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Applied Research Programme

Electrification Pathways for Ethiopia

Work Package 3: On-grid and Off-grid power sector planning- Modelling results from the soft-link of OnSSET and OSeMOSYS models

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Abstract

In this report, we investigate the implications for the future electrification pathways of Ethiopia under five plausible scenarios. These scenarios are *not* predictions or forecasts of the future, but instead allow us to explore alternative energy pathways under a range of conditions. The scenarios are implemented using two models which are soft-linked. This approach provides insights into the long-term energy system pathways incorporating a mixture of grid connected technologies and off-grid spatially distributed supply technologies.

The results highlight a number of key insights across a range of broad topics: the dominance of hydroelectric power before 2030, the role of non-hydroelectric power technologies in electricity supply after 2030; the importance of off-grid technologies to reduce the cost of electrification; the opportunity for Ethiopia to become a key energy trader; and finally, some open questions for future work.

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2 Introduction

In this technical report, a deliverable of WP3, we present quantitative analysis conducted by KTH Royal Institute of Technology (KTH) and Addis Ababa Institute of Technology (AAiT) to investigate plausible electrification pathways for Ethiopia. This report focusses on the quantitative modelling of narrative scenarios and demand projections which were developed by University College London (UCL) in WP1 and 2 through a stakeholder interaction stakeholder workshop and interviews that took place in Addis Ababa in 2019 [1].

We adopt two different modelling approaches, which are described in detail in Section 4 together with the general assumptions common across the scenarios. We use the Open-Source Energy System Modelling framework (OSeMOSYS) to investigate long-term scenarios focusing on the supply side mix for the power sector. The Open-Source Spatial Electrification Tool (OnSSET) provides insights into the spatial evolution of on-grid and off-grid technologies, focused on meeting latent demand for residential electricity. The two tools were soft-linked to provide coherent insights across on-grid and off-grid sectors.

In Section 5 we present the narrative scenarios, which provide a qualitative description of a broad range of plausible futures for the Ethiopian energy sector. The purpose of the narrative scenarios, as an explorative scenario exercise, is to explore alternatives, challenge conventional thinking, and help policy and decision makers think through near-term actions which could avoid undesirable futures, while achieving desired outcomes robustly and at low cost. To provide a quantitative implementation of the narratives, we convert the qualitative storylines into a range of assumptions, constraints and projections. These are documented in Table 6 and together with other numerical assumptions in Section 9. We present the results in Section 6.

3 Background

Ethiopia is a low-income country situated in sub-Saharan Africa. With a rapidly growing population of 112 million (2019) and GDP of $96B (2019), Ethiopia's sustained economic growth since 2000 points to an urgent need for energy planning to support the country's transition to middle-income status by 2025. Ethiopia's current reliance on large hydropower generation means that greenhouse gas emissions are very low on an absolute and per-capita basis, and indicate the opportunity to continue to support climate compatible growth and development. There are significant challenges, including financing and debt, power sector and tariff reform, energy access and exposure to climate risks through reliance on large hydropower.

3.1 Socio-economic Situation

The Federal Democratic Republic of Ethiopia is a land-locked country in East Africa located on the Horn of Africa. It is surrounded by Eritrea to the north, Somalia and Djibouti to the east, Kenya to the south and Sudan and South Sudan to the west. The country is part of the Eastern African Power Pool (EAPP) and part of the Ethiopia-Kenya-Tanzania corridor with plans to extend to the Central-Northern corridor (Ethiopia – Sudan – Egypt) [2].

Figure 1: Map of Ethiopia showing location in Africa
(Source: WikiMedia CC-BY-4.0).

The population of Ethiopia was 112 million people in 2019, is the 2nd most populated country in Africa behind Nigeria, and is expected to reach 140 million by 2030 and 170 million by 2040 (medium variant scenario)[3]. The average annual population growth rate of the country was around 2.6% over the past five years. The proportion of urban population in the country is low at 21.2 % in 2019[4] but is increasing at 4-5% annually.

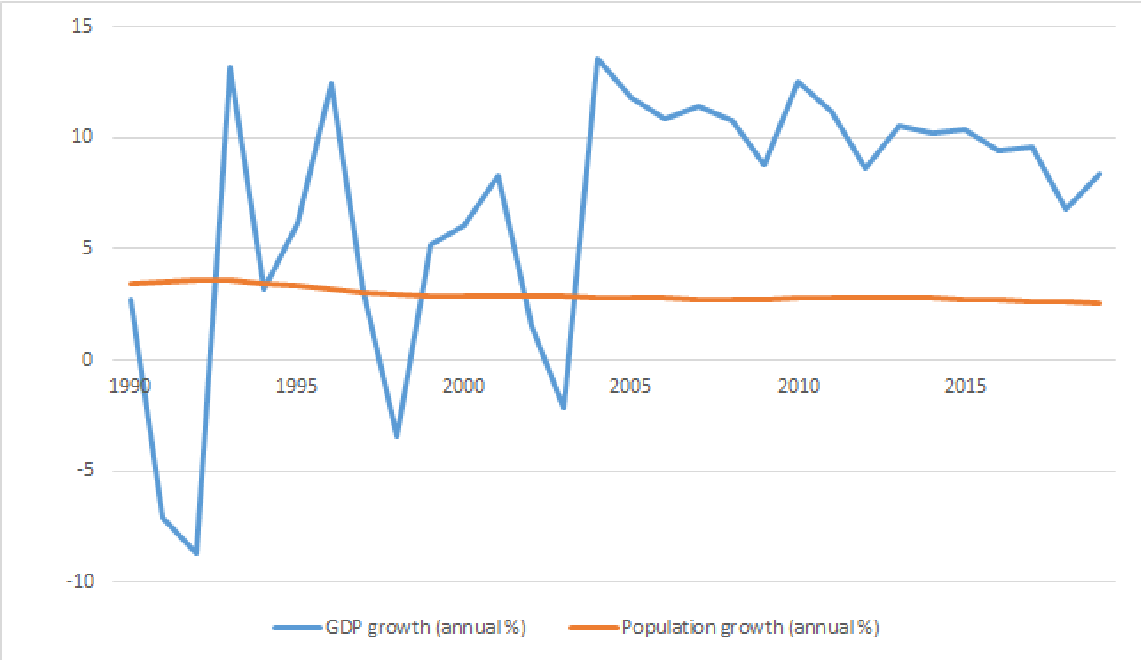


Figure 2 GDP growth (annual %) and population growth (annual %) of Ethiopia the period 1990-2019 [4].

While Ethiopia remains a low-income country and one of the poorest countries in Africa, its Gross domestic product (GDP) growth of 8.3% p.a. makes it one of the fastest-growing economies in the region and gives credence to the government's ambitions of reaching a low middle-income status by 2025, increasing the gross national income per capita from 790 USD in 2018 to between 1006 USD and 3955 USD [5], [6]. The country depends largely on the agricultural sector, which employs around 80 % of the population (Ministry of Environment and Forest 2015). The GDP is driven by the service sector, contributing 37.1% of the GDP, followed by the agriculture and industry at 33.5 and 24.8% respectively in 2019. Supporting these combined dynamics suggests substantial increases in the country's energy needs, yet low national electricity access levels remain a significant hurdle for the government's ambitions.

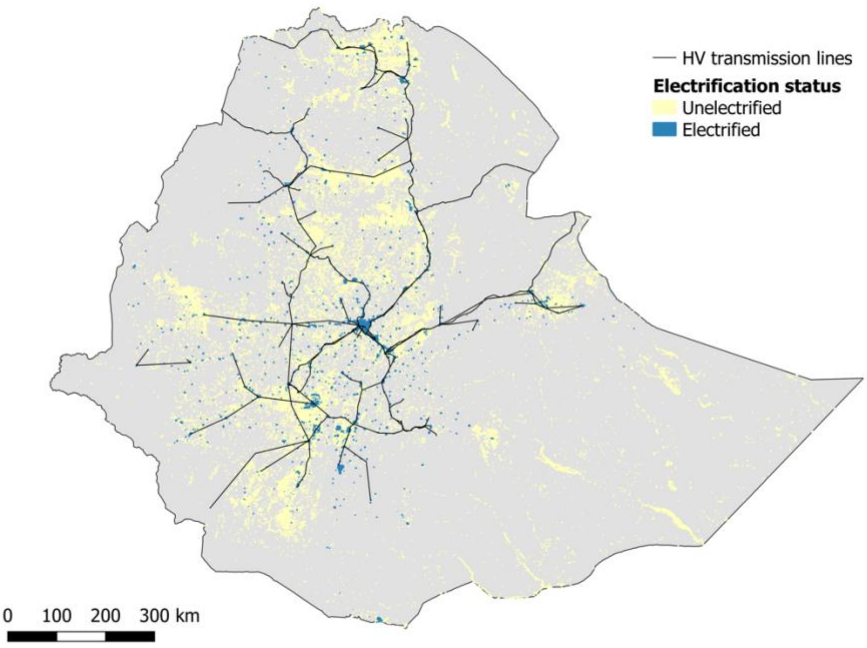


Figure 3 Settlement electrification status in Ethiopia in 2018 based on night-time lights analysis and grid network proximity.

Electricity access in Ethiopia has increased by only 30 percentage points over the past 25 years, reaching 45% in 2018. Extrapolating the average annual growth rate of 7% between 2010 and 2018 means that universal access would be achieved by 2042 [7]. Besides, the electricity consumption per capita is among the lowest globally and, at 83 kWh/capita in 2018, is lower than the African continent average in the same year (500 kWh/capita) [7]. The fact that 80% of the country's population is rural, that electrification is currently concentrated in denser urban areas, and that only a low number of households are connected to the national grid infrastructure in 2018, the rest is off grid, further increase complexity [8].

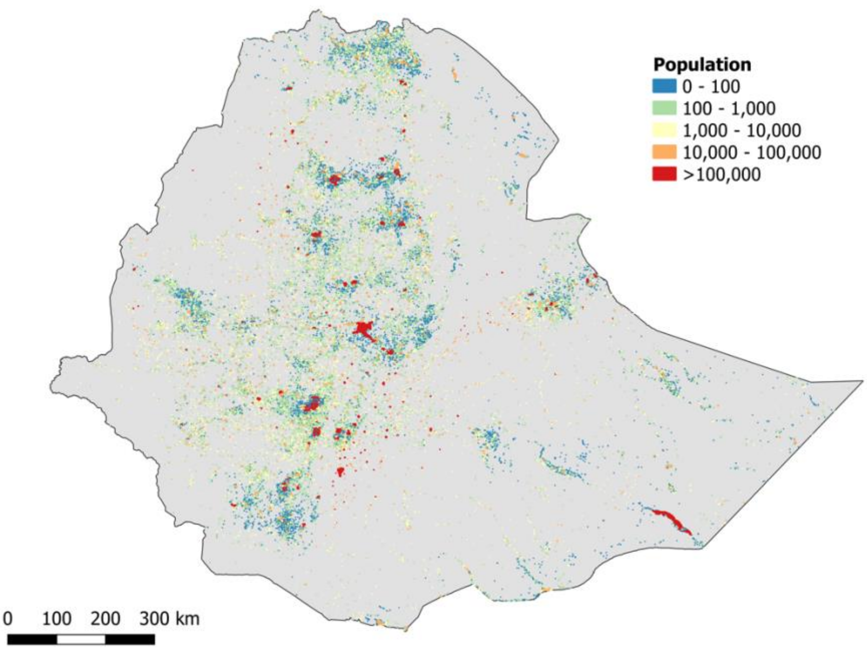


Figure 4 Population Density of Ethiopia

3.2 Policy Context

Key policies and plans which are under implementation by the government of Ethiopia are the Sustainable Development Goals (SDGs) (2015-2030), the Climate-Resilient Green Economy (CRGE) (2019) which is mainstreamed into the second phase of its Integrated Growth and Transformation GTP II (2015-2020)[9] and the National Electrification Programme 2.0 (NEP II)[10]. The government has finished the first phase of GTP I (2010-2015) and is planning to start the other phases of its GTP in the following years GTP III (2022-2025) and GTP IV (2026-2030) [11].

- The Climate-Resilient Green Economy (CRGE) strategy aims to transform Ethiopia into a middle-income status country by 2025 and a carbon neutral economy by 2030, decreasing the country's emissions to less than 150 Mt CO_2 eq/y.[1] Some of the targets include achieving 100% electricity access by 2025, becoming an electricity hub exporter in the Easter African power pool and increasing the share of renewables in the energy mix.
- Also, the CRGE considers the adverse effects of climate change in the energy sector by promoting the expansion of electricity generation from renewable sources of energy (grid, off-grid) for domestic and regional markets as an adaptation initiative; promoting the use of modern and energy-efficient technologies in transport, industrial sectors, and buildings; improving the agricultural practices; and protecting the forestry and ecosystem services.
- NEP II intends to achieve universal access in electricity in Ethiopia by 2025. In 2025, the population residing within 2.5 km of the existing network are to be connected to the centralized grid, accounting for 65% of the population. The remaining 35% are to be served by an off-grid technology. By 2030, the aim is to connect everyone residing within 25 km of the existing network, or 96% of the total population, with only people living in more remote areas served by off-grid technologies.

3.3 Energy Resources

In terms of renewable energy potential, Ethiopia exhibits vast potential in hydropower (45 GW), one of the largest in Africa, however, less than 10% of it has been tapped. Further potential also exists for CSP, PV, Wind, and Geothermal. Developing these high levels of renewable energy resources is at the root of Ethiopia's ambition to establish international trade and become an electricity export hub for the neighbouring East African Power Pool (EAPP) [9].

Table 1 Estimated Ethiopian Energy Reserves [13]

Resource	Unit	Exploitable Reserve	Exploited Percent
Hydropower	GW	45	<20 percent
Solar	kWh per meter square per day	5–6	<1 percent
Wind power	GW	10	<1 percent
Geothermal	GW	5	<1 percent

[1] As part of the Paris Agreement, the government of Ethiopia will need to reduce its greenhouse gas emissions, to 145 MtCO2eq. in 2030, to the levels of 2010 base, including land use, land-use change, and forestry (LULUCF). At a national scale, the total greenhouse gas emissions amounted to 127 Mt of CO_2 equivalent (excluding forestry) in 2017 [12]

Wood	Million tons	1120	50 percent
Agricultural waste	Million tons	15–20	30 percent

3.3.1 Fossil Fuel Reserves

The country has proven reserves for crude oil and natural gas, amounting in 2016 to 0.43 million barrels and 113 billion cubic meter respectively[9].

Table 2 Fossil Fuel Reserves

No	Resource	Unit	Exploitable Reserve	Exploited Percent
1	Natural gas	Billion cubic meters	113	0 percent
2	Coal	Million tons oil equivalent	300	0 percent
3	Oil shale	Million tons oil equivalent	253	0 percent
4	Crude Oil	Billion barrels	0.000428	0 percent

3.3.2 Solar resource

The solar irradiation in Ethiopia is relatively high (5000 – 6000 Wh/m2) (Figure 5) and consequently there is a great potential for the use of solar energy in the country to invest in solar PV and CSP technologies (Table 1). Less than 1 percent of this resource is currently being used.

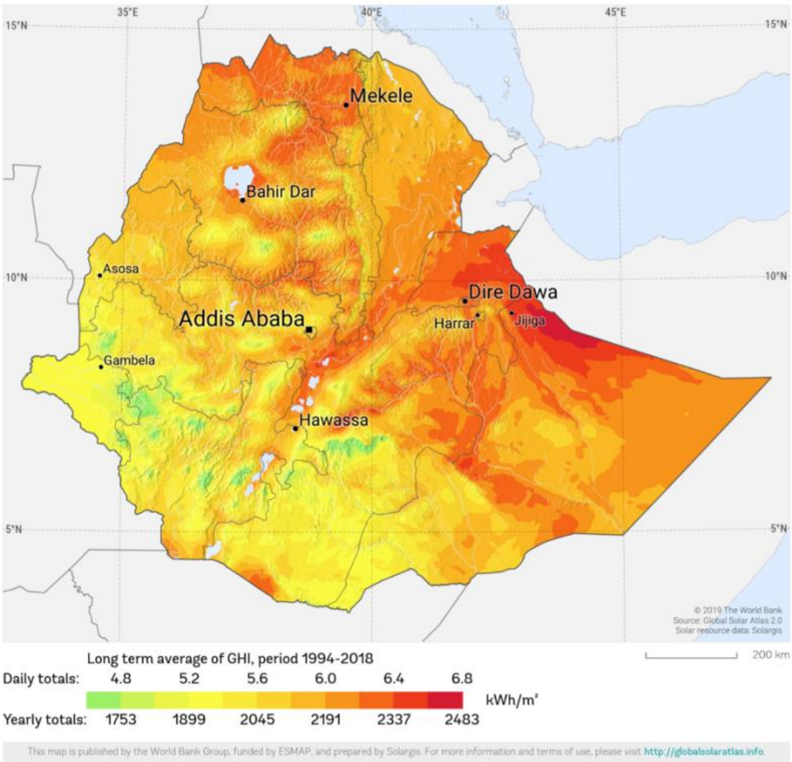


Figure 5. Solar Global Horizonal Irradiation. Highest potential is found in northern and eastern parts of the country. Source: World Bank/Globalsolaratlas.info[14]

3.3.3 Wind resource

The wind speed, see Figure 6, is relatively high in the eastern part of the country (6-8 m/s) while the potential is lower in the western part (2.5-5 m/s). Figure 6. Mean wind speed at 100m height. Potential is lower in the western parts of the country[15]). Currently, the country has exploited less than 1 percent (Table 1) of the potential.

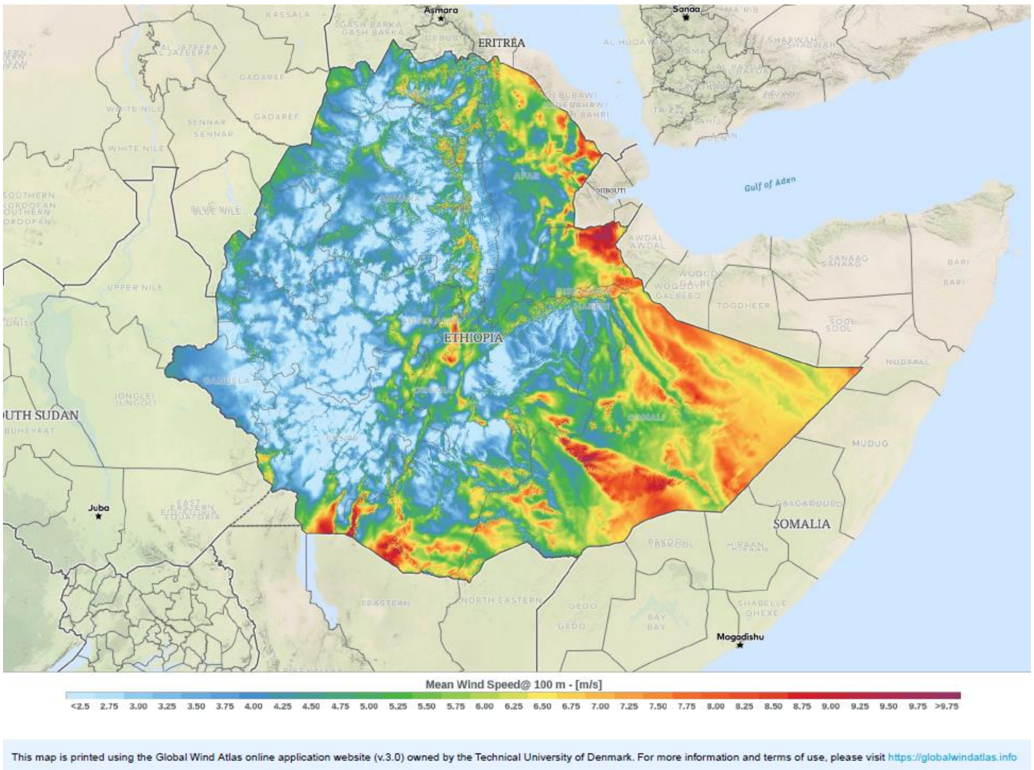


Figure 6. Mean wind speed at 100m height. Potential is lower in the western parts of the country[15]

3.3.4 Hydropower resource

With 45 GW identified potential, hydropower resources in the country are second among the largest on the African continent after the Democratic Republic of Congo. Approximately 30GW is estimated to be economically feasible. However, the current electricity production from hydropower of 13TWh corresponds only to 4.5GW in 2018. Small and mini-hydro potential (Figure 7) is used from [16].

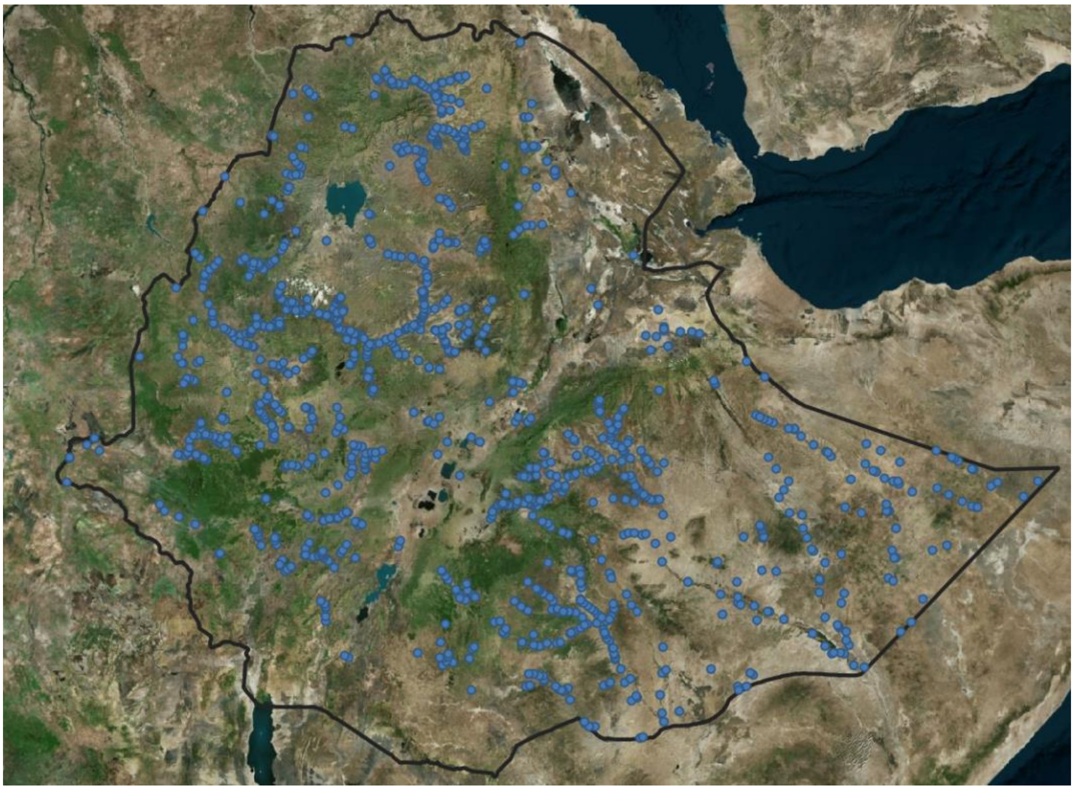


Figure 7. Small- and mini hydro potential sites for mini-grids.

3.3.5 Geothermal resource

The geothermal resources in the country are estimated to be 5GW (Table 1). They are primarily located in the Rift Valley area where temperatures of 50-300°C prevail at depths of between 1,300 – 2,500 m [17]. As of 2018, 268.5MW of geothermal resource are exploited (Table 4).

3.4 Main Objective

The objective of this study is to estimate the cost optimal electricity supply mix of on-grid and off-grid technologies to satisfy Ethiopia´s future electricity demand. To do so, UCL previously developed five scenarios [1] which describe the conditions of plausible futures for Ethiopia. These are based on and are able to capture the country's energy strategies and policies, which are portrayed in the NEP II, CRGE and GTP documents apart from the stakeholders' inputs. The scenarios are quantified by linking the qualitative scenario descriptions to model parameters which influence the model results. The levers chosen include drivers such as the absolute and relative level across tiers of future electricity demand, the level of electricity export via interconnectors with neighbouring countries and discount rate. All of which could affect the future electrification plans of the country.

4 Methodology

We applied two different models to model on-grid and off-grid systems which were then soft-linked to develop the quantitative implementations of the scenarios. The first model is an open-source cost optimization tool for long-term energy planning, the Open-Source energy Modelling System (OSeMOSYS)[18]. As an optimisation model, based on linear programming, OSeMOSYS represents the Ethiopian electricity system as a system of linear equations, which are then solved using a “solver”. The energy system is depicted through technologies and fuels which are joined together to represent a reference energy system (RES) – see Annex 10.4. The RES consists of the energy resources (coal, gas, oil, hydro, nuclear, solar, wind a geothermal) available to the country, historical and potential future power stations, which convert these resources into other energy vectors including electricity, existing and new transmission and distribution technologies/networks or lines to represent losses, and interconnectors which represent electricity trade. The second model is the Open Source Spatial Electrification Tool (OnSSET) [19]. OnSSET computes the least-cost pathway to provide electricity to the unelectrified population. OnSSET is explicitly spatial, so it takes into account the topography of the existing transmission and distribution network and the location of the unelectrified population. It uses the levelized cost of electricity (LCOE) as a heuristic for selecting the least-cost technology for each population cluster. And like OSeMOSYS, OnSSET is dynamic, so it can explore effects of path dependency. Decisions made in an earlier year will change the state of the system, and influence later decisions. The two tools are soft-linked through electricity cost and demands of newly electrified residential population. The models are parameterised so as to represent the existing electricity supply system of Ethiopia, and then run forward through time, considering five scenarios that capture key policies, such as the targets of the National Electrification Plan II, capital costs in power generation technologies, levels of exported electricity to other countries and availability of future power plants, newly constructed and project delays for the ongoing ones.

