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MINISTRY OF WATER AND ENVIRONMENT

CLIMATE CHANGE DEPARTMENT

Economic Assessment of the Impacts of Climate Change in Uganda

National Level Assessment:

Energy Sector report

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LIST OF ACRONYMS

Acronym	Definition
CCS	Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
CDKN	Climate Change & Development Knowledge Network
GDP	Gross Domestic Product
GHGs	GreenHouse Gases
GJ	Giga Joules
GoU	Government of Uganda
GWh	Gigawatt Hours
KWh	Kilowatt Hours
LEAP	Long-range Energy Alternatives Planning system
LPG	Liquefied Petroleum Gas
MEMD	Ministry Of Energy and Mineral Development
MIROC	Model for Interdisciplinary Research on Climate
MT	Metric Tonnes
MW	Megawatt
MWE	Ministry of Water and Environment of Uganda
NCCP	National Climate Change Policy
NFA	National Forest Authority
NPV	Net Present Value
O&M	Operations and Maintenance
OPM	Office of the Prime Minister
PJ	Peta Joules
PV	Photovoltaic
TOE	Metric Tonnes of Oil Equivalent
T&D	Transmission and Distribution
TED	Technology and Environment Database
TWh	Terawatt Hours
UBOS	Uganda Bureau of Statistics
UCA	Uganda Census of Agriculture
UETCL	Uganda Electricity Transmission Company Limited
UNFCCC	United Nations Framework Convention on Climate Change
WEAP	Water Evaluation and Planning

EXECUTIVE SUMMARY

This report analyses the supply and demand for energy in Uganda to 2050, the impact that climate change could have on supply and demand and possible adaptation measures to deal with any climate change impacts. The analysis has been performed using the LEAP model, which is an energy sector planning model widely used for this purpose. The model allows different kinds of energy supply to be evaluated as sources to meet demand by type of energy service in different sectors and for different periods of time. Options are then assessed in terms of costs and the model allows the analyst to choose the least cost combinations subject to whatever constraints are considered appropriate.

The report starts out by noting that energy use in Uganda is dominated by traditional biomass, with electricity and other fuels playing a very small role. The current balance between supply and demand for biomass, however, is very fragile and predictions from the modelling are that if no action is taken there will be a huge deficit of biomass (1,710 million tonnes) over the period 2010-2050. The report concludes that a Business as Usual scenario for growth in biomass demand is not sustainable and a solution is needed to address the predicted deficit. We evaluate options involving a major increase in the use of alternative fuels such as imported biomass, LPG and kerosene as well as electricity for households that currently use biomass almost exclusively, in addition to efficiency gains in biomass uses for some scenarios. We conclude that this switch can be made but that it will entail a large programme to import alternative fuels. In addition, more electricity will have to be generated. With the currently proposed electricity investment programme not all of the extra demand will be met and in this scenario there will be a deficit in electricity of around 9 percent of total demand. This deficit could be eliminated if part of the biomass deficit is met through the use of imported biomass. In this scenario biomass imports are about 86 million tons in the next 40 years, or around 2.2 million tons per year. Importing wood, however, is a logistically complicated option that needs further study. An alternative might be to import electricity from neighbouring countries.

These broad conclusions hold under a variety of scenarios, including a higher growth in electricity demand and a reduction in hydropower capacity of 746MW.

When climate change impacts on the energy sector are evaluated, two things stand out. The first is that such change will almost certainly reduce biomass availability, although it is difficult to quantify by how much. Hence if the country follows the Base Case scenario for biomass, the predicted gap between supply and demand will be even bigger than that seen when climate change is not taken into account. We estimate a plausible loss of 5 to 10 percent of domestic wood between 2020 and 2050 would imply the need for additional expenditures of US$0.5-1.3 billion if the gap is filled with imported biomass and between US$5-11 billion if it is filled by LPG. Other options would include kerosene or increased electricity generation, which would have a cost similar to LPG.

The second impact of climate change relates to the availability of water resources for hydropower generation. There is a possibility that hydropower potential will decrease due to a reduction in precipitation. A possible decline of 26 percent by 2050 has been estimated in the water sector study. Under that scenario, the analysis shows that the government's current expansion programme for the power sector is sufficient to cover the hydropower deficit, as long as the other components of the programme are implemented according to the proposed schedule. It is important to remember, however, that this is a very ambitious programme, which will demand large financial resources as well as highly skilled manpower that is able to operate a much more sophisticated electricity system than the one that Uganda has at present. The estimated additional capital investment in hydro, nuclear and other generation from now to 2050 is around US$83 billion. According to these plans, in the period 2015-2020 the country will need to invest around one billion dollars in the electricity system, or around US$200 million per year, a sum which is equal to about one percent of national GDP. In future years the amounts increase very sharply.

