GWh)	Nominal Service Life (Years)
1	Kititimo Singida I	Wind	300	0.4	1,051.20	25
2	Same	Wind	50	0.4	175.20	25
3	Makambako	Wind	100	0.4	350.40	25
4	Waging'ombe Njombe I	Wind	300	0.4	1,051.20	25

S/N	Plant Name/Location	Fuel Type	Capacity (MW)	Maximum Plant Factor (%)	Available Energy (GWh)	Nominal Service Life (Years)
5	Ikungi Phase I	Wind	300	0.4	1,051.20	25
6	Singida II	Wind	300	0.4	1,051.20	25
7	Makambako Njombe I	Wind	300	0.4	1,051.20	25
8	Ikungi Phase II	Wind	300	0.4	1,051.20	25
9	Makambako Njombe II	Wind	200	0.4	700.80	25
10	Ikungi wind Singida	Wind	300	0.4	1,051.20	25
11	Kisima Wind Dodoma	Wind	300	0.4	1,051.20	25
12	Iringa wind	Wind	300	0.4	1,051.20	25
Total Capacity			**3,050.00**		**10,687.20**	

4.4.4.5 Geothermal Power Projects

The Plan considered the development of 1,110MW out of 5,000MW potential to be candidates for generating 8,751.24 GWh as shown in **Table 4-23.**

Table 4-23: Geothermal Power Projects

S/N.	Plant Name/Location	Fuel	Capacity MW	Maximum Plant Factor (%)	Available Energy (GWh)	Nominal Service Life (Years)
1	Ibadakuli Shinyanga Phase I	Steam	5	90	39.42	25
2	Ibadakuli Shinyanga Phase II	Steam	55	90	433.62	25
3	Kiejo Mbaka Phase I	Steam	70	90	551.88	25
4	Kiejo Mbaka Phase III	Steam	30	90	236.52	25
5	Kioje Mbaka Phase IV	Steam	125	90	985.50	25
6	Kisaki Morogoro Phase I	Steam	30	90	236.52	25
7	Kisaki Morogoro Phsae II	Steam	115	90	906.66	25
8	Luhoi	Steam	45	90	354.78	25
9	Meru (Arusha) Phase I	Steam	30	90	236.52	25

S/N.	Plant Name/Location	Fuel	Capacity MW	Maximum Plant Factor (%)	Available Energy (GWh)	Nominal Service Life (Years)
10	Meru (Arusha) Phase II	Steam	115	90	906.66	25
11	Natron Phase I	Steam	60	90	473.04	25
12	Natron Phase II	Steam	150	90	1,182.60	25
13	Ngozi Phase I	Steam	60	90	473.04	25
14	Ngozi Phase II	Steam	40	90	315.36	25
15	Ngozi Phase III	Steam	30	90	236.52	25
16	Ngozi Phase IV	Steam	30	90	236.52	25
17	Ngozi Phase V	Steam	30	90	236.52	25
18	Ngozi Phase VI	Steam	30	90	236.52	25
19	Songwe Phase 1	Steam	5	90	39.42	25
20	Songwe Phase II	Steam	10	90	78.84	25
21	Songwe Phase III	Steam	20	90	157.68	25
22	Songwe Phase IV	Steam	25	90	197.10	25
Total Capacity			**1,110.00**		**8,751.24**	

4.4.4.6 Power Project Development Costs

The lifetime unit costs for each power generation technology were estimated using overnight capital cost estimates for power plants identified under Engineering, Procurement, and Construction (EPC) specifications. The cost estimates include interest during construction (IDC), excluding expenses related to land acquisition. The estimates were also based on benchmarking from various sources, including;

i. Projects Feasibility Studies.
ii. Information from previous Power System Master Plans (2008, 2012, 2016, and 2020 PSMP Updates).
iii. Data from the International Atomic Energy Agency (IAEA) and the U.S. Energy Information Administration (EIA) 2020 and 2025 Reports.
iv. Information from completed and ongoing power generation projects

Table 4-24 and

Table 4-25 present a detailed evaluation of each project, which forms the basis for the screening and ranking of projects. The expected online year is a sum of the base year and estimated construction years, implying that the project can be included in the generation plan on or after the expected online year.

Table 4-24: Hydropower Project Construction Costs

Plant	Units	Capacity (MW)	Average Energy (GWh)	Unit Capital Cost ($/kW) 2024	Capital cost $M no IDC / 2024 1, 2 &3	Project Preparation (months)	Construction Period (months)	Expected Online Year	Pre-construction costs (%ge of total capital cost)	Annual expenditure as % of total capital cost						TOTAL (%)
										1	2	3	4	5	6	
Malagarasi HPP	3	49.5	181.00	2911.9	144.1	0.0	36	2027	4.5	35.5	40.0	15.0	5.0	0.0	0.0	100.0
Kakono HPP	2	87.8	415.33	3193.6	280.4	12.0	48	2029	4.5	20.5	40.0	15.0	15.0	5.0	0.0	100.0
Kidunda Morogoro DAWASA	2	20	87.60	2911.9	58.2	0.0	36	2027	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Ruhudji	4	358	2,000.00	1138.0	888.47[13]	12.0	72	2030	4.5	35.5	30.0	15.0	10.0	5.0	0.0	100.0
Rumakali	3	222	1,322.00	1690.2	602.6[14]	12.0	60	2030	4.5	35.5	30.0	15.0	15.0	0.0	0.0	100.0
Masigira	2	118	664.00	2214.0	261.3	24.0	60	2031	4.5	35.5	30.0	15.0	10.0	5.0	0.0	100.0
Songwe Manolo -lower	2	90	536.11	3055.6	275.0	12.0	60	2030	4.5	35.5	40.0	15.0	5.0	0.0	0.0	100.0
Kikonge	3	321	1,356.76	2308.1	740.9	24.0	66	2030	4.5	10.5	15.0	25.0	25.0	15.0	5.0	100.0
Mpanga Iringa	2	160	756.86	1865.6	298.5	36.0	60	2032	4.5	35.5	30.0	15.0	10.0	5.0	0.0	100.0
Mnyera Kisingo	2	119.8	577.30	2621.4	314.0	36.0	60	2032	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mnyera Mnyera	2	137.4	662.30	4845.7	665.8	36.0	60	2032	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Songwe Sofre - Middle	5	81.6	382.50	1865.2	152.2	36.0	48	2031	4.5	35.5	30.0	15.0	10.0	5.0	0.0	100.0
Mnyera Kwanini	2	143.9	693.80	1141.8	164.3	36.0	60	2032	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Nsongezi (TZ-Portion)	1	12	52.56	2814.4	33.8	24.0	36	2029	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Upper Kihansi	2	120	69.00	1840.0	220.8	48.0	60	2033	4.5	35.5	30.0	20.0	10.0	0.0	0.0	100.0
Songwe Upper	1	29	151.82	3778.6	109.6	36.0	36	2030	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mnyera Pumbwe	2	122	587.86	1797.6	219.3	36.0	60	2032	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0

[13] The cost estimate of USD 888.47 Million excludes the cost of transmission line from Kisada Iringa to Ruhudji power plant

[14] The cost estimate of USD 602.6 Million excludes the cost of transmission line from Iganjo susbtation to Rumakali power plant

Plant	Units	Capacity (MW)	Average Energy (GWh)	Unit Capital Cost ($/kW) 2024	Capital cost $M no IDC / 2024 1, 2 &3	Project Preparation (months)	Construction Period (months)	Expected Online Year	Pre-construction costs (%ge of total capital cost)	Annual expenditure as % of total capital cost						TOTAL (%)
										1	2	3	4	5	6	
Mnyera Taveta	2	83.9	404.23	2452.3	205.8	36.0	60	2032	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Iringa Nginayo	2	52	264.20	2413.0	125.5	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mbarali	2	39	198.15	4256.4	166.0	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Iringa Ibosa	2	36	186.06	3418.0	123.0	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Songwe Bupigu	5	17	75.95	3440.6	58.5	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Njombe	2	32	165.39	4250.0	136.0	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mhanga	2	27	118.26	3518.0	95.0	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Songea	2	15	65.70	3518.0	52.8	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Nakatuta (Liparamba)	2	15	65.70	3518.0	52.8	48.0	36	2031	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Kikuletwa	2	11	48.18	3518.0	38.7	24.0	36	2029	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mnyera Ruaha	2	60.3	290.53	4230.2	255.1	36.0	36	2030	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0

Table 4-25: Thermal and Renewable Project Construction Costs

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
GAS FIRED PLANTS															
Mtwara I	Natural Gas	CCGT	300	1128.4	338.52	24.00	36	2031	5.00	15	40	40	0	0	100.00
Kinyerezi III	Natural Gas	SC	1000	1124.0	1124.00	12.00	24	2027	5.00	50	45	0	0	0	100.00
Somanga Fungu Site II Phase I	Natural Gas	SC	400	1124.0	449.60	24.00	24	2028	5.00	55	40	0	0	0	100.00
Somanga Fungu Site II Phase II	Natural Gas	CCGT	200	1128.4	225.68	24.00	24	2029	5.00	65	30	0	0	0	100.00
Mtwara II	Natural Gas	CCGT	300	1128.4	338.52	24.00	24	2035	5.00	55	40	0	0	0	100.00
Ubungo I New	Natural Gas	CCGT	320	1128.4	361.09	24.00	24	2028	5.00	50	45	0	0	0	100.00
Ubungo II New	Natural Gas	CCGT	470	1128.4	530.35	24.00	24	2045	5.00	65	30	0	0	0	100.00
Somanga Fungu PPP	Natural Gas	CCGT	320	1128.4	361.09	24.00	36	2031	5.00	15	50	30	0	0	100.00
Dodoma	Natural Gas	CCGT	300	1128.4	338.52	24.00	36	2038	5.00	15	50	30	0	0	100.00
Somanga Mtama	Natural Gas	CCGT	318	1128.4	358.83	24.00	36	2028	5.00	15	50	30	0	0	100.00
Somanga Fungu site III	Natural Gas	CCGT	350	1128.4	394.94	24.00	36	2032	5.00	15	50	30	0	0	100.00
Mkuranga	Natural Gas	CCGT	320	1128.4	361.09	24.00	24	2040	5.00	55	40	0	0	0	100.00
Kinyerezi IV	Natural Gas	CCGT	1000	1128.4	1128.40	24.00	36	2030	5.00	15	50	30	0	0	100.00
Shinyanga Phase I	Natural Gas	CCGT	300	1128.4	338.52	24.00	36	2034	5.00	15	50	30	0	0	100.00
Tegeta New	Natural Gas	CCGT	320	1128.4	361.09	24.00	36	2044	5.00	15	50	30	0	0	100.00
Bagamoyo	Natural Gas	CCGT	300	1128.4	338.52	24.00	36	2039	5.00	15	50	30	0	0	100.00
Mtwara OCGT	Natural Gas	SC	30	1124.0	33.72	24.00	36	2035	5.00	15	50	30	0	0	100.00
Ubungo I OCGT	Natural Gas	SC	60	1124.0	67.44	24.00	36	2028	5.00	15	50	30	0	0	100.00
Kinyerezi IV	Natural Gas	CCGT	1000	1128.4	1128.40	24.00	36	2030	5.00	15	50	30	0	0	100.00
Tegeta OCGT	Natural Gas	SC	30	1124.0	33.72	24.00	36	2029	5.00	15	50	30	0	0	100.00
COAL FIRED PLANTS															
Kiwira I	Coal	IGCC	200	2186.0	437.20	12.00	36	2030	5.00	35	40	20	0	0	100.00
Kiwira II	Coal	IGCC	400	2186.0	874.40	12.00	36	20228	5.00	35	40	20	0	0	100.00
Mchuchuma I	Coal	IGCC	300	2185.7	655.71	24.00	36	2029	5.00	35	40	20	0	0	100.00
Mchuchuma II	Coal	IGCC	400	2185.7	874.28	24.00	36	2032	5.00	35	40	20	0	0	100.00
Mchuchuma III	Coal	IGCC	300	2185.7	655.71	24.00	36	2024	5.00	35	40	20	0	0	100.00
Ngaka I	Coal	IGCC	200	2186.0	437.20	24.00	36	2031	5.00	35	40	20	0	0	100.00

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
Ngaka II	Coal	IGCC	400	2344.4	937.76	24.00	36	2028	5.00	35	40	20	0	0	100.00
Rukwa I	Coal	IGCC	300	2344.4	703.32	24.00	36	2040	5.00	35	40	20	0	0	100.00
Mbeya I	Coal	IGCC	300	2185.7	655.71	24.00	36	2037	5.00	35	40	20	0	0	100.00
Rungwe	Coal	IGCC	600	2185.7	1311.42	24.00	36	2044	5.00	35	40	20	0	0	100.00
Mbeya II	Coal	IGCC	600	2319.3	1391.58	24.00	36	2047	5.00	35	40	20	0	0	100.00
Mbeya III	Coal	IGCC	600	2347.1	1408.26	24.00	36	2037	5.00	35	40	20	0	0	100.00
Kiwira III	Coal	IGCC	300	2319.3	695.79	24.00	36	2033	5.00	35	30	30	0	0	100.00
Rukwa II	Coal	IGCC	600	2185.7	1311.42	24.00	36	2039	5.00	35	40	20	0	0	100.00
Mkuju Ruvuma	Nuclear	7x80MW Small Modular Reactor	560	8936.0	5004.16	12.00	60	2048	5.00	15	30	30	10	10	100.00
RENEWABLE PROJECTS															
A. SOLAR															
Kishapu Phase I	Solar	PV	50	1785.0	89.25	12.00	24	2026	5.00	55	40	0	0	0	100.00
Kishapu Phase II	Solar	PV	100	1785.0	178.50	12.00	24	2026	5.00	55	40	0	0	0	100.00
Zuzu Dodoma	Solar	PV	130	1706.9	221.90	12.00	24	2026	5.00	55	40	0	0	0	100.00
Manyoni Phase I	Solar	PV	150	1785.0	267.75	12.00	24	2026	5.00	55	40	0	0	0	100.00
Same	Solar	PV	100	1785.0	178.50	12.00	24	2026	5.00	55	40	0	0	0	100.00
Manyoni Phase II	Solar	PV	150	1785.0	267.75	12.00	24	2027	5.00	55	40	0	0	0	100.00
Kitapilimwa Iringa	Solar	PV	100	1785.0	178.50	12.00	24	2026	5.00	55	40	0	0	0	100.00
Kisima Iringa	Solar	PV	144	780.7	112.42	12.00	24	2026	5.00	5	90	0	0	0	100.00
Shinyanga II	Solar	PV	150	1785.0	267.75	12.00	24	2027	5.00	55	40	0	0	0	100.00
Makambako Njombe II	Solar	PV	150	1785.0	267.75	12.00	24	2032	5.00	55	40	0	0	0	100.00
Ikungi Solar Singida	Solar	PV	150	1785.0	267.75	12.00	24	2036	5.00	55	40	0	0	0	100.00
Kisima Dodoma Solar	Solar	PV	150	1785.0	267.75	12.00	24	2040	5.00	55	40	0	0	0	100.00
Iringa Solar	Solar	PV	150	1785.0	267.75	12.00	24	2044	5.00	55	40	0	0	0	100.00
B. WIND															
Kititimo Singida I	Wind	Wind	300	1530.0	459.00	24.00	12	2026	5.00	95	0	0	0	0	100.00
Same	Wind	Wind	50	1530.0	76.50	24.00	12	2027	5.00	55	40				100.00
Makamako	Wind	Wind	100	1530.0	153.00	24.00	12	2028	5.00	95	0	0	0	0	100.00

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
Waging'ombe Njombe I	Wind	Wind	300	1530.0	459.00	24.00	12	2028	5.00	95	0	0	0	0	100.00
Ikungi Phase I	Wind	Wind	300	1530.0	459.00	24.00	12	2028	5.00	95	0	0	0	0	100.00
Singida II	Wind	Wind	300	1530.0	459.00	24.00	12	2027	5.00	95	0	0	0	0	100.00
Makambako Njombe I	Wind	Wind	300	1530.0	459.00	24.00	12	2029	5.00	95	0	0	0	0	100.00
Ikungi Phase II	Wind	Wind	300	1530.0	459.00	24.00	12	2030	5.00	95	0	0	0	0	100.00
Makambako Njombe II	Wind	Wind	300	1530.0	459.00	24.00	12	2034	5.00	95	0	0	0	0	100.00
Ikungi wind Singida	Wind	Wind	300	1530.0	459.00	24.00	12	2038	5.00	95	0	0	0	0	100.00
Kisima Wind Dodoma	Wind	Wind	300	1530.0	459.00	24.00	12	2042	5.00	95	0	0	0	0	100.00
Iringa wind	Wind	Wind	300	1530.0	459.00	24.00	12	2046	5.00	95	0	0	0	0	100.00
C. GEOTHERMAL															
Songwe Phase I	Geothermal	Geothermal	5	3963.0	19.82	12.00	36	2028	5.00	25	60	10	0	0	100.00
Ngozi phase I	Geothermal	Geothermal	60	3963.0	237.78	12.00	36	2028	5.00	25	60	10	0	0	100.00
Kiejo – Mbaka Phase I Mbeya	Geothermal	Geothermal	70	3963.0	277.41	12.00	36	2028	5.00	25	60	10	0	0	100.00
Songwe Phase II	Geothermal	Geothermal	10	3963.0	39.63	12.00	36	2030	5.00	25	60	10	0	0	100.00
Natron Phase I	Geothermal	Geothermal	60	3963.0	237.78	12.00	36	2028	5.00	25	60	10	0	0	100.00
Ngozi phase II	Geothermal	Geothermal	40	3963.0	158.52	12.00	36	2030	5.00	25	60	10	0	0	100.00
Meru (Arusha) Phase II	Geothermal	Geothermal	30	3963.0	118.89	12.00	36	2031	5.00	25	60	10	0	0	100.00
Ibadakuli Shinyanga Phase I	Geothermal	Geothermal	5	3963.0	19.82	12.00	36	2031	5.00	25	60	10	0	0	100.00
Songwe Phase III	Geothermal	Geothermal	20	3963.0	79.26	12.00	36	2033	5.00	25	60	10	0	0	100.00
Kiejo Mbaka Phase II	Geothermal	Geothermal	30	3963.0	118.89	12.00	36	2033	5.00	25	60	10	0	0	100.00
Kisaki Morogoro	Geothermal	Geothermal	30	3963.0	118.89	12.00	36	2035	5.00	25	60	10	0	0	100.00
Natron Phase II	Geothermal	Geothermal	150	3963.0	594.45	12.00	36	2041	5.00	25	60	10	0	0	100.00
Kisaki Morogoro Phsae II	Geothermal	Geothermal	115	3963.0	455.75	12.00	36	2042	5.00	25	60	10	0	0	100.00
Meru (Arusha) Phase II	Geothermal	Geothermal	115	3963.0	455.75	12.00	36	2043	5.00	25	60	10	0	0	100.00
Kioje Mbaka Phase IV	Geothermal	Geothermal	125	3963.0	495.38	12.00	36	2044	5.00	25	60	10	0	0	100.00
Ngozi Phase III	Geothermal	Geothermal	30	3963.0	118.89	12.00	36	2045	5.00	25	60	10	0	0	100.00
Songwe Phase IV	Geothermal	Geothermal	25	3963.0	99.08	12.00	36	2045	5.00	25	60	10	0	0	100.00
Ngozi Phase IV	Geothermal	Geothermal	30	3963.0	118.89	12.00	36	2046	5.00	25	60	10	0	0	100.00
Ibadakuli Shinyanga Phase II	Geothermal	Geothermal	55	3963.0	217.97	12.00	36	2046	5.00	25	60	10	0	0	100.00

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost ($/kW)[3]	Capital cost $M no IDC / 2024 [1, 2, 3 & 4]	Financing Close & Project Readiness	Construction Period (months)	Expected Online Year	Pre-construction costs(%ge of total capital cost)	Annual expenditure as % of total capital cost					TOTAL
										1	2	3	4	5	
Ngozi Phase V	Geothermal	Geothermal	30	3963.0	118.89	12.00	36	2047	5.00	25	60	10	0	0	100.00
Luhoi	Geothermal	Geothermal	45	3963.0	178.34	12.00	36	2047	5.00	25	60	10	0	0	100.00
Ngozi Phase VI	Geothermal	Geothermal	30	3963.0	118.89	12.00	36	2048	5.00	25	60	10	0	0	100.00

4.4.4.7 Thermal Power Plant Fuel Cost

The Plant heat rate and corresponding prices for thermal power generation are shown in **Table 4-26**.

Table 4-26: Thermal Pricing Cost

Plant	Fuel Type	Installed Capacity MW	Capital cost $M no IDC / 2024 1, 2, 3 & 4	Fuel price $/mmBTU	Plant heat rate BTU/kWh	Fuel cost $/kWh	Fixed operating cost /kW-year	Variable operating cost $/kWh
Gas, Coal and Nuclear-Fired Power Plants								
Mtwara I	NG	300	338.52	5.6711	6,266	0.0355	12.12	0.0034
Kinyerezi III	NG	1000	1124.00	6.1285	6,266	0.0384	12.12	0.0034
Somanga Fungu Site II Phase I	NG	400	449.60	5.5835	6,266	0.0350	12.12	0.0034
Somanga Fungu Site II Phase II	NG	200	225.68	5.5835	6,266	0.0350	12.12	0.0034
Mtwara II	NG	300	338.52	6.0631	6,266	0.0380	12.12	0.0034
Ubungo I New	NG	320	361.09	6.4736	6,266	0.0406	12.12	0.0034
Ubungo II New	NG	470	530.35	6.4736	6,266	0.0406	12.12	0.0034
Somanga Fungu PPP	NG	320	361.09	5.9582	6,266	0.0373	12.12	0.0034
Dodoma	NG	300	338.52	6.3571	6,266	0.0398	12.12	0.0034
Somanga Mtama	NG	318	358.83	5.1983	6,266	0.0326	12.12	0.0034
Somanga Fungu site III	NG	350	394.94	5.1983	6,266	0.0326	12.12	0.0034
Mkuranga	NG	320	361.09	5.1290	6,266	0.0321	12.12	0.0034
Kinyerez IV	NG	1000	1128.40	6.1285	6,266	0.0384	12.12	0.0034

Plant	Fuel Type	Installed Capacity MW	Capital cost $M no IDC / 2024 1, 2, 3 & 4	Fuel price $/mmBTU	Plant heat rate BTU/kWh	Fuel cost $/kWh	Fixed operating cost /kW-year	Variable operating cost $/kWh
Shinyanga Phase I	NG	300	338.52	5.5590	6,266	0.0348	12.12	0.0034
Tegeta New	NG	320	361.09	6.4736	6,266	0.0406	12.12	0.0034
Bagamoyo	NG	300	338.52	6.4736	6,266	0.0406	12.12	0.0034
Mtwara OCGT	Coal	30	33.72	6.4736	6,266	0.0406	61.60	0.0064
Ubungo I OCGT	Coal	60	67.44	6.4736	6,266	0.0406	61.60	0.0064
Kinyerezi IV	Coal	1000	1128.40	6.4736	6,266	0.0406	61.60	0.0064
Tegeta OCGT	Coal	30	33.72	6.4736	6,266	0.0406	61.60	0.0064
Kiwira I	Coal	200	437.20	1.8762	8,700	0.0163	61.60	0.0064
Kiwira II	Coal	400	874.40	1.8762	8,700	0.0163	61.60	0.0064
Mchuchuma I	Coal	300	655.71	1.8762	8,700	0.0163	61.60	0.0064
Mchuchuma II	Coal	400	874.28	1.8762	8,700	0.0163	61.60	0.0064
Mchuchuma III	Coal	300	655.71	1.8762	8,700	0.0163	61.60	0.0064
Ngaka I	Coal	200	437.20	1.8762	8,700	0.0163	61.60	0.0064
Ngaka II	Coal	400	937.76	1.8762	8,700	0.0163	61.60	0.0064
Rukwa I	Coal	300	703.32	1.8762	8,700	0.0163	61.60	0.0064
Mbeya I	Coal	300	655.71	1.8762	8,700	0.0163	61.60	0.0064
Rungwe	Coal	600	1311.42	1.8762	8,700	0.0163	61.60	0.0064
Mbeya II	Coal	600	1391.58	1.8762	10,599	0.0199	121.99	0.0032
Mbeya III	Coal	600	1408.26	1.8762	8,700	0.0163	121.99	0.0032
Kiwira III	Coal	300	695.79	1.8762	8,700	0.0163	121.99	0.0032
Rukwa II	Coal	600	1311.42	1.8762	8,700	0.0163	121.99	0.0032
Mkuju Ruvuma	Nuclear	560	5004.16	0.5283	10,599	0.0056	121.99	0.0032

Sources:

i. The petroleum (Natural Gas Indicative Price) (Special Strategic Investment) Order 2017;
ii. Feasibility Studies; and
iii. Indicative costs for large power plants (Above 10 MW) in Tanzania.

4.4.4.8 Screening of Candidate Power Projects

For sequencing and timing of the next power generation project(s), candidate projects were assessed to ascertain their readiness for implementation in a given year. Key criteria include the level at which the candidate project has been studied (feasibility studies, pre-feasibility studies, and concept notes); other considerations include the unit capital costs for alternative technologies and the amount of available energy from the project.

The screening of thermal, hydro and renewable power projects is shown in

Table *4-27***, Table 4-28** and

Table *4-29* respectively.

Table 4-27: Screening of Thermal Projects

PROJECT NAME	Unit	Mtwara I	Kinyerezi III	Somanga Fungu Site II	Somanga Fungu Site II	Mtwara II	Ubungo I New	Ubungo II New	Somanga Fungu PPP	Dodoma	Somanga Mtama	Somanga Fungu site III	Mkuranga	Kinyerez IV	Shinyanga Phase I	Tegeta New	Bagamoyo
Capital Cost	$M	338.52	1124	449.6	225.68	338.52	361.088	530.348	361.088	338.52	358.8312	394.94	361.088	1128.4	338.52	361.088	338.52
Installed capacity	MW	300	1000	400	200	300	320	470	320	300	318	350	320	1000	300	320	300
Station service	%	2.0%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Net capacity	MW	294.00	980.00	392.00	196.00	294.00	313.60	460.60	313.60	294.00	311.64	343.00	313.60	980.00	294.00	313.60	294.00
Unit availability																	
Scheduled maintenance	wks per unit	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Forced outage rate	%	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Scheduled maintenance	%	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69
Combined outage rate	%	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19
Net capacity available (after derating for outage)	MW	265	882	353	176	265	282	415	282	265	280	309	282	882	265	282	265
Earliest on-power date	Yr	2031	2026	2028	2029	2035	2045	2045	2031	2038	2028	2032	2040	2029	2034	2044	2039
Service life	Yrs	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
O & M																	
Fixed O & M	$/kW	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12	12.12
Variable O & M	$/kWh	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034
Total capital cost with IDC																	
Unit capital cost	US $/kW	1128.4	1124.0	1124.0	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4	1128.4
Capital cost	USD Mil.	331.7	1101.5	440.6	221.2	331.7	353.9	519.7	353.9	331.7	351.7	387.0	353.9	1105.8	331.7	353.9	331.7
Avg capital cost per available capacity	$/kW avail	1253.8	1248.9	1248.9	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8	1253.8
Annual fixed cost	$/kW avail	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Cashflow in year prior to on-power																	
-7	% of capital																
-6	% of capital																
-5	% of capital																
-4	% of capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
-3	% of capital	40	0	0	0	0	0	0	30	30	30	30	0	30	30	30	30
-2	% of capital	40	45	40	30	50	45	30	50	50	50	50	40	50	50	50	50
-1	% of capital	20	55	60	70	50	55	70	20	20	20	20	60	20	20	20	20
0	% of capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avg total cost at on-power	$/kW avail	1409.2	1305.1	1298.8	1291.4	1316.5	1310.2	1291.4	1395.5	1395.5	1395.5	1395.5	1303.9	1395.5	1395.5	1395.5	1395.5
Annuity over economic life (year-end)	$/kW avail	155.3	143.8	143.1	142.3	145.0	144.3	142.3	153.7	153.7	153.7	153.7	143.7	153.7	153.7	153.7	153.7
Total annual fixed cost	$/kW avail	168.7	157.2	156.6	155.7	158.5	157.8	155.7	167.2	167.2	167.2	167.2	157.1	167.2	167.2	167.2	167.2
Fuel cost calculation																	
Fuel type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Heat rate	kJ/kWh	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611	6,611
Fuel cost	$/kWh	0.04	0.04	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.04	0.03	0.04	0.04
Total fixed cost	$/kW avail.	168.7	157.2	156.6	155.7	158.5	157.8	155.7	167.2	167.2	167.2	167.2	157.1	167.2	167.2	167.2	167.2
Total variable cost	$/kWh avail	0.03895	0.04181	0.03840	0.03840	0.04140	0.04397	0.04397	0.04074	0.04324	0.03598	0.03598	0.03555	0.04181	0.03824	0.04397	0.04397

PROJECT NAME	Unit	Mtwara OCGT	Ubungo I OCGT	Kinyerezi IV	Tegeta OCGT	Kiwira I	Kiwira II	Mchuchuma I	Mchuchuma II	Mchuchuma III	Ngaka I	Ngaka II	Rukwa I	Mbeya I	Rungwe	Mbeya II	Mbeya III	Kiwira III	Rukwa II	Mkuju Ruvuma
Capital Cost	$M	33.72	67.44	1128.4	33.72	437.2	874.4	655.71	874.28	655.71	437.2	937.76	703.32	655.71	1311.42	1391.6	1408.26	695.79	1311.42	5004.16
Installed capacity	MW	30	60	1000	30	200	400	300	400	300	200	400	300	300	600	600.0	600	300	600	560
Station service	%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Net capacity	MW	28.50	57.00	950.00	28.50	190.00	380.00	285.00	380.00	285.00	190.00	380.00	285.00	285.00	570.00	570.00	570.00	285.00	570.00	532.00
Unit availability																				
Scheduled maintenance	wks per unit	6	6	6	6	6	6	6	6	6	6	6	6	6	6	2	2	2	2	2
Forced outage rate	%	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Scheduled maintenance	%	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	3.85	3.85	3.85	3.85	3.85
Combined outage rate	%	19.54	19.54	19.54	19.54	19.54	19.54	19.54	19.54	19.54	19.54	19.54	19.54	19.54	19.54	11.85	11.85	11.85	11.85	11.85
Net capacity available (after derating for outage)	MW	23	46	773	23	155	309	232	309	232	155	309	232	232	464	504	504	252	504	471
Earliest on-power date	Yr	2026	2028	2029	2029	2043	2032	2036	2036	2029	2034	2033	2039	2038	2044	2044	2045	2046	2047	2047
Service life	Yrs	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	50
O & M																				
Fixed O & M	$/kW	61.6	61.6	61.6	61.6	61.6	61.6	61.6	61.6	61.6	61.6	61.6	61.6	61.6	61.6	122.0	121.99	121.99	121.99	121.99
Variable O & M	$/kWh	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0032	0.0032	0.0032	0.00319	0.00319
Total capital cost with IDC																				
Unit capital cost	US $/kW	1124.0	1124.0	1128.4	1124.0	2186.0	2186.0	2185.7	2185.7	2185.7	2186.0	2344.4	2344.4	2185.7	2185.7	2319.3	2347.1	2319.3	2185.7	8936.0
Capital cost	USD Mil.	32.0	64.1	1072.0	32.0	415.3	830.7	622.9	830.6	622.9	415.3	890.9	668.2	622.9	1245.8	1322.0	1337.8	661.0	1245.8	4754.0
Avg capital cost per available capacity	$/kW avail	1381.1	1381.1	1386.5	1381.1	2686.0	2686.0	2685.6	2685.6	2685.6	2686.0	2880.6	2880.6	2685.6	2685.6	2621.8	2653.2	2621.8	2470.8	10101.6
Annual fixed cost	$/kW avail	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7	137.9	137.9	137.9	137.9	137.9
Cashflow in year prior to on-power																				
-7	% of capital																			
-6	% of capital																			
-5	% of capital																			
-4	% of capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
-3	% of capital	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
-2	% of capital	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
-1	% of capital	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
0	% of capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avg total cost at on-power	$/kW avail	1494.3	1494.3	1500.2	1494.3	2906.3	2906.3	2905.9	2905.9	2905.9	2906.3	3116.9	3116.9	2905.9	2905.9	2836.8	2870.8	2836.8	2673.4	10929.9
Annuity over economic life (year-end)	$/kW avail	154.9	154.9	155.6	154.9	301.3	301.3	301.3	301.3	301.3	301.3	323.2	323.2	301.3	301.3	294.1	297.7	294.1	277.2	1102.4
Total annual fixed cost	$/kW avail	230.6	230.6	231.2	230.6	377.0	377.0	377.0	377.0	377.0	377.0	398.9	398.9	377.0	377.0	432.0	435.6	432.0	415.1	1240.3
Fuel cost calculation																				
Fuel type		Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Nuclear
Heat rate	kJ/kWh	6,611	6,611	6,611	6,611	9,179	9,179	9,179	9,179	9,179	9,179	9,179	9,179	9,179	9,179	11,183	9,179	9,179	9,179	11182.72101
Fuel cost	$/kWh	0.04	0.04	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.0056
Total fixed cost	$/kW avail.	230.6	230.6	231.2	230.6	377.0	377.0	377.0	377.0	377.0	377.0	398.9	398.9	377.0	377.0	432.0	435.6	432.0	415.1	1240.3
Total variable cost	$/kWh avail	0.04696	0.04696	0.04696	0.04696	0.02272	0.02272	0.02272	0.02272	0.02272	0.02272	0.02272	0.02272	0.02272	0.02272	0.02308	0.01951	0.01951	0.01951	0.00879

Table 4-28: Screening of Hydropower projects

PROJECTNAME / CHARACTERISTICS			Malagarasi HPP	Kakono HPP	Kidunda Morogoro DAWASA	Ruhudji	Rumakali	Masigira	Songwe Manolo - lower	Kikonge	Mpanga Iringa	Mnyera Kisingo	Mnyera mnyera	Songwe Sofre - Middle	Mnyera Kwanini	Nsongezi (TZ-Portion)	Upper Kihansi	Songwe Upper	Mnyera Pumbwe	Mnyera Taveta	Iringa nginayo	Mbarali	Iringa Ibosa	Songwe Bupigu	Njombe	Mhanga	Songea	Nakatuta (Liparamba)	Kikuletwa	Mnyera Ruaha
Installed capacity MW			49.5	87.8	20.0	358.0	222.0	118.0	90.0	321.0	160.0	119.8	137.4	81.6	143.9	12.0	120.0	29.0	122.0	83.9	52.0	39.0	36.0	17.0	32.0	27.0	15.0	15.0	11.0	60.3
Average Energy GWH			181.0	415.3	87.6	2,000.0	1,322.0	664.0	536.1	1,356.8	756.9	577.3	662.3	382.5	693.8	52.6	69.0	151.8	587.9	404.2	264.2	198.2	186.1	75.9	165.4	118.3	65.7	65.7	48.2	290.5
Capital costs																															
Capital cost $ Million			144.1	280.4	58.2	888.4	602.6	261.3	275.0	740.9	298.5	314.0	665.8	152.2	164.3	33.8	220.8	109.6	219.3	205.8	125.5	166.0	123.0	58.5	136.0	95.0	52.8	52.8	38.7	255.1
Expected Online Year			2027	2029	2027	2030	2030	2031	2030	2030	2032	2032	2032	2031	2032	2029	2033	2030	2032	2032	2031	2031	2031	2031	2031	2031	2031	2031	2029.00	2030.00
IDC calculation																															
% cost year -6	-6	1.772	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	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
% cost year -5	-5	1.611	0.00	0.05	0.00	0.05	0.00	0.05	0.00	0.15	0.05	0.00	0.00	0.05	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
% cost year -4	-4	1.464	0.05	0.15	0.00	0.10	0.15	0.10	0.05	0.25	0.10	0.00	0.00	0.10	0.00	0.00	0.10	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
% cost year -3	-3	1.331	0.15	0.15	0.20	0.15	0.15	0.15	0.15	0.25	0.15	0.20	0.20	0.15	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
% cost year -2	-2	1.210	0.40	0.40	0.40	0.30	0.30	0.30	0.40	0.15	0.30	0.40	0.40	0.30	0.40	0.40	0.30	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
% cost year -1	-1	1.100	0.36	0.21	0.36	0.36	0.36	0.36	0.36	0.11	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
% cost of pre-Construction	0	1.000	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
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	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, USD Mil.			171.9	351.7	69.1	1,088.4	733.8	320.1	327.9	1,015.7	365.7	372.4	789.4	186.5	194.8	40.0	267.4	129.9	260.0	244.0	148.8	196.8	145.9	69.4	161.3	112.6	62.6	62.6	45.9	302.4
Unit Capital Cost, USD/kW			3,472.0	4,005.7	3,452.7	3,040.1	3,305.5	2,712.3	3,643.3	3,164.2	2,285.6	3,108.2	5,745.6	2,285.0	1,353.8	3,337.0	2,228.4	4,480.3	2,131.4	2,907.7	2,861.1	5,046.8	4,052.7	4,079.5	5,039.2	4,171.3	4,171.3	4,171.3	4,171.3	5,015.7
Fixed annual cost																															
Fixed annual cost (capital + interest UAP)			17.33	35.47	6.96	109.77	74.01	32.28	33.07	102.44	36.88	37.56	79.62	18.81	19.65	4.04	26.97	13.10	26.23	24.61	15.01	19.85	14.72	6.99	16.26	11.36	6.31	6.31	4.63	30.50
Fixed O & M, USD Mil.	10		0.50	0.88	0.20	3.58	2.22	1.18	0.90	3.21	1.60	1.20	1.37	0.82	1.44	0.12	1.20	0.29	1.22	0.84	0.52	0.39	0.36	0.17	0.32	0.27	0.15	0.15	0.11	0.60
Total fixed annual cost			17.83	36.35	7.16	113.35	76.23	33.46	33.97	105.65	38.48	38.75	81.00	19.62	21.09	4.16	28.17	13.39	27.45	25.44	15.53	20.24	15.08	7.16	16.58	11.63	6.46	6.46	4.74	31.11
Unit cost of energy																															
Average energy $/kWh			0.10	0.09	0.08	0.06	0.06	0.05	0.06	0.08	0.05	0.07	0.12	0.05	0.03	0.08	0.41	0.09	0.05	0.06	0.06	0.10	0.08	0.09	0.10	0.10	0.10	0.10	0.10	0.11

Table 4-29: Screening of Renewable Projects

Project / Name / Characteristics	Unit	Kishapu Phase I	Kishapu Phase II	Kihamba I Zuzu	Kihamba I Manyoni Phase I	Kihamba I Same	Kihamba I Manyoni Phase II	Kitapilimwa Iringa	Kisima Iringa	Shinyanga II	Kititimo Singida I	Same	Kihamba II Makamako	Waging'ombe Njombe I	Kihamba II Ikungi Phase I	Singida II	Njombe II	Makambako Njimbe I	Songwe Phase I	Ngozi phase I	Kiejo – Mbaka Phase I Mbeya	Songwe Phase II	Natron Phase I	Ngozi phase II	Meru (Arusha) Phase II	Ibadakuli Shinyanga Phase I	Songwe Phase III	Kiejo Mbaka Phase II	Kisaki Morogoro	Natron Phase II	Kisaki Morogoro Phsae II	Meru (Arusha) Phase II	Kioje Mbaka Phase IV	Ngozi Phase III	Songwe Phase IV	Ngozi Phase IV	Ibadakuli Shinyanga Phase II	Ngozi Phase V	Luhoi	Ngozi Phase VI
Source		Solar	Solar	Solar	Solar	Solar	Solar	Solar	Solar	Solar	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal
Capital Cost		89.25	178.5	221.897	267.75	178.5	267.75	178.5	112.4208	267.75	459	76.5	153	459	459	459	153	459	19.815	237.78	277.41	39.63	237.78	158.52	118.89	19.815	79.26	118.89	118.89	594.45	455.745	455.745	495.375	118.89	99.075	118.89	217.965	118.89	178.335	118.89
Installed capacity	MW	50	100	130	150	100	150	100	144	150	300	50	100	300	300	300	100	300	5	60	70	10	60	40	30	5	20	30	30	150	115	115	125	30	25	30	55	30	45	30
Station service	%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Net capacity	MW	49.5	99	128.7	148.5	99	148.5	99	142.56	148.5	297	49.5	99	297	294	294	98	294	4.9	58.8	68.6	9.8	58.8	39.2	29.4	4.9	19.6	29.4	29.4	147	112.7	112.7	122.5	29.4	24.5	29.4	53.9	29.4	44.1	29.4
Unit availability																																								
Scheduled maintenance	wks per unit	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Forced outage rate	%	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Scheduled maintenance	%	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Combined outage rate	%	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Net capacity available	MW	44.1	88.1	114.6	132.2	88.1	132.2	88.1	126.9	132.2	264.3	44.1	88.1	264.3	261.7	261.7	87.2	261.7	4.2	50.0	58.3	8.3	50.0	33.3	25.0	4.2	16.7	25.0	25.0	125.0	95.8	95.8	104.1	25.0	20.8	25.0	45.8	25.0	37.5	25.0
(after derating for outage)																																								
Earliest on-power date	Yr	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2027	2028	2028	2028	2030	2028	2030	2031	2031	2033	2033	2035	2041	2042	2043	2044	2045	2045	2046	2046	2047	2047	2048
Service life	Yrs	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
O & M																																								
Fixed O & M	$/kW	20.23	20.23	20.23	20.23	20.23	20.23	20.23	20.23	20.23	33.06	33.06	33.06	33.06	33.06	33.06	33.06	33.06	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6	150.6
Variable O & M	$/kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116
Total capital cost with IDC																																								
Unit capital cost	US $/kW	560.22	560.22	585.86	560.22	560.22	560.22	560.22	1,280.90	560.22	653.59	653.59	653.59	653.59	1,530.00	1,530.00	1,530.00	1,530.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00	3,963.00
Capital cost	US $ x 10^6	28.01	56.02	76.16	84.03	56.02	84.03	56.02	184.45	84.03	196.08	32.68	65.36	196.08	459.00	459.00	153.00	459.00	19.82	237.78	277.41	39.63	237.78	158.52	118.89	19.82	79.26	118.89	118.89	594.45	455.75	455.75	495.38	118.89	99.08	118.89	217.97	118.89	178.34	118.89
Avg capital cost per available capacity	$/kW avail	635.60	635.60	664.69	635.60	635.60	635.60	635.60	1,453.25	635.60	741.79	741.79	741.79	741.79	1,754.18	1,754.18	1,754.18	1,754.18	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50	4,757.50
Annual fixed cost	$/kW avail	29.08	29.08	29.37	29.08	29.08	29.08	29.08	37.25	29.08	44.56	44.56	44.56	44.56	54.69	54.69	54.69	54.69	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75	224.75
Cashflow in year prior to on-power																																								
-7	% of capital																																							
-6	% of capital																																							
-5	% of capital																																							
-4	% of capital																																							
-3	% of capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
-2	% of capital	40	40	40	40	40	40	90	40	90	0	0	0	0	0	0	0	0	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
-1	% of capital	60	60	60	60	60	60	10	60	10	100	100	100	100	100	100	100	100	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
0	% of capital																																							
Avg total cost at on-power	$/kW avail	661.028	661.028	691.274	661.028	661.028	661.028	692.808	1,511.381	692.808	741.794	741.794	741.794	741.794	1,754.185	1,754.185	1,754.185	1,754.185	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861	5,142.861
Annuity over economic life (year-end)	$/kW avail	72.824	72.824	76.156	72.824	72.824	72.824	76.325	166.506	76.325	81.722	81.722	81.722	81.722	193.255	193.255	193.255	193.255	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579	566.579
Total annual fixed cost	$/kW avail	101.903	101.903	105.526	101.903	101.903	101.903	105.404	203.761	105.404	126.286	126.286	126.286	126.286	247.943	247.943	247.943	247.943	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331	791.331
Fuel cost calculation																																								
Fuel type																																								
Fuel price	$/GJ																																							
Heat rate	kJ/kWh																																							
Fuel cost	$/kWh																																							
Total fixed cost	$/kW avail.	101.90	101.90	105.53	101.90	101.90	101.90	105.40	203.76	105.40	126.29	126.29	126.29	126.29	247.94	247.94	247.94	247.94	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33	791.33
Total variable cost	$/kWh avail.	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116

Source: *PSMP 2024 Update Team Compilation*

4.5 Results of Generation Expansion Plans

The generation expansion plan covers the short-term, medium-term and the long-term plan. The Plan considers three load forecast scenarios and aligns with the existing generation capacity and candidate projects for future power generation using available power generation resources complemented by imports. Further, the Plan observes the set planning criteria, such as the need to maintain capacity and energy balance, fuel requirement, operational and maintenance cost, reliability indices, and sensitivities to variation in load forecast.

Three generation expansion plans have been prepared in line with the Base, Low, and High load forecast scenarios. A Base Case Generation Expansion Plan is recommended to be an ideal expansion scenario for the development of the power generation system in the country.

Overall, the Base Case Generation expansion plan shown in **Error! Reference** source not found.

Table 4-30 indicates that Tanzania requires power capacity of 8,735.09 MW, 15,638.19 MW and 19,905.19 MW in the short, Medium and Long terms, respectively. As shown in **Table 4-** *31* The corresponding electricity generation is 40,379.19 GWh, 80,920.88 GWh and to 108,203.90 GWh in the same planning horizons. The detailed annual generation expansion plan is presented in Error! Reference source not found.