4.1 Grid-connected modelling assumptions (OSeMOSYS)

The modelling period spans from 2015-2070, with results calculated annually to 2075. The final five years of results are discarded to avoid spurious results. In order to capture the key features of electricity load demand pattern, each year has been divided into four seasons and two dayparts creating eight time slices. (Season 1: March-May, Season 2: June-August, Season 3: Sept. – Nov., Season 4: Dec. – Feb.; Daypart 1: 09:00 – 18:00, Daypart 2: 19:00 – 08:00). An hourly load profile is used to represent the electricity demand profile in the OSeMOSYS model, which is then aggregated into the 8 time slices. Electricity demands are then allocated to the time slices according to the load profile.

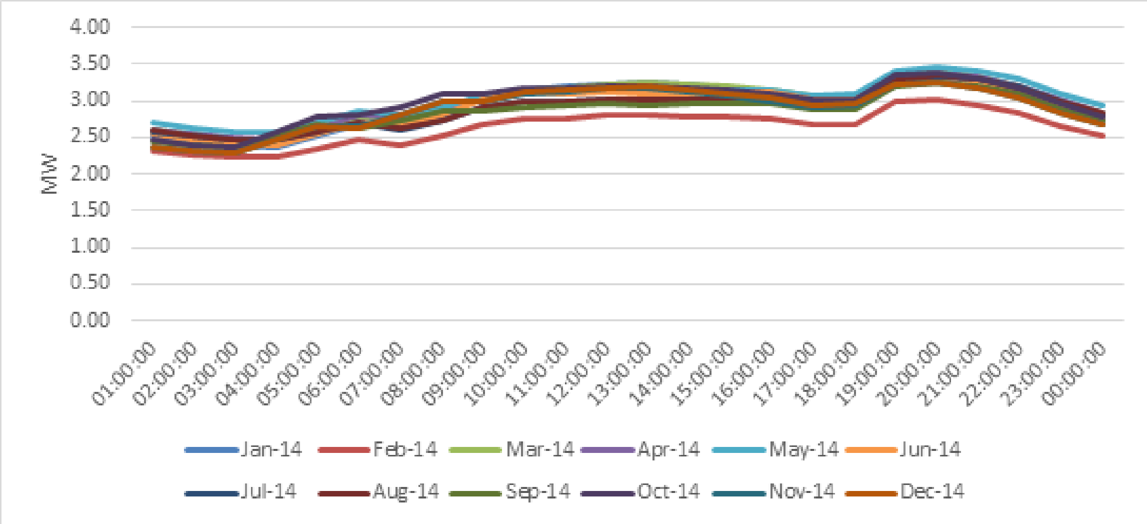


Figure 8 Hourly load profile

To represent the requirement for system security, constraints are imposed upon the model to ensure that an 18% reserve margin is maintained, in line with the national policy plan. This ensures that the total installed capacity of dependable plant exceeds the peak demand by the reserve margin.

However, not all power plants can contribute towards the peak demand, with the peak contribution varying by power plant type. For example, variable output renewables such as wind often have a low peak contribution, because the probability of generation during peak time is low, while baseload technologies, such as a nuclear plant, have limited ability to increase output to meet peak demand. Country specific capacity factors for renewable energy technologies (solar, wind) are derived from www.renewables.ninja. In the OnSSET model, site-specific energy resources are extracted from www.globalsolaratlas.info, www.globalwindatlas.info and an assessment of small and mini hydropower potential [16]. Generic capacity factors assumed for hydro power plants. The hydropower plants are divided into the following categories: small (<20 MW), medium (20-100 MW), large (>100 MW). Generic capacity factors are assumed for hydro power plants: small hydro is assumed to be 25% while for medium and large 50% has been assumed.

Table 3. List of centralized and decentralized technologies included into the model.

	Fossil and nuclear	**Renewables**
Centralized	Diesel	Geothermal
	Heavy Fuel Oil	Biomass and waste CHP[2]
	Natural Gas: OCGT[3], CCGT[4]	Hydro: small, medium, large
	Coal	Wind: onshore

[2] Combined Heat and Power
[3] Open Cycle Gas Turbine
[4] Closed Cycle Gas Turbine

	Nuclear	Solar PV (utility scale)
		Solar PV (roof top)
		Solar PV with storage
		CSP with storage
		CSP without storage
Decentralised	Diesel Genset Micro Grid (rural, urban)	Small Hydro Micro Grid (rural, urban)
	Diesel Genset Stand Alone (rural, urban)	Solar PV Micro Grid (rural, urban)
		Solar PV 1-5 Stand Alone (0.02kW, 0.05kW, 0.1kW, 0.2kW, >0.2kW; urban, rural)
		Wind Micro Grid (rural, urban)

The power generation technologies considered in the model are shown in Table 3 The grid-connected power generation technologies are vintaged. That is, they are differentiated into "old" (existing capacity until 2014) and "new" (capacity investments in 2015-2065) with efficiency improvements. Only the capacity of the committed future projects (power plants, electricity trade links) for which their contract has been signed or the construction has started are included in the model (see Table 4 and Table 5. List of electricity interconnector projects included into the model [10].). The remainder of the future power plants and trade links are provided as an option for the model to invest in.

Table 4. List of grid-connected power plants. Year in brackets indicates when construction is expected to be completed [10]

Technology	Installed Capacity (MW) in 2019	Future power sector projects (MW)
Biomass	196.2	276 (2020)
Diesel	141.634	
Geothermal	8.5	20 (2020), 50 (2021), 150 (2022), 170 (2023), 200 (2024), 250 (2025), 200 (2026)
Hydro **- Large (>100 MW)** **- Medium (20-100 MW)** **- Small (<20 MW)**	4241.528 (total) - 4049.8 (Large) - 182.12 (Medium) - 9.608 (Small)	254.1 (2020); 1830 (2021); 1080 (2022); 2405 (2023); 2125 (2024)
Solar	13.16	350 (2020)
Wind	322.18	120 (2020); 100 (2021)

Table 5. List of electricity interconnector projects included into the model [10].

Connection (From – to)	Capacity (MW)	Investment cost (USD / kW)	Included in the model	Year of commission	Status
Ethiopia – Djibouti	100	-	Yes	Existing	Operational
Ethiopia – Eritrea	200	746	No	-	Planned
Ethiopia – Kenya	400	630	CON	2020	Constructed

Ethiopia – Kenya II	200; 200; 200; 200; 200	630	CON	2022; 2024; 2025; 2027; 2028	Constructed
Ethiopia - Somalia	400	1044	No	-	Planned
Ethiopia – Sudan	100	190	Yes	Existing	Operational
Ethiopia – Sudan or Egypt	1500; 1500	190	Yes	2023; 2025;	Constructed
Ethiopia - Tanzania	412	423	Yes	2021	Constructed

Electricity trades are considered in the analysis. Unless otherwise constrained, it is assumed that the respective installed capacity of the electricity interconnector will be exported to the neighbouring countries (Djibouti, Eritrea, Sudan, Kenya, and Tanzania) driven by the assumed electricity export price.

Techno-economic assumptions for the power generation technologies are derived from the IEA [20], [21]. Cost reductions due to learning are kept constant across scenarios (see Table 30), but the discount rate changes. The same discount rate is used in both OSeMOSYS and OnSSET models.

Adjustments on the potential future capacity annual investments by technology have been made in the model according to the different scenarios to capture the effects of economic growth. The availability of annual investments in power generation technologies are described in Section 4.1.1-4.5.1.

4.2 Demands and residential tier split

Quantitative scenarios of electricity demands were created by UCL in WP2 using the Low Emissions Analysis Platform (LEAP) tool model. The electricity demand is categorized into “electrified (others)” and “residential (currently un-electrified settlements)”. The “electrified (others)” includes the electricity demand of the current electrified people in the residential sector as well as the demand of the rest of the sectors (industry, commercial & public services, and agriculture and forestry). The “residential (currently un-electrified settlements)” includes the estimated future electricity demand of the newly electrified people both in rural and urban areas.

Residential demand tier splits were based on the Multi-Tier Framework [22], but with adjusted levels to account for Ethiopian appliances. The demand projections used in the High Ambition and Ambition scenarios are identical.

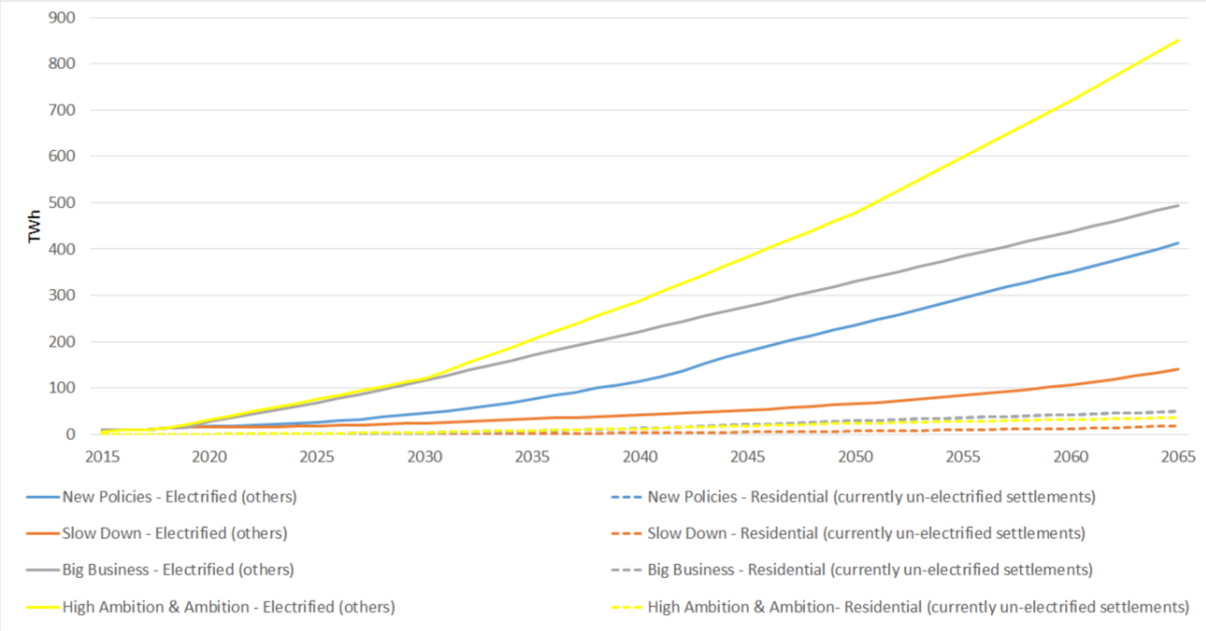


Figure 9. Evolution of electricity demand (GWh) in each scenario.

4.3 Off-grid modelling assumptions (OnSSET)

For each settlement, the OnSSET model determines which is the least-cost technology to meet the electricity supply target. Six electrification technology options are considered in this study: the national grid, PV mini-grids, Diesel mini-grids, Wind mini-grids, Hydro mini-grids and stand-alone PV technologies (Solar Home Systems).

- The OnSSET tool runs in six steps; 2018-2025, 2025-2030 and then in 10-year intervals from 2030-2070. In each step a settlement may change technology, but may only go in the direction of stand-alone → mini-grid → grid.
- The model only considers electricity demand for the residential demand sector. Each settlement is assigned a target demand level between 1 and 5 based on the adjusted version of the Multi-Tier Framework. The national split between Tiers is a result of WP2. Tiers are distributed based on settlement size and density, with the highest Tiers assumed to be found in the largest urban centres and the lowest Tiers in the smallest rural settlements.
- The power generation technologies considered into the OnSSET model can be found in appendix to this report (see Table 27).

4.4 Soft Coupling of OSeMOSYS and OnSSET

The OnSSET model considers off-grid technologies and extension of the centralized grid network to calculate the cost-optimal split of technologies to satisfy the residential electricity demand. However, the OnSSET model does not optimize the mix of technologies supplying the centralized grid and does not include the electricity demand from other sectors. Instead, these are provided by OSeMOSYS. In this study, soft-linking OnSSET and OSeMOSYS provides the least-cost optimal mix of on-grid and off-grid technologies. The soft-link includes the spatial aspects of electrification planning together with least-cost energy planning of the supply system to cover the future electricity demand in all sectors.

The process is as follows:

1. the OSeMOSYS model computes the cost-optimal electricity supply system of Ethiopia considering electricity demands in all sectors excluding transport (see Table 7 to Table 11);

2. the levelized cost of generating centralized grid electricity is calculated from the output of the OSeMOSYS model by dividing the discounted total system cost by the discounted total electricity supplied;

3. the levelized cost of generating grid electricity is fed into the OnSSET model and used to calculate the least-cost electrification mix (on-grid and off-grid) that to meets the residential electricity demand of newly electrified settlements;

4. the transmission and distribution costs for grid expansion per kW of new generation capacity, capacity factors for the off-grid technologies identified based on local energy resource characteristics at off-grid locations, and the demand split between grid- and off-grid technologies for the country are calculated;

5. This information is used as an input into the OSeMOSYS model to cost-optimize the whole electricity supply system and define the new levelized cost of generating grid electricity. This process will impact the cost-optimization process of the OSeMOSYS model and, eventually, the grid cost. Thus, a second iteration is required to calibrate the modelling outputs between the two models. The iterations of the two models continue until they converge to a point where the levelised cost of generating grid electricity in each scenario does not change over two successive iterations.

The formula used in OnSSET to calculate the Levelized Cost of Electricity (LCOE) is the following:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + O\&M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

In year t, I is the investment cost, O&M are the operation and maintenance costs, F is the fuel expenditure, and E is the generated electricity. Further, r is the discount rate, and n corresponds to the technology's lifetime.

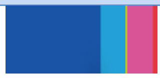
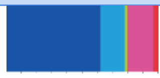
5 Scenario Implementation

In this section, we describe the five scenarios developed to investigate plausible future developments in the Ethiopia electricity system. Some are desirable, while others are not. Some present a different structural emphasis than is currently reflected in the country or in the other scenarios.

The scenario narratives were co-created by UCL College London and participants in a stakeholder workshop held in Addis Ababa during 2019 . The text below describes how the scenarios were parameterised in the OSeMOSYS and OnSSET models, while Table 6 offers an overview of the key levers across the scenarios.

The most important driver of the grid-connected supply model results is total electricity demand, and how it grows over the modelling period from 2015 to 2065. A higher absolute demand requires a larger power system capacity, higher levels of investment, and greater expansion of transmission and distribution capacity. Also important is the discount rate, which determines the timing of investments. In the scenarios, we use the discount rate to explore the influence of a change in the relative cost of technologies. Increasing the discount rate makes low operating-cost but capital-intensive investments, such as large hydropower, solar photovoltaics, wind and nuclear, less attractive in comparison to low-capital cost, high operating-cost generation plants (coal, gas and oil). Another key lever the scenarios explore is the opportunity provided by electricity trade. Across the scenarios, an upper bound on the use of stated interconnector capacity (existing and planned) for export is varied between 70% and 100%. Finally, constraints on technology availability remove some technologies (nuclear and diesel) from the portfolio of possible investments. In these scenarios, the model has no choice but to select alternative investment options.

Table 6. Overview of the scenarios and levers

	New Policies	Slow Down	Big Business	High Ambition	Ambition
Total electricity demand growth	High	Low	Very High	Very High	Very High
Residential demand tier shares (2030)					
Universal Access	2025	2042	2042	2025	2025
Max Connections (2030)	-	500,000	500,000	-	-
Max Connections (2050)	-	1,000,000	1,000,000	-	-
Proximity Constraint	<25km	<2km	<2km	<25km + exp.	No + exp.
Future committed investments (implementation year)	As per current policies	5 years delay on the current start year	As per current policies	As per current policies	As per current policies

Interconnector capacity available for export	100% + driver by electricity export price	100% + driver by electricity export price	100% + driver by electricity export price	100%	70%
Discount rate	10%	20%	8.5%	5%	8.5%
Technology availability	Section 4.1.1 (all technologies allowed)	Section 4.2.1 No nuclear	Section 4.3.1 (all technologies allowed)	Section 4.4.1 (all technologies allowed)	Section 4.5.1 (all technologies allowed)

5.1 New Policy

This scenario considers current energy policy and plans detailed in NEP II. It assumes that most of what is past Final Investment Decision (FID) is built, but may introduce delays where reasonable. This might be for known difficult projects, or for projects that were planned for e.g. 2020 but are not yet online, which also considers country experiences of project completion and delays for various hydropower projects. The scenario inhabits a central level of optimism with high total electricity demand growth. This scenario describes a relative status quo: institutions stay, if not identical, very similar – the pace of change within society is slow, electrification progresses and national targets are met, but the energy access agenda is not as ambitious as it could be.

5.1.1 Implementation

Demands increase to over ≈45TWh in 2030 and 400TWh in 2065 (Table 7) exhibiting a high growth in line with the narrative. By 2030, almost 80% of the population is projected to have a demand in Tiers 1 or 2. By 2050 however, the majority of population has transitioned into Tier 3 or Tier 4.

Power generation projects that are past FID are included as forced investments in the model (Table 27). Nevertheless, we impose upper bounds on annual investments for fossil fuel technologies of 0.5GW for the period 2021-2030, 1GW for the period 2031-2060 and 1.5GW for the period 2061-2070. Similarly, for CSP, solar PV utility and wind technologies annual investments of 0.5GW for the period 2021-2030 and 1GW for the period 2031-2070. Lower annual investments are allowed on private solar PV and PV with storage technologies of 0.1GW for the period 2020-2030 and of 0.25GW for the period 2031-2070. For biomass technologies annual investments of 0.25GW are allowed for the period 2021-2070 based on the size of current investments.

In this scenario, the NEP II targets are met. Universal access to electricity is achieved by 2025. Everyone within 2.5 km of the existing grid is connected by 2025 (65% of the population), the remainder are electrified via off-grid technologies. Everyone within 25 km of the existing grid is connected by 2030 (96% of the population), the remainder are electrified via off-grid technologies. After 2030, the grid may expand further in places where grid-connection is less costly than off-grid technologies.

Table 7 Demands for New Policies

Scenario	2015	2018	2030	2040	2050	2065
Industry (GWh)	2,713	4,936	16,824	40,735	79,585	173,177

Residential (GWh)	3,889	6,386	15,616	39,285	76,233	131,122
Commercial and public services (GWh)	2,284	2,528	7,948	22,387	71,665	86,735
Agriculture/ forestry (GWh)	0	26	3,141	4,567	4,783	6,502
Total final consumption (GWh)	8,886	13,875	43,530	106,974	232,268	397,560

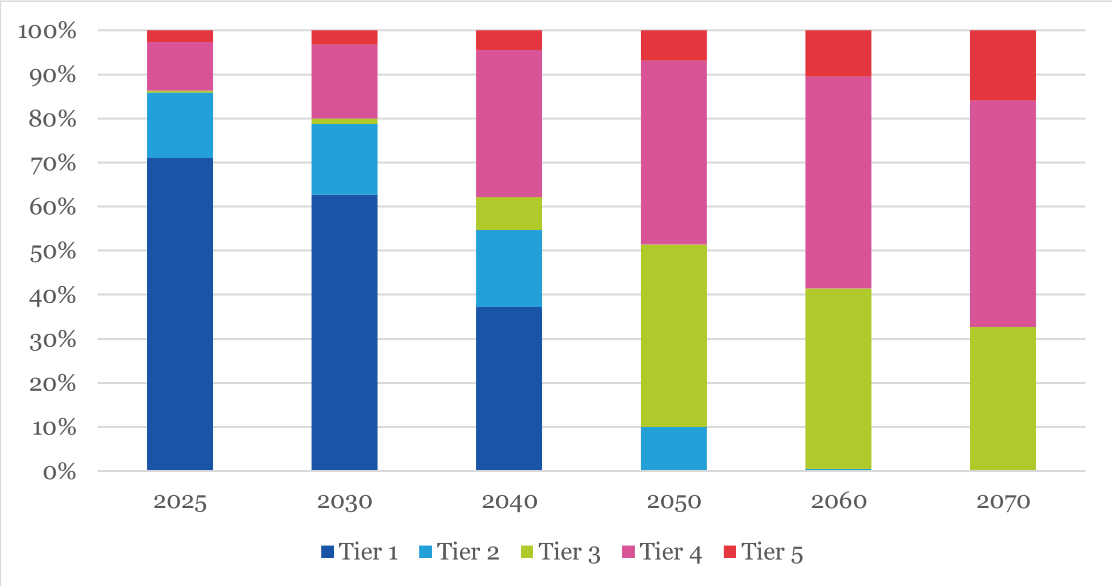


Figure 10. Residential demand Tier shares of total population – New Policies

5.2 Slow Down

This scenario explores an undesirable future where the energy sector truly struggles to meet its targets. Most trends continue forward at current rates, and the large infrastructure projects that are required suffer long delays. Energy shortages and the use of fossil (diesel genset) back up continue. The NEP targets are not achieved. Electrification creeps along at a slow pace. Institutions are fragmented and fail to restructure or re-organize in any way. Investment projects are delayed and there is under investment in capacity – which leads to unserved demand. There are no tariff reforms in the industrial and residential sector. Exported electricity trade is low and new projects do not materialize on time, but imports through existing lines are maximised – affecting energy security. The cost of new technologies remains high: they are imported from foreign manufacturers, and the cost of capital is high. More advanced technologies (e.g. nuclear) are not available. Grid extension is difficult and slow.

5.2.1 Implementation

In comparison to New Policies, this scenario has a considerably lower rate of demand growth. In 2030, total final consumption (~14TWh) is just over half of that in New Policies, while in 2065, demand has continued to increase slowly to ~157TWh. The Slow Down scenario is defined by a very slow growth in residential demand, where even by 2070 almost half of the population is still in one of the two lowest Tiers.

Annual investments in power generation technologies are lower than the New Policies scenario. In addition, investments start from 2026 onwards, 5 years later than in the New

Policies scenario. Specifically, we impose upper bounds of 0.1GW for heavy fuel and natural gas for the period 2026-2070 while for Light Fuel Oil of 1GW for the period 2026-2039 and 2GW of 2040-2070. We impose upper bounds on annual investments on CSP of 0.15 GW from 2026-2070, on solar PV utility and solar PV of 0.1GW and 0.05GW, on wind of 0.1GW for the same period. Nuclear investments are not allowed.

Table 8 Demands for Slow Down

Scenario	2015	2018	2030	2040	2050	2065
Industry (GWh)	2,713	4,936	10,751	17,720	26,943	53,831
Residential (GWh)	3,889	6,386	7,823	14,160	24,451	54,272
Commercial and public services (GWh)	2,284	2,528	2,934	4,128	6,789	16,895
Agriculture/ forestry (GWh)	0	26	2,292	4,523	4,740	6,284
Total final consumption (GWh)	8,886	13,875	23,800	40,531	62,923	131,282

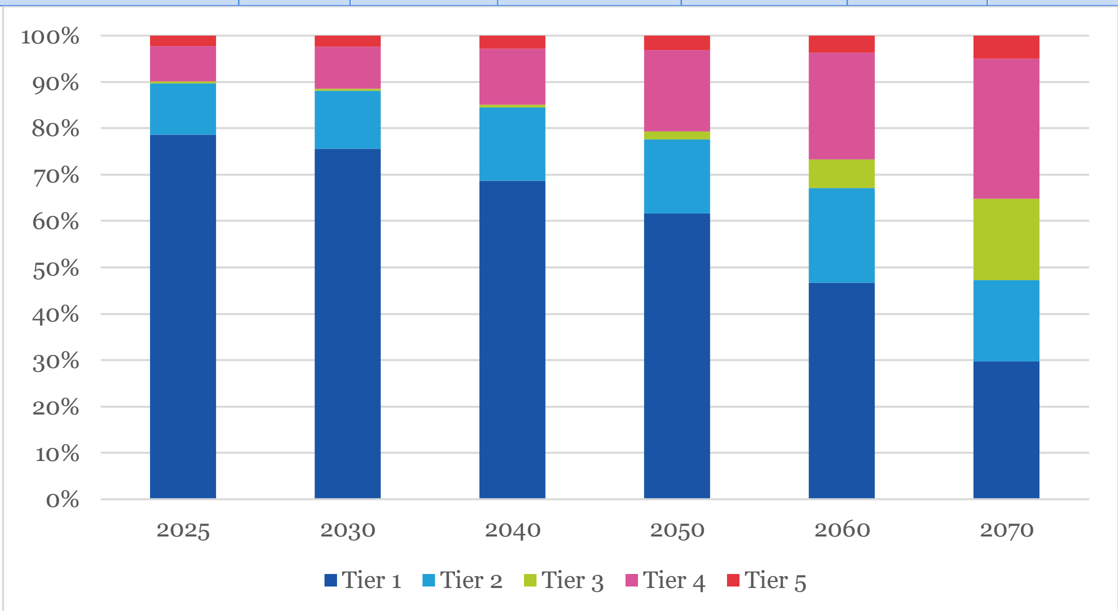


Figure 11. Residential demand Tier shares of total population – SLOW DOWN

Electrification follows the same rate as in the last decade. This means universal access is not achieved until 2042. The maximum number of new connections to the grid is constrained to 500,000 households per year until 2030 (the current level), then ramped up to 1,000,000 households per year from 2030 to 2050. Settlements within 1 km of the grid are connected after 2040, even if grid-connection is not the least-cost alternative, and settlements within 2 km are connected at the latest by 2050. Settlements within 2 km may be connected in earlier years if it is the least-cost technology and remains within the maximum number of grid-connections allows. The target to connect everyone within 2.5 and 25 km as in the NEP II is not imposed in this scenario.

