

Uganda Energy Status Report 2026

Demand, supply, grid, distribution, gaps, least-cost plan, investment and expansion across 135 districts: a spatial analysis with the AICTEM Energy Modelling Engine (PyPSA + GIS)

Final demand 2023: 4,330 GWh | Peak 2040: 4,866 MW | Plan capex 2024–2040: USD 15.6 bn | 26 mapped indicators

Base scenario S0 (least cost) · dataset uganda_2023 · base year 2023 · horizon 2026–2040 · 29 simulations

September 2026

About this report

This report sets out the status of Uganda's electricity system and what it will take to meet the country's needs to 2040. It answers the planning questions of the nine design chapters of the AICTEM Energy Modelling Engine: how much electricity is needed and by whom, what the current system can generate, transmit and distribute, where the gaps are, what the least-cost plan to close them is, what it costs and in what order it should be built. Every figure is produced by the engine from the evidence in its data layers and carries a status: OBSERVED, CALIBRATED, MODELLED or ASSUMED.

Item	Value
Engine	AICTEM Energy Modelling Engine (energy_engine/), PyPSA 1.2 + HiGHS for power-system optimisation, geopandas for GIS
Base scenario	S0 least cost: base demand, no carbon price, no renewable target, 15 % reserve margin, VoLL 10,000 USD/MWh, discount rate 10 %
Horizon	Base year 2023 (metered); planning periods 2026, 2030, 2035 and 2040; annual paths 2023–2040
Geography	135 districts (ADM2) in 4 regions; 17 transmission buses (supply zones) for power flow
Time resolution	25 representative slices per year (4 seasons × 6 diurnal blocks + a 100-hour system peak)
Currency	Constant 2023 US dollars; UGX at 3,775.03 per USD where shown (ERA 2023Q4)
Simulations	29 least-cost plans: the standard scenario set S0–S7 and one-at-a-time sensitivities
Status labels	OBSERVED (metered, registered, published) · CALIBRATED (derived from observed data) · MODELLED (solved model output) · ASSUMED (planning assumption) · NOT_AVAILABLE
Rules	gaps are kept separate and never combined into an index; reliability gaps come from solved dispatch, not assumptions; no scenario is called recommended; every table has a spatial key
Reproduction	python scripts/ingest_external.py; python report/build/collect.py; python report/build/figures.py; python report/build/render_equations.py; node report/build/build_docx.js

Contents

About this report	2
Contents	3
List of figures	9
List of tables.....	14
Executive summary.....	17
The demand and its drivers	17
What the system has	17
The grid and distribution	18
The gaps.....	18
The least-cost plan.....	19
The simulations.....	19
The money	19
Where and when	20
What the evidence is, and is not	20
1 Introduction	22
1.1 Purpose of the report	22
1.2 Uganda in 2023: the planning context.....	22
1.3 How the power sector is organised	23
1.4 The planning questions.....	24
1.5 Scope: what is modelled and what is not	24
1.6 Principles.....	24
1.7 How to read the report.....	25
1.8 Structure of the report	25
1.9 Implications for planning	26
2 Approach and architecture	27
2.1 A planning chain from need to investment	27
2.2 The demand identity.....	27
2.3 The power system in PyPSA.....	28
2.4 The GIS engine	29
2.5 Status labels and their propagation.....	30
2.6 Gates: validation that runs with the model.....	30
2.7 Reproducibility.....	30
2.8 Limitations of the approach.....	31
2.9 Implications for planning	31

3	Data sources, governance and quality.....	32
3.1	An overview of the evidence base.....	32
3.2	Geography.....	33
3.3	Demand and customers.....	35
3.4	Generation.....	36
3.5	Transmission and distribution	37
3.6	Governance and licences	38
3.7	Quality across the evidence base	38
3.8	Known gaps in the data	38
3.9	Implications for planning	39
4	Energy demand.....	40
4.1	What the module produces	40
4.2	The base year: 2023.....	40
4.3	Method	43
4.4	Results: the national demand path.....	45
4.5	The geography of demand.....	56
4.6	Data quality and limitations.....	67
4.7	Implications for planning	67
5	Current generation	68
5.1	The existing fleet.....	68
5.2	What the fleet produced in 2023	72
5.3	Method: least-cost dispatch	74
5.4	Results: the base year	76
5.5	Results: the existing fleet against growing demand.....	79
5.6	The resource beyond the fleet	81
5.7	Data quality and limitations.....	81
5.8	Implications for planning	82
6	Transmission and network gaps	83
6.1	The network.....	83
6.2	Method	86
6.3	Results: loading and congestion	87
6.4	Results: N-1 security	92
6.5	Results: transmission losses.....	94
6.6	Results: coverage	95
6.7	Results: reinforcement	99
6.8	Observed substation loading	101
6.9	Data quality and limitations.....	103

6.10 Implications for planning	103
7 Distribution	104
7.1 The energy waterfall	104
7.2 Losses by utility and territory	105
7.3 Losses by district	107
7.4 The value of reducing losses	109
7.5 Customers, tariffs and cross-subsidies	110
7.6 The reach of the MV network	111
7.7 Substation service areas	115
7.8 Distribution capacity for growth	116
7.9 Data quality and limitations	118
7.10 Implications for planning	118
8 Gap analysis: eight dimensions, never combined	120
8.1 The eight gaps	120
8.2 Why the gaps are never added	120
8.3 G1 Capacity and G2 Energy	120
8.4 G3 Reliability: the gap from a solved model	122
8.5 Zonal balance	124
8.6 G4 Network and G5 Distribution	126
8.7 G6 Access	126
8.8 G7 Sector service	131
8.9 G8 Security and resilience	133
8.10 The gap register	133
8.11 Where the gaps are: spatial statistics	135
8.12 Data quality and limitations	135
8.13 Implications for planning	136
9 The least-cost plan to close the gaps	137
9.1 How the plan is formulated	137
9.2 The candidates	137
9.3 What gets built	139
9.4 Capacity and generation	141
9.5 Cost	143
9.6 Emissions and the renewable share	145
9.7 How the planned system operates	146
9.8 The grid build	147
9.9 The value of firm capacity	150
9.10 The supply–demand balance after the plan	151

9.11 Data quality and limitations.....	151
9.12 Implications for planning	152
10 Simulations: what changes the plan	153
10.1 How to read the simulations	153
10.2 The standard scenario set.....	153
10.3 One-at-a-time sensitivities.....	157
10.4 What is robust and what is not.....	162
10.5 Data quality and limitations.....	162
10.6 Implications for planning	163
11 Investment plan	164
11.1 What is costed	164
11.2 The total.....	165
11.3 When the money is needed.....	166
11.4 Who pays	167
11.5 Where the money goes.....	169
11.6 The cost of each technology	172
11.7 What it does to the cost of electricity	173
11.8 Access investment	174
11.9 The project pipeline.....	175
11.10 Data quality and limitations.....	176
11.11 Implications for planning	176
12 Expansion plan: the year-by-year build-out	178
12.1 From periods to commissioning years.....	178
12.2 The roadmap.....	178
12.3 The system every year	180
12.4 The critical path	185
12.5 Gap-closure milestones	185
12.6 Delivery and spend	186
12.7 The system as it grows.....	186
12.8 Data quality and limitations.....	187
12.9 Implications for planning	188
13 The spatial picture: GIS analysis across the system	189
13.1 The GIS engine	189
13.2 Clustering across all layers.....	190
13.3 The hot-spots and the cold-spots.....	192
13.4 Distance and access	193
13.5 Where the grid is the answer, and where it is not	194

13.6	What the spatial analysis means for delivery	196
13.7	Data quality and limitations.....	196
13.8	Implications for planning	197
14	Equity: who is served and who pays.....	198
14.1	How equity is measured	198
14.2	Where the power is	198
14.3	Who uses the power	199
14.4	Does the plan narrow the gaps?	200
14.5	Who pays	201
14.6	Institutions.....	202
14.7	Data quality and limitations.....	202
14.8	Implications for planning	202
15	Validation: can the results be trusted?.....	203
15.1	The validation framework.....	203
15.2	Results for this report	204
15.3	Calibration against the observed 2023 system.....	207
15.4	What validation does not cover.....	207
15.5	Reproducibility.....	207
15.6	Data quality and limitations.....	208
15.7	Implications for planning	208
16	Using the engine: the web application and planning integration	209
16.1	Architecture	209
16.2	The pages.....	209
16.3	Running a scenario.....	215
16.4	Headless runs.....	216
16.5	Exports and the API.....	216
16.6	Links to government planning systems	216
16.7	Keeping the engine current	218
16.8	Data quality and limitations.....	218
16.9	Implications for planning	218
17	Conclusions and recommendations.....	219
17.1	The status of the system in 2023.....	219
17.2	What is coming	219
17.3	What the plan requires	219
17.4	The risks to the plan.....	220
17.5	What the simulations show	220
17.6	Recommendations.....	221

17.7 A closing remark	222
A Formula compendium	223
A.1 Demand	223
A.2 Generation and dispatch	224
A.3 Transmission	225
A.4 Distribution	225
A.5 Gaps	226
A.6 Least-cost plan	226
A.7 Investment	227
A.8 Expansion	228
A.9 GIS and spatial statistics	228
B Model catalogues and parameters	230
B.1 The network model	230
B.2 The existing fleet	230
B.3 Candidate projects	232
B.4 Scenario parameters of the base scenario	233
B.5 Definitions of the 29 simulations	234
B.6 Engine planning defaults	234
B.7 Status of the main inputs	235
C District tables	237
C.1 Demand by district	237
C.2 Access and institutions by district	242
C.3 Grid, losses and resources by district	247
C.4 Investment by district	252
D Glossary and abbreviations	257
D.1 Abbreviations	257
D.2 Glossary	258
D.3 Status labels	259

List of figures

Figure 3.1: Regions, districts and the 17 supply zones of the power model.....	34
Figure 3.2: Population on the 1 km grid (WorldPop 2020 constrained, aggregated from 100 m)	35
Figure 3.3: Industrial parks (UIA 2024) and mining areas	36
Figure 4.1: Final electricity consumption by segment, 2023 (4,330 GWh metered, carved into segments).....	41
Figure 4.2: System load shape by season and diurnal block, 2023 (metered) and 2040 (projected)	42
Figure 4.3: Load-duration curves, 2023, 2030 and 2040.....	42
Figure 4.4: Tariff classes: share of customers against share of energy, 2023	43
Figure 4.5: Final electricity demand by segment, 2023–2040, base scenario.....	45
Figure 4.6: Growth multiple of each segment's demand, 2040 over 2023	46
Figure 4.7: Segment demand by planning year, GWh (colour on a log scale)	47
Figure 4.8: Large new loads: IERMP step loads (increment over 2024) and project loads	48
Figure 4.9: Household access path and new connections per year, base scenario	49
Figure 4.10: Health-sector electricity demand by facility level, 2023–2040	50
Figure 4.11: Health facilities and their modelled electrification status in 2023	51
Figure 4.12: Education electricity demand by institution type, 2023–2040	52
Figure 4.13: Schools in the EMIS layer by type (21,193 institutions)	53
Figure 4.14: Transport electrification: energy by vehicle type and the electric SGR	54
Figure 4.15: From final consumption to generation requirement: 2023 and 2040	55
Figure 4.16: Peak demand under the low, base and high demand scenarios.....	56
Figure 4.17: Ch.1 - Electricity demand 2023 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations	57
Figure 4.18: Ch.1 - Consumption per person 2023 (kWh / person), by district; right: local Moran (LISA) clusters, 999 permutations	58
Figure 4.19: Ch.1 - Population density (persons / km ²), by district; right: local Moran (LISA) clusters, 999 permutations	59
Figure 4.20: Ch.1 - Commercial facilities (IERMP) (count), by district; right: local Moran (LISA) clusters, 999 permutations	60
Figure 4.21: Ch.1 - Electricity demand 2040 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations	61
Figure 4.22: Ch.1 - Demand growth 2040 / 2023 (multiple), by district; right: local Moran (LISA) clusters, 999 permutations	61
Figure 4.23: The 20 districts with the highest demand in 2040	62
Figure 4.24: Ch.1 - Household demand 2040 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations	63
Figure 4.25: Ch.1 - Industrial demand 2040 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations	64

Figure 4.26: Ch.1 - Health-facility demand 2030 (MWh), by district; right: local Moran (LISA) clusters, 999 permutations	65
Figure 4.27: Ch.1 - School demand 2035 (MWh), by district; right: local Moran (LISA) clusters, 999 permutations	65
Figure 4.28: Final demand by supply zone (transmission bus), 2023 and 2040.....	66
Figure 5.1: Installed and firm capacity by technology, 2023.....	69
Figure 5.2: Existing generating plants by technology and size, 2023	70
Figure 5.3: Generating units by installed capacity, coloured by technology	71
Figure 5.4: Ch.2 - Firm generating capacity 2023 (MW), by district; right: local Moran (LISA) clusters, 999 permutations	72
Figure 5.5: Metered monthly generation of the major plants, 2023	73
Figure 5.6: Observed capacity factor by plant, 2023.....	74
Figure 5.7: Merit order of the existing fleet with the 2023 system peak.....	75
Figure 5.8: Calibration: modelled against metered 2023 generation by plant	76
Figure 5.9: PyPSA least-cost dispatch of the existing fleet over the 25 time slices, 2023.....	78
Figure 5.10: Reservoir state of charge across the 25 slices, 2023 (PyPSA)	78
Figure 5.11: Hydro concentration: share of modelled 2023 generation by plant (Nile cascade in red)	79
Figure 5.12: The existing fleet against each year's demand: generation mix and unserved energy (PyPSA)	80
Figure 5.13: Emissions of the existing fleet as demand grows (no new build)	80
Figure 5.14: Ch.2 - Mean wind speed at 100 m (m/s), by district; right: local Moran (LISA) clusters, 999 permutations	81
Figure 6.1: The transmission network: lines by voltage and status, and transmission substations	84
Figure 6.2: Transmission line length by voltage and status	85
Figure 6.3: Peak corridor loading: 2023 against the 2030 grid-stress test.....	88
Figure 6.4: Corridor loading by time slice, 2030 grid-stress test.....	89
Figure 6.5: Stressed and congested hours by corridor, 2030.....	90
Figure 6.6: Nodal prices by bus, 2030 grid-stress test.....	91
Figure 6.7: Where the grid binds: corridor loading (2030) and N-1 critical corridors (width $\propto$ MW shed)	92
Figure 6.8: Flow-duration curves of the six most-used corridors, 2030 (dashed = rating)	92
Figure 6.9: N-1 screening at the 2030 peak: load shed when each corridor is out (red = critical)	93
Figure 6.10: Modelled transmission losses by corridor, 2023.....	94
Figure 6.11: Population within a given distance of the grid.....	95
Figure 6.12: The 20 districts farthest from the transmission grid	96
Figure 6.13: Ch.3 - Population-weighted distance to transmission (km), by district; right: local Moran (LISA) clusters, 999 permutations	97
Figure 6.14: Coverage gap: population-weighted distance to transmission, with 25 km (dashed) and 50 km (solid) substation buffers.....	98
Figure 6.15: Ch.3 - Population-weighted distance to the MV network (km), by district; right: local Moran (LISA) clusters, 999 permutations.....	99

Figure 6.16: Reinforcement screening 2030: economic MW to add (levelised-cost supply).....	100
Figure 6.17: Candidate generation and storage sites (area $\propto$ potential) and candidate new corridors.....	101
Figure 6.18: Observed 2023 peaks at substations and injection points.....	102
Figure 7.1: The 2023 energy waterfall: from gross generation to collected energy	105
Figure 7.2: Observed 2023 distribution loss rate by utility and territory.....	106
Figure 7.3: Distribution service territories and their observed 2023 loss rates	107
Figure 7.4: Ch.4 - Distribution loss rate (modelled) (%), by district; right: local Moran (LISA) clusters, 999 permutations	108
Figure 7.5: Distribution losses under business-as-usual and the target path, and the value of the reduction	109
Figure 7.6: Tariffs against cost to serve, and the resulting cross-subsidies, 2023	110
Figure 7.7: Revenue by class: collected, uncollected and cost to serve, 2023.....	111
Figure 7.8: Distance from every populated square kilometre to the MV (33/11 kV) network.....	112
Figure 7.9: Population by distance to the MV network	113
Figure 7.10: Ch.4 - MV line density (km / km ²), by district; right: local Moran (LISA) clusters, 999 permutations	114
Figure 7.11: Ch.4 - Distribution transformers per 1,000 households (per 1,000 hh), by district; right: local Moran (LISA) clusters, 999 permutations.....	114
Figure 7.12: Distribution substations, the people they serve, and the transformer network	115
Figure 7.13: The 20 distribution substations serving the most people (red = over-extended).....	116
Figure 7.14: Cumulative distribution capacity required, 2023 to each planning year	117
Figure 7.15: UEDCL 33 kV feeder maximum demand, 2023 and 2030 forecast, by territory	118
Figure 8.1: Capacity gap (G1): existing firm capacity against peak plus reserve.....	121
Figure 8.2: Energy gap (G2): requirement against the existing fleet's average-year capability.....	122
Figure 8.3: Reliability gap (G3): unserved energy and loss-of-load hours of the existing fleet (PyPSA)	123
Figure 8.4: Where and when load is shed in 2040 if nothing is built (MW, bus $\times$ slice).....	124
Figure 8.5: Zonal capacity balance, 2030	125
Figure 8.6: Ch.5 - Zonal capacity gap share 2030 (MW), by district; right: local Moran (LISA) clusters, 999 permutations	126
Figure 8.7: Ch.5 - Grid access rate 2023 (calibrated) (%), by district; right: local Moran (LISA) clusters, 999 permutations	127
Figure 8.8: Access gap (G6) by least-cost supply mode.....	128
Figure 8.9: The 20 districts with the largest access gap, 2030	129
Figure 8.10: Ch.5 - Access gap 2030 (households), by district; right: local Moran (LISA) clusters, 999 permutations	130
Figure 8.11: Ch.5 - Access gap 2030 (% of households), by district; right: local Moran (LISA) clusters, 999 permutations	130
Figure 8.12: Sector-service gap (G7): health facilities and schools not electrified in 2023 (modelled)	131
Figure 8.13: Ch.5 - Unelectrified health facilities (per 100,000 people), by district; right: local Moran (LISA) clusters, 999 permutations.....	132

Figure 8.14: Ch.5 - Unelectrified schools (2023) (count), by district; right: local Moran (LISA) clusters, 999 permutations	132
Figure 8.15: Security and resilience indicators (G8) against benchmarks.....	133
Figure 8.16: The gap register: each gap by planning year (colour scaled to each gap's maximum)	134
Figure 8.17: Is each gap spatially clustered? Global Moran's I of the gap layers (navy = significant at 5 %).....	135
Figure 9.1: Least-cost plan: new capacity by technology and period (PyPSA multi-period expansion).....	139
Figure 9.2: Build schedule by candidate project and period	140
Figure 9.3: Least-cost plan: cumulative new generation and storage by period (area $\propto$ MW)	141
Figure 9.4: Installed capacity (existing + new) against the firm requirement	142
Figure 9.5: Generation mix by period, least-cost plan	143
Figure 9.6: Annual system cost of new assets and operation, by component and period	144
Figure 9.7: Incremental system cost and long-run marginal cost by period	145
Figure 9.8: Emissions and renewable share of the least-cost plan by period	146
Figure 9.9: Dispatch of the planned system in 2040 across the 25 slices	146
Figure 9.10: Storage state of charge in 2040: reservoirs and batteries	147
Figure 9.11: Transmission reinforcement and new corridors by period	148
Figure 9.12: Least-cost plan: transmission reinforcement and new corridors, 2026–2040 (width $\propto$ MW)	149
Figure 9.13: Nodal prices after the plan, by bus and period	150
Figure 9.14: Zonal supply–demand balance: 2023 existing fleet vs 2040 after the plan (blue surplus, red deficit)	151
Figure 10.1: Standard scenarios: net present cost against cumulative emissions	155
Figure 10.2: Cost of each scenario against least cost (\$0).....	156
Figure 10.3: New capacity by technology in each standard scenario	156
Figure 10.4: Sensitivity of the net present system cost to one-at-a-time changes.....	158
Figure 10.5: Step-load realisation sweep: cost, renewable share and emissions	159
Figure 10.6: Carbon-price sweep: cost, renewable share and emissions	159
Figure 10.7: Renewable-target sweep: cost, renewable share and emissions	160
Figure 10.8: Sensitivities: renewable share in 2040 against cumulative emissions	160
Figure 10.9: New capacity by technology in each sensitivity simulation	162
Figure 11.1: Capital expenditure by category, and generation capex by technology	165
Figure 11.2: Annual capital expenditure by category, 2024–2040.....	166
Figure 11.3: Cumulative capital expenditure by category.....	167
Figure 11.4: Financing sources per year (ASSUMED finance mix) and the indicative public envelope.....	168
Figure 11.5: Public capital requirement in UGX for the MTEF (public share $\times$ FX 3,775 UGX/USD)	168
Figure 11.6: Capital expenditure by region and category	169
Figure 11.7: The 20 districts with the highest capital expenditure per person.....	170
Figure 11.8: Ch.7 - Plan capital expenditure 2024–2040 (MUSD), by district; right: local Moran (LISA) clusters, 999 permutations	171

Figure 11.9: Ch.7 - Capital expenditure per person (USD / person), by district; right: local Moran (LISA) clusters, 999 permutations	171
Figure 11.10: Ch.7 - Access investment 2024–2040 (MUSD), by district; right: local Moran (LISA) clusters, 999 permutations	172
Figure 11.11: Levelised cost of electricity by candidate (capacity factor from the plan where built)	173
Figure 11.12: Average cost of supply against the 2023 average tariff	174
Figure 11.13: Access investment by mode and year	175
Figure 11.14: Project pipeline: cost per household reached against cost per tonne of CO2 avoided (area $\propto$ cost)	176
Figure 12.1: Roadmap: commissioning window of every plan project (colour = technology; grey-blue = transmission)	179
Figure 12.2: Annual capacity additions by technology.....	180
Figure 12.3: Installed capacity every year against peak and the firm requirement.....	181
Figure 12.4: Reserve margin every year against the target	182
Figure 12.5: Annual verification: unserved energy of the commissioned system in every year, 2024–2040.....	183
Figure 12.6: Transition indicators every year: renewable share, access and distribution losses	184
Figure 12.7: Transmission grid length by voltage, 2023–2040.....	184
Figure 12.8: Critical path: slack to financial close (red = already late)	185
Figure 12.9: Delivery against spend: cumulative capex and cumulative capacity commissioned	186
Figure 12.10: The system as it grows: district access rate (shading) and commissioned new plants, 2026–2040.....	187
Figure 13.1: Spatial clustering of every mapped district layer (navy = significant at 5 %, 999 permutations)	191
Figure 13.2: Distribution of district access rates and distance to transmission	194
Figure 13.3: Spatial least-cost electrification: dominant mode and grid share by district	195
Figure 13.4: Least-cost electrification mode for unconnected households, by region.....	196
Figure 14.1: Concentration curve of firm generating capacity against need	199
Figure 14.2: Regional comparison: population, demand, access gap and investment	200
Figure 16.1: Web application: Overview page with national KPIs, the needs–gaps–plan–cost storyline and the headline map	211
Figure 16.2: Web application: Demand page with scenario panel, KPI tiles, map and charts	212
Figure 16.3: Web application: Least-Cost Plan page with the Run plan and Compare scenarios controls.....	213
Figure 16.4: Web application: GIS Explorer with layer tree and district profile.....	214
Figure 16.5: Web application: Expansion page in dark mode, with the time-enabled map	215

List of tables

Table 1.1: The nine planning questions and where they are answered	24
Table 2.1: The five status labels	30
Table 3.1: Ingested external data (data/external/uganda)	32
Table 3.2: Observed utility unit costs (UEDCL/Umememe cost sheets)	37
Table 4.1: Base-year (2023) final consumption by segment, carved from metered tariff-class sales	41
Table 4.2: Electricity customers and tariffs by class, 2023 (ERA)	43
Table 4.3: Final electricity demand by segment, GWh, base scenario	46
Table 4.4: Large new loads: IERMP step loads (increment over 2024) and project loads	48
Table 4.5: Household access path, base scenario (targets 60 % by 2030 and 100 % by 2040)	49
Table 4.6: Health-sector electricity demand by facility level (MoH registry, 3,169 facilities)	50
Table 4.7: Education electricity demand by institution type (EMIS school layer, 21,193 schools)	52
Table 4.8: Transport electrification: vehicle stock and energy (ASSUMED paths)	54
Table 4.9: From final consumption to generation requirement and peak, base scenario	55
Table 4.10: Demand scenarios: generation requirement and peak	56
Table 4.11: The 20 districts with the highest electricity demand in 2040	62
Table 4.12: Final demand by supply zone (districts assigned to their nearest transmission bus)	66
Table 5.1: Installed and firm capacity by technology, 2023	69
Table 5.2: The existing fleet (ERA licensed plants, reservoir hydro and batteries)	71
Table 5.3: Merit order of the existing fleet at the evening peak (solar excluded)	75
Table 5.4: Calibration: modelled against metered 2023 generation by plant	77
Table 5.5: PyPSA dispatch of the existing fleet against each year's demand (GWh unless stated)	80
Table 6.1: Transmission lines by voltage and status, km (IERMP GIS)	85
Table 6.2: The 24 modelled transmission corridors (AEGID / UETCL)	85
Table 6.3: Corridor loading: 2023 dispatch and the 2030 grid-stress test	88
Table 6.4: Nodal prices under the 2030 grid-stress test (USD/MWh)	91
Table 6.5: N-1 screening at the 2030 system peak	93
Table 6.6: Population within a given distance of the grid (WorldPop 2020, 1 km grid)	95
Table 6.7: The 20 districts farthest from the transmission grid (population-weighted distance)	96
Table 6.8: Reinforcement screening 2030: economic MW to add (levelised-cost supply)	100
Table 6.9: IERMP planned lines mapped onto the model as candidate new corridors	100
Table 6.10: Observed 2023 substation peaks (UETCL)	102
Table 7.1: Energy waterfall 2023: from gross generation to collected energy	105
Table 7.2: Observed 2023 distribution losses by utility and territory (ERA statistics)	106
Table 7.3: The 20 districts with the highest modelled distribution loss rates	108

Table 7.4: Distribution loss path and the value of loss reduction (valued at 69 USD/MWh)	109
Table 7.5: Tariffs, cost to serve and cross-subsidies by class, 2023 (USD/MWh unless stated)	110
Table 7.6: Population by distance to the MV (33/11 kV) network.....	113
Table 7.7: The 20 distribution substations serving the largest populations	116
Table 7.8: Cumulative distribution capacity required from 2023	117
Table 7.9: UEDCL 33 kV feeder demand forecasts by territory.....	118
Table 8.1: The eight gaps and the instruments that close them.....	120
Table 8.2: Capacity (G1) and energy (G2) gaps of the existing fleet	121
Table 8.3: Reliability gap (G3): PyPSA dispatch of the existing fleet, normal and dry hydrology	123
Table 8.4: Zonal capacity balance, 2030 (location signal: zones import across the grid)	125
Table 8.5: Access gap (G6) by least-cost supply mode.....	128
Table 8.6: The 20 districts with the largest access gap in 2030	129
Table 8.7: Health facilities not electrified in 2023 (modelled: nearest-to-grid first, calibrated shares).....	131
Table 8.8: Security and resilience indicators (G8)	133
Table 8.9: The gap register passed to the least-cost plan.....	134
Table 8.10: Global spatial autocorrelation of the gap layers (k = 6 nearest neighbours, 999 permutations)	135
Table 9.1: Candidate options for the least-cost plan (IRP set + engine battery candidates)	138
Table 9.2: Least-cost build schedule by candidate and period (MW), base scenario S0	140
Table 9.3: Installed capacity (existing + new) by technology and period, MW.....	142
Table 9.4: Generation by technology and period, GWh.....	143
Table 9.5: Annual system cost of new assets and operation by period, MUSD/yr	144
Table 9.6: Plan indicators by period, base scenario S0	145
Table 9.7: Transmission reinforcement and new corridors selected by the plan, MW	148
Table 9.8: Nodal prices after the plan, USD/MWh (load-weighted mean over slices)	150
Table 9.9: Shadow prices of the plan constraints	151
Table 10.1: Standard scenario set S0–S7: cost, capacity and emissions	153
Table 10.2: New capacity by technology in each standard scenario, MW (2026–2040)	156
Table 10.3: One-at-a-time sensitivity simulations around the base scenario.....	157
Table 11.1: Capital expenditure 2024–2040 by category and financing source, MUSD	165
Table 11.2: Generation and storage capex by technology.....	166
Table 11.3: MTEF export: public capital requirement and physical outputs, 2025–2031	168
Table 11.4: Capital expenditure by region (ADM1) and category, MUSD.....	169
Table 11.5: The 20 districts receiving the most capital expenditure, MUSD	170
Table 11.6: Levelised cost of electricity by candidate	173
Table 11.7: Revenue requirement and average cost of supply against the 2023 average tariff	174
Table 11.8: Access investment by mode	175
Table 11.9: Project pipeline appraisal (MEMD pipeline, projects.csv).....	176

Table 12.1: Commissioning windows of the plan's generation and storage projects.....	179
Table 12.2: Commissioning of transmission reinforcements and new corridors.....	180
Table 12.3: Annual system state 2023–2040, base scenario	181
Table 12.4: Annual PyPSA verification of the commissioned system.....	183
Table 12.5: Transmission grid length by voltage, km	184
Table 12.6: Critical path: projects with long lead times or a large firm contribution	185
Table 12.7: Gap-closure milestones of the plan.....	185
Table 13.1: Spatial autocorrelation of every mapped district layer (k = 6, 999 permutations)	191
Table 13.2: Least-cost electrification mode for unconnected households, by region	196
Table 14.1: Regional (ADM1) comparison.....	200
Table 15.1: Validation checks of the base run (docs/01–09)	204
Table 15.2: Calibration of the engine against observed 2023 quantities.....	207
Table 16.1: Financing sources by year, MUSD	217
Table 16.2: Annual capital expenditure by category, MUSD.....	217
Table B.1: Buses of the 17-bus network model	230
Table B.2: Reservoir hydro plants	231
Table B.3: Other existing generating units.....	231
Table B.4: Generation candidates of the least-cost plan	232
Table B.5: Parameters of the base scenario S0	233
Table B.6: The standard scenario set	234
Table B.7: The one-at-a-time sensitivities.....	234
Table B.8: Engine planning defaults (config/engine_defaults.yml)	234
Table B.9: Status of the main input groups.....	235
Table C.1: Electricity demand by district, 2023 and 2040	238
Table C.2: Access, electrification mode and institutions by district.....	243
Table C.3: Grid reach, losses and resources by district	248
Table C.4: Plan capital expenditure by district, 2024–2040 (MUSD)	253

Executive summary

This report sets out the status of Uganda's electricity system in 2023 and what it will take to meet the country's needs to 2040. Every number in it is computed by the AICTEM Energy Modelling Engine. The engine is a spatial planning system built on PyPSA for the power system and on a geographic information system (GIS) of 135 districts. Its inputs are metered 2023 system data, the Integrated Energy Resource Master Plan (IERMP) geodatabase, Electricity Regulatory Authority (ERA) statistics and the AICTEM Spatial Data Infrastructure. The analysis runs one base scenario (S0, least cost) and 29 simulations around it. Every figure carries a status label: OBSERVED, CALIBRATED, MODELLED or ASSUMED. The purpose of these labels is to let the reader separate what was measured from what was modelled and from what was assumed.

The demand and its drivers

Uganda consumed **4,330 GWh** of electricity at the meter in 2023. The system generated **5,987 GWh** and met a metered peak of **988 MW**.

- **Industry dominates.** Industry took more than half of final consumption: 2,319 GWh, or 53.6 %. Households took 966 GWh (22.3 %) and commerce and services 325 GWh (7.5 %). The remaining 16.6 % went to mining, agriculture, water, education, health, transport and public lighting.
- **Health and education are small today.** Health facilities consumed an estimated 71 GWh and schools 105 GWh. Both were estimated bottom-up from 3,169 registered health facilities and 21,193 EMIS schools.
- **Most households are not connected.** Only **25.3 %** of Uganda's 10.7 million households were connected to the grid in 2023. Each connected household used, on average, 481 kWh a year.

In the base scenario, final demand rises to **9,759 GWh by 2030** and **24,185 GWh by 2040**, a 5.6-fold increase. Peak demand rises to **2,008 MW in 2030** and **4,866 MW in 2040**.

- **Industrial step loads drive the growth.** The largest single driver is the set of IERMP step loads for industrial parks, iron and steel, data centres and phosphates. Together they add 11,123 GWh by 2040, nearly half of 2040 demand. The industrial parks alone reach 7,348 GWh and steel 2,596 GWh.
- **Households grow almost fourfold**, to 3,784 GWh, as access rises from 25.3 % to the 60 % target in 2030 and to universal access in 2040. That means 15.0 million new connections, 85 % of them on the grid.
- **Transport starts from almost nothing** and reaches 980 GWh through electric motorcycles, cars and buses, and the electric Standard Gauge Railway.

The low and high demand scenarios bracket the 2040 peak between **3,620 MW** and **5,374 MW**. Chapter 4 shows how much of the growth depends on the step loads.

What the system has

The existing fleet is **2,033 MW** of installed capacity, of which **1,191 MW** is firm, that is, dependable at the system peak.

- **Hydro dominates.** Hydro is 85 % of installed capacity. The five large Nile-cascade stations (Nalubaale, Kiira, Bujagali, Isimba and Karuma) produced about three-quarters of 2023 generation. The PyPSA dispatch reproduces metered generation within 3.4 % and the hydro share within 3 points.
- **Two large concentration risks.**
 - About 76 % of generation depends on one river.
 - The largest unit, Karuma at 600 MW, equals 61 % of the 2023 peak.

- **Imported fuel.** Thermal back-up is 100 MW of heavy fuel oil at 194 USD/MWh, with 21 days of storage and entirely imported fuel.

Dispatching the existing fleet against each year's demand shows when it runs out. The system is adequate to 2026. It sheds **3,073 GWh (25 % of demand) in 2030** and **20,120 GWh (69 %) in 2040** if nothing is built. In a dry year the 2030 shortfall is 4,608 GWh.

The grid and distribution

Transmission. The operational grid is 2,956 km of line, with 686 km under construction and 3,977 km planned.

- **The grid, not supply, binds first in some places.** The 2030 grid-stress test supplies every candidate site at its levelised cost. Under it, six corridors run at their thermal limit or are stressed for more than 500 hours a year. The worst are:
 - Nalubaale–Namanve, the eastern supply into Kampala;
 - Kabulasoke–Nkonge and Nkonge–Kahungye, the export path from the western geothermal and gas sites;
 - Mutundwe–Kabulasoke.
- **Three corridors fail N-1 at peak.** Losing Namanve–Kampala North, Nalubaale–Namanve or Nalubaale–Lugazi sheds load.
- **Coverage.** About 4.15 million people in 19 districts, mostly in Karamoja and West Nile, live more than 50 km from a transmission substation.

Distribution. The medium-voltage (MV) network reaches much further than transmission: 96.8 % of the population lives within 5 km of a 33 or 11 kV line. The distribution problem is therefore not reach but losses and last-mile connection.

- **Losses.** Distribution lost **17.35 %** of the energy it received in 2023, or 909 GWh. ERA statistics show 16.4 % in the Umeme concession, but 50–54 % in the rural UEDCL territories of the north-west and in the Kilembe territory.
- **Cross-subsidies.** Residential customers pay 63 USD/MWh above their cost to serve. Large and extra-large industry pay below it.
- **Value of meeting the loss target.** Reaching the 12 % target by 2030 avoids 593 GWh a year by 2030 and 1,470 GWh a year by 2040. The 2040 saving is worth about 102 million USD a year and replaces 245 MW of generation.

The gaps

The gaps are kept separate. Each has a different remedy, so none is added into a composite index.

Gap	When it opens	Size
Capacity	2026	983 MW by 2030; 4,270 MW by 2040
Energy	2028	2,916 GWh by 2030
Reliability (solved dispatch)	2030	3,073 GWh unserved in 2030
Access	now	5.19 million households by 2030; 14.98 million by 2040
Health facilities	now	1,096 not electrified in 2023
Schools	now	13,349 not electrified in 2023

The gaps are strongly clustered in space.

- **Access.** Moran's I for the access gap is 0.51 ($p = 0.001$). There is a hot-spot of 12 districts in Karamoja and the north-east: Abim, Agago, Kaabong, Karenga, Kitgum, Kotido, Moroto, Napak and neighbours. A cold-spot of 22 districts runs along the Kampala–Masaka–Mbarara corridor.
- **Distance to the grid** clusters in West Nile and Karamoja.

The least-cost plan

PyPSA's multi-period expansion closes the gaps at a net present cost of **4.37 bn USD** (new assets and operation, 2024–2040, at 10 %). It builds **5,935 MW** of new capacity by 2040:

- 1,060 MW of geothermal at Katwe and Buranga;
- 3,096 MW of gas: 200 MW combined-cycle at Tilenga, 1,250 MW combined-cycle in the east and 1,646 MW of open-cycle peaking capacity;
- 1,170 MW of solar;
- 120 MW of wind;
- 489 MW of diesel peakers.

It reinforces seven corridors and builds two IERMP planned lines, Buloba–Nkenda and Kapeeka–Kiboga, adding 2,466 MW of transfer capacity. Unserved energy falls to zero in every period.

- **Renewable share.** It stays at 85–100 % to 2035 and falls to **61 %** by 2040, as gas meets the steep industrial demand after 2035.
- **Emissions.** They rise from almost zero to **4.1 Mt CO₂** in 2040.
- **Long-run marginal cost.** It rises from 50 USD/MWh in 2030 to 75 USD/MWh in 2040.

The simulations

29 simulations test the plan. The main results:

- **Cleaner paths cost little.**
 - A renewable share of at least 90 % in every period (S1) costs 165 million USD more in net present terms, and cuts cumulative emissions from 27.7 Mt to 10.4 Mt. That is about 10 USD per tonne avoided.
 - A carbon price of 50 USD/t (S2) costs 292 million USD more.
 - Excluding all new fossil capacity (S6) costs 868 million USD more. It is met with 2.6 GW of run-of-river hydro, 1.6 GW of batteries and 0.7 GW of nuclear.
- **Demand uncertainty matters far more than technology choice.**
 - Realising only half of the IERMP step loads lowers the net present cost by 1.4 bn USD.
 - Realising none lowers it by 2.7 bn USD.
 - GDP growth of 8 % instead of 6 % raises it by 0.7 bn USD.
- **The grid is indispensable.** Planning generation without any transmission reinforcement leaves so much load unserved that the net present cost rises from 4.4 to **29.9 bn USD**.

The money

Closing all the gaps requires **15.6 bn USD** of capital between 2024 and 2040 (net present value 6.8 bn USD). Spending peaks at 1.19 bn USD in 2037.

Category	Capex (bn USD)
Generation	7.8

Category	Capex (bn USD)
Grid access	4.0
Distribution networks	3.3
Transmission	0.36
Electrification of health facilities and schools	0.18

The indicative financing mix assigns:

Source	bn USD
Public budget	3.6
Concessional lenders	6.4
Private investors	5.0
Consumers and results-based finance	0.6

The public share peaks at 257 million USD in 2032. The average cost of supply rises from 118 USD/MWh to about **158 USD/MWh by 2040**, against a 2023 average tariff of 133 USD/MWh. Without tariff adjustment, subsidy or efficiency gains, the shortfall in 2040 would be about 622 million USD a year.

Where and when

The annual build-out, verified year by year with PyPSA, keeps unserved energy at zero from 2024 to 2040. It has two warnings.

- **Transition gap, 2027–2029.** The reserve margin falls below its 15 % target and reaches –2.5 % in 2029. The open-cycle gas plant that closes the gap cannot come online before 2030. No load is shed in the modelled average year, but the system has no margin for a dry year or an outage in those years.
- **Geothermal is already late.** Katwe and Buranga need 5-year lead times. To commission on the plan's schedule they would have needed financial close in 2022 and 2023.

Geographically, the investment concentrates on:

- the western generation sites in Kasese and Kazo, 5.5 bn USD between them;
- the eastern gas site at Tororo;
- the Kampala metropolitan distribution network.

Access investment is spread across all regions roughly in proportion to their access gaps. The Northern region has 26 % of the 2030 gap and receives 25 % of the access investment. A quarter of its new connections are solar home systems.

What the evidence is, and is not

The base year is measured. Generation, sales, losses, customers, households, the fleet, the grid and the population grid are all OBSERVED or CALIBRATED against metered data. Every validation check of the base run passes (43 of 43).

Four inputs are ASSUMED and are the most important to review:

- how commercial and industrial sales are split between segments;
- the institutional energy intensities;
- the e-mobility paths and the oil, gas and irrigation loads;
- the financing mix.

The step loads come from the IERMP, but whether they are realised is uncertain. The report therefore presents them as a scenario lever, not a forecast.

The power model is a 17-bus transport model with 25 time slices per year. It captures thermal limits, losses, hydro scheduling and storage. It does not capture AC power flow, stability or chronological hour-by-hour operation. No scenario in this report is recommended. The report sets out the trade-offs so that the choice can be made where it belongs.

CHAPTER 1

1 Introduction

1.1 Purpose of the report

This report describes the state of Uganda's electricity system and what it would take to meet the country's electricity needs to 2040. It covers Uganda as a whole, each of its 135 districts, and the 17 transmission supply zones of the power model. It is produced by the AICTEM Energy Modelling Engine, a spatial planning system built for the Economic Development Integrated Planning (EDIP) platform of the African Institute for Climate, Trade and Economic Modelling.

The report is written for the officials who turn an energy strategy into investments and budgets:

- planners in the Ministry of Energy and Mineral Development (MEMD);
- system planners at UETCL;
- the distribution utilities;
- the Electricity Regulatory Authority;
- budget and fiscal analysts in the Ministry of Finance, Planning and Economic Development;
- analysts at the National Planning Authority;
- the development partners who co-finance the sector.

It answers a normative planning question, not only a descriptive one. Most sector reviews describe what was generated, sold and lost. This report asks what the country's electricity *requirement* is: who needs electricity, how much, where and when. It then asks what the current system can generate, transmit and distribute. It locates the gaps between the two, by type and by district. It uses an optimisation model to find the least-cost combination of generation, storage and grid reinforcement that closes them. Finally it prices, schedules, locates and finances that plan.

Three features make the analysis useful for decisions rather than for advocacy.

- **Every figure is traceable.** Each number is produced by a module of the engine from a named data layer and carries a status: OBSERVED (metered, registered or published), CALIBRATED (derived from observed data by a documented transformation), MODELLED (the output of a solved model) or ASSUMED (a planning assumption that can be changed).
- **The gaps are kept apart.** Capacity, energy, reliability, network, distribution, access, sector-service and security gaps are reported separately. Each is closed by a different instrument, so none is added into a single index.
- **The choices are not made for the reader.** Chapter 10 compares 29 simulations. It states what each costs and what it buys, and leaves the trade-off between cost, emissions, speed of access and security to the policy process.

1.2 Uganda in 2023: the planning context

1.2.1 Population and households

Uganda's population was about **46.1 million** in 2023 on the district population layer used by the engine. The 2024 census counted **10.7 million** households. Only 2.71 million of them, **25.3 %**, were connected to the grid. The population is young and growing at about 3 % a year. At that rate the number of households reaches 17.7 million

by 2040. Every one of those households is a potential electricity connection, and most of them are not yet connected.

1.2.2 Electricity consumption

Metered final consumption was **4,330 GWh** in 2023, sold to 2.1 million customers.

- The residential class had 2.0 million customers but took only 966 GWh: an average of 481 kWh per customer per year.
- The 49 extra-large industrial customers took 1,060 GWh between them.

This structure, where a very small number of large industrial consumers take most of the energy and a very large number of households take little, shapes almost every result in this report.

1.2.3 Generation

Uganda generated **5,987 GWh** in 2023 from a fleet dominated by hydropower on the Victoria Nile. The system peak was **988 MW**. With the commissioning of Karuma (600 MW), installed capacity reached **2,033 MW**, more than twice the peak. On paper, 2023 was a year of surplus capacity. The planning question is how long that surplus lasts.

1.2.4 The step change in demand

The IERMP provides step loads for large new consumers. In the base scenario they add 11.1 TWh of annual demand by 2040:

- industrial parks;
- integrated iron and steel;
- data centres;
- a phosphate and fertiliser complex.

These step loads are more than twice total consumption in 2023. Together with universal household access, industrial growth and the electrification of transport, they turn the 2023 surplus into a deficit within a few years.

1.3 How the power sector is organised

Uganda's electricity sector was unbundled in 2001.

- **Generation.** Generation is shared between public plants, owned by UEGCL and operated under concession, and independent power producers, licensed by ERA.
- **Transmission.** UETCL owns and operates the high-voltage transmission network at 400, 220, 132 and 66 kV. It is the single buyer of bulk power.
- **Distribution.** Distribution was concessioned to Umeme for the central and main grid areas until 2025. Rural territories were served by UEDCL and a set of smaller operators:
 - WENRECO in West Nile;
 - Kilembe Investments (KIL) in the Rwenzori area;
 - several cooperatives, including BECS, KRECS and PACMECS.
- **Regulation.** ERA regulates tariffs, licences and quality of supply.
- **Policy and planning.** MEMD sets policy and leads integrated resource planning. The Rural Electrification Agency, since merged into MEMD, financed rural extension.

The engine reflects this structure. Generation is modelled plant by plant. Transmission is modelled corridor by corridor on UETCL's network. Distribution is analysed by service territory, using ERA's statistics on energy purchased and sold by each utility.

1.4 The planning questions

The report answers nine questions, one for each module of the engine. The chapters of the design specification (docs/01...09) define them. Table 1.1 lists them and where each is answered.

Table 1.1: The nine planning questions and where they are answered

#	Question	Engine module	Chapter
1	How much electricity is needed, by which segment, where and when?	Demand (Ch.1 of the design)	4
2	What is installed, what is firm, what did it produce and how does it dispatch?	Generation (Ch.2)	5
3	Can the grid move the power? Which corridors congest or fail N-1, and who is beyond the grid?	Transmission (Ch.3)	6
4	How much energy is lost between substation and customer, and who pays for what?	Distribution (Ch.4)	7
5	What are the gaps, when do they open and where are they?	Gap analysis (Ch.5)	8
6	What mix of generation, storage and grid closes the gaps at least cost?	Least-cost plan (Ch.6)	9, 10
7	How much capital is needed, when, where and financed by whom?	Investment (Ch.7)	11
8	How is every result located, mapped and tested for clustering?	GIS engine (Ch.8)	13
9	In what order should the system be built, year by year?	Expansion (Ch.9)	12

1.5 Scope: what is modelled and what is not

The engine models **grid-connected electricity**, from generation to the paying customer, together with the least-cost choice between grid, mini-grid and solar home systems for households that are not yet connected. It does not model:

- cooking fuels;
- transport fuels;
- other petroleum products.

These enter only as the fuel-import dependence indicator of the security gap, and as the electrification of transport and institutions.

Imports and exports of electricity are held at their 2023 net level of 451 GWh. The model does not optimise regional trade.

The power system is represented by:

- 17 transmission buses (supply zones);
- 24 existing corridors, plus four candidate new corridors taken from the IERMP planned lines;
- 25 representative time slices per year: four seasons × six diurnal blocks, plus a 100-hour system-peak block.

This is enough to capture the main planning constraints: firm capacity, energy, reservoir scheduling, storage, corridor limits and losses. It is not a chronological, hour-by-hour or AC-power-flow model, and it does not study stability or protection. Chapter 2 discusses what this means for the results.

1.6 Principles

The engine follows a small number of rules. The report respects them throughout.

1. **Every number carries a status.** A result inherits the weakest status of its inputs. A missing input is reported as NOT_AVAILABLE, never as zero.
2. **Calibrate before projecting.** The base year reproduces the metered 2023 figures before anything is projected:
 - segment demand sums to metered sales;
 - the generation requirement matches metered generation within 1 %;
 - the modelled national access rate equals the census.
3. **Gaps come from solved models.** The reliability gap is the unserved energy of a PyPSA dispatch, not an assumed shortfall. The plan is a PyPSA optimisation, not a list of projects.
4. **Gaps are never combined.** Each gap is shown by itself and mapped by itself.
5. **Every table has a place.** Every result has a spatial key (district, bus, corridor, facility or settlement), so that it can be mapped and tested for clustering.
6. **No scenario is recommended.** The least-cost scenario is least cost on its stated objective and constraints. It is a reference point, not a recommendation.

1.7 How to read the report

Each substantive chapter follows the same pattern:

- it states the question and why it matters;
- it explains the method in words and equations, and defines every symbol;
- it presents the results in tables, charts and maps, and interprets them;
- it sets out the quality of the data and the main limitations;
- it closes with implications for planning.

Most district maps come in pairs. The left panel shows the value of the indicator in quantile classes. The right panel shows its local Moran (LISA) clusters:

- **High-high hot-spots:** districts where a high value is surrounded by high values.
- **Low-low cold-spots:** districts where a low value is surrounded by low values.
- **Outliers:** high–low and low–high districts.

The global Moran's I in the title of the right panel measures whether the indicator is clustered at all. Chapter 13 explains the statistics.

Money is in constant 2023 US dollars unless stated. Uganda shillings are converted at 3,775.03 UGX per USD, ERA's 2023Q4 rate. "2030" means the calendar year 2030. The planning periods 2026, 2030, 2035 and 2040 each represent the years that lead up to them, as explained in Chapter 9.

1.8 Structure of the report

The report has three parts.

Foundations. Chapter 2 describes the approach and the architecture of the engine. Chapter 3 describes the data sources and their quality.

The diagnostic chain and the plan (Chapters 4 to 12):

- Chapters 4 to 7 describe demand, generation, transmission and distribution.
- Chapter 8 brings them together in the gap register.
- Chapter 9 presents the least-cost plan.
- Chapter 10 presents the simulations.

- Chapter 11 presents the investment plan.
- Chapter 12 presents the year-by-year expansion plan.

Cross-cutting chapters (Chapters 13 to 17):

- Chapter 13 is the spatial analysis and GIS atlas.
- Chapter 14 covers equity and access.
- Chapter 15 covers calibration and validation.
- Chapter 16 covers integration with national systems and the web application.
- Chapter 17 draws conclusions and sets out next steps.

Annexes. The annexes give the formula compendium, the reference catalogues, the district statistical tables and a glossary.

1.9 Implications for planning

- The 2023 surplus is temporary. The capacity gap opens in 2026 and the reliability gap in 2030 in the base scenario. Decisions on plants with five-year lead times therefore needed to be taken already.
- Uganda's electricity future is decided by a small number of very large loads (industrial parks, steel, data centres, refining) and by a very large number of small ones (15 million new household connections). The plan has to serve both. The two call for different instruments.
- The engine's value is not a single forecast. It is the ability to recompute every result, including maps, gaps, plan and investment, when an assumption changes. The simulations in Chapter 10 show which assumptions matter most.

CHAPTER 2

2 Approach and architecture

2.1 A planning chain from need to investment

The engine is organised as a chain of nine modules. Each takes the results of the one before it and adds one layer of the planning answer.

1. **Demand** projects electricity need by segment, district and year, together with the hourly shape of the load.
2. **Generation** describes the existing fleet and dispatches it with PyPSA against each year's demand.
3. **Transmission** tests whether the grid can move the power.
4. **Distribution** traces energy from the bulk supply point to the paying customer.
5. **Gap analysis** compares need with what the system can supply and deliver, and records each gap separately.
6. **Least-cost plan** runs a PyPSA multi-period capacity expansion. It finds the portfolio of new generation, storage and transmission that closes the gaps at minimum discounted cost.
7. **Investment** turns the plan into capital, a disbursement profile, a financing mix and a tariff path.
8. **Expansion** splits the plan into annual commissioning tranches, verifies every year with PyPSA and identifies the critical path.
9. **The GIS engine** runs underneath all the others. It supplies the geography, the spatial joins, the maps and the spatial statistics.

The chain is deliberately one-directional. Demand never looks at supply, the gap analysis never looks at the plan, and the plan never looks at the budget. This keeps each answer honest. The requirement is what the country needs. The gap is what the existing system cannot provide. The plan is the cheapest way to provide it. Money becomes a constraint only in the financing and fiscal analysis of Chapter 11.

2.2 The demand identity

Every segment's demand in every year follows one identity, inherited from the AICTEM driver framework:

$$E_{s,y} = E_{s,y_0} A_{s,y} \eta_{s,y} \epsilon_{s,y} + N_{s,y} \quad (2.1)$$

where

- $E_{s,y}$ is the final electricity demand of segment s in year y (GWh);
- E_{s,y_0} is the base-year (2023) demand of the segment, carved from metered sales;
- $A_{s,y}$ is the activity index: cumulative growth of the segment's output relative to 2023;
- $\eta_{s,y}$ is the efficiency factor (less than one means savings);
- $\epsilon_{s,y}$ is the electrification factor (fuel switching into electricity);
- $N_{s,y}$ is additive new load from discrete projects, such as the IERMP step loads.

Households, health, education and transport replace the generic identity with bottom-up models:

- households: connections $\times$ use per connection;
- health: facility points $\times$ level intensity $\times$ electrified share;

- education: school points × type intensity × electrified share;
- transport: vehicle stock × energy per vehicle.

The generation requirement adds network losses and net exports to final demand:

$$G_y = \frac{F_y}{(1 - \ell_y^D)(1 - \ell^T)} + X_y \quad (2.2)$$

where $F_y = \sum_s E_{\{s,y\}}$ is final demand, ℓ_y^D the distribution loss rate, ℓ^T the transmission loss rate and X_y net exports.

2.3 The power system in PyPSA

2.3.1 The network

The power system is represented in **PyPSA**, an open-source power-system optimisation framework. The engine uses one network builder for every solve:

- **Buses.** Each of the 17 transmission buses is a PyPSA `Bus`.
- **Loads.** Each bus carries a `Load` with the demand of its supply zone in each of the 25 time slices.
- **Corridors.** Each corridor becomes two directed `Links`, one per direction, with efficiency $1 - \text{loss factor}$. This is a transport model with losses. It represents thermal limits and losses but not loop flows.
- **Generators.** Existing units are `Generators` with marginal cost equal to variable cost plus carbon price × emission factor.
- **Reservoirs.** Reservoir hydro is a `StorageUnit` with inflow and a cyclic state of charge, so the reservoir cannot be drawn down for free.
- **Batteries.** Batteries are `StorageUnits`.
- **Load shedding.** Load shedding is a generator at every bus priced at the value of lost load (VoLL, 10,000 USD/MWh), so unserved energy is always visible.

2.3.2 Dispatch

The least-cost dispatch of a given fleet solves

$$\min \sum_t w_t \left[\sum_g c_g p_{g,t} + V \sum_b u_{b,t} \right] \quad (2.3)$$

subject to nodal balance, generator availability, storage dynamics and link limits. Here:

- w_t is the weight of slice t in hours (the weights sum to 8,760);
- c_g is the marginal cost of unit g and $p_{\{g,t\}}$ its output;
- V is the value of lost load;
- $u_{\{b,t\}}$ is the load shed at bus b .

The dual of the nodal balance is the **nodal price**, which the report uses to read congestion and scarcity.

2.3.3 Capacity expansion

The least-cost plan is a **multi-investment-period** expansion over the periods 2026, 2030, 2035 and 2040. Each candidate project is represented by one extendable copy per period, with a build year and a lifetime. The copy is active in every period from its build year until the end of its life. The objective discounts each period's annual cost:

$$\min \sum_p \Omega_p \left[\sum_{c, q \leq p} \kappa_c K_{c,q} + \sum_t w_t \left(\sum_g c_g p_{g,t,p} + V \sum_b u_{b,t,p} \right) \right] \quad (2.4)$$

where

- Ω_p is the discounted number of years the period represents;
- κ_c is the annualised capital cost plus fixed O&M of candidate c ;
- $K_{\{c,q\}}$ is the capacity of candidate c built in period q .

The main constraints are:

- **Reserve margin.** In every period, capacity-credited firm capacity must cover peak demand plus a 15 % reserve margin.
- **Resource potential.** The capacity of each candidate summed across periods cannot exceed its potential.
- **Build rate.** The capacity built per period cannot exceed the candidate's annual build limit $\times$ the years in the period.
- **Availability.** A candidate cannot be built before its first available year.
- **Tied reinforcement.** The two directions of each reinforced corridor are built to the same capacity.
- **Optional targets.** A renewable-share target and a CO2 cap can be imposed. A technology can be excluded, or a minimum build forced.

The reserve-margin constraint is

$$\sum_g cc_g K_g + \sum_{c, q \leq p} cc_c K_{c,q} \geq (1 + r) P_p \quad (2.5)$$

where cc is the capacity credit, r the reserve margin and P_p the peak demand of period p . The problem is solved with the open-source HiGHS solver. It has 100 snapshots and about 90 generator copies and 270 link copies, and solves in 15–40 seconds.

2.4 The GIS engine

The GIS engine holds the country's geography: 4 regions and 135 districts. It holds the network assets from the IERMP geodatabase:

- 113 transmission lines;
- 66 transmission substations;
- 99 distribution substations;
- 20,683 distribution transformers;
- the MV network.

It also holds the service points: 3,169 health facilities, 21,193 schools, 14 industrial parks and 17 mining areas. Finally it holds the WorldPop 2020 population on a 1 km grid, which covers 126,986 populated cells.

It links every model entity to a place:

- settlements to their nearest substation;
- facilities to their district;
- plants and candidates to their bus;
- districts to their supply zone, the nearest transmission bus;
- corridors to the districts they cross.

Distances and areas are computed in UTM zone 36N. On top of these joins the engine computes:

- coverage curves (population within x km of the grid);
- service areas (Voronoi polygons of distribution substations);
- a spatial least-cost electrification model (grid, mini-grid or solar home system for each household);

- spatial statistics: global Moran's I and local Moran (LISA) clusters, a concentration index and a Gini coefficient.

2.5 Status labels and their propagation

Every number carries one of five labels. A result inherits the weakest label of its inputs. For example, a district's health demand combines observed facility locations with assumed energy intensities, so it is CALIBRATED at best. The status appears in every table and in the source line of every figure.

Table 2.1: The five status labels

Label	Meaning	Examples in this report
OBSERVED	metered, registered, licensed or published	2023 sales, generation, losses, fleet, lines, substations, schools, health facilities
CALIBRATED	derived from observed data by a documented transformation	25-slice load shape, capacity credits, segment carve-out, district access rates
MODELLED	the output of a solved model or engine calculation	dispatch, gaps, plan, investment, spatial statistics
ASSUMED	a planning assumption, editable in <code>config/engine_defaults.yml</code>	institutional intensities, e-mobility paths, financing mix, unit costs of access
NOT_AVAILABLE	input missing; never replaced by zero	—

2.6 Gates: validation that runs with the model

Each module carries validation checks that run every time the model runs. They are known answers the model must reproduce:

- segment demand equals metered sales;
- the requirement equals metered generation within 1 %;
- modelled 2023 generation is within 5 % of metered, and the hydro share within 10 points;
- every PyPSA solve is optimal;
- the energy waterfall closes;
- district totals equal national totals;
- the plan's net present value reconciles with the PyPSA objective;
- every year of the expansion plan passes a PyPSA adequacy test.

All 43 checks of the base run pass. Chapter 15 reports them.

2.7 Reproducibility

The whole report can be regenerated from the repository with five commands:

1. `scripts/ingest_external.py` rebuilds the external data layers from the source archives.
2. `report/build/collect.py` runs the engine for the base scenario and all 29 simulations, and writes every table and number the report quotes.
3. `report/build/figures.py` draws every chart and map.
4. `report/build/render_equations.py` renders the equations.
5. `report/build/build_docx.js` assembles the document.

Results are cached by a hash of the scenario and of the engine's source code, so a change to either triggers a recomputation.

The same engine runs the analytical web application described in Chapter 16. In the application, any parameter of this report (demand growth, access targets, carbon price, renewable targets, reserve margin, technology exclusions) can be changed and every chapter's results recomputed.

2.8 Limitations of the approach

- **Transport model of the grid.** The grid is a transport model with losses, not an AC or DC load-flow model. Loop flows on the meshed Kampala ring are not represented, and corridor loadings there are indicative.
- **25 time slices.** Twenty-five slices per year capture seasonal and diurnal patterns and the system peak. They understate the value of storage and the curtailment of solar compared with a full hourly model, and they cannot represent multi-day dry spells.
- **Perfect foresight.** The plan optimises across all periods knowing future demand. In reality, decisions are taken with less information. The annual verification of Chapter 12 and the simulations of Chapter 10 partly compensate for this.
- **Candidate sites at their bus.** Candidates are located at their connecting bus. New corridors to unconnected regions, such as a West Nile backbone, are not candidates unless they are among the IERMP planned lines that map onto the 17-bus model.
- **Existing plants do not retire.** No retirement year is supplied for the existing fleet within the horizon.

2.9 Implications for planning

- The engine is built to answer "what if" questions quickly and consistently. The result of any single run matters less than how results move between runs, which Chapter 10 shows.
- Because the reliability gap and the plan come from solved models, they already account for hydro scheduling, storage, corridor limits and losses. Rule-of-thumb capacity balances cannot do this.
- The spatial key on every table means that every national result can be taken down to a district, a zone or a corridor. That is the level at which budgets and projects are actually decided.

CHAPTER 3

3 Data sources, governance and quality

3.1 An overview of the evidence base

The engine draws on four families of evidence.

- **The calibrated 2023 power-system case** (`data/uganda_2023`). This is the core of the model: metered hourly system load, the licensed fleet, reservoir data, the transmission corridors, customer classes, households and the national energy balance. It was assembled from UETCL, ERA, UBOS and MEMD sources and reconciled so that it reproduces the metered 2023 figures.
- **The IERMP geodatabase and planning workbooks** of MEMD's Integrated Energy Resource Master Plan (`D:\EDIP\Data\EnergyData`). These give the network in its true geography:
 - operational, under-construction and planned transmission lines;
 - transmission and distribution substations;
 - distribution transformers;
 - the MV network;
 - industrial parks, service territories and commercial facilities;
 - the step-load projections, UEDCL feeder forecasts, utility unit costs and ERA's distribution statistics.
- **The AICTEM Spatial Data Infrastructure** (`D:\EDIP\SDInfrastructure`). This supplies the population grid, schools, generation sites, mining areas and the wind atlas.
- **Sibling AICTEM models**. From these come the district boundaries, the MoH health facility registry and the district population layer.

The external archives are read by one ingestion script, `scripts/ingest_external.py`. It extracts, reprojects and cleans each layer, tags every point to a district, and writes 18 analysis-ready files with a provenance record (Table 3.1). The engine reads these files but never modifies its source data.

Table 3.1: Ingested external data (`data/external/uganda`)

File	Source	Content
<code>tx_lines.geojson</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	113 lines: operational/under-construction/planned with kV, year, length (UTM)
<code>tx_substations.csv</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	66 transmission substations with status
<code>dist_substations.csv</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	99 distribution substations (2023)
<code>dist_transformers.csv</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	20683 distribution transformers (UEDCL/WENRECO/UMEME)
<code>mv_points.parquet</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	185796 points sampled ≤ 1 km along 33/11 kV MV lines (distance-to-grid engine)
<code>mv_km_by_district.csv</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	MV (33/11 kV) line length per district
<code>industrial_parks.csv</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	14 industrial parks (UIA 2024) with power-connection status
<code>service_territories.geojson</code>	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	13 distribution service territories

File	Source	Content
commercial_by_district.csv	IERMP_GIS_DATA.gdb (MEMD Integrated Energy Resource Master Plan, 15 GIS Data)	13628 commercial facilities counted by district (commerce allocation key)
step_loads.csv	7 Electrification policies-20260826T120323Z-1-001.zip / Step loads.xlsx (MEMD IERMP)	large step loads by year, GWh (data centres, steel, parks, phosphates)
feeder_forecasts.csv	6 Demand Forecast-20260826T120226Z-1-001.zip / Feeder_Demand_Forecasts_UEDCL.xlsx	73 UEDCL 33 kV feeders, max demand 2023 + forecast to 2030 (kVA)
unit_costs_observed.csv	14 Customer Demand and Distribution Planning-20260826T120409Z-1-001.zip	101 utility unit costs (USD)
utility_losses_2023.csv	2 Historical Energy and electricity demand-20260826T120247Z-1-001.zip / ERA DistributionStatisticsQ1_2024.xlsx	energy purchased vs sold per distribution utility/territory, calendar 2023
schools.csv	AICTEM SDI (SDIInfrastructure/data/GIS)/Education (MoES EMIS)	21193 schools with type, students, grid distance, design kWh
generation_sites.csv	AICTEM SDI (SDIInfrastructure/data/GIS)/Energy (MEMD 2018)	71 generation sites with coordinates, capacity, status
mining_areas.geojson	Maus et al. global mining polygons v2 (SDI raw/UGA)	17 mining polygons in Uganda
pop_grid_1km.parquet	WorldPop 2020 constrained (SDI raw/UGA), aggregated ×12 (~1 km)	126986 populated cells, total 42,176,605; distance to MV network and to transmission (km)
wind_by_district.csv	Global Wind Atlas 100 m (SDI raw/UGA)	mean / max wind speed at 100 m by district

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_sources.csv).

3.2 Geography

The district layer has the 135 districts of the current administrative map, grouped into the four regions (Figure 3.1). Every district is assigned to the nearest of the 17 transmission buses of the power model. The districts assigned to a bus form its **supply zone**, and the zone is the bridge between district-level demand and bus-level power flow.

The supply zones are very unequal in size.

- **Northern zones.** The Lira bus serves 34 districts and the Opuyo bus 20, covering most of the north and north-east. This is a direct consequence of the thin northern network.
- **Kampala.** The metropolitan area is split between five buses that serve one to three districts each.

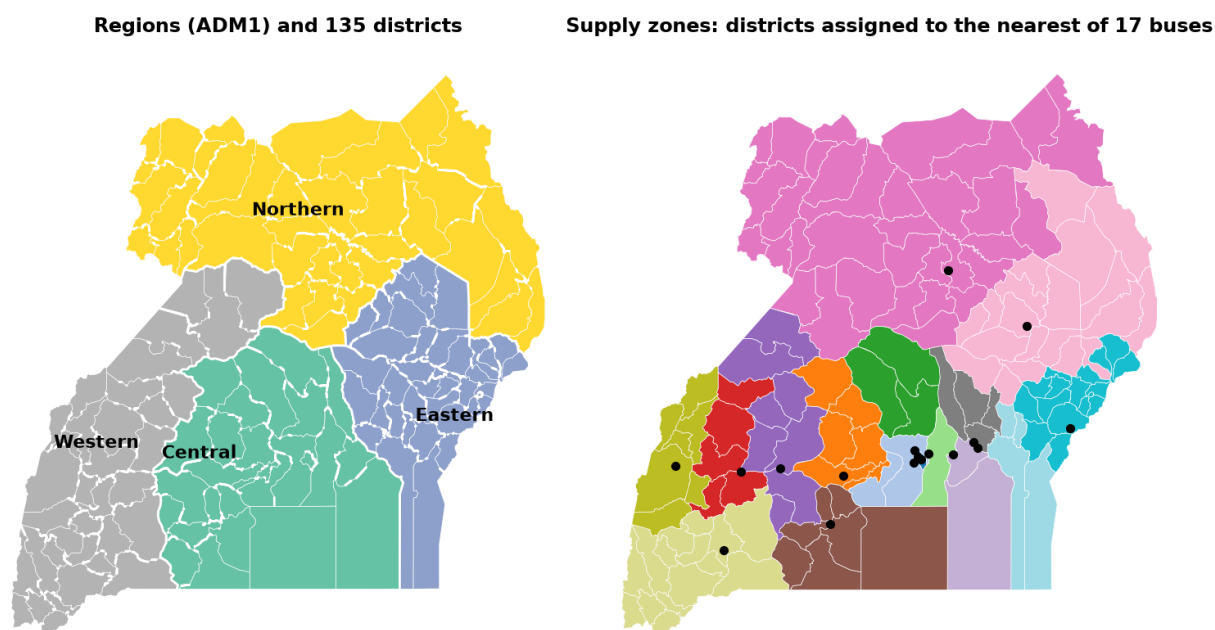


Figure 3.1: Regions, districts and the 17 supply zones of the power model

Source: Boundaries: national admin boundaries via AICTEM SDI

Population comes from the WorldPop 2020 constrained estimate at 100 m resolution. The engine aggregates it to a 1 km grid of 126,986 populated cells, totalling 42.2 million people in 2020 (Figure 3.2). The grid serves two purposes:

- it gives the distance from every populated square kilometre to the transmission and MV networks, from which the coverage statistics of Chapters 6 and 7 are computed;
- it gives the population-weighted distances used in the access model.

District populations are grown at 3 % a year to 2023, giving 46.1 million. Household numbers are scaled so that the national total equals the 2024 census count of 10,698,913.

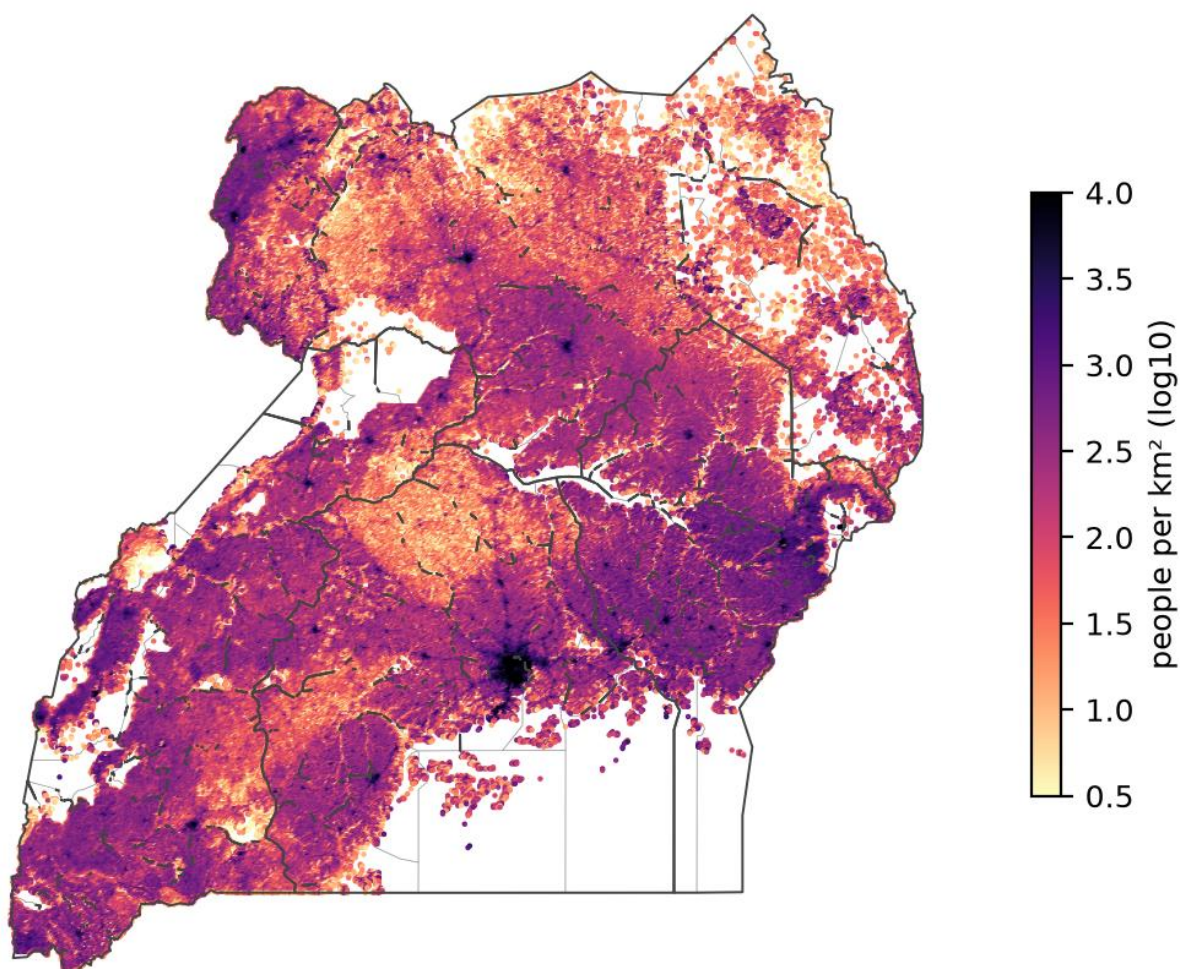


Figure 3.2: Population on the 1 km grid (WorldPop 2020 constrained, aggregated from 100 m)

Source: WorldPop 2020 via AICTEM SDI

3.3 Demand and customers

Demand. The demand side starts from the metered 2023 load: UETCL's Annual Load Curves 2023, 8,760 hourly values. These are reduced to 25 slices that preserve the annual energy exactly and carry a 100-hour system-peak block. The bus split follows UETCL's Feeder Maximum Demand register.

Sales and customers. Sales and customers by tariff class come from ERA's IRP data sheet and the 2023 tariff schedule. The six classes (residential, commercial, medium industrial, large industrial, extra-large industrial and street lighting) sum to 4,329.8 GWh of billed energy.

Households. The census gives 10.7 million households, of which 25.3 % are grid-connected. It splits them into rural and urban, connected and unconnected groups, each with an income and a spend on electricity and cooking.

Step loads. The IERMP step loads (Step loads.xlsx) give annual energy from 2024 to 2040 for four large new loads: data centres, iron and steel, industrial parks and phosphates. The engine adds only the increment over their 2024 level, to avoid double-counting the part already in metered sales.

Institutions.

- Health: the MoH National Health Facility Registry gives 3,169 geolocated facilities by level, from HC II to regional referral hospitals.

- **Schools:** the MoES EMIS school layer, via the SDI, gives 21,193 schools by type, with enrolment and a design energy estimate.
- **Industry:** the IERMP layer of 14 industrial parks gives their status and power-connection status. The IERMP commercial facilities layer gives 13,628 points, used to locate commercial demand.

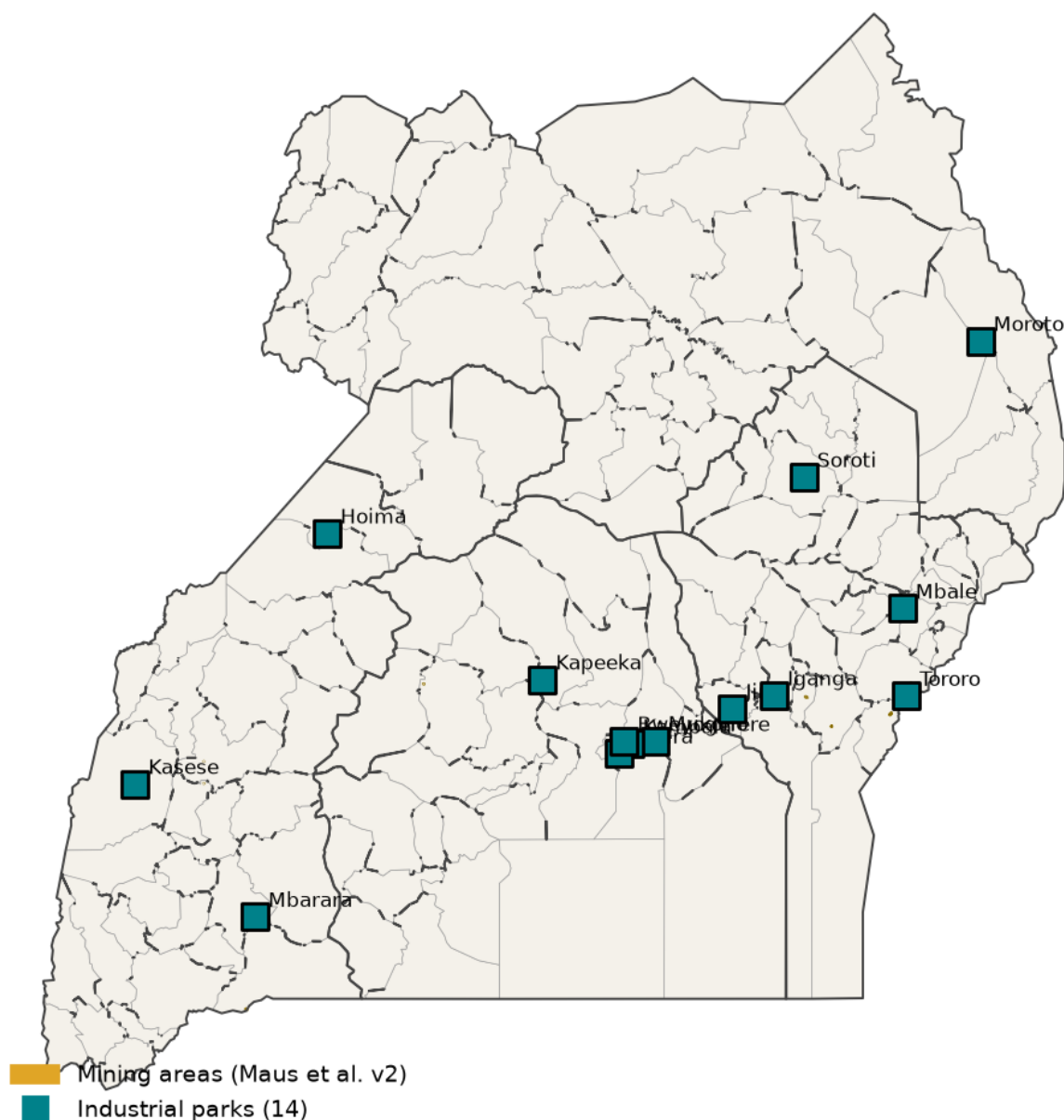


Figure 3.3: Industrial parks (UIA 2024) and mining areas

Source: IERMP GIS IndustrialParks_2024; global mining polygons v2 (SDI)

3.4 Generation

Fleet. The existing fleet comes from ERA's register of licensed plants in operation. Metered energy comes plant by plant from UETCL's System Operation Data 2023. Monthly metered energy for the main plants and the independent power producers supports the analysis of seasonality in Chapter 5.

Plant locations. Where plant names match, locations come from the MEMD 2018 generation-sites layer; otherwise from the plant's connecting substation.

Candidates. The candidate set for the least-cost plan comes from the MEMD/ERA IRP list of generation power plants. For each candidate it gives capital cost, lifetime, fixed and variable O&M and heat rate. These are annuitised at 10 % in the dataset. The engine recovers overnight capital cost by dividing by the capital recovery factor at 10 %.

Batteries. The engine adds three battery candidates at Kampala, Lira and Tororo. These are marked ASSUMED.

3.5 Transmission and distribution

The power model's grid. The model uses the 24 corridors of the AEGID/UETCL transmission layer, each with its thermal rating, loss factor, length, voltage and status. Five corridors are under construction; they are available from 2026 in the model.

The full network. The IERMP geodatabase gives the network in full:

- 51 operational, 10 under-construction and 52 planned transmission line segments, with voltage and commissioning year;
- 66 transmission substations: 41 operational, 6 under construction and 19 at planning stage.

Distribution assets. The IERMP layers give:

- 99 distribution substations (2023);
- 20,683 distribution transformers of UEDCL, Umeme and WENRECO;
- the 33 kV and 11 kV MV lines, 262,000 line segments in all.

The engine samples the MV lines at 1 km or finer, giving 185,796 points. These points are used to compute the distance from every populated cell to the MV network.

Losses and unit costs.

- ERA's Distribution Statistics workbook gives energy purchased and sold by each distribution utility and UEDCL territory for each quarter of 2023. From these the engine computes observed loss rates by territory.
- Utility cost sheets give the high-level unit costs of MV equipment and the cost per km of 33 and 11 kV lines (Table 3.2). These replace assumed values in the distribution and access costing.

Table 3.2: Observed utility unit costs (UEDCL/Umeme cost sheets)

Category	Item	Unit	USD
MV EQUIPMENT	33kV bays	each	80,000
MV EQUIPMENT	ABS 33kV	package	5,000
MV EQUIPMENT	auto recloser	package	30,000
MV EQUIPMENT	11kV bays	each	50,000
MV EQUIPMENT	11kV outdoor ring main	each	30,000
MV EQUIPMENT	Auxilliary transformer and installation		10,000
MV EQUIPMENT	10/14 MVA transformer	each	400,000
MV EQUIPMENT	15/20 MVA transformer 33/11kV	each	400,000
MV EQUIPMENT	5MVA power transformer	each	300,000
MV EQUIPMENT	33kV outdoor switch gear sytem	package	100,000
MV EQUIPMENT	Ring main unit(RMU)	package	100,000
MV EQUIPMENT	Ring main unit - automated (RMU)	package	130,000
33KV 3-PHASE COST PER KM - OVERHEAD LINE	25MMSQ ACSR	km	16,521
33KV 3-PHASE COST PER KM - OVERHEAD LINE	50MMSQ ACSR	km	18,034
33KV 3-PHASE COST PER KM - OVERHEAD LINE	100MMSQ ACSR	km	20,570
33KV 3-PHASE COST PER KM - OVERHEAD LINE	150MMSQ AAAC	km	22,726

Category	Item	Unit	USD
33KV 3-PHASE COST PER KM - OVERHEAD LINE	200MMSQ AAAC	km	27,245
11KV 3-PHASE COST PER KM - OVERHEAD LINE	25MMSQ ACSR	km	16,480

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_unit_costs.csv).

3.6 Governance and licences

The source data belong to their publishers: MEMD, UETCL, ERA, UBOS, MoH, MoES and UEDCL.

- The IERMP geodatabase and planning workbooks are government planning data made available to the EDIP programme.
- WorldPop and the Global Wind Atlas are published under open licences.
- The district boundaries derive from national administrative boundaries held in the AICTEM SDI.

The engine records the source and extraction of every file in `data/external/uganda/PROVENANCE.md`. It never alters the source archives. Assumptions are held in one file, `config/engine_defaults.yml`, so that they can be reviewed and changed in one place.

3.7 Quality across the evidence base

The quality of the evidence is uneven, and the report is explicit about it.

- **Strong (OBSERVED):** the base-year electricity system. Metered generation, sales, losses, peak and the fleet are measured, and the engine reproduces them.
- **Strong (OBSERVED):** the network geography. Lines, substations, transformers and the MV network are digitised utility data.
- **Moderate (CALIBRATED):** the split of metered sales into segments. Only the tariff-class totals are measured. The share of commercial sales that goes to health, education and transport comes from bottom-up estimates. The shares of industrial sales that go to mining, agriculture and water are ASSUMED.
- **Moderate (CALIBRATED):** district access rates. No district-level measurement of grid access exists in the data. The engine distributes the census national rate in proportion to the observed density of distribution transformers.
- **Weakest (ASSUMED):** the future. This covers the realisation of the step loads, the pace of e-mobility, the oil and gas projects, institutional energy intensities, and the financing mix. The simulations of Chapter 10 test the most important of these.

3.8 Known gaps in the data

- **District access rates.** No surveyed district access rates are available. The UNHS or a new energy access survey would replace the transformer-based estimate.
- **Feeder losses.** No feeder-level loss data are available. District loss rates are modelled from MV feeder distance and scaled to the observed national total.
- **Plant coordinates.** Some small hydro plants are aggregated into regional clusters in the fleet table, and their exact coordinates are not used.
- **Substation ratings.** The distribution substations carry no transformer rating (MVA) in the layer. Service-area loading is compared with population and distance, not with capacity.
- **Planning load flow.** The UETCL PSS/E planning models in the transmission-planning archive are not yet read by the engine. Using them would allow AC load-flow checks of the plan.

3.9 Implications for planning

- The base-year diagnosis of generation, grid, losses, customers and access is on firm ground and can be used directly.
- The forward view depends heavily on a few assumptions, above all the realisation of the IERMP step loads. Planners should treat the base scenario as one point in the range of Chapter 10, not as a forecast.
- The most valuable data investments would be:
 - a district-level access survey;
 - feeder-level loss metering;
 - substation ratings in the GIS;
 - regular updates of the step-load register.

Each of these would move a result from CALIBRATED or ASSUMED to OBSERVED.

CHAPTER 4

4 Energy demand

This chapter asks how much electricity Uganda needs: by which segment of the economy and society, in which district, and in which hour of the year. The answer sets the load that the power system must serve in every later chapter. The chapter implements design Chapter 1 (`docs/01_energy_demand.md`).

4.1 What the module produces

For each of ten segments, each of 135 districts and each year from 2023 to 2040, the demand module produces final electricity demand in GWh. From these it derives three further results:

- the national generation requirement, after network losses and exports;
- the peak demand;
- the load in each of the 25 time slices at each of the 17 transmission buses. This is the input to every PyPSA run.

The ten segments are:

- households;
- commerce and services;
- industry;
- mining and extractives;
- transport;
- health;
- education;
- agriculture and agro-processing;
- water and sanitation;
- public lighting.

4.2 The base year: 2023

4.2.1 From tariff classes to segments

ERA records sales by tariff class, not by segment. Health facilities, schools and water utilities buy on commercial or industrial tariffs. Mines and cement plants buy as large or extra-large industrial customers. The engine therefore carves each metered class into segments, following the rules in Table 4.1:

- **Households** take all residential sales.
- **Health and education** are estimated bottom-up from the facility and school registers and subtracted from commercial sales. What remains is commerce and services.
- **Industrial sales** are split between industry, agriculture and agro-processing, water, and mining in fixed shares.

The segments sum exactly to the metered 4,329.8 GWh. This is validation check V1-1.

Table 4.1: Base-year (2023) final consumption by segment, carved from metered tariff-class sales

Segment	GWh 2023	Share	Carved from	Status
Households	965.8	22.3 %	residential (100 %)	OBSERVED
Commerce & services	325.2	7.5%	commercial – health – education – transport	CALIBRATED
Industry	2,318.9	53.6 %	medium 75 % + large 90 % + extra-large 75 %	CALIBRATED
Mining & extractives	265.0	6.1%	extra-large 25 %	ASSUMED
Transport	5.8	0.1%	commercial (e-mobility pilots)	ASSUMED
Health	71.0	1.6%	commercial — 3,169 MoH facilities bottom-up	CALIBRATED
Education	105.0	2.4%	commercial — EMIS schools bottom-up	CALIBRATED
Agriculture & agro-processing	151.8	3.5%	medium industrial 25 %	ASSUMED
Water & sanitation	118.7	2.7%	large industrial 10 %	ASSUMED
Public lighting	2.6	0.1%	street lighting (100 %)	OBSERVED

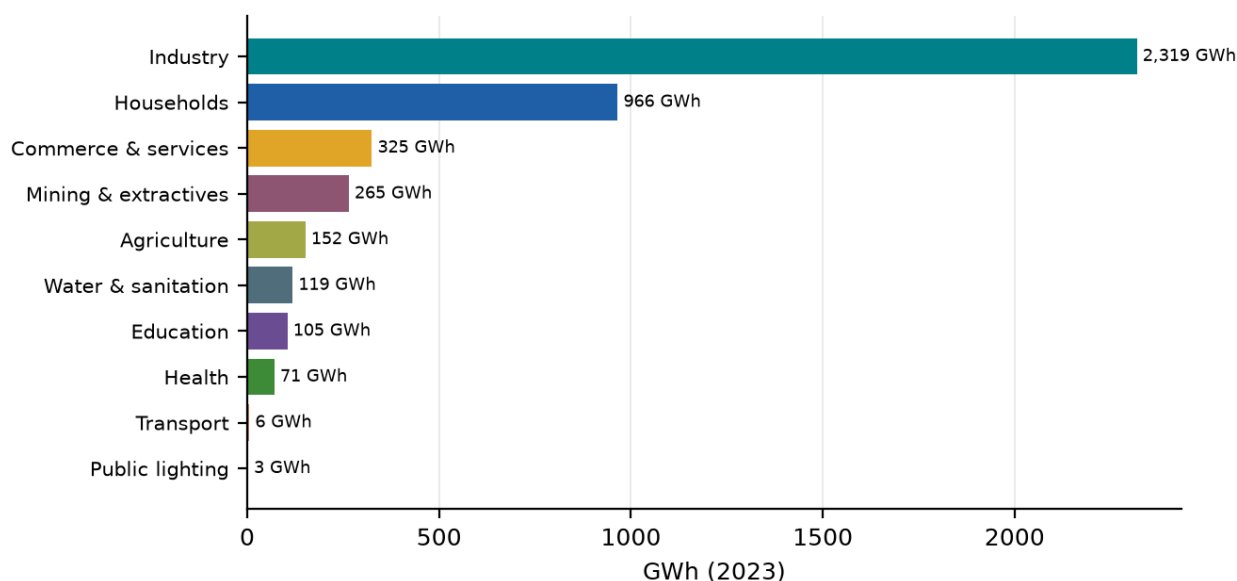
Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_seg_base.csv).

Figure 4.1 shows the result. Industry dominates: 2,319 GWh, more than half of all electricity sold. Households come second at 966 GWh, and commerce third at 325 GWh.

The social sectors are small in energy terms but large in development terms:

- health facilities used an estimated 71 GWh;
- schools used 105 GWh.

Transport used a negligible 5.8 GWh, from the first electric motorcycles and cars.

**Figure 4.1:** Final electricity consumption by segment, 2023 (4,330 GWh metered, carved into segments)

Source: ERA tariff-class sales 2023; segment carve-out Ch.1 §1.2

4.2.2 The shape of demand in time

The metered 2023 load gives the shape of demand through the year (Figure 4.2). The system peak of 988 MW falls in the evening block, when household lighting and cooking coincide with commercial load. The load factor, annual energy divided by peak × 8,760 hours, is 68.6 %. That is high for a developing system and reflects the weight of continuous industrial load.

The load-duration curve (Figure 4.3) shows the same thing. Demand never falls below 55 % of the peak slice, and it exceeds 70 % for about 5,840 hours a year. After the 100-hour peak block, the highest slices are the evening blocks. Uganda needs mainly base-load energy, with a relatively modest peaking requirement.

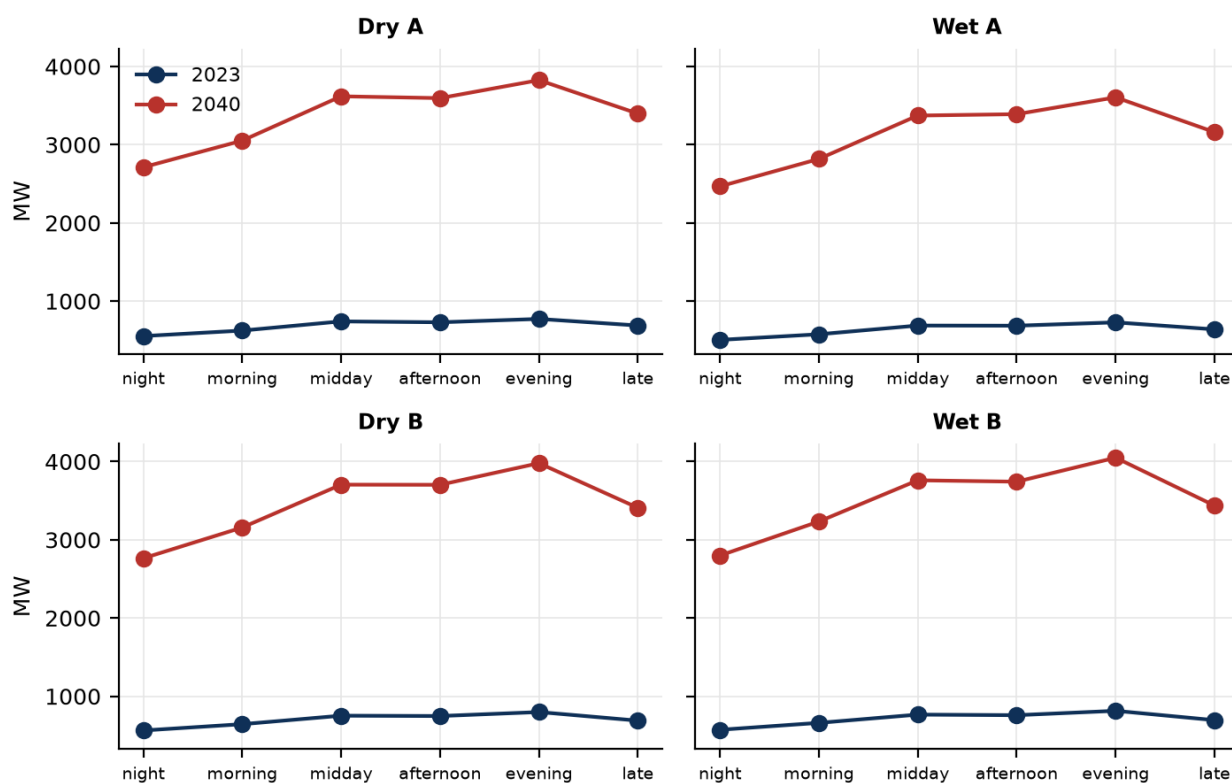


Figure 4.2: System load shape by season and diurnal block, 2023 (metered) and 2040 (projected)

Source: UETCL Annual Load Curves 2023 reduced to 25 slices; engine projection

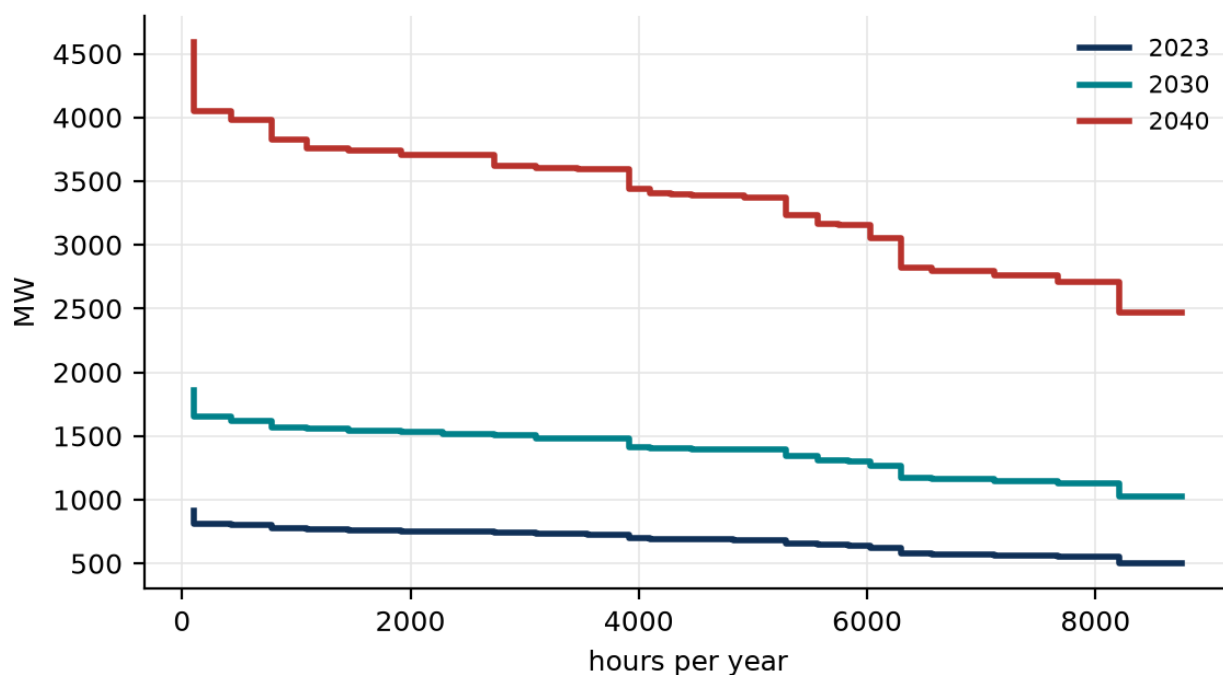


Figure 4.3: Load-duration curves, 2023, 2030 and 2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

4.2.3 Customers

Figure 4.4 and Table 4.2 show the customer structure behind these numbers. Residential customers are 95 % of all customers but take 22 % of the energy. The extra-large industrial class has 49 customers and takes 24 % of the energy. The average residential customer used 481 kWh in 2023. An extra-large industrial customer used 21,600 MWh. Tariffs follow the same gradient in reverse: residential customers pay 213 USD/MWh and extra-large industry 86 USD/MWh. Chapter 7 returns to what this means for cross-subsidies.

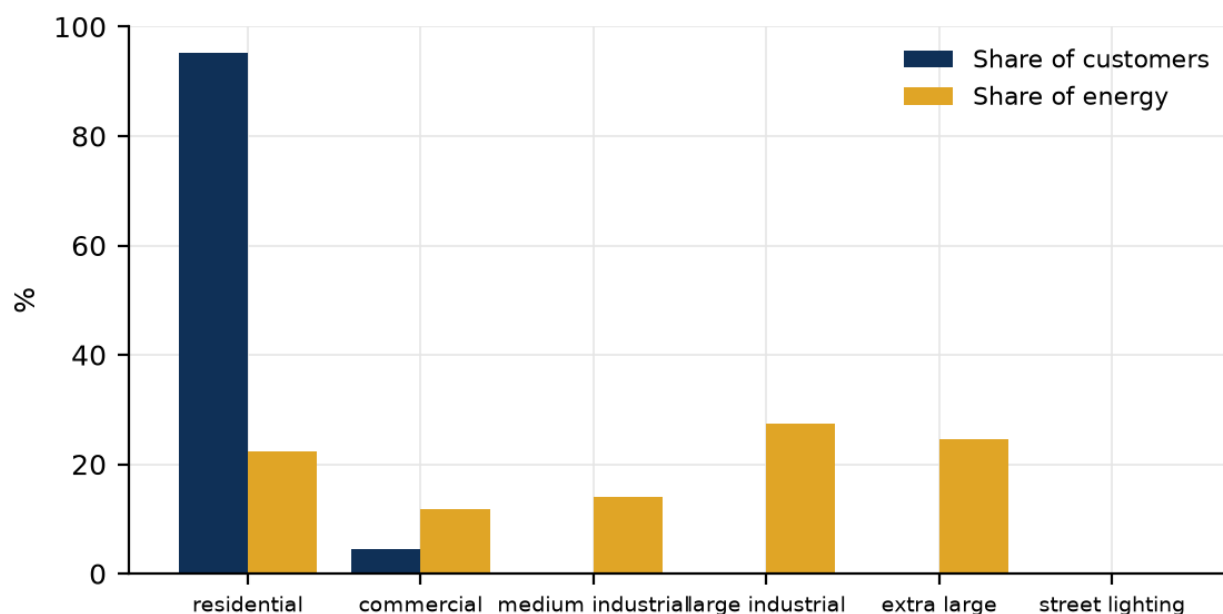


Figure 4.4: Tariff classes: share of customers against share of energy, 2023

Source: ERA IRP data sheet 2023

Table 4.2: Electricity customers and tariffs by class, 2023 (ERA)

Class	Customers	Energy (GWh)	kWh per customer	Tariff (USD/MWh)	Cost to serve (USD/MWh)	Collection rate
residential	2,008,044	965.8	481	213.2	150.0	92.0%
commercial	95,068	507.0	5,333	162.1	138.0	95.0%
medium_industrial	3,709	607.3	163,750	122.3	120.0	97.0%
large_industrial	690	1,187.0	1,720,223	101.8	105.0	98.0%
extra_large	49	1,060.1	21,635,245	86.1	92.0	99.0%
street_lighting	346	2.6	7,488	98.0	115.0	85.0%

Source: AICTEM Energy Modelling Engine, base scenario SO (report/build/data/t_customers.csv).

4.3 Method

4.3.1 Driver-based projection

Commerce, industry, mining, agriculture and water follow the driver identity of Equation (2.1). Their activity grows with real GDP (6 % a year in the base scenario) times a segment income elasticity:

- 1.0 for commerce;
- 0.9 for industry when the step loads are modelled separately, and 1.1 otherwise;
- 1.0 for mining;
- 0.8 for agriculture;
- 0.7 for water.

Commerce and industry also improve their efficiency by 0.5 % a year.

4.3.2 Households: access and use

Household demand has two parts:

- **Existing connections.** Use per existing connection grows at 2 % a year as appliance ownership rises.
- **New connections.** New connections start at the level of a Tier 2 connection (200 kWh a year). They reach that level over three years: 60 % of it in the first year, 80 % in the second and 100 % from the third.

$$E_y^{HH} = H_{y_0}^c u_{y_0} (1 + g_u)^{y - y_0} + \sum_{\tau = y_0 + 1}^y \Delta H_{\tau}^{grid} u^{new} \rho(y - \tau) \quad (4.1)$$

where

- $H_{y_0}^c$ is the number of connected households in 2023 (2.71 million);
- u_{y_0} is the use per connection (481 kWh);
- g_u is the growth in use (2 %);
- ΔH_{τ}^{grid} is the number of new grid connections in year τ ;
- u^{new} is the Tier 2 use (200 kWh);
- ρ is the ramp.

The access rate rises linearly from 25.3 % in 2023 to the 2030 target of 60 %, and then to universal access in 2040. Of the new connections, 85 % are made to the grid. This is the national grid share of the least-cost electrification model of Chapter 13. The rest are served off-grid and do not load the transmission system.

4.3.3 Health and education: bottom-up from the registers

Every one of the 3,169 health facilities is a demand point with an annual energy intensity set by its level (Table 4.6):

- 5 MWh for a HC II;
- 15 MWh for a HC III;
- 60 MWh for a HC IV;
- 250 MWh for a general hospital;
- 1,000 MWh for a regional referral hospital.

In 2023, 50 % of HC IIs, 75 % of HC IIIs, 95 % of HC IVs and all hospitals are assumed to be electrified. These shares are chosen so that health demand is about 71 GWh. They rise to 100 % by 2030, and the facilities closest to the MV network are electrified first. Intensity grows at 3 % a year as services improve.

Schools follow the same logic, with EMIS schools by type and electrification completed by 2035 (Table 4.7). The 250 tertiary institutions are not in the school layer, so they are allocated by population.

4.3.4 Transport

Transport demand comes from assumed vehicle paths (Table 4.8):

- electric motorcycles rise from 5,000 in 2023 to 100,000 in 2030 and 600,000 in 2040;
- electric cars rise from 500 to 60,000;
- electric buses reach 1,500 by 2040.

Electric traction on the Standard Gauge Railway adds 200 GWh a year from 2032.

4.3.5 Large new loads

The IERMP step loads and the project loads enter as additive new load (Table 4.4).

- The IERMP step loads are industrial parks, iron and steel, data centres and phosphates. Each is located at the districts where the load is expected: the 14 industrial parks, and Kabale, Tororo and Mukono for steel.
- The oil and gas project loads are EACOP pumping, the Hoima refinery and the Kilembe mine revival.
- Four irrigation schemes are also included.

All the non-IERMP loads are ASSUMED placeholders. Each can be switched off.

4.3.6 From final demand to requirement and peak

The generation requirement follows Equation (2.2), calibrated on 2023:

- a distribution loss rate of 17.35 %, falling to the 12 % target by 2030;
- a transmission loss rate of 5.22 %;
- net exports of 451 GWh.

The 2023 requirement is 5,978 GWh against 5,987 GWh generated, a 0.15 % statistical difference. Peak demand is the requirement divided by the load factor $\times 8,760$ hours. The bus loads keep each bus's metered 2023 shape and scale it by the demand growth of its supply zone.

4.4 Results: the national demand path

Figure 4.5 and Table 4.3 show the projected demand by segment. Final demand grows 5.6-fold:

- 4,330 GWh in 2023;
- 5,734 GWh in 2026;
- 9,759 GWh in 2030;
- 15,162 GWh in 2035;
- 24,185 GWh in 2040.

The average growth rate is 10.6 % a year.