The government of Uganda's National Climate Change Policy (NCCP) Costed Implementation Strategy document (Government of Uganda, 2012) reflects a number of the issues discussed above. The document focusses on reducing dependence on biomass, but it also gives importance to promoting energy conservation and efficient utilisation of energy to reduce GHG emissions and to protecting watersheds for the generation of hydropower. Table 5 of this report analyses the proposed strategic interventions for the energy sector in Uganda 2015-2030. Those interventions are:

1. Promote and participate in water resource regulation so as to ensure the availability of water for hydropower production.
2. Promote and participate in water catchment protection as part of hydroelectric power infrastructure development
3. Diversify energy sources by promoting the use of alternative renewable energy sources (such as solar, biomass, mini-hydro, geothermal and wind) that are less sensitive to climate change
4. Promote energy-efficient firewood cook stoves, solar and liquefied petroleum gas (LPG) cookers
5. Conduct research to determine the potential impacts of climate change elements on the country's power supply chain
6. Promote the development of energy conservation and efficiency projects in all sectors; for example, to promote the use of stabilised bricks and efficient brick kilns in the building sector
7. Enforce building codes to reduce energy consumption
8. Promote the use of energy-efficient technologies such as compact fluorescent and other commercially available high-efficiency lamps
9. Promote efficient firewood/charcoal stoves and solar and LPG cookers, and address the high upfront costs of acquiring these technologies through household subsidies or tax waivers

The following conclusions emerge from our analysis of those interventions:

1. It is very important that those components focussing on reducing biomass demand (namely strategic interventions 4, 6 and 9) are implemented effectively and urgently given the critical nature of the problem. In addition to those strategic interventions, we would expand the programme to increase electricity connections and to extend the supply network for some alternative fuel to biomass. LPG is one option but imported biomass or kerosene are others. These alternatives need further investigation but a preliminary analysis indicates that the benefits of developing an alternative fuel program (in terms of reducing unmet demand) are well in excess of costs. Given that some poor households will not be able to afford the alternative fuel, some kind of support (e.g. "address the high upfront costs of acquiring these technologies through household subsidies or tax waivers" as proposed in strategic intervention 9) needs to be factored into the programme.

2. The components dealing with energy efficiency are similar to others that have been implemented in many developing countries by national and international agencies (interventions 4, 6, 7, 8 and 9). Reviews of such programmes indicate a high level of cost effectiveness in promoting energy efficiency and reducing Green House Gases (GHGs). Item 7 ("Enforce building codes to reduce energy consumption") has worked well in other countries and should be a priority but its effects will be felt gradually as new construction takes place. For items 4, 6, 8 and 9 the main difficulties arise when the programme requires an up-front expense by the user and when the user has limited resources. In Uganda similar considerations will apply: energy efficiency programmes designed with care, taking account of lessons learnt from other countries in a similar situation, should yield high benefits relative to costs.

3. As far as electricity is concerned the main impact is on water resources for hydropower and the situation is more complex. In relation to extreme events measures to strengthen structures of small dams are already needed and will be needed even more if such events increase in intensity. Water catchment protection is also a part of the current development plans and this will become more important. Afforestation and reforestation measures to protect watersheds that supply major hydroelectricity generating sources are a key part of such protection. Items 1 and 2 address these problems and need to be initiated now, but with a longer time horizon in mind.

4. Regarding the availability of water resources for hydro generation there is a possibility that capacity will decrease due to a fall in precipitation, but that is not certain. If it happens the analysis shows the government's current expansion programme can handle the fall, as long as the other components are implemented according to the proposed schedule. Responding to such possibilities needs more information and that is what item 5 addresses. This is a high priority item but one that will yield results over the medium term.

Detailed estimates of the benefits and costs of individual components in the adaptation programme require more data than was available for this report. Hence they will need further analysis at the local level. Some examples of such analysis will be available from the case studies to be undertaken in this study.

1. INTRODUCTION

This report on the Economic Assessment of the Impacts of Climate Change in Uganda (Energy Sector), prepared for the Ministry of Water and Environment of Uganda (MWE) and the Climate & Development Knowledge Network (CDKN) focuses on the energy sector.