5.3 Big Business

In this scenario, the energy sector favours industrial partners and big business over other consumers. While economic growth does happen, many of the characteristics of ambitious social change do not – including curbing the sector's impact upon the environment. This implies progress as well as regress compared to the New Policies scenario.

The focus here is on developing the centralized energy system in support of anchor industrial projects with high energy demands. Residential customers are not prioritized. Collaboration between the public and private sectors is strong with a focus is on big business rather than on e.g. limiting emissions, lowering biomass use, or residential electrification. These aspects still evolve faster than in the "Slow Down" scenario, but may not hit all NDC or NEP targets. Industrial demand and financial flows through the country increase, but the costs of technologies (variable renewable energy, clean, advanced tech in particular) remain relatively high: there is no capacity transfer to Ethiopia in a model where overseas industries do not contribute as much as they could. Social targets and job creation suffer here compared to the Ambition scenarios. This scenario has a higher level of institutional reform than "New Policies" and "Slow down" – but it focuses on the financial side rather than on the people / communities.

5.3.1 Implementation

Total final demands increase at a higher rate than for New Policies, but residential demand is at the same level (131 TWh in 2065). The remainder of the growth is focussed on in industrial and commercial sectors. In the residential sector, the country transitions from the majority of the population in Tier 1 or 2 by 2030 to Tier 3 or 4 by 2050.

In this scenario, due to higher support for expanding the capacity of the power generation mix we impose upper bounds on investment for heavy fuel oil (0.5GW: 2021-2030; 1.5GW: 2031-2070), light fuel oil and natural gas technologies (1GW: 2021-2030; 1.5GW: 2031-2060). Also, annual investments on CSP, solar PV utility and wind technologies of 1GW for the period 2021-2030 and 1.5GW for the period 2031-2070. Lower investments are allowed in solar PV and PV with storage technologies of 0.25GW for the period 2020-2030 and of 0.5GW for the period 2031-2070. Higher annual investments in biomass are allowed than the New Policies of 0.5GW for the period 2021-2030 and 1.5GW for 2031-2070. Similarly, on annual investments in nuclear technologies may reach 1GW starting from 2027 onwards.

Table 9 Demands for Big Business

Scenario	2015	2018	2030	2040	2050	2065
Industry (GWh)	2,713	4,936	65,578	111,022	160,436	239,417
Residential (GWh)	3,889	6,386	13,812	38,191	76,723	131,144
Commercial and public services (GWh)	2,284	2,528	33,327	58,858	85,029	104,306
Agriculture/ forestry (GWh)	0	26	2,292	4,523	4,740	6,284

Total final consumption (GWh)	8,886	13,875	115,009	212,594	326,928	481,151

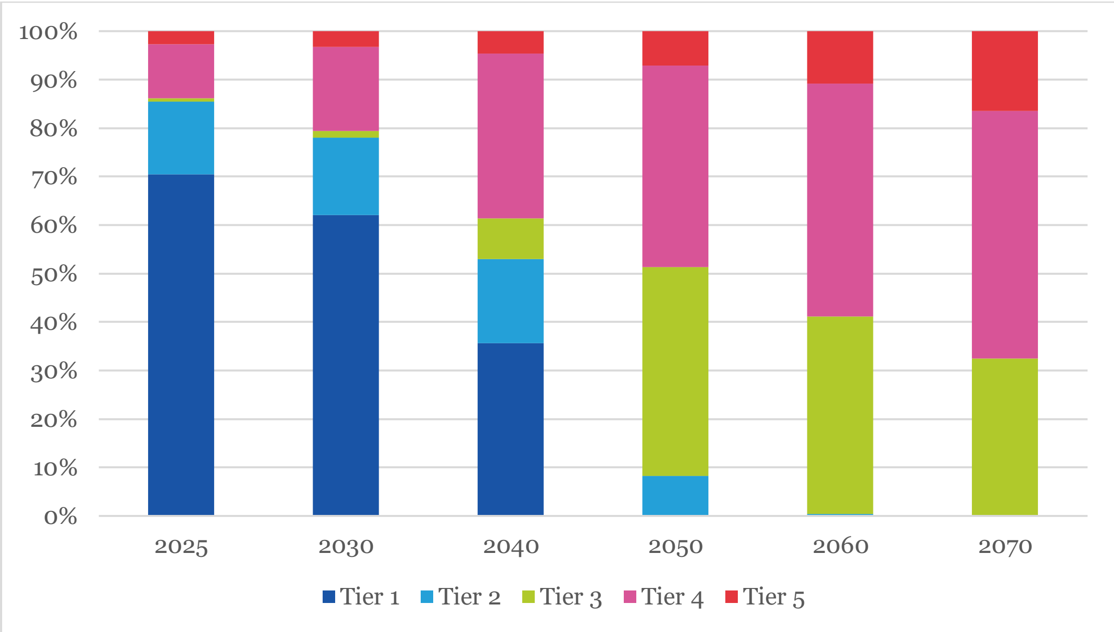


Figure 12. Residential demand Tier shares of total population – Big Business

As in the Slow Down scenario, residential electrification follows follows the same rate as in the last decade. This means universal access is not achieved until 2042. The maximum number of new connections to the grid is constrained to 500,000 households per year until 2030 (the current level), then ramped up to 1,000,000 households per year from 2030 to 2050. Settlements within 1 km of the grid are connected after 2040, even if grid-connection is not the least-cost alternative, and settlements within 2 km are connected at the latest by 2050. Settlements within 2 km may be connected in earlier years if it is the least-cost technology and remains within the maximum number of grid-connections allows. The target to connect everyone within 2.5 and 25 km as in the NEP II is not imposed in this scenario.

5.4 High Ambition

In this best-case scenario, Ethiopia outperforms its goals, builds a renewable energy system that serves as a regional hub for electricity trade, undergoes substantial institutional reform, attracts international investment and retains the human capacity – developing its own markets.

This scenario represents the best case and mirrors workshop participants' positive view of the future. Electrification is aggressive, occurs early, and provides higher standards of living; this is aligned with the country's CRGE plan targeting 100% electrification by 2025. The energy system is structured along local contexts with mini grids growing to form regional systems that rely on regional strengths. These systems eventually interconnect. The main source of power is renewable energy – nuclear technology is expensive and available late. Hydropower continues to play a dominant role. There is deep and efficient institutional reform to provide structural support to investors that see energy as a worthwhile business. Workforces are created, trained, and retained in the country through public private partnerships that expect capacity transfer allowing Ethiopia – in time – to bring costs of technologies and RE down significantly. Ethiopia trades heavily with the Eastern Africa power pool (EAPP) and becomes a regional power hub.

5.4.1 Implementation

The total demand in the High Ambition scenario grows to 518 TWh. Industrial demand growth leads the demand to reach similar levels as in the Big Business scenario. High Ambition sees the highest levels of residential demand (168 TWh). By 2030, 30% of the population has Tier 4 or Tier 5 level of electricity demand, and by 2040 only 30% of the population is in Tier 1 or 2 (as compared to 55% in the New Policies scenario).

In this scenario, due to higher electricity demand than the New Policies scenario, the upper bounds on investment of the power system are higher, specifically: on heavy fuel oil (0.5GW: 2021-2030; 1.5GW: 2031-2070), light fuel oil, heavy fuel oil and natural gas technologies (0.5GW: 2021-2030; 1.5GW: 2031-2070). Also, the annual investment constraints on CSP and solar PV utility technologies are 0.5GW in the period 2021-2030; 1.5GW during 2031-2070. Those on solar PV rooftop technologies are 0.25GW between 2020-2030 and, 0.5GW 2031-2070 thereafter. Finally, annual investments in wind technologies are limited to of 0.5GW during 2022-2030, 1.5GW 2031-2070, biomass 0.5GW 2021-2030, 1.5GW 2031-2070, geothermal 0.25GW 2027-2070 and nuclear 0.5GW 2027-2030, 1.5GW 2031-2070.

In this scenario, electrification achieves the NEP II targets. Universal access to electricity in Ethiopia is to be achieved by 2025, all settlements within 2.5 km of the existing grid network will be connected to the grid by 2025, and all settlements within 25 km will also be connected to the grid by 2030. However, the grid is allowed to expand further than those limits in those years, if it is the least-cost option. This is a somewhat more positive outlook on the grid compared to the NEP, under a higher demand growth compared to the New Policies scenario. The maximum number of new household connections to the grid is allowed to be freely decided by the model in all years based on the LCOE.

Table 10 Demand for High Ambition

Scenario	2015	2018	2030	2040	2050	2065
Industry (GWh)	2,713	5,189	30,470	56,993	99,888	217,425
Residential (GWh)	3,889	6,386	23,951	50,751	84,009	168,104
Commercial and public services (GWh)	2,284	2,269	62,888	176,101	289,314	459,134
Agriculture/ forestry (GWh)	0	26	3,141	4,567	4,783	6,502

Total final consumption (GWh)	8,886	13,875	120,450	288,412	477,994	851,165

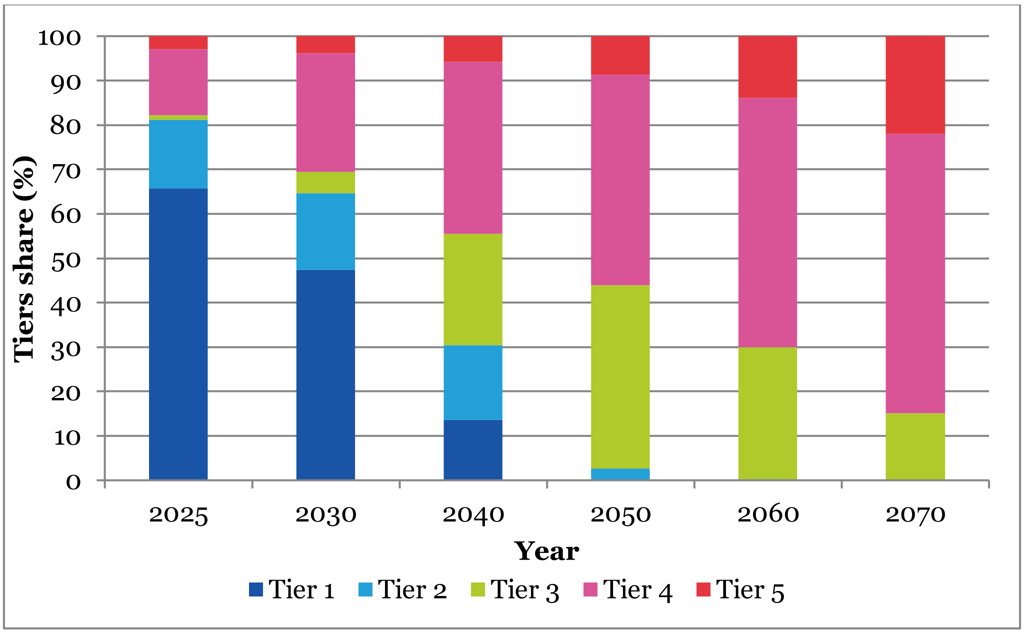


Figure 13. Residential demand Tier shares of total population – High ambition

5.5 Ambition

This is a variation of High Ambition that explores the point at which the best-case scenario starts to fail or get delayed, and this is defined in the model by a slightly higher discount rate at 8.5%.

5.5.1 Implementation

The Ambition scenario follows the same demand growth as the High Ambition scenario. The difference is seen on the supply side with the Ambition case answering the question 'what if' the electrification plans in the high ambition scenario are not fully achieved?'. 100% electricity access is achieved by 2025 according to NEP II, but the distance connection targets are not imposed, instead letting the model decide how the grid expands based on the LCOE only.

In this scenario, the annual investment constraints on the power generation technologies are similar to the High Ambition scenario.

Table 11 Demands for Ambition

Scenario	2015	2018	2030	2040	2050	2065
Industry (GWh)	2,713	5,189	30,470	56,993	99,888	217,425
Residential (GWh)	3,889	6,386	23,951	50,751	84,009	168,104
Commercial and public services (GWh)	2,284	2,269	62,888	176,101	289,314	459,134
Agriculture/ forestry (GWh)	0	26	3,141	4,567	4,783	6,502

Total final consumption (GWh)	8,886	13,875	120,450	288,412	477,994	851,165

6 Results

This section presents the key results for five scenarios. In Section 5.1 we present the supply-side pathways for the electricity sector from OSeMOSYS. Results are presented in 5-year increments between 2015 and 2065. In Sections 5.2 and 5.3 we present the electrification results from the OnSSET model: the population connected per technology option, the residential electricity demand per technology option and maps of where the different technologies should be utilized. The results are presented for the end years of 2025, 2030 and 2070.

6.1 Power generation capacity and supply mix

In the following figures, we show an overview of the evolution of electricity generation capacity and supply mix across the scenarios. In Figure 14 we show how the overall growth and timing of the growth in capacity differs across the scenarios as a function of the demand for electricity, addition the number of newly electrified residences and levels of electricity exports. In addition, the technological composition of the generation capacity changes due to constraints on the availability of different technologies – either outright or delayed availability, - and interactions with decreases in technology costs, and upper bounds on Ethiopian renewable (solar, wind, geothermal and hydro) and fossil (natural gas) resources.

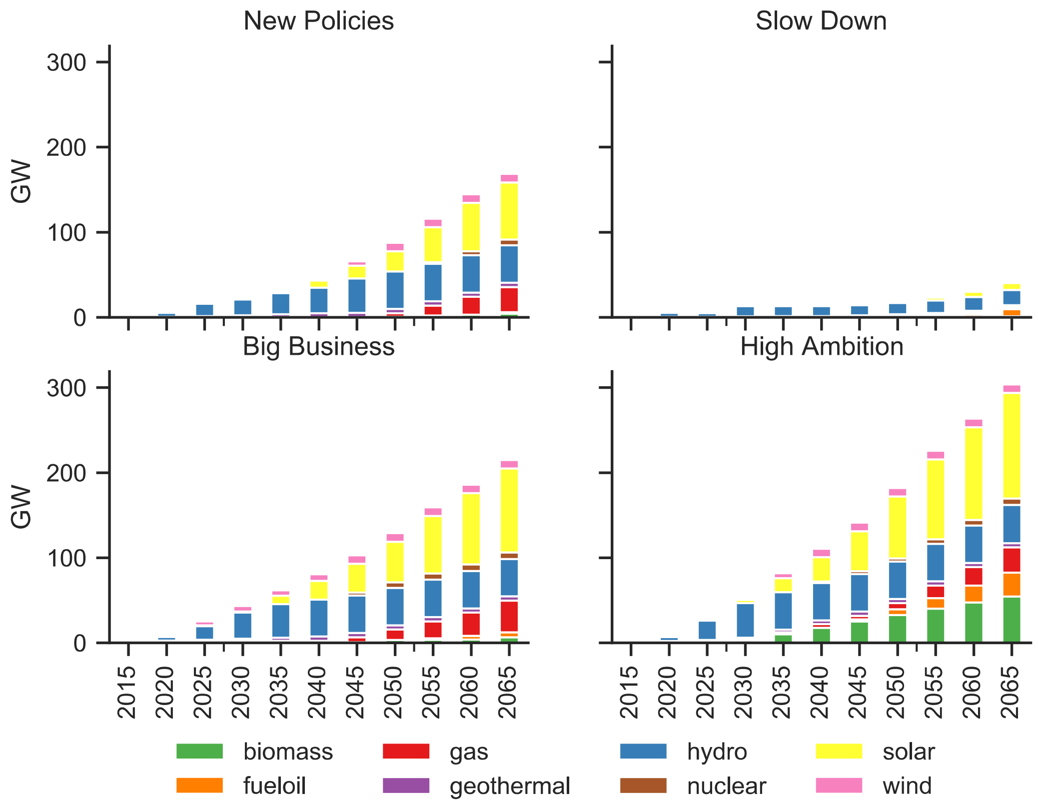


Figure 14 Installed capacity in key model years by scenario

The supply mix in Figure 15 shows how the installed capacity is used in each year. This is useful for highlighting where capacity is used to meet system security requirements which is modelled using an 18% reserve margin constraint, as well as revealing how the differing capacity factors of different technologies play out, particularly for renewables. The on-grid supply results for the Ambition scenario are not sufficiently different to warrant reporting separately from High Ambition hence, only power generation capacity and supply mix of the High Ambition scenario is discussed in section 5.1.4.

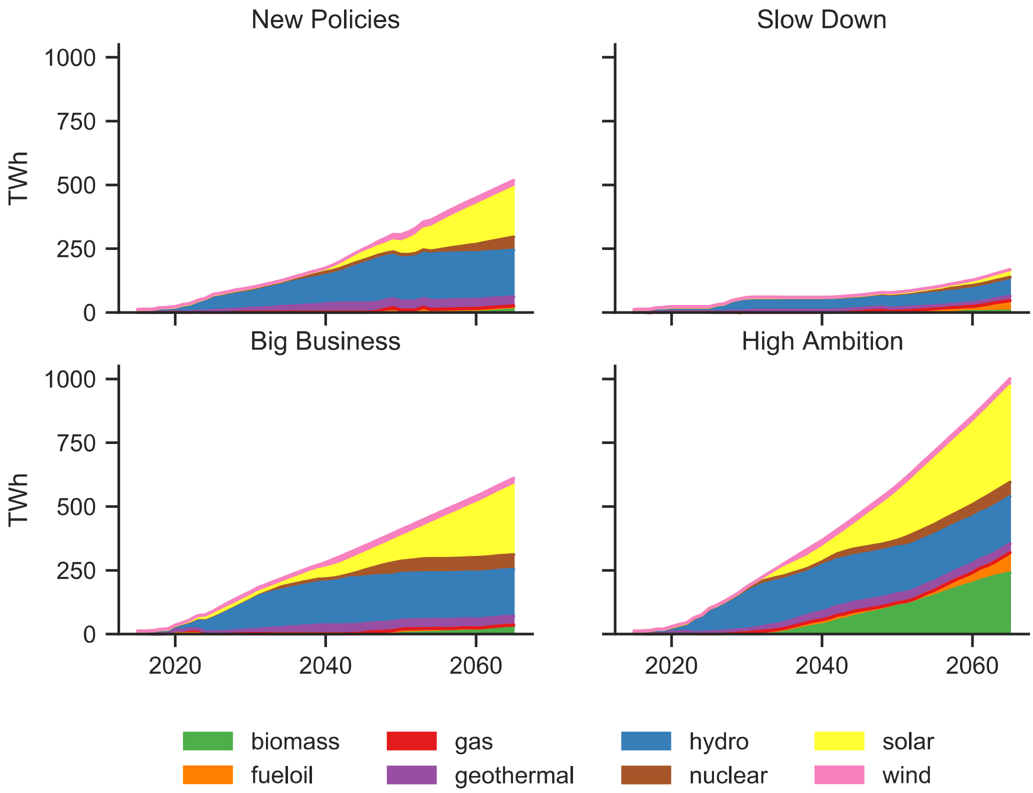


Figure 15 Electricity supply mix by technology (TWh) in key model years by scenario

6.1.1 New Policies scenario

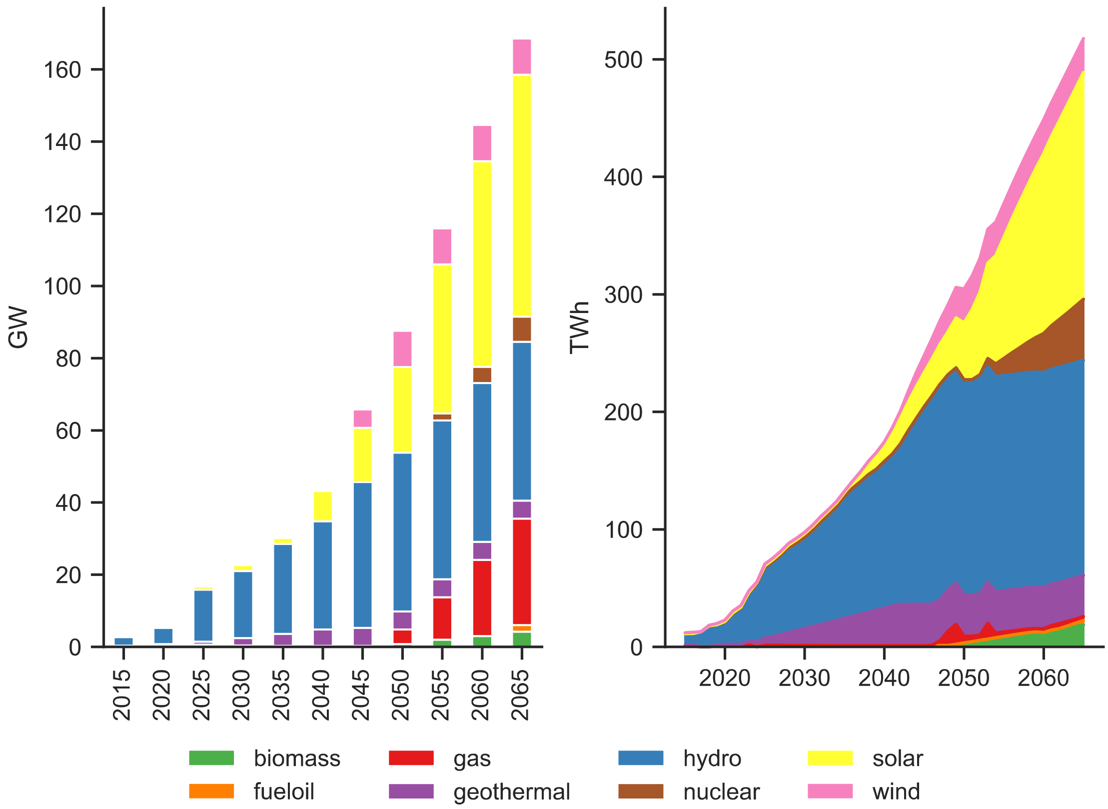


Figure 16. Power generation capacity by technology (GW) and Electricity supply mix by technology (TWh) in the New Policies scenario.

Total generation capacity in 2030, shown in Figure 16, reaches 23GW with hydropower dominating the supply mix. This level of dependence upon hydropower raises the issue of increased vulnerability to climate impacts. As the least-cost option, hydropower potential is fully exploited by 2047 and the geothermal resource is fully exploited by 2042. From 2030, there is a rapid increase in solar photovoltaic capacity, followed by wind and natural gas from 2040. Demand growth in the later stages of the model horizon is met by small investments in nuclear (<1GW), heavy and light fuel-oil plants to maintain reserve margin of 18%, and continued growth in solar technologies including concentrating solar power (CSP) and solar photovoltaic (PV) generation with and without storage (see Figure 36 for detailed results). Although, there is an increase in capacity on natural gas technologies from 2046 onwards to also manage the reserve margin of 18%, the generated electricity is relatively low due to the small domestic natural gas reserves. This highlights the potential strategic and high-value of these reserves if used to maintain system security, firing a times of large supply/demand mismatches and hence high electricity prices.

Nuclear power together with a small capacity of biomass generation helps meet the rapid and continuing growth in electricity demand after 2050 as solar and wind resources and annual growth rate constraints are met.

6.1.2 Slow Down

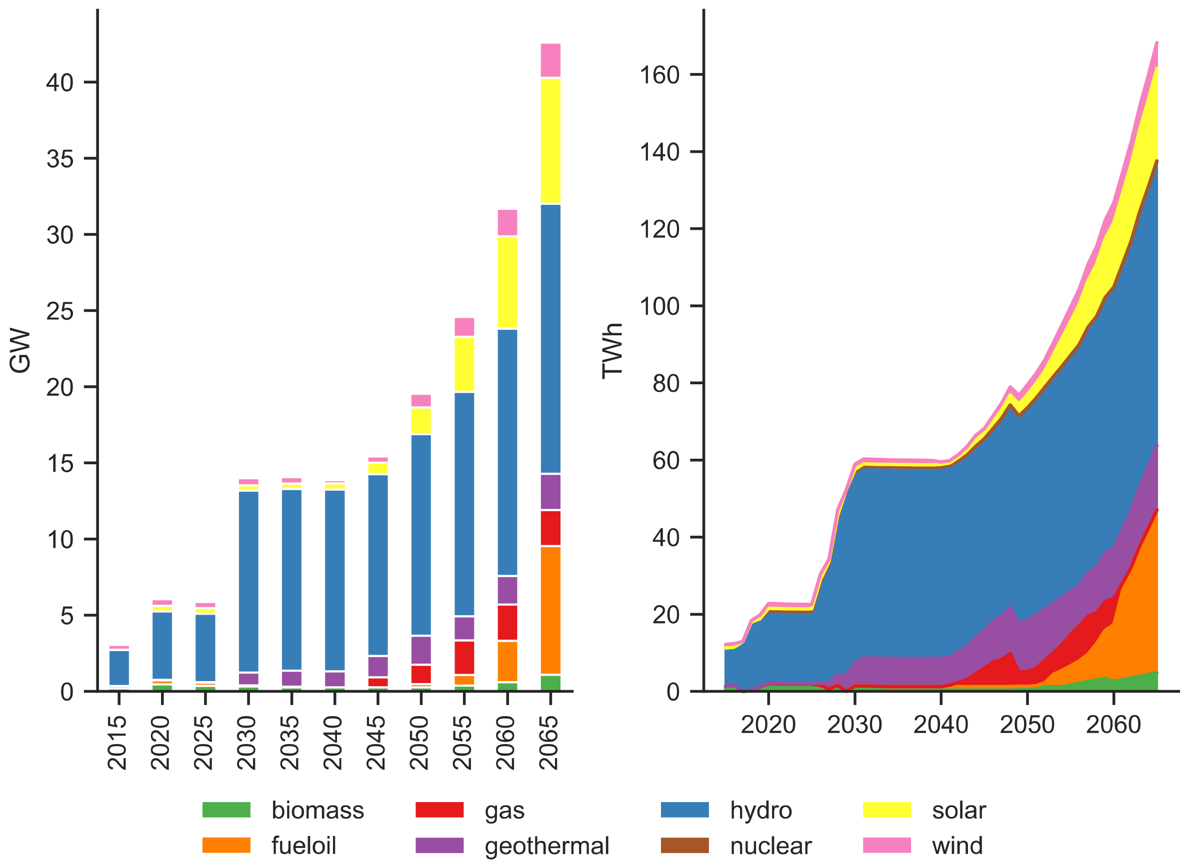


Figure 17. Power generation capacity by technology (GW) and Electricity supply mix by technology (TWh) in the Slow Down scenario.