Table 4-30: Cumulative Installed Capacity by Technology

Installed Capacity by Technology	2024 - 2028		2029 - 2038		2039 - 2050	
	MW	Proportion to Total	MW	Proportion to Total	MW	Proportion to Total
Hydropower	2,835.77	32.5%	5,207.87	33.3%	5,264.87	26.4%
Gas Fired	3,074.82	35.2%	5,980.82	38.2%	8,010.82	40.2%
Imports	200.00	2.3%	200.00	1.3%	200.00	1.0%
Geothermal	135.00	1.5%	360.00	2.3%	1,110.00	5.6%
Wind	1,350.00	15.5%	2,450.00	15.7%	3,050.00	15.3%
Solar	1,129.00	12.9%	1,429.00	9.1%	1,729.00	8.7%
Diesel	0.00	0.0%	0.00	0.0%	0.00	0.0%
HFO	0.00	0.0%	0.00	0.0%	0.00	0.0%
Biomass	10.50	0.1%	10.50	0.1%	10.50	0.1%
Uranium	0.00	0.0%	0.00	0.0%	480.00	2.4%
Hydrogen	0.00	0.0%	0.00	0.0%	50.00	0.3%
Total	**8,735.09**	**100.0%**	**15,638.19**	**100.0%**	**19,905.19**	**100.0%**

Table 4- 31: Cumulative Genaration by Technology

Generation by Technology	2024 - 2028		2029 - 2038		2039 - 2050	
	GWh	Proportion to Total	GWh	Proportion to Total	GWh	Proportion to Total
Hydropower	10,625.60	26.3%	22,109.07	27.3%	22,358.73	20.7%
Gas Fired	20,356.74	50.4%	43,129.66	53.3%	57,355.90	53.0%
Imports	1,699.44	4.2%	1,699.44	2.1%	1,699.44	1.6%
Geothermal	1,064.34	2.6%	2,838.24	3.5%	8,751.24	8.1%
Wind	4,730.40	11.7%	8,584.80	10.6%	10,687.20	9.9%
Solar	1,870.26	4.6%	2,527.26	3.1%	3,184.26	2.9%
Diesel	0.00	0.0%	0.00	0.0%	0.00	0.0%
HFO	0.00	0.0%	0.00	0.0%	0.00	0.0%
Biomass	32.41	0.1%	32.41	0.0%	32.41	0.0%
Uranium	0.00	0.0%	0.00	0.0%	3,784.32	3.5%
Hydrogen	0.00	0.0%	0.00	0.0%	350.40	0.3%
Total	**40,379.19**	**100.0%**	**80,920.88**	**100.0%**	**108,203.90**	**100.0%**

4.5.1 Short Term Generation Expansion Plan (2024-2028)

4.5.1.1 Capacity expansion plan

The short-term plan indicated in **Table 4-32** and **Figure 4- 3** show an increase in power capacity installation ranging from 3,191.71MW to 8,735.09 MW in 2024 and 2028, respectively.The contribution of renewable energy to total installed capacity ranges from 59.3% in 2024 to 64.8% in 2028. The detailed annual capacity addition is shown in **Appendix-Gen- 1.**

Table 4-32: Cumulative Capacity Additions (2024-2028)

Installed Capacity by Generation Mix	Units	2024	2025	2026	2027	2028
Total Renewable Energy	MW	**1,891.77**	**2,881.77**	**3,905.77**	**4,555.77**	**5,660.27**
Contribution to Renewable	***P/Cent***	*59.3%*	*68.9%*	*68.1%*	*64.6%*	*64.8%*
Total Non Renewable Energy	MW	**1,299.94**	**1,299.94**	**1,828.82**	**2,498.82**	**3,074.82**
Contribution to Non Renewable	***P/Cent***	*40.7%*	*31.1%*	*31.9%*	*35.4%*	*35.2%*
Total Gneration Mix	**MW**	**3,191.71**	**4,181.71**	**5,734.59**	**7,054.59**	**8,735.09**
Total Percent	***P/Cent***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

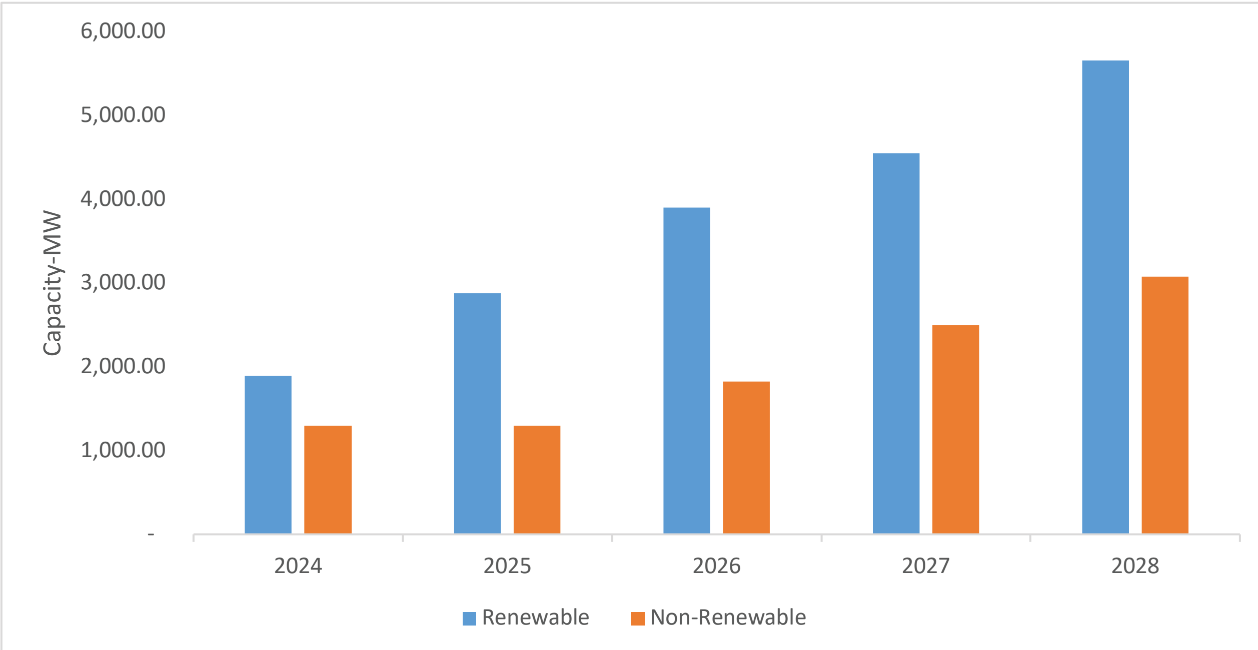

Figure 4- 3: Cumulative Capacity Additions (2024-2028)

4.5.1.2 Energy Generation

The corresponding energy generation ranges from 16,445.63 GWh in 2024 to 40,379.19 GWh in 2028 as shown in **Table 4- 33**. The contribution of renewable energies is 49.6% of total generation by 2028.

Table 4- 33 Cumulative Energy Generation by Technology (2024-2028)

Electricity Generation by Technology	Units	2024	2025	2026	2027	2028
Hydro Generation						
Hydro Existing		2,599.00				
Additional Hydro	GWh	5,920.00	93.00	1,490.96	0.00	522.64
Cumulative Hydro Generation	*GWh*	***8,519.00***	***8,612.00***	***10,102.96***	***10,102.96***	***10,625.60***
Hydro Contribution to Total Generation	*P/Cent*	*51.8%*	*52.3%*	*41.2%*	*32.6%*	*26.3%*
Natural Gas Generation						
Gas Existing	GWh	6,847.50				
Additional Gas	GWh	0.00	0.00	4,415.04	4,695.36	4,398.84
Cumulative Gas Generation	***GWh***	***6,847.50***	***6,847.50***	***11,262.54***	***15,957.90***	***20,356.74***
Gas contribution to Total Generation	*P/Cent*	*41.6%*	*41.6%*	*45.9%*	*51.5%*	*50.4%*
Imported Generation						
Existing Imports		0.00				
Additional Imports	GWh	849.72	0.00	0.00	0.00	849.72
Cumulative Imports Generation	***GWh***	**849.72**	**849.72**	**849.72**	**849.72**	**1,699.44**
Imports contribution to Total Generation	*P/Cent*	*5.2%*	*5.2%*	*3.5%*	*2.7%*	*4.2%*
Geothermal Generation						
Existing		0.00				
Additional Geothermal	GWh	0.00	0.00	0.00	0.00	1,064.34
Cumulative Geothermal Generation	***GWh***	0.00	0.00	0.00	0.00	1,064.34
Geoth. contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*2.6%*
Wind Generation						
Existing Wind		0.00				
Additional Wind	GWh	0.00	0.00	1,051.20	1,226.40	2,452.80
Cumulative Wind Generation	***GWh***	**0.00**	**0.00**	**1,051.20**	**2,277.60**	**4,730.40**
Wind contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*4.3%*	*7.4%*	*11.7%*
Solar Generation						
Existing Solar	GWh	0.00				
Additional Solar	GWh	0.00	109.50	1,103.76	547.50	109.50
Cumulative Solar Generation	***GWh***	**0.00**	**109.50**	**1,213.26**	**1,760.76**	**1,870.26**
Solar contribution to Total Generation	*P/Cent*	*0.0%*	*0.7%*	*4.9%*	*5.7%*	*4.6%*
Diesel Generation						
Existing Diesel	GWh	29.32				
Additional Diesel	GWh	0.00	(29.32)	0.00	0.00	0.00
Cumulative Diesel Generation	***GWh***	**29.32**	**0.00**	**0.00**	**0.00**	**0.00**
Diesel contribution to Total Generation	*P/Cent*	*0.2%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Heavy Fuel Oil Generation (HFO)						
Existing HFO	GWh	167.67				
Additional HFO	GWh	0.00	(167.67)	0.00	0.00	0.00
Cumulative HFO Generation	***GWh***	**167.67**	**0.00**	**0.00**	**0.00**	**0.00**
HFO contribution to Total Generation	*P/Cent*	*1.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Biomass Generation						
Existing Biomass	GWh	32.41				
Additional Biomass	GWh	0.00	0.00	0.00	0.00	0.00
Cumulative Biomass Generation	***GWh***	**32.41**	**32.41**	**32.41**	**32.41**	**32.41**
Biomass contribution to Total Generatio	*P/Cent*	*0.2%*	*0.2%*	*0.1%*	*0.1%*	*0.1%*
Uranium Generation						
Existing Uranium	GWh	0.00				
Additional Uranium	GWh	0.00	0.00	0.00	0.00	0.00
Cumulative Uranium Generation	***GWh***	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Uranium contribution to Total Generatio	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Hydrojen Generation						
Existing Hydrojen	GWh					
Additional Hydrogen	GWh	0.00	0.00	0.00	0.00	0.00
Cumulative Hydrogen Generation	***GWh***	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Hydrogen contribution to Total Generati	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Total Annual Generation	**GWh**	**16,445.63**	**16,451.13**	**24,512.09**	**30,981.35**	**40,379.19**
Total		**100%**	**100%**	**100%**	**100%**	**100%**

4.5.2 Medium Term Generation Expansion Plan (2029-2038)

4.5.2.1 Capacity expansion plan.

The Medium term plan indicated in **Table 4-34** and **Figure 4- 4** show an increase in power capacity installation ranging from 9,931.09 MW to 15,638.19 MW in 2029 and 2038 respectively. The contribution of renewable energy to total installed capacity ranges from 60.1% in 2029 to 61.8% in 2038. The detailed annual capacity addition is shown in **Appendix-Gen- 2**

Table 4-34: Cumulative Capacity Additions (2029-2038)

Installed Capacity by Generation Mix	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Total Renewable Energy	MW	**5,971.27**	**7,490.07**	**7,733.07**	**7,883.07**	**8,212.87**	**8,706.17**	**8,887.17**	**9,121.07**	**9,272.37**	**9,657.37**
Contribution to Renewable	***P/Cent***	*60.1%*	*63.4%*	*61.0%*	*60.8%*	*61.8%*	*61.8%*	*61.0%*	*61.6%*	*62.0%*	*61.8%*
Total Non Renewable Energy	MW	**3,959.82**	**4,332.32**	**4,952.32**	**5,080.82**	**5,080.82**	**5,380.82**	**5,680.82**	**5,680.82**	**5,680.82**	**5,980.82**
Contribution to Non Renewable	***P/Cent***	*39.9%*	*36.6%*	*39.0%*	*39.2%*	*38.2%*	*38.2%*	*39.0%*	*38.4%*	*38.0%*	*38.2%*
Total Gneration Mix	**MW**	**9,931.09**	**11,822.39**	**12,685.39**	**12,963.89**	**13,293.69**	**14,086.99**	**14,567.99**	**14,801.89**	**14,953.19**	**15,638.19**
Total Percent	***P/Cent***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

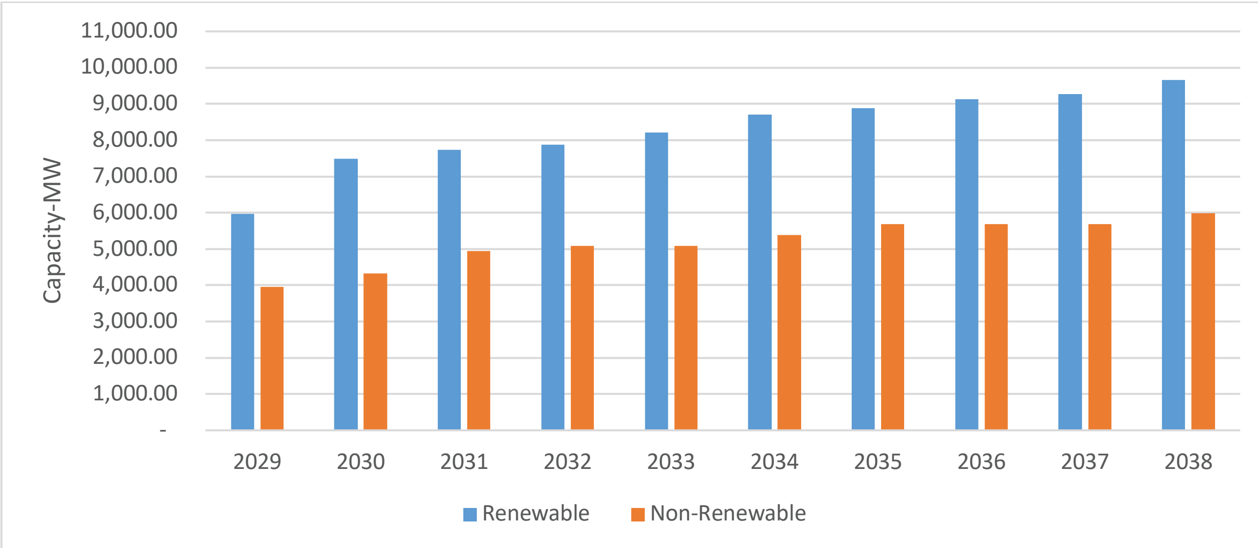

Figure 4- 4: Cumulative Capacity Additions (2029-2038)

4.5.2.2 Energy Generation

The corresponding energy generation ranges from 47,735.70 GWh in 2029 to 80,920.88 GWh in 2038 as shown in **Table 4- 35**. The contribution of renewable energies is 46.7% of total generation by 2038.

Table 4- 35 Cumulative Energy Generation by Technology (2029-2038)

Electricity Generation by Technology	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Hydro Generation											
Hydro Existing by 2029		10,625.60					10,625.60				
Additional Hydro	GWh	48.18	5,168.15	1,200.11	0.00	1,334.16	1,408.66	739.69	404.23	752.88	427.40
Cumulative Hydro Generation	*GWh*	***10,673.78***	***15,841.93***	***17,042.05***	***17,042.05***	***18,376.21***	***19,784.87***	***20,524.56***	***20,928.79***	***21,681.67***	***22,109.07***
Hydro Contribution to Total Generation	*P/Cent*	*22.4%*	*27.5%*	*26.9%*	*26.3%*	*27.6%*	*28.0%*	*27.8%*	*28.1%*	*28.8%*	*27.3%*
Natural Gas Generation											
Gas Existing by 2029	GWh	20,356.74									
Additional Gas	GWh	6,257.13	2,693.68	4,344.96	1,067.55	0.00	2,102.40	2,102.40	0.00	0.00	4,204.80
Cumulative Gas Generation	***GWh***	***26,613.87***	***29,307.55***	***33,652.51***	***34,720.06***	***34,720.06***	***36,822.46***	***38,924.86***	***38,924.86***	***38,924.86***	***43,129.66***
Gas contribution to Total Generation	*P/Cent*	*55.8%*	*51.0%*	*53.1%*	*53.6%*	*52.2%*	*52.1%*	*52.8%*	*52.3%*	*51.7%*	*53.3%*
Imported Generation											
Existing Imports by 2029		1,699.44									
Additional Imports	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Imports Generation	***GWh***	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44
Imports contribution to Total Generatior	*P/Cent*	*3.6%*	*3.0%*	*2.7%*	*2.6%*	*2.6%*	*2.4%*	*2.3%*	*2.3%*	*2.3%*	*2.1%*
Geothermal Generation											
Existing by 2029		1,064.34									
Additional Geothermal	GWh	0.00	867.24	275.94	0.00	394.20	0.00	236.52	0.00	0.00	0.00
Cumulative Geothermal Generation	***GWh***	1,064.34	1,931.58	2,207.52	2,207.52	2,601.72	2,601.72	2,838.24	2,838.24	2,838.24	2,838.24
Geoth. contribution to Total Generation	*P/Cent*	*2.2%*	*3.4%*	*3.5%*	*3.4%*	*3.9%*	*3.7%*	*3.8%*	*3.8%*	*3.8%*	*3.5%*
Wind Generation											
Existing Wind by 2029		4,730.40									
Additional Wind	GWh	1,051.20	1,051.20	0.00	0.00	0.00	700.80	0.00	0.00	0.00	1,051.20
Cumulative Wind Generation	***GWh***	5,781.60	6,832.80	6,832.80	6,832.80	6,832.80	7,533.60	7,533.60	7,533.60	7,533.60	8,584.80
Wind contribution to Total Generation	*P/Cent*	*12.1%*	*11.9%*	*10.8%*	*10.6%*	*10.3%*	*10.7%*	*10.2%*	*10.1%*	*10.0%*	*10.6%*
Solar Generation											
Existing Solar by 2029	GWh	1,870.26									
Additional Solar	GWh	0.00	0.00	0.00	328.50	0.00	0.00	0.00	328.50	0.00	0.00
Cumulative Solar Generation	***GWh***	1,870.26	1,870.26	1,870.26	2,198.76	2,198.76	2,198.76	2,198.76	2,527.26	2,527.26	2,527.26
Solar contribution to Total Generation	*P/Cent*	*3.9%*	*3.3%*	*3.0%*	*3.4%*	*3.3%*	*3.1%*	*3.0%*	*3.4%*	*3.4%*	*3.1%*
Diesel Generation											
Existing Diesel by 2029	GWh	0.00									
Additional Diesel	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Diesel Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Heavy Fuel Oil Generation (HFO)											
Existing HFO by 2029	GWh	0.00									
Additional HFO	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative HFO Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFO contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Biomass Generation											
Existing Biomass by 2029	GWh	32.41									
Additional Biomass	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Biomass Generation	***GWh***	32.41	32.41	32.41	32.41	32.41	32.41	32.41	32.41	32.41	32.41
Biomass contribution to Total Generatio	*P/Cent*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Uranium Generation											
Existing Uranium by 2029	GWh	0.00									
Additional Uranium	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Uranium Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uranium contribution to Total Generatio	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Hydrojen Generation											
Existing Hydrojen by 2029	GWh	0.00									
Additional Hydrogen	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Hydrogen Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen contribution to Total Generati	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Total Annual Generation	**GWh**	**47,735.70**	**57,515.98**	**63,336.99**	**64,733.04**	**66,461.41**	**70,673.27**	**73,751.87**	**74,484.60**	**75,237.48**	**80,920.88**
Total	***P/Cent***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

4.5.3 Long Term Generation Expansion Plan (2039-2050)

4.5.3.1 Capacity expansion plan

The long term plan indicated in **Appendix-Gen- 3.**

Table 4-36 and **Figure 4- 5** show an increase in power capacity installation ranging from 15,995.19 MW to 19,905.19 MW in 2039 and 2050 respectively. The contribution of renewable energy to total installed capacity ranges from 60.7% in 2039 to 57.3% in 2050. The detailed annual capacity addition is shown in **Appendix-Gen- 3.**

Table 4-36: Cumulative Capacity Additions (2039-2050)

Installed Capacity by Generation Mix	Units	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048/50
Total Renewable Energy	MW	**9,714.37**	**9,864.37**	**10,014.37**	**10,429.37**	**10,544.37**	**10,819.37**	**10,874.37**	**11,259.37**	**11,334.37**	**11,414.37**
Contribution to Renewable	***P/Cent***	*60.7%*	*58.8%*	*59.2%*	*60.2%*	*58.9%*	*58.5%*	*57.6%*	*58.4%*	*58.6%*	*57.3%*
Total Non Renewable Energy	MW	**6,280.82**	**6,900.82**	**6,900.82**	**6,900.82**	**7,370.82**	**7,690.82**	**8,010.82**	**8,010.82**	**8,010.82**	**8,490.82**
Contribution to Non Renewable	***P/Cent***	*39.3%*	*41.2%*	*40.8%*	*39.8%*	*41.1%*	*41.5%*	*42.4%*	*41.6%*	*41.4%*	*42.7%*
Total Gneration Mix	**MW**	**15,995.19**	**16,765.19**	**16,915.19**	**17,330.19**	**17,915.19**	**18,510.19**	**18,885.19**	**19,270.19**	**19,345.19**	**19,905.19**
Total Percent	***P/Cent***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

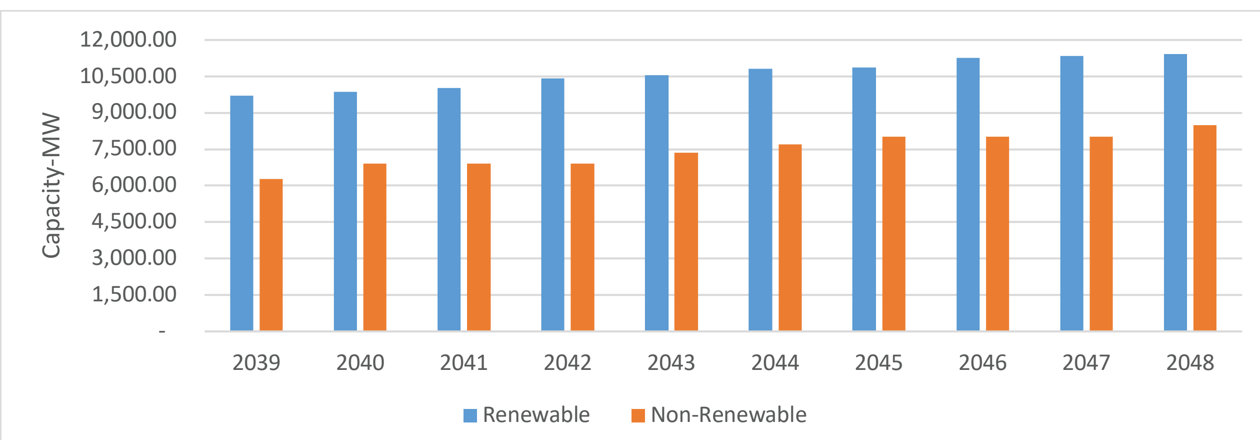

Figure 4- 5: Cumulative Capacity Additions (2039-2050)

4.5.3.2 Energy Generation

The corresponding energy generation ranges from 83,272.94 GWh in 2039 to 108,203.90 GWh in 2050 as shown in **Table 4- 37.** The contribution of renewable energies is 43.5% of total generation by 2050.

Table 4- 37 Cumulative Energy Generation by Technology (2039-2050)

Electricity Generation by Technology	Units	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Hydro Generation											
Hydro Existing by 2039		22,109.07									
Additional Hydro	GWh	249.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Hydro Generation	*GWh*	***22,358.73***	***22,358.73***	***22,358.73***	***22,358.73***	***22,358.73***	***22,358.73***	***22,358.73***	***22,358.73***	***22,358.73***	***22,358.73***
Hydro Contribution to Total Generation	*P/Cent*	*26.8%*	*25.4%*	*25.1%*	*24.5%*	*23.5%*	*22.6%*	*22.0%*	*21.7%*	*21.5%*	*20.7%*
Natural Gas Generation											
Gas Existing by 2039	GWh	43,129.66									
Additional Gas	GWh	2,102.40	4,344.96	0.00	0.00	3,293.76	2,242.56	2,242.56	0.00	0.00	0.00
Cumulative Gas Generation	***GWh***	***45,232.06***	***49,577.02***	***49,577.02***	***49,577.02***	***52,870.78***	***55,113.34***	***57,355.90***	***57,355.90***	***57,355.90***	***57,355.90***
Gas contribution to Total Generation	*P/Cent*	*54.3%*	*56.4%*	*55.6%*	*54.4%*	*55.5%*	*55.8%*	*56.5%*	*55.6%*	*55.2%*	*53.0%*
Imported Generation											
Existing Imports by 2039		1,699.44									
Additional Imports	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Imports Generation	***GWh***	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44	1,699.44
Imports contribution to Total Generation	*P/Cent*	*2.0%*	*1.9%*	*1.9%*	*1.9%*	*1.8%*	*1.7%*	*1.7%*	*1.6%*	*1.6%*	*1.6%*
Geothermal Generation											
Existing by 2029		2,838.24									
Additional Geothermal	GWh	0.00	0.00	1,182.60	906.66	906.66	985.50	433.62	670.14	591.30	236.52
Cumulative Geothermal Generation	***GWh***	2,838.24	2,838.24	4,020.84	4,927.50	5,834.16	6,819.66	7,253.28	7,923.42	8,514.72	8,751.24
Geoth. contribution to Total Generation	*P/Cent*	*3.4%*	*3.2%*	*4.5%*	*5.4%*	*6.1%*	*6.9%*	*7.1%*	*7.7%*	*8.2%*	*8.1%*
Wind Generation											
Existing Wind by 2039		8,584.80									
Additional Wind	GWh	0.00	0.00	0.00	1,051.20	0.00	0.00	0.00	1,051.20	0.00	0.00
Cumulative Wind Generation	***GWh***	8,584.80	8,584.80	8,584.80	9,636.00	9,636.00	9,636.00	9,636.00	10,687.20	10,687.20	10,687.20
Wind contribution to Total Generation	*P/Cent*	*10.3%*	*9.8%*	*9.6%*	*10.6%*	*10.1%*	*9.7%*	*9.5%*	*10.4%*	*10.3%*	*9.9%*
Solar Generation											
Existing Solar by 2039	GWh	2,527.26									
Additional Solar	GWh	0.00	328.50	0.00	0.00	0.00	328.50	0.00	0.00	0.00	0.00
Cumulative Solar Generation	***GWh***	2,527.26	2,855.76	2,855.76	2,855.76	2,855.76	3,184.26	3,184.26	3,184.26	3,184.26	3,184.26
Solar contribution to Total Generation	*P/Cent*	*3.0%*	*3.2%*	*3.2%*	*3.1%*	*3.0%*	*3.2%*	*3.1%*	*3.1%*	*3.1%*	*2.9%*
Diesel Generation											
Existing Diesel by 2039	GWh	0.00									
Additional Diesel	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Diesel Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Heavy Fuel Oil Generation (HFO)											
Existing HFO by 2039	GWh	0.00									
Additional HFO	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative HFO Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFO contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Biomass Generation											
Existing Biomass by 2039	GWh	32.41									
Additional Biomass	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Biomass Generation	***GWh***	32.41	32.41	32.41	32.41	32.41	32.41	32.41	32.41	32.41	32.41
Biomass contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Uranium Generation											
Existing Uranium by 2039	GWh	0.00									
Additional Uranium	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,784.32
Cumulative Uranium Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,784.32
Uranium contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*3.5%*
Hydrojen Generation											
Existing Hydrojen by 2039	GWh	0.00									
Additional Hydrogen	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	350.40
Cumulative Hydrogen Generation	***GWh***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	350.40
Hydrogen contribution to Total Generation	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.3%*
Total Annual Generation	**GWh**	**83,272.94**	**87,946.40**	**89,129.00**	**91,086.86**	**95,287.28**	**98,843.84**	**101,520.02**	**103,241.36**	**103,832.66**	**108,203.90**
Total	***P/Cent***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

4.5.4 Generation Expansion Scenarios

The Low, Base and High case generation expansion scenarios shown in **Table 4-38.** The Plan indicates an average reserve margine of 41.41%, 28.29% and 18.32% for Low, Base and High Case, respectively, over the planning horizon. It can be observed that the power expansion plan is capable of meeting the High Case forecast, even though the reserve capacity remains above 15% in 2026 and below 10% in 2027, 2028 and 2029 during the short term.

Table 4-38: Generation Expansion Scenarios (2024-2050)

Year	LOW CASE 80%			BASE CASE 100%			HIGH CASE 120%		
	Available Capacity-MW	Forecast Demand-MW	Reserve Margin-%	Available Capacity -MW	Forecast Demand-MW	Reserve Margin-%	Available Capacity -MW	Forecast Demand-MW	Reserve Margin-%
2024	2565.77	2,119.32	21.07	2565.77	2,159.80	18.80	2565.77	2,200.28	16.61
2025	2552.77	2,398.61	6.43	2552.77	2,507.80	1.79	2552.77	2,616.98	-2.45
2026	3746.77	3,003.67	24.74	3746.77	3,203.54	16.96	3746.77	3,403.41	10.09
2027	4416.77	4,125.88	7.05	4416.77	4,415.27	0.03	4416.77	4,704.66	-6.12
2028	5347.27	4,860.54	10.01	5347.27	5,256.01	1.74	5347.27	5,651.49	-5.38
2029	6243.27	5,401.35	15.59	6243.27	5,856.96	6.60	6243.27	6,312.56	-1.10
2030	7834.57	6,031.09	29.90	7834.57	6,571.09	19.23	7834.57	7,111.09	10.17
2031	8697.57	6,284.14	38.41	8697.57	6,878.85	26.44	8697.57	7,473.55	16.38
2032	8826.07	6,438.39	37.09	8826.07	7,062.54	24.97	8826.07	7,686.70	14.82
2033	9155.87	6,570.78	39.34	9155.87	7,218.64	26.84	9155.87	7,866.49	16.39
2034	9749.17	6,700.67	45.50	9749.17	7,371.19	32.26	9749.17	8,041.70	21.23
2035	10230.17	6,832.26	49.73	10230.17	7,525.66	35.94	10230.17	8,219.06	24.47
2036	10314.07	6,958.87	48.21	10314.07	7,673.59	34.41	10314.07	8,388.31	22.96
2037	10465.37	7,093.98	47.52	10465.37	7,831.93	33.62	10465.37	8,569.87	22.12
2038	10850.37	7,222.78	50.22	10850.37	7,982.27	35.93	10850.37	8,741.76	24.12
2039	11207.37	7,494.15	49.55	11207.37	8,310.59	34.86	11207.37	9,127.03	22.79
2040	11827.37	7,641.14	54.79	11827.37	8,483.29	39.42	11827.37	9,325.45	26.83
2041	11977.37	7,788.57	53.78	11977.37	8,656.42	38.36	11977.37	9,524.28	25.76
2042	12092.37	7,926.78	52.55	12092.37	8,817.99	37.13	12092.37	9,709.21	24.55
2043	12677.37	8,079.15	56.91	12677.37	8,997.10	40.91	12677.37	9,915.05	27.86
2044	13122.37	8,221.99	59.60	13122.37	9,164.21	43.19	13122.37	10,106.43	29.84
2045	13497.37	8,380.69	61.05	13497.37	9,351.07	44.34	13497.37	10,321.46	30.77
2046	13582.37	8,529.38	59.24	13582.37	9,525.36	42.59	13582.37	10,521.35	29.09
2047	13657.37	8,696.34	57.05	13657.37	9,722.43	40.47	13657.37	10,748.53	27.06
2048	14217.37	8,895.80	59.82	14217.37	9,954.00	42.83	14217.37	11,012.20	29.11
Average Reserve Capacity -%			**41.41**	**Average Reserve Capacity -%**		**28.79**	**Average Reserve Capacity -%**		**18.32**

4.5.5 Capital Cost for Base-Case Generation Expansion

The Base Case Generation expansion scenario was selected as optimal plan taking consideration of the base case demand forecast. The plan requires a total of USD 31,842.37 million over the plan horizon. **Table 4-39** shows a breakdown of the required capital cost for each technology for the short, medium and long terms, respectively. These are overnight costs based on engineering estimations.

5.6.2.2 Medium Term (2029-2038)

The major additional lines consist of 400 kV double Circuit Lines, including: Segera - Same, Same - Kisongo, Sumbawanga – Mpanda - Kigoma, Tanzania - Malawi Interconnector, Shinyanga-Nyakanazi-Kyaka, Tanzania-Mozambique Interconnector, Sumbawanga-Kala, Shinyanga-Bunda, Bunda-Kilgoris Interconnector and Mtwara-Mahumbika.

Table 4-39: Summary Capital Cost requirement by Technology

S/N.	Description by Technology	Cost Estimates (USD)- million			
		2024-2028	2029-2038	2039-2050	Total
1	Hydro power	202.30	6,183.28	200.60	6,586.18
2	Gas Power	1,892.75	3,721.83	2,290.66	7,905.24
3	Solar power	1,762.32	535.50	535.50	2,833.32
4	Wind power	1,912.50	1,836.00	918.00	4,666.50
5	Geothermal power	535.01	891.68	2,972.28	4,398.97
6	Hydrogen power	0.00	0.00	448.00	448.00
7	Nuclear power	0.00	0.00	5,004.16	5,004.16
Total Generation Cost		**6,304.88**	**13,168.29**	**12,369.20**	**31,842.37**

4.6 Conclusion

Power Generation Planning provides a comprehensive roadmap for expanding electricity generation capacity from 2,565.57MW to 19,905.19 MW in the year 2024 to 2050, respectively. The cumulative generation capacity is projected to be 8,735.09 MW in the short term, 15,638.19 MW in the medium term, and 19,905.19 MW in the long term. The contribution of renewable generation capacity is 64.8%, 61.8% and 57.3% in 2028, 2038 and 2050 respectively.

The plan prioritizes a diverse energy mix, including hydropower, natural gas, solar, wind, geothermal, and nuclear energy. The contribution of renewable energies is 49.6%, 46.7% and 43.5% of total generation energy in 2028, 2038 and 2050 respectively.

Three power generation expansion scenarios, namely, Low, Base, and High, were evaluated, with the Base-Case scenario selected as a feasible power expansion scenario. The power capacity reserves for the three power generation expansion scenarios average 41.41%, 28.29% and 18.32% for Low, Base and High Case, respectively, over the planning horizon. The estimated capital cost of USD 31,842.37 million is required for the development of the earmarked power generation projects across the planning period.

CHAPTER FIVE

TRANSMISSION LINE NETWORK EXPANSION

5.1 Introduction

The Plan presents the transmission infrastructure expansion requirement to cater for the country's load forecast and generation plan. The planning horizon is from 2024 to 2050, and it is divided into short-term (2024-2028), medium-term (2029-2038), and long-term (2039-2050). It includes the objective, approach and methodologies, assessment of the existing grid system, factors considered in transmission planning, results from load flow analysis, and conclusion.

The logical planning process used in this plan is more or less similar to the PSMP 2008 and its Updates (2009, 2012, 2016 and 2020). Thus, significant power flow assessment was conducted across the country throughout the planning horizon to plan for reinforcement and new transmission lines. The assessment involved calculating ranges of major interface power flow for critical system conditions. These ranges of major interface power flow between geographic subsystems follow 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 infrastructure additions or changes where necessary. Likewise, the information provided feedback on infrastructure expansion costs associated with the least cost-generation plan. Likewise, load flow simulations were carried out using load forecast and generation data as input to the transmission plan.

The transmission plan result indicates that the required total transmission line additions (400 kV, 220 kV and 132 kV) in the planning horizon are 16,552.16km, as indicated in **Table 5-9**. It includes 5,884.59km in the short term, 8,503.75km in the medium term, and 2,086.82km in the long term. These additions with respective substations (transformers, switchgear, bays, and compensators) have cost estimates of USD 8,109.53 million as indicated in **Table 5-21** comprising USD 3,518.63 million in the short term, USD 3,507.22 million in the medium term, and USD 1,089.67 million in the long term.

The transmission development plan projects a reduction in system losses from 5.80% in 2024 to 5.17% by 2028, further declining to 3.65% in 2038 and 2.85% in the long term. This improvement is driven by increased distributed generation, grid expansion, and reinforcement initiatives aimed at improving power transfer efficiency, reducing transmission losses, and enhancing overall system reliability.

5.2 Objective

The main objective is to identify a definitive short-term, medium-term and an indicative long-term plan for the transmission system expansion and required reinforcement. Specific objectives are:

i. To ensure the security of supply in the short, medium and long terms by coordinating electricity supply and demand.

ii. To ensure the reliability of transmission lines by implementing good maintenance practices;

iii. To determine the location, capacity and type of the required power transmission development and upgrades over the planning horizon.

iv. To establish the timing of the transmission upgrades across years 2028, 2038 and 2050.

v. To estimate the capital cost in the investment plan associated with the transmission system development and upgrades.

5.3 Approach and Methodology

The Planning methodologies and criteria used include, among others, reliability criteria, System Voltage Criteria, Equipment Thermal Loading Criteria, Substation Planning criteria, Transmission System Parameters, and Grid Substation Demand.

5.3.1 Reliability Criteria

The planning of the transmission grid considers the operation of a power system under two possible situations, which are Normal operating conditions (N-0) and Contingency operating conditions (N-1).

5.3.2 Normal Operating Conditions (N-0)

Under normal operating conditions, all the equipment shall remain within the normal thermal loading and voltage ratings (transmission infrastructure is assumed to be entirely available, as no equipment has been forced out of service). The angular separation between adjacent buses under ('N-0') conditions shall not exceed 30 degrees.

5.3.3 Contingency Operating Conditions (N-1)

The principle is that the National 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 or transformer) will not influence the general power supply. This criterion establishes security of supply as a stronger driving force in grid development.

The Plan has set a target to rectify all known breaches of the planning criteria by 2050. The deadline has been predetermined to ensure that there is a 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 N-1 criteria.

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

5.3.4 System Voltage Criteria

The acceptable voltage range for operating the system is based on factors such as equipment limitations and motor operation under normal and contingency conditions, as shown in **Table 5-1.**

Table 5-1: Acceptable Operating Voltage Range

System Voltage [kV]	Acceptable Voltage Range	
	Normal condition	Contingency condition
400	95% – 105%	95% – 105%
330	95% – 105%	90% – 110%
220	95% – 105%	90% – 110%
132	95% – 105%	90% – 110%
66	95% – 105%	90% – 110%

Note: Healthy systems usually target a minimum voltage close to 1.0 per unit (p.u) in the bulk system.

5.3.5 Equipment Thermal Loading Criteria

The transmission system must be planned/designed to allow all transmission lines and equipment to operate within the following limits, as indicated in **Table 5-2.**

Table 5-2: Thermal Loading Criteria

S/N	Condition	Thermal Loading Limit
1	Normal System Conditions	Defined Normal Load Capacity
2	System Design Contingencies of Long Duration (i.e. an outage involving the failure of a transformer)	Defined Normal Load Capacity
3	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)
4	The loading limit for an inter-connecting transformer (ICT)	20% of the rated normal capacity must be kept for unpredictable power flow.

5.3.6 Substation Planning Criteria

Rating of the various substation equipment is planned such that they do not limit the loading limits of connected transmission lines. The maximum short-circuit level on any new substation bus does not exceed 80% of the rated short-circuit capacity of the substation equipment. The 20% margin is intended to take care of the increase in short-circuit levels as the system grows. The applicable rated breaking current capability of switchgear at different voltage levels is in **Table 5-3.** The size and number of interconnecting transformers (ICTs) are planned in such a way that the outage of any single unit would not overload the remaining ICT(s) or the underlying system.

Table 5-3: Rated breaking current capability of switchgear

Voltage Level	Rated Breaking Capacity
400 kV	63 kA
220 kV	40 kA
132 kV	31.5 kA
66 kV	31.5 kA

5.3.7 Transmission System Parameters

In designing and recommending transmission line addition, various parameters were used as indicated in **Table 5-4**

Table 5-4: Transmission Line Assumed Parameters

Voltage	Conductor	Name	Size (mm2)	*Normal Rating (MVA)
400 kV	AAAC	Sorbus	659.40	593.73
	ACSR	Blue jay	603.68	692.80
220 kV	AAAC	Sorbus	659.40	326.55
	ACSR	Blue jay	603.68	381.04
	XLPE	-	800.00	299.89
132 kV	ACSR	Wolf	150.00	74.00
		Hawk	280.84	120.53
	AAAC	Aster	288.30	142.11
	XLPE	—	300/400	143.00
		—	95	52.00

Note: ** 80% of current rating*

5.3.8 Grid Substation Demand

Individual existing and future grid substations were modelled in the load flow simulations in the short, medium and long terms. The corresponding total updated load forecasts in all districts and regions were used as one of the inputs.

5.3.9 Load Flow Analysis

The proposed transmission system is based on the load forecast and the new power plants as presented in Chapters Three and Four. The analysis considered segments of the planning horizon, namely, short, medium and long terms. Each term was analyzed under both normal (N-0) and contingency (N-1) conditions. System reinforcement, including transmission lines, transformers/substations and reactive power compensations, was defined as appropriate.

5.4 Assessment of Existing Grid System

The transmission system infrastructure consists of transmission lines of different voltage capacities and route lengths all over the country. These comprise 1,524.75 km of 400 kV, 4,095.62 km of 220 kV, 1,832.01 km of 132 kV, and 580 km of 66 kV as of December 2024. **Figure 5-1** shows the existing grid network, and **Table 5-5** shows the existing transmission line system with respective line parameters.

The simulation of the existing power system under peak load conditions revealed constraints in the following transmission lines;

i. 220 kV Iringa-Kihansi and 220 kV Kidatu-Iringa Transmission Lines, which were temporarily relieved by the construction of 220 kV Msamvu-Dodoma Transmission line for electrification of SGR.
ii. 220kV Kinyerezi-Ubungo Transmission Line, in which the immediate intervention is the fast-tracking of the completion of the 220kV Kinyerezi (Kimara T-off)–Ubungo – Mabibo-Ilala project and 132kV Kinyerezi-Gongolamboto transmission line project.
iii. 132kV Kinyerezi–Gongolamboto-Mbagala Transmission Line, in which the immediate intervention is the fast-tracking reconductoring of the line.

In addition to that, the simulation results indicated low voltage in the following Grid Network

i. Musoma and Nyamongo substation, in which the short-term intervention is to install appropriate compensating equipment (STATCOM of 45 MVAr) at Nyamongo and the medium-term intervention is to fast-track construction of the 400 kV Shinyanga-Bunda-Kilgoris (Kenya) transmission line.
ii. Tanga Region in which the short-term intervention is the installation of appropriate compensating equipment (STATCOM of 45 MVAr) at Tanga and the medium-term intervention is to fast-track the construction of a 400 kV Chalinze-Segera transmission line and a 220 kV Segera-Tanga transmission line.
iii. Dar es Salaam region at Dege and Kurasini in which the short-term intervention is the install appropriate compensating equipment, and the medium-term intervention is to fast-tracking the construction of a 220 kV Dundani- Pembamnazi-Dege-Kurasini transmission line.
iv. Mbeya Region, where the short-term intervention involves the installation of suitable compensation equipment at the substation to address voltage quality issues.
v. Karatu and Mbulu, in which the short-term intervention is the installation of appropriate compensating equipment, and the medium-term intervention is to fast-track the construction of a 220 kV Makuyuni-Karatu transmission line.

vi. Moreover, the analysis of existing grid network intel that there is an overload at Kondoa (2x8.5 MVA, 66/33 kV), 50 MVA,132/33 kV Mbagala and 50 MVA,132/33 kV Gongolamboto Transformers, in which the short-term intervention is to fast-track the installation of 120 MVA, 132/33 kV at Mbagala and Gongolamboto transformer, the construction of 220kV Pugu-Dundani transmission line with associated substations. The commissioning of the projects will enable the shifting of some load from the Mbagala substation to the Dundani substation, including Mkuranga customers.

Further analysis observes the constraints on the Grid Network, including the following portions of lines: 220 kV Kinyerezi–Ubungo, 132 kV Kinyerezi–Gongolamboto–Mbagala – Kurasini, 132 kV Ubungo–Mlandizi–Chalinze, 132 kV Chalinze–Hale–Arusha and 132 kV Ubungo–Makumbusho, which had exceeded their thermal limits. Therefore, these lines could not transmit all the demanded power. This led to the introduction of new lines such as 136 km of 400 kV Chalinze–Kinyerezi-Mkuranga, 345 km of 400 kV Chalinze-Dodoma, and 90 km of 220 kV Chalinze– Bagamoyo, 511 km of 400 kV of Chalinze – Segera – Arusha, 64 km of 220 kV Segera– Tanga, 5.2 km of 220 kV to Zegereni Industrial area, upgrade of 132/33 kV Dege Kigamboni Substation, 18.42 km of 220 kV Ubungo – Kunduchi – Ununio, 22 km of 220 kV Kinyerezi – Ubungo–Mabibo–Ilala, 47 km of 220kV Pugu - Dundani, 18 km of 220 kV Dundani – Mkuranga.

The proposed increase of power generation in Mtwara, Lindi, Pwani, Dar es Salaam, Morogoro, Kilimanjaro, Arusha, Singida, Dodoma, Iringa, Mbeya, Shinyanga, Kigoma, and Kagera regions has necessitated the reinforcement of the transmission lines in these areas so that power can be evacuated to the load centers. Following this, 136 km of 400 kV Chalinze – Kinyerezi - Mkuranga; 345 km of 400 kV Chalinze–Dodoma; and 616km Iringa–Kisada–Mbeya–Tunduma–Sumbawanga; 280 km of 400 kV Nyakanazi-Kigoma, to mention a few, are planned for construction as per **Table 5-9** for the short term**,** for the medium term and **Table 5-11** for long-term plan.