Like most other countries in Sub-Saharan Africa, Uganda is mainly dependent on traditional biomass for its energy. In 2012 total energy consumption was 11,709,711 TOE[1]. Of this fuel wood accounted for 9,203,470 TOE and charcoal, which is mostly used by urban households and commercial sectors, was 654,816 TOE. Including some other traditional biomass such as vegetal wastes the share for this type of energy in the total was 88.9 percent, with petroleum products and electricity contributing 9.7 percent and 1.4 percent respectively (MEMD 2013).

Traditional biomass energy totally dominates household energy demand, accounting for 99.7 percent of the sector's total household energy, but it is also the dominant form for the commercial sectors (at 98.4 percent) and the industrial sector (80.4 percent). Thus with the exception of transport, biomass is the main energy resource not only for household but all the other sectors.

Electricity access in Uganda is about 15 percent and it constitutes about 1.4 percent of the total energy. The total electricity generation for 2012 was 2,855GWh (UETCL, 2012) equating to 73KWh per capita which is 7 and 30 times lower than Africa's and world's averages respectively (MEMD 2014). Almost 72 percent of the generated electricity energy is consumed by only three urban centres (Kampala, Entebbe and Jinja; MEMD, 2014). Of total electricity use, 64.6 percent is in the industrial sector, 11.2 percent in the commercial sector and 24.2 percent in the household sector.

The present situation is one where demand and supply for each type of energy is in a precarious balance. For biomass supply is being met in an unsustainable way through deforestation. Uganda has a total of 3.6 million hectares of forest land. The total deforestation rate per year is 1.8 percent (not all of which is due to fuel wood demand), which translates into an absolute overall loss of about 88,638 ha per year (NFA2009). Although the rate of deforestation has been declining, studies indicate that with growing biomass demand and constant rates of deforestation there will be a deficit of around 16 percent by 2016 (Helio International, 2009).

As far as electricity is concerned, demand is growing at 8.8 percent p.a. and supply struggles to meet demand. One way to deal with this has been to implement a load shedding scheme. There are major plans to increase supply, through hydropower, other renewable sources and, later, nuclear energy generation. The aim is to increase access to electricity and to meet a greater share of total energy demand from this source and less from traditional biomass. In achieving this there is an important role for increasing efficiency in the use of biomass, as well as switching to Liquefied Petroleum Gas (LPG) and other fuels such as kerosene. These shifts are expected to play an important part in the transition to an energy system that is more dependent on electricity (MEMD, 2013).

The analysis in this report looks at four pathways in which the energy sector develops to 2050 in the absence of climate change and onto these are overlaid three scenarios where climatic effects are taken into account. The reason for looking at a number of alternatives in the absence of climate change is the considerable uncertainties on how fast electricity supply can expand and on how successful will be the programme for switching users from biomass to other sources of energy. The first part of the report examines the alternatives and estimates the ways in which demand and supply for different sources will be brought into balance. In each case the social costs of meeting energy demand are calculated as are the costs of any unmet demand. The second part of the

[1] Metric Tonnes of Oil Equivalent

report looks at the impacts of climate change on these scenarios, through possible reductions in the potential supply of electricity.

The analysis is carried out through the LEAP[2] model, which is an energy sector planning model that is widely used for this purpose. Section 2 describes the model and how it has been deployed in this study. It also lays out the different scenarios and data inputs that have been made in the model. Sections 3 and 4 provide the results from the analysis of these scenarios. Section 5 sets out the climate impacts and the results from these impacts and Section 6 offers some conclusions.

Annex I documents details of the socio-economic assumptions, forecasts of demand for different kinds of energy and planned electricity sector investments, as well as the costs of different plants and prices. It also provides other data that are external to the model but required to run it and estimate costs and quantities of energy supplied and demanded.

This report was written by Joseph Spadaro and Anil Markandya of Metroeconomica and Adam Sebbit of Makerere University, College of Engineering, Art and Design Technology, with contributions from Morna Isaac of Eco Ltd and Olivier Beucher of Baastel. We gratefully acknowledge the helpful comments and suggestions provided on initial results of the assessment by Government of Uganda officials during the mission to Uganda in September 2014.