Given the much lower demand for electricity in Slow Down than in all other scenarios, the electricity supply system is correspondingly smaller –only reaching 23GW in 2054, two decades later than the system in New Policies (Figure 17). As a consequence of the smaller system size, hydropower resources are not fully developed. By 2050, solar photovoltaic costs have reduced to the point that they are responsible for the majority of growth in capacity. As in New Policies, natural gas, light and heavy fuel-oil plants are introduced in the latter part of the model horizon to help manage system security through ensuring a reserve margin of 18%. Nuclear power is not available in this scenario. Instead, a small capacity (0.3GW in 2050 growing to 1.1GW in 2065) of biomass generation is introduced.

6.1.3 Big Business

With high demand growth and absolute electricity demand, generation capacity increases rapidly and continually throughout the model horizon from the low base in 2015 to reach 43GW in 2030, 129GW in 2050 and over 215GW in 2065, Figure 18. The speed and magnitude of demand growth means that renewable and fossil resources are fully exploited.

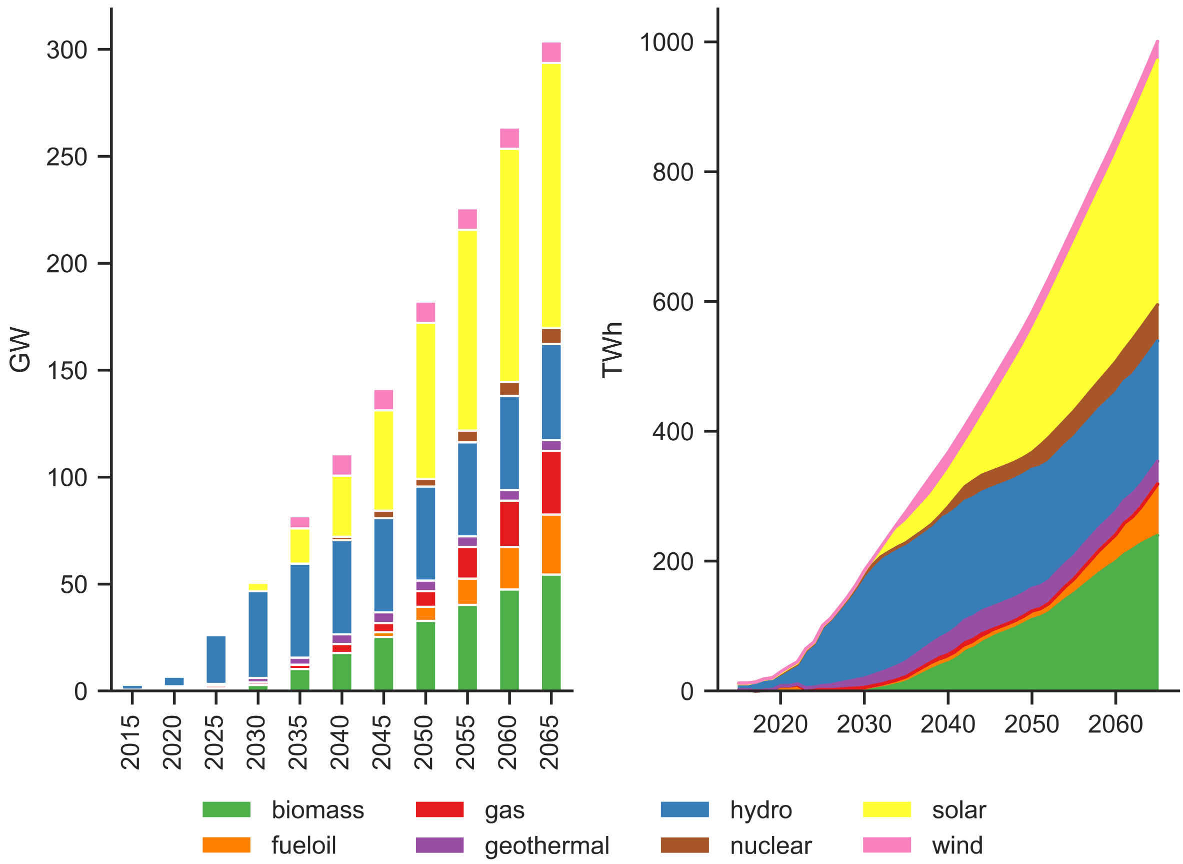


Figure 18. Power generation capacity by technology (GW) and Electricity supply mix by technology (TWh) in the Big Business scenario.

Hydropower developments reach their full resource potential by 2041, and solar photovoltaic and concentrating solar power technologies are extensively developed reaching 46GW and 1.5GW in 2050 and 58GW and 41GW in 2065 respectively. Nuclear power plays an earlier role than in all other scenarios, reaching 6.5GW in 2050 and 7.7W in 2065. Wind and geothermal reach their maximum resource potential of 5GW and 10GW respectively before 2050.

Natural gas and light and heavy fuel-oil plants area again required to maintain a reserve margin of 18% of total capacity (around 40 GW in 2065). Almost 6GW of fuel-oil plants and 37GW of natural gas fired plants are installed in 2065.

The exhaustion of renewable resource potential by 2040 means that a lower proportion of capacity is renewable in comparison to Slow Down and New Policies scenarios.

6.1.4 High Ambition (and Ambition)

Scenario results for Ambition and High Ambition scenarios in terms of on-grid supply are very similar and are therefore reported under one combined heading.

In the High Ambition scenario, capacity increases rapidly from 3GW in 2015 to 51 GW in 2030, 182 GW in 2050, reaching a total of 304 GW in 2065, Figure 19.

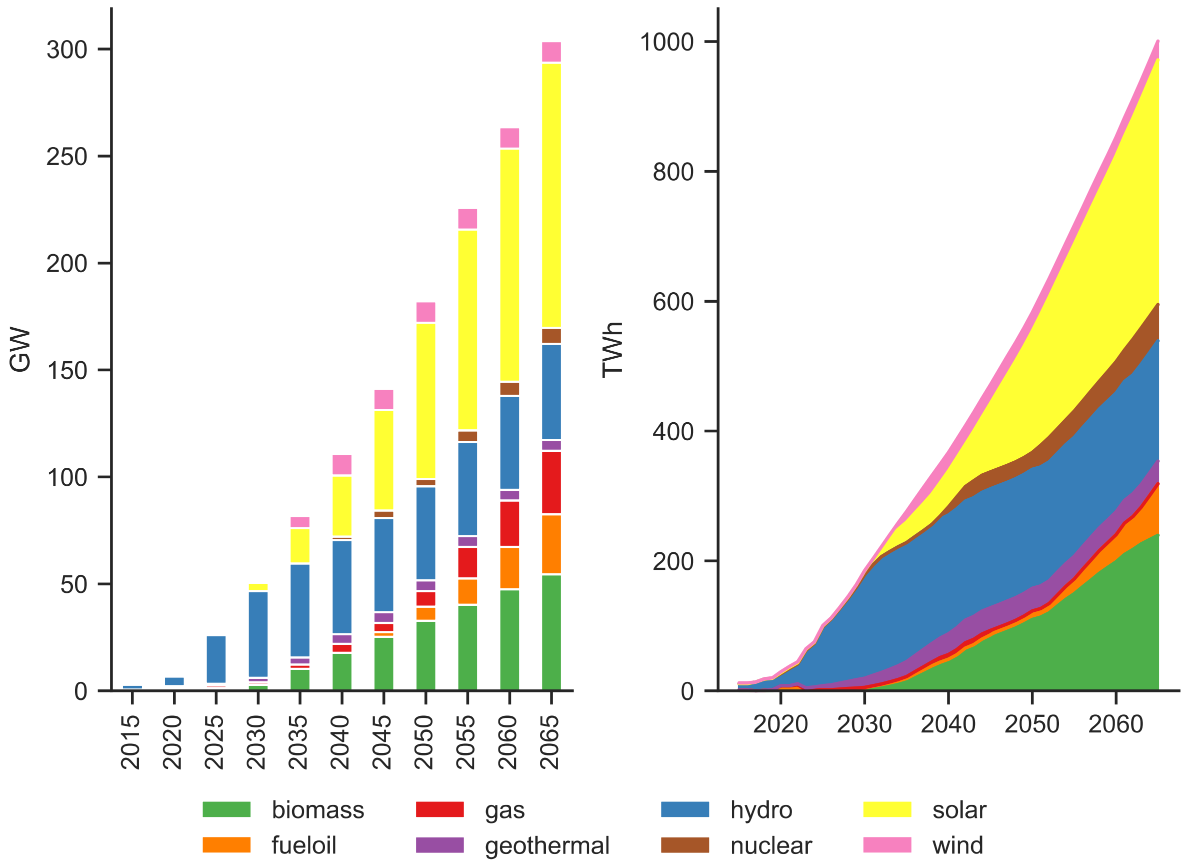


Figure 19 Power generation capacity by technology (GW) and Electricity supply mix by technology (TWh) in the High Ambition scenario.

Annual investment limits are similar to those in New Policies and the installation of the new upcoming projects proceeds according to the NEP. Between 2020 and 2032, there are large investments in hydropower and variable renewable sources of electricity generation (mostly, wind and solar power).

From 2030 onwards, the national electricity system undergoes a period of significant change as it transitions from a generation mix dominated by large-scale hydroelectric power to one where intermittent renewable generation is more prevalent, with dispatchable fossil and sustainable biomass plants used to meet the reserve margin constraint. In 2030, renewables represent a 98% share of in total capacity installed out of which 81.5 % is from hydro power.

In 2030, the share of renewable energy is 10% higher than in 2015. The increase is driven by an increase in renewable electricity generation after more than 4GW of solar PV and about

38GW of hydropower is completed by 2030. The share of renewable capacity gradually decreases to ~80% in 2065 from 98% in 2030.

The scenario reaches the maximum resource potential for hydropower (44GW) in 2048, geothermal (5GW) in 2042, and wind (10GW) in 2050. Due to the high demand, there is significant investment in non-renewables from 2030 onwards, continuing growth of natural gas and oil up to 30GW and 28GW, respectively in 2065. This shows that to satisfy the high level of electricity demand in this scenario, and in the absence of any control of emissions non-renewable energy power plants (nuclear, gas, fuel oil) are cost effective after 2030. The remaining demand growth is supplied through a large increase in biomass capacity, reaching 33GW in 2050 and 55GW in 2065, although this raises questions on availability of sufficient quantities of sustainable biomass feedstocks.

6.2 Electrification – on-grid versus off-grid

In this section we explore the difference in patterns of electrification across the scenarios. The results are presented in terms of the total population connected and of total demand. While the totals change by scenario, so do the role of off-grid technologies versus the grid. In addition, the spatial patterns (explored in Section 6.3) change, indicating how subtle changes in the scenario assumptions alter not only how electrification happens, but who gets access to electricity and by which technology.

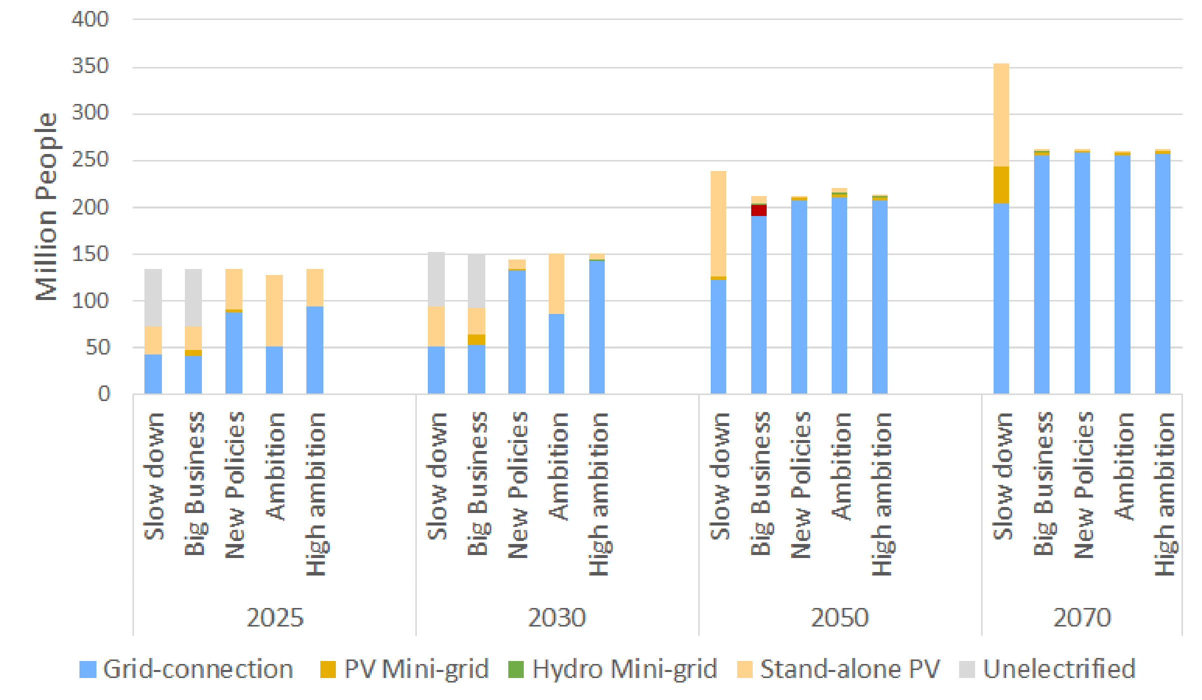
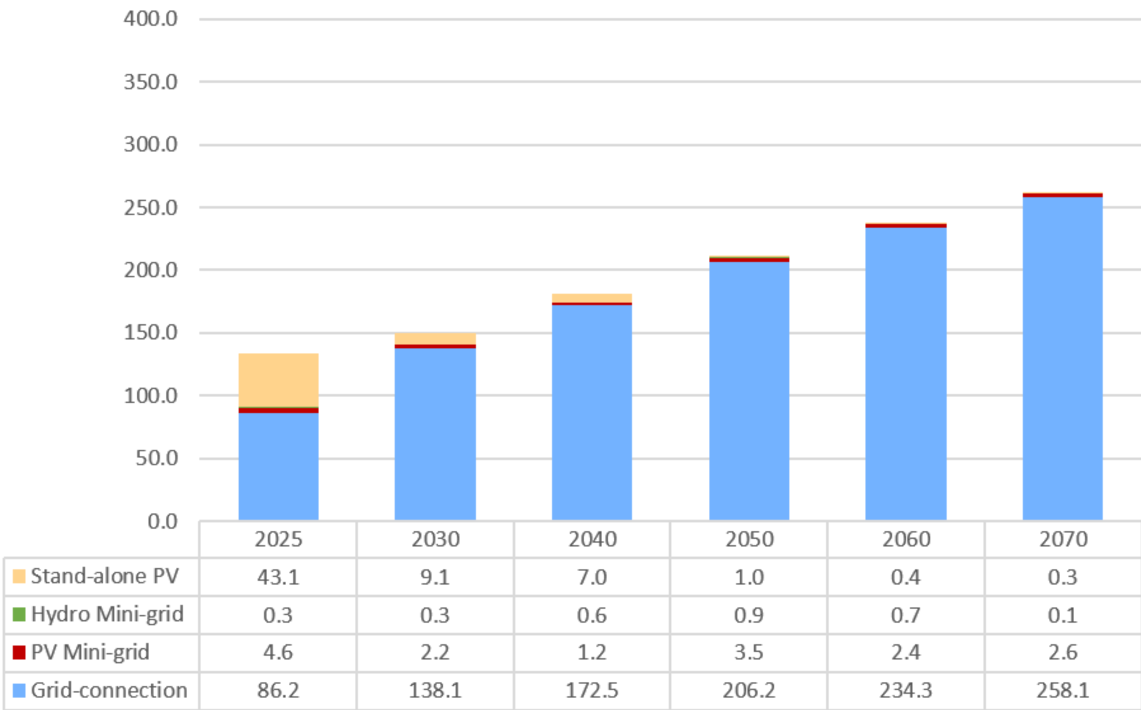


Figure 20 Population connected per technology across the five scenarios

In Figure 20, we see the evolution of grid- and off-grid technologies in the examined scenarios. The scenarios take different routes in the earlier years of the analysis. Slow Down and Big Business scenarios see a slow connection of households to the centralized grid network in the early years of the analysis. In the former, off-grid-connections are solely based on stand-alone PV technologies, whereas the higher demand growth in the latter leads to the implementation of mini-grids as well. Notably, a significant share of the population remains unelectrified by 2030 in both of these scenarios. In the New Policies and High Ambition scenario, a rapid deployment of stand-alone PV in 2025 is quickly replaced by grid-connection in 2030. In the Ambition scenario however, where technology choice is based only on LCOE (see Section 4.4), the pace of grid-expansion is slower compared to New Policies and High Ambition. Stand-alone PV technologies are mostly deployed to low-demand areas by 2030, covering 43% of the population, but only 1% of the residential demand. In other words, in 2030 a significant share of the population are still at very low levels of electricity consumption.

Notably, all but the Slow Down scenarios converge towards a similar technology split by the later years of the analysis (2050 and 2070), with the vast majority of the population eventually connected to the centralized grid network, and just a small share of the population residing mostly in remote areas served by off-grid technologies. In the Slow Down scenario, population growth is higher and demand growth is significantly slower, thus leaving a large share of the population to be served by off-grid technologies at the lowest cost.

6.2.1 New Policies



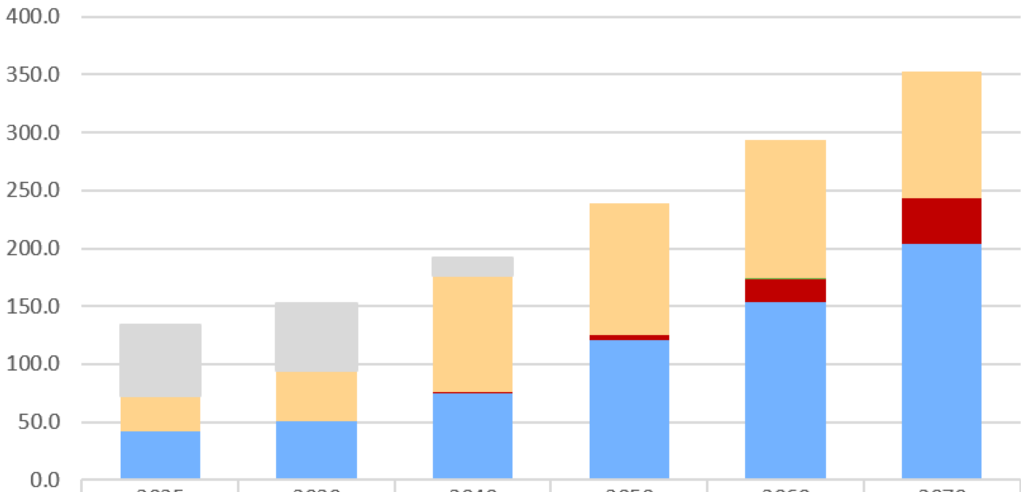
	2025	2030	2040	2050	2060	2070
Stand-alone PV	43.1	9.1	7.0	1.0	0.4	0.3
Hydro Mini-grid	0.3	0.3	0.6	0.9	0.7	0.1
PV Mini-grid	4.6	2.2	1.2	3.5	2.4	2.6
Grid-connection	86.2	138.1	172.5	206.2	234.3	258.1

Figure 21 Population connected per technology (million people) for the New Policies scenario

The results of the New Policies scenario are in line with the NEP II targets, where the grid vs. off-grid split is prescribed until 2030. Once grid-connected, a settlement remains so throughout the analysis, and only the most remote locations remain powered by an off-grid technology in the later years of the analysis. Off-grid technologies play an important role as a stop-gap solution to provide (in this scenario) universal access by 2025, albeit at very different service levels (tiers). Stand-alone PV deployments spike by 2025, where a total of 10.1 million people are served at the least-cost by these systems, then quickly drops to serve 2.2 million households as the primary source of electricity by 2030 as the grid expands. A similar story is seen for mini-grids, serving 1.1 million households by 2025 and reducing to 0.6 million households by 2030. Such a rapid increase and decrease of these systems risk leading to duplicate investments for millions of households in Ethiopia unless there is a clear strategy for how to integrate them when the grid arrives.

The grid throughout the analysis meets most of the demand. While a significant portion of the population is served by off-grid technologies in 2025, they require mostly Tier 1 and Tier 2 systems, and account for less than 1% of the residential electricity demand. By 2030, demand growth in remote areas sees the role of off-grid technologies increasing to 8% of the total residential demand, despite covering a smaller share of the population, and thereafter dropping again to only a few percent of the demand for the rest of the years. The key to implementing this scenario is the expansion of the national grid, as 110 million people need to be connected to the grid by 2030, and another 120 million people by 2070.

6.2.2 Slow Down



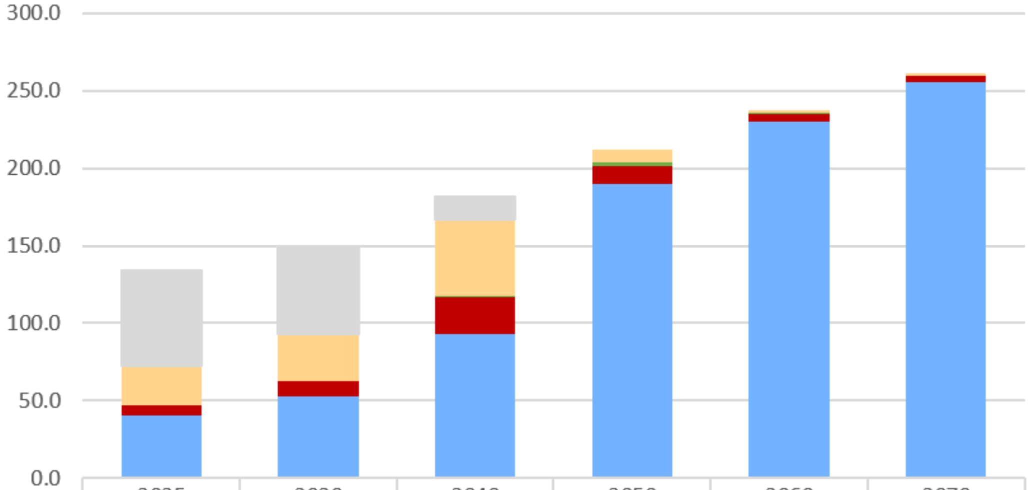
	2025	2030	2040	2050	2060	2070
Unelectrified	61.8	57.8	15.4	0	0	0
Stand-alone PV	30.6	43.3	100.6	114.1	118.7	109.8
Hydro Mini-grid	0.0	0.0	0.0	0.0	1.2	0.0
PV Mini-grid	0.0	0.0	0.8	3.4	19.2	39.2
Grid-connection	41.9	51.1	75.1	121.2	153.9	204.0

Figure 22 Population connected by technology in the Slow Down scenario

The Slow Down scenario shown in Figure 22 provides a very different picture compared to the New Policies scenario. Grid-connection happens at a slower pace, connecting 23 million people until by 2030, then ramping up to add 24-50 million people in each of the following 10-year intervals until 2070. Demand growth is much slower, with almost half of the population still in Tier 1 or Tier 2 by the end of the analysis. At these levels, stand-alone PV remains the least-cost option in most cases, thus serving more than 100 million people from 2040 until the end of the analysis.

Mini-grids play an increasingly important role from 2040 onwards, serving almost 40 million people by 2070. Their growth is driven by two factors. First, demand growth in remote areas makes mini-grids replace stand-alone PV as the least-cost off grid technology option. Second, the high cost of electricity from the centralized grid network in this scenario makes connection to the centralized grid prohibitively expensive for much of the population. Despite their higher cost of capital (discount rate), mini-grids draw on renewable energy resources rather than diesel.