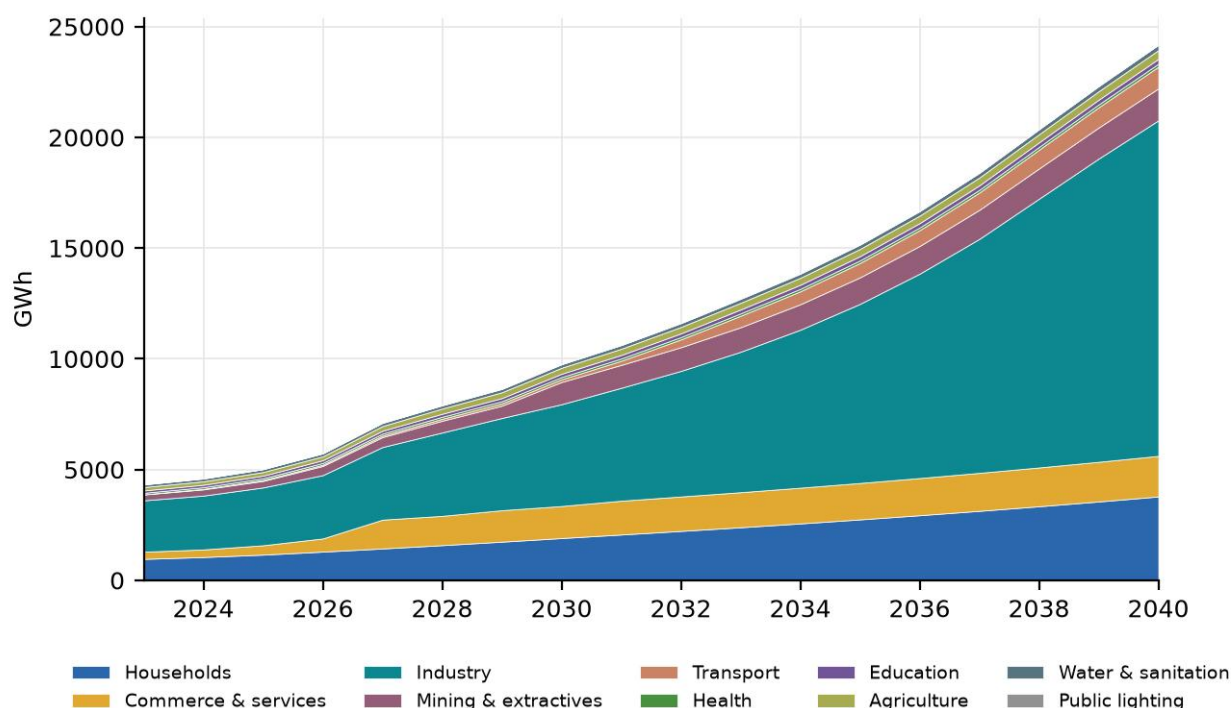


Figure 4.5: Final electricity demand by segment, 2023–2040, base scenario

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

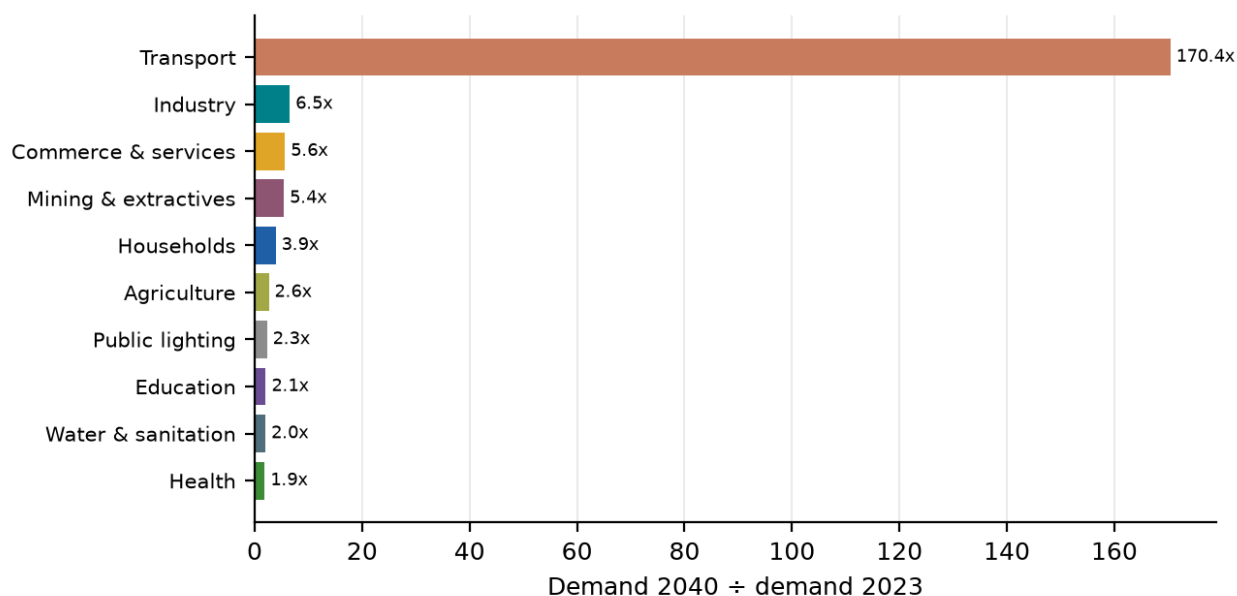
Table 4.3: Final electricity demand by segment, GWh, base scenario

Segment	2023	2026	2030	2035	2040	Multiple 2040/2023	CAGR
Agriculture & agro-processing	152	175	272	328	398	2.6x	5.8%
Commerce & services	325	595	1,446	1,646	1,834	5.6x	10.7%
Education	105	123	151	193	218	2.1x	4.4%
Health	71	82	99	115	133	1.9x	3.8%
Households	966	1,294	1,907	2,748	3,784	3.9x	8.4%
Industry	2,319	2,859	4,597	8,088	15,151	6.5x	11.7%
Public lighting	3	3	4	5	6	2.3x	5.0%
Mining & extractives	265	414	1,005	1,196	1,443	5.4x	10.5%
Transport	6	55	120	650	980	170.4x	35.3%
Water & sanitation	119	134	158	194	239	2.0x	4.2%
Total final consumption	4,330	5,734	9,759	15,162	24,185	5.6x	10.6%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_seg_path.csv).

The growth is very uneven across segments (Figure 4.6).

- **Industry** grows 6.5-fold, to 15,151 GWh in 2040. It is 63 % of total demand in 2040, against 54 % in 2023.
- **Commerce and services** grow 5.6-fold, largely because of the data-centre step load, which reaches about 1,000 GWh by 2030.
- **Mining and extractives** grow 5.4-fold, as the refinery, EACOP, phosphates and Kilembe come online.
- **Households** grow 3.9-fold, to 3,784 GWh, driven by access.
- **Transport** grows from almost nothing to 980 GWh. It is the fastest-growing segment in relative terms, but a small one in 2040.
- **Health and education** double. Electrification of the remaining facilities and growth in service intensity drive them to 133 GWh and 218 GWh respectively.

**Figure 4.6:** Growth multiple of each segment's demand, 2040 over 2023

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Figure 4.7 summarises the segment path in the four planning years. It is the compact form of the table the plan is built on.

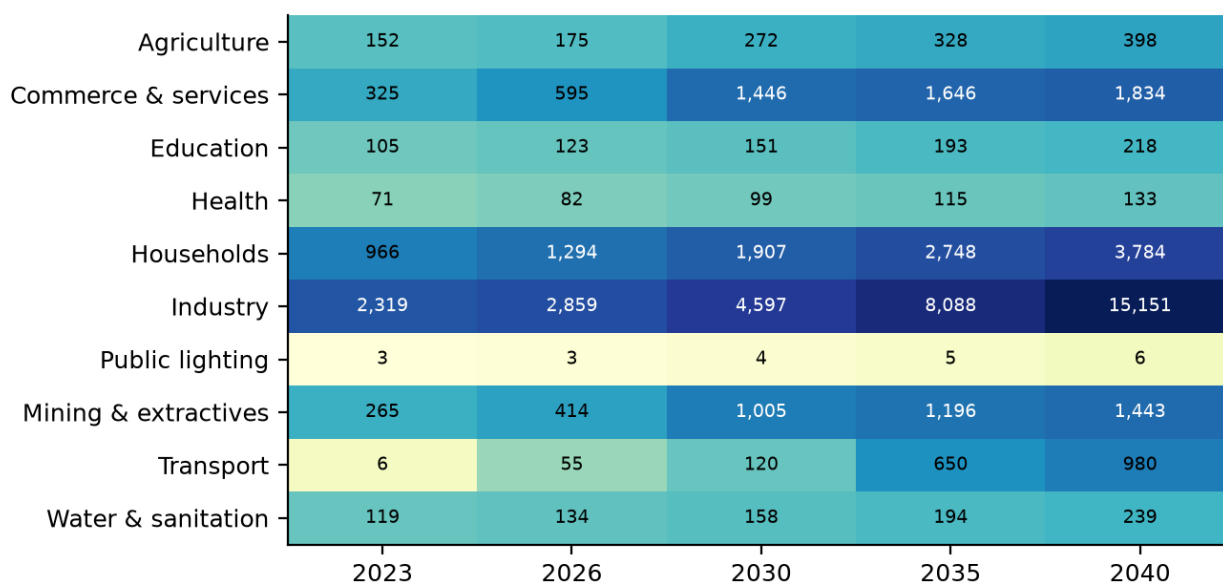


Figure 4.7: Segment demand by planning year, GWh (colour on a log scale)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

4.4.1 The large new loads

Figure 4.8 shows how much of the growth comes from discrete projects. The IERMP step loads alone reach 11,123 GWh by 2040, which is 46 % of final demand in that year:

- industrial parks: 7,348 GWh;
- iron and steel: 2,596 GWh;
- data centres: 1,029 GWh;
- phosphates: 149 GWh.

The industrial-park load ramps up continuously from 2025. Steel ramps up steeply after 2035.

These are the loads that turn Uganda's current surplus into a deficit. They are also the loads whose realisation is least certain. Chapter 10 shows what happens to the plan if only half of them, or none, are realised.

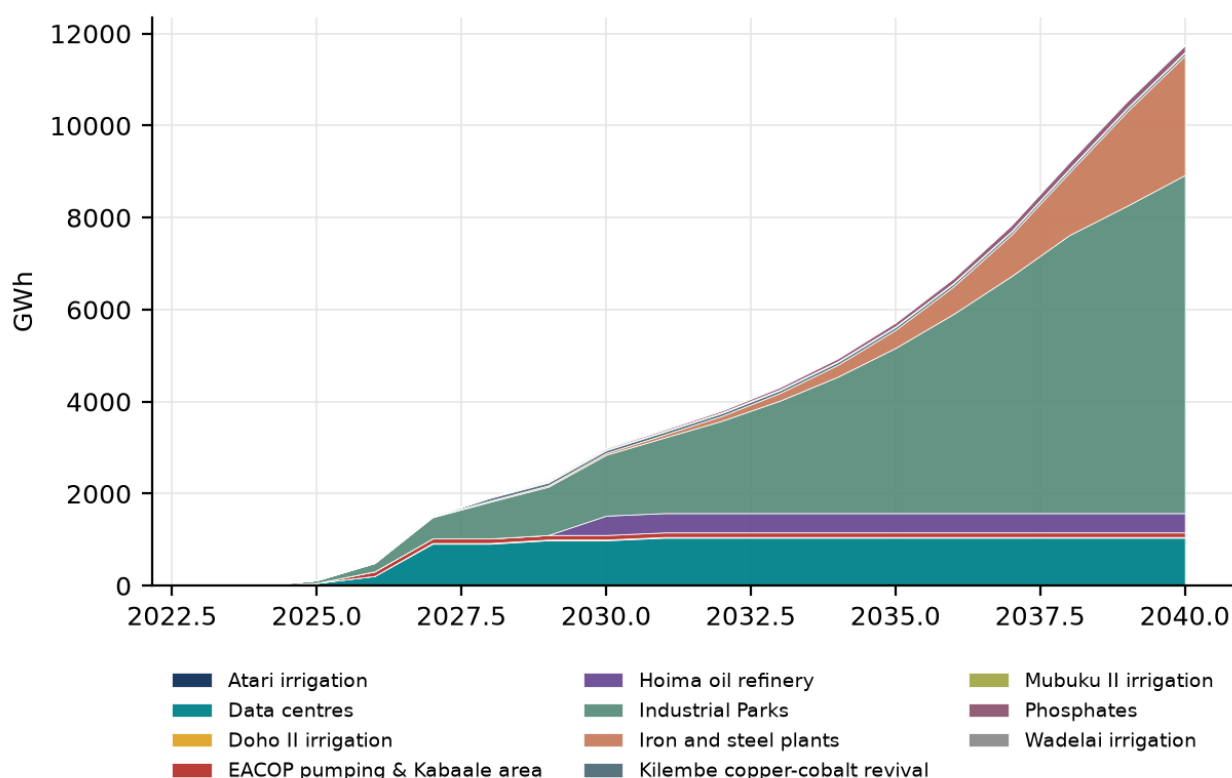


Figure 4.8: Large new loads: IERMP step loads (increment over 2024) and project loads

Source: IERMP Step loads.xlsx (MEMD); project loads engine_defaults.yml (ASSUMED)

Table 4.4: Large new loads: IERMP step loads (increment over 2024) and project loads

Load	Segment	Status	First year	GWh 2030	GWh 2035	GWh 2040
Atari irrigation	Agriculture & agro-processing	ASSUMED	2027	15	15	15
Data centres	Commerce & services	OBSERVED	2025	974	1,029	1,029
Doho II irrigation	Agriculture & agro-processing	ASSUMED	2027	15	15	15
EACOP pumping & Kabaale area	Mining & extractives	ASSUMED	2026	99	99	99
Hoima oil refinery	Mining & extractives	ASSUMED	2030	420	420	420
Industrial Parks	Industry	OBSERVED	2025	1,323	3,591	7,348
Iron and steel plants	Industry	OBSERVED	2027	39	393	2,596
Kilembe copper-cobalt revival	Mining & extractives	ASSUMED	2028	61	61	61
Mubuku II irrigation	Agriculture & agro-processing	ASSUMED	2028	15	15	15
Phosphates	Mining & extractives	OBSERVED	2027	26	83	149
Wadelai irrigation	Agriculture & agro-processing	ASSUMED	2029	15	15	15

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_new_loads.csv).

4.4.2 Households and access

The access path (Figure 4.9, Table 4.5) shows the scale of the household programme.

- **Households.** The number of households grows from 10.7 million to 17.7 million.
- **Access.** To reach 60 % access in 2030 and 100 % in 2040, the country must connect about 600,000 households a year in the mid-2020s, rising to over 1 million a year by 2040: 15.0 million new connections in total.
- **Grid versus off-grid.** 85 % of the new connections are to the grid. The grid access rate therefore rises to 87.5 % by 2040, and the rest of the population is served by solar home systems.

The new connections add less energy than their number suggests, because each starts at 200 kWh a year. Household demand grows 3.9-fold while the number of connections grows 6.5-fold.

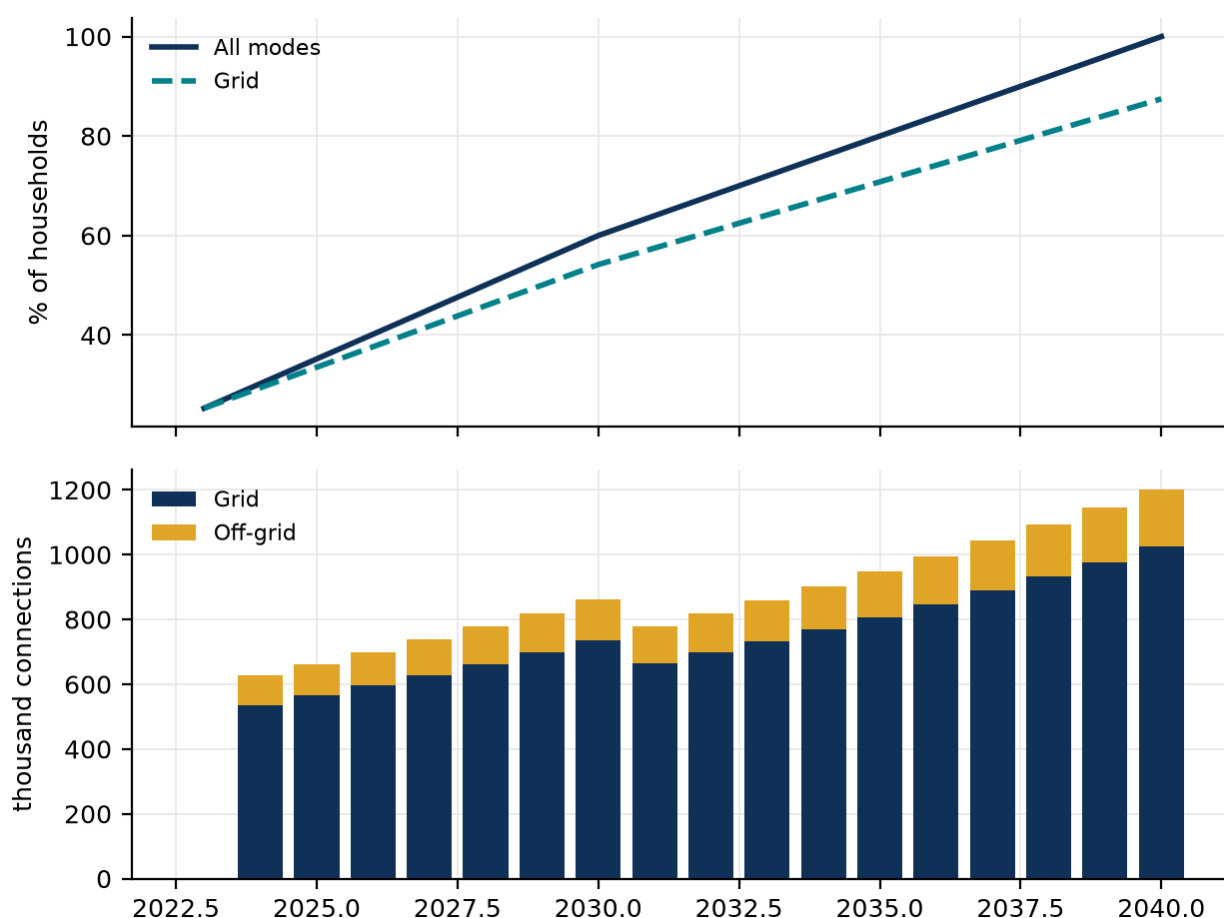


Figure 4.9: Household access path and new connections per year, base scenario

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.5: Household access path, base scenario (targets 60 % by 2030 and 100 % by 2040)

Year	Households (m)	Connected (m)	Access rate	Grid access rate	New grid connections in year	New off-grid connections in year
2023	10.70	2.71	25.3%	25.3%	0	0
2026	11.69	4.70	40.2%	37.7%	596,087	103,362
2030	13.16	7.89	60.0%	54.2%	735,664	127,565
2035	15.25	12.20	80.0%	70.8%	807,760	140,067
2040	17.68	17.68	100.0%	87.5%	1,024,205	177,598

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_access_path.csv).

4.4.3 Health, education and transport

Health-sector demand rises from 71 GWh to 99 GWh in 2030 and 133 GWh in 2040 (Figure 4.10, Table 4.6).

- By 2030 all 1,492 HC IIs and 1,358 HC IIIs are electrified. In 2023 an estimated 746 HC IIs and 340 HC IIIs were not.
- In energy terms, general hospitals and HC IIIs remain the largest users.

The location of the facilities (Figure 4.11) matters more than their energy. The unelectrified facilities are concentrated where the MV network is thinnest.

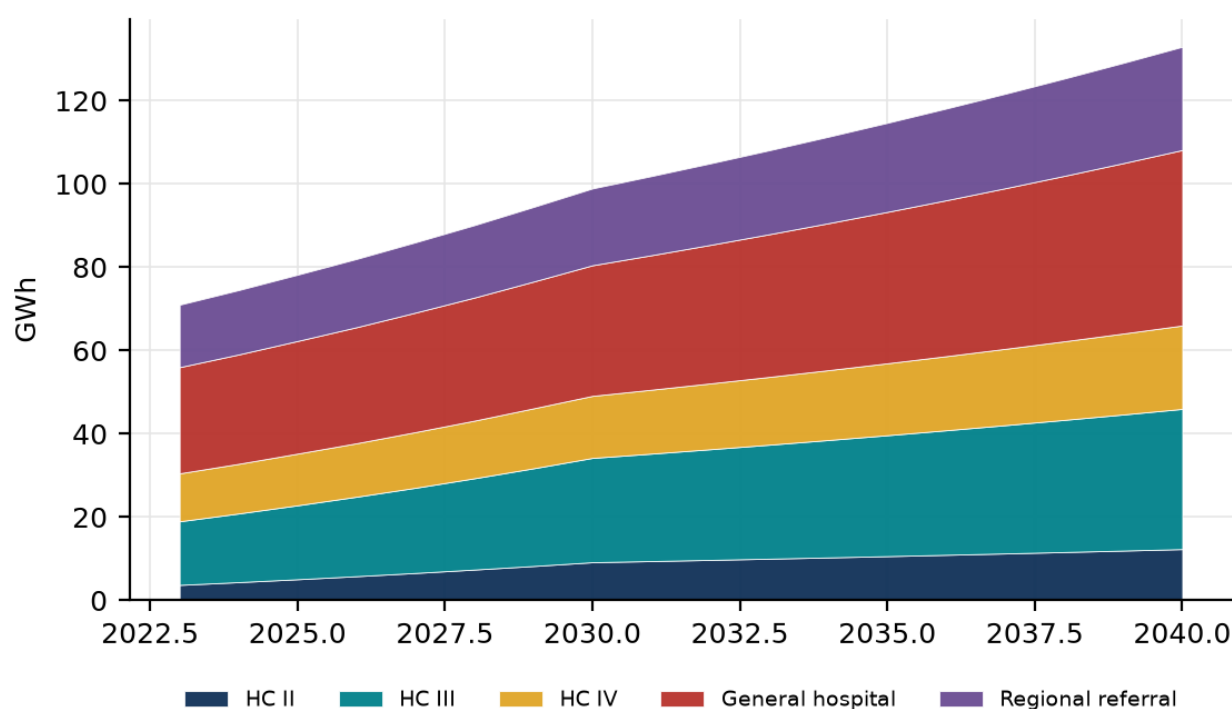


Figure 4.10: Health-sector electricity demand by facility level, 2023–2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.6: Health-sector electricity demand by facility level (MoH registry, 3,169 facilities)

Level	Facilities	Intensity (MWh/yr)	Electrified 2023	Electrified 2030	GWh 2023	GWh 2030	GWh 2040
HC II	1,492	5	746	1,492	3.7	9.2	12.3
HC III	1,358	15	1,018	1,358	15.3	25.1	33.7
HC IV	202	60	192	202	11.5	14.9	20.0
General hospital	102	250	102	102	25.5	31.4	42.1
Regional referral	15	1,000	15	15	15.0	18.4	24.8

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_health.csv).

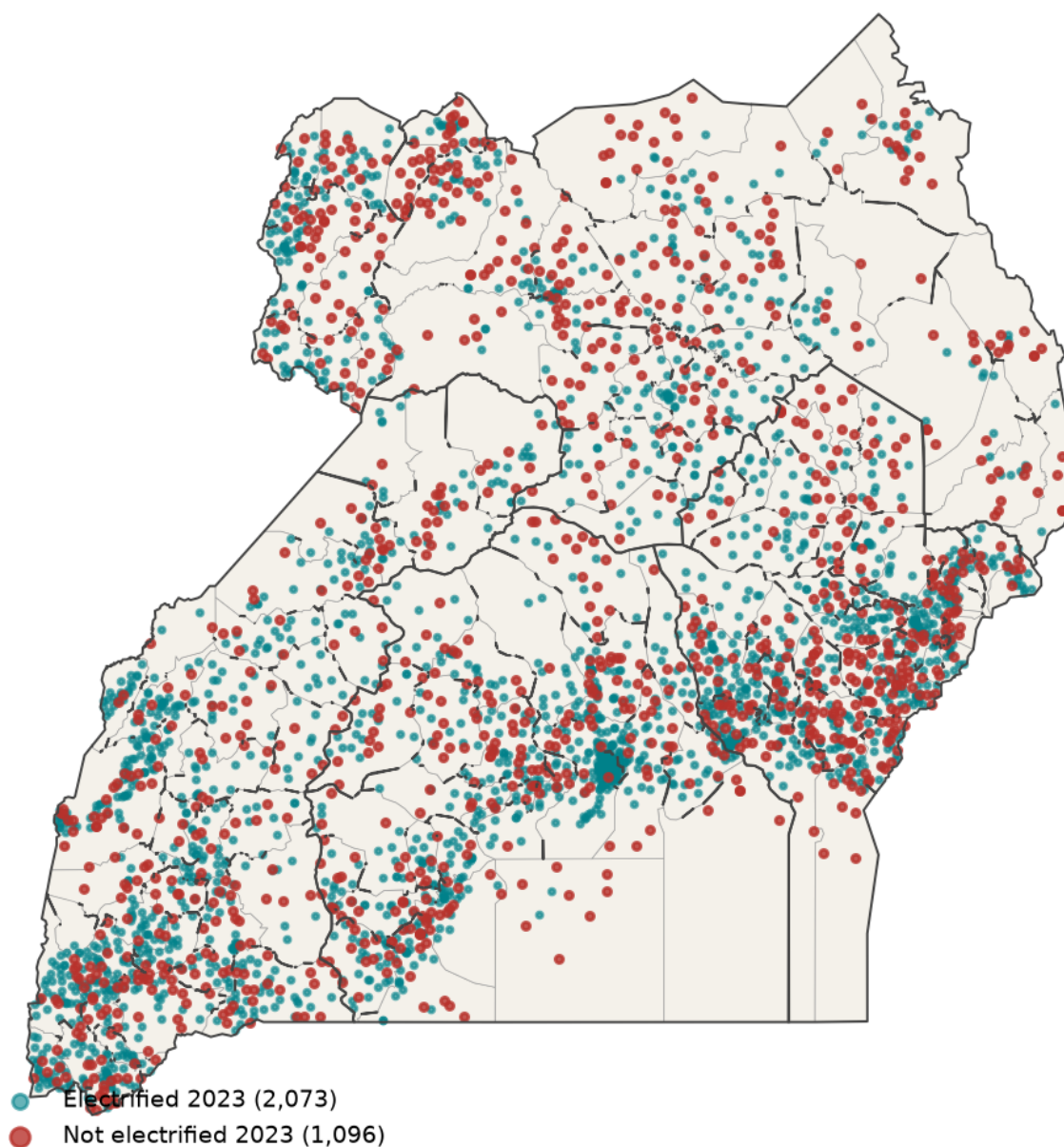


Figure 4.11: Health facilities and their modelled electrification status in 2023

Source: MoH National Health Facility Registry; electrification modelled nearest-to-MV first, calibrated to level shares

Education demand grows from 105 GWh to 218 GWh (Figure 4.12, Table 4.7). The largest share of the new demand is from primary schools: 22,707 of them are electrified by 2035. Only 5,065 were electrified in 2023. The school layer (Figure 4.13) shows how evenly schools are spread across the country. Electrifying them is an access programme in its own right.

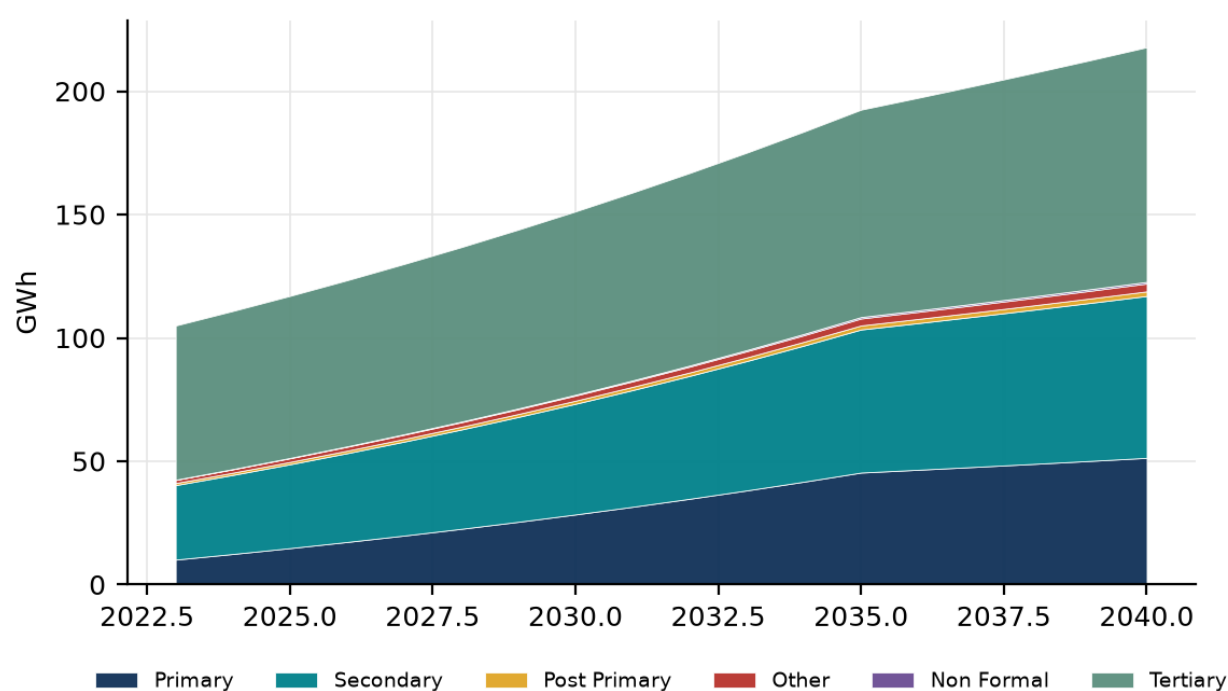


Figure 4.12: Education electricity demand by institution type, 2023–2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.7: Education electricity demand by institution type (EMIS school layer, 21,193 schools)

Institution type	Institutions 2023	Electrified 2023	Electrified 2035	GWh 2023	GWh 2040
Primary	16,884	5,065	22,707	10.1	51.4
Secondary	3,594	2,516	4,834	30.2	65.6
Post Primary	102	71	137	0.9	1.9
Other	174	104	234	1.2	3.2
Non Formal	439	88	590	0.1	0.7
Tertiary	250	250	336	62.5	95.1

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_education.csv).

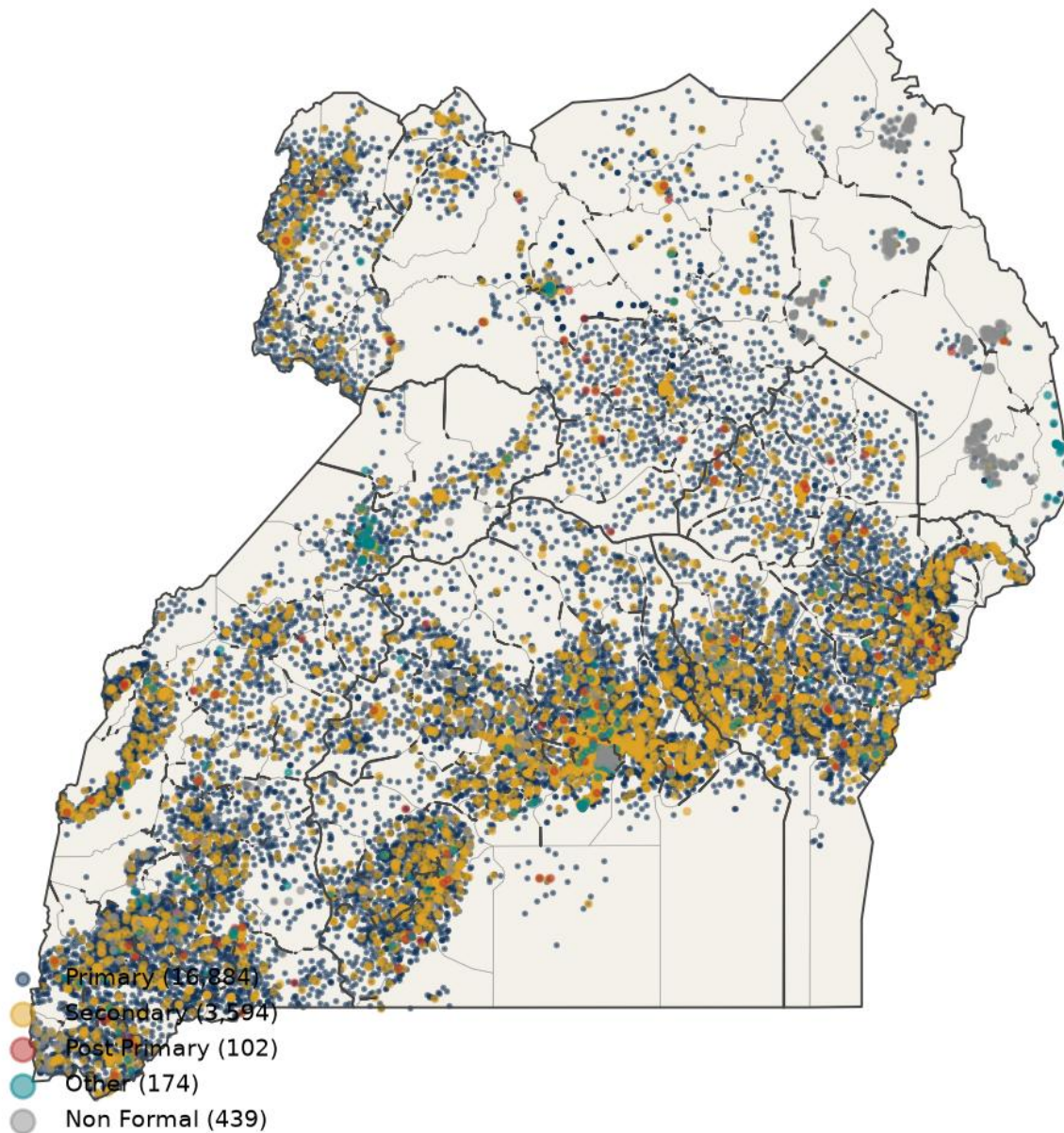


Figure 4.13: Schools in the EMIS layer by type (21,193 institutions)

Source: MoES EMIS school layer via AICTEM SDI

Transport demand (Figure 4.14, Table 4.8) is dominated by electric motorcycles, the boda-bodas, which reach 540 GWh in 2040, and by the electric SGR at 200 GWh. The e-mobility paths are ASSUMED. The high e-mobility simulation of Chapter 10 doubles them.

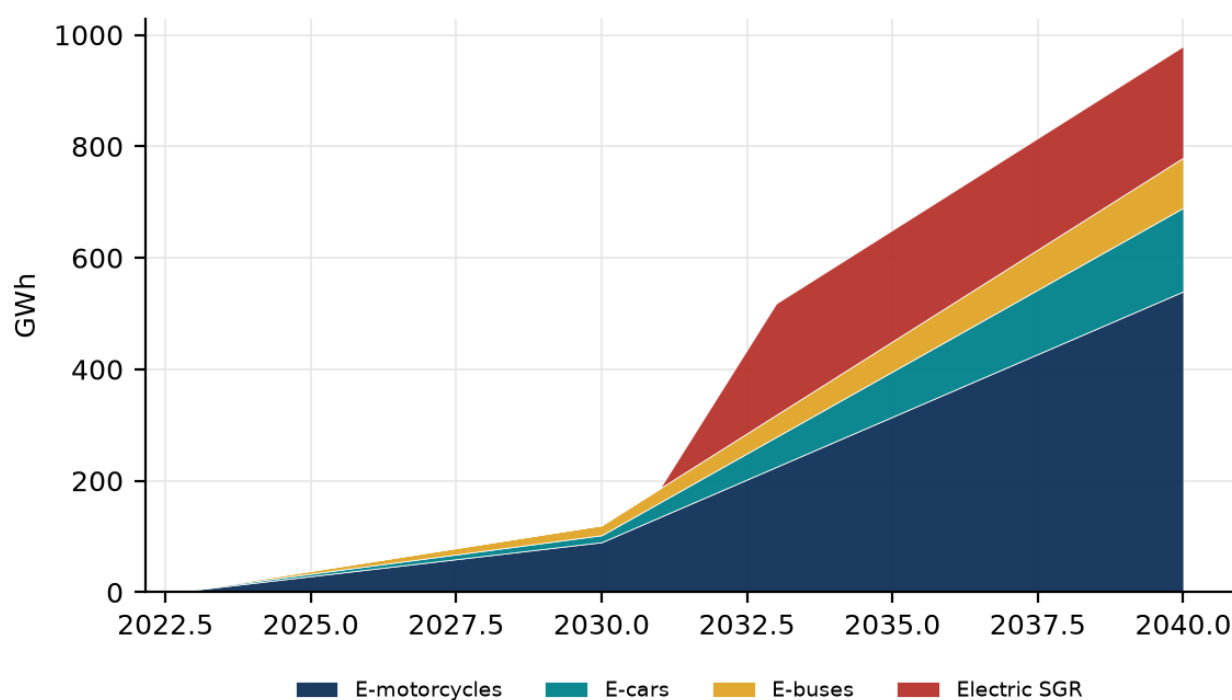


Figure 4.14: Transport electrification: energy by vehicle type and the electric SGR

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.8: Transport electrification: vehicle stock and energy (ASSUMED paths)

Component	Units 2023	Units 2030	Units 2040	GWh 2023	GWh 2030	GWh 2040
Electric motorcycles	5,000	100,000	600,000	4.5	90.0	540.0
Electric cars / LCV	500	5,000	60,000	1.2	12.5	150.0
Electric buses	0	300	1,500	0.0	18.0	90.0
Electric SGR	0	0	1	0.0	0.0	200.0

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_transport.csv).

4.4.4 Requirement and peak

Adding losses and exports turns final demand into the generation requirement (Figure 4.15, Table 4.9).

- **2023.** Final consumption of 4,330 GWh requires 5,978 GWh of generation. That is 909 GWh more for distribution losses, 289 GWh for transmission losses and 451 GWh of net exports.
- **2040.** The requirement is 29,449 GWh.
- **Loss reduction.** The fall in the distribution loss rate to 12 % by 2030 saves 1,470 GWh of generation a year by 2040 (Chapter 7).

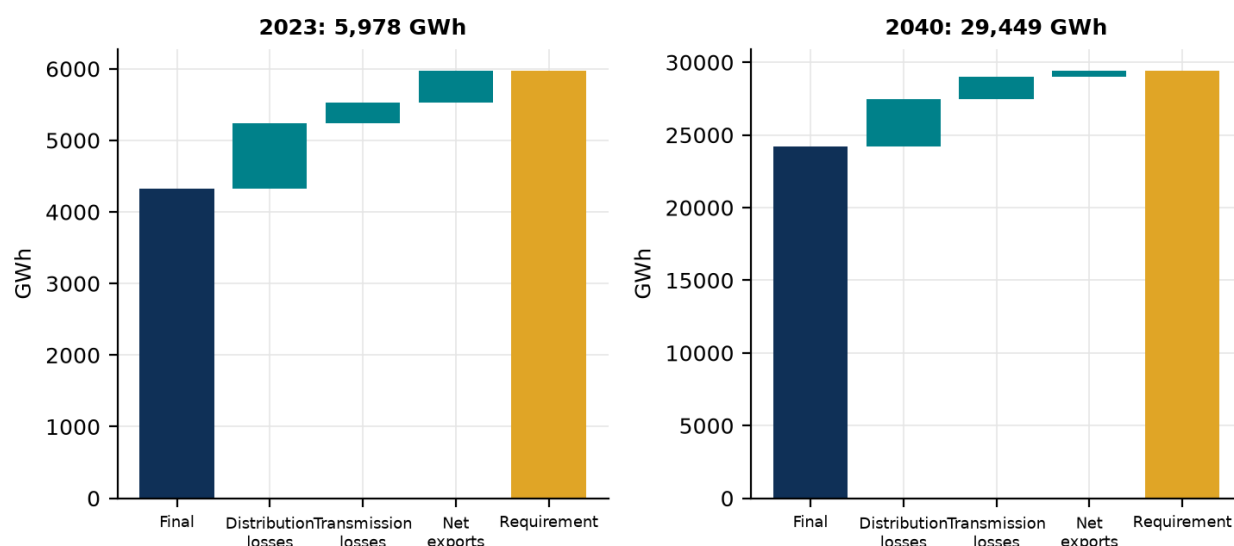


Figure 4.15: From final consumption to generation requirement: 2023 and 2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.9: From final consumption to generation requirement and peak, base scenario

Year	Final (GWh)	Distribution loss rate	Distribution losses (GWh)	Transmission losses (GWh)	Net exports (GWh)	Requirement (GWh)	Peak (MW)
2023	4,330	17.3%	909	289	451	5,978	988
2026	5,734	15.1%	1,016	372	451	7,574	1,251
2028	7,905	13.5%	1,237	504	451	10,097	1,668
2030	9,759	12.0%	1,331	611	451	12,152	2,008
2033	12,714	12.0%	1,734	796	451	15,695	2,593
2035	15,162	12.0%	2,068	949	451	18,630	3,078
2038	20,369	12.0%	2,778	1,275	451	24,873	4,110
2040	24,185	12.0%	3,298	1,514	451	29,449	4,866

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_nat_path.csv).

Peak demand follows the requirement (Figure 4.16, Table 4.10). It is 1,251 MW in 2026, 2,008 MW in 2030, 3,078 MW in 2035 and 4,866 MW in 2040, five times the 2023 peak. The demand scenarios frame the uncertainty:

- **Low scenario.** GDP growth is 1.5 points lower, e-mobility is halved and 60 % of the step loads are realised. The 2040 peak is 3,620 MW.
- **High scenario.** GDP growth is 1.5 points higher and e-mobility doubles. The 2040 peak is 5,374 MW.

The low–high range for 2040 is 1,750 MW, about the size of the whole existing Nile cascade.

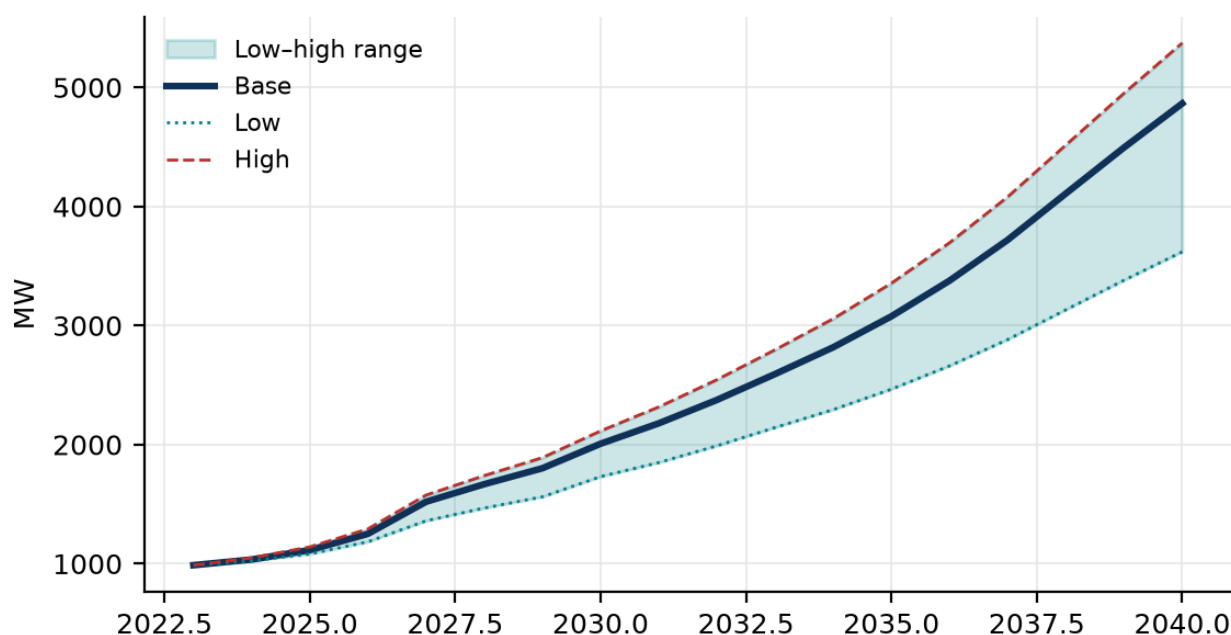


Figure 4.16: Peak demand under the low, base and high demand scenarios

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.10: Demand scenarios: generation requirement and peak

Year	Low: requirement (GWh)	Base: requirement (GWh)	High: requirement (GWh)	Low: peak (MW)	Base: peak (MW)	High: peak (MW)
2023	5,978	5,978	5,978	988	988	988
2026	7,168	7,574	7,821	1,184	1,251	1,292
2030	10,481	12,152	12,801	1,732	2,008	2,115
2035	14,927	18,630	20,312	2,466	3,078	3,356
2040	21,910	29,449	32,523	3,620	4,866	5,374

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_demand_scen.csv).

4.5 The geography of demand

4.5.1 Where demand is today

Electricity demand is highly concentrated.

- **Kampala metropolitan area.** Kampala, Wakiso and Mukono together took 1,413 GWh in 2023, a third of national consumption.
- **Industrial districts.** Buikwe, Jinja, Mayuge and Tororo add much of the rest.

Figure 4.17 maps district demand in 2023. The local Moran analysis finds a single significant high-high cluster in the central region: Buikwe, Kampala, Luwero, Mpigi, Mukono and Wakiso. There is no significant low-low cluster. Demand is uniformly low across most of the country, so no district stands out as low among low neighbours.

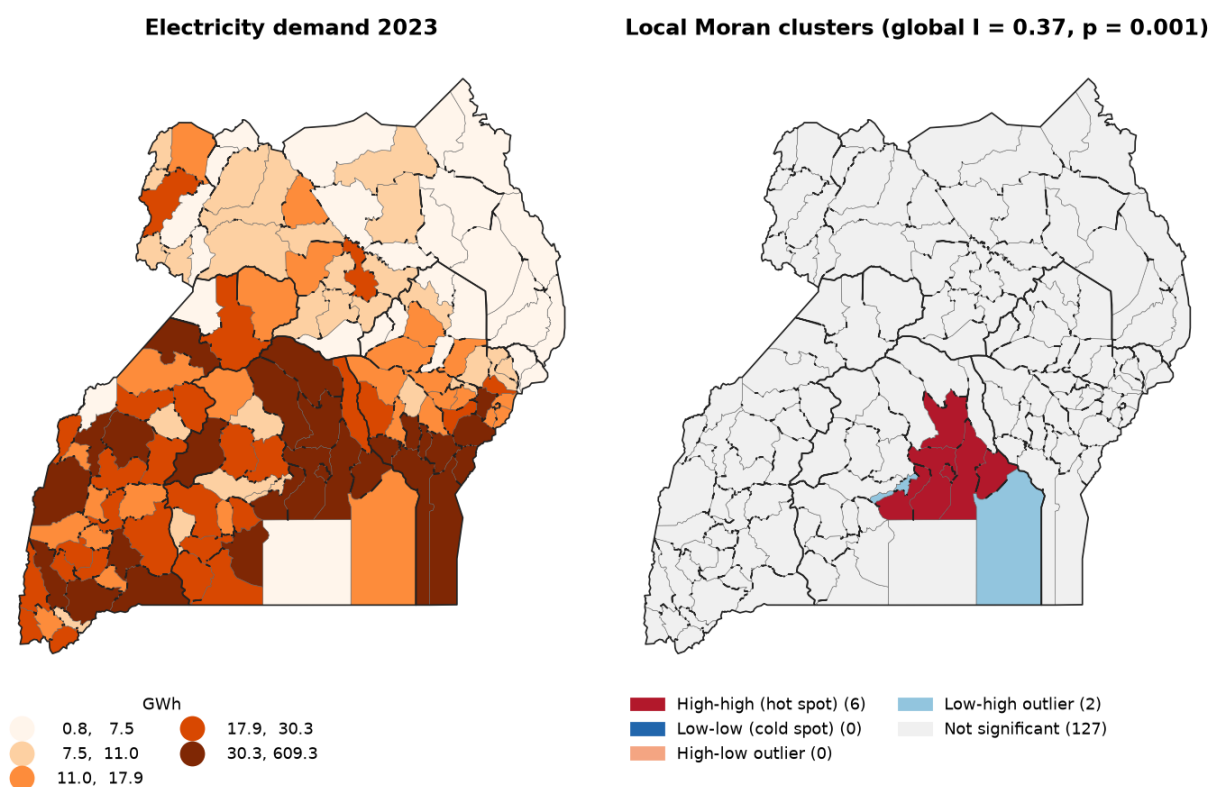


Figure 4.17: Ch.1 - Electricity demand 2023 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

Per person (Figure 4.18) the picture is sharper still. The high-high cluster is Buikwe, Buvuma, Kampala, Luwero, Mpigi, Mukono, Namayingo and Wakiso, which also takes in the island and lakeshore districts east of Kampala. Moran's I is 0.45. In most districts of the north and north-east, consumption is below 30 kWh per person a year, compared with more than 300 kWh in Kampala.

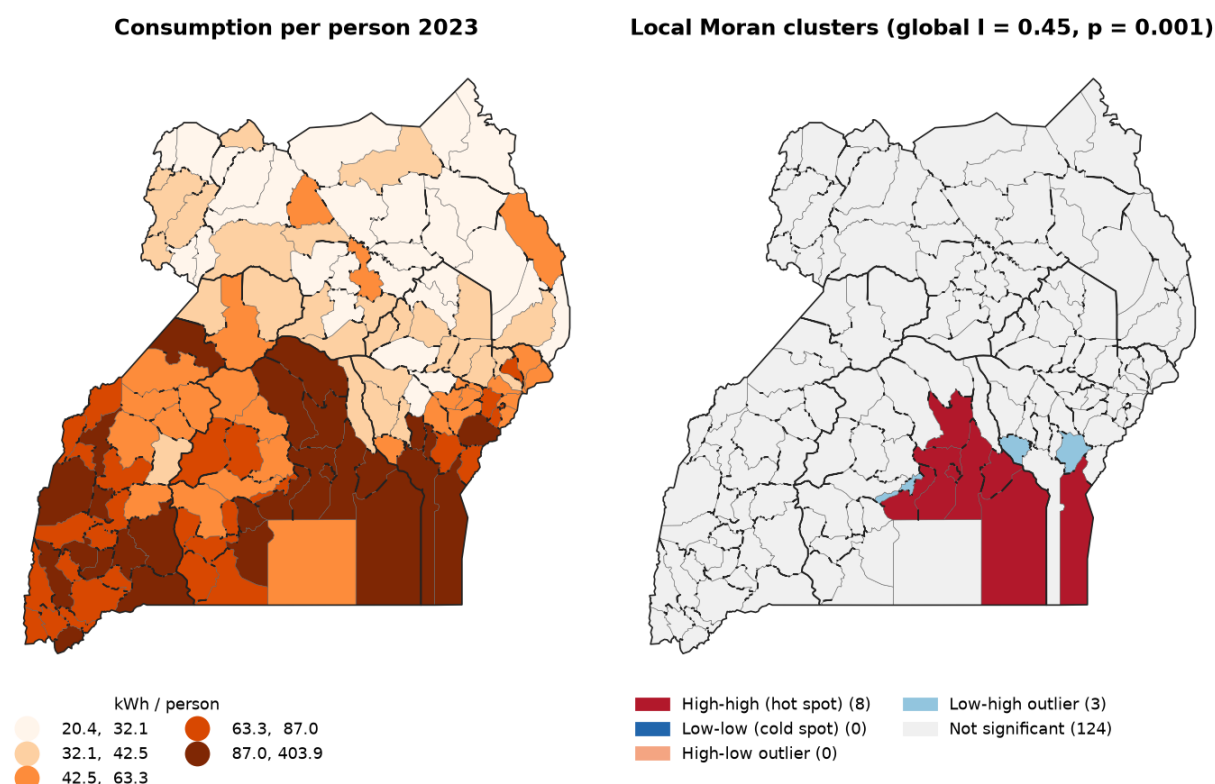


Figure 4.18: Ch.1 - Consumption per person 2023 (kWh / person), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

Population density (Figure 4.19) explains only part of this pattern. Its hot-spot is the densely settled Mbale–Tororo–Bugisu area in the east (Budaka, Bududa, Butaleja, Manafwa, Mbale, Namisindwa, Sironko, Tororo) together with Wakiso. Its cold-spot is the sparsely populated north: Amuru, Gulu, Kaabong, Kitgum, Moroto and Napak.

The difference between the density map and the demand map is the access gap. The east is densely populated but lightly electrified.

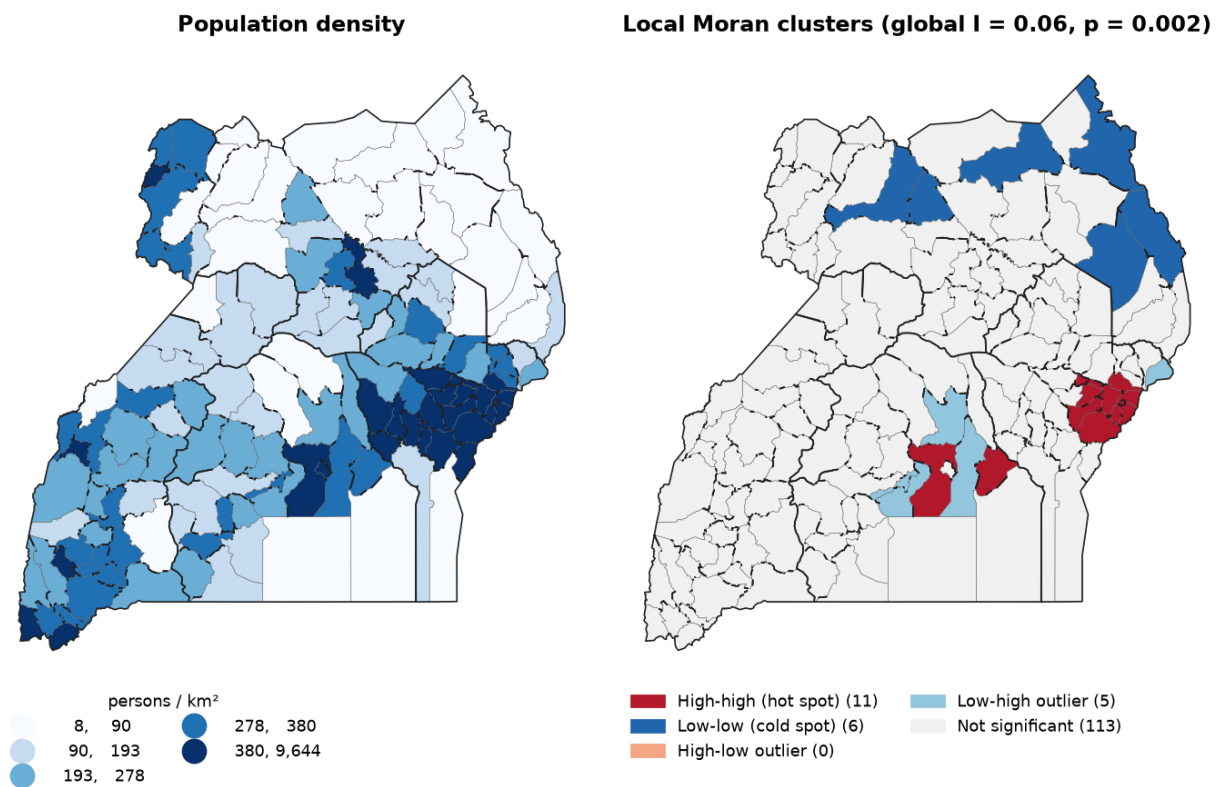


Figure 4.19: Ch.1 - Population density (persons / km²), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

The IERMP commercial-facilities layer (Figure 4.20) provides the location key for commercial demand. Its hot-spot is the south-west and west:

- Buhweju, Bunyangabu, Bushenyi and Hoima;
- Ibanda, Kabale, Kabarole and Kagadi;
- Kamwenge, Kazo, Kibaale and Kisoro;
- Kitagwenda, Kyegegwa, Kyenjojo and Mbarara;
- Mitooma, Mubende, Rubirizi, Rwampara and Sheema.

This reflects the density of trading centres there. The cold-spot covers Karamoja and the north-east.

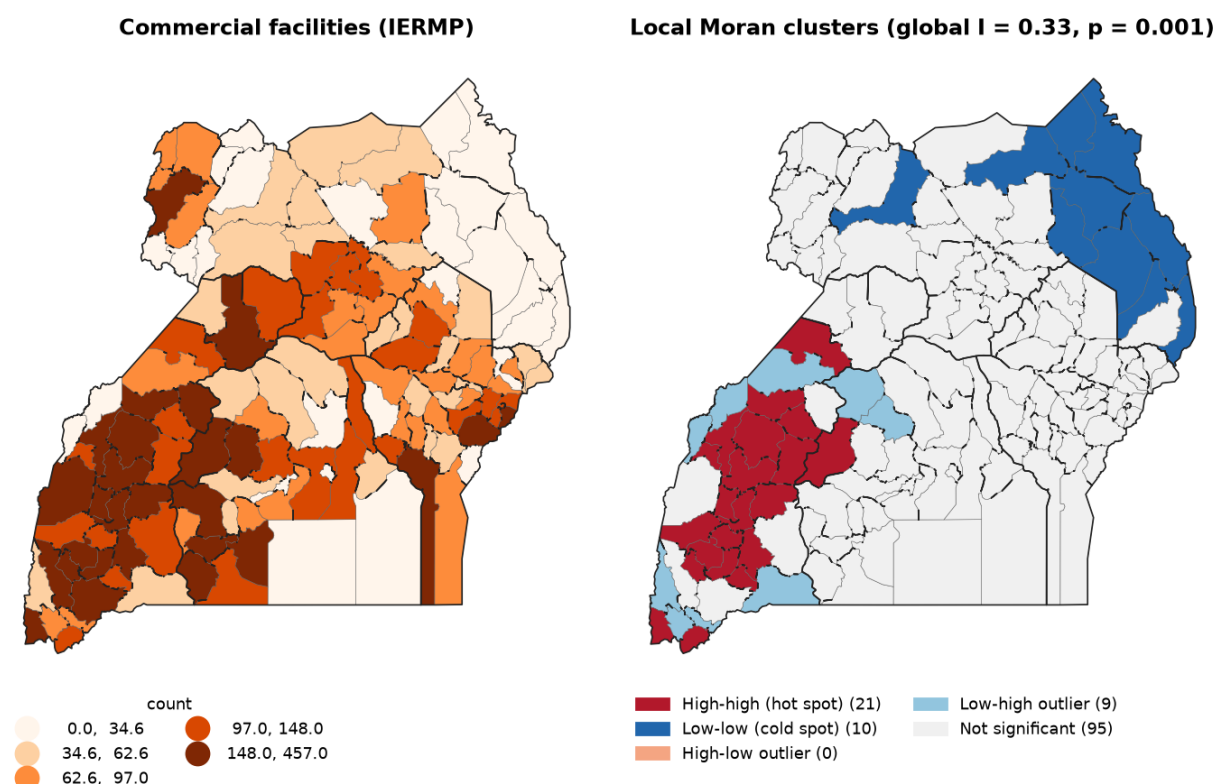


Figure 4.20: Ch.1 - Commercial facilities (IERMP) (count), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

4.5.2 Where demand grows

Figure 4.21 maps demand in 2040, and Figure 4.22 the growth multiple.

- **The central cluster persists** (Buikwe, Jinja, Kampala, Luwero, Mukono, Wakiso), because the industrial parks of Namanve, Kapeeka, Mukono and Jinja are there.
- **Outside the centre, growth is driven by projects.** The district growth multiple is not spatially clustered: Moran's I is -0.02 , not significant. Growth comes from discrete projects in scattered places, not from a regional trend:
 - Hoima: 49 GWh to 1,181 GWh, with the refinery, EACOP and the industrial park;
 - Kabale: 24 GWh to 930 GWh, with steel;
 - Tororo: 128 GWh to 1,915 GWh, with steel, phosphates, the industrial park and the SGR;
 - Soroti and Napak: the Soroti and Moroto industrial parks.

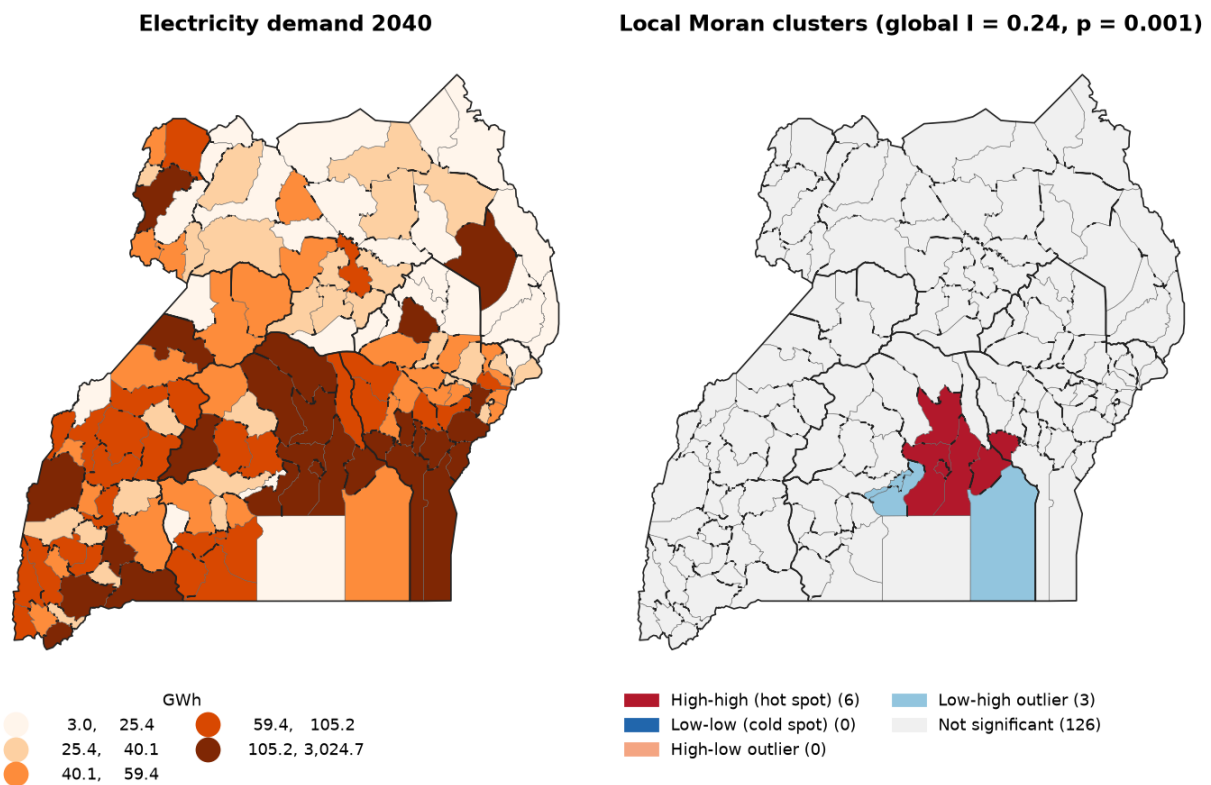


Figure 4.21: Ch.1 - Electricity demand 2040 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

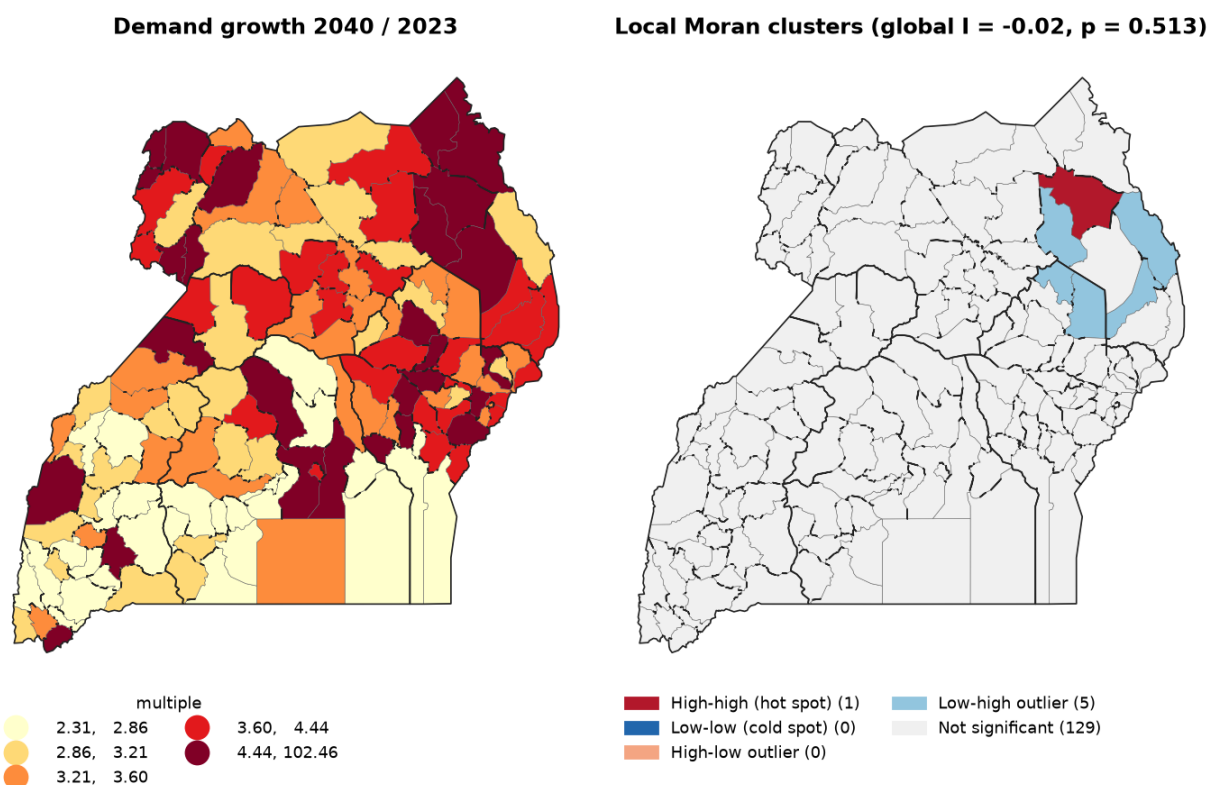


Figure 4.22: Ch.1 - Demand growth 2040 / 2023 (multiple), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

Table 4.11 and Figure 4.23 list the 20 districts with the highest demand in 2040. In 2040 Mukono becomes the single largest consuming district, at 3,025 GWh. It overtakes Kampala (2,341 GWh) and Wakiso (2,224 GWh) because of the Namanve and Mukono industrial parks. Tororo is fourth, at 1,915 GWh.

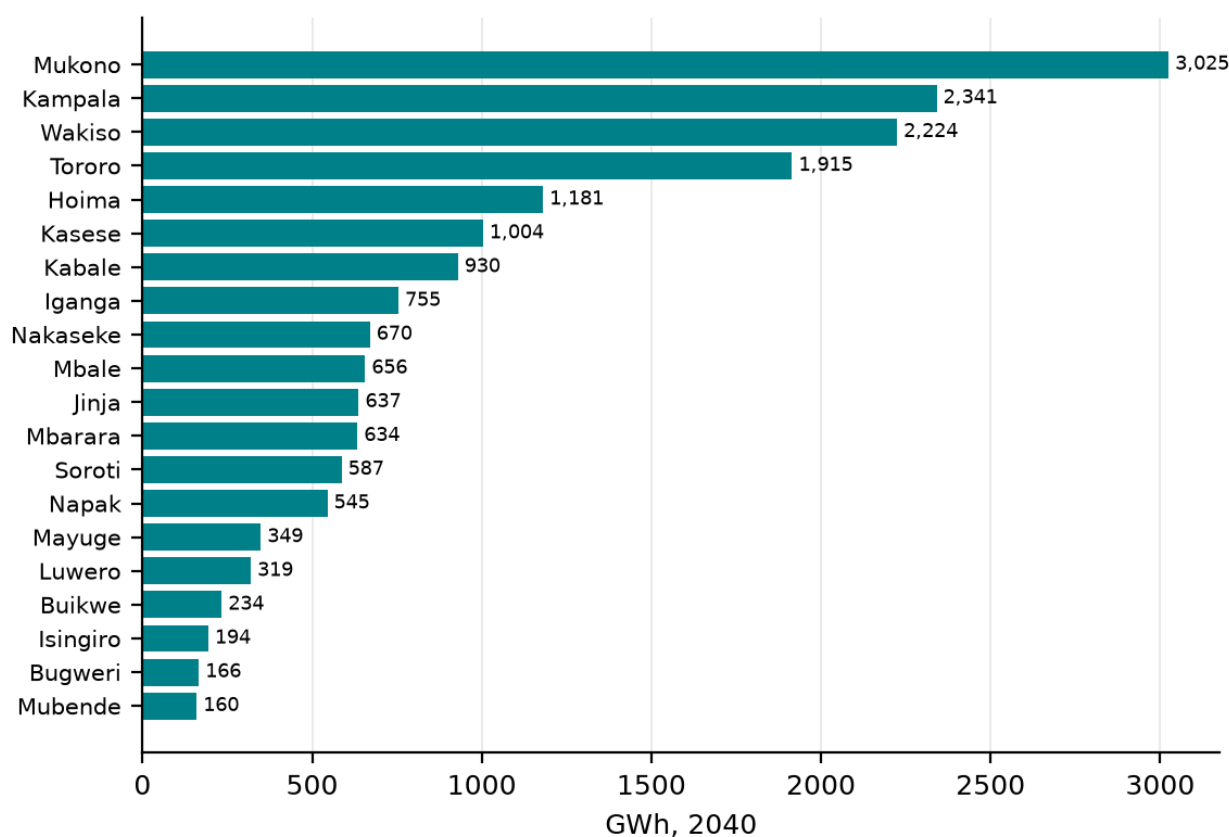


Figure 4.23: The 20 districts with the highest demand in 2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.11: The 20 districts with the highest electricity demand in 2040

District	Region	GWh 2023	GWh 2030	GWh 2040	Growth multiple
Mukono	Central	314.4	969.6	3,024.7	9.6x
Kampala	Central	609.3	1,277.0	2,341.1	3.8x
Wakiso	Central	489.2	1,151.8	2,224.4	4.5x
Tororo	Eastern	127.5	329.6	1,915.0	15.0x
Hoima	Western	48.7	689.2	1,180.6	24.2x
Kasese	Western	133.9	387.9	1,003.9	7.5x
Kabale	Western	24.3	49.9	930.0	38.3x
Iganga	Eastern	92.7	230.4	754.5	8.1x
Nakaseke	Central	64.3	184.2	670.5	10.4x
Mbale	Eastern	43.1	165.3	656.2	15.2x
Jinja	Eastern	34.5	146.3	637.3	18.5x
Mbarara	Western	47.9	161.1	633.7	13.2x
Soroti	Eastern	17.0	125.7	586.9	34.5x
Napak	Northern	5.3	104.4	545.0	102.5x
Mayuge	Eastern	129.7	191.8	348.6	2.7x
Luwero	Central	134.0	192.4	319.4	2.4x
Buikwe	Central	89.2	127.5	233.5	2.6x
Isingiro	Western	66.1	105.7	194.0	2.9x
Bugweri	Eastern	65.0	96.3	166.0	2.6x
Mubende	Central	49.8	83.7	159.8	3.2x

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_top_demand.csv).

4.5.3 Demand by segment and place

The segment maps separate the drivers.

- **Households** (Figure 4.24). Household demand in 2040 clusters in Buikwe, Kampala, Luwero, Mityana, Mpigi, Mukono and Wakiso: the most populous and most urban districts, where connections are densest.
- **Industry** (Figure 4.25). Industrial demand in 2040 clusters in Buikwe, Jinja, Kampala, Luwero, Mukono and Wakiso: the Kampala–Jinja industrial corridor.

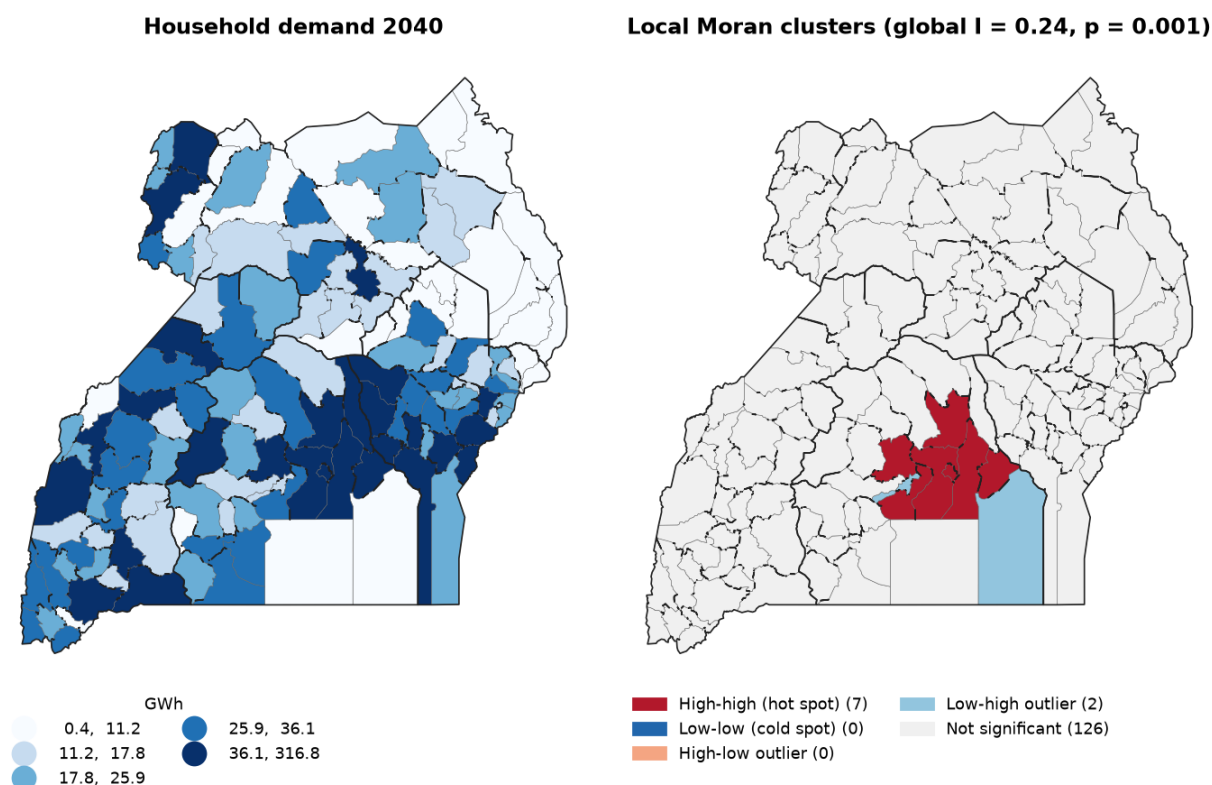


Figure 4.24: Ch.1 - Household demand 2040 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

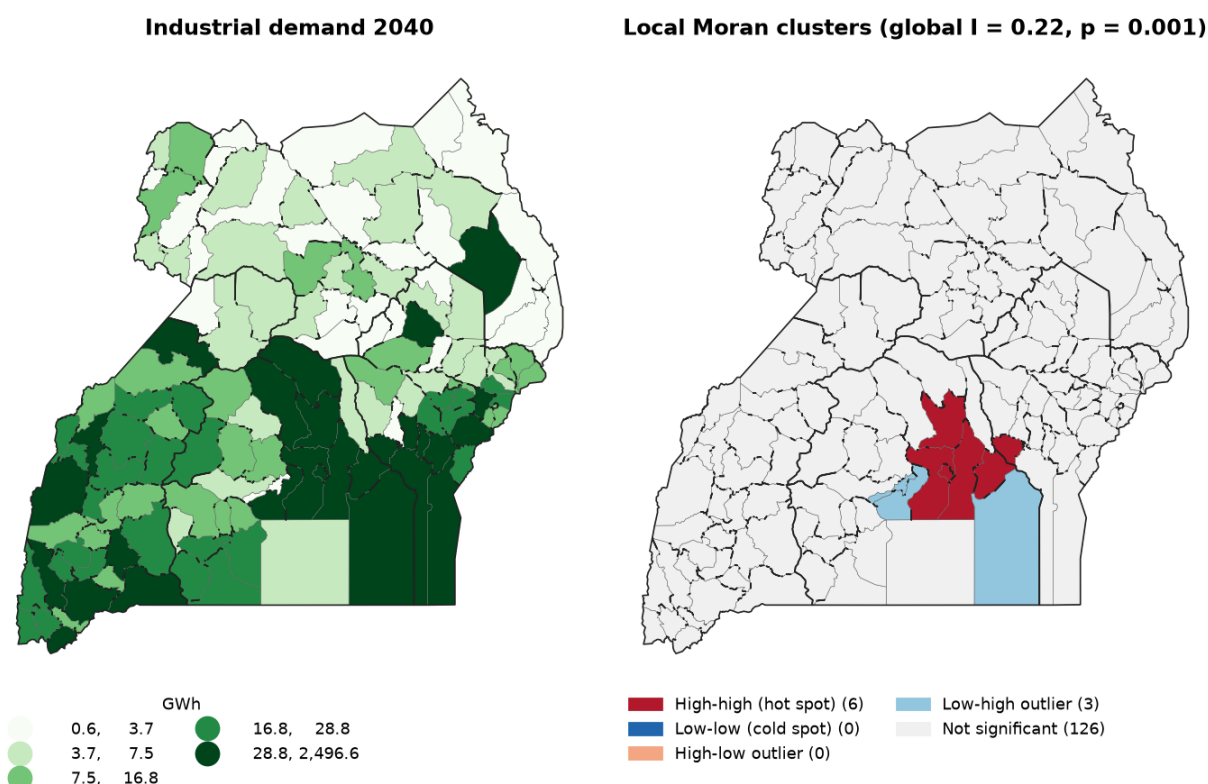


Figure 4.25: Ch.1 - Industrial demand 2040 (GWh), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

Health-facility demand in 2030 (Figure 4.26) is much more evenly spread. Its Moran's I of 0.10 is the lowest of any demand layer, because health facilities are distributed with population and administration, not with income. Its hot-spot is the capital region (Kampala, Luwero, Mpigi, Mukono, Wakiso), where the national referral hospitals are.

School demand in 2035 (Figure 4.27) clusters in the same central districts plus Buikwe and Mityana, which have the most secondary schools and tertiary institutions.

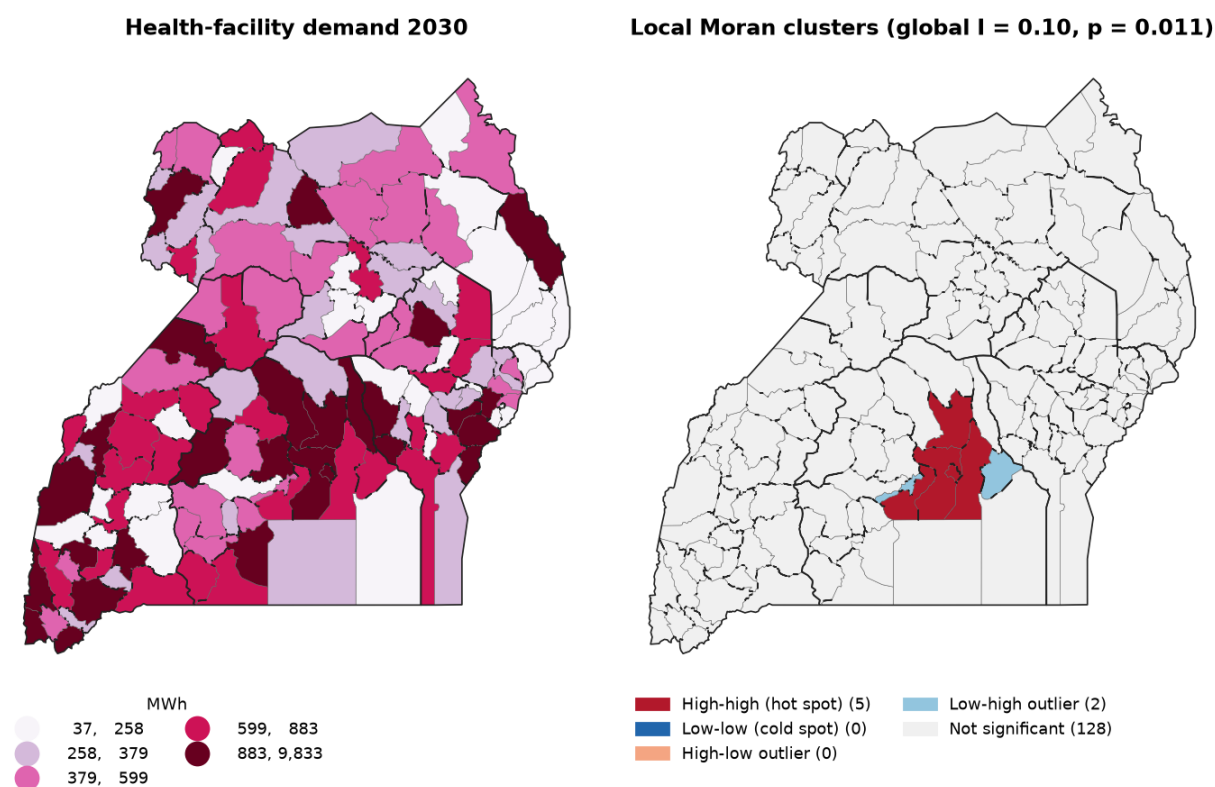


Figure 4.26: Ch.1 - Health-facility demand 2030 (MWh), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

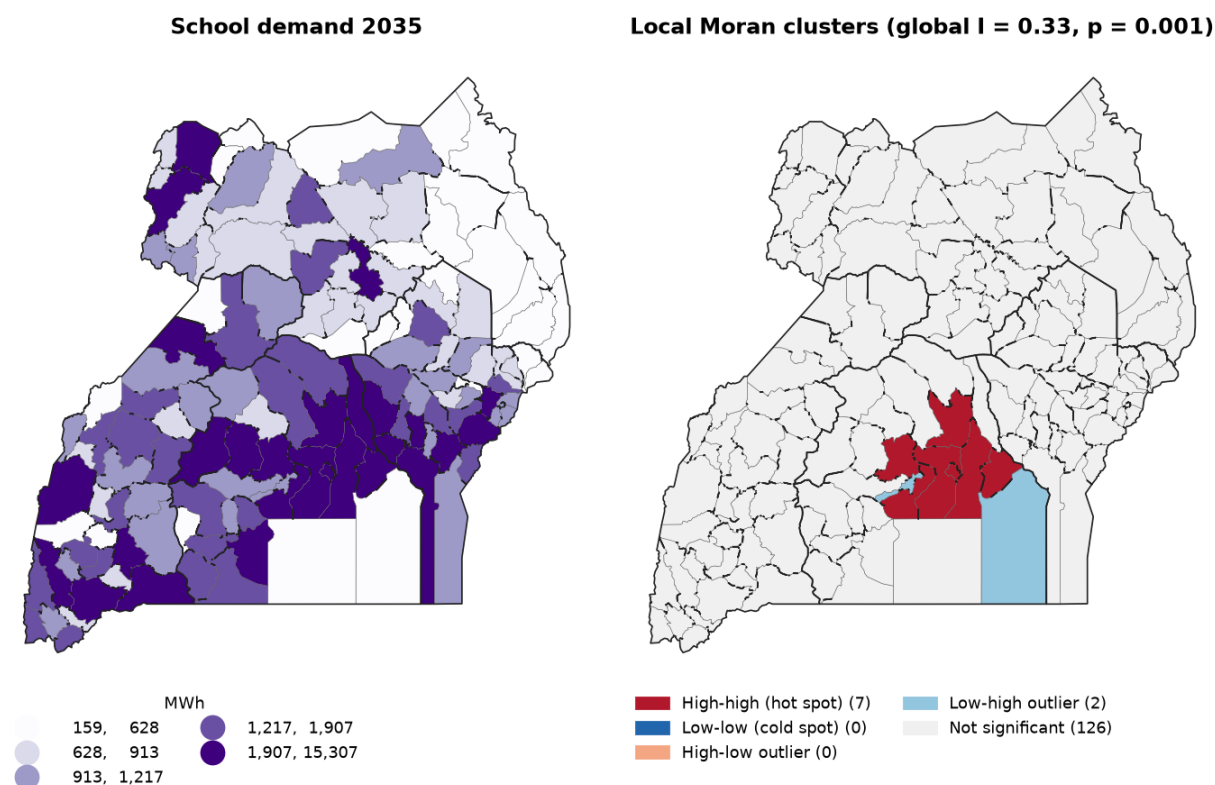


Figure 4.27: Ch.1 - School demand 2035 (MWh), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

4.5.4 Demand by supply zone

For the power system, what matters is the demand at each transmission bus. Figure 4.28 and Table 4.12 show it.

- **Kampala buses.** Lugogo, Mutundwe, Namanve and Kawanda carry the largest zonal demand in 2040.
- **Fastest-growing zones:**
 - Namanve, 9.6-fold, with the industrial parks;
 - Opuyo, 10.6-fold, with the Soroti and Moroto parks and access growth across the north-east;
 - Bujagali, 9.1-fold;
 - Tororo, 8.5-fold.
- **The largest zone.** The Tororo bus serves 16 districts and 3,410 GWh in 2040. It becomes the largest single supply zone, and the transmission corridors into it become a planning priority (Chapter 6).

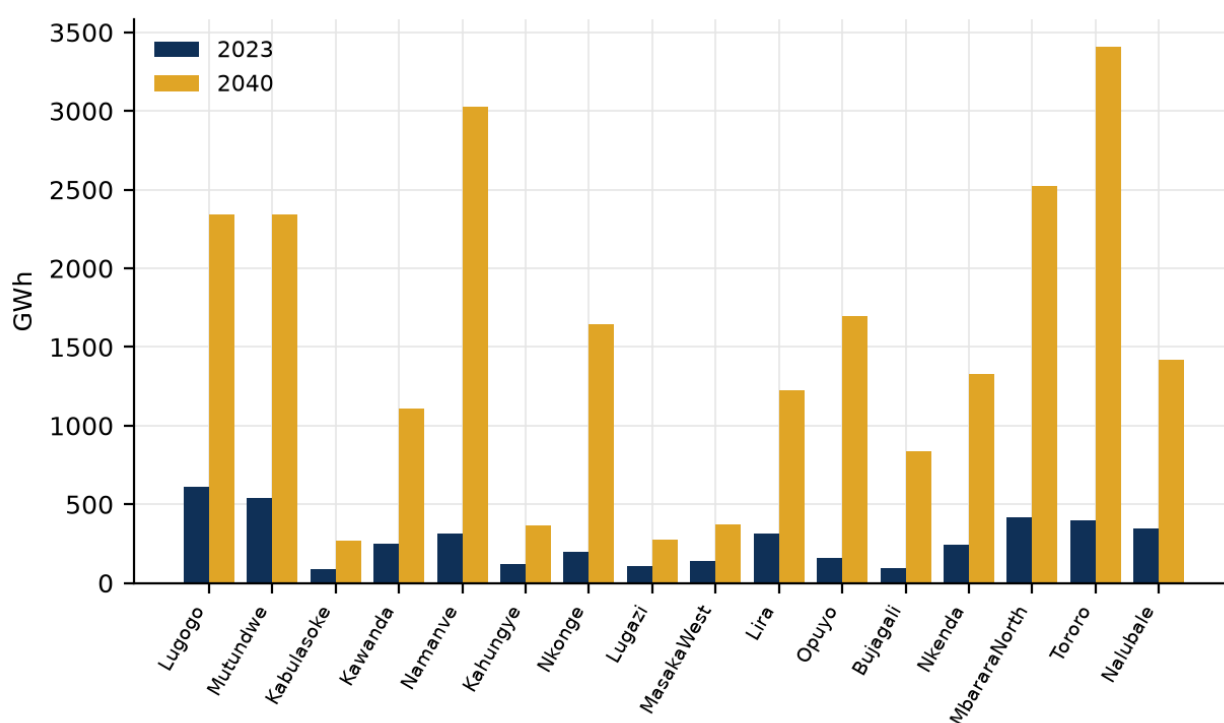


Figure 4.28: Final demand by supply zone (transmission bus), 2023 and 2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 4.12: Final demand by supply zone (districts assigned to their nearest transmission bus)

Supply zone (bus)	Districts	GWh 2023	GWh 2030	GWh 2040	Multiple
B01_Lugogo	1	609	1,277	2,341	3.8x
B04_Mutundwe	2	540	1,224	2,344	4.3x
B05_Kabulasoke	6	87	144	270	3.1x
B06_Kawanda	3	250	450	1,111	4.4x
B07_Namanve	1	314	970	3,025	9.6x
B08_Kahungye	5	121	197	366	3.0x
B09_Nkonge	8	196	935	1,644	8.4x
B10_Lugazi	2	106	152	274	2.6x
B11_MasakaWest	7	139	212	374	2.7x
B12_Lira	34	312	609	1,225	3.9x
B13_Opuyo	20	159	512	1,696	10.6x
B14_Bujagali	4	92	248	836	9.1x
B15_Nkenda	7	244	565	1,328	5.4x
B16_MbararaNorth	15	415	746	2,521	6.1x
B17_Tororo	16	399	913	3,410	8.5x
B18_Nalubale	4	345	605	1,419	4.1x

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_zone_demand.csv).

4.6 Data quality and limitations

- **Base year: strong.** Base-year demand is OBSERVED at the level of tariff classes and CALIBRATED at the level of segments. The split of commercial sales rests on bottom-up estimates of health and education demand that use ASSUMED intensities. The split of industrial sales into mining, agriculture and water uses ASSUMED shares.
- **The step loads.** They come from the IERMP, but their realisation is uncertain. The report treats them as a planning input, and Chapter 10 shows the consequences of partial realisation.
- **Suppressed demand.** Latent demand, such as load shedding or connected customers who cannot afford more, is not added to the base year.
- **Fixed load shape.** The shape of demand is held fixed per bus. New daytime loads, such as irrigation pumping or daytime EV charging, would flatten the evening peak and favour solar. The model does not yet capture this.
- **District allocation.** District allocation uses observed keys (health facilities, schools, transformers, commercial facilities, population, mining areas and industrial parks). The shares within each key are CALIBRATED, not measured.

4.7 Implications for planning

- Uganda's electricity demand is set to grow more than five-fold by 2040. More than half of that growth is decided by a handful of large industrial and extractive projects. Tracking the actual progress of these projects is the single most important input to the plan. The IERMP step-load register should be updated every year and fed into the engine.
- The household access programme is enormous in connections: 15 million by 2040. It is modest in energy: 3.8 TWh by 2040. Its cost is in the distribution network and in connections, not in generation (Chapter 11).
- Demand is concentrated in space. The Kampala–Jinja corridor, Tororo, Hoima, Kasese and Kabale together account for most of the growth. The transmission plan must follow these places, not the national average.
- Health and school electrification is small in energy but should be planned as a targeted programme. Its location follows the MV network gap, not the demand map.

CHAPTER 5

5 Current generation

This chapter describes the generating system Uganda has today:

- what is installed, where, and of which technology;
- how much of it can be counted on at the evening peak;
- what it actually produced in 2023;
- how it dispatches at least cost against today's demand and tomorrow's.

The dispatch is solved with PyPSA. It gives the merit order, capacity factors, reservoir scheduling, emissions, nodal prices and, when demand outgrows the fleet, unserved energy. The chapter implements design Chapter 2 (docs/02_current_generation.md).

5.1 The existing fleet

The modelled fleet has 23 generating units and two battery systems. Its installed capacity is **2,033 MW** (Table 5.1, Figure 5.1).

- **Hydro.** Hydro is **1,733 MW**, 85 % of the total.
 - Large hydro: the five large stations of the Victoria Nile cascade. They are Nalubaale (180 MW), Kiira (200 MW), Bujagali (250 MW), Isimba (183 MW) and Karuma (600 MW), 1,413 MW in all.
 - Small hydro: five regional clusters of small hydro in the west, south-west, east, north and Albertine region, 320 MW in all.
- **Bagasse.** Bagasse cogeneration at the sugar estates (Kakira, SCOUL, Kinyara, Mayuge and others) contributes 136 MW.
- **Heavy fuel oil.** Two HFO plants at Namanve and Tororo (Electromaxx) contribute 100 MW.
- **Solar.** Six solar plants contribute 65 MW.
- **Batteries.** Two battery systems of 150 MW / 600 MWh complete the fleet.

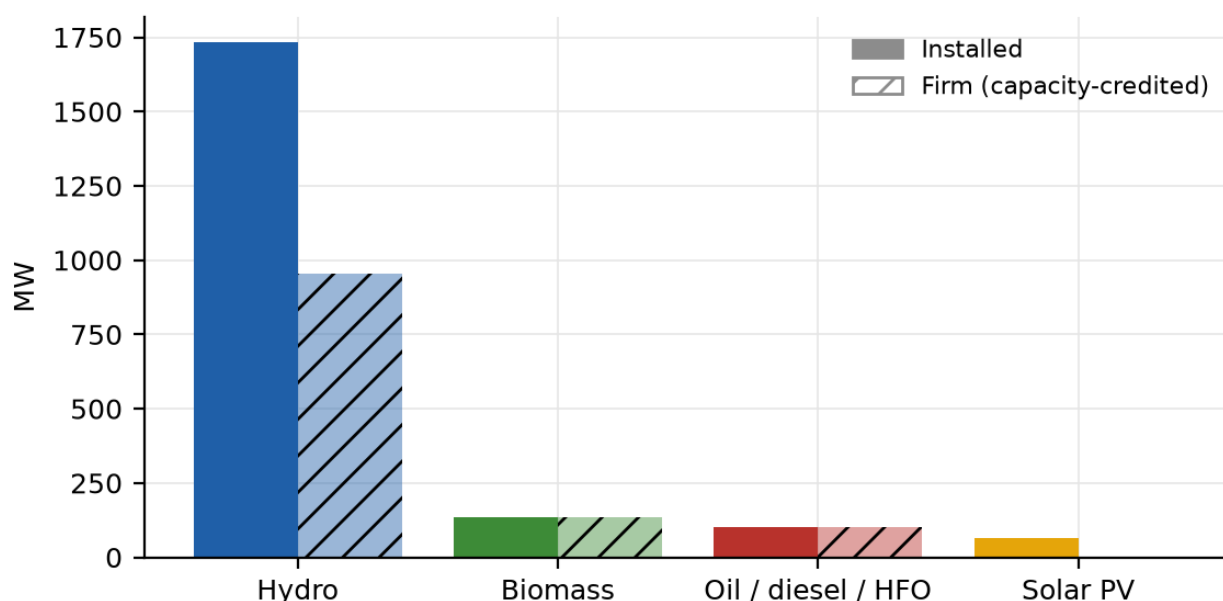


Figure 5.1: Installed and firm capacity by technology, 2023

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 5.1: Installed and firm capacity by technology, 2023

Technology	Units	Installed MW	Firm MW	Share of installed
Hydro	10	1,732.7	953.0	85.2%
Biomass	5	135.8	135.8	6.7%
Oil / diesel / HFO	2	100.2	100.2	4.9%
Solar PV	6	64.6	1.9	3.2%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_capacity.csv).

5.1.1 Firm capacity

Installed capacity overstates what the system can count on at the evening peak. The engine applies a **capacity credit** to each unit: the fraction of its capacity that is dependable at peak.

- **Hydro: 0.55.** This reflects the difference between installed capacity and the output the cascade can sustain in the dry season.
- **Bagasse and HFO: 1.0.**
- **Solar: 0.03.** The evening peak falls after sunset.

Firm capacity is therefore **1,191 MW**: 953 MW of hydro, 136 MW of bagasse and 100 MW of HFO. With the batteries, firm capacity is 1,326 MW. That is the figure against which the capacity gap of Chapter 8 is measured.

The difference between installed and firm capacity is the first lesson of this chapter. The 2023 fleet looks like twice the peak on paper. In firm terms it is only 34 % above the 2023 peak, and the margin disappears within three years of demand growth.

5.1.2 Where the plants are

Figure 5.2 shows the fleet on the map. The generation is concentrated at the source of the Nile, around Jinja, where Nalubaale, Kiira, Bujagali and Isimba sit within 30 km of each other. Karuma lies further down the Nile, in Kiryandongo.

The small hydro clusters sit on the Rwenzori and Albertine rivers in the west, and the bagasse plants at the sugar estates east of Kampala. The thermal plants are near the loads, at Namanve and Tororo.

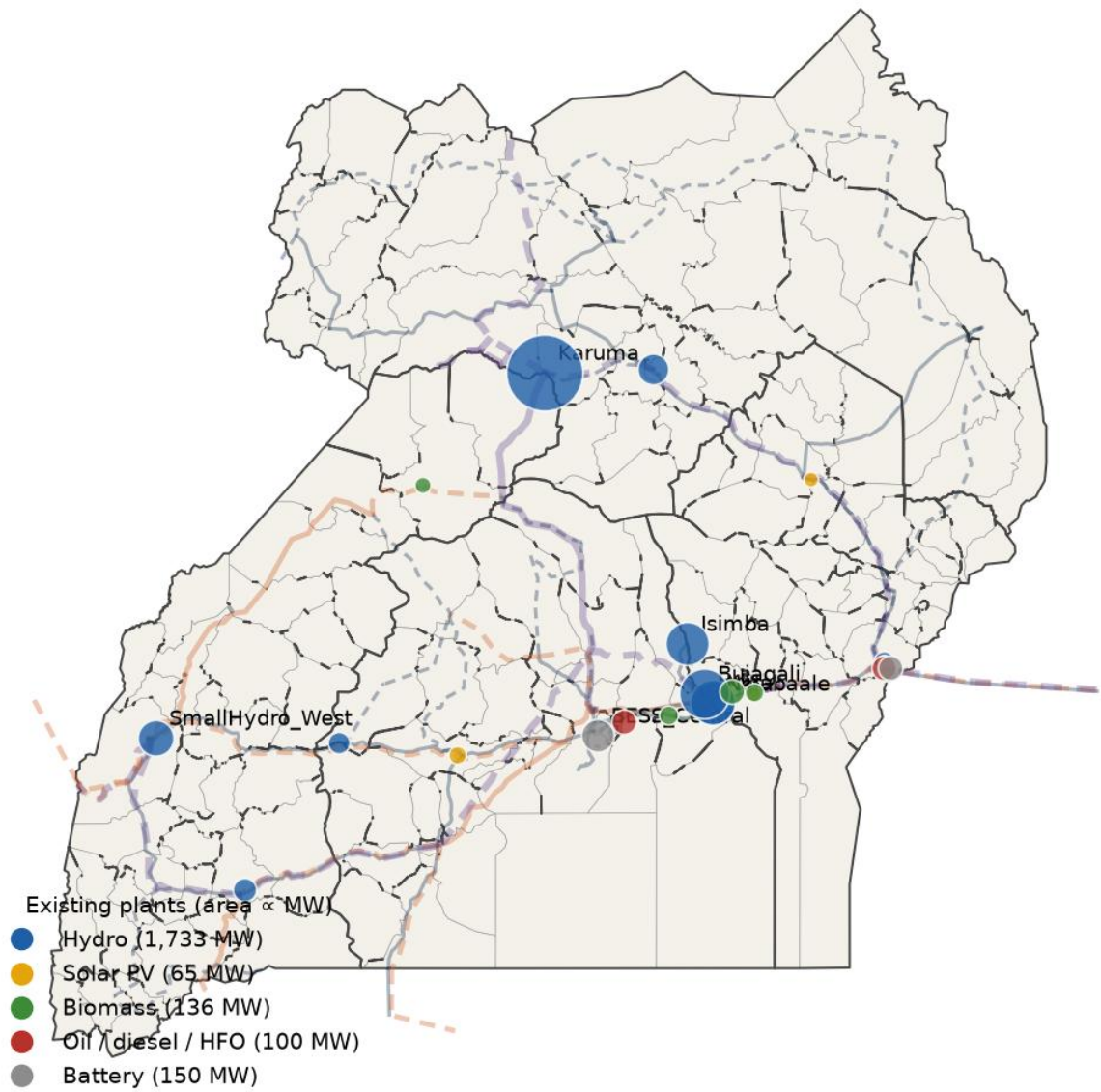


Figure 5.2: Existing generating plants by technology and size, 2023

Source: ERA licensed plants; locations from MEMD generation sites (SDI) where matched, else the connecting substation

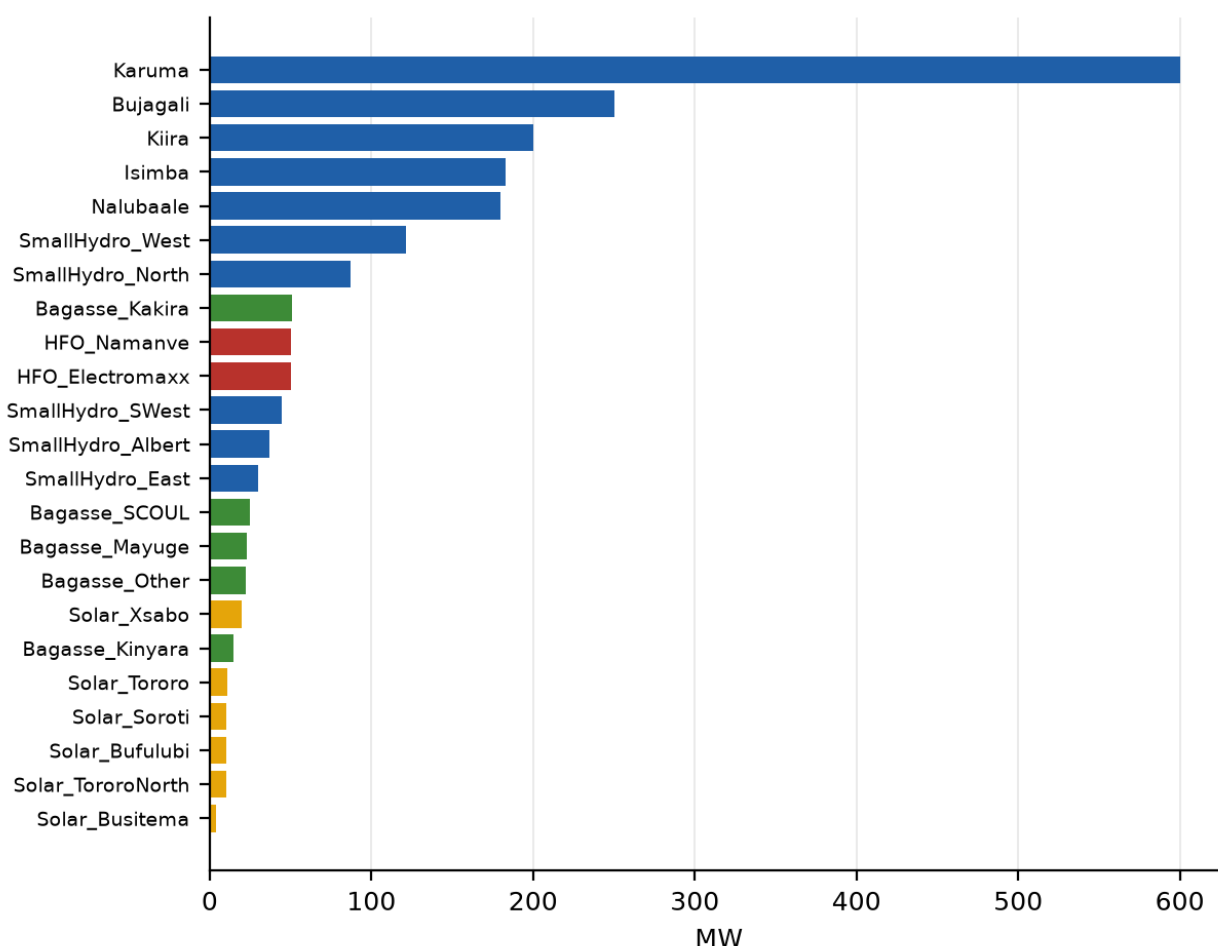


Figure 5.3: Generating units by installed capacity, coloured by technology

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 5.2: The existing fleet (ERA licensed plants, reservoir hydro and batteries)

Unit	Technology	Bus	District	MW	Capacity credit	Firm MW	Variable cost (USD/MWh)	2023 GWh (metered)
SmallHydro_West	Hydro	B15_Nkenda	Kasese	121.6	0.55	66.9	1.0	480.0
SmallHydro_SWest	Hydro	B16_MbararaNorth	Mbarara	44.3	0.55	24.4	1.0	190.0
SmallHydro_East	Hydro	B17_Tororo	Tororo	29.8	0.55	16.4	1.0	76.5
SmallHydro_North	Hydro	B12_Lira	Lira	87.2	0.55	48.0	1.0	64.4
SmallHydro_Albert	Hydro	B09_Nkongwe	Ssembabule	36.8	0.55	20.2	1.0	123.5
Solar_Soroti	Solar PV	B13_Opuyo	Soroti	10.0	0.03	0.3	0.0	16.0
Solar_TororoNorth	Solar PV	B17_Tororo	Tororo	10.0	0.03	0.3	0.0	15.7
Solar_Tororo	Solar PV	B17_Tororo	Tororo	10.6	0.03	0.3	0.0	20.8
Solar_Xsabo	Solar PV	B05_Kabulasoke	Gomba	20.0	0.03	0.6	0.0	28.9
Solar_Bufulubi	Solar PV	B18_Nalubale	Mayuge	10.0	0.03	0.3	0.0	16.8
Solar_Busitema	Solar PV	B17_Tororo	Tororo	4.0	0.03	0.1	0.0	0.0
Bagasse_Kakira	Biomass	B18_Nalubale	Jinja	51.1	1.00	51.1	27.5	55.7
Bagasse_SCOUL	Biomass	B10_Lugazi	Buikwe	25.0	1.00	25.0	27.5	140.8
Bagasse_Kinyara	Biomass	B09_Nkongwe	Masindi	14.5	1.00	14.5	27.5	9.6
Bagasse_Mayuge	Biomass	B18_Nalubale	Mayuge	23.0	1.00	23.0	27.5	24.0
Bagasse_Other	Biomass	B17_Tororo	Tororo	22.2	1.00	22.2	27.5	4.2
HFO_Namanve	Oil / diesel / HFO	B07_Namanve	Mukono	50.2	1.00	50.2	194.0	64.0
HFO_Electromaxx	Oil / diesel / HFO	B17_Tororo	Tororo	50.0	1.00	50.0	194.0	0.0
Nalubaale	Hydro	B18_Nalubale	Buikwe	180.0	0.55	99.0	0.0	790.0
Kiira	Hydro	B18_Nalubale	Jinja	200.0	0.55	110.0	0.0	880.3
Bujagali	Hydro	B14_Bujagali	Jinja	250.0	0.55	137.5	0.0	1,492.2

Unit	Technology	Bus	District	MW	Capacity credit	Firm MW	Variable cost (USD/MWh)	2023 GWh (metered)
Isimba	Hydro	B14_Bujagali	Kamuli	183.0	0.55	100.7	0.0	1,114.8
Karuma	Hydro	B12_Lira	Kiryandongo	600.0	0.55	330.0	0.0	404.4
BESS_Central	Battery	B04_Mutundwe	Wakiso	100.0	0.90	90.0	1.0	-
BESS_East	Battery	B17_Tororo	Tororo	50.0	0.90	45.0	1.0	-

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_fleet.csv).