[2] Long-range Energy Alternatives Planning system

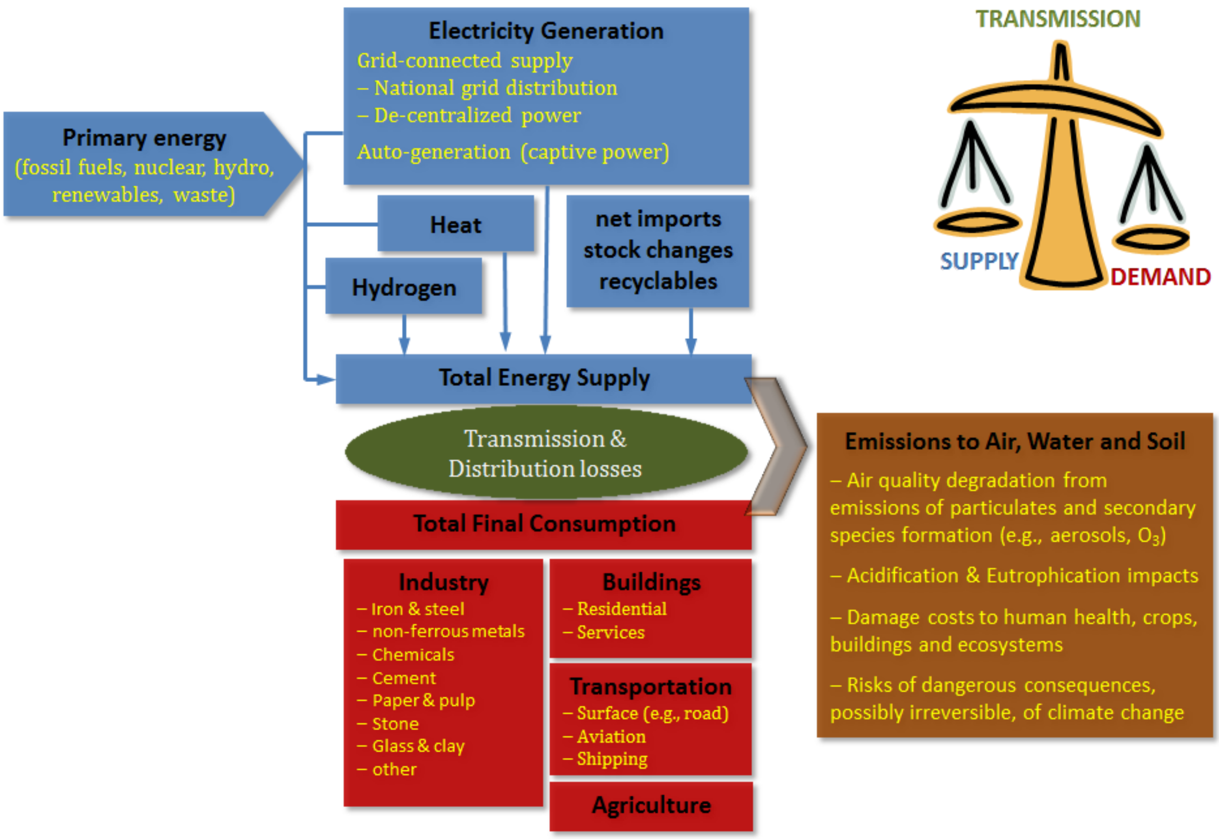
2. MODELLING AND INPUT DATA

This section describes the model used in the analysis (Section 2.1), provides a description of the scenarios considered and the electricity system expansion plans (Section 2.2), and lays out the key assumptions and input data for the analysis (Section 2.3).

2.1. Long-range Energy Alternatives Planning system (LEAP) model

Planning for a low carbon, sustainable world requires the use of long-term forecasting models for analysing and ranking alternative economic development pathways. Figure 1. Energy planning framework shows the typical framework of an energy planning assessment. Such an effort requires balancing energy demand and supply based on assumptions about future demographic and economic growth, technological transformation, resource availability and costs, fiscal measures and incentive, pollution and climate policy constraints, and changes in public attitudes and behaviours.

Figure 1. Energy planning framework



LEAP is an integrated energy planning and climate change mitigation analysis tool developed by the Stockholm Environment Institute (Heaps, 2012). LEAP is used worldwide by government agencies, academics, NGOs, energy utilities and consulting firms. Many countries use LEAP as part of their commitment to report to the U.N. Framework Convention on Climate Change (UNFCCC). More details of the model are given in Annex I.

2.2. Scenario descriptions and electricity system expansion plans

As outlined in the introduction, seven future pathways have been identified: (a) four in which there are no impacts of climate change; and (b) three in which climate change has an impact (either positive or negative) on the renewable water resources in Uganda. A description of these scenarios is presented in Table 1

The Base Case **(Demand Base, Supply Base Wood Base or DBSBWB)** scenario takes the government's middle projections for wood and electricity demand and Base Case planned electricity system expansion, details of which are given in Annex I[3]. Indigenous wood supply increases to meet demand until 2020 and after that year supply is constant[4]. The expansion of the power system is based on government plans for different kinds of power generation investments from now to 2050[5]. Total generation capacity in 2050 is 9,971 MW, of which nearly a third will be hydro, just under half nuclear (coming on line from 2030 onwards), about 7 percent from renewables other than hydro (solar, bagasse and geothermal) and 13 percent from thermal sources. If there is a shortfall in wood or electricity supply, the demand remains unmet. Power plant dispatch considers three variants to reflect different trade-offs between cost and generation. Population growth to 2050 is assumed to be 2.5 percent p.a. and GDP per capita growth is set at 4.9 percent p.a. Wood demand is assumed to grow at 4 percent p.a. and electricity demand at 4.9 percent p.a. (from 2,000 GWh in 2012 to around 12,000 GWh in 2050).