6.2.3 Big Business



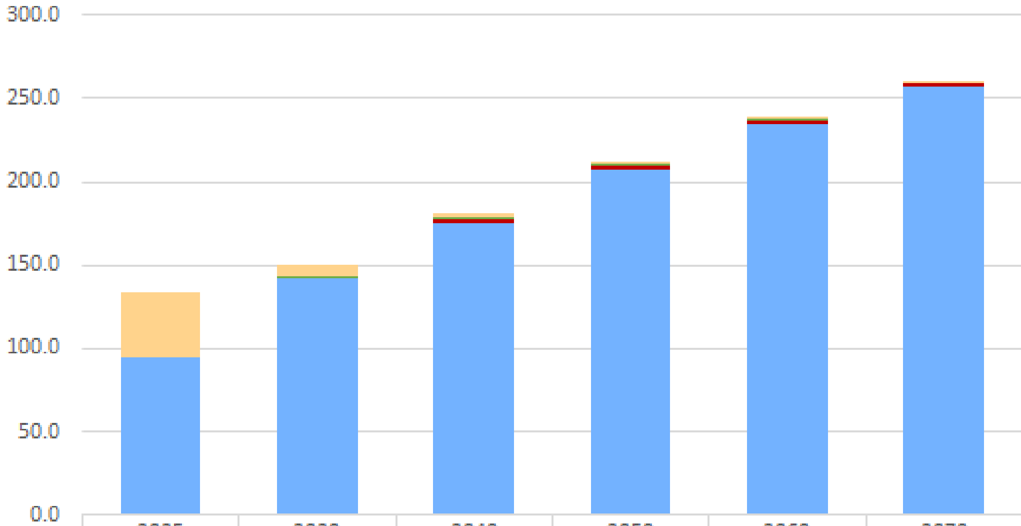
	2025	2030	2040	2050	2060	2070
Unelectrified	61.8	57.1	14.5	0	0	0
Stand-alone PV	25.0	29.9	49.3	8.0	2.0	1.8
Hydro Mini-grid	0.0	0.0	1.0	2.1	0.7	0.1
PV Mini-grid	6.8	10.3	23.8	11.7	4.8	3.5
Grid-connection	40.7	52.6	92.7	189.8	230.2	255.8

Figure 23 Population connected per technology (millions) in the Big Business scenario

In the Big Business scenario, shown in Figure 23, a significant part of the population is served by off-grid technologies before 2050, as the centralized grid is focused on serving the industrial demand instead of new residential connections, in order to enable economic growth in the industrial sector. Electrification continues according to the current pace, leaving a large part of the population unelectrified in the early years as in the Slow Down scenario. The relatively slower pace of grid-connection in the early years see shifts to a very rapid expansion of the grid during the middle of the analysis, with approximately 90 million people connecting to the grid between 2040 and 2050.

Off-grid technologies play an important role until 2050, while the ability of the grid to connect new residential customers is limited. Residential demand for electricity is high in this scenario, and mini-grids play an important role in serving high-demand areas that cannot be supplied by the centralized grid. In 2040, almost 24 million people are supplied by mini-grids. Although not explicitly modelled, many of the mini-grids that are deployed will later be connected to the grid, even before their system lifetime has expired. This requires that interconnection of mini-grids to the centralized grid is possible from both a technology- and business/policy-perspective in order to attract the investments from mini-grid operators and avoid duplication of investments as the grid arrives.

6.2.4 High Ambition

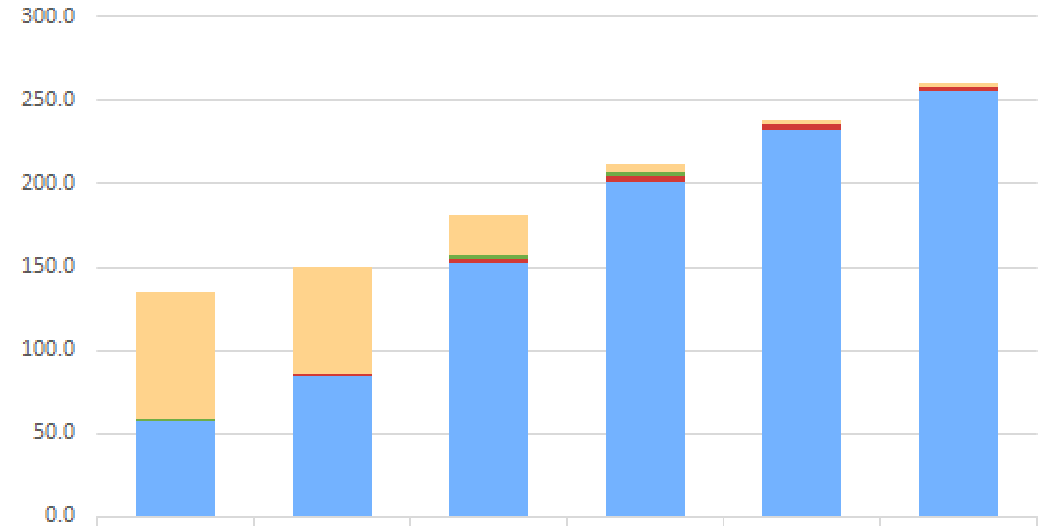


	2025	2030	2040	2050	2060	2070
Stand-alone PV	39.9	7.1	2.4	0.4	0.2	0.1
Hydro Mini-grid	0.3	0.5	1.0	1.2	1.1	0.2
PV Mini-grid	0.0	0.6	2.2	2.9	2.6	2.9
Grid-connection	94.1	141.7	175.8	207.1	234.0	256.7

Figure 24 Population connected by technology in the High Ambition scenario

The High Ambition scenario, shown in Figure 24, can be termed as the best-case scenario, and displays large similarities with the New Policies scenario, but is able to serve a higher level of electricity demand. In this scenario, the NEP II targets with respect to grid-expansion are set as the minimum level for the grid. Stand-alone PV systems are still found to be the least-cost alternative for areas with mostly Tier 1 and Tier 2 demand by 2025 and for some remote areas by 2030. After that however, no more than 3% of households are served by off-grid technologies, located mainly in very remote areas of the country. Even if in smaller capacities, PV mini-grids will have contributions in later years of the analysis where their deployment is essential for rural population in the eastern part of the country where grid expansion would be very costly.

6.2.5 Ambition



	2025	2030	2040	2050	2060	2070
Stand-alone PV	76.0	63.8	24.9	4.8	2.0	1.7
Hydro Mini-grid	0.3	0.3	1.7	1.7	0.6	0.1
PV Mini-grid	0.0	0.6	2.2	3.7	3.3	2.2
Grid-connection	58.0	85.1	152.8	201.5	231.9	255.9

Figure 25 Population by technology in the Ambition scenario

The Ambition scenario, shown in Figure 25, sees the same high level of demand growth as in the High Ambition scenario, but does not force the grid-expansion targets of NEP II. Stand-alone PV technologies play a significant role in the electrification process as long as a significant share of the population only have Tier 1 or Tier 2 level of demand (until 2050). The role of mini-grids is small in this scenario, as the optimistic view on the capabilities of the grid to expand leads to grid-connection of almost all areas with a high level of electricity demand. Mini-grid deployment is seen in remote areas where expansion of the centralized grid network would be very costly.

6.3 Spatial aspects of electrification

The results exhibit dramatic differences as a result of the scenario assumptions. Most noticeably in 2030, when NEP II targets state that 95% of the population should be grid connected (New Policies and High Ambition scenarios), we see the vast majority of settlements connected to the grid. Other technologies are mostly concentrated in the eastern parts of Ethiopia, not reached by the high-voltage (HV) transmission backbone, and a few other areas located further than 25 km from the existing grid network. This is displayed on the top-left part of Figure 26 for the New Policies scenario. In the Ambition scenario, where technology selection is made based only on LCOE, low demand areas are met by stand-alone PV technologies in all parts of the country. Densely populated areas with high demand are grid-connected when in proximity to the grid, and the few mini-grids are located in the south-eastern parts of the country far from the existing HV lines. The Slow Down and Big Business scenarios display similar patterns. Electrification occurs first in larger settlements in close proximity to existing the HV network, while many smaller and remote settlements remain unelectrified by 2030. Most notably, the higher demand in the Big Business scenario leads to the deployment of mini-grids. Contrary to the New Policies and High Ambition scenario, these mini-grids are found in high demand areas close to the existing grid network, and will eventually be integrated into or replaced by the centralized grid.

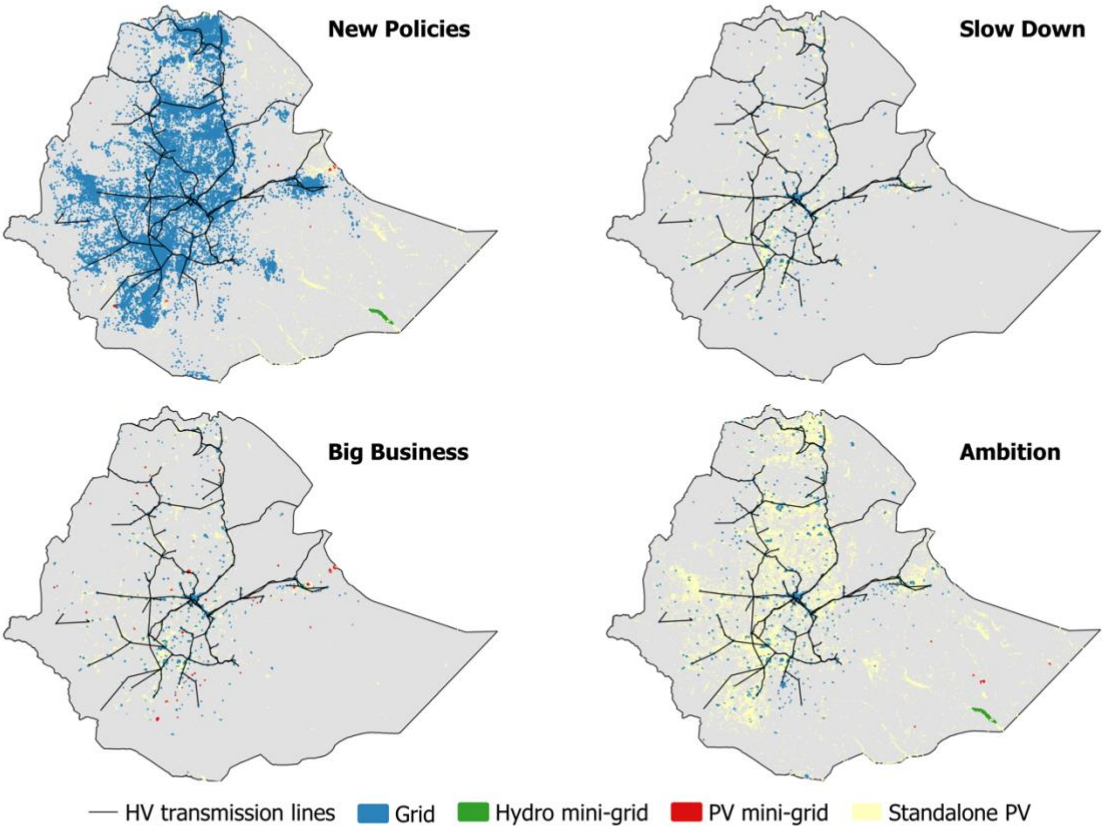


Figure 26 A comparison of four spatial patterns of residential electrification in 2030

6.3.1 New Policies scenario

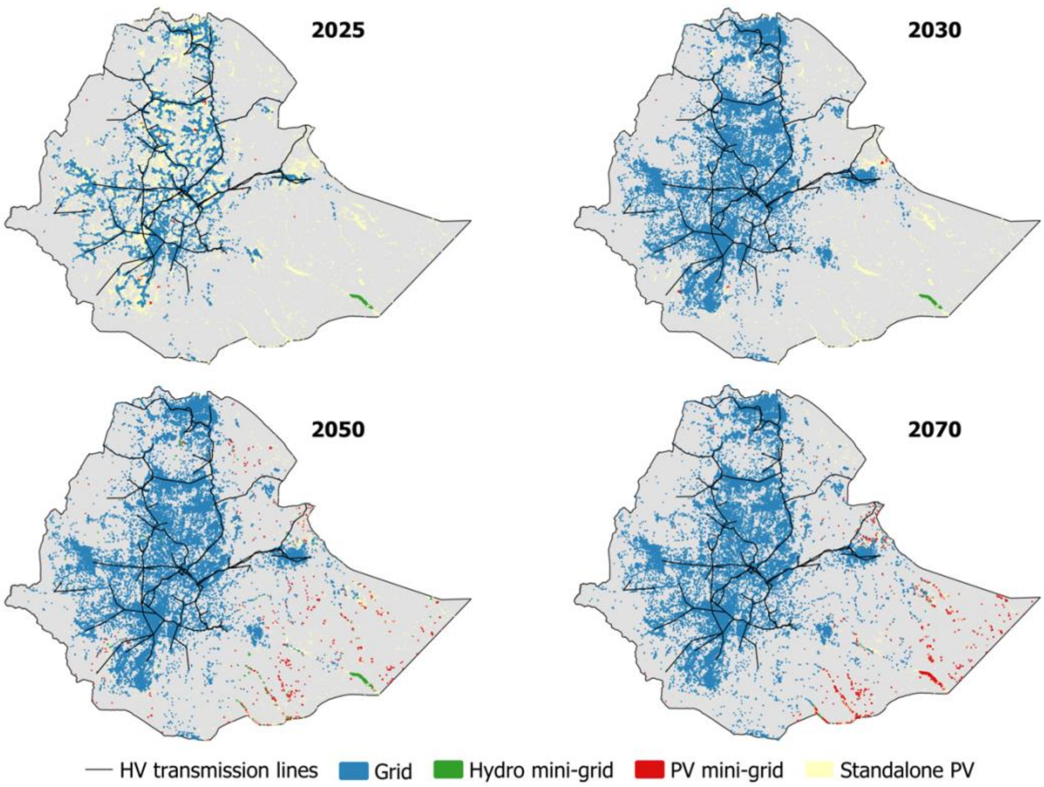


Figure 27 Spatial distribution of residential electrification technologies in the New Policies scenario.

In the New Policies Scenario, the geospatial analysis displays a deployment of mini-grids and stand-alone PV beyond 5 km of the existing medium voltage lines throughout the country by 2025, Figure 27. Mini-grids are seen both in remote areas, but also relatively close to the existing network. By 2030, the grid expands and connects the vast majority of settlements. After 2030, an increasing number of remote settlements transition from stand-alone PV to mini-grids as demand grows.

6.3.2 Slow Down scenario

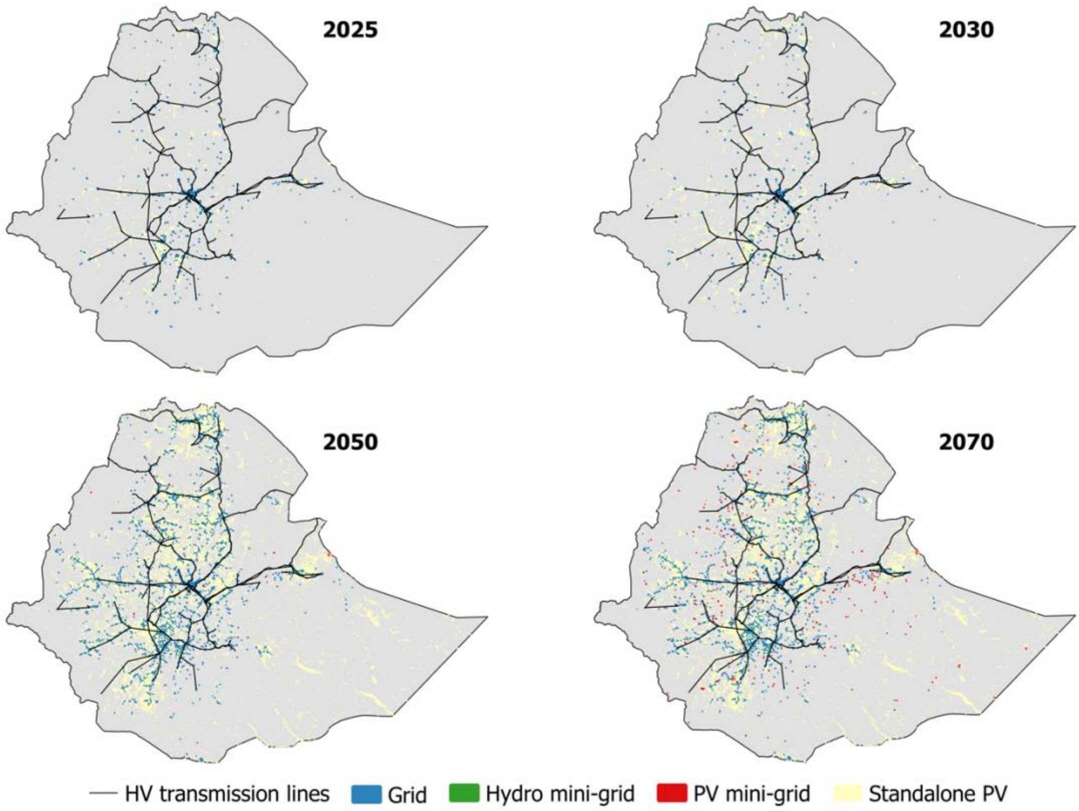


Figure 28 Spatial distribution of residential electrification technologies in the Slow Down scenario

The Slow Down scenario (Figure 28) shows a slow expansion of electricity access in the early years. Increased electricity access is seen primarily in central parts of the country and around the existing network until 2030. After 2030, settlements across the country gain access, largely driven by a deployment of stand-alone PV technologies. Due to the slow demand growth in this scenario, stand-alone PV technologies are seen in all regions of the country even in 2070.

6.3.3 Big business scenario

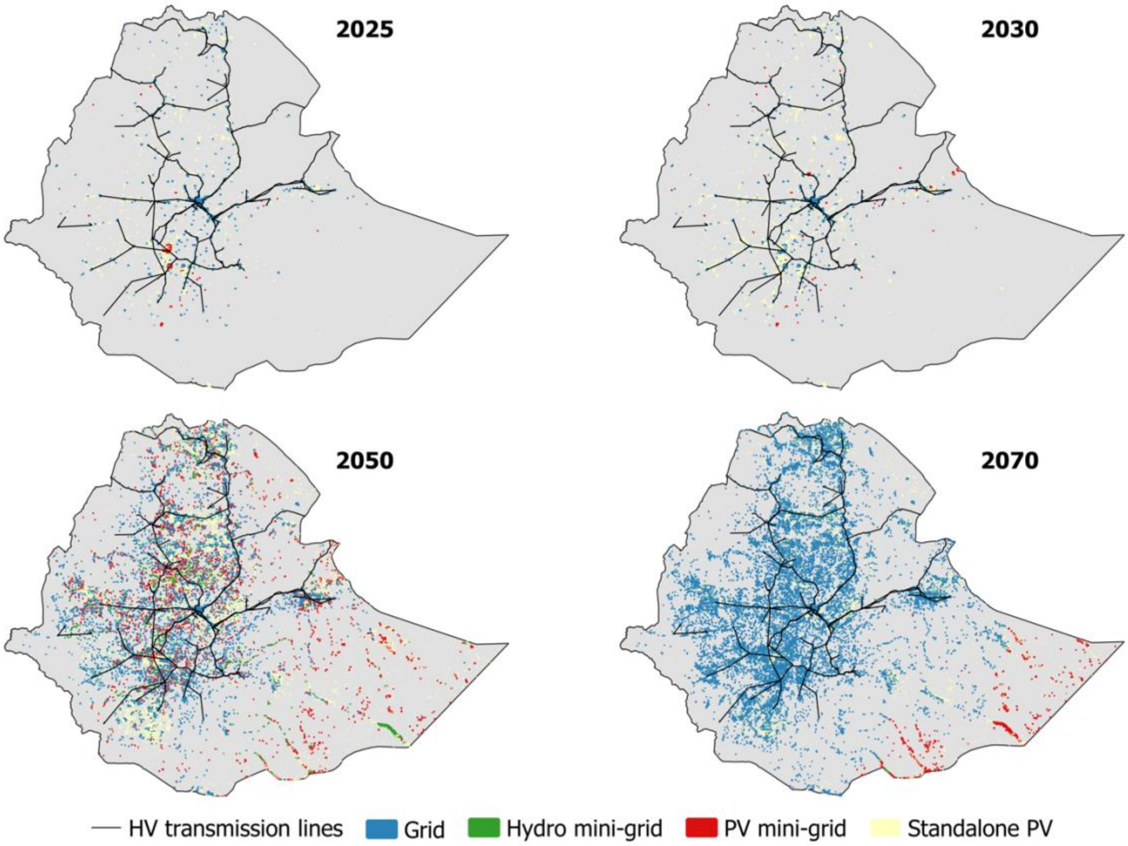


Figure 29 Spatial distribution of residential electrification technologies in the Big Business scenario

The Big Business scenario (Figure 29) also show a slow expansion of electricity access in the early years. Again, increased electricity access is seen primarily in central parts of the country and around the existing network until 2030, including a few mini-grids in the southwestern parts of the country. After 2030, settlements across the country gain access, through a combination of mini-grids in high demand areas and stand-alone PV technologies in low demand areas. As demand grows, a majority of settlements are connected to the grid around the HV lines by 2070.

6.3.4 High ambition scenario

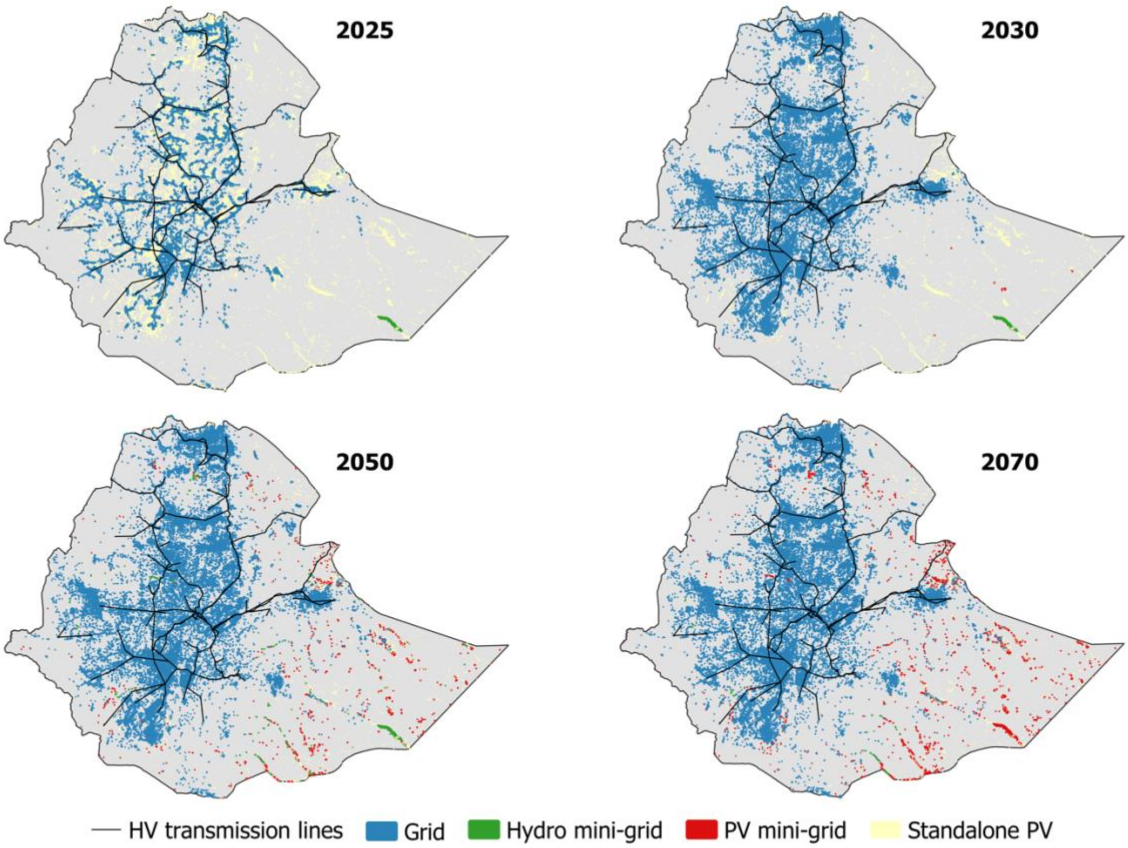


Figure 30 Spatial distribution of residential electrification technologies in the High Ambition scenario

The geospatial analysis (Figure 30) displays a rapid expansion of the grid network and deployment of stand-alone technologies throughout the country by 2025, with a few mini-grids found on the eastern side of Ethiopia. By 2030, the grid expands and connects the vast majority of settlements. After 2030, an increasing number of remote settlements transition from stand-alone PV to mini-grids as demand grows.