Figure 5.4 maps firm capacity by district. The high-high cluster is Buikwe, Jinja, Mayuge and Mukono: the Jinja generation hub and its neighbours. Most districts have no generation at all. That is why the grid matters: almost every district depends on imports over the transmission network.

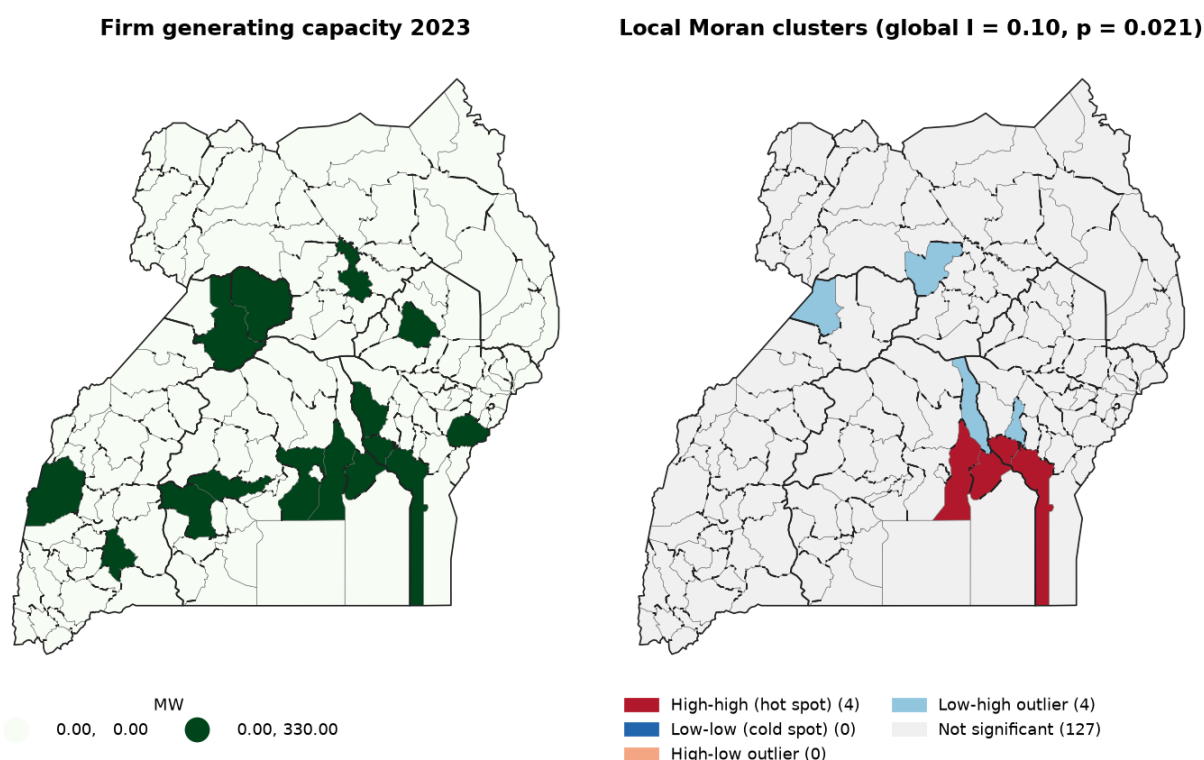


Figure 5.4: Ch.2 - Firm generating capacity 2023 (MW), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

5.2 What the fleet produced in 2023

UETCL's metered data give each plant's 2023 output. The five large Nile stations produced **4,681 GWh**, about 78 % of the 5,987 GWh generated. Figure 5.5 shows the monthly pattern of the major plants.

- **Bujagali and Kiira–Nalubaale** produce steadily through the year, with dips in April–June and November–December when the lake outflow is managed down.
- **Isimba** follows Bujagali, because it uses the same water downstream.
- **Karuma** produced nothing in January and February and first power in March. It ramped to 40–58 GWh a month from April as its units were commissioned, so its 2023 capacity factor of 7.7 % reflects commissioning, not its capability.

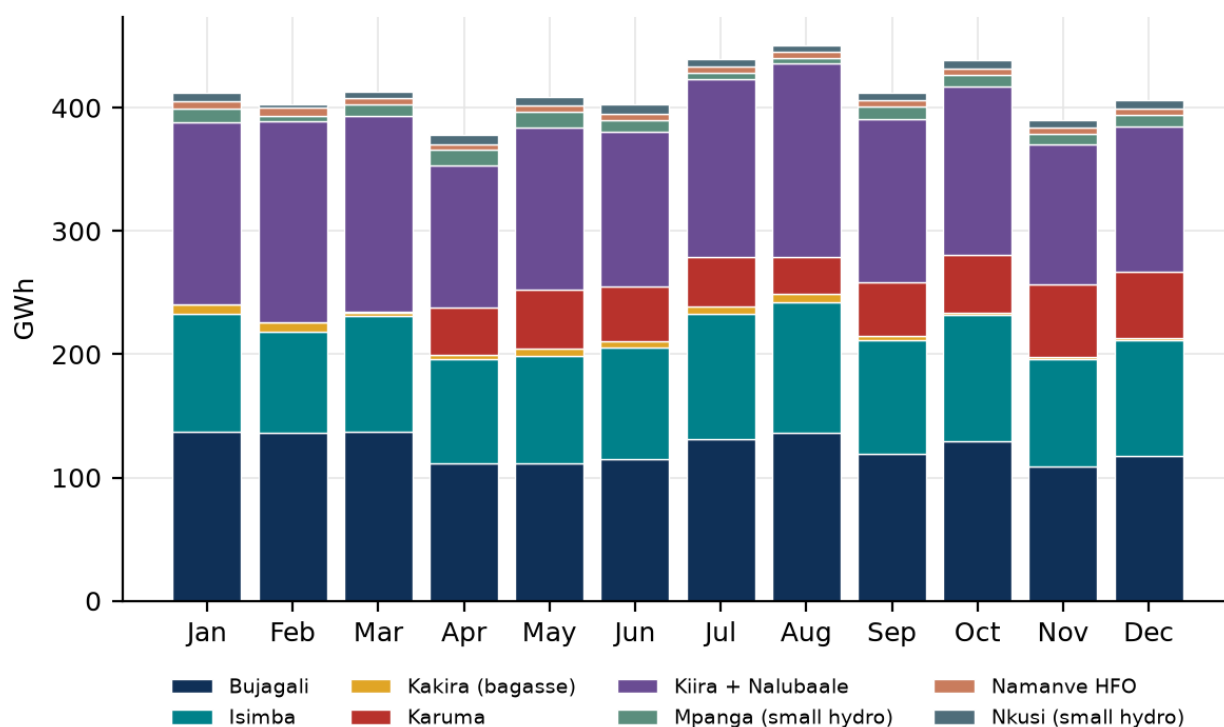


Figure 5.5: Metered monthly generation of the major plants, 2023

Source: UETCL System Operation Data 2023

Capacity factors differ widely (Figure 5.6).

- **Large hydro.** Bujagali (68 %) and Isimba (70 %) run close to their design factors. Kiira and Nalubaale run at 50 %.
- **Small hydro.** The small-hydro clusters run at 8–49 %, depending on river flow. The northern cluster runs lowest and the south-western cluster highest.
- **Bagasse.** SCOU's bagasse plant runs at 64 %, but most bagasse plants run far below that, because they export only surplus steam from the crushing season.
- **HFO.** Namanve HFO ran at 15 %. Electromaxx did not run.
- **Solar.** Solar plants run at 16–22 %, as expected for Uganda's latitude. The exception is Busitema, which was commissioned at the very end of the year.

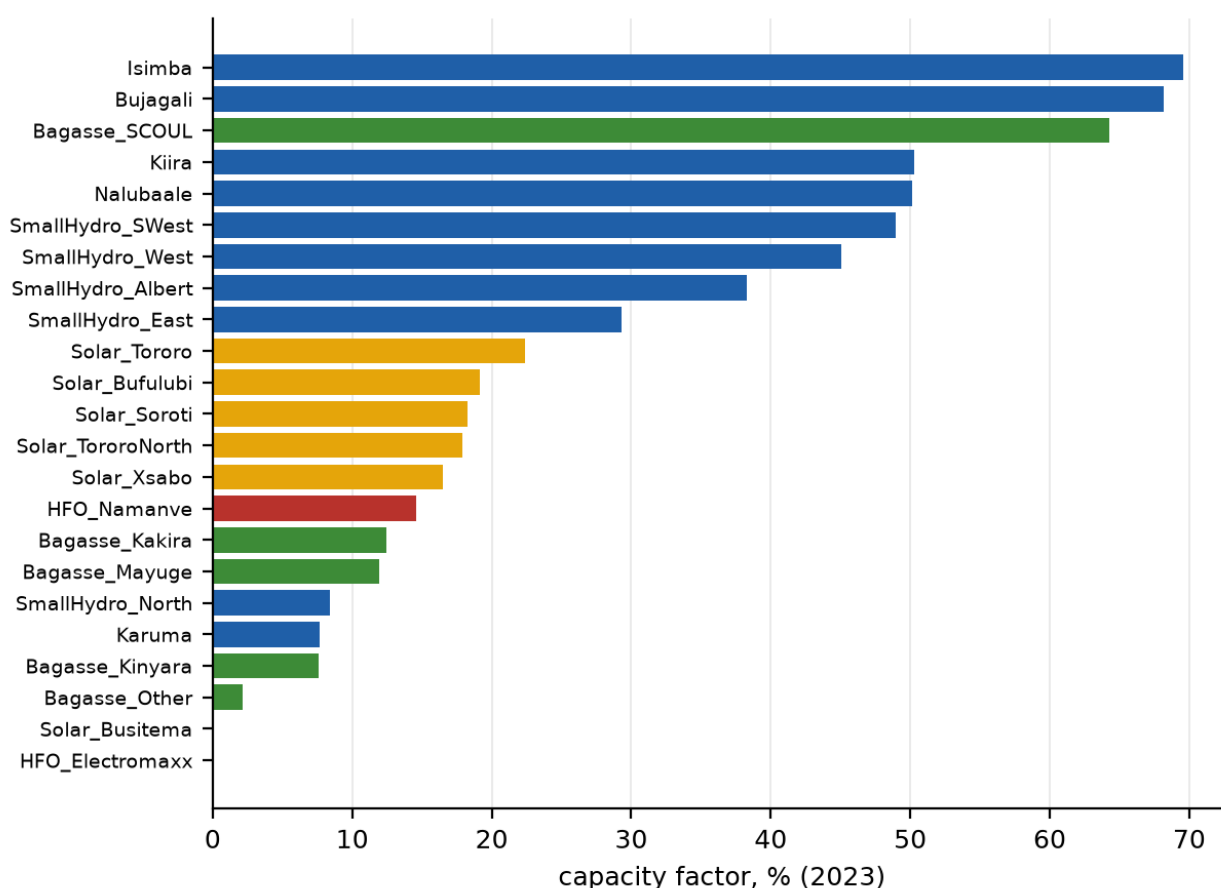


Figure 5.6: Observed capacity factor by plant, 2023

Source: UETCL metered energy; ERA capacities

5.3 Method: least-cost dispatch

5.3.1 The merit order

The merit order (Figure 5.7, Table 5.3) ranks units by marginal cost:

1. Large hydro, with no marginal cost.
2. Small hydro (about 1 USD/MWh).
3. Bagasse (27.5 USD/MWh).
4. HFO (194 USD/MWh).

At the evening peak, when solar contributes nothing, the fleet offers 1,969 MW of dependable capacity against the 988 MW metered peak. The price-setting unit at peak is hydro. HFO is needed only when the reservoirs or the grid bind.

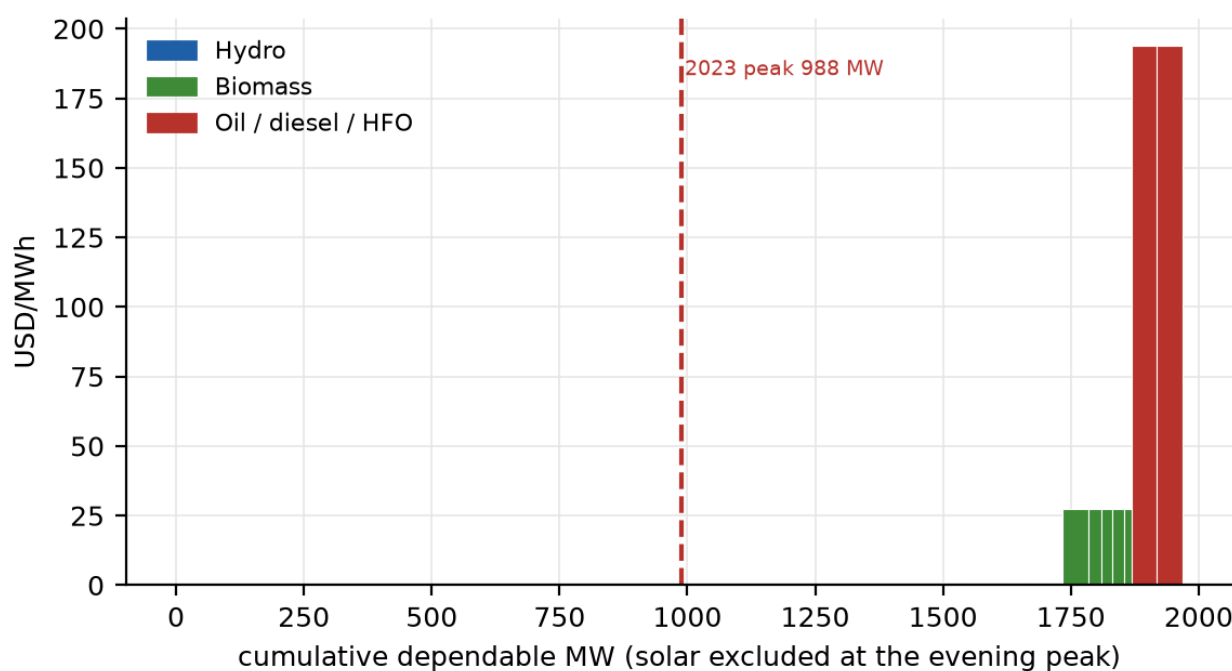


Figure 5.7: Merit order of the existing fleet with the 2023 system peak

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 5.3: Merit order of the existing fleet at the evening peak (solar excluded)

Unit	Technology	Dependable MW	Marginal cost (USD/MWh)	Cumulative MW
Karuma	Hydro	600.0	0.0	600
Bujagali	Hydro	250.0	0.0	850
Kiira	Hydro	200.0	0.0	1,050
Isimba	Hydro	183.0	0.0	1,233
Nalubaale	Hydro	180.0	0.0	1,413
Solar_Xsabo	Solar PV	0.0	0.0	1,413
Solar_Tororo	Solar PV	0.0	0.0	1,413
Solar_Soroti	Solar PV	0.0	0.0	1,413
Solar_TororoNorth	Solar PV	0.0	0.0	1,413
Solar_Bufulubi	Solar PV	0.0	0.0	1,413
Solar_Busitema	Solar PV	0.0	0.0	1,413
SmallHydro_West	Hydro	121.6	1.0	1,535
SmallHydro_North	Hydro	87.2	1.0	1,622
SmallHydro_SWest	Hydro	44.3	1.0	1,666
SmallHydro_Albert	Hydro	36.8	1.0	1,703
SmallHydro_East	Hydro	29.8	1.0	1,733
Bagasse_Kakira	Biomass	51.1	27.5	1,784
Bagasse_SCOUL	Biomass	25.0	27.5	1,809
Bagasse_Mayuge	Biomass	23.0	27.5	1,832
Bagasse_Other	Biomass	22.2	27.5	1,854
Bagasse_Kinyara	Biomass	14.5	27.5	1,868
HFO_Namanve	Oil / diesel / HFO	50.2	194.0	1,919
HFO_Electromaxx	Oil / diesel / HFO	50.0	194.0	1,969

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_merit.csv).

5.3.2 The PyPSA dispatch

The dispatch model (Equation (2.3)) represents each reservoir as storage with its 2023 inflow. Nalubaale and Kiira share the Owen Falls release, and Bujagali and Isimba have smaller reservoirs. The cyclic state-of-charge condition means that a reservoir must end the year where it began, so the model cannot draw down stored water to cover a shortage. Each corridor carries its thermal rating and loss factor. For the base year, the five corridors still under construction are excluded.

5.4 Results: the base year

5.4.1 Calibration against metered generation

The 2023 dispatch produces **6,194 GWh** against 5,987 GWh metered, 3.4 % higher. The difference is transmission losses, which the model computes endogenously. The modelled hydro share is **90.7 %** against 93.4 % metered.

Figure 5.8 and Table 5.4 compare plant by plant.

- **Hydro and bagasse** are reproduced almost exactly, because their energy is set by inflow and crushing.
- **Solar** is within 15 % for all but Busitema, which was commissioned late in 2023.
- **HFO is the notable exception.** The model runs Namanve HFO for 234 GWh against 64 GWh metered. The reason is visible in the flows. The Nalubaale–Namanve corridor is at 99 % of its rating in 2023, and the model uses Namanve to supply the eastern Kampala load that the corridor cannot carry. In reality the system operator managed the constraint partly by redispatch and partly by imports that the model does not represent. The HFO over-run is a signal of the grid constraint, not a calibration failure. Chapter 6 returns to it.

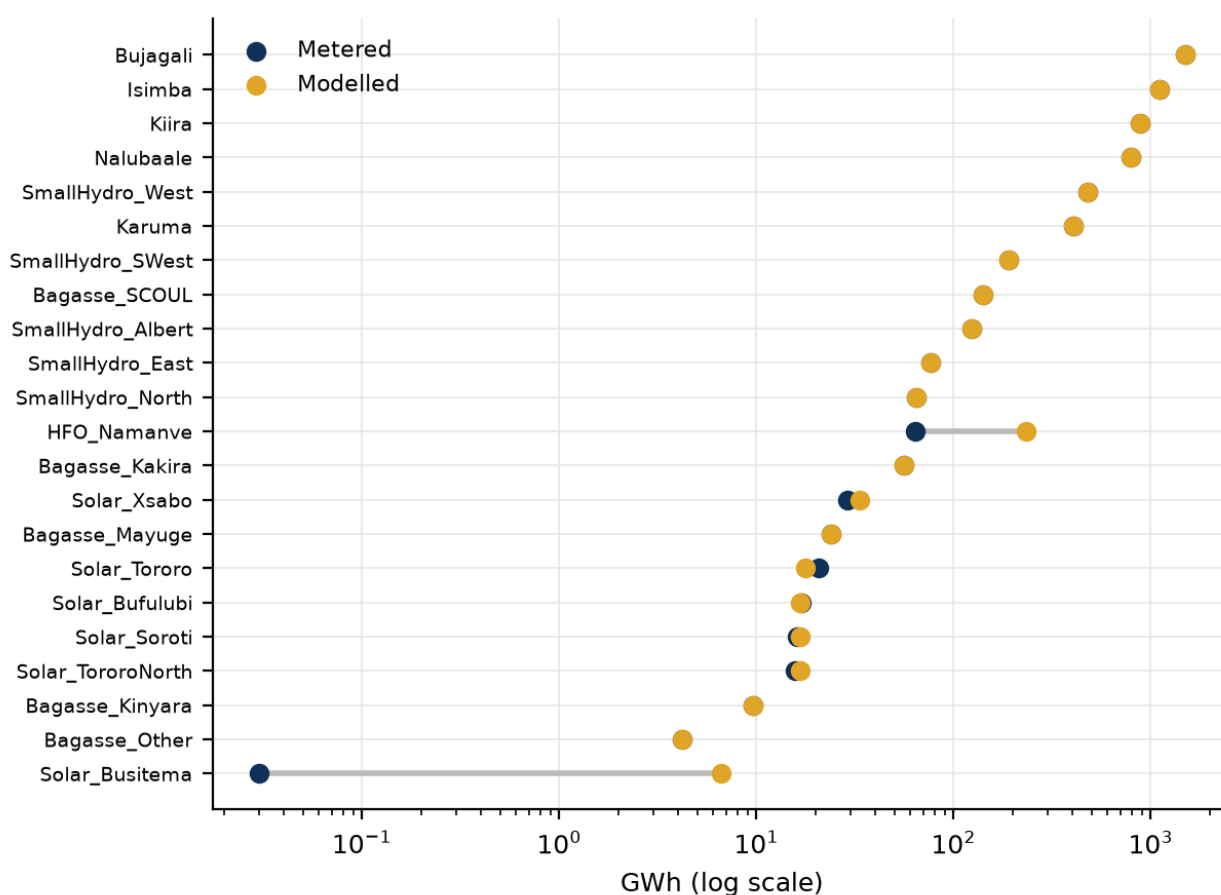


Figure 5.8: Calibration: modelled against metered 2023 generation by plant

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 5.4: Calibration: modelled against metered 2023 generation by plant

Unit	Technology	Metered 2023 (GWh)	Modelled 2023 (GWh)	Error
SmallHydro_West	Hydro	480.0	480.9	0.2%
SmallHydro_SWest	Hydro	190.0	190.3	0.2%
SmallHydro_East	Hydro	76.5	76.6	0.2%
SmallHydro_North	Hydro	64.4	64.5	0.2%
SmallHydro_Albert	Hydro	123.5	123.7	0.2%
Solar_Soroti	Solar PV	16.0	16.6	4.0%
Solar_TororoNorth	Solar PV	15.7	16.6	6.0%
Solar_Tororo	Solar PV	20.8	17.6	-15.2%
Solar_Xsabo	Solar PV	28.9	33.3	15.2%
Solar_Bufulubi	Solar PV	16.8	16.6	-0.9%
Solar_Busitema	Solar PV	0.0	6.7	22,091.7%
Bagasse_Kakira	Biomass	55.7	55.7	-0.0%
Bagasse_SCOUL	Biomass	140.8	140.8	-0.0%
Bagasse_Kinyara	Biomass	9.6	9.6	0.0%
Bagasse_Mayuge	Biomass	24.0	24.0	-0.0%
Bagasse_Other	Biomass	4.2	4.2	0.0%
HFO_Namanve	Oil / diesel / HFO	64.0	234.0	265.6%
Nalubaale	Hydro	790.0	790.0	0.0%
Kiira	Hydro	880.3	880.3	-0.0%
Bujagali	Hydro	1,492.2	1,492.2	0.0%
Isimba	Hydro	1,114.8	1,114.8	0.0%
Karuma	Hydro	404.4	404.4	0.0%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_calibration.csv).

5.4.2 The dispatch stack

Figure 5.9 shows how the fleet meets the load in each of the 25 slices of 2023. Large hydro runs as the base, flexing within its reservoirs, and bagasse runs in the crushing seasons. Small hydro and solar run whenever available. HFO fills the evening peaks where the grid into Kampala binds.

The reservoir trajectories (Figure 5.10) show the model using storage the way the cascade is operated. Water is held back in low-demand slices and released in high-demand ones. The reservoir levels move within their limits and return to their starting level over the year. The Owen Falls reservoirs of Nalubaale and Kiira carry by far the largest storage. Bujagali and Isimba, with small head ponds, follow their inflow more closely.

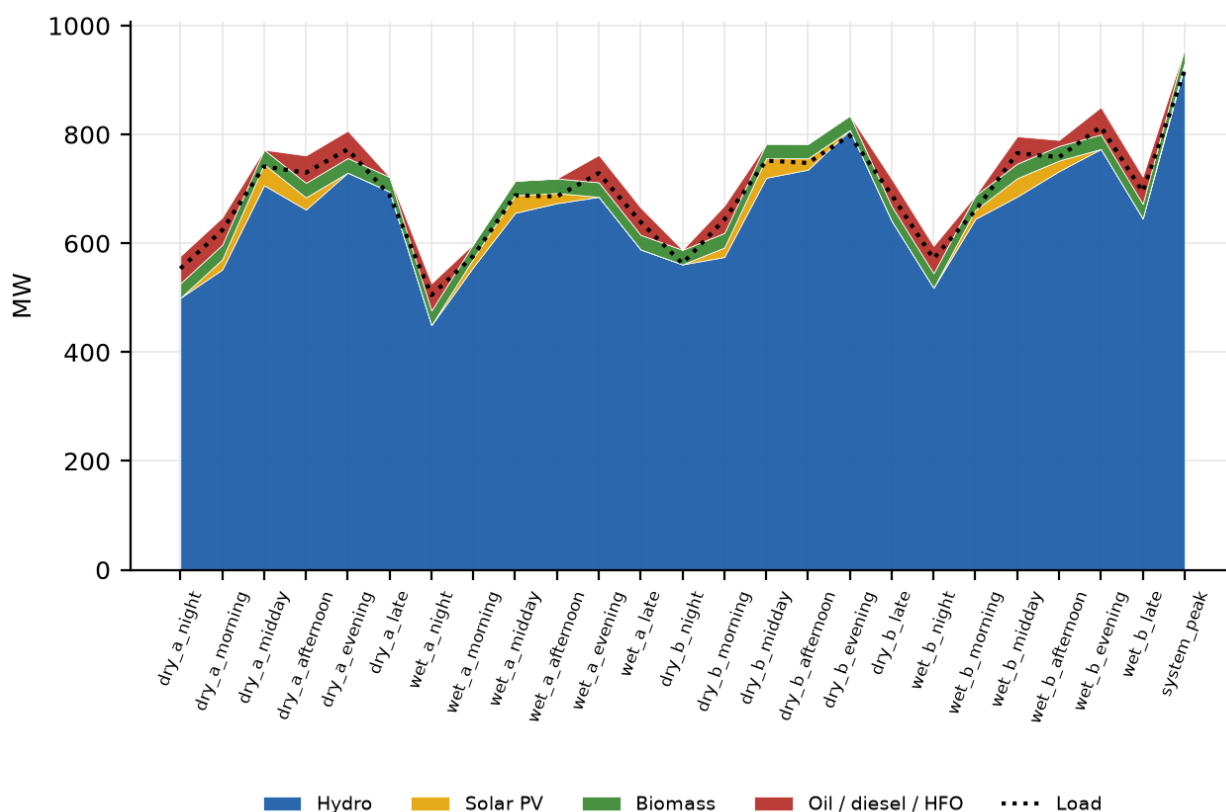


Figure 5.9: PyPSA least-cost dispatch of the existing fleet over the 25 time slices, 2023

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

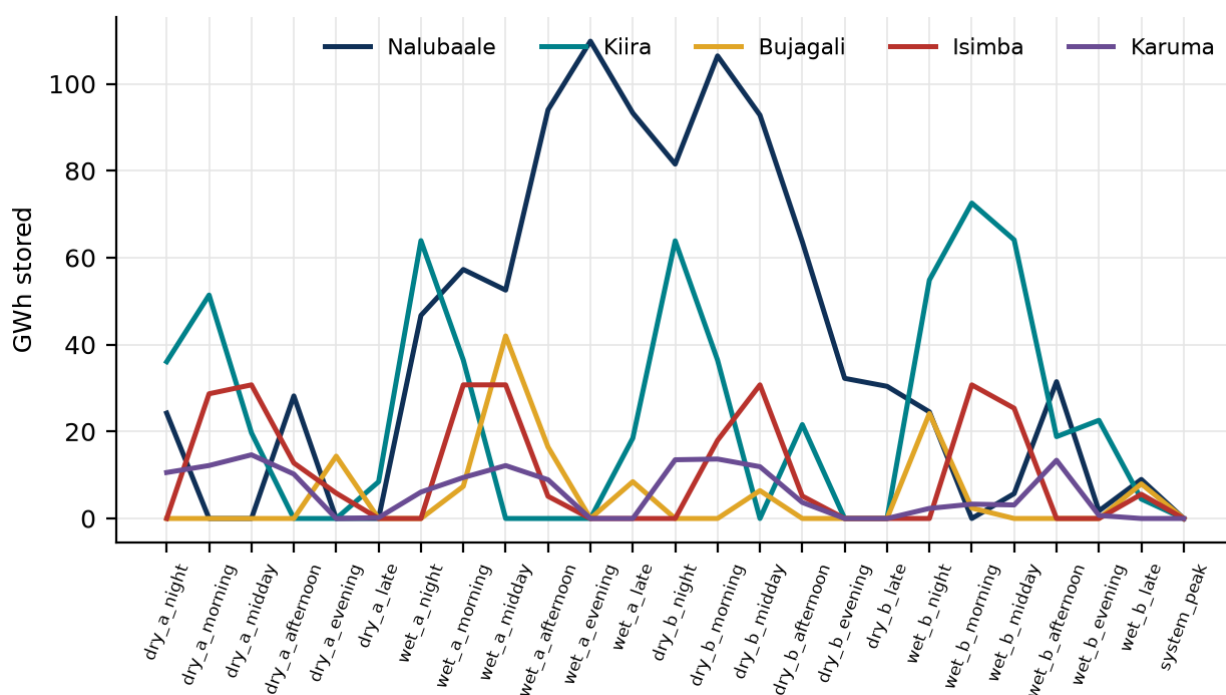


Figure 5.10: Reservoir state of charge across the 25 slices, 2023 (PyPSA)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

5.4.3 Concentration

Figure 5.11 shows how concentrated the supply is. The Nile cascade produced 76 % of modelled 2023 generation, and Bujagali alone 24 %. The Herfindahl index of generation by plant is 1,409.

- **Hydrological risk.** A dry year on the Victoria Nile affects three-quarters of Uganda's electricity at once. Chapter 8 shows that a 20 % reduction in inflow creates 415 GWh of unserved energy even in 2023, when there is surplus capacity.
- **Contingency risk.** The largest unit, Karuma, is 600 MW, equal to 61 % of the 2023 peak. Losing it would take out more capacity than the whole thermal and bagasse fleet combined.

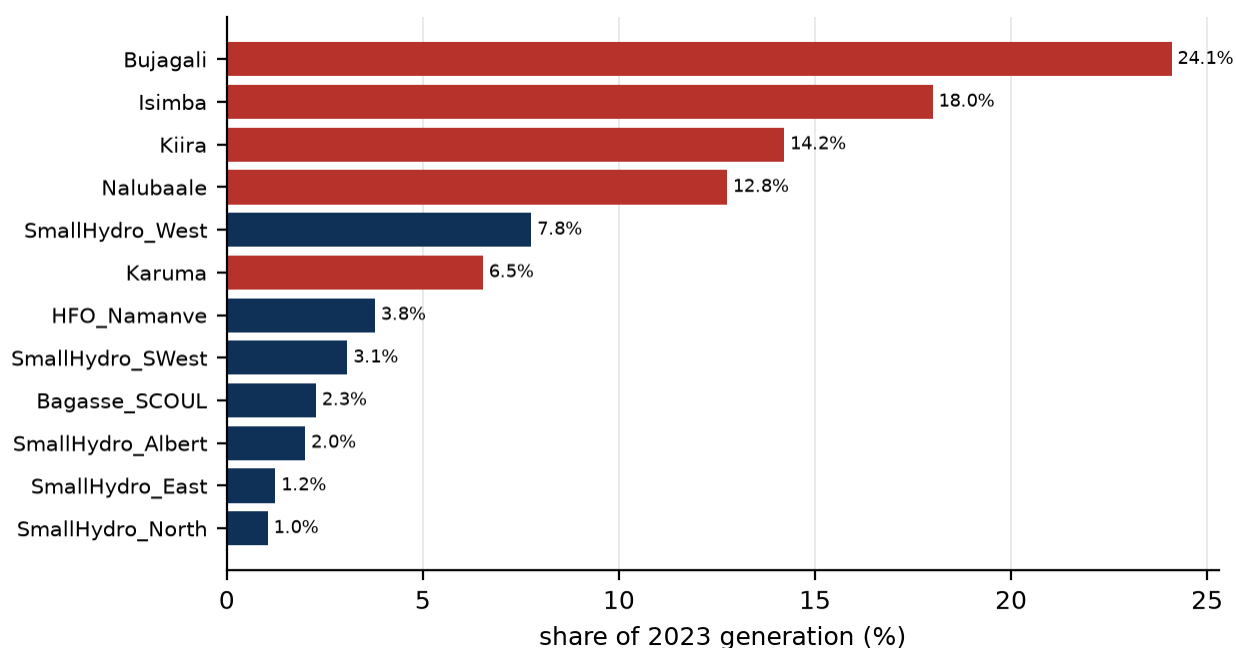


Figure 5.11: Hydro concentration: share of modelled 2023 generation by plant (Nile cascade in red)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

5.5 Results: the existing fleet against growing demand

The most useful result of this chapter is the dispatch of the **existing fleet against each future year's demand** (Figure 5.12, Table 5.5). This is the "do nothing" case: how long the system Uganda has today can serve the demand of Chapter 4.

- **2026.** The existing fleet still serves all demand. Karuma is now at its design output (the model raises its inflow to a 55 % capacity factor from 2024), and hydro alone covers 7,823 GWh. Bagasse and HFO are not needed, and the mean price falls to almost zero: 2026 is a year of hydro surplus.
- **2030.** The fleet produces all it can: 8,104 GWh of hydro, 234 GWh of bagasse, 878 GWh of HFO and 108 GWh of solar. It still sheds **3,073 GWh**, a quarter of demand. The price is set by VoLL in every slice.
- **2035 and 2040.** Unserved energy rises to 9,440 GWh in 2035 and **20,120 GWh** in 2040, when more than two-thirds of demand would be unserved.

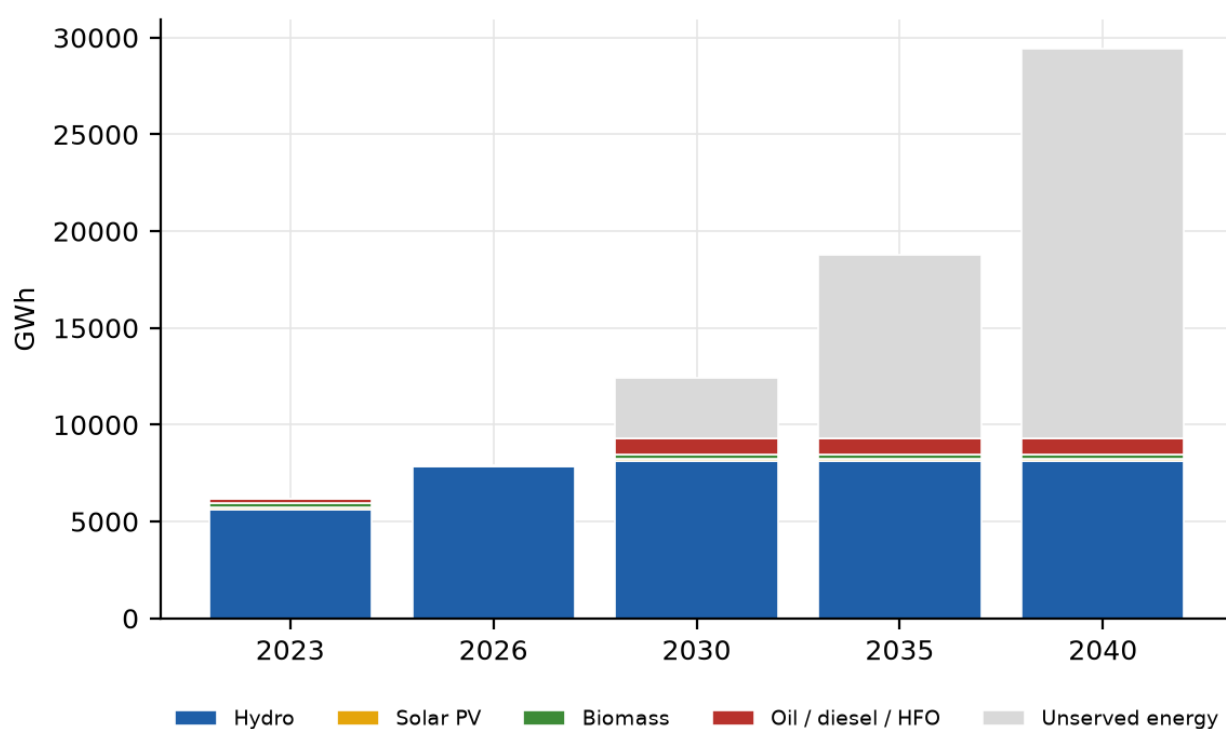


Figure 5.12: The existing fleet against each year's demand: generation mix and unserved energy (PyPSA)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 5.5: PyPSA dispatch of the existing fleet against each year's demand (GWh unless stated)

Year	Hydro	Biomass	Oil / diesel / HFO	Solar PV	Unserved (GWh)	LOLE (h)	Emissions (kt)	Mean price (USD/MWh)
2023	5,618	234	234	108	0	0	154	194.4
2026	7,823	0	0	108	0	0	0	0.9
2030	8,104	234	878	108	3,073	8,760	578	5,000.0
2035	8,104	234	878	108	9,440	8,760	578	5,000.0
2040	8,104	234	878	108	20,120	8,760	578	5,000.0

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_dispatch_years.csv).

The emissions of the existing fleet rise from 154 kt in 2023 to 578 kt by 2030, as the HFO plants run flat out, and then stay flat because there is nothing more to run (Figure 5.13). The grid intensity is low by international standards throughout. Emissions are not the problem of the existing fleet; its size is.

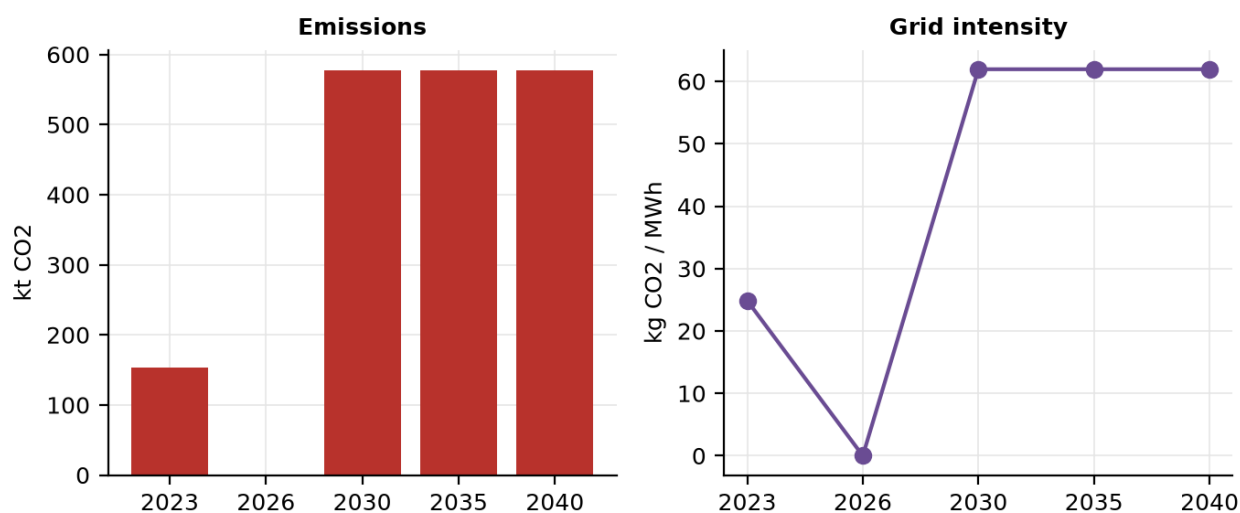


Figure 5.13: Emissions of the existing fleet as demand grows (no new build)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

5.6 The resource beyond the fleet

The fleet map shows where generation *is*. Figure 5.14 shows one of the resources for where it *could* be.

The Global Wind Atlas gives the mean wind speed at 100 m by district. It is highest in Karamoja and the north-east: Abim, Agago, Kaabong, Karenga, Kitgum, Kotido, Moroto, Nabilatuk and Napak form the high-high cluster, together with Rakai. It is lowest in the Mount Elgon and Rwenzori districts.

This is consistent with the one wind candidate in the IRP set, Wind_Karamoja (120 MW), which the least-cost plan builds by 2040. It also suggests that the Karamoja wind resource, far from the grid today, could matter once the northern transmission is built.

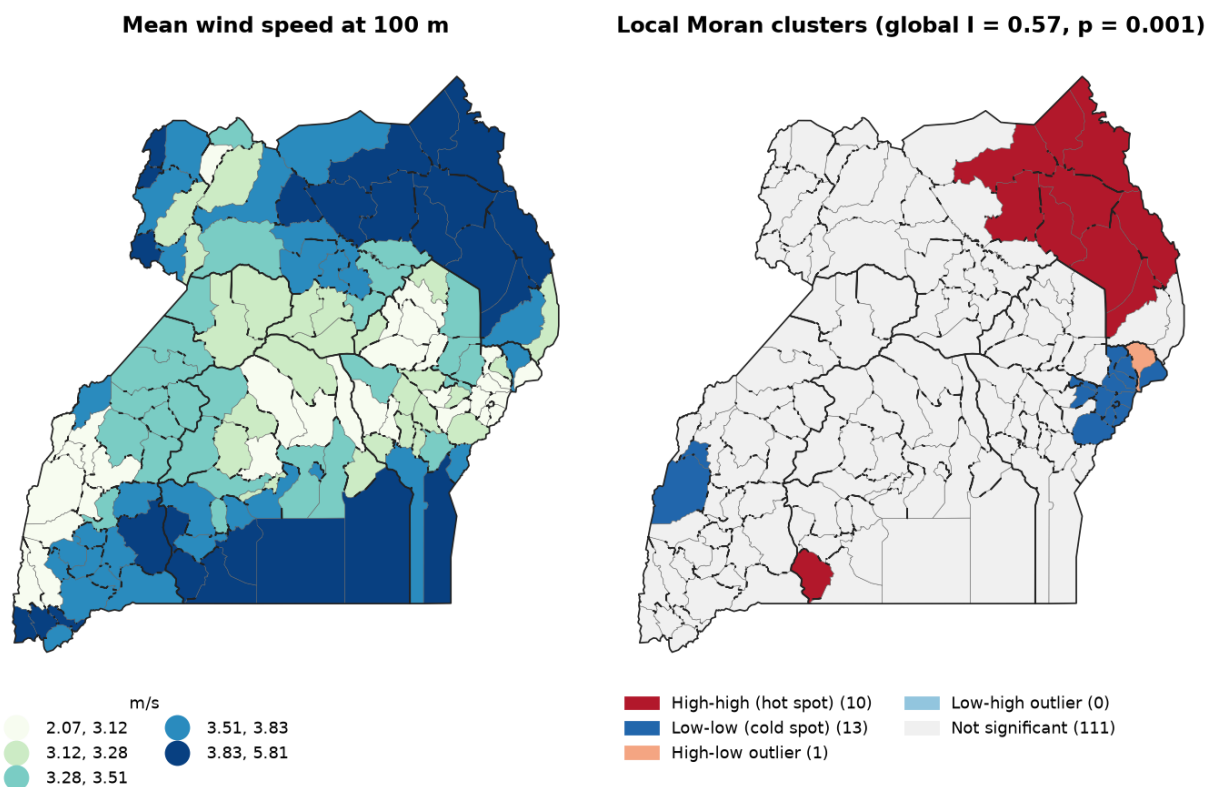


Figure 5.14: Ch.2 - Mean wind speed at 100 m (m/s), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

5.7 Data quality and limitations

- **Observed inputs.** Installed capacity and 2023 metered energy are OBSERVED, from ERA and UETCL. Plant locations come from MEMD's 2018 generation-sites layer where names match. The small-hydro clusters and the unmatched plants are placed at their connecting substation.
- **Capacity credits** are CALIBRATED. The hydro credit of 0.55 is a planning convention. A dry-season firm capability study of the cascade would sharpen it.
- **Constant inflow.** Reservoir inflow is constant within the year. Seasonality enters only through the small-hydro availability profiles and the hydrology scenario (dry: inflow $\times$ 0.8; wet: $\times$ 1.1).
- **Imports.** Imports from Kenya and Tanzania are not modelled as supply. Net exports are treated as demand.
- **Outages.** Forced outages are represented through capacity credits, not through probabilistic outage modelling.

5.8 Implications for planning

- The existing fleet can serve demand until about 2026. After that, unserved energy grows rapidly in the base scenario. The planning horizon for new firm capacity is therefore already short.
- Uganda's generation depends on one river and one large unit. Diversification of technology, of location and of the size of the largest contingency has value beyond least cost. The dry-year and security results of Chapter 8 quantify it.
- The HFO over-run in the calibration is the first sign of the grid constraint into eastern Kampala. Reinforcing Nalubaale–Namanve has operational value today, not only in 2030.
- The 2026 surplus is an opportunity. Cheap hydro energy is available for new industrial load and for export before the deficit opens. Timing new loads to that window is itself a planning decision.

CHAPTER 6

6 Transmission and network gaps

This chapter tests whether the transmission grid can move power from where it is generated to where it is needed, now and as demand grows. It identifies four kinds of network gap:

- **Capacity gaps:** corridors that run at their limit.
- **Security gaps:** corridors whose loss at peak sheds load.
- **Coverage gaps:** people too far from the grid to be served economically from it.
- **Timing gaps:** corridors needed before the lines under construction or planned are complete.

The chapter implements design Chapter 3 (`docs/03_transmission_and_gaps.md`).

6.1 The network

6.1.1 What exists and what is planned

The IERMP geodatabase gives Uganda's transmission lines in their true geography (Figure 6.1, Table 6.1).

- **Operational.** In 2023 the operational grid had **2,956 km** of line: 2,187 km at 132 kV, 490 km at 220 kV, 248 km at 400 kV and 30 km at 66 kV.
- **Under construction.** 686 km were under construction.
- **Planned.** A further **3,977 km** were at the planning stage. Most of it is 132 kV lines to the north and north-east, 220 kV lines in the west, and a 400 kV backbone from Karuma to Tororo and from Masaka to the Rwenzori.

The map shows the structure of the network clearly.

- **The core.** The core is a ring around Kampala fed from the Jinja generation hub, with 132 kV spokes to the west (Mubende, Fort Portal, Kasese), south-west (Masaka, Mbarara), east (Tororo, Mbale) and north (Lira, Gulu, Arua).
- **The 400 kV spine.** The new 400 kV line from Karuma runs south to Kawanda and north to Olwiyo.
- **Planned lines.** The planned lines (dashed) would close loops in the north, reach Karamoja and West Nile, and link to South Sudan, the DRC, Rwanda and Tanzania.

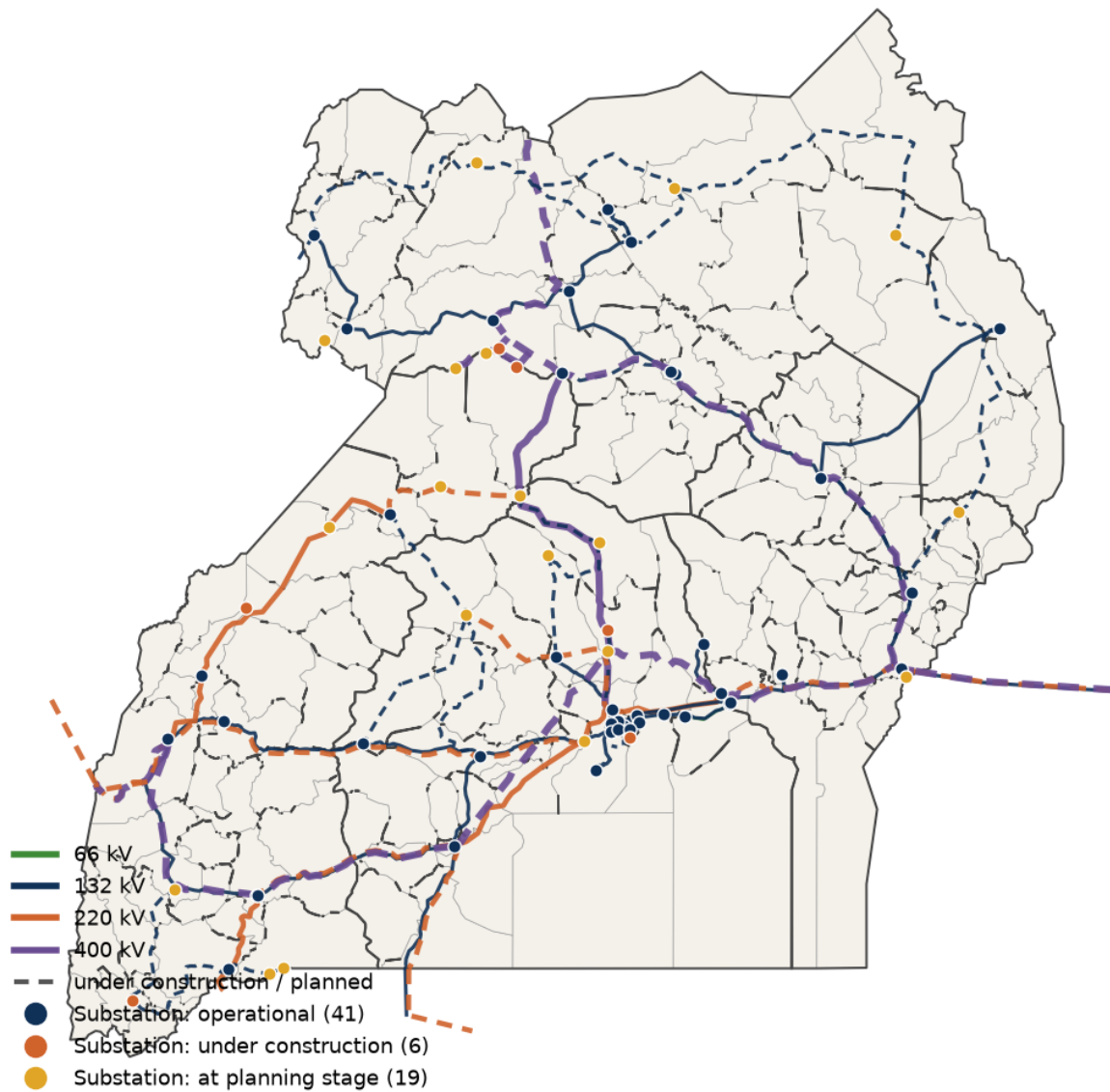


Figure 6.1: The transmission network: lines by voltage and status, and transmission substations

Source: IERMP GIS (MEMD/UETCL), data/external/uganda/tx_lines.geojson and tx_substations.csv

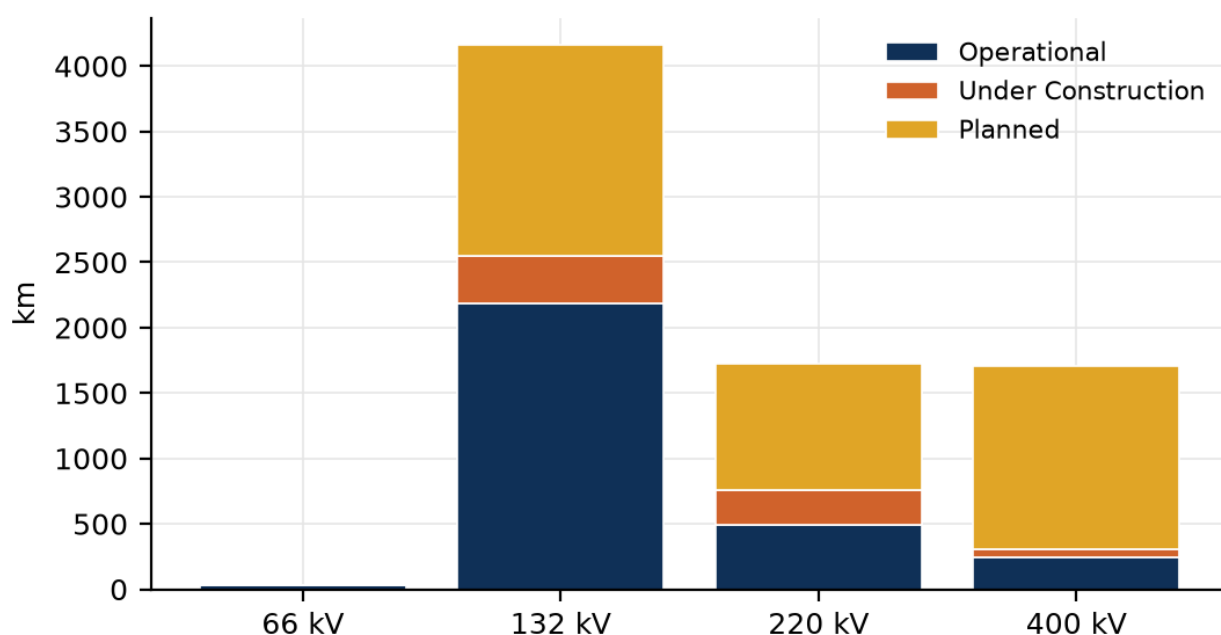


Figure 6.2: Transmission line length by voltage and status

Source: IERMP GIS (UETCL lines)

Table 6.1: Transmission lines by voltage and status, km (IERMP GIS)

Voltage	Operational	Planned	Under Construction	Total
66 kV	30	0	0	30
132 kV	2,187	1,608	364	4,160
220 kV	490	965	269	1,723
400 kV	248	1,403	54	1,705

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_grid_inventory.csv).

6.1.2 The model's corridors

The power model represents the grid by 24 corridors between the 17 transmission buses (Table 6.2). Each carries its thermal rating, loss factor and length. Five corridors are under construction and become available from 2026:

- Bujagali–Tororo (2) at 220 kV;
- Nkenda–Hoima at 220 kV;
- Kafu–Kawanda at 400 kV;
- Kawanda–Masaka at 220 kV;
- Mbarara–Nkenda at 132 kV.

Table 6.2: The 24 modelled transmission corridors (AEGID / UETCL)

Line	Corridor	kV	km	Rating (MW)	Loss factor	Status
L01	Bujagali - Kawanda	220	71.0	1,200	3.4%	Operational
L02	Bujagali - Nalubaale	132	8.4	400	2.2%	Operational
L03	Bujagali - Tororo	132	116.0	400	4.3%	Operational
L04	Bujagali - Tororo (2)	220	117.9	1,200	4.4%	Under Construction
L05	Nkenda - Hoima	220	224.4	1,200	6.5%	Under Construction
L06	Kabulasoke - Masaka West	132	61.3	200	3.2%	Operational
L07	Kabulasoke - Nkonge	132	76.4	200	3.5%	Operational
L08	Rugonjo - Nkenda	132	94.2	200	3.9%	Operational
L09	Kampala North - Mutundwe	132	9.4	400	2.2%	Operational
L10	Kafu - Kawanda	400	165.7	2,800	5.3%	Under Construction
L11	Kawanda - Masaka	220	137.2	1,200	4.7%	Under Construction

Line	Corridor	kV	km	Rating (MW)	Loss factor	Status
L12	Kawanda - Mutundwe	132	17.3	400	2.3%	Operational
L13	Lugogo - Kampala North	132	5.1	400	2.1%	Operational
L14	Lugogo - Mutundwe	132	10.1	400	2.2%	Operational
L15	Masaka West - Mbarara North	132	130.1	200	4.6%	Operational
L16	Mbarara - Nkenda	132	102.1	400	4.0%	Under Construction
L17	Mutundwe - Kabulasoke	132	84.2	200	3.7%	Operational
L18	Nalubale - Lugazi	66	30.5	80	2.6%	Operational
L19	Nalubale - Lugogo	132	69.9	400	3.4%	Operational
L20	Nalubale - Namanve	132	57.1	200	3.1%	Operational
L21	Namanve - Kampala North	132	12.2	200	2.2%	Operational
L22	Nkongwe - Kahungye	132	46.2	200	2.9%	Operational
L23	Opuyo - Lira (2)	132	115.3	400	4.3%	Operational
L24	Tororo - Opuyo (2)	132	147.7	400	5.0%	Operational

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_corridors.csv).

6.2 Method

6.2.1 Loading and congestion

For each corridor ℓ and time slice t , the flow f is read from the PyPSA dispatch. The loading is the flow divided by the rating K :

$$\text{loading}_{\ell, t} = \frac{|f_{\ell, t}|}{K_{\ell}} \quad (6.1)$$

The chapter reports:

- **peak loading;**
- **utilisation:** energy carried as a share of the rating over the year;
- **congested hours:** hours at 98 % of the rating or more;
- **stressed hours:** hours at 80 % or more;
- **congestion rent:** flow $\times$ the price difference between the ends of the corridor, a measure of what the constraint costs the system.

A corridor is a **capacity gap** if it reaches its rating or is stressed for 500 hours a year or more.

6.2.2 The grid-stress test

Testing future loadings with the existing fleet would be meaningless: by 2030 the existing fleet sheds a quarter of demand, so there is little power to move. The engine therefore uses a **grid-stress dispatch** for the future years.

1. Every candidate site of the plan is made available up to its build-rate-limited potential.
2. Each candidate is priced at its levelised cost, meaning annualised capital cost divided by expected output, plus variable cost.

The dispatch then uses the cheapest resources wherever they are, and the flows show where the grid binds when it has to carry them. The test isolates the grid from the question of which plants are built.

6.2.3 N-1 security

For the system peak of 2030, each corridor is removed in turn. The peak is re-dispatched with reservoir hydro fixed at its intact output, and the load that has to be shed is recorded. A corridor whose loss sheds load is **N-1 critical**.

6.2.4 Coverage

For every populated cell of the 1 km population grid, the engine computes the distance to the nearest operational transmission line and to the nearest MV line. From these it derives:

- the coverage curve: the share of the population within x km of the grid;
- the population-weighted distance of each district to the grid.

A district is a **coverage gap** when its population-weighted distance exceeds 50 km.

6.3 Results: loading and congestion

6.3.1 2023

In the 2023 dispatch, most corridors are lightly loaded (Figure 6.3). The exception is **Nalubaale–Namanve**, at 99.3 % of its rating. This is the corridor that carries the Jinja generation into the Namanve industrial area and eastern Kampala. Its constraint is what makes the model run the Namanve HFO plant (Chapter 5).

Kawanda–Mutundwe (57 %), Bujagali–Nalubaale (50 %) and Namanve–Kampala North (48 %) are the next most loaded: all in the Kampala supply ring.

6.3.2 2030: the grid-stress test

Under the 2030 grid-stress test the picture changes (Table 6.3). Six corridors reach their rating, and they fall into three groups.

- **The eastern supply into Kampala:**
 - Nalubaale–Namanve, at its rating for 6,294 hours;
 - Bujagali–Nalubaale, at its rating for 919 hours.
- **The western export path:**
 - Kabulasoke–Nkonge, Nkonge–Kahungye and Mutundwe–Kabulasoke, at their ratings for 4,283–8,760 hours;
 - Masaka West–Mbarara North, at its rating for 1,843 hours.

The western corridors carry the output of the geothermal candidates at Katwe and Buranga and of the Albertine gas site at Kahungye towards Kampala. At 132 kV and 200 MW they cannot carry it.

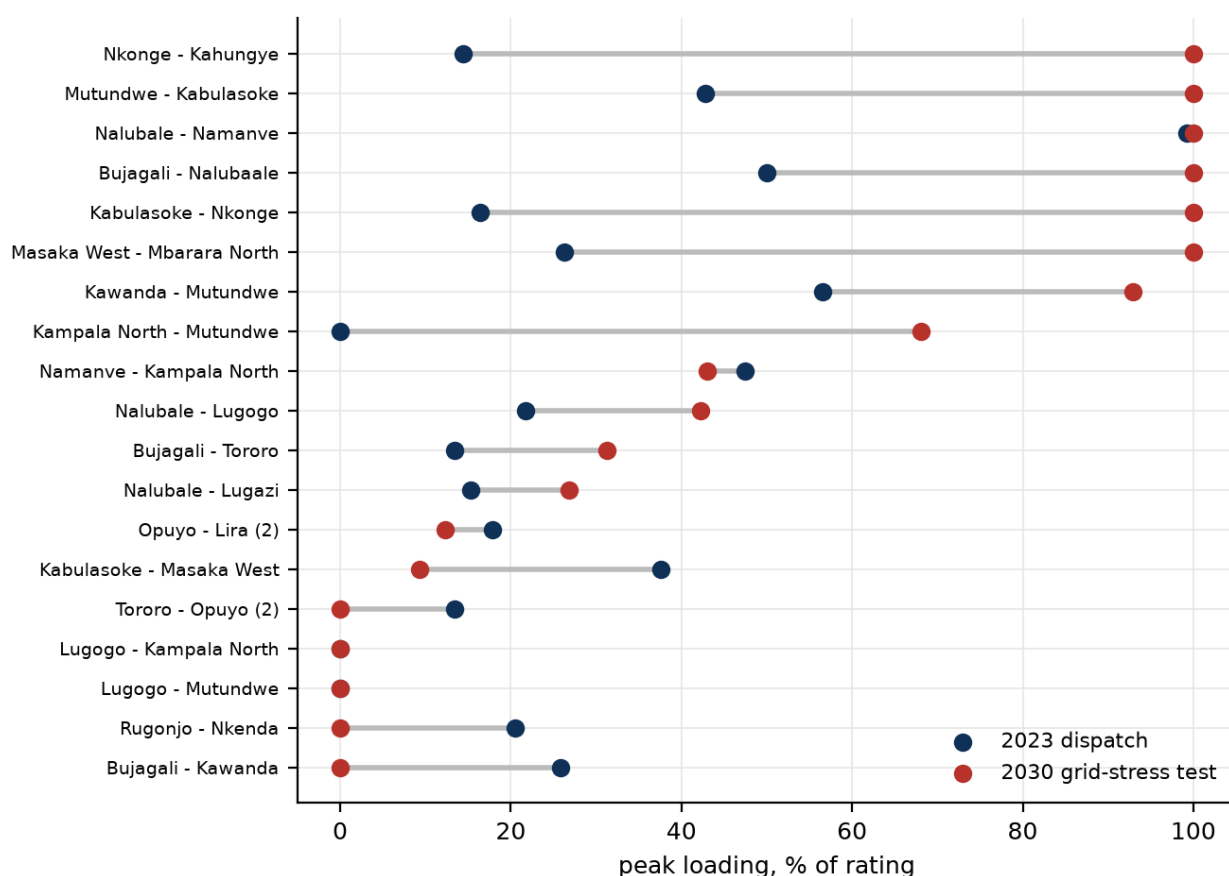


Figure 6.3: Peak corridor loading: 2023 against the 2030 grid-stress test

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 6.3: Corridor loading: 2023 dispatch and the 2030 grid-stress test

Line	Corridor	Peak loading 2023	Peak loading 2030	Stressed hours 2030	Congested hours 2030	Congestion rent (MUSD/yr)	Losses 2023 (GWh)	Gap flag
L02	Bujagali - Nalubaale	50.0%	100.0%	3,004	919	3.63	15.4	yes
L15	Masaka West - Mbarara North	26.3%	100.0%	2,207	1,843	2.19	11.3	yes
L07	Kabulasoke - Nkonge	16.4%	100.0%	4,383	4,283	4.52	4.4	yes
L22	Nkonge - Kahungye	14.4%	100.0%	8,760	8,760	7.02	3.5	yes
L17	Mutundwe - Kabulasoke	42.8%	100.0%	8,760	8,760	6.15	11.6	yes
L20	Nalubale - Namanve	99.3%	100.0%	8,760	6,294	7.57	34.4	yes
L12	Kawanda - Mutundwe	56.5%	93.0%	100	0	2.90	29.0	
L09	Kampala North - Mutundwe	0.0%	68.0%	0	0	2.39	0.0	
L21	Namanve - Kampala North	47.5%	43.1%	0	0	0.39	14.2	
L19	Nalubale - Lugogo	21.8%	42.2%	0	0	2.79	20.1	
L03	Bujagali - Tororo	13.4%	31.3%	0	0	0.50	2.8	
L18	Nalubale - Lugazi	15.3%	26.9%	0	0	0.21	1.3	
L23	Opuyo - Lira (2)	17.8%	12.3%	0	0	0.96	13.2	
L06	Kabulasoke - Masaka West	37.6%	9.3%	0	0	0.15	12.7	
L01	Bujagali - Kawanda	25.9%	0.0%	0	0	0.00	62.0	

Line	Corridor	Peak loading 2023	Peak loading 2030	Stressed hours 2030	Congested hours 2030	Congestion rent (MUSD/yr)	Losses 2023 (GWh)	Gap flag
L14	Lugogo - Mutundwe	0.0%	0.0%	0	0	0.00	0.0	
L13	Lugogo - Kampala North	0.0%	0.0%	0	0	0.00	0.0	
L08	Rugonjo - Nkenda	20.6%	0.0%	0	0	0.00	9.2	
L24	Tororo - Opuyo (2)	13.4%	0.0%	0	0	0.00	10.0	

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_loading.csv).

Figure 6.4 shows the loading of every corridor in every slice of 2030. Nkonge–Kahungye and Mutundwe–Kabulasoke are full in every slice, and Kabulasoke–Nkonge in about half of them. The western constraint is structural, not a peak phenomenon. The eastern corridors are full in most slices and relieved only at night. Figure 6.5 counts the hours.

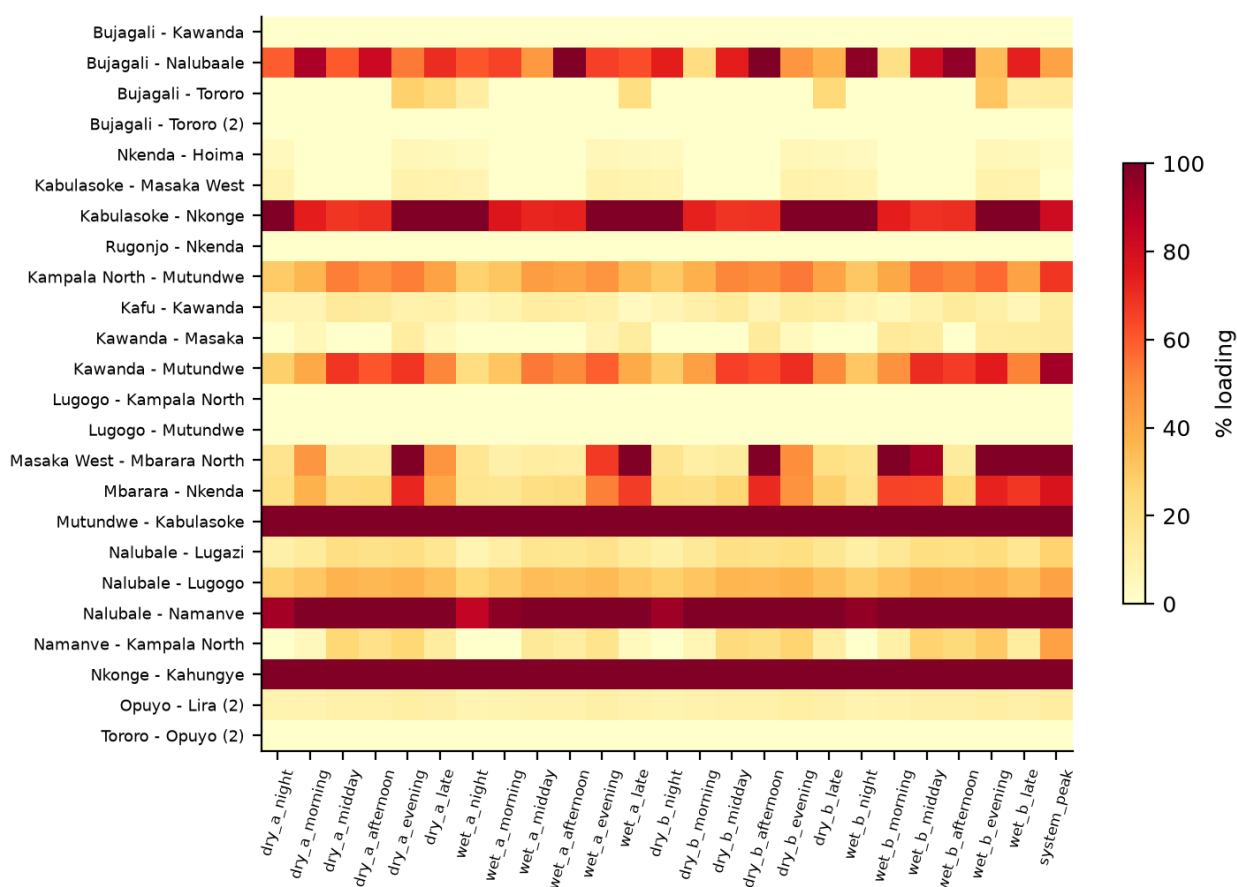


Figure 6.4: Corridor loading by time slice, 2030 grid-stress test

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

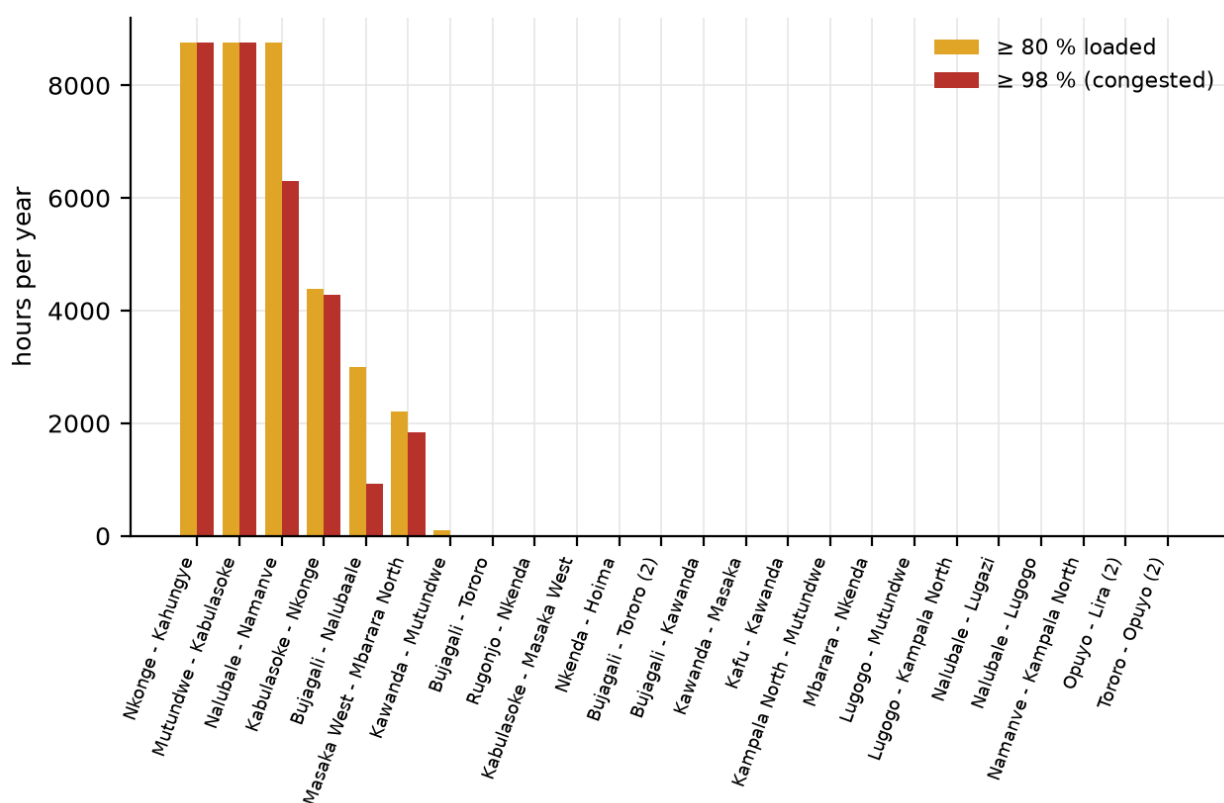


Figure 6.5: Stressed and congested hours by corridor, 2030

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

The congestion rents in Table 6.3 measure what the constraints are worth. Nalubaale–Namanve (7.6 million USD a year), Nkonge–Kahungye (7.0 million USD) and Mutundwe–Kabulasoke (6.2 million USD) each cost the system several million dollars a year in more expensive dispatch. Reinforcing them costs about 1.0–1.2 million USD a year per 100 MW in annualised terms (Table 6.8). The rents are several times the cost of relieving the constraints.

The nodal prices of Figure 6.6 and Table 6.4 show the same constraints from the price side.

- **Western buses.** Prices are lowest at the western buses: 60 USD/MWh at Kahungye and Nkenda, where cheap geothermal and gas are trapped.
- **Kampala buses.** Prices are highest at the Kampala buses: 71–73 USD/MWh at Lugogo, Kampala North and Namanve, which import across the constrained corridors.

The spread of 13 USD/MWh between west and east is the value of more transfer capacity.

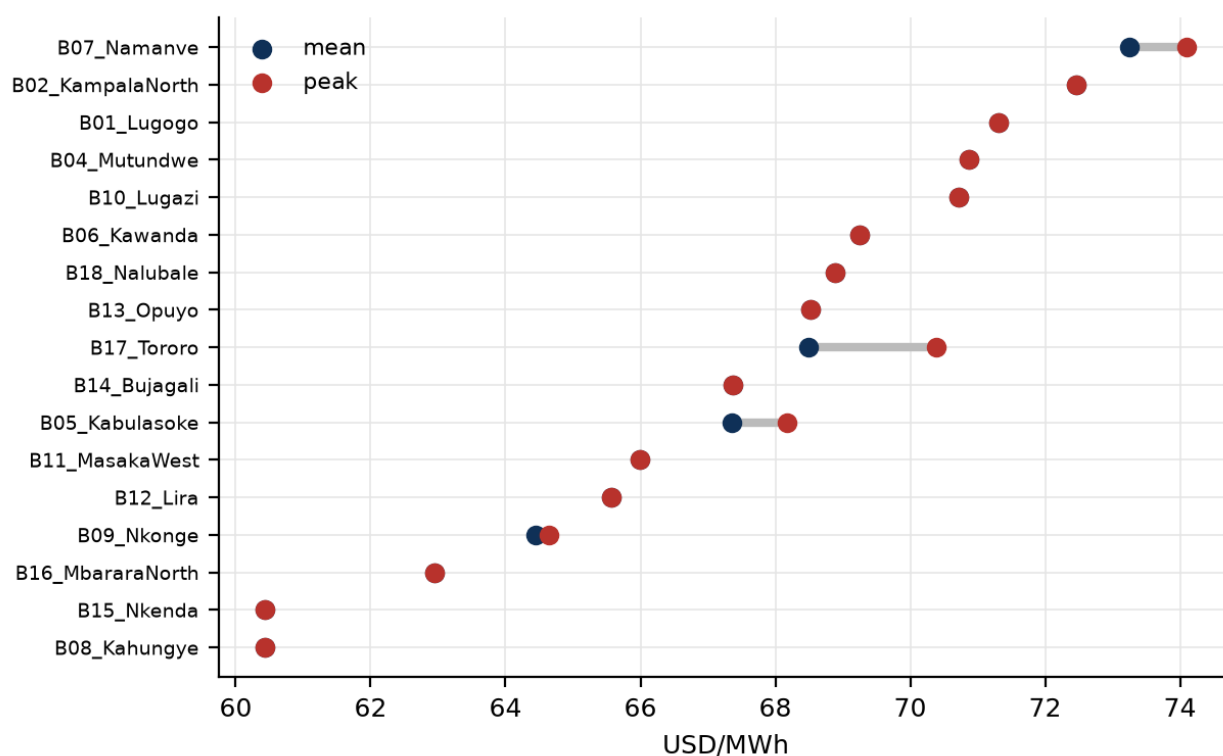


Figure 6.6: Nodal prices by bus, 2030 grid-stress test

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 6.4: Nodal prices under the 2030 grid-stress test (USD/MWh)

Bus	Region	Mean price 2030	Peak price 2030
B08_Kahungye	Kyenjojo	60.4	60.4
B15_Nkenda	Kasese	60.4	60.4
B16_MbararaNorth	Isingiro	63.0	63.0
B09_Nkongge	Kibaale	64.4	64.6
B12_Lira	Apac	65.6	65.6
B11_MasakaWest	Rakai	66.0	66.0
B05_Kabulasoke	Mubende	67.4	68.2
B14_Bujagali	Kamuli	67.4	67.4
B17_Tororo	Bugiri	68.5	70.4
B13_Opuyo	Amuria	68.5	68.5
B18_Nalubale	Mayuge	68.9	68.9
B06_Kawanda	Nakaseke	69.2	69.2
B10_Lugazi	Buikwe	70.7	70.7
B04_Mutundwe	Wakiso	70.9	70.9
B01_Lugogo	Mukono	71.3	71.3
B02_KampalaNorth	Wakiso	72.5	72.5
B07_Namanve	Mukono	73.2	74.1

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_prices_bus.csv).

Figure 6.7 puts loading and N-1 criticality on the map. The loaded corridors form two chains: one westward from Kampala to Kasese, one eastward from Kampala to Jinja.

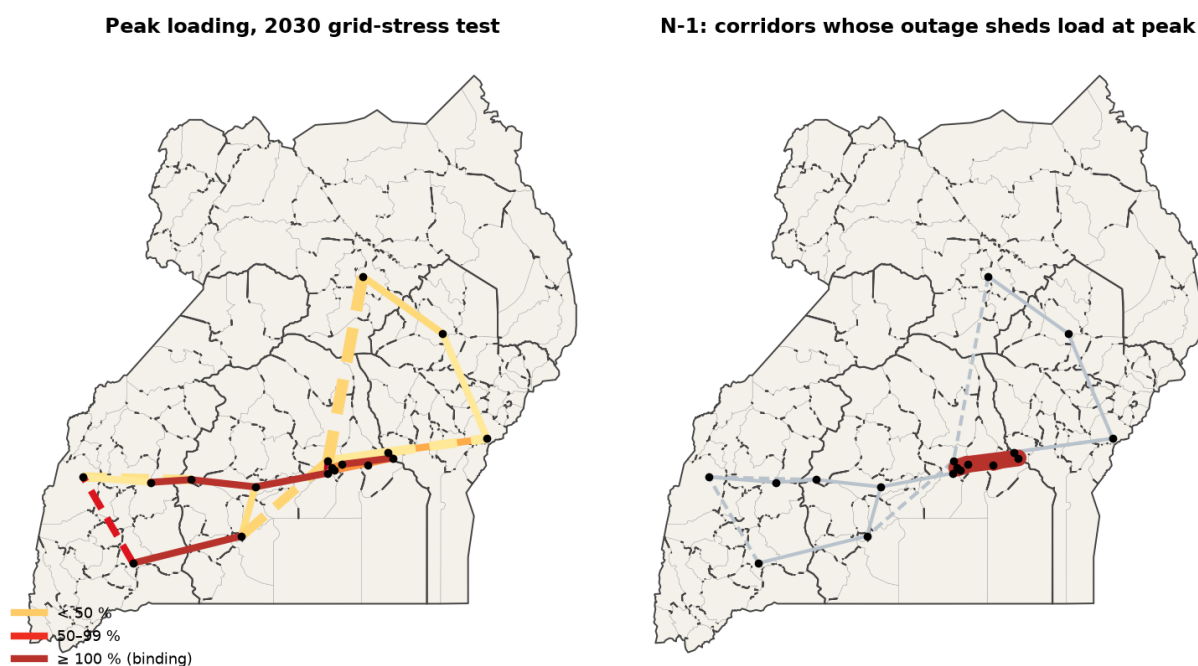


Figure 6.7: Where the grid binds: corridor loading (2030) and N-1 critical corridors (width $\propto$ MW shed)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

The flow-duration curves of the six most-used corridors (Figure 6.8) show how the loaded corridors sit at their rating for most of the year. The Bujagali–Kawanda 220 kV corridor, by contrast, has spare capacity.

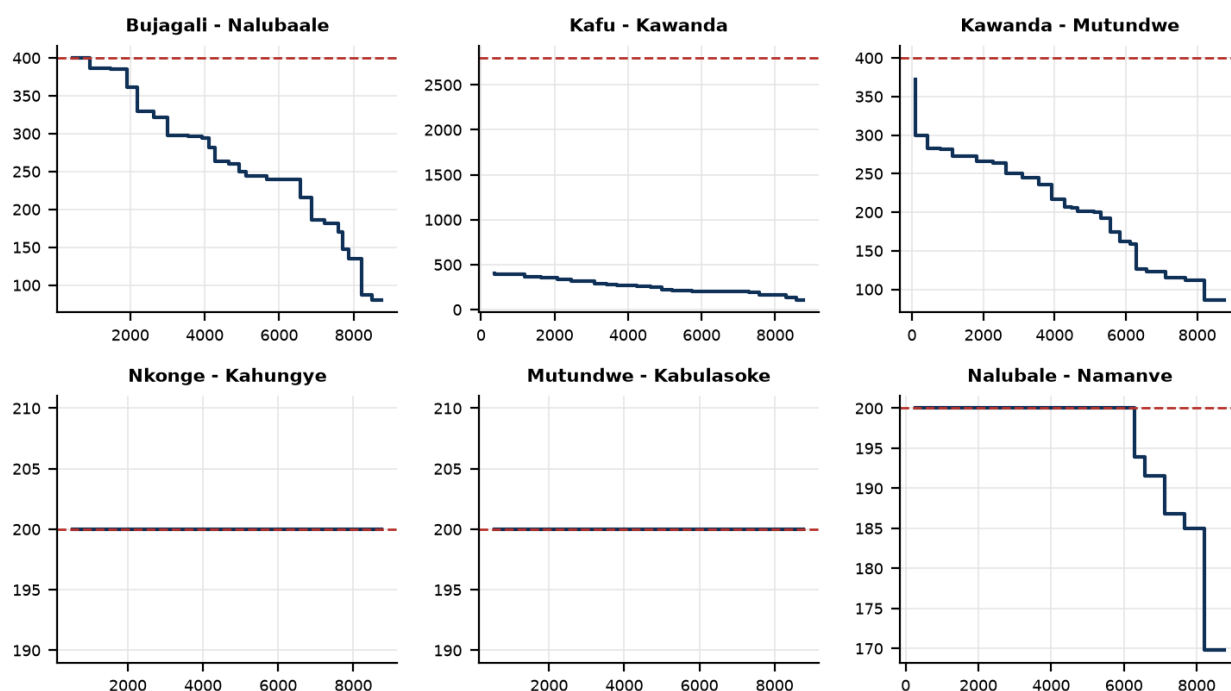


Figure 6.8: Flow-duration curves of the six most-used corridors, 2030 (dashed = rating)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

6.4 Results: N-1 security

Three corridors are N-1 critical at the 2030 peak (Figure 6.9, Table 6.5). Losing any one of them sheds load at peak even when supply is available elsewhere:

- **Namanve–Kampala North:** 34 MW shed;

- **Nalubaale–Namanve:** 32 MW shed;
- **Nalubaale–Lugazi:** 21 MW shed.

All three are in the eastern supply to Kampala and the Lugazi industrial area. They are radial or near-radial paths, and the system cannot route around them. No other corridor is N-1 critical at the 2030 peak.

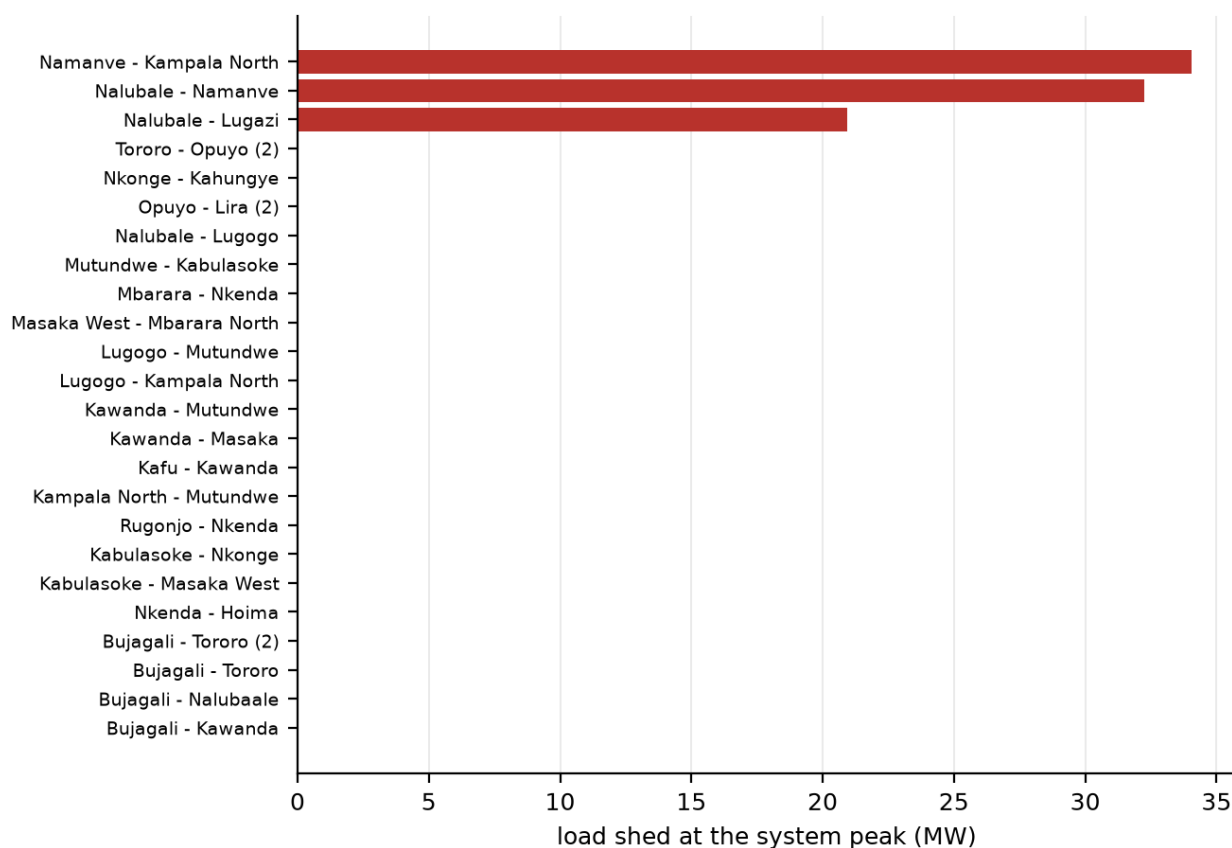


Figure 6.9: N-1 screening at the 2030 peak: load shed when each corridor is out (red = critical)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 6.5: N-1 screening at the 2030 system peak

Line	Corridor outage	Load shed at peak (MW)	Max post-contingency loading	N-1 critical
L21	Namanve - Kampala North	34.0	100.0%	yes
L20	Nalubale - Namanve	32.2	100.0%	yes
L18	Nalubale - Lugazi	20.9	100.0%	yes
L01	Bujagali - Kawanda	0.0	100.0%	
L05	Nkenda - Hoima	0.0	100.0%	
L02	Bujagali - Nalubaale	0.0	100.0%	
L03	Bujagali - Tororo	0.0	100.0%	
L04	Bujagali - Tororo (2)	0.0	100.0%	
L08	Rugonjo - Nkenda	0.0	100.0%	
L07	Kabulasoke - Nkonge	0.0	100.0%	
L06	Kabulasoke - Masaka West	0.0	100.0%	
L09	Kampala North - Mutundwe	0.0	100.0%	
L13	Lugogo - Kampala North	0.0	100.0%	
L10	Kafu - Kawanda	0.0	100.0%	
L11	Kawanda - Masaka	0.0	100.0%	
L12	Kawanda - Mutundwe	0.0	100.0%	

Line	Corridor outage	Load shed at peak (MW)	Max post-contingency loading	N-1 critical
L16	Mbarara - Nkenda	0.0	100.0%	
L15	Masaka West - Mbarara North	0.0	100.0%	
L14	Lugogo - Mutundwe	0.0	100.0%	
L17	Mutundwe - Kabulasoke	0.0	100.0%	
L19	Nalubale - Lugogo	0.0	100.0%	
L22	Nkonge - Kahungye	0.0	100.0%	
L23	Opuyo - Lira (2)	0.0	100.0%	
L24	Tororo - Opuyo (2)	0.0	100.0%	

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_n1.csv).

6.5 Results: transmission losses

Modelled 2023 transmission losses are 255 GWh against 289 GWh observed, a 12 % difference (validation check V3-3). The transport model does not represent all the reactive and transformer losses that the metered figure includes.

Figure 6.10 shows the corridors that carry the losses. The long, heavily loaded 132 kV lines lose the most: Bujagali–Kawanda (62 GWh), Nalubaale–Namanve (34 GWh), Kawanda–Mutundwe (29 GWh) and Nalubaale–Lugogo (20 GWh).

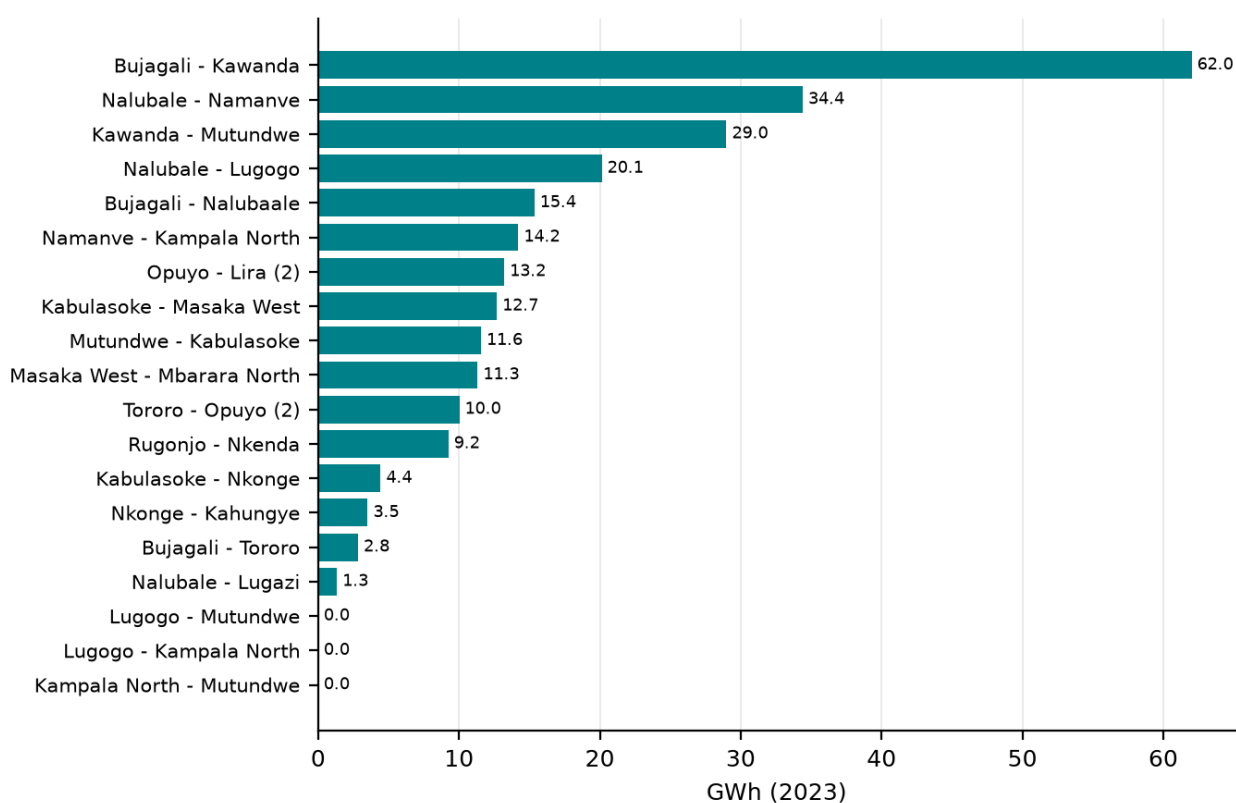


Figure 6.10: Modelled transmission losses by corridor, 2023

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

6.6 Results: coverage

6.6.1 How far the grid reaches

The coverage curve (Figure 6.11, Table 6.6) shows how close Ugandans live to the grid:

- **28 %** of the population lives within 5 km of a transmission line;
- **41 %** within 10 km;
- **68 %** within 25 km;
- **91 %** within 50 km.

The MV network reaches much further: **96.6 %** of the population lives within 5 km of a 33 or 11 kV line. The difference between the two curves is the work that distribution has already done. The coverage problem is not that people are far from wires. It is that the wires near them are MV lines at the end of long radial feeders from a small number of transmission substations.

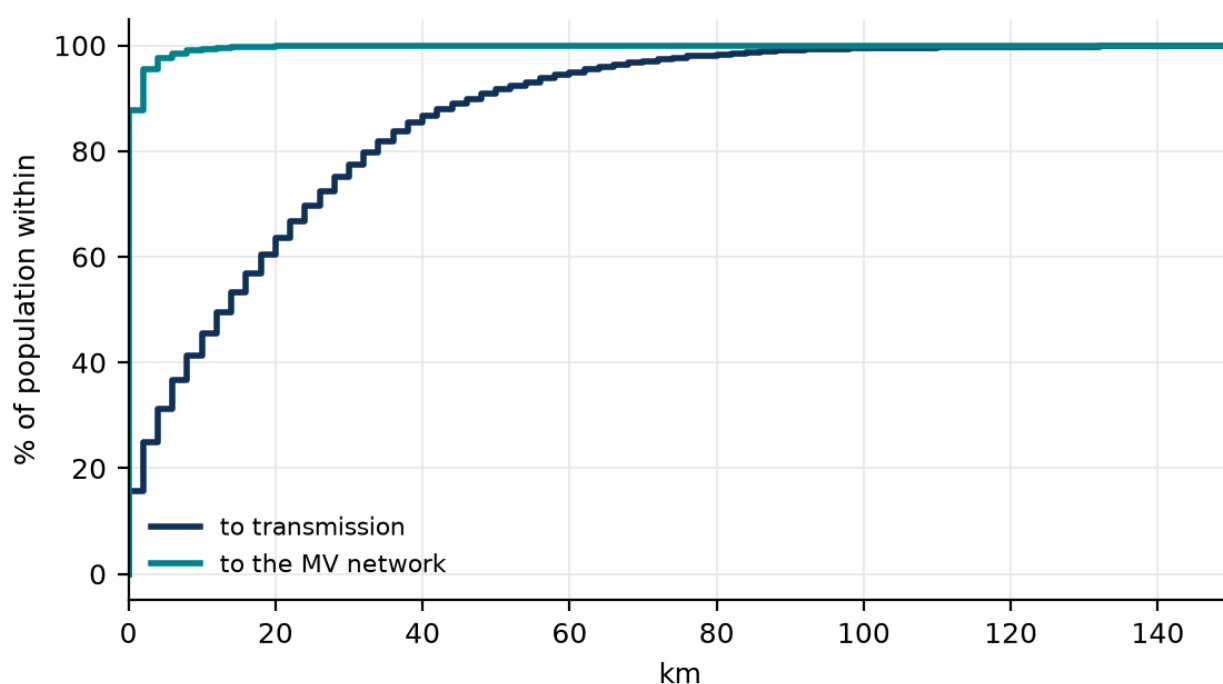


Figure 6.11: Population within a given distance of the grid

Source: WorldPop 2020 1 km grid × IERMP lines

Table 6.6: Population within a given distance of the grid (WorldPop 2020, 1 km grid)

Distance (km)	Share within, transmission	People within, transmission (m)	Share within, MV network
5	28.1%	11.87	96.6%
10	41.2%	17.39	99.0%
25	68.2%	28.77	99.9%
50	90.9%	38.32	100.0%
75	97.5%	41.14	100.0%
100	99.4%	41.93	100.0%
150	100.0%	42.16	100.0%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_coverage.csv).

6.6.2 Who is beyond the grid

Nineteen districts, with **4.15 million** people, have a population-weighted distance of more than 50 km to transmission (Figure 6.12, Table 6.7). They form two groups.

- **Karamoja and the north-east:** Karenga (143 km), Kaabong (132 km), Kotido (81 km), Abim (75 km), Amudat (70 km) and Nakapiripirit (57 km).
- **West Nile and the Madi sub-region:** Moyo (99 km), Obongi (76 km), Adjumani (75 km), Yumbe (66 km) and Koboko (52 km).

Agago, Kitgum and Lamwo in Acholi, and Bukwo and Kween on Mount Elgon, complete the list.

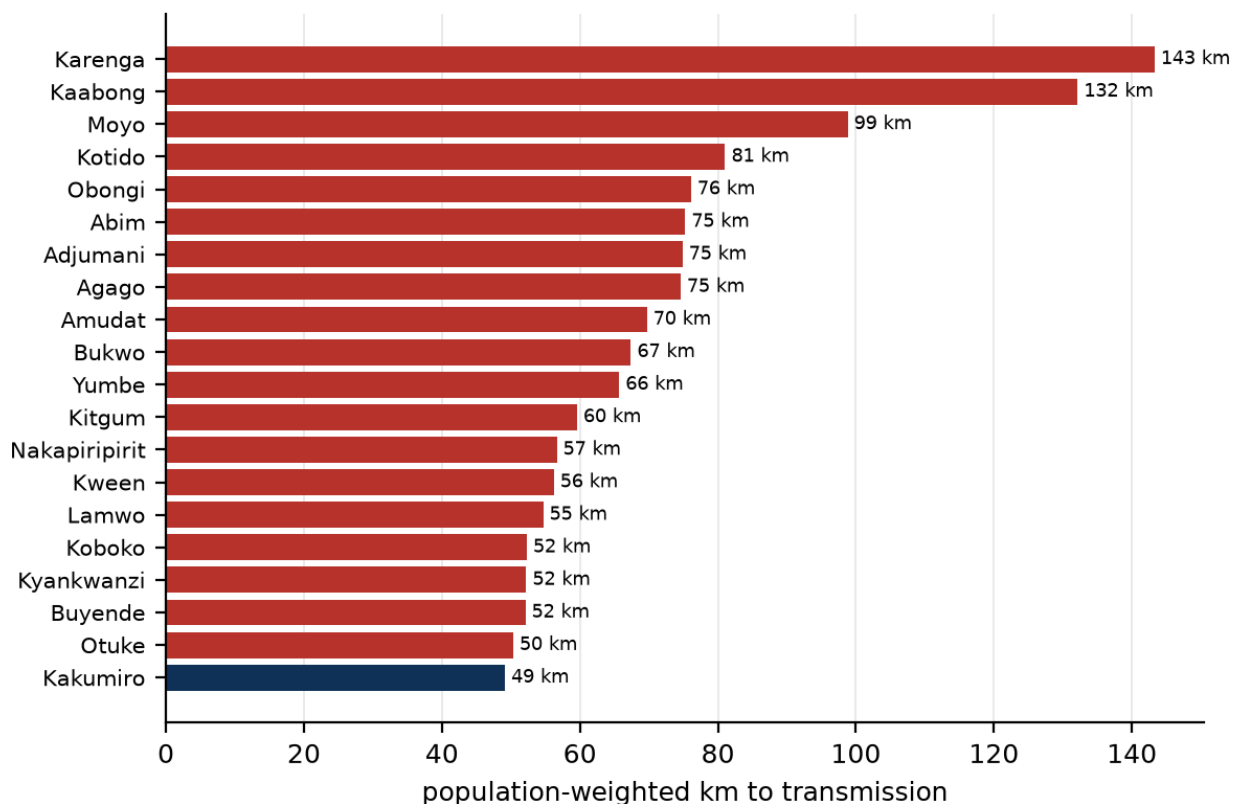


Figure 6.12: The 20 districts farthest from the transmission grid

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 6.7: The 20 districts farthest from the transmission grid (population-weighted distance)

District	Region	Population	Pop-weighted km to transmission	Nearest substation
Karenga	Northern	50,103	143.3	Agago
Kaabong	Northern	117,929	132.1	Moroto
Moyo	Northern	87,063	98.8	Achwa
Kotido	Northern	237,545	81.1	Moroto
Obongi	Northern	39,812	76.1	Arua
Abim	Northern	172,139	75.3	Moroto
Adjumani	Northern	269,415	74.9	Olwiyo
Agago	Northern	275,485	74.6	Agago
Amudat	Northern	157,136	69.7	Moroto
Bukwo	Eastern	133,635	67.4	Mbale
Yumbe	Northern	735,084	65.7	Arua
Kitgum	Northern	249,615	59.6	Agago
Nakapiripirit	Northern	142,795	56.6	Moroto
Kween	Eastern	120,974	56.2	Mbale
Lamwo	Northern	157,887	54.7	Achwa
Koboko	Northern	287,656	52.3	Arua
Kyankwanzi	Central	312,159	52.2	Hoima
Buyende	Eastern	455,067	52.1	Isimba

District	Region	Population	Pop-weighted km to transmission	Nearest substation
Otuke	Northern	149,515	50.3	Lira
Kakumiro	Western	450,381	49.1	Hoima

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_far_districts.csv).

Figure 6.13 maps the population-weighted distance to transmission, and Figure 6.14 shows the 25 km and 50 km buffers around the operational substations. Distance to the grid is one of the most strongly clustered layers in the engine (Moran's I 0.48).

- **Hot-spot.** Adjumani, Agago, Amudat, Amuru, Kaabong, Karenga, Kitgum, Koboko, Kotido, Moyo, Nakapiripirit, Obongi and Yumbe: the West Nile–Acholi–Karamoja arc.
- **Cold-spot.** Buikwe, Bukomansimbi, Butambala, Kalungu, Kampala, Mpigi, Mukono and Wakiso: the central region.