The second scenario **(Demand Base, Supply Base Wood Low or DBSBWL)** assumes a lower growth in the demand for wood (at 1.9 percent p.a. instead of 4 percent). This is achieved through increased efficiency in biomass use as well as a switch to fuels such as LPG, imported wood and kerosene, and electricity. The programme that would take the country from the Base Case of wood demand to the Low Case of demand has been the subject of a great deal of research in the country. The Biomass Strategy discusses the measures in detail. In this report they are summarised in Table 2. We note that the strategy does not quantify the contribution of different measures; rather is provides an overall shift of biomass demand as shown in Figure 3

The third scenario **(Demand Base, Supply Base Wood Low and Imported or DBSBWLI)** is similar to the second with the difference that one-third of future unmet biomass demand is imported. This is an option that raises a lot of questions and needs further investigation, which is beyond the scope of this report. At this point we include it as a possible way to meet the biomass deficit while not creating one for electricity. Another option might be to import electricity from neighbours such as Kenya and Ethiopia. We chose one third because with this amount of imports we can eliminate the unmet electricity demand, as shown later.

The last scenario **(Demand High, Supply Low, Wood Base or DHSLWB)** is the same as the Base Case with the difference that: (a) electricity demand follows the government's high growth scenario, resulting in annual growth of 7.4 percent instead of 4.9 percent and (b) hydro capacity is limited to 2,470MW instead of 3,216MW, reflecting the possibility that there will be a delay in the construction of future projects in this sector.

The installed capacities for electricity generation under different scenarios are shown in Annex I, Figure AI-1.

All the above scenarios assume no climate change. Impacts of climate change are discussed in Section 5. For the modelling of climate change effects we consider a Base Case situation in which the hydropower yield falls linearly from 2025 to 2050, so that it is 26 percent lower in that year compared to the no climate scenario. This

[3] Projections are for wood rather than biomass as the latter depends in part on the conversion of wood to charcoal and other vegetal matter, which are not included in the base forecasts.

[4] The Helio (2009) study indicated a deficit could arise in 2016. Given the improvements in biomass efficiency that have already started we assume that the deficit will start in 2020.

[5] The generation expansion plan is not derived from an optimisation exercise; rather the assumption is that the government has carried out such an exercise to arrive at the plan that is most desirable from an economic, social and political viewpoint.

fall is due to a decline in water availability and is based on projections elaborated in the water report from an application of the WEAP model. In addition three alternatives are considered.

In the first, electricity demand follows the high growth path, hydro supply capacity follows the limited path and biomass demand the base scenario. This is referred to as **(Demand High, Supply Low, Wood Base with Climate Change or DHSLWBC).**

The second alternative is identical to the one above, except that nuclear development is excluded. It is referred to as **(Demand High, Supply Low, Wood Base, Climate Change and No Nuclear or DHSLWBCN).**

The last scenario considers an alternative climate scenario in which precipitation increases and hydropower capacity rises by 15 percent by 2050 against 2025 forecast yield. Otherwise, all modelling parameters are the same as in the first of the climate scenarios. It is referred to as **(Demand High, Supply Low, Wood Base and Climate Change High or DHSLWBCH).**