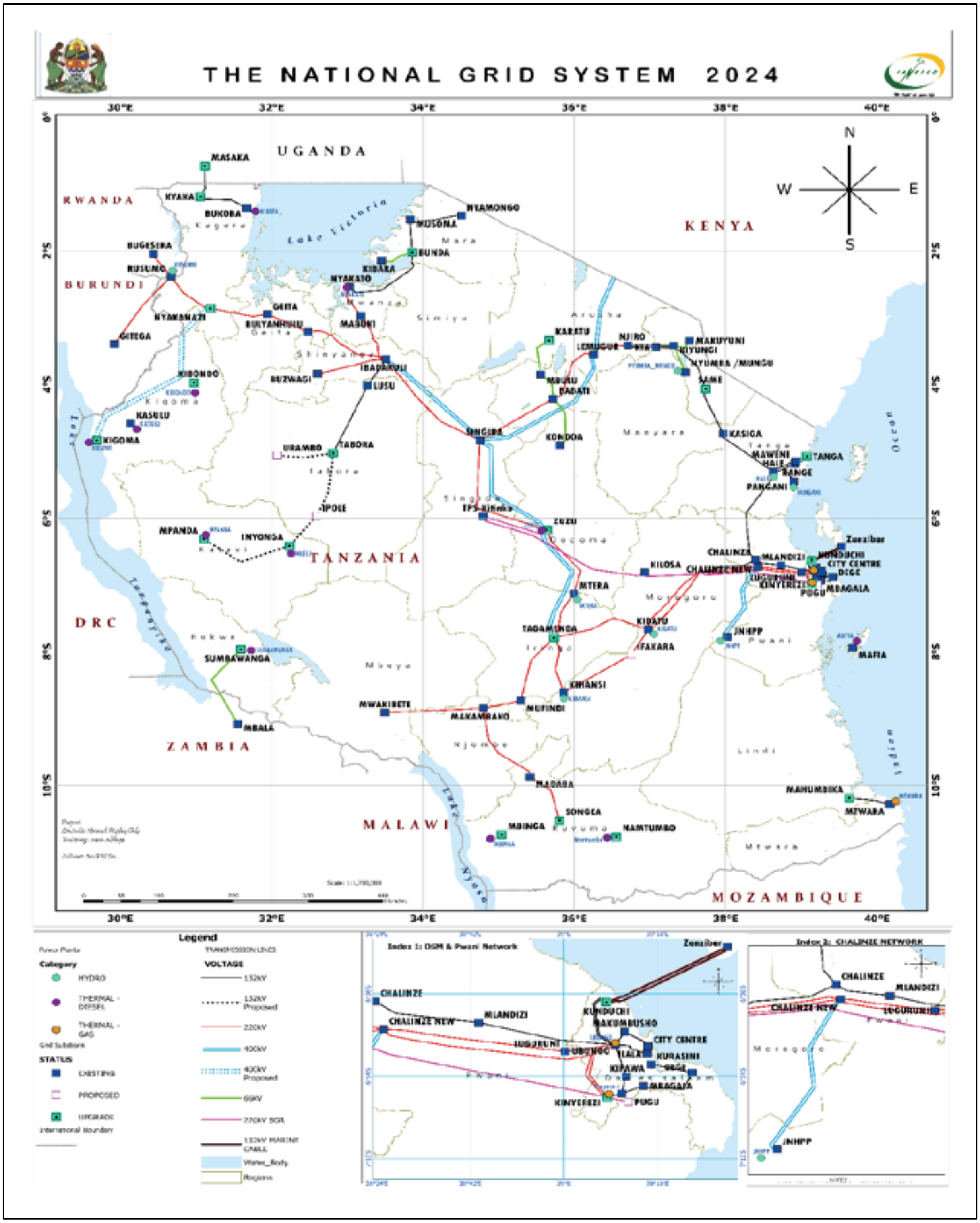

Figure 5-1: Existing Grid System

Source: *PSMP 2024 Update Team Compilation*

Table 5-5: Parameters of the Existing Transmission Line System

No	From- To Substation	Voltage [Kv]	Route Length (Km)	No. Of Towers	Type of Support	Type of Foundation	Tower Configuration	Type & No. of Insulators/Phase	Conductor Type and Size (Al)	Line Capacity (Amps)	Year of Commissioning
1	MOROROGO - UBUNGO 1st	220	172	456	GUYED	GRILLAGE	HORIZONTAL	15/16 STANDARD TYPE	BLUEJAY 565 sq mm ACSR	1000	1975
2	MOROGORO - UBUNGO 2nd	220	179	477	SELF SUPPORT	CONCRETE	TRIANGULAR	15/16 STANDARD TYPE	BLUEJAY 565 sq mm ACSR	1000	1995
3	**MOROGORO - KIDATU 1st**										
	Section I (MINDU-MOROGORO)	220	12	41	GUYED	CONCRETE/	HORIZONTAL	15/16 STANDARD TYPE	BLUEJAY 565 sq mm ACSR	1000	1982
	Section II(KIDATU-MINDU)	220	116	279	GUYED	CONCRETE/	HORIZONTAL	15/16 STANDARD TYPE	BLUEJAY 565 sq mm ACSR	1000	1975
4	MOROGORO-KIDATU 2nd	220	130	328	SELF SUPPORT	CONCRETE	TRIANGULAR	15/16 STANDARD TYPE	BLUEJAY 565 sq mm ACSR	1000	1993
5	KIDATU- IRINGA	220	160	441	SELF SUPPORT	CONCRETE/	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm ACSR	800	1985
6	IRINGA- MUFINDI	220	130	336	SELF SUPPORT	CONCRETE/	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm ACSR	800	1985
7	MUFINDI - MAKAMBAKO	220	60.3	148	SELF SUPPORT	CONCRETE/	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm ACSR	800	1985
8	MAKAMBAKO - MBEYA	220	159.7	396	SELF SUPPORT	CONCRETE/	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm ACSR	800	1985
9	IRINGA- MTERA	220	107	297	SELF SUPPORT	CONCRETE	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm ACSR	800	1985
10	MTERA- DODOMA	220	130	303	SELF SUPPORT	CONCRETE	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm ACSR	800	1985
11	DODOMA- SINGIDA	220	210	528	SELF SUPPORT	CONCRETE	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm ACSR	800	1988
12	SINGIDA-SHINYANGA	220	200	532	SELF SUPPORT	CONCRETE	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm	800	1988
13	SHINYANGA - MWANZA	220	140	336	SELF SUPPORT	CONCRETE	HORIZONTAL	15/16 STANDARD TYPE	BISON 382 sq. mm	800	1988
14	UBUNGO-CHALINZE	132	97	334	GUYED	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1963
15	CHALINZE-MOROGORO	132	82	288	GUYED	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1967
16	CHALINZE- HALE	132	175	534	GUYED	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1963
17	HALE-TANGA	132	60	389	WOODEN H-POLE	-	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1971
18	**HALE-KIYUNGI**										
	Section I (HALE-SAME)	132	173	561	GUYED	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1975
	Section II(SAME-KIYUNGI)	132	102	291	GUYED	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1975
19	UBUNGO- ILALA 1st	132	9.5	25	SELF SUPPORT	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1963
20	UBUNGO-ZANZIBAR(T)	132	41	146	SELF SUPPORT	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 150 sq. mm ACSR	405	1980

No	From- To Substation	Voltage [Kv]	Route Length (Km)	No. Of Towers	Type of Support	Type of Foundation	Tower Configuration	Type & No. of Insulators/Phase	Conductor Type and Size (Al)	Line Capacity (Amps)	Year of Commissioning
21	UBUNGO-ZANZIBAR(C)	132	38	NONE	N/A	N/A	-	N/A	Submarine cable, 94sq.mm CU		1980
22	UBUNGO - KUNDUCHI	132	17	88	MONOPOLE				HAWK 240 sq.mm ACSR	610	
23	KUNDUCHI - WAZO	132	3	27	CONCRETE POLES		TRIANGULAR		HAWK 240 sq.mm ACSR	610	
24	MWANZA-MUSOMA	132	210	628	SELF SUPPORT	GRILLAGE	HORIZONTAL	9/ 10 STANDARD TYPE	WOLF 158 sq. mm	405	1989
25	SHINYANGA-TABORA	132	203	587	SELF SUPPORT	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 158 sq. mm	405	1989
26	KIYUNGI - ARUSHA	132	70	208	SELF SUPPORT	GRILLAGE	HORIZONTAL	9/10 STANDARD TYPE	WOLF 158 sq. mm ACSR	405	1983
27	MTWARA - LINDI	132	80	490	WOODEN H-POLE		HORIZONTAL	9/10 STANDARD TYPE	HAWK 240 sq.mm ACSR	610	2017
28	**ILALA - NEW CITY CENTRE**										
	Section I (OVERHEAD LINE)	132	1.3	3	SELF SUPPORT	CONCRETE	TRIANGULAR	9/10 STANDARD TYPE	HAWK 240 sq.mm ACSR	610	2013
	Section II UNDERGROUND CABLE)	132	1.8								2013
29	NCC - MAKUMBUSHO - UNDERGROUND	132	6.67								2013
30	NYM - KIYUNGI	66	53	463	WOODEN POLES	-	TRIANGULAR	5/ 6 STANDARD TYPE	RABBIT 50 sq. mm ACSR	190	1968
31	KIYUNGI - ARUSHA	66	78	625	WOODEN POLES	-	TRIANGULAR	5/ 6 STANDARD TYPE	RABBIT 50 sq. mm ACSR	190	1967
32	BABATI- KONDOA	66	85	251	SELF SUPPORT	CONCRETE	TRIANGULAR	7/ 7 STANDARD TYPE	WOLF 158 sq. mm ACSR	405	1999
33	BABATI- MBULU	66	85	192	SELF SUPPORT	CONCRETE	TRIANGULAR	7/ 7 STANDARD TYPE	WOLF 158 sq. mm ACSR	405	1999
34	MBULU- KARATU	66	65	172	SELF SUPPORT	CONCRETE	TRIANGULAR	7/ 7 STANDARD TYPE	WOLF 158 sq. mm ACSR	405	1999
35	KIHANSI- IRINGA	220	95.23	277	SELF SUPPORT	CONCRETE	TRIANGULAR	15/ 16 STANDARD TYPE	BLUEJAY 565 sq mm ACSR	1000	1998
36	KIHANSI- ESCAPMET	220	1.67	2	SELF SUPPORT	CONCRETE	TRIANGULAR	15/ 16 STANDARD TYPE	PHEASANT 702 sq. mm AACSR	688	1998
37	KIHANSI - KIDATU	220	180	529	SELF SUPPORT	CONCRETE	TRIANGULAR	15/ 16 STANDARD TYPE	BLUEJAY 565 sq mm ACSR	1000	1999
38	UBUNGO- ILALA 2nd	132	9.5	25	SELF SUPPORT	CONCRETE	VERTICAL	11/ 12 STANDARD TYPE	WOLF 158 sq. mm ACSR	405	1999
39	KINYEREZI - GONGO LA MBOTO	132	3	17	SELF SUPPORT	CONCRETE	TRIANGULAR	11/ 12 STANDARD TYPE	HAWK 241 sq. mm ACSR	610	2013
40	UBUNGO- KIPAWA	132	11	35	SELF SUPPORT	CONCRETE	VERTICAL DOUBLE CIRCUIT	11/ 12 STANDARD TYPE	WOLF 158 sq. mm ACSR	405	2000
41	KIPAWA - GONGO LA MBOTO	132	7	57	MONOPOLE	CONCRETE	VERTICAL	11/ 12 STANDARD TYPE	HAWK 241 sq. mm ACSR	610	2015
42	GONGO LA MBOTO - MBAGALA	132	16.2		SELF SUPPORT & MONOPOLE	CONCRETE	TRIANGULAR	11/ 12 STANDARD TYPE	HAWK 241 sq. mm ACSR	610	2015

No	From- To Substation	Volt age [Kv]	Rout e Len gth (Km)	No. Of Tow ers	Type of Support	Type of Foundati on	Tower Configuration	Type & No. of Insulators/P hase	Conductor Type and Size (Al)	Line Capacit y (Amps)	Year of Commi ssionin g
43	MBAGALA - DEGE BEACH	132	28		SELF SUPPORT & MONOPOL E	CONCRE TE	VERTICAL DOUBLE CIRCUIT	11/ 12 STANDARD TYPE	HAWK 241 sq. mm ACSR	610	2015
44	DEGE BEACH - KURASINI	132	22		SELF SUPPORT & MONOPOL E	CONCRE TE	VERTICAL DOUBLE CIRCUIT	11/ 12 STANDARD TYPE	HAWK 241 sq. mm ACSR	610	2020
45	P/FALLS-SONGA	132	8.5	33	SELF SUPPORT	GRILLAG E	VERTICAL	10/12 STANDARD TYPE	HAWK 241 sq. mm ACSR	610	1995
46	HALE- TANGA	132	60	200	SELF SUPPORT	GRILLAG E	TRIANGULAR	10/12 STANDARD TYPE	HAWK 241 sq. mm ACSR	610	1994
47	SINGIDA-BABATI	220	150	424	SELF SUPPORT	CONCRE TE	TRIANGULAR	15/16 STANDARD TYPE	RAIL 517 sq. mm ACSR	920	1996
48	BABATI- ARUSHA	220	162	433	SELF SUPPORT	CONCRE TE	TRIANGULAR	15/16 STANDARD TYPE	RAIL 517 sq. mm ACSR	920	1996
49	MTUKULA- KYAKA	132	30	85	SELF SUPPORT	CONCRE TE	HORIZONTAL	10/12 STANDARD TYPE	TIGER 130 sq. mm ACSR	354	1992
50	KYAKA - BUKOBA	132	54	157	SELF SUPPORT	CONCRE TE	HORIZONTAL	10/12 STANDARD TYPE	TIGER 130 sq. mm ACSR	364	1992
51	SHINYANGA - BULYANHULU	220	129. 46	277	SELF SUPPORT	CONCRE TE	HORIZONTAL	POLYMERIC TYPE	BISON 382 sq. mm ACSR	800	2000
52	MBALA- S/WANGA	66	120	569	MONOPOL E	CONCRE TE	TRIANGULAR	COMPOSITE TYPE	WOLF 171 sq. mm ACS	405	2002
53	BUNDA-KIBARA	66	60	300	WOODEN POLES	-	HORIZONTAL	5/6STANDAR D TYPE	WOLF 150 sq. mm ACSR		2007
54	MUSOMA- N/MONGO	132	90	238	SELF SUPPORT	CONCRE TE	TRIANGULAR	POLYMERIC TYPE	WOLF194,SQ MM ACSR	405	2009
55	SHY-BUZWAGI	220	108	237	SELF SUPPORT	CONCRE TE	TRIANGULAR	POLYMERIC TYPE	Bison 382sq.mm	800	2009
56	UBUNGO - MAKUMBUSHO	132	7	37	SELF SUPPORT - MONOPOL E	CONCRE TE	VERTICAL	PORCELAIN	HAWK 241 sq. mm ACSR	610	2010
57	KIYUNGI - MAKUYUNI	66	34	172	SELF SUPPORT LATTICE	CONCRE TE	VERTICAL	PORCELAIN	WOLF194,SQ MM ACSR	405	2012
58	UBUNGO - RASKILOMON (II) T	132	17	88	SELF SUPPORT LATTICE	CONCRE TE	TRIANGULAR	POLYMERIC TYPE	HAWK 241 sq. mm ACSR	610	2013
59	RAS FUMBA- MTONI Z/BAR (T)	132	21.5 4	108	STEEL POLES	CONCRE TE	TRIANGULAR	POLYMERIC TYPE	HAWK 281.1 sq. mm ACSR	610	2013
60	KIYUNGI - KIA (II)	132	35	85	SELF SUPPORT LATTICE	CONCRE TE	TRIANGULAR	9/10 PORCELAIN	HAWK 241 sq. mm ACSR	610	2015
61	KIA - ARUSHA (II)	132	35	122	SELF SUPPORT LATTICE	CONCRE TE	TRIANGULAR	9/10 PORCELAIN	HAWK 241 sq. mm ACSR	610	2015
62	KINYEREZI - KIMARA (to MGII Termination)	220	8	23	SELF SUPPORT LATTICE	CONCRE TE	VERTICAL	16 GLASS	BLUEJAY 565 sq mm ACSR	1000	2015
63	MAKAMBAKO- SONGEA	220	250	711	SELF SUPPORT LATTICE	CONCRE TE	VERTICAL	17 GLASS	BLUEJAY 565 sq mm ACSR	1000	2019
64	BULYANHULU - GEITA	220	55	163	SELF SUPPORT LATTICE	CONCRE TE	VERTICAL	18 GLASS	BLUEJAY 565 sq mm ACSR	1000	2019
65	DAR ES SALAAM- MOROGORO SGR	220	159		SELF SUPPORT LATTICE	CONCRE TE	VERTICAL	17 GLASS	BLUEJAY 565 sq mm ACSR	1000	2020
66	GEITA-NYAKANAZI	220	143. 16	423	SELF SUPPORT LATTICE	CONCRE TE	VERTICAL	GLASS INSULATOR S	AAAC - SORBUS	805	2021

No	From- To Substation	Voltage [Kv]	Route Length (Km)	No. Of Towers	Type of Support	Type of Foundation	Tower Configuration	Type & No. of Insulators/Phase	Conductor Type and Size (Al)	Line Capacity (Amps)	Year of Commissioning
67	IRINGA-DODOMA	400	225	590	SELF SUPPORT LATTICE	CONCRETE	VERTICAL	POLYMER INSULATORS	BLUEJAY 565 sq mm ACSR	1000	2016
68	DODOMA- SINGIDA	400	164	363	SELF SUPPORT LATTICE	CONCRETE	VERTICAL	POLYMER INSULATORS	BLUEJAY 565 sq mm ACSR	1000	2016
69	SINGIDA-SHINYANGA	400	282	482	SELF SUPPORT LATTICE	CONCRETE	VERTICAL	POLYMER INSULATORS	BLUEJAY 565 sq mm ACSR	1000	2016
70	SINGIDA-ARUSHA-NAMANGA	400	414	771	SELF SUPPORT LATTICE	CONCRETE	VERTICAL	GLASS INSULATORS	BLUEJAY 565 sq mm ACSR	1000	2022
71	SGR 2-1 MORO-IHUMWA-	220	239	671	SELF SUPPORT LATTICE	CONCRETE	TRIANGULAR	21 GLASS INSULATORS	BLUEJAY 603 sq mm ACSR	1000	2023
72	SGR 2-1 MORO-IHUMWA	220	239	671	SELF SUPPORT LATTICE	CONCRETE	TRIANGULAR	Glass Insulator / 21 Discs per String/phase	BLUEJAY 603 sq mm ACSR	1000	January, 2024
73	SGR 2-2 IHUMWA-KINTINKU ZUZU	220	176	540	SELF SUPPORT LATTICE	CONCRETE	TRIANGULAR	Glass Insulator / 21 Discs per String/phase	BLUEJAY 603 sq mm ACSR	1000	January, 2024
74	JNHPP -CHALINZE	400	159.75	397	SELF SUPPORT LATTICE	CONCRETE	VERTICAL	GLASS INSULATORS	AAAC SORBUS CONDUCTOR - 659.4 SQ MM		2024
75	RUSUMO-NYAKANAZI	220	94.1	240	SELF SUPPORT LATTICE	CONCRETE	VERTICAL	GLASS INSULATORS	AAAC - ASTER - 2x 570sq mm	600 (with Single circuit)	2023
76	ILALA-KURASINI - UNDERGROUND	132	7	N/A	N/A	N/A	N/A	N/A	Single Core XLPE Soli Alluminium	796	2024
	Total Route Length										**7752.4km**

	VOLTAGE LEVEL	% Route Length	Route Length(km)
TOTAL LENGTH IN KMS:	400kV	16.06	1244.75
	220kV	52.83	4095.62
	132kV	23.63	1832.01
	66kV	7.48	580
	Total	**100**	**7732.38**

	VOLTAGE LEVEL	CONNECTED TO THE GRID	OFF GRID	TOTAL GRID
TOTAL NO. OF LINE SEGMENTS	400kV	6	0	6
	220kV	27	0	27
	132kV	22	2	24
	66kV	7	1	8
	Total	**62**	**3**	**65**

Source: *TANESCO (December 2024)*

5.5 Factors Considered in Transmission Planning

5.5.1 Reinforcement of Grid Security

The Government intends to connect all isolated grids and reinforce the National Grid to ensure grid reliability and security of power supply in the country. In this regard, the plan addresses the need for additional transmission capacities and reinforcement to supply adequate and reliable power to the load centres.

The Government has initiated several projects to reinforce Grid security and reliability, particularly in the short term. These projects include a 400 kV transmission line from JNHPP to Chalinze and thereafter to upcountry through 400 kV Chalinze–Dodoma, Chalinze–Kinyerezi – Mkuranga and Chalinze – Segera – Arusha and 220 kV Chalinze– Bagamoyo. Other transmission projects include 400 kV Iringa– Mbeya – Tunduma – Sumbawanga, 220 kV Benako Kyaka, 400 kV Nyakanazi – Kigoma – Mpanda – Sumbawanga, 400 kV Mtwara – Somanga – Mkuranga and 400 kV JNHPP – Mkuranga and Grid Imara Projects.

5.5.2 Demand Growth

The load forecast shows that there will be high growth of power demand mainly due to the increase in industrial, agricultural, construction, implementation of Energy Compact Program (Mission 300) and extractive activities. The growth in these activities will lead to higher levels of energy consumption. It is anticipated that the grid system needs to be reinforced for a more reliable connection between regions and to contribute to uniform electricity prices across the country.

5.5.3 Grid Expansion to Explore Generation Resources

The Grid expansion considered the requirement to evacuate power from the generation sources to the load centres which requires a stable grid network. Among the sources are power generation from variable renewable energy (solar and wind), geothermal, hydro, gas, uranium, hydrogen, etc. Thus, the Plan accommodates the intermittency of power generation from variable renewable energy sources because an increase in the generation of renewable energy will further increase instabilities in the grid power system between years with low precipitation and years with high precipitation. Initiatives are in place to motivate renewable power generation, such as the ongoing construction of 150MWp Solar at Shinyanga.

5.5.4 Grid Expansion to Underserved and Isolated Areas

The transmission plan also aims to connect currently grid-isolated areas that are presently supplied through cross-border power imports and standalone diesel power plants. These areas include isolated load centers with a combined nominal capacity of 20.19 MW operated by TANESCO using thermal power plants, 251.22 MW of private captive generation and electricity imports from Uganda via the 132 kV Masaka–Kyaka line and the 33 kV Kigagati hydropower plant to Kagera Region, as well as from Zambia through 66 kV transmission lines to Rukwa Region.

5.5.5 Development of New Interconnectors

Power interconnection with neighbouring countries is essential for enhancing cross-border power trade to ensure reliability and security of power supply. Thus, the transmission plan considered the following interconnectors:

a) **Tanzania, Rwanda, and Burundi 220 kV Interconnection Project:** The project has been driven by the construction of an 80 MW hydropower project at the Rusumo border. The project enables the National Grids of the three countries to interconnect through the 220 kV transmission line. The interconnection has been commissioned since 2023.

b) **Tanzania (Singida – Arusha – Namanga) – Kenya (Isinya) 400 kV interconnection project**: The project was constructed and commissioned in 2024.

c) **Tanzania – Zambia 400 kV interconnection project:** The project is under construction, whereby Substation construction commenced in November 2023 and is expected to be commissioned by 2025, while the transmission line commenced in May 2024 and is expected to be commissioned in 2026.

d) **Tanzania – Malawi 400 kV interconnection project:** A feasibility study has been completed, and solicitation of funds to implement the project from Mbeya (Iganjo) to the proposed Kyela substation is underway, with commissioning planned in 2030.

e) **Tanzania (Ibadakuli - Nyakanazi – Kyaka) – Uganda (Masaka) 400 kV interconnection project**: A joint feasibility study under World Bank financing has been completed. The conduct of the ESIA study is underway. The project is planned to be commissioned by 2030.

f) **Tanzania (Shinyanga – Bunda) – Kenya (Kilgoris) 400 kV interconnection project:** Feasibility study has been completed. The soliciting of funds to implement the project is underway. The project is planned to be commissioned in 2030.

g) **Tanzania – Mozambique 400 kV interconnection project:** The project is under solicitation of funds for undertaking the feasibility study. The project is planned to be commissioned in 2032.

h) Tanzania (Kigoma) – Burundi (Itaba) 220 kV Interconnection Project: The project is in the planning stage.

i) Tanzania (Rukwa) – DRC (Katanga Province) 400 kV Interconnection Project: A pre-feasibility study has been completed. The soliciting of funds to implement the project is underway.

5.6 Results of Load Flow Analysis

The load flow analysis serves as the critical component of PSMP, providing a comprehensive assessment of power system performance in the existing network and its respective expansion plans in the short, medium and long terms. This analysis evaluates the adequacy, efficiency and reliability of the transmission network under various system conditions to ensure a stable and secure electricity supply.

5.6.1 Grid Substation Demand

The grid substation demands throughout the country are presented in this section. It includes load forecast results in short, medium and long terms. It is a result of the load flow analysis of the existing and future grid substations to establish the corresponding total updated load forecasts in all districts and regions.

5.6.1.1 Grid Substation Demand for Short-Term (2024-2028)

Grid substation demand for the short term is summarised in **Table 5-6** and detailed in **Appendix-Trans- 1** The results indicate grid substation demand will reach an active load of 4984.81 MW and reactive load of 1863.43 MVAr by 2028. It is worth mentioning that the successful completion of the proposed reinforcement and new additions projects will enhance demand distribution between regions, particularly Dar es Salaam, where significant demand will shift to substations in the Pwani region.

Table 5-6: Summarised Grid Substation Load Demand for Short Term (2024-2028)

S/N	Region	MW	MVAr
1	ARUSHA	164.24	76.46
2	PWANI	985.64	335.26
3	DAR ES SALAAM	993.88	360.74
4	DODOMA	161.81	75.64
5	EXPORT	216.00	68.00
6	GEITA	127.59	61.82
7	IRINGA	76.74	25.21
8	KAGERA	82.92	30.10
9	KATAVI	61.70	21.88
10	KIGOMA	61.70	61.70
11	KILIMANJARO	82.58	26.62
12	LINDI	31.50	10.36
13	LNG	75.60	35.78
14	MANYARA	62.93	19.69
15	MARA	70.57	25.10
16	MBEYA	134.50	44.20
17	MOROGORO	116.54	38.32
18	MTWARA	142.45	39.76
19	MWANZA	144.89	41.71
20	NJOMBE	34.26	11.26
21	RUKWA	42.01	13.81
22	RUVUMA	66.01	21.69
23	SGR	164.03	82.04
24	SHINYANGA	185.49	87.19
25	SIMIYU	30.85	10.14
26	SINGIDA	42.51	13.97
27	SONGWE	61.69	20.28
28	TABORA	57.37	20.82
29	TANGA	260.86	94.62
30	ZANZIBAR	245.96	89.26
	TOTAL	**4,984.81**	**1,863.43**

5.6.1.2 Grid Substation Demand for Medium-Term (2029-2038)

Grid substation demand for the medium term is indicated in **Table 5-7** and detailed **Appendix-Trans- 2.** The results indicate grid substation demand will reach an active load of 7,738.05 MW and reactive load of 2,801.70 MVAr by 2038.

Table 5-7: Summarised Grid substation Demand for Medium Term (2029-2038)

S/N	Region	MW	MVAr
1	ARUSHA	227.72	81.81
2	PWANI	1,442.15	552.24
3	DAR ES SALAAM	1,378.95	507.73
4	DODOMA	227.58	70.41
5	EXPORT	462.00	155.46
6	GEITA	177.21	48.00
7	IRINGA	96.80	28.98
8	KAGERA	114.90	35.21
9	KATAVI	85.51	22.83
10	KIGOMA	85.51	29.83
11	KILIMANJARO	114.44	36.90
12	LINDI	55.57	30.14
13	LNG	229.08	101.23
14	MANYARA	87.13	28.48
15	MARA	148.72	35.12
16	MBEYA	186.42	65.29
17	MOROGORO	186.58	78.77
18	MTWARA	208.43	67.44
19	MWANZA	178.65	51.35
20	NJOMBE	47.49	19.61
21	RUKWA	58.24	19.84
22	RUVUMA	91.51	26.52
23	SGR	609.64	308.40
24	SHINYANGA	258.12	73.27
25	SIMIYU	42.76	20.99
26	SINGIDA	68.91	37.45
27	SONGWE	85.52	27.74
28	TABORA	79.33	20.33
29	TANGA	361.58	128.81
30	ZANZIBAR	341.60	91.52
	TOTAL	**7,738.05**	**2,801.70**

5.6.1.3 Grid Substation Demand for Long-Term (2039-2050)

Grid substation demand for the medium term is indicated in **Table 5-8** and detailed in **Appendix-Trans- 3.** The results indicate grid substation demand will reach an active load of 9,670.69 MW and reactive load of 3,507.78 MVAr by 2050.

Table 5-8: Summarised Grid Substation Demand for long-Term (2039-2050)

S/N	Region	MW	MVAr
1	ARUSHA	273.44	97.80
2	PWANI	1,815.53	684.46
3	DAR ES SALAAM	1,644.31	642.66
4	DODOMA	263.96	91.87
5	EXPORT	600.00	152.00
6	GEITA	211.80	67.52
7	IRINGA	128.46	35.17
8	KAGERA	160.18	62.73
9	KATAVI	103.26	37.24
10	KIGOMA	103.25	38.01
11	KILIMANJARO	138.19	42.40
12	LINDI	52.06	23.91
13	LNG	297.50	100.00
14	MANYARA	105.32	44.39
15	MARA	162.81	55.53
16	MBEYA	225.59	86.40
17	MOROGORO	220.05	97.59
18	MTWARA	251.68	68.60
19	MWANZA	245.59	79.85
20	NJOMBE	59.92	23.33
21	RUKWA	70.91	24.12
22	RUVUMA	110.59	36.74
23	SGR	948.95	423.88
24	SHINYANGA	306.32	124.14
25	SIMIYU	51.34	23.24
26	SINGIDA	71.14	38.88
27	SONGWE	105.39	30.59
28	TABORA	95.69	20.29
29	TANGA	436.60	150.92
30	ZANZIBAR	410.86	103.52
	TOTAL	**9,670.69**	**3,507.78**

Source:*PSMP 2024 Update*

5.6.2 Transmission System Addition - Least Cost Expansion Plan

In mitigating transmission system overloads in the existing network, a series of proposed projects have been identified to enhance system reliability, efficiency and capacity. These initiatives aim to alleviate congestion, improve voltage stability and ensure seamless transfer of power across the grid. Following the result of the transmission planning analysis, there is a requirement for additional transmission systems that include transmission lines, substations and compensators in short, medium and long-term plans which fulfil transmission planning criteria. A summary of the results from transmission line analysis is shown in **Table 5-9** and further details are shown in **Table 5-10**, **Table 5-11** and **Table 5-12** for short, medium and long-term plans respectively.

Table 5-9: Summary of Transmission System Additions for 2024 – 2050

S/N	Voltage Levels	Transmission System Additions (km)			
		2024-2028	**2029-2038**	**2039-2050**	**Total**
1	400kV	1,922.00	2,558.33	880.22	5,360.55
2	220kV	2,663.58	5,769.72	1,098.00	9,531.30
	132kV	1,299.01	175.7	108.6	1,583.31
Total		**5,884.59**	**8,503.75**	**2,086.82**	**16,552.16**

5.6.2.1 Short term (2024-2028)

From the study results, it was observed that the existing transmission system, under construction and planned for the period 2024-2028, is adequate to transfer power to meet the projected demand.

The major transmission lines additions by 2028 are divided into two categories. The first is the expansion of a 400 kV network which will consist of 400 kV double Circuit Lines: Chalinze – Dodoma, Chalinze-Kinyerezi-Mkuranga, Chalinze – Segera, Kigoma-Nyakanazi, Iringa – Mbeya – Tunduma – Sumbawanga; Mkuranga– Somanga – Mahumbika –Mtwara.

The second is the expansion of 220 kV transmission lines, which consist of Segera – Tanga, Chalinze-Bagamoyo, Pugu-Dundani, Shinyanga-Simiyu, Tunduru-Masasi, Dundani-Pembamnazi-Dege-Kurasini, Morogoro-Dumila, Mbinga-Songea, Ifakara-Mahenge, Nyakanazi-Kabanga, Benaco-Kyaka, Bulyanhulu-Nyanzaga, Bulyanhulu-Bukombe, and Iganjo-Chunya.

Contingency analysis was evaluated in the N-1 state. This static security assessment was performed for all high-voltage (≥66 kV) assets. Under contingency conditions, the voltage check was based on the (0.9-1.1 pu) limits and the loading was based on the transmission line/transformer emergency capacity (rating B).

In 2028, there are buses with voltage violations such as Kondoa, Mbulu, Karatu and Mpanda. The overload was observed on 220 kV Shinyanga - Bulyanhulu and 132 kV Mwanza - Bunda transmission lines, while on other transmission lines, there were no overloading problems encountered in the bulk system during normal conditions.

Contingency was observed on the 220 kV Shinyanga – Nyakanazi corridor. In case a fault occurs on these assets, a voltage collapse occurs. If one of the lines in this corridor is not available, the active power has to go through the Tabora-Urambo-Kigoma loop to reach Nyakanazi and Geita loads, leading to a voltage collapse. This necessitates the construction of 400 kV Shinyanga-Nyakanazi transmission line.

Another contingency was observed on 220 kV Lemugur-Njiro. The loss of the line between Lemugur and Njiro leads to undervoltage in the Njiro substation. This line supports the voltage in the Arusha and Kilimanjaro regions. There are insufficient generating units that can provide reactive reserves to avoid this voltage collapse, therefore results indicate the need for installing a second line in parallel with the existing one.The Planned transmission lines for the period of 2024-2028 are given in **Figure 5- 2** and **Table 5-10.**

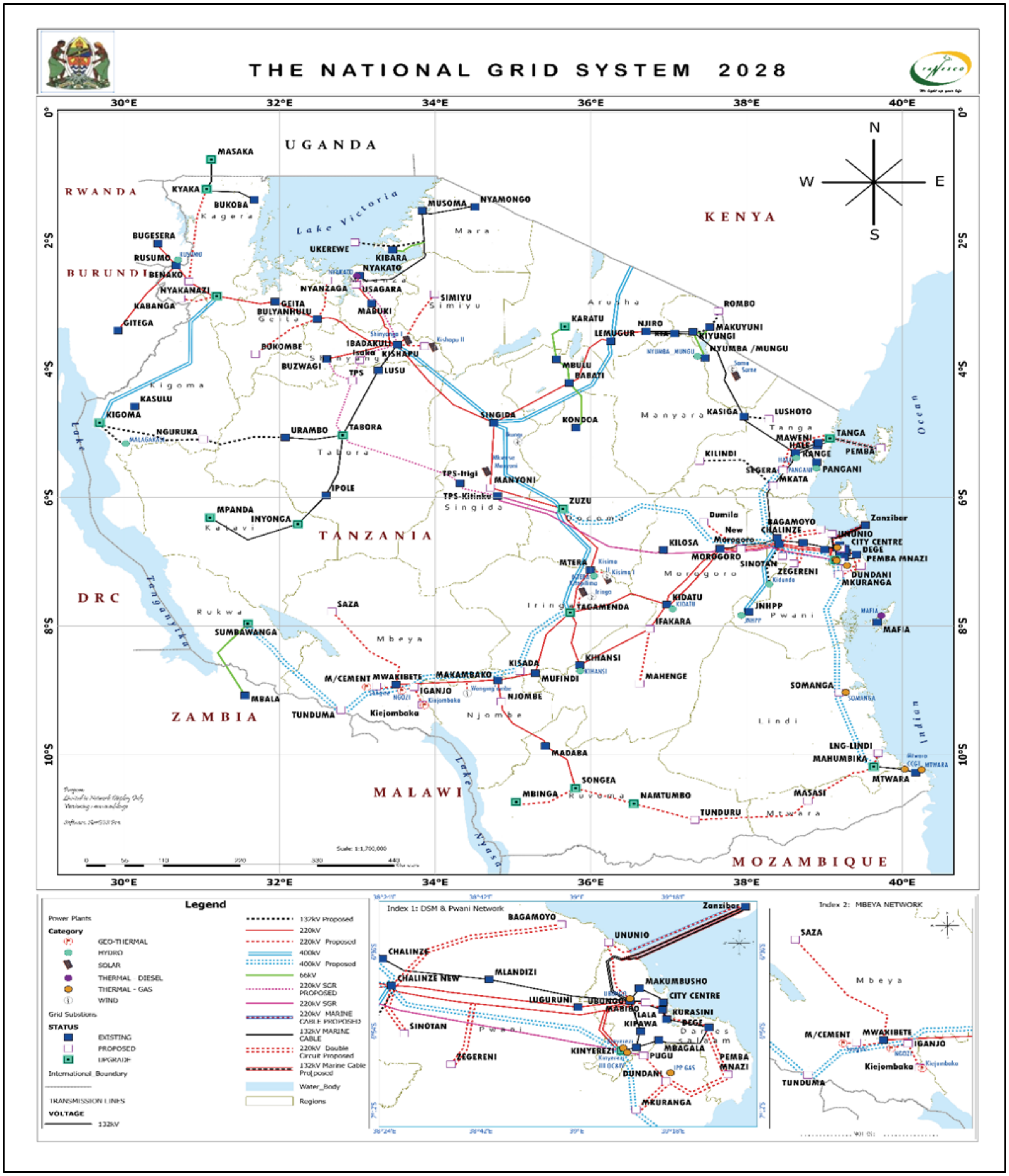

Figure 5- 2: Transmission Plan-Year 2024-2028

Table 5-10: Transmission System Additions for 2024 – 2028

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	Project Status	COD
1	Nyakanazi	Kigoma	400	Sorbus	659.40	2	2	280.0	857	1900	2375	Under Construction	2025
2	Tabora	Ipole	132	HAWK	280.84	1	1	102.51	659	121	151	Under Construction	2025
3	Ipole	Inyonga	132	HAWK	280.84	1	1	133.54	659	121	151	Under Construction	2025
4	Inyonga	Mpanda	132	HAWK	280.84	1	1	123.95	659	121	151	Under Construction	2025
5	Kinyerezi (Kimara-Toff)	Ubungo	220	Finch	635.33	1	1	7.00	1964	599	748	Under Construction	2026
6	Kinyerezi (Kimara-Toff)	Mabibo	220	Finch	635.33	1	1	9.50	1964	599	748	Under Construction	2026
7	Mabibo	Ilala	220	Finch	635.33	1	1	7.00	1964	599	748	Under Construction	2026
8	Ubungo	Ununio	220	Sorbus	659.40	1	1	18.42	857	261	327	Under Construction	2026
9	Tabora	Urambo	132	HAWK	280.84	1	1	115.00	659	121	151	Under Construction	2026
10	Malagarasi	Kigoma	132	Bison	431.20	1	1	54.50	800	146	183	Under Construction	2026
11	Chalinze	Dodoma	400	Sorbus	659.40	2	3	345.00	857	2850	3562	Under Construction	2026
12	Shinyanga	Simiyu	220	Sorbus	659.40	1	1	110.00	857	261	327	Under Construction	2026
13	Bunda	Ukerewe	132	AAAC ASTER	288.30	1	1	96.80	777	142	178	Under Construction	2026
14	Songea	Tunduru	220	Sorbus	659.40	1	1	214.50	857	261	327	Under Construction	2026
15	Tunduru	Masasi	220	Sorbus	659.40	1	1	179.00	857	261	327	Under Construction	2026
16	Isaka	Mwanza (SGR Lot 5)	220	Blue jay	603.68	1	1	228.62	1000	305	381	Under Construction	2026
17	Pugu	Dundani	220	Sorbus	659.40	1	1	47.00	857	261	327	Under Construction	2026
18	Kiyungi	Rombo	132	AAAC ASTER	288.30	1	1	61.31	777	142	178	Under Construction	2026
19	T-off	Zegereni Industrial	220	Blue jay	603.68	2	1	5.20	1000	610	762	Under Construction	2026
20	Chalinze	Kinyerezi	400	Sorbus	659.40	2	3	93.00	857	2850	3562	Under Construction	2026
21	Kinyerezi	Mkuranga	400	Sorbus	659.40	2	3	42.50	857	2850	3562	Under Construction	2026
22	Mkata	Kilindi	132	AAAC ASTER	288.30	1	1	143.60	777	142	178	Under Construction	2026
23	Urambo	Nguruka	132	HAWK	280.84	1	1	116.00	659	121	151	Under Construction	2026
24	Iringa	Kisada	400	Blue jay	603.68	2	2	106.00	1000	2217	2771	Under Construction	2026
25	Iringa	Kitapilimwa	220	AAAC ASTER	288.30	1	1	20.50	777	237	296	No FS	2026
26	Kisada	Iganjo	400	Blue jay	603.68	2	2	185.00	1000	2217	2771	Under Construction	2026

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	Project Status	COD
27	Iganjo	Tunduma	400	Blue jay	603.68	2	2	122.00	1000	2217	2771	Under Construction	2026
28	Tunduma	Sumbawanga	400	Blue jay	603.68	2	2	203.00	1000	2217	2771	Under Construction	2026
29	Masasi	Mahumbika	220	Sorbus	659.40	1	1	126.00	857	261	327	Under Construction	2026
30	Kasiga	Lushoto	132	AAAC ASTER	288.30	1	1	37.00	777	142	178	Under Construction	2026
31	Dundani	Mkuranga	220	Blue jay	603.68	2	2	18.00	1000	1219	1524	Under Construction	2026
32	Chalinze	Segera	400	Sorbus	659.40	2	2	181.00	857	1900	2375	FS completed	2027
33	Segera	Tanga	220	Blue jay	603.68	2	2	64.00	1000	1219	1524	FS completed	2027
34	Chalinze	Bagamoyo	220	Blue jay	603.68	2	2	90.00	1000	1219	1524	FS completed	2027
35	Benaco	Kyaka	220	Blue jay	603.68	2	1	166.17	1000	610	762	FS completed	2027
36	Ew8	Tabora (SGR Lot 3)	220	Blue jay	603.68	1	1	320.68	1000	305	381	FS completed	2027
37	Tabora	Isaka (SGR Lot 4)	220	Blue jay	603.68	1	1	198.38	1000	305	381	FS completed	2027
38	Nguruka	Kigoma	132	HAWK	280.84	1	1	148.00	659	121	151	FS completed	2027
39	Chalinze	Sino tan	220	Bluejay	603.68	1	2	35.90	1000	610	762	Pre - FS completed	2027
40	Songea	Mbinga	220	Sorbus	659.40	1	1	102.50	857	261	327	Pre - FS completed	2027
41	Ifakara	Mahenge	220	Bluejay	603.68	1	1	68.00	1000	305	381	FS completed	2027
42	Bulyanhulu	Bukombe	220	Sorbus	659.40	1	1	68.59	857	261	327	Pre - FS completed	2027
43	Bulyanhulu	Nyanzaga	220	Blue jay	603.68	1	1	53.00	1000	305	381	FS completed	2027
44	Iganjo	Saza	220	Sorbus	659.40	1	1	103.62	857	261	327	Pre - FS completed	2028
45	New Morogoro	Dumila	220	Bluejay	603.68	1	1	66.00	1000	305	381	Pre - FS completed	2028
46	Mkuranga	Somanga	400	Bluejay	603.68	2	2	155.50	1000	2217	2771	FS completed	2028
47	Somanga	Mahumbika	400	Bluejay	603.68	2	2	209.00	1000	2217	2771	FS completed	2028
48	Dundani	Pemba Mnazi	220	Bluejay	603.68	2	1	25.00	1000	610	762	Pre - FS completed	2028
49	Pemba Mnazi	Dege	220	Bluejay	603.68	2	1	24.00	1000	610	762	Pre - FS completed	2028
50	Dege	Kurasini	220	Bluejay	603.68	2	1	20.00	1000	610	762	Pre - FS completed	2028
51	Mahumbika	LNG	220	Bluejay	603.68	2	1	41.00	1000	610	762	No FS	2028
52	Ununio	Zanzibar Marine cable	220	XLP	1000.00	1	1	38.00	1196	365	456	FS Inprogress	2028
53	Tanga	Pemba	132	XLP	600.00	1	1	86.80	904	165	207	FS inprogress	2028
54	Iganjo	Kiejombaka Plant	220	Bluejay	603.68	1	1	35.00	1000	305	381	No FS	2028

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	Project Status	COD
55	Iganjo	Ngozi Power Plant	220	Bluejay	603.68	1	1	17.00	1000	305	381	No FS	2028
56	Nyakanazi	Kabanga Nickel	220	Sorbus	659.40	1	1	87.00	857	261	327	FS completed	2028
57	Kidunda	Chalinze	132	AAAC ASTER	288.30	1	1	80.00	777	142	178	No FS	2028
58	Iganjo	Songwe Geothermal	220	Bluejay	603.68	1	1	49.00	1000	305	381	No FS	2028
Total Route Length													**5884.59km**

31,842.37 million over the plan horizon. **Table 4-39** shows a breakdown of the required capital cost for each technology for the short, medium and long terms, respectively. These are overnight costs based on engineering estimations.

5.6.2.2 Medium Term (2029-2038)

The major additional lines consist of 400 kV double Circuit Lines, including: Segera - Same, Same - Kisongo, Sumbawanga – Mpanda - Kigoma, Tanzania - Malawi Interconnector, Shinyanga-Nyakanazi-Kyaka, Tanzania-Mozambique Interconnector, Sumbawanga-Kala, Shinyanga-Bunda, Bunda-Kilgoris Interconnector and Mtwara-Mahumbika.

The 220 kV transmission line addition includes: Makuyuni -Karatu, Lemugur-Njiro, Tabora-Kigoma (SGR Lot 6), Ununio-Kunduchi, Bagamoyo-Kunduchi, Dodoma City (Zuzu – Msalato – Ihumwa – Kikombo – Zuzu) Ring Circuit; Madaba-Ludewa, Msalato-Chemba and Sinotani-Elsewedy-Kamaka-Zegereni.

The load flow analysis for the planned 2038 grid network was undertaken. 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 (66kV and above). Transmission line power flows are also below the line's normal capacity (rating current (A)).