6.3.5 Ambition Scenario

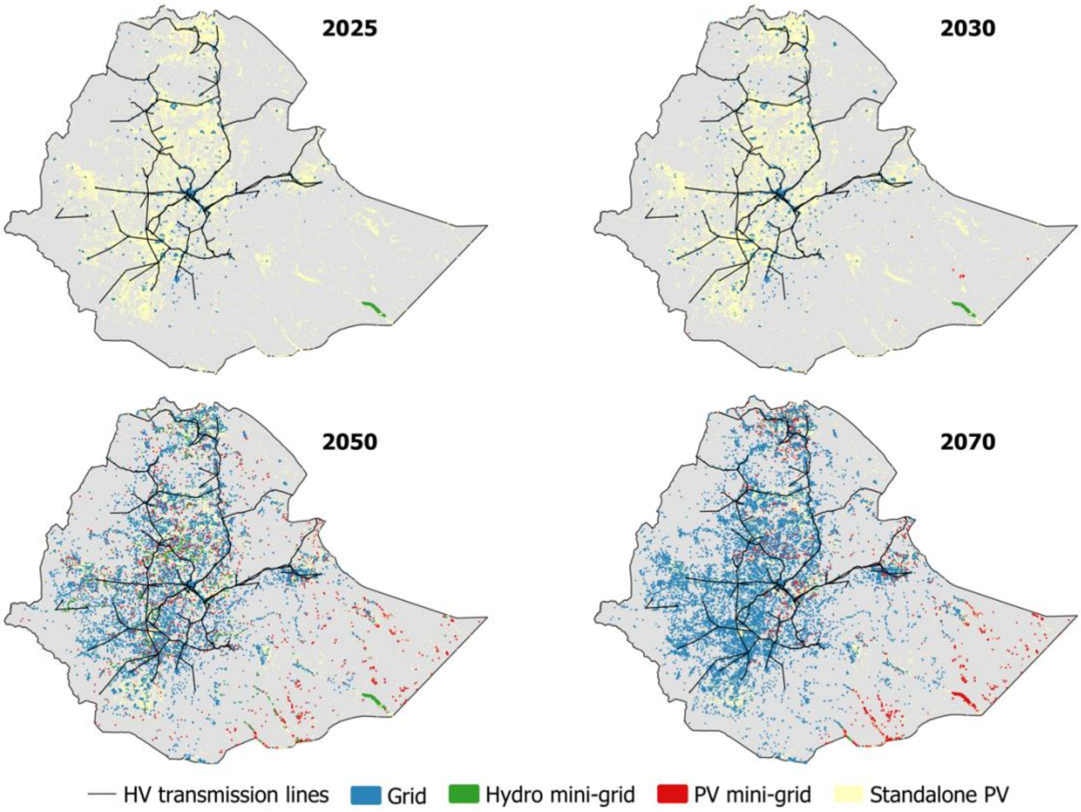


Figure 31 Spatial distribution of residential electrification technologies in the Ambition scenario

The Ambition scenario results (Figure 31) display the largest deployment of stand-alone PV technologies by 2025, and grid-connection for all high demand areas except for in the south-eastern part of the country. This remains the case in 2030, with a few more locations connected to the grid and mini-grids as demand grows. By 2050 and 2070, many settlements gain access to grid electricity, and mini-grids become increasingly common in the eastern parts of the country far from the HV lines.

6.4 Annual Emissions

The government of Ethiopia has committed to a 2°C compliant Nationally Determined Contributions (NDC) target as an outcome of the 2015 Paris Agreement of limiting 2030 GHG emissions to 145 MtCO2e, i.e., a 64% drop compared to baseline projections. Nevertheless, the CO2 emissions from the power sector represent only 3% of the 2010 baseline and are expected to remain low through the high share of renewable technologies in the power generation mix.

Emissions prior to 2050 remain at a very low level across all the scenarios (Figure 32). The transient peaks in emissions, particularly visible in the Big Business and New Policies scenarios result from supply side constraints on renewable technologies. As demand exceeds the supply of renewable electricity, fossil fuel generation, including natural gas, and fuel oil, are used to meet the shortfall.

In the Slow Down scenario, the higher penetration of fossil fuel technologies lead to higher CO2 emissions reaching 30Mton in 2065. The sharp decrease in emissions in 2049 is due to the non-use of natural gas power plants. In the Big Business scenario, the emissions reach 4.4Mton in 2065 while in the High Ambition and Ambition scenarios they increase to 57Mton and 85Mton respectively in the same year. In the Big Business scenario, the higher electricity demand compared to the New Policies scenario leads to higher CO2 emissions. The high electricity demands in High Ambition and Ambition scenarios, and high penetration of diesel and heavy fuel oil technologies mean emissions are relatively high in comparison to the other scenarios, but still low on a per capita level and when compared internationally.

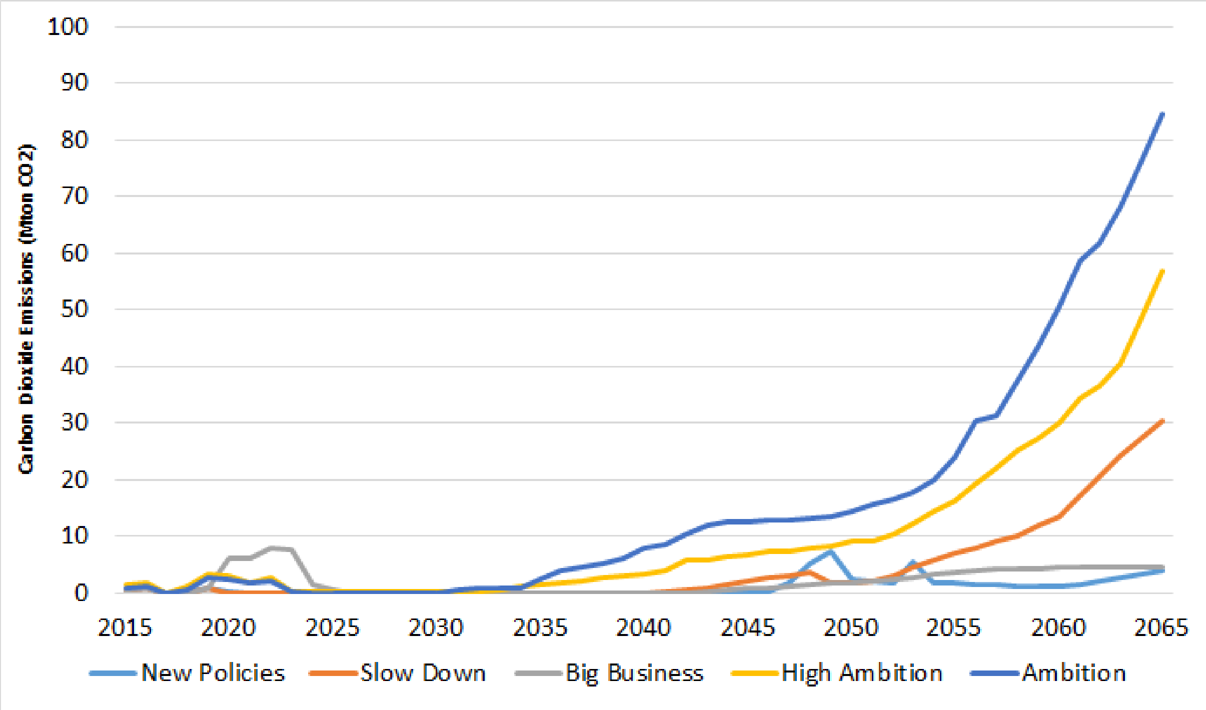


Figure 32 Carbon dioxide emissions (Mton CO2) in the scenario

Peaks in emissions (for example between 2020 and 2025) occur in the Big Business, New Policies and Ambition scenarios, and are associated with use of heavy fuel oil and natural gas plants to cover large increases in electricity demand growth and other plants reach the end of their lifetime, but are not yet replaced.

6.5 Electricity exports

The export of electricity across the scenario results is directly influenced by the proportion of interconnectors available for export (versus import) and, for New Policies, Big Business and Slow Down, the export price. If the generation price is lower than export price, then the model will choose to export electricity. While these results are sensitive to the export price chosen (and the implicit assumption that all electricity produced would be purchased), they provide some insight into the potential role of interconnectors and export revenues (described in Section 6.6) under different conditions. In contrast the Ambition and High Ambition scenarios ignore export prices and aim to export up to 70% and 100% of interconnector capacity respectively. These results are indirectly influenced by the technology mix, producing a different marginal price of generation, and the internal demand for electricity.

As shown in Figure 33, electricity exports differ across the scenarios, with all except the Slow Down scenario following a broadly similar pattern. In the near term, exports rapidly increase as interconnector capacity is expanded rapidly and large supply capacity of hydropower generation is brought online. The increase of Big Business and Slow Down scenarios is delayed due to the near-term constraints on interconnectors, reaching a peak almost 10 years after the New Policies, Ambition and High Ambition scenarios.

After this peak, the scenarios follow two different trajectories. In the price driven scenarios, the growth in internal demand gradually consumes the electricity that was previously available for export resulting in declining export quantities. In the Ambition and High Ambition scenarios exports remain at a maximum level.

Phenomena in the export trajectories result from changes in the supply technologies. For example, in the Big Business scenario hydropower reaches its maximum electricity generation potential in 2041. To maintain the high levels of electricity exports in the High Ambition and Ambition scenarios, we see higher penetration of fossil fuel technologies in these scenarios than the New Policy one and specifically fuel oil power plants replace gas-based power generation.

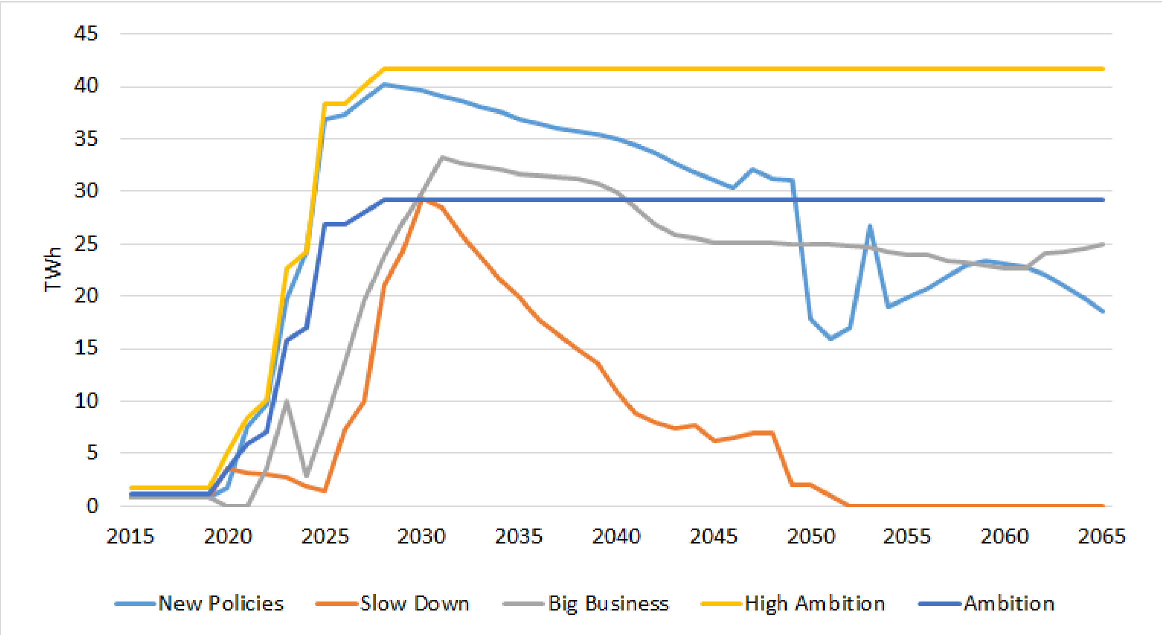


Figure 33 Exports of electricity

6.6 Total system costs

In this section, we report total system costs from the OSeMOSYS model solutions, shown in Figure 34. OSeMOSYS minimises the total discounted costs of the energy system, where total costs include capital investments of on- and off-grid generation capacity and transmission expansion, fixed and variable operating costs and export revenues. To compare these costs across scenarios, each of which used a different discount rate (see Table 6) we report undiscounted costs below.

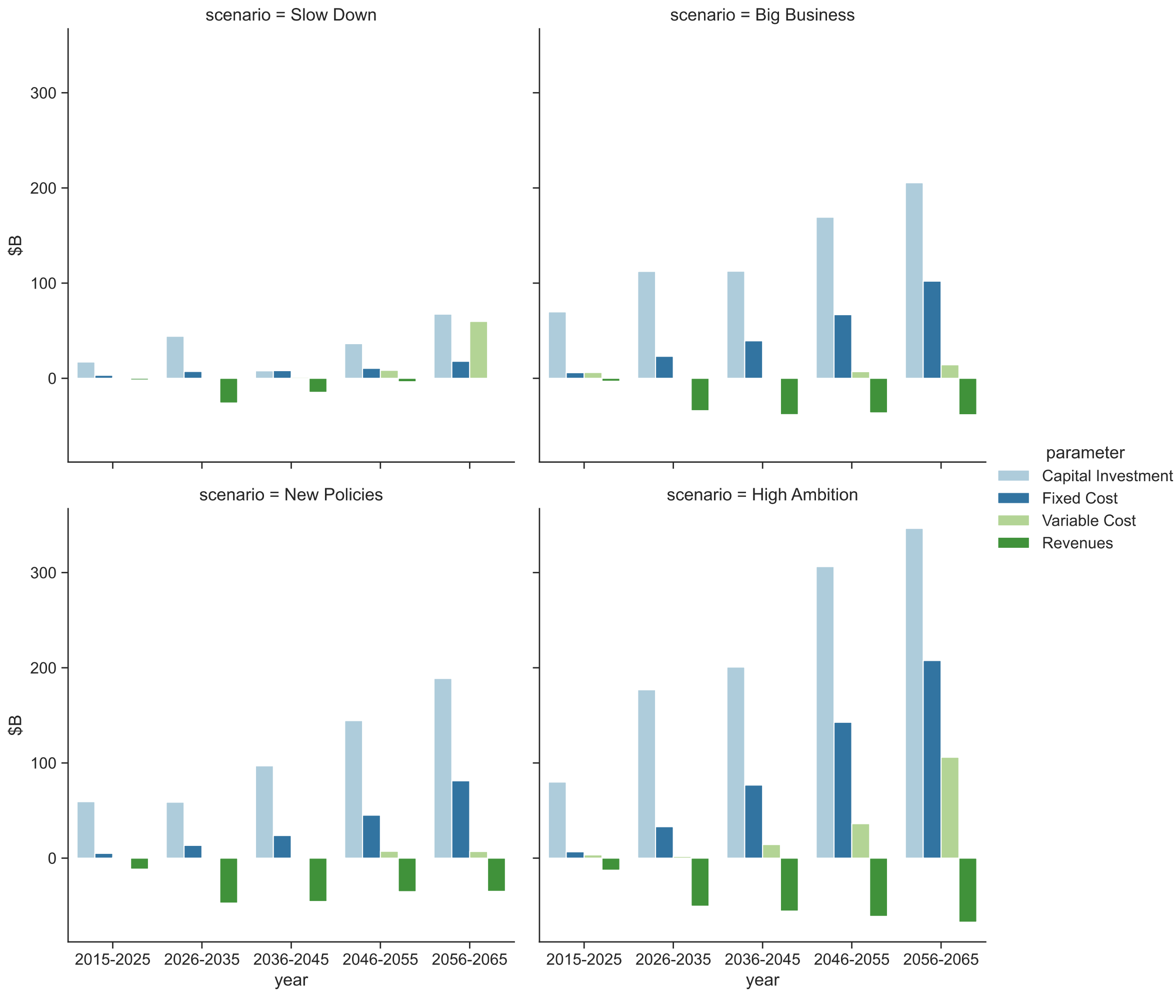


Figure 34 Undiscounted capital, fixed and variable operating costs and revenues for the scenarios

Under the New Policies scenario, total capital expenditure is $535B for the period 2015–2065. 85% of this is due to grid connected capacity, 6% for off-grid technologies and 9% for interconnectors and grid expansion. In the near-term, capital expenditure is $48B for the period 2020-2025 and $30B for the period 2026-2030. The remaining $459B is spent over the period 2031-2065. Total system costs in the Big Business scenario are marginally higher than the New Policies scenario, although export revenues are lower in the near-term. Instead, there is a near-term increase in investment as the energy system is rapidly scaled to meet demands. In the High Ambition scenario, total capital investment costs are $1294B, reflecting the much larger supply system. In this scenario, export revenues reach their highest level out of all the scenarios. In the Ambition scenario (not shown), the revenues are lower due to less electricity exports.

Ethiopia could play a key regional role as an energy hub, importing and exporting electricity to neighbouring countries with benefits including both improved energy security and income from export revenues. Total electricity export revenues range from $48B to $280B depending on the size of the energy system, interconnector capacity and export price. Annual revenues grow over time, doubling following investments in interconnector capacity in the mid-2030s.

6.7 Levelised cost of generation

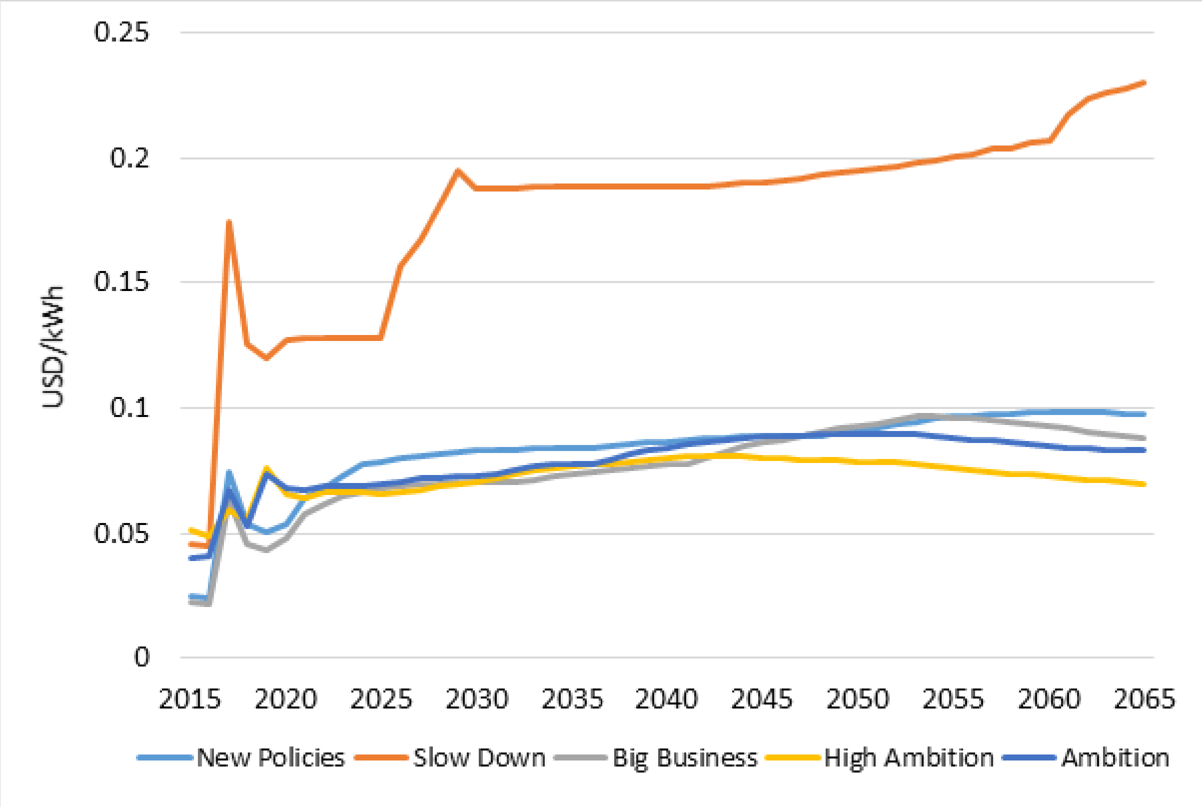


Figure 35. Average electricity cost (USD/kWh) by scenario.

Figure 35 shows the levelized cost of generation from each of the scenarios. This is the OSeMOSYS result parameter used as an input to the OnSSET model. Higher levelized costs of generation on the grid make (more expensive) off-grid technologies more competitive. Aside from the Slow Down scenario, where constraints on technology availability and the high discount rate increase the on-grid electricity supply costs, the levelized cost of generation is reasonably constant through the model horizon and across the scenarios. There is a slow increase in the cost of generation over time, due to the increasing investment required as the hydro power resource is fully connected and alternative sources of generation come online.

7 Discussion

In this report, we investigate the implications for the future electrification pathways of Ethiopia under five plausible scenarios. These scenarios are *not* predictions or forecasts of the future, but instead allow us to explore alternative energy pathways under a range of conditions.

The results highlight a number of key insights across a range of broad topics: the role of non-hydroelectric power technologies in electricity supply; the importance of off-grid technologies to reduce the cost of electrification; the opportunity for Ethiopia to become a key energy trader; and finally, some open questions that are raised by these results.

7.1 Supply side implications of electrification

In terms of electricity supply to all sectors, the results show that rapid growth in electricity supply is needed to meet the demand projections in the New Policies, Big Business, Ambition and High Ambition scenarios. For example, while electricity demands quadruple between 2040 and 2060 in the Big Business scenario, supply capacity must grow to reach 200GW by 2065. In the near term, most scenarios show a very rapid growth in hydro-electric capacity to 2030. As the lowest marginal cost producer of electricity, hydro maintains dominance over the electricity supply system as demands rapidly increase. However, in the medium-term, that hydro potential is exceeded, which means that alternative technologies are required to meet continuing demand growth. The technologies which appear most favourable include solar, wind, geothermal and natural gas. In the long-term, there is a small but significant role for nuclear and, under very high demands, sustainable biomass. In all scenarios, fossil resources, including heavy fuel oil and natural gas generation are used. The role played by natural gas power plants is primarily to cover the reserve margin of 18%, while heavy fuel oil is used for electricity generation. This raises the question of how to maintain system security in a way that is compatible with the international net zero emission targets.

7.2 The role of off-grid technologies for achieving electrification

The results highlight that there are different pathways to achieve universal energy access in Ethiopia. Crucially, cost-effective electrification patterns differ as a function of demand growth, in particular, how quickly newly connected settlements ascend the tiers from low-electricity consumption to higher-consumption. Low demand growth means that stand-alone PV technologies are most appropriate, avoiding the need for expensive grid connections which would be underused. However, for settlements whose demands increase quickly, resulting in high demand growth, then earlier grid-connection is required. The comparison of the High Ambition and Ambition results demonstrate that when electrification is determined by the cheapest cost connection, and not constrained using a proximity policy, then grid connection is delayed until necessary, with stand-alone PV and PV mini-grids replacing more expensive grid extension and connections. In the long-term, demand growth means that the total demand for electricity can no longer be met by stand-alone technologies, grid connections must be used to meet the demand for electricity at tiers 4 and 5. Finally, off-grid technologies do continue to have a role in remote locations which are distant from existing networks and where extending the grid is cost-prohibitive.

7.3 Ethiopia as a key energy hub

Given the very low marginal cost of electricity generation, particularly in the medium terms while hydro-electric power is the dominant and marginal producer, the potential for exporting electricity is good. The assumptions around relatively high electricity export prices mean that we see relatively high investment in interconnector capacity, and in all scenarios, except the pessimistic Slow Down scenario, we see 20-40TWh of annual electricity exports, with the potential to raise between $48B and $280B (undiscounted) cumulative revenue depending upon the assumptions of export price, size of the electricity system and investment in interconnector capacity. Annual revenues grow over time, doubling following investments in interconnector capacity in the mid-2030s.

7.4 Further work

The results highlight a number of potential risks and open questions for the Ethiopian power sector associated with the use of technologies, emissions and climate change. While Ethiopia's reliance on large hydropower capacity presents a great opportunity for low-carbon emission generation, it also presents an increased vulnerability to droughts, given the uncertain impacts of climate change on precipitation patterns. At the very least, further research should be conducted to better understand the potential implications on system security of droughts, or times of reduced rainfall. This also presents a risk for export revenues, which would only be profitable if the marginal cost of generation is lower than the export price. One option to mitigate this risk is diversification of the supply sector to other technologies. The results show large uptake of solar, of which there is a very large energy potential, use of the moderate wind resource as well as geothermal. However, the high levels of demand growth explored in this research demonstrate the challenge. Higher levels of demand than those studied here are also plausible. Each technology has a down-side. Under high demand growth increasing levels of alternative technologies are used, with implications for the environment, balance of payments and system security.

In the highest demand scenario – High Ambition – a large capacity of biomass fuelled electricity generation is installed. While this could potentially provide a sustainable and low-carbon source of electricity, there are environmental implications as well as emissions, resulting from land-use change to grow the quantity of biomass required for large-scale electricity generation. Biomass for electricity would also result in competition with other uses of land and sustainability of its utilization and adequacy of potential for the intended electricity capacity. In particular the strategic growth industry of agriculture.

Other consequences of the high demand scenarios were the increased use of fossil fuels, as potentially cheap sources of electricity. While still making up a minor proportion of total electricity generation, the carbon dioxide emissions from the combustion of heavy fuel oil would dramatically increase the proportion of total energy emissions, and make the Ethiopian NDC unachievable. Moreover, it also would pose extra challenge on the country's economic activity and foreign markets volatility due to the high dependence on those fossil fuels, which currently are imported. This then raises the question of what alternative technology could be used if heavy fuel oil was not?

8 Availability of Data and Tools

The open-source tools used for the research underpinning this report, together with the data are freely available for download, re-use, extension and to reproduce this study.

You can find out more about OSeMOSYS at the website:

http://www.osemosys.org/

or download the source-code directly from Github:

https://github.com/OSeMOSYS/OSeMOSYS_GNU_MathProg

The input data, scenarios and model used to generate the results in this report are available here:

https://github.com/KTH-dESA/OPML-Ethiopia

You can find more out about the OnSSET model at the website:

http://www.onsset.org/

8.1 Other publications

A journal publication reported a set of earlier results [23].