Table 1: Future demand and supply scenarios

NO Impacts of climate change	**Scenario: Base Case (short-name: DBSBWB)** • Base Case projections are taken for biomass and electricity demand (Figure 3 and Figure 4 and for the electricity system more details are given in Annex I) • If there is a shortfall in wood or electricity supply, the demand remains unmet. • Power plant dispatch is based on three variants: (i) dispatch units according to least running costs (fuel plus O&M costs), (ii) dispatch plants in proportion to their available capacity (installed capacity × capacity factor), or (iii) run units at full (100 percent) capacity regardless of energy requirements. • If electricity generation exceeds demand, as could happen in variant (iii), the power could be exported at a benefit or could be used to expand the national grid. Results of these simulations are summarized in Figure 5 -Figure 7.
	Scenario: Low wood demand with biomass substitution (DBSBWL) • Dispatch power plants operate according to variant (i): least running costs. • Biomass demand follows the Low Wood Demand scenario (Figure 3) with a sustainable indigenous supply to meet 2020 Base Case biomass demand. • Fuel substitution is therefore required in future years, specifically the use of LPG and electricity (on an equal energy basis). Initially, the shortfall is provided only by LPG, but by 2050 both LPG and electricity contribute equally. • Results for this scenario are presented in Figure 8 - Figure 10.
	Scenario: Low wood demand with biomass substitution and imported wood (DBSBWLI) • Same as the previous scenario (DBSBWL), except 1/3 of the future unmet wood demand is imported. • Scenario results are shown in Figure 11 and Figure 12.
	Scenario: High electricity demand and low hydro supply capacity (DHSLWB) • Same as Base Case (DBSBWB) scenario (least running costs dispatch scheme) with the exception of High Electricity Demand (Figure 4) and Low Hydro Supply Capacity (Table AI-1). • Results are displayed in Figure 13.
YES Impacts	**Scenario: High electricity demand and low hydro supply capacity with reduced runoff caused by climate change (DHSLWBC)** • Between 2025 and 2050 hydropower yield falls linearly by 26 percent because of a decline in renewable water resources in Uganda due to changes in runoff caused by climate change (See Section 5).

	• Whereas the country experiences high electricity demand, the installed hydro capacity is low. • Fuelwood demand corresponds to the Base Case scenario with no fuel switch or biomass import. • Figure 14 shows changes in the electricity generation mix, assuming a least running cost dispatch scheme. • Demand and social costs for other fuels (e.g., kerosene ...) remain the same as in the Base Case (DBSBWB).
	Scenario: Reduced runoff caused by climate change with high electricity demand, low hydro supply and no nuclear generation (DHSLWBCN) • This scenario is identical to the previous one (DHSLWBC) but nuclear energy is excluded from the generation mix. • Results are presented in Figure 15 and Figure 16.
	Scenario: Increased runoff and hydro availability due to climate change with high electricity demand, low hydro supply and no nuclear generation (DHSLWBCH) • Hydropower capacity availability rises linearly 15 percent by 2050 against 2025 forecast yield levels in response to greater precipitation in Uganda due to climate change (Hamududu et al., 2009). • Otherwise, all modelling parameters are the same as in DHSLWBCN.

Table 2. Policies and Measures to Make the Transition to a Low Wood Demand Scenario for Uganda

Policy Area	Expected Impacts
Policy and Regulatory Framework: • Communication Strategy • Biomass Information System • Enhance Institutional Capacity to regulate use	• Informed fuel and technology choices • Harmonized biomass information • Laws and regulations adopted and harvesting of wood from private and public land regulated • Forestry management plans developed and silvi-cultural assistance provided for private land Better charcoal transportation and distribution system developed
Biomass Demand Interventions • Fuel efficiency and clean cooking environment • Efficient technologies for wood substitution through technologies that enable use of alternative biomass • Promote use of biogas • Promote use of LPG among wealthier urban households • Promote use of biofuels possibly via carbon subsidies	• Reduced illness related to indoor air pollution • Reduced charcoal demand due to increased use of improved charcoal stove which translates into wood savings • Reduced demand for charcoal and increase in the use of these other sources of energy.
Biomass Supply Interventions • Build on existing programmes such as FIEFCO and ensure that biomass deficit areas are among the first beneficiaries. • Develop a Nationwide plan for multipurpose trees and shrubs. • Implement govt. plans to invest in energy crops both annual and perennial crops and in addition encourage private sector to do the same.	• Sustainable fuelwood supply attained in rural communities. • Maintain wood demand for charcoal at the 2013 level by increasing per cent of charcoal made using improved technologies to 75% by year 2020.

• Enhance current government and private sector tree planting efforts by tapping into existing Payment for Ecosystem Services (PES) • Where substantial forest plantations exist promote usage of forest prunnings and thinnings for energy purposes. • Aggressively promote use of improved charcoal kilns and gasification technologies –partnerships between investors, research institutions and govt. agencies needed.	
Cross Cutting Interventions	
• Creation of SMART financing mechanisms such as Creation of a National Fund for renewable energy projects to provide seed –money for projects	• Innovative and sustainable financing programmes for renewable energy technologies established.

2.3. Key assumptions and input data for LEAP analysis

A large number of assumption have to be made to characterise the scenarios, run the model and produce the results for the different scenarios. Some of the key ones have been mentioned; in this section we provide a list of all of them, with details for the technical ones being put in Annex I.