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 on the transmission line/transformer emergency capacity (rating B). The planned transmission lines for the period of 2029-2038 are given in **Figure 5-3** and **Table 5-11.**

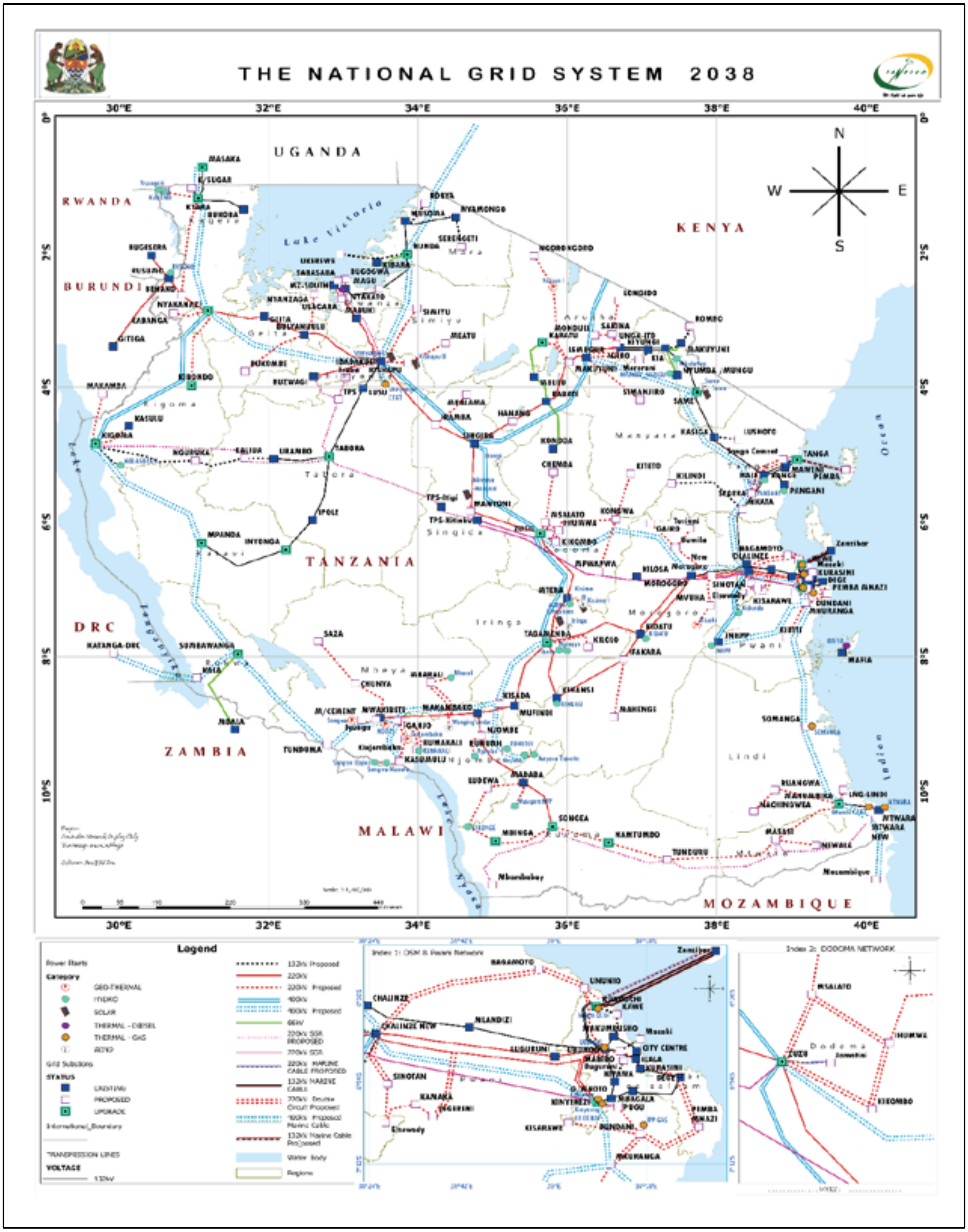

Figure 5-3: Transmission Plan – Year 2038

Table 5-11: Transmission System Addition for 2029-2038

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	COD
1	Lemugur	Njiro	220	Sorbus	659.40	2	2	17.00	857	1045	1306	2029
2	Mahumbika	Ruangwa	220	Sorbus	659.40	1	1	96.70	857	261	327	2029
3	New Morogoro	Mvuha	220	Bluejay	603.68	1	1	74.40	1000	305	381	2029
4	New Tanga	Tanga Cement	220	Bluejay	603.68	1	1	11.00	1000	305	381	2029
5	Mwakibete	Mbeya Cement	220	Bluejay	603.68	1	1	47.88	1000	305	381	2029
6	Kipawa	Buguruni	132	AAAC ASTER	288.30	1	1	6.20	777	142	178	2029
7	Kunduchi	Kawe	132	AAAC ASTER	288.30	1	1	10.00	777	142	178	2029
8	Makuyuni	Karatu	220	Bluejay	603.68	1	1	54.60	1000	305	381	2029
9	Dumila	Turiani	220	Bluejay	603.68	1	1	47.00	1000	305	381	2029
10	Kyaka	Kagera Sugar	132	AAAC ASTER	288.30	1	1	18.00	777	142	178	2029
11	Shinyanga	Nyakanazi	400	Sorbus	659.40	2	2	300.00	857	1900	2375	2029
12	Nyakanazi	Kyaka	400	Sorbus	659.40	2	2	235.00	857	1900	2375	2029
13	Tanzania(Kyaka)	Uganda(Mutukula) interconnector	400	Sorbus	659.40	2	2	24.00	857	1900	2375	2029
14	Songwe Geothermal	Mbeya Cement	220	Bluejay	603.68	1	1	15.00	1000	305	381	2030
15	Mabibo	Masaki	132	AAAC ASTER	288.30	1	1	17.00	777	142	178	2030
16	Tagamenda	Kilolo	220	Bluejay	603.68	1	1	78.70	1000	305	381	2030
17	Zuzu	Kikombo	220	Bluejay	603.68	1	1	43.34	1000	305	381	2030
18	Zuzu	Msalato	220	Bluejay	603.68	1	1	28.57	1000	305	381	2030
19	Msalato	Ihumwa	220	Bluejay	603.68	1	1	20.44	1000	305	381	2030
20	Ihumwa	Kikombo	220	Bluejay	603.68	1	1	21.82	1000	305	381	2030
21	Tanzania(Iganjo)	Malawi (Kasumulu) Interconnector	400	Bluejay	603.68	2	2	82.33	1000	2217	2771	2030
22	Tabora	Kigoma (SGR Lot 6)	220	Bluejay	603.68	1	1	350.00	1000	305	381	2030
23	Ununio	Kunduchi	220	Sorbus	659.40	1	1	4.80	857	261	327	2030
24	Bagamoyo	Ununio	220	Bluejay	603.68	2	2	22.00	1000	1219	1524	2030
25	Nyakato	Bugogwa	220	Bluejay	603.68	1	1	16.29	1000	305	381	2030
26	Bugogwa	Sabasaba	220	Bluejay	603.68	1	1	12.92	1000	305	381	2030
27	Sabasaba	Mwanza South	220	Bluejay	603.68	1	1	11.00	1000	305	381	2030

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	COD
28	Segera	Same	400	Sorbus	659.40	2	2	164.00	857	1900	2375	2030
29	Same	Kisongo	400	Sorbus	659.40	2	2	166.00	857	1900	2375	2030
30	Njiro	Unga Limited	220	Bluejay	603.68	1	1	11.00	1000	305	381	2030
31	Unga limited	Sakina	220	Bluejay	603.68	1	1	17.00	1000	305	381	2030
32	Kyaka	Kakono	220	Sorbus	659.40	1	1	37.00	857	261	327	2030
33	Sino tan	Kamaka	220	Bluejay	603.68	1	1	21.41	1000	305	381	2030
34	Kamaka	Zegereni	220	Bluejay	603.68	1	1	7.86	1000	305	381	2030
35	Makuyuni	Natron Geothermal	220	Bluejay	603.68	1	1	160.00	1000	305	381	2030
36	Kisada	Ruhudji	400	Bluejay	603.68	2	2	170.00	1000	2217	2771	2030
37	Sumbawanga	Kala	400	Sorbus	659.40	2	2	100.00	857	1900	2375	2030
38	Shinyanga	Shinyanga CCGT	400	Sorbus	659.40	2	2	11.00	857	1900	2375	2030
39	Shinyanga	Bunda	400	Sorbus	659.40	2	2	237.00	857	1900	2375	2030
40	Tanzania (Bunda)	Kenya (Klegoris) Interconnector	400	Sorbus	659.40	2	2	177.00	857	1900	2375	2030
41	Sumbawanga	Mpanda	400	Sorbus	659.40	2	2	232.00	857	1900	2375	2031
42	Mpanda	Kigoma	400	Sorbus	659.40	2	2	246.00	857	1900	2375	2031
43	Mkuranga	JNHPP	400	Sorbus	659.40	2	3	224.00	857	2850	3562	2031
44	Mtwara	Mahumbika	400	Bluejay	603.68	2	2	70.00	1000	2217	2771	2031
45	Madaba	Ludewa	220	Bluejay	603.68	1	1	54.30	1000	305	381	2031
46	Mwakibete	Iyunga	220	Bluejay	603.68	1	1	7.20	1000	305	381	2031
47	Madaba	Masigira HPP	220	Bluejay	603.68	1	1	110.00	1000	305	381	2031
48	Kasumulu	Songwe Manolo HPP	220	Sorbus	659.40	1	1	27.00	857	261	327	2031
49	Kia	Mererani	132	AAAC ASTER	288.30	1	1	21.00	777	142	178	2031
50	Msalato	Chemba	220	Bluejay	603.68	1	1	100.20	1000	305	381	2032
51	Musoma	Rorya	132	AAAC ASTER	288.30	1	1	47.80	777	142	178	2032
52	Nyamongo	Serengeti	132	AAAC ASTER	288.30	1	1	49.50	777	142	178	2032
53	Tanzania	Mozambique Interconnector	400	Sorbus	659.40	2	2	70.00	857	1900	2375	2032
54	Sino tan	Elsewedy	220	Bluejay	603.68	1	1	24.85	1000	305	381	2032
55	Kawe	Makumbusho	132	AAAC ASTER	288.30	1	1	6.20	777	142	178	2032

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	COD
56	Iganjo	Rumakali	220	Bluejay	603.68	2	2	68.00	1000	1219	1524	2032
57	Ruangwa	Nachingwea	220	Sorbus	659.40	1	1	52.00	857	261	327	2032
58	Natron	Ngorongoro	220	Bluejay	603.68	1	1	57.00	1000	305	381	2032
59	Madaba	Kikonge HPP	220	Sorbus	659.40	2	1	67.00	857	522	653	2032
60	Ihumwa	Kongwa	220	Bluejay	603.68	1	1	94.50	1000	305	381	2033
61	Kidahwe	Kasulu	220	Sorbus	659.40	1	1	62.00	857	261	327	2033
62	Nyakanazi	Kibondo	220	Sorbus	659.40	1	1	89.00	857	261	327	2033
63	Ruhudji	Mnyera HPP	400	Bluejay	603.68	2	2	50.00	1000	2217	2771	2033
64	Mkuranga	Kibiti	220	Sorbus	659.40	1	1	66.70	857	261	327	2033
65	Kongwa	Kiteto	220	Bluejay	603.68	1	1	78.20	1000	305	381	2033
66	Mtwara - Mbamba Bay	Liganga and Mchuchuma (SGR Southern corridor)	220	Bluejay	603.68	1	1	1500.00	1000	305	381	2034
67	Masasi	Newala	220	Sorbus	659.40	1	1	59.10	857	261	327	2034
68	Kigoma	Burundi interconnector	220	Sorbus	659.40	2	2	161.00	857	1045	1306	2034
69	Kakono	Nsongezi HPP	220	Sorbus	659.40	1	1	55.00	857	261	327	2034
70	Kongwa	Mpwapwa	220	Bluejay	603.68	1	1	94.50	1000	305	381	2035
71	Songwe Manolo HPP	Songwe Upper HPP	220	Sorbus	659.40	1	1	40.00	857	261	327	2035
72	Mvuha	Kisaki	220	Bluejay	603.68	1	1	59.70	1000	305	381	2035
73	Mnyera mnyera	Mnyera Teveta HPP	220	Bluejay	603.68	1	1	27.00	1000	305	381	2035
74	Dumila	Gairo	220	Sorbus	659.40	1	1	55.80	857	261	327	2036
75	Tanga	Musoma (SGR Northern corridor)	220	Bluejay	603.68	1	1	1000.00	1000	305	381	2036
76	Kishapu	Meatu	220	Bluejay	603.68	1	1	116.00	1000	305	381	2036
77	Zuzu	Jamatini	220	XLPE	1000.00	1	1	8.44	796	243	303	2037
78	Sakina	Longido	220	Bluejay	603.68	1	1	56.10	1000	305	381	2037
79	Lemugur	Simanjiro	220	Bluejay	603.68	1	1	105.00	1000	305	381	2037
80	Tagamenda	Nginayo	220	Bluejay	603.68	1	1	91.00	1000	305	381	2037
81	Mbalali	Mbalali HPP	220	Bluejay	603.68	1	1	20.00	1000	305	381	2037
82	Sakina	Monduli	220	Bluejay	603.68	1	1	25.40	1000	305	381	2038

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	COD
83	Iramba	Mkalama	220	Bluejay	603.68	1	1	54.00	1000	305	381	2038
84	Usagara	Mwanza South	220	Bluejay	603.68	1	1	25.00	1000	305	381	2038
85	Njombe Substation	Njombe HPP	220	Sorbus	659.40	1	1	31.00	857	261	327	2038
Total Route Length			**8503.75km**									

5.6.2.3 Long Term (Year 2039-2050)

The line addition for 2039-2050 consists of 400 kV double Circuit Lines including: Shinyanga-Tabora, Tabora-Mpanda, Mtwara-Songea and Songea-Ruhudji.

The 220 kV transmission line addition includes: Bulyanhulu-Nyangwale, Kasulu- Buhigwe, Dundani-Kisarawe, Tunduma-Ileje, Kibeta-Muleba, Tunduma-Momba, Chemba-Kondoa, Tunduma-Mbozi, Mpanda-Tanganyika, Mahenge-Malinyi, Kibiti-Rufiji, Karagwe - Kyerwa, Kala-Nkasi, Tabora-Uyui, New Tanga-Mkinga, Gairo-Kongwa and Kasulu-Kibondo.

The load flow analysis for the planned 2050 grid network shows that 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 violation is recorded in the bulk system (220 kV and above). Transmission line power flows are also below the line's normal capacity (rating current (A)).

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 on the transmission line/transformer emergency capacity (rating B). The planned transmission lines for the period of 2024-2028 are given in **Figure 5-4** and **Table 5-12.**

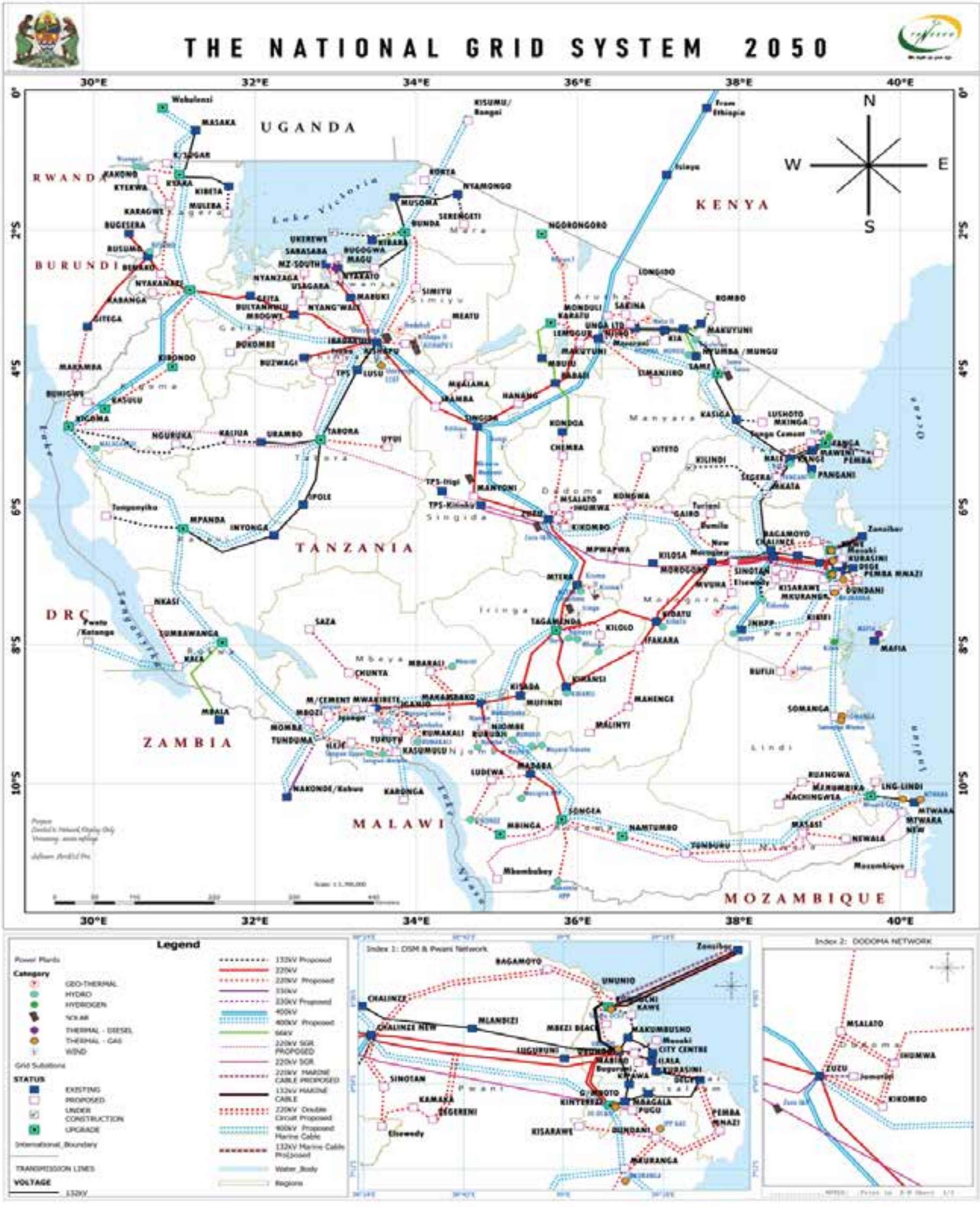

Figure 5-4: Generation and Transmission Plan – Year 2050

Table 5-12: Transmission System Addition for 2039-2050

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Current Rating [Amps]	Normal Rating [MVA]	Full Rating [MVA]	COD
1	Bulyanhulu	Nyangwale	220	Bluejay	603.68	1	1	23	1000	305	381.04	2039
2	Kasulu	Buhigwe	220	Bluejay	603.68	1	1	27	1000	305	381.04	2039
3	Dundani	Kisarawe	220	Bluejay	603.68	1	1	53	1000	305	381.04	2039
4	Tunduma	Ileje	220	Bluejay	603.68	1	1	60	1000	305	381.04	2039
5	Kilolo	Mhanga HPP	220	Sorbus	659.40	1	1	42	857	261	326.55	2039
6	Songea	Nakatuta HPP	220	Sorbus	659.40	1	1	90	857	261	326.55	2039
7	Kibeta	Muleba	132	AAAC ASTER	288.30	1	1	80	777	142	177.64	2041
8	Tunduma	Momba	220	Bluejay	603.68	1	1	90	1000	305	381.04	2041
9	Chemba	Kondoa	220	Bluejay	603.68	1	1	39	1000	305	381.04	2042
10	Tunduma	Mbozi	220	Bluejay	603.68	1	1	52	1000	305	381.04	2042
11	Mahumbika	Songea	400	Bluejay	603.68	2	2	301	1000	2217	2771.20	2043
12	Songea	Ruhudji	400	Bluejay	603.68	2	2	188	1000	2217	2771.20	2043
13	Shinyanga	Tabora	400	Bluejay	603.68	2	2	195	1000	2217	2771.20	2044
14	Tabora	Mpanda	400	Bluejay	603.68	2	2	196	1000	2217	2771.20	2044
15	Mpanda	Tanganyika	132	AAAC ASTER	288.30	1	1	29	777	142	177.64	2045
16	Njiro	Meru Gothermal	220	Bluejay	603.68	1	1	20	1000	305	381.04	2045
17	Mahenge	Malinyi	220	Sorbus	659.40	1	1	80	857	261	326.55	2045
18	Kibiti	Rufiji	220	Sorbus	659.40	1	1	47	857	261	326.55	2045
19	Karagwe	Kyerwa	220	Sorbus	659.40	1	1	65	857	261	326.55	2045
20	Kala	Nkasi	220	Bluejay	603.68	1	1	105	1000	305	381.04	2047
21	Tabora	Uyui	220	Bluejay	603.68	1	1	93	1000	305	381.04	2048
22	New Tanga	Mkinga	220	Sorbus	659.40	1	1	42	857	261	326.55	2048
23	Gairo	Kongwa	220	Sorbus	659.40	1	1	55	857	261	326.55	2048
24	Kasulu	Kibondo	220	Bluejay	603.68	1	1	116	1000	305	381.04	2048
Total Route Length												**2086.82km**

5.6.2.4 Reactive Compensation

It was assumed that each 400kV line would be compensated by two line-connected reactors located at the two line ends. The magnitude of each reactor was taken as 35 per cent of the full line charging value, which is equivalent to a total of 70 per cent compensation. These line-connected reactors would be switched on and off based on the system operation requirements. However, for line switching (or energization), these reactors must be switched on to avoid high voltages at the open line ends (Ferranti Effect). These factors are subject to a detailed dynamic study performed at the design stage. Variable reactors were sized to ensure the adequacy of the system operating conditions as given in the planning criteria.

5.6.2.5 Substation Additions

The numbers of circuit breakers for the 400 kV and 220 kV systems are based on the breaker-and-a-half scheme, as shown in **Figure 5-5.** 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.

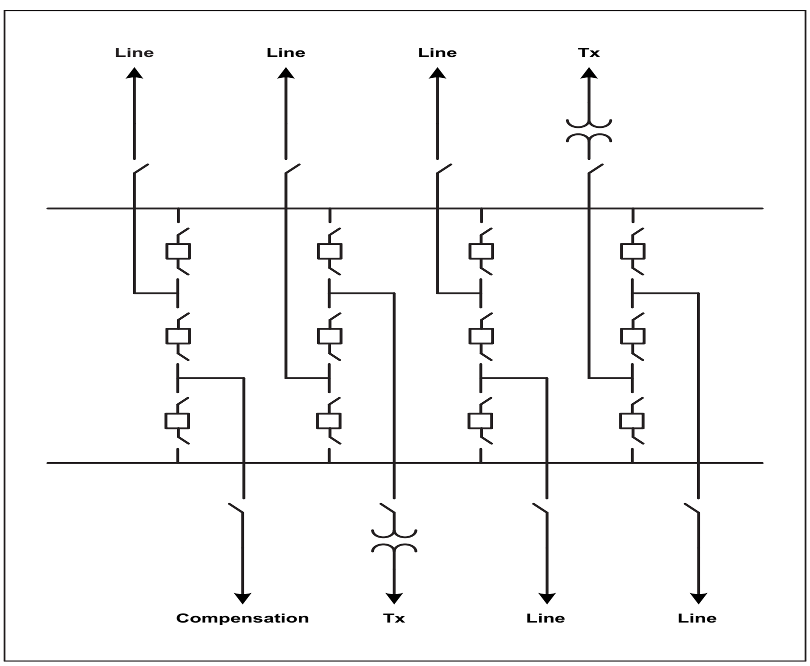

Figure 5-5: *Breaker and Half Scheme*

5.6.2.6 Short Circuit Study

A Short circuit study was performed only on the bulk system (66kV and above) and results are given in **Table 5-13** for 400 kV**, Table 5-14** for 330kV**, Table 5-15** for 220 kV, **Table 5-**

16 for 132 kV and **Table 5-17** for 66 kV**.** A typical equivalent machine reactance of 15 per cent and step-up transformer reactance of 10 per cent were assumed for short circuit current calculations. Classical assumptions (flat conditions) were assumed, and all bus voltages were set to 1.05 pu. All fault currents are well within the limits of the circuit breakers' ratings except for 132kV Ubungo substation and Songas power plant, which are 41.86 kA and 41.86 kA respectively, caused by additional power plants and generation capacity at Kinyerezi, Ubungo and Tegeta. We recommend upgrading the circuit breakers to one with a higher rating, or any new technology may also be adopted to limit the short circuit levels wherever they are likely to cross the designed limits. The minimum switchgear short circuit rating is 63 kA for the 400 kV level, 40 kA for the 220 kV level and 31.5 kA for the 132 kV level.

Table 5-13: Short Circuit Results at 400kV Voltage Level at Year 2050

3 Phase short circuit Currents						
S/N	**Bus No.**	**Bus Name**	**Voltage Level [kV]**	**MVA**	**I"k rms [kA]**	**X/R Ratio**
1	301	[KE_1 400.00]	400	2450.58	3537.10	13.00
2	302	[KE_1 400.00]	400	2450.58	3537.10	13.00
3	3501	[K_T BORDER 400.00]	400	2657.51	3835.80	12.88
4	3502	[K_T BORDER 400.00]	400	2657.51	3835.80	12.88
5	324001	[K_ISINYA 400.00]	400	2450.58	3537.10	13.00
6	501004	[TSHINYANGA 400.00]	400	4268.49	6161.00	13.53
7	501021	[TIRINGA_4B1 400.00]	400	6042.73	8721.90	15.58
8	501022	[TDODOMA_4B1 400.00]	400	7004.17	10109.60	16.99
9	501031	[TSINGIDA_4B1400.00]	400	5317.15	7674.60	14.40
10	501032	[SHY_4B1 400.00]	400	4268.49	6161.00	13.53
11	501041	[TLEMUGUR_4B1400.00]	400	4269.62	6162.70	13.43
12	501044	[TKISADA 400.00]	400	5770.19	8328.50	16.50
13	501045	[TMBEYA_4B1 400.00]	400	4325.25	6243.00	14.84
14	501047	[TTUNDUMA 400.00]	400	3482.26	5026.20	12.70
15	501049	[TSUMBAW_4B1 400.00]	400	2962.14	4275.50	10.48
16	501051	[TCHALI_4B1 400.00]	400	13848.07	19988.00	25.27
17	501052	[TCHALI_4B2 400.00]	400	13848.07	19988.00	25.27
18	501053	[TJNHPP 400.00]	400	13256.46	19134.10	37.29
19	501054	[TJNHPP 400.00]	400	13256.46	19134.10	37.29
20	501055	[TJNHPP 400.00]	400	13256.46	19134.10	37.29
21	501056	[TKINY_4B2 400.00]	400	15076.15	21760.50	32.52
22	501057	[MKURANGA 400.00]	400	13293.17	19187.00	26.18
23	501058	[TIRINGA 400.00]	400	6042.73	8721.90	15.58
24	501059	[TIRINGA 400.00]	400	6042.73	8721.90	15.58
25	501060	[TIRINGA 400.00]	400	6042.73	8721.90	15.58
26	501061	[TIRINGA 400.00]	400	6042.73	8721.90	15.58

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
27	501062	[TKISADA 400.00]	400	5770.19	8328.50	16.50
28	501063	[TKISADA 400.00]	400	5770.19	8328.50	16.50
29	501064	[TKISADA 400.00]	400	5770.19	8328.50	16.50
30	501065	[TKISADA 400.00]	400	5770.19	8328.50	16.50
31	501066	[TIGANJO 400.00]	400	4325.25	6243.00	14.84
32	501067	[TIGANJO 400.00]	400	4325.25	6243.00	14.84
33	501068	[TIGANJO 400.00]	400	4325.25	6243.00	14.84
34	501069	[TIGANJO 400.00]	400	4325.25	6243.00	14.84
35	501070	[TTUNDUMA 400.00]	400	3482.26	5026.20	12.70
36	501071	[TTUNDUMA 400.00]	400	3482.26	5026.20	12.70
37	501072	[TTUNDUMA 400.00]	400	3482.26	5026.20	12.70
38	501073	[TTUNDUMA 400.00]	400	3482.26	5026.20	12.70
39	501074	[TSUMBAWANGA 400.00]	400	2962.14	4275.50	10.48
40	501075	[TSUMBAWANGA 400.00]	400	2962.14	4275.50	10.48
41	501076	[TDODOMA 400.00]	400	7004.17	10109.60	16.99
42	501077	[TDODOMA 400.00]	400	7004.17	10109.60	16.99
43	501078	[TDODOMA 400.00]	400	7004.17	10109.60	16.99
44	501079	[TDODOMA 400.00]	400	7004.17	10109.60	16.99
45	501080	[TDODOMA 400.00]	400	7004.17	10109.60	16.99
46	501081	[TDODOMA 400.00]	400	7004.17	10109.60	16.99
47	501082	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
48	501083	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
49	501084	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
50	501085	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
51	501086	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
52	501087	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
53	501088	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
54	501089	[TCHALINZE 400.00]	400	13848.07	19988.00	25.27
55	501090	[TCHALINZE 400.00]	400	5895.98	8510.10	14.98
56	501091	[TCHALINZE 400.00]	400	5895.98	8510.10	14.98
57	501092	[TSINGIDA 400.00]	400	5317.15	7674.60	14.40
58	501093	[TSINGIDA 400.00]	400	5317.15	7674.60	14.40
59	501095	[TSINGIDA 400.00]	400	5317.15	7674.60	14.40
60	501096	[TSINGIDA 400.00]	400	5317.15	7674.60	14.40
61	501097	[TSINGIDA 400.00]	400	5317.15	7674.60	14.40
62	501098	[TSINGIDA 400.00]	400	5317.15	7674.60	14.40
63	501099	[TLEMUGUR 400.00]	400	4269.62	6162.70	13.43
64	501100	[TLEMUGUR 400.00]	400	4269.62	6162.70	13.43
65	501101	[TLEMUGUR 400.00]	400	4269.62	6162.70	13.43
66	501102	[TLEMUGUR 400.00]	400	4269.62	6162.70	13.43

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
67	501103	[TSHINYANGA 400.00]	400	4268.49	6161.00	13.53
68	501104	[TKIGOMA 400.00]	400	2689.20	3881.50	4.46
69	501105	[TNYAKANAZI 400.00]	400	2820.95	4071.70	3.98
70	501106	[TKIGOMA 400.00]	400	2689.20	3881.50	4.46
71	501107	[TNYAKAZI 400.00]	400	2820.95	4071.70	3.98
72	501108	[TNYAKANAZI 400.00]	400	2820.95	4071.70	3.98
73	501109	[TKIGOMA 400.00]	400	2689.20	3881.50	4.46
74	501110	[TKINYEREZ 400.00]	400	15076.15	21760.50	32.52
75	501111	[TSOMNAGA 400.00]	400	7471.62	10784.30	20.89
76	501112	[TMAHUMBIKA 400.00]	400	4634.06	6688.70	16.35
77	501113	[TMTWARA 400.00]	400	3912.16	5646.70	15.92
78	501114	[TSAME 400.00]	400	4476.66	6461.50	12.79
79	501115	[TKYAKA 400.00]	400	1811.82	2615.10	2.66
80	501116	[TMASAKA 400.00]	400	1517.75	2190.70	3.08
81	501117	[TMPANDA 400.00]	400	3050.91	4403.60	8.21
82	501118	[TBUNDA 400.00]	400	2371.61	3423.10	12.07
83	501119	[TKILGORIS 400.00]	400	1687.25	2435.30	12.11
84	501120	[TKASUMULU 400.00]	400	3345.63	4829.00	14.32
85	501121	[TRUHUDJI 400.00]	400	5151.77	7435.90	18.65
86	501123	[TKILWA 400.00]	400	6389.40	9222.30	24.16
87	501125	[TMOZAMBIQ 400.00]	400	3140.09	4532.30	14.93
88	502324	[TSOMANGA III400.00]	400	6399.83	9237.40	24.17
89	502325	[TMKURANGA 400.00]	400	13293.17	19187.00	26.18
90	502326	[TSHINYANGA 400.00]	400	4151.71	5992.50	13.66
91	502328	[TTUNDURU 400.00]	400	3826.49	5523.10	14.79
92	502329	[TSONGEA 400.00]	400	4340.24	6264.60	15.79
93	509853	[TSEGERA 400.00]	400	5895.98	8510.10	14.98
94	509856	[TSEGERA 400.00]	400	5895.98	8510.10	14.98

Source: *PSMP 2024 Update Team Compilation.*

Table 5-14: Short Circuit Results at 330 kV Voltage Level at Year 2050

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
1	502057	[TTUNDUMA 330.00]	330	2148.81	3759.40	19.21
2	502058	[TNAKONDE 330.00]	330	2124.72	3717.30	19.08

Source: *PSMP 2024 Update Team Compilation*

Table 5-15: Short Circuit Results at 220 kV Voltage Level at Year 2050

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
1	202409	[TMAHUMBIKA 220.00]	220	4624.57	12136.40	16.38
2	501012	[220-MKURANGA220.00]	220	6123.23	16069.30	10.50
3	501019	[MANYONI 220.00]	220	2247.40	5897.90	7.27
4	501122	[TMNYERA 220.00]	220	4518.14	11857.00	18.75
5	502022	[TDODOMA_2B2 220.00]	220	3958.89	10389.40	12.74
6	502023	[TMKATA 220.00]	220	2076.56	5449.60	8.35
7	502024	[TMKATA 220.00]	220	2076.56	5449.60	8.35
8	502025	[KIDETE 220.00]	220	1387.16	3640.40	7.82
9	502026	[KIDETE 220.00]	220	1387.16	3640.40	7.82
10	502027	[TGODEGODE 220.00]	220	1150.97	3020.50	7.37
11	502028	[TGODEGODE 220.00]	220	1150.97	3020.50	7.37
12	502031	[TIRINGA_2B1 220.00]	220	5027.24	13193.10	14.62
13	502032	[TIRINGA_2B2 220.00]	220	5027.24	13193.10	14.62
14	502033	[TMSAGALI 220.00]	220	1075.14	2821.50	6.93
15	502034	[TMSAGALI 220.00]	220	1075.14	2821.50	6.93
16	502035	[TIHUMWA 220.00]	220	1105.81	2902.00	6.34
17	502036	[TIHUMWA 220.00]	220	1105.81	2902.00	6.34
18	502037	[TKIGWE 220.00]	220	1266.48	3323.70	5.53
19	502038	[TKINTINKU 220.00]	220	1779.93	4671.10	4.20
20	502039	[TKINTINKU 220.00]	220	1779.93	4671.10	4.20
21	502040	[TSALANDA 220.00]	220	2610.23	6850.10	3.04
22	502041	[TITIGI 220.00]	220	2212.54	5806.40	6.00
23	502042	[TKAZIKAZI 220.00]	220	1504.49	3948.30	7.30
24	502043	[TMALONGWE 220.00]	220	1362.42	3575.40	8.02
25	502044	[TNYAHUA 220.00]	220	1472.20	3863.50	8.72
26	502045	[NDEVELWA 220.00]	220	2098.90	5508.20	10.14
27	502046	[TTABORA 220.00]	220	3336.68	8756.50	13.27
28	502047	[TTPS 18 220.00]	220	2189.23	5745.20	10.76
29	502048	[TTPS 19 220.00]	220	1654.88	4342.90	9.88
30	502049	[TTPS 20 220.00]	220	1633.90	4287.90	9.82
31	502050	[TBUGOGWA 220.00]	220	1146.40	3008.50	6.46
32	502051	[TMBEYA _2B1 220.00]	220	2426.78	6368.70	13.19
33	502052	[TLEMUGUR 220.00]	220	2735.77	7179.50	14.49
34	502053	[TKISADA 220.00]	220	2201.28	5776.90	31.17
35	502054	[TKISADA 220.00]	220	2201.28	5776.90	31.17
36	502055	[TPUGU 220.00]	220	7742.14	20317.90	11.04
37	502056	[TSHYSOLAR 220.00]	220	2244.68	5890.80	9.65
38	502059	[TTURIANI 220.00]	220	2875.17	7545.40	2.56
39	502072	[TSHINYA_2B2 220.00]	220	2643.53	6937.50	11.69

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
40	502073	[TKITAPILIMWA220.00]	220	4606.14	12088.00	6.23
41	502081	[TSINGID_2B1 220.00]	220	3020.29	7926.20	13.50
42	502082	[TSINGID_2B2 220.00]	220	3020.29	7926.20	13.50
43	502091	[TBABATI_2B1 220.00]	220	1283.00	3367.00	7.27
44	502092	[TBABATI_2B2 220.00]	220	1283.00	3367.00	7.27
45	502111	[TBULYAN_2B1 220.00]	220	1656.47	4347.10	4.31
46	502121	[TBUZWAG_2B1 220.00]	220	1411.05	3703.00	9.24
47	502151	[TKIDATH_2B1 220.00]	220	3183.76	8355.20	10.94
48	502152	[TKIDATH_2B2 220.00]	220	3183.76	8355.20	10.94
49	502169	[TBAGAMOYO 220.00]	220	5796.40	15211.60	11.76
50	502171	[TKIHANH_2B1 220.00]	220	2556.84	6710.00	14.48
51	502172	[TKIHANH_2B2 220.00]	220	2556.84	6710.00	14.48
52	502181	[TKINYE1_2B1 220.00]	220	12462.60	32705.80	25.73
53	502182	[TKINYE1_2B2 220.00]	220	12462.60	32705.80	25.73
54	502190	[TKINYE2_2B1 220.00]	220	12425.16	32607.60	25.41
55	502191	[TKINYE2_2B2 220.00]	220	12425.16	32607.60	25.41
56	502201	[TMABUKI_2B1 220.00]	220	1227.45	3221.20	6.83
57	502231	[TMOROGO_2B1 220.00]	220	4351.45	11419.60	9.51
58	502241	[TMTERAH_2B1 220.00]	220	1862.38	4887.50	7.78
59	502251	[TMUFIND_2B1 220.00]	220	1458.50	3827.60	6.86
60	502261	[TMWANZA_2B1 220.00]	220	1165.40	3058.40	6.46
61	502281	[TNJIRO _2B1 220.00]	220	2735.73	7179.40	14.49
62	502311	[TUBU220_2B1 220.00]	220	10471.12	27479.60	19.76
63	502312	[TUBU220_2B2 220.00]	220	10471.12	27479.60	19.76
64	502331	[TUBUGP1_2B1 220.00]	220	10116.37	26548.60	14.86
65	502333	[TSUMBAWANGA 220.00]	220	2953.87	7751.90	10.51
66	502334	[TBUKOMBE 220.00]	220	879.86	2309.00	5.27
67	502335	[TMBINGA 220.00]	220	995.54	2612.60	9.19
68	502336	[TNJOMBE 220.00]	220	1461.25	3834.80	8.94
69	502337	[TKILOSA 220.00]	220	3355.88	8806.90	3.65
70	502338	[TCHUNYA 220.00]	220	862.01	2262.20	9.05
71	502339	[TPEMBAMNAZI 220.00]	220	5769.60	15141.30	8.24
72	502340	[TDEGE 220.00]	220	5808.41	15243.10	7.67
73	502341	[TKURASINI 220.00]	220	6851.74	17981.20	7.38
74	502342	[TSINOTAN 220.00]	220	8033.67	21082.90	5.92
75	502343	[TKASUMULU 220.00]	220	3336.06	8754.90	14.37
76	502344	[TRUMAKALI 220.00]	220	1912.64	5019.40	13.54
77	502345	[TNGOZI 220.00]	220	2018.49	5297.20	15.70
78	502346	[TKAKONO 220.00]	220	1256.18	3296.60	3.61
79	502347	[TDODMA 220.00]	220	3958.89	10389.40	12.74

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I''k rms [kA]	X/R Ratio
80	502348	[TMANYONI 220.00]	220	2247.40	5897.90	7.27
81	502350	[TCHUNYA 220.00]	220	1088.84	2857.50	9.60
82	502351	[TIRAMBA 220.00]	220	1558.18	4089.20	7.36
83	502352	[TMKALAMA 220.00]	220	874.09	2293.90	7.66
84	502353	[TMEATU 220.00]	220	655.98	1721.50	8.48
85	502354	[NAMTUMBO 220.00]	220	1648.84	4327.10	9.73
86	502355	[TKALA 220.00]	220	2334.34	6126.00	10.77
87	502356	[TLUDEWA 220.00]	220	961.67	2523.70	9.57
88	502357	[TSABASABA 220.00]	220	1126.49	2956.30	6.36
89	502358	[TMWANZASOUTH220.00]	220	1147.13	3010.40	6.06
90	502359	[TNEWALA 220.00]	220	762.63	2001.40	10.50
91	502360	[TGAIRO 220.00]	220	1569.12	4117.90	6.89
92	502361	[TMVUHA 220.00]	220	1257.01	3298.80	22.45
93	502362	[TCEMENT 220.00]	220	1166.60	3061.50	9.93
94	502364	[TMBALALI 220.00]	220	1648.62	4326.50	7.95
95	502365	[TRUANGWA 220.00]	220	896.56	2352.90	8.96
96	502366	[TNACHIGWEA 220.00]	220	625.38	1641.20	8.67
97	502367	[TKASULU 220.00]	220	1463.57	3840.90	4.88
98	502368	[TKIBONDO 220.00]	220	1430.02	3752.80	4.46
99	502369	[TKARAGWE 220.00]	220	1254.17	3291.30	3.92
100	502370	[TKILOLO 220.00]	220	1104.40	2898.30	9.20
101	502371	[TMSALATO 220.00]	220	2478.89	6505.40	9.78
102	502372	[TIHUMWA 220.00]	220	2295.68	6024.60	9.60
103	502373	[TKIKOMBO 220.00]	220	2182.09	5726.50	9.73
104	502379	[TKONGWA 220.00]	220	1406.08	3690.00	8.12
105	502380	[TKITET0 220.00]	220	695.12	1824.20	8.10
106	502381	[TJAMATINI 220.00]	220	3020.78	7927.50	11.21
107	502382	[THANANG 220.00]	220	1463.41	3840.50	7.94
108	502383	[TSIMANJIRO 220.00]	220	743.22	1950.40	9.18
109	502384	[TCHEMBA 220.00]	220	829.20	2176.10	7.11
110	502385	[TUNGALIMITED220.00]	220	2137.96	5610.70	12.35
111	502386	[TSAKINA 220.00]	220	1597.64	4192.70	10.56
112	502387	[TMONDULI 220.00]	220	1159.94	3044.00	9.74
113	502388	[TLONGIDO 220.00]	220	871.34	2286.70	9.27
114	502389	[TMAKUYUNI 220.00]	220	2265.56	5945.60	11.56
115	502390	[TKARATU 220.00]	220	1085.05	2847.50	8.66
116	502391	[TNGORONGORO 220.00]	220	783.76	2056.80	8.04
117	502392	[TKAMAKA 220.00]	220	5612.04	14727.80	9.59
118	502393	[TELSEWEDY 220.00]	220	3060.36	8031.40	7.09
119	502394	[TKIBITI 220.00]	220	1381.66	3625.90	9.17

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
120	502395	[TMAHENGE 220.00]	220	770.93	2023.20	1.48
121	502397	[T-K_TPS1 220.00]	220	1314.03	3448.40	9.28
122	502398	[T-K_TPS2 220.00]	220	1013.34	2659.30	8.75
123	502399	[T-K_TPS3 220.00]	220	881.68	2313.80	8.42
124	502400	[T-K_TPS4 220.00]	220	831.19	2181.30	8.13
125	502401	[T-K_TPS5 220.00]	220	837.84	2198.80	7.83
126	502402	[T-K_TPS6 220.00]	220	904.53	2373.80	7.46
127	502403	[T-K_TPS7 220.00]	220	1064.80	2794.40	6.95
128	502404	[T-K_TPS8 220.00]	220	1439.94	3778.90	6.12
129	502406	[TMPWAPWA 220.00]	220	700.92	1839.40	8.00
130	502407	[TKABANGA 220.00]	220	956.41	2509.90	5.94
131	502408	[TLNG 220.00]	220	2615.29	6863.30	11.18
132	502409	[T-B_TPS1 220.00]	220	747.90	1962.70	7.20
133	502410	[T-B_TPS2 220.00]	220	576.35	1512.50	7.35
134	502411	[T-B_TPS3 220.00]	220	468.82	1230.30	, 7.44361
135	502412	[TKISIMA 220.00]	220	3105.71	8150.40	8.77
136	502413	[TKIEJO 220.00]	220	2015.53	5289.40	15.70
137	502414	[TNJOMBE 220.00]	220	2426.78	6368.70	13.19
138	502415	[TKUNDUCHI 220.00]	220	8319.29	21832.50	12.85
139	502416	[TNATRON 220.00]	220	815.79	2140.90	12.26
140	502417	[TMASIGIRA 220.00]	220	1606.51	4216.00	4.43
141	502418	[TSONGWE 220.00]	220	3110.64	8163.30	7.02
142	502419	[TNSONGEZI 220.00]	220	1195.10	3136.30	3.17
143	502420	[TSONGWE UPP 220.00]	220	2788.54	7318.00	4.14
144	502421	[TMNYERA 220.00]	220	4095.52	10747.90	6.37
145	502422	[TRUHUDJI 220.00]	220	5147.75	13509.30	18.67
146	502424	[TKONDOA 220.00]	220	811.55	2129.80	6.08
147	502425	[TIBOSA 220.00]	220	3636.24	9542.70	2.84
148	502426	[TNGINAYO 220.00]	220	3636.24	9542.70	2.84
149	502427	[TMBALALI 220.00]	220	1602.76	4206.10	6.51
150	502428	[TNJOMBE 220.00]	220	1406.58	3691.30	6.66
151	502429	[TNYAMW'ALE 220.00]	220	1596.70	4190.30	3.80
152	502430	[TKYERWA 220.00]	220	1184.45	3108.40	3.32
153	502431	[TKAKONKO 220.00]	220	1508.75	3959.50	4.88
154	502432	[TBUHIGWE 220.00]	220	1410.65	3702.00	4.27
155	502433	[TLIWALE 220.00]	220	818.36	2147.70	4.98
156	502437	[TANDAHIMBA 220.00]	220	746.49	1959.00	8.49
157	502438	[TRUFIJI 220.00]	220	1315.25	3451.60	6.39
158	502439	[TKISARAWE 220.00]	220	5736.07	15053.30	2.27
159	502440	[TNKASI 220.00]	220	1888.04	4954.80	3.46

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I''k rms [kA]	X/R Ratio
160	502441	[TMASWA 220.00]	220	1417.99	3721.30	9.67
161	502442	[TMBOZI 220.00]	220	2973.76	7804.10	4.35
162	502443	[TILEJE 220.00]	220	2934.88	7702.10	5.12
163	502444	[TMOMBA 220.00]	220	2666.39	6997.50	3.14
164	502445	[TUYUI 220.00]	220	2589.89	6796.70	3.24
165	502446	[TMKINGA 220.00]	220	2183.13	5729.20	5.98
166	502447	[TMHANGA 220.00]	220	926.03	2430.20	9.09
167	502448	[TNAKATUTA 220.00]	220	3147.32	8259.60	2.86
168	502449	[TMERU 220.00]	220	1889.50	4958.70	12.09
169	502991	[TOFF-MABUKI 220.00]	220	1232.60	3234.70	6.84
170	502994	[TLEMUGUR_2B1220.00]	220	2735.77	7179.50	14.49
171	502995	[TMAKAMBA_2B1220.00]	220	1661.99	4361.60	7.70
172	502996	[TMADABA_2B1 220.00]	220	1869.31	4905.70	11.60
173	502997	[TSONGEA_2B1 220.00]	220	4333.95	11373.70	15.81
174	502999	[TMBEYA_2B3 220.00]	220	3069.07	8054.20	20.14
175	503002	[TCHALI_2B1 220.00]	220	9004.36	23630.30	17.36
176	503004	[220KV-GEITA 220.00]	220	2011.95	5280.00	2.78
177	503005	[220KV-NYAKA 220.00]	220	2818.70	7397.20	3.98
178	503006	[220KV-RUSUMO220.00]	220	1261.35	3310.20	5.25
179	503009	[220-KINY NEW220.00]	220	12447.86	32667.20	25.68
180	503010	[220-KINY NEW220.00]	220	12447.86	32667.20	25.68
181	503012	[TUSAGARA 220.00]	220	1163.58	3053.60	6.53
182	503045	[TMAHUMBIKA 220.00]	220	4624.57	12136.40	16.38
183	503046	[TKIGOMA 220.00]	220	2686.58	7050.40	4.46
184	503449	[TKIKONGE 220.00]	220	1672.42	4389.00	11.84
185	504066	[TKINYEREZI-E220.00]	220	12462.60	32705.80	25.73
186	505011	[LUGURUNI 220.00]	220	7734.91	20298.90	11.70
187	507001	[TTUNDU_33B1 220.00]	220	3470.82	9108.50	12.74
188	507010	[TPS 1 220.00]	220	1126.61	2956.60	6.80
189	507011	[TPS1 220.00]	220	1126.61	2956.60	6.80
190	507014	[TPS2 220.00]	220	1125.44	2953.50	7.75
191	507015	[TPS2 220.00]	220	1125.44	2953.50	7.75
192	507018	[TPS3 220.00]	220	1369.95	3595.20	8.79
193	507019	[TPS3 220.00]	220	1369.95	3595.20	8.79
194	507023	[TPS4 220.00]	220	2224.79	5838.60	10.70
195	507024	[TPS4 220.00]	220	2224.79	5838.60	10.70
196	507028	[TPS5 220.00]	220	1588.11	4167.70	10.23
197	507029	[TPS5 220.00]	220	1588.11	4167.70	10.23
198	507051	[KINGOLWIRA 220.00]	220	3330.60	8740.60	9.16
199	507052	[KINGOLWIRA 220.00]	220	3330.60	8740.60	9.16

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I''k rms [kA]	X/R Ratio
200	507053	[KIDUGALO 220.00]	220	2273.50	5966.40	8.83
201	507054	[TKIDUGALO 220.00]	220	2273.50	5966.40	8.83
202	507057	[RUVU-SGR 220.00]	220	2651.27	6957.80	8.97
203	507058	[RUVU-SGR 220.00]	220	2651.27	6957.80	8.97
204	507061	[PUGU-SGR 220.00]	220	7742.14	20317.90	11.04
205	507066	[220-TANGA 220.00]	220	2380.32	6246.70	12.82
206	509010	[BENAKO 220.00]	220	1440.19	3779.50	4.92
207	509830	[TNWMORG 220.00]	220	4449.77	11677.60	9.77
208	509836	[TIFAKARA 220.00]	220	1860.71	4883.10	9.34
209	509838	[TZEGERENI 220.00]	220	6484.72	17018.00	11.25
210	509839	[TZEGERENI 220.00]	220	6484.72	17018.00	11.25
211	509842	[TDUNDANI 220.00]	220	7297.54	19151.10	8.60
212	509843	[TDUNDANI 220.00]	220	7297.54	19151.10	8.60
213	509846	[TMABIBO 220.00]	220	7287.80	19125.50	19.26
214	509847	[TMABIBO 220.00]	220	7287.80	19125.50	19.26
215	509854	[TSEGERA 220.00]	220	2989.29	7844.90	20.62
216	509857	[TSEGERA 220.00]	220	2989.29	7844.90	20.62
217	509874	[TTUNDURU 220.00]	220	3820.91	10027.30	14.81
218	509880	[TNYANZAGA 220.00]	220	989.95	2598.00	5.32
219	509883	[TSIMIYU 220.00]	220	910.98	2390.70	9.02
220	509886	[TLUHOI 220.00]	220	1075.47	2822.40	6.77