A policy brief presented highlights of the work to decision makers in Ethiopia [24], with an accompanying presentation [25], [25].

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10 Appendix

10.1 Results Data Tables

10.1.1 Generation Capacity

Table 12 Generation Capacity by technology (GW) in the New Policies Scenario

Capacity (GW)	2015	2030	2050	2065
Biomass	0.2	0.33	0.78	4.25
LFO/HFO	0.14	0.07	0	1.80
Gas	0	0	4.03	29.49
Nuclear	0	0	0	6.96
Hydro	2.36	18.59	44.01	44.01
Geothermal	0.01	2.05	5.00	5.00
Wind	0.32	0.46	10.00	10.00
Solar PV	0.01	1.64	21.75	35.00
Solar CSP	0	0	2.00	32.00
Total	**3.04**	**23.12**	**87.57**	**168.51**
RET share	**95%**	**100%**	**95%**	**77%**
Djibouti exports	0.10	0.10	0.10	0.10
Kenya exports	0.00	1.40	1.40	1.40
Sudan exports	0.10	3.10	3.10	3.10
Tanzania exports	0.00	0.41	0.41	0.41
Exports	0.2	5.01	5.01	5.01

Table 13 Generation capacity by technology (GW) in the Slow Down scenario

Capacity (GW)	2015	2030	2050	2065
Biomass	0.20	0.33	0.28	1.10
LFO/HFO	0.14	0.07	0.20	7.78
Gas	0.00	0.00	1.28	2.37
Nuclear	0.00	0.00	0.00	0.00
Hydro	2.36	11.94	13.24	17.74
Geothermal	0.01	0.85	1.90	2.38
Wind	0.32	0.46	0.90	2.30
Solar PV	0.01	0.36	1.75	4.40
Solar CSP	0	0	0	3.86
Total	**3.04**	**14.00**	**19.55**	**41.94**
RET share	**95%**	**99%**	**92%**	**76%**
Djibouti exports	0.10	0.10	0.10	0.10
Kenya exports	0.00	1.00	1.40	1.40
Sudan exports	0.10	3.10	3.10	3.10
Tanzania exports	0.00	0.41	0.41	0.41
Exports	0.20	4.61	5.01	5.01

Table 14 Generation capacity by technology (GW) in the Big Business scenario

Capacity (GW)	2015	2030	2050	2065

Biomass	0.20	0.33	3.40	6.68
LFO/HFO	0.14	0.07	0.00	5.68
Gas	0.00	2.18	12.27	37.27
Nuclear	0.00	0.00	6.50	7.70
Hydro	2.36	30.94	44.01	44.01
Geothermal	0.01	2.20	5.00	5.00
Wind	0.32	6.46	10.00	10.00
Solar PV	0.01	1.10	46.24	57.5
Solar CSP	0	0	1.48	41.07
Total	**3**	**42**	**130**	**211**
RET share	**93%**	**95%**	**86%**	**77%**
Djibouti exports	0.10	0.10	0.10	0.10
Kenya exports	0.00	1.40	1.40	1.40
Sudan exports	0.10	3.10	3.10	3.10
Tanzania exports	0.00	0.41	0.41	0.41
Exports	0.2	5.01	5.01	5.01

Table 15 Generation capacity by technology (GW) in the High Ambition scenario

Capacity (GW)	2015	2030	2050	2065
Biomass	0.20	2.83	32.78	54.50
LFO/HFO	0.14	0.07	6.63	28.06
Gas	0.00	1.16	7.22	29.67
Nuclear	0.00	0.00	3.50	7.50
Hydro	2.36	40.60	44.01	45.00
Geothermal	0.01	2.05	5.00	5.00
Wind	0.32	0.46	10.00	10.00
Solar PV	0.01	3.89	51.50	57.50
Solar CSP	0.00	0.00	21.45	66.45
Total	**3.04**	**51.06**	**182.08**	**303.68**
RET share	**88%**	**98%**	**90%**	**79%**
Djibouti exports	0.10	0.10	0.10	0.10
Kenya exports	0.00	1.40	1.40	1.40
Sudan exports	0.10	3.10	3.10	3.10
Tanzania exports	0.00	0.41	0.41	0.41
Exports	0.20	5.01	5.01	5.01

Table 16 Generation capacity by technology (GW) in the Ambition scenario

Capacity (GW)	2015	2030	2050	2065
Biomass	0.20	0.33	18.99	41.22
LFO/HFO	0.14	0.07	8.86	30.35
Gas	0.00	0.57	13.42	35.69
Nuclear	0.00	0.00	3.50	7.50
Hydro	2.36	34.48	44.01	44.01
Geothermal	0.01	2.05	5.00	5.00
Wind	0.32	0.71	10.00	10.00
Solar PV	0.01	5.36	52.00	57.50

Solar CSP	0.00	0.00	23.52	68.52
Total	**3.04**	**43.56**	**179.30**	**299.79**
RET share	**93%**	**99%**	**86%**	**75%**
Djibouti exports	0.10	0.10	0.10	0.10
Kenya exports	0.00	1.40	1.40	1.40
Sudan exports	0.10	3.10	3.10	3.10
Tanzania exports	0.00	0.41	0.41	0.41
Exports	0.20	5.01	5.01	5.01

10.1.2 Energy Supply Mix

Table 17 New Policies

ELC supply (GWh)	2015	2030	2050	2065
Biomass	783	1,410	3,414	18,697
LFO/HFO	554	0	0	3,813
Gas	0	0	5,656	3,336
Nuclear	0	0	0	51,839
Hydro	9,834	77,326	183,104	183,104
Geothermal	60	14,341	35,040	35,040
Wind	925	1,310	28,700	28,700
Solar PV	18	3,247	41,585	66,365
Solar CSP	0	0	7,046	126,697
Total	**12,174**	**97,635**	**304,545**	**517,590**
RET share (not includes Nuclear)	**95%**	**100%**	**98%**	**89%**
Djibouti exports	416	832	520	389
Kenya exports	0	11,651	4,229	7,241
Sudan exports	416	24,967	12,060	10,893
Tanzania exports	0	2,143	1,074	0
Exports	832	39,592	17,884	18,523

Table 18 Slow Down

ELC supply (GWh)	2015	2030	2050	2065
Biomass	783	1,410	1,214	4,839
LFO/HFO	555	0.00	47	42,243
Gas	0.00	0.00	3,907	0.00
Nuclear	0.00	0.00	0.00	0.00
Hydro	9,834	49,644	55,052	73,777
Geothermal	60	5,931	13,340	16,704
Wind	925	1,310	2,583	6,601
Solar PV	18	634	3,450	8,668
Solar CSP	0.00	0	0	15,930
Total	**12,174**	**58,930**	**79,593**	**168,222**
RET share (not includes Nuclear)	**95%**	**100%**	**95%**	**75%**
Djibouti exports	416	789	390	0.00

Kenya exports	0.00	7,553	1,552	0.00
Sudan exports	416	20,912	0.00	0.00
Tanzania exports	0.00	0.00	0.00	0.00
Exports	832	29,549	13,290	8,342

Table 19 Big Business

ELC supply (GWh)	2015	2030	2050	2065
Biomass	783	1,410	14,941	29,393
LFO/HFO	565	0	0	6,122
Gas	0	0	4,266	0
Nuclear	0	0	48,399	57,346
Hydro	9,834	128,703	183,104	183,104
Geothermal	60	15,392	35,040	35,040
Wind	925	18,530	28,700	28,700
Solar PV	18	1,948	89,345	110,592
Solar CSP	0	0	5,222	160,603
Total	**12,184**	**165,984**	**409,018**	**610,900**
RET share (not includes Nuclear)	**95%**	**100%**	**87%**	**90%**
Djibouti exports	416	832	520	597
Kenya exports	0	11,647	8,175	7,776
Sudan exports	416	16,168	13,842	13,815
Tanzania exports	0	1,182	2,460	2,774
Exports	832	29,830	24,997	24,962

Table 20 High Ambition

ELC supply (GWh)	2015	2030	2050	2065
Biomass	783	4,870	109,912	239,760
LFO/HFO	531	0.00	12,359	79,119
Gas	0	489	861	0

Nuclear	0	0	26,061	55,845
Hydro	9,834	159,478	183,104	185,165
Geothermal	60	14,341	35,040	35,040
Wind	925	508	28,700	28,700
Solar PV	18	5,713	99,966	110,592
Solar CSP	0	0	86,744	266,220
Total	**12,151**	**185,309**	**582,746**	**1,000,440**
RET share (not includes Nuclear)	**96%**	**100%**	**93%**	**87%**
Djibouti exports	832	832	832	832
Kenya exports	0	11,651	11,651	11,651
Sudan exports	832	25,798	25,798	25,798
Tanzania exports	0	3,429	3,429	3,429
Exports	1,664	41,710	41,710	41,710

Table 21 Ambition

ELC supply (GWh)	2015	2030	2050	2065
Biomass	783	1,410	80,295	181,325
LFO/HFO	531	0.00	19,605	117,577
Gas	0.00	0.00	431	0.00
Nuclear	0.00	0.00	26,061	55,845
Hydro	9,834	143,461	183,104	183,104
Geothermal	60	14,341	35,040	35,040
Wind	925	2,031	28,700	28,700
Solar PV	18	10,584	100,851	110,592
Solar CSP	0.00	0.00	95,341	274,818
Total	**12,151**	**171,827**	**569,428**	**986,999**
RET share (not includes Nuclear)	**96%**	**100%**	**92%**	**82%**

Djibouti exports	583	583	583	583
Kenya exports	0	8,156	8,156	8,156
Sudan exports	583	18,059	18,059	18,059
Tanzania exports	0	2,400	2,400	2,400
Exports	1,156	29,197	29,197	29,197

10.1.3 Total System Costs

Table 22 System costs for the New Policies Scenario

Total system costs (BUSD)	2015-2025	2026-2035	2036-2045	2045-2055	2055-2065
Capital Investment	59	59	97	144	189
Fixed Cost	5	13	24	45	81
Variable Cost	1	0.1	0.1	7	7
Revenues (ECL exports)	-12	-47	-46	-35	-35

Table 23 Total System Costs for the Slow Down Scenario

Total system costs (BUSD)	2015-2025	2025-2035	2035-2045	2045-2055	2055-2065
Capital Investment	17	44	8	36	67
Fixed Cost	3	7	8	10	18
Variable Cost	1	0.1	1	8	60
Revenues (ECL exports)	-2	-26	-15	-4	0

Table 24 Total System Costs in the Big Business Scenario

Total system costs (BUSD)	2015-2025	2025-2035	2035-2045	2045-2055	2055-2065
Capital Investment	70	112	113	169	205
Fixed Cost	6	23	39	67	102
Variable Cost	6	0.1	0.5	7	14
Revenues (ECL exports)	-3	-34	-38	-36	-38

Table 25 Total System Costs for the High Ambition Scenario

	2015-2025	2025-2035	2035-2045	2045-2055	2055-2065
Capital Investment	80	177	201	306	346
Fixed Cost	7	33	77	143	208
Variable Cost	3	2	14	36	106
Revenues (ECL exports)	-13	-51	-56	-61	-67

Table 26 Total System Costs for the Ambition scenario

Total system costs (BUSD)	2015-2025	2025-2035	2035-2045	2045-2055	2055-2065
Capital Investment	75	180	252	368	413
Fixed Cost	6	24	57	124	189
Variable Cost	2	1	22	48	153
Revenues (ECL exports)	-9	-35	-39	-43	-47

10.2 Detailed Plots

10.2.1 Generation Capacity

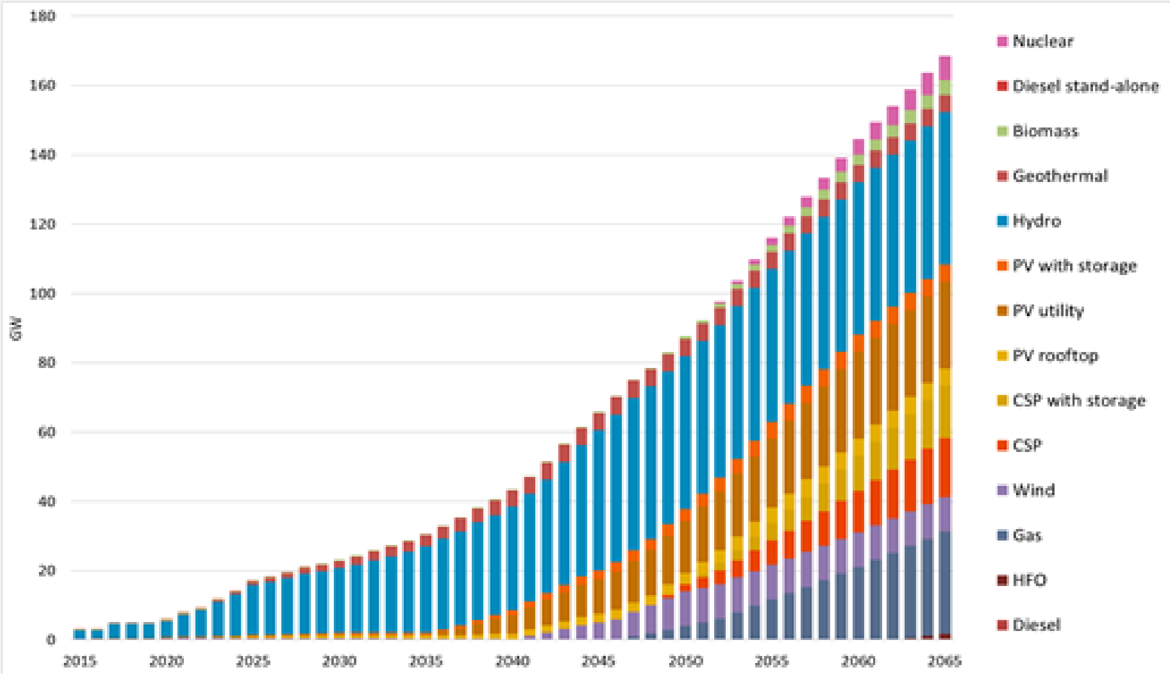


Figure 36. Power generation capacity by technology (GW) in the New Policies scenario.

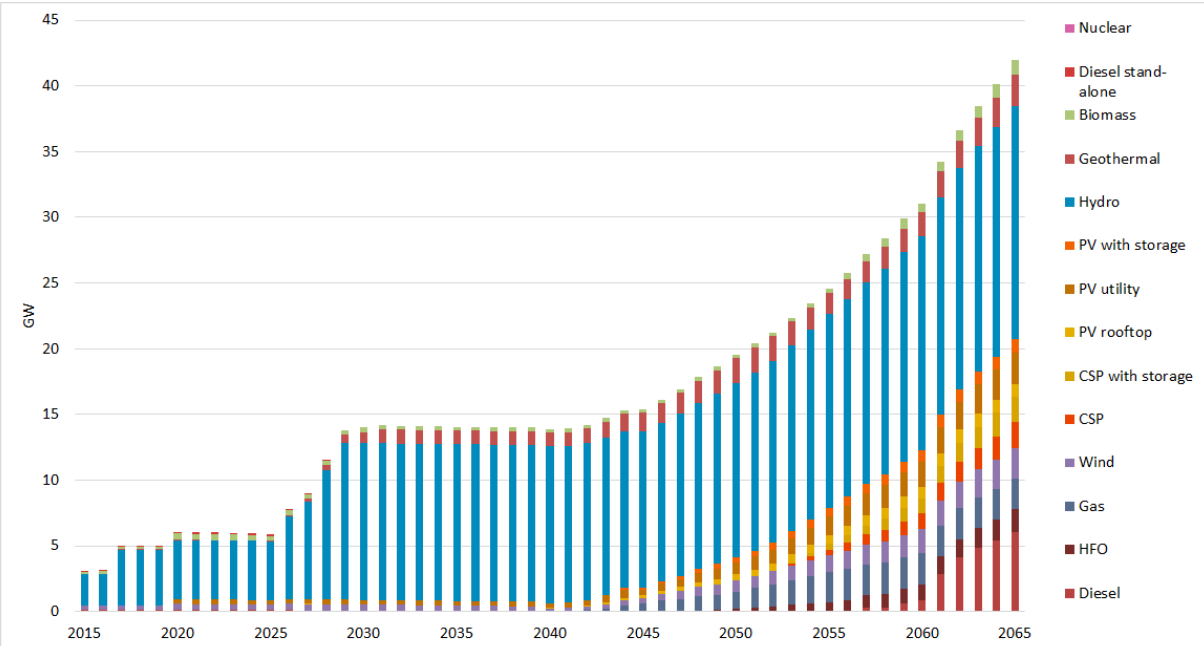


Figure 37. Power generation capacity by technology (GW) in the Slow Down scenario.

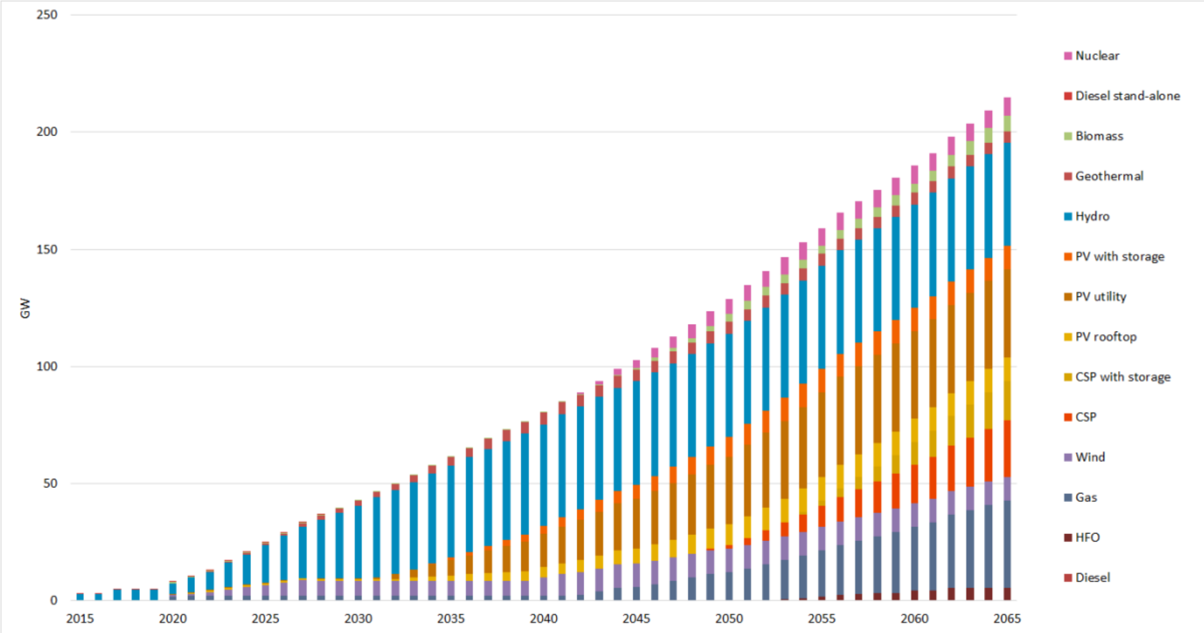


Figure 38. Power generation capacity by technology (GW) in the Big Business scenario.

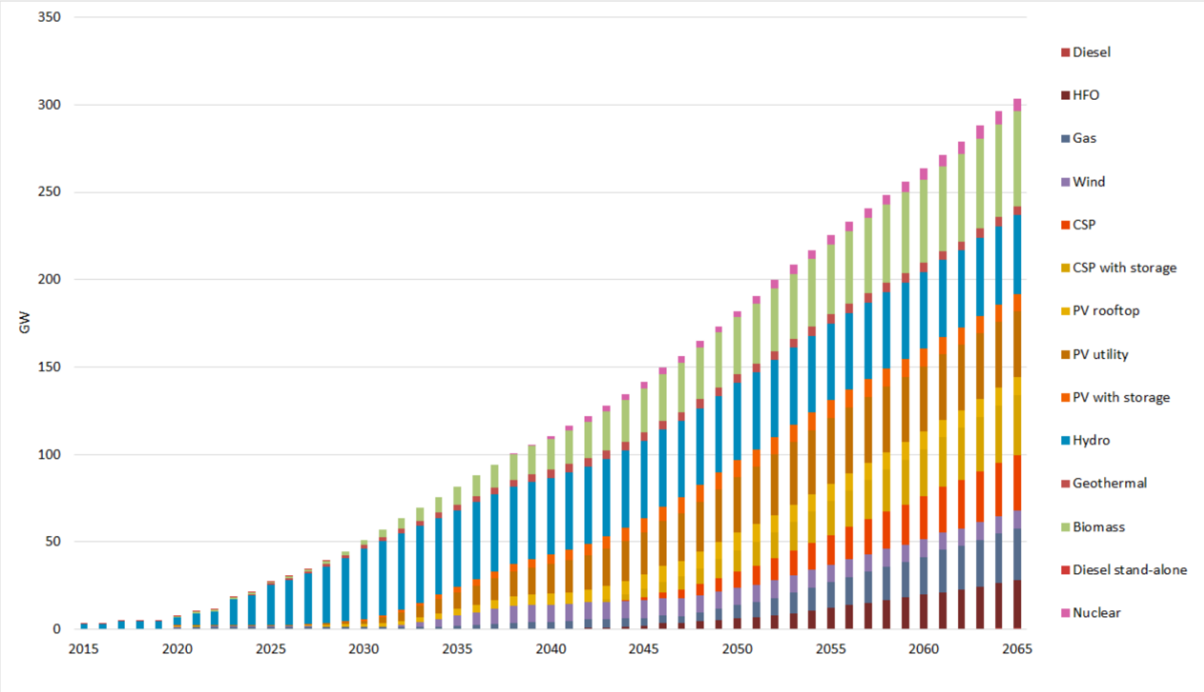


Figure 39. Power generation capacity by technology (GW) in the High Ambition scenario.

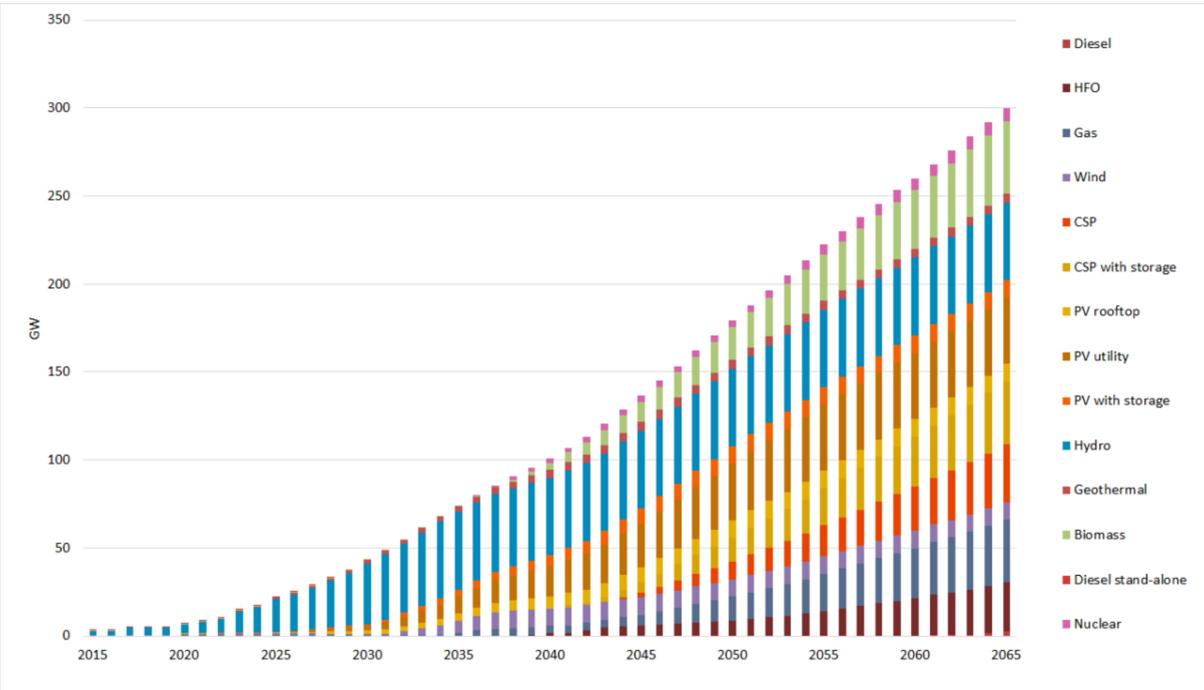


Figure 40 Power generation capacity by technology (GW) in the Ambition scenario

10.2.2 Electricity Supply

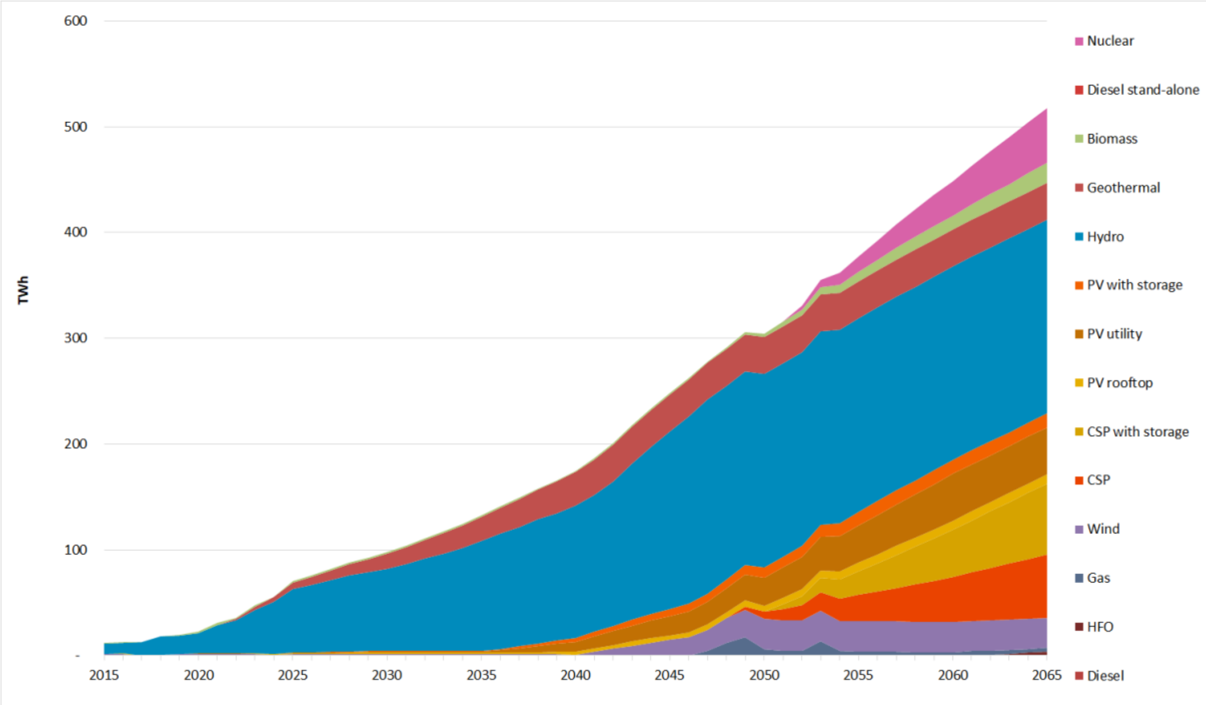


Figure 41. Electricity supply mix by technology (TWh) in the New Policies scenario.