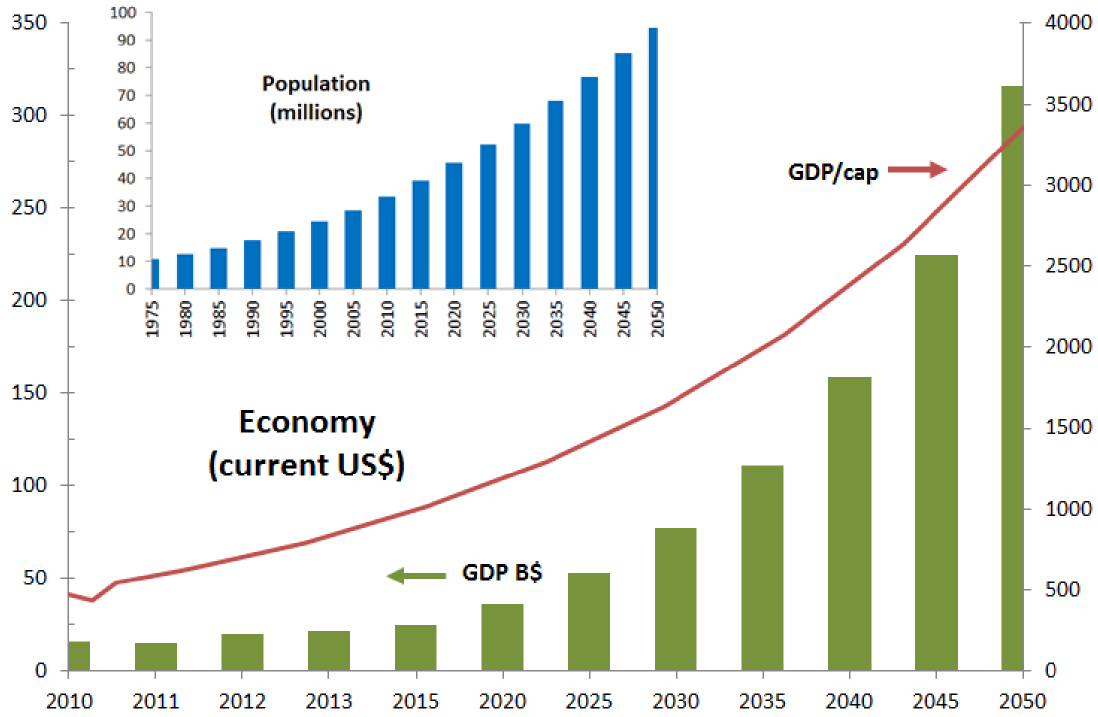
2.3.1. Socio-economic projections

Population growth is assumed to be 2.6 percent per annum, from the 2012 level of 36 million, reaching a total of 95 million by 2050. Figures are from the UN Statistical Services.

Economic growth is assumed to be such as to raise GDP by 6 percent over the period 2010 to 2050 and to raise per capita GDP by 4.9 percent. Estimates are from the World Bank and other literature sources.

Figure 2 presents the data in a graphical form.

Figure 2. Historical and projected population and economic characteristics for Uganda