Table 5-16: Short Circuit Results at 132 kV Voltage Level at Year 2050

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I''k rms [kA]	X/R Ratio
1	501016	[GMG 132.00]	132	3475.52	15201.50	11.80
2	503011	[TCHALIN_1B1 132.00]	132	3384.78	14804.60	11.89
3	503013	[132KV-IPOLE 132.00]	132	448.41	1961.30	3.81
4	503014	[132KV-INYONG132.00]	132	430.51	1883.00	3.78
5	503015	[132KV-KATAVI132.00]	132	3042.37	13306.90	8.23
6	503016	[132KV-URAMBO132.00]	132	458.54	2005.60	3.97
7	503017	[132KV-NGURUK132.00]	132	413.85	1810.10	4.62
8	503071	[TSHINYA_1B1 132.00]	132	1026.95	4491.70	10.93
9	503111	[TGMBOTO_G1 132.00]	132	3475.52	15201.50	11.80
10	503181	[TKINYE1_1B1 132.00]	132	3608.10	15781.30	13.87
11	503201	[TMABUKI_1B1 132.00]	132	477.90	2090.30	12.40
12	503221	[TMKAMBA_1B1 132.00]	132	497.32	2175.20	14.97
13	503231	[TMOROGO_1B1 132.00]	132	1307.84	5720.30	7.29
14	503261	[TMWANZA_1B1 132.00]	132	911.45	3986.60	6.23

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
15	503281	[TNJIRO _1B1 132.00]	132	1423.92	6228.00	10.52
16	503311	[TUBU220_1B1 132.00]	132	9571.45	41864.30	17.93
17	503321	[TUBU110_1B1 132.00]	132	9571.45	41864.30	17.93
18	503322	[TKINYE 132.00]	132	3608.10	15781.30	13.87
19	503324	[TKAGERA 132.00]	132	1511.25	6610.00	2.66
20	503341	[TUBUGP2_1B1 132.00]	132	9571.45	41864.30	17.93
21	503342	[TPEMBA 132.00]	132	387.23	1693.70	15.35
22	503361	[TBUNDA _1B1 132.00]	132	2366.76	10351.90	12.09
23	503362	[TMAHUMBIKA 132.00]	132	1592.55	6965.60	9.90
24	503364	[TMTWARA 132.00]	132	1456.22	6369.30	5.40
25	503365	[TBAGAMOYO 132.00]	132	5438.86	23788.80	11.82
26	503381	[THALEHY_1B1 132.00]	132	1383.03	6049.20	4.67
27	503382	[THALEHY_1B2 132.00]	132	1383.03	6049.20	4.67
28	503391	[TILALA _1B1 132.00]	132	8003.00	35004.00	10.28
29	503411	[MBAGALA 132.00]	132	3046.93	13326.90	5.44
30	503412	[DEGE 132.00]	132	5800.18	25369.20	7.68
31	503413	[TKURA 132.00]	132	6864.90	30026.20	7.36
32	503421	[TKANGE _1B1 132.00]	132	1689.81	7391.00	9.84
33	503425	[TUSAGARA 132.00]	132	1162.31	5083.80	6.53
34	503431	[TKASIGA_1B1 132.00]	132	906.51	3964.90	3.09
35	503441	[TKIA _1B1 132.00]	132	1417.06	6198.00	10.30
36	503461	[TKIPAWA_1B1 132.00]	132	4472.51	19562.20	5.47
37	503471	[TKIYUNG_1B1 132.00]	132	1059.10	4632.40	4.47
38	503481	[TKUNDUC_1B1 132.00]	132	8326.89	36420.70	12.83
39	503501	[TLUSU _1B1 132.00]	132	612.71	2679.90	3.44
40	503511	[TMKUMBU_1B1 132.00]	132	7186.13	31431.20	8.54
41	503531	[TMAWENI_1B1 132.00]	132	1469.92	6429.20	7.13
42	503551	[TMLANDI_1B1 132.00]	132	1404.55	6143.30	2.84
43	503561	[TMUSOMA_1B1 132.00]	132	451.03	1972.80	2.75
44	503571	[TNCC _1B1 132.00]	132	7533.81	32951.90	8.55
45	503581	[TNYAMON_1B1 132.00]	132	229.55	1004.00	2.51
46	503591	[TPANGAH_1B1 132.00]	132	1282.00	5607.30	5.45
47	503592	[TPANGAH_1B2 132.00]	132	1282.00	5607.30	5.45
48	503601	[TSAME _1B1 132.00]	132	4468.19	19543.30	12.80
49	503611	[TSONGAS_1B1 132.00]	132	9571.45	41864.30	17.93
50	503621	[TTABORA_1B1 132.00]	132	3331.75	14572.60	13.29
51	503631	[TTANGA _1B1 132.00]	132	1402.61	6134.80	7.05
52	503641	[TTEGETG_1B1 132.00]	132	8326.89	36420.70	12.83
53	503651	[TWAZO _1B1 132.00]	132	4286.21	18747.30	5.66
54	503661	[TZANZI1_1B1 132.00]	132	1005.11	4396.20	3.26
55	503671	[TZANZI2_1B1 132.00]	132	2079.48	9095.40	6.63
56	503898	[TRASKIL_1B1 132.00]	132	4905.66	21456.70	6.25
57	503899	[TRASFUM_1B1 132.00]	132	2522.81	11034.40	3.80
58	503991	[TTOFF110_1 132.00]	132	912.75	3992.20	3.09

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
59	503992	[TTOFF110_2 132.00]	132	4454.83	19484.80	12.63
60	503993	[TTOFF110_3 132.00]	132	615.89	2693.80	3.45
61	503996	[TCPAN_HAL 132.00]	132	1299.04	5681.80	5.11
62	503998	[TRASFUM_1B2 132.00]	132	2005.62	8772.30	3.08
63	503999	[TRASKIL_1B2 132.00]	132	4489.40	19636.00	5.75
64	504001	[TMARAGARASI 132.00]	132	1019.98	4461.20	7.75
65	504003	[TMPANDA 132.00]	132	3042.37	13306.90	8.23
66	504004	[TBUNDA 132.00]	132	2366.76	10351.90	12.09
67	504005	[TKIVULE 132.00]	132	3082.88	13484.10	6.32
68	504006	[THANDENI 132.00]	132	344.31	1506.00	3.20
69	504007	[TMAGU 132.00]	132	759.28	3321.00	3.34
70	504008	[TRORYA 132.00]	132	298.25	1304.50	2.58
71	504009	[TMERERANI 132.00]	132	1109.92	4854.60	9.72
72	504010	[TKIDUNDA 132.00]	132	983.59	4302.10	9.10
73	504019	[TBUGURUNI 132.00]	132	3556.39	15555.20	5.86
74	504020	[TMASAKI 132.00]	132	4658.21	20374.40	4.57
75	504021	[TKAWE 132.00]	132	6152.62	26910.70	10.99
76	504022	[TZANZIBAR 132.00]	132	2390.70	10456.60	10.09
77	504023	[TMULEBA 132.00]	132	604.38	2643.50	3.59
78	504025	[TUVINZA 132.00]	132	584.37	2555.90	4.87
79	504045	[132-CHALINZE132.00]	132	2700.35	11811.00	5.63
80	504100	[TKIGOMA 132.00]	132	2684.11	11739.90	4.47
81	504101	[TKIBETA 132.00]	132	621.87	2720.00	3.93
82	505777	[TMTWARA 132.00]	132	3899.52	17056.00	15.97
83	505819	[TSERENGETI 132.00]	132	180.33	788.70	2.46
84	507067	[132-NEW TANG132.00]	132	1708.46	7472.60	10.03
85	509015	[TKYAKA 132.00]	132	1807.51	7905.80	2.67
86	509024	[KIA 132 132.00]	132	921.77	4031.70	5.18
87	509848	[TMABIBO 132.00]	132	8742.57	38238.80	11.97
88	509849	[TMABIBO 132.00]	132	8742.57	38238.80	11.97
89	509859	[132-LUSHOTO 132.00]	132	504.52	2206.70	3.31
90	509861	[TROMBO 132.00]	132	417.81	1827.50	3.93
91	509863	[TMKATA 132.00]	132	722.06	3158.20	2.81
92	509865	[TKILINDI 132.00]	132	209.15	914.80	3.36
93	509867	[TUKEREWE 132.00]	132	370.63	1621.10	4.09

Table 5-17: Year 2050 Short Circuit Results at 66kV Voltage Level

3 Phase short circuit Currents						
S/N	Bus No.	Bus Name	Voltage Level [kV]	MVA	I"k rms [kA]	X/R Ratio
1	504091	[TBABATI_6B1 66.000]	66	516.72	4520.10	6.22
2	504361	[TBUNDA _6B1 66.000]	66	311.01	2720.70	3.01
3	504471	[TKIYUNG_6B1 66.000]	66	256.98	2248.00	9.16

4	504472	[TKIYUNG_6B2 66.000]	66	256.98	2248.00	9.16
5	504681	[TKARATU_6B1 66.000]	66	1084.54	9487.20	8.67
6	504691	[TKIBARA_6B1 66.000]	66	109.81	960.60	2.58
7	504701	[TKONDOA_6B1 66.000]	66	811.31	7097.10	6.08
8	504711	[TMAKUYU_6B1 66.000]	66	140.92	1232.70	4.02
9	504712	[TKARATU 66.000]	66	1084.54	9487.20	8.67
10	504721	[TMBULU _6B1 66.000]	66	245.35	2146.20	2.54
11	504732	[TSUMB_6B1 66.000]	66	2945.64	25767.7	10.53

Source: *PSMP 2024 Update Team Compilation*

5.7 Transmission and Substation Costs

The cost estimates correspond to the transmission system expansion requirement for the planning horizon. The cost consists of transmission line (132kV, 220kV and 400kV) and substation including: transformer, circuit breakers, disconnector and compensators.

5.7.1 Transmission Unit Costs

Transmission line and substation costs have been benchmarked from recent TANESCO studies and transmission line projects under implementation in Tanzania based on international competitive bidding. **Table 5-18** shows transmission line unit costs, **Table 5-19** shows substation bay unit costs, and **Table 5-20** shows transformers and reactive compensation unit costs. The costs for new switching substations, including circuit breakers, disconnectors, switches, current and voltage transformers, relay buildings, structures and site preparation, have been taken care of on the provided unit costs.

Table 5-18: Unit Cost of Transmission Lines

Rated Voltage (kV)	Unit Cost (1,000 USD/km)	
	Single Circuit	Double Circuit
400	300 – 400	350 - 470
220	190 – 280	235 - 330
132	160 – 220	175 - 260

Source: *PSMP 2024 Update Team Compilation.*

Table 5-19: Unit Cost of Substation per Bay

Substation Cost MUSD/bay		
132 kV	220 kV	400 kV
3.49	5.89	8.00

Source: *PSMP 2024 Update Team Compilation*

Table 5-20: Unit cost of transformers and reactive compensation

	kUSD/MVA	MUSD /100 MVAr	
Transformer	12.805		
Variable Shunt Reactor (SVR)		3.88	
Line Shunt Reactor (LSR)		2.96	

Source: *PSMP 2020 Update Team Compilation.*

5.7.2 Transmission System Project Costs

The total transmission system costs estimated in the planning horizon (2024-2050) is **USD 8,109.53 million** as indicated in **Table 5-21**. It indicates that the Least Cost Expansion Plan is approximately **USD 3,518.63** million from 2024 up to 2028**, USD 3,507.22 million** from 2029 to 2038 and **USD 1,089.67 million** from 2038 up to 2050**.**

Detailed costs for the transmission line are provided in **Table 5-22 ,Table 5-23** and **Table 5-24** for short, medium and long term, respectively. Detailed costs for the substation transformer are provided in **Table 5-25, Table 5-26** and **Table 5-27** for short, medium and long term, respectively**.** Detailed costs for Phased Substation Switch Gear and Bays are provided in **Table 5-28, Table 5-29** and **Table 5-30** for short, medium and long term, respectively**.** Detailed costs for Phased Substation Reactive Compensation are provided in **Table 5-31** for short, medium and long term, respectively. These are overnight costs based on engineering estimations.

Table 5-21: Total Transmission System Costs Estimates (2024-2050)

S/N	Description	Cost Estimates (USD)- million			
		2024-2028	2029-2038	2039-2050	Total
1	Phased Transmission Line	1666.00	2474.58	639.55	4,780.14
2	Phased Substation Transformer	371.32	145.91	48.02	565.25
3	Phased Substation Switch Gear and Bays	1369.49	816.19	343.31	2,528.99
4	Phased Substation Reactive Compensation	105.82	70.54	58.79	235.15
	Total	**3,518.63**	**3,507.22**	**1,089.67**	**8,109.53**

Source*: Team Analysis*

Table 5-22: Phased Transmission Lines Cost Estimates (2024-2028)

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Total Cost M$ Per km	Total Cost M$	COD
1	Nyakanazi	Kigoma	400	Sorbus	659.40	2	2	280.00	0.289	81.00	2025
2	Tabora	Ipole	132	HAWK	280.84	1	1	102.51	0.089	9.17	2025
3	Ipole	Inyonga	132	HAWK	280.84	1	1	133.54	0.089	11.94	2025
4	Inyonga	Mpanda	132	HAWK	280.84	1	1	123.95	0.089	11.09	2025
5	Kinyerezi (Kimara-Toff)	Ubungo	220	Finch	635.33	1	1	7.00	0.577	4.04	2025
6	Kinyerezi (Kimara-Toff)	Mabibo	220	Finch	635.33	1	1	9.50	0.577	5.48	2025
7	Mabibo	Ilala	220	Finch	635.33	1	1	7.00	0.577	4.04	2025
8	Ubungo	Ununio	220	Sorbus	659.40	1	1	18.42	0.285	5.25	2025
9	Tabora	Urambo	132	HAWK	280.84	1	1	115.00	0.089	10.29	2025
10	Malagarasi	Kigoma	132	Bison	431.20	1	1	54.50	0.229	12.48	2025
11	Chalinze	Dodoma	400	Sorbus	659.40	2	3	345.00	0.464	159.98	2025
12	Shinyanga	Simiyu	220	Sorbus	659.40	1	1	110.00	0.191	21.01	2025
13	Bunda	Ukerewe	132	AAAC ASTER	288.30	1	1	96.80	0.323	31.27	2025
14	Songea	Tunduru	220	Sorbus	659.40	1	1	214.50	0.165	35.32	2025
15	Tunduru	Masasi	220	Sorbus	659.40	1	1	179.00	0.197	35.26	2025
16	Isaka	Mwanza (SGR Lot 5)	220	Blue jay	603.68	1	1	228.62	0.235	53.73	2025
17	Pugu	Dundani	220	Sorbus	659.40	1	1	47.00	0.295	13.85	2025
18	Kiyungi	Rombo	132	AAAC ASTER	288.30	1	1	61.31	0.232	14.22	2025
19	T-off	Zegereni Industrial	220	Blue jay	603.68	2	1	5.20	0.235	1.22	2025
20	Chalinze	Kinyerezi	400	Sorbus	659.40	2	3	93.00	0.464	43.13	2026
21	Kinyerezi	Mkuranga	400	Sorbus	659.40	2	3	42.50	0.460	19.55	2026
22	Mkata	Kilindi	132	AAAC ASTER	288.30	1	1	143.60	0.148	21.29	2026
23	Urambo	Nguruka	132	HAWK	280.84	1	1	116.00	0.091	10.61	2026
24	Iringa	Kisada	400	Blue jay	603.68	2	2	106.00	0.451	47.80	2026
25	Iringa	Kitapilimwa	220	AAAC ASTER	288.30	1	1	20.50	0.190	3.90	2026
26	Kisada	Iganjo	400	Blue jay	603.68	2	2	185.00	0.356	65.95	2026
27	Iganjo	Tunduma	400	Blue jay	603.68	2	2	122.00	0.431	52.61	2026
28	Tunduma	Sumbawanga	400	Blue jay	603.68	2	2	203.00	0.279	56.65	2026
29	Masasi	Mahumbika	220	Sorbus	659.40	1	1	126.00	0.197	24.82	2026
30	Kasiga	Lushoto	132	AAAC ASTER	288.30	1	1	37.00	0.283	10.48	2026
31	Dundani	Mkuranga	220	Blue jay	603.68	2	2	18.00	0.282	5.08	2026
32	Chalinze	Segera	400	Sorbus	659.40	2	2	181.00	0.415	75.12	2027
33	Segera	Tanga	220	Blue jay	603.68	2	2	64.00	0.309	19.78	2027
34	Chalinze	Bagamoyo	220	Blue jay	603.68	2	2	90.00	0.309	27.81	2027
35	Benaco	Kyaka	220	Blue jay	603.68	2	1	166.17	0.283	46.94	2027
36	Makutupora	Tabora (SGR Lot 3)	220	Blue jay	603.68	1	1	320.68	0.235	75.36	2027
37	Tabora	Isaka (SGR Lot 4)	220	Blue jay	603.68	1	1	198.38	0.235	46.62	2027

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Total Cost M$ Per km	Total Cost M$	COD
38	Nguruka	Kigoma	132	HAWK	280.84	1	1	148.00	0.089	13.24	2027
39	Chalinze	Sino tan	220	Bluejay	603.68	1	2	35.90	0.235	8.44	2027
40	Songea	Mbinga	220	Sorbus	659.40	1	1	102.50	0.235	24.09	2027
41	Ifakara	Mahenge	220	Bluejay	603.68	1	1	68.00	0.235	15.98	2027
42	Bulyanhulu	Bukombe	220	Sorbus	659.40	1	1	68.59	0.235	16.12	2027
43	Bulyanhulu	Nyanzaga	220	Blue jay	603.68	1	1	53.00	0.235	12.46	2027
44	Iganjo	Saza	220	Sorbus	659.40	1	1	103.62	0.235	24.35	2028
45	New Morogoro	Dumila	220	Bluejay	603.68	1	1	66.00	0.235	15.51	2028
46	Mkuranga	Somanga	400	Bluejay	603.68	2	2	155.50	0.410	63.76	2028
47	Somanga	Mahumbika	400	Bluejay	603.68	2	2	209.00	0.410	85.69	2028
48	Dundani	Pemba Mnazi	220	Bluejay	603.68	2	1	25.00	0.235	5.88	2028
49	Pemba Mnazi	Dege	220	Bluejay	603.68	2	1	24.00	0.235	5.64	2028
50	Dege	Kurasini	220	Bluejay	603.68	2	1	20.00	0.245	4.90	2028
51	Mahumbika	LNG	220	Bluejay	603.68	2	1	41.00	0.235	9.64	2028
52	Ununio	Zanzibar Marine cable	220	XLP	1000.00	1	1	38.00	1.795	68.21	2028
53	Tanga	Pemba	132	XLP	600.00	1	1	86.80	0.768	66.66	2028
54	Iganjo	Kiejombaka Geothermal Plant	220	Bluejay	603.68	1	1	35.00	0.235	8.23	2028
55	Iganjo	Ngozi Geothermal Plant	220	Bluejay	603.68	1	1	17.00	0.235	4.00	2028
56	Nyakanazi	Kabanga Nickel	220	Sorbus	659.40	1	1	87.00	0.235	20.45	2028
57	Kidunda	Chalinze	132	AAAC ASTER	288.30	1	1	80.00	0.089	7.15	2028
58	Iganjo	Songwe Geothermal	220	Bluejay	603.68	1	1	49.00	0.235	11.52	2028
Total Cost											**1666.00M$**

Table 5-23: Phased Transmission Lines Cost Estimates (2029 – 2038)

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Total Cost M$ Per km	Total cost [M$]	COD
1	Lemugur	Njiro	220	Sorbus	659.40	2	2	17.00	0.285	4.85	2029
2	Mahumbika	Ruangwa	220	Sorbus	659.40	1	1	96.70	0.245	23.69	2029
3	New Morogoro	Mvuha	220	Bluejay	603.68	1	1	74.40	0.235	17.48	2029
4	New Tanga	Tanga Cement	220	Bluejay	603.68	1	1	11.00	0.235	2.59	2029
5	Mwakibete	Mbeya Cement	220	Bluejay	603.68	1	1	47.88	0.235	11.25	2029
6	Kipawa	Buguruni	132	AAAC ASTER	288.30	1	1	6.20	0.290	1.80	2029
7	Kunduchi	Kawe	132	AAAC ASTER	288.30	1	1	10.00	0.190	1.90	2029
8	Makuyuni	Karatu	220	Bluejay	603.68	1	1	54.60	0.235	12.83	2029
9	Dumila	Turiani	220	Bluejay	603.68	1	1	47.00	0.235	11.05	2029
10	Kyaka	Kagera Sugar	132	AAAC ASTER	288.30	1	1	18.00	0.190	3.42	2029
11	Songwe Geothermal	Mbeya Cement	220	Bluejay	603.68	1	1	15.00	0.235	3.53	2030
12	Mabibo	Masaki	132	AAAC ASTER	288.30	1	1	17.00	0.290	4.93	2030
13	Tagamenda	Kilolo	220	Bluejay	603.68	1	1	78.70	0.235	18.49	2030
14	Zuzu	Kikombo	220	Bluejay	603.68	1	1	43.34	0.235	10.18	2030
15	Zuzu	Msalato	220	Bluejay	603.68	1	1	28.57	0.235	6.71	2030
16	Msalato	Ihumwa	220	Bluejay	603.68	1	1	20.44	0.235	4.80	2030
17	Ihumwa	Kikombo	220	Bluejay	603.68	1	1	21.82	0.235	5.13	2030
18	Tanzania(Iganjo)	Malawi (Kasumulu) Interconnector	400	Bluejay	603.68	2	2	82.33	0.410	33.76	2030
19	Tabora	Kigoma (SGR Lot 6)	220	Bluejay	603.68	1	1	350.00	0.235	82.25	2030
20	Ununio	Kunduchi	220	Sorbus	659.40	1	1	4.80	0.235	1.13	2030
21	Bagamoyo	Ununio	220	Bluejay	603.68	2	2	22.00	0.283	6.23	2030
22	Nyakato	Bugogwa	220	Bluejay	603.68	1	1	16.29	0.235	3.83	2030
23	Bugogwa	Sabasaba	220	Bluejay	603.68	1	1	12.92	0.235	3.04	2030
24	Sabasaba	Mwanza South	220	Bluejay	603.68	1	1	11.00	0.235	2.59	2030
25	Segera	Same	400	Sorbus	659.40	2	2	164.00	0.410	67.24	2030
26	Same	Kisongo	400	Sorbus	659.40	2	2	166.00	0.410	68.06	2030
27	Njiro	Unga Limited	220	Bluejay	603.68	1	1	11.00	0.235	2.59	2030
28	Unga limited	Sakina	220	Bluejay	603.68	1	1	17.00	0.235	4.00	2030
29	Kyaka	Kakono	220	Sorbus	659.40	1	1	37.00	0.235	8.70	2030
30	Sino tan	Kamaka	220	Bluejay	603.68	1	1	21.41	0.235	5.03	2030
31	Kamaka	Zegereni	220	Bluejay	603.68	1	1	7.86	0.235	1.85	2030
32	Makuyuni	Natron Geothermal	220	Bluejay	603.68	1	1	160.00	0.235	37.60	2030
33	Kisada	Ruhudji	400	Bluejay	603.68	2	2	170.00	0.470	79.90	2030
34	Shinyanga	Shinyanga CCGT	400	Sorbus	659.40	2	2	11.00	0.410	4.51	2030
35	Shinyanga	Bunda	400	Sorbus	659.40	2	2	237.00	0.410	97.17	2030
36	Tanzania (Bunda)	Kenya (Klegoris) Interconnector	400	Sorbus	659.40	2	2	177.00	0.410	72.57	2030

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Total Cost M$ Per km	Total cost [M$]	COD
37	Iganjo	Rumakali	220	Bluejay	603.68	2	2	68.00	0.383	26.04	2030
38	Sumbawanga	Mpanda	400	Sorbus	659.40	2	2	232.00	0.410	95.12	2031
39	Mpanda	Kigoma	400	Sorbus	659.40	2	2	246.00	0.410	100.86	2031
40	Mkuranga	JNHPP	400	Sorbus	659.40	2	3	224.00	0.410	91.84	2031
41	Mtwara	Mahumbika	400	Bluejay	603.68	2	2	70.00	0.410	28.70	2031
42	Madaba	Ludewa	220	Bluejay	603.68	1	1	54.30	0.235	12.76	2031
43	Mwakibete	Iyunga	220	Bluejay	603.68	1	1	7.20	0.235	1.69	2031
44	Madaba	Masigira HPP	220	Bluejay	603.68	1	1	110.00	0.235	25.85	2031
45	Kasumulu	Songwe Manolo HPP	220	Sorbus	659.40	1	1	27.00	0.235	6.35	2031
46	Kia	Mererani	132	AAAC ASTER	288.30	1	1	21.00	0.190	3.99	2031
47	Msalato	Chemba	220	Bluejay	603.68	1	1	100.20	0.235	23.55	2032
48	Musoma	Rorya	132	AAAC ASTER	288.30	1	1	47.80	0.190	9.08	2032
49	Nyamongo	Serengeti	132	AAAC ASTER	288.30	1	1	49.50	0.190	9.41	2032
50	Shinyanga	Nyakanazi	400	Sorbus	659.40	2	2	300.00	0.410	123.00	2032
51	Nyakanazi	Kyaka	400	Sorbus	659.40	2	2	235.00	0.410	96.35	2032
52	Tanzania(Kyaka)	Uganda(Mutukula) interconnector	400	Sorbus	659.40	2	2	24.00	0.410	9.84	2032
53	Tanzania	Mozambique Interconnector	400	Sorbus	659.40	2	2	70.00	0.410	28.70	2032
54	Sino tan	Elsewedy	220	Bluejay	603.68	1	1	24.85	0.235	5.84	2032
55	Kawe	Makumbusho	132	AAAC ASTER	288.30	1	1	6.20	0.190	1.18	2032
56	Ruangwa	Nachingwea	220	Sorbus	659.40	1	1	52.00	0.235	12.22	2032
57	Natron	Ngorongoro	220	Bluejay	603.68	1	1	57.00	0.235	13.40	2032
58	Madaba	Kikonge HPP	220	Sorbus	659.40	2	1	67.00	0.283	18.96	2032
59	Ihumwa	Kongwa	220	Bluejay	603.68	1	1	94.50	0.235	22.21	2033
60	Kidahwe	Kasulu	220	Sorbus	659.40	1	1	62.00	0.235	14.57	2033
61	Nyakanazi	Kibondo	220	Sorbus	659.40	1	1	89.00	0.235	20.92	2033
62	Ruhudji	Mnyera HPP	400	Bluejay	603.68	2	2	50.00	0.410	20.50	2033
63	Mkuranga	Kibiti	220	Sorbus	659.40	1	1	66.70	0.235	15.67	2033
64	Kongwa	Kiteto	220	Bluejay	603.68	1	1	78.20	0.235	18.38	2033
65	Mtwara - Mbamba Bay	Liganga and Mchuchuma (SGR Southern corridor)	220	Bluejay	603.68	1	1	1500.00	0.235	352.50	2034
66	Masasi	Newala	220	Sorbus	659.40	1	1	59.10	0.235	13.89	2034
67	Sumbawanga	Kala	400	Sorbus	659.40	2	2	100.00	0.410	41.00	2034
68	Kigoma	Burundi interconnector	220	Sorbus	659.40	2	2	161.00	0.283	45.56	2034
69	Kakono	Nsongezi HPP	220	Sorbus	659.40	1	1	55.00	0.235	12.93	2034
70	Kongwa	Mpwapwa	220	Bluejay	603.68	1	1	94.50	0.235	22.21	2035
71	Songwe Manolo HPP	Songwe Upper HPP	220	Sorbus	659.40	1	1	40.00	0.235	9.40	2035

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Total Cost M$ Per km	Total cost [M$]	COD
72	Mvuha	Kisaki	220	Bluejay	603.68	1	1	59.70	0.235	14.03	2035
73	Mnyera mnyera	Mnyera Teveta HPP	220	Bluejay	603.68	1	1	27.00	0.235	6.35	2035
74	Dumila	Gairo	220	Sorbus	659.40	1	1	55.80	0.235	13.11	2036
75	Tanga	Musoma (SGR Northern corridor)	220	Bluejay	603.68	1	1	1000.00	0.235	235.00	2036
76	Kishapu	Meatu	220	Bluejay	603.68	1	1	116.00	0.235	27.26	2036
77	Zuzu	Jamatini	220	XLPE	1000.00	1	1	8.44	0.235	1.98	2037
78	Sakina	Longido	220	Bluejay	603.68	1	1	56.10	0.235	13.18	2037
79	Lemugur	Simanjiro	220	Bluejay	603.68	1	1	105.00	0.235	24.68	2037
80	Tagamenda	Nginayo	220	Bluejay	603.68	1	1	91.00	0.235	21.39	2037
81	Mbalali	Mbalali HPP	220	Bluejay	603.68	1	1	20.00	0.235	4.70	2037
82	Sakina	Monduli	220	Bluejay	603.68	1	1	25.40	0.235	5.97	2038
83	Iramba	Mkalama	220	Bluejay	603.68	1	1	54.00	0.235	12.69	2038
84	Usagara	Mwanza South	220	Bluejay	603.68	1	1	25.00	0.235	5.88	2038
85	Njombe Substation	Njombe HPP	220	Sorbus	659.40	1	1	31.00	0.235	7.29	2038
Total cost											**2474.58M$**

Table 5-24: Phased Transmission Lines Cost Estimates (2039 – 2050)

S/NO	From	To	Rated Voltage (kV)	Conductor Type	Conductor Size	No. of Circuits	No. of Conductor per phase	Route Length [km]	Total Cost M$ Per km	Total Cost M$	Year of commisioning
1	Bulyanhulu	Nyangwale	220	Bluejay	603.68	1	1	22.60	0.24	5.31	2039
2	Kasulu	Buhigwe	220	Bluejay	603.68	1	1	26.80	0.24	6.30	2039
3	Dundani	Kisarawe	220	Bluejay	603.68	1	1	53.00	0.24	12.46	2039
4	Tunduma	Ileje	220	Bluejay	603.68	1	1	60.00	0.24	14.10	2039
5	Kilolo	Mhanga HPP	220	Sorbus	659.40	1	1	42.30	0.24	9.94	2039
6	Songea	Nakatuta HPP	220	Sorbus	659.40	1	1	90.00	0.24	21.15	2039
7	Kibeta	Muleba	132	AAAC ASTER	288.30	1	1	80.00	0.19	15.20	2041
8	Tunduma	Momba	220	Bluejay	603.68	1	1	90.00	0.24	21.15	2041
9	Chemba	Kondoa	220	Bluejay	603.68	1	1	38.90	0.24	9.14	2042
10	Tunduma	Mbozi	220	Bluejay	603.68	1	1	52.00	0.24	12.22	2042
11	Mahumbika	Songea	400	Bluejay	603.68	2	2	301.30	0.41	123.53	2043
12	Songea	Ruhudji	400	Bluejay	603.68	2	2	187.92	0.41	77.05	2043
13	Shinyanga	Tabora	400	Bluejay	603.68	2	2	195.00	0.41	79.95	2044
14	Tabora	Mpanda	400	Bluejay	603.68	2	2	196.00	0.41	80.36	2044
15	Mpanda	Tanganyika	132	AAAC ASTER	288.30	1	1	28.60	0.19	5.43	2045
16	Njiro	Meru Gothermal	220	Bluejay	603.68	1	1	20.00	0.24	4.70	2045
17	Mahenge	Malinyi	220	Sorbus	659.40	1	1	80.00	0.24	18.80	2045
18	Kibiti	Rufiji	220	Sorbus	659.40	1	1	47.00	0.24	11.05	2045
19	Karagwe	Kyerwa	220	Sorbus	659.40	1	1	65.00	0.24	15.28	2045
20	Kala	Nkasi	220	Bluejay	603.68	1	1	105.00	0.24	24.68	2047
21	Tabora	Uyui	220	Bluejay	603.68	1	1	93.00	0.24	21.86	2048
22	New Tanga	Mkinga	220	Sorbus	659.40	1	1	42.30	0.24	9.94	2048
23	Gairo	Kongwa	220	Sorbus	659.40	1	1	54.60	0.24	12.83	2048
24	Kasulu	Kibondo	220	Bluejay	603.68	1	1	115.50	0.24	27.14	2048
Total cost											**639.55M$**

Table 5-25: Phased Transformer Cost Estimates (2024 – 2028)

S/NO	Substation Name	Region	Voltage Level [kV]	Rating [MVA]	Number of Transfomer	Tolat cost (M$)	Status	Commissioning Year
1	Mbagala	Dar es Salaam	132/33	120	1	3.00	Under Construction	2025
2	Gongolamboto	Dar es Salaam	132/33	120	1	3.00	Under Construction	2025
3	Dege	Dar es Salaam	132/33	120	1	7.02	Under Construction	2025
4	Bulyanhulu	Shinyanga	220/33	120	1	3.00	Under Construction	2025
5	Lusu	Tabora	132/33	60	1	2.75	Under Construction	2025
6	Ipole	Tabora	132/33	15	2	1.29	Under Construction	2025
7	Inyonga	Katavi	132/33	35	1	1.50	Under Construction	2025
8	Mpanda	Katavi	132/33	35	2	3.00	Under Construction	2025
9	Urambo	Tabora	132/33	15	2	1.29	Under Construction	2025
10	Mlandizi	Pwani	132/33	120	1	3.00	Under Construction	2025
11	Same	Kilimanjaro	132/33	20	2	2.15	Under Construction	2025
12	Musoma	Mara	132/33	45/60	2	5.50	Under Construction	2025
13	Tabora	Tabora	132/33	45/60	2	5.50	Under Construction	2025
14	Kibeta	Kagera	132/33	45/60	2	2.75	Under Construction	2025
15	Mwakibete	Mbeya	220/33	90	1	2.85	Under Construction	2025
16	Rombo	Kilimanjaro	132/33	45	2	3.86	Under Construction	2025
17	Zegereni	Pwani	220/33	120	2	5.66	Under Construction	2025
18	Dundani	Pwani	220/33	120	2	5.66	Under Construction	2025
19	Simiyu	Simiyu	220/33	90	2	4.40	Under Construction	2025
20	Tunduru	Ruvuma	220/33	60	2	3.77	Under Construction	2025
21	Masasi	Mtwara	220/33	60	2	3.77	Under Construction	2025
22	Ukerewe	Mwanza	132/33	45	2	4.30	Under Construction	2025
23	Ubungo	Dar es Salaam	220/132/33	300	1	4.54	Under Construction	2025
24	Mabibo	Dar es Salaam	220/132/33	200/200/45	2	6.05	Under Construction	2025
25	Mabibo	Dar es Salaam	132/33	90	2	5.25	Under Construction	2025
26	Ununio	Dar es Salaam	220/33	120	2	5.66	Under Construction	2025
27	Makambako	Njombe	220/33	120	1	2.83	Planned	2025
28	Nyamongo	Mara	132/33	50	1	2.67	Planned	2025
29	Njiro	Arusha	220/132	120	1	3.00	Under Construction	2025
30	Chalinze	Pwani	132/33	150	2	5.15	Under Construction	2025
31	Geita	Geita	220/33	120	1	1.54	Planned	2025
32	Kondoa	Dodoma	66/33	60	1	0.77	Planned	2025
33	Ilala	Dar es Salaam	132/33	90	2	5.50	Under Construction	2025
34	Kinyerezi	Dar es Salaam	400/220	315	5	21.97	Under Construction	2026
35	Mkuranga	Pwani	400/220	150	2	7.16	Under Construction	2026
36	Mkuranga	Pwani	220/33	90	2	5.09	Under Construction	2026
37	Tagamenda	Iringa	400/220/33	250/250/85	2	7.86	Under Construction	2026
38	Tagamenda	Iringa	220/33/11	125	2	4.99	Under Construction	2026

S/NO	Substation Name	Region	Voltage Level [kV]	Rating [MVA]	Number of Transfomer	Tolat cost (M$)	Status	Commissioning Year
39	Kisada	Iringa	400/220/33	250	2	7.27	Under Construction	2026
40	Kisada	Iringa	220/33/11	60	2	4.27	Under Construction	2026
41	Iganjo	Mbeya	400/220/33	250/250/65	2	7.56	Under Construction	2026
42	Iganjo	Mbeya	220/33/11	125	2	5.11	Under Construction	2026
43	Tunduma	Songwe	400/330/33	315	3	14.29	Under Construction	2026
44	Tunduma	Songwe	400/220/33	250/250/65	2	7.56	Under Construction	2026
45	Tunduma	Songwe	220/33/11	125	2	5.18	Under Construction	2026
46	Sumbawanga	Rukwa	400/220/33	150	2	6.44	Under Construction	2026
47	Sumbawanga	Rukwa	220/66/33	90	2	5.31	Under Construction	2026
48	Mkata	Tanga	132/33	60	2	4.75	Under Construction	2026
49	Kia	Kilimanjaro	132/33	60	2	5.50	Planned	2026
50	Lushoto	Tanga	132/33	30	2	2.91	Under Construction	2026
51	Kilindi	Tanga	132/33	60	2	4.75	Under Construction	2026
52	Mahumbika	Lindi	220/132/33	120/120	2	6.01	Under Construction	2026
53	Nguruka	Kigoma	132/33	15	2	1.29	Under Construction	2026
54	Nyazanga	Mwanza	220/33	30	2	1.50	FS Completed	2027
55	Nyanzaga	Mwanza	220/11	33	1	1.03	FS Completed	2027
56	Segera	Tanga	400/220	250	2	6.14	FS Completed	2027
57	Segera	Tanga	220/33	150	2	5.15	FS Completed	2027
58	New Tanga	Tanga	220/132	150	2	4.27	FS Completed	2027
59	New Tanga	Tanga	132/33	150	2	3.87	FS Completed	2027
60	Bagamoyo	Pwani	220/132/33	150/150/50	2	5.12	FS Completed	2027
61	Bagamoyo	Pwani	132/33	150	2	4.98	FS Completed	2027
62	Benaco	Kagera	220/33	40	2	2.75	FS Completed	2027
63	Kyaka	Kagera	220/132/33	100/100/30	2	5.00	FS Completed	2027
64	Morogoro	Morogoro	220/33	150	2	5.15	Under Construction	2027
65	Kidahwe	Kigoma	400/132/33	120/70/50	2	6.14	Under Construction	2027
66	Nyakanazi	Kagera	400/220	150	2	6.25	Under Construction	2027
67	Babati	Manyara	220/33	60	1	3.00	Planned	2027
68	Sino Tan	Pwani	220/33	150	2	3.84	Pre - FS completed	2027
69	Mbinga	Pwani	220/33	60	2	1.54	Pre - FS completed	2027
70	Saza	Songwe	220/33	45	2	1.15	Pre - FS completed	2027
71	Ifakara	Morogoro	220/33	45	2	1.15	Pre - FS completed	2027
72	Bukombe	Geita	220/33	50	2	1.28	Pre - FS completed	2027
73	Manyoni	Singida	220/34	45	2	1.15	Pre - FS completed	2027
74	Njombe	Njombe	220/33	60	2	1.54	Pre - FS completed	2027
75	Usagara	Mwanza	220/132/33	150/150/50	2	5.12	FS Completed	2028
76	Usagara	Mwanza	132/33	90	2	5.50	FS Completed	2028
77	Unguja	Zanzibar	220/132	200	2	5.12	FS Inprogress	2028
78	Pemba	Zanzibar	132/33	120	2	3.07	FS Inprogress	2028

S/NO	Substation Name	Region	Voltage Level [kV]	Rating [MVA]	Number of Transfomer	Tolat cost (M$)	Status	Commissioning Year
79	Dumila	Morogoro	220/33	60	2	1.54	Pre - FS completed	2028
80	Somanga	Lindi	400/220/33	90	2	2.30	Pre - FS completed	2028
81	Mahumbika	Lindi	400/220	250	2	6.40	Pre - FS completed	2028
82	Mahumbika	Lindi	220/132	60	2	1.54	Pre - FS completed	2028
83	Pemba mnazi	Pwani	220/33	150	2	3.84	Pre - FS completed	2028
84	Dege	Pwani	220/132	150	2	3.84	Pre - FS completed	2028
85	Kurasini	Dar es Salaam	220/132	150	2	3.84	Pre - FS completed	2028
Total Cost								**371.32M$**

Table 5-26: Phased Substation Transformer Cost Estimates (2029-2038)

S/NO	Substation Name	Region	Voltage Level [kV]	Rating [MVA]	Number of Transfomer	Total Cost M$	Year of commisioning
1	Ruangwa	Lindi	220/33	60	2	1.54	2029
2	Mvuha	Morogoro	220/33	60	2	1.54	2029
3	Mbeya Cement	Mbeya	220/33	60	2	0.77	2029
4	Hanang	Manyara	220/33	60	1	0.77	2029
5	Ihumwa	Dodoma	220/33	90	3	3.46	2029
6	Makuyuni	Arusha	220/33	45	2	1.15	2029
7	Karatu	Arusha	220/66	60	2	1.54	2029
8	Kasumulu	Mbeya	400/220/33	150/150/50	2	3.84	2030
9	Kasumulu	Mbeya	220/33	45	2	1.15	2030
10	Kilolo	Iringa	220/33	60	2	1.54	2030
11	Kikombo	Dodoma	220/33	90	2	2.30	2030
12	Masaki	Dar es Salaam	132/33	120	2	3.07	2030
13	Mbulu	Manyara	66/33	45	1	0.58	2030
14	Babati	Manyara	220/33	60	2	1.54	2030
15	Bugogwa	Mwanza		150	2	3.84	2030
16	Sabasaba	Mwanza	220/33	150	2	3.84	2030
17	Mwanza South	Mwanza	220/33	120	2	3.07	2030
18	Rumakali	Njombe	220/33	60	2	1.54	2030
19	Kamaka	Pwani	220/33	150	2	3.84	2030
20	Kasulu	Kigoma	220/33	60	2	1.54	2030
21	Unga Lmited	Arusha	220/33	90	2	2.30	2030
22	Sakina	Arusha	220/33	90	2	2.30	2030
23	Same	Kilimmanjaro	400/132/33	150/15/50	2	3.84	2030
24	Ludewa	Njombe	220/33	60	2	1.54	2031
25	Iyunga	Mbeya	220/33	120	2	3.07	2031
26	Mererani	Arusha	132/33	60	2	1.54	2031
27	Mpanda	Katavi	400/132/33	90/90/50	2	2.30	2031
28	Mahumbika	Lindi	400/220/33	250	2	6.40	2031
29	Rorya	Mara	132/33	60	2	1.54	2032
30	Serengeti	Mara	132/33	60	2	1.54	2032
31	Msalato	Dodoma	220/33	90	2	2.30	2032
32	Kawe	Dar es Salaam	132/33	120	2	3.07	2032
33	Chemba	Dodoma	220/33	60	2	1.54	2032
34	Kyaka	Kagera	400/220/33	250/250/85	2	6.40	2032
35	Kyaka	Kagera	220/132/33	100/100/30	2	2.56	2032
36	Kunduchi	Dar es Salaam	220/132	150	2	3.84	2032
37	Elsewedy	Pwani	220/33	120	2	3.07	2032
38	Iramba	Singida	220/33	45	2	1.15	2032
39	Nachingwea	Lindi	220/33	60	2	1.54	2032
40	Magu	Mwanza	132/33	60	2	1.54	2032
41	Namtumbo	Ruvuma	220/33	60	2	1.54	2032
42	Handeni	Tanga	132/33	60	2	1.54	2032

S/NO	Substation Name	Region	Voltage Level [kV]	Rating [MVA]	Number of Transfomer	Total Cost M$	Year of commisioning
43	Kiteto	Manyara	220/33	50	1	0.64	2033
44	Kongwa	Dodoma	220/33	60	2	1.54	2033
45	Ngorongoro	Arusha	220/33	60	2	1.54	2033
46	Bunda	Mara	400/132/33	250/250/85	2	6.40	2033
47	Kibiti	Pwani	220/33	90	2	2.30	2033
48	Chunya	Mbeya	220/33	60	2	1.54	2033
49	Kibondo	Kigoma	220/33	60	2	1.54	2033
50	Kala	Rukwa	400/220/33	150/150/50	2	3.84	2033
51	Newala	Mtwara	220/33	60	2	1.54	2034
52	Mbalali	Mbeya	220/33	60	2	1.54	2034
53	Mpwapwa	Dodoma	220/33	60	2	1.54	2035
54	Kisaki	Morogoro	220/33	45	2	1.15	2035
55	Gairo	Morogoro	220/33	60	2	1.54	2036
56	Meatu	Simiyu	220/33	45	2	1.15	2036
57	Jamatini	Dodoma	220/33	90	2	2.30	2036
58	Simanjiro	Manyara	220/33	60	2	1.54	2037
59	Longido	Arusha	220/33	60	2	1.54	2037
60	Karagwe	Kagera	220/33	45	2	1.15	2037
61	Mkalama	Singida	220/33	45	2	1.15	2038
62	Monduli	Arusha	220/33	60	2	1.54	2038
63	Buguruni	Dar es Salaam	220/33	150	2	3.84	2038
64	Bunda	Mara	220/132	120	2	3.07	2038
65	Kivule	Dar es Salaam	132/33	120	2	3.07	2038
Total Cost					**145.91M$**		

Table 5-27: Phased Substation Transformer Cost Estimates (2039-2050)

S/NO	Substation Name	Region	Voltage Level [kV]	Rating [MVA]	Number of Transfomer	Total Cost M$	Year of commisioning
1	Nyangwale	Geita	220/33	60	2	1.54	2039
2	Buhigwe	Kigoma	220/33	45	2	1.15	2039
3	Tukuyu	Mbeya	220/33	60	2	1.54	2039
4	Kisarawe	Pwani	220/33	120	2	3.07	2039
5	Kakonko	Kigoma	220/33	45	2	1.15	2039
6	Ileje	Songwe	220/33	45	2	1.15	2039
7	Muleba	Kagera	220/33	45	2	1.15	2041
8	Momba	Songwe	220/33	45	2	1.15	2041
9	Kondoa	Dodoma	220/66	60	2	1.54	2042
10	Mbozi	Songwe	220/33	45	2	1.15	2042
11	Tunduru	Ruvuma	400/220	250	2	6.40	2043
12	Songea	Ruvuma	400/220	250	2	6.40	2043
13	Shinyanga	Tabora	400/220	250	2	6.40	2044
14	Tabora	Tabora	400/223	45	2	1.15	2044
15	Tanganyika	Katavi	220/33	45	2	1.15	2045
16	Malinyi	Morogoro	220/33	45	2	1.15	2045
17	Rufiji	Pwani	220/33	60	2	1.54	2045
18	Kyerwa	Kagera	220/33	45	2	1.15	2045
19	Nkasi	Nkasi	220/33	45	2	1.15	2047
20	Maswa	Simiyu	220/33	45	2	1.15	2047
21	Uyui	Tabora	220/33	45	2	1.15	2048
22	Mkinga	Tanga	220/33	60	2	1.54	2048
23	Kongwa	Dodoma	220/33	60	2	1.54	2048
24	Kibondo	Kigoma	220/33	60	2	1.54	2048
Total Cost							**48.02M$**