Population-weighted distance to transmission Local Moran clusters (global $I = 0.48$, $p = 0.001$)

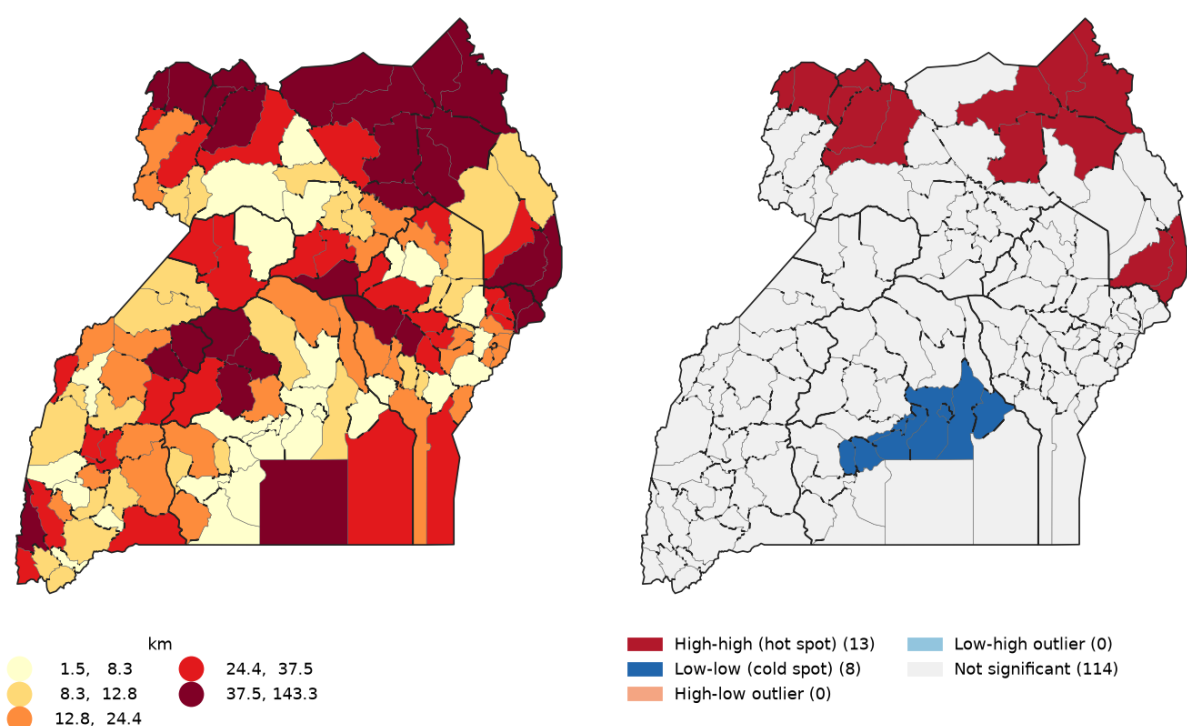


Figure 6.13: Ch.3 - Population-weighted distance to transmission (km), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

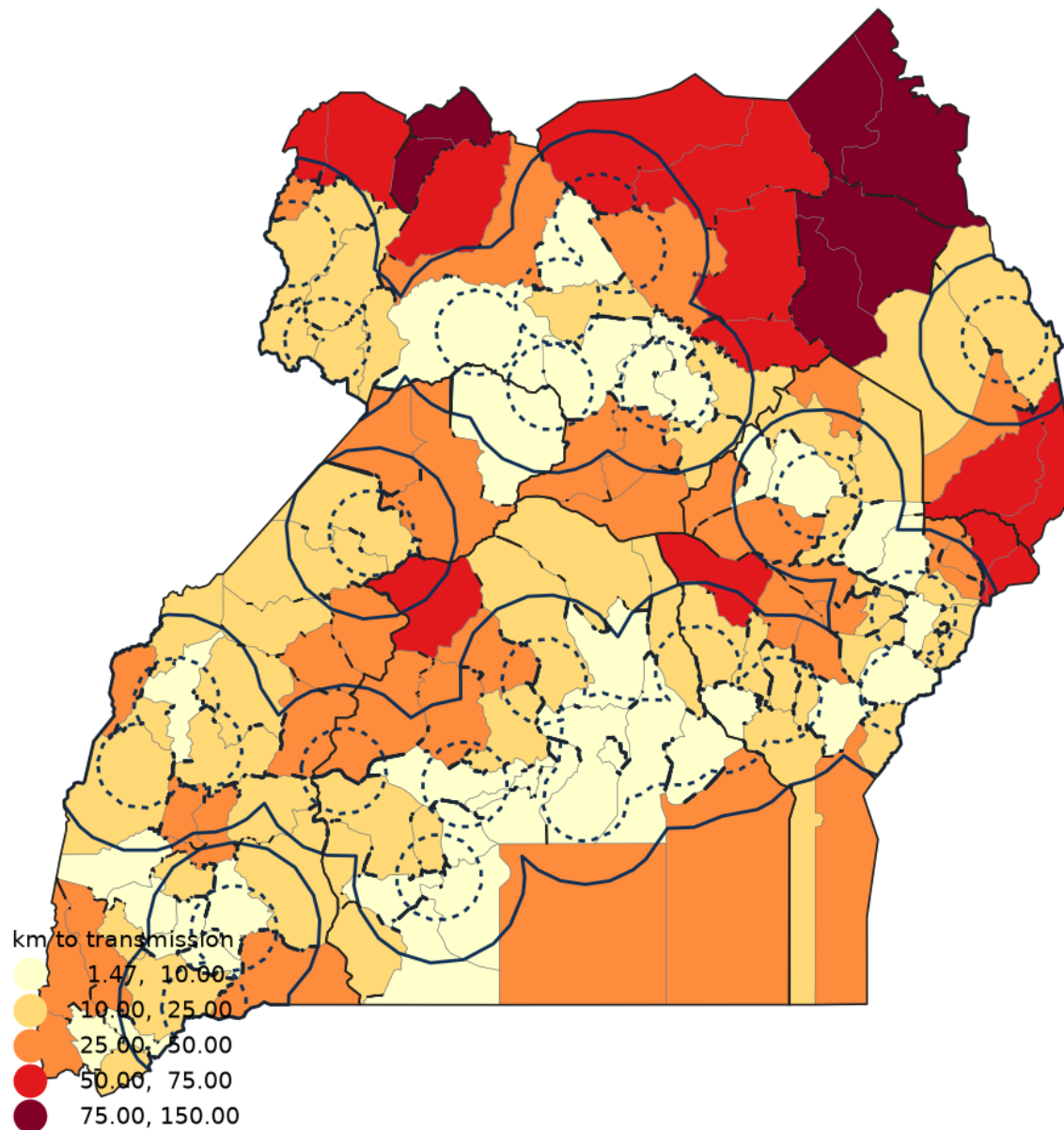


Figure 6.14: Coverage gap: population-weighted distance to transmission, with 25 km (dashed) and 50 km (solid) substation buffers

Source: WorldPop 2020; IERMP transmission lines and substations

The distance to the MV network (Figure 6.15) is much smaller everywhere but clusters too. Its hot-spot is the islands of Buvuma and Kalangala and parts of Karamoja and the north (Karenga, Kitgum, Moroto, Moyo, Nabilatuk).

Population-weighted distance to the MV network Local Moran clusters (global I = 0.25, p = 0.001)

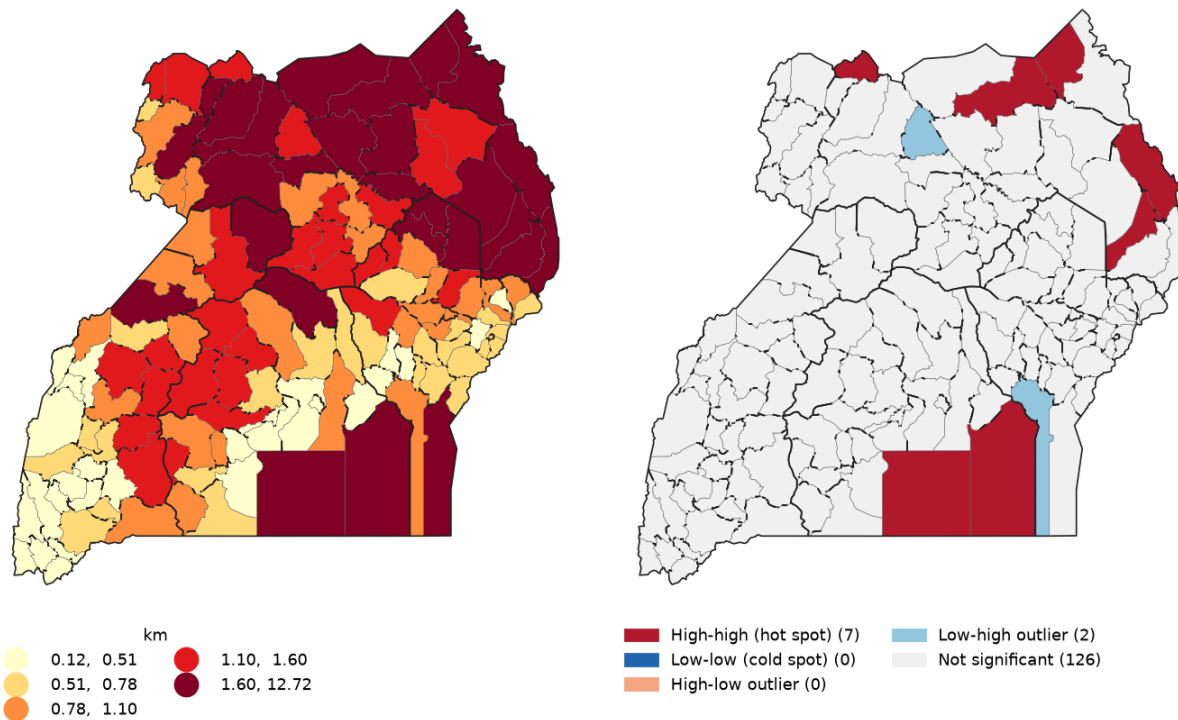


Figure 6.15: Ch.3 - Population-weighted distance to the MV network (km), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

6.7 Results: reinforcement

6.7.1 Screening

The reinforcement screen solves the 2030 grid-stress dispatch with every corridor allowed to expand at its annualised cost (Figure 6.16, Table 6.8). It adds capacity on three corridors:

- Nkonge–Kahungye: 66 MW;
- Nalubaale–Namanve: 29 MW;
- Kabulasoke–Nkonge: 11 MW.

This is the economic reinforcement at 2030 demand with only operating costs at stake. The full least-cost plan of Chapter 9 co-optimises reinforcement with the choice and location of new generation, and adds much more.

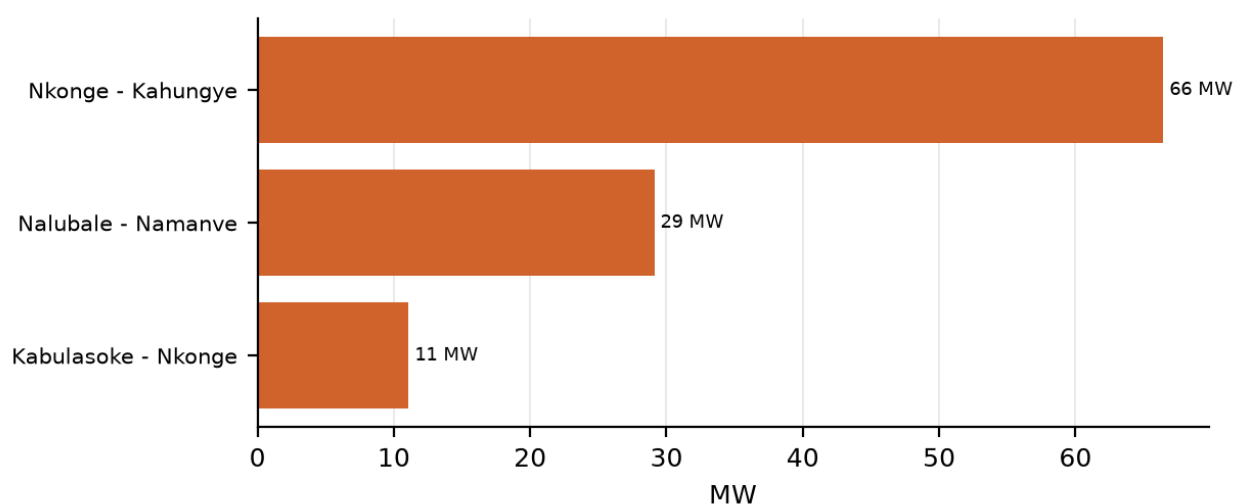


Figure 6.16: Reinforcement screening 2030: economic MW to add (levelised-cost supply)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 6.8: Reinforcement screening 2030: economic MW to add (levelised-cost supply)

Line	Corridor	MW added	Annualised cost (MUSD/yr)
L07	Kabulasoke - Nkonge	11.1	0.13
L20	Nalubale - Namanve	29.1	0.31
L22	Nkonge - Kahungye	66.4	0.69

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_reinf_screen.csv).

6.7.2 Candidate new corridors from the IERMP

The IERMP planned lines were mapped onto the 17-bus model. Four of them connect buses that are not already connected, and they become candidate new corridors in the plan (Table 6.9, Figure 6.17):

- **Buloba–Nkenda** (220 kV, 271 km): a second western path from Kampala to Kasese.
- **Kapeeka–Kiboga** (220 kV, 65 km): a link from the Kawanda area to the central-west.
- **Karuma–Tororo** (400 kV, 332 km): a northern 400 kV loop from the Lira area to the east.
- **Masaka–Kasese** (400 kV, 272 km): a south-western 400 kV path.

Each is costed at its length and voltage.

Table 6.9: IERMP planned lines mapped onto the model as candidate new corridors

Id	IERMP line	From bus	To bus	kV	km	Max MW	Annualised cost (USD/MW-yr)
N01	Buloba - Nkenda	B04_Mutundwe	B15_Nkenda	220	271	1,000	19,376
N02	Kapeeka - Kiboga	B06_Kawanda	B05_Kabulasoke	220	65	1,000	4,678
N03	Karuma - Tororo	B17_Tororo	B12_Lira	400	332	3,000	13,560
N04	Masaka-Kasese	B15_Nkenda	B11_MasakaWest	400	272	3,000	11,145

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_new_corridors.csv).

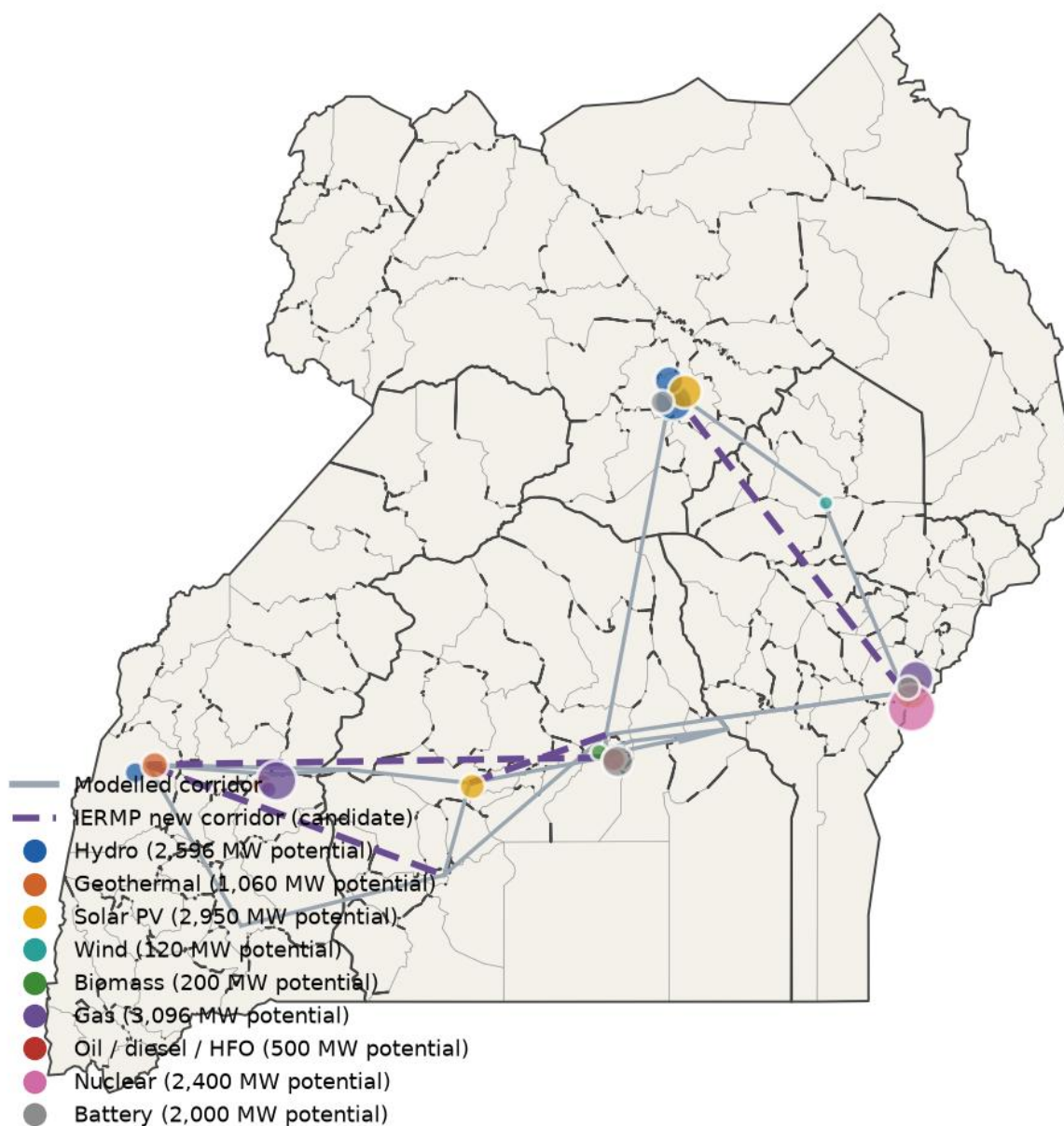


Figure 6.17: Candidate generation and storage sites (area $\propto$ potential) and candidate new corridors

Source: MEMD/ERA IRP candidate set; IERMP planned lines; engine battery candidates

6.8 Observed substation loading

UETCL's 2023 peak records (Figure 6.18, Table 6.10) confirm where the network is stressed today.

- **Injection points.** The highest peaks are at the Bujagali, Kawanda and Owen Falls injection points.
- **Load substations.** The highest load peaks are at the Kampala substations: Lugogo, Mutundwe and Kawanda.

The substations with the highest recorded peaks are the ends of the corridors that the model finds most loaded.

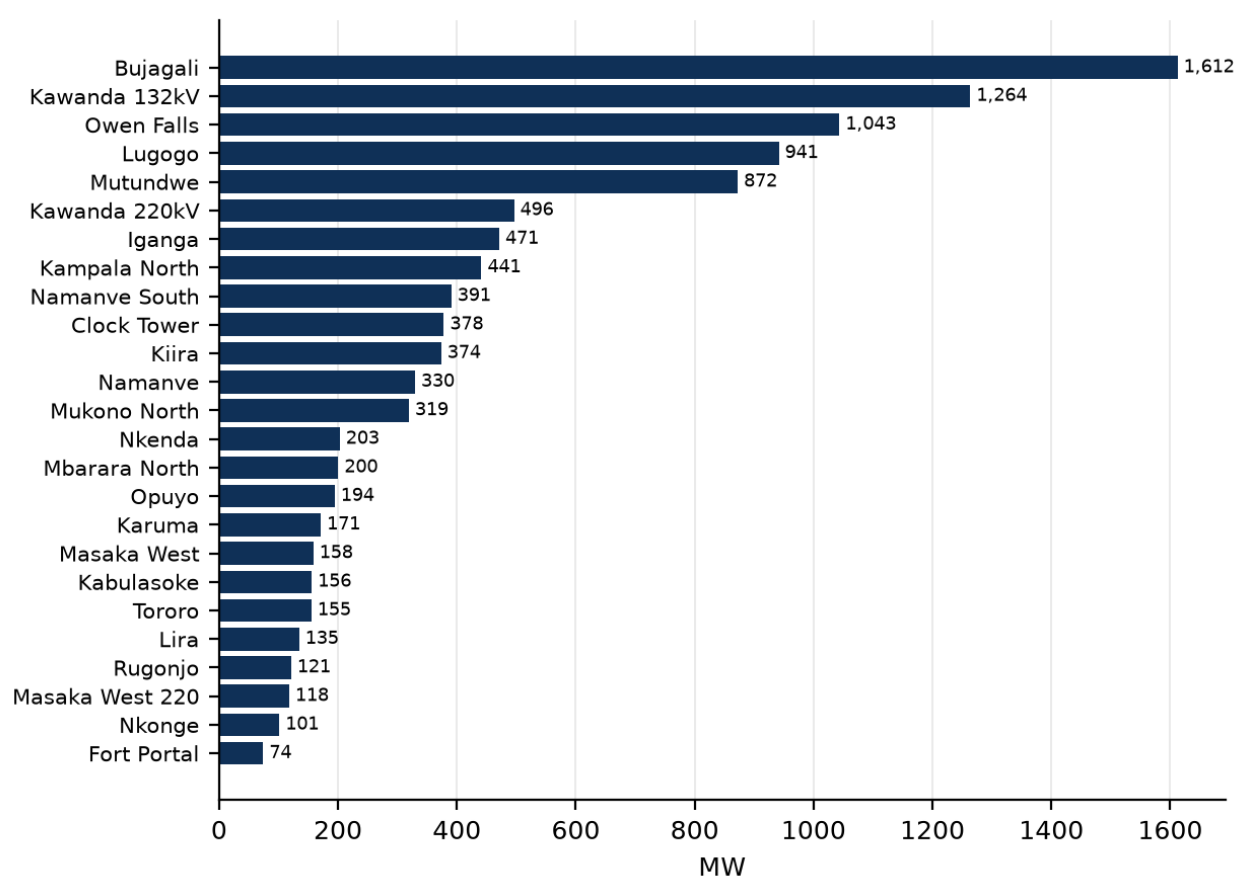


Figure 6.18: Observed 2023 peaks at substations and injection points

Source: UETCL 2023

Table 6.10: Observed 2023 substation peaks (UETCL)

Substation / point	2023 peak (MW)
Bujagali	1,612.2
Kawanda 132kV	1,263.6
Owen Falls	1,043.4
Lugogo	941.4
Mutundwe	872.4
Kawanda 220kV	496.1
Iganga	471.2
Kampala North	441.2
Namanve South	390.6
Clock Tower	378.0
Kiira	373.6
Namanve	329.5
Mukono North	319.2
Nkenda	203.0
Mbarara North	200.5
Opuyo	194.4
Karuma	171.1
Masaka West	158.5
Kabulasoke	155.9
Tororo	155.3
Lira	134.7
Rugonjo	121.2

Substation / point	2023 peak (MW)
Masaka West 220	117.9
Nkonge	101.4
Fort Portal	74.1

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_obs_peaks.csv).

6.9 Data quality and limitations

- **Transport model.** The grid is a transport model with losses. Loop flows on the meshed Kampala ring are not represented, so the loadings there are indicative. A load-flow check of the plan with UETCL's PSS/E models is the natural next step.
- **Thermal ratings only.** Corridor ratings are thermal limits from the AEGID layer. Stability and voltage limits, which bind first on long 132 kV lines, are not modelled. The loaded western and northern lines may be more constrained than shown.
- **Peak-only N-1.** N-1 is screened at the 2030 peak only, for single corridor outages. Maintenance outages, double contingencies and generator contingencies are not included.
- **Straight-line distances.** Coverage distances are straight-line distances in UTM. Real line routes are typically 20–40 % longer.

6.10 Implications for planning

- The first transmission constraint is not in the far north but in the heart of the system: the eastern supply into Kampala. Nalubaale–Namanve is loaded to 99 % already in 2023, and three corridors in the same area are N-1 critical in 2030. Reinforcing this ring is urgent and cheap relative to what it costs the system.
- The second constraint is the western export path. If the least-cost resources in the west (geothermal at Katwe and Buranga, Albertine gas) are developed, the 132 kV lines from Kasese and Hoima to Kampala cannot carry their output. New 220 kV capacity westward, as in the IERMP Buloba–Nkenda line, is a precondition, not an option.
- The coverage gap is concentrated in West Nile, Acholi and Karamoja. 4.15 million people are more than 50 km from transmission. For them the choice is between extending the transmission backbone (the planned Olwiyo, Agago–Kitgum and Moroto–Kotido lines) and serving the population with distribution extensions, mini-grids and solar home systems. Chapter 13 compares the options.

CHAPTER 7

7 Distribution

Distribution is where most of Uganda's electricity is lost, where customers are connected, and where tariffs and collections determine the finances of the sector. This chapter traces energy from the bulk supply point to the paying customer. It measures technical and commercial losses, the customer and tariff structure, cross-subsidies and collection. It uses the IERMP network layers to measure the spatial reach of the MV network and the loading of distribution substations. It implements design Chapter 4 (`docs/04_distribution.md`).

7.1 The energy waterfall

Figure 7.1 and Table 7.1 follow the 2023 energy from generation to collected revenue.

- **Generation to distribution.** Of the 5,987 GWh generated (plus 34 GWh imported):
 - 289 GWh were lost in transmission;
 - 485 GWh were exported;
 - 8.7 GWh were a statistical difference.

That left **5,239 GWh** to enter the distribution networks.

- **Losses in distribution.** Of this energy, **909 GWh**, or 17.35 %, was lost. The engine splits it into:
 - 545 GWh of technical losses, 60 % of the total by an ASSUMED split: heat in lines and transformers;
 - 364 GWh of commercial losses: unbilled consumption, theft and metering errors.
- **Billing and collection.** The utilities billed 4,330 GWh. At the energy-weighted collection rate of 96.4 %, 156 GWh of billed energy went uncollected.

In total, **30 %** of the energy generated in 2023 was either lost, exported or not paid for. The distribution loss alone, at 909 GWh, is almost equal to all the electricity sold to households.

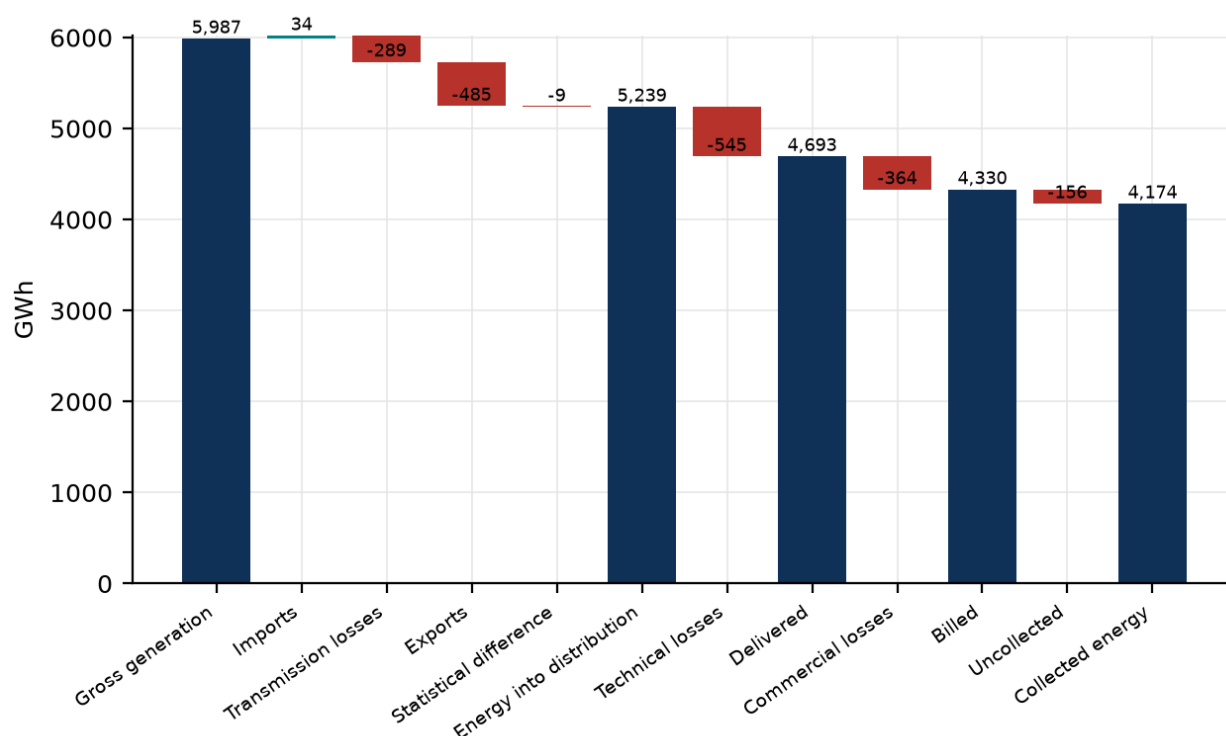


Figure 7.1: The 2023 energy waterfall: from gross generation to collected energy

Source: UETCL System Operation Data 2023; ERA

Table 7.1: Energy waterfall 2023: from gross generation to collected energy

Stage	GWh	Kind
Gross generation	5,987.2	total
Imports	33.6	gain
Transmission losses	-288.6	loss
Exports	-484.8	loss
Statistical difference	-8.7	loss
Energy into distribution	5,238.6	total
Technical losses	-545.3	loss
Delivered	4,693.3	total
Commercial losses	-363.5	loss
Billed	4,329.8	total
Uncollected	-155.6	loss
Collected energy	4,174.2	total

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_waterfall.csv).

7.2 Losses by utility and territory

ERA's distribution statistics record the energy each distribution utility bought and sold in each quarter of 2023. From them the engine computes observed loss rates by utility and territory (Figure 7.2, Table 7.2).

- **Umeme's concession** covered most of the grid and 5,037 GWh of purchases. It lost **16.4 %**.
- **The rural UEDCL territories** lost far more:
 - 50 % in the North Western territory;
 - 53 % in the North North West;
 - 33 % in the South;
 - 22–26 % in the Eastern, South Western, Mid Western and Central North territories.

- **Kilembe Investments** lost 54 % in its western territory.
- **The North Eastern territory** is the exception, with 14 %.

The high-loss territories are small in energy: together they bought less than 200 GWh. But they are where new connections will be made. Their loss rates show what happens when long, lightly loaded rural networks are extended without investment in metering and maintenance.

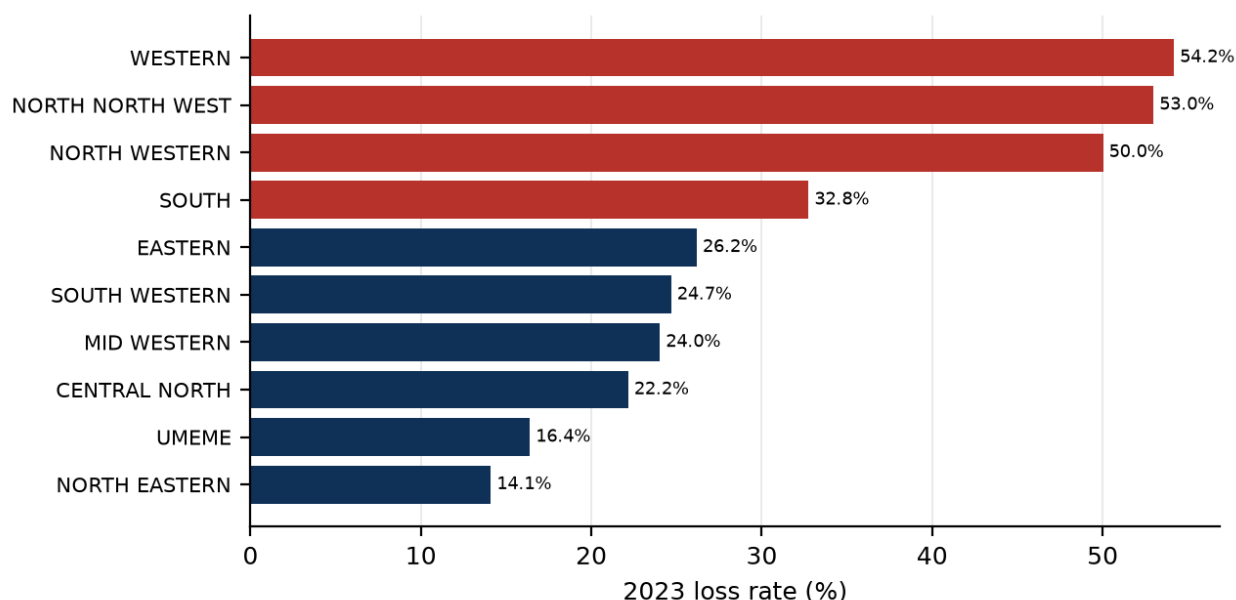


Figure 7.2: Observed 2023 distribution loss rate by utility and territory

Source: ERA Distribution Statistics Q1 2024 workbook (2023 quarters)

Table 7.2: Observed 2023 distribution losses by utility and territory (ERA statistics)

Code	Territory / utility	Purchased (GWh)	Sold (GWh)	Loss rate
KIL	WESTERN S/T	17.1	7.8	54.2%
NNWST	NORTH NORTH WEST S/T	26.1	12.3	53.0%
NWST	NORTH WESTERN S/T	63.3	31.6	50.0%
SST	SOUTH S/T	19.4	13.0	32.8%
EST	EASTERN S/T	9.1	6.7	26.2%
SWST	SOUTH WESTERN S/T	13.5	10.2	24.7%
MWST	MID WESTERN S/T	8.4	6.4	24.0%
CNST	CENTRAL NORTH S/T	5.6	4.4	22.2%
UMEME	UMEME	5,037.4	4,211.4	16.4%
NEST	NORTH EASTERN	11.7	10.0	14.1%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_territory_losses.csv).

Figure 7.3 shows the service territories with their observed loss rates. The highest losses are in the north-west and West Nile, and in the Rwenzori region.

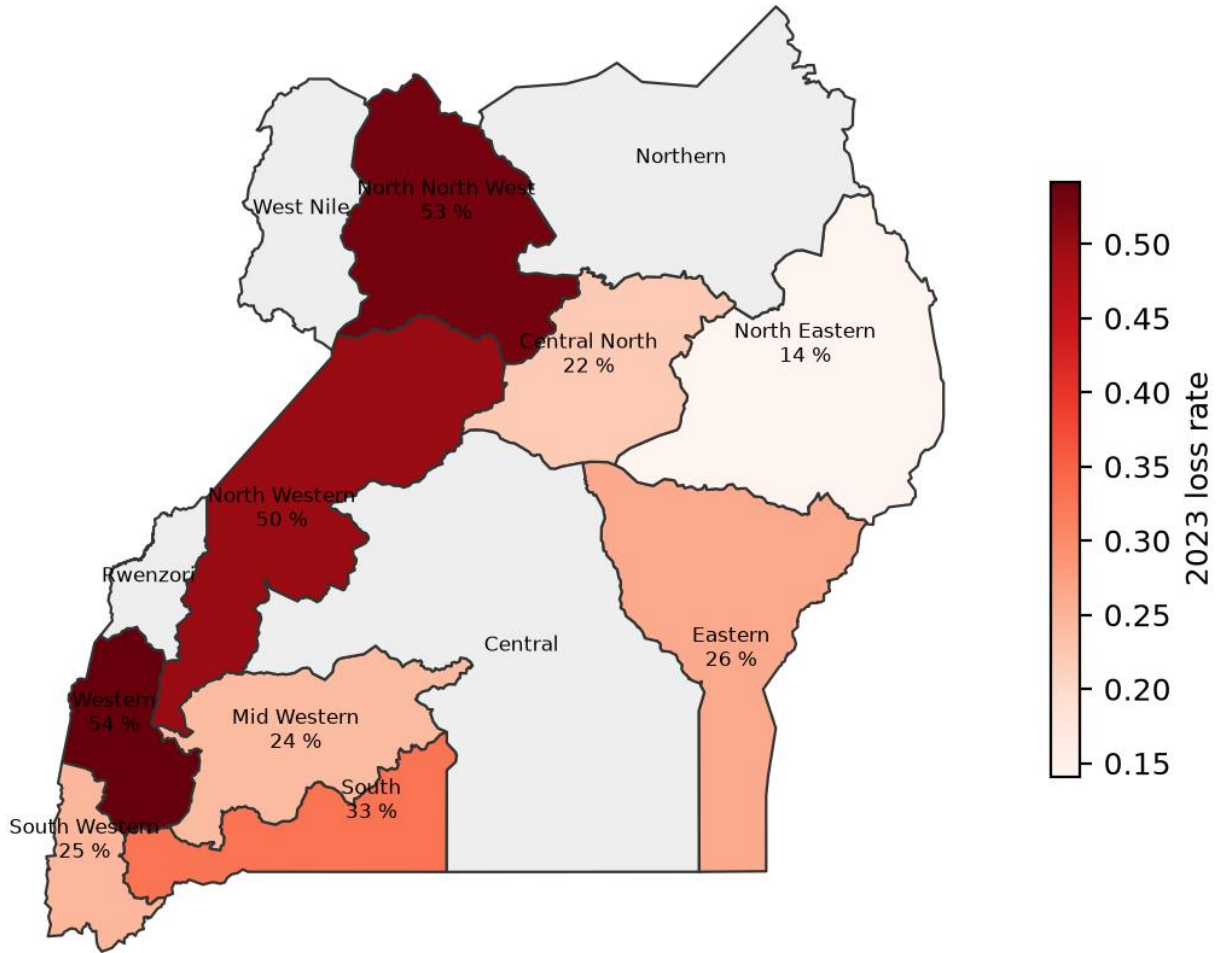


Figure 7.3: Distribution service territories and their observed 2023 loss rates

Source: IERMP service territories; ERA Distribution Statistics (energy purchased vs sold, 2023)

7.3 Losses by district

District loss rates are not measured. The engine estimates them by allocating the national distribution loss in proportion to each district's energy, weighted by a loss-propensity index:

$$L_d = L \frac{S_d \pi_d}{\sum_{d'} S_{d'} \pi_{d'}}, \quad \pi_d = 1 + \beta \frac{\bar{\delta}_d - \bar{\delta}}{\bar{\delta}} \quad (7.1)$$

where

- L is the national distribution loss (909 GWh);
- S_d is the energy entering the district;
- $\bar{\delta}_d$ is the population-weighted distance from the district's people to the MV network, where longer feeders mean higher technical losses;
- $\bar{\delta}$ is the national average of that distance;
- $\beta = 0.5$.

The national total is preserved exactly (validation check V4-2).

Figure 7.4 and Table 7.3 show the result. The modelled loss rate is highest on the islands of Buvuma (64 %) and Kalangala (56 %), whose supply comes over long lines, and in Karamoja and the north: Lamwo, Amudat, Napak, Moroto and Nakapiripirit, at 37–50 %.

- **Hot-spot.** Abim, Gulu, Kaabong, Kapelebyong, Karenga, Katakwi, Kitgum, Kotido, Lamwo, Moroto, Moyo, Nabilatuk and Napak.
- **Cold-spot.** The dense networks of the south-west (Kabale, Kanungu, Kisoro, Ntungamo, Rukungiri, Sheema and neighbours) and Buikwe and Mukono.

The pattern agrees with the observed territory rates. The north and north-west lose most.

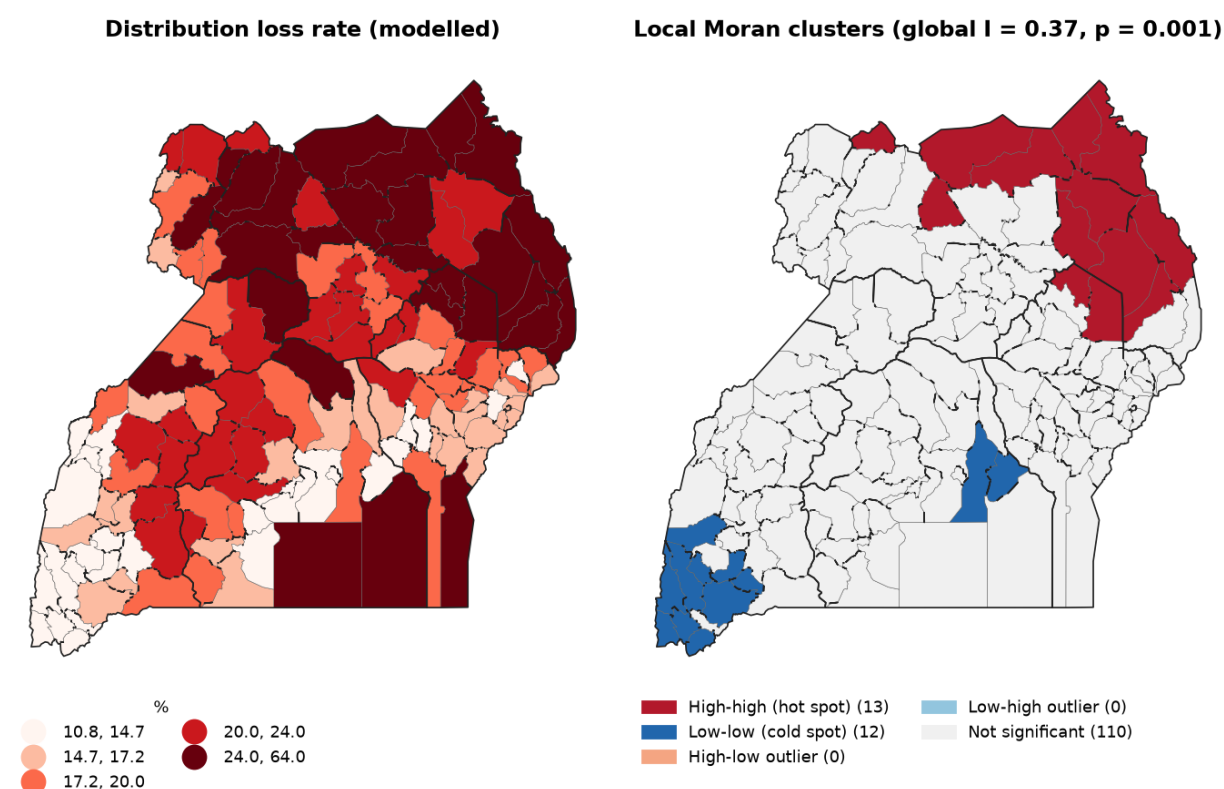


Figure 7.4: Ch.4 - Distribution loss rate (modelled) (%), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

Table 7.3: The 20 districts with the highest modelled distribution loss rates

District	Region	Final GWh 2023	Mean km to MV	Loss rate (modelled)
Buvuma	Central	17.3	12.72	64.0%
Kalangala	Central	3.2	8.92	56.1%
Lamwo	Northern	4.4	6.82	50.1%
Amudat	Northern	4.3	5.44	45.1%
Napak	Northern	5.3	3.95	38.5%
Moroto	Northern	5.8	3.81	37.8%
Nakapiripirit	Northern	4.7	3.68	37.1%
Kapelebyong	Eastern	2.7	3.47	36.0%
Karenga	Northern	1.2	3.22	34.6%
Namayingo	Eastern	57.6	2.97	33.1%
Nwoya	Northern	8.3	2.95	33.1%
Amuru	Northern	7.6	2.89	32.7%
Kaabong	Northern	2.9	2.83	32.3%
Nakasongola	Central	51.9	2.78	32.0%
Pader	Northern	7.0	2.66	31.3%

District	Region	Final GWh 2023	Mean km to MV	Loss rate (modelled)
Obongi	Northern	0.8	2.55	30.6%
Madi Okollo	Northern	6.2	2.51	30.4%
Otuke	Northern	4.7	2.45	30.0%
Kitgum	Northern	9.1	2.12	27.8%
Amuria	Eastern	7.7	2.11	27.7%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_district_losses.csv).

7.4 The value of reducing losses

The base scenario reduces the distribution loss rate from 17.35 % to 12 % by 2030. Figure 7.5 and Table 7.4 show what that is worth.

- **2030.** Compared with keeping the 2023 rate, the reduction avoids 593 GWh a year: 99 MW of generation that does not need to be built.
- **2040.** It avoids **1,470 GWh a year**, or 245 MW of capacity. Valued at the modelled long-run cost of 69 USD/MWh, that saving is worth **102 million USD a year**.

The loss-reduction programme is costed at 150 USD per MWh of annual losses avoided: metering, network rehabilitation and anti-theft measures. The avoided generation pays for it within about two years.

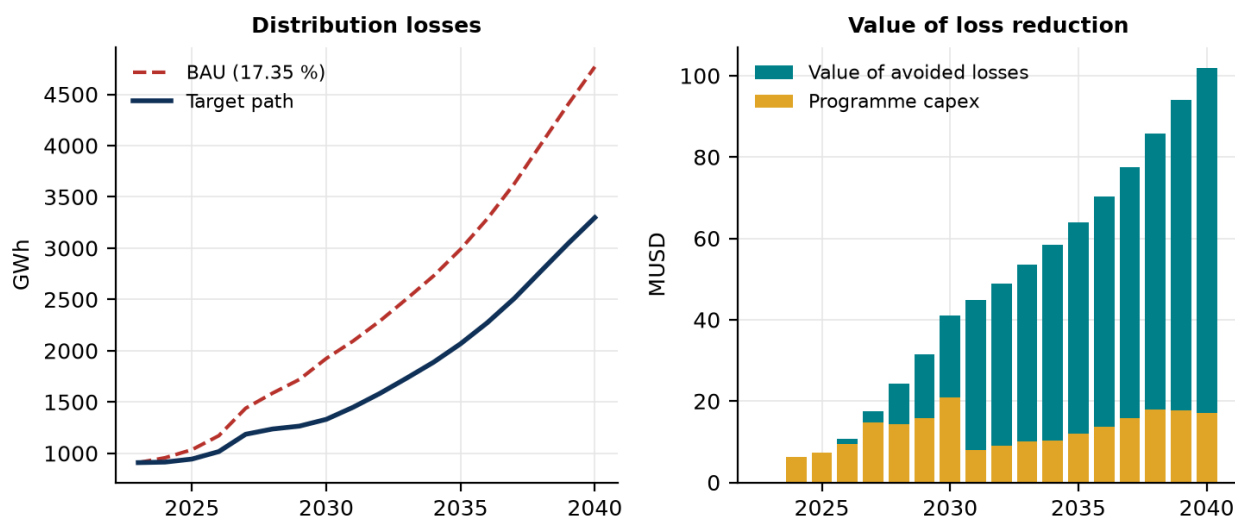


Figure 7.5: Distribution losses under business-as-usual and the target path, and the value of the reduction

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 7.4: Distribution loss path and the value of loss reduction (valued at 69 USD/MWh)

Year	Into distribution (GWh)	Loss rate	Losses (GWh)	BAU losses (GWh)	Avoided (GWh)	Avoided (MW)	Value (MUSD/yr)
2023	5,239	17.3%	909	909	0	0	0.0
2026	6,751	15.1%	1,016	1,171	155	26	10.7
2030	11,090	12.0%	1,331	1,924	593	99	41.1
2035	17,230	12.0%	2,068	2,989	922	153	63.9
2040	27,484	12.0%	3,298	4,768	1,470	245	101.9

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_loss_path.csv).

7.5 Customers, tariffs and cross-subsidies

Figure 7.6 and Table 7.5 compare each class's tariff with its cost to serve.

- **Classes that pay above cost.**
 - Residential customers pay 213 USD/MWh against a cost to serve of 150 USD/MWh, a margin of 63 USD/MWh. Across their 966 GWh this is a cross-subsidy of **61 million USD a year**.
 - Commercial customers pay 24 USD/MWh above cost (12 million USD a year).
- **Classes that pay below cost.**
 - Large industry pays 3 USD/MWh below its cost to serve (–4 million USD).
 - Extra-large industry pays 6 USD/MWh below (–6 million USD).
 - Street lighting pays 17 USD/MWh below.

The tariff structure therefore transfers money from households and small businesses to large industry. That is the opposite of the usual pattern in which the lifeline tariff protects poor households. It matters for the plan, because most of the growth in demand is industrial and most of the growth in customers is residential.

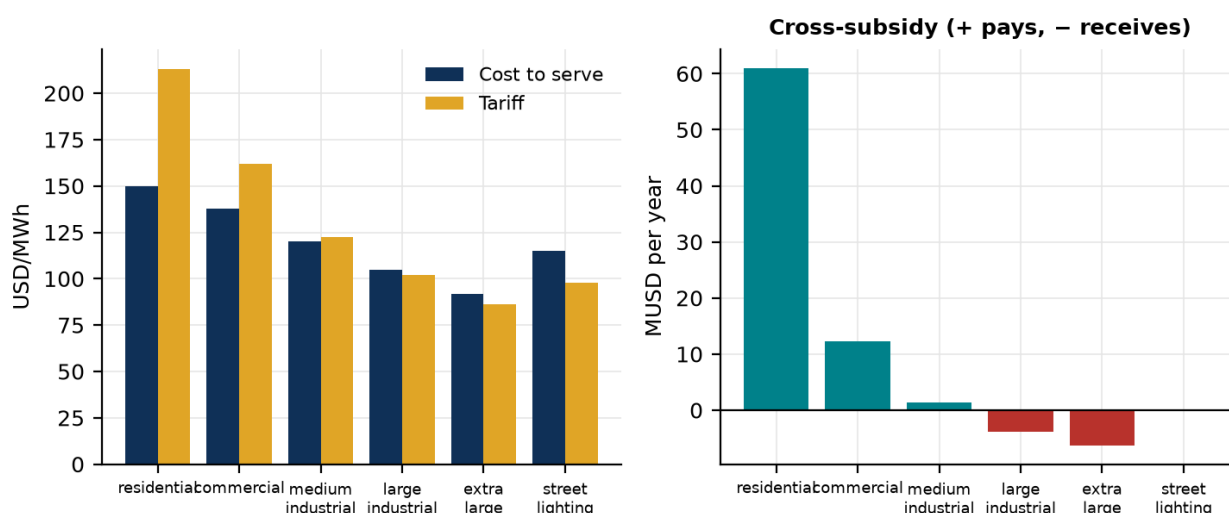


Figure 7.6: Tariffs against cost to serve, and the resulting cross-subsidies, 2023

Source: ERA tariff schedule and cost-to-serve, 2023

Table 7.5: Tariffs, cost to serve and cross-subsidies by class, 2023 (USD/MWh unless stated)

Class	Tariff	Cost to serve	Margin	Cross-subsidy (MUSD/yr)	Billed (MUSD)	Collected (MUSD)
residential	213.2	150.0	63.2	61.0	205.9	189.4
commercial	162.1	138.0	24.1	12.2	82.2	78.1
medium_industrial	122.3	120.0	2.3	1.4	74.3	72.1
large_industrial	101.8	105.0	-3.2	-3.8	120.8	118.4
extra_large	86.1	92.0	-5.9	-6.3	91.3	90.4
street_lighting	98.0	115.0	-17.0	-0.0	0.3	0.2

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_tariff.csv).

Figure 7.7 shows revenue by class. Collected revenue exceeds the cost to serve in total, by about 38 million USD in 2023. Most of that comes from the residential cross-subsidy. Uncollected bills are largest for the residential class, 16 million USD, at a collection rate of 92 %.

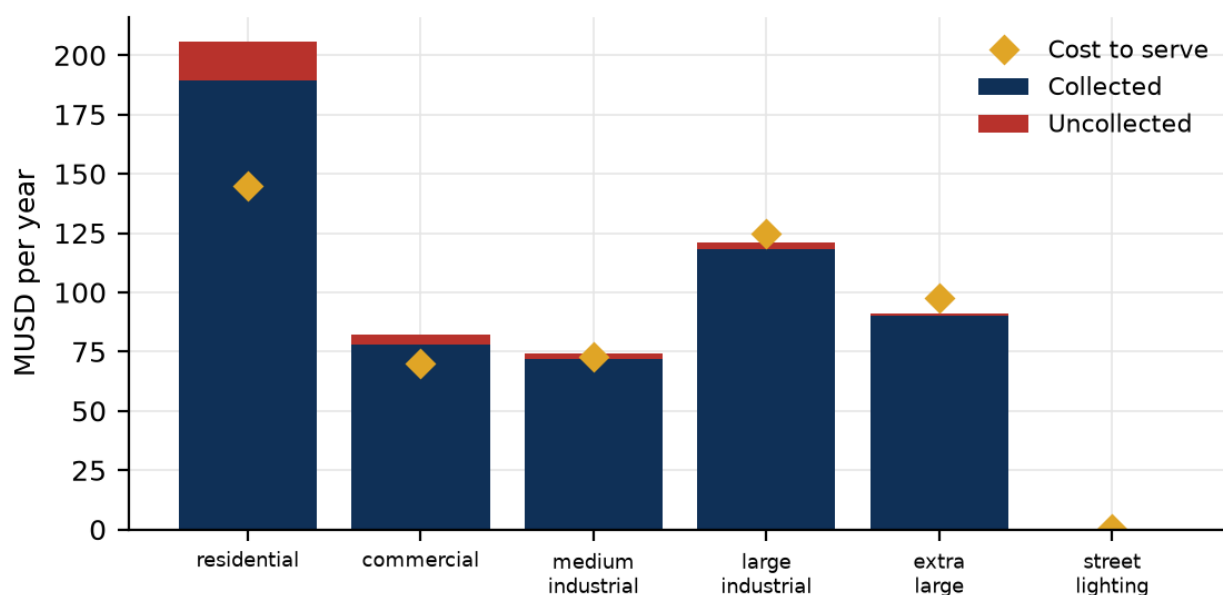


Figure 7.7: Revenue by class: collected, uncollected and cost to serve, 2023

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

7.6 The reach of the MV network

The IERMP MV network is extensive. Sampled every kilometre, it gives 185,796 points. Comparing them with the population grid (Figure 7.8, Figure 7.9, Table 7.6):

- **96.8 %** of Uganda's population, 40.8 million people, lives within 5 km of a 33 kV or 11 kV line. This is the zone of grid densification.
- 1.17 million people (2.8 %) live 5–15 km away, the zone of MV extension.
- 137,000 people live 15–30 km away.
- Only 28,000 people live more than 30 km away.

This is the most important finding of the distribution analysis. Uganda's access problem is **not a problem of network reach**. Almost everyone lives near an MV line. It is a problem of:

- the last mile: transformers, LV lines and service connections;
- connection cost;
- affordability.

Only a quarter of households are connected, although nearly all are within reach of the MV network.

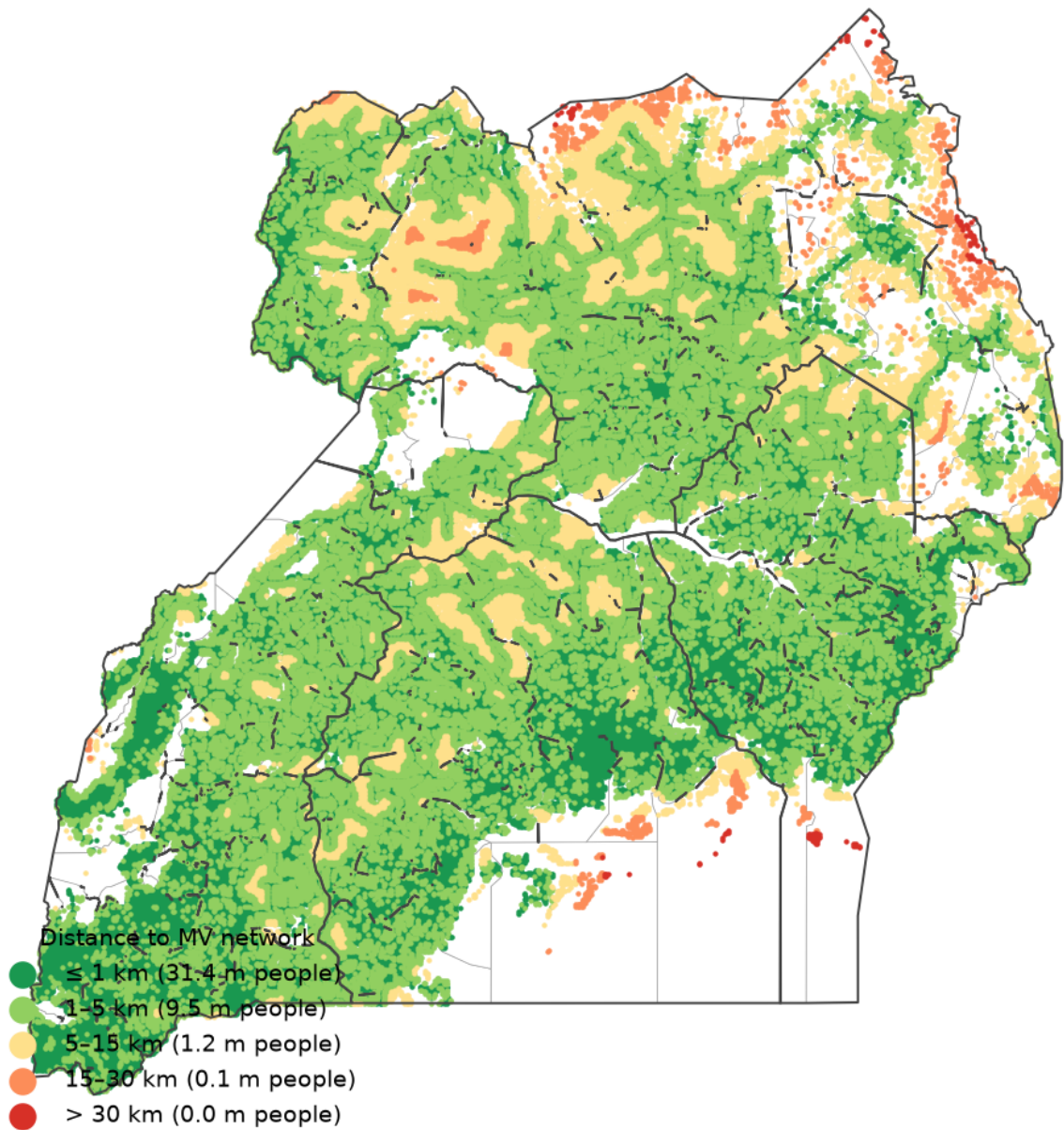


Figure 7.8: Distance from every populated square kilometre to the MV (33/11 kV) network

Source: WorldPop 2020 × IERMP MV lines (185,796 sampled points)

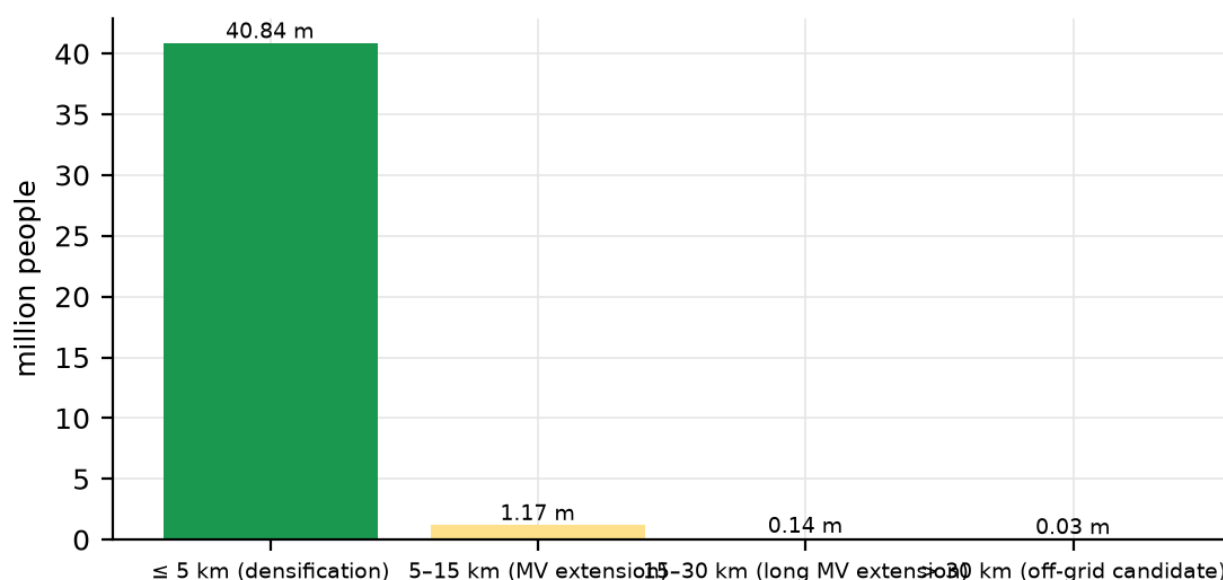


Figure 7.9: Population by distance to the MV network

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 7.6: Population by distance to the MV (33/11 kV) network

Band	Population (m)	1 km cells	Share
≤ 5 km (densification)	40.84	111,351	96.8%
5-15 km (MV extension)	1.17	14,048	2.8%
15-30 km (long MV extension)	0.14	1,455	0.3%
> 30 km (off-grid candidate)	0.03	132	0.1%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_mv_reach.csv).

The density of the MV network and of distribution transformers confirms it.

- **MV line density** (Figure 7.10) is highest in the south-west (Kabale, Kisoro, Ntungamo, Rubanda, Rukiga, Rukungiri, Rwampara, Sheema) and around Kampala (Buikwe, Butambala, Mpigi, Mukono, Wakiso). It is lowest in Karamoja, Acholi and the Madi sub-region.
- **Transformer density** (Figure 7.11), transformers per 1,000 households, is the engine's proxy for LV reach. It clusters even more strongly (Moran's I 0.53). The hot-spot is the central and south-western districts from Kampala to Mbarara. The cold-spot is Karamoja, Acholi and Teso (Abim, Agago, Kalaki, Kapelebyong, Karenga, Kitgum, Moroto, Moyo, Soroti).

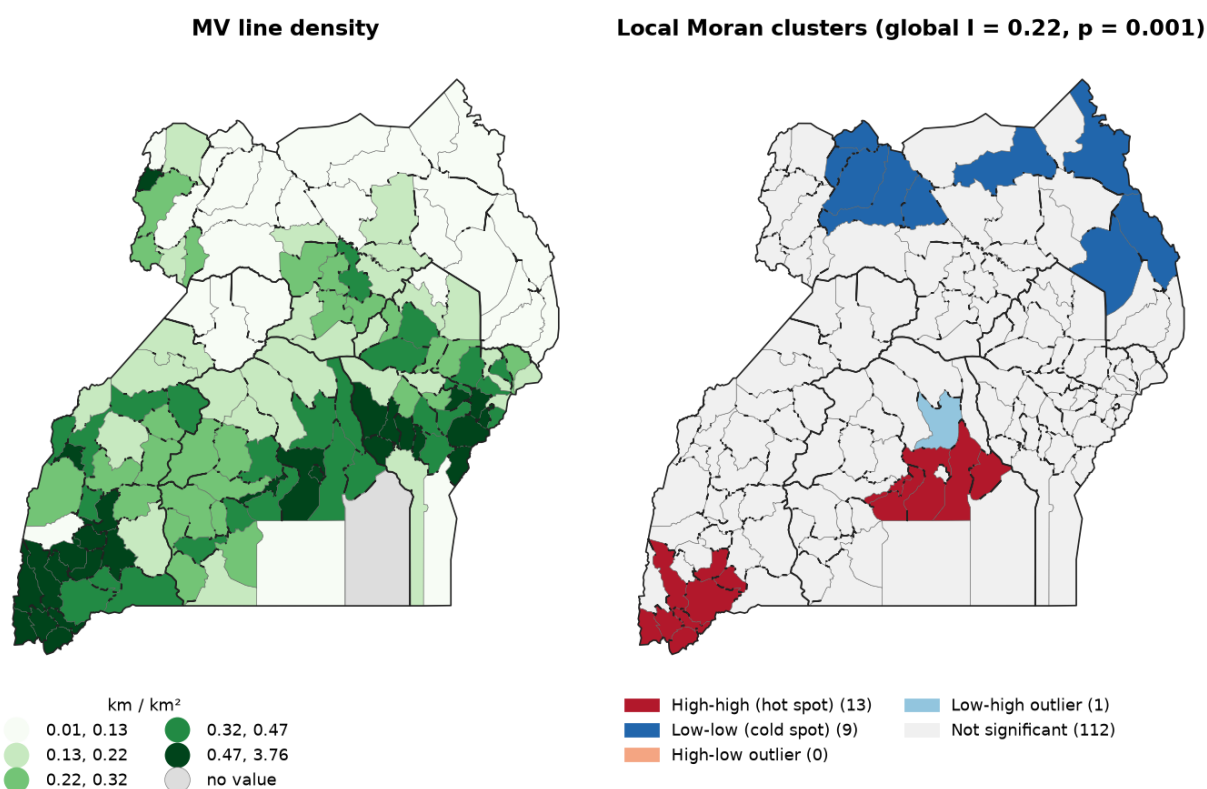


Figure 7.10: Ch.4 - MV line density (km / km²), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

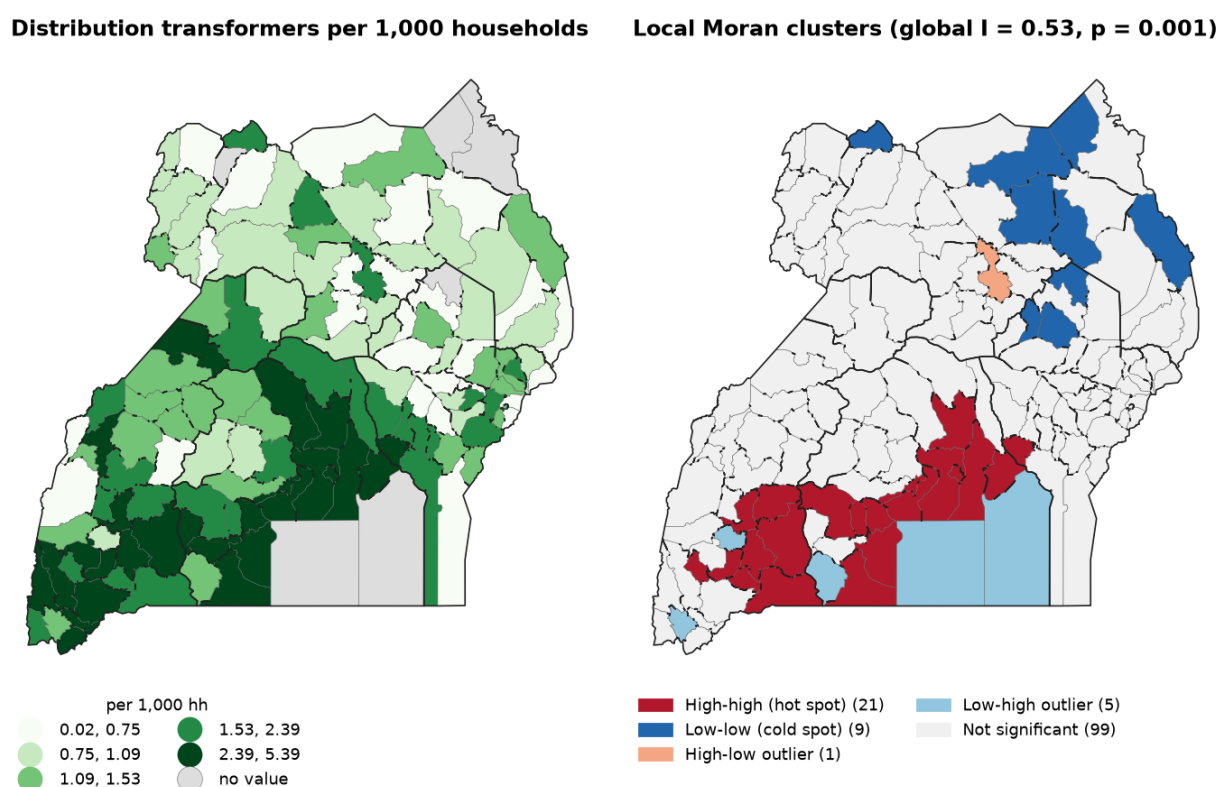


Figure 7.11: Ch.4 - Distribution transformers per 1,000 households (per 1,000 hh), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

7.7 Substation service areas

Each populated cell is assigned to its nearest distribution substation. This gives each substation a service area, the population it serves and the distance to its furthest customers (Figure 7.12, Figure 7.13, Table 7.7).

- **62 of 98** substations are over-extended: their furthest customers are more than 30 km away, or they serve more than a million people.
- The largest service areas are Arua (2.1 million people, feeders up to 114 km), Masaka West, Mbale, Mubende, Gulu and Lira (1.1–1.3 million people each).
- Moroto's substation serves 0.9 million people over feeders up to 149 km, and Kitgum's over up to 157 km.

These long feeders are the cause of the high technical losses and low reliability in the north. They are the case for new 33/11 kV substations in the far service areas.

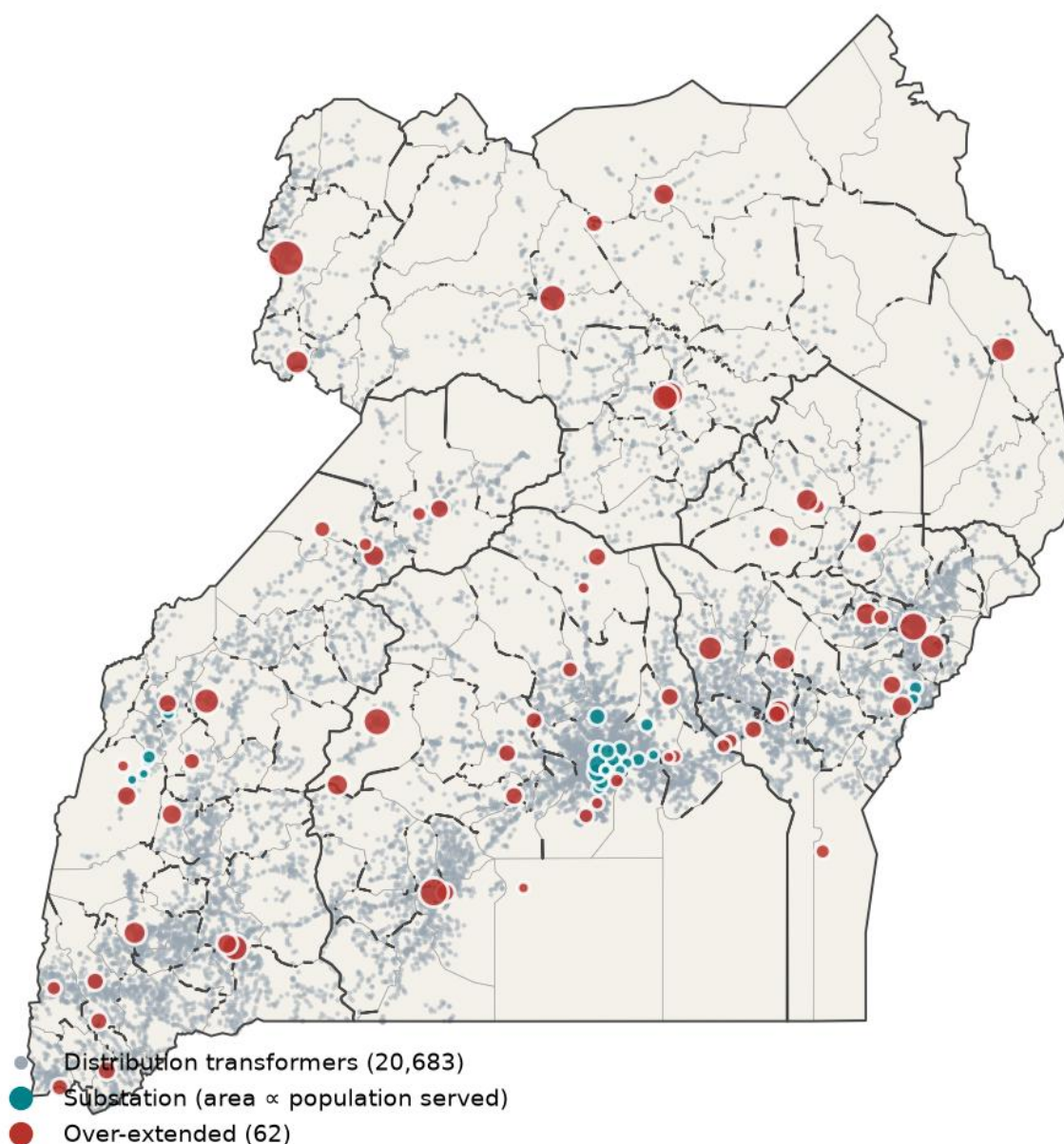


Figure 7.12: Distribution substations, the people they serve, and the transformer network

Source: IERMP GIS (distribution substations 2023, transformers UEDCL/UMEME/WENRECO); WorldPop 2020

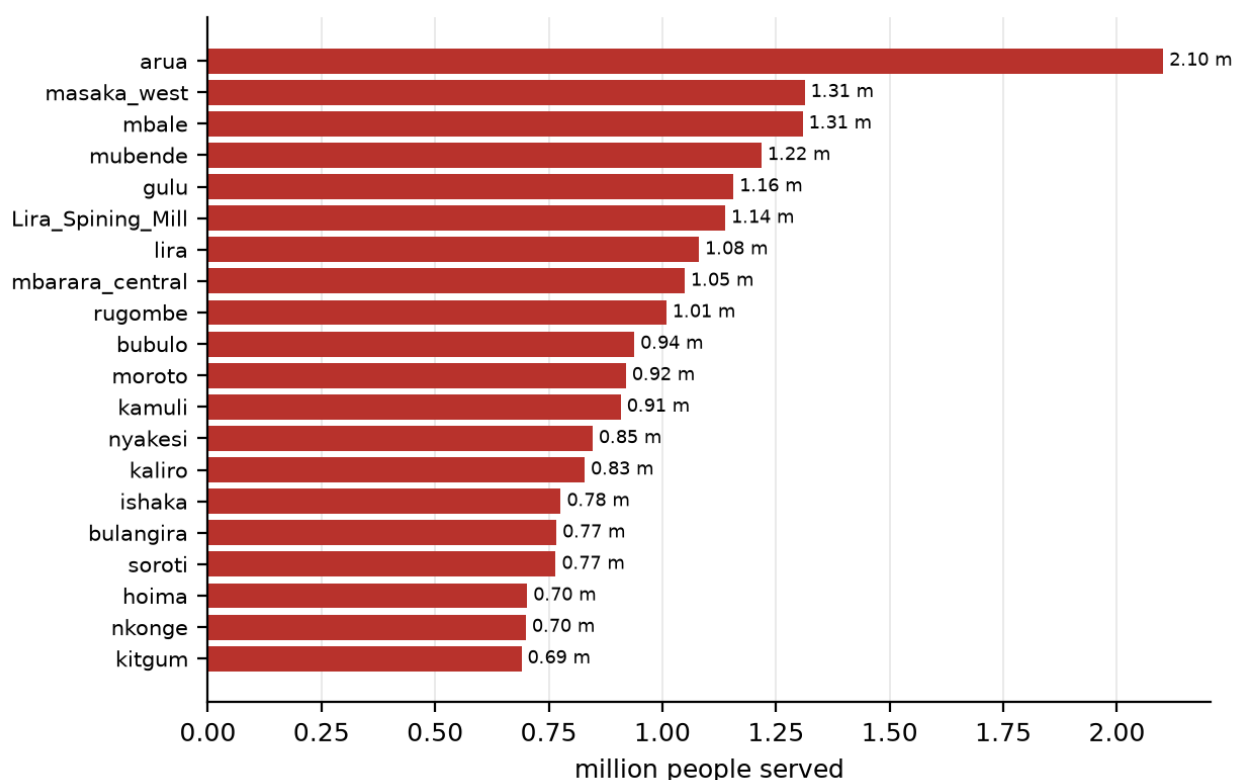


Figure 7.13: The 20 distribution substations serving the most people (red = over-extended)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 7.7: The 20 distribution substations serving the largest populations

Substation	Operator	District	Population served (m)	Max feeder km	Load 2030 (MW)	Over-extended
arua	WENRECO	Arua	2.10	114	24.4	yes
masaka_west	UETCL	Lwengo	1.31	85	26.6	yes
mbale	UETCL	Mbale	1.31	98	39.3	yes
mubende	UMEME	Mubende	1.22	65	23.5	yes
gulu	UMEME	Gulu	1.16	95	13.1	yes
Lira_Spinning_Mill	UMEME	Lira	1.14	108	12.5	yes
lira	UETCL	Lira	1.08	74	11.9	yes
mbarara_central	UMEME	Mbarara	1.05	84	36.0	yes
rugombe	UMEME	Kyenjojo	1.01	64	16.8	yes
bubulo	UMEME	Manafwa	0.94	101	20.0	yes
moroto	UEDCL	Moroto	0.92	149	24.6	yes
kamuli	UMEME	Kamuli	0.91	51	11.8	yes
nyakesi	WENRECO	Zombo	0.85	79	12.4	yes
kaliro	UMEME	Kaliro	0.83	37	23.9	yes
ishaka	UMEME	Bushenyi	0.78	46	19.4	yes
bulangira	UMEME	Budaka	0.77	36	12.2	yes
soroti	UMEME	Soroti	0.77	99	21.4	yes
hoima	UMEME	Hoima	0.70	66	53.1	yes
nkonge	UETCL	Mubende	0.70	61	11.8	yes
kitgum	UMEME	Kitgum	0.69	157	7.3	yes

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_service_areas.csv).

7.8 Distribution capacity for growth

The demand growth of Chapter 4 has to be carried by the distribution networks. For each supply zone the engine converts the growth in coincident peak into new transformer capacity, using a power factor of 0.9 and a design

margin of 20 %. It converts new grid connections into new MV and LV line, using norms recalibrated to the observed MV reach:

- MV: 0.6 km per 100 rural connections and 0.1 km per 100 urban;
- LV: 1.5 km and 0.6 km respectively.

Figure 7.14 and Table 7.8 show the cumulative requirement.

Period	New transformer capacity (MVA)	New MV (km)	New LV (km)	Grid connections
to 2030	1,360	18,800	52,400	4.4 million
to 2040	5,171	54,200	151,200	12.8 million

The LV network is the largest physical task in the entire plan.

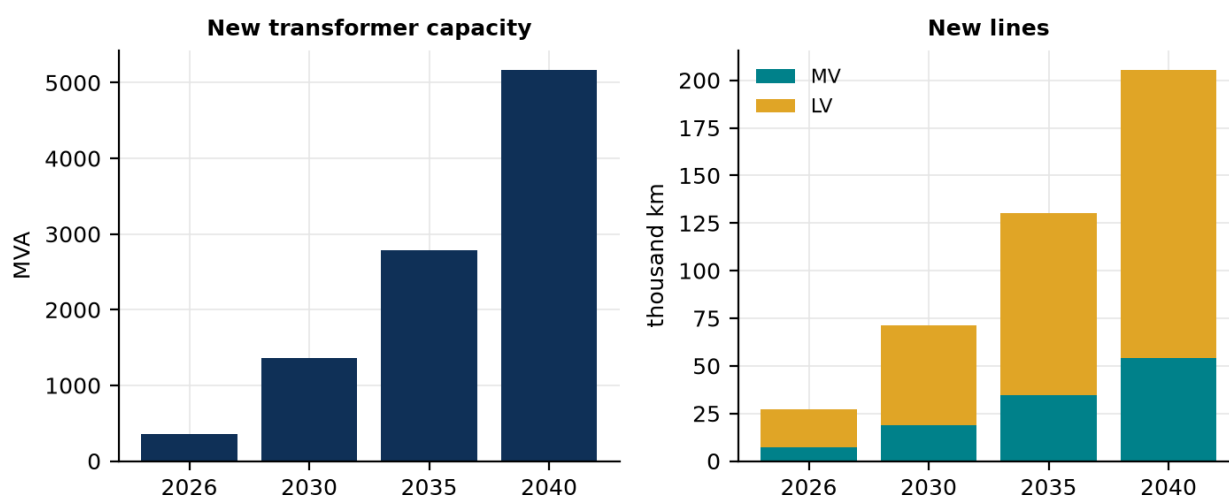


Figure 7.14: Cumulative distribution capacity required, 2023 to each planning year

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 7.8: Cumulative distribution capacity required from 2023

Year	Peak growth (MW)	New MVA	New MV km	New LV km	New grid connections
2026	264	352	7,206	20,093	1,695,595
2030	1,020	1,360	18,791	52,394	4,421,474
2035	2,090	2,787	34,396	95,903	8,093,096
2040	3,878	5,171	54,245	151,249	12,763,621

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_dist_need.csv).

UEDCL's own feeder forecasts (Figure 7.15, Table 7.9) apply a uniform 3 % annual growth to every 33 kV feeder: 23 % between 2023 and 2030. That is far below the demand growth this report projects, 2.3-fold nationally to 2030. The difference is the access programme and the step loads, neither of which the feeder forecasts include. Distribution planning based on the feeder forecasts would under-build the networks.

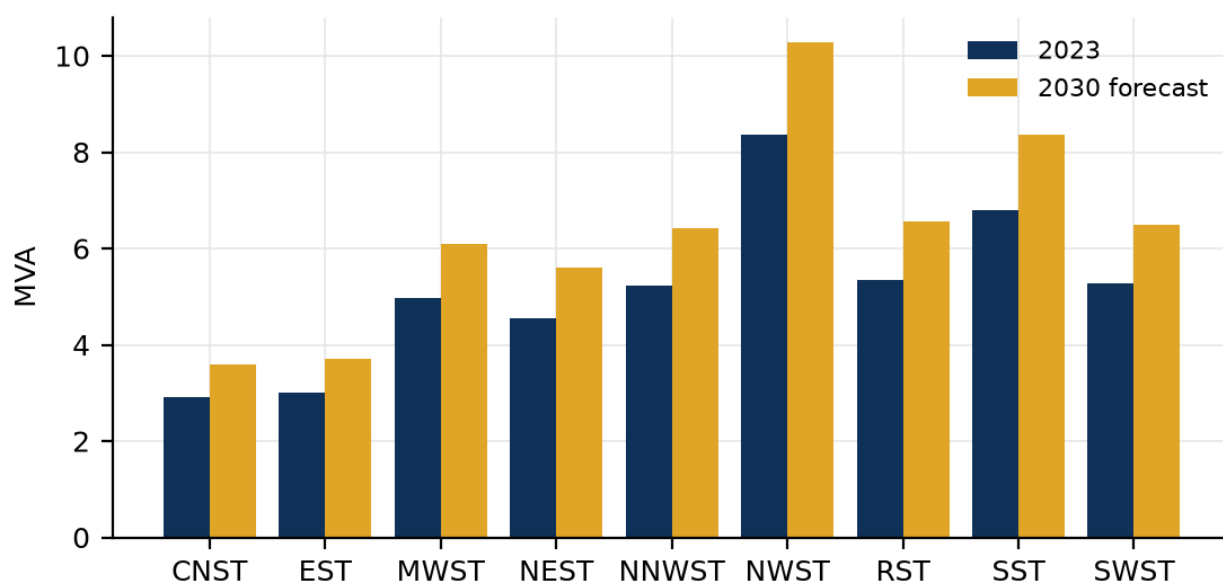


Figure 7.15: UEDCL 33 kV feeder maximum demand, 2023 and 2030 forecast, by territory

Source: UEDCL Feeder_Demand_Forecasts.xlsx

Table 7.9: UEDCL 33 kV feeder demand forecasts by territory

Territory	Feeders	Max demand 2023 (kVA)	Forecast 2030 (kVA)	Growth
CNST	8	2,914	3,584	23.0%
EST	5	3,007	3,698	23.0%
MWST	5	4,962	6,103	23.0%
NEST	7	4,549	5,595	23.0%
NNWST	5	5,225	6,426	23.0%
NWST	9	8,368	10,292	23.0%
RST	2	5,338	6,565	23.0%
SST	14	6,801	8,364	23.0%
SWST	6	5,275	6,488	23.0%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_feeders.csv).

7.9 Data quality and limitations

- **Observed.** The waterfall is OBSERVED: generation, losses and sales are metered. Territory loss rates are OBSERVED from ERA's quarterly statistics.
- **Technical versus commercial losses.** The 60/40 split is ASSUMED. Feeder-level loss metering would replace it.
- **District loss rates** are MODELLED from feeder distance and scaled to the observed total.
- **Service areas.** They are computed by nearest distance, not by feeder topology, so they overstate the reach of some substations and understate others. The substations carry no transformer rating in the layer, so over-extension is judged by distance and population.
- **Distribution unit costs.** The MV line cost is OBSERVED from the utility cost sheet. The transformer cost per kVA and the LV cost are ASSUMED.

7.10 Implications for planning

- Distribution loss reduction is one of the cheapest resources in the plan. Reaching 12 % by 2030 is worth 593 GWh a year by 2030 and avoids 245 MW of generation by 2040. The rural UEDCL, WENRECO and KIL territories, at 33–54 % losses, should be the first targets.

- Almost every Ugandan lives within 5 km of an MV line. The access programme should therefore be designed as last-mile densification: transformers, LV lines and service connections, with connection subsidies. It should not be designed as network extension.
- The tariff structure cross-subsidises industry from households. As industrial demand grows five-fold, the cross-subsidy will grow with it unless the tariffs are rebalanced. Chapter 11 shows the pressure on the average tariff.
- Sixty-two distribution substations are over-extended. New 33/11 kV substations in Arua, Moroto, Kitgum, Gulu, Lira and Mbale service areas would shorten feeders, cut losses and improve reliability where the gaps are largest.

CHAPTER 8

8 Gap analysis: eight dimensions, never combined

This chapter puts the need of Chapter 4 against what the current system can supply and deliver (Chapters 5 to 7). The result is a **gap register**: how large each gap is in each planning year, when it opens and where it is. The chapter implements design Chapter 5 (`docs/05_gap_analysis.md`).

8.1 The eight gaps

The engine distinguishes eight gaps. Each is closed by a different instrument, so they are measured in their own units and never added together.

Table 8.1: The eight gaps and the instruments that close them

Gap	Question	Unit	Closed by
G1 Capacity	Is there enough firm capacity for peak plus reserve?	MW	new firm generation or storage
G2 Energy	Can the fleet produce the energy needed in an average year?	GWh	new energy-producing generation
G3 Reliability	With optimal operation, how much load is shed?	GWh unserved, hours	generation, storage and grid together
G4 Network	Which corridors overload or fail N-1? Who is beyond the grid?	corridors, people	transmission reinforcement, new corridors
G5 Distribution	How much energy is lost above the target?	GWh	loss reduction, substations
G6 Access	How many households lack electricity against the target?	households	densification, extension, mini-grids, SHS
G7 Sector service	Which health facilities and schools lack power?	facilities, schools	targeted connections, solar for institutions
G8 Security	How concentrated, import-dependent and drought-exposed is supply?	ratios	diversification, storage, hardening

8.2 Why the gaps are never added

A capacity gap in MW, an access gap in households and a network gap in corridors have no common unit. Combining them into an index would hide the choice between them.

The same district can have a small capacity gap and a large access gap. Kasese, for example, is a generation zone with only 8 % of its households connected. A single score would rank such a district in the middle and hide both problems. The engine therefore maps and ranks each gap separately (Chapter 13), and the plan closes each with its own instrument.

8.3 G1 Capacity and G2 Energy

The capacity gap compares firm capacity with peak demand plus the 15 % reserve margin:

$$\text{Gap}_y^{\text{cap}} = P_y(1 + r) - K^{\text{firm}} \quad (8.1)$$

The energy gap compares the requirement with the energy the existing fleet can produce in an average year:

$$\text{Gap}_y^{en} = G_y - E^{cap} \quad (8.2)$$

The average-year capability E^{cap} counts non-hydro units at their average availability and the reservoir hydro stations at their inflow.

Figure 8.1 and Table 8.2 show the capacity gap. Existing firm capacity, including the batteries, is 1,326 MW.

- **2023.** Required firm capacity is 1,136 MW, so there is a surplus of 190 MW.
- **2026.** Requirement rises to 1,439 MW and the gap opens at **113 MW**.
- **Afterwards**, the gap grows to 983 MW in 2030, 2,214 MW in 2035 and **4,270 MW in 2040**.

To keep the reserve margin, Uganda needs almost a gigawatt of new firm capacity by 2030 and more than four gigawatts by 2040.

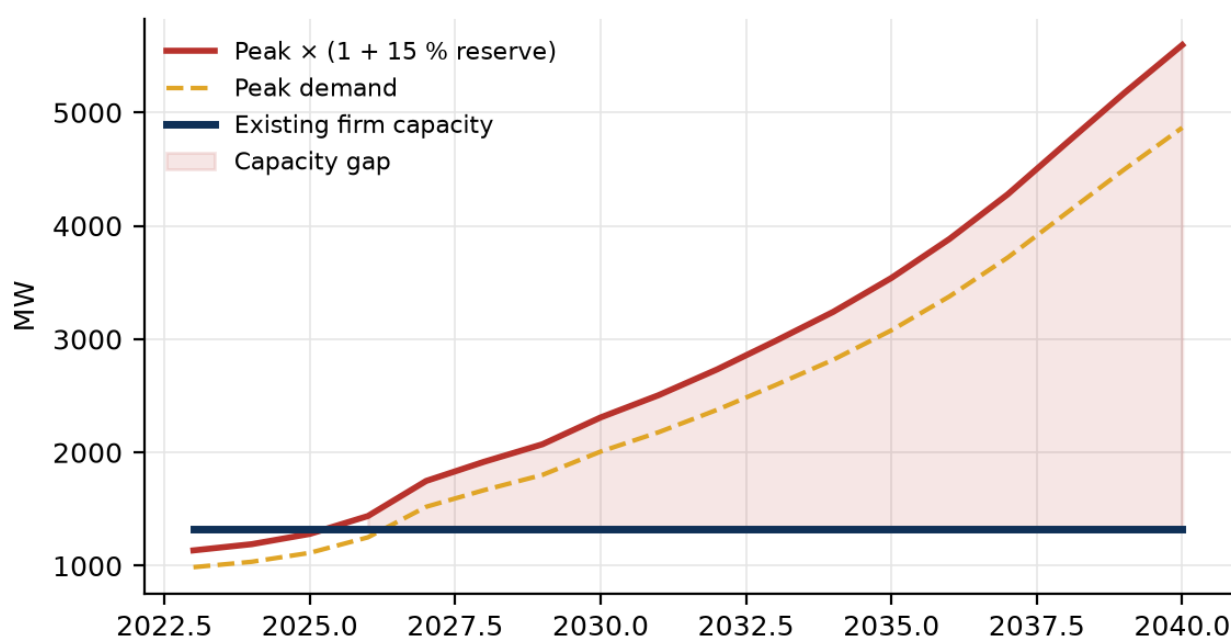


Figure 8.1: Capacity gap (G1): existing firm capacity against peak plus reserve

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.2: Capacity (G1) and energy (G2) gaps of the existing fleet

Year	Peak (MW)	Required firm (MW)	Existing firm (MW)	Capacity gap (MW)	Requirement (GWh)	Capability normal (GWh)	Energy gap normal (GWh)	Energy gap dry (GWh)
2023	988	1,136	1,326	-190	5,978	6,750	-771	352
2025	1,114	1,282	1,326	-44	6,745	9,236	-2,491	-870
2026	1,251	1,439	1,326	113	7,574	9,236	-1,662	-41
2027	1,521	1,749	1,326	423	9,203	9,236	-33	1,588
2028	1,668	1,919	1,326	593	10,097	9,236	861	2,482
2030	2,008	2,309	1,326	983	12,152	9,236	2,916	4,537
2032	2,376	2,732	1,326	1,406	14,379	9,236	5,143	6,764
2035	3,078	3,540	1,326	2,214	18,630	9,236	9,394	11,015
2038	4,110	4,726	1,326	3,400	24,873	9,236	15,637	17,258
2040	4,866	5,596	1,326	4,270	29,449	9,236	20,213	21,834

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_annual_gap.csv).

The energy gap opens two years later, in 2028 (Figure 8.2).

- **2028 onwards.** The fleet's average-year capability of 9,236 GWh, with Karuma at its design output, covers the requirement until 2027. The gap is 861 GWh in 2028, 2,916 GWh in 2030 and 20,213 GWh in 2040.
- **Dry year.** Capability falls, and the energy gap opens already in 2027.

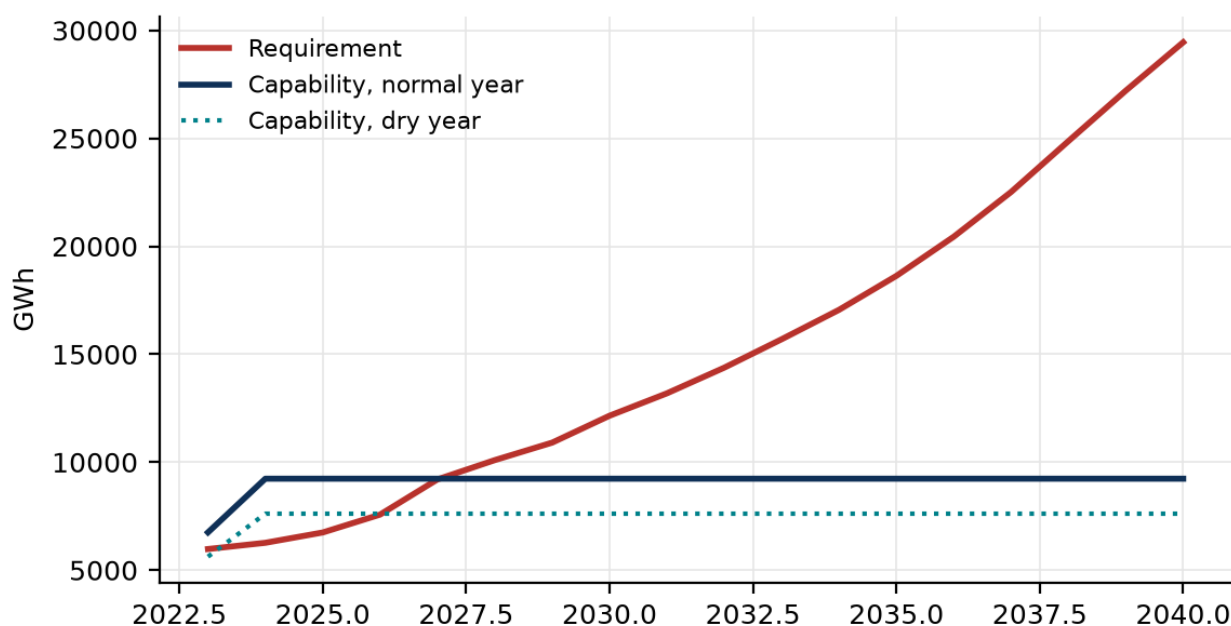


Figure 8.2: Energy gap (G2): requirement against the existing fleet's average-year capability

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

8.4 G3 Reliability: the gap from a solved model

The capacity and energy gaps are accounting comparisons. The reliability gap is the output of a solved model: the PyPSA dispatch of the existing fleet against each year's demand, in a normal and a dry year. It already accounts for:

- hydro scheduling;
- storage;
- grid limits;
- losses.

It is the gap as the system would experience it (Figure 8.3, Table 8.3).

- **Normal hydrology.**
 - The existing fleet serves all demand in 2023 and 2026. Validation check V5-1 is that 2023 unserved energy is zero.
 - In 2030 it sheds **3,073 GWh**, 25.5 % of demand, with load shed in every slice. At the value of lost load this costs 30.7 billion USD, which is why VoLL sets the price.
 - Unserved energy reaches 9,440 GWh in 2035 and 20,120 GWh in 2040.
- **Dry year** (inflow $\times$ 0.8).
 - The system sheds 415 GWh even in 2023. Uganda's reliability today depends on normal rainfall.
 - It sheds 155 GWh in 2026 and 4,608 GWh in 2030.

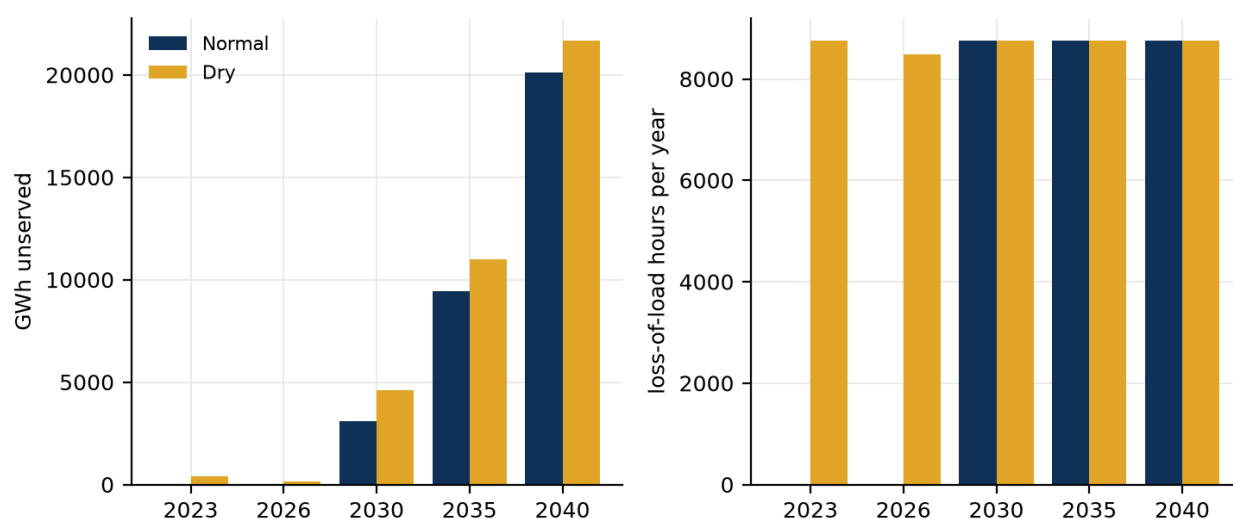


Figure 8.3: Reliability gap (G3): unserved energy and loss-of-load hours of the existing fleet (PyPSA)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.3: Reliability gap (G3): PyPSA dispatch of the existing fleet, normal and dry hydrology

Year	Hydrology	Demand (GWh)	Unserved (GWh)	EUE	LOLE (h/yr)	Cost at VoLL (MUSD)
2023	normal	5,938	0	0.0%	0	0
2026	normal	7,523	0	0.0%	0	0
2030	normal	12,071	3,073	25.5%	8,760	30,726
2035	normal	18,505	9,440	51.0%	8,760	94,403
2040	normal	29,251	20,120	68.8%	8,760	201,198
2023	dry	5,938	415	7.0%	8,760	4,153
2026	dry	7,523	155	2.1%	8,487	1,548
2030	dry	12,071	4,608	38.2%	8,760	46,078
2035	dry	18,505	10,980	59.3%	8,760	109,796
2040	dry	29,251	21,682	74.1%	8,760	216,818

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_reliability.csv).

Figure 8.4 shows where and when the 2040 shortfall falls. The model sheds load where the grid runs out of imports, not where the plants are.

- **Largest shortfalls.** The largest annual shortfalls fall at the load buses: Namanve (5,463 GWh), Mutundwe (3,698 GWh), Kampala North (2,247 GWh), Mbarara North (2,200 GWh), Lugogo (2,034 GWh) and Tororo (1,796 GWh).
- **Generation buses.** Kawanda, Bujagali, Nalubaale, Lira and Opuyo shed nothing, because generation sits there.

With the existing fleet, every major load centre would be short of power in 2040, in every time slice.

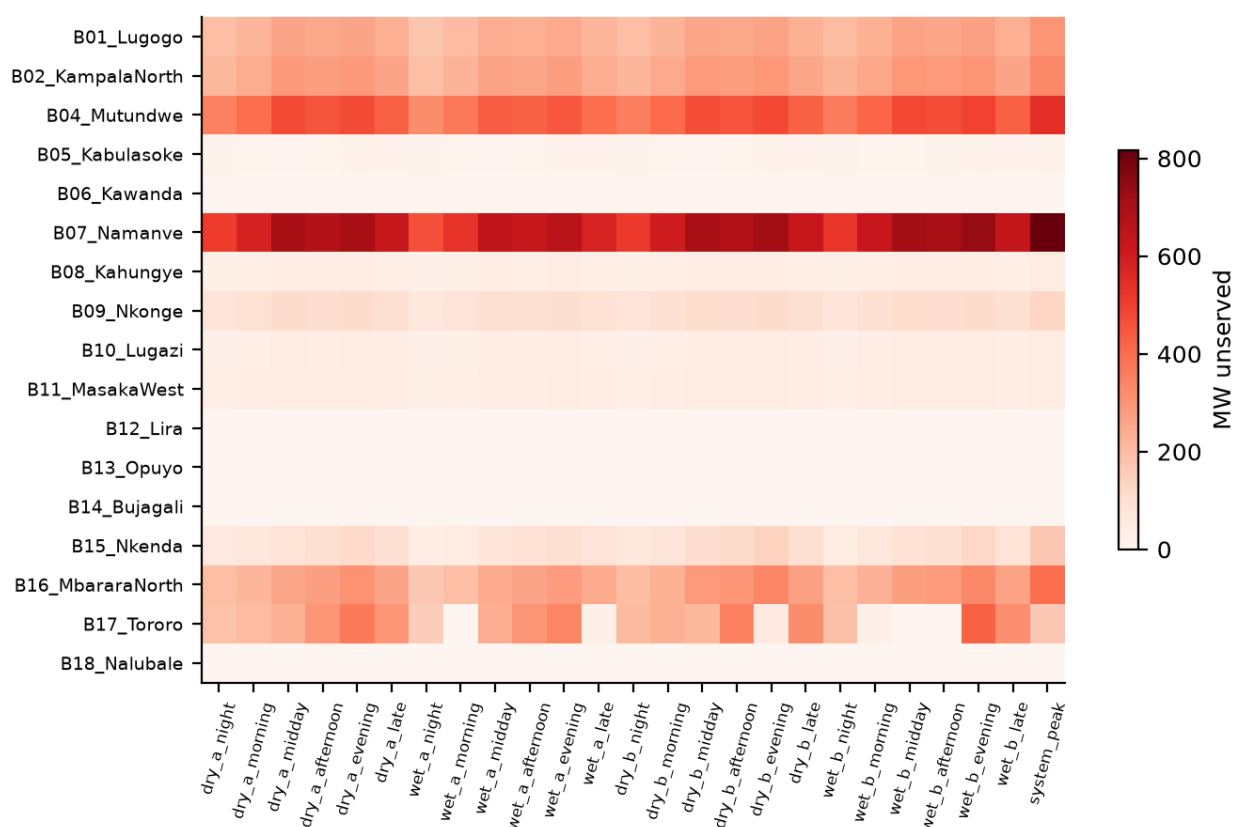


Figure 8.4: Where and when load is shed in 2040 if nothing is built (MW, bus × slice)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

8.5 Zonal balance

The zonal capacity gap compares each supply zone's share of the peak with the firm capacity located in the zone (Figure 8.5, Table 8.4).

It is a location signal, not a shortfall: zones import across the grid. But it shows where firm supply is thin.

- **Kampala.** The Kampala buses are the largest net importers in 2030. Lugogo has a deficit of 302 MW, Mutundwe 200 MW and Namanve 179 MW.
- **Mid-west.** Nkongwe has a 186 MW deficit, driven by the Hoima refinery and industrial park.
- **Surplus zones.** Lira (Karuma), Bujagali and Nalubaale are the generation zones.

The 2030 zonal gap in Figure 8.6 clusters in the central region: Buikwe, Kampala, Luwero, Mpigi, Mukono and Wakiso.