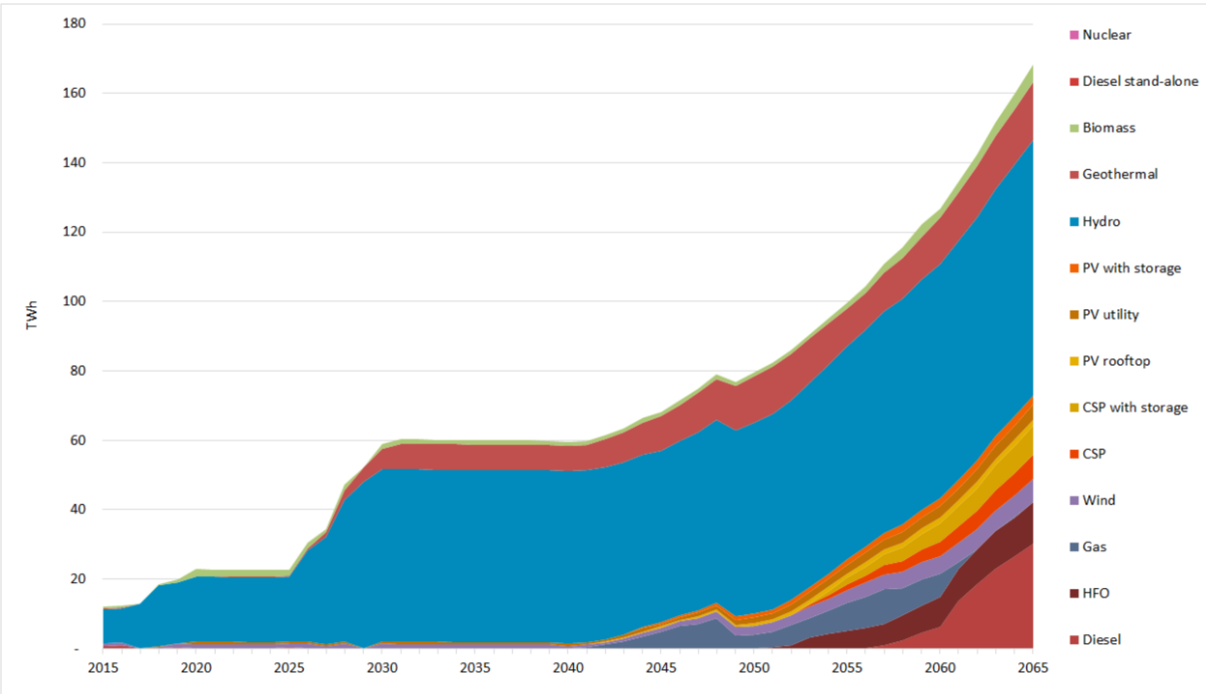


Figure 42. Electricity supply mix by technology (TWh) in the Slow Down scenario.

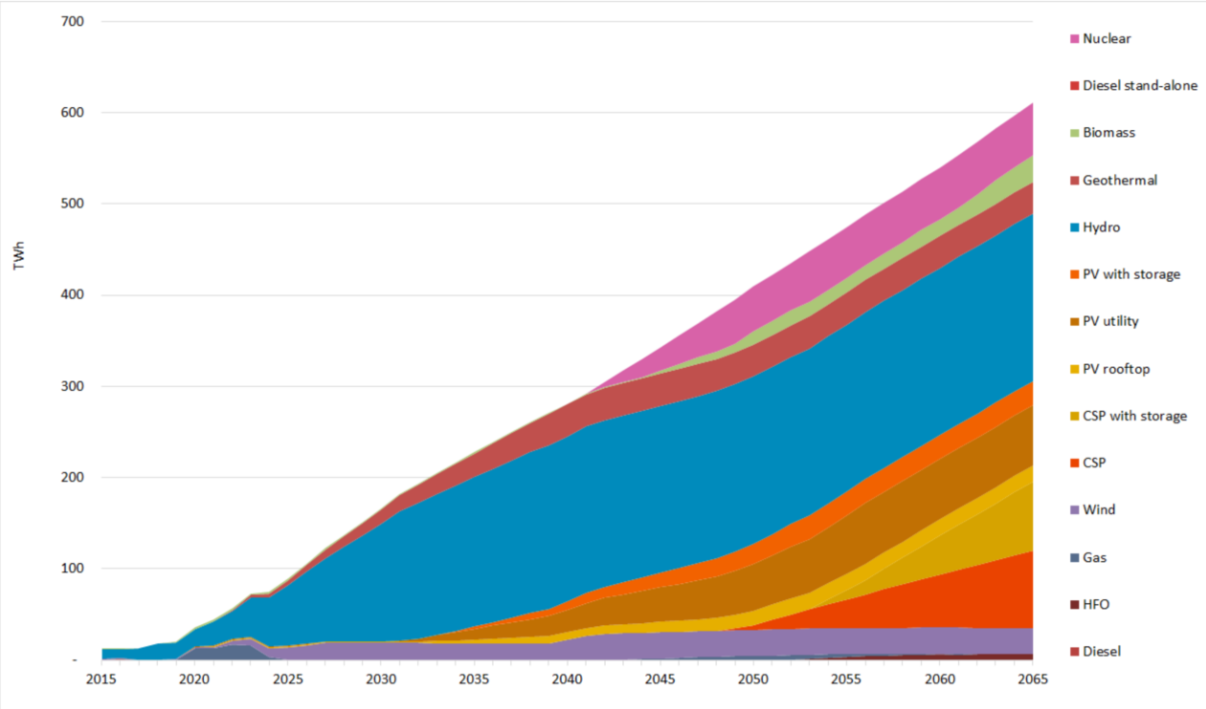


Figure 43. Electricity supply mix by technology (TWh) in the Big Business scenario.

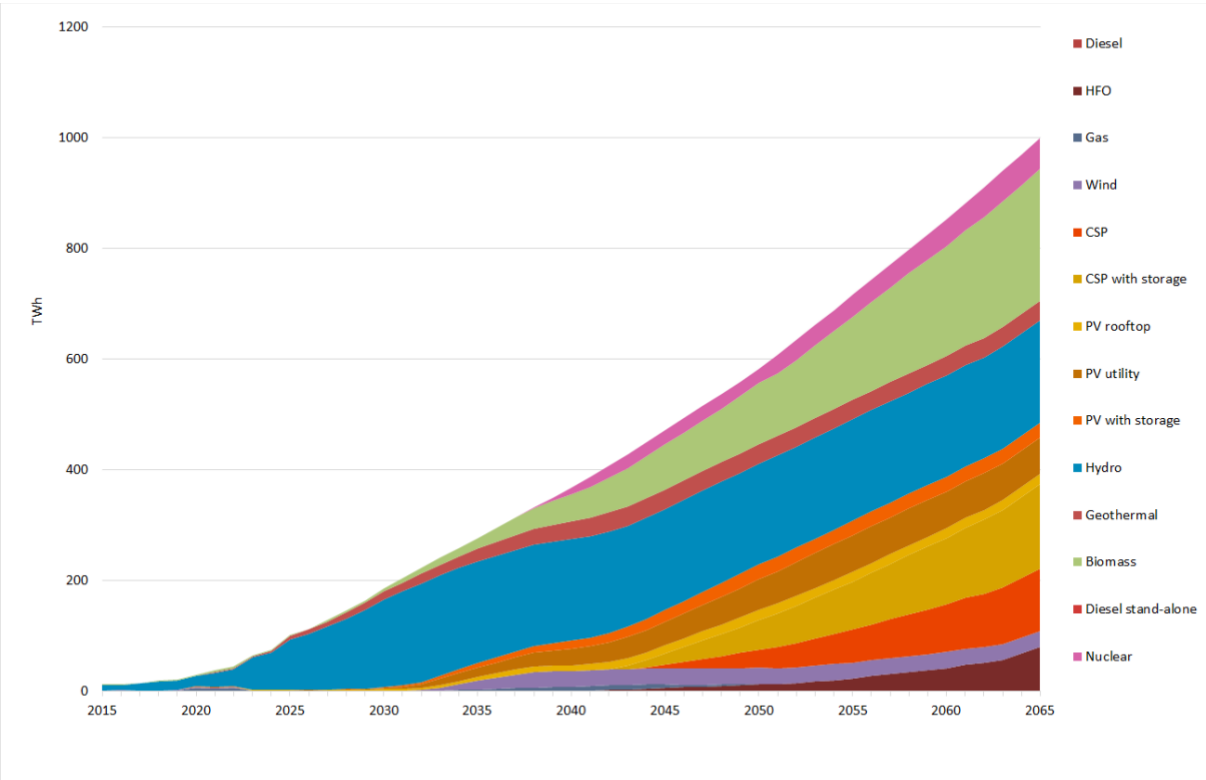
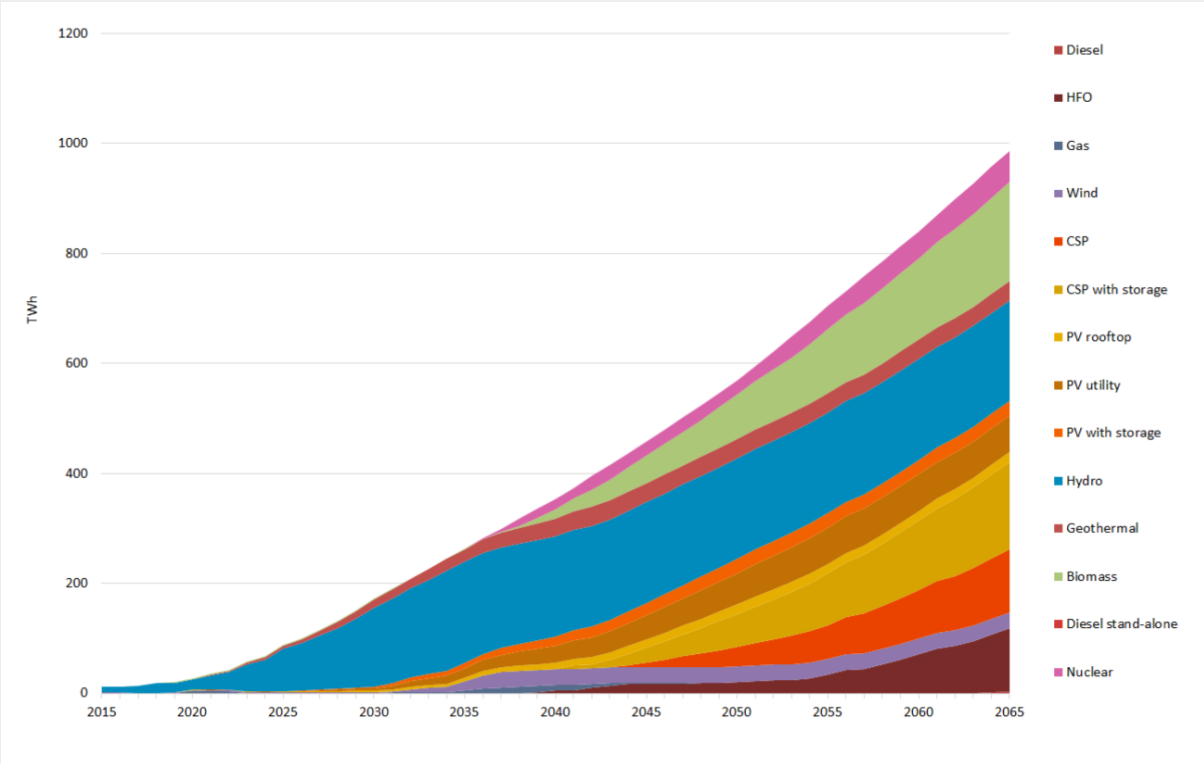


Figure 44. Electricity supply mix by technology (TWh) in the High Ambition scenario.



Electricity supply mix by technology (GWh) in the Ambition scenario.

10.3 Modelling Assumptions

The detailed list of the existing and future identified power sector projects (national grid connected) can be found in Appendix, **Table 27**. The aggregated capacity can be found in **Table 4.** List of grid-connected power plants. Year in brackets indicates when construction is expected to be completed [10] below.

Table 27. List of detailed power plants included into the model.

Technology	Name of the plant	Capacity (MW)	Earliest Year	Status
Biomass				
	BotorBecho Sawmill	1	1990	Operational
Diesel				
	Ghimbi	0.2	1962	Operational
	GODE	0.15	1967	Operational
	BIZET	0.55	1969	Operational
	ASAYTA	0.15	1970	Operational
	DEGEHABOUR	0.15	1970	Operational
	JINKA	0.55	1970	Operational

	KEBRI DEHAR	0.15	1970	Operational
	KEBRI DEHAR	0.15	1970	Operational
	NEFAS MEWICHA	0.15	1970	Operational
	SETIT HUMERA	0.15	1970	Operational
	ASAYTA	0.15	1971	Operational
	BONGA	0.12	1974	Operational
	BONGA	0.075	1974	Operational
	BONGA	0.075	1974	Operational
	ALEM KETEMA	0.15	1975	Operational
	GINIR	0.15	1975	Operational
	HAWZEIN	0.15	1975	Operational
	MOYALIE	0.15	1975	Operational
	MOYALIE	0.15	1975	Operational
	NEGELE BORENA	0.15	1975	Operational
	NEGELE BORENA	0.155	1975	Operational
	NEJJO	0.15	1975	Operational
	SHIRE	0.15	1975	Operational
	SHIRE	0.15	1975	Operational
	ALEM KETEMA	0.136	1981	Operational
	DEGEHABOUR	0.136	1981	Operational
	ABI ADDI	0.155	1982	Operational
	KOREM	0.155	1983	Operational
	GHIMBI	0.155	1984	Operational
	GHIMBI	0.155	1984	Operational
	GHIMBI	0.568	1984	Operational
	GINIR	0.155	1984	Operational
	GODE	0.155	1984	Operational

	KOREM	0.568	1984	Operational
	KOREM	0.568	1984	Operational
	NEGELE BORENA	0.568	1984	Operational
	NEKEMTE	0.568	1984	Operational
	NEKEMTE	0.568	1984	Operational
	NEKEMTE	0.568	1984	Operational
	NEKEMTE	0.568	1984	Operational
	ASAYTA	0.155	1988	Operational
	ASOSSA	0.144	1991	Operational
	JINKA	0.155	1991	Operational
	MOYALIE	0.155	1992	Operational
	LALIBELA	0.155	1993	Operational
	MEHAL MEDA	0.155	1993	Operational
	ASOSSA	0.14	1994	Operational
	BONGA	0.5	1994	Operational
	MEHAL MEDA	0.14	1994	Operational
	SEKOTA	0.155	1994	Operational
	SETIT HUMERA	0.14	1994	Operational
	TENTA	0.14	1994	Operational
	WARDER	0.14	1994	Operational
	WORE-ILU	0.14	1994	Operational
	WORE-ILU	0.14	1994	Operational
	ASAYTA	0.486	1995	Operational
	ASOSSA	0.155	1995	Operational
	DUBTI	0.486	1995	Operational
	GODE	0.486	1995	Operational
	METEMA	0.14	1995	Operational

	SHIRE	0.486	1995	Operational
	NEGELE BORENA	1.28	1996	Operational
	TEPPI	0.486	1996	Operational
	SHEARATON ADDIS	0.8	1999	Operational
	SHEARATON ADDIS	0.8	1999	Operational
	SHEARATON ADDIS	0.8	1999	Operational
	AWASH SEBAT	40	2003	Operational
	DIRE DAWA	40	2003	Operational
	PHARMACURE PLANT	0.938	2003	Operational
	PHARMACURE PLANT	0.263	2003	Operational
	ADDIS BREWERY	2	2009	Operational
	ADDIS BREWERY	1.8	1990	Operational
	ALEM KETEMA	0.2	1990	Operational
	ASOSSA	0.2	1990	Operational
	ASOSSA	0.2	1990	Operational
	DIRE DAWA	0.3	1990	Operational
	HARAR BREWERY	1.125	1990	Operational
	HARAR BREWERY	0.54	1990	Operational
	MEHAL MEDA	0.2	1990	Operational
	MEHAL MEDA	0.084	1990	Operational
	MOYALIE	0.264	1990	Operational
	NEFAS MEWICHA	0.14	1990	Operational
	NEFAS MEWICHA	0.55	1990	Operational
	SHIRE	0.25	1990	Operational
Geothermal				
	ALUTO LANGANO	3.9	1998	Operational
	ALUTO LANGANO	4.6	2001	Operational

	ALUTO LANGANO Expansion	60	2015	Constructed
	CORBETTI	10	2016	Planned
	CORBETTI	90	2017	Planned
	TENDAHO	100	1998	Planned
Hydropower				
	Awash IV	34	2025	Planned
	Aba Samuel	6.6	2016	Planned
	Adola	1.86	1964	Operational
	BunoBedelle	0.153	1966	Operational
	Dembi	0.8	1994	Operational
	Djima	0.195	1959	Operational
	Kara Dobe	1600	2025	Planned
	Gojeb	150	2025	Planned
	GenaleDawa VI	246	2025	Planned
	GenaleDawa III	254.1	2016	Constructed
	ChemogaYeda I & II	208	2025	Planned
	Dedessa Dam	300	2025	Planned
	Halele	96	2025	Planned
	Werabessa	339	2025	Planned
	Beles	460	2010	Operational
	GilgelGibe IV	1450	2025	Planned
	GilgelGibe III	187	2015	Operational
	GilgelGibe III	1683	2016	Constructed
	Mendya	2000	2025	Planned
	Grand Renaissance	4750	2017;2018	Constructed
	TisAbbay (1&2)	85.12	1999;2001	Operational
	Finchaa-Amerti-Neshe	97	2011	Operational

	Awash (I,II,III)	109.6	1960;1966;1971	Operational
	Finchaa	133.9	1973;2003	Operational
	Melka Wakena	153	1989	Operational
	GilgelGibe I	183.9	2004	Operational
	Tekeze I	300	2009	Operational
	GilgelGibe II	420	2009(210),2010(210)	Operational
	Geba 2	165	2025	Planned
	AleltuEast	186	2025	Planned
	Geba 1	220	2025	Planned
	Aleltu West	219	2025	Planned
	Tekeze II	450	2025	Planned
	Birbir R	465	2035	Planned
	LowerDidessa	550	2025	Planned
	GilgelGibe V	600	2025	Planned
	Baro 1 and 2 + Genji	900	2025	Planned
	Tams	1060	2025	Planned
Solar				
	Bahir Dar University	0.01	2010	Operational
	RemaDire	0.15	2008	Operational
Wind				
	ADAMA	51	2012	Operational
	ADAMA	51	2015	Operational
	ASHEGODA-1	30	2011	Operational
	ASHEGODA-2	90.18	2013	Operational
	AYSHA	100		Planned
	MESOBO-HARENA	51		Planned

Table 28. Energy resources included into the model [10].

No	Resource	Unit	Exploitable reserve	Exploited Percent
1	Hydropower	MW	45,000	<10 percent
2	Solar	kWh per meter square ped day	5 - 6	< 1 percent
3	Wind power	GW	1,350	< 1 percent
4	Geothermal	MW	5,000	< 1 percent
5	Wood	Million tons	1,120	50 percent
6	Agricultural waste	Million tons	15-20	30 percent
7	Natural gas	Billion cubic meters	113	0 percent
8	Coal	Million tons	300	0 percent
9	Oil shale	Million tons	253	0 percent
10	Crude Oil	Billion barrels	0.000428	0 percent

Table 29. Fuel prices

USD/GJ	2015	2030	2040	2050	2065
Biomass (domestic)	1.60	1.60	1.60	1.60	1.60
Biomass (imported)	2.40	2.40	2.40	2.40	2.40
Coal (imported)	7.35	8.75	8.85	8.86	8.87
Diesel (domestic)	15.96	23.80	27.76	28.19	28.82
Diesel (imported)	16.80	25.05	29.22	29.67	30.34
Heavy fuel oil (domestic)	9.41	14.00	16.34	16.59	16.96
Heavy fuel oil (imported)	9.90	14.74	17.20	17.46	17.85
Natural gas (domestic)	7.10	10.48	10.92	11.43	12.20
Natural gas (imported)	8.60	12.69	13.23	13.85	14.78
Uranium imported	0.21	0.15	0.17	0.19	0.22

Electricity export price	6.7	31.1	34.2	37.6	45.5

Sources: [20], [26], [27].

Table 30 Economic and technical parameters for generic power generation technologies

Technology			**Overnight cost (USD/kW)**			**Operational and Maintenance cost (USD/kW)**				
	2015	**2030**	**2040**	**2050**	**2065**	**2015**	**2030**	**2040**	**2050**	**2065**
Diesel[5] centralized	1200	1200	1200	1200	1200	35	35	35	35	35
Diesel stand-alone[8] (1 kW) (decentralised)*	752	752	752	752	752	23	23	23	23	23
Heavy fuel oil[8]	1467	1467	1467	1467	1467	44	44	44	44	44
OCGT[6]	400	400	400	400	400	20	20	20	20	20
CCGT[9]	700	700	700	700	700	25	25	25	25	25
Supercritical coal[9]	1600	1600	1600	1600	1600	65	65	65	65	65
Hydro (large scale) [9]	2100	2100	2100	2100	2100	55	55	55	55	55
Hydro (small scale) [9]	3300	3300	3300	3300	3300	65	65	65	65	65
Hydro (medium scale) [9]	2100	2100	2100	2100	2100	55	55	55	55	55
Biomass[9]	2100	2100	2100	2100	2100	55	55	55	55	55
Biomass & Waste CHP plant[9]	4800	4600	4500	4400	4250	180	170	170	170	170
Nuclear[9]	4000	4000	4000	4000	4000	170	170	170	170	170
Geothermal[9]	3100	2900	2800	2700	2550	60	60	55	50	43

[5] International Renewable Energy Agency, Abu Dhabi, 'Planning and prospects for renewable power: West Africa'. 2018.
[6] International Energy Agency, World Energy Outlook 'New policies scenario'. 2016

Technology	Overnight cost (USD/kW)					Operational and Maintenance cost (USD/kW)				
Wind onshore[9]	1880	1760	1720	1680	1620	48	44	44	44	44
Solar PV (centralised)[9]	2400	1400	1240	1080	840	24	22	22	22	22
Solar PV (decentralised)[9]	2840	1640	1440	1240	940	28	26	26	26	26
Solar PV with battery[9]	4449	2373	2146	1845	1449	48	46	46	46	46
Solar CSP[9]	5050	3800	3350	2900	2180	200	150	130	110	80
Solar CSP with storage[9]	6789	4929	4463	3997	3251	228	178	158	138	104
Diesel Genset – Micro Grid	721	721	721	721	721	72.1	72.1	72.1	72.1	72.1
Small Hydro – Micro Grid	3000	3000	3000	3000	3000	90	90	90	90	90
Solar PV – Micro Grid	3900	2252	1977	1703	1291	58.5	34	30	26	19
Wind power – Micro Grid	4500	4213	4117	4021	3878	90	84	82	80	78
Diesel Genset – Stand Alone	938	938	938	938	938	93.8	94	94	94	94
Solar PV – 1 Stand Alone	12500	7218	6338	5458	4137	250	144	127	109	83
Solar PV – 2 Stand Alone	11700	6756	5932	5108	3873	234	135	119	102	77
Solar PV – 3 Stand Alone	8500	4908	4309	3711	2813	170	98	86	74	56
Solar PV – 4 Stand Alone	5950	3436	3016	2598	1969	119	69	60	52	39
Solar PV – 5 Stand Alone	9250	5342	4690	4039	3062	185	107	94	81	61

10.4 Reference Energy System