Table 5-28: Phased Substation Switch Gear and Bays Cost Estimates (2024 – 2028)

S/NO	Substation Name	Region	Switchgear Rated voltage [kV]	No. of Bays	Total Cost M$	Commissioning Year
1	Rombo	Kilimanjaro	132/33	2	23.61	2025
2	Ipole	Tabora	132/33	3	5.18	2025
3	Inyonga	Tabora	132/33	2	6.04	2025
4	Mpanda	Katavi	132/33	1	12.09	2025
5	Urambo	Tabora	132/33	2	5.18	2025
6	Zegereni	Pwani	220/33	2	23.44	2025
7	Dundani	Pwani	220/33	2	22.99	2025
8	Simiyu	Simiyu	220/33	2	21.40	2025
9	Tunduru	Ruvuma	220/33	3	29.24	2025
10	Masasi	Mtwara	220/33	2	32.27	2025
11	Ukerewe	Mwanza	132/33	2	25.23	2025
12	Mabibo	Dar es Salaam	220/132/33	6	49.78	2025
13	Ununio	Dar es Salaam	220/33	3	20.45	2025
14	Tagamenda	Iringa	400/220/33	4	79.95	2026
15	Kisada	Iringa	400/220/33	4	78.13	2026
16	Iganjo	Mbeya	400/220/33	4	84.61	2026
17	Tunduma	Mbeya	400/330/33	6	84.09	2026
18	Sumbawanga	Rukwa	400/220/66/33	2	56.19	2026
19	Mkata	Tanga	132/33	3	18.18	2026
20	Lushoto	Tanga	132/33	2	19.78	2026
21	Kilindi	Tanga	132/33	2	22.81	2026
22	Mahumbika	Lindi	220/132/33	2	23.27	2026
23	Nguruka	Tabora	132/33	3	5.18	2026
24	Kinyerezi	Dar es Salaam	400/220	4	71.44	2026
25	Mkuranga	Pwani	400/220	6	53.38	2026
26	Nyazanga	Mwanza	220/33/11	2	13.33	2027
27	Segere	Tanga	400/220/33	6	45.97	2027
28	New Tanga	Tanga	220/132/33	6	31.64	2027
29	Bagamoyo	Pwani	220/132/33	4	32.02	2027
30	Benaco	Kagera	220/33	4	21.02	2027
31	New Morogoro	Morogoro	220/33	4	21.25	2027
32	Kidahwe	Kigoma	400/132/33	2	20.00	2027
33	Nyakanazi	Kagera	400/220	2	25.00	2027
34	Kyaka	Kagera	220/132/33	2	32.22	2027
35	Sinotan	Pwani	220/33	2	38.80	2027
36	Manyoni	Singida	220/33	2	38.80	2027
37	Mbinga	Songea	220/33	2	11.78	2027
38	Saza	Songwe	220/33	2	16.65	2027

S/NO	Substation Name	Region	Switchgear Rated voltage [kV]	No. of Bays	Total Cost M$	Commissioning Year
39	Bukombe	Geita	220/33	2	17.71	2027
40	Kabanga	Kagera	220/33	2	11.78	2027
41	Mahenge	Morogoro	220/33	2	11.78	2027
42	Njombe	Njombe	220/33	2	11.78	2027
43	Usagara	Mwanza	220/132/33	2	30.53	2028
44	Dumila	Morogoro	220/33	2	11.78	2028
45	Pemba mnazi	Pwani	220/33	4	27.76	2028
46	Mahumbika	Lindi	400/220	3	24.00	2028
Total Cost				**1369.49M$**		

Table 5-29: Phased Substation Switch Gear and Bays Cost Estimates (2029 -2038)

S/NO	Substation Name	Region	Switchgear Rated voltage [kV]	No. of Bays	Unit Cost M$	Total Cost M$	Commissioning Year
1	Ruangwa	Lindi	220/33	2	5.89	11.78	2029
2	Mvuha	Morogoro	220/33	3	5.89	17.67	2029
3	Mbeya Cement	Mbeya	220/33	2	5.89	11.78	2029
4	Hanang	Manyara	220/33	2	5.89	11.78	2029
5	Kawe	Dar es Salaam	132/33	4	3.49	13.96	2029
6	Makuyuni	Arusha	220/33	2	5.89	11.78	2029
7	Karatu	Arusha	220/33	2	5.89	11.78	2029
8	Buguruni	Dar es Salaam	220/33	2	5.89	11.78	2029
9	Kasumulu	Mbeya	400/220/33	4	8.00	32.00	2030
10	Kilolo	Iringa	220/33	2	5.89	11.78	2030
11	Msalato	Dodoma	220/33	2	5.89	11.78	2030
12	Ihumwa	Dodoma	220/33	2	5.89	11.78	2030
13	Kikombo	Dodoma	220/33	4	5.89	23.56	2030
14	Masaki	Dar es Salaam	132/33	2	3.49	6.98	2030
15	Bugogwa	Mwanza	220/33	2	5.89	11.78	2030
16	Sabasaba	Mwanza	220/33	2	5.89	11.78	2030
17	Mwanza South	Mwanza	220/33	2	5.89	11.78	2030
18	Kamaka	Pwani	220/33	4	5.89	23.56	2030
19	Unga Lmited	Arusha	220/33	2	5.89	11.78	2030
20	Sakina	Arusha	220/33	2	5.89	11.78	2030
21	Same	Kilimmanjaro	400/132/33	4	8.00	32.00	2030
22	Ibadakuli	Shinyanga	400/132/33	2	8.00	16.00	2030
23	Bunda	Mara	400/132/33	4	8.00	32.00	2030
24	Ludewa	Njombe	220/33	2	5.89	11.78	2031
25	Iyunga	Mbeya	220/33	2	5.89	11.78	2031
26	Mererani	Arusha	132/33	2	3.49	6.98	2031
27	Mpanda	Katavi	400/132/33	4	8.00	32.00	2031
28	Iramba	Singida	220/33	2	5.89	11.78	2031
29	Rorya	Mara	132/33	3	3.49	10.47	2032
30	Serengeti	Mara	132/33	2	3.49	6.98	2032
31	Chemba	Dodoma	220/33	2	5.89	11.78	2032
32	Kyaka	Kagera	400/220/33	4	8.00	32.00	2032
33	Elsewedy	Pwani	220/33	2	5.89	11.78	2032
34	Nachingwea	Lindi	220/33	2	5.89	11.78	2032
35	Magu	Mwanza	132/33	2	3.49	6.98	2032
36	Namtumbo	Ruvuma	220/33	3	5.89	17.67	2032
37	Handeni	Tanga	132/33	2	3.49	6.98	2032
38	Ngorongoro	Arusha	220/33	2	5.89	11.78	2032

S/NO	Substation Name	Region	Switchgear Rated voltage [kV]	No. of Bays	Unit Cost M$	Total Cost M$	Commissioning Year
39	Kasulu	Kigoma	220/33	2	5.89	11.78	2033
40	Kiteto	Manyara	220/33	2	5.89	11.78	2033
41	Kongwa	Dodoma	220/33	2	5.89	11.78	2033
42	Kibiti	Pwani	220/33	2	5.89	11.78	2033
43	Chunya	Mbeya	220/33	2	5.89	11.78	2033
44	Kibondo	Kigoma	220/33	2	5.89	11.78	2033
45	Kala	Rukwa	400/220/33	4	8.00	32.00	2034
46	Newala	Mtwara	220/33	2	5.89	11.78	2034
47	Mbalali	Mbeya	220/33	2	5.89	11.78	2034
48	Mpwapwa	Dodoma	220/33	2	5.89	11.78	2035
49	Kisaki	Morogoro	220/33	2	5.89	11.78	2035
50	Gairo	Morogoro	220/33	2	5.89	11.78	2036
51	Meatu	Simiyu	220/33	2	5.89	11.78	2036
52	Simanjiro	Manyara	220/33	2	5.89	11.78	2037
53	Jamati	Dodoma	220/33	2	5.89	11.78	2037
54	Longido	Arusha	220/33	2	5.89	11.78	2037
55	Mkalama	Singida	220/33	2	5.89	11.78	2038
56	Karagwe	Kagera	220/33	2	5.89	11.78	2038
57	Monduli	Arusha	220/33	2	5.89	11.78	2038
58	Kivule	Dar es Salaam	132/33	2	3.49	6.98	2038
Total Cost							**816.19M$**

Table 5-30: Phased Substation Switch Gear and Bays Cost Estimates (2039 – 2050)

S/NO	Substation Name	Region	Switchgear Rated voltage [kV]	No. of Bays	Unit Cost M$	Total Cost M$	Commissioning Year
1	Nyangwale	Geita	220/33	2	5.89	11.78	2039
2	Buhigwe	Kigoma	220/33	2	5.89	11.78	2039
3	Ileje	Songwe	220/33	2	5.89	11.78	2039
4	Kisarawe	Pwani	220/33	2	5.89	11.78	2039
5	Kakonko	Kigoma	220/33	2	3.49	6.98	2039
6	Muleba	Kagera	220/33	2	3.49	6.98	2041
7	Momba	Songwe	220/33	2	5.89	11.78	2041
8	Kondoa	Dodoma	220/66	2	5.89	11.78	2042
9	Mbozi	Songwe	220/33	2	5.89	11.78	2042
10	Tunduru	Ruvuma	400/220	4	8.00	32.00	2043
11	Songea	Ruvuma	400/220	6	8.00	48.00	2043
12	Tabora	Tabora	400/223	6	8.00	48.00	2044
13	Tanganyika	Katavi	132/33	2	3.49	6.98	2045
14	Malinyi	Morogoro	220/33	2	5.89	11.78	2045
15	Rufiji	Pwani	220/33	2	5.89	11.78	2045
16	Kyerwa	Kagera	220/33	2	5.89	11.78	2045
17	Nkasi	Nkasi	220/33	2	5.89	11.78	2047
18	Maswa	Simiyu	220/33	2	5.89	11.78	2047
19	Uyui	Tabora	220/33	2	5.89	11.78	2048
20	Mkinga	Tanga	220/33	2	5.89	11.78	2048
21	Kongwa	Dodoma	220/33	2	5.89	11.78	2048
22	Kibondo	Kigoma	220/33	3	5.89	17.67	2048
Total Cost							**343.31M$**

i. Cost estimate is based on “a breaker and a half” scheme.
ii. Switchgear associated with the power plants is not included.
iii. Subs transmission or distribution switchgear is not included.
iv. Expansion of existing substation is not included.

Table 5-31: Phased Substation Reactive Compensation Cost Estimate (2024-2050)

S/N	Substation Name	SVR			LSR			Commissioning Year
		MVAr	Total No.	Cost [MUSD]	MVAr	Total No.	Cost [MUSD]	
1	Masasi				-15	2	0.888	2025
2	Tunduru				-15	2	0.888	2025
3	Mlandizi				15	2	0.888	2025
4	Bunda				10	1	0.296	2025
5	Ununio				-15	1	0.444	2026
6	Kilindi				10	1	0.296	2026
7	Dundani				10	1	0.296	2026
8	Benako				-15	1	0.444	2026
9	Ipole				-10	1	0.296	2026
10	Inyonga				-10	1	0.296	2026
11	Tabora				-10	1	0.296	2026
12	Sumbawanga	40-60	2	4.656				2026
13	Mkuranga				-50	2	2.960	2026
14	Mkuranga				-30	2	1.776	2026
15	Kinyerezi				-40	2	2.368	2026
16	Chalinze				-50	2	2.960	2026
17	Chailinze				-60	2	3.552	2026
18	Dodoma				-60	2	3.552	2026
19	Iringa				-60	2	3.552	2026
20	Kisada				-35	2	2.072	2026
21	Kisada				-30	2	1.776	2026
22	Iganjo	40-60	2	4.656			0.000	2026
23	Iganjo				-30	2	1.776	2026
24	Tunduma				-30	2	1.776	2026
25	Tunduma	40-60	2	4.656				2026
26	Sumbawanga	40-60	2	4.656				2026
27	Mahumbika				-15	1	0.444	2026
28	Morogoro	±45	1	3.492				2026
29	Kidahwe				-60	2	3.552	2027
30	Chalinze				-60	2	3.552	2027
31	Segera				-80	2	4.736	2027
32	Nyakanazi				-60	2	3.552	2027
33	Kondoa				10	1	0.296	2027
34	Mbulu				10	1	0.296	2027
35	Dundani				20	2	1.184	2028

S/N	Substation Name	SVR			LSR			Commissioning Year
		MVAr	Total No.	Cost [MUSD]	MVAr	Total No.	Cost [MUSD]	
36	Tanga				-30	2	1.776	2028
37	Pembamnazi				-50		0.000	2028
38	Musoma	±45	1					2028
39	Mtwara				-40	1	1.184	2028
40	Mahumbika				-60	2	3.552	2028
41	mahumbika				-40	1	1.184	2028
42	Somanga				-60	2	3.552	2028
43	Somanga				-50	2	2.960	2028
44	Pembamnazi				20	2	1.184	2028
45	Dundani				20	2	1.184	2028
46	Ruangwa				-15	1	0.444	2029
47	Mpanda	±45	1	3.492				2029
48	Zanzibar				-25	2	1.480	2029
49	Lemugur				-60	2	3.552	2029
50	Segera				-50	2	2.960	2030
51	Same				-50	4	5.920	2030
52	Nyakanazi	50-70	4	10.864			0.000	2030
53	Kyaka	50-70	2	5.432				2030
54	Ibadakuli	50-70	2	5.432				2030
55	Kasumulu				-45	1	1.332	2030
56	Segera				-50	2	2.960	2030
57	Same				-50	4	5.920	2030
58	Lemugur				-50	2	2.960	2030
59	kisada				-40	2	2.368	2030
60	Kyaka				-50	2	2.960	2030
61	Natron				-20	1	0.592	2030
62	Kidahwe				-70	2	4.144	2031
63	Mkuranga				-60	2	3.552	2031
64	NJHPP				-60	2	3.552	2031
65	Sumbawanga				-50	2	2.960	2031
66	Mpanda				-70	4	8.288	2031
67	Bunda				-50	2	2.960	2032
68	Bunda				-80	2	4.736	2032
69	Kongwa				-20	1	0.592	2032
70	Kala				-45	2	2.664	2034
71	Sumbawanga				-50	2	2.960	2034
72	Sumbawanga				-50	2	2.960	2034
73	Kala				-50	2	2.960	2034

S/N	Substation Name	SVR			LSR			Commissioning Year
		MVAr	Total No.	Cost [MUSD]	MVAr	Total No.	Cost [MUSD]	
74	Ibadakuli				-80	2	4.736	2035
75	Bunda				-80	2	4.736	2035
76	Bunda				-50	2	2.960	2035
77	Ngorongoro				-30	1	0.888	2037
78	Simanjiro				-30	1	0.888	2037
79	Mpanda				-80	2	4.736	2042
80	Tabora				-80	2	4.736	2042
81	Tabora				-60	2	3.552	2042
82	Ibadakuli				-50	2	2.960	2042
83	Mahumbika				-80	2	4.736	2045
84	Ruhudji				-50	2	2.960	2045
85	Songea				-50	2	2.960	2045
86	Songea				-60	2	3.552	2045
	Total SVR			**47.34M$**				
	Total LSR			**187.81M$**				
	Total (SVR+LSR)			**235.15M$**				

5.8 Conclusion

The Transmission plan considered several government agendas including: the Government Industrialization Agenda, which requires substantial power supply to meet demand growth and connect all regions to the Tanzania Grid network. In this regard, the connection of Off-Grid and partially connected regions such as Lindi, Mtwara, Kigoma, Katavi and Rukwa has been given high priority during the transmission plan by considering the power demand forecast, which is the base for generation, transmission and investment planning. Likewise, interconnections with neighbouring countries and power pools were taken into consideration.

The Plan indicates that the required total transmission line additions in the planning horizon (2024-2050) are 16,552.16km as indicated in **Table 5-9.** It includes 5,884.59km in the short term (2024-2028), 8,503.75km in the medium term (2029-2038), and 2,086.82km in the long term (2039-2050). The transmission line additions with respective substations (transformers, switchgear, bays, and compensators), command the total transmission system cost estimates in the planning horizon (2024-2050) of USD 8,109.53 million as indicated in **Table 5-21.** It indicates that the Least Cost Expansion Plan is approximately USD 3,518.63 million in the short term (2024- 2028), USD 3,507.22 million in the medium term (2029 – 2038), and USD 1,089.67 million in the long term (2038 up to 2050).

CHAPTER SIX

ECONOMIC AND FINANCIAL ANALYSIS

6.1 Introduction

The Plan presents the financial investment requirement to cater for the planned generation and transmission infrastructure expansion. The planning horizon is from 2024 to 2050, and it is divided into short-term (2024-2028), medium-term (2029-2038), and long-term (2039-2050). It includes the objective, methodologies, factors considered, results, and conclusion.

The assessment took into consideration various factors. The capital cost for each project has been distributed based on estimated construction schedules to establish the required annual investment cost streams (Capex) that support implementation of the expansion plan. The required annual cost (Capex), in addition to annual operating cost (Opex), has been used to determine the Levelized Cost of Electricity (LCOE) for the power system across the planning horizon. The annual costs have been further adjusted with interest expenses, considering that funding for the projects comes from financial institutions. Using a set of planning criteria, the Plan further estimates the system's Long-Run Marginal Cost (LRMC) of power in the planning horizon.

The report shows that Tanzania requires funds amounting to USD 39,951.90 million for additional investment in power generation and transmission projects over the plan period, as in **Table 6-3**Error! Reference source not found.**.** The required investment will enable the growth of the power generation capacity from 3,191.71MW in 2024 to 19,905.19MW in 2050, equivalent to an additional capacity of 16,713.48MW. It will also enable transmission line additions of 16,552.16km.

6.2 Objective

The objectives for the Economic and Financial Analysis are:

i. To assess annual investment requirement for the Short, Medium and Long Terms.
ii. To determine the Levelized Cost of Electricity (LCOE).
iii. To estimate Long-Run Marginal Costs (LRMC).
iv. To assess the impact of interest and inflation on total funding requirement.
v. To analyze funding sources and financial structures.

6.3 Approach and Methodology

The approach and methodology integrate economic cost assessment, financial modelling, and investment requirement over the planning horizon. It further developed the Levelized Cost of Electricity (LCOE), and Long-Run Marginal Cost (LRMC) of the power system expansion plan. Given the long-term nature of power investments, foreign exchange, inflation, and financing terms have been integrated into the analysis.

6.4 Factors considered in Economic and Financial Analysis

The following key factors have been used in completing the economic and financial analyses.

6.4.1 Project Economic Life and Depreciation

The economic life and applicable depreciation rates for generation and transmission expansion projects are shown in **Table 6-1.** This factor, combined with the yearly electricity generated, enables the computation of the levelized unit cost of electricity for a given power generation project.

Table 6-1: Assumptions on Project Life Depreciation Rates

SN	Type of Power Infrastructure	Economic Life (years)	Depreciation Rate (%)
1	Hydro Power Plants	50	2
2	Gas-Fired Power Plants	24	4
3	Geothermal Power Plants	25	4
4	Nuclear Power Plants	25	4
5	Solar Power Plants	25	4
6	Wind Power Plants	25	4
7	Transmission Lines Projects	35	3

6.4.2 Project Construction Schedules

The construction schedules and percentage of capital cost drawdown shown in **Table 6-2** have been assumed to distribute the project cost into equivalent annual cost disbursements. The annual disbursements ascertain the applicable amount of Interest During Construction (IDC), which will effectively accrue into the total capital costs for a given power project.

Table 6-2: Project Cost Disbursement Schedules

Expected Online Year	Pre-Construction (%)	Annual Expenditure as a Percentage of Total Capital Cost					TOTAL
		1	2	3	4	5	
Hydropower Plants	5	20	25	25	15	10	100
Gas-Fired Power Plants	5	50	45	0	0	0	100
Geothermal Power Plants	0	25	60	15	0	0	100

Expected Online Year	Pre-Construction (%)	Annual Expenditure as a Percentage of Total Capital Cost					TOTAL
		1	2	3	4	5	
Hydrogen Power Plant	5	25	60	10	0	0	100
Nuclear Power Plant	5	25	30	30	10	0	100
Solar Power Plants	5	25	40	0	0	0	100
Wind Power Plants	5	95	0	0	0	0	100
Transmission Lines Projects	5	65	30	0	0	0	100

6.4.3 Project Cost Estimates

The summary cost estimates shown in **Table 6-3** have been derived from generation and transmission expansion plans for the short, medium and long term; these costs exclude IDC and inflation.

Table 6-3: Summary Cost Estimates for Power Projects

S/N	Project Description	Estimated Costs (USD Mil)	Share of Costs (%)
A	**Thermal Generation**	**12,909.38**	32.31%
1	Gas	7,905.22	
2	Nuclear	5,004.16	
B	**Renewable Generation**	**18,932.98**	47.39%
1	Hydropower	6,586.14	
2	Wind	4,666.58	
3	Solar	2833.32	
4	Geothermal	4,398.95	
5	Hydrogen	448	
C	**Transmission Lines and Substations**	**8,109.53**	20.30%
1	Grid Extension	6,873.37	
2	Power Evacuation	471.53	
3	Grid Reinforcement	764.63	
D	**Total Required Costs**	**39,951.90**	100.00%

6.4.4 Inflation Rate on Capital Cost

The project cost shown in **Table 6-3** have been adjusted using the USBLS Producer Price Index (PPI)[15] for construction materials to assess the impact of inflation on the

[15] U.S. Bureau of Labor Statistics, Producer Price Index by Commodity: Special Indexes: Construction Materials [WPUSI012011], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/WPUSI012011, December 15, 2024.

Investment Plan. The Operation and Maintenance costs were also escalated based on composite inflation rates of 2.4% for foreign and local construction materials.

6.4.5 Discount and Interest Rates

The power projects are expected to draw funding from the government, development partners, and private capital through commercial loans, therefore discount rate used in economic and financial analyses tends to mimic the Weighted Average Cost of Capital (WACC) of 7.8% based on existing capital structures and financing terms.

The interest rate, which is commonly considered as the cost of the loan and returns to financiers, usually varies from one Financier to another. The financial analysis uses an average of 8.5% as a representative interest rate for commercial loans. Based on experience, the interest rate for long-term concessional borrowing ranged from 1.5% to 3% for Government lending; the required interest rates by private investors ranged from 6% to 12%.

6.4.6 Debt-Equity Ratio and Loan Tenure

The estimated investment plan will be developed using a mix of funds from the government, private developers, or in collaboration between the government and private developers through a Public-Private Partnership (PPP) arrangement. A standard debt-equity ratio of 70:30 has been used to assess funding requirements from debt and equity financing, respectively. The tenure for the commercial loan is considered to be fifteen (15) years, including a grace period of two (2) years for all other power projects except for hydropower projects with four (4) years.

The economic and financial analyses used the debt-to-equity ratio to estimate the streams of Annual Revenue Requirement (ARR). A ratio of ARR and annual energy generation in a particular year is then computed as a proxy for the minimum average unit costs of electricity.

6.4.7 Interest During Construction (IDC)

The Financial analysis adopted commercial loan interest rates of 8.5% as the IDC cost incurred and payable by project developers. The IDC informs the computation of the annual revenue requirement, average annual unit cost, and the long-run marginal cost of electricity over the plan period.

6.4.8 Foreign Exchange Rate

The financial analysis used an exchange rate of **TZS 2,555** per **1 USD** as provided in the Government guidelines for the Preparation of Plans and Budgets for the Financial Year 2024/25.

6.4.9 Income Tax

The Corporate Income Tax (CIT) in Tanzania is set at 30%. This implies that benefits that exceed the cost are subject to a deduction of CIT of 30%. The financial analysis applies the CIT rate to determine a tax component on return on equity, which will inform the computation of ARR to support the Investment over the planning horizon.

6.4.10 Return On Equity

An average Return On Equity (ROE) of utilities in the power sector ranges from 10 to 12.5 per cent. The economic and financial analysis adopted a rate of 12% to determine return on equity.

6.5 Results of Economic and Financial Analysis

6.5.1 Economic Analysis

The investment requirement for the power expansion plan is shown in **Table 6-4**

Table 6-4: Summary Investment Requirement

Description	**Investment Requirement (USD) - Million**			
	Short-Term	**Medium-Term**	**Long-Term**	**Total**
Generation	9,302.60	11,466.08	11,073.70	31,842.37
Transmission	3,632.02	3,472.41	1,005.10	8,109.53
Total Investments	**12,934.62**	**14,938.49**	**12,078.80**	**39,951.90**
Investments Based on Debt:Equity				
Govt Fully Financed Investments	666.11	33.12	0.00	**699.23**
Debt (70%)	8,587.96	10,433.76	8,455.16	**27,476.87**
Equity (30%)	3,680.55	4,471.61	3,623.64	**11,775.80**
Total	**12,934.62**	**14,938.49**	**12,078.80**	**39,951.90**

6.5.1.1 Short Term Funding Requirement

Based on the factors described in the sub-section 6.4, the capital costs for each project were distributed into annual investment costs as shown in

Table *6-5* and **Figure 6-1**. It is noted that approximately USD 8,587.96 Million will be raised as debt, while USD 4,346.66 million forms an equity component. About 72% of the total funds requirement is earmarked for power generation projects and 28% for transmission line projects. The financing in the short term represents 32.37% of the total financing requirement.

Table 6-5: Annual Investment Plan for Short Term

Investments	**2024**	**2025**	**2026**	**2027**	**2028**
Generation	7.21	1,107.12	3,067.57	2,915.03	2,205.68
Transmission	192.34	835.87	1,223.03	811.91	568.87
Total Investments	**199.55**	**1,942.99**	**4,290.59**	**3,726.94**	**2,774.55**
Investments subjected to Debt:Equity	**192.34**	**1,785.01**	**3,988.22**	**3,615.34**	**2,687.59**
Financing					
Govt Fully Financed Investments	7.21	157.98	302.37	111.60	86.96
Debt	134.64	1,249.51	2,791.76	2,530.74	1,881.31
Equity	57.70	535.50	1,196.47	1,084.60	806.28
Total Debt/Year	134.64	1,249.51	2,791.76	2,530.74	1,881.31
Total Equity/Year	64.91	693.48	1,498.84	1,196.20	893.23
Cumm. Debt	**134.64**	**1,384.15**	**4,175.91**	**6,706.65**	**8,587.96**
Cumm. Equity	**64.91**	**758.39**	**2,257.23**	**3,453.43**	**4,346.66**
Cumm. Investments	**199.55**	**2,142.54**	**6,433.13**	**10,160.07**	**12,934.62**

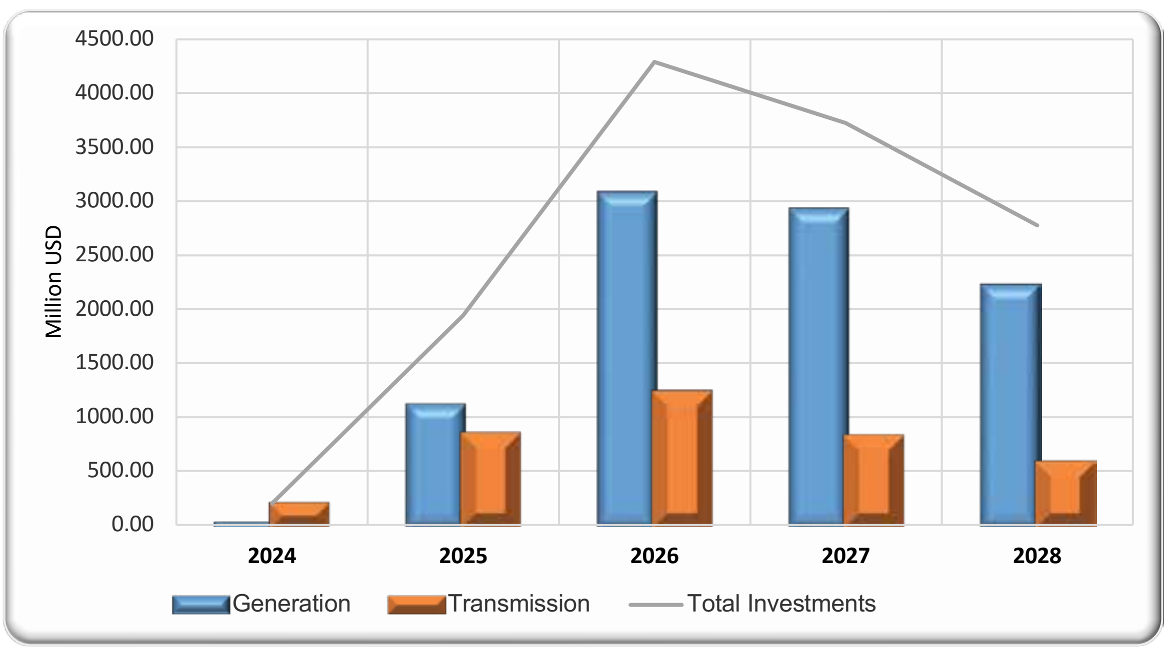

Figure 6-1: Annual Investment Plan for Short Term

6.5.1.2 Medium Term Funding Requirement

The capital costs for each project in the medium term were distributed into annual investment costs as shown in **Table 6-6** and

Figure 6-2. It is noted that approximately USD 10,433.76 million and USD 4,471.61 million will be raised as debt and equity respectively. About 76.75% of the total funds requirement is earmarked for power generation projects and 23.24% for transmission line projects. The financing in the medium term represents 37.39% of the total financing requirement.

Table 6-6: Annual Investment Plan for Medium Term

Investments	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Generation	2,168.61	1,871.66	1,094.84	1,088.43	1,107.61	1,421.59	640.80	493.86	485.78	1,092.89
Transmission	505.05	864.82	375.79	437.85	451.08	197.11	142.77	267.01	137.77	93.15
Total Investments	2,673.66	2,736.48	1,470.64	1,526.27	1,558.69	1,618.70	783.57	760.87	623.56	1,186.04
Investments subjected to Debt:Equit	2,651.58	2,725.44	1,470.64	1,526.27	1,558.69	1,618.70	783.57	760.87	623.56	1,186.04
Financing										
Govt Fully Financed Investments	22.08	11.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Debt (70%)	1,856.10	1,907.81	1,029.44	1,068.39	1,091.09	1,133.09	548.50	532.61	436.49	830.23
Equity (30%)	795.47	817.63	441.19	457.88	467.61	485.61	235.07	228.26	187.07	355.81
Total Debt/Year	1,856.10	1,907.81	1,029.44	1,068.39	1,091.09	1,133.09	548.50	532.61	436.49	830.23
Total Equity/Year	817.55	828.67	441.19	457.88	467.61	485.61	235.07	228.26	187.07	355.81
Cumm. Debt	**1,856.10**	**3,763.91**	**4,793.36**	**5,861.75**	**6,952.83**	**8,085.93**	**8,634.43**	**9,167.04**	**9,603.53**	**10,433.76**
Cumm. Equity	**817.55**	**1,646.23**	**2,087.42**	**2,545.30**	**3,012.91**	**3,498.52**	**3,733.59**	**3,961.85**	**4,148.92**	**4,504.73**
Cumm. Investments	**2,673.66**	**5,410.14**	**6,880.77**	**8,407.05**	**9,965.74**	**11,584.44**	**12,368.02**	**13,128.89**	**13,752.45**	**14,938.49**

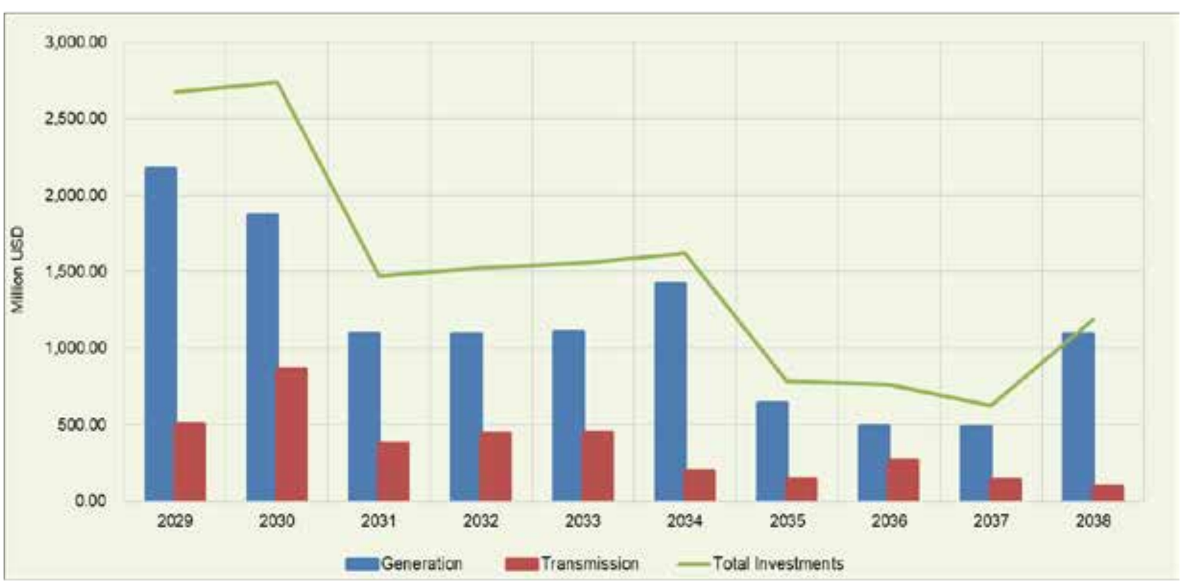

Figure 6-2: Annual Investment Plan for Medium Term

6.5.1.3 Long Term Funding Requirement

The capital costs for each project in the long term were distributed into annual investment costs as shown in **Table 6-7** and **Figure 6-3**. It is noted that approximately USD 8,455.16 Million and USD 3,626.64 million will be raised as debt and equity respectively.

About 91.67% of the total funds requirement is earmarked for power generation projects and 8.33% for transmission line projects. The financing in the long term represents 30.23% of the total financing requirement.

Table 6-7: Annual Investment Plan for Long Term

Investments	2024	2025	2026	2027	2028	2029	2030	2035	2038	2039	2040	2045	2048-2050
Generation	7.21	1,107.12	3,067.57	2,915.03	2,205.68	2,168.61	1,871.66	640.80	1,092.89	596.96	396.73	1,168.88	835.66
Transmission	192.34	835.87	1,223.03	811.91	568.87	505.05	864.82	142.77	93.15	83.33	17.26	61.18	43.45
Total Investments	199.55	1,942.99	4,290.59	3,726.94	2,774.55	2,673.66	2,736.48	783.57	1,186.04	680.30	414.00	1,230.06	879.10
Cumm. Investments	199.55	2,142.54	6,433.13	10,160.07	12,934.62	15,608.28	18,344.75	25,302.64	27,873.10	28,553.40	28,967.40	34,941.50	**39,951.90**
Investments subjected to Debt:E	192.34	1,785.01	3,988.22	3,615.34	2,687.59	2,651.58	2,725.44	783.57	1,186.04	680.30	414.00	1,230.06	879.10
Financing													
Govt Fully Financed Investments	7.21	157.98	302.37	111.60	86.96	22.08	11.04	0.00	0.00	0.00	0.00	0.00	0.00
Debt	134.64	1,249.51	2,791.76	2,530.74	1,881.31	1,856.10	1,907.81	548.50	830.23	476.21	289.80	861.05	615.37
Equity	57.70	535.50	1,196.47	1,084.60	806.28	795.47	817.63	235.07	355.81	204.09	124.20	369.02	263.73
Total Debt/Year	134.64	1,249.51	2,791.76	2,530.74	1,881.31	1,856.10	1,907.81	548.50	830.23	476.21	289.80	861.05	615.37
	134.64	1,384.15	4,175.91	6,706.65	8,587.96	10,444.06	12,351.87	17,222.39	19,021.71	19,497.92	19,787.72	23,969.59	27,476.87
Total Equity/Year	64.91	693.48	1,498.84	1,196.20	893.23	817.55	828.67	235.07	355.81	204.09	124.20	369.02	263.73
	64.91	758.39	2,257.23	3,453.43	4,346.66	5,164.21	5,992.88	8,080.25	8,851.39	9,055.48	9,179.68	10,971.91	12,475.03

Figure 6-3: Annual Investment Plan for the long term

6.5.2 Financial Analysis

The investment cost established under the economic analysis was adjusted to include the capital investment cost that caters for the distribution segment. The investment in generation and transmission should end up with the last mile connectivity, therefore inclusion of the distribution cost component is paramount. Furthermore, generation and transmission costs were adjusted to account for IDC and inflation.

6.5.2.1 Interest During Construction and Inflation

The total investment requirement for the generation and transmission amounts to USD 39,951.90 million by 2050. The cost for the distribution segment is USD 16,186 million making a total investment requirement to USD 56,138.03 million. The respective financing structure will be 69% and 31% for debt and equity.

Based on the assumed inflation rate of 2.4%, the additional cost due to inflation on generation and transmission costs is USD 2,850 million while its respective IDC component is estimated to be USD 10,159 million. Therefore, the inclusion of Inflation and IDC in the required investment costs tend to alter the average composition of the debt-to-equity ratio as shown in **Table 6-8.**

Table 6-8: Breakdown of Cost for the Investment Plan

Capital Costs and Financing Items	Mill. USD	Mill. USD	Percentage (%)
1) Capital Costs without Inflation and IDC			
Generation		31,842.4	56.72
Transmission		8,109.5	14.45
Distribution		16,186	28.83
Total Capital Cost (excl. Inflation & IDC)		56,138.03	100.00
2) Drawdowns for Financing Capital Expenditures			
Debt financed		38,807	69.13
Equity financed		17,331	30.87
Total Financing without IDC		**56,138**	100.00
3) Overall Financing including IDC and Inflation			
IDC	10,159		
Inflation	2,850		

Debt	38,807		
Total Debt (Drawdown + IDC)		50,961	74%
Equity		18,186	26%
Total Financing including IDC		**69,147**	**100%**

6.5.3 Projected Unit Cost of Power Supply over the Investment Plan

The system unit cost of power supply derived on a financial basis for the new power projects was calculated for each year of the planning horizon by dividing the Annual Revenue Requirements (ARR) by the annual energy supplied. The financial cost of power supply is derived from the perspective of accounting, and it includes the operation expenses, depreciation, interest expenses and net income to the Utility. **Table 6-9** presents the ARR and energy supplied with a corresponding computed system unit cost of annual power supply. **Table 6-9** Shows that the system unit cost of power supply in 2025 is higher than the rest of the years due to low generation against the revenue requirement. For the rest of the years, the unit cost averages 6.5 USD cents/kWh.

Table 6-9: System Unit Cost of Additional Power Supply

Year	Annual Rev. Requirement (Mill. USD)	Energy Supply (GWh)	Unit Cost of Supply (USc/kWh)
2024	-	-	-
2025	93	105	88.7
2026	299	2,460	12.2
2027	919	11,025	8.3
2028	1,410	20,146	7.0
2029	1,446	21,024	6.9
2030	1,985	34,298	5.8
2031	2,125	39,886	5.3
2032	2,291	42,556	5.4
2033	2,372	44,215	5.4
2034	2,750	49,352	5.6
2035	2,855	52,307	5.5
2036	2,950	53,011	5.6
2037	3,040	53,733	5.7
2038	3,296	56,793	5.8
2039	3,477	59,666	5.8
2040	3,696	62,160	5.9
2041	3,766	62,160	6.1
2042	3,978	63,677	6.2
2043	4,335	67,751	6.4
2044	4,655	71,201	6.5
2045	4,918	73,797	6.7

Year	Annual Rev. Requirement (Mill. USD)	Energy Supply (GWh)	Unit Cost of Supply (USc/kWh)
2046	5,136	75,084	6.8
2047	5,313	75,658	7.0
2048-2050	6,048	80,917	7.5

6.5.4 Results of Long-Run Marginal Costs

The Long-Run Marginal Cost (LRMC) under this Plan is considered the cost of supplying an incremental unit of electricity (kWh) to the system at a future date. The LRMC was calculated yearly as a ratio of both the discounted incremental cost and energy over the Plan horizon. The derived system marginal unit cost for the period of 2024-2050 is 14.4 USc/kWh as presented in **Table 6-10**. The unit cost includes the effects of losses in the transmission and distribution systems.

Table 6-10: Long-Run Marginal Cost: 2024-2050

Period	Marginal Cost of Power Supply (USc Cents per kWh)			
	Generation	Transmission	Distribution	System Marginal
2024-2028	32.3	9.1	13.6	52.9
2029-2038	5.9	1.9	4.0	11.2
2039-2050	4.8	0.9	2.0	7.5
2024-2050	**7.6**	**2.3**	**5.1**	**14.4**

6.6 Conclusion

The estimated capital cost required is USD 56,138.03 million, consisting of USD 31,842.37 million of generation, USD 8,109.53 million of transmission and USD 16,186 million of distribution investment. The respective contribution is 56.72%, 14.45% and 28.83% for generation, transmission and distribution investment requirement respectively. The expected financing structure is assumed to be 69% of Debt and 31% of Equity.

The investment requirement increases to USD 69,147 million considering USD 10,159 million as IDC and USD 2,850 million of inflation. Therefore, the expected financing structure changes to 74% of Debt and 26% of Equity. The annual unit cost averages 6.5 USD cents/kWh and the system Long-run Marginal Cost (LRMC) is 14.4 USc/kWh over the planning horizon.

CHAPTER SEVEN

IMPLEMENTATION STRATEGY

7.1 Introduction

The PSMP 2024 Update Implementation strategy proposes strategies focusing on enhancing institutional capacity building, legal and regulatory, as well as investment and operational processes. It includes: institutional structure of the electricity sub-sector, government commitment, targets and timelines, implementation strategies, and conclusion.

The government is committed to ensuring reliable and affordable electricity to all. As such, it aims to achieve several targets, including electricity connectivity of 75 per cent by 2030, clean cooking accessibility of 80 per cent by 2034, a share of renewable energy in the generation mix of 75 per cent by 2030, and create an enabling environment for private-sector participation.

To achieve targets among others, the government commits to rehabilitate and expand energy infrastructure at competitive costs, leverage benefits of increased regional integration, embrace distributed renewable energy (DRE) and clean cooking solutions as critical elements of the access agenda, incentivize private-sector participation to unlock additional resources and develop local capacity, as well as advance financially viable utilities that ensure energy security and provide reliable and affordable services. Likewise, a significant mobilization of public- and private-sector financing is needed.

The Implementation Strategy propose a plan of action designed to operationalize the PSMP 2024 update to achieve short-term, medium-term and long-term target incorporating both public and private participation to address the aforementioned government targets. The success of initiatives will position Tanzania as a leader in sustainable development and socio-economic transformation and ensure clean energy for all.

7.2 Institutional Structure of the Electricity Supply Industry

The electricity supply industry consists of various institutions. The key institutions and their respective roles are presented in **Error! Reference source not found.**.

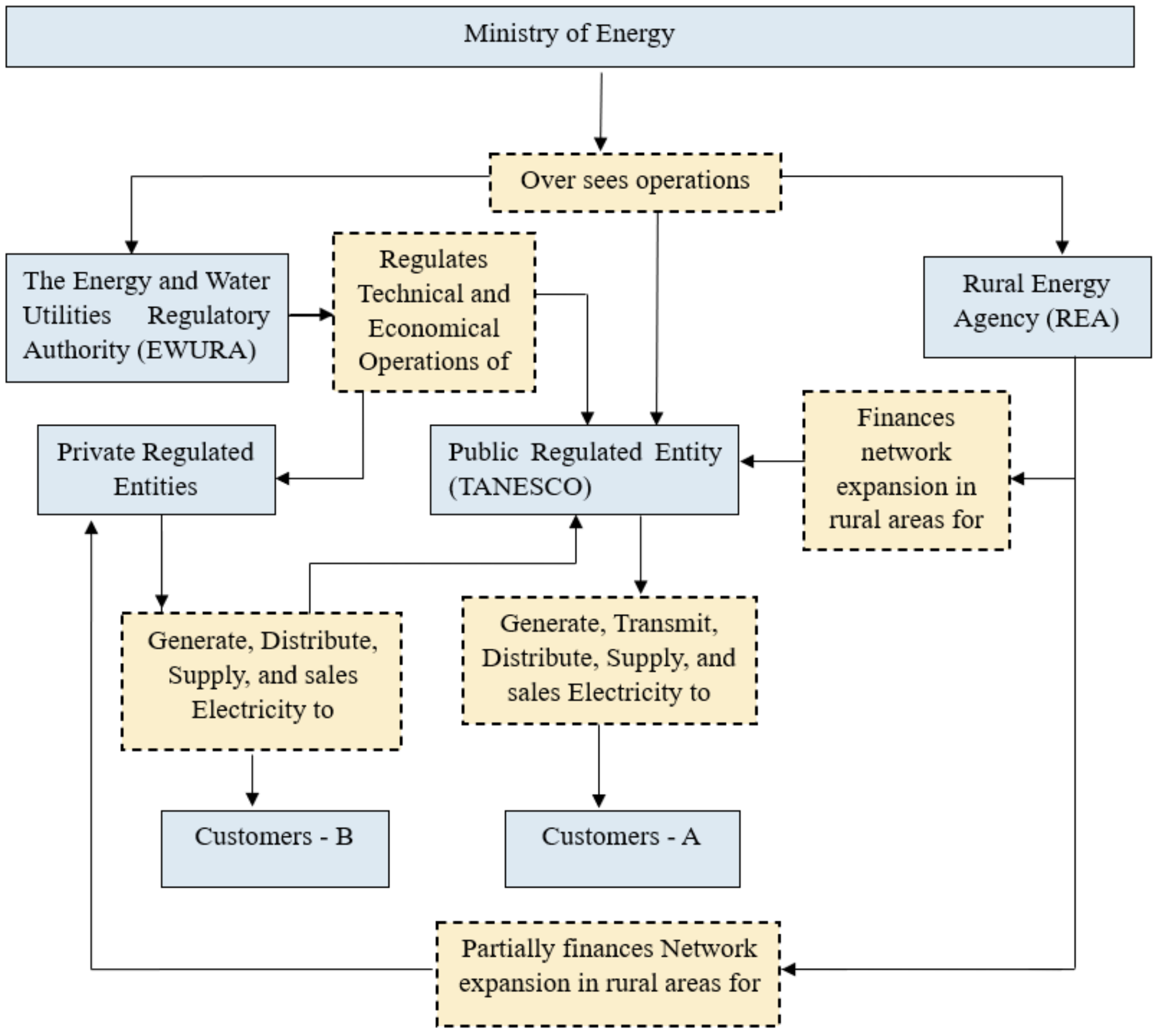

Figure 7- 1: The Electricity Supply Industry Institutional Structure

7.3 Government Commitment

The government of the United Republic of Tanzania provides five (5) commitments through the National Energy Compact on the development of the electricity sector to ensure reliable, affordable, sustainable, inclusive, and clean energy for all.