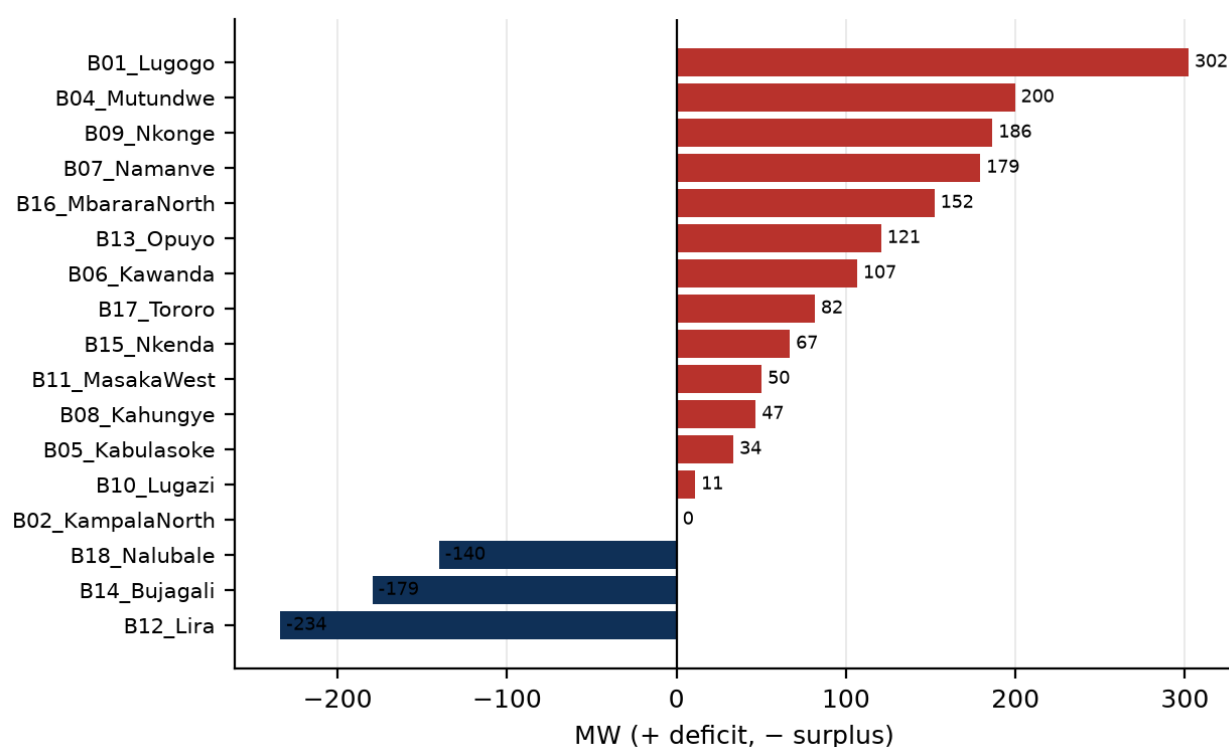


Figure 8.5: Zonal capacity balance, 2030

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.4: Zonal capacity balance, 2030 (location signal: zones import across the grid)

Bus	Region	Zone peak (MW)	Local firm (MW)	Zonal gap (MW)
B01_Lugogo	Mukono	263	0	302
B04_Mutundwe	Wakiso	252	90	200
B09_Nkongge	Kibaale	192	35	186
B07_Namanve	Mukono	199	50	179
B16_MbararaNorth	Isingiro	153	24	152
B13_Opuyo	Amuria	105	0	121
B06_Kawanda	Nakaseke	93	0	107
B17_Tororo	Bugiri	188	134	82
B15_Nkenda	Kasese	116	67	67
B11_MasakaWest	Rakai	44	0	50
B08_Kahungye	Kyenjojo	41	0	47
B05_Kabulasoke	Mubende	30	1	34
B10_Lugazi	Buikwe	31	25	11
B02_KampalaNorth	Wakiso	0	0	0
B18_Nalubale	Mayuge	125	283	-140
B14_Bujagali	Kamuli	51	238	-179
B12_Lira	Apac	125	378	-234

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_zonal_gap.csv).

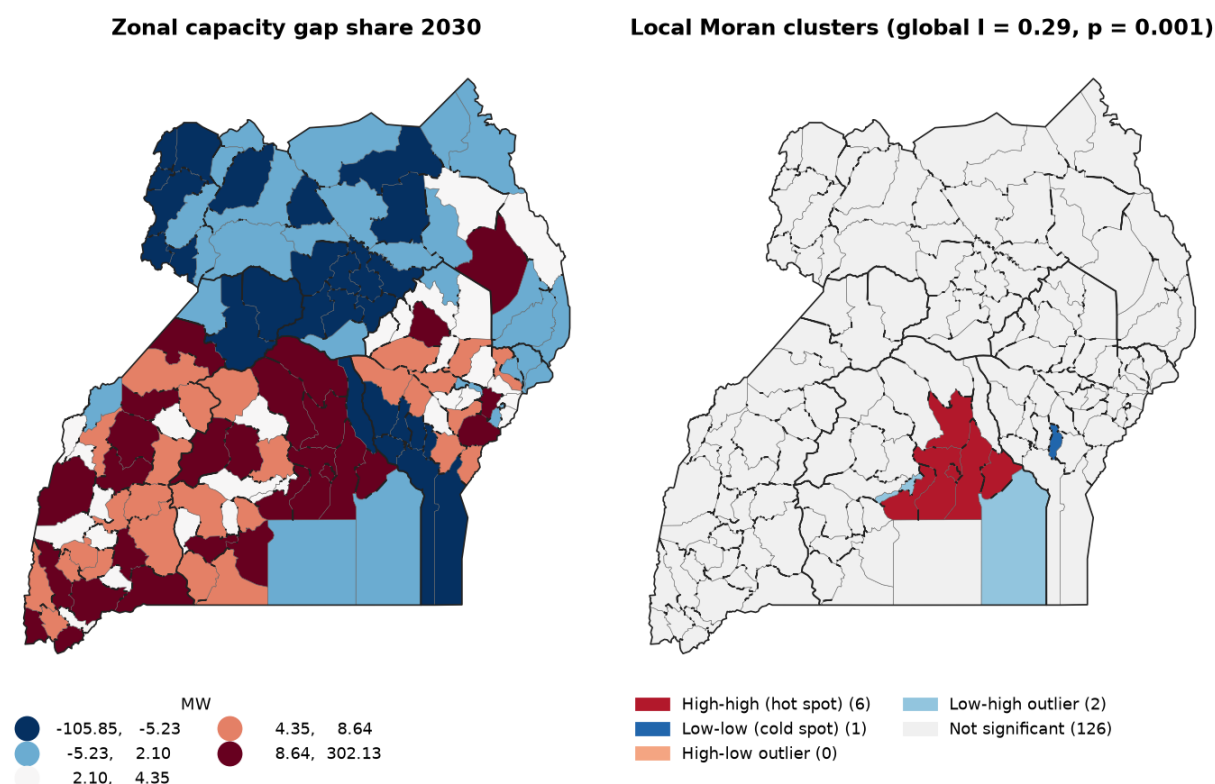


Figure 8.6: Ch.5 - Zonal capacity gap share 2030 (MW), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

8.6 G4 Network and G5 Distribution

The network and distribution gaps were measured in Chapters 6 and 7. The register records them:

- **Network.** Six corridors are at their rating or stressed in the 2030 grid-stress test. Three are N-1 critical at the 2030 peak. 4.15 million people live more than 50 km from transmission.
- **Distribution.** Losses exceed the 12 % target by 280 GWh in 2023 and 206 GWh in 2026. The gap closes in 2030 if the target path is followed.

8.7 G6 Access

The access gap is the number of households that must be connected to reach the target, district by district:

$$\text{Gap}_{d,y}^{\text{acc}} = a_y^* H_{d,y} - a_{d,y_0} H_{d,y_0} \quad (8.3)$$

where

- a_y^* is the national access target;
- $H_{d,y}$ is the number of households in district d in year y ;
- a_{d,y_0} is the district's estimated 2023 access rate.

The 2023 district access rates are estimated from the observed density of distribution transformers and calibrated so that the national rate equals the census 25.3 % (Chapter 13). Figure 8.7 maps them.

- **Highest access.** Kampala (70 %), Mukono (68 %) and Mbarara (64 %). The central and south-western districts form the high-high cluster.
- **Lowest access.** Access is below 5 % in much of Karamoja and in the islands. The low-low cluster is Abim, Agago, Kaabong, Karenga, Kitgum, Kotido, Maracha, Moroto, Moyo, Napak, Ouke and Soroti.

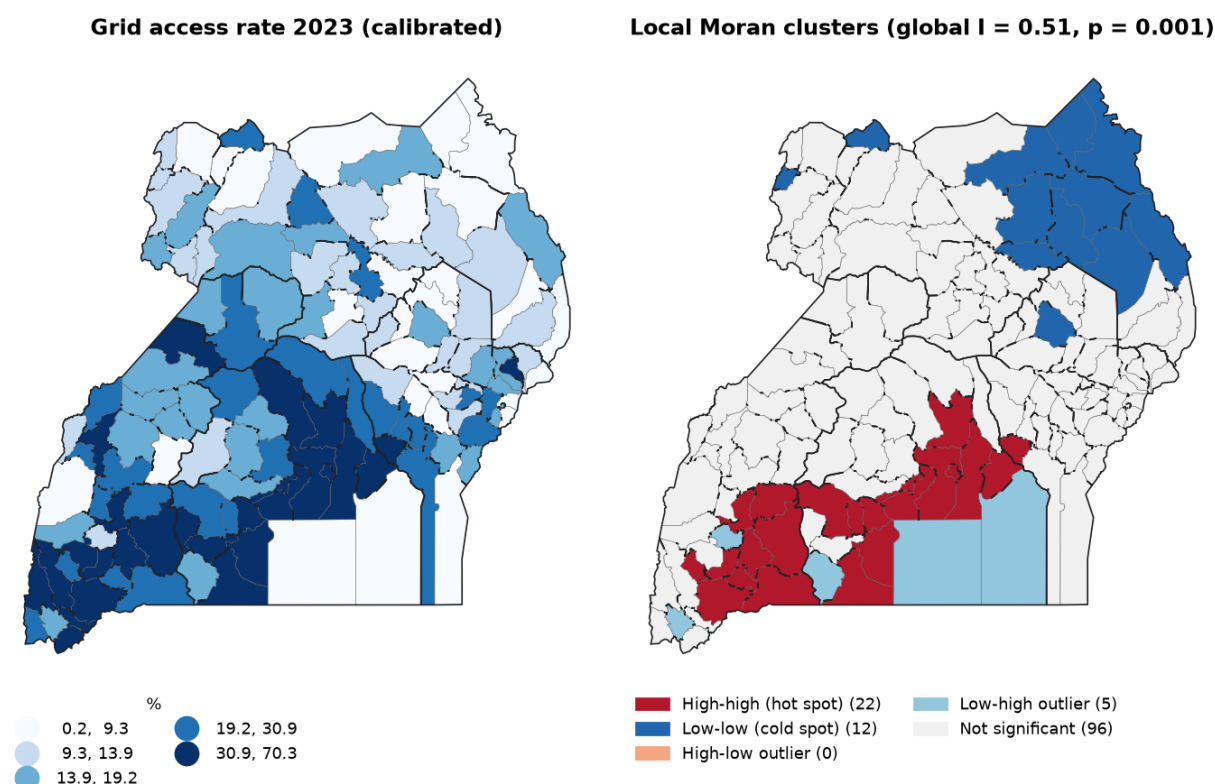


Figure 8.7: Ch.5 - Grid access rate 2023 (calibrated) (%), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

Figure 8.8 and Table 8.5 show the national gap by least-cost supply mode.

- **2030.** To reach 60 % access, **5.19 million** households must be connected: 4.37 million by grid and 0.82 million by solar home systems.
- **2040.** Universal access requires **14.98 million** connections.

No district's least-cost mode is the mini-grid at the Tier 2 service level assumed here. For small consumptions the solar home system is cheaper, and for dense settlements near the MV network the grid is. Chapter 13 discusses this result and its sensitivity.

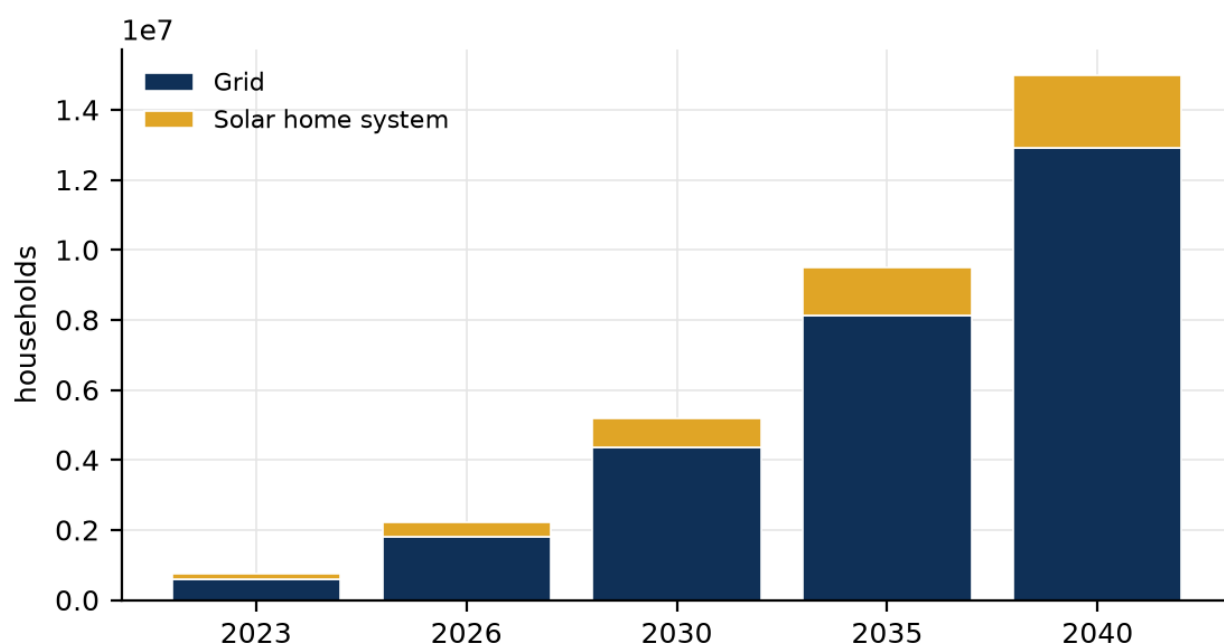


Figure 8.8: Access gap (G6) by least-cost supply mode

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.5: Access gap (G6) by least-cost supply mode

Year	Access gap (households)	Grid	Mini-grid	Solar home systems
2023	758,013	593,484	0	164,529
2026	2,211,929	1,801,260	0	410,669
2030	5,188,169	4,368,388	0	819,781
2035	9,496,454	8,121,586	0	1,374,868
2040	14,976,854	12,895,881	0	2,080,973

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_access_gap.csv).

The access gap in households (Figure 8.9, Table 8.6) is largest in the most populous districts. Wakiso needs 227,000 connections by 2030 although its access rate is already 44 %. Kasese, Arua and Yumbe need 120,000–135,000 each, from access rates of 4–12 %.

In households the gap is not spatially clustered (Figure 8.10; Moran's I 0.03): large districts have large gaps wherever they are. As a share of households it is one of the most clustered layers in the engine (Figure 8.11; Moran's I 0.51).

- **Hot-spot** (12 districts). Abim, Agago, Kaabong, Karenga, Kitgum, Kotido, Maracha, Moroto, Moyo, Napak, Otuke and Soroti. More than half of the households in these districts must be connected by 2030 to reach the national target.
- **Cold-spot** (22 districts). The Kampala–Masaka–Mbarara corridor.

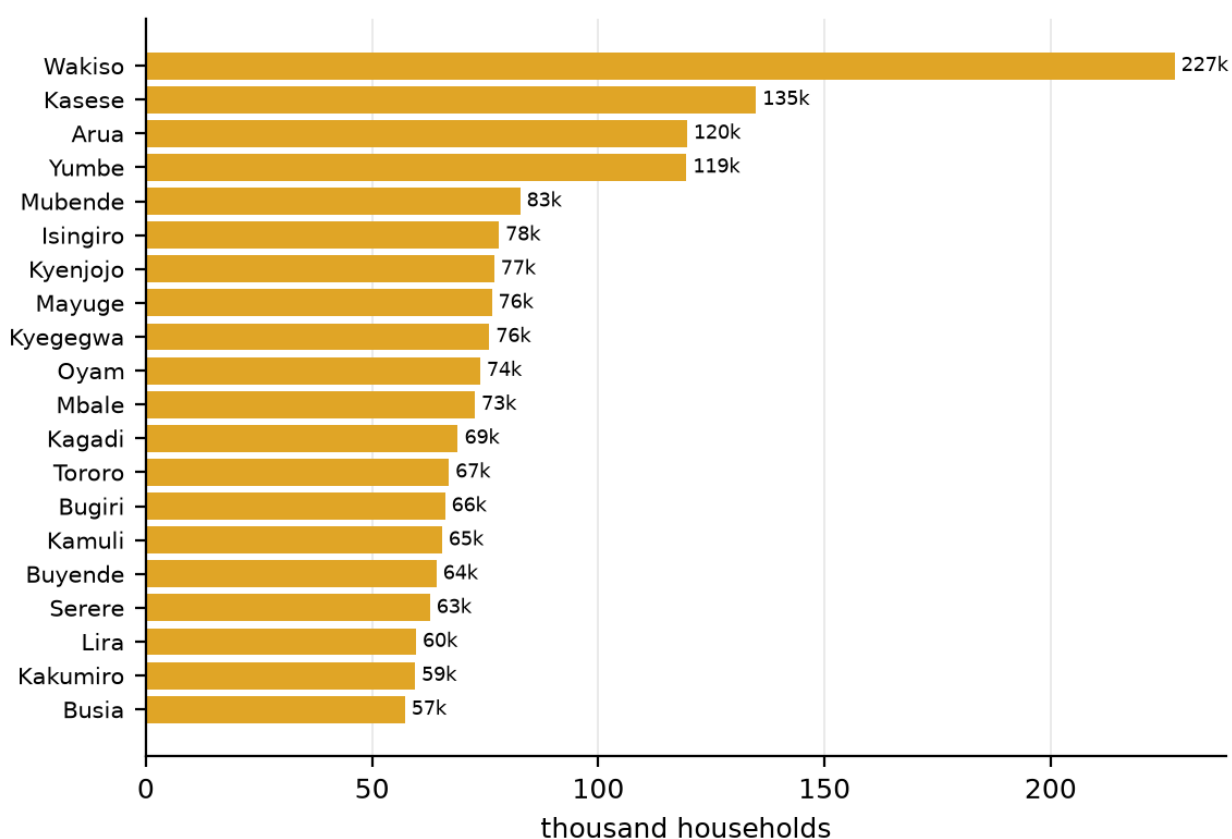


Figure 8.9: The 20 districts with the largest access gap, 2030

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.6: The 20 districts with the largest access gap in 2030

District	Region	Households	Access rate 2023	Access gap 2030
Wakiso	Central	929,145	43.7%	227,393
Kasese	Western	252,472	8.1%	134,851
Arua	Northern	238,399	12.1%	119,624
Yumbe	Northern	209,898	3.8%	119,482
Mubende	Central	164,039	11.8%	82,704
Isingiro	Western	190,371	23.4%	78,024
Kyenjojo	Western	166,011	16.8%	76,975
Mayuge	Eastern	180,565	21.7%	76,445
Kyegegwa	Western	137,907	6.1%	75,896
Oyam	Northern	144,981	11.1%	73,879
Mbale	Eastern	186,276	25.8%	72,696
Kagadi	Western	153,102	18.4%	68,968
Tororo	Eastern	191,697	30.8%	66,949
Bugiri	Eastern	145,933	18.1%	66,102
Kamuli	Eastern	177,234	28.4%	65,445
Buyende	Eastern	129,941	13.0%	64,203
Serere	Eastern	112,132	4.9%	62,779
Lira	Northern	150,049	24.9%	59,700
Kakumiro	Western	128,603	16.9%	59,487
Busia	Eastern	121,826	16.0%	57,247

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_access_top.csv).

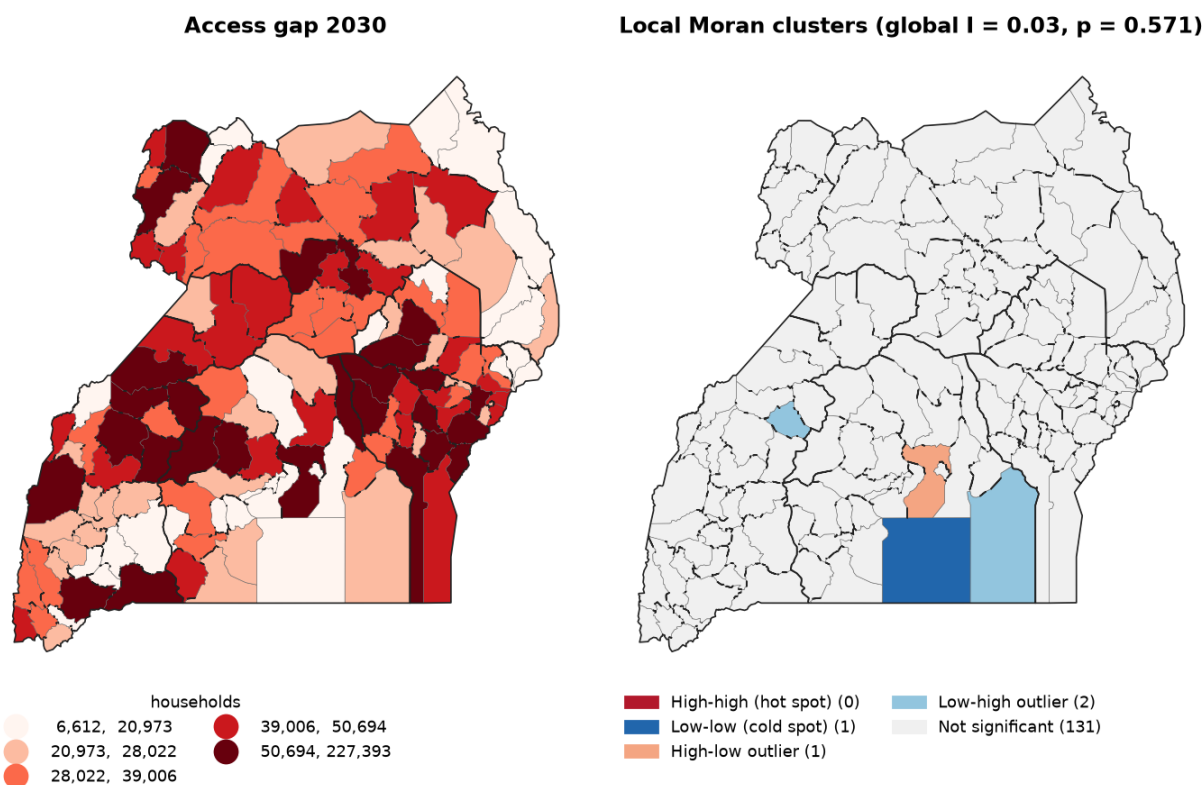


Figure 8.10: Ch.5 - Access gap 2030 (households), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

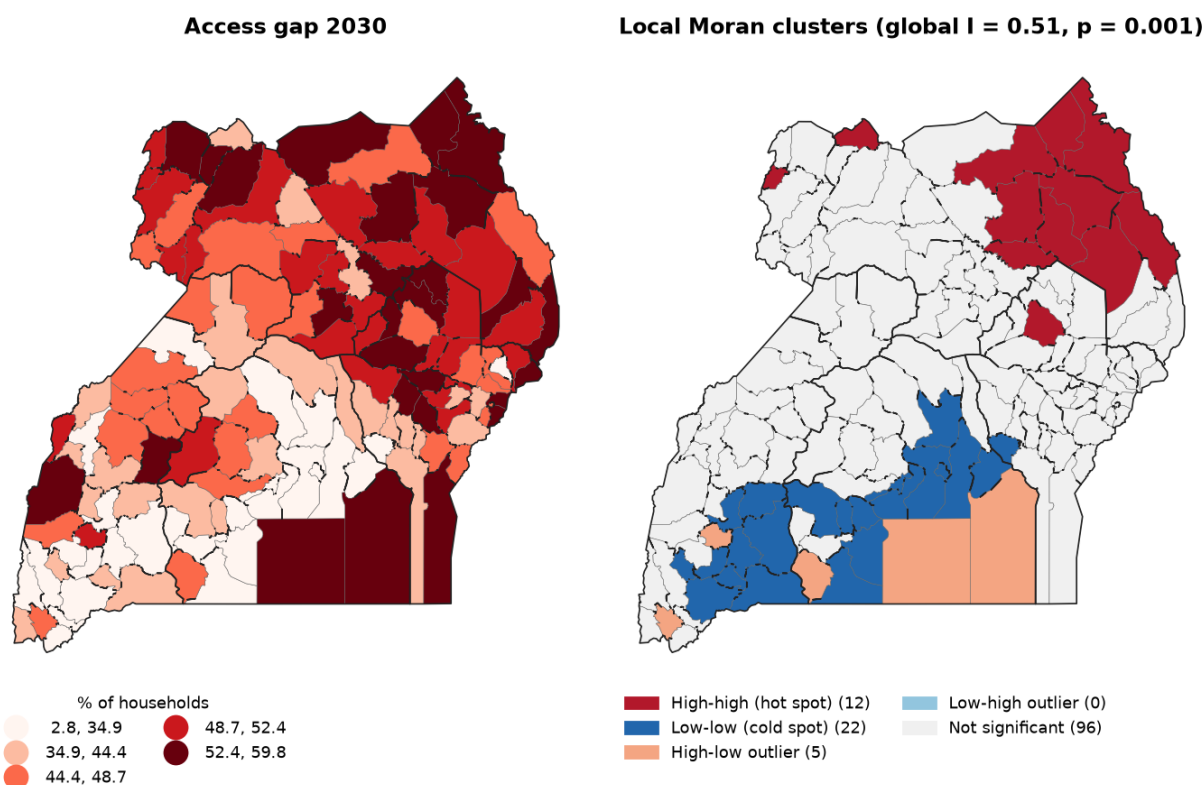


Figure 8.11: Ch.5 - Access gap 2030 (% of households), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

8.8 G7 Sector service

The health and school registers allow the engine to count unelectrified institutions directly (Figure 8.12, Table 8.7).

- **Health.** In 2023, an estimated **1,096** health facilities were not electrified: 746 HC IIs, 340 HC IIIs and 10 HC IVs.
- **Schools.** An estimated **13,349** schools were not electrified, most of them primary schools.

The status of each facility is modelled: facilities nearest the MV network are assumed electrified first, calibrated to the level shares. It is not a survey result.

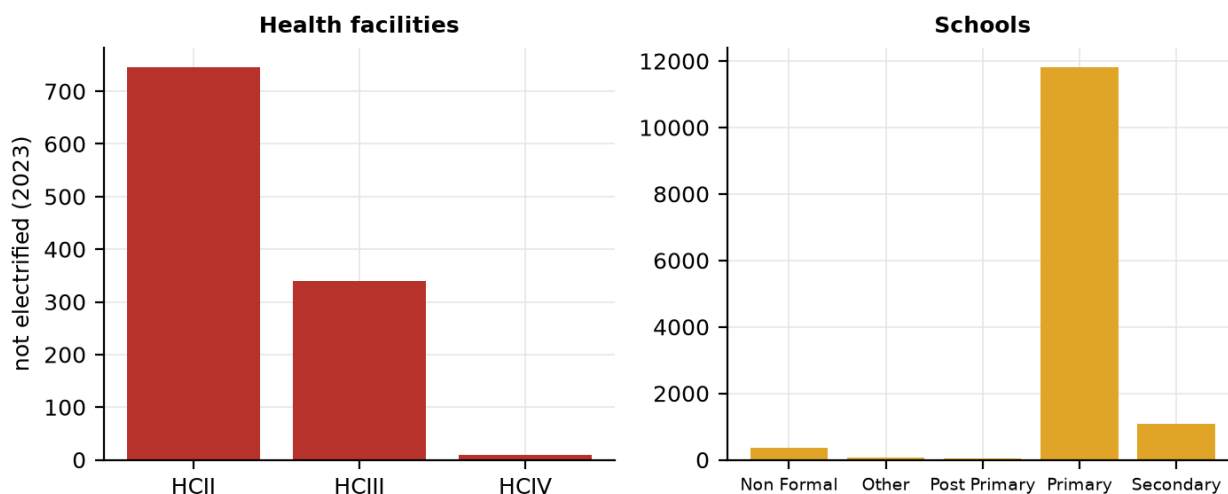


Figure 8.12: Sector-service gap (G7): health facilities and schools not electrified in 2023 (modelled)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.7: Health facilities not electrified in 2023 (modelled: nearest-to-grid first, calibrated shares)

Level	Not electrified (2023)
HC II	746
HC III	340
HC IV	10

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_health_gap.csv).

The health gap per 100,000 people (Figure 8.13) clusters in the north-west (Moran's I 0.20): Adjumani, Amuru, Gulu, Madi Okollo, Moyo and Obongi, where facilities are far from the MV network.

The count of unelectrified schools (Figure 8.14) clusters in the populous central districts, where there are simply more schools. This is why the sector gap should be read both in absolute and in relative terms.

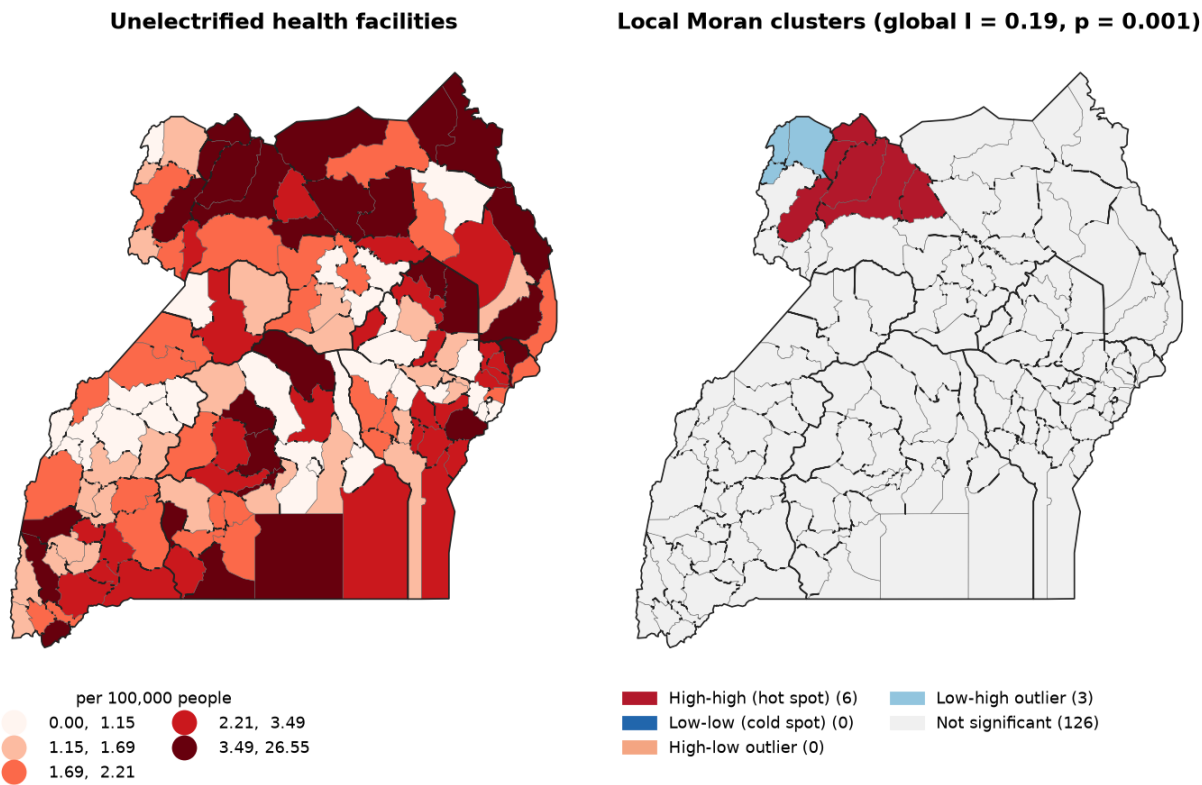


Figure 8.13: Ch.5 - Unelectrified health facilities (per 100,000 people), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

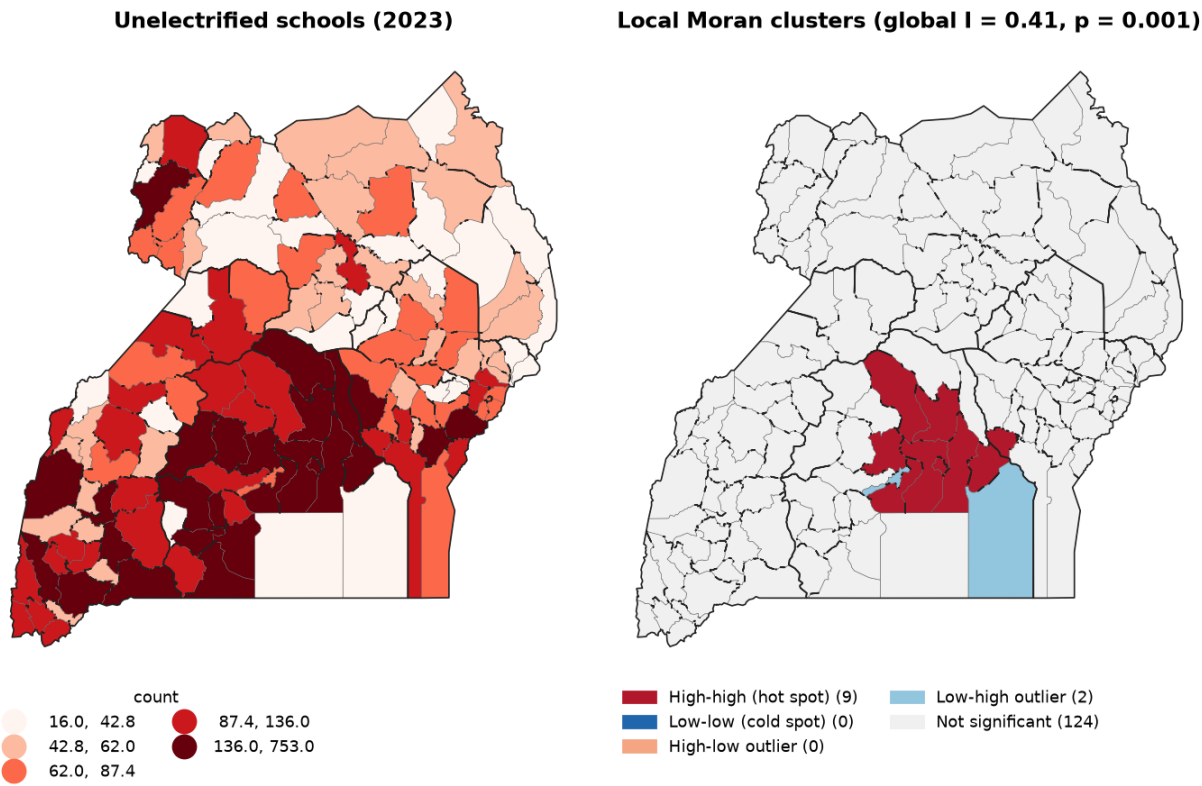


Figure 8.14: Ch.5 - Unelectrified schools (2023) (count), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

8.9 G8 Security and resilience

Figure 8.15 and Table 8.8 compare the security indicators with benchmarks.

- **Nile cascade share.** 76 % of generation comes from one river, against a diversification benchmark of 50 %.
- **Largest unit.** The largest unit, Karuma, is 61 % of the peak, against a benchmark of 20 %.
- **Oil.** Oil is 100 % imported, and storage covers 21 days against a 90-day norm.
- **Dry year.** A dry year in 2030 would leave 4,608 GWh unserved.
- **Hardening.** Hardening the hydro assets against drought and flood is the one indicator that is favourable. The expected avoided loss is 2.2 times the hardening cost.

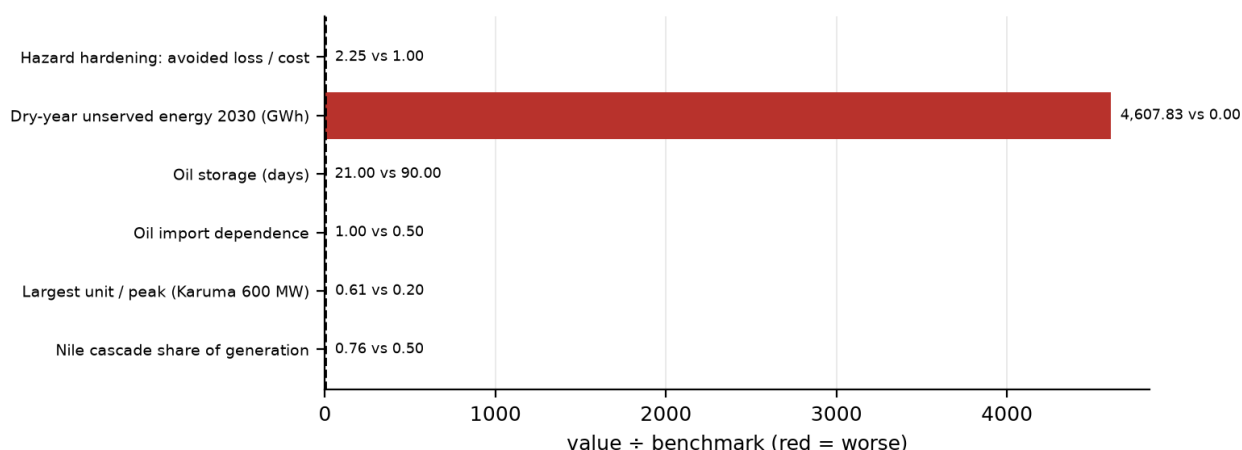


Figure 8.15: Security and resilience indicators (G8) against benchmarks

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.8: Security and resilience indicators (G8)

Indicator	Value	Benchmark	Unit	Flag
Nile cascade share of generation	0.76	0.50	share	worse than benchmark
Largest unit / peak (Karuma 600 MW)	0.61	0.20	share	worse than benchmark
Oil import dependence	1.00	0.50	share	worse than benchmark
Oil storage (days)	21.00	90.00	days	worse than benchmark
Dry-year unserved energy 2030 (GWh)	4,607.83	0.00	GWh	worse than benchmark
Hazard hardening: avoided loss / cost	2.25	1.00	ratio	

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_security.csv).

8.10 The gap register

Figure 8.16 and Table 8.9 bring the gaps together, each in its own unit and with the year it opens. This register is handed to the least-cost plan as its targets:

- the reserve margin, for G1;
- zero unserved energy at the value of lost load, for G3;
- corridor limits, for G4;
- the access target, for G6.

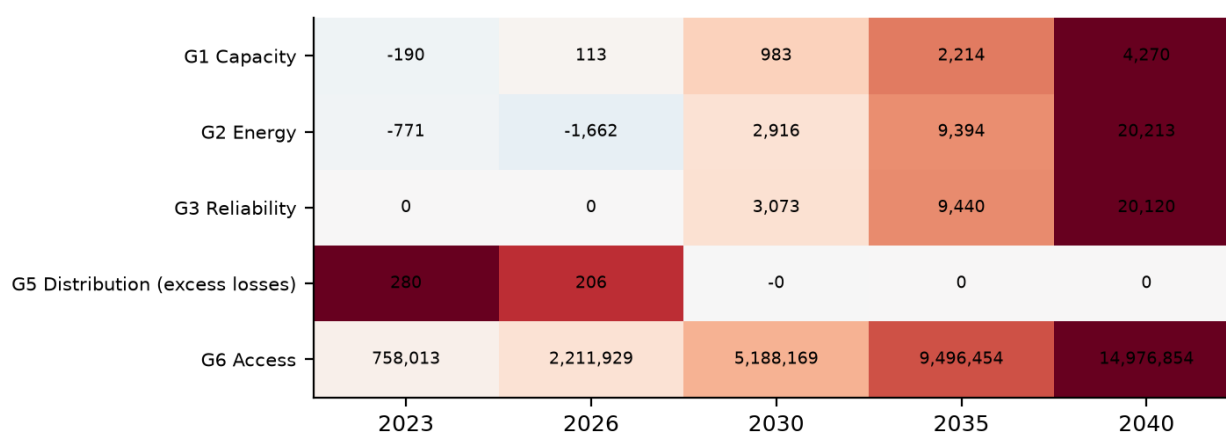


Figure 8.16: The gap register: each gap by planning year (colour scaled to each gap's maximum)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.9: The gap register passed to the least-cost plan

Gap	Year	Value	Unit	Opens
G1 Capacity	2023	-190	MW	2026
G2 Energy	2023	-771	GWh	2028
G3 Reliability	2023	0	GWh unserved	2030
G5 Distribution (excess losses)	2023	280	GWh	2023
G6 Access	2023	758,013	households	2023
G1 Capacity	2026	113	MW	2026
G2 Energy	2026	-1,662	GWh	2028
G3 Reliability	2026	0	GWh unserved	2030
G5 Distribution (excess losses)	2026	206	GWh	2023
G6 Access	2026	2,211,929	households	2023
G1 Capacity	2030	983	MW	2026
G2 Energy	2030	2,916	GWh	2028
G3 Reliability	2030	3,073	GWh unserved	2030
G5 Distribution (excess losses)	2030	-0	GWh	2023
G6 Access	2030	5,188,169	households	2023
G1 Capacity	2035	2,214	MW	2026
G2 Energy	2035	9,394	GWh	2028
G3 Reliability	2035	9,440	GWh unserved	2030
G5 Distribution (excess losses)	2035	0	GWh	2023
G6 Access	2035	9,496,454	households	2023
G1 Capacity	2040	4,270	MW	2026
G2 Energy	2040	20,213	GWh	2028
G3 Reliability	2040	20,120	GWh unserved	2030
G5 Distribution (excess losses)	2040	0	GWh	2023
G6 Access	2040	14,976,854	households	2023
G4 Network (corridors $\geq 100\%$ / ≥ 500 h stressed)	2030	6	corridors	-
G4 Network (N-1 critical)	2030	3	corridors	2023
G4 Network (population > coverage km)	2023	4,151,014	people	2023
G7 Health facilities not electrified	2023	1,096	facilities	2023
G7 Schools not electrified	2023	13,349	schools	2023
G8 Dry-year unserved energy	2030	4,608	GWh	-

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_register.csv).

8.11 Where the gaps are: spatial statistics

Figure 8.17 and Table 8.10 test whether each gap layer is geographically clustered. All five layers tested are significantly clustered at $p = 0.001$:

- the access gap as a share of households: Moran's I 0.51;
- the distance to transmission: 0.48;
- demand: 0.31;
- the zonal capacity gap: 0.29;
- the unelectrified health facilities: 0.20.

The gaps are not scattered. They sit in identifiable clusters that can be targeted as programmes:

- Karamoja and the north-east for access;
- West Nile and Acholi for coverage;
- the Kampala supply ring for capacity and network.

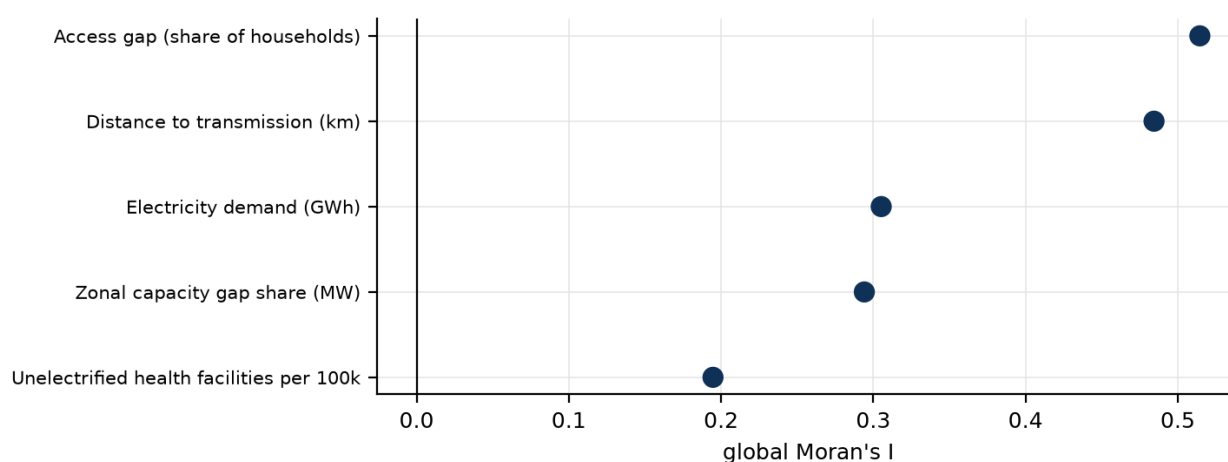


Figure 8.17: Is each gap spatially clustered? Global Moran's I of the gap layers (navy = significant at 5 %)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 8.10: Global spatial autocorrelation of the gap layers (k = 6 nearest neighbours, 999 permutations)

Layer	Moran's I	p-value	z	Hot-spots (HH)	Cold-spots (LL)
Access gap (share of households)	0.514	0.001	11.68	12	22
Distance to transmission (km)	0.484	0.001	10.79	13	8
Unelectrified health facilities per 100k	0.195	0.001	5.51	6	0
Zonal capacity gap share (MW)	0.294	0.001	7.16	6	1
Electricity demand (GWh)	0.305	0.001	7.31	7	0

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_spatial_stats.csv).

8.12 Data quality and limitations

- **Accounting gaps.** The capacity and energy gaps use static capacity credits and average availability. When they disagree with the reliability gap, the reliability gap, which comes from a solved model, takes precedence.
- **Access rates.** District access rates are CALIBRATED from transformer density, not surveyed. Access gaps by district inherit that uncertainty.
- **Institutional status** is MODELLED.
- **Time resolution.** The 25-slice resolution under-represents multi-day dry spells. The dry-year case is the stress test for hydrological risk.

8.13 Implications for planning

- The capacity gap opens in 2026, the energy gap in 2028 and the reliability gap in 2030. Plants with five-year lead times needed to be committed by 2021–2025 to close them on time. Chapter 12 shows that the geothermal candidates are already late.
- The dry-year result is a gap today. Uganda's supply security depends on normal rainfall on the Nile basin. Storage, diversification away from the cascade and a thermal or geothermal reserve have value even before the demand gap opens.
- The access gap is large, clustered and structured. Karamoja and the north-east have the lowest rates. The populous districts of the centre, east and west have the largest numbers. The two call for different programmes: extension and off-grid in the first, densification in the second.
- The gaps are separate and must be closed separately. Generation closes G1–G3, the grid G4, the distribution programme G5, and the access and institutional programmes G6 and G7. The investment plan of Chapter 11 keeps them apart.

CHAPTER 9

9 The least-cost plan to close the gaps

This chapter presents the least-cost plan. It is the portfolio of new generation, storage and transmission reinforcement that closes the gaps of Chapter 8 at the minimum discounted cost to the system, between 2026 and 2040. The plan is a solved PyPSA multi-investment-period expansion (Equation (2.4)). It chooses what to build, where, when and how much, while dispatching the whole system in the 25 slices of every period. The chapter implements design Chapter 6 (`docs/06_least_cost_plan.md`). Chapter 10 tests the plan against 29 alternative assumptions.

9.1 How the plan is formulated

The plan has four investment periods, each representing the years that lead up to it:

- 2026 represents 2024–2026;
- 2030 represents 2027–2030;
- 2035 represents 2031–2035;
- 2040 represents 2036–2040.

Each period's demand is the demand of its final year, so the capacity built for a period serves the highest demand of that period.

Cost. Costs are discounted to 2023 at 10 % a year. Each candidate's annualised capital cost and fixed O&M are charged in every period in which it is active.

Operation. In every period the plan must serve the load at every bus in every slice, or pay the value of lost load (10,000 USD/MWh).

Constraints:

- Capacity-credited firm capacity must cover peak demand plus 15 % (Equation (2.5)).
- No candidate may exceed its potential or its annual build rate, or be built before its first available year.

What is fixed and what is chosen. The existing fleet, the reservoirs, the two existing batteries and the five corridors under construction are part of every period (the corridors from 2026). The plan chooses from:

- 15 IRP generation candidates;
- 3 battery candidates;
- reinforcement of the 24 existing corridors;
- the 4 IERMP new corridors.

9.2 The candidates

Table 9.1 lists the candidates with their costs and limits. Overnight costs range widely:

Candidate	Overnight cost (USD/kW)
Diesel	500
Combined-cycle gas	800–900
Solar	900
Wind	1,300

Candidate	Overnight cost (USD/kW)
Run-of-river hydro	2,830
Geothermal	3,500
Biomass	3,750
Nuclear	4,900

Variable costs run the other way: nearly zero for the renewables, 40–76 USD/MWh for gas and 245 USD/MWh for diesel. Capacity credits reflect each technology's contribution at the evening peak:

- 0.03 for solar;
- 0.25 for wind;
- 0.40 for run-of-river hydro;
- 0.90 for geothermal, gas and batteries;
- 0.95 for nuclear and diesel.

Table 9.1: Candidate options for the least-cost plan (IRP set + engine battery candidates)

Candidate	Technology	Bus	Max MW	Max MW / yr	Overnight (USD/kW)	Fixed O&M (USD/kW-yr)	Variable (USD/MWh)	tCO ₂ /MWh	Credit	From
RoR_North	Hydro	B12_Lira	1,412	300	2,830	40	1.0	0.000	0.40	2026
RoR_West	Hydro	B15_Nkenda	384	300	2,830	40	1.0	0.000	0.40	2026
RoR_WestNile	Hydro	B12_Lira	800	300	2,830	40	1.0	0.000	0.40	2026
Geothermal_Katwe	Geothermal	B15_Nkenda	680	300	3,500	75	0.5	0.000	0.90	2026
Geothermal_Buranga	Geothermal	B08_Kahungye	380	190	3,500	75	0.5	0.000	0.90	2028
Solar_Central	Solar PV	B05_Kabulasoke	600	300	900	10	1.0	0.000	0.03	2026
Solar_East	Solar PV	B17_Tororo	1,200	300	900	10	1.0	0.000	0.03	2026
Solar_North	Solar PV	B12_Lira	1,150	300	900	10	1.0	0.000	0.03	2026
Wind_Karamoja	Wind	B13_Opuyo	120	120	1,300	40	1.0	0.000	0.25	2026
Biomass_Central	Biomass	B04_Mutundwe	200	100	3,750	75	27.5	0.000	1.00	2028
CCGT_Tilenga	Gas	B08_Kahungye	200	200	800	25	40.4	0.340	0.90	2026
CCGT_East	Gas	B17_Tororo	1,250	250	900	25	53.2	0.340	0.90	2030
OCGT_West	Gas	B08_Kahungye	1,646	250	800	20	75.5	0.478	0.90	2030
Nuclear_Buyende	Nuclear	B17_Tororo	2,400	1,200	4,900	56	16.1	0.000	0.95	2036
Diesel_Central	Oil / diesel / HFO	B04_Mutundwe	500	500	500	60	244.5	0.878	0.95	2026
BESS_Kampala	Battery	B04_Mutundwe	1,000	250	1,100	10	1.0	0.000	0.90	2026
BESS_North	Battery	B12_Lira	500	250	1,100	10	1.0	0.000	0.90	2026
BESS_East	Battery	B17_Tororo	500	250	1,100	10	1.0	0.000	0.90	2026

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_candidates.csv).

The candidates are located at their connecting bus (Figure 6.17 in Chapter 6):

- **West.** Geothermal at Katwe (Nkenda bus) and Buranga (Kahungye); Albertine gas at Kahungye.
- **North.** Run-of-river hydro at Lira and Nkenda.
- **Solar.** Kabulasoke, Tororo and Lira.

- **Wind.** Karamoja (Opuyo).
- **East.** The eastern gas plant, which would use imported gas, and the nuclear candidate at Tororo.

9.3 What gets built

Figure 9.1, Figure 9.2 and Table 9.2 show the plan. It builds **5,935 MW** of new capacity by 2040.

- **2026: 126 MW.** Combined-cycle gas at Tilenga, the Albertine gas site. It is the only candidate available at once with a high capacity credit and a low capital cost.
- **2030: 967 MW.**
 - Geothermal at Katwe (237 MW) and Buranga (110 MW): high-credit, low-variable-cost base load.
 - Open-cycle gas in the west (546 MW) for firm capacity.
 - The rest of Tilenga (74 MW).
- **2035: 1,368 MW.**
 - The rest of the geothermal potential: Katwe to 680 MW, Buranga to 380 MW.
 - More open-cycle gas (463 MW).
 - The first combined-cycle unit in the east (192 MW).
- **2040: 3,474 MW.** The steepest period, driven by the steel and industrial-park step loads.
 - The eastern combined-cycle plant to its full 1,250 MW.
 - The western open-cycle gas to its full 1,646 MW.
 - 1,170 MW of solar at Kabulasoke and Lira.
 - 120 MW of wind in Karamoja.
 - 489 MW of diesel peaking capacity at Kampala.

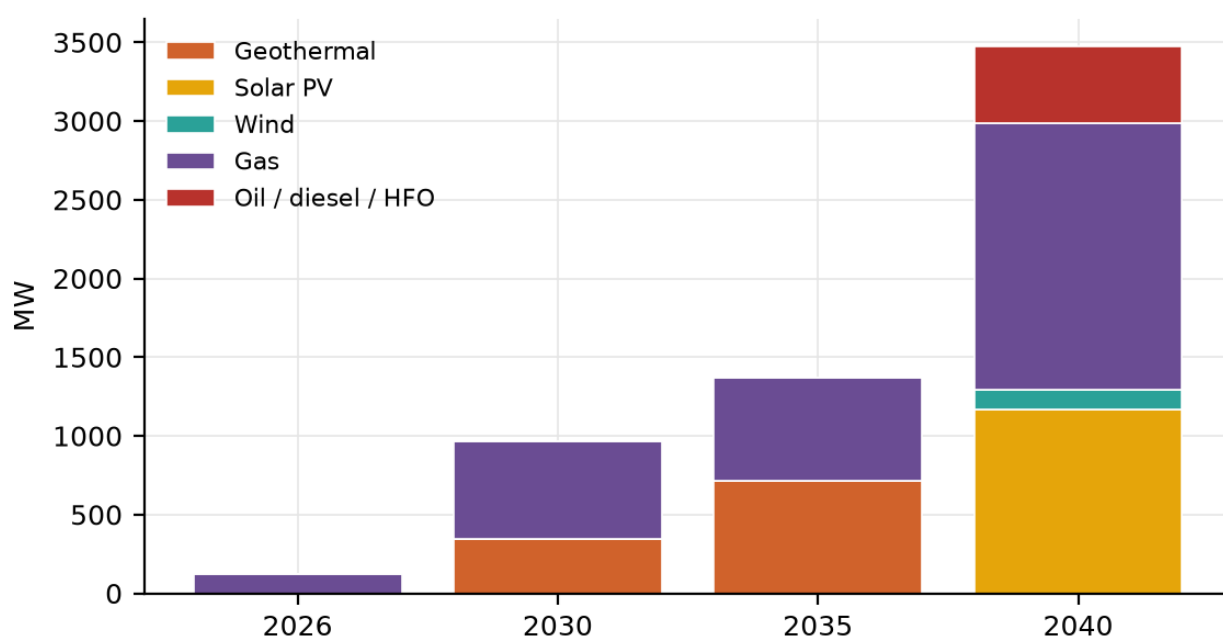


Figure 9.1: Least-cost plan: new capacity by technology and period (PyPSA multi-period expansion)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

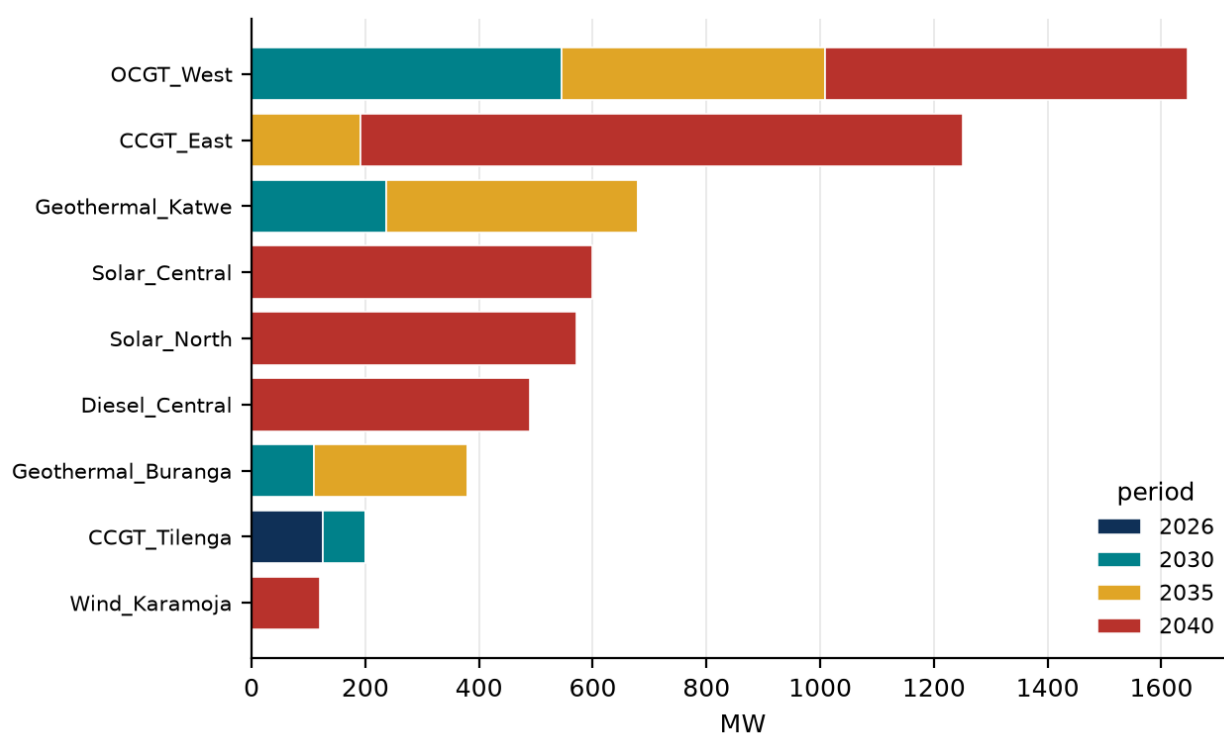


Figure 9.2: Build schedule by candidate project and period

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 9.2: Least-cost build schedule by candidate and period (MW), base scenario S0

Candidate	Technology	District	2026	2030	2035	2040	Total MW
OCGT_West	Gas	Kazo	0	546	463	638	1,646
CCGT_East	Gas	Tororo	0	0	192	1,058	1,250
Geothermal_Katwe	Geothermal	Kasese	0	237	443	0	680
Solar_Central	Solar PV	Gomba	0	0	0	600	600
Solar_North	Solar PV	Lira	0	0	0	570	570
Diesel_Central	Oil / diesel / HFO	Kampala	0	0	0	489	489
Geothermal_Buranga	Geothermal	Kazo	0	110	270	0	380
CCGT_Tilenga	Gas	Kazo	126	74	0	0	200
Wind_Karamoja	Wind	Soroti	0	0	0	120	120

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_builds.csv).

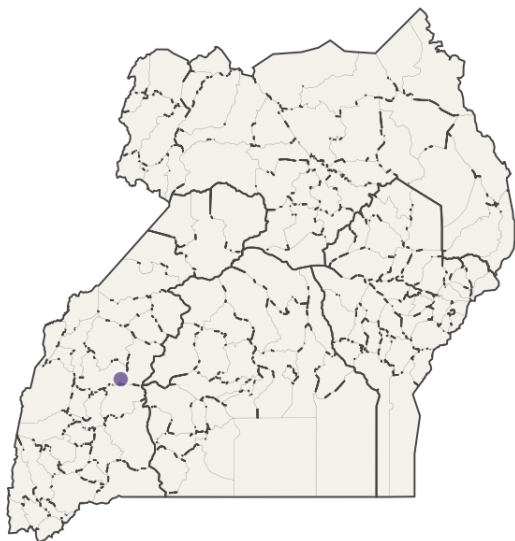
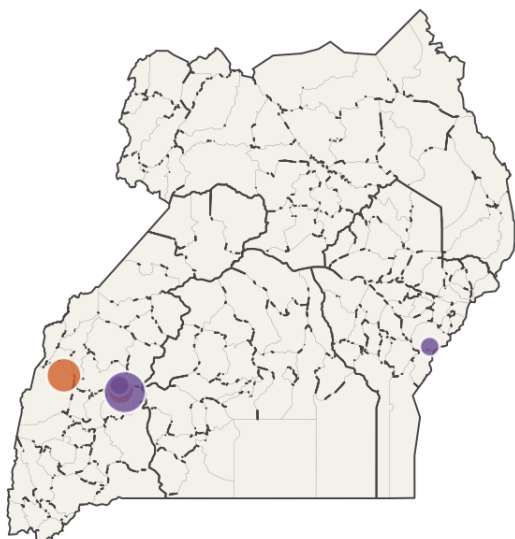
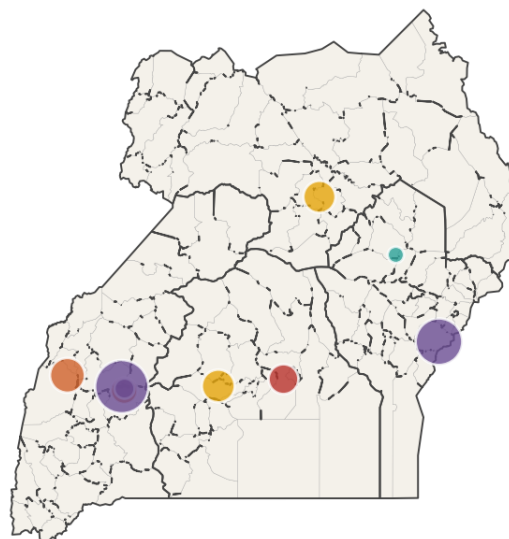
Some candidates are **not built** in the base scenario:

- run-of-river hydro (LCOE 83 USD/MWh);
- nuclear (86 USD/MWh, available only from 2036);
- biomass (105 USD/MWh);
- the batteries.

At a 10 % discount rate and with no carbon price, geothermal and combined-cycle gas are cheaper sources of firm energy. The simulations of Chapter 10 show when the others enter:

- run-of-river hydro under a renewable target or a carbon price;
- nuclear under a nuclear target;
- batteries when fossil fuels are excluded.

Figure 9.3 maps the cumulative build by period. Most new capacity sits at the western generation sites of Nkenda and Kahungye (geothermal, Albertine gas) and at Tororo in the east (combined-cycle gas). Solar is at Kabulasoke and Lira, wind in Karamoja and the diesel peakers in Kampala.

Cumulative new capacity by 2026: 126 MW**Cumulative new capacity by 2030: 1,092 MW****Cumulative new capacity by 2035: 2,460 MW****Cumulative new capacity by 2040: 5,935 MW**

● Geothermal
 ● Solar PV
 ● Wind
 ● Gas
 ● Oil / diesel / HFO

Figure 9.3: Least-cost plan: cumulative new generation and storage by period (area $\propto$ MW)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

9.4 Capacity and generation

Figure 9.4 and Table 9.3 show installed capacity (existing plus new) against the firm requirement.

- **Capacity.** Installed capacity rises from 2,310 MW in 2026 to 8,120 MW in 2040.
- **Reserve.** Firm capacity tracks peak demand plus 15 % in every period. The reserve-margin constraint binds throughout.
- **Mix.** Hydro remains the largest block to 2035. Gas becomes the largest in 2040, at 3,096 MW.

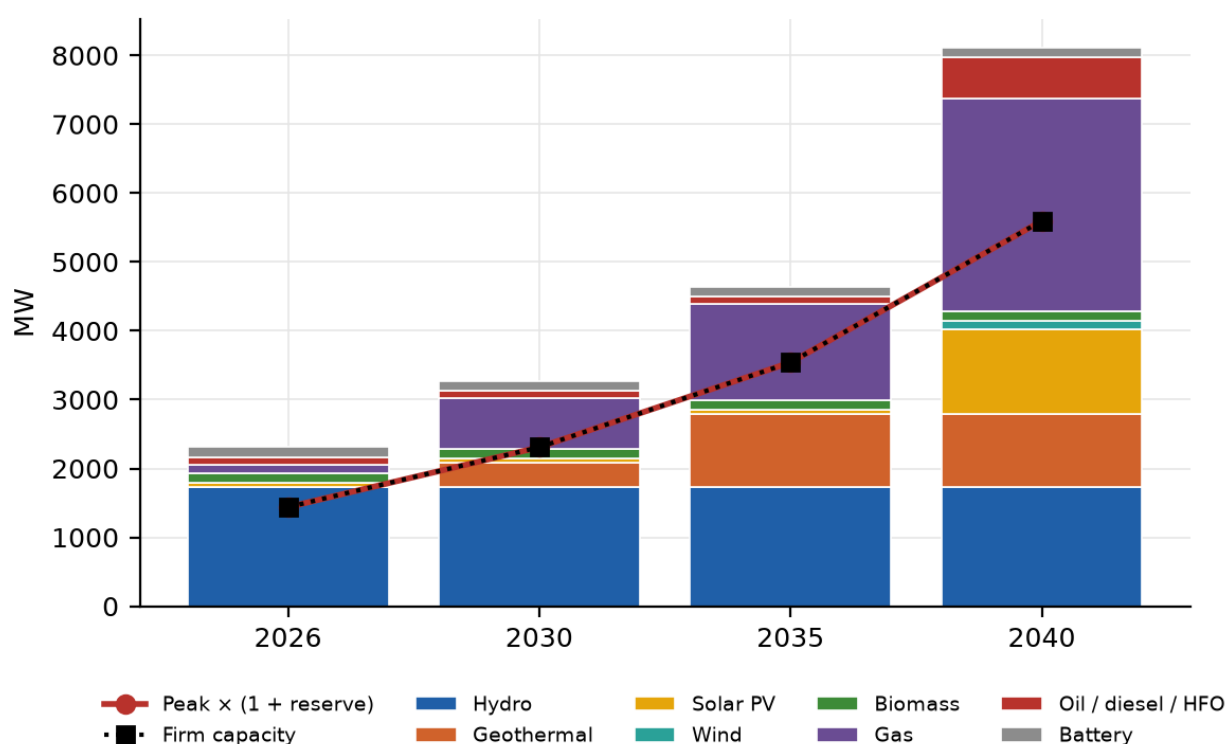


Figure 9.4: Installed capacity (existing + new) against the firm requirement

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 9.3: Installed capacity (existing + new) by technology and period, MW

Technology	2026	2030	2035	2040
Battery	150	150	150	150
Biomass	136	136	136	136
Gas	126	746	1,400	3,096
Geothermal	0	347	1,060	1,060
Hydro	1,733	1,733	1,733	1,733
Nuclear	0	0	0	0
Oil / diesel / HFO	100	100	100	589
Solar PV	65	65	65	1,235
Wind	0	0	0	120

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_capacity_path.csv).

Generation tells a different story from capacity (Figure 9.5, Table 9.4).

- **2026.** Generation is 98.6 % hydro.
- **2030.** Hydro still produces 8,104 GWh, but geothermal adds 2,734 GWh and gas 1,612 GWh.
- **2035.** Geothermal reaches 8,357 GWh, as much as hydro.
- **2040.** Gas produces 11,987 GWh (38.6 %), geothermal 26.9 %, hydro 26.1 %, solar 6.6 % and wind 1.0 %.

The open-cycle gas plants run very little. Their capacity factor is about 4 %: they are built for the reserve margin, not for energy. The combined-cycle plants run as base and intermediate load.

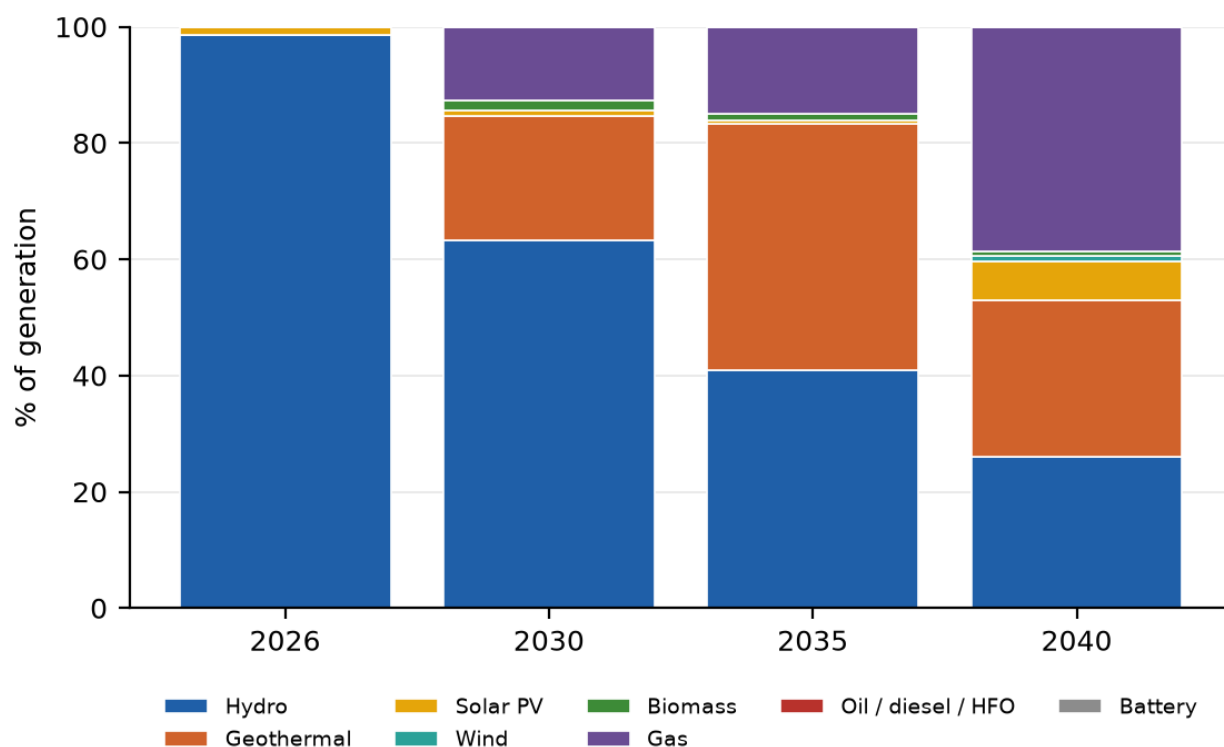


Figure 9.5: Generation mix by period, least-cost plan

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 9.4: Generation by technology and period, GWh

Technology	2026	2030	2035	2040	Share 2026	Share 2040
Battery	0	0	1	1	0.0%	0.0%
Biomass	0	234	234	234	0.0%	0.8%
Gas	0	1,612	2,954	11,987	0.0%	38.6%
Geothermal	0	2,734	8,357	8,357	0.0%	26.9%
Hydro	7,823	8,104	8,104	8,104	98.6%	26.1%
Nuclear	0	0	0	0	0.0%	0.0%
Oil / diesel / HFO	0	0	0	37	0.0%	0.1%
Solar PV	108	108	108	2,056	1.4%	6.6%
Wind	0	0	0	297	0.0%	1.0%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_gen_path.csv).

9.5 Cost

The plan's net present cost, meaning the discounted cost of new assets and of operating the whole system from 2024 to 2040, is **4.37 bn USD**. This reconciles exactly with the PyPSA objective (validation check V6-5). Figure 9.6 and Table 9.5 break down the annual cost by period.

- **Capital costs rise with the build.** Annualised generation and storage capital rises from 14 million USD a year in 2026 to 234 million in 2030, 624 million in 2035 and 1,023 million in 2040.
- **Fuel and variable costs** rise from almost nothing to 652 million USD a year in 2040, as gas generation grows.
- **Transmission.** Annualised transmission capital reaches 28 million USD a year.
- **Unserved energy** costs nothing in any period: the plan closes the reliability gap completely.

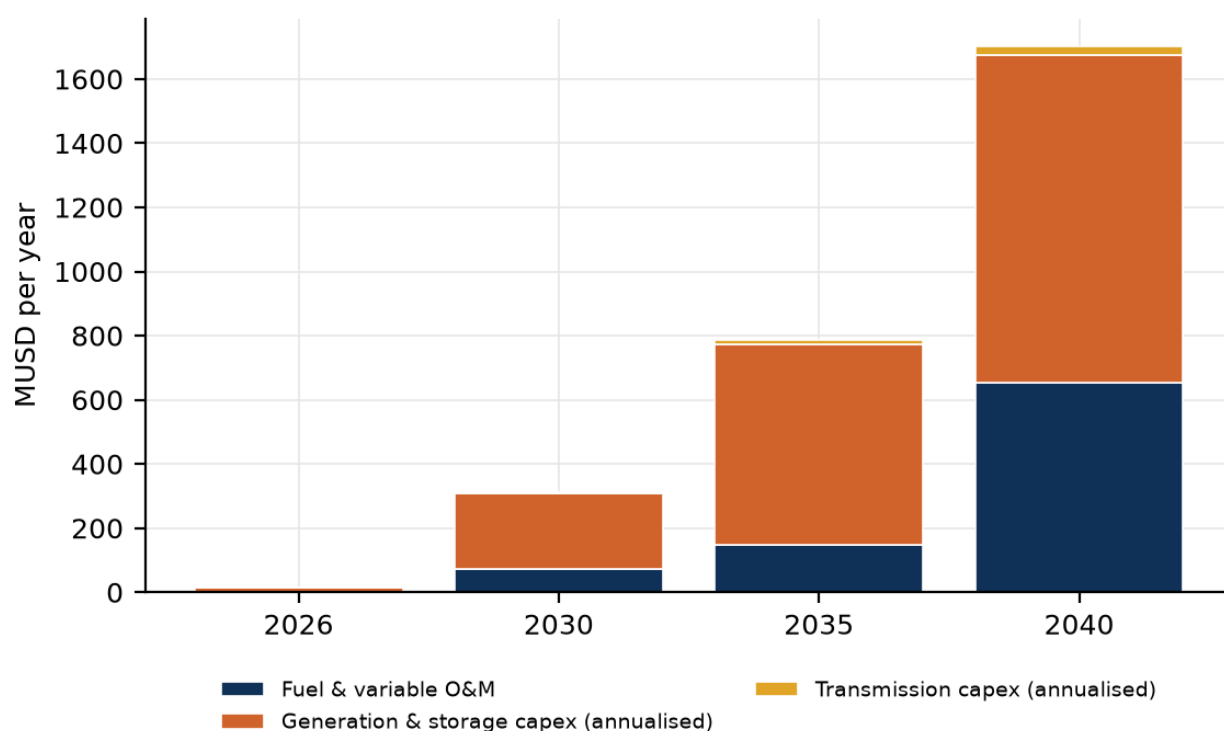


Figure 9.6: Annual system cost of new assets and operation, by component and period

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 9.5: Annual system cost of new assets and operation by period, MUSD/yr

Component	2026	2030	2035	2040
Fuel & variable O&M	0.7	73.9	148.4	652.4
Generation & storage capex (annualised)	13.8	233.9	623.9	1,022.6
Transmission capex (annualised)	0.0	2.5	15.7	28.3
Unserved energy (VoLL)	0.0	0.0	0.0	0.0

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_costs.csv).

Figure 9.7 and Table 9.6 show two cost indicators.

- **Incremental system cost.** The annual cost of the new assets and of all generation, divided by the energy served. It rises from almost zero in 2026, when the existing hydro serves nearly all demand, to 24 USD/MWh in 2030 and 55 USD/MWh in 2040.
- **Long-run marginal cost.** The load-weighted nodal price, rising from 50 USD/MWh in 2030 to 75 USD/MWh in 2040. It is the cost of serving one more MWh, and the right basis for tariffs and for valuing efficiency and losses.

Neither indicator includes the sunk cost of the existing fleet and networks, which Chapter 11 adds in the revenue requirement.

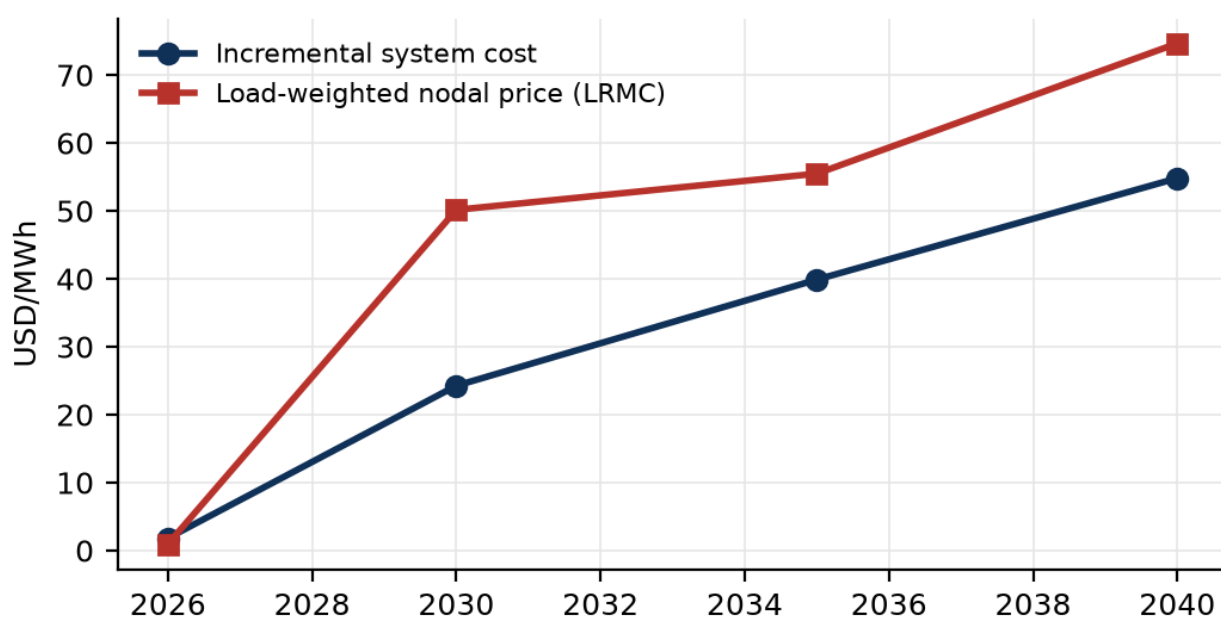


Figure 9.7: Incremental system cost and long-run marginal cost by period

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 9.6: Plan indicators by period, base scenario S0

Period	Demand (GWh)	Peak (MW)	Firm (MW)	RE share	Emissions (kt)	Intensity (kg/MWh)	Incremental cost (USD/MWh)	LRMC (USD/MWh)	Unserved (GWh)
2026	7,523	1,251	1,439	100.0%	0	0	1.8	0.9	0.00
2030	12,071	2,008	2,309	87.4%	548	43	24.3	50.2	0.00
2035	18,505	3,078	3,540	85.0%	1,004	51	39.9	55.5	0.00
2040	29,251	4,866	5,596	61.3%	4,097	132	54.8	74.7	0.00

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_plan_kpis.csv).

9.6 Emissions and the renewable share

Figure 9.8 shows the emissions and renewable share of the plan.

- **Renewable share.** 100 % in 2026, 87 % in 2030 and 85 % in 2035. It falls to **61 %** in 2040, when gas meets most of the new industrial demand.
- **Emissions.** From almost zero in 2026 to 548 kt in 2030, 1.0 Mt in 2035 and **4.1 Mt** in 2040.
- **Cumulative emissions.** 27.7 Mt CO₂ over 2024–2040.
- **Grid intensity.** 132 kg/MWh in 2040, still low by international standards but eight times the 2023 level.

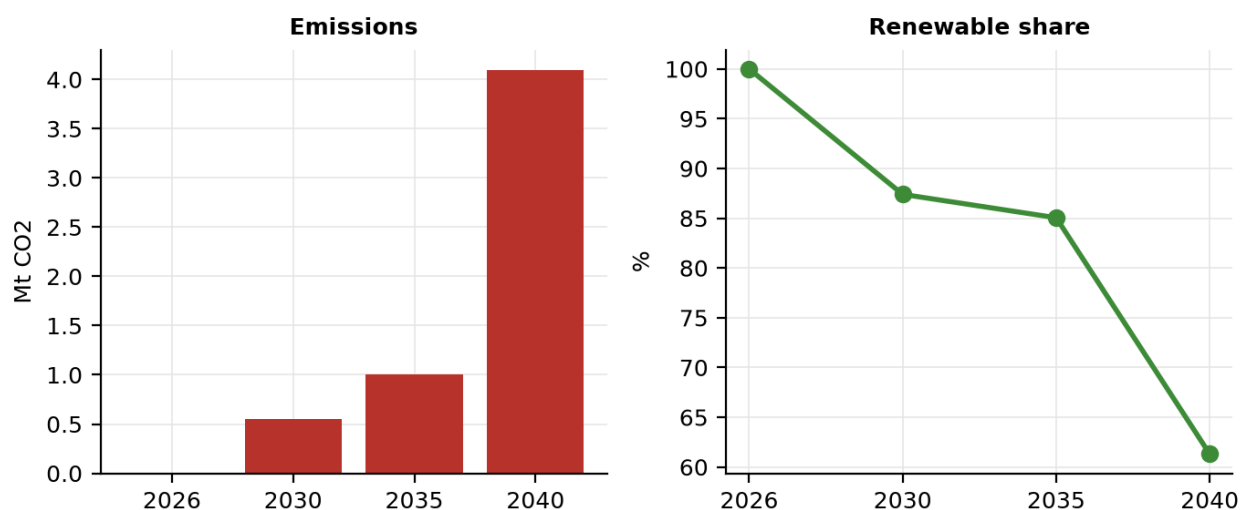


Figure 9.8: Emissions and renewable share of the least-cost plan by period

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

9.7 How the planned system operates

Figure 9.9 shows the dispatch of the planned system in 2040.

- **Base.** Hydro and geothermal run as base load across all slices.
- **Gas.** Combined-cycle gas provides the bulk of the remaining energy, following load.
- **Solar and wind.** Solar provides midday energy, and wind runs whenever available.
- **Peakers.** The open-cycle gas and diesel peakers run only in the evening and peak blocks.

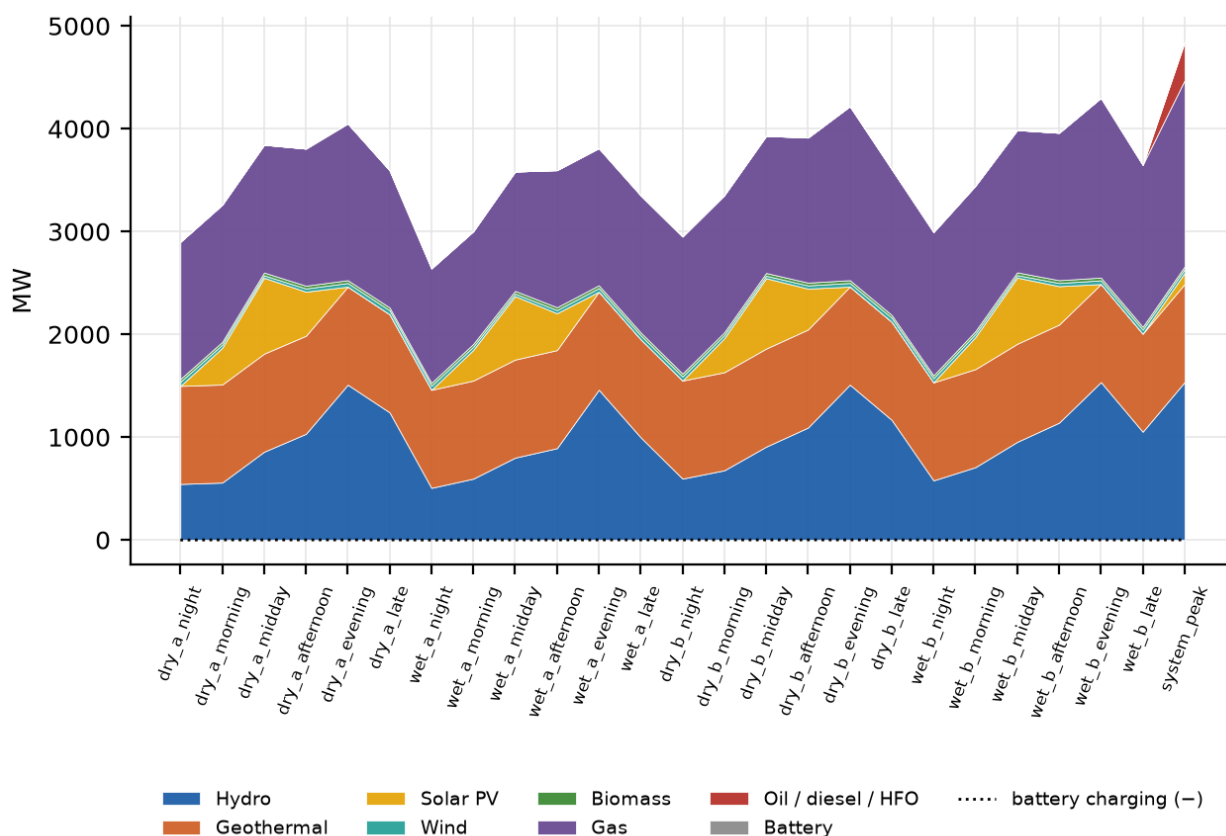


Figure 9.9: Dispatch of the planned system in 2040 across the 25 slices

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

The storage trajectories of 2040 (Figure 9.10) show the reservoirs doing more work than in 2023. With solar in the system, the reservoirs fill through the morning and midday blocks and are drawn down in the evening and late blocks. They act as Uganda's largest battery. The two existing batteries stay charged and discharge only in the system-peak block and one evening block: in the planned system they are a peak reserve, not a daily arbitrage device.

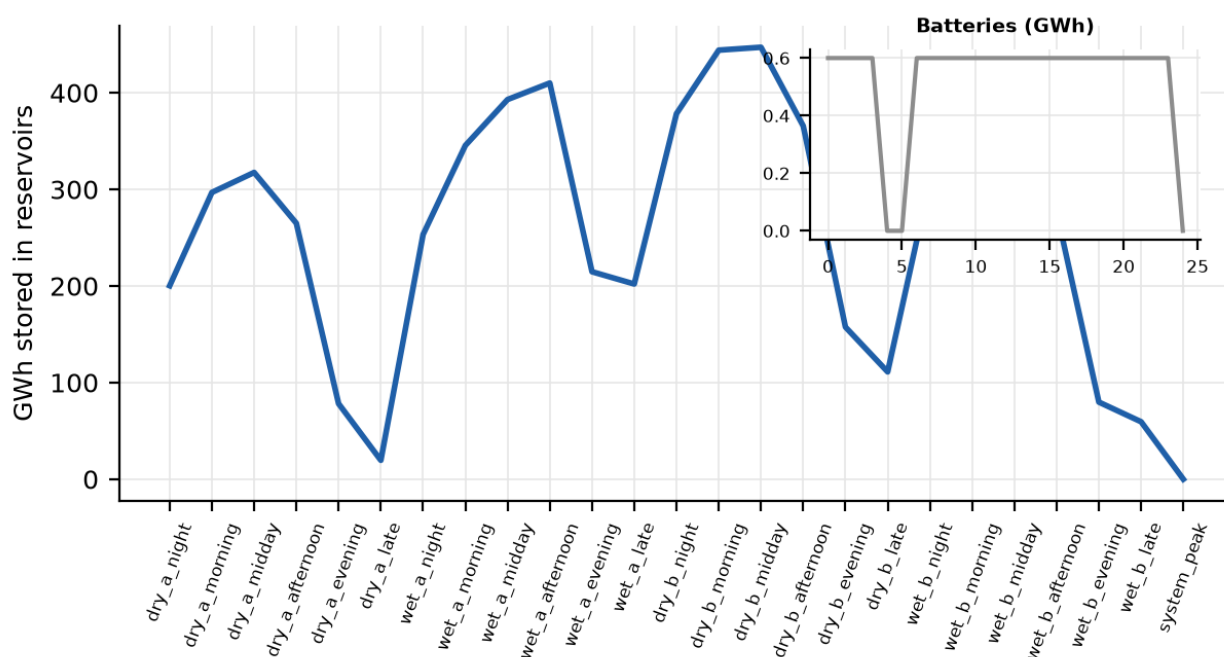


Figure 9.10: Storage state of charge in 2040: reservoirs and batteries

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

9.8 The grid build

The plan reinforces seven existing corridors and builds two IERMP new corridors, adding **2,466 MW** of transfer capacity by 2040 (Figure 9.11, Table 9.7, Figure 9.12).

- **Western export path.**
 - Nkonge–Kahungye: +451 MW.
 - Kabulasoke–Nkonge: +261 MW.
 - Mutundwe–Kabulasoke: +204 MW.
 - Rugonjo–Nkenda: +107 MW.
 - The new **Buloba–Nkenda** 220 kV corridor: 381 MW, from 2030.
 - The new **Kapeeka–Kiboga** 220 kV corridor: 158 MW, from 2035.

Together these carry the western geothermal and gas to Kampala.

- **Eastern supply into Kampala.**
 - Bujagali–Nalubaale: +462 MW.
 - Nalubaale–Namanve: +400 MW.
 - Namanve–Kampala North: +41 MW.

The two IERMP 400 kV candidates (Karuma–Tororo and Masaka–Kasese) are not built in the base scenario. Their capacity is not needed once the 220 kV reinforcements are made, and their long lengths make them expensive per MW.

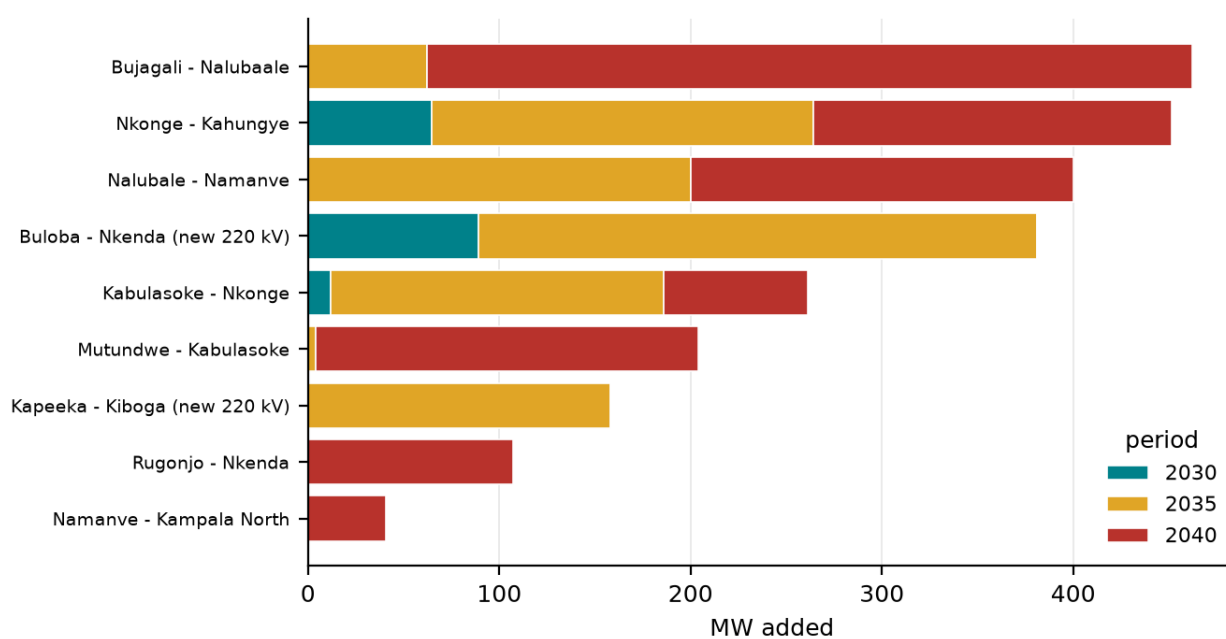


Figure 9.11: Transmission reinforcement and new corridors by period

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 9.7: Transmission reinforcement and new corridors selected by the plan, MW

Corridor	Type	2026	2030	2035	2040	Total MW
Bujagali - Nalubaale	reinforcement	-	0	62	400	462
Buloba - Nkenda (new 220 kV)	new corridor	-	89	292	0	381
Kabulasoke - Nkonge	reinforcement	-	12	174	75	261
Kapeeka - Kiboga (new 220 kV)	new corridor	-	0	158	0	158
Mutundwe - Kabulasoke	reinforcement	-	0	4	200	204
Nalubale - Namanve	reinforcement	-	0	200	200	400
Namanve - Kampala North	reinforcement	-	0	0	41	41
Nkonge - Kahungye	reinforcement	-	64	200	187	451
Rugonjo - Nkenda	reinforcement	-	0	0	107	107

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_line_build.csv).

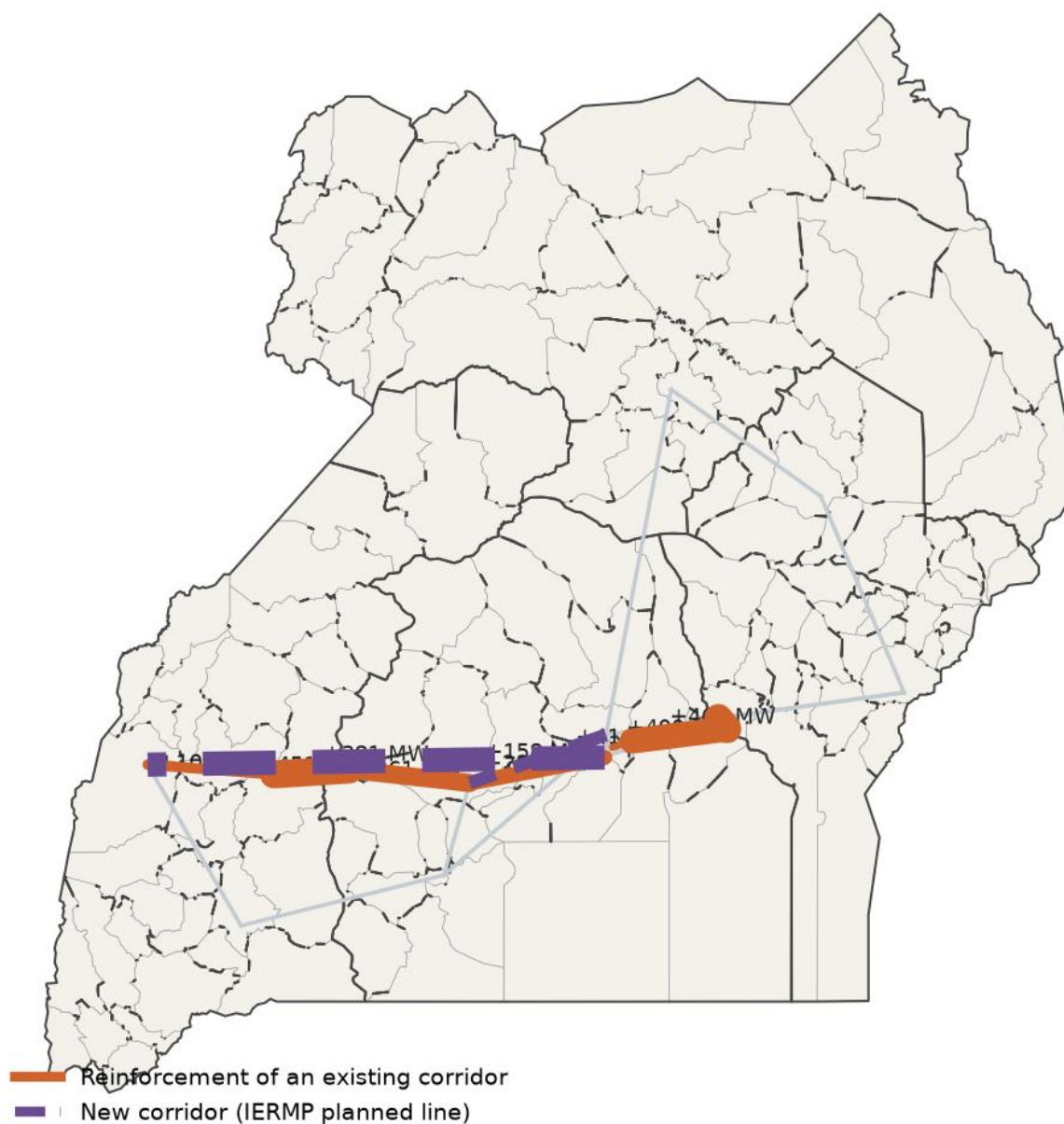


Figure 9.12: Least-cost plan: transmission reinforcement and new corridors, 2026–2040 (width $\propto$ MW)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

After the plan, nodal prices still differ between west and east (Figure 9.13, Table 9.8).

- **2030.** Prices range from 44 USD/MWh at Kahungye and Nkenda to 53 USD/MWh at Namanve.
- **2040.** They range from 63 USD/MWh at Kahungye to 79 USD/MWh at Namanve.

The plan relieves congestion only as far as it pays. The remaining spread is the point where one more MW of transfer capacity would cost more than it saves in dispatch. The Kampala buses remain the most expensive places to serve load, and the western generation buses the cheapest.

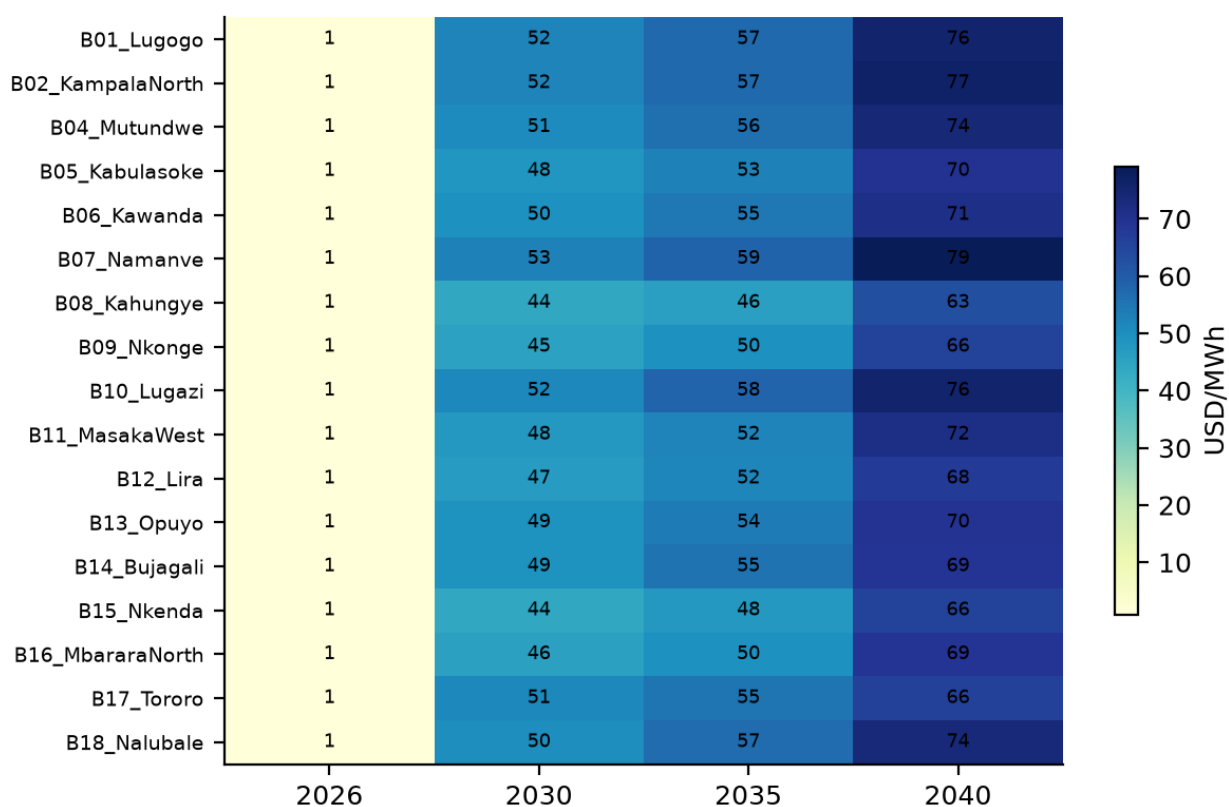


Figure 9.13: Nodal prices after the plan, by bus and period

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 9.8: Nodal prices after the plan, USD/MWh (load-weighted mean over slices)

Bus	2026	2030	2035	2040
B01_Lugogo	0.9	52.0	57.2	75.6
B02_KampalaNorth	1.0	52.0	57.2	76.5
B04_Mutundwe	0.9	50.8	55.9	74.0
B05_Kabulasoke	1.0	48.5	52.7	69.7
B06_Kawanda	0.9	49.7	54.6	71.5
B07_Namanve	0.9	52.8	58.6	79.1
B08_Kahungye	1.0	43.8	45.9	62.9
B09_Nkongge	1.0	45.5	49.5	66.0
B10_Lugazi	0.9	51.6	58.1	75.5
B11_MasakaWest	1.0	47.8	52.2	71.7
B12_Lira	0.9	47.0	51.7	67.7
B13_Opuyo	0.9	49.1	54.1	69.6
B14_Bujagali	0.9	49.1	55.3	69.2
B15_Nkenda	1.0	43.8	47.8	65.8
B16_MbararaNorth	1.0	45.6	49.8	69.3
B17_Tororo	0.9	51.4	55.1	66.2
B18_Nalubale	0.9	50.2	56.6	73.6

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_prices_period.csv).

9.9 The value of firm capacity

The shadow price of the reserve-margin constraint is **117–122 USD per kW per year** in every period (Table 9.9). This is what the system would save if the reserve requirement were 1 kW lower. It measures the value of firm

capacity and of anything that provides it more cheaply. Examples are demand response, interruptible industrial contracts, imports with firm capacity, or a smaller reserve margin.

A 1 percentage-point reduction in the reserve margin in 2040, about 49 MW, would be worth about 5.8 million USD a year.

Table 9.9: Shadow prices of the plan constraints

Period	Constraint	Shadow price
2026	reserve margin (USD/MW-yr)	122,070
2030	reserve margin (USD/MW-yr)	116,514
2035	reserve margin (USD/MW-yr)	116,514
2040	reserve margin (USD/MW-yr)	118,989

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_duals.csv).

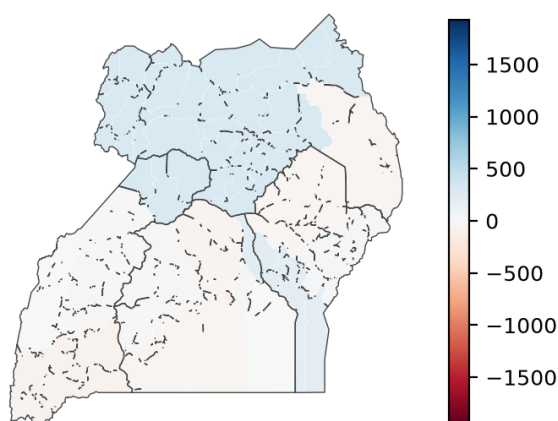
9.10 The supply–demand balance after the plan

Figure 9.14 compares the zonal balance of firm capacity and local peak in 2023 with the balance in 2040 after the plan.

- **2023.** The generation zones around Jinja and Karuma are in surplus and the Kampala zones in deficit.
- **2040.** The western zones of Nkenda and Kahungye and the eastern zone of Tororo become large surplus zones. The Kampala zones remain the main deficit, supplied over the reinforced corridors.

The plan does not put generation where the demand is. It puts it where the resource is cheapest and pays to move the power.

2023: firm capacity – zone peak



2040 after the plan: firm capacity – zone peak

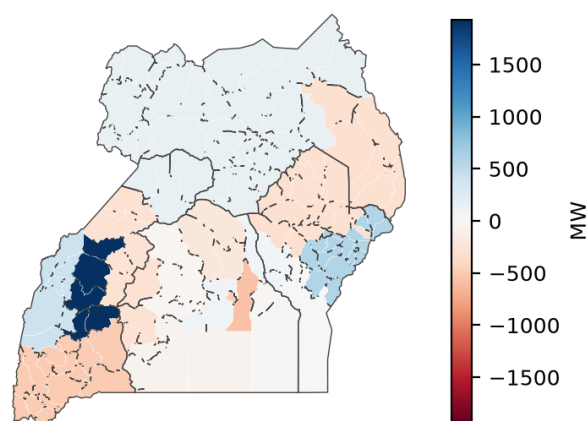


Figure 9.14: Zonal supply–demand balance: 2023 existing fleet vs 2040 after the plan (blue surplus, red deficit)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

9.11 Data quality and limitations

- **Candidate costs.** The candidate costs are the IRP values, annuitised at 10 %. They are OBSERVED as planning data but uncertain as future prices. Chapter 10 varies solar and gas capital costs by ± 30 %.
- **Time resolution.** Twenty-five slices per period understate the value of storage and overstate the firm contribution of the reservoirs. A chronological run with data/uganda_hires would refine the battery and solar results.
- **Gas supply.** The eastern gas plant assumes imported gas at the IRP fuel cost. Its availability, price and the infrastructure to deliver it are outside the model.