7.3.1 Rehabilitate and Expand Energy Infrastructure at Competitive Costs

S/N	Description
1.	The government commits to adopting and **periodically updating a comprehensive least-cost power system master plan starting in 2025** to guide future public and private investments in the energy sector, **incorporating regional resources** and **emerging demand from e-mobility, e-cooking, etc.**

S/N	Description
2.	The government commits to **developing and operationalizing by 2027 a competitive procurement framework for power projects** in accordance with the Public Procurement Act of 2023 and to **establishing a Renewable Energy Independent Power Producer (IPP) Procurement Program by 2026** for the competitive procurement of renewable energy projects.
3.	To meet the investment needs in transmission, the government commits **to undertaking a pilot independent power transmission project by 2027** and **adopting the framework for future investments by 2028**.

7.3.2 Leverage Benefits of Increased Regional Integration

The government commits to Leverage Benefits of Increased Regional Integration. The description of the commitments is depicted in **Table 7- 1**

Table 7- 1; Leverage Benefits of Increased Regional Integration

S/N	Description
1.	Recognizing the crucial importance of cross-border electricity trade in optimizing energy supply costs, the government commits to **establishing an appropriately resourced trading unit within Tanzania Electric Supply Company Limited (TANESCO) by 2025** and to **identifying and implementing critical interconnection investments** to facilitate increased power trade with neighboring countries through the Power Pools.
2.	To facilitate and improve cost-effectiveness in regional power exchanges, the government commits to **harmonizing the regulatory framework**, **including transmission tariffs** with the Southern African Power Pool (SAPP) and Eastern Africa Power Pool (EAPP) by 2026

7.3.3 Embrace Distributed Renewable Energy (DRE) and Clean Cooking Solutions as Critical Elements of the Access Agenda.

S/N	Description
1.	The government recognizes the crucial importance of both intensive investments in on-grid and off-grid electrification solutions to achieve its ambitious electrification targets. To this end, **by 2027 the government commits to revising and implementing the Rural Energy Master Plan and the Zanzibar Electrification Master Plan and their respective implementation strategies** with clear roles for the private sector. The monitoring and evaluation plan will be revised to include the multi-tier framework for electricity and clean cooking by 2026.

2.	To facilitate private investment in DRE, the government commits to mobilizing adequate resources **to strengthen the institutional capacity of Tanzania's Bureau of Standards to enforce quality standards for off-grid equipment.**
3.	To address the crucial challenge of clean cooking, the government has established the National Clean Cooking Strategy 2024–2034 that targets 80 per cent access by 2034. **The government and private-sector institutions will adopt the strategy and action plan** and will **focus on increasing access to alternative fuels and clean cooking technologies**, particularly for women. **National quality and performance standards and adequate infrastructure for testing will be developed**. **The results-based financing (RBF) facility for improved cookstoves will be scaled up in 2025,** and **taxes, duties, and fees will be reduced for clean cooking appliances by 2026**.

7.3.4 Incentivize Private-Sector Participation to Unlock Additional Resources and Develop Local Capacity.

S/N	Description
1.	Recognizing the private sector's crucial role in mobilizing necessary resources and to incentivize its participation in the energy sector (both on-grid and off-grid), and unlock additional resources, the government commits to **revising the Small Power Projects (SPP) framework to establish cost-reflective tariffs for small power producers by 2026**, **update the net-metering rules for renewable energy by 2027**, and develop and enact Zanzibar's Energy Act by 2026.
2.	The government commits to **strengthening the legal and regulatory frameworks for public-private partnerships (PPPs) across the energy value chain by 2025** and to **retaining transaction advisors in the Ministry of Energy to facilitate the financial closure of priority projects under PPP arrangements by 2027**.

7.3.5 Advanced Financially Viable Utilities That Ensure Energy Security and Provide Reliable and Affordable Services

S/N	Description
1.	Strengthening the financial and operational performance of TANESCO and ZECO is a critical priority of the government and will be achieved through a combination of measures, including tariff adjustments and performance improvements. **A cost-of-service study will be completed by June 2026** to assist in developing the methodology for cost-recovery tariffs and **annual tariff adjustments to be implemented by 2027** while still protecting poor and vulnerable groups. Specific **regulator-approved performance improvement plans will be developed by June 2026** to strengthen the quality of service provided, efficiency, transparency, and accountability in the operations of TANESCO and ZECO. The regulator will **publish annually the progress made in implementing the performance improvement plans starting in 2027.**
2.	The government is committed to **building institutional capacity** within the Ministry of Energy, TANESCO and ZECO, the Rural Energy Agency (REA), and the Energy and Water Utilities Regulatory Authority (EWURA) to **ensure effective implementation of energy projects and policies**.
3.	The government commits to **ensuring rigorous and transparent monitoring of the National Energy Compact** through a structured monitoring and evaluation (M&E) framework supported by the Ministry of Energy and other stakeholders. **Data collection and feedback mechanisms** will guide policy adjustments and track progress in achieving universal energy access. Monitoring efforts will be integrated into the program budget.

7.4 Targets And Timelines

The government, through the energy compact, provides high-level commitment actions with specific targets and timelines to drive progress toward the achievement of universal access to energy in a reliable, affordable, and sustainable manner. The targets are depicted in **Table 7- 2**

Table 7- 2: Targets and Timeline

S/N	Indicator	Annual Pace Between 2017 and 2022	Targeted Pace Between 2023 and 2030
1.	Increase Electricity Connectivity Rate	7% p.a. • *Connectivity* was 46% in 2022 • *The access rate was 78.4% and connectivity was 39.9% in 2020, according to an NBS survey. According to*	7% p.a. • To *achieve* 75% connectivity by 2030) • *The increase in connectivity each year must equal or exceed 7% to achieve 75% connectivity by 2030.*

S/N	Indicator	Annual Pace Between 2017 and 2022	Targeted Pace Between 2023 and 2030
		Tracking SDG7, connectivity increased to 46% in 2022, an average increase of 7% per year. In 2024, the number of new connections made per year was 562,940.	*This will require, on average, 1.6 million connections per year from 2025 to 2030. It is expected that electricity access will reach 100% by 2030.*
2.	Increase Access to Clean Cooking	11.9% p.a. *Access to clean cooking was 6.9% in 2021*	21% p.a. *To achieve 75% access by 2030 and 80% access by 2034*
3.	Increase Share of Renewable Energy	61.8% • *2,011.27 MW of 3,404.20 MW installed capacity in December 2024*	75% • *463 MW solar* • *500 MW wind* • *130 MW geothermal* • *880 MW large hydro* • ***Total 1,973***
4.	Amount of Private Capital Mobilized	US$0.5 billion	US$4.039 billion

7.5 Implementation Strategies

7.5.1 Implementing Planned Generation Projects

The government commits to implementing additional electricity generation infrastructure capacity to cater for demand growth. Section 8(1)(a) of the Electricity Act, cap.131 mandates TANESCO and other private licensed entities to conduct electricity generation activities. The strategies for implementing Planned Electricity generation Projects are depicted in **Table 7- 3**

Table 7- 3: Strategies for Implementing Planned Generation Projects

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Identify the project to be developed by the government	60 days after the approval of the PSMP	TANESCO	MoE	Project list

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
2	Identifying a project to be developed by the private sector	90 days after the approval of the PSMP	TANESCO	MoE	Project list
3	Identify firmed-up investment cost	90 days after PSMP approval	TANESCO	MoE	cost
4	Establish the mode of implementation of the investment requirements (e.g. PPP,	120 days after PSMP approval	TANESCO	MoE	Report
5	Establish the implementation strategy	150 days after PSMP approval	TANESCO	MoE	Strategy
6	Implement the projects	180 days after the approval of the PSMP	TANESCO	MoE	Progress Reports

7.5.2 Implementing Planned Electricity Transmission Projects

The government commits to implementing additional electricity transmission infrastructure capacity to cater for demand growth and generation requirements. Section 8(1)(b) of the Electricity Act, cap.131 mandates TANESCO to conduct electricity transmission activities. The strategies for implementing Planned Electricity Transmission Projects are depicted in **Table 7- 4.**

Table 7- 4: Strategies for Implementing Planned Transmission Projects

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Identify the project to be developed by the government	60 days after the approval of the PSMP	TANESCO	MoE	Project list
2	Identify a project to be developed by the private sector	90 days after the approval of the PSMP	TANESCO	MoE	Project list
3	Identify firmed-up investment cost	90 days after PSMP approval	TANESCO	MoE	cost
4	Establish the mode of implementation of the investment requirements	120 days after PSMP approval	TANESCO	MoE	Report
5	Establish the implementation strategy and schedule	150 days after PSMP approval	TANESCO	MoE	Strategy

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
6	Implement the projects	180 days after the approval of the PSMP	TANESCO	MoE	Progress Reports

7.5.3 Implementing Critical Interconnection Investments

The government recognizes the crucial importance of cross-border electricity trade in optimizing energy supply costs, thus commits to identifying and implementing critical interconnection investments to facilitate increased power trade with neighbouring countries through the Power Pools. Section 8(1)(b) of the Electricity Act, cap.131 mandates TANESCO to conduct electricity transmission activities. Section 20(d) of the Electricity Act, cap.131, advocates for the system operator (TANESCO) to monitor the cross-border electricity trade. The strategies for implementing Critical Interconnection Investments are depicted in **Table 7- 5.**

Table 7- 5: Strategies for Implementing Critical Interconnection Investments

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Identify a critical interconnection project	60 days after the approval of the PSMP	TANESCO	MoE	Project list
2	Identify firmed-up investment cost	90 days after PSMP approval	TANESCO	MoE	cost
3	Establish the mode of implementation of the investment requirements	120 days after PSMP approval	TANESCO	MoE	Report
4	Establish the implementation strategy	150 days after PSMP approval	TANESCO	MoE	Strategy
5	Implement the projects	180 days after the approval of the PSMP	TANESCO	MoE	Progress Reports

7.5.4 Adopting The Framework for the Independent Power Transmission Project

The government, through the National Energy Compact, commits to undertaking a pilot independent power transmission project by 2027 and adopting the framework for future investments by 2028 to meet the investment needs in transmission. Rule 5(4) of the Electricity (Generation, Transmission and Distribution Activities) Rules, 2024 advocates for transmission activities to be done by a state-owned company only. The strategies for adopting the Framework for Independent Power Transmission Project are depicted in **Table 7- 6**

Table 7- 6: Strategies for Adopting the Framework for the Independent Power Transmission Project

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Revise the relevant legislation to accommodate the framework	60 days after the approval of the PSMP	EWURA	MoE & TANESCO	Revised framework
2	Publish the framework	90 days after the approval of the PSMP	EWURA	MoE & TANESCO	Published framework

7.5.5 Establishing A Renewable Energy Independent Power Producer (IPP) Procurement Program

The government, through the National Energy Compact, commits to establishing a Renewable Energy Independent Power Producer (IPP) Procurement Program by 2026 for the competitive procurement of renewable energy projects.

The Electricity Act, cap.131, provides for the facilitation and regulation of the electricity supply industry in promoting competition among others. Section 40 in particular advocates for restructuring the electricity supply industry to foster competition for increased efficiency, enhance the development of private capital investment and promote regional electricity trading.

The Electricity (Market Re-Organisation and Promotion of Competition) Regulations, 2016 govern the regulatory processes related to re-organisation of the electricity market; promotion of competition in generation, transmission and distribution of electricity; and promotion of competition in consumer services and private sector participation in the electricity sub-sector. Regulation 13 in particular advocates for the establishment of the Electricity Infrastructure Procurement Committee (EIPC) to coordinate the competitive procurement of electricity infrastructure.

The strategies for establishing a Renewable Energy Independent Power Producer (IPP) Procurement Program are depicted in **Table 7- 7**

Table 7- 7: strategies for Establishing a Renewable Energy Independent Power Producer (IPP) Procurement Program

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Establish Electricity Infrastructure Procurement Committee (EIPC)	60 days after the approval of the PSMP	MoE	PPRA, TANESCO, TR, OAG, REA, MoF, TIC, EWURA	EIPC established
2	Employment of the coordinator of the EIPC and competitive bidding	90 days after the approval of the PSMP	MoE	PPRA, TANESCO, TR, OAG, REA, MoF, TIC, EWURA	Coordinator employed
3	Liaise with PPRA to include reverse auctioning of Renewable Energy Independent Power Producer Procurement Program (REI4P) as one of the procurement methods in the Public Procurement Act/regulations	90 days after the approval of the PSMP	MoE	PPRA, TANESCO, TR, OAG, REA, MoF, TIC, EWURA	Reverse auction adopted in the PPRA Act/regulations
4	Revise all regulatory framework (Regulations) to incorporate the REI4P	120 days after the approval of the PSMP	MoE	PPRA, TANESCO, TR, OAG, REA, MoF, TIC, EWURA	Published regulation
5	Revise all regulatory framework (Rules) to incorporate the REI4P	120 days after the approval of the PSMP	EWURA	PPRA, TANESCO, TR, OAG, REA, MoF, TIC, EWURA	Published rules
6	Provide REI4P tailored certification training to the relevant experts at the Solar Energy Corporation of India Limited (SECI)	120 days after the approval of the PSMP	MoE	PPRA, EWURA, OAG, TANESCO	Report
7	Procure and operationalize REI4P	180 days after the approval of the PSMP	MoE	PPRA, TANESCO, TR, OAG, REA, MoF, TIC, EWURA	REI4P operational

7.5.6 Developing And Operationalizing a Competitive Procurement Framework for Power Projects

The Electricity (Procurement of Power Projects and Approval of Power Purchase Agreements) Rules, 2019 govern the regulatory and processes related to the initiation and procurement process for procurement of power projects and the approval of power purchase agreements. The rules advocate for procurement of power projects in line with the Public Procurement Act of 2023.

The Electricity (Market Re-Organization and Promotion of Competition) Regulations, 2016 govern the regulatory and processes related to re-organization of the electricity market; promotion of competition in generation, transmission and distribution of electricity; and promotion of competition in consumer services and private sector participation in the electricity sub-sector. Regulation 12 in particular, advocates for competitive procurement of power projects through the Electricity Infrastructure Procurement Committee (EIPC).

The government, through the National Energy Compact commits to developing and operationalizing by 2027, a competitive procurement framework for power projects in accordance with the Public Procurement Act of 2023.

The strategies for the Developing and Operationalizing a Competitive Procurement Framework for Power Projects are depicted in **Table 7- 8.**

Table 7- 8: Strategies for Developing and Operationalizing a Competitive Procurement Framework for Power Projects

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Establish projects for competitive procurement of power projects	60 days after the approval of the PSMP	EIPC	MoE, TANESCO	Projects list
2	Acquire necessary tools and systems to enhance competitive procurement of power projects	90 days after the approval of the PSMP	EIPC	MoE, TANESCO	Tools
3	Advertise competitive procurement of power projects	120 days after the approval of the PSMP	EIPC	MoE, TANESCO	Advertisement

7.5.7 Updating the Net Metering Rules for Renewable Energy

The Electricity (Net-Metering) Rules, 2018, govern the regulatory and procedural matters relating to net-metering frameworks. The rules intend among others to enhance the security of supply by allowing private investment (customers) to generate and sell electricity in both the main grid and off-grid. It also intends to enhance private investment, hence relieves the government and the utility's investment to generate the capacity filled by the net-metering customers.

The government, through the National Energy Compact recognises the private sector's crucial role in mobilizing necessary resources and incentivises its participation in the energy sector (both on-grid and off-grid), and unlocks additional resources; hence commits to updating the net-metering rules for renewable energy by 2027.

The strategies for updating the Net-Metering Rules by 2027 are depicted in **Table 7- 9**

Table 7- 9: Strategies for Updating the Net-Metering Rules by 2027

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Updating the Net-Metering Rules	60 days after the approval of the PSMP	EWURA	MoE, TANESCO, SPPs, IPPs, REA	Updated rules
2	Publish the Rules	90 days after the approval of the PSMP	EWURA	OAG	published
3	Publish (website) the Bi-Directional Net-Metering specifications for measuring the imported and exported energy of each net-metering customer.	120 days after the approval of the PSMP	TANESCO	MoE, EWURA, TBS, WMA	standard
4	Advertise the framework to enhance public awareness and participation in the framework	150 days after the approval of the PSMP	TANESCO	MoE, EWURA,	advertisement
5	Implement the framework to enhance the	180 days after the approval of the PSMP	TANESCO	MoE, EWURA	Implementation report

	security of the electricity supply				

7.5.8 Revising The Small Power Projects (SPP) Framework to Establish Cost-Reflective Tariffs

The power system master plan 2024 updates recognize the contribution of small power projects (SPP) in enhancing the security of the electricity supply. It projects the SPP to contribute 100MW of additional capacity in power generation by 2028.

The Electricity (Development of Small Power Projects) Rules, 2020, govern the regulatory and procedural matters relating to the Development of Small Power Projects in Tanzania. The rules intend, among others to enhance the security of supply by allowing private investment to generate and sell electricity in both main grid and off grid. It also intends to relieve the government and the utility's investment to generate the capacity filled by the SPP investors.

The government through the National Energy Compact, recognize the private sector's crucial role in mobilizing necessary resources. To incentivize its participation in the energy sector (both on-grid and off-grid) and unlock additional resources, commits to revising the Small Power Projects (SPP) framework to establish cost-reflective tariffs for small power producers by 2026.

The strategies for revising the Small Power Projects (SPP) Framework to Establish Cost-Reflective Tariffs for Small Power Producers is depicted in **Table 7- 10.**

Table 7- 10: Strategies for Revising the Small Power Projects (SPP)

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Revising The Small Power Projects (SPP) Framework	60 days after the approval of the PSMP	EWURA	TANESCO, SPPs	Revised rules
2	Publication of the Framework	90 days after the approval of the PSMP	EWURA	OAG	Published rules
3	Implement the framework	180 days after the approval of the PSMP	EWURA	TANESCO, SPPs	report

7.5.9 Publication of Strategic Areas for Small Power Project Developments

The Electricity Act, cap.131 provides for the facilitation and regulation of the electricity supply industry in promoting competition among others. Section 40 in particular advocates for restructuring the electricity supply industry to foster competition for increased efficiency, enhance the development of private capital investment and promote regional electricity trading.

The Electricity (Development of Small Power Projects) Rules, 2020 advocates for determination and publish strategic areas for investors to develop small power projects. The Rules intend to attract private investors to develop small power projects, aiming at improving the security of the electricity supply including voltage improvement and loss reduction. It also intends to attract private investment and relieve the government from investing requirements.

The government, through the National Energy Compact recognize the private sector's crucial role in mobilizing necessary resources and to incentivize its participation in the energy sector (both on-grid and off-grid), and unlock additional resources, hence commits to Incentivize Private-Sector Participation to Unlock Additional Resources and Develop Local Capacity.

The strategies for enhancing Private Participation in Small Power Projects Through Determination and Publication of Strategic Areas are depicted in **Table 7- 11.**

Table 7- 11: Strategies for Publication of Strategic Areas for Development of Small Power Projects

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Determine the strategic areas	60 days after the approval of the PSMP	TANESCO	MoE, EWURA, REA	List Of Areas
2	Publish the strategic areas for the development of small power projects	90 days after the approval of the PSMP	TANESCO	MoE, EWURA, REA	Publication
3	Invite private investors to develop small power projects in the strategic areas	120 days after the approval of the PSMP	TANESCO	MoE, EWURA, REA	Invitation

7.5.10 Private Sector Participation in Financing the Construction of The

Electric Supply Line

Regulation 4 of the Electricity (General) Regulations, 2020 provides an option for customers to pay (finance) the cost of construction of an electric supply line and be reimbursed by the licensee (TANESCO) through a deduction from electricity bills at the rate of forty per cent of the monthly bill or every purchase of electricity charges until full recovery of incurred costs.

The government, through the National Energy Compact, recognize the private sector's crucial role in mobilizing necessary resources and incentivizes its participation in the energy sector (both on-grid and off-grid), and unlocks additional resources, hence commits to Incentivize Private-Sector Participation to Unlock Additional Resources and Develop Local Capacity.

The strategies for enhancing Private Sector Participation in financing the Construction of the Electric Supply Lines are depicted in **Table 7- 12**

Table 7- 12: Strategies for Incentivizing Private Sector Participation in Financing the Construction of The Electric Supply Lines

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Publish the standard agreement form (contract) to enhance transparency and reduce negotiation delays	60 days after the approval of the PSMP	TANESCO	MoE, EWURA	Published Agreement
2	Establish standard (indicative) service supply line charges per kilometer of the transmission and distribution network	90 days after the approval of the PSMP	TANESCO	MoE, EWURA	Approved Charges
3	Publish (website) the framework to enhance public awareness and participation in the framework	120 days after the approval of the PSMP	TANESCO	MoE, EWURA	Published
4	Implement the framework fully	150 days after the approval of the PSMP	TANESCO	MoE, EWURA	Implementation Report

7.5.11 Establishment of Infrastructure Development Investment Funds

Section 40 of the Electricity Act, cap.131 mandates the Minister responsible for electricity, in consultation with the Minister responsible for finance and the EWURA, to restructure the electricity supply industry to foster competition for increased efficiency, enhance the development of private capital investment and promote regional electricity trading.

The establishment of the Infrastructure Development Investment Funds (IDIF) intends to enhance the development of the infrastructure by the government. It also intends to provide payment guarantees to public and private investors in the procurement and development of the infrastructure.

The strategies for the Strategies for Establishment of Infrastructure Development Investment Funds (IDIF) to enhance infrastructure Development and Private Sector Participation are depicted in **Table 7- 12**

Table 7- 13: Strategies for the Establishment of Infrastructure Development Investment Funds

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Establish sources of funds	60 days after PSMP approval	MoE	MoF, EWURA, TANESCO	Report
2	Establish funds that can be contributed through the established source of funds	90 days after PSMP approval	MoE	MoF, EWURA, TANESCO	Report
3	Establish the policy and regulatory framework to be revised to accommodate the framework	120 days after PSMP approval	MoE	MoF, EWURA, TANESCO	Report
4	Revise the policy and regulatory framework to accommodate the framework	150 days after the PSMP approval	MoE	MoF, EWURA, TANESCO	revised policy
5	Implement the framework	210 days after the approval of the PSMP	MoE	MoF, EWURA, TANESCO	Implementation report

7.5.12 Establishing An Appropriately Resourced Trading Unit Within TANESCO

The government, through the National Energy Compact, recognizes the crucial importance of cross-border electricity trade in optimizing energy supply costs, thus commits to establishing an appropriately resourced trading unit within Tanzania Electric Supply Company Limited (TANESCO) by 2025. Section 20(d) of the Electricity Act, cap.131 advocates for the system operator (TANESCO) to monitor the cross-border trade of electricity. The strategies for establishing an Appropriately Resourced Trading Unit Within TANESCO are depicted in **Table 7- 14.**

Table 7- 14: Strategies for Establishing a Trading Unit Within TANESCO

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Establish the functions of the trading unit	60 days after PSMP approval	TANESCO	MoE, EWURA	Report
2	Establish the mode of functioning of the trading unit	90 days after PSMP approval		MoE, EWURA	Report
3	Establish the trading unit	120 days after PSMP approval	TANESCO	MoE, EWURA	Report
4	Operationalize the trading unit	150 days after PSMP approval	TANESCO	MoE, EWURA	Report

7.5.13 Harmonizing The Regulatory Framework to Facilitate Power Exchanges

The government, through the National Energy Compact, recognizes the crucial importance of facilitating and improving cost-effectiveness in regional power exchanges, thus commits to harmonizing the regulatory framework, including transmission tariffs with the Southern African Power Pool (SAPP) and Eastern Africa Power Pool (EAPP) by 2026. Section 45(b)(i)7(vii) of the Electricity Act, cap.131 advocates for the regulator (EWURA) to make rules describing the determination of tariffs and fees and the trading of electricity respectively. The strategies for Harmonizing the Regulatory Framework to Facilitate Power Exchanges are depicted in **Table 7- 15.**

Table 7- 15; Strategies for Harmonizing the Regulatory Framework to Facilitate Power Exchanges

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Establish the regulatory framework that needs to be revised	60 days after PSMP approval	EWURA	MoE, TANESCO	report
2	Establish the regulatory framework that needs to be developed	60 days after PSMP approval	EWURA	MoE, TANESCO	report
3	Establish the implementation strategy for Harmonizing the regulatory framework	90 days after PSMP approval	EWURA	MoE, TANESCO	report
4	Harmonize the regulatory framework	150 days after PSMP approval	EWURA	MoE, TANESCO	Harmonised framework

7.5.14 Promoting The Development Of Indigenous Energy Resources

Section 4(1) (e) of the electricity act cap.131 advocates for the minister responsible for electricity to promote the Development of Indigenous Energy Resources. The PSMP have considered power generation from various indigenous resources including, hydro, natural gas, geothermal, solar, wind, biomass and uranium. Some of these resources need to be developed. The strategies for promoting the Development of Indigenous Energy Resource are depicted in **Table 7- 16**.

Table 7- 16: Strategies For Promoting The Development Of Indigenous Energy Resources

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Establish key stakeholders for the development of indigenous resources	Within 30 days after the approval of the PSMP	MoE	MoW, TANESCO, EWURA, REA, TPDG, TGDC, NDC, STAMICO	List

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
2	Establish a strategy for promoting the development of indigenous resources	Within 60 days after the approval of the PSMP	MoE	MoW, TANESCO, EWURA, REA, TPDG, TGDC, NDC, STAMICO	strategy
3	Implement the strategy	Within 60 days after the approval of the PSMP	MoE	MoW, TANESCO, EWURA, REA, TPDG, TGDC, NDC, STAMICO	Progress reports

7.5.15 Updating A Comprehensive Least-Cost Power System Master Plan Periodically

The Electricity Act cap.131, (part I-preliminary provisions) defines the Power System Expansion Plan (namely Power system master plan (PSMP) as a planning document prepared by the Minister and updated on an annual basis by the System Operator (TANESCO) and dealing with indicative medium and long-term plans for the expansion the transmission system to cater for expected generation and demand developments. Section 20(2) in particular advocates for the System Operator (TANESCO) to update on an annual basis, a Power System Expansion plan taking into consideration policies, plans and strategies as well as developments in generation and demand.

The government, through the National Energy Compact, commits to adopting and periodically updating a comprehensive least-cost power system master plan starting in 2025 to guide future public and private investments in the energy sector, incorporating regional resources and emerging demand from e-mobility and e-cooking, among others.

The strategies for updating a Comprehensive Least-Cost Power System Master Plan are depicted in **Table 7- 17.**

Table 7- 17; Strategies for Updating a Comprehensive Least-Cost Power System Master Plan

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
4	Acquiring all the modern planning tools and systems	Within 60 days after the approval of the PSMP	TANESCO	MoE	Tools
5	Training the responsible staff to ensure adequate expertise in updating the PSMP	Within 90 days after the approval of the PSMP	TANESCO	MoE, REA, EWURA, TPDC, TGDC, NPC	Training Report
6	Establish a planning committee incorporating key stakeholders	Within 120 days after the approval of the PSMP	TANESCO	MoE, REA, EWURA, TPDC, TGDC, NPC	Report
7	Updating PSMP annually	Within 120 days after the end of the year	TANESCO	MoE, REA, EWURA, TPDC, TGDC, NPC	Report

7.5.16 Monitoring and Evaluation of PSMP Implementation

Section 4(1) of the Electricity Act Cap 131 advocates that the Minister responsible for electricity undertake overall supervision and oversight of the electricity supply industry. Section 4(1)(b) advocates that the minister prepare, publish and revise policies, plans and strategies for the development of the electricity sub-sector. Part I (preliminary provisions) defines the Power System Expansion Plan (namely Power system master plan (PSMP) as a planning document prepared by the Minister and updated on an annual basis by the System Operator (TANESCO). The strategies for monitoring the implementation are depicted in **Table 7- 18.**

Table 7- 18: Strategies for Monitoring and Evaluation of PSMP Implementation

S/N	Activity	Timeline	Lead Responsibility	Other Parties Involved	Indicator
1	Establish a Strategy for monitoring and evaluation of the PSMP implementation	Within 30 days after the approval of the PSMP	MoE	TANESCO, EWURA, REA	Strategy
2	Implement the Strategy	Within 60 days after the approval of the PSMP	MoE	TANESCO, EWURA, REA	Progress reports

7.6 Conclusion

The government believe that the PSMP 2024 Update implementation strategy provides a plan of action designed to achieve short-term, medium-term and long-term targets and that incorporates both public and private participation. The success of initiatives will position Tanzania as a leader in sustainable development and socio-economic transformation. Hence, the government invites both public and private sector participation to invest in the development of the electricity supply industry and ensure reliable, affordable, sustainable, inclusive, and clean energy for all.

APPENDICES

Appendix-A: Detailed Generation Expansion Plan from 2024 to 2050

YEAR	PLANT	FUEL	TYPE	PROJECT COST USDM	ADDITION	
					CAPACITY (MW)	ANNUAL ENERGY (GWH)
2024	JNHPP FOUR UNITS	Hydro	Hydro		846	5920
	Import from EEP	Import	Import		100	849.72
2025	Hale	Hydro	Hydro		21	93
	Kishapu Phase I	Solar	PV	89.25	50	109.5
2026	Kishapu Phase II	Solar	PV	178.5	100	219
	JNHPP SIX UNITS	Hydro	Hydro		1410	7410.96
	Mtwara OCGT III	Gas	SC	338.52	30	210.24
	Zuzu Dodoma	Solar	PV	221.9	130	131.4
	Same	Solar	PV	178.5	100	109.5
	Manyoni Phase I	Solar	PV	267.75	150	219
	Kitapilimwa Iringa	Solar	PV	178.5	100	109.5
	Kititimo Singida I	Wind	Wind	459	300	1051.2
	Kisima Iringa	Solar	PV	112.42	144	315.36
	Kinyerezi III OC	Gas	SC	1124	600	4204.8
2027	Kinyerezi III OC	Gas	CC		400	2803.2
	Manyoni Phase II	Solar	PV	267.75	150	0
	IPP GAS	Gas	Gas		200	1401.6
	Ubungo II Conversion	Gas	CC	78.68	70	490.56
	Shinyanga II	Solar	PV	267.75	150	328.5
	Same	Wind	Wind	76.5	50	175.2
	Singida II	Wind	Wind	459	300	1051.2
2028	SPPs (WITH SPP CONTRACT 196.7MW SOLAR)	Solar	PV		50	109.5
	SPPs (WITH SPP CONTRACT 196.7MW HYDRO)	Hydro	Hydro		50	254.04
	Kidunda Morogoro DAWASA	Hydro	Hydro	58.2	20	87.6
	Import	Import	Import		100	849.72
	Somanga Mtama	Gas	CC	358.83	318	2228.544
	Ikungi Phase I	Wind	Wind	459	300	1051.2
	Wanging'ombe Njombe I	Wind	Wind	459	300	1051.2
	Ngozi Phase 1	Geothermal	Geothermal	237.78	60	473.04
	Songwe Phase 1	Geothermal	Geothermal	19.82	5	39.42
	Kiejo Mbaka Phase I (Mbeya)	Geothermal	Geothermal	277.41	70	551.88

YEAR	PLANT	FUEL	TYPE	PROJECT COST USDM	ADDITION	
					CAPACITY (MW)	ANNUAL ENERGY (GWH)
	Malagarasi HPP	Hydro	Hydro	144.1	49.5	181
	Ubungo 1 OCGT	Gas	Gas	67.44	60	420.48
	Somanga Fungu Site II	Gas	CC	449.6	300	2102.4
2029	Somanga Fungu Site II	Gas	CC		300	2102.4
	Kikuletwa	Hydro	Hydro	38.7	11	48.18
	Makambako Njombe I	Wind	Wind	459	300	1051.2
	Tegeta OCGT	Gas	Gas	33.72	30	210.24
	Kinyerezi IV	Gas	Gas	1124	600	4204.8
2030	Kinyerezi IV	Gas	SC		400	2803.2
	Kakono HPP	Hydro	Hydro	280.4	87.8	415.32912
	Ruhudji	Hydro	Hydro	888.47	358	2007.0912
	Kikonge	Hydro	Hydro	740.9	321	1349.7408
	Rumakali	Hydro	Hydro	602.6	222	1322.4096
	Ikungi Phase II	Wind	Wind	459	300	1051.2
	Songwe Phase II	Geothermal	Geothermal	39.63	10	78.84
	Geothermal (Natron)	Geothermal	Geothermal	237.78	60	473.04
	Ngozi Phase II Songwe	Geothermal	Geothermal	158.52	40	315.36
	Kihansi Addition	Hydro	Hydro	220.8	120	73.584
2031	Masigira	Hydro	Hydro	261.3	118	664
	Somangafungu PPP	Gas	Gas	361.09	320	2242.56
	Meru (Arusha) Phase I	Geothermal	Geothermal	118.89	30	236.52
	Ibadakuli Shinyanga Phase I	Geothermal	Geothermal	19.82	5	39.42
	Songwe Manolo Lower	Hydro	Hydro	275	90	536.112
	Mtwara I CCGT	Gas	Gas	338.52	300	2102.4
2032	Makambako Njombe II	Solar	Solar	267.75	150	328.5
	Somanga Fungu Site III	Gas	SC	394.94	350	2452.8
2033	Mnyera Kisingo	Hydro	Hydro	314	119.8	577.3
	Songwe Phase III	Geothermal	Geothermal	79.26	20	157.68
	Mpanga Iringa	Hydro	Hydro	298.5	160	756.864
	Kiejo Mbaka Phase II	Geothermal	Geothermal	118.89	30	236.52
2034	Mnyera mnyera	Hydro	Hydro	665.8	137.4	662.3
	Makambako Njombe II	Wind	Wind	459	300	1051.2
	Shinyanga CCGT Phase I	Gas	Gas	338.52	300	2102.4
	Mnyera Kwanini	Hydro	Hydro	164.3	143.9	693.8

YEAR	PLANT	FUEL	TYPE	PROJECT COST USDM	ADDITION	
					CAPACITY (MW)	ANNUAL ENERGY (GWH)
	Nsongezi (TZ-Portion)	Hydro	Hydro	33.8	12	52.56
2035	Mtwara II CCGT	Gas	CC	338.52	300	2102.4
	Songwe Upper	Hydro	Hydro	109.6	29	151.823529
	Mnyera Pumbwe	Hydro	Hydro	219.3	122	587.863303
	Kisaki Morogoro	Geothermal	Geothermal	118.89	30	236.52
2036	Ikungi Solar Singida	Solar	Solar	267.75	150	328.5
	Mnyera Taveta	Hydro	Hydro	205.8	83.9	404.2302
2037	Mnyera Ruaha	Hydro	Hydro	255.01	60.3	290.5254
	Iringa nginayo	Hydro	Hydro	125.5	52	264.2016
	Mbarali	Hydro	Hydro	166	39	198.1512
2038	Iringa Ibosa	Hydro	Hydro	123	36	186.0624
	Ikungi Wind Singida	Wind	Wind	459	300	1051.2
	Songwe Bupigu	Hydro	Hydro	58.5	17	75.9492
	Njombe	Hydro	Hydro	136	32	165.3888
	Dodoma	Gas	Gas	338.52	300	4204.8
2039	Mhanga	Hydro	Hydro	95	27	118.26
	Songea	Hydro	Hydro	52.8	15	65.7
	Nakatuta (Liparamba)	Hydro	Hydro	52.8	15	65.7
	Bagomoyo	Gas	Gas	338.52	300	2102.4
2040	Mkuranga	Gas	Gas	361.09	320	2242.56
	Kisima Dodoma Solar	Solar	Solar	267.75	150	328.5
	Shinyanga Phase II	Gas	Gas	338.52	300	2102.4
2041	Natron Phase II	Geothermal	Geothermal	594.45	150	1182.6
2042	Kisima Dodoma Wind	Wind	Wind	459	300	1051.2
	Kisaki Morogoro Phsae II	Geothermal	Geothermal	455.75	115	906.66
2043	Ubungo II New	Gas	Gas	530.35	470	3293.76
	Meru (Arusha) Phase II	Geothermal	Geothermal	455.75	115	906.66
2044	Tegeta New	Gas	Gas	361.09	320	2242.56
	Iringa Solar	Solar	Solar	267.75	150	328.5
	Kioje Mbaka Phase III	Geothermal	Geothermal	495.38	125	985.5
2045	Ngozi Phase III	Geothermal	Geothermal	118.89	30	236.52
	Ubungo I New	Gas	Gas	361.09	320	2242.56
	Songwe Phase IV	Geothermal	Geothermal	99.08	25	197.1
2046	Ngozi Phase IV	Geothermal	Geothermal	118.89	30	236.52

YEAR	PLANT	FUEL	TYPE	PROJECT COST USDM	ADDITION	
					CAPACITY (MW)	ANNUAL ENERGY (GWH)
	Iringa Wind	Wind	Wind	459	300	1051.2
	Ibadakuli Shinyanga Phase II	Geothermal	Geothermal	217.97	55	433.62
2047	Ngozi Phase V	Geothermal	Geothermal	118.89	30	236.52
	Luhoi	Geothermal	Geothermal	178.34	45	354.78
2048	Hydrogen	Hydrogen	Hydrogen	448	50	350.4
	Nuclear(Small Modular Reactor)	Uranium	Uranium	5004.16	480	3784.32
	Ngozi Phase VI	Geothermal	Geothermal	118.89	30	236.52

Appendix-Gen- 1 Annual Capacity Addition by Technology(2024-2028)

Installed Capacity by Technology	Units	2024	2025	2026	2027	2028
Hydro Power						
Existing	MW	601.27				
Hydro Additions	MW	1,175.00	940.00	0.00	0.00	119.50
Cumulative Hydro Capacity	***MW***	***1,776.27***	***2,716.27***	***2,716.27***	***2,716.27***	***2,835.77***
Contribution to Total Capacity	*P/Cent*	*55.7%*	*65.0%*	*47.4%*	*38.5%*	*32.5%*
Gas Power						
Existing	MW	1,198.82				
Gas Additions	MW	0.00	0.00	630.00	670.00	576.00
Cumulative Gas Capacity	***MW***	***1,198.82***	***1,198.82***	***1,828.82***	***2,498.82***	***3,074.82***
Contribution to Total Capacity	*P/Cent*	*37.6%*	*28.7%*	*31.9%*	*35.4%*	*35.2%*
Import Power						
Existing	MW	0.00				
Import Addition	MW	100.00	0.00	0.00	0.00	100.00
Cumulative Import Capacity	***MW***	***100.00***	***100.00***	***100.00***	***100.00***	***200.00***
Contribution to Total Capacity	*P/Cent*	*3.1%*	*2.4%*	*1.7%*	*1.4%*	*2.3%*
Geothermal Power						
Existing	MW	0.00				
Geothermal Addition	MW	0.00	0.00	0.00	0.00	135.00
Cumulative Geothermal Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***135.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*1.5%*
Wind Power						
Existing	MW	0.00				
Wind Addition	MW	0.00	0.00	300.00	350.00	700.00
Cumulative Wind Capacity	***MW***	***0.00***	***0.00***	***300.00***	***650.00***	***1,350.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*5.2%*	*9.2%*	*15.5%*
Solar Power						
Existing	MW	5.00				
Solar Addition	MW	0.00	50.00	724.00	300.00	50.00
cumulative Solar Capacity	***MW***	***5.00***	***55.00***	***779.00***	***1,079.00***	***1,129.00***
Contribution to Total Capacity	*P/Cent*	*0.2%*	*1.3%*	*13.6%*	*15.3%*	*12.9%*
Diesel Power						
Existing	MW	101.12				
Diesel Addition	MW	0.00	0.00	(101.12)	0.00	0.00
Cumulative Diesel Addition	***MW***	***101.12***	***101.12***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*3.2%*	*2.4%*	*0.0%*	*0.0%*	*0.0%*
HFO Power						
Existing	MW	0.00				
HFO Addition	MW	0.00	0.00	0.00	0.00	0.00
Cumulative HFO Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Biomass Power						
Existing (Net Avail. Out of 10.5MW)	MW	10.50	0.00	0.00	0.00	0.00
Biomass Addition	MW	0.00	0.00	0.00	0.00	0.00
Cumulative Biomass Capacity	***MW***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***
Contribution to Total Capacity	*P/Cent*	*0.3%*	*0.3%*	*0.2%*	*0.1%*	*0.1%*
Uranium Power						
Existing	MW	0.00				
Uranium Addition	MW	0.00	0.00	0.00	0.00	0.00
Cumulative Uranium Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Hydrogen Power						
Existing	MW	0.00				
Hydrogen Addition	MW	0.00	0.00	0.00	0.00	0.00
Cumulative Hydrogen Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Total Annual Generation Capacity	**MW**	**3,191.71**	**4,181.71**	**5,734.59**	**7,054.59**	**8,735.09**
Total Percent		***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

Appendix-Gen- 2 Annual Capacity Addition by Technology(2029-2038)

Installed Capacity by Technology	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Hydro Power											
Existing by 2029	MW	2,835.77									
Hydro Additions	MW	11.00	1,108.80	208.00	0.00	279.80	293.30	151.00	83.90	151.30	85.00
Cumulative Hydro Capacity	***MW***	***2,846.77***	***3,955.57***	***4,163.57***	***4,163.57***	***4,443.37***	***4,736.67***	***4,887.67***	***4,971.57***	***5,122.87***	***5,207.87***
Contribution to Total Capacity	*P/Cent*	*28.7%*	*33.5%*	*32.8%*	*32.1%*	*33.4%*	*33.6%*	*33.6%*	*33.6%*	*34.3%*	*33.3%*
Gas Power											
Existing by 2029	MW	3,074.82									
Gas Additions	MW	885.00	372.50	620.00	128.50	0.00	300.00	300.00	0.00	0.00	300.00
Cumulative Gas Capacity	***MW***	***3,959.82***	***4,332.32***	***4,952.32***	***5,080.82***	***5,080.82***	***5,380.82***	***5,680.82***	***5,680.82***	***5,680.82***	***5,980.82***
Contribution to Total Capacity	*P/Cent*	*39.9%*	*36.6%*	*39.0%*	*39.2%*	*38.2%*	*38.2%*	*39.0%*	*38.4%*	*38.0%*	*38.2%*
Import Power											
Existing by 2029	MW	200.00									
Import Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Import Capacity	***MW***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***
Contribution to Total Capacity	*P/Cent*	*2.0%*	*1.7%*	*1.6%*	*1.5%*	*1.5%*	*1.4%*	*1.4%*	*1.4%*	*1.3%*	*1.3%*
Geothermal Power											
Existing by 2029	MW	135.00									
Geothermal Addition	MW	0.00	110.00	35.00	0.00	50.00	0.00	30.00	0.00	0.00	0.00
Cumulative Geothermal Capacity	***MW***	***135.00***	***245.00***	***280.00***	***280.00***	***330.00***	***330.00***	***360.00***	***360.00***	***360.00***	***360.00***
Contribution to Total Capacity	*P/Cent*	*1.4%*	*2.1%*	*2.2%*	*2.2%*	*2.5%*	*2.3%*	*2.5%*	*2.4%*	*2.4%*	*2.3%*
Wind Power											
Existing by 2029	MW	1,350.00									
Wind Addition	MW	300.00	300.00	0.00	0.00	0.00	200.00	0.00	0.00	0.00	300.00
Cumulative Wind Capacity	***MW***	***1,650.00***	***1,950.00***	***1,950.00***	***1,950.00***	***1,950.00***	***2,150.00***	***2,150.00***	***2,150.00***	***2,150.00***	***2,450.00***
Contribution to Total Capacity	*P/Cent*	*16.6%*	*16.5%*	*15.4%*	*15.0%*	*14.7%*	*15.3%*	*14.8%*	*14.5%*	*14.4%*	*15.7%*
Solar Power											
Existing by 2029	MW	1,129.00									
Solar Addition	MW	0.00	0.00	0.00	150.00	0.00	0.00	0.00	150.00	0.00	0.00
cumulative Solar Capacity	***MW***	***1,129.00***	***1,129.00***	***1,129.00***	***1,279.00***	***1,279.00***	***1,279.00***	***1,279.00***	***1,429.00***	***1,429.00***	***1,429.00***
Contribution to Total Capacity	*P/Cent*	*11.4%*	*9.5%*	*8.9%*	*9.9%*	*9.6%*	*9.1%*	*8.8%*	*9.7%*	*9.6%*	*9.1%*
Diesel Power											
Existing by 2029	MW	0.00									
Diesel Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Diesel Addition	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
HFO Power											
Existing by 2029	MW	0.00									
HFO Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative HFO Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Biomass Power											
Existing (Net Avail. Out of 10.5MW) by 2(	MW	10.50									
Biomass Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Biomass Capacity	***MW***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***
Contribution to Total Capacity	*P/Cent*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*
Uranium Power											
Existing by 2029	MW	0.00									
Uranium Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Uranium Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Hydrogen Power											
Existing by 2029	MW	0.00									
Hydrogen Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Hydrogen Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Total Annual Generation Capacity	**MW**	**9,931.09**	**11,822.39**	**12,685.39**	**12,963.89**	**13,293.69**	**14,086.99**	**14,567.99**	**14,801.89**	**14,953.19**	**15,638.19**
Total	*P/Cent*	*100.0%*	*100.0%*	*100.0%*	*100.0%*	*100.0%*	*100.0%*	*100.0%*	*100.0%*	*100.0%*	*100.0%*

Appendix-Gen- 3 Annual Capacity Addition by Technology(2039-2050)

Installed Capacity by Technology	Units	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Hydro Power											
Existing by 2039	MW	***5,207.87***									
Hydro Additions	MW	57.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Hydro Capacity	***MW***	***5,264.87***	***5,264.87***	***5,264.87***	***5,264.87***	***5,264.87***	***5,264.87***	***5,264.87***	***5,264.87***	***5,264.87***	***5,264.87***
Contribution to Total Capacity	*P/Cent*	*32.9%*	*31.4%*	*31.1%*	*30.4%*	*29.4%*	*28.4%*	*27.9%*	*27.3%*	*27.2%*	*26.4%*
Gas Power											
Existing by 2039	MW	***5,980.82***									
Gas Additions	MW	300.00	620.00	0.00	0.00	470.00	320.00	320.00	0.00	0.00	0.00
Cumulative Gas Capacity	***MW***	***6,280.82***	***6,900.82***	***6,900.82***	***6,900.82***	***7,370.82***	***7,690.82***	***8,010.82***	***8,010.82***	***8,010.82***	***8,010.82***
Contribution to Total Capacity	*P/Cent*	*39.3%*	*41.2%*	*40.8%*	*39.8%*	*41.1%*	*41.5%*	*42.4%*	*41.6%*	*41.4%*	*40.2%*
Import Power											
Existing by 2039	MW	***200.00***									
Import Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Import Capacity	***MW***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***	***200.00***
Contribution to Total Capacity	*P/Cent*	*1.3%*	*1.2%*	*1.2%*	*1.2%*	*1.1%*	*1.1%*	*1.1%*	*1.0%*	*1.0%*	*1.0%*
Geothermal Power											
Existing by 2039	MW	***360.00***									
Geothermal Addition	MW	0.00	0.00	150.00	115.00	115.00	125.00	55.00	85.00	75.00	30.00
Cumulative Geothermal Capacity	***MW***	***360.00***	***360.00***	***510.00***	***625.00***	***740.00***	***865.00***	***920.00***	***1,005.00***	***1,080.00***	***1,110.00***
Contribution to Total Capacity	*P/Cent*	*2.3%*	*2.1%*	*3.0%*	*3.6%*	*4.1%*	*4.7%*	*4.9%*	*5.2%*	*5.6%*	*5.6%*
Wind Power											
Existing by 2039	MW	***2,450.00***									
Wind Addition	MW	0.00	0.00	0.00	300.00	0.00	0.00	0.00	300.00	0.00	0.00
Cumulative Wind Capacity	***MW***	***2,450.00***	***2,450.00***	***2,450.00***	***2,750.00***	***2,750.00***	***2,750.00***	***2,750.00***	***3,050.00***	***3,050.00***	***3,050.00***
Contribution to Total Capacity	*P/Cent*	*15.3%*	*14.6%*	*14.5%*	*15.9%*	*15.4%*	*14.9%*	*14.6%*	*15.8%*	*15.8%*	*15.3%*
Solar Power											
Existing by 2039	MW	***1,429.00***									
Solar Addition	MW	0.00	150.00	0.00	0.00	0.00	150.00	0.00	0.00	0.00	0.00
cumulative Solar Capacity	***MW***	***1,429.00***	***1,579.00***	***1,579.00***	***1,579.00***	***1,579.00***	***1,729.00***	***1,729.00***	***1,729.00***	***1,729.00***	***1,729.00***
Contribution to Total Capacity	*P/Cent*	*8.9%*	*9.4%*	*9.3%*	*9.1%*	*8.8%*	*9.3%*	*9.2%*	*9.0%*	*8.9%*	*8.7%*
Diesel Power											
Existing by 2039	MW	***0.00***									
Diesel Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Diesel Addition	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
HFO Power											
Existing by 2039	MW	***0.00***									
HFO Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative HFO Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Biomass Power											
Existing (Net Avail. Out of 10.5MW) by 2029	MW	***10.50***									
Biomass Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Biomass Capacity	***MW***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***	***10.50***
Contribution to Total Capacity	*P/Cent*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*
Uranium Power											
Existing by 2039	MW	***0.00***									
Uranium Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	480.00
Cumulative Uranium Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***480.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*2.4%*
Hydrogen Power											
Existing by 2039	MW	***0.00***									
Hydrogen Addition	MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
Cumulative Hydrogen Capacity	***MW***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***50.00***
Contribution to Total Capacity	*P/Cent*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.3%*
Total Annual Generation Capacity	**MW**	**15,995.19**	**16,765.19**	**16,915.19**	**17,330.19**	**17,915.19**	**18,510.19**	**18,885.19**	**19,270.19**	**19,345.19**	**19,905.19**
Total	***P/Cent***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

Appendix-Trans- 1: Detailed Grid Substation Load Demand for Short Term (2024-2028)

Area	Bus Number	Bus Name	MW	MVAr
ARUSHA	505281	TNJIRO _3B1 33.000	49.30	23.84
	505282	TNJIRO _3B2 33.000	49.30	23.84
	505681	TKARATU_3B1 33.000	16.41	4.95
	505735	TLEMUGUR_3B233.000	49.23	23.83
	Total		**164.24**	**76.46**
PWANI	501011	TCHALINZE 33.000	61.20	20.12
	501011	TCHALINZE 33.000	61.20	20.12

Area	Bus Number	Bus Name	MW	MVAr
	501012	220-MKURANGA220.00	193.00	68.06
	503365	TBAGAMOYO 132.00	69.50	25.14
	505551	TMLANDI_3B1 33.000	25.50	8.38
	505552	TMLANDI_3B2 33.000	25.50	8.38
	505765	TBAGAMOYO 33.000	64.20	25.14
	505766	TMKURANGA 33.000	87.74	29.17
	505785	TPEMBAMNAZI 33.000	51.00	16.76
	505786	TSINOTAN 33.000	122.40	40.23
	509840	TZEGERENI 33.000	122.40	40.23
	509844	TDUNDANI 33.000	102.00	33.53
	Total		**985.64**	**335.26**
DAR ES SALAAM	50106	TLUGURUNI 33.000	51.03	18.52
	503414	TKUASINI 33.000	21.69	7.87
	503424	MBAGALA 33.000	30.62	11.11
	503651	TWAZO _1B1 132.00	31.90	11.58
	505321	TUBU110_3B1 33.000	31.90	11.58
	505391	TILALA _3B1 33.000	76.55	27.78
	505392	TILALA _3B2 33.000	76.55	27.78
	505461	TKIPAWA_3B1 33.000	76.55	27.78
	505462	TKIPAWA_3B2 33.000	76.55	27.78
	505482	TKUNDUC_3B2 33.000	63.79	23.15
	505511	TMKUMBU_3B1 33.000	76.55	27.78
	505571	TNCC _3B1 33.000	35.09	12.73
	505572	TNCC _3B2 33.000	35.09	12.79
	505732	TFZII_33B1 33.000	59.96	21.76
	505733	TMBGL_33B1 33.000	30.62	11.11
	505734	DEGE 33.000	15.95	5.79
	505772	TKURASINI 33.000	21.69	7.87
	505773	TDEGE 33.000	15.95	5.79
	505796	TKIVULE 33.000	25.52	9.26
	505836	TRUGURUNI 33.000	38.27	13.89
	509850	TMABIBO 33.000	63.79	23.15
	509879	TUNUNIO 33.000	38.27	13.89
	Total		**993.88**	**360.74**
DODOMA	505021	TDODOMA_3B1 33.000	143.55	66.62
	505701	TKONDOA_3B1 33.000	9.14	3.88
	505701	TKONDOA_3B1 33.000	3.14	3.88
	509901	MTERA33 33.000	5.98	1.26
	Total		**161.81**	**75.64**

Area	Bus Number	Bus Name	MW	MVAr
EXPORT	324001	K_ISINYA 400.00	16.00	8.00
	502058	TNALONDE 330.00	200.00	60.00
	Total		**216.00**	**68.00**
GEITA	505746	33KV-GEITA 33.000	51.03	24.72
	505774	TGEITA 33.000	51.03	24.74
	505775	TBUKOMBE 33.000	25.52	12.36
	Total		**127.59**	**61.82**
IRINGA	505031	TIRINGA_3B1 33.000	38.37	12.61
	505042	TKISADA 33.000	25.33	8.32
	505251	TMUFIND_3B1 33.000	6.52	2.14
	506251	TMUFIND_7B1 11.000	6.52	2.14
	Total		**76.74**	**25.21**
KAGERA	501124	TKABANGA 33.000	16.58	6.04
	505747	33KV-NYAKA 33.000	12.44	4.51
	505767	TKIBETA 33.000	20.73	7.52
	509012	TBENAKO 33.000	4.15	1.50
	509017	TKYAKA 33.000	29.02	10.53
	Total		**82.92**	**30.10**
KATAVI	505750	33KV-INYONG 33.000	12.34	4.48
	505751	33KV-KATAVI 33.000	49.36	17.40
	Total		**61.70**	**21.88**
KIGOMA	502010	TKIGOMA 33.000	49.36	16.22
	505753	33KV-NGURUK 33.000	12.34	4.06
	Total		**61.70**	**61.70**
KILIMANJARO	505441	TKIA _3B1 33.000	8.26	2.71
	505442	TKIA _3B2 33.000	8.26	2.71
	505471	TKIYUNG_3B1 33.000	30.90	10.16
	505601	TSAME _3B1 33.000	8.18	2.17
	505712	TMAKUYU_3B2 33.000	13.08	4.30
	505731	TNYMHYD_3B1 33.000	4.91	1.61
	509862	TROMBO 33.000	8.99	2.96
	Total		**82.58**	**26.62**
LINDI	501111	TSOMNAGA 400.00	12.60	4.14
	503362	TMAHUMBIKA 132.00	9.45	3.11
	505758	TMAHUMBIKA 33.000	9.45	3.11
	Total		**31.50**	**10.36**
LNG	505837	TLNG 33.000	75.60	35.78
	Total		**75.60**	**35.78**
MANYARA	505721	TMBULU _3B1 33.000	6.59	3.14

Area	Bus Number	Bus Name	MW	MVAr
	505824	TBABATI 33.000	56.34	16.55
		Total	**62.93**	**19.69**
MARA	505362	TBUNDA _3B2 33.000	13.00	4.20
	505561	TMUSOMA_3B1 33.000	16.86	8.83
	505581	TNYAMON_3B1 33.000	37.34	10.89
	505691	TKIBARA_3B1 33.000	3.37	1.18
		Total	**70.57**	**25.10**
MBEYA	505040	TIGANJO 33.000	40.35	13.26
	505051	TMBEYA _3B1 33.000	67.25	22.10
	505784	TCHUNYA 33.000	26.90	8.84
		Total	**134.50**	**44.20**
MOROGORO	505151	TKIDATH_3B1 33.000	17.48	5.75
	505171	TKIHANH_3B1 33.000	5.83	1.92
	505232	TMOROGO_3B2 33.000	23.31	7.66
	505783	TDUMILA 33.000	11.65	3.83
	505846	TMAHENGE 33.000	22.14	7.28
	509831	TNWMORG 33.000	29.14	9.58
	509837	TIFAKARA 33.000	6.99	2.30
		Total	**116.54**	**38.32**
MTWARA	503364	TMTWARA 132.00	58.65	25.89
	505760	TMTWARA 33.000	28.76	8.93
	509877	TMASASI 33.000	15.04	4.94
	505777	TOFF DANGOTE	40.00	0.00
		Total	**142.45**	**39.76**
MWANZA	501017	TNYANZAGA_1111.000	19.03	6.26
	505201	TMABUKI_3B1 33.000	12.69	4.17
	505261	TMWANZA_3B1 33.000	65.22	15.85
	507086	TUSAGARA 33.000	41.87	13.76
	509869	TUKEREWE 33.000	6.08	1.67
		Total	**144.89**	**41.71**
NJOMBE	505221	TMKAMBA_3B1 33.000	17.13	5.63
	505782	TNJOMBE 33.000	17.13	5.63
		Total	**34.26**	**11.26**
RUKWA	505743	TSUMB_3B1 33.000	42.01	13.81
		Total	**42.01**	**13.81**
RUVUMA	505736	TMADABA_3B1 33.000	9.90	3.25
	505737	TSONGEA_3B1 33.000	33.01	10.85
	505781	TMBINGA 33.000	6.60	2.17
	509875	TTUNDURU 33.000	16.50	5.42

Area	Bus Number	Bus Name	MW	MVAr
	Total		**66.01**	**21.69**
SGR	502030	TGODEGODE 25.000	6.56	3.21
	503021	TMKATA 25.000	6.56	3.21
	506072	TKILOSA 25.000	6.56	3.21
	506079	TMSAGALI 25.000	6.56	3.21
	506084	TIHUMWA 25.000	6.56	3.21
	507013	TPS1 25.000	6.56	3.21
	507017	TPS2 25.000	6.56	3.21
	507022	TPS3 25.000	6.56	3.21
	507027	TPS4 25.000	6.56	3.21
	507031	TPS5 25.000	6.56	3.21
	507050	TKIDUGALO 25.000	6.56	3.21
	507055	TKIDUGALO 25.000	6.56	3.21
	507059	RUVU 25.000	6.56	3.21
	507062	PUGU-SGR 25.000	6.56	3.21
	509833	TKINTINKU 25.000	6.56	3.21
	509922	TSALANDA 25.000	6.56	3.21
	509923	TITIGI 25.000	6.56	3.21
	509925	TKIGWE 25.000	6.56	3.21
	509926	TKAZIKAZI 25.000	6.56	3.21
	509927	TMALONGWE 25.000	6.56	3.21
	509928	TNYAHUA 25.000	6.56	3.21
	509929	TNDEVELWA 25.000	6.56	3.21
	509930	TTPS18 25.000	6.56	3.21
	509931	TTPS19 25.000	6.56	3.21
	509932	TTPS20 25.000	6.56	5.00
	Total		**164.03**	**82.04**
SHINYANGA	505111	TBULYAN_3B1 33.000	39.88	26.22
	505121	TBUZWAG_3B1 33.000	37.10	12.19
	505780	TKISHAPU 33.000	3.71	1.22
	505850	TSHINYANGA 33.000	64.92	21.34
	506722	BULYANHULU 10.000	39.88	26.22
	Total		**185.49**	**87.19**
SIMIYU	509884	TSIMIYU 33.000	30.85	10.14
	Total		**30.85**	**10.14**
SINGIDA	505081	TSINGID_3B1 33.000	29.76	9.78
	505779	TMANYAONI 33.000	12.75	4.19
	Total		**42.51**	**13.97**
SONGWE	505038	TTUNDUMA 33.000	61.69	20.28

Area	Bus Number	Bus Name	MW	MVAr
	Total		61.69	20.28
TABORA	505621	TTABORA_3B1 33.000	22.95	8.33
	505749	33KV-IPOLE 33.000	4.59	1.67
	505752	33KV-URAMBO 33.000	5.16	1.87
	509903	TLUSU 33.000	24.67	8.95
	Total		57.37	20.82
TANGA	501014	33-NEW TANGA33.000	67.82	24.64
	503421	TKANGE _1B1 132.00	41.74	15.15
	505381	THALEHY_3B1 33.000	7.83	2.84
	505421	TKANGE _3B1 33.000	13.04	4.73
	505432	TKASIGA_3B2 33.000	13.04	4.73
	505531	TMAWENI_3B1 33.000	41.74	15.15
	505631	TTANGA _3B1 33.000	26.08	9.47
	505771	TSEGERA 33.000	23.48	8.52
	509860	33KV-LUSHOTO33.000	5.22	1.82
	509864	TMKATA_3B 33.000	13.04	4.73
	509866	TKILINDI 33.000	7.83	2.84
	Total		260.86	94.62
ZANZIBAR	503661	TZANZI1_1B1 132.00	21.08	7.65
	503671	TZANZI2_1B1 132.00	84.32	30.60
	504022	TZANZIBAR 132.00	105.39	38.25
	505443	TPEMBA 33.000	35.17	12.76
	Total		245.96	89.26
	Grand Total		4,984.81	1,863.43

Appendix-Trans- 2: Detailed Grid substation Demand for Medium Term (2029-2038)

Area	Bus Number	Bus Name	MW	MVAr
ARUSHA	502390	TKARATU 220.00	34.12	12.96
	505281	TNJIRO _3B1 33.000	20.00	7.67
	505282	TNJIRO _3B2 33.000	30.00	12.60
	505735	TLEMUGUR_3B233.000	45.49	18.96
	505836	TUNGALIMITED33.000	20.47	6.20
	505837	TSAKINA 33.000	20.47	6.80
	505838	TMONDULI 33.000	5.68	1.25
	505839	TLONGIDO 33.000	5.69	1.25
	505840	TMAKUYUNI 33.000	6.82	2.12
	505841	TNGORONGORO 33.000	5.69	1.56
	505842	TMERERANI 33.000	27.29	7.96
	505681	TKARATU_3B1 33.000	3.00	1.25
	505855	TKARATU 33.000	3.00	1.23
	Total		**227.72**	**81.81**
PWANI	501012	220-MKURANGA220.00	220	56.86
	504049	33-CHALINZE 33.000	49	18.96
	504062	33-CHALINZE 33.000	49	17.93
	505552	TMLANDI_3B2 33.000	70.96	29.82
	505765	TBAGAMOYO 33.000	212.08	92.96
	505766	TMKURANGA 33.000	96.91	36.86
	505785	TPEMBAMNAZI 33.000	70.69	28.28
	505786	TSINOTAN 33.000	113.11	48.96
	505843	TKAMAKA 33.000	113.11	48.96
	505844	TELSEWEDY 33.000	98.97	42.97
	505845	TKIBITI 33.000	28.28	11.96
	509840	TZEGERENI 33.000	169.66	74.86
	509844	TDUNDANI 33.000	150.38	42.86
	Total		**1442.15**	**552.24**
DAR ES SALAAM	503414	TKUASINI 33.000	28.62	7.96
	503424	MBAGALA 33.000	40	16.98
	503651	TWAZO _1B1 132.00	43.1	16.96
	504048	TLUGURUNI 33.000	68.97	28.96
	505321	TUBU110_3B1 33.000	43.1	16.96
	505391	TILALA _3B1 33.000	103.1	35.96
	505392	TILALA _3B2 33.000	103.63	36.82
	505461	TKIPAWA_3B1 33.000	103.92	38.29
	505462	TKIPAWA_3B2 33.000	103.92	36.21
	505482	TKUNDUC_3B2 33.000	86.21	31.86

Area	Bus Number	Bus Name	MW	MVAr
	505511	TMKUMBU_3B1 33.000	103.45	36.35
	505571	TNCC _3B1 33.000	47	17.18
	505572	TNCC _3B2 33.000	47.43	18.18
	505732	TFZII_33B1 33.000	81.03	30.21
	505733	TMBGL_33B1 33.000	42.76	11.89
	505734	DEGE 33.000	20	6.96
	505772	TKURASINI 33.000	30	12.67
	505773	TDEGE 33.000	23.1	9.6
	505799	TKIVULE 33.000	34.48	13.68
	505847	TBUGURUNI 33.000	52.72	19.88
	505848	TMASAKI 33.000	17.24	6.65
	505849	TKAWE 33.000	17.24	6.65
	509850	TMABIBO 33.000	86.21	32
	509879	TUNUNIO 33.000	51.72	18.87
	Total		**1378.95**	**507.73**
DODOMA	505021	TDODOMA_3B1 33.000	64.56	17.92
	505701	TKONDOA_3B1 33.000	0.214	0.052
	505827	TMSALATO 33.000	44.86	14.26
	505828	TIHUMWA 33.000	44.86	14.96
	505829	TKIKOMBO 33.000	17.94	5.98
	505830	TKONGWA 33.000	11.22	3.68
	505832	TJAMATINI 33.000	11.22	3.96
	505835	TCHEMBA 33.000	11.22	3.45
	505850	TMPWAPWA 33.000	4.49	1.25
	505851	TKONDOA 33.000	7	3.67
	506701	TKONDOA_7B1 11.000	10	1.23
	Total		**227.58**	**70.41**
EXPORT	324001	K_ISINYA 400.00	12	5.46
	501120	TKASUMULU 400.00	50	20
	501124	TKALA 400.00	150	50
	501125	TMOZAMBIQ 400.00	50	30
	502058	TNAKONDE 330.00	200	50
	Total		**462.00**	**155.46**
GEITA	505746	33KV-GEITA 33.000	63	14.2
	505774	TGEITA 33.000	70	19.86
	505775	TBUKOMBE 33.000	44.21	13.94
	Total		177.21	48
IRINGA	505031	TIRINGA_3B1 33.000	19	5.9
	505032	TIRINGA_3B2 33.000	19.3	5.02

Area	Bus Number	Bus Name	MW	MVAr
	505042	TKISADA 33.000	31.91	8.86
	505251	TMUFIND_3B1 33.000	18.08	6.96
	505826	TKILOLO 33.000	8.51	2.24
	Total		**96.80**	**28.98**
KAGERA	502407	TKABANGA 220.00	22.99	6.65
	505715	TKAGERA 33.000	20	9.6
	505747	33KV-NYAKA 33.000	17.24	5.64
	505767	TKIBETA 33.000	28.73	3.97
	505825	TKARAGWE 33.000	5.75	1.16
	509012	TBENAKO 33.000	9.19	3.23
	509017	TKYAKA 33.000	11	4.96
	Total		**114.90**	**35.21**
KATAVI	505750	33KV-INYONG 33.000	17.1	3.96
	505751	33KV-KATAVI 33.000	68.41	18.87
	Total		85.51	22.83
KIGOMA	502010	TKIGOMA 33.000	47.03	16.53
	505753	33KV-NGURUK 33.000	17.1	6.23
	505823	TKASULU 33.000	12.83	4.39
	505824	TKIBONDO 33.000	8.55	2.68
	Total		**85.51**	**29.83**
KILIMANJARO	505441	TKIA _3B1 33.000	22.89	7.6
	505471	TKIYUNG_3B1 33.000	42.83	14.28
	505601	TSAME _3B1 33.000	11.33	3.45
	505712	TMAKUYU_3B2 33.000	18.13	5.64
	505731	TNYMHYD_3B1 33.000	6.8	1.96
	509862	TROMBO 33.000	12.46	3.97
	Total		**114.44**	**36.90**
LINDI	501111	TSOMNAGA 400.00	17.47	13.95
	505758	TMAHUMBIKA 33.000	15	1.25
	505821	TRUANGWA 33.000	10.92	9.68
	505822	TNACHIGWEA 33.000	2.18	0.25
	509907	TMAHUMBIKA 33.000	10	5.01
	Total		**55.57**	**30.14**
LNG	502408	TLNG 220.00	229.08	101.23
	Total		**229.08**	**101.23**
MANYARA	505721	TMBULU _3B1 33.000	8	1
	505831	TKITETO 33.000	8.72	2.94
	505833	THANANG 33.000	4.36	1.2
	505834	TSIMANJIRO 33.000	17.44	5.43

Area	Bus Number	Bus Name	MW	MVAr
	505853	TBABATI 33.000	43.61	14.95
	505854	TMBULU 33.000	5	2.96
	Total		**87.13**	**28.48**
MARA	505362	TBUNDA _3B2 33.000	34.05	8.21
	505561	TMUSOMA_3B1 33.000	32.76	7.96
	505581	TNYAMON_3B1 33.000	59.56	14.87
	505691	TKIBARA_3B1 33.000	7.45	1.16
	505818	TRORYA 33.000	7.45	1.46
	505820	TSERENGETI 33.000	7.45	1.46
	Total		**148.72**	**35.12**
MBEYA	505040	TIGANJO 33.000	52.2	17.86
	505051	TMBEYA _3B1 33.000	37.28	13.15
	505791	TKASUMULU 33.000	18.64	6.48
	505801	TCHUNYA 33.000	35.42	12.96
	505815	TCEMENT 33.000	22.37	7.6
	505816	TIYUNGA 33.000	11.19	3.9
	505817	TMBALALI 33.000	9.32	3.34
	Total		**186.42**	**65.29**
MOROGORO	505151	TKIDATH_3B1 33.000	24.18	11.98
	505171	TKIHANH_3B1 33.000	8.06	4.15
	505232	TMOROGO_3B2 33.000	22.62	12.92
	505783	TDUMILA 33.000	16.15	5.45
	505813	TGAIRO 33.000	8.06	3.25
	505814	TMVUHA 33.000	9.67	4.25
	505846	TMAHENGE 33.000	27.4	12.25
	509831	TNWMORG 33.000	36.54	11.96
	509837	TIFAKARA 33.000	9.67	4.96
	505714	TTURIANI 33.000	24.23	7.6
	Total		**186.58**	**78.77**
MTWARA	503364	TMTWARA 132.00	41.69	14.22
	505777	TMTWARA 132.00	125.06	39.82
	505812	TNEWALA 33.000	20.84	6.98
	509877	TMASASI 33.000	20.84	6.42
	Total		**208.43**	**67.44**
MWANZA	501017	TNYANZAGA_1111.000	24	6.96
	505201	TMABUKI_3B1 33.000	17.59	5.5
	505261	TMWANZA_3B1 33.000	20	7.69
	505713	TBUGOGWA 33.000	18	7.6
	505809	TSABASABA 33.000	17.59	4.99

Area	Bus Number	Bus Name	MW	MVAr
	505810	TMWANZASOUTH33.000	17.59	5.214
	505811	TMAGU 33.000	8.79	2.8
	507086	TUSAGARA 33.000	43.97	6.98
	509869	TUKEREWE 33.000	8.79	2.5
	509881	TNYANZAGA 33.000	2.33	1.12
	Total		**178.65**	**51.35**
NJOMBE	505221	TMKAMBA_3B1 33.000	19	7.62
	505782	TNJOMBE 33.000	19	8.1
	505807	TLUDEW 33.000	7.12	2.89
	505808	TRUMAKALI 33.000	2.37	1
	Total		**47.49**	**19.61**
RUKWA	505743	TSUMB_3B1 33.000	46.59	16.28
	505806	TKALA 33.000	11.65	3.56
	Total		**58.24**	**19.84**
RUVUMA	505736	TMADABA_3B1 33.000	13.73	3.66
	505737	TSONGEA_3B1 33.000	36.6	11.24
	505781	TMBINGA 33.000	9.15	2.43
	505805	TNAMTUMBO 33.000	9.15	2.23
	509875	TTUNDURU 33.000	22.88	6.96
	Total		**91.51**	**26.52**
SGR	501113	TMTWARA 400.00	35.44	16.28
	501114	TSAME 400.00	35.44	16.64
	501118	TBUNDA 400.00	35.44	16.64
	502030	TGODEGODE 25.000	7.09	3.96
	502356	TLUDEWA 220.00	35.44	16.64
	502994	TLEMUGUR_2B1220.00	35.44	16.64
	502996	TMADABA_2B1 220.00	35.44	16.64
	502997	TSONGEA_2B1 220.00	35.44	16.64
	503021	TMKATA 25.000	7.09	3.96
	506072	TKILOSA 25.000	7.09	3.96
	506079	TMSAGALI 25.000	7.09	3.96
	506084	TIHUMWA 25.000	7.09	3.96
	507013	TPS1 25.000	7.09	3.96
	507017	TPS2 25.000	7.09	3.96
	507022	TPS3 25.000	7.09	3.96
	507027	TPS4 25.000	7.09	3.96
	507031	TPS5 25.000	7.09	3.96
	507050	TKNGOLWIRA 25.000	7.09	3.96
	507055	TKIDUGALO 25.000	7.09	3.96

Area	Bus Number	Bus Name	MW	MVAr
	507059	RUVU 25.000	7.09	3.96
	507062	PUGU-SGR 25.000	7.09	3.96
	507066	220-TANGA 220.00	35.44	16.44
	509833	TKINTINKU 25.000	7.09	3.96
	509874	TTUNDURU 220.00	35.44	16.64
	509876	TMASASI 220.00	35.44	16.64
	509922	TSALANDA 25.000	7.09	3.96
	509923	TITIGI 25.000	7.09	3.96
	509925	TKIGWE 25.000	7.09	3.96
	509926	TKAZIKAZI 25.000	7.09	3.96
	509927	TMALONGWE 25.000	7.09	3.96
	509928	TNYAHUA 25.000	7.09	3.96
	509929	TNDEVELWA 25.000	7.09	3.96
	509930	TTPS18 25.000	7.09	3.96
	509931	TTPS19 25.000	7.09	3.96
	509932	TTPS20 25.000	7.09	3.96
	509933	T-K_TPS1 25.000	7.09	3.96
	509934	T-K_TPS2 25.000	7.09	3.96
	509935	T-K_TPS3 25.000	7.09	3.96
	509936	T-K_TPS4 25.000	7.09	3.96
	509937	T-K_TPS5 25.000	7.09	3.96
	509938	T-K_TPS6 25.000	7.09	3.96
	509939	T-K_TPS7 25.000	7.09	3.96
	509940	T-K_TPS8 25.000	7.09	3.96
	509941	T-B_TPS1 25.000	7.09	3.96
	509942	T-B_TPS2 25.000	7.09	3.96
	509943	T-B_TPS3 25.000	7.09	3.96
	Total		**609.64**	**308.40**
SHINYANGA	505111	TBULYAN_3B1 33.000	40	6.89
	505121	TBUZWAG_3B1 33.000	51.42	14.21
	505780	TKISHAPU 33.000	12.86	3.46
	505852	TSHINYANGA 33.000	102.85	30.25
	506722	BULYANHULU 10.000	50.99	18.46
	Total		**258.12**	**73.27**
SIMIYU	505804	TMEATU 33.000	8.55	4.15
	509884	TSIMIYU 33.000	34.21	16.84
	Total		**42.76**	**20.99**
SINGIDA	505081	TSINGID_3B1 33.000	48.3	24.86
	505779	TMANYAONI 33.000	11.78	7.21

Area	Bus Number	Bus Name	MW	MVAr
	505802	TIRAMBA 33.000	4.71	2.5
	505803	TMKALAMA 33.000	4.12	2.88
	Total		**68.91**	**37.45**
SONGWE	505038	TTUNDUMA 33.000	41.05	12.86
	505784	TCHUNYA 33.000	44.47	14.88
	Total		**85.52**	**27.74**
TABORA	505501	TLUSU _3B1 33.000	17	3.51
	505621	TTABORA_3B1 33.000	31.81	7.96
	505749	33KV-IPOLE 33.000	6.36	1.391
	505752	33KV-URAMBO 33.000	7.16	1.606
	509903	TLUSU 33.000	17	5.86
	Total		**79.33**	**20.33**
TANGA	501014	33-NEW TANGA33.000	94	32.86
	503421	TKANGE _1B1 132.00	48.81	17.96
	505381	THALEHY_3B1 33.000	10.85	3.25
	505421	TKANGE _3B1 33.000	18.08	6.42
	505432	TKASIGA_3B2 33.000	18.08	5.92
	505531	TMAWENI_3B1 33.000	57.85	21.24
	505631	TTANGA _3B1 33.000	36.16	13.88
	505771	TSEGERA 33.000	36.16	12.96
	505800	THANDENI 33.000	9.04	3.25
	509860	33KV-LUSHOTO33.000	3.62	1.15
	509864	TMKATA_3B 33.000	18.08	5.96
	509866	TKILINDI 33.000	10.85	3.96
	Total		**361.58**	**128.81**
ZANZIBAR	502396	TZANZIBAR 220.00	177.86	42.64
	503661	TZANZI1_1B1 132.00	25.00	11.96
	503671	TZANZI2_1B1 132.00	90.00	21.96
	505443	TPEMBA 33.000	48.74	14.96
	Total		**341.60**	**91.52**
	Grand Total		**7,738.05**	**2,801.70**

Appendix-Trans- 3: Detailed Grid substation Demand for Long Term (2039-2050)

Area	Bus Number	Bus Name	MW	MVAr
ARUSHA	505281	TNJIRO _3B1 33.000	37.20	16.53
	505282	TNJIRO _3B2 33.000	30.00	12.65
	505735	TLEMUGUR_3B233.000	54.00	19.10
	505836	TUNGALIMITED33.000	24.72	7.21
	505837	TSAKINA 33.000	24.72	7.21
	505838	TMONDULI 33.000	6.80	2.00
	505839	TLONGIDO 33.000	6.80	2.20
	505840	TMAKUYUNI 33.000	8.24	2.45
	505841	TNGORONGORO 33.000	6.80	2.00
	505842	TMERERANI 33.000	32.96	12.77
	505856	TKARATU 33.000	41.20	13.68
	Total		**273.44**	**97.80**
PWANI	501012	220-MKURANGA220.00	200.00	76.00
	502169	TBAGAMOYO 220.00	100.00	19.96
	504049	33-CHALINZE 33.000	54.36	18.00
	504062	33-CHALINZE 33.000	62.80	-23.66
	505552	TMLANDI_3B2 33.000	85.40	36.16
	505765	TBAGAMOYO 33.000	256.20	100.87
	505766	TMKURANGA 33.000	134.00	59.00
	505785	TPEMBAMNAZI 33.000	85.40	38.00
	505786	TSINOTAN 33.000	136.85	60.99
	505843	TKAMAKA 33.000	136.58	65.34
	505844	TELSEWEDY 33.000	119.51	57.11
	505845	TKIBITI 33.000	34.14	15.79
	505866	TRUFIJI 33.000	34.14	12.34
	505867	TKISARAWE 33.000	42.68	18.56
	509840	TZEGERENI 33.000	204.87	72.00
	509844	TDUNDANI 33.000	128.60	58.00
	Total		**1815.53**	**684.46**
DAR ES SALAM	50106	TLUGURUNI 33.000	83.28	34.21
	503414	TKUASINI 33.000	30.00	9.86
	503424	MBAGALA 33.000	59.00	26.34
	503651	TWAZO _1B1 132.00	52.00	21.89
	505321	TUBU110_3B1 33.000	52.05	21.45
	505391	TILALA _3B1 33.000	149.83	56.07
	505392	TILALA _3B2 33.000	100.00	46.07
	505461	TKIPAWA_3B1 33.000	149.83	56.72
	505462	TKIPAWA_3B2 33.000	100.00	36.72
	505482	TKUNDUC_3B2 33.000	104.10	38.78
	505511	TMKUMBU_3B1 33.000	124.91	46.23

Area	Bus Number	Bus Name	MW	MVAr
	505571	TNCC _3B1 33.000	64.50	24.11
	505572	TNCC _3B2 33.000	50.00	24.11
	505732	TFZII_33B1 33.000	97.85	35.45
	505733	TMBGL_33B1 33.000	40.00	12.00
	505734	DEGE 33.000	14.61	7.22
	505772	TKURASINI 33.000	22.05	16.00
	505773	TDEGE 33.000	30.00	12.00
	505799	TKIVULE 33.000	41.64	13.98
	505847	TBUGURUNI 33.000	62.46	23.76
	505848	TMASAKI 33.000	20.82	9.67
	505849	TKAWE 33.000	20.82	8.34
	509850	TMABIBO 33.000	104.10	38.56
	509879	TUNUNIO 33.000	70.46	23.12
	Total		**1644.31**	**642.66**
DODOMA	505021	TDODOMA_3B1 33.000	73.13	22.00
	505701	TKONDOA_3B1 33.000	0.21	0.05
	505827	TMSALATO 33.000	54.17	15.67
	505828	TIHUMWA 33.000	54.17	15.67
	505829	TKIKOMBO 33.000	14.64	8.34
	505830	TKONGWA 33.000	13.54	4.34
	505832	TJAMATINI 33.000	13.54	4.26
	505835	TCHEMBA 33.000	13.54	6.45
	505850	TMPWAPWA 33.000	5.42	1.53
	505851	TKONDOA 33.000	11.60	12.11
	506701	TKONDOA_7B1 11.000	10.00	1.45
	Total		**263.96**	**91.87**
EXPORT	324001	K_ISINYA 400.00	20.00	0.00
	501120	TKASUMULU 400.00	100.00	22.00
	501124	TKALA 400.00	180.00	50.00
	501125	TMOZAMBIQ 400.00	100.00	30.00
	502058	TNAKONDE 330.00	200.00	50.00
	Total		**600.00**	**152.00**
GEITA	505746	33KV-GEITA 33.000	90.00	28.67
	505774	TGEITA 33.000	57.74	18.67
	505775	TBUKOMBE 33.000	42.71	13.83
	505857	TNYAMW'ALE 33.000	21.35	6.35
	Total		**211.80**	**67.52**
IRINGA	505031	TIRINGA_3B1 33.000	27.80	7.65
	505032	TIRINGA_3B2 33.000	30.00	7.65
	505042	TKISADA 33.000	38.54	10.54
	505251	TMUFIND_3B1 33.000	21.84	6.45

Area	Bus Number	Bus Name	MW	MVAr
	505826	TKILOLO 33.000	10.28	2.88
	Total		**128.46**	**35.17**
KAGERA	502407	TKABANGA 220.00	27.76	9.46
	505715	TKAGERA 33.000	20.00	9.60
	505747	33KV-NYAKA 33.000	20.82	8.76
	505767	TKIBETA 33.000	26.37	8.76
	505825	TKARAGWE 33.000	6.94	2.12
	505858	TKYERWA 33.000	4.16	1.23
	505859	TMULEBA 33.000	8.33	3.72
	509012	TBENAKO 33.000	11.10	4.12
	509017	TKYAKA 33.000	34.70	14.96
	Total		**160.18**	**62.73**
KATAVI	505750	33KV-INYONG 33.000	20.65	6.56
	505751	33KV-KATAVI 33.000	72.28	26.34
	505860	TTANGANYIKA 33.000	10.33	4.34
	Total		**103.26**	**37.24**
KIGOMA	335862	TUVINZA 33.000	5.16	1.23
	502010	TKIGOMA 33.000	46.47	16.33
	505753	33KV-NGURUK 33.000	20.65	7.27
	505823	TKASULU 33.000	5.15	2.12
	505824	TKIBONDO 33.000	10.33	4.87
	505861	TKAKONKO 33.000	5.16	2.45
	505862	TBUHIGWE 33.000	10.33	3.74
	Total		**103.25**	**38.01**
KILIMANJARO	505441	TKIA _3B1 33.000	27.64	8.14
	505471	TKIYUNG_3B1 33.000	51.72	16.56
	505601	TSAME _3B1 33.000	13.68	4.32
	505712	TMAKUYU_3B2 33.000	21.89	6.22
	505731	TNYMHYD_3B1 33.000	8.21	2.43
	509862	TROMBO 33.000	15.05	4.73
	Total		**138.19**	**42.40**
LINDI	501111	TSOMNAGA 400.00	21.09	9.87
	505062	TLIWALE 33.000	2.64	1.08
	505758	TMAHUMBIKA 33.000	10.14	5.00
	505821	TRUANGWA 33.000	10.55	4.69
	505822	TNACHIGWEA 33.000	2.64	1.12
	509907	TMAHUMBIKA 33.000	5.00	2.15
	Total		**52.06**	**23.91**
LNG	502408	TLNG 220.00	297.50	100.00
	Total		**297.50**	**100.00**

Area	Bus Number	Bus Name	MW	MVAr
MANYARA	505831	TKITETO 33.000	10.53	4.34
	505833	THANANG 33.000	5.27	1.20
	505834	TSIMANJIRO 33.000	21.06	8.64
	505853	TBABATI 33.000	52.66	22.00
	505854	TMBULU 33.000	15.80	8.21
		Total	**105.32**	**44.39**
MARA	505362	TBUNDA _3B2 33.000	41.36	17.12
	505561	TMUSOMA_3B1 33.000	39.56	14.06
	505581	TNYAMON_3B1 33.000	50.73	15.12
	505691	TKIBARA_3B1 33.000	8.99	3.11
	505818	TRORYA 33.000	16.18	8.23
	505820	TSERENGETI 33.000	5.99	-2.11
		Total	**162.81**	**55.53**
MBEYA	505040	TIGANJO 33.000	60.78	22.34
	505051	TMBEYA _3B1 33.000	45.02	15.34
	505791	TKASUMULU 33.000	18.49	8.63
	505791	TKASUMULU 33.000	9.00	2.86
	505801	TCHUNYA 33.000	40.52	15.63
	505815	TCEMENT 33.000	27.01	12.45
	505816	TIYUNGA 33.000	13.51	5.09
	505817	TMBALALI 33.000	11.26	4.06
		Total	**225.59**	**86.40**
MOROGORO	505151	TKIDATH_3B1 33.000	29.26	13.45
	505171	TKIHANH_3B1 33.000	9.75	4.46
	505232	TMOROGO_3B2 33.000	27.31	13.76
	505783	TDUMILA 33.000	19.51	6.45
	505813	TGAIRO 33.000	9.75	3.00
	505814	TMVUHA 33.000	11.70	6.13
	505846	TMAHENGE 33.000	31.21	13.89
	505864	TMALINYI 33.000	3.90	1.67
	509831	TNWMORG 33.000	40.96	21.96
	509837	TIFAKARA 33.000	11.70	5.22
	505714	TTURIANI 33.000	25.00	7.60
		Total	**220.05**	**97.59**
MTWARA	503364	TMTWARA 132.00	50.34	14.05
	505777	TMTWARA 132.00	151.01	40.99
	505812	TNEWALA 33.000	12.58	3.11
	505865	TTANDAHIMBA 33.000	12.58	3.11
	509877	TMASASI 33.000	25.17	7.34
		Total	**251.68**	**68.60**
MWANZA	501017	TNYANZAGA_1111.000	25.00	11.00

Area	Bus Number	Bus Name	MW	MVAr
	505201	TMABUKI_3B1 33.000	21.24	8.98
	505261	TMWANZA_3B1 33.000	45.86	12.12
	505713	TBUGOGWA 33.000	20.00	9.60
	505809	TSABASABA 33.000	21.24	7.14
	505810	TMWANZASOUTH33.000	21.24	6.32
	505811	TMAGU 33.000	10.00	3.48
	507086	TUSAGARA 33.000	53.09	16.98
	509869	TUKEREWE 33.000	10.62	2.25
	509881	TNYANZAGA 33.000	17.30	1.98
	Total		**245.59**	**79.85**
NJOMBE	505221	TMKAMBA_3B1 33.000	22.94	8.12
	505782	TNJOMBE 33.000	22.94	9.22
	505807	TLUDEW 33.000	8.04	3.12
	505808	TRUMAKALI 33.000	6.00	2.87
	Total		**59.92**	**23.33**
RUKWA	505743	TSUMB_3B1 33.000	49.22	17.23
	505806	TKALA 33.000	14.06	5.00
	505869	TNKASI 33.000	7.63	1.89
	Total		**70.91**	**24.12**
RUVUMA	505736	TMADABA_3B1 33.000	16.67	5.23
	505737	TSONGEA_3B1 33.000	44.20	14.32
	505781	TMBINGA 33.000	11.05	3.65
	505805	TNAMTUMBO 33.000	11.05	3.67
	509875	TTUNDURU 33.000	27.62	9.87
	Total		**110.59**	**36.74**
SGR	501113	TMTWARA 400.00	46.00	19.96
	501114	TSAME 400.00	46.00	19.96
	501118	TBUNDA 400.00	46.00	19.96
	502030	TGODEGODE 25.000	9.20	4.21
	502152	TKIDATH_2B2 220.00	26.30	12.12
	502171	TKIHANH_2B1 220.00	26.30	12.12
	502356	TLUDEWA 220.00	46.00	19.96
	502361	TMVUHA 220.00	26.30	12.12
	502439	TKISARAWE 220.00	26.30	12.12
	502994	TLEMUGUR_2B1220.00	46.00	19.96
	502996	TMADABA_2B1 220.00	46.00	19.96
	502997	TSONGEA_2B1 220.00	46.00	19.96
	502999	TMBEYA_2B3 220.00	26.30	12.12
	503021	TMKATA 25.000	9.15	4.21
	506072	TKILOSA 25.000	9.20	4.21
	506079	TMSAGALI 25.000	9.20	4.21

Area	Bus Number	Bus Name	MW	MVAr
	506084	TIHUMWA 25.000	9.20	4.21
	507001	TTUNDU_33B1 220.00	26.30	12.12
	507013	TPS1 25.000	9.20	4.21
	507017	TPS2 25.000	9.20	4.21
	507022	TPS3 25.000	9.20	4.21
	507027	TPS4 25.000	9.20	4.21
	507031	TPS5 25.000	9.20	4.21
	507050	TKNGOLWIRA 25.000	9.20	4.21
	507055	TKIDUGALO 25.000	9.20	4.21
	507059	RUVU 25.000	9.20	4.21
	507062	PUGU-SGR 25.000	9.20	4.21
	507066	220-TANGA 220.00	46.00	19.96
	509833	TKINTINKU 25.000	9.20	4.21
	509874	TTUNDURU 220.00	46.00	19.96
	509876	TMASASI 220.00	46.00	19.96
	509922	TSALANDA 25.000	9.20	4.21
	509923	TITIGI 25.000	9.20	4.21
	509925	TKIGWE 25.000	9.20	4.21
	509926	TKAZIKAZI 25.000	9.20	4.21
	509927	TMALONGWE 25.000	9.20	4.21
	509928	TNYAHUA 25.000	9.20	4.21
	509929	TNDEVELWA 25.000	9.20	4.21
	509930	TTPS18 25.000	9.20	4.21
	509931	TTPS19 25.000	9.20	4.21
	509932	TTPS20 25.000	9.20	4.21
	509933	T-K_TPS1 25.000	9.20	4.21
	509934	T-K_TPS2 25.000	9.20	4.21
	509935	T-K_TPS3 25.000	9.20	4.21
	509936	T-K_TPS4 25.000	9.20	4.21
	509937	T-K_TPS5 25.000	9.20	4.21
	509938	T-K_TPS6 25.000	9.20	4.21
	509939	T-K_TPS7 25.000	9.20	4.21
	509940	T-K_TPS8 25.000	9.20	4.21
	509941	T-B_TPS1 25.000	9.20	4.21
	509942	T-B_TPS2 25.000	9.20	4.21
	509943	T-B_TPS3 25.000	9.20	4.21
	Total		**948.95**	**423.88**
SHINYANGA	505111	TBULYAN_3B1 33.000	44.22	18.95
	505121	TBUZWAG_3B1 33.000	62.09	26.72
	505780	TKISHAPU 33.000	15.52	5.28
	505852	TSHINYANGA 33.000	124.49	48.19

Area	Bus Number	Bus Name	MW	MVAr
	506722	BULYANHULU 10.000	60.00	25.00
		Total	**306.32**	**124.14**
SIMIYU	505804	TMEATU 33.000	10.33	5.11
	505868	TMASWA 33.000	11.36	5.68
	509884	TSIMIYU 33.000	29.65	12.45
		Total	**51.34**	**23.24**
SINGIDA	505081	TSINGID_3B1 33.000	46.24	25.65
	505779	TMANYAONI 33.000	14.23	8.12
	505802	TIRAMBA 33.000	5.69	2.98
	505803	TMKALAMA 33.000	4.98	2.13
		Total	**71.14**	**38.88**
SONGWE	505038	TTUNDUMA 33.000	33.04	7.98
	505784	TCHUNYA 33.000	43.37	13.00
	505870	TMBOZI 33.000	15.56	4.56
	505871	TILEJE 33.000	8.26	3.99
	505872	TMOMBA 33.000	5.16	1.06
		Total	**105.39**	**30.59**
TABORA	505501	TLUSU _3B1 33.000	10.00	1.23
	505621	TTABORA_3B1 33.000	34.57	8.46
	505749	33KV-IPOLE 33.000	7.68	1.67
	505752	33KV-URAMBO 33.000	8.64	1.19
	505873	TUYUI 33.000	4.80	1.60
	509903	TLUSU 33.000	30.00	6.14
		Total	**95.69**	**20.29**
TANGA	501014	33-NEW TANGA33.000	113.51	37.22
	503421	TKANGE _1B1 132.00	56.76	21.23
	505381	THALEHY_3B1 33.000	13.10	4.34
	505421	TKANGE _3B1 33.000	21.83	7.23
	505432	TKASIGA_3B2 33.000	21.83	7.87
	505531	TMAWENI_3B1 33.000	69.85	25.92
	505631	TTANGA _3B1 33.000	43.66	15.17
	505771	TSEGERA 33.000	43.66	15.06
	505800	THANDENI 33.000	8.73	2.12
	505874	TMKINGA 33.000	4.37	1.08
	509860	33KV-LUSHOTO33.000	4.37	1.56
	509864	TMKATA_3B 33.000	21.83	7.36
	509866	TKILINDI 33.000	13.10	4.76
		Total	**436.60**	**150.92**
ZANZIBAR	502396	TZANZIBAR 220.00	200.00	40.00
	503661	TZANZI1_1B1 132.00	30.00	18.60
	503671	TZANZI2_1B1 132.00	122.00	24.96

Area	Bus Number	Bus Name	MW	MVAr
	505443	TPEMBA 33.000	58.86	19.96
	Total		**410.86**	**103.52**
	Grand Total		**9,670.69**	**3,507.78**