- **Perfect foresight.** The plan optimises with perfect foresight of the base demand. The expansion plan of Chapter 12 tests it year by year. Chapter 10 shows how it changes when demand is lower or higher.

9.12 Implications for planning

- The least-cost plan combines three roles:
 - geothermal and combined-cycle gas as the backbone of new firm energy;
 - open-cycle gas and diesel for the reserve margin;
 - solar and wind for low-cost energy as their cost falls.

Hydro remains the base of the system but is not expanded in the base scenario, because run-of-river hydro is more expensive per MWh than geothermal or gas at a 10 % discount rate.

- Every new plant the plan builds needs the grid to reach Kampala. The western 220 kV reinforcements and the Buloba–Nkenda line carry the geothermal and the Albertine gas. The eastern ring carries the Tororo gas. Grid and generation must be planned and financed together.
- The emissions of the least-cost plan rise to 4.1 Mt by 2040, from almost zero. Chapter 10 shows that this can be avoided at modest cost. The choice is a policy choice, not a technical one.
- The reserve-margin shadow price of about 120 USD/kW-yr is the benchmark against which firm imports, demand response and interruptible industrial contracts should be valued.

CHAPTER 10

10 Simulations: what changes the plan

A single least-cost plan is only as good as its assumptions. This chapter re-solves the plan under 29 sets of assumptions:

- the eight scenarios of the standard set S0–S7, defined in design Chapter 6;
- 21 one-at-a-time sensitivities, each changing one assumption of the base scenario.

Every simulation is a complete PyPSA multi-period expansion over the same four periods, with its own demand projection where the assumption changes demand. The purpose is to show which assumptions matter, by how much, and which parts of the plan survive every simulation. No simulation is presented as the recommended one.

10.1 How to read the simulations

Each simulation reports:

- the **net present cost (NPV)** of new assets and system operation over 2024–2040 at the scenario's discount rate;
- the difference from S0 (**ΔNPV**);
- the new capacity by technology;
- the renewable share of generation in 2040;
- cumulative CO₂ emissions over 2024–2040;
- the long-run marginal cost in 2040.

Where a simulation reduces emissions relative to S0, the **abatement cost** is ΔNPV divided by the emissions avoided, in USD per tonne of CO₂.

Two cautions apply.

- **Different demand.** Simulations that change demand (S3, S4, step loads, GDP, e-mobility, access) change what is being delivered as well as its cost. Their ΔNPV is not the cost of a policy but the cost consequence of a different future.
- **Different discounting.** The discount-rate simulations change the discounting itself, so their NPVs are not comparable with the others in level.

10.2 The standard scenario set

Table 10.1 and Figure 10.1 compare the eight standard scenarios.

Table 10.1: Standard scenario set S0–S7: cost, capacity and emissions

Scenario	NPV (bn USD)	ΔNPV vs S0 (MUSD)	New MW	RE 2040	Emissions 2040 (kt)	Cumulative CO ₂ (Mt)	USD per tCO ₂ avoided	LRMC 2040 (USD/MWh)
S0 Least cost	4.37	0	5,935	61.3%	4,097	27.7	-	74.7
S1 High renewables	4.53	165	8,280	90.0%	1,056	10.4	9.5	76.5
S2 Carbon price	4.66	292	7,634	76.0%	1,574	10.2	16.7	78.3
S3 High demand	5.13	767	6,792	66.1%	3,955	29.9	-	73.0

Scenario	NPV (bn USD)	ΔNPV vs S0 (MUSD)	New MW	RE 2040	Emissions 2040 (kt)	Cumulative CO2 (Mt)	USD per tCO2 avoided	LRMC 2040 (USD/MWh)
S4 Low demand	2.72	-1,647	3,152	72.7%	2,150	15.7	-137.1	59.8
S5 Dry hydrology	4.98	618	6,491	61.7%	4,045	31.3	-	75.8
S6 No new fossil	5.23	868	6,214	87.2%	7	0.1	31.4	91.4
S7 Nuclear option	4.49	122	4,684	53.9%	2,212	18.3	12.9	62.1

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_scenarios.csv).

- **S0 Least cost.** The reference: NPV 4.37 bn USD, 5,935 MW of new capacity, 61 % renewable in 2040, 27.7 Mt cumulative CO2.
- **S1 High renewables** (at least 90 % renewable in every period). It costs **165 million USD** more (+3.8 %) and builds 8,280 MW:
 - the full 2,950 MW of solar potential;
 - 1,122 MW of run-of-river hydro;
 - all 1,060 MW of geothermal;
 - 2,763 MW of gas, mostly open-cycle for firm capacity, which runs little.

It cuts cumulative emissions to 10.4 Mt. The abatement cost is **9.5 USD per tonne**, the lowest of any decarbonisation scenario.

- **S2 Carbon price** (50 USD/t from 2026). It costs 292 million USD more and builds solar to its potential, 357 MW of nuclear and less diesel. Its cumulative emissions (10.2 Mt) are close to S1's, at 16.7 USD per tonne.
- **S3 High demand.** It costs 767 million USD more, because it delivers 10 % more energy in 2040. It adds 556 MW of run-of-river hydro and 170 MW of batteries to the S0 mix.
- **S4 Low demand.** It costs 1.65 bn USD less and needs only 3,152 MW of new capacity: geothermal and gas, and no solar or diesel.
- **S5 Dry hydrology** (inflow 20 % lower throughout). It costs **618 million USD** more. It replaces the missing hydro energy with 1,750 MW of solar instead of 1,170 MW and runs the gas harder. This is the value of the hydrological risk that Chapter 8 identified.
- **S6 No new fossil.** No gas or oil candidates may be built. It costs **868 million USD** more (+20 %) and builds:
 - the full 2,596 MW of run-of-river hydro;
 - all the geothermal;
 - 671 MW of nuclear;
 - **1,567 MW of batteries**, which provide the firm capacity that gas would otherwise provide.

Emissions fall to almost zero, 0.06 Mt cumulative, at 31 USD per tonne avoided. Its long-run marginal cost in 2040 is the highest of the set at 91 USD/MWh.

- **S7 Nuclear option** (at least 1,000 MW of nuclear by 2040). It costs 122 million USD more. It displaces 554 MW of gas, all the solar and the wind, and halves 2040 emissions to 2.2 Mt. Its long-run marginal cost in 2040 is the lowest of the set at 62 USD/MWh, because nuclear's low variable cost sets the price in most slices.

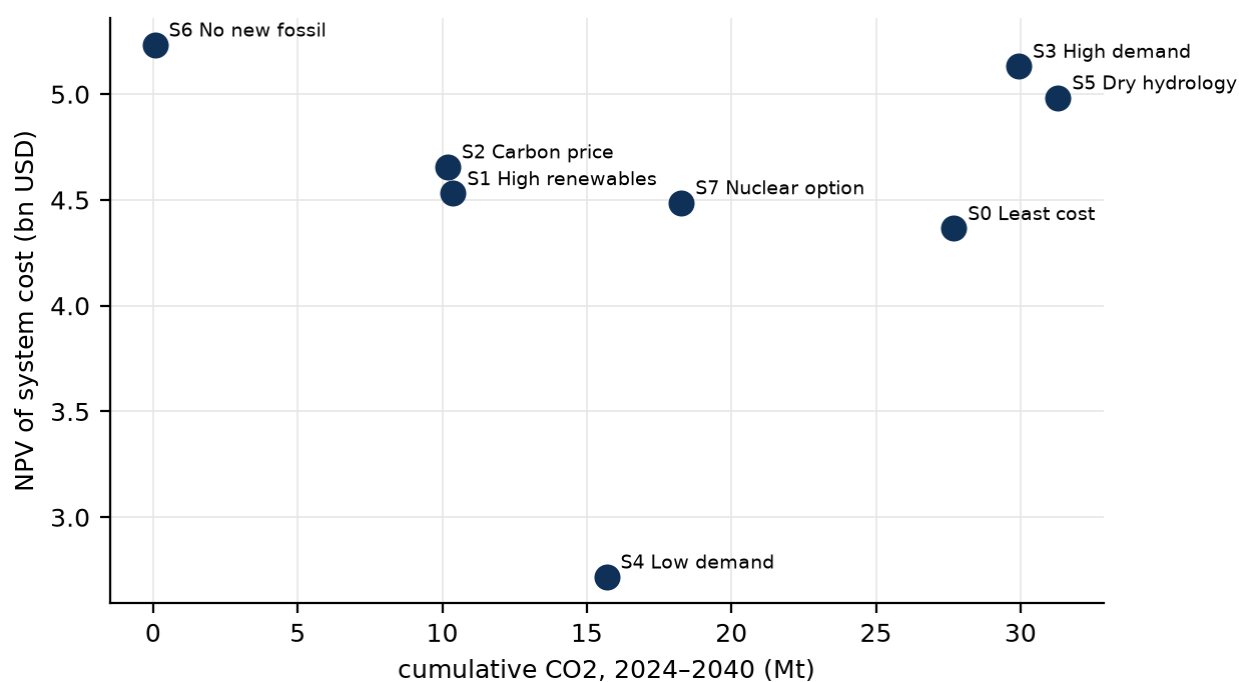


Figure 10.1: Standard scenarios: net present cost against cumulative emissions

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Figure 10.2 ranks the scenarios by their cost difference from S0, and Figure 10.3 and Table 10.2 show what each builds.

What every standard scenario builds:

- **Geothermal.** All eight build the full 1,060 MW. It is the most robust decision in the plan.
- **Gas.** All except S6 build between 2,092 and 3,096 MW of gas.
- **Grid.** All build between 1,268 and 2,579 MW of transmission capacity.

What differs between scenarios:

- solar (from 0 to 2,950 MW);
- run-of-river hydro (0 to 2,596 MW);
- nuclear (0 to 1,000 MW);
- batteries (0 to 1,567 MW).

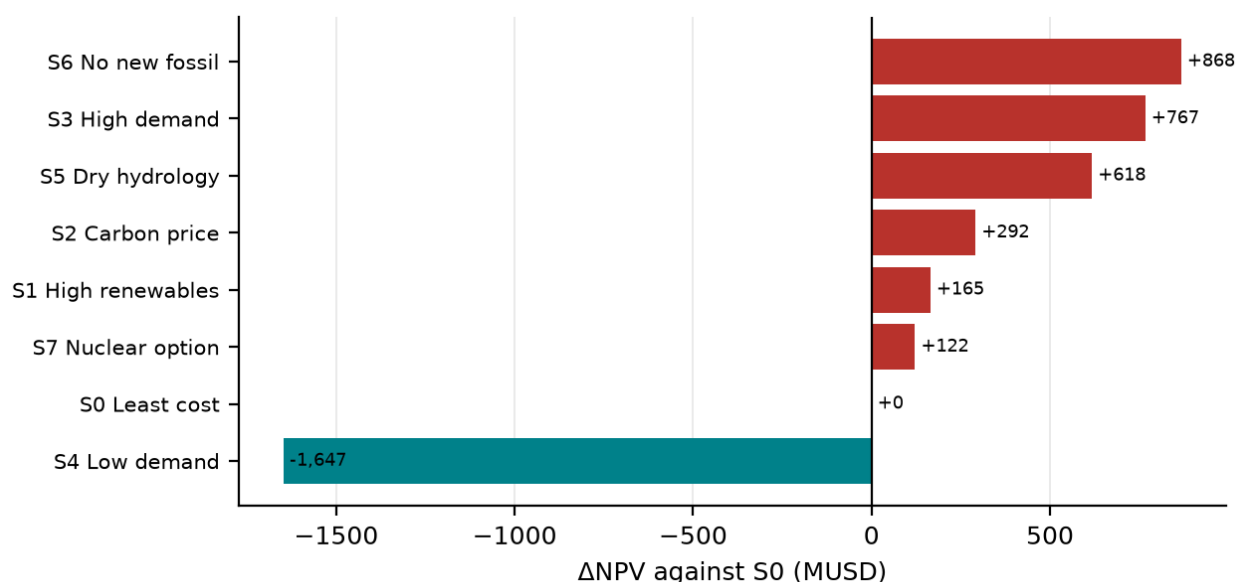


Figure 10.2: Cost of each scenario against least cost (S0)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

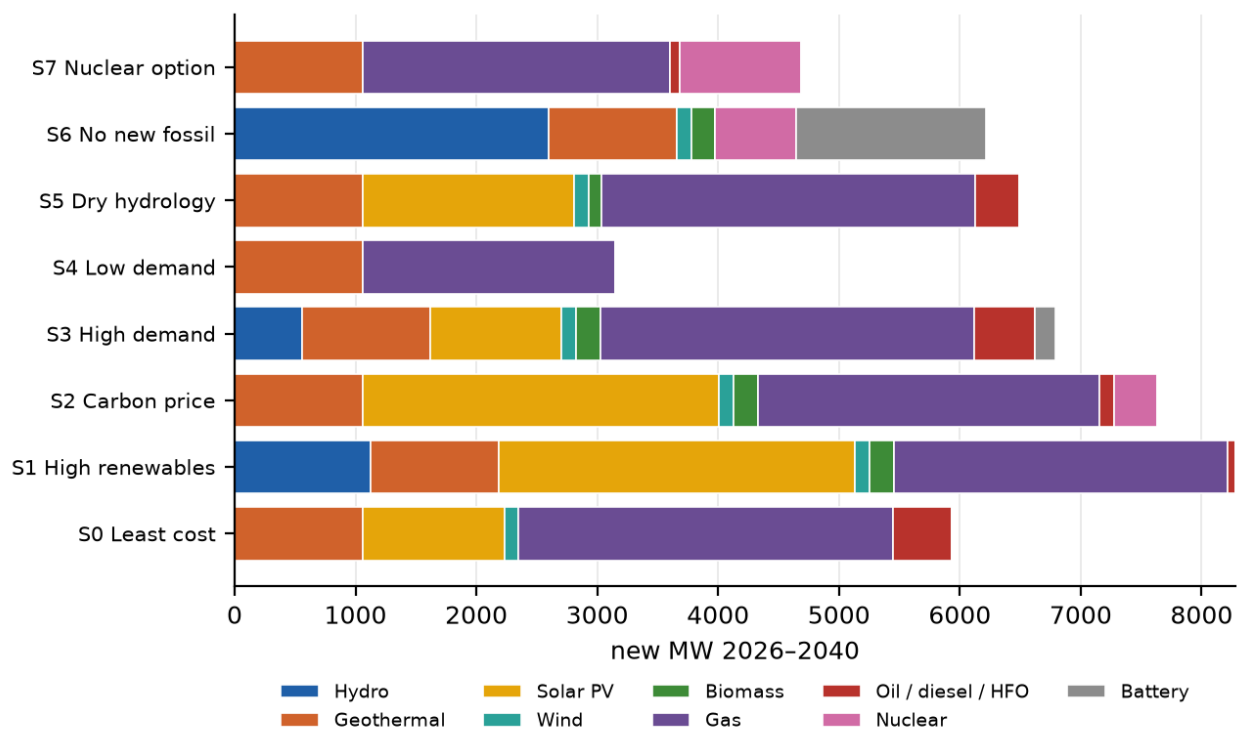


Figure 10.3: New capacity by technology in each standard scenario

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 10.2: New capacity by technology in each standard scenario, MW (2026–2040)

Scenario	Hydro	Geothermal	Solar PV	Wind	Gas	Oil / diesel / HFO	Nuclear	Battery	Grid MW
S0 Least cost	0	1,060	1,170	120	3,096	489	0	0	2,466
S1 High renewables	1,122	1,060	2,950	120	2,763	65	0	0	2,287
S2 Carbon price	0	1,060	2,950	120	2,828	119	357	0	2,151
S3 High demand	556	1,060	1,090	120	3,096	500	0	170	2,579
S4 Low demand	0	1,060	0	0	2,092	0	0	0	1,268
S5 Dry hydrology	0	1,060	1,750	120	3,096	361	0	0	2,479
S6 No new fossil	2,596	1,060	0	120	0	0	671	1,567	1,936
S7 Nuclear option	0	1,060	0	0	2,542	82	1,000	0	2,247

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_scen_mix.csv).

10.3 One-at-a-time sensitivities

Table 10.3 lists the 21 sensitivities. Figure 10.4 ranks them by their effect on the net present cost.

Table 10.3: One-at-a-time sensitivity simulations around the base scenario

Simulation	Requirement 2040 (GWh)	NPV (bn USD)	ΔNPV (MUSD)	New MW	RE 2040	Cum. CO2 (Mt)	Gas MW	Solar MW	Geothermal MW	LRMC 2040
Step loads 0 %	16,113	1.63	-2,736	1,929	90.9%	7.1	1,037	0	891	51.6
Step loads 50 %	22,781	2.95	-1,418	3,336	69.9%	17.2	2,276	0	1,060	60.1
Carbon 25	29,449	4.54	179	5,761	64.8%	23.4	3,096	1,000	1,060	75.8
Carbon 100	29,449	4.72	353	7,295	80.6%	2.4	2,266	2,203	1,060	80.0
RE 50 %	29,449	4.37	0	5,935	61.3%	27.7	3,096	1,170	1,060	74.7
RE 70 %	29,449	4.39	26	6,707	70.0%	23.0	3,096	1,977	1,060	72.7
Discount 7 %	29,449	6.00	1,632	5,950	61.4%	27.6	3,096	1,185	1,060	74.1
Discount 13 %	29,449	3.24	-1,126	5,923	61.2%	27.7	3,096	1,158	1,060	74.5
Reserve 10 %	29,449	4.25	-117	5,676	61.3%	27.7	3,048	1,170	1,060	74.6
Reserve 20 %	29,449	4.49	124	5,758	64.0%	26.2	3,096	731	1,060	71.3
Fast access (80 % by 2030)	29,490	4.51	148	5,963	61.3%	28.3	3,096	1,191	1,060	74.7
Slow loss reduction (15 %)	30,472	4.66	297	6,059	63.4%	28.3	3,096	1,098	1,060	73.9
Wet hydrology	29,449	4.12	-241	5,493	63.6%	25.3	3,096	597	1,060	71.4
No grid expansion	29,449	29.86	25,495	4,694	56.4%	38.2	3,096	0	781	1,151.1
No batteries	29,449	4.37	0	5,935	61.3%	27.7	3,096	1,170	1,060	74.7
Solar capex -30 %	29,449	4.27	-98	7,658	70.9%	20.5	3,096	2,950	1,060	66.9
Gas capex +30 %	29,449	4.52	158	5,632	63.6%	24.3	2,921	875	1,060	72.4
E-mobility high	30,384	4.59	224	6,051	63.2%	28.2	3,096	1,106	1,060	73.8
GDP 8 %	32,404	5.10	737	6,742	66.0%	29.7	3,096	1,077	1,060	73.0
GDP 4 %	27,209	3.80	-564	4,744	61.9%	23.7	3,067	404	1,060	69.3
No new fossil + RE 90 %	29,449	5.24	878	6,295	90.0%	0.1	0	84	1,060	100.9

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_sensitivity.csv).

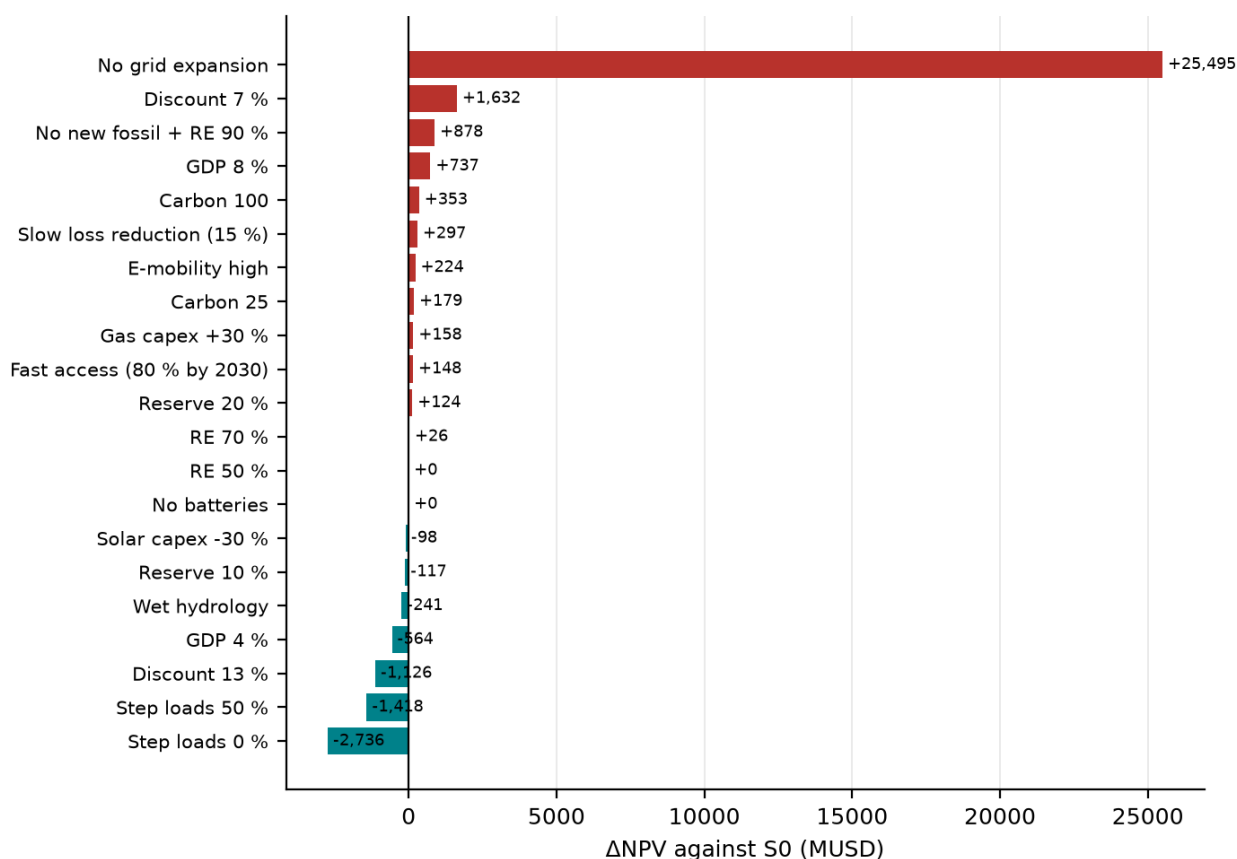


Figure 10.4: Sensitivity of the net present system cost to one-at-a-time changes

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

10.3.1 Demand: the step loads dominate

The largest effects by far come from demand. Whether the IERMP step loads are realised decides the size of the plan.

Step-load realisation	Requirement 2040 (GWh)	New capacity (MW)	NPV change	RE share 2040
100 % (S0)	29,449	5,935	–	61 %
50 %	22,781	3,336	–1.42 bn USD	70 %
0 %	16,113	1,929	–2.74 bn USD	91 %

With half the step loads the plan needs no solar, wind or diesel. With none of them it builds only geothermal and gas (Figure 10.5). The renewable share rises because the base-load geothermal and existing hydro cover a larger share of a smaller demand.

GDP growth matters too:

- at 8 % instead of 6 %, the NPV rises by 737 million USD and the plan adds run-of-river hydro and batteries;
- at 4 %, it falls by 564 million USD.

High e-mobility adds 224 million USD. Faster access (80 % by 2030 instead of 60 %) adds 148 million USD, a modest cost for bringing 2.6 million households forward.

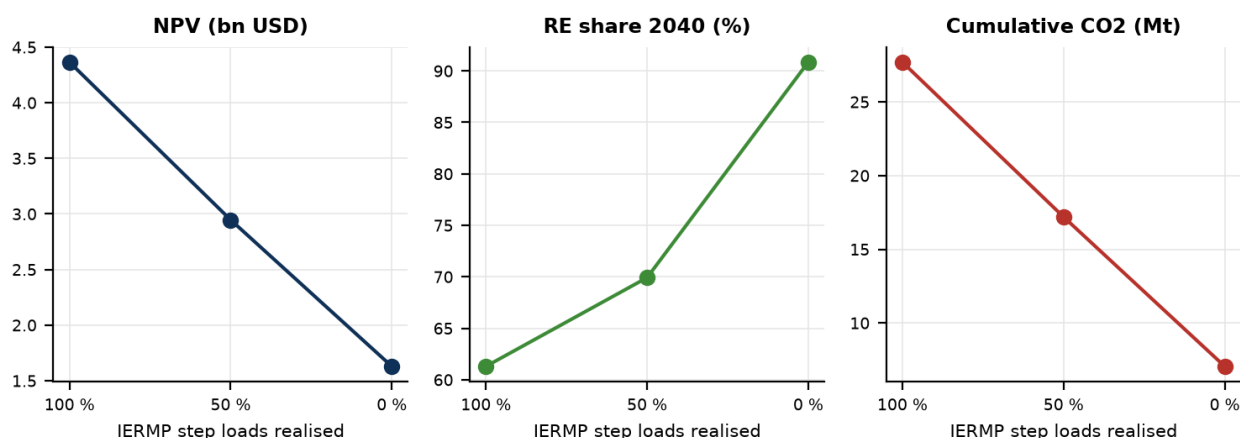


Figure 10.5: Step-load realisation sweep: cost, renewable share and emissions

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

10.3.2 Climate policy: cheap decarbonisation

The carbon-price and renewable-target sweeps (Figure 10.6, Figure 10.7) show that deep cuts in emissions are cheap in Uganda.

- **Carbon price.** A price of 25 USD/t costs 179 million USD and cuts cumulative emissions by 4.3 Mt (42 USD per tonne). At 50 USD/t (S2), emissions fall to 10.2 Mt. At 100 USD/t they fall to **2.4 Mt**, for 353 million USD, and the plan adds 715 MW of run-of-river hydro and 611 MW of nuclear.
- **Renewable target.**
 - 50 %: non-binding, because S0 already exceeds 61 % in every period. The result is identical to S0.
 - 70 %: costs only 26 million USD (5.5 USD per tonne), adding 807 MW of solar.
 - 90 % (S1): costs 165 million USD.

The cheapest tonnes are the first ones. Moving from 61 % to 70 % renewable in 2040 costs almost nothing. Most of the emissions reduction in S1 costs less than 10 USD per tonne.

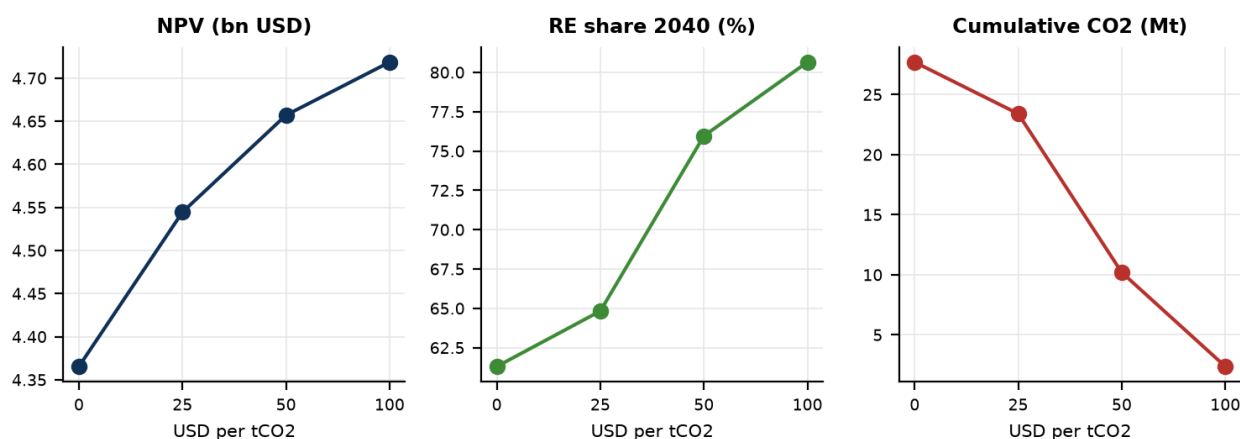


Figure 10.6: Carbon-price sweep: cost, renewable share and emissions

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

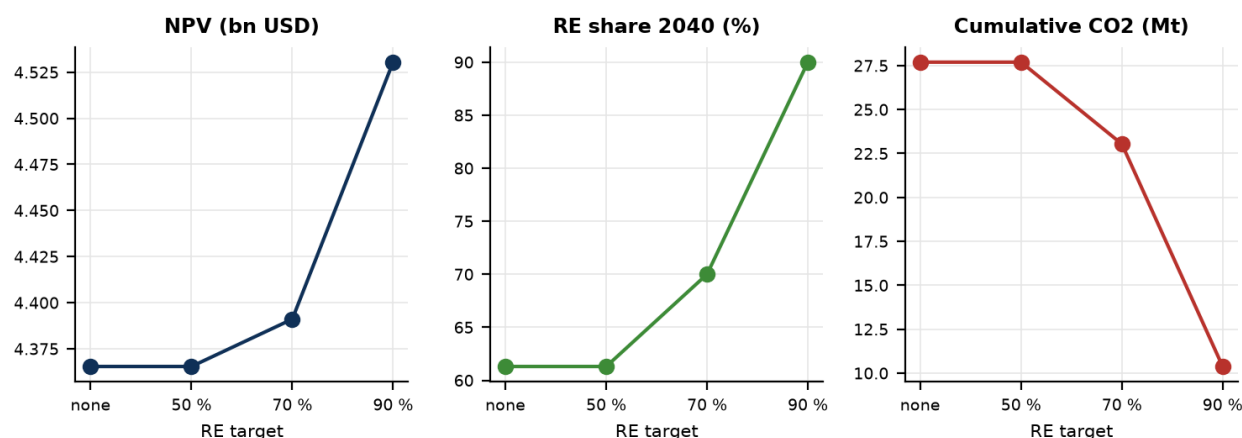


Figure 10.7: Renewable-target sweep: cost, renewable share and emissions

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Figure 10.8 plots every sensitivity by its renewable share and its cumulative emissions. The sensitivities that raise the renewable share are:

- lower demand;
- cheaper solar;
- a carbon price;
- a renewable target.

The ones that lower it are higher demand and the absence of grid expansion.

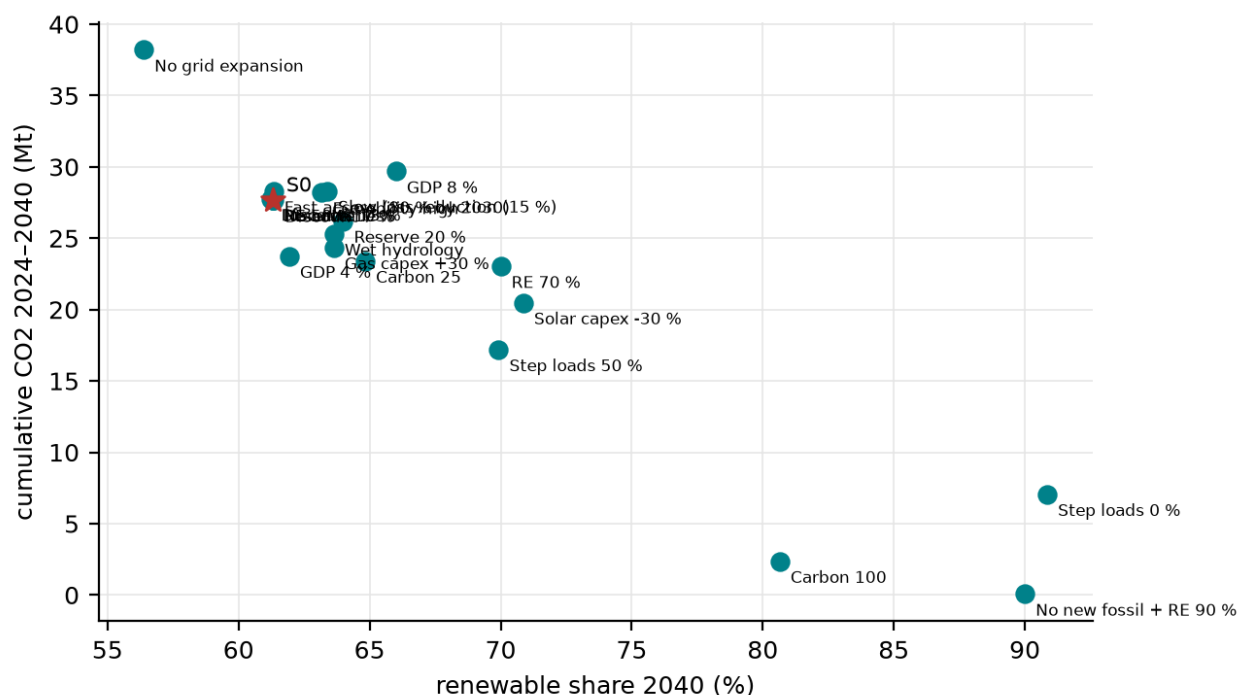


Figure 10.8: Sensitivities: renewable share in 2040 against cumulative emissions

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

10.3.3 Finance and reliability standards

- **Discount rate.** The discount rate changes the NPV level (6.00 bn USD at 7 %, 3.24 bn USD at 13 %) but hardly changes the plan. New capacity varies by less than 30 MW. The plan's technology choice is robust to the cost of capital within this range. A lower rate would favour capital-intensive options such as hydro and nuclear only at rates below those tested.

- **Reserve margin.**
 - 10 % instead of 15 % saves 117 million USD and 259 MW of new capacity, mostly diesel.
 - 20 % costs 124 million USD and adds 51 MW of batteries.

The reserve margin is a real lever: each 5 points is worth about 120 million USD in net present terms.

- **Distribution losses.** Slower loss reduction (15 % instead of 12 % by 2030) costs **297 million USD** and adds 124 MW. That is more than the cost of the 90 % renewable target. Loss reduction is one of the cheapest resources available.

10.3.4 Hydrology

A wet future (inflow 10 % higher) saves 241 million USD and 442 MW. A dry future (S5) costs 618 million USD. The asymmetry is large: a dry decade costs two and a half times what a wet one saves. This argues for diversifying away from the cascade even at some cost.

10.3.5 The grid is indispensable

The most dramatic sensitivity is **no grid expansion**. The generation plan is re-solved with the corridors fixed at their existing and under-construction capacity. The western geothermal and gas cannot reach Kampala, and the plan cannot build enough firm capacity near the loads to replace them. It sheds so much load that the NPV rises from 4.37 bn USD to **29.86 bn USD**, and the 2040 long-run marginal cost is set by the value of lost load (1,151 USD/MWh).

The transmission reinforcements cost less than 360 million USD in capital (Chapter 11). Without them, the rest of the plan does not work.

10.3.6 Technology costs

- **Solar 30 % cheaper.** Solar is built to its full 2,950 MW, and the NPV falls by 98 million USD. The renewable share rises to 71 % and cumulative emissions fall to 20.5 Mt. Solar is the technology whose role depends most on its future cost.
- **Gas 30 % dearer.** Gas capacity falls by 175 MW, solar by 295 MW, and diesel rises. The NPV rises by 158 million USD. Gas remains in the plan because nothing else provides cheap firm capacity at the scale required.
- **No batteries.** Identical to S0, because the base plan builds no new batteries. Batteries enter only when fossil fuels are excluded or demand is higher.

10.3.7 Combined policy

Excluding new fossil capacity and requiring 90 % renewables together (S6 + RE 90 %) costs **878 million USD**. It builds 2,596 MW of hydro, 1,060 MW of geothermal, 662 MW of nuclear and 1,573 MW of batteries, and emissions fall to almost zero. Its long-run marginal cost in 2040 is 101 USD/MWh, a third above S0's. The fossil-free path is feasible and costs about a fifth more than least cost. Most of the extra cost comes from replacing gas as firm capacity with batteries and nuclear.

Figure 10.9 shows the new capacity of every sensitivity side by side.

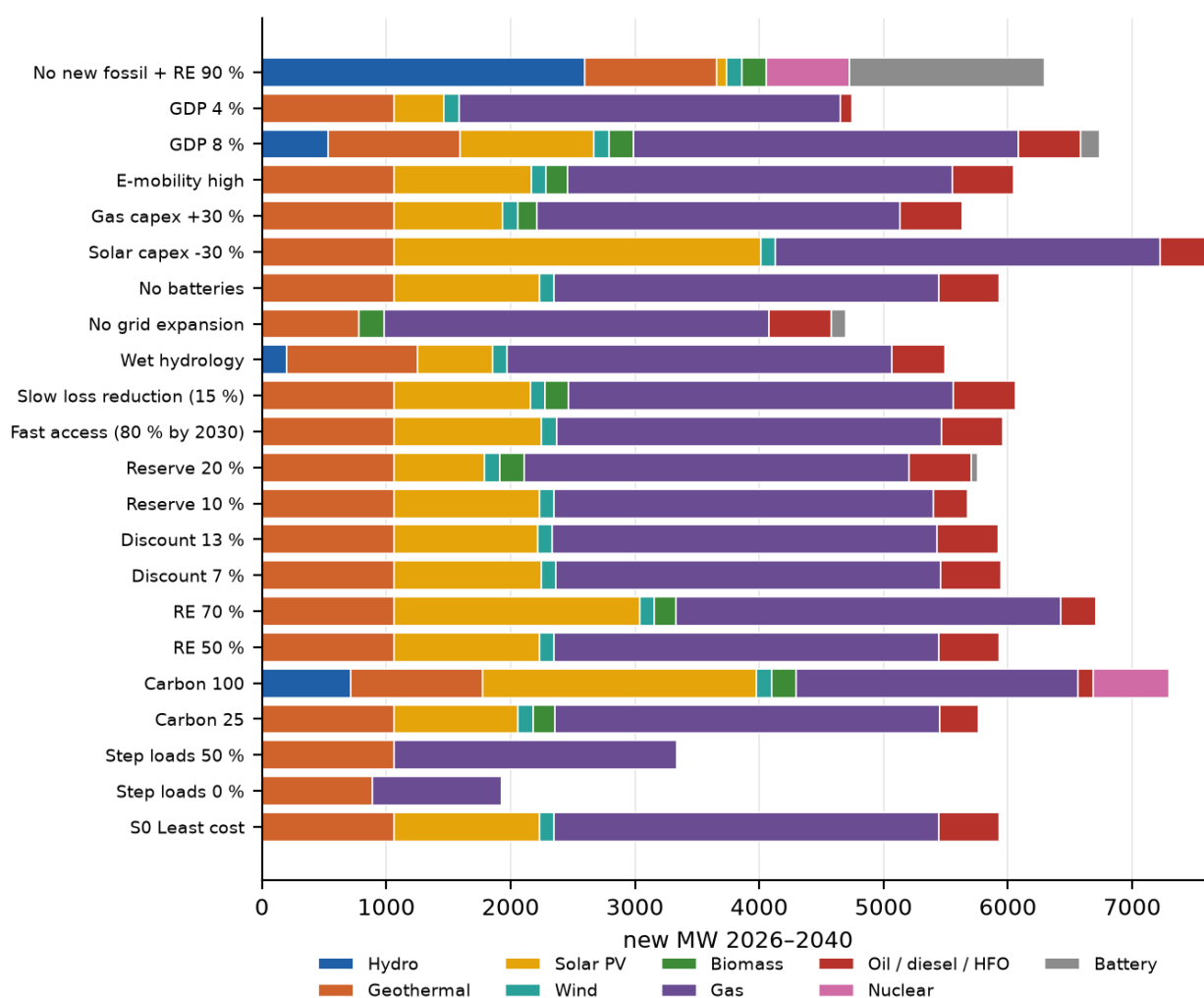


Figure 10.9: New capacity by technology in each sensitivity simulation

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

10.4 What is robust and what is not

Across all 29 simulations:

- **Robust.** Geothermal is always built. It reaches its full 1,060 MW in every simulation except two: zero step loads (891 MW) and no grid expansion (781 MW, because its output cannot reach Kampala). Gas is always built unless excluded. The grid is always reinforced. These are "no-regret" elements: the plan should proceed with them whichever future unfolds.
- **Scale depends on demand.** The scale of the plan depends mostly on the step loads. With them, the country needs about 6 GW of new capacity by 2040. Without them, about 2 GW.
- **Composition depends on policy and cost.** The mix of solar, run-of-river hydro, nuclear and batteries depends on climate policy and technology cost. Decisions on these can wait for better information, as long as the robust elements proceed.
- **Cost of decarbonisation.** A renewable share of at least 90 % costs 165 million USD in net present terms. Eliminating fossil fuels entirely costs about 870 million USD.

10.5 Data quality and limitations

- **One at a time.** Each sensitivity changes one assumption; interactions are not explored. The combined-policy case is the exception.

- **Perfect foresight.** Every simulation is solved with perfect foresight of its own demand. A plan committed under one demand and then faced with another would cost more than the difference between the two NPVs.
- **Abatement costs** are computed against SO's cumulative emissions. They do not include the social value of avoided emissions or local pollution.

10.6 Implications for planning

- The robust core of the plan can be committed now:
 - geothermal at Katwe and Buranga;
 - combined-cycle gas;
 - the western and eastern grid reinforcements;
 - distribution loss reduction.
- The rest should be staged against evidence of how much of the IERMP step-load demand materialises. A register of committed industrial loads, updated yearly, is the most valuable planning instrument this analysis points to.
- A renewable share of 70 % costs almost nothing extra, and 90 % costs about 4 % of the plan's net present cost. If the government wishes to limit emissions, the cost of doing so is small in Uganda.
- Transmission is not optional. Without it the plan collapses. The grid should be treated as the precondition of the generation plan, and financed accordingly.

CHAPTER 11

11 Investment plan

This chapter turns the least-cost plan and the access and distribution programmes into an investment plan. It answers five questions:

- How much capital is needed?
- For which assets?
- In which year?
- In which district?
- Financed by whom?

It then shows what the plan does to the average cost of electricity and the tariff. The chapter implements design Chapter 7 (`docs/07_investment_plan.md`).

11.1 What is costed

The investment plan prices five categories.

- **Generation and storage.** The new capacity of the least-cost plan, at its overnight cost. Overnight cost is the IRP annualised cost divided by the capital recovery factor at 10 % over the asset's life. This recovers, for example, 900 USD/kW for solar and 3,500 USD/kW for geothermal (validation check V7-4).
- **Transmission.** The plan's corridor reinforcements and new corridors, at their annualised cost per MW recovered over 40 years, plus two substation bays for each reinforced corridor. The bays are 2, 4 and 8 million USD at 132, 220 and 400 kV respectively.
- **Distribution.**
 - New transformer capacity at 120 USD/kVA;
 - new MV line at the observed 20,570 USD/km;
 - new LV line at 9,000 USD/km;
 - the loss-reduction programme at 150 USD per MWh of annual losses avoided.
- **Access.**
 - Grid connections at 250 USD each;
 - solar home systems at 360 USD each (Tier 2);
 - mini-grids at 700 USD per connection.

None of the district least-cost modes is a mini-grid.

- **Institutions.** Electrification of health facilities (15,000–80,000 USD by level) and schools (12,000 USD each), in the year each is electrified.

Each item's capital is spread over the years before it comes into service. The disbursement profile follows its technology:

- 2 years for solar, wind and batteries;
- 3 years for gas and transmission;
- 5 years for hydro, geothermal and biomass;
- 8 years for nuclear.

Every item is located to a district:

- generation at its bus;
- transmission across the districts each corridor crosses, in proportion to length;
- distribution by demand growth within each zone;
- access and institutions by district.

11.2 The total

The plan requires **15.6 bn USD** of capital between 2024 and 2040 (Table 11.1, Figure 11.1). Its net present value at 10 % is 6.8 bn USD.

Category	Capex (bn USD)	Share
Generation	7.77	49.7 %
Access	3.99	25.5 %
Distribution	3.32	21.3 %
Transmission	0.36	2.3 %
Institutions	0.18	1.2 %

Half of the money is for generation. The other half is for getting the power to the customer: distribution and access together take 47 %. Transmission is small in capital but indispensable, as Chapter 10 showed.

Table 11.1: Capital expenditure 2024–2040 by category and financing source, MUSD

Category	Capex (MUSD)	Share	Public	Concessional	Private	Consumer / RBF
Generation	7,766	49.7%	1,087	2,666	4,012	0
Access	3,988	25.5%	1,276	1,755	319	638
Distribution	3,318	21.3%	995	1,659	664	0
Transmission	357	2.3%	107	250	0	0
Institutions	181	1.2%	90	90	0	0

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_inv_category.csv).

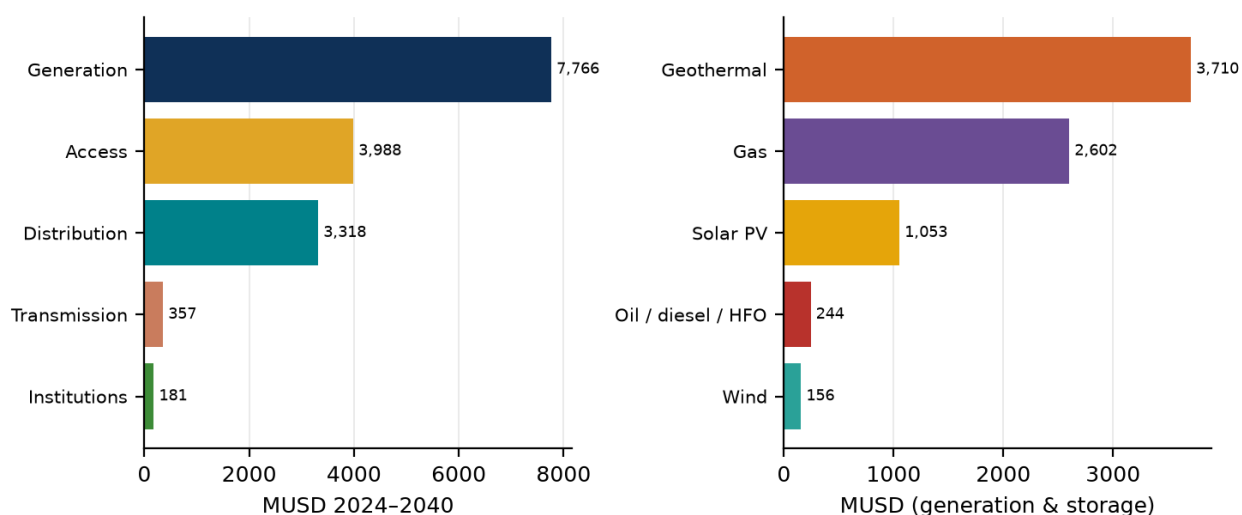


Figure 11.1: Capital expenditure by category, and generation capex by technology

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Within generation (Table 11.2):

- geothermal is the largest item at 3.71 bn USD for 1,060 MW;
- gas takes 2.60 bn USD for 3,096 MW;
- solar takes 1.05 bn USD for 1,170 MW;

- diesel takes 0.24 bn USD;
- wind takes 0.16 bn USD.

Geothermal costs more per MW than any other technology built, but it provides firm, low-variable-cost energy. That is why the plan chooses it despite the price.

Table 11.2: Generation and storage capex by technology

Technology	Capex (MUSD)	MW	USD/kW
Geothermal	3,710	1,060	3,500
Gas	2,602	3,096	840
Solar PV	1,053	1,170	900
Oil / diesel / HFO	244	489	500
Wind	156	120	1,300

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_inv_tech.csv).

11.3 When the money is needed

Figure 11.2 and Figure 11.3 show the annual and cumulative profile.

- **2024.** Spending starts at 486 million USD, mostly access, distribution and the first gas plant.
- **2029–2032.** It rises to about 1.04–1.09 bn USD a year, as the geothermal and gas plants for 2030 and 2035 are built.
- **2034.** It dips to 798 million USD.
- **2037.** It peaks at **1.19 bn USD**, when the eastern combined-cycle plant, the solar and the diesel peakers for 2040 are built at the same time.

Access and distribution spending grows steadily, from about 300 million USD a year in 2024 to 576 million USD in 2040, as the connection rate rises.

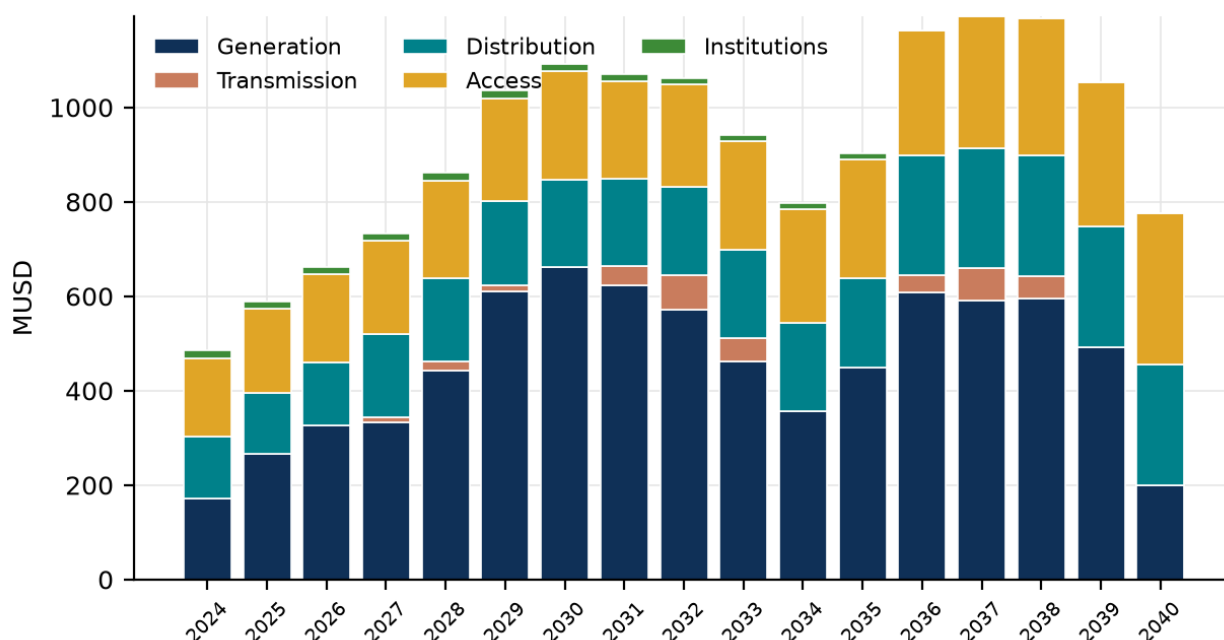


Figure 11.2: Annual capital expenditure by category, 2024–2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

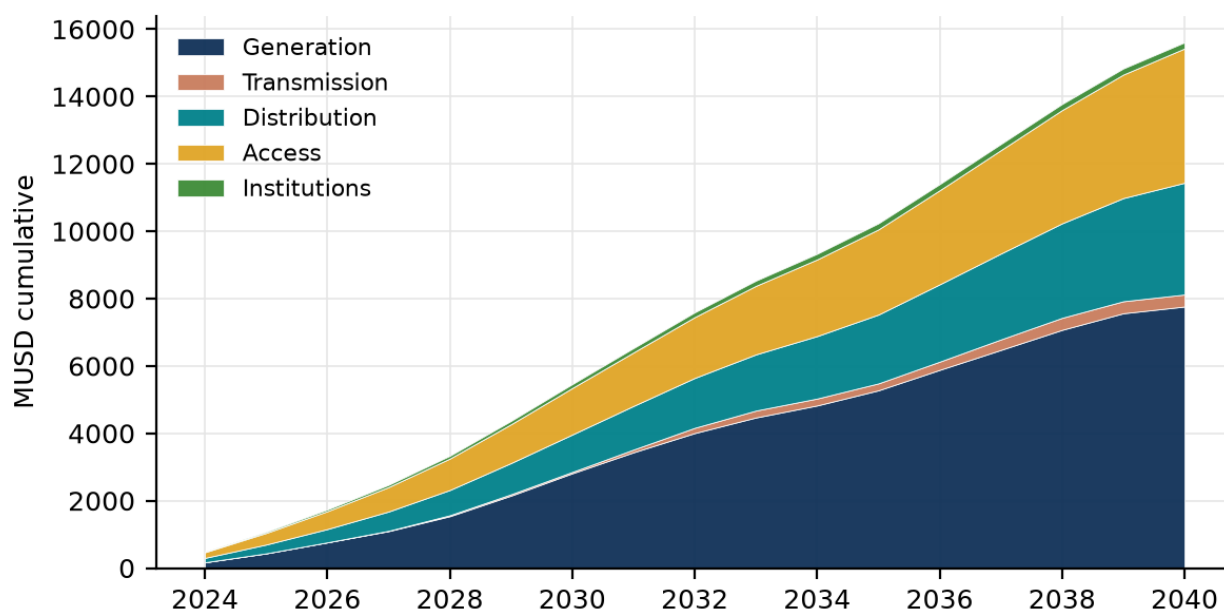


Figure 11.3: Cumulative capital expenditure by category

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

11.4 Who pays

The engine applies an indicative financing mix by category. The shares are ASSUMED and follow Uganda's practice of independent power producers and concessional finance (Figure 11.4).

- **Generation.** Private investors finance most renewable and gas capacity: 75 % of solar, 70 % of gas. Concessional lenders finance half of geothermal and hydro.
- **Transmission.** Largely concessional (70 %) and public (30 %).
- **Distribution and access.** A mix of public, concessional, private and consumer finance, with results-based finance for solar home systems.

Over 2024–2040 the plan would be financed by:

Source	bn USD	Share
Public budget	3.56	23 %
Concessional lenders	6.42	41 %
Private investors	4.99	32 %
Consumers and results-based finance	0.64	4 %

The public share peaks at **257 million USD in 2032**. That is about half of the indicative energy vote of about 517 million USD a year, the FY2026/27 energy budget of 1.95 trillion UGX. The public requirement of the plan is therefore affordable within the current envelope, provided that the concessional and private shares are mobilised.

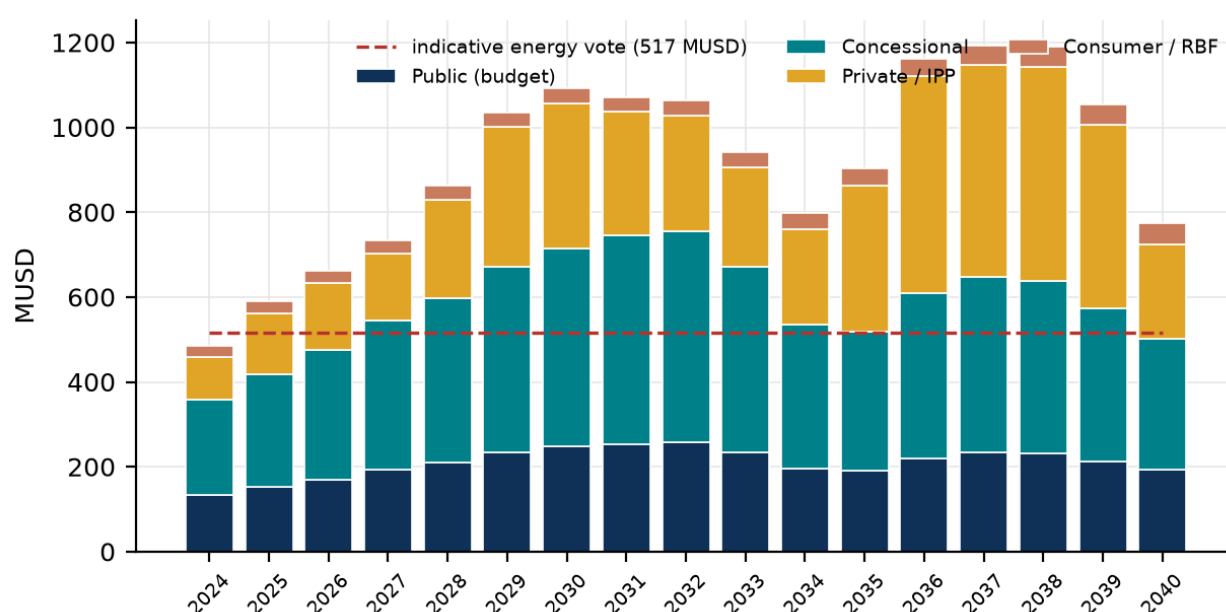


Figure 11.4: Financing sources per year (ASSUMED finance mix) and the indicative public envelope

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

The public capital requirement is exported to the Medium-Term Expenditure Framework in shillings (Figure 11.5, Table 11.3). It is 572 bn UGX in 2025 and 636 bn in 2026, rising to 934 bn in 2030 and 955 bn in 2031. The table also shows the physical outputs that go with it: MW added and households connected each year.

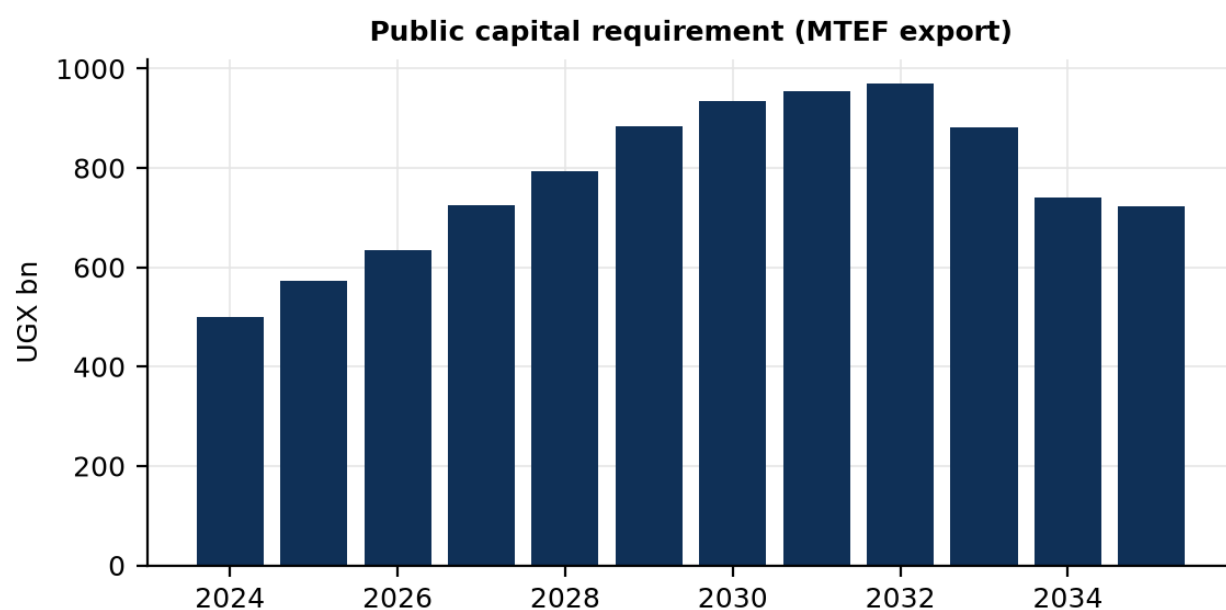


Figure 11.5: Public capital requirement in UGX for the MTEF (public share × FX 3,775 UGX/USD)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 11.3: MTEF export: public capital requirement and physical outputs, 2025–2031

Year	Public capital (UGX bn)	Recurrent (UGX bn)	MW added	Access gain (households)
2025	572	24	0	662,688
2026	636	39	126	699,449
2027	726	56	150	737,818
2028	793	76	120	777,861
2029	883	99	84	819,642
2030	934	124	612	863,229

Year	Public capital (UGX bn)	Recurrent (UGX bn)	MW added	Access gain (households)
2031	955	148	290	778,972

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_mtef.csv).

11.5 Where the money goes

The investment is concentrated where the generation is built (Figure 11.6, Table 11.4).

- **The Western region** receives 7.13 bn USD, 46 % of the total, mostly the geothermal and Albertine gas plants.
- **The Eastern region** receives 3.35 bn USD: the Tororo gas plant and a large access programme.
- **The Central region** receives 3.34 bn USD, mainly distribution in the Kampala metropolitan area.
- **The Northern region** receives 1.80 bn USD, mostly access (1.02 bn USD). It has little generation.

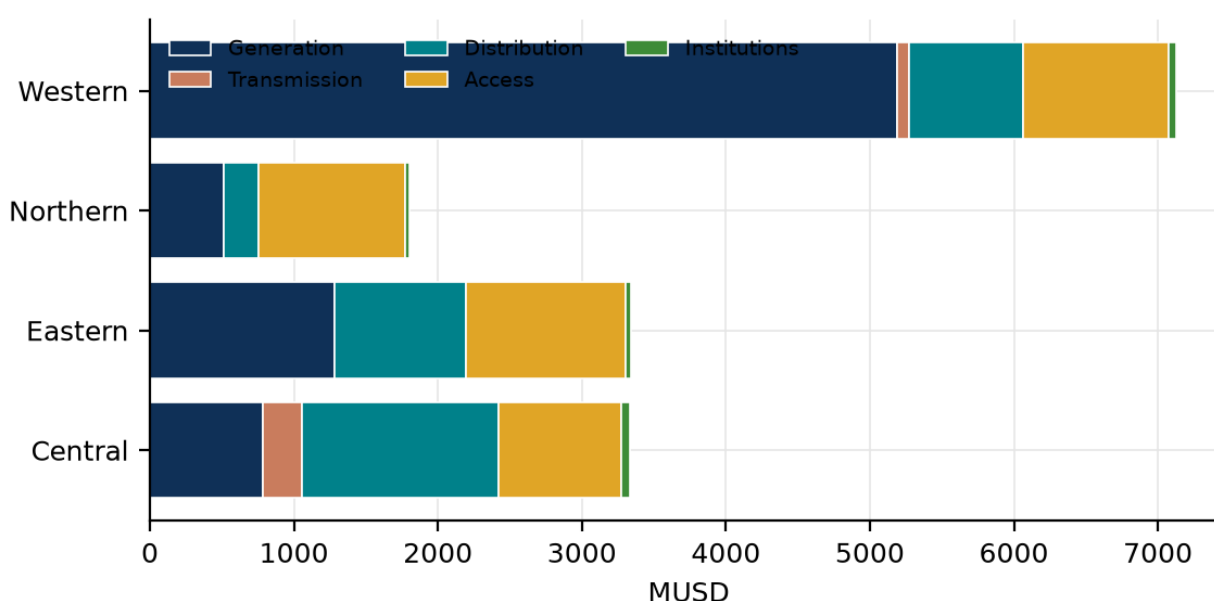


Figure 11.6: Capital expenditure by region and category

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 11.4: Capital expenditure by region (ADM1) and category, MUSD

Region	Access	Distribution	Generation	Institutions	Transmission	Total
Central	851	1,370	784	63	268	3,337
Eastern	1,110	912	1,281	39	2	3,345
Northern	1,015	242	513	31	0	1,802
Western	1,011	794	5,187	48	87	7,126

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_inv_region.csv).

By district (Table 11.5):

- **The generation sites dominate.** Kazo, which hosts the Kahungye bus with the Buranga geothermal and western gas, receives 2.84 bn USD. Kasese (Katwe geothermal) receives 2.63 bn USD. Tororo (eastern gas) receives 1.45 bn USD.
- **Kampala, Wakiso and Mukono** receive 0.5–0.6 bn USD each, mostly distribution and access.
- **Per person** (Figure 11.7), the generation-site districts receive thousands of dollars per inhabitant. The median district receives a few hundred dollars per inhabitant, mostly for access and distribution.

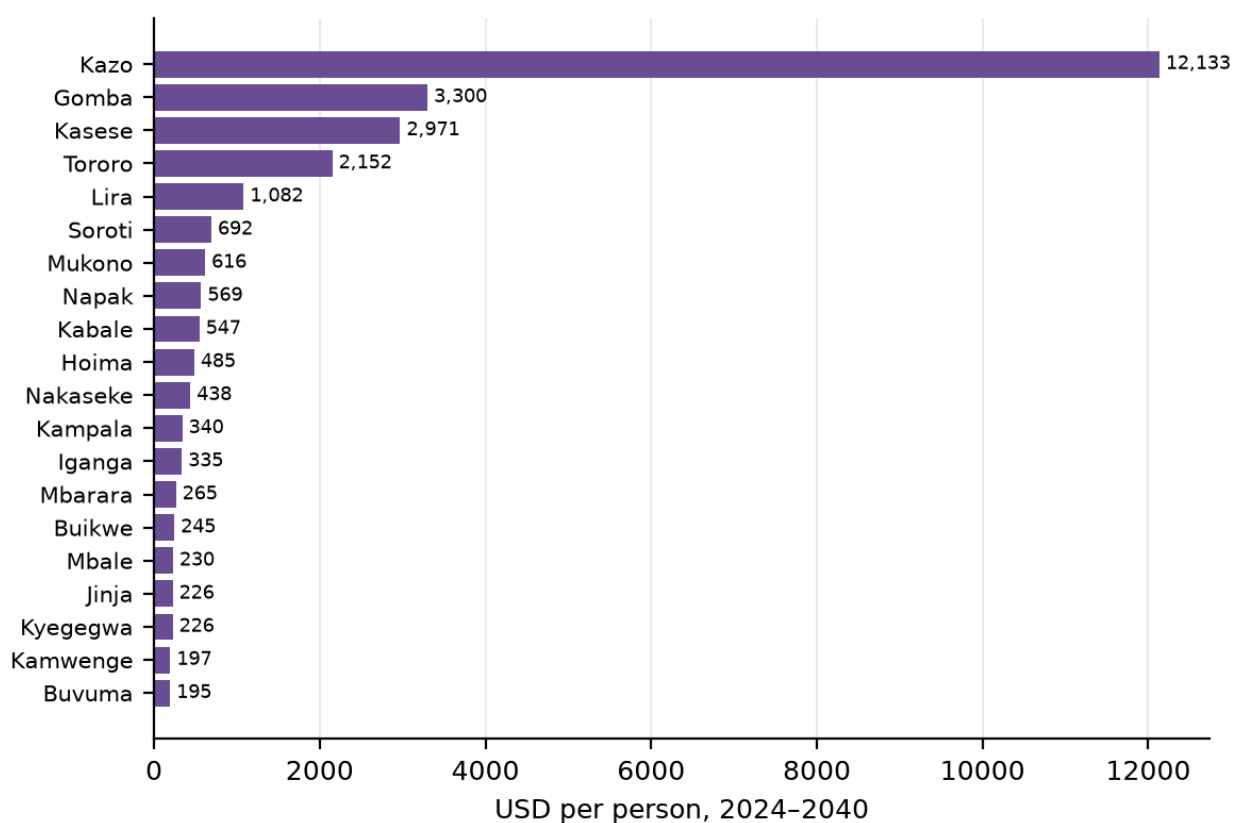


Figure 11.7: The 20 districts with the highest capital expenditure per person

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 11.5: The 20 districts receiving the most capital expenditure, MUS\$

District	Total (MUSD)	USD per person	Generation	Transmission	Distribution	Access	Institutions
Kazo	2,841	12,133	2,807	4	5	24	1
Kasese	2,627	2,971	2,380	10	143	89	4
Tororo	1,445	2,152	1,125	0	267	51	2
Kampala	634	340	244	5	320	60	5
Gomba	632	3,300	540	67	4	20	1
Lira	569	1,082	513	0	10	43	2
Wakiso	532	164	0	15	309	199	9
Mukono	480	616	0	29	419	27	5
Soroti	280	692	156	0	85	37	1
Hoima	211	485	0	0	176	34	1
Mbale	150	230	0	0	96	53	2
Kabale	149	547	0	0	129	18	2
Iganga	147	335	0	0	112	34	2
Buikwe	132	245	0	69	31	29	3
Jinja	128	226	0	2	92	32	2
Mbarara	115	265	0	0	96	17	2
Nakaseke	113	438	0	0	100	12	1
Mubende	111	192	0	32	19	58	2
Kyegegwa	109	226	0	42	8	59	1
Napak	101	569	0	0	80	21	1

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_inv_district.csv).

Figure 11.8 and Figure 11.9 map the investment.

- **Neither map is spatially clustered** (Moran's I close to zero). Investment follows the location of discrete projects, not a regional pattern. A generation site is next to districts that receive only access funding.

- **Access investment** (Figure 11.10) is spread across all districts in proportion to their access gaps. It is weakly clustered around Kampala and Mityana, the districts with the most households to connect.

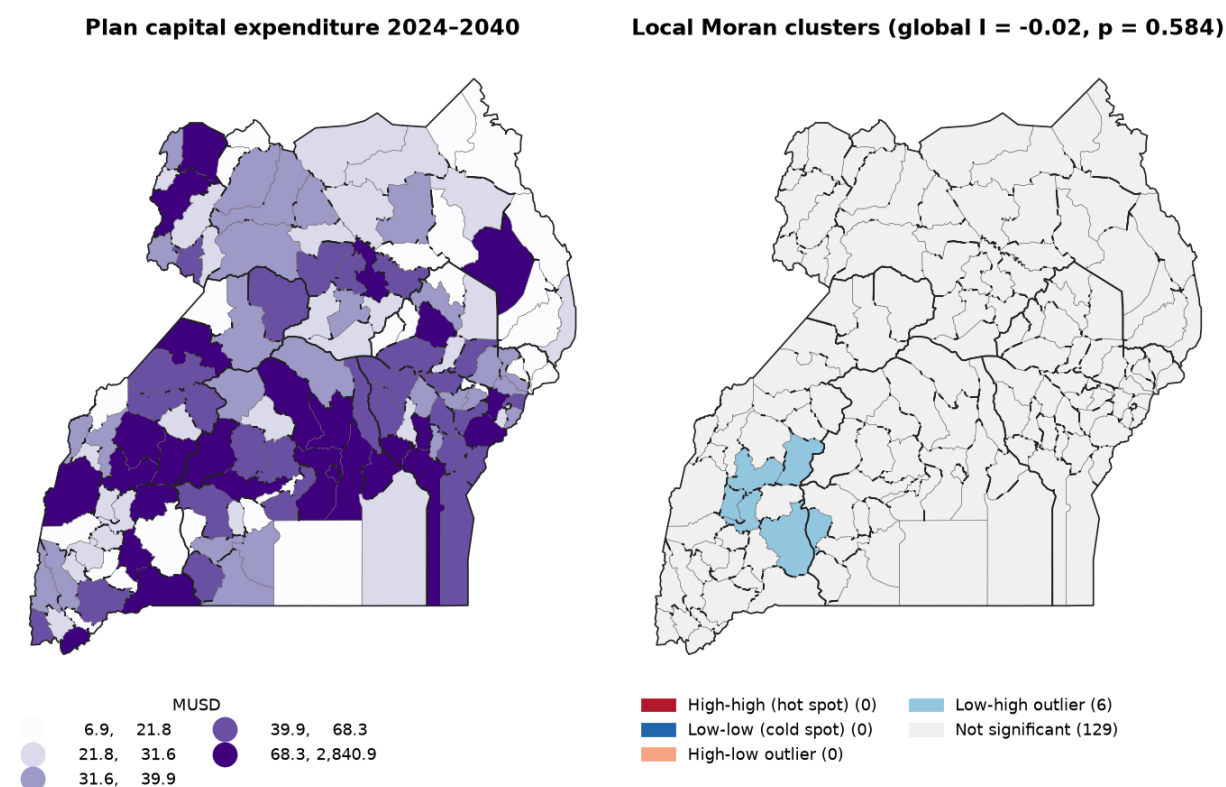


Figure 11.8: Ch.7 - Plan capital expenditure 2024–2040 (MUSD), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

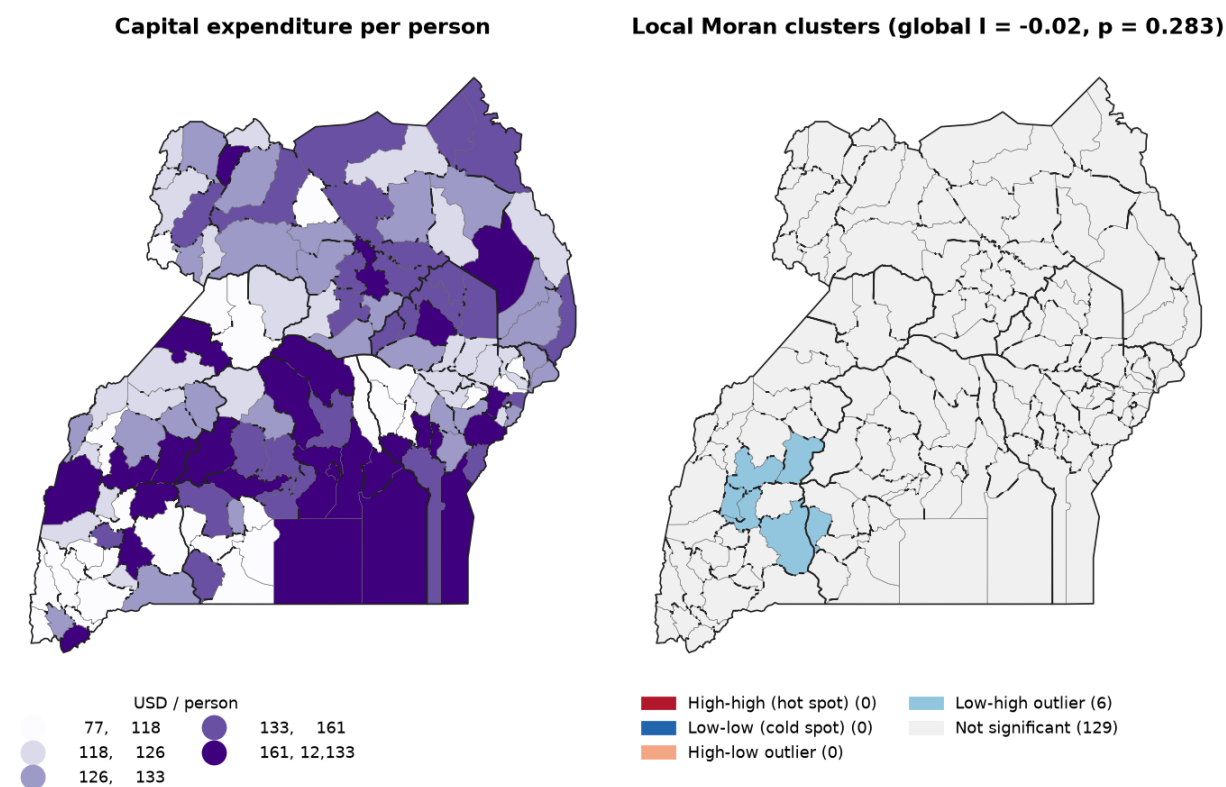


Figure 11.9: Ch.7 - Capital expenditure per person (USD / person), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

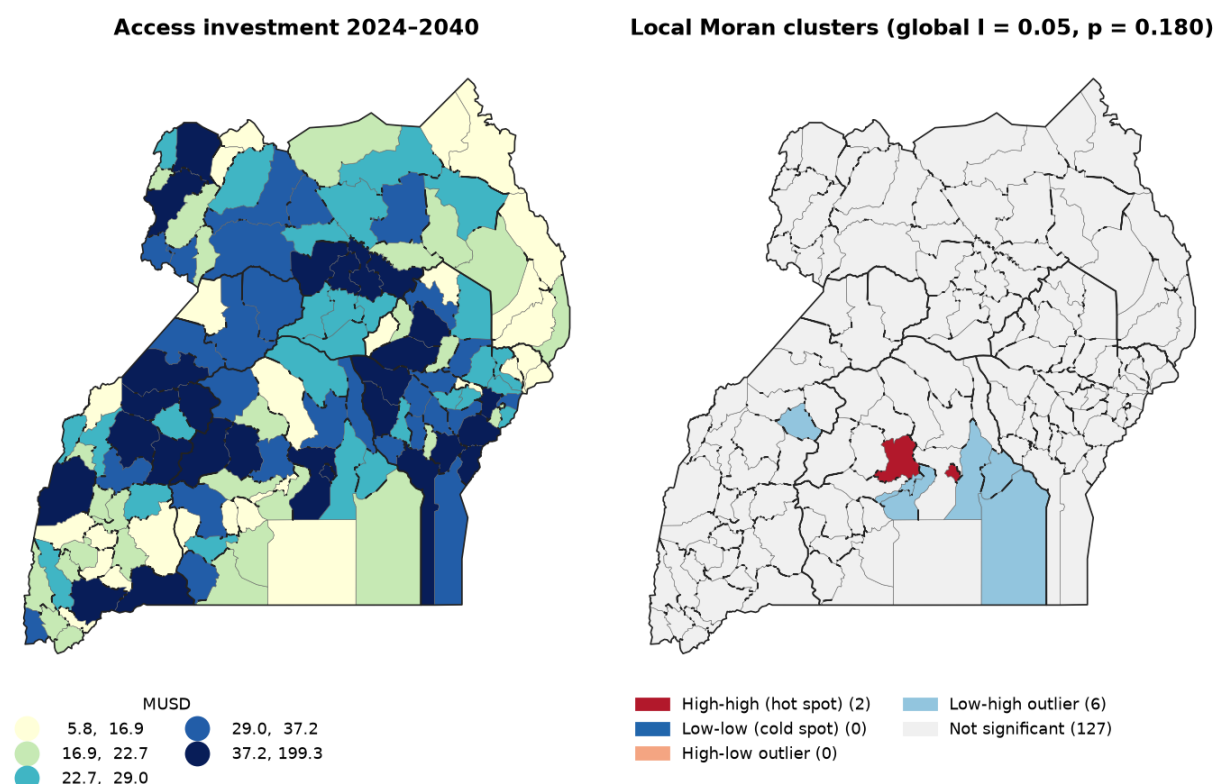


Figure 11.10: Ch.7 - Access investment 2024–2040 (MUSD), by district; right: local Moran (LISA) clusters, 999 permutations

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023). Boundaries: national admin boundaries via AICTEM SDI.

11.6 The cost of each technology

Figure 11.11 and Table 11.6 give the levelised cost of electricity of each candidate. Where a candidate is built, the capacity factor comes from the plan's dispatch; otherwise it comes from its resource availability.

Candidate	LCOE (USD/MWh)
Tilenga combined-cycle gas	54
Katwe and Buranga geothermal	57
Solar	67
Eastern combined-cycle gas	69
Karamoja wind	73
Run-of-river hydro (not built)	83
Nuclear (not built)	86
Batteries (not built)	89
Biomass (not built)	105

The western open-cycle gas plant (371 USD/MWh) and the diesel peakers (270 USD/MWh) have very high levelised costs because they run so little. They are built for firm capacity, not for energy. Their cost should be read against the reserve-margin shadow price of about 120 USD/kW-yr, not against the energy LCOE.

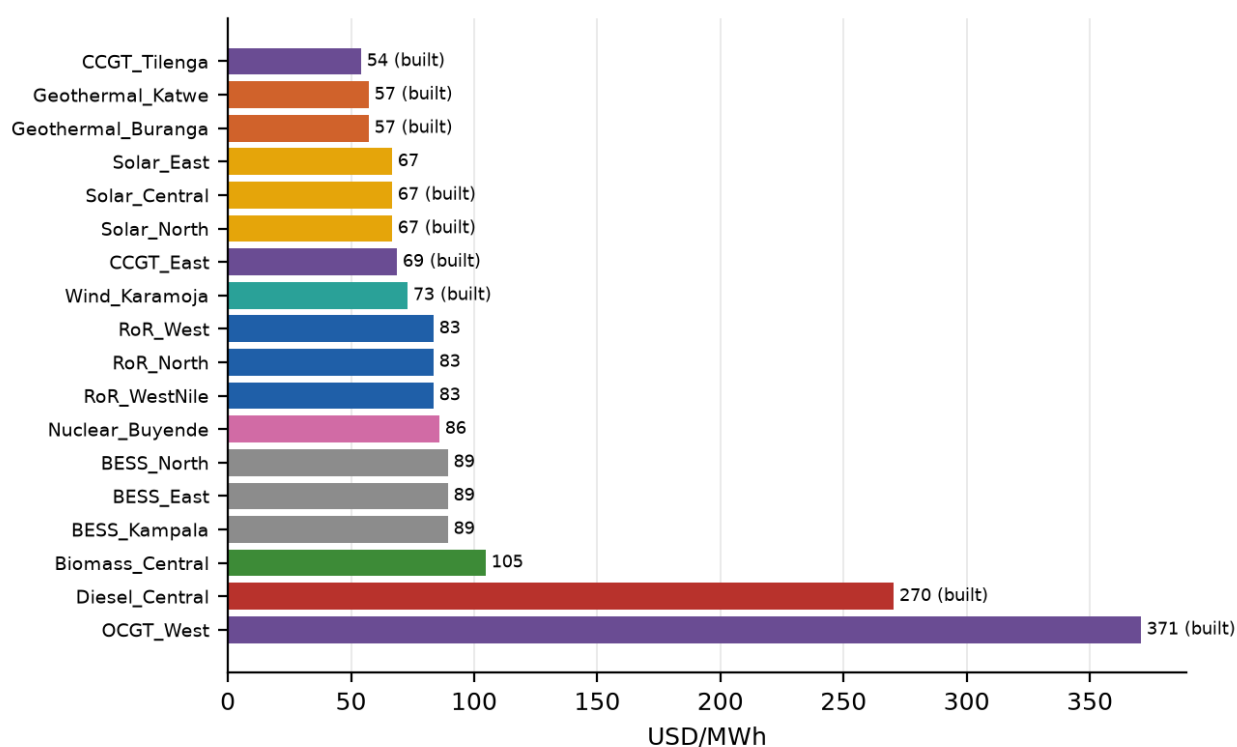


Figure 11.11: Levelised cost of electricity by candidate (capacity factor from the plan where built)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 11.6: Levelised cost of electricity by candidate

Candidate	Technology	Capacity factor	CF source	LCOE (USD/MWh)	Built MW
CCGT_Tilenga	Gas	92.0%	modelled (plan)	54.0	200
Geothermal_Katwe	Geothermal	90.0%	modelled (plan)	57.1	680
Geothermal_Buranga	Geothermal	90.0%	modelled (plan)	57.1	380
Solar_East	Solar PV	19.0%	availability-based	66.6	0
Solar_Central	Solar PV	19.0%	modelled (plan)	66.6	600
Solar_North	Solar PV	19.0%	modelled (plan)	66.6	570
CCGT_East	Gas	89.4%	modelled (plan)	68.6	1,250
Wind_Karamoja	Wind	28.3%	modelled (plan)	72.9	120
RoR_West	Hydro	45.1%	availability-based	83.4	0
RoR_North	Hydro	45.1%	availability-based	83.4	0
RoR_WestNile	Hydro	45.1%	availability-based	83.4	0
Nuclear_Buyende	Nuclear	90.0%	availability-based	85.8	0
BESS_Kampala	Battery	20.0%	availability-based	89.3	0
BESS_North	Battery	20.0%	availability-based	89.3	0
BESS_East	Battery	20.0%	availability-based	89.3	0
Biomass_Central	Biomass	70.0%	availability-based	104.6	0
Diesel_Central	Oil / diesel / HFO	50.0%	availability-based	270.3	489
OCGT_West	Gas	4.1%	modelled (plan)	370.7	1,646

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_lcoe.csv).

11.7 What it does to the cost of electricity

The revenue requirement is what the sector must recover from customers to pay for the existing system and the plan. It adds:

- the 2023 cost to serve on 2023 energy;

- the capital recovery of all new investment at a weighted average cost of capital of 8 %;
- the fuel and variable costs of the plan;
- O&M;
- the network and retail cost of the demand growth.

Figure 11.12 and Table 11.7 compare the average cost of supply with the 2023 average tariff of 133 USD/MWh.

- **2023.** The average cost of supply is 118 USD/MWh, below the tariff. The sector recovers its costs, as the cross-subsidy analysis of Chapter 7 showed.
- **2026.** Average cost rises to 136 USD/MWh, just above the tariff.
- **2030.** It reaches 149 USD/MWh.
- **2038.** It peaks at 170 USD/MWh in the year of heavy 2040 investment.
- **2040.** It settles at **158 USD/MWh**.

At 2023 tariffs the gap would be 162 million USD a year in 2030 and **622 million USD** in 2040. It would have to be closed by tariff adjustment, subsidy, efficiency, or cheaper finance than the 8 % assumed.

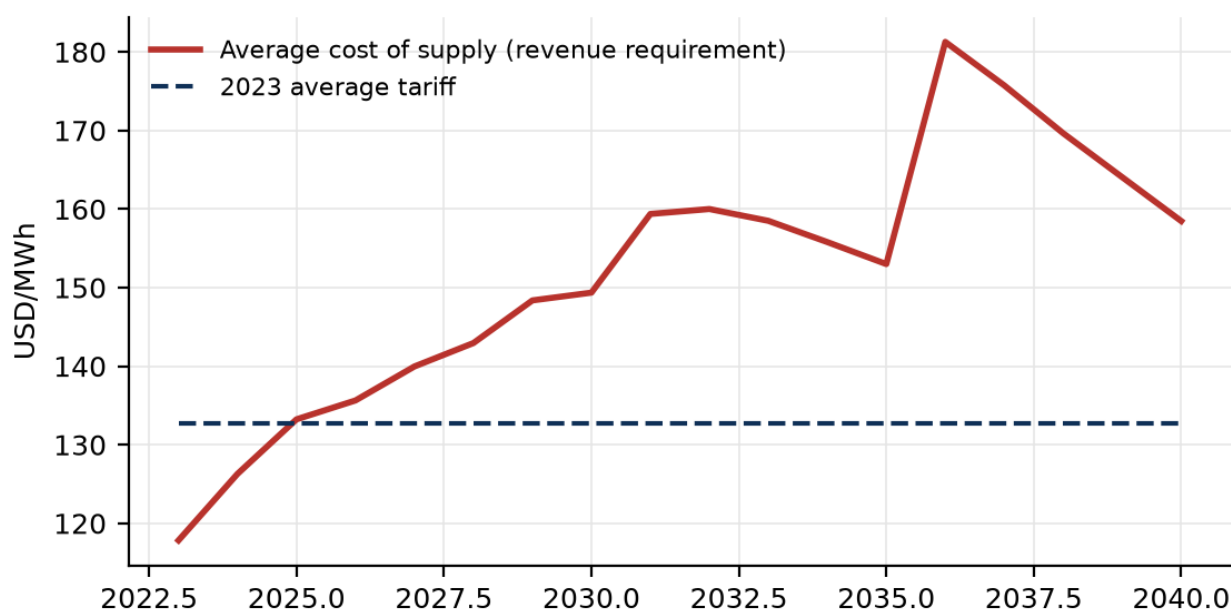


Figure 11.12: Average cost of supply against the 2023 average tariff

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 11.7: Revenue requirement and average cost of supply against the 2023 average tariff

Year	Billed (GWh)	Revenue requirement (MUSD)	Capital recovery (MUSD)	Average cost (USD/MWh)	2023 tariff (USD/MWh)	Gap (MUSD)
2023	4,330	510	0	117.8	132.7	-65
2026	5,734	778	174	135.6	132.7	17
2028	7,905	1,130	332	142.9	132.7	81
2030	9,759	1,458	540	149.4	132.7	162
2033	12,714	2,015	840	158.5	132.7	328
2035	15,162	2,320	1,010	153.0	132.7	307
2038	20,369	3,455	1,356	169.6	132.7	752
2040	24,185	3,833	1,539	158.5	132.7	622

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_tariff_path.csv).

11.8 Access investment

Figure 11.13 and Table 11.8 show the access investment.

- **Grid.** 12.76 million grid connections at 250 USD each cost 3.19 bn USD.
- **Solar home systems.** 2.21 million cost 0.80 bn USD.
- **Average.** 266 USD per connection.

This is the direct connection cost. The MV and LV network that the grid connections require is counted under distribution. Including it (3.32 bn USD spread over 12.76 million connections), the full cost of a grid connection is roughly 500 USD.

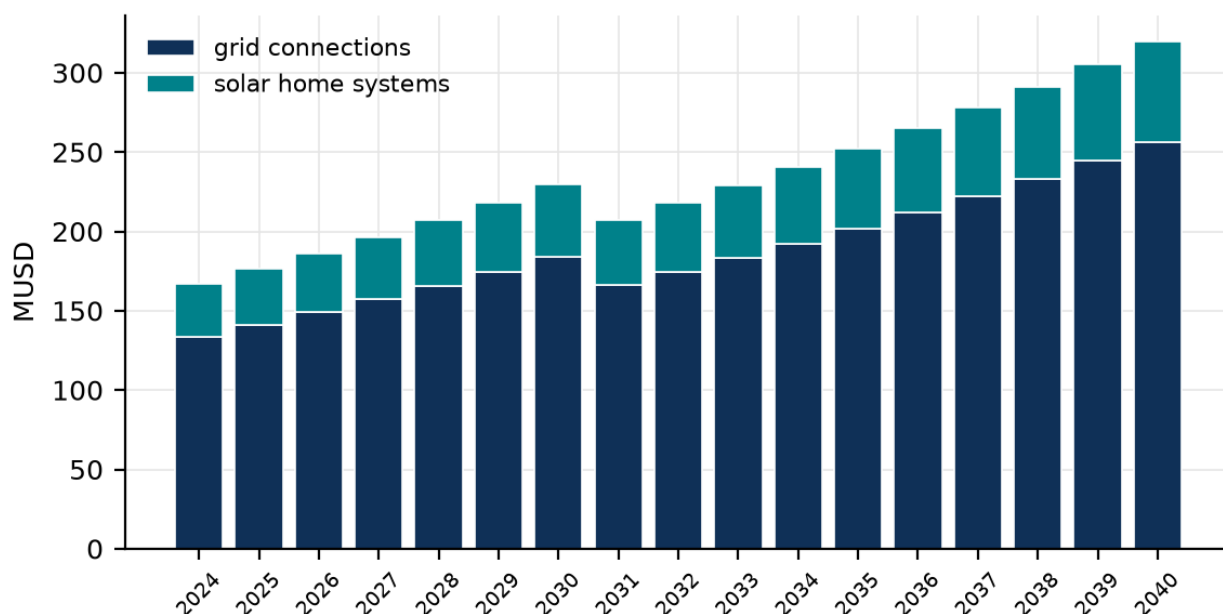


Figure 11.13: Access investment by mode and year

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 11.8: Access investment by mode

Mode	Capex (MUSD)	Connections	USD per connection
grid connections	3,191	12,763,621	250
solar home systems	797	2,213,227	360

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_access_capex.csv).

11.9 The project pipeline

MEMD's project pipeline (projects.csv) lists five named projects with cost, access gain, emissions reduction and jobs. Figure 11.14 and Table 11.9 appraise them on two measures.

- **Cost per household reached:**
 - solar mini-grids: 667 USD;
 - the EASP grid extension: 709 USD;
 - the Karuma evacuation: 1,160 USD;
 - Katwe geothermal: 15,867 USD. It is a generation project, not an access one.
- **Cost per tonne of CO2 avoided:** clean cooking, 243 USD; solar mini-grids, 1,667 USD.

These lifetime-cost ratios are not comparable with the annual abatement costs of Chapter 10. They rank the projects against each other, not against the plan.

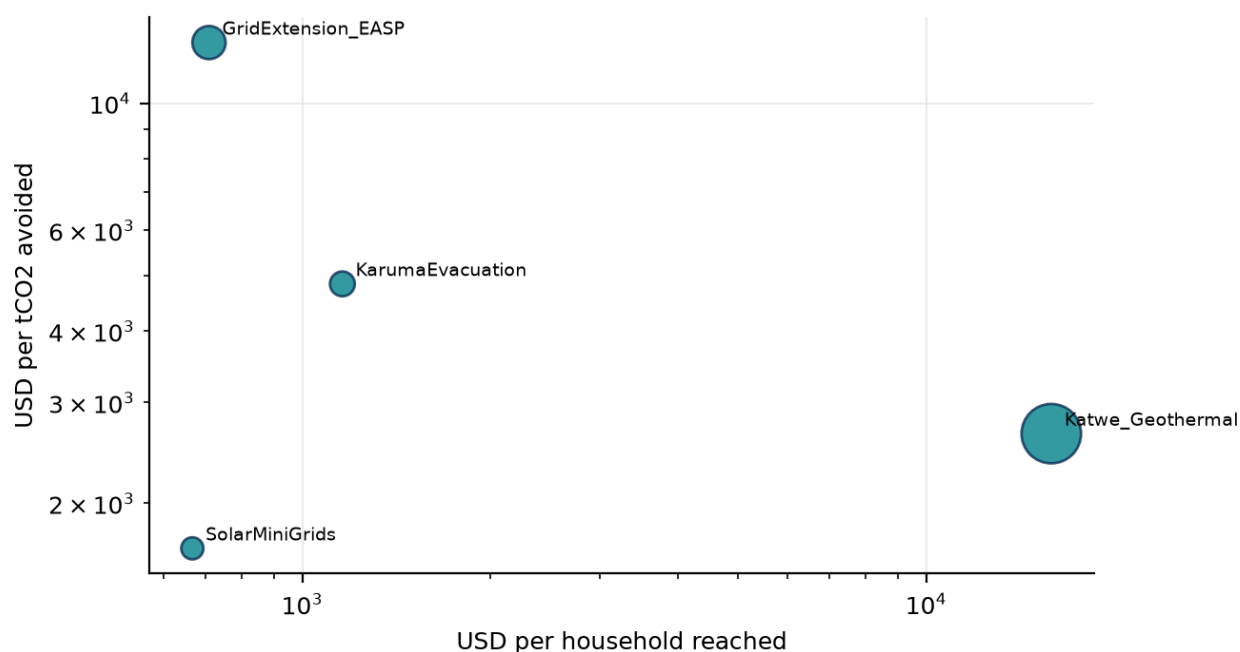


Figure 11.14: Project pipeline: cost per household reached against cost per tonne of CO2 avoided (area $\propto$ cost)

Source: MEMD project pipeline (projects.csv)

Table 11.9: Project pipeline appraisal (MEMD pipeline, projects.csv)

Project	Cost (MUSD)	Access gain (hh)	CO2 reduction (t/yr)	USD per household	USD per tCO2	Jobs	Rank (USD/hh)
KarumaEvacuation	290	250,000	60,000	1,160	4,832	1,800	3
GridExtension_EASP	638	900,000	50,000	709	12,760	4,200	2
SolarMiniGrids	200	300,000	120,000	667	1,667	2,200	1
Katwe_Geothermal	2,380	150,000	900,000	15,867	2,644	3,600	4
CleanCooking_ECook	340	0	1,400,000	-	243	2,600	5

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_pipeline.csv).

11.10 Data quality and limitations

- **Generation and transmission costs** are the IRP values, OBSERVED as planning data.
- **Distribution, access and institutional unit costs** are partly OBSERVED (the MV line cost) and partly ASSUMED (transformers, LV, connections, solar home systems, institutions).
- **The financing mix** is ASSUMED. It is illustrative until matched to actual financing agreements.
- **Real dollars.** Capex is in constant 2023 USD. Escalation, interest during construction and exchange-rate risk are excluded.
- **The revenue requirement** uses a single weighted average cost of capital. It does not model the balance sheets of the individual utilities.

11.11 Implications for planning

- The plan needs 15.6 bn USD over 17 years, about 0.9 bn USD a year. Half of it is for generation, and much of that can be private. Half is for distribution and access, which depend on public and concessional finance.
- The public share of about 250 million USD a year at peak fits within the current energy budget, but only if concessional and private finance come in at the assumed shares. Mobilising them is the binding constraint.

- The average cost of supply rises above the current tariff from 2026. Without a tariff and subsidy strategy, the sector's finances will deteriorate as the plan is built. Rebalancing the tariffs, so that industry pays its cost to serve, would close part of the gap.
- Investment is concentrated in a few districts that host the generation. The benefits reach the whole country through the grid, which is why the transmission investment is the precondition of the whole plan.

CHAPTER 12

12 Expansion plan: the year-by-year build-out

The least-cost plan decides what to build in each of four periods. This chapter turns it into an **annual roadmap** for 2024 to 2040. It covers:

- when each project should come online;
- how the system evolves year by year;
- whether every year, not only the planning years, is adequate;
- which projects are on the critical path.

It implements design Chapter 9 (`docs/09_expansion_plan.md`).

12.1 From periods to commissioning years

Capacity that the plan builds *for* a period must be available through that period's years:

- 2027–2030 for the 2030 period;
- 2031–2035 for the 2035 period;
- 2036–2040 for the 2040 period.

The engine spreads each period's build into annual tranches with a **just-in-time** rule. Each project's capacity comes online in the year the annual firm requirement first needs it, rounded to realistic unit sizes:

- 50 MW for hydro, solar and gas;
- 20 MW for geothermal and wind;
- 300 MW for nuclear.

No project may come online before its first available year. The rule is:

$$K_{c,y}^{com} = K_{c,p} \omega_{c,y}, \quad \sum_{y \in (p_{prev}, p]} \omega_{c,y} = 1 \quad (12.1)$$

where

- $K_{c,y}^{com}$ is the capacity of candidate c commissioned in year y ;
- $K_{c,p}$ is the capacity the plan builds for period p ;
- $\omega_{c,y}$ is the share commissioned in year y , rising with the year's firm requirement.

Validation check V9-1 confirms that the tranches add up to the plan: 5,935 MW. Check V9-2 confirms that none precedes its first available year.

12.2 The roadmap

Figure 12.1 and Table 12.1 show the commissioning window of every project.

1. **Tilenga combined-cycle gas** (200 MW) comes online first, from 2026 to 2029.
2. **Katwe geothermal** (680 MW) follows in steps of 20–100 MW a year from 2027 to 2035, and **Buranga geothermal** (380 MW) from 2028 to 2035.
3. **Western open-cycle gas** (1,646 MW) comes online from 2030 to 2040.

4. **Eastern combined-cycle gas** (1,250 MW) follows from 2031 to 2040.
5. **Solar** (1,170 MW), **wind** (120 MW) and **diesel peakers** (489 MW) come online in the last period, 2036–2040.

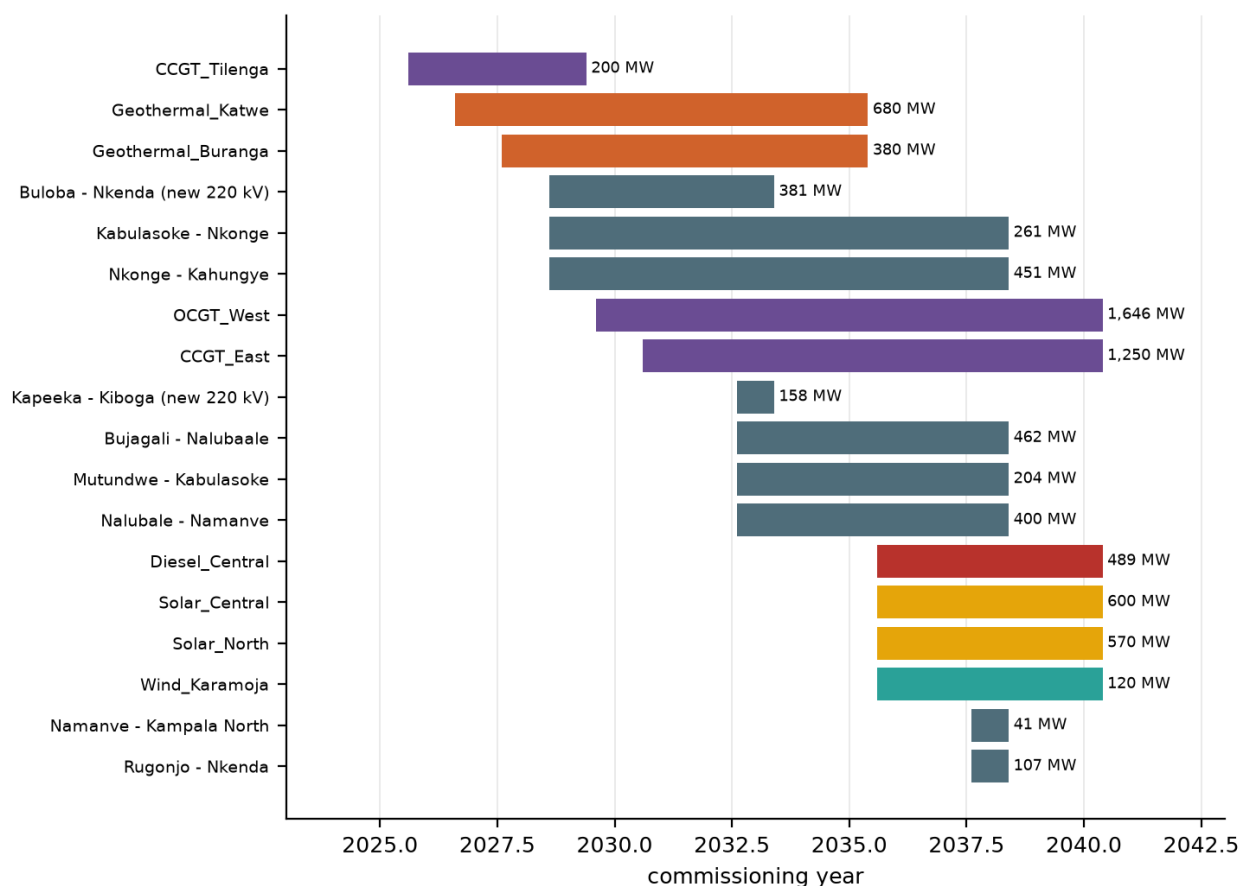


Figure 12.1: Roadmap: commissioning window of every plan project (colour = technology; grey-blue = transmission)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 12.1: Commissioning windows of the plan's generation and storage projects

Project	Technology	First unit	Last unit	MW	Capex (MUSD)	Financial close by
CCGT_Tilenga	Gas	2026	2029	200	160	2023
Geothermal_Katwe	Geothermal	2027	2035	680	2,380	2022
Geothermal_Buranga	Geothermal	2028	2035	380	1,330	2023
OCGT_West	Gas	2030	2040	1,646	1,317	2027
CCGT_East	Gas	2031	2040	1,250	1,125	2028
Diesel_Central	Oil / diesel / HFO	2036	2040	489	244	2033
Solar_Central	Solar PV	2036	2040	600	540	2034
Solar_North	Solar PV	2036	2040	570	513	2034
Wind_Karamoja	Wind	2036	2040	120	156	2034

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_commissioning.csv).

The transmission build follows the generation it serves (Table 12.2).

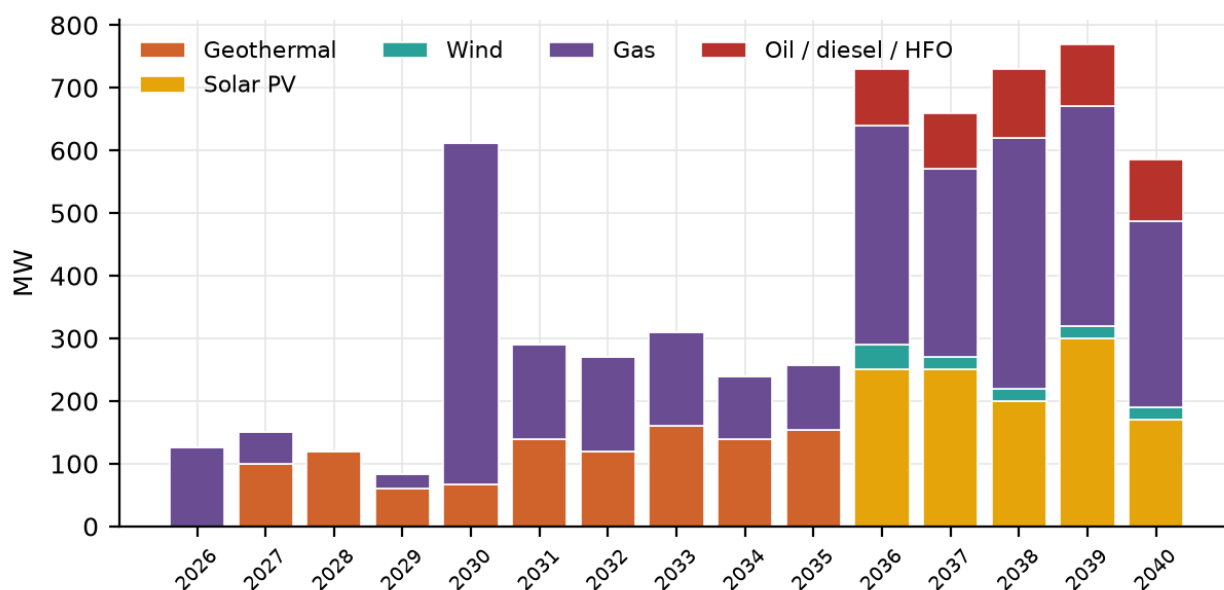
- **Western path.** The first Nkonge–Kahungye and Kabulasoke–Nkonge reinforcements and the first 89 MW of the Buloba–Nkenda corridor come in 2029, ahead of the western geothermal and gas.
- **Eastern ring.** The Nalubaale–Namanve reinforcement comes in 2033.
- **2038.** The largest reinforcements come in 2038, ahead of the 2040 build: Bujagali–Nalubaale +400 MW and Mutundwe–Kabulasoke +200 MW.

Table 12.2: Commissioning of transmission reinforcements and new corridors

Corridor	Type	Year	MW	Capex (MUSD)
Bujagali - Nalubaale	reinforcement	2033	62	5.6
Bujagali - Nalubaale	reinforcement	2038	400	36.2
Kabulasoke - Nkonge	reinforcement	2029	12	1.3
Kabulasoke - Nkonge	reinforcement	2033	174	19.2
Kabulasoke - Nkonge	reinforcement	2038	75	8.3
Rugonjo - Nkenda	reinforcement	2038	107	12.4
Mutundwe - Kabulasoke	reinforcement	2033	4	0.5
Mutundwe - Kabulasoke	reinforcement	2038	200	22.5
Nalubale - Namanve	reinforcement	2033	200	21.0
Nalubale - Namanve	reinforcement	2038	200	21.0
Namanve - Kampala North	reinforcement	2038	41	3.7
Nkonge - Kahungye	reinforcement	2029	64	6.5
Nkonge - Kahungye	reinforcement	2033	200	20.3
Nkonge - Kahungye	reinforcement	2038	187	19.0
Buloba - Nkenda (new 220 kV)	new corridor	2029	89	16.9
Buloba - Nkenda (new 220 kV)	new corridor	2033	292	55.3
Kapeeka - Kiboga (new 220 kV)	new corridor	2033	158	7.2

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_tx_commissioning.csv).

Figure 12.2 shows the annual additions by technology. Additions are small until 2029, at 85–150 MW a year. They jump to 612 MW in 2030, when the first open-cycle gas units arrive. They run at 240–310 MW a year from 2031 to 2035, then at 585–770 MW a year from 2036 to 2040, when gas, solar, diesel and wind come online together.

**Figure 12.2:** Annual capacity additions by technology

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

12.3 The system every year

Figure 12.3 and Table 12.3 show the annual state of the system.

- **Capacity.** Installed capacity grows from 2,183 MW in 2023, including the batteries, to 8,120 MW in 2040.
- **Firm capacity** grows from 1,326 MW to 5,596 MW, tracking peak plus reserve.
- **Renewable share** falls from 100 % to 61 %.
- **Emissions** rise from 154 kt to 4.1 Mt.

- **Access** rises from 25 % to 100 %.
- **Distribution losses** fall from 17.3 % to 12 %.

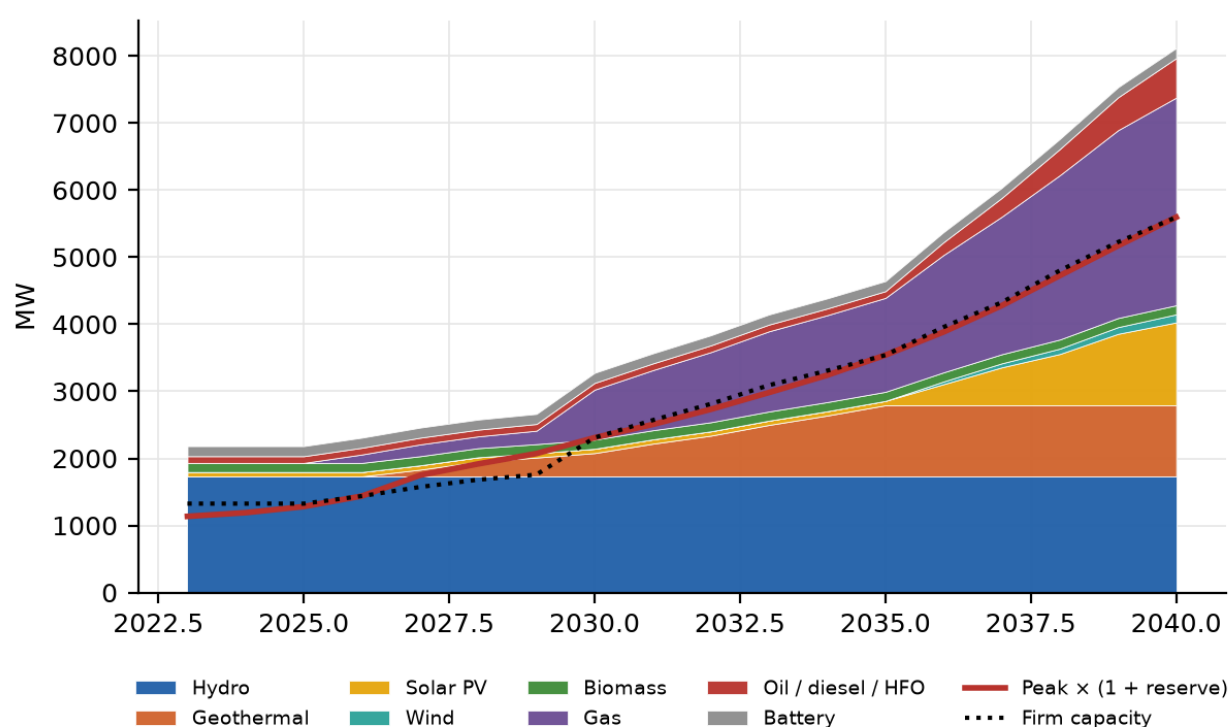


Figure 12.3: Installed capacity every year against peak and the firm requirement

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 12.3: Annual system state 2023–2040, base scenario

Year	Peak (MW)	Firm (MW)	Reserve margin	RE share	Emissions (kt)	Access	Loss rate
2023	988	1,326	34.2%	100.0%	154	25.3%	17.3%
2024	1,036	1,326	28.0%	100.0%	0	30.3%	16.6%
2025	1,114	1,326	19.0%	100.0%	0	35.2%	15.8%
2026	1,251	1,439	15.0%	100.0%	0	40.2%	15.1%
2027	1,521	1,574	3.5%	96.8%	137	45.1%	14.3%
2028	1,668	1,682	0.8%	93.7%	274	50.1%	13.5%
2029	1,802	1,758	-2.5%	90.5%	411	55.0%	12.8%
2030	2,008	2,309	15.0%	87.4%	548	60.0%	12.0%
2031	2,179	2,570	17.9%	86.9%	639	64.0%	12.0%
2032	2,376	2,813	18.4%	86.5%	730	68.0%	12.0%
2033	2,593	3,092	19.2%	86.0%	821	72.0%	12.0%
2034	2,818	3,308	17.4%	85.5%	912	76.0%	12.0%
2035	3,078	3,540	15.0%	85.0%	1,004	80.0%	12.0%
2036	3,378	3,958	17.2%	80.3%	1,622	84.0%	12.0%
2037	3,720	4,326	16.3%	75.6%	2,241	88.0%	12.0%
2038	4,110	4,801	16.8%	70.8%	2,860	92.0%	12.0%
2039	4,496	5,225	16.2%	66.1%	3,479	96.0%	12.0%
2040	4,866	5,596	15.0%	61.3%	4,097	100.0%	12.0%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_state.csv).

12.3.1 A transition gap in 2027–2029

The reserve margin, firm capacity over peak minus one, falls below its 15 % target in three years (Figure 12.4):

- 3.5 % in 2027;
- 0.8 % in 2028;

- **-2.5 % in 2029**, when firm capacity (1,758 MW) is below the peak (1,802 MW).

The reason is visible in the roadmap. The 2030-period build includes 546 MW of open-cycle gas that cannot be commissioned before 2030, its first available year. Geothermal comes online only gradually, and its first unit is available only from 2027.

PyPSA's annual verification shows no load shed in these years. The expected energy can still be served from the reservoirs, the existing HFO and the new geothermal and Tilenga units. But the system would have no reserve against a dry year, an outage of a large unit or faster demand growth.

This is a **transition gap**. The planning-period model cannot see it, because it checks only the final year of each period. Bridging it requires fast firm capacity in 2027–2029. Options include:

- battery storage;
- a temporary diesel or HFO lease;
- firm imports from Kenya or Tanzania;
- interruptible contracts with the new industrial loads;
- bringing forward the open-cycle gas plant.

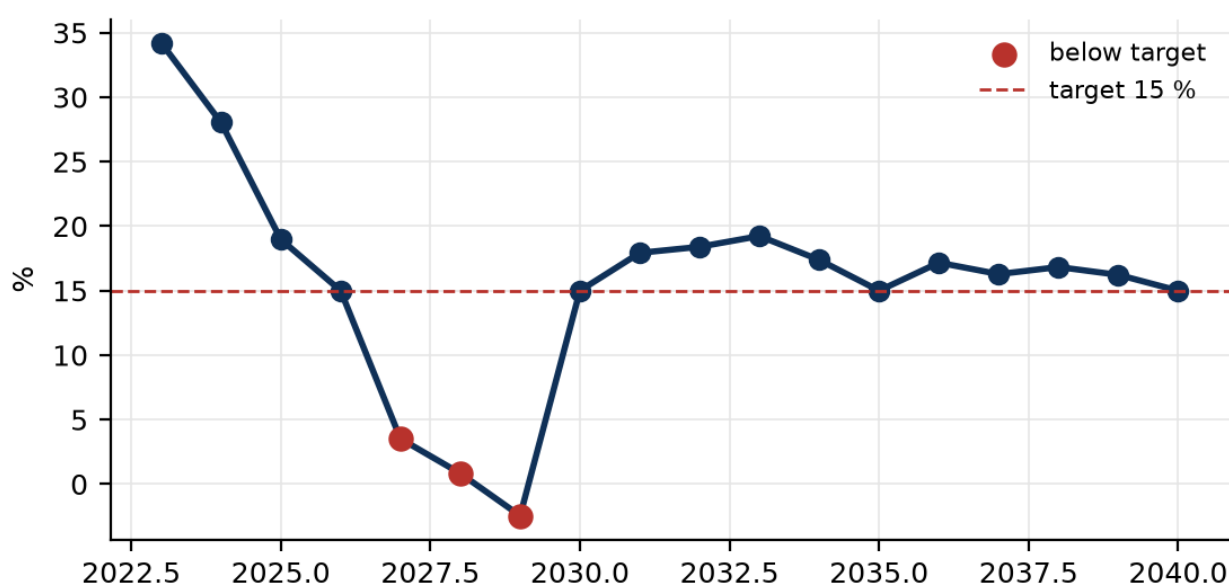


Figure 12.4: Reserve margin every year against the target

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

12.3.2 Annual verification

Every year from 2024 to 2040 is re-dispatched with PyPSA, using that year's commissioned fleet and grid and that year's demand (Figure 12.5, Table 12.4). Unserved energy is zero in every year. The commissioning schedule is adequate in energy even through the transition gap. This is what validation check V9-4 tests: any year with unserved energy above 0.01 % of demand would trigger a bridging action and a re-verification. None does.

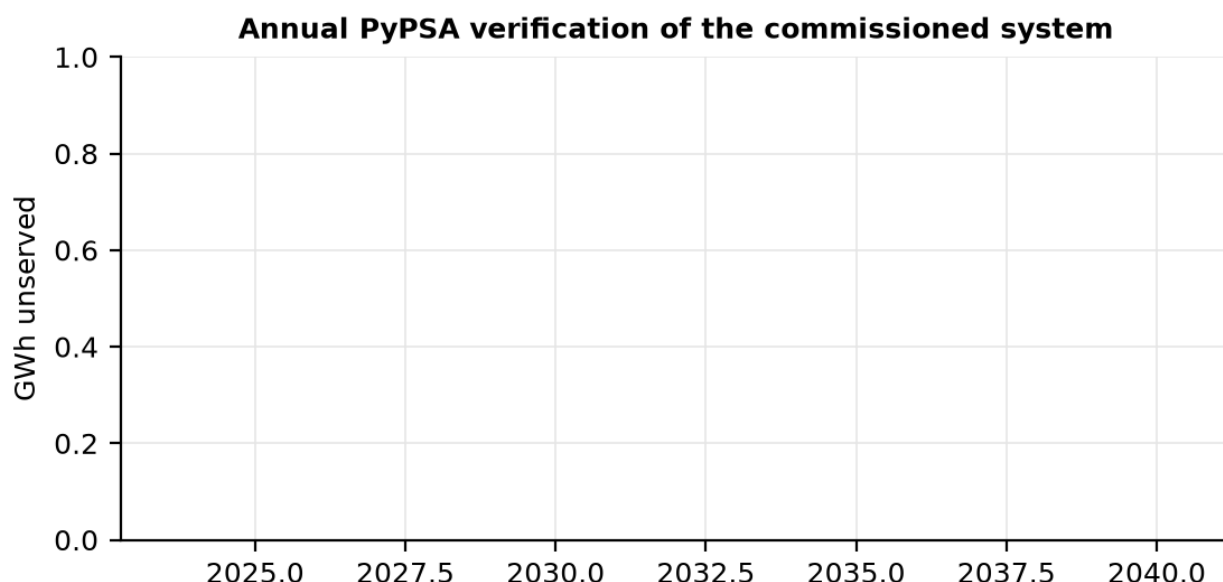


Figure 12.5: Annual verification: unserved energy of the commissioned system in every year, 2024–2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 12.4: Annual PyPSA verification of the commissioned system

Year	Unserved (GWh)	LOLE (h)	EUE	Status
2024	0.00	0	0.000%	ok:optimal
2025	0.00	0	0.000%	ok:optimal
2026	0.00	0	0.000%	ok:optimal
2027	0.00	0	0.000%	ok:optimal
2028	0.00	0	0.000%	ok:optimal
2029	0.00	0	0.000%	ok:optimal
2030	0.00	0	0.000%	ok:optimal
2031	0.00	0	0.000%	ok:optimal
2032	0.00	0	0.000%	ok:optimal
2033	0.00	0	0.000%	ok:optimal
2034	0.00	0	0.000%	ok:optimal
2035	0.00	0	0.000%	ok:optimal
2036	0.00	0	0.000%	ok:optimal
2037	0.00	0	0.000%	ok:optimal
2038	0.00	0	0.000%	ok:optimal
2039	0.00	0	0.000%	ok:optimal
2040	0.00	0	0.000%	ok:optimal

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_verification.csv).

12.3.3 The energy transition, access and losses

Figure 12.6 shows three indicators year by year.

- **Renewable share.** It stays above 85 % until 2035, while geothermal carries the new demand. It then falls steadily, as the combined-cycle and open-cycle gas plants of the 2040 period come online.
- **Access.** It rises linearly to 60 % in 2030 and 100 % in 2040.
- **Distribution losses.** They reach the 12 % target in 2030 and hold.

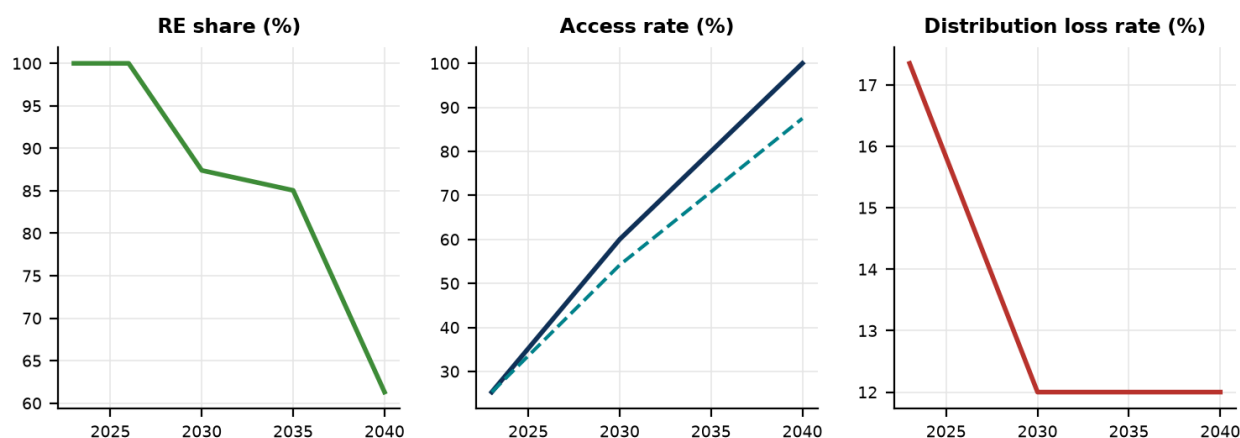


Figure 12.6: Transition indicators every year: renewable share, access and distribution losses

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

12.3.4 The grid

Figure 12.7 and Table 12.5 show the transmission grid length by voltage.

- **2026.** The under-construction corridors come into service, adding 364 km at 132 kV, 268 km at 220 kV and 54 km at 400 kV.
- **2029–2033.** The plan's two new 220 kV corridors (Buloba–Nkenda from 2029, Kapeeka–Kiboga from 2033) add 607 km. That is 271 km by 2030 and 336 km more by 2035, taking the 220 kV network to 1,365 km.

The reinforcements of existing corridors add capacity, not length.

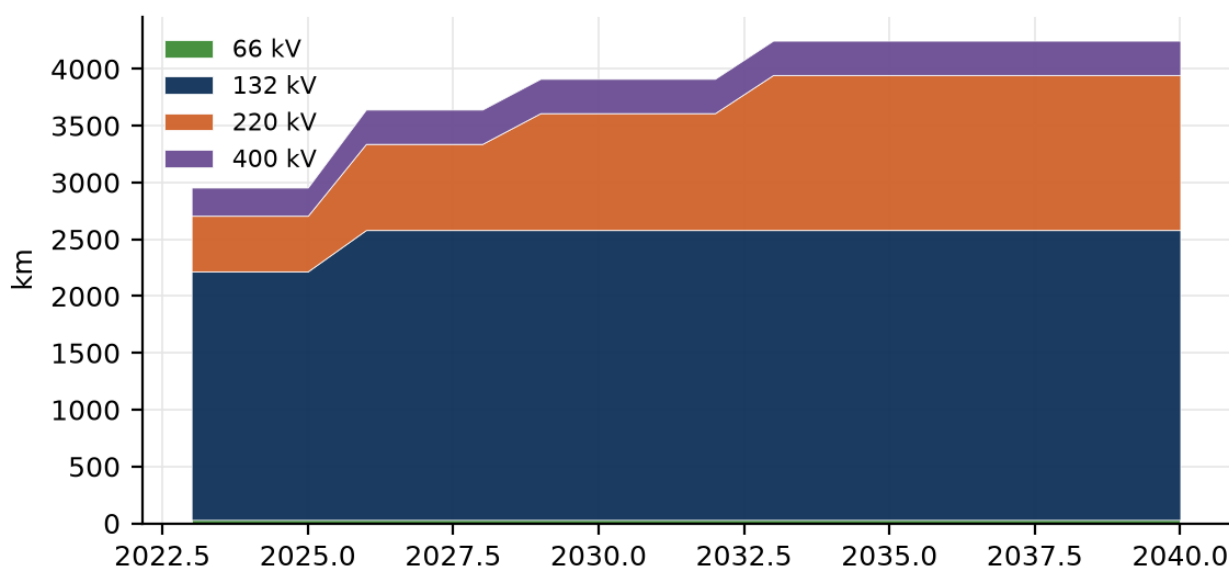


Figure 12.7: Transmission grid length by voltage, 2023–2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 12.5: Transmission grid length by voltage, km

Year	66 kV	132 kV	220 kV	400 kV
2023	30	2,187	490	248
2026	30	2,551	758	302
2030	30	2,551	1,029	302
2035	30	2,551	1,365	302
2040	30	2,551	1,365	302

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_grid_km.csv).

12.4 The critical path

A project is **critical** if its lead time is five years or more, or if it provides 10 % or more of the year's firm requirement. For each critical project the engine computes the latest year for financial close (commissioning year minus lead time) and the slack from 2026 (Figure 12.8, Table 12.6).

- **Katwe geothermal** needs financial close by **2022** for its first unit in 2027: 4 years late.
- **Buranga geothermal** needs financial close by **2023**: 3 years late.
- **Western open-cycle gas** needs financial close by 2027 for its first 546 MW in 2030. It has one year of slack.

The geothermal projects are the plan's most robust element (Chapter 10), and they are already behind schedule. If they cannot be accelerated, the least-cost plan must be re-solved with a later geothermal availability, and more gas will fill the gap. The transition gap of 2027–2029 would also deepen.

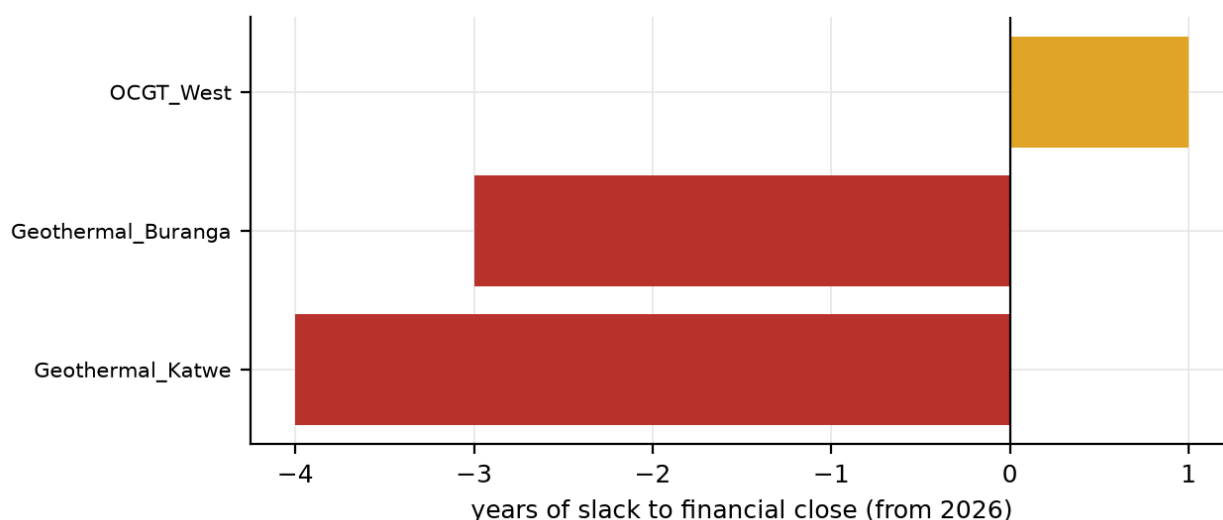


Figure 12.8: Critical path: slack to financial close (red = already late)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 12.6: Critical path: projects with long lead times or a large firm contribution

Project	MW (critical tranches)	Financial close by	Slack from 2026 (years)
Geothermal_Katwe	680	2022	-4
Geothermal_Buranga	380	2023	-3
OCGT_West	546	2027	1

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_critical.csv).

12.5 Gap-closure milestones

Table 12.7 gives the year in which each gap closes in the expansion plan.

- **G1 Capacity:** 2030, when the reserve margin returns to its target and stays there.
- **G3 Reliability:** 2024. Unserved energy is zero from the first year.
- **G5 Distribution losses:** 2030.
- **G4 Network:** 2038, when the last plan reinforcement is in service.
- **G6 Access:** 2040.

Table 12.7: Gap-closure milestones of the plan

Gap	Closure year	Target
G1 Capacity (reserve $\geq$ target)	2030	15%
G3 Reliability (EUE $\leq$ 0.01 %)	2024	0.01 %

Gap	Closure year	Target
G6 Access (target)	2040	100%
G5 Distribution losses	2030	12%
G4 Network (plan reinforcements in service)	2038	all plan corridors

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_milestones.csv).

12.6 Delivery and spend

Figure 12.9 compares cumulative capital expenditure with cumulative capacity commissioned. The capex curve leads the capacity curve by the construction lead times. Nearly half of the 15.6 bn USD (7.6 bn USD) is spent by 2032, when only 28 % of the new capacity (about 1,650 MW) is in service. This is the financing burden of building ahead of need, and the reason why the financing strategy of Chapter 11 matters as much as the technology choice.

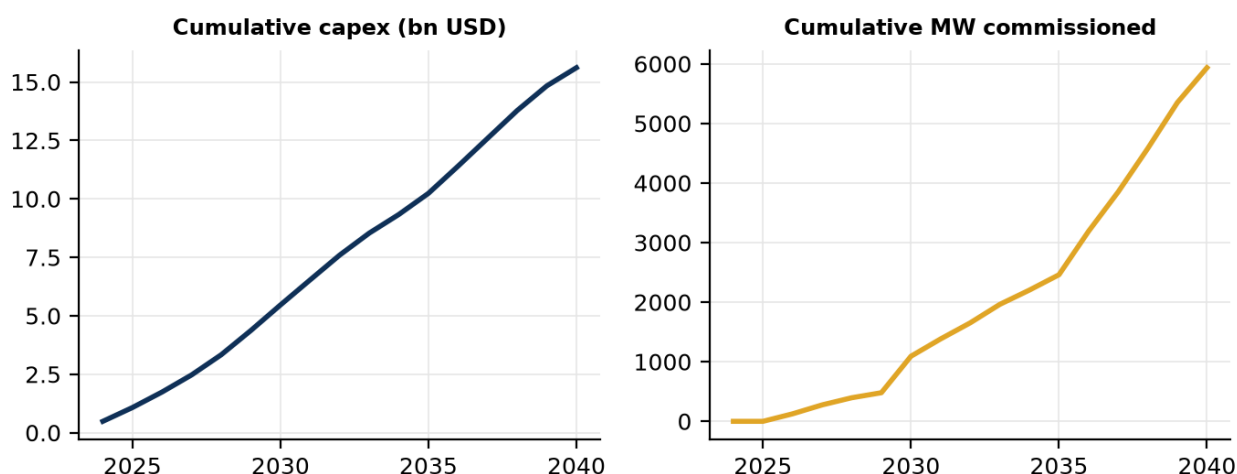


Figure 12.9: Delivery against spend: cumulative capex and cumulative capacity commissioned

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

12.7 The system as it grows

Figure 12.10 shows the system in 2026, 2030, 2035 and 2040. Shading shows each district's access rate; dots show the plants commissioned by that year.

- **2026.** Access is 40 %. The first gas plant is at Kahungye.
- **2030.** Access is 60 %, and geothermal and gas are in service in the west.
- **2035.** Access is 80 %, and the western sites are fully developed.
- **2040.** Access is universal, and the eastern gas plant, the solar sites and the Karamoja wind farm are in service.

The last districts to reach high access are in Karamoja, Acholi and West Nile, where the 2023 rates were lowest.

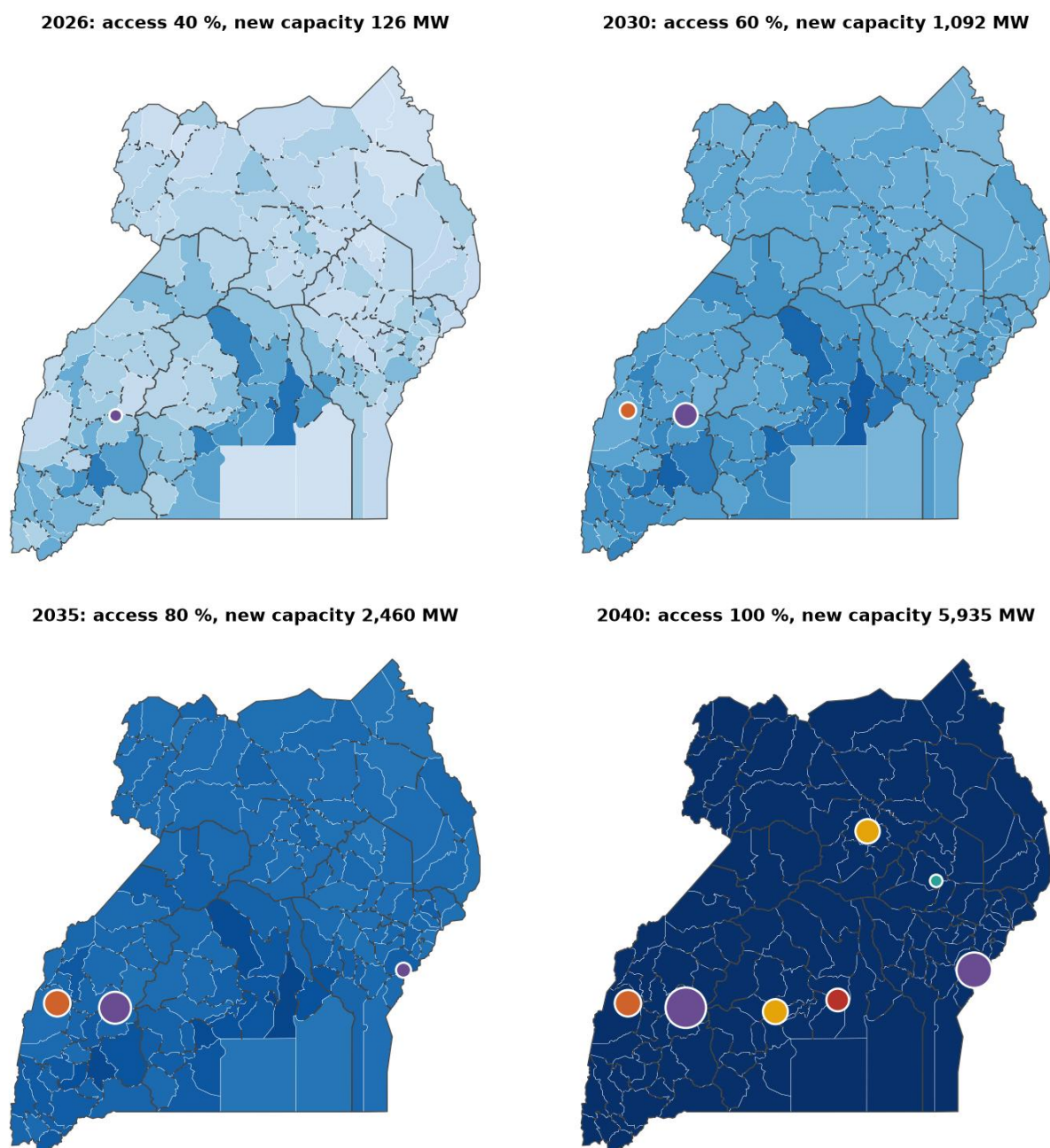


Figure 12.10: The system as it grows: district access rate (shading) and commissioned new plants, 2026–2040

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

12.8 Data quality and limitations

- **Generic lead times.** Lead times are generic by technology, not project-specific. The actual status of each project (feasibility, permitting, financing) should replace them.
- **Interpolated indicators.** Annual generation mix, emissions and renewable share between the planning years are interpolated in proportion to active capacity. Only the verification dispatch is solved every year.
- **Just-in-time rule.** The rule delays capacity to the latest year it is needed. An "even" rule, which spreads capacity evenly across the period, would reduce the transition gap at the cost of building earlier.

12.9 Implications for planning

- The expansion plan is adequate in energy every year from 2024, but it has **no firm reserve in 2027–2029**. A bridging arrangement for those years should be put in place now: batteries, leased thermal capacity, firm imports or interruptible industrial contracts.
- The geothermal projects at Katwe and Buranga are on the critical path and already late. Their exploration, financing and procurement should be accelerated. Otherwise the plan should be re-solved with later dates.
- The western and eastern grid reinforcements must be in service before the generation they serve: from 2029 in the west and from 2033 in the east. Their procurement should start now.
- Capital is spent well ahead of capacity. The financing plan must be in place years before the megawatts appear.

CHAPTER 13

13 The spatial picture: GIS analysis across the system

Every chapter of this report has used maps. This chapter looks across all of them. It asks three questions:

- Which features of the energy system are geographically clustered?
- Where are the persistent hot-spots and cold-spots?
- What does the spatial pattern imply for the way the plan is delivered?

It implements design Chapter 8 (`docs/08_gis_engine.md`). It also draws on the spatial least-cost electrification analysis, which splits each district's unconnected households between the grid, mini-grids and solar home systems.

13.1 The GIS engine

The engine holds four layers of geographic data.

1. **Administrative.** 135 districts in four regions, with population, households and the census access rate, joined to the 17 zone buses of the transmission model.
2. **Assets.**
 - Power plants and substations.
 - Transmission lines by voltage.
 - The MV network.
 - Distribution substations and transformers.
 - 3,169 health facilities and 21,193 schools.
 - The IERMP commercial and industrial facilities.
3. **Population grid.** A 1 km population raster of 126,986 populated cells. Each cell carries its distance to the nearest transmission substation and MV line, and the distribution substation that serves it.
4. **Resource.** Mean wind speed at 100 m and solar irradiance.

Every module result that has a location is aggregated to districts. The engine then computes two statistics for each district layer:

- a **global Moran's I**, which tests whether the layer is clustered;
- a **local Moran (LISA)** classification, which finds where the clusters are.

13.1.1 Global Moran's I

The spatial weights are the six nearest neighbours of each district's centroid in UTM coordinates, row-standardised. Moran's I is:

$$I = \frac{n}{\sum_i \sum_j w_{ij}} \frac{\sum_i \sum_j w_{ij} (x_i - \bar{x})(x_j - \bar{x})}{\sum_i (x_i - \bar{x})^2} \quad (13.1)$$

where

- x_i is the value of the layer in district i ;
- $\bar{x}$ is the mean over the $n = 135$ districts;
- w_{ij} is the weight of neighbour j for district i .

The expected value under no clustering is $-1/(n - 1) \approx -0.007$.

- **I well above zero:** similar values cluster together.
- **I near zero:** no spatial pattern.
- **I below zero:** a checkerboard, where high values are next to low ones.

The significance is tested by 999 random permutations of the values across districts, with a fixed seed (validation check V5-4).

13.1.2 Local Moran and the cluster classes

The local statistic of district i measures how much it contributes to the global pattern:

$$I_i = z_i \sum_j w_{ij} z_j \quad (13.2)$$

where z is the standardised value of the layer. Significance is tested by conditional permutation: district i 's value is held fixed while its neighbours are drawn at random from the other districts. A district that is significant at 5 % is classified by the sign of its own value and of its neighbours' average (the spatial lag):

- **HH (hot-spot):** a high value surrounded by high values;
- **LL (cold-spot):** a low value surrounded by low values;
- **HL and LH (outliers):** a high value among low neighbours, or a low value among high neighbours.

Districts that are not significant are shown in grey on the right-hand panel of each layer map.

13.2 Clustering across all layers

Figure 13.1 and Table 13.1 give Moran's I for all 26 district layers of the report. 21 are significantly clustered at 5 %; five are not.

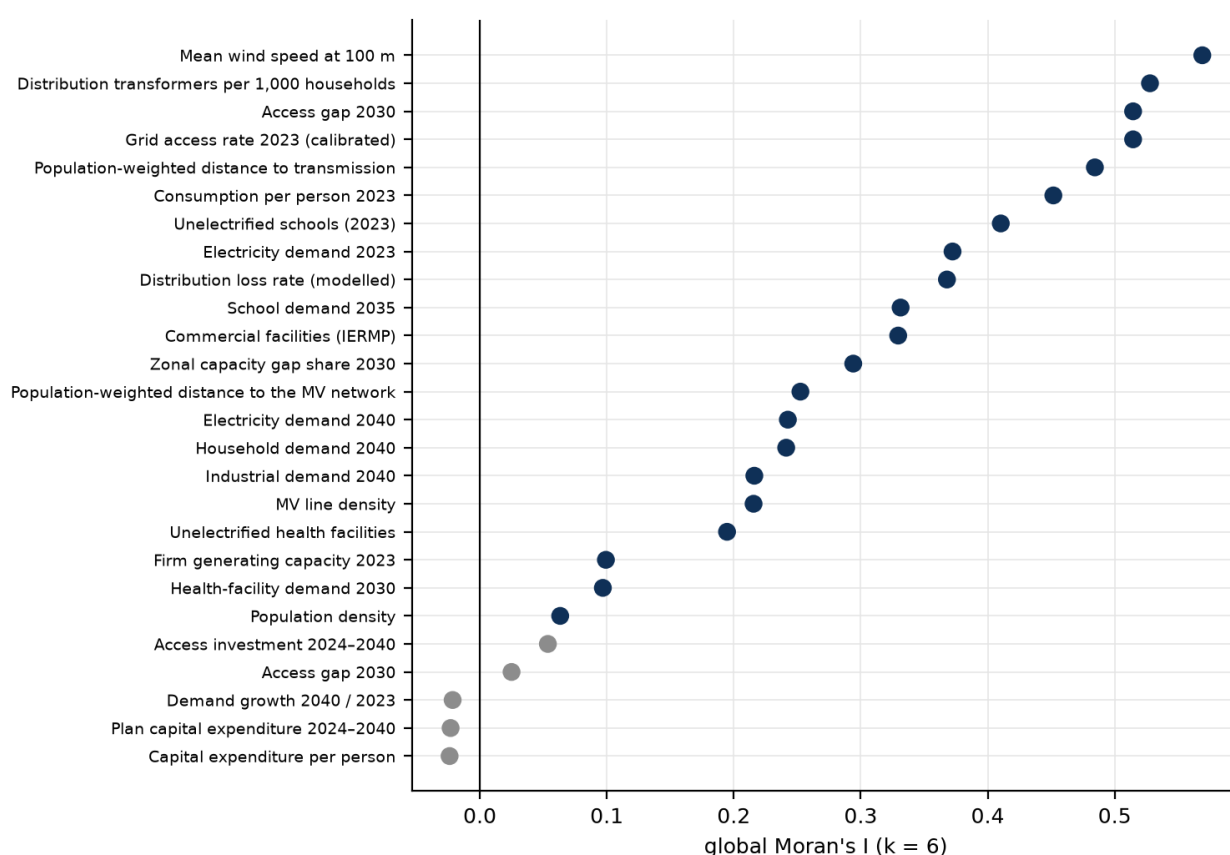


Figure 13.1: Spatial clustering of every mapped district layer (navy = significant at 5 %, 999 permutations)

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 13.1: Spatial autocorrelation of every mapped district layer (k = 6, 999 permutations)

Chapter	Layer	Unit	Moran's I	p	Hot-spots	Cold-spots
Ch.1	Population density	persons / km ²	0.063	0.002	11	6
Ch.1	Electricity demand 2023	GWh	0.372	0.001	6	0
Ch.1	Electricity demand 2040	GWh	0.243	0.001	6	0
Ch.1	Consumption per person 2023	kWh / person	0.452	0.001	8	0
Ch.1	Demand growth 2040 / 2023	multiple	-0.021	0.513	1	0
Ch.1	Household demand 2040	GWh	0.241	0.001	7	0
Ch.1	Industrial demand 2040	GWh	0.216	0.001	6	0
Ch.1	Health-facility demand 2030	MWh	0.097	0.011	5	0
Ch.1	School demand 2035	MWh	0.331	0.001	7	0
Ch.1	Commercial facilities (IERMP)	count	0.330	0.001	21	10
Ch.2	Firm generating capacity 2023	MW	0.099	0.021	4	0
Ch.2	Mean wind speed at 100 m	m/s	0.569	0.001	10	13
Ch.3	Population-weighted distance to transmission	km	0.484	0.001	13	8
Ch.3	Population-weighted distance to the MV network	km	0.253	0.001	7	0
Ch.4	MV line density	km / km ²	0.216	0.001	13	9
Ch.4	Distribution transformers per 1,000 households	per 1,000 hh	0.528	0.001	21	9
Ch.4	Distribution loss rate (modelled)	%	0.368	0.001	13	12
Ch.5	Grid access rate 2023 (calibrated)	%	0.514	0.001	22	12
Ch.5	Access gap 2030	% of households	0.514	0.001	12	22
Ch.5	Access gap 2030	households	0.025	0.571	0	1
Ch.5	Unelectrified health facilities	per 100,000 people	0.195	0.001	6	0
Ch.5	Unelectrified schools (2023)	count	0.410	0.001	9	0
Ch.5	Zonal capacity gap share 2030	MW	0.294	0.001	6	1
Ch.7	Plan capital expenditure 2024–2040	MUSD	-0.023	0.584	0	0

Chapter	Layer	Unit	Moran's I	p	Hot-spots	Cold-spots
Ch.7	Capital expenditure per person	USD / person	-0.024	0.283	0	0
Ch.7	Access investment 2024–2040	MUSD	0.054	0.180	2	0

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_gis_layers.csv).

The layers fall into three groups.

Strongly clustered (I above 0.4). Nature and infrastructure are the most clustered.

Layer	Moran's I
Wind speed	0.57
Transformers per 1,000 households	0.53
Access rate 2023	0.51
Access gap 2030 (share of households)	0.51
Distance to transmission	0.48
Consumption per person 2023	0.45
Unelectrified schools	0.41

Access, distance to the grid and LV reach cluster almost as strongly as the wind resource. The grid was built outward from Kampala and along the main roads, and it has reached the districts near its trunk. Access is not only low in the north; it is low in whole blocks of neighbouring districts. That is why the access problem is regional as well as local.

Moderately clustered (I from 0.1 to 0.4).

- Demand in 2023 and 2040, household, industrial and school demand, and commercial facilities, all centred on Kampala.
- Distribution losses (0.37), high in the north and north-east.
- MV line density (0.22).
- The zonal capacity gap (0.29).
- Unelectrified health facilities (0.20).

Not clustered (p above 0.05).

- Demand growth (–0.02).
- The access gap in households (0.03).
- Capital expenditure (–0.02), capex per person (–0.02) and access capex (0.05).

These are the layers driven by discrete projects or by district size, not by geography. Growth comes where a step load is sited. Investment goes where a plant is built. The absolute access gap is largest in the most populous districts, wherever they are.

Population density itself is only weakly clustered (0.06). Dense districts, such as Kampala and the Mbale highlands, are separated by sparse ones.

13.3 The hot-spots and the cold-spots

The local analysis identifies the same few regions again and again.

13.3.1 The central core

A cluster of high demand, high access and dense networks in six to eight districts:

- Kampala, Wakiso, Mukono, Buikwe, Mpigi and Luwero;

- with Jinja, Mityana, Buvuma and Namayingo in some layers.

It is the hot-spot of:

- demand in 2023 and 2040;
- consumption per person;
- household, industrial, health and school demand;
- the zonal capacity gap;
- unelectrified schools.

It is the cold-spot of distance to transmission. The central core is where the load, the growth in absolute terms and the network capacity problem are.

13.3.2 The south-western corridor

A hot-spot of access and LV reach stretching from Kampala through Masaka to Mbarara, 22 districts in all:

- Bukomansimbi, Butambala, Kalungu, Masaka, Kyotera and Ssembabule;
- Isingiro, Ibanda, Kiruhura, Kazo, Mbarara, Mitooma, Rwampara, Sheema and Ntungamo.

Its access rates are two to three times the national average, and its loss rates are among the lowest in the country. It is also the hot-spot of IERMP commercial facilities, with Hoima, Kabale and the Rwenzori districts.

13.3.3 Karamoja, Acholi and the north-east

The mirror image of the corridor. It is the hot-spot of the access gap and of distribution losses, and the cold-spot of access and LV reach:

- Karamoja: Abim, Kaabong, Karenga, Kotido, Moroto, Napak and Nabilatuk;
- Acholi: Agago and Kitgum;
- with Moyo, Otuke, Soroti and Maracha in some layers.

Distances to transmission are the longest in the country: Karenga 143 km, Kaabong 132 km, Kotido 81 km. The same districts are the hot-spot of the wind resource. Karamoja is the only part of Uganda where wind generation is viable (Chapter 5).

13.3.4 West Nile and the north-west

A hot-spot of distance to transmission and unelectrified health facilities: Adjumani, Amuru, Gulu, Madi Okollo, Moyo and Obongi. Koboko, Yumbe and Obongi are among the districts farthest from the grid.

13.3.5 The eastern highlands

The Mbale and Elgon districts are a hot-spot of population density. They are also a cold-spot of wind, being sheltered by Mount Elgon:

- Bududa, Butaleja, Manafwa, Mbale, Namisindwa, Sironko and Tororo.

Their access is middling. The plan's eastern gas plant at Tororo will make them one of the new supply centres.

13.4 Distance and access

Figure 13.2 shows the distribution of district access rates and of the population-weighted distance to transmission.

- **Access.** The median district access rate in 2023 was 16.6 %.
 - A quarter of districts were below 10 %.
 - Only 8 were above 50 %: Kampala, Mukono, Mbarara, Kalungu, Nakaseke, Sheema, Mpigi and Buikwe.

- Seven districts had access below 1 %. These are islands (Buvuma, Kalangala) or remote districts of Karamoja and the north (Kaabong, Kotido, Karenga, Obongi, Kapelebyong).
- **Distance to transmission.** The median district is 17.5 km from a transmission substation, and a quarter are more than 33 km away. The long tail, from 70 to 143 km, is the north and north-east.

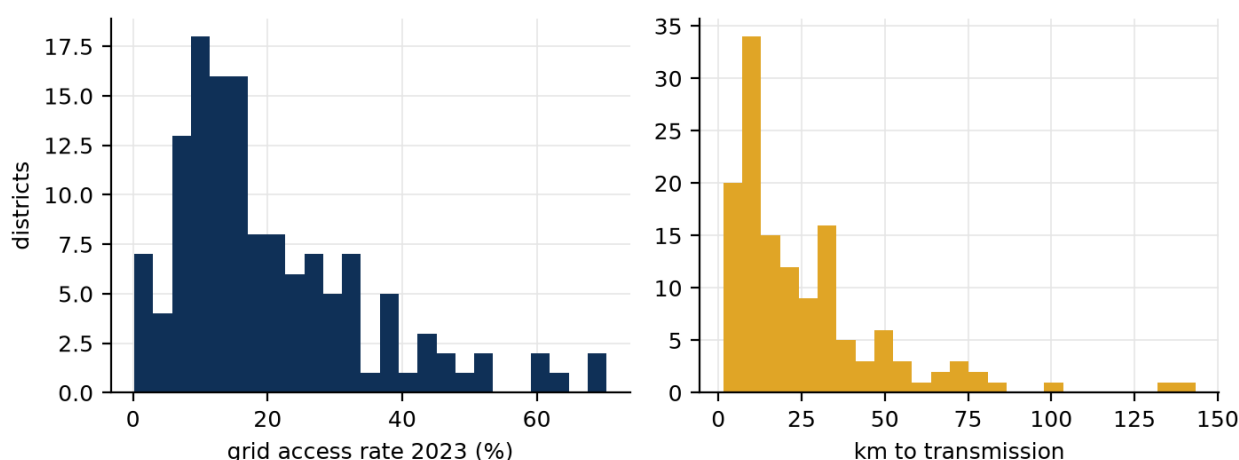


Figure 13.2: Distribution of district access rates and distance to transmission

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

The two are closely related. The rank correlation between access and distance to transmission is -0.57 , and between access and transformer density it is almost 1. Access is also strongly related to consumption per person (0.74) and inversely to distribution losses (-0.58).

Districts far from the grid have:

- fewer customers;
- longer and more lightly loaded lines;
- higher losses;
- lower consumption per connected customer.

Extending access there is both more expensive and less remunerative for the utility. That is why the access gap will not close by itself.

13.5 Where the grid is the answer, and where it is not

The spatial least-cost electrification analysis divides each district's unconnected households among six distance-to-MV bands, using the 1 km population grid. For each band it compares three options on a 20-year lifecycle cost per household at Tier 2 service (about 200 kWh a year):

- **grid extension:** connection, plus the MV line needed at the district's settlement density, plus grid energy;
- **mini-grid:** capital plus energy at the mini-grid levelised cost;
- **solar home system:** the system with two replacements over 20 years.

The lifecycle cost per household is:

$$C_m = K_m + \sum_{t=1}^{20} \frac{q c_m}{(1+r)^t} \quad (13.3)$$

where

- K_m is the upfront cost of mode m ;
- q is the household consumption;

- c_m is the cost of energy per kWh by mode;
- r is the discount rate.

Figure 13.3 maps the result.

- **Dominant mode.** The grid is the least-cost mode for most unconnected households in 117 of the 135 districts. Solar home systems dominate in 18:
 - eight in the north: Amuru, Lamwo, Madi Okollo, Nwoya, Obongi, Otuke, Pader and Alebtong;
 - five in Teso: Amuria, Kaberamaido, Kalaki, Kapelebyong and Katakwi;
 - three in the centre: the island districts of Buvuma and Kalangala, and Nakasongola;
 - two sparsely settled rangeland districts in the west: Kazo and Kiruhura.
- **Share of the grid.** In the median district, 94 % of unconnected households are best served by the grid. The share falls to 20–40 % in Obongi, Kapelebyong, Lamwo, Otuke, Amuria, Pader and Nwoya, and to 3 % in Buvuma.

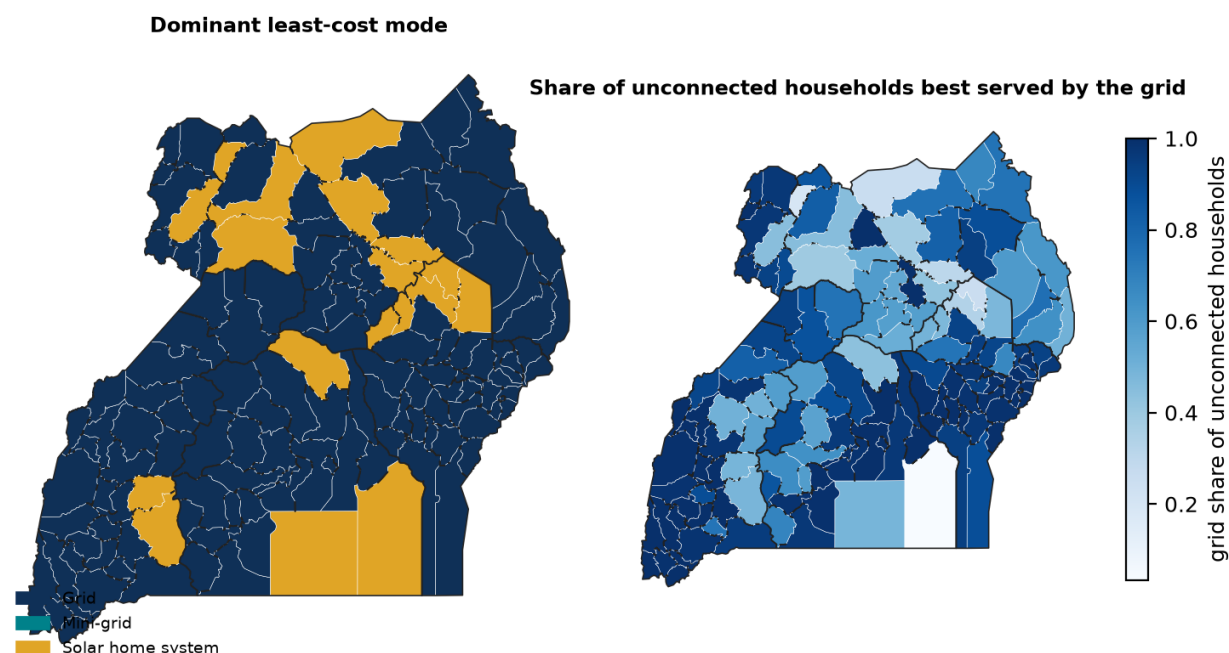


Figure 13.3: Spatial least-cost electrification: dominant mode and grid share by district

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Figure 13.4 and Table 13.2 aggregate the result by region.

The grid share of households to be connected is 87.5 % in the Central region, 91.2 % in the Eastern, 87.1 % in the Western and 74.2 % in the Northern region, where half a million households are best served by solar home systems.

Nationally, 85 % of households to be connected are best served by the grid and 15 % by solar home systems. No district band chooses mini-grids as its least-cost mode. At the Tier 2 service level, a mini-grid's upfront cost of 700 USD per connection and its higher energy cost cannot compete with either a solar home system, for dispersed households, or grid extension, for clustered ones.

This result is sensitive to the service tier. At Tier 3 and above, where households use appliances and small productive loads, mini-grids become competitive in dense settlements far from the MV network, such as trading centres, islands and refugee settlements. Their role should be assessed village by village with the settlement-level tools that the GIS engine prepares for, not district by district.

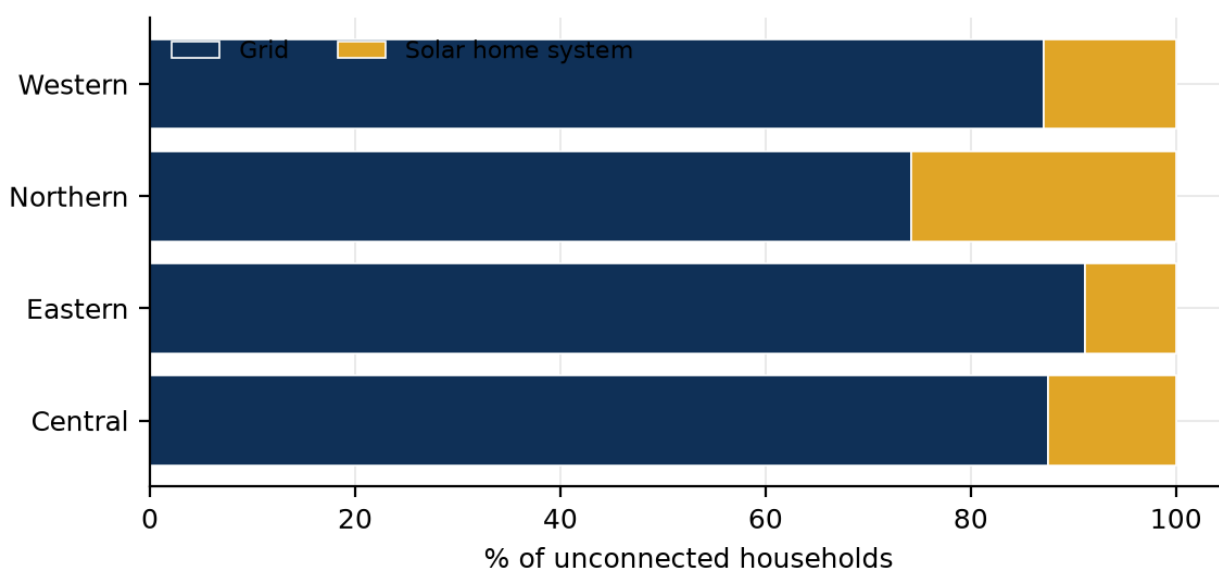


Figure 13.4: Least-cost electrification mode for unconnected households, by region

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 13.2: Least-cost electrification mode for unconnected households, by region

Region	Grid (hh)	Mini-grid (hh)	SHS (hh)	Grid share
Central	1,506,554	0	215,482	87.5%
Eastern	2,080,162	0	201,364	91.2%
Northern	1,444,943	0	501,719	74.2%
Western	1,779,391	0	262,479	87.1%

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_modes_region.csv).

13.6 What the spatial analysis means for delivery

The spatial pattern has four practical consequences.

1. **Access is a regional programme.** The access gap as a share of households is strongly clustered. A national programme allocated in proportion to the number of households would favour the populous central districts. A programme designed to close the gap must target the northern and north-eastern cluster, where the gap is proportionally largest and the cost per connection highest.
2. **Grid extension first, off-grid at the edge.** The grid is the least-cost option for 85 % of households, and for three quarters even in the north. Solar home systems are the answer at the edge of the network and in 18 sparsely settled districts, not a regional solution. The division between the two should be set on the 1 km population grid, band by band, and updated as the MV network grows.
3. **The network cold-spot is also a loss hot-spot.** The districts with the lowest transformer density have the highest losses. Extending the LV network and adding transformers there both connects households and reduces losses.
4. **Investment is not geographically targeted.** The plan's capital is not clustered. It follows the location of plants and corridors. Equity of benefit must therefore come from the design of the access and distribution programmes, not from the location of the big projects. Chapter 14 examines this.

13.7 Data quality and limitations

- **District scale.** District totals hide large differences within districts. A district with 30 % access may have a fully connected town and unconnected villages. The 1 km grid resolves part of this, but not the actual location of households.

- **Nearest-neighbour weights.** Moran's I depends on the choice of weights. The six-nearest-neighbour weights treat island and lakeshore districts as neighbours of mainland districts across water.
- **Multiple testing.** With 26 layers and 135 districts, some LISA clusters will be significant by chance. Isolated significant districts should be interpreted with care; the large, persistent clusters described above are robust.
- **Access modes.** The mode split uses average costs and a single service tier. Actual project costs vary with terrain and road access, which the analysis does not model.

13.8 Implications for planning

- Target the access programme at the northern and north-eastern cluster, measured by the share of households unconnected, not by their number.
- Use the 1 km population grid and the MV network to divide households between grid extension and solar home systems. Update the division yearly as the network grows.
- Combine LV extension with loss reduction in the network cold-spot. Both have the same geography.
- Keep the GIS layers current. New MV lines, transformers and connections change the least-cost boundaries every year, and the engine can recompute them in minutes.

CHAPTER 14

14 Equity: who is served and who pays

A least-cost plan minimises the total cost of the system. It does not ask who receives the electricity or who bears its cost. This chapter asks both questions. It measures the distribution of supply, consumption, access and investment across regions, districts and customer classes, and asks whether the plan narrows or widens the gaps.

14.1 How equity is measured

The engine computes four measures.

- **Concentration index of firm supply.** Districts are ranked by their need per person, meaning demand per capita. The index compares the cumulative share of firm generating capacity with the cumulative share of population. It is zero if supply is spread in proportion to population. It is positive if supply is concentrated in the districts with the highest need, and negative if it is concentrated in those with the lowest.
- **Gini coefficient of consumption per person.** This measures inequality in electricity use between districts, weighted by population. It is zero if every district consumes the same per person, and approaches one if one district consumes everything.
- **Regional shares.** Each region's share of population, demand, access gap and investment.
- **Cost to serve and tariff by class.** Who pays more than their cost, and who pays less (Chapter 7).

The concentration index is computed from the concentration curve:

$$CI = 1 - \sum_k (P_k - P_{k-1})(S_k + S_{k-1}) \quad (14.1)$$

where

- P_k is the cumulative population share of the first k districts, ranked by need per person;
- S_k is their cumulative share of supply.

The Gini coefficient uses the same formula, with districts ranked by consumption per person and S_k as the cumulative share of consumption.

14.2 Where the power is

Figure 14.1 plots the concentration curve of firm generating capacity against need.

The concentration index is **0.15**. Firm capacity is concentrated in the districts with higher demand per person. This is because the Nile cascade (Nalubaale, Kiira, Bujagali, Isimba, Karuma) is sited near the Kampala–Jinja load centre, together with the thermal plants at Namanve and Tororo.

In a transmission-connected system this concentration does no harm in itself. The grid carries the power to where it is used. It matters in two ways.

- **Network.** The districts far from the plants depend on long radial lines. Those lines have the highest losses and lowest reliability (Chapters 6 and 7).
- **Security.** If the grid is interrupted, the north and west have no firm supply of their own. The plan's western geothermal and gas, and the Karamoja wind, spread the generation more widely by 2040.

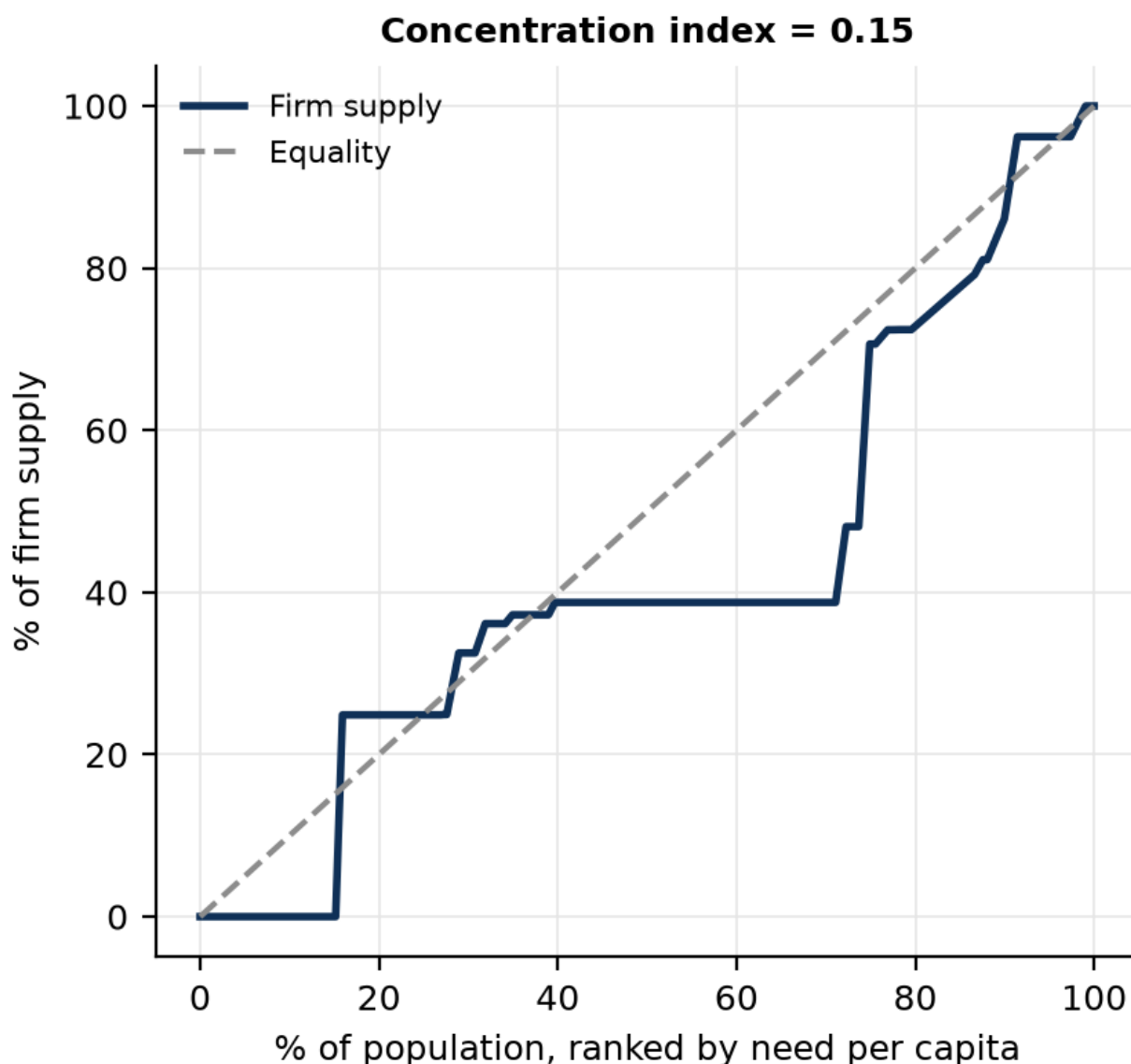


Figure 14.1: Concentration curve of firm generating capacity against need

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

14.3 Who uses the power

Electricity use is highly unequal.

- **The engine's Gini coefficient** of consumption per person across districts is **0.50**. That is higher than the Gini of household income in Uganda, which is about 0.43.
- **Kampala** has 4 % of the population and consumes 14 % of the electricity.
- **The bottom half:** the half of the population living in the districts with the lowest consumption per person uses only 21 % of the electricity.
- **The top tenth:** the tenth of the population in the highest-consuming districts uses 34 %.

Figure 14.2 and Table 14.1 compare the four regions.

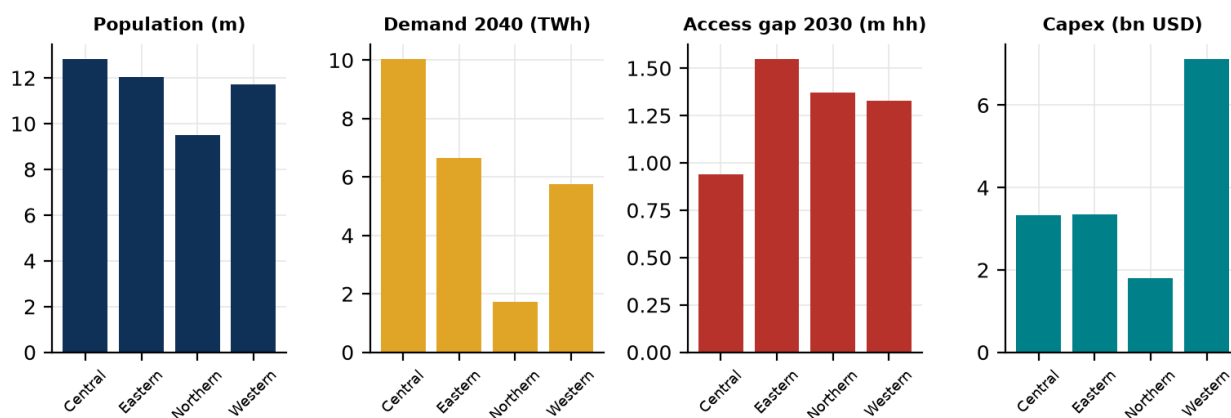


Figure 14.2: Regional comparison: population, demand, access gap and investment

Source: AICTEM Energy Modelling Engine, base scenario S0 (uganda_2023)

Table 14.1: Regional (ADM1) comparison

Region	Population 2023 (m)	Demand 2023 (GWh)	Demand 2040 (GWh)	Access gap 2030 (hh)	Capex (MUSD)	kWh per person 2023
Central	12.8	2,143	10,046	940,933	3,337	167
Eastern	12.0	948	6,656	1,549,564	3,345	79
Northern	9.5	304	1,736	1,369,569	1,802	32
Western	11.7	935	5,748	1,328,103	7,126	80

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_regions.csv).

Region	Population (m)	kWh per person 2023	Access 2023	Demand growth to 2040	Capex per person (USD)
Central	12.8	167	42 %	4.7×	260
Eastern	12.0	79	18 %	7.0×	278
Northern	9.5	32	12 %	5.7×	190
Western	11.7	80	25 %	6.1×	608

Access rates are population-weighted averages of the district rates.

- **The Central region** consumes more than five times as much electricity per person as the Northern region. Its access rate is more than three times as high.
- **The Eastern and Western regions** are in between, at about half the Central level per person.
- **The Northern region**, with a fifth of the population, used 7 % of the electricity in 2023.

14.4 Does the plan narrow the gaps?

14.4.1 Access: yes, strongly

The plan's access programme reaches 100 % in every district by 2040. The regional gap in access, from 12 % to 42 % in 2023, closes completely. Access investment is distributed roughly in proportion to the access gap.

Region	Share of the 2030 access gap	Share of access investment
Central	18 %	21 %
Eastern	30 %	28 %
Northern	26 %	25 %
Western	26 %	25 %

The Northern region receives slightly less per household to be connected. More of its households are best served by solar home systems (26 %, compared with 9–13 % elsewhere; Chapter 13), and these cost less upfront than a

grid connection. A solar home system at Tier 2 provides a lower level of service than a grid connection. The "equal access" of 2040 is therefore not equal service: a quarter of northern households would have a 200 kWh-a-year system rather than a grid connection.

14.4.2 Consumption: no, the gap widens in absolute terms

Demand grows fastest in the Eastern region (7.0×), driven by the Tororo and Mbale industrial parks and the step loads. It grows slowest in the Central region (4.7×), which starts from the highest level.

However, the step loads are concentrated in a few districts:

- Kampala, Wakiso, Mukono and Buikwe;
- Jinja;
- the western oil region.

A recomputation from this report's district layers, holding 2023 population weights, gives a Gini of consumption per person of 0.43 in 2023 and **0.58 in 2040**. The engine's gap module gives 0.50 for 2023, because it works on its own district cube. On either basis the direction is clear: consumption concentrates further, even as household access becomes universal.

This is not a failure of the plan. Industrial demand is where industry is. But the figure should not be read as a measure of welfare.

14.4.3 Investment: concentrated where plants are built

Capital expenditure per person is highest in the Western region (608 USD), where the geothermal and gas plants are built, and lowest in the Northern region (190 USD). The Gini of capex per person across districts is 0.59, the highest of any measure. Investment is not clustered geographically (Chapter 13), but it is very unequal between districts: a few host projects worth billions, and most receive only access and distribution funding.

The benefits of generation investment are national. The local benefits are not:

- construction jobs;
- local procurement;
- royalties and district revenue.

They go to the host districts. A benefit-sharing arrangement for the districts that host generation and those crossed by transmission would spread them more widely.

14.5 Who pays

Chapter 7 showed that the 2023 tariff structure transfers money **from households to industry**.

- **Residential customers** pay 213 USD/MWh against a cost to serve of 150 USD/MWh. They provide a cross-subsidy of 61 million USD a year.
- **Commercial customers** provide 12 million USD.
- **Large and extra-large industrial customers** pay 3–6 USD/MWh less than their cost to serve.

For the average residential customer using 481 kWh a year, the bill is about 100 USD a year. Of that, about 30 USD is the cross-subsidy.

As the plan is built, the average cost of supply rises from 118 to 158 USD/MWh (Chapter 11). If the increase is passed through in proportion to the current tariffs, the household cross-subsidy would grow with it. Industry's share of demand is growing, from about half in 2023 to almost two thirds in 2040, so the pressure to keep industrial tariffs competitive will grow too.

The equity of the plan therefore depends on tariff policy as much as on its physical content. The options are:

- **Rebalance the tariffs**, so that each class pays its cost to serve. Residential tariffs would fall by about 30 % and industrial tariffs would rise slightly.
- **A targeted lifeline tariff** for low-consumption households, funded from the general budget rather than from other customers.
- **Connection subsidies**, so that the cost of the connection is not a barrier. It is 250 USD for the grid and about 360 USD for a solar home system, compared with a rural household cash income of a few hundred dollars a year.

14.6 Institutions

The access programme includes the electrification of 1,096 unelectrified health facilities and 13,349 unelectrified schools (Chapter 8).

- **Health facilities.** The unelectrified facilities cluster in the north-west (Adjumani, Amuru, Gulu, Madi Okollo, Moyo, Obongi).
- **Schools.** The largest numbers are in the populous central districts, where many schools are still not connected.

The plan electrifies all of them by 2030 for health facilities and by 2035 for schools, at a cost of 181 million USD. This is the most direct equity investment in the plan. It brings electricity-dependent services (vaccine refrigeration, maternity lighting, laboratory equipment, ICT in schools) to populations whose own homes may wait until the late 2030s for a connection.

14.7 Data quality and limitations

- **District averages.** Equity within districts, between urban and rural, rich and poor, and men and women, cannot be measured with the engine's data. The Uganda National Household Survey would allow analysis of access and consumption by income quintile and by sex of household head, and should be linked to the engine in a future version.
- **Consumption, not welfare.** Consumption per person includes industrial use. It measures where electricity is used, not who benefits from it.
- **Tariff simulation.** Tariff rebalancing is described, not simulated. The engine does not model the price elasticity of demand.

14.8 Implications for planning

- Universal access by 2040 closes the largest equity gap. The access programme should be front-loaded in the north and north-east, where the gap is proportionally largest.
- The quarter of northern households served by solar home systems should have a path to a higher service tier, through system upgrades or later grid extension, so that "access" does not mean permanently lower service.
- The tariff structure should be rebalanced so that households do not subsidise industry. A targeted lifeline tariff can protect low-consumption households at lower cost.
- Institutions should be electrified early. Health facilities and schools bring the benefits of electricity to communities before households are connected.
- Districts that host generation and transmission should share in the benefits through a transparent benefit-sharing mechanism.

CHAPTER 15

15 Validation: can the results be trusted?

A planning model is only useful if its results can be trusted. This chapter sets out how the engine is checked:

- **Internal consistency:** its accounts close.
- **Calibration:** it reproduces the observed 2023 system.
- **Solution quality:** its optimisations solve to optimality and respect their constraints.
- **Reproducibility:** the same inputs give the same results.

It reports the result of every validation check run for this report, and closes with the known limitations of the model.

15.1 The validation framework

Each design chapter of the engine defines a set of validation checks. The engine runs them automatically every time the modules are solved. A check has three possible results:

- **pass:** the condition holds within its tolerance;
- **warn:** it holds only approximately, or holds with a documented exception;
- **fail:** it does not hold. The results of that module should not be used until the cause is found.

The checks are of four kinds.

1. **Identity checks.** An account that must close exactly does close. Examples:
 - the sum of segment demands equals the national total;
 - district losses sum to national losses;
 - the energy waterfall from generation to billed energy closes.
2. **Calibration checks.** The model reproduces an observed quantity within a stated tolerance. Examples:
 - 2023 modelled generation compared with metered generation;
 - modelled transmission losses compared with observed losses;
 - modelled national access compared with the census.
3. **Solver checks.** Every PyPSA optimisation reports status "ok:optimal", and its solution respects the constraints:
 - flows within line ratings;
 - reserve met;
 - builds within resource potentials;
 - the NPV reported equal to the solver's objective.
4. **Data integrity checks.**
 - Every district has population, geometry and a zone bus.
 - Every health facility is tagged to a district.
 - The GeoJSON coordinates are in the right order.
 - No year is duplicated.

The engine also has 29 automated unit and integration tests (`tests/`). They cover:

- data loading and GIS;

- each module's main function;
- the web application's API;
- the rendering of every diagnostic and planning page.

15.2 Results for this report

All **43 of 43** checks pass for the base scenario S0 (Table 15.1).

Table 15.1: Validation checks of the base run (docs/01–09)

Check	Result	Detail
V1-1	pass	Σ segments 2023 = 4,329.8 GWh vs metered 4,329.8 GWh
V1-2	pass	requirement 2023 5,978.5 GWh vs generated 5,987.2 GWh
V1-3	pass	Σ bus-slice energy = system load (max error 2.22e-16)
V1-4	pass	district totals = national segment totals
V1-5	pass	access $\leq$ 100 %, non-decreasing; 2040 access 100.0%
V1-6	pass	no duplicate (segment, year) rows
V2-1	pass	installed 2,033.3 MW = technology + hydro tables
V2-2	pass	2023 modelled 6,194 GWh vs metered 5,987 GWh (+3.4 %); hydro share 90.7% vs 93.4%
V2-3	pass	PyPSA status ok for every dispatch year: 2023:ok:optimal, 2026:ok:optimal, 2030:ok:optimal, 2035:ok:optimal, 2040:ok:optimal
V2-4	pass	supply $\geq$ load in every slice (min surplus 21.867 MW = losses)
V2-5	pass	cyclic_state_of_charge=True on every reservoir and battery: PyPSA closes each storage balance over the slice sequence (end state = start state)
V3-1	pass	24 corridors with valid endpoints and coordinates
V3-2	pass	$ \text{flow} \leq \text{capacity}$ on every corridor and slice (non-expansion solves)
V3-3	pass	modelled 2023 transmission losses 255.3 GWh vs observed 288.6 GWh (-12 %)
V3-4	pass	N-1 intact baseline shed 0.0 MW = peak-slice shed of the full dispatch
V3-5	pass	coverage population 46,081,757 = national district total
V4-1	pass	waterfall closes: generation – losses – net exports = billed; statistical difference 8.7 GWh
V4-2	pass	district losses 908.9 GWh = national 908.9 GWh
V4-3	pass	class energies 4,329.8 GWh = final consumption
V4-4	pass	every populated 1 km cell assigned to one distribution substation (126,986 cells)
V5-1	pass	2023 unserved with observed demand 0.00 GWh $\approx$ 0
V5-2	pass	district access gaps sum to the national gap
V5-3	pass	every gap row has a unit and status
V5-4	pass	Moran's I permutation p-value reproducible (seed 42)
V6-1	pass	solver status ok:optimal in 39.8 s
V6-2	pass	unserved $\leq$ 0.01 % of demand in every period: 2026: 0.00 GWh, 2030: 0.00 GWh, 2035: 0.00 GWh, 2040: 0.00 GWh
V6-3	pass	reserve constraint met: 2026: 1,439 $\geq$ 1,439 MW, 2030: 2,309 $\geq$ 2,309 MW, 2035: 3,540 $\geq$ 3,540 MW, 2040: 5,596 $\geq$ 5,596 MW
V6-4	pass	Σ builds $\leq$ resource potential for every candidate
V6-5	pass	NPV from cost table 4,365.4 MUSD vs PyPSA objective 4,365.4 MUSD
V6-6	pass	no RE target set (RE share reported, not constrained)
V7-1	pass	Σ disbursements 7,765.5 MUSD = Σ overnight capex of generation & storage
V7-2	pass	Σ district capex = national capex
V7-3	pass	finance shares sum to 100 % in every category
V7-4	pass	recovered overnight capex matches IRP (solar 900 USD/kW)
V9-1	pass	Σ commissioned 5,935.1 MW = Σ plan builds 5,935.1 MW
V9-2	pass	no commissioning before available_from
V9-3	pass	system state in planning years equals the Ch.6 capacity path

Check	Result	Detail
V9-4	pass	0 transition-gap years, each with a bridging action and re-verification
V8-1	pass	135 districts; all with population, geometry and zone bus: True
V8-2	pass	3169 health facilities tagged to districts
V8-3	pass	modelled national access 0.2530 vs census 0.253
V8-4	pass	district households sum 10,698,913 = census total
V8-5	pass	GeoJSON lon/lat order, 135 features

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_checks.csv).

15.2.1 Demand (V1)

- **V1-1.** The segment demands for 2023 sum to exactly the metered final consumption of 4,329.8 GWh.
- **V1-2.** The requirement at generation, with losses and exports added, is 5,978.5 GWh. That is within 0.2 % of the 5,987.2 GWh actually generated.
- **V1-3 and V1-4.** The allocation of demand to buses, slices and districts preserves the national total to machine precision.
- **V1-5.** Access is bounded and non-decreasing.
- **V1-6.** No year is duplicated.

15.2.2 Generation (V2)

- **V2-1.** Installed capacity (2,033 MW) matches the technology and hydro plant tables.
- **V2-2.** The 2023 dispatch produces 6,194 GWh, 3.4 % above metered generation, with a hydro share of 90.7 % against 93.4 % observed.

Plant by plant (Table 5.4, Chapter 5):

- the large hydro plants are calibrated exactly;
- small hydro and bagasse are within 0.2 %;
- the solar plants are within ± 15 %.

The two exceptions are documented.

- **Busitema solar** has no metered output for 2023 in the data. The model dispatches it at its resource availability (6.7 GWh), so the percentage error is meaningless.
- **The Namanve HFO plant** is dispatched at 234 GWh in the model, against 64 GWh metered. In practice it was held in reserve behind the hydro plants more than the model's slice-based dispatch allows.

Both have a negligible effect on the national balance.

- **V2-3.** The solver status is optimal for every dispatch year.
- **V2-4.** Supply meets load in every slice.
- **V2-5.** Every storage unit's state of charge is cyclic.

15.2.3 Transmission (V3)

- **V3-1.** All 24 corridors have valid endpoints and coordinates.
- **V3-2.** Flows are within ratings in every slice of the non-expansion solves.
- **V3-3.** Modelled transmission losses in 2023 are 255 GWh against 289 GWh observed, 12 % below. The transport model does not represent reactive power and voltage, which account for part of the observed losses.
- **V3-4.** The N-1 baseline is consistent with the full dispatch.
- **V3-5.** The coverage analysis accounts for the whole population, 46.08 million.

15.2.4 Distribution (V4)

- **V4-1.** The energy waterfall closes to a statistical difference of 8.7 GWh, 0.15 % of generation.
- **V4-2.** District losses sum to national losses.
- **V4-3.** Class energies sum to final consumption.
- **V4-4.** Every one of the 126,986 populated 1 km cells is assigned to exactly one distribution substation.

15.2.5 Gaps (V5)

- **V5-1.** With the observed 2023 demand, the model sheds no load. The model does not invent a gap that did not exist in 2023.
- **V5-2.** District access gaps sum to the national gap.
- **V5-3.** Every row of the gap register has a unit and a status.
- **V5-4.** Moran's I permutation tests are reproducible with a fixed seed.

15.2.6 Least-cost plan (V6)

- **V6-1.** The four-period expansion solved to optimality in 40 seconds.
- **V6-2.** Unserved energy is zero in every period.
- **V6-3.** The reserve constraint binds exactly in every period, at 1,439, 2,309, 3,540 and 5,596 MW. This confirms that the plan builds no more firm capacity than the reserve requires.
- **V6-4.** No candidate exceeds its resource potential.
- **V6-5.** The NPV computed from the cost table (4,365.4 million USD) equals the solver's objective to the nearest 0.1 million USD.
- **V6-6.** No renewable target was imposed on S0.

15.2.7 Investment (V7)

- **V7-1.** Disbursements sum to overnight capex.
- **V7-2.** District capex sums to national capex.
- **V7-3.** Financing shares sum to 100 % in every category.
- **V7-4.** The overnight cost recovered from the annualised IRP cost matches the IRP value (900 USD/kW for solar).

15.2.8 GIS (V8)

- **V8-1.** All 135 districts have population, geometry and a zone bus.
- **V8-2.** All 3,169 health facilities are tagged to districts.
- **V8-3.** The modelled national access rate (25.30 %) equals the census rate (25.3 %).
- **V8-4.** District households sum to the census total of 10,698,913.
- **V8-5.** The GeoJSON is in longitude–latitude order.

15.2.9 Expansion (V9)

- **V9-1.** Commissioned capacity (5,935.1 MW) equals the plan's builds.
- **V9-2.** Nothing is commissioned before its first available year.
- **V9-3.** The system in each planning year equals the plan's capacity path.
- **V9-4.** No year of the annual verification has unserved energy above the threshold, so no bridging action was triggered.

Check V9-4 tests energy adequacy, not reserve. The transition gap in firm reserve in 2027–2029 identified in Chapter 12 does not cause V9-4 to fail. It is reported separately.

15.3 Calibration against the observed 2023 system

Table 15.2 summarises how closely the engine reproduces the observed 2023 system.

Table 15.2: Calibration of the engine against observed 2023 quantities

Quantity	Observed	Modelled	Difference	Status
Final consumption (GWh)	4,329.8	4,329.8	0.0 %	OBSERVED
Generation (GWh)	5,987.2	6,193.6	+3.4 %	CALIBRATED
Hydro share of generation	93.4 %	90.7 %	−2.7 pp	CALIBRATED
System peak (MW)	988	988	0.0 %	OBSERVED
Transmission losses (GWh)	288.6	255.3	−11.5 %	MODELLED
Distribution loss rate	17.3 %	17.3 %	0.0 %	CALIBRATED
National access rate	25.3 %	25.3 %	0.0 %	CALIBRATED
Unserved energy (GWh)	≈ 0	0.0	–	MODELLED
Emissions (kt CO ₂)	–	154	–	MODELLED

The model reproduces the observed energy balance, peak, losses and access closely. The quantities it reproduces less well are:

- **Transmission losses**, because of the simplified network model.
- **The thermal dispatch**. The model runs thermal plants when they are cheapest in its slices, while the actual system held them in reserve.

Neither affects the planning conclusions materially.

15.4 What validation does not cover

Passing every check means that the engine is internally consistent and reproduces 2023. It does not mean that its projections are right. The projections depend on assumptions that cannot be validated against the past:

- **The step loads**. The IERMP industrial parks, steel, data centres and mining are the largest source of uncertainty. Chapter 10 shows that they determine the scale of the plan.
- **Hydrology**. The engine uses a single average year with a dry-year sensitivity. It does not model the sequence of wet and dry years or climate change.
- **Technology costs**. IRP costs for 2023 are used for the whole horizon, except in the sensitivities.
- **Network physics**. The transport model does not represent AC power flow, voltage stability or dynamic stability. The corridor capacities are thermal limits. The actual transfer capacity of long radial lines may be lower.
- **Behaviour**. Demand does not respond to price. Utilities and investors are assumed to build what the plan says, on time.

15.5 Reproducibility

Every result in this report can be reproduced from the repository. The steps are:

1. `python report/build/collect.py` runs all modules and the 29 simulations for the base dataset `uganda_2023`, and writes the tables and bundle to `report/build/data/`.
2. `python report/build/figures.py` draws the figures and maps.
3. `node report/build/build_docx.js` builds this document.

The engine caches each module result by a hash of its inputs, so a re-run with unchanged inputs is fast. The seeds of all random permutation tests are fixed. The PyPSA models are solved with HiGHS, which is deterministic for a given problem.

The web application at <http://127.0.0.1:8070> shows the same results interactively and lets the planner run new scenarios.

15.6 Data quality and limitations

- The validation checks are necessary, not sufficient. They catch errors of arithmetic and data, not errors of assumption.
- Several inputs are ASSUMED rather than OBSERVED (Chapter 3 and Annex B). Their influence is tested in Chapter 10, but the tests are one at a time.
- The model has not been validated against an independent planning study. A comparison with the IRP's own results would be a useful next step.

15.7 Implications for planning

- The engine can be used for planning with confidence in its accounts and its optimisation. Its projections should be read as conditional on the assumptions stated.
- The weakest parts of the model (step loads, hydrology, network physics) should be the priority for improvement:
 - a register of committed industrial loads;
 - a hydrological series for the Nile and Lake Victoria;
 - an AC load-flow study of the plan's corridors.
- The validation checks should be run and published with every planning update, so that users can see the status of each result.

CHAPTER 16

16 Using the engine: the web application and planning integration

This report is one output of the AICTEM Energy Modelling Engine. The engine is also a working tool. Planners can use it to:

- re-run the analysis with new data or assumptions;
- explore the results interactively;
- export them to the budget and planning systems of government.

This chapter describes the web application, the headless command line, the exports, and the links to the Medium-Term Expenditure Framework and the unit-cost system. It implements design Chapter 10 (`docs/10_web_application.md`).

16.1 Architecture

The engine is a Python package, `energy_engine/`, with one module for each chapter of the design:

- data;
- demand;
- generation;
- transmission;
- distribution;
- gaps;
- planning;
- investment;
- GIS;
- expansion.

It also has a PyPSA model builder (`pypsa_model.py`), a chart builder (`charts.py`) and the page assemblers.

The web application, `app/`, is a FastAPI server with a single-page front end built on Plotly.js and Leaflet.

- **Charts and GeoJSON.** Every chart is built on the server as Plotly figure JSON, and every map layer is served as GeoJSON with its legend. The numbers and their presentation therefore come from the same code.
- **Caching.** Results are cached in memory and on disk, keyed by a hash of the dataset, the scenario parameters and the module. A page whose inputs have not changed loads in under a second.
- **Background jobs.** The least-cost plan (about 40 seconds) and the eight-scenario comparison (a few minutes) run as background jobs with progress reporting.

16.2 The pages

The application has ten module pages, a scenario manager and a data page. Every module page follows the same layout:

1. **KPI tiles**, each with its status chip (OBSERVED, CALIBRATED, MODELLED or ASSUMED);

2. **a map**, with layer toggles, legend and table view;
3. **charts**, each with a title, the question it answers, a status footnote, a table view and CSV and PNG download;
4. **tables** with download.

Tab	Page	Content
0	Overview	National KPIs; the needs → gaps → plan → cost storyline; the headline map of access-gap hot-spots and plan builds; validation status
1	Demand	Segment demand, households and access, step loads, load shape, district demand maps
2	Generation	Fleet, dispatch, hydrology, merit order, emissions, calibration
3	Transmission	Grid inventory, corridor loading, N-1, coverage, reinforcement screen
4	Distribution	Energy waterfall, losses, customers and tariffs, MV reach, substation loading
5	Gaps	Capacity, energy, reliability, network, loss and access gaps; gap register
6	Least-cost plan	Run plan; capacity path, generation mix, prices, reserve duals, scenario comparison
7	Investment	Capex by category, year, region and district; financing; tariff path; MTEF export
8	GIS explorer	Full-screen map of all layers, district profile, spatial statistics
9	Expansion	Roadmap, annual state, verification, critical path, time-enabled map

Across the pages there are about 130 charts and 20 maps. The charts follow one design system:

- a fixed colour for each technology and segment on every page;
- one y-axis per chart;
- hover tooltips;
- a table view for every chart;
- a dark mode validated separately from the light mode.

Figure 16.1 shows the Overview page. The national KPIs run along the top. The headline map shows the access-gap hot-spots (red) in the north and north-east, the cold-spot (blue) along the Kampala–Mbarara corridor, and the plan's new plants sized by capacity. The scenario panel on the left holds every assumption of the base scenario.

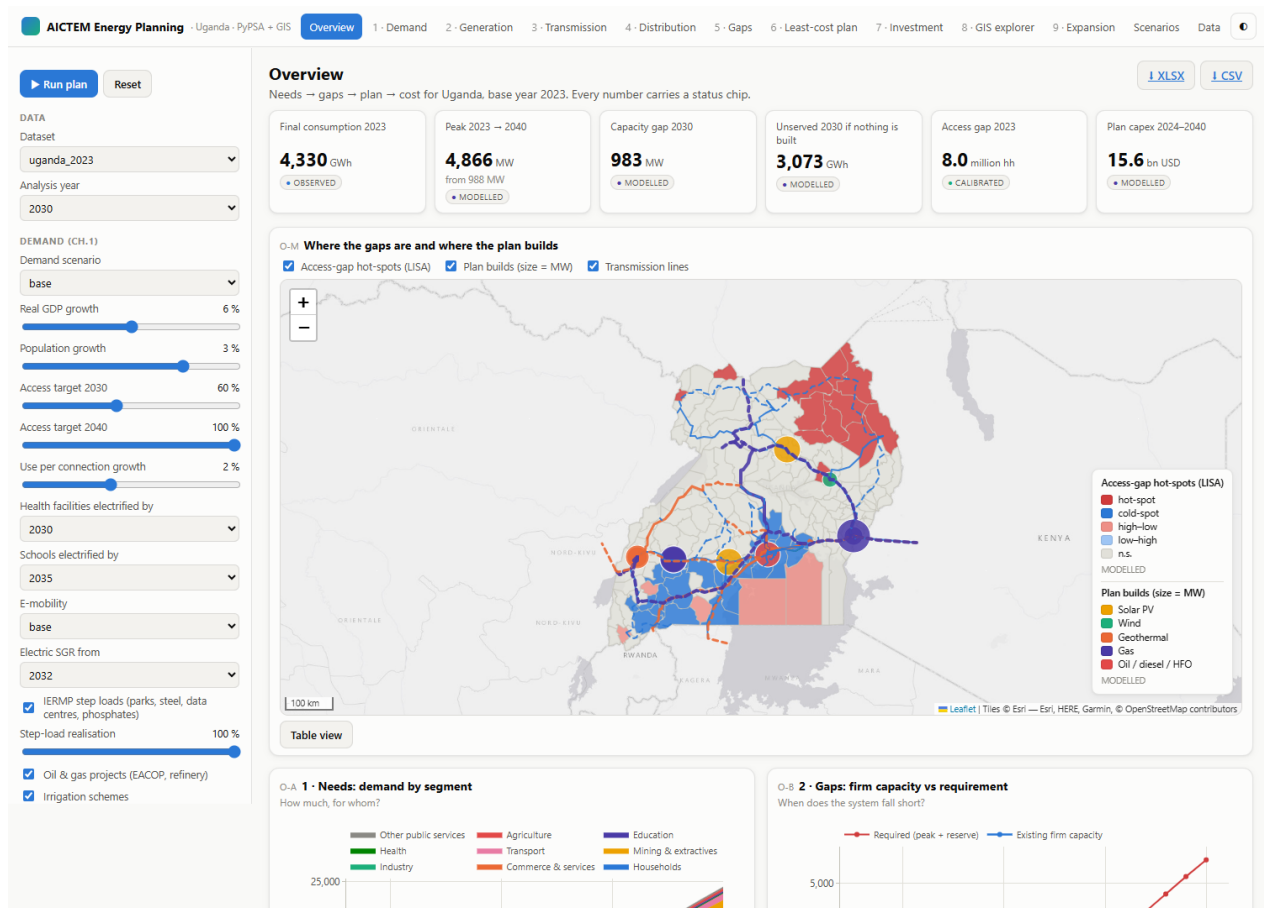


Figure 16.1: Web application: Overview page with national KPIs, the needs–gaps–plan–cost storyline and the headline map

Source: AICTEM Energy Modelling Engine web application (<http://127.0.0.1:8070/>), base scenario S0

Figure 16.2 shows the Demand page, and Figure 16.3 the Least-cost plan page. The **Run plan** button starts the PyPSA multi-period solve for the current scenario. **Compare scenarios** solves the standard set S0–S7 in the background.

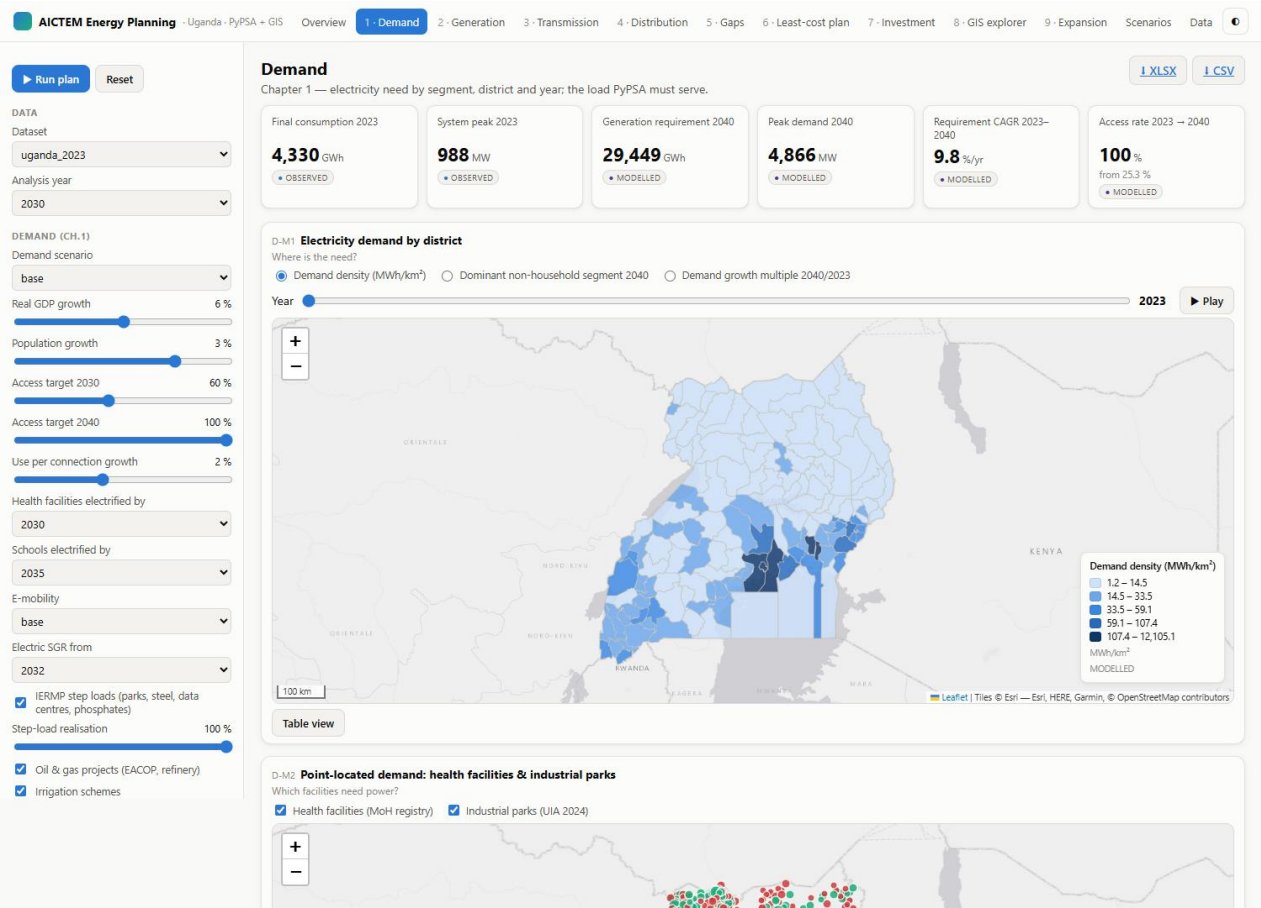


Figure 16.2: Web application: Demand page with scenario panel, KPI tiles, map and charts
Source: AICTEM Energy Modelling Engine web application (<http://127.0.0.1:8070/>), base scenario S0

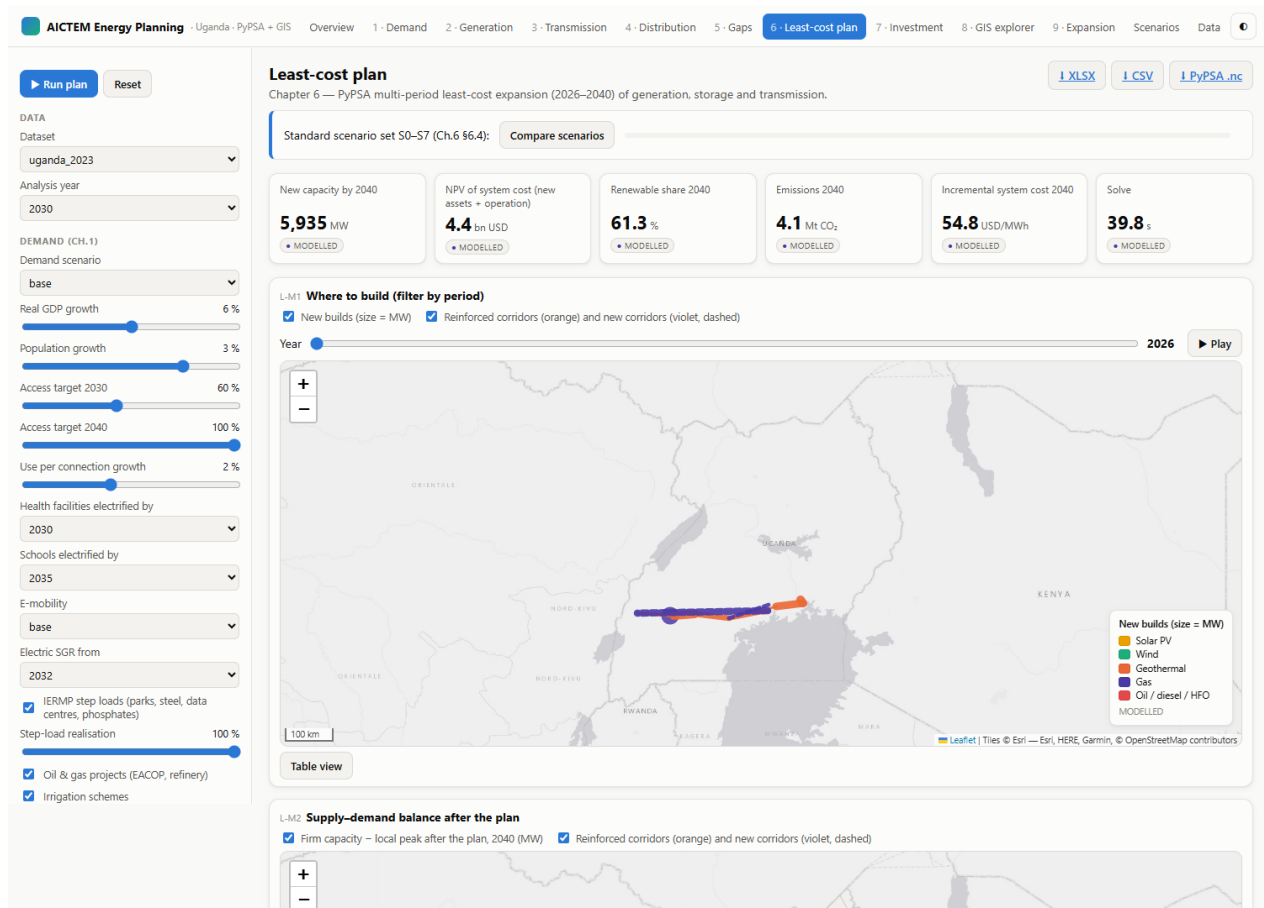


Figure 16.3: Web application: Least-Cost Plan page with the Run plan and Compare scenarios controls

Source: AICTEM Energy Modelling Engine web application (<http://127.0.0.1:8070>), base scenario S0

Figure 16.4 shows the GIS explorer. Every district layer of Chapter 13, with its LISA classification, can be displayed. Clicking a district opens its profile: demand, access, grid distance, losses, gaps and investment for that district.

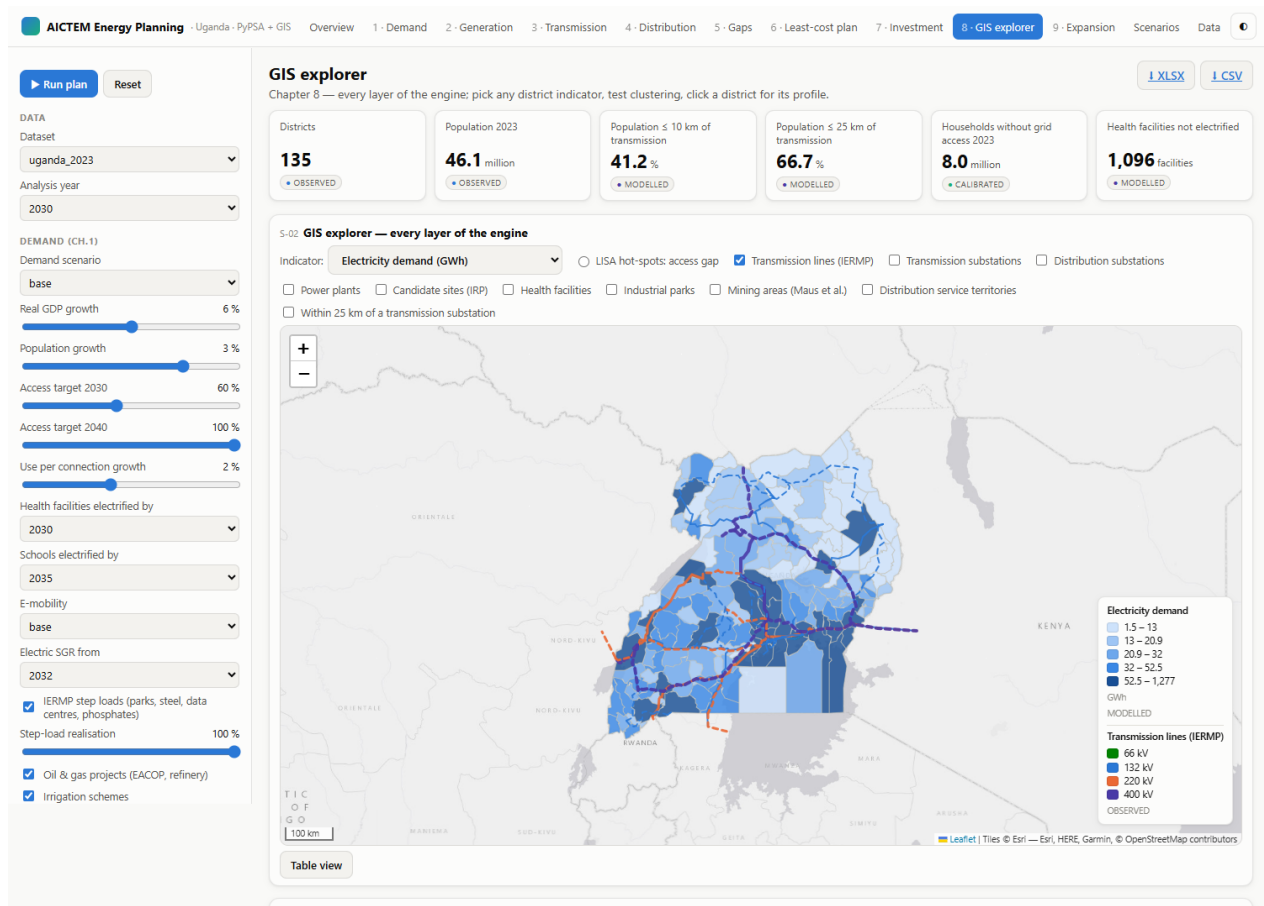


Figure 16.4: Web application: GIS Explorer with layer tree and district profile

Source: AICTEM Energy Modelling Engine web application (<http://127.0.0.1:8070/>), base scenario S0

Figure 16.5 shows the Expansion page in dark mode. Its map has a year slider and a play button. They show the plants coming online and district access rising year by year from 2023 to 2040.

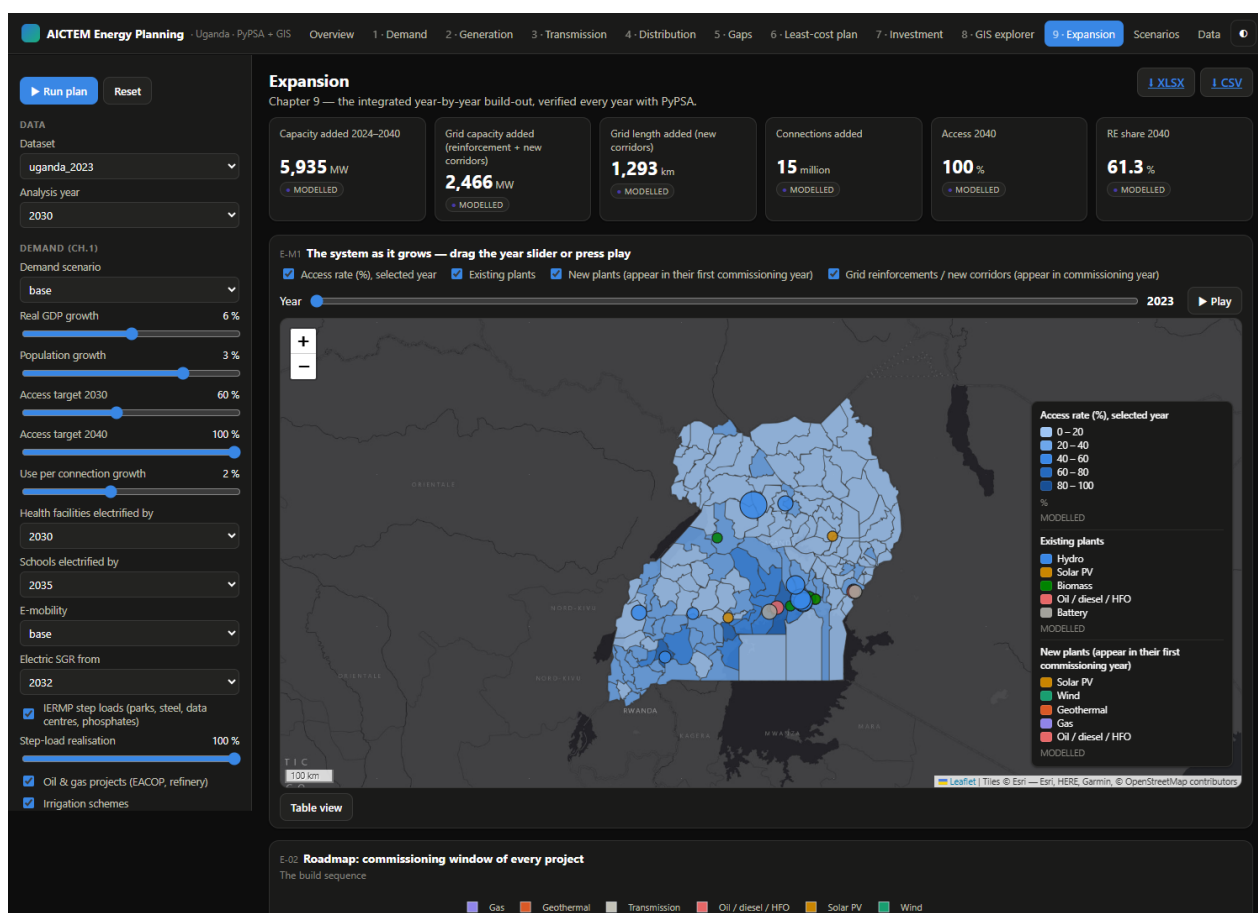


Figure 16.5: Web application: Expansion page in dark mode, with the time-enabled map

Source: AICTEM Energy Modelling Engine web application (<http://127.0.0.1:8070/>), base scenario S0

On a phone the scenario panel collapses into a drawer and the charts stack in one column.

16.3 Running a scenario

The scenario panel exposes every assumption of the engine.

Group	Controls
Data	Dataset, base year, analysis year
Demand	Demand scenario, GDP and population growth, access targets for 2030 and 2040, use per connection growth, health and school electrification years, e-mobility, SGR year, step loads and their realisation, oil and gas projects, irrigation
Losses	Distribution loss target and year, collection target
Supply	Hydrology, carbon price, renewable target, CO2 cap, reserve margin, value of lost load, excluded technologies, batteries, transmission expansion, capex multipliers
Finance	Discount rate, WACC, financing mix
Periods	Planning years

- **Diagnostic pages.** Changing a parameter recomputes the Demand to Gaps pages immediately.
- **Plan pages.** Least-cost plan, Investment and Expansion require **Run plan**.
- **Saving.** Scenarios can be saved by name and compared side by side.

Every simulation in Chapter 10 can be reproduced in the application by changing one control.

16.4 Headless runs

Every result can also be produced without the browser:

- `python scripts/run_plan.py --preset S0 --out results/base` runs a standard scenario;
- `python scripts/run_plan.py --scenario config/scenario.yml --out results/custom` runs a scenario defined in a YAML file.

A headless run executes all modules for the scenario and writes:

- every table as CSV and XLSX;
- the district layers as GeoJSON;
- the solved PyPSA network as netCDF.

This report was built the same way: `report/build/collect.py` runs the modules and simulations, `figures.py` draws the figures, and `build_docx.js` assembles the document.

16.5 Exports and the API

The application exposes a REST API, used by the front end and available to other systems.

Route	Returns
GET /api/meta	Datasets, default scenario, planning years, status legend
GET /api/page/{module}	The KPIs, charts, maps and tables of a module page for a scenario
POST /api/plan	Starts the multi-period plan; returns a job id
POST /api/plan/compare	Starts the S0–S7 comparison
GET /api/jobs/{id}	Job status, progress and log
GET /api/gis/layers	The catalogue of map layers
GET /api/gis/districts	District GeoJSON with indicators
GET /api/gis/district/{name}	A district's profile across all modules
GET /api/export/{module}.{csv, xlsx, json, zip}	A module's tables
GET /api/export/plan.nc	The solved PyPSA network

The server binds to the local machine by default. For wider use it should sit behind an authenticating proxy.

16.6 Links to government planning systems

The engine is designed as one component of the AICTEM planning system. Its outputs feed three other systems.

16.6.1 Medium-Term Expenditure Framework

The investment module exports the public capital requirement of the plan in the MTEF format:

- by year;
- in billions of shillings at 3,775 UGX/USD;
- with the physical outputs that go with it: MW added and households connected.

Chapter 11 shows the export for the base scenario (Table 11.3). The public requirement rises from 572 bn UGX in 2025 to 955 bn UGX in 2031. The MTEF team can compare it with the energy sector ceiling and propose the phasing that fits the fiscal envelope. The engine can then re-solve the plan under that phasing.

Chapter 11 gives the full split of the plan's financing by source and year. Table 16.1 gives it for reference, and Table 16.2 gives the annual capex by category that underlies the MTEF export.

Table 16.1: Financing sources by year, MUSD

Year	Public	Concessional	Private	Consumer
2024	133	225	101	27
2025	152	267	142	28
2026	168	306	159	30
2027	192	352	158	31
2028	210	387	232	33
2029	234	437	330	35
2030	247	467	341	37
2031	253	493	290	33
2032	257	499	271	35
2033	234	438	233	37
2034	196	340	224	38
2035	191	326	346	40
2036	219	391	510	42
2037	233	415	499	44
2038	231	407	504	47
2039	211	361	433	49
2040	194	309	222	51

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_financing.csv).

Table 16.2: Annual capital expenditure by category, MUSD

Year	Access	Distribution	Generation	Institutions	Transmission	Total
2024	167	130	172	16	0	486
2025	176	131	265	16	0	589
2026	186	133	327	16	0	663
2027	196	177	333	16	10	733
2028	207	177	443	16	18	862
2029	218	178	610	16	12	1,036
2030	230	183	663	16	0	1,093
2031	207	185	623	13	41	1,070
2032	218	186	571	13	74	1,062
2033	229	187	463	13	50	941
2034	240	187	357	13	0	798
2035	252	189	449	13	0	903
2036	265	252	607	0	38	1,162
2037	278	254	592	0	68	1,192
2038	291	256	596	0	45	1,189
2039	305	256	492	0	0	1,054
2040	320	256	200	0	0	775

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/t_inv_year.csv).

16.6.2 Unit-cost system (UCSN) and bills of engineering (BOE)

The engine's distribution, access and institutional unit costs are, for this report, planning values (Annex B). The engine is designed to replace them with the governed unit-cost coefficients of the national unit-cost system (UCSN), and with project bills of engineering where these exist. When a governed coefficient is used, the provenance label changes from ASSUMED to "UCSN (governed)". The investment plan then becomes directly comparable with the costings of the budget and of the development partners.

16.6.3 Sector plans and the national development plan

The expansion roadmap (Chapter 12) and the district investment tables (Annex C) are formatted so that they can be read against:

- the sector's development plan;
- the District Development Plans;
- the National Development Plan IV results framework.

The gap register (Chapter 8) gives each gap a unit, a status and a closure year that can be used as a target.

16.7 Keeping the engine current

The engine's value depends on its data being current. The annual update cycle should be:

1. **Metered data.** Update generation, consumption, losses and peak for the latest year from ERA, UEDCL and UETCL. The calibration checks (V1–V2, V4) confirm that the model reproduces them.
2. **Committed projects.** Update the status of every generation and transmission project in the pipeline: financial close, construction, commissioning. Projects under construction move from candidate to committed.
3. **Industrial loads.** Update the register of step loads with the status of each industrial park, mine and large customer. This is the most important update, because the step loads determine the scale of the plan (Chapter 10).
4. **Networks.** Update the MV network, transformers and connections from the utility GIS. The access and distribution analyses follow automatically.
5. **Re-solve.** Re-solve the plan and publish the new report with its validation checks.

The whole cycle, from new data to a new version of this report, takes less than a day of computing once the data are assembled.

16.8 Data quality and limitations

- The application is a planning tool, not an operational one. It does not model real-time dispatch, protection or the distribution network below the MV level.
- The links to the MTEF and UCSN are defined as export formats and data interfaces. They have not yet been tested in the government's systems.
- The application runs on a single machine. Multi-user deployment would need authentication, a shared result store and a job queue.

16.9 Implications for planning

- The engine should be institutionalised in the sector's planning unit, with a named owner, an annual update cycle and published validation.
- The MTEF export should be used in the next budget cycle. The fiscal envelope should be compared with the plan's public requirement, and the plan re-solved if the two do not match.
- The step-load register and the project status tracker should be maintained jointly by the Ministry, the regulator and the utilities. They are the inputs that change the plan most.

CHAPTER 17

17 Conclusions and recommendations

This chapter draws together the findings of the report. It states what the evidence says about the status of Uganda's electricity system, what the plan requires, and what decisions follow. The recommendations are grouped by the institution best placed to act on them. As in the rest of the report, no scenario is recommended as the plan. The report identifies the decisions that are robust across the simulations and the choices that remain for policy.

17.1 The status of the system in 2023

Uganda's electricity system in 2023 is **adequate but narrow**.

- **Adequate.** Supply met demand. The 2023 dispatch sheds no load, and the reserve margin was 34 %. The large Nile-cascade projects commissioned in the last decade (Bujagali, Isimba, Karuma) have created a temporary surplus of firm capacity.
- **Narrow in its resource base.** About 90 % of generation is hydro, and three quarters comes from one river. A dry year on the Nile would shed 415 GWh even with 2023 demand.
- **Narrow in its reach.** Only a quarter of households are connected. Consumption is 94 kWh per person a year, one of the lowest levels in the world, and far lower in the north (32 kWh) than in the centre (167 kWh).
- **Narrow in its finances.** Losses of 17 % in distribution and 5 % in transmission, and a tariff structure in which households subsidise industry, leave the sector with a small margin to finance its own expansion.

17.2 What is coming

The base scenario projects a **5.6-fold increase** in final demand to 2040, and a peak of **4,866 MW**, five times the 2023 peak. The growth has three sources:

- **industrial step loads:** industrial parks, steel, data centres and phosphates, which make up nearly half of 2040 demand;
- **universal access:** 15 million new connections;
- **new sectors:** transport and oil and gas.

The step loads are the largest source of uncertainty in the whole analysis. Without them, 2040 demand would be almost half lower and the plan a third of the size.

The surplus runs out quickly:

- the capacity gap opens in **2026**;
- the energy gap opens in **2028**;
- without new capacity, a quarter of demand would be unserved in 2030 and two thirds in 2040.

17.3 What the plan requires

The least-cost plan meets demand in every year to 2040. It requires:

- **Generation.**
 - 5,935 MW of new generation: geothermal first, then gas, and solar, wind and peakers after 2035.

- Geothermal (1,060 MW at Katwe and Buranga) is the most robust decision. It is built to its full potential in 27 of 29 simulations.
- Gas (3.1 GW) provides the firm capacity that hydro and solar cannot.
- **Transmission.**
 - Reinforcement of the western export path and the eastern supply into Kampala.
 - Two new 220 kV corridors.
 - In all, 2,466 MW of transfer capacity for 0.36 bn USD. Without it, the plan fails.
- **Distribution.**
 - Loss reduction from 17 % to 12 % by 2030. It avoids 245 MW of generation by 2040 and is one of the cheapest resources available.
 - 5,200 MVA of new transformer capacity and 54,000 km of MV line.
- **Access.**
 - 12.8 million grid connections and 2.2 million solar home systems.
 - Electrification of 1,096 health facilities and 13,349 schools.
- **Capital.** 15.6 bn USD over 2024–2040, about 0.9 bn USD a year:
 - 50 % for generation;
 - 47 % for distribution and access;
 - 2 % for transmission;
 - 1 % for institutions.

17.4 The risks to the plan

1. **The transition gap of 2027–2029.** The reserve margin falls to –2.5 % in 2029 because the first large capacity additions cannot come online before 2030. A dry year or a major outage in those years would shed load.
2. **The late geothermal.** Katwe and Buranga are on the critical path and already three to four years behind the schedule the plan assumes.
3. **Demand uncertainty.** A plan built for the full step loads would be oversized by 2.6–4 GW if half or none of them materialise. A plan built for none would be short by the same amount if they do.
4. **Hydrology.** A dry decade would cost 618 million USD more in net present terms. The cascade's dominance makes the system vulnerable.
5. **Finance.** The average cost of supply rises from 118 to 158 USD/MWh. Without tariff reform the sector would face a revenue gap of 622 million USD a year by 2040.
6. **Emissions.** The renewable share falls from nearly 100 % to 61 % as gas grows, and emissions rise to 4 Mt a year.

17.5 What the simulations show

- **Robust across all futures:** geothermal, gas (unless excluded), the grid reinforcements and loss reduction.
- **Scale depends on demand:** about 6 GW of new capacity with the step loads, about 2 GW without them.
- **Decarbonisation is cheap:**
 - a 70 % renewable share in 2040 costs almost nothing;
 - 90 % costs 165 million USD (about 10 USD per tonne avoided);
 - a fossil-free path costs about 870 million USD, a fifth more than least cost.
- **The grid is indispensable.** Without it the net present cost rises seven-fold.

17.6 Recommendations

17.6.1 Ministry of Energy and Mineral Development

1. **Commit the robust core now:**

- geothermal at Katwe and Buranga;
- the Tilenga combined-cycle plant;
- the western and eastern grid reinforcements.

These are no-regret decisions.

2. **Arrange bridging capacity for 2027–2029:**

- battery storage;
- leased thermal capacity;
- firm imports;
- interruptible contracts with new industrial loads.

3. **Accelerate geothermal.** Drill the exploration wells and secure the financing for Katwe and Buranga, or re-plan with realistic dates.

4. **Stage the rest against evidence of demand.** Establish a register of committed industrial loads, updated yearly, and add capacity as the step loads commit.

5. **Decide the decarbonisation level.** The cost of a 70–90 % renewable system is small. The choice is a policy one and should be made explicitly.

17.6.2 Electricity Regulatory Authority

6. **Rebalance tariffs**, so that each customer class pays its cost to serve, and introduce a targeted lifeline tariff for low-consumption households.
7. **Enforce the loss-reduction trajectory** to 12 % by 2030 through the distribution licences. Loss reduction is cheaper than new generation.
8. **Adopt a reliability standard**, such as a reserve margin or an expected-unserved-energy target, so that the plan's adequacy can be measured against a legal benchmark.

17.6.3 Uganda Electricity Transmission Company

9. **Procure the plan's corridor reinforcements now.** The western path is needed from 2029 and the eastern ring from 2033.
10. **Carry out an AC load-flow and stability study** of the plan's corridors. The transport model of this report does not capture voltage and stability limits on the long radial lines.

17.6.4 Distribution companies and the access programme

11. **Target access at the north and north-east.** That is where the share of unconnected households is highest, and the engine's GIS layers show where grid extension or solar home systems are least-cost.
12. **Combine LV extension with loss reduction** in the network cold-spot of Karamoja, Acholi and Teso.
13. **Electrify health facilities and schools early:** health by 2030 and schools by 2035.

17.6.5 Ministry of Finance, Planning and Economic Development

14. **Use the MTEF export** of the plan's public capital requirement in the budget cycle. The requirement peaks at about 257 million USD in 2032, within the current energy envelope. The concessional and private finance that the plan assumes must be mobilised in parallel.
15. **Finance the grid as the precondition of the plan.** It is small in capital but carries the whole plan.

17.6.6 All institutions

16. **Institutionalise the engine** in the sector's planning unit, with an annual update of metered data, project status, step loads and networks, and publication of the validation checks with every update.

17.7 A closing remark

Uganda enters the second half of the 2020s with a surplus of clean electricity and a small, concentrated grid. By 2040 the country could have five times as much electricity, reach every household, and remain largely renewable, for an investment of about 1 bn USD a year. The evidence in this report shows that this is technically feasible and affordable within the sector's financial capacity, provided three conditions are met:

- the robust decisions are taken now;
- the uncertain ones are staged against evidence;
- tariffs and finance are reformed alongside the physical investment.

ANNEX A

A Formula compendium

This annex collects the main formulas of the engine in one place, grouped by module. Each formula is stated in the notation of the design chapters (docs/01–docs/09). The formulas that appear in the body of the report are repeated here so that the annex can be read on its own. Units are given in brackets where they are not obvious.

A.1 Demand

Segment identity. Final demand of segment s in year y :

$$E_{s,y} = E_{s,y_0} A_{s,y} \eta_{s,y} \epsilon_{s,y} + N_{s,y} \quad (\text{A.1})$$

- A is the activity index;
- η is the efficiency factor;
- ϵ is the electrification factor;
- N is additive project load [GWh].

Activity index from GDP. For segments driven by output, with segment elasticity e_s and GDP growth g :

$$A_{s,y} = (1 + e_s g)^{y - y_0} \quad (\text{A.2})$$

Households. Existing connections grow their use; new connections ramp up to the new-connection use u^{new} over a ramp ρ :

$$E_y^{HH} = H_{y_0}^c u_{y_0} (1 + g_u)^{y - y_0} + \sum_{\tau=y_0+1}^y \Delta H_{\tau}^{grid} u^{new} \rho (y - \tau) \quad (\text{A.3})$$

Connections. Households with grid access in year y , for an access path a_y rising linearly to the target a^* in the target year:

$$H_y^c = a_y H_y, \quad a_y = a_{y_0} + (a^* - a_{y_0}) \frac{y - y_0}{Y^* - y_0} \quad (\text{A.4})$$

Health facilities. For facility level l with intensity ι_l [MWh per facility per year] and electrified share $\sigma_{l,y}$:

$$E_y^H = \sum_l n_l \iota_l \sigma_{l,y} \quad (\text{A.5})$$

Schools use the same form, by school type.

Transport. For vehicle class v with stock $S_{v,y}$ and specific energy e_v [kWh per vehicle per year]:

$$E_y^T = \sum_v S_{v,y} e_v + E_y^{SGR} \quad (\text{A.6})$$

Step loads. A project with capacity M [MW] and load factor λ , from its start year:

$$N_y = M \lambda 8.76 \cdot \mathbf{1}[y \geq y^{start}] \quad (\text{A.7})$$

Generation requirement. Final demand grossed up for distribution and transmission losses, plus net exports:

$$G_y = \frac{F_y}{(1 - \ell_y^D)(1 - \ell^T)} + X_y \quad (\text{A.8})$$

Peak demand. From the requirement and the load factor LF:

$$P_y = \frac{G_y \cdot 10^3}{8760 \text{LF}_y} \quad (\text{A.9})$$

Bus-slice load. The load at bus b in slice t is the national load shared by the bus's demand share $\pi_{\{b,y\}}$:

$$D_{b,t,y} = \pi_{b,y} P_y \phi_t \quad (\text{A.10})$$

where ϕ_t is the calibrated load factor of slice t relative to peak.

A.2 Generation and dispatch

Nodal balance. For every bus b and slice t:

$$\sum_{g \in b} p_{g,t} + \sum_{s \in b} (p_{s,t}^{dis} - p_{s,t}^{ch}) + \sum_{\ell \rightarrow b} \eta_{\ell} f_{\ell,t} - \sum_{\ell \leftarrow b} f_{\ell,t} + u_{b,t} = D_{b,t} \quad (\text{A.11})$$

Generator availability. Output is limited by capacity and the per-slice availability α :

$$0 \leq p_{g,t} \leq \alpha_{g,t} K_g \quad (\text{A.12})$$

Storage. State of charge of a reservoir or battery s, with inflow $I_{\{s,t\}}$, efficiencies η , spillage σ , and cyclic end condition:

$$e_{s,t} = e_{s,t-1} + w_t \left(\eta^{ch} p_{s,t}^{ch} - \frac{p_{s,t}^{dis}}{\eta^{dis}} + I_{s,t} - \sigma_{s,t} \right), \quad e_{s,T} = e_{s,0} \quad (\text{A.13})$$

Dispatch objective.

$$\min \sum_t w_t \left[\sum_g c_g p_{g,t} + V \sum_b u_{b,t} \right] \quad (\text{A.14})$$

Marginal cost with carbon price. For variable cost v_g , emission factor ϵ_g [t/MWh] and carbon price π^C :

$$c_g = v_g + \pi^C \epsilon_g \quad (\text{A.15})$$

Emissions.

$$\text{CO}_2 = \sum_t w_t \sum_g \epsilon_g p_{g,t} \quad (\text{A.16})$$

Capacity factor.

$$\text{CF}_g = \frac{\sum_t w_t p_{g,t}}{8760 K_g} \quad (\text{A.17})$$

Herfindahl–Hirschman index of generation shares s_g [%]:

$$HHI = \sum_g s_g^2 \quad (A.18)$$

A.3 Transmission

Link limits. Each corridor ℓ is two directed links with capacity K_ℓ :

$$0 \leq f_{\ell,t} \leq K_\ell \quad (A.19)$$

Loading.

$$\text{loading}_{\ell,t} = \frac{|f_{\ell,t}|}{K_\ell} \quad (A.20)$$

Hours at limit. Corridor ℓ is stressed if it runs at or above 95 % of its rating for more than 500 hours a year:

$$h_\ell = \sum_t w_t \mathbf{1}[\text{loading}_{\ell,t} \geq 0.95] \quad (A.21)$$

Transmission losses.

$$L^T = \sum_t w_t \sum_\ell (1 - \eta_\ell) f_{\ell,t} \quad (A.22)$$

N-1. For each corridor k , the peak slice is re-solved with $K_k = 0$. The load shed is:

$$\Delta u_k = \sum_b u_{b,t^*}^{(-k)} - \sum_b u_{b,t^*} \quad (A.23)$$

Coverage curve. Share of population within distance x of an operational substation, over 1 km cells i with population q_i and distance d_i :

$$C(x) = \frac{\sum_i q_i \mathbf{1}[d_i \leq x]}{\sum_i q_i} \quad (A.24)$$

A.4 Distribution

Energy waterfall. Generation less transmission losses and net exports gives energy into distribution. Less distribution losses gives billed energy:

$$B = (G - L^T - X)(1 - \ell^D) \quad (A.25)$$

Technical and commercial losses.

$$L^D = L^{tech} + L^{comm}, \quad L^{comm} = L^D - L^{tech} \quad (A.26)$$

District loss allocation. Losses are shared in proportion to energy supplied S_d , weighted by a network-distance factor:

$$L_d = L^D \frac{S_d \pi_d}{\sum_{d'} S_{d'} \pi_{d'}}, \quad \pi_d = 1 + \beta \frac{\bar{\delta}_d - \bar{\delta}}{\bar{\delta}} \quad (A.27)$$

Cross-subsidy of class k. With tariff τ_k , cost to serve κ_k and energy E_k :

$$X_k = (\tau_k - \kappa_k) E_k \quad (\text{A.28})$$

Collection.

$$R^{coll} = \sum_k \tau_k E_k \chi_k \quad (\text{A.29})$$

where χ_k is the collection rate.

Avoided generation from loss reduction. Moving from loss rate ℓ_0 to target ℓ^* :

$$\Delta G_y = \frac{F_y}{1 - \ell_0} - \frac{F_y}{1 - \ell^*} \quad (\text{A.30})$$

Substation loading. Loading of distribution substation j, with peak served P_j , power factor ψ and rating S_j [MVA]:

$$\lambda_j = \frac{P_j}{\psi S_j} \quad (\text{A.31})$$

A.5 Gaps

Capacity gap.

$$\text{Gap}_y^{cap} = P_y(1 + r) - K^{firm} \quad (\text{A.32})$$

Energy gap.

$$\text{Gap}_y^{en} = G_y - E^{cap} \quad (\text{A.33})$$

Reliability. Expected unserved energy and loss-of-load expectation from the solved dispatch:

$$\text{EUE}_y = \frac{\sum_t w_t \sum_b u_{b,t}}{G_y}, \quad \text{LOLE}_y = \sum_t w_t \mathbf{1} \left[\sum_b u_{b,t} > 0 \right] \quad (\text{A.34})$$

Access gap.

$$\text{Gap}_{d,y}^{acc} = a_y^* H_{d,y} - a_{d,y_0} H_{d,y_0} \quad (\text{A.35})$$

Firm capacity.

$$K^{firm} = \sum_g \text{cc}_g K_g \quad (\text{A.36})$$

Reserve margin.

$$\text{RM}_y = \frac{K_y^{firm}}{P_y} - 1 \quad (\text{A.37})$$

A.6 Least-cost plan

Expansion objective.

$$\min \sum_p \Omega_p \left[\sum_{c, q \leq p} \kappa_c K_{c, q} + \sum_t w_t \left(\sum_g c_g p_{g, t, p} + V \sum_b u_{b, t, p} \right) \right] \quad (\text{A.38})$$

Period weight. For a period p of n_p years starting in y_p, at discount rate r:

$$\Omega_p = \sum_{k=0}^{n_p-1} (1+r)^{-(y_p+k-y_0)} \quad (\text{A.39})$$

Annualised capital cost.

$$\kappa_c = \text{CAPEX}_c \cdot \text{CRF}(r, n_c) + \text{FOM}_c \quad (\text{A.40})$$

Capital recovery factor.

$$\text{CRF}(r, n) = \frac{r(1+r)^n}{(1+r)^n - 1} \quad (\text{A.41})$$

Reserve constraint.

$$\sum_g cc_g K_g + \sum_{c, q \leq p} cc_c K_{c, q} \geq (1+r) P_p \quad (\text{A.42})$$

Resource potential and build rate.

$$\sum_q K_{c, q} \leq \bar{K}_c, \quad K_{c, q} \leq \beta_c n_q \quad (\text{A.43})$$

Renewable target (optional), with renewable set R and share θ :

$$\sum_{g \in R} \sum_t w_t p_{g, t, p} \geq \theta \sum_g \sum_t w_t p_{g, t, p} \quad (\text{A.44})$$

Long-run marginal cost. The load-weighted average nodal price:

$$\text{LRMC}_p = \frac{\sum_t \sum_b w_t \lambda_{b, t, p} D_{b, t, p}}{\sum_t \sum_b w_t D_{b, t, p}} \quad (\text{A.45})$$

Abatement cost of simulation k relative to S0:

$$\text{AC}_k = \frac{\text{NPV}_k - \text{NPV}_0}{\text{CO}_{20} - \text{CO}_{2k}} \quad (\text{A.46})$$

A.7 Investment

Overnight cost from the IRP annualised cost.

$$\text{CAPEX}_c = \frac{\kappa_c - \text{FOM}_c}{\text{CRF}(r, n_c)} \quad (\text{A.47})$$

Disbursement. Capital of an asset commissioned in year y is spread over its construction years with a profile ω_k :

$$I_{c,y-k} = \text{CAPEX}_c K_c \omega_k, \quad \sum_{k=1}^{L_c} \omega_k = 1 \quad (\text{A.48})$$

Levelised cost of electricity.

$$\text{LCOE}_c = \frac{\kappa_c}{8760 \text{CF}_c} + v_c + \pi^C \epsilon_c \quad (\text{A.49})$$

Revenue requirement in year y:

$$RR_y = \text{CTS}_{y_0} E_{y_0} + \sum_c \text{CAPEX}_c K_{c,y} \text{CRF}(\text{WACC}, n_c) + \text{VC}_y + \text{FOM}_y + \Delta \text{NR}_y \quad (\text{A.50})$$

where ΔNR is the network and retail cost of demand growth.

Average cost of supply.

$$\bar{C}_y = \frac{RR_y}{B_y} \quad (\text{A.51})$$

Net present value of capex.

$$\text{NPV} = \sum_y \frac{I_y}{(1+r)^{y-y_0}} \quad (\text{A.52})$$

Financing. For category k with source shares $\phi_{\{k,f\}}$:

$$I_{f,y} = \sum_k \phi_{k,f} I_{k,y} \quad (\text{A.53})$$

A.8 Expansion

Commissioning tranches.

$$K_{c,y}^{\text{com}} = K_{c,p} \omega_{c,y}, \quad \sum_{y \in (p_{\text{prev}}, p]} \omega_{c,y} = 1 \quad (\text{A.54})$$

Financial close. For lead time L_c :

$$y_c^{\text{FC}} = y_c^{\text{com}} - L_c, \quad \text{slack}_c = y_c^{\text{FC}} - y^{\text{now}} \quad (\text{A.55})$$

A.9 GIS and spatial statistics

Global Moran's I.

$$I = \frac{\sum_i \sum_j w_{ij}}{\sum_i \sum_j w_{ij}} \frac{\sum_i \sum_j w_{ij} (x_i - \bar{x})(x_j - \bar{x})}{\sum_i (x_i - \bar{x})^2} \quad (\text{A.56})$$

Permutation p-value.

$$p = \frac{1 + \#\{m : I^{(m)} \geq I\}}{1 + M} \quad (\text{A.57})$$

Local Moran.

$$I_i = z_i \sum_j w_{ij} z_j \quad (\text{A.58})$$

Concentration index.

$$CI = 1 - \sum_k (P_k - P_{k-1})(S_k + S_{k-1}) \quad (\text{A.59})$$

Access mode lifecycle cost.

$$C_m = K_m + \sum_{t=1}^{20} \frac{q c_m}{(1+r)^t} \quad (\text{A.60})$$

Population-weighted distance of district d:

$$\bar{\delta}_d = \frac{\sum_{i \in d} q_i d_i}{\sum_{i \in d} q_i} \quad (\text{A.61})$$

Great-circle distance (used where UTM is not applicable), for latitudes ϕ , longitudes λ and Earth radius R:

$$d = 2R \arcsin \sqrt{\sin^2 \frac{\Delta\phi}{2} + \cos \phi_1 \cos \phi_2 \sin^2 \frac{\Delta\lambda}{2}} \quad (\text{A.62})$$

ANNEX B

B Model catalogues and parameters

This annex lists the inputs of the base scenario:

- the buses of the network model;
- the existing fleet;
- the candidate projects;
- the scenario parameters;
- the definitions of the 29 simulations;
- the engine's default planning parameters.

Every value can be changed in the web application's scenario panel, or in `config/engine_defaults.yml` and the dataset files in `data/uganda_2023/`.

B.1 The network model

The transmission system is represented by 17 buses. Each bus is a substation or group of substations, and each serves a supply zone of the districts nearest to it.

Table B.1: Buses of the 17-bus network model

Bus	Host district	Latitude	Longitude	Role
B01 Lugogo	Mukono	0.324	32.607	Kampala east load
B02 Kampala North	Wakiso	0.347	32.575	Kampala load
B04 Mutundwe	Wakiso	0.294	32.534	Kampala west load; battery; diesel candidate
B05 Kabulasoke	Mubende	0.158	31.820	Central west; solar
B06 Kawanda	Nakaseke	0.414	32.542	Kampala north load
B07 Namanve	Mukono	0.381	32.679	Industrial load; HFO
B08 Kahungye	Kyenjojo	0.204	30.785	Western generation hub (gas, geothermal)
B09 Nkongwe	Kibaale	0.229	31.184	Western transit; small hydro
B10 Lugazi	Buikwe	0.377	32.936	Sugar and industry
B11 Masaka West	Rakai	-0.329	31.684	South-central load
B12 Lira	Apac	2.242	32.886	Northern hub; Karuma
B13 Opuyo	Amuria	1.677	33.677	North-east; Karamoja wind
B14 Bujagali	Kamuli	0.502	33.136	Nile cascade (Bujagali, Isimba)
B15 Nkenda	Kasese	0.256	30.117	Rwenzori; Katwe geothermal
B16 Mbarara North	Isingiro	-0.597	30.611	South-west load
B17 Tororo	Bugiri	0.638	34.118	Eastern hub; Kenya interconnector; gas
B18 Nalubaale	Mayuge	0.444	33.182	Nile cascade (Nalubaale, Kiira)

The host district is the district in which the bus coordinates fall in the dataset. The supply zone of each bus is wider.

B.2 The existing fleet

B.2.1 Reservoir hydro

The five large Nile-cascade plants are modelled as storage units with inflow, a reservoir and a minimum release.

Table B.2: Reservoir hydro plants

Plant	Bus	Capacity (MW)	Mean inflow (MWh/h)	Reservoir (GWh)	Minimum release (MWh/h)	Capacity credit
Nalubaale	B1 8	180	90.2	129.6	4.5	0.55
Kiira	B1 8	200	100.5	144.0	5.0	0.55
Bujagali	B1 4	250	170.3	42.0	8.5	0.55
Isimba	B1 4	183	127.3	30.7	6.4	0.55
Karuma	B1 2	600	46.2	100.8	2.3	0.55

B.2.2 Other existing units

Table B.3: Other existing generating units

Unit	Bus	MW	Variable cost (USD/MWh)	Emission factor (t/MWh)	Capacity credit	2023 energy (GWh)
Small hydro, West	B 1 5	121.6	1.0	0	0.55	480.0
Small hydro, South-west	B 1 6	44.3	1.0	0	0.55	190.0
Small hydro, East	B 1 7	29.8	1.0	0	0.55	76.5
Small hydro, North	B 1 2	87.2	1.0	0	0.55	64.4
Small hydro, Albertine	B 0 9	36.8	1.0	0	0.55	123.5
Solar Soroti	B 1 3	10.0	0	0	0.03	16.0
Solar Tororo North	B 1 7	10.0	0	0	0.03	15.7
Solar Tororo	B 1 7	10.6	0	0	0.03	20.8
Solar Xsabo	B 0 5	20.0	0	0	0.03	28.9
Solar Bufulubi	B 1 8	10.0	0	0	0.03	16.8
Solar Busitema	B 1 7	4.0	0	0	0.03	0.0
Bagasse Kakira	B 1 8	51.1	27.5	0	1.0	55.7
Bagasse SCOUL	B 1 0	25.0	27.5	0	1.0	140.8
Bagasse Kinyara	B 0 9	14.5	27.5	0	1.0	9.6

Unit	Bus	MW	Variable cost (USD/MWh)	Emission factor (t/MWh)	Capacity credit	2023 energy (GWh)
Bagasse Mayuge	B18	23.0	27.5	0	1.0	24.0
Bagasse, other	B17	22.2	27.5	0	1.0	4.2
HFO Namanve	B07	50.2	194.0	0.658	1.0	64.0
HFO Electromaxx	B17	50.0	194.0	0.658	1.0	0.0
Battery, Central	B04	100 MW / 400 MWh	1.0	0	0.9	–
Battery, East	B17	50 MW / 200 MWh	1.0	0	0.9	–

For small hydro, solar, bagasse and HFO, the 2023 energy is the metered output. It is used as the energy limit of each unit in the calibration year.

B.3 Candidate projects

The candidate set of the least-cost plan comes from the MEMD/ERA Integrated Resource Plan, plus generic battery candidates. The annualised capital cost is at 10 % over the lifetime. The overnight cost is recovered from it (Annex A, Equation (A.47)).

Table B.4: Generation candidates of the least-cost plan

Candidate	Bus	Max MW	Annualised capex (USD/MW-yr)	Fixed O&M (USD/MW-yr)	Variable cost (USD/MWh)	Emission factor (t/MWh)	Available from	Capacity credit	Max MW per year	Life (yr)
Run-of-river hydro, North	B12	1,412	285,431	40,000	1.0	0	2026	0.40	300	50
Run-of-river hydro, West	B15	384	285,431	40,000	1.0	0	2026	0.40	300	50
Run-of-river hydro, West Nile	B12	800	285,431	40,000	1.0	0	2026	0.40	300	50
Geothermal Katwe	B15	680	371,277	75,000	0.5	0	2026	0.90	300	30
Geothermal Buranga	B08	380	371,277	75,000	0.5	0	2028	0.90	190	30
Solar, Central	B05	600	99,151	10,000	1.0	0	2026	0.03	300	25
Solar, East	B17	1,200	99,151	10,000	1.0	0	2026	0.03	300	25
Solar, North	B12	1,150	99,151	10,000	1.0	0	2026	0.03	300	25
Wind, Karamoja	B13	120	137,903	40,000	1.0	0	2026	0.25	120	30
Biomass, Central	B04	200	397,797	75,000	27.5	0	2028	1.00	100	30
CCGT Tilenga	B08	200	84,863	25,000	40.4	0.340	2026	0.90	200	30
CCGT East	B17	1,250	95,471	25,000	53.2	0.340	2030	0.90	250	30
OCGT West	B08	1,646	84,863	20,000	75.5	0.478	2030	0.90	250	30

Candidate	Bus	Max MW	Annualised capex (USD/MW-yr)	Fixed O&M (USD/MW-yr)	Variable cost (USD/MWh)	Emission factor (t/MWh)	Available from	Capacity credit	Max MW per year	Life (yr)
Nuclear, Buyende	B17	2,400	494,210	55,560	16.1	0	2036	0.95	1,200	50
Diesel, Central	B04	500	53,040	60,000	244.5	0.878	2026	0.95	500	30
Battery candidates	various	–	at 1,100 USD/kW over 15 years	10,000	1.0	0	2026	0.90	–	15

B.4 Scenario parameters of the base scenario

Table B.5: Parameters of the base scenario S0

Group	Parameter	Base value
Data	Dataset, base year, horizon	uganda_2023, 2023, 2040
Data	Planning periods	2026, 2030, 2035, 2040
Demand	Demand scenario	base (low and high variants)
Demand	Real GDP growth	6 % a year
Demand	Population growth	3 % a year
Demand	Access target	60 % in 2030, 100 % in 2040
Demand	Growth of use per connection	2 % a year
Demand	Health facilities electrified by	2030
Demand	Schools electrified by	2035
Demand	E-mobility	base path
Demand	Electric SGR from	2032
Demand	IERMP step loads, realisation	included, 100 %
Demand	Oil and gas projects, irrigation	included
Demand	Load-factor trend	constant
Demand	Net exports	451.2 GWh a year
Distribution	Loss target and year	12 % by 2030
Distribution	Technical share of losses	60 %
Distribution	Collection target	98 %
Distribution	Loss allocation distance weight β	0.5
Supply	Hydrology	normal (dry –20 %, wet +10 % inflow)
Supply	Karuma capacity factor	0.55
Supply	Carbon price	0 USD/t
Supply	Renewable target, CO2 cap	none
Supply	Reserve margin	15 %
Supply	Value of lost load	10,000 USD/MWh
Supply	Discount rate	10 %
Supply	Battery candidates, transmission expansion, new corridors	allowed
Transmission	Analysis year	2030
Transmission	Under-construction lines in service from	2026
Transmission	Stress threshold	80 % loading
Transmission	Coverage distance	50 km
Finance	Weighted average cost of capital	8 %
Finance	Exchange rate	3,775.03 UGX/USD
Expansion	Commissioning rule	just in time

B.5 Definitions of the 29 simulations

Table B.6: The standard scenario set

Code	Name	Change from S0
S0	Least cost	–
S1	High renewables	Renewable share of at least 90 % in every period
S2	Carbon price	50 USD per tonne of CO ₂ from 2026
S3	High demand	High demand scenario
S4	Low demand	Low demand scenario
S5	Dry hydrology	Inflows 20 % below normal throughout
S6	No new fossil	Gas and oil candidates excluded
S7	Nuclear option	At least 1,000 MW of nuclear by 2040

Table B.7: The one-at-a-time sensitivities

No.	Sensitivity	Change from S0
1	Step loads 0 %	No IERMP step loads realised
2	Step loads 50 %	Half of each step load realised
3	Carbon 25	Carbon price 25 USD/t
4	Carbon 100	Carbon price 100 USD/t
5	RE 50 %	Renewable share of at least 50 %
6	RE 70 %	Renewable share of at least 70 %
7	Discount 7 %	Discount rate 7 %
8	Discount 13 %	Discount rate 13 %
9	Reserve 10 %	Reserve margin 10 %
10	Reserve 20 %	Reserve margin 20 %
11	Fast access	80 % access by 2030
12	Slow loss reduction	Distribution loss target 15 %
13	Wet hydrology	Inflows 10 % above normal
14	No grid expansion	No corridor reinforcement or new corridor
15	No batteries	No battery candidates
16	Solar capex –30 %	Solar capital cost × 0.7
17	Gas capex +30 %	Gas capital cost × 1.3
18	E-mobility high	High e-mobility path
19	GDP 8 %	Real GDP growth 8 % a year
20	GDP 4 %	Real GDP growth 4 % a year
21	No new fossil + RE 90 %	S6 combined with a 90 % renewable target

B.6 Engine planning defaults

Table B.8 lists the planning defaults of `config/engine_defaults.yml` used in this report. Unit sizes are the steps in which the expansion module commissions capacity.

Table B.8: Engine planning defaults (`config/engine_defaults.yml`)

Group	Parameter	Value
demand	persons_per_household	4.5
demand	households_2023	10698913
demand	connected_share_2023	0.253
demand	new_connection_kwh	200
demand	public_lighting_growth	0.05

Group	Parameter	Value
demand	industry_elasticity_with_step_loads	0.9
health	growth	0.03
education	growth	0.025
education	tertiary_count	250
education	target_2023_gwh	120
transport	sgr_gwh	200
access_model	decay_km	60
access_model	urban_uplift	0.3
access_model	cap	0.95
access_model	conn_cost_usd	250
access_model	mv_cost_usd_km	20570
access_model	lv_cost_usd_km	9000
access_model	uptake	0.8
access_model	minigrid_lcoe	0.35
access_model	grid_horizon_km	30
access_model	life_years	20
distribution	power_factor	0.9
distribution	design_margin	0.2
distribution	loss_programme_usd_per_mwh_yr	150
unit_costs	transformer_usd_per_kva	120
unit_costs	mv_line_usd_km	20570
unit_costs	lv_line_usd_km	9000
unit_costs	substation_33_11_usd	1200000
unit_costs	bess_overnight_usd_kw	1100
unit_costs	bess_life	15
unit_costs	bess_fom_usd_kw	10
unit_size_mw	hydro	50
unit_size_mw	nuclear	300
unit_size_mw	solar	50
unit_size_mw	geothermal	20
unit_size_mw	gas	50
unit_size_mw	wind	20
unit_size_mw	biomass	10
unit_size_mw	oil	10
unit_size_mw	battery	25
generation	storage_capacity_credit	0.9
tariff	avg_2023_usd_mwh	132.7

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/a_params.csv).

B.7 Status of the main inputs

Table B.9: Status of the main input groups

Input group	Source	Status
2023 sales by customer class	ERA / UEDCL / Umeme	OBSERVED
2023 generation by plant	ERA, metered	OBSERVED
Installed capacity and plant data	ERA / MEMD	OBSERVED
Transmission lines and substations	IERMP geodatabase	OBSERVED
MV network, distribution substations, transformers	IERMP geodatabase	OBSERVED

Input group	Source	Status
Households and access by district	UBOS census 2024	OBSERVED / CALIBRATED
Population grid	WorldPop 2020, scaled to 2023	CALIBRATED
Health facilities	MoH facility register	OBSERVED
Schools	MoES EMIS	OBSERVED
Industrial parks and step loads	IERMP, MEMD step-load workbook	OBSERVED (planning input)
Segment split of commercial and industrial sales	Engine carve-out	CALIBRATED / ASSUMED
Institutional energy intensities	Engine defaults	ASSUMED
Candidate costs and potentials	MEMD / ERA IRP	OBSERVED (planning data)
Distribution and access unit costs	Engine defaults; MV line cost observed	ASSUMED / OBSERVED
Financing mix	Engine defaults	ASSUMED
Wind resource	Global Wind Atlas via SDI	OBSERVED

ANNEX C

C District tables

This annex gives the main indicators of the report for each of Uganda's 135 districts. The districts are in alphabetical order. The four tables cover:

1. demand;
2. access and institutions;
3. grid, losses and resources;
4. investment.

Every value comes from the base scenario S0 and can be regenerated with the engine, or viewed as a district profile in the GIS explorer of the web application.

How to read the tables:

- **Rounding.** Totals may not add exactly because of rounding.
- **District demand.** Demand is allocated to districts by the engine's spatial keys (Chapter 4). It is a planning estimate, not a metered district sale.
- **District access rates** are CALIBRATED from the census national rate and the density of distribution transformers (Chapter 3).
- **Generation and transmission investment** is attributed to the district that hosts the plant or that the corridor crosses. Its benefits are national.

C.1 Demand by district

The table gives:

- the 2023 population;
- the electricity demand in 2023 and 2040;
- consumption per person in 2023;
- the growth multiple from 2023 to 2040;
- household and industrial demand in 2040.

Table C.1: Electricity demand by district, 2023 and 2040

District	Region	Population	GWh 2023	GWh 2040	kWh/person 2023	Growth	Households GWh 2040	Industry GWh 2040
Abim	Northern	172,139	5.0	23.3	29	4.6x	14.1	2.6
Adjumani	Northern	269,415	7.6	34.6	28	4.6x	19.5	4.0
Agago	Northern	275,485	8.0	35.5	29	4.4x	19.8	4.1
Alebtong	Northern	291,311	7.8	27.9	27	3.6x	11.6	4.4
Amolatar	Northern	199,193	7.0	23.0	35	3.3x	10.4	3.0
Amudat	Northern	157,136	4.3	16.1	27	3.8x	7.3	3.2
Amuria	Eastern	245,451	7.7	24.2	31	3.2x	8.5	4.9
Amuru	Northern	243,630	7.6	25.2	31	3.3x	11.2	3.7
Apac	Northern	246,324	9.5	31.4	39	3.3x	15.3	3.7
Arua	Northern	834,898	28.5	122.2	34	4.3x	70.9	12.6
Budaka	Eastern	280,849	17.6	56.5	63	3.2x	25.2	18.1
Bududa	Eastern	299,935	14.6	58.0	49	4.0x	25.2	19.4
Bugiri	Eastern	511,072	33.8	131.8	66	3.9x	44.3	33.0
Bugweri	Eastern	219,806	65.0	166.0	296	2.6x	20.2	84.5
Buhweju	Western	163,508	11.2	36.2	69	3.2x	13.0	13.1
Buikwe	Central	539,871	89.2	233.5	165	2.6x	53.8	132.2
Bukedea	Eastern	266,470	10.6	35.1	40	3.3x	17.8	5.4
Bukomansimbi	Central	171,954	11.8	31.6	68	2.7x	11.6	11.6
Bukwo	Eastern	133,635	7.2	26.3	54	3.7x	11.0	8.6
Bulambuli	Eastern	258,691	9.4	52.8	36	5.6x	21.9	5.2
Buliisa	Western	165,206	6.0	24.0	36	4.0x	13.8	2.5
Bundibugyo	Western	291,097	19.3	65.0	66	3.4x	25.0	28.1
Bunyangabu	Western	214,618	17.0	51.8	79	3.0x	19.2	20.7
Bushenyi	Western	274,905	26.3	69.4	96	2.6x	26.3	22.1
Busia	Eastern	426,649	33.4	129.7	78	3.9x	37.6	27.6
Butaleja	Eastern	334,916	19.4	82.0	58	4.2x	29.1	21.6
Butambala	Central	118,372	8.0	21.9	68	2.7x	11.5	3.5
Butebo	Eastern	150,784	7.9	29.2	53	3.7x	13.0	9.7
Buvuma	Central	142,991	17.3	40.2	121	2.3x	0.4	35.0
Buyende	Eastern	455,067	15.5	64.0	34	4.1x	36.6	9.1
Dokolo	Northern	235,501	7.7	27.4	33	3.6x	13.1	3.5
Gomba	Central	191,609	8.3	26.5	43	3.2x	12.2	5.7
Gulu	Northern	367,117	16.7	56.8	45	3.4x	33.5	5.5
Hoima	Western	435,564	48.7	1,180.6	112	24.2x	38.8	541.2
Ibanda	Western	303,898	21.8	60.9	72	2.8x	28.9	14.2
Iganga	Eastern	438,740	92.7	754.5	211	8.1x	40.6	693.5
Isingiro	Western	666,700	66.1	194.0	99	2.9x	58.5	53.6

District	Region	Population	GWh 2023	GWh 2040	kWh/person 2023	Growth	Households GWh 2040	Industry GWh 2040
Jinja	Eastern	564,354	34.5	637.3	61	18.5x	55.7	529.7
Kaabong	Northern	117,929	2.9	14.4	25	5.0x	7.3	1.8
Kabale	Western	271,639	24.3	930.0	89	38.3x	26.0	887.2
Kabarole	Western	378,927	37.1	96.5	98	2.6x	36.3	36.6
Kaberamaido	Eastern	144,263	5.4	17.2	37	3.2x	7.3	2.9
Kagadi	Western	536,180	30.1	101.5	56	3.4x	47.0	25.0
Kakumiro	Western	450,381	24.4	72.5	54	3.0x	27.1	16.9
Kalaki	Eastern	153,657	5.3	17.5	35	3.3x	7.1	3.1
Kalangala	Central	72,929	3.2	10.8	44	3.3x	3.0	4.9
Kaliro	Eastern	319,893	9.7	46.5	30	4.8x	27.2	6.4
Kalungu	Central	214,852	21.2	49.5	99	2.3x	22.1	14.5
Kampala	Central	1,865,125	609.3	2,341.1	327	3.8x	198.0	1,580.7
Kamuli	Eastern	620,692	25.8	88.4	42	3.4x	57.0	5.4
Kamwenge	Western	377,926	24.3	77.5	64	3.2x	33.5	17.6
Kanungu	Western	304,386	24.5	67.9	81	2.8x	28.6	24.5
Kapchorwa	Eastern	136,366	10.3	29.5	76	2.9x	12.7	8.8
Kapelebyong	Eastern	117,132	2.7	9.5	23	3.5x	2.5	2.4
Karenga	Northern	50,103	1.2	5.7	24	4.8x	2.8	0.8
Kasese	Western	884,183	133.9	1,003.9	151	7.5x	75.4	610.3
Kassanda	Central	382,395	26.7	79.8	70	3.0x	21.7	11.4
Katakwi	Eastern	214,056	7.4	24.2	35	3.3x	10.4	4.3
Kayunga	Central	452,364	19.2	67.0	42	3.5x	40.6	3.9
Kazo	Western	234,146	13.9	37.7	59	2.7x	13.5	10.9
Kibaale	Western	212,056	10.6	30.7	50	2.9x	11.5	7.9
Kiboga	Central	188,969	8.6	31.1	46	3.6x	15.0	5.6
Kibuku	Eastern	276,677	15.0	52.3	54	3.5x	22.9	17.9
Kikuube	Western	374,247	16.4	57.8	44	3.5x	28.1	14.0
Kiruhura	Western	212,257	19.8	45.7	93	2.3x	16.1	17.1
Kiryandongo	Western	350,845	12.3	45.9	35	3.7x	24.4	5.3
Kisoro	Western	353,609	26.4	79.9	75	3.0x	32.0	28.4
Kitagwenda	Western	199,427	17.8	52.6	89	3.0x	18.0	19.3
Kitgum	Northern	249,615	9.1	32.7	36	3.6x	17.8	3.8
Koboko	Northern	287,656	9.0	41.0	31	4.6x	24.1	4.3
Kole	Northern	320,382	9.8	35.4	30	3.6x	16.6	4.8
Kotido	Northern	237,545	5.1	30.0	21	5.9x	17.5	4.8
Kumi	Eastern	339,215	11.3	48.8	33	4.3x	27.2	6.8
Kwania	Northern	245,522	7.5	28.1	30	3.8x	13.3	3.7
Kween	Eastern	120,974	7.1	24.1	58	3.4x	9.9	7.8
Kyankwanzi	Central	312,159	13.8	41.7	44	3.0x	19.5	9.3

District	Region	Population	GWh 2023	GWh 2040	kWh/person 2023	Growth	Households GWh 2040	Industry GWh 2040
Kyegegwa	Western	482,966	18.2	63.3	38	3.5x	24.8	18.1
Kyenjojo	Western	581,388	31.0	88.8	53	2.9x	31.6	27.1
Kyotera	Central	295,303	23.3	64.2	79	2.7x	27.5	19.9
Lamwo	Northern	157,887	4.4	13.8	28	3.1x	4.5	2.4
Lira	Northern	525,487	22.3	79.3	43	3.5x	47.9	7.9
Luuka	Eastern	299,602	12.2	43.7	41	3.6x	27.3	2.6
Luwero	Central	579,283	134.0	319.4	231	2.4x	56.0	236.7
Lwengo	Central	320,642	24.2	69.4	76	2.9x	29.7	21.6
Lyantonde	Central	123,132	8.3	23.4	67	2.8x	10.6	4.6
Madi Okollo	Northern	177,994	6.2	19.9	35	3.2x	8.6	2.7
Manafwa	Eastern	189,740	12.2	40.0	64	3.3x	16.8	12.3
Maracha	Northern	227,619	7.5	33.8	33	4.5x	19.7	3.4
Masaka	Central	370,346	32.7	83.6	88	2.6x	36.0	25.0
Masindi	Western	377,139	18.6	58.0	49	3.1x	32.1	5.7
Mayuge	Eastern	632,358	129.7	348.6	205	2.7x	54.6	243.1
Mbale	Eastern	652,357	43.1	656.2	66	15.2x	59.6	567.0
Mbarara	Western	432,398	47.9	633.7	111	13.2x	45.0	559.6
Mitooma	Western	216,561	18.3	52.7	84	2.9x	19.9	17.4
Mityana	Central	402,455	22.0	69.4	55	3.2x	36.2	12.0
Moroto	Northern	132,102	5.8	17.7	44	3.0x	8.3	2.7
Moyo	Northern	87,063	3.7	12.8	42	3.5x	7.0	1.3
Mpigi	Central	317,469	50.6	120.1	159	2.4x	31.5	71.7
Mubende	Central	574,480	49.8	159.8	87	3.2x	45.6	21.5
Mukono	Central	778,486	314.4	3,024.7	404	9.6x	81.4	2,496.6
Nablatuk	Northern	101,013	3.0	12.6	29	4.2x	6.9	2.0
Nakapiripirit	Northern	142,795	4.7	17.1	33	3.6x	8.8	2.9
Nakaseke	Central	259,039	64.3	670.5	248	10.4x	25.9	630.7
Nakasongola	Central	237,706	51.9	121.4	218	2.3x	13.6	97.1
Namayingo	Eastern	296,266	57.6	149.9	195	2.6x	22.8	113.9
Namisindwa	Eastern	260,259	14.4	53.2	55	3.7x	22.2	16.8
Namutumba	Eastern	339,632	17.3	65.0	51	3.8x	28.7	21.9
Napak	Northern	178,104	5.3	545.0	30	102.5x	10.0	528.4
Nebbi	Northern	317,595	9.4	58.3	29	6.2x	25.9	4.8
Ngora	Eastern	183,777	5.9	26.4	32	4.5x	15.1	3.7
Ntoroko	Western	83,570	6.3	18.8	76	3.0x	7.1	8.1
Ntungamo	Western	603,279	51.8	143.0	86	2.8x	56.2	48.5
Nwoya	Northern	253,425	8.3	25.4	33	3.0x	11.2	3.8
Obongi	Northern	39,812	0.8	3.0	20	3.7x	0.7	0.6
Omoro	Northern	218,833	7.8	24.9	36	3.2x	12.0	3.3

District	Region	Population	GWh 2023	GWh 2040	kWh/person 2023	Growth	Households GWh 2040	Industry GWh 2040
Otuke	Northern	149,515	4.7	14.2	32	3.0x	5.2	2.2
Oyam	Northern	507,738	15.8	57.6	31	3.7x	28.7	7.6
Pader	Northern	222,904	7.0	21.7	31	3.1x	9.3	3.4
Pakwach	Northern	196,397	5.5	25.9	28	4.7x	15.5	3.0
Pallisa	Eastern	369,276	11.7	54.2	32	4.6x	31.0	7.4
Rakai	Central	343,871	22.0	65.3	64	3.0x	23.1	23.2
Rubanda	Western	234,743	15.5	50.9	66	3.3x	20.4	18.9
Rubirizi	Western	159,116	12.6	39.0	79	3.1x	13.9	15.4
Rukiga	Western	119,665	10.1	28.3	85	2.8x	11.2	9.6
Rukungiri	Western	375,391	34.2	92.4	91	2.7x	35.7	30.2
Rwampara	Western	160,513	13.4	36.0	83	2.7x	12.4	12.9
Serere	Eastern	392,698	11.4	50.0	29	4.4x	25.4	7.9
Sheema	Western	248,139	25.0	61.0	101	2.4x	24.9	20.0
Sironko	Eastern	308,789	18.5	61.3	60	3.3x	27.5	19.9
Soroti	Eastern	404,152	17.0	586.9	42	34.5x	34.0	533.0
Ssembabule	Central	327,454	19.8	55.8	60	2.8x	23.1	12.3
Tororo	Eastern	671,344	127.5	1,915.0	190	15.0x	62.2	1,433.6
Wakiso	Central	3,253,962	489.2	2,224.4	150	4.5x	316.8	1,259.9
Yumbe	Northern	735,084	17.1	97.8	23	5.7x	60.1	11.1
Zombo	Northern	312,104	10.2	43.8	33	4.3x	27.0	4.7

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/a_dist_demand.csv).

C.2 Access and institutions by district

The table gives:

- the grid access rate in 2023;
- the access gap in 2030, in households and as a share of households;
- the least-cost dominant electrification mode;
- distribution transformers per 1,000 households;
- unelectrified health facilities per 100,000 people;
- the number of unelectrified schools.

Table C.2: Access, electrification mode and institutions by district

District	Region	Access 2023	Gap 2030 (hh)	Gap 2030 (%)	Dominant mode	Transformers/1,000 hh	Health unelectrified /100k	Schools unelectrified
Abim	Northern	10.0%	25,513	51.9%	grid	0.8	1.9	42
Adjumani	Northern	8.2%	41,005	53.3%	grid	0.6	5.4	87
Agago	Northern	8.7%	41,654	53.0%	grid	0.7	4.7	63
Alebtong	Northern	5.5%	46,191	55.5%	shs	0.4	0.8	57
Amolatar	Northern	12.8%	28,192	49.6%	grid	1.0	1.2	32
Amudat	Northern	6.6%	24,508	54.6%	grid	0.5	2.1	30
Amuria	Eastern	7.4%	37,812	54.0%	shs	0.6	2.7	60
Amuru	Northern	10.9%	35,544	51.1%	shs	0.8	5.0	32
Apac	Northern	17.0%	32,484	46.2%	grid	1.3	2.0	50
Arua	Northern	12.1%	119,624	50.2%	grid	0.9	1.8	171
Budaka	Eastern	21.1%	34,355	42.8%	grid	1.6	1.2	41
Bududa	Eastern	3.6%	48,843	57.0%	grid	0.3	1.9	77
Bugiri	Eastern	18.1%	66,102	45.3%	grid	1.4	3.3	148
Bugweri	Eastern	27.2%	23,765	37.9%	grid	2.1	2.2	61
Buhweju	Western	12.5%	23,252	49.8%	grid	0.9	3.5	49
Buikwe	Central	50.6%	29,032	18.8%	grid	3.9	1.1	273
Bukedea	Eastern	18.0%	34,500	45.3%	grid	1.4	0.3	56
Bukomansimbi	Central	27.3%	18,568	37.8%	grid	2.1	1.9	145
Bukwo	Eastern	7.8%	20,482	53.7%	grid	0.6	1.8	38
Bulambuli	Eastern	16.2%	34,602	46.8%	grid	1.2	2.5	48
Buliisa	Western	14.8%	22,630	48.0%	grid	1.1	1.0	26
Bundibugyo	Western	9.6%	43,415	52.2%	grid	0.7	0.6	96
Bunyangabu	Western	19.8%	26,921	43.9%	grid	1.5	1.1	54
Bushenyi	Western	38.9%	22,248	28.3%	grid	3.0	1.2	136
Busia	Eastern	16.0%	57,247	47.0%	grid	1.2	3.0	105
Butaleja	Eastern	13.8%	46,618	48.7%	grid	1.1	3.2	75
Butambala	Central	42.5%	8,605	25.5%	grid	3.2	4.1	84
Butebo	Eastern	9.9%	22,376	52.0%	grid	0.7	1.6	31
Buvuma	Central	0.2%	24,433	59.8%	shs	-	2.8	34
Buyende	Eastern	13.0%	64,203	49.4%	grid	1.0	0.2	66
Dokolo	Northern	10.9%	34,412	51.2%	grid	0.8	0.7	38
Gomba	Central	16.9%	25,326	46.3%	grid	1.3	2.5	93
Gulu	Northern	25.0%	41,569	39.7%	grid	1.9	2.7	73
Hoima	Western	31.5%	42,729	34.4%	grid	2.4	1.9	98
Ibanda	Western	37.1%	25,912	29.9%	grid	2.8	1.3	138
Iganga	Eastern	29.1%	45,490	36.3%	grid	2.2	1.3	118
Isingiro	Western	23.4%	78,024	41.0%	grid	1.8	2.4	205

District	Region	Access 2023	Gap 2030 (hh)	Gap 2030 (%)	Dominant mode	Transformers/1,000 hh	Health unelectrified /100k	Schools unelectrified
Jinja	Eastern	47.8%	34,009	21.1%	grid	3.7	2.0	136
Kaabong	Northern	0.2%	20,139	59.8%	grid	-	7.6	55
Kabale	Western	38.8%	22,080	28.5%	grid	3.0	4.2	102
Kabarole	Western	38.9%	30,678	28.4%	grid	3.0	1.1	62
Kaberamaido	Eastern	12.3%	20,607	50.0%	shs	0.9	2.3	39
Kagadi	Western	18.4%	68,968	45.0%	grid	1.4	0.8	109
Kakumiro	Western	16.9%	59,487	46.3%	grid	1.3	0.7	64
Kalaki	Eastern	9.0%	23,129	52.7%	shs	0.7	0.0	42
Kalangala	Central	0.4%	12,430	59.7%	shs	-	8.9	19
Kaliro	Eastern	8.0%	48,871	53.5%	grid	0.6	1.0	62
Kalungu	Central	60.5%	6,612	10.8%	grid	4.6	1.9	99
Kampala	Central	70.3%	14,887	2.8%	grid	5.4	0.0	441
Kamuli	Eastern	28.4%	65,445	36.9%	grid	2.2	1.7	160
Kamwenge	Western	21.6%	45,768	42.4%	grid	1.7	1.3	64
Kanungu	Western	33.9%	28,212	32.5%	grid	2.6	1.3	111
Kapchorwa	Eastern	31.1%	13,514	34.7%	grid	2.4	3.0	44
Kapelebyong	Eastern	0.2%	20,003	59.8%	shs	-	4.9	37
Karenga	Northern	0.6%	8,519	59.5%	grid	-	6.5	16
Kasese	Western	8.1%	134,851	53.4%	grid	0.6	2.2	325
Kassanda	Central	14.2%	52,926	48.5%	grid	1.1	2.3	223
Katakwi	Eastern	11.7%	30,868	50.5%	shs	0.9	4.2	72
Kayunga	Central	25.1%	51,087	39.6%	grid	1.9	0.9	210
Kazo	Western	22.7%	27,788	41.6%	shs	1.7	1.7	96
Kibaale	Western	16.6%	28,178	46.5%	grid	1.3	0.0	39
Kiboga	Central	14.7%	25,918	48.0%	grid	1.1	3.9	90
Kibuku	Eastern	12.5%	39,380	49.8%	grid	0.9	0.6	36
Kikuube	Western	15.1%	51,008	47.7%	grid	1.2	1.7	70
Kiruhura	Western	46.7%	13,341	22.0%	shs	3.6	1.9	111
Kiryandongo	Western	14.0%	48,695	48.6%	grid	1.1	1.6	78
Kisoro	Western	22.6%	41,993	41.6%	grid	1.7	1.6	125
Kitagwenda	Western	22.1%	23,927	42.0%	grid	1.7	1.6	60
Kitgum	Northern	16.1%	33,438	46.9%	grid	1.2	2.0	50
Koboko	Northern	10.1%	42,565	51.8%	grid	0.8	0.8	45
Kole	Northern	9.4%	47,911	52.4%	grid	0.7	0.5	50
Kotido	Northern	0.4%	40,501	59.7%	grid	0.0	0.7	55
Kumi	Eastern	9.5%	50,615	52.3%	grid	0.7	1.2	71
Kwania	Northern	8.6%	37,172	53.0%	grid	0.6	1.7	50
Kween	Eastern	12.3%	17,269	50.0%	grid	0.9	4.0	37
Kyankwanzi	Central	20.1%	38,936	43.7%	grid	1.5	1.3	98

District	Region	Access 2023	Gap 2030 (hh)	Gap 2030 (%)	Dominant mode	Transformers/1,000 hh	Health unelectrified /100k	Schools unelectrified
Kyegegwa	Western	6.1%	75,896	55.0%	grid	0.5	1.2	55
Kyenjojo	Western	16.8%	76,975	46.4%	grid	1.3	1.1	124
Kyotera	Central	36.0%	25,873	30.7%	grid	2.8	5.2	166
Lamwo	Northern	6.9%	24,506	54.4%	shs	0.5	7.7	62
Lira	Northern	24.9%	59,700	39.8%	grid	1.9	1.9	128
Luuka	Eastern	25.2%	33,784	39.5%	grid	1.9	2.2	78
Luwero	Central	42.0%	42,698	25.8%	grid	3.2	2.9	276
Lwengo	Central	32.0%	31,128	34.0%	grid	2.4	1.8	180
Lyantonde	Central	32.2%	11,900	33.8%	grid	2.4	5.9	37
Madi Okollo	Northern	14.1%	24,690	48.6%	shs	1.1	5.5	67
Manafwa	Eastern	17.3%	24,876	45.9%	grid	1.3	0.9	63
Maracha	Northern	10.7%	33,323	51.3%	grid	0.8	1.4	42
Masaka	Central	44.5%	25,164	23.8%	grid	3.4	1.8	145
Masindi	Western	29.1%	39,112	36.3%	grid	2.2	2.8	101
Mayuge	Eastern	21.7%	76,445	42.3%	grid	1.7	1.5	136
Mbale	Eastern	25.8%	72,696	39.0%	grid	2.0	0.7	120
Mbarara	Western	64.1%	9,706	7.9%	grid	4.9	2.4	155
Mitooma	Western	27.4%	23,340	37.7%	grid	2.1	1.5	106
Mityana	Central	28.5%	42,275	36.8%	grid	2.2	3.8	282
Moroto	Northern	18.5%	16,958	45.0%	grid	1.4	5.5	40
Moyo	Northern	20.3%	10,807	43.5%	grid	1.5	11.2	46
Mpigi	Central	51.1%	16,757	18.5%	grid	3.9	1.5	142
Mubende	Central	11.8%	82,704	50.4%	grid	0.9	1.8	151
Mukono	Central	68.2%	10,169	4.6%	grid	5.2	1.7	369
Nabilatuk	Northern	9.2%	15,154	52.5%	grid	0.7	1.6	57
Nakapiripirit	Northern	13.2%	20,095	49.3%	grid	1.0	4.6	49
Nakaseke	Central	60.0%	8,312	11.2%	grid	4.6	0.3	123
Nakasongola	Central	26.6%	26,050	38.4%	shs	2.0	5.1	159
Namayingo	Eastern	8.2%	45,084	53.3%	grid	0.6	3.0	73
Namisindwa	Eastern	7.7%	39,958	53.8%	grid	0.6	0.6	64
Namutumba	Eastern	8.0%	51,861	53.5%	grid	0.6	2.6	82
Napak	Northern	9.9%	26,405	51.9%	grid	0.7	3.2	40
Nebbi	Northern	10.5%	46,650	51.4%	grid	0.8	2.0	87
Ngora	Eastern	10.2%	27,116	51.7%	grid	0.8	2.7	51
Ntoroko	Western	21.2%	10,209	42.8%	grid	1.6	1.9	32
Ntungamo	Western	33.6%	56,331	32.7%	grid	2.6	2.3	237
Nwoya	Northern	14.1%	35,135	48.6%	shs	1.1	1.9	36
Obongi	Northern	0.7%	6,756	59.4%	shs	-	26.6	30
Omoro	Northern	16.3%	29,209	46.7%	grid	1.2	4.8	30

District	Region	Access 2023	Gap 2030 (hh)	Gap 2030 (%)	Dominant mode	Transformers/1,000 hh	Health unelectrified /100k	Schools unelectrified
Otuke	Northern	10.0%	22,159	51.9%	shs	0.7	2.7	30
Oyam	Northern	11.1%	73,879	51.0%	grid	0.8	1.9	82
Pader	Northern	12.2%	31,862	50.1%	shs	0.9	5.1	55
Pakwach	Northern	9.6%	29,278	52.2%	grid	0.7	3.3	58
Pallisa	Eastern	8.4%	56,026	53.1%	grid	0.6	1.5	75
Rakai	Central	16.8%	45,543	46.4%	grid	1.3	3.1	125
Rubanda	Western	14.7%	32,195	48.0%	grid	1.1	2.1	88
Rubirizi	Western	16.8%	21,065	46.4%	grid	1.3	4.1	43
Rukiga	Western	32.6%	11,436	33.5%	grid	2.5	2.0	59
Rukungiri	Western	36.7%	32,289	30.1%	grid	2.8	4.1	159
Rwampara	Western	28.2%	16,999	37.1%	grid	2.1	3.0	59
Serere	Eastern	4.9%	62,779	56.0%	grid	0.4	0.8	65
Sheema	Western	52.2%	12,445	17.6%	grid	4.0	1.6	109
Sironko	Eastern	18.8%	39,403	44.7%	grid	1.4	2.4	103
Soroti	Eastern	17.9%	52,480	45.5%	grid	1.4	1.4	84
Ssembabule	Central	26.2%	36,208	38.7%	grid	2.0	1.5	180
Tororo	Eastern	30.8%	66,949	34.9%	grid	2.4	3.5	154
Wakiso	Central	43.7%	227,393	24.5%	grid	3.3	0.3	753
Yumbe	Northern	3.8%	119,482	56.9%	grid	0.3	1.5	89
Zombo	Northern	15.0%	42,579	47.8%	grid	1.1	1.6	75

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/a_dist_access.csv).

C.3 Grid, losses and resources by district

The table gives:

- the supply zone (transmission bus);
- the population-weighted distance to transmission and to the MV network;
- MV line density;
- the modelled distribution loss rate;
- firm generating capacity in the district in 2023;
- mean wind speed at 100 m.

Table C.3: Grid reach, losses and resources by district

District	Region	Supply zone	km to transmission	km to MV	MV km/km ²	Loss rate	Firm MW	Wind m/s
Abim	Northern	B12_Lira	75.3	1.37	0.07	22.2%	0.0	4.15
Adjumani	Northern	B12_Lira	74.9	1.95	0.10	26.5%	0.0	3.25
Agago	Northern	B12_Lira	74.6	1.66	0.19	24.5%	0.0	4.28
Alebtong	Northern	B12_Lira	23.3	1.60	0.21	24.0%	0.0	3.41
Amolatar	Northern	B12_Lira	44.8	1.25	0.13	21.2%	0.0	3.15
Amudat	Northern	B13_Opuyo	69.7	5.44	0.06	45.1%	0.0	3.23
Amuria	Eastern	B13_Opuyo	17.2	2.11	0.14	27.7%	0.0	2.98
Amuru	Northern	B12_Lira	32.5	2.89	0.08	32.7%	0.0	3.73
Apac	Northern	B12_Lira	25.9	1.13	0.22	20.3%	0.0	3.23
Arua	Northern	B12_Lira	14.5	1.05	0.31	19.6%	0.0	3.64
Budaka	Eastern	B17_Tororo	14.8	0.61	0.50	15.6%	0.0	3.26
Bududa	Eastern	B17_Tororo	20.7	0.71	0.22	16.5%	0.0	2.07
Bugiri	Eastern	B17_Tororo	7.8	0.75	0.39	17.0%	0.0	3.33
Bugweri	Eastern	B18_Nalubale	10.1	0.54	0.54	15.0%	0.0	3.21
Buhweju	Western	B16_MbararaNorth	22.9	0.49	0.52	14.5%	0.0	3.65
Buikwe	Central	B10_Lugazi	6.4	0.48	0.44	14.4%	124.0	3.28
Bukedea	Eastern	B13_Opuyo	8.3	0.86	0.42	17.9%	0.0	3.33
Bukomansimbi	Central	B11_MasakaWest	10.6	1.04	0.27	19.5%	0.0	3.47
Bukwo	Eastern	B17_Tororo	67.4	0.73	0.21	16.7%	0.0	2.53
Bulambuli	Eastern	B13_Opuyo	28.6	1.10	0.20	20.0%	0.0	3.04
Buliisa	Western	B12_Lira	35.5	0.97	0.07	18.8%	0.0	3.30
Bundibugyo	Western	B15_Nkenda	30.9	0.48	0.39	14.4%	0.0	2.92
Bunyangabu	Western	B15_Nkenda	10.1	0.35	0.60	13.1%	0.0	2.66
Bushenyi	Western	B16_MbararaNorth	4.4	0.40	0.66	13.7%	0.0	3.54
Busia	Eastern	B17_Tororo	19.2	0.53	0.48	14.8%	0.0	3.53
Butaleja	Eastern	B17_Tororo	16.5	0.69	0.32	16.4%	0.0	3.12
Butambala	Central	B05_Kabulasoke	5.8	0.46	0.51	14.2%	0.0	3.28
Butebo	Eastern	B17_Tororo	12.3	0.78	0.37	17.2%	0.0	3.34
Buvuma	Central	B10_Lugazi	31.6	12.72	-	64.0%	0.0	3.91
Buyende	Eastern	B13_Opuyo	52.1	1.16	0.21	20.5%	0.0	3.37
Dokolo	Northern	B12_Lira	13.9	1.07	0.29	19.7%	0.0	3.37
Gomba	Central	B05_Kabulasoke	3.6	1.14	0.23	20.3%	0.6	3.41
Gulu	Northern	B12_Lira	7.8	1.34	0.12	21.9%	0.0	3.91
Hoima	Western	B09_Nkongwe	10.3	1.00	0.20	19.2%	0.0	3.45
Ibanda	Western	B08_Kahungye	31.2	0.59	0.49	15.4%	0.0	3.34
Iganga	Eastern	B18_Nalubale	11.4	0.46	0.59	14.2%	0.0	3.19
Isingiro	Western	B16_MbararaNorth	25.7	0.82	0.32	17.5%	0.0	3.60

District	Region	Supply zone	km to transmission	km to MV	MV km/km ²	Loss rate	Firm MW	Wind m/s
Jinja	Eastern	B14_Bujagali	5.1	0.34	0.75	13.1%	298.6	3.20
Kaabong	Northern	B12_Lira	132.1	2.83	0.03	32.3%	0.0	5.81
Kabale	Western	B16_MbararaNorth	10.5	0.41	0.68	13.7%	0.0	3.81
Kabarole	Western	B15_Nkenda	6.1	0.44	0.44	14.0%	0.0	2.96
Kaberamaido	Eastern	B13_Opuyo	26.6	1.30	0.21	21.7%	0.0	3.26
Kagadi	Western	B08_Kahungye	14.0	0.70	0.45	16.4%	0.0	3.38
Kakumiro	Western	B09_Nkongwe	49.1	1.06	0.40	19.7%	0.0	3.36
Kalaki	Eastern	B13_Opuyo	6.7	1.38	0.29	22.3%	0.0	3.08
Kalangala	Central	B11_MasakaWest	45.0	8.92	0.01	56.1%	0.0	4.02
Kaliro	Eastern	B13_Opuyo	48.0	0.81	0.32	17.4%	0.0	3.21
Kalungu	Central	B11_MasakaWest	2.8	0.49	0.37	14.5%	0.0	3.68
Kampala	Central	B01_Lugogo	1.5	0.12	3.76	10.8%	0.0	3.55
Kamuli	Eastern	B14_Bujagali	21.3	0.53	0.52	14.9%	100.7	3.02
Kamwenge	Western	B08_Kahungye	10.5	0.91	0.29	18.4%	0.0	2.96
Kanungu	Western	B16_MbararaNorth	39.4	0.38	0.54	13.4%	0.0	2.72
Kapchorwa	Eastern	B17_Tororo	37.3	0.46	0.44	14.2%	0.0	3.19
Kapelebyong	Eastern	B13_Opuyo	35.3	3.47	0.06	36.0%	0.0	3.25
Karenga	Northern	B12_Lira	143.3	3.22	0.05	34.6%	0.0	5.22
Kasese	Western	B15_Nkenda	12.5	0.47	0.30	14.3%	66.9	2.80
Kassanda	Central	B05_Kabulasoke	38.4	1.24	0.27	21.2%	0.0	3.15
Katakwi	Eastern	B13_Opuyo	11.7	1.60	0.16	24.0%	0.0	3.39
Kayunga	Central	B14_Bujagali	14.0	0.56	0.39	15.2%	0.0	3.08
Kazo	Western	B08_Kahungye	17.5	1.36	0.25	22.1%	0.0	3.52
Kibaale	Western	B09_Nkongwe	44.5	1.39	0.31	22.4%	0.0	3.29
Kiboga	Central	B05_Kabulasoke	40.2	1.22	0.18	21.0%	0.0	3.23
Kibuku	Eastern	B17_Tororo	33.7	0.98	0.30	19.0%	0.0	3.12
Kikuube	Western	B09_Nkongwe	11.3	1.67	0.13	24.6%	0.0	3.51
Kiruhura	Western	B16_MbararaNorth	21.6	1.54	0.19	23.5%	0.0	3.95
Kiryandongo	Western	B12_Lira	5.0	2.02	0.08	27.1%	330.0	3.23
Kisoro	Western	B16_MbararaNorth	29.9	0.37	0.66	13.4%	0.0	3.98
Kitagwenda	Western	B15_Nkenda	28.9	0.65	0.36	16.0%	0.0	2.81
Kitgum	Northern	B12_Lira	59.6	2.12	0.09	27.8%	0.0	4.10
Koboko	Northern	B12_Lira	52.3	1.36	0.13	22.1%	0.0	3.92
Kole	Northern	B12_Lira	8.5	1.18	0.31	20.6%	0.0	3.63
Kotido	Northern	B13_Opuyo	81.1	1.59	0.09	23.9%	0.0	5.32
Kumi	Eastern	B13_Opuyo	8.9	1.25	0.29	21.2%	0.0	3.37
Kwania	Northern	B12_Lira	29.2	1.22	0.26	21.0%	0.0	3.26
Kween	Eastern	B17_Tororo	56.2	0.86	0.25	17.9%	0.0	3.72
Kyankwanzi	Central	B05_Kabulasoke	52.2	1.38	0.19	22.3%	0.0	3.32

District	Region	Supply zone	km to transmission	km to MV	MV km/km ²	Loss rate	Firm MW	Wind m/s
Kyegegwa	Western	B09_Nkongge	28.6	1.24	0.31	21.2%	0.0	3.31
Kyenjojo	Western	B08_Kahungye	22.8	1.50	0.22	23.2%	0.0	3.30
Kyotera	Central	B11_MasakaWest	6.0	0.77	0.17	17.1%	0.0	3.91
Lamwo	Northern	B12_Lira	54.7	6.82	0.02	50.1%	0.0	3.83
Lira	Northern	B12_Lira	9.8	0.78	0.41	17.2%	48.0	3.67
Luuka	Eastern	B14_Bujagali	22.7	0.47	0.70	14.3%	0.0	3.12
Luwero	Central	B06_Kawanda	8.1	0.77	0.33	17.1%	0.0	3.02
Lwengo	Central	B11_MasakaWest	5.2	0.63	0.45	15.8%	0.0	3.83
Lyantonde	Central	B09_Nkongge	12.1	1.33	0.24	21.9%	0.0	4.00
Madi Okollo	Northern	B12_Lira	24.8	2.51	0.08	30.4%	0.0	3.14
Manafwa	Eastern	B17_Tororo	15.9	0.54	0.59	15.0%	0.0	2.64
Maracha	Northern	B12_Lira	26.9	0.76	0.64	17.0%	0.0	4.12
Masaka	Central	B11_MasakaWest	5.9	0.44	0.23	14.0%	0.0	4.12
Masindi	Western	B12_Lira	30.1	1.33	0.12	21.9%	14.5	3.25
Mayuge	Eastern	B18_Nalubale	16.7	0.99	0.16	19.1%	23.3	3.83
Mbale	Eastern	B17_Tororo	5.3	0.33	0.82	12.9%	0.0	2.68
Mbarara	Western	B16_MbararaNorth	10.0	0.46	0.60	14.2%	24.4	3.60
Mitooma	Western	B16_MbararaNorth	17.4	0.44	0.75	14.0%	0.0	3.69
Mityana	Central	B05_Kabulasoke	17.6	0.77	0.36	17.1%	0.0	3.06
Moroto	Northern	B13_Opuyo	11.8	3.81	0.03	37.8%	0.0	5.05
Moyo	Northern	B12_Lira	98.8	1.37	0.08	22.2%	0.0	3.34
Mpigi	Central	B04_Mutundwe	3.7	0.49	0.39	14.5%	0.0	3.54
Mubende	Central	B09_Nkongge	34.3	1.11	0.30	20.1%	0.0	3.34
Mukono	Central	B07_Namanve	9.6	1.07	0.42	19.7%	50.2	3.29
Nabilatuk	Northern	B13_Opuyo	32.9	1.82	0.08	25.6%	0.0	4.42
Nakapiripirit	Northern	B13_Opuyo	56.6	3.68	0.06	37.1%	0.0	3.83
Nakaseke	Central	B06_Kawanda	11.8	1.08	0.18	19.9%	0.0	3.07
Nakasongola	Central	B06_Kawanda	13.0	2.78	0.14	32.0%	0.0	3.17
Namayingo	Eastern	B18_Nalubale	33.3	2.97	0.05	33.1%	0.0	4.12
Namisindwa	Eastern	B17_Tororo	24.1	0.56	0.47	15.2%	0.0	2.48
Namutumba	Eastern	B17_Tororo	32.6	0.75	0.37	17.0%	0.0	3.21
Napak	Northern	B13_Opuyo	10.7	3.95	0.05	38.5%	0.0	4.38
Nebbi	Northern	B12_Lira	10.0	0.90	0.20	18.3%	0.0	3.57
Ngora	Eastern	B13_Opuyo	11.5	1.01	0.26	19.2%	0.0	3.07
Ntoroko	Western	B15_Nkenda	21.1	0.94	0.21	18.6%	0.0	3.83
Ntungamo	Western	B16_MbararaNorth	10.2	0.62	0.46	15.7%	0.0	3.66
Nwoya	Northern	B12_Lira	7.0	2.95	0.07	33.1%	0.0	3.47
Obongi	Northern	B12_Lira	76.1	2.55	0.08	30.6%	0.0	2.89
Omoro	Northern	B12_Lira	10.5	1.61	0.17	24.1%	0.0	3.68

District	Region	Supply zone	km to transmission	km to MV	MV km/km ²	Loss rate	Firm MW	Wind m/s
Otuke	Northern	B12_Lira	50.3	2.45	0.16	30.0%	0.0	3.50
Oyam	Northern	B12_Lira	7.8	1.08	0.22	19.9%	0.0	3.57
Pader	Northern	B12_Lira	32.6	2.66	0.08	31.3%	0.0	3.85
Pakwach	Northern	B12_Lira	11.8	1.07	0.24	19.7%	0.0	3.21
Pallisa	Eastern	B13_Opuyo	35.8	1.07	0.17	19.8%	0.0	3.20
Rakai	Central	B11_MasakaWest	16.6	0.96	0.31	18.8%	0.0	3.87
Rubanda	Western	B16_MbararaNorth	8.9	0.45	0.61	14.1%	0.0	4.06
Rubirizi	Western	B15_Nkenda	6.4	0.52	0.13	14.7%	0.0	2.61
Rukiga	Western	B16_MbararaNorth	7.4	0.36	0.60	13.2%	0.0	4.19
Rukungiri	Western	B16_MbararaNorth	29.9	0.43	0.49	13.9%	0.0	3.09
Rwampara	Western	B16_MbararaNorth	7.2	0.71	0.36	16.6%	0.0	3.75
Serere	Eastern	B13_Opuyo	31.9	0.71	0.35	16.6%	0.0	3.12
Sheema	Western	B16_MbararaNorth	8.3	0.41	0.78	13.8%	0.0	3.60
Sironko	Eastern	B17_Tororo	19.9	0.65	0.38	16.0%	0.0	2.25
Soroti	Eastern	B13_Opuyo	6.2	1.01	0.32	19.2%	0.3	2.92
Ssembabule	Central	B09_Nkongwe	15.8	1.06	0.25	19.7%	20.2	3.70
Tororo	Eastern	B17_Tororo	6.6	0.59	0.57	15.5%	134.3	3.25
Wakiso	Central	B04_Mutundwe	3.2	0.27	0.70	12.3%	90.0	3.43
Yumbe	Northern	B12_Lira	65.7	1.45	0.15	22.9%	0.0	3.77
Zombo	Northern	B12_Lira	22.7	0.73	0.27	16.7%	0.0	4.00

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/a_dist_grid.csv).

C.4 Investment by district

The table gives:

- the total capital expenditure of the plan in 2024–2040 attributed to each district;
- the same expenditure per person;
- its split by category.

Table C.4: Plan capital expenditure by district, 2024–2040 (MUSD)

District	Region	Capex (MUSD)	USD per person	Access capex (MUSD)	Generation	Transmission	Distribution	Institutions
Abim	Northern	21.1	123	17.3	0.0	0.0	3.3	0.5
Adjumani	Northern	35.2	131	28.9	0.0	0.0	4.9	1.4
Agago	Northern	35.7	129	29.6	0.0	0.0	5.0	1.1
Alebtong	Northern	41.9	144	37.5	0.0	0.0	3.7	0.7
Amolatar	Northern	26.3	132	22.9	0.0	0.0	3.0	0.5
Amudat	Northern	21.8	139	19.4	0.0	0.0	1.9	0.4
Amuria	Eastern	35.6	145	31.9	0.0	0.0	2.8	0.9
Amuru	Northern	33.2	136	29.3	0.0	0.0	3.3	0.7
Apac	Northern	30.7	125	26.0	0.0	0.0	4.0	0.7
Arua	Northern	100.2	120	80.8	0.0	0.0	17.0	2.4
Budaka	Eastern	31.6	113	24.1	0.0	0.0	6.9	0.6
Bududa	Eastern	40.1	134	31.4	0.0	0.0	7.6	1.1
Bugiri	Eastern	65.3	128	46.2	0.0	0.0	16.9	2.1
Bugweri	Eastern	38.2	174	17.4	0.0	0.0	19.9	0.8
Buhweju	Western	21.8	133	16.3	0.0	0.0	4.8	0.7
Buikwe	Central	132.4	245	29.0	0.0	68.8	31.2	3.4
Bukedea	Eastern	31.9	120	27.2	0.0	0.0	4.1	0.7
Bukomansimbi	Central	22.1	129	16.1	0.0	0.0	4.2	1.8
Bukwo	Eastern	17.5	131	13.6	0.0	0.0	3.4	0.5
Bulambuli	Eastern	32.0	124	24.1	0.0	0.0	7.1	0.8
Buliisa	Western	19.4	117	15.7	0.0	0.0	3.3	0.4
Bundibugyo	Western	38.1	131	28.7	0.0	0.0	8.3	1.2
Bunyangabu	Western	25.8	120	18.7	0.0	0.0	6.3	0.7
Bushenyi	Western	28.3	103	18.3	0.0	0.0	8.4	1.7
Busia	Eastern	57.2	134	39.0	0.0	0.0	16.6	1.6
Butaleja	Eastern	43.7	130	31.5	0.0	0.0	11.0	1.2
Butambala	Central	19.0	161	7.4	0.0	7.7	2.8	1.1
Butebo	Eastern	18.9	126	14.8	0.0	0.0	3.7	0.4
Buvuma	Central	27.8	195	22.1	0.0	0.0	5.1	0.6
Buyende	Eastern	53.5	118	44.8	0.0	0.0	7.9	0.8
Dokolo	Northern	31.1	132	27.0	0.0	0.0	3.6	0.5
Gomba	Central	632.4	3,300	20.1	540.0	67.5	3.6	1.2
Gulu	Northern	38.5	105	29.9	0.0	0.0	7.4	1.1
Hoima	Western	211.3	485	33.5	0.0	0.0	176.4	1.4
Ibanda	Western	30.5	100	20.8	0.0	0.0	7.9	1.7
Iganga	Eastern	146.9	335	33.8	0.0	0.0	111.5	1.5
Isingiro	Western	83.9	126	56.7	0.0	0.0	24.5	2.8

District	Region	Capex (MUSD)	USD per person	Access capex (MUSD)	Generation	Transmission	Distribution	Institutions
Jinja	Eastern	127.6	226	32.0	0.0	2.1	91.6	1.9
Kaabong	Northern	17.0	144	14.2	0.0	0.0	2.1	0.7
Kabale	Western	148.7	547	18.1	0.0	0.0	129.0	1.6
Kabarole	Western	37.1	98	25.2	0.0	0.0	11.0	0.9
Kaberamaido	Eastern	19.3	134	16.8	0.0	0.0	2.0	0.5
Kagadi	Western	63.6	119	48.0	0.0	0.0	14.2	1.4
Kakumiro	Western	57.2	127	48.1	0.0	0.0	8.2	0.9
Kalaki	Eastern	21.3	138	18.7	0.0	0.0	2.0	0.5
Kalangala	Central	11.7	161	9.7	0.0	0.0	1.6	0.5
Kaliro	Eastern	38.9	122	32.1	0.0	0.0	6.0	0.8
Kalungu	Central	16.6	77	9.2	0.0	0.0	6.1	1.3
Kampala	Central	634.4	340	60.1	244.3	4.8	319.9	5.2
Kamuli	Eastern	61.2	99	48.5	0.0	0.0	10.6	2.1
Kamwenge	Western	74.4	197	32.5	0.0	30.4	10.6	0.9
Kanungu	Western	31.7	104	21.9	0.0	0.0	8.4	1.4
Kapchorwa	Eastern	14.3	105	10.2	0.0	0.0	3.4	0.6
Kapelebyong	Eastern	18.5	158	16.9	0.0	0.0	1.1	0.6
Karenga	Northern	7.3	145	6.2	0.0	0.0	0.8	0.3
Kasese	Western	2,626.6	2,971	88.5	2,380.0	10.5	143.3	4.3
Kassanda	Central	59.4	155	42.5	0.0	3.6	10.5	2.8
Katakwi	Eastern	29.1	136	25.3	0.0	0.0	2.8	1.1
Kayunga	Central	47.9	106	37.2	0.0	0.0	8.1	2.6
Kazo	Western	2,840.9	12,133	24.1	2,806.8	3.9	4.8	1.3
Kibaale	Western	27.3	129	23.4	0.0	0.0	3.4	0.5
Kiboga	Central	24.1	128	18.5	0.0	0.0	4.4	1.3
Kibuku	Eastern	34.1	123	27.0	0.0	0.0	6.6	0.5
Kikuube	Western	45.3	121	37.3	0.0	0.0	7.0	1.1
Kiruhura	Western	21.7	102	15.1	0.0	0.0	5.1	1.5
Kiryandongo	Western	43.6	124	36.4	0.0	0.0	6.1	1.0
Kisoro	Western	41.6	118	29.8	0.0	0.0	10.2	1.6
Kitagwenda	Western	24.1	121	16.9	0.0	0.0	6.4	0.8
Kitgum	Northern	30.2	121	25.2	0.0	0.0	4.3	0.7
Koboko	Northern	35.0	122	28.6	0.0	0.0	5.8	0.6
Kole	Northern	43.3	135	37.9	0.0	0.0	4.7	0.7
Kotido	Northern	31.6	133	27.0	0.0	0.0	4.0	0.5
Kumi	Eastern	41.6	123	34.5	0.0	0.0	6.1	0.9
Kwania	Northern	33.4	136	28.9	0.0	0.0	3.8	0.7
Kween	Eastern	15.4	127	11.9	0.0	0.0	3.0	0.5
Kyankwanzi	Central	38.8	124	32.0	0.0	0.0	5.6	1.3

District	Region	Capex (MUSD)	USD per person	Access capex (MUSD)	Generation	Transmission	Distribution	Institutions
Kyegegwa	Western	108.9	226	58.7	0.0	41.8	7.6	0.8
Kyenjojo	Western	77.4	133	64.1	0.0	0.0	11.6	1.7
Kyotera	Central	31.8	108	20.8	0.0	0.0	8.6	2.3
Lamwo	Northern	24.0	152	21.2	0.0	0.0	1.7	1.1
Lira	Northern	568.6	1,082	42.9	513.4	0.0	10.4	1.8
Luuka	Eastern	30.8	103	24.4	0.0	0.0	5.3	1.1
Luwero	Central	77.2	133	36.5	0.0	0.0	36.9	3.7
Lwengo	Central	35.7	111	23.9	0.0	0.0	9.5	2.3
Lyantonde	Central	12.8	104	9.6	0.0	0.0	2.6	0.6
Madi Okollo	Northern	24.3	137	20.7	0.0	0.0	2.5	1.1
Manafwa	Eastern	22.8	120	17.1	0.0	0.0	4.9	0.8
Maracha	Northern	27.5	121	22.1	0.0	0.0	4.8	0.6
Masaka	Central	35.2	95	22.4	0.0	0.0	10.8	1.9
Masindi	Western	39.4	104	30.7	0.0	0.0	7.3	1.4
Mayuge	Eastern	99.8	158	55.2	0.0	0.0	42.8	1.8
Mbale	Eastern	149.8	230	52.7	0.0	0.0	95.6	1.6
Mbarara	Western	114.6	265	16.9	0.0	0.0	95.7	2.1
Mitooma	Western	25.1	116	17.1	0.0	0.0	6.6	1.4
Mityana	Central	60.6	151	31.8	0.0	15.7	9.4	3.7
Moroto	Northern	16.3	124	13.7	0.0	0.0	2.0	0.7
Moyo	Northern	10.5	120	8.0	0.0	0.0	1.7	0.8
Mpigi	Central	47.9	151	17.0	0.0	16.1	13.0	1.9
Mubende	Central	110.6	192	57.6	0.0	32.4	18.6	2.0
Mukono	Central	479.7	616	27.3	0.0	28.7	418.9	4.8
Nabilatuk	Northern	13.2	130	11.0	0.0	0.0	1.6	0.6
Nakapiripirit	Northern	18.4	129	15.6	0.0	0.0	2.0	0.7
Nakaseke	Central	113.3	438	11.7	0.0	0.0	100.2	1.5
Nakasongola	Central	39.8	167	23.7	0.0	0.0	13.9	2.2
Namayingo	Eastern	50.4	170	31.0	0.0	0.0	18.2	1.1
Namisindwa	Eastern	33.7	130	26.1	0.0	0.0	6.8	0.8
Namutumba	Eastern	43.7	129	34.2	0.0	0.0	8.3	1.1
Napak	Northern	101.3	569	20.5	0.0	0.0	80.2	0.6
Nebbi	Northern	42.0	132	31.8	0.0	0.0	9.1	1.2
Ngora	Eastern	22.4	122	18.4	0.0	0.0	3.3	0.7
Ntoroko	Western	10.1	121	7.4	0.0	0.0	2.3	0.4
Ntungamo	Western	64.7	107	43.9	0.0	0.0	17.6	3.2
Nwoya	Northern	33.7	133	30.0	0.0	0.0	3.2	0.6
Obongi	Northern	6.9	173	5.8	0.0	0.0	0.4	0.7
Omoro	Northern	28.0	128	24.1	0.0	0.0	3.2	0.6

District	Region	Capex (MUSD)	USD per person	Access capex (MUSD)	Generation	Transmission	Distribution	Institutions
Otuke	Northern	21.4	143	19.1	0.0	0.0	1.8	0.5
Oyam	Northern	66.8	132	57.9	0.0	0.0	7.7	1.2
Pader	Northern	30.7	138	27.1	0.0	0.0	2.7	0.9
Pakwach	Northern	24.7	126	20.1	0.0	0.0	3.7	0.8
Pallisa	Eastern	45.2	122	37.2	0.0	0.0	6.9	1.1
Rakai	Central	46.2	134	35.4	0.0	0.0	9.1	1.7
Rubanda	Western	29.8	127	21.9	0.0	0.0	6.7	1.2
Rubirizi	Western	20.0	126	14.5	0.0	0.0	4.8	0.7
Rukiga	Western	13.0	109	8.8	0.0	0.0	3.5	0.8
Rukungiri	Western	39.3	105	25.8	0.0	0.0	11.3	2.2
Rwampara	Western	19.1	119	13.9	0.0	0.0	4.4	0.8
Serere	Eastern	52.3	133	45.1	0.0	0.0	6.3	0.9
Sheema	Western	21.4	86	12.9	0.0	0.0	7.0	1.4
Sironko	Eastern	36.3	117	27.3	0.0	0.0	7.6	1.5
Soroti	Eastern	279.6	692	37.2	156.0	0.0	85.2	1.1
Ssembabule	Central	46.7	143	30.3	0.0	8.0	6.2	2.3
Tororo	Eastern	1,444.5	2,152	50.7	1,125.0	0.0	266.5	2.3
Wakiso	Central	532.4	164	199.3	0.0	15.0	308.9	9.2
Yumbe	Northern	93.8	128	78.0	0.0	0.0	14.5	1.3
Zombo	Northern	36.2	116	29.1	0.0	0.0	6.1	1.0

Source: AICTEM Energy Modelling Engine, base scenario S0 (report/build/data/a_dist_invest.csv).

ANNEX D

D Glossary and abbreviations

D.1 Abbreviations

Abbreviation	Meaning
AICTEM	The integrated planning and modelling system of which the Energy Modelling Engine is a part
BESS	Battery energy storage system
BOE	Bill of engineering (detailed project cost estimate)
CCGT	Combined-cycle gas turbine
CF	Capacity factor
CI	Concentration index
CO ₂	Carbon dioxide
CRF	Capital recovery factor
EACOP	East African Crude Oil Pipeline
EMIS	Education Management Information System
ERA	Electricity Regulatory Authority
EUE	Expected unserved energy
FOM	Fixed operation and maintenance cost
GIS	Geographic information system
GWh	Gigawatt-hour (million kWh)
HFO	Heavy fuel oil
HHI	Herfindahl–Hirschman index
IERMP	Integrated Energy Resource Master Plan
IRP	Integrated Resource Plan
kV	Kilovolt
kWh	Kilowatt-hour
LCOE	Levelised cost of electricity
LISA	Local indicator of spatial association (local Moran)
LOLE	Loss-of-load expectation
LRMC	Long-run marginal cost
LV	Low voltage (below 1 kV)
MEMD	Ministry of Energy and Mineral Development
MoES	Ministry of Education and Sports
MoFPED	Ministry of Finance, Planning and Economic Development
MoH	Ministry of Health
MTEF	Medium-Term Expenditure Framework
MUSD	Million US dollars
MV	Medium voltage (11 and 33 kV)
MVA	Megavolt-ampere
MW	Megawatt
N-1	Security criterion: the system withstands the loss of any one element
NPV	Net present value
O&M	Operation and maintenance
OCGT	Open-cycle gas turbine
PyPSA	Python for Power System Analysis, the open-source optimisation framework used by the engine
RE	Renewable energy

Abbreviation	Meaning
SDI	Spatial Data Infrastructure
SGR	Standard Gauge Railway
SHS	Solar home system
UBOS	Uganda Bureau of Statistics
UCSN	The national unit-cost system for governed cost coefficients
UEDCL	Uganda Electricity Distribution Company Limited
UETCL	Uganda Electricity Transmission Company Limited
UGX	Uganda shilling
USD	US dollar
UTM	Universal Transverse Mercator projection (zone 36N for Uganda)
VoLL	Value of lost load
WACC	Weighted average cost of capital

D.2 Glossary

Term	Definition
Abatement cost	The extra net present cost of a scenario divided by the emissions it avoids relative to S0, in USD per tonne of CO ₂
Access rate	The share of households with a grid connection. In 2040, the share with a grid connection or a solar home system
Activity index	The growth of a segment's output relative to the base year, which drives its demand
Availability	The share of a unit's capacity that can produce in a given time slice, from the resource or from outages
Capacity credit	The share of a unit's capacity that can be counted on at the system peak
Capacity gap	Peak demand plus reserve margin, minus existing firm capacity
Commissioning tranche	A block of capacity that comes into service in a given year
Concentration curve	The cumulative share of supply plotted against the cumulative share of population, ranked by need
Corridor	A transmission connection between two buses, which may contain several lines
Cost to serve	The average cost of supplying a customer class, including generation, transmission, distribution and retail
Critical path	The projects whose lead time or size make them decisive for the schedule
Cross-subsidy	The difference between what a customer class pays and its cost to serve, times its energy
Dual (shadow price)	The change in the optimal cost from relaxing a constraint by one unit
Energy gap	The generation requirement minus the energy the existing fleet can produce
Firm capacity	The sum of each unit's capacity multiplied by its capacity credit
Hot-spot (HH)	A district with a high value surrounded by high values, significant in the local Moran test
Cold-spot (LL)	A district with a low value surrounded by low values, significant in the local Moran test
Just-in-time rule	The commissioning rule that brings capacity online in the year it is first needed
Load factor	Average demand divided by peak demand
Load shedding	Demand that is not supplied; modelled as a generator priced at the value of lost load

Term	Definition
Moran's I	A statistic of spatial autocorrelation: positive if similar values cluster together
Multi-investment-period optimisation	A capacity expansion that decides investments in several periods at once, with each asset active from its build period
Nodal price	The marginal cost of supplying one more MWh at a bus, the dual of its energy balance
Overnight cost	The capital cost of a project as if built instantly, without interest during construction
Requirement	The electricity that must be generated to meet final demand, including network losses and net exports
Reserve margin	Firm capacity divided by peak demand, minus one
Revenue requirement	The revenue the sector must collect to cover the cost of the existing system and the plan
Slack	The number of years between now and the latest date for financial close. Negative slack means the project is late
Step load	A large discrete new load (industrial park, steel plant, data centre, mine) added in a specific year
Time slice	One of the 25 representative periods of the year used by the power model, each with a weight in hours
Transition gap	Years between planning periods in which the reserve margin falls below target
Transport model	A network model in which power flows are limited only by line capacities, without the physics of AC flow
Validation check	An automatic test of consistency or calibration that runs with every model solve

D.3 Status labels

Label	Meaning
OBSERVED	Metered, registered, licensed or published
CALIBRATED	Derived from observed data by a documented transformation
MODELLED	The output of a solved model or engine calculation
ASSUMED	A planning assumption, editable in the engine's configuration
NOT_AVAILABLE	An input that is missing; never replaced by zero