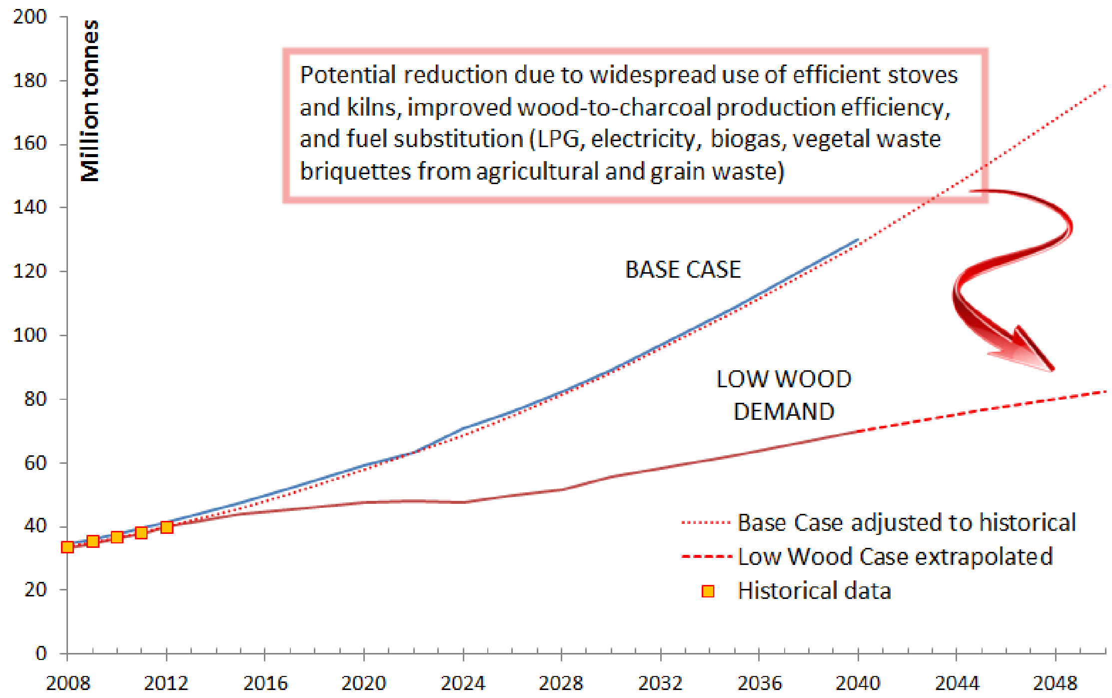


(Sources: United Nations, Department of Economic and Social Affairs, http://esa.un.org/wpp/; World Bank, http://data.worldbank.org/country/uganda, Hillebrand 2008, and A. Sebbit)

2.3.2. Projected demand of biomass, electricity and petroleum products

There are two projections for the demand for wood: a Base Case where it grows at 4 percent per year and a low case where the growth rate is reduced to 1.9 percent with a combination of measures involving increased efficiency, improved wood-to-charcoal production efficiency and fuel substitution to LPG, electricity, biogas and other sources of energy. Figure 3 shows the projections and some historical data.

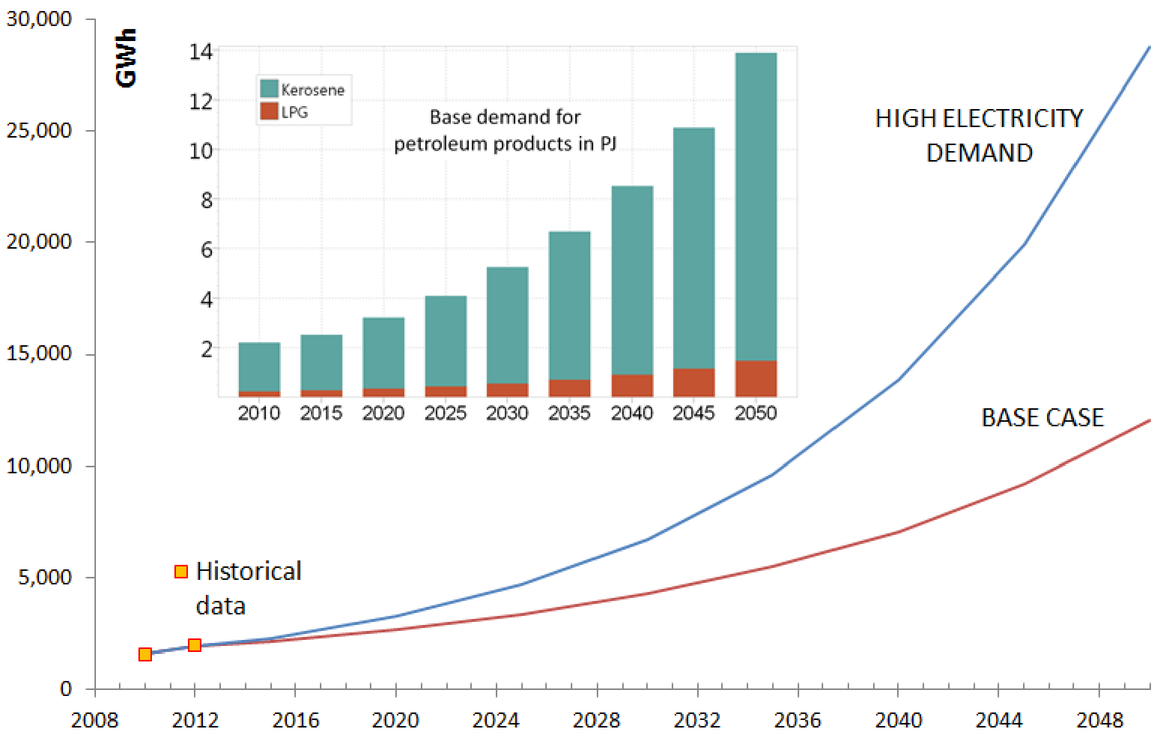
Figure 3. Scenarios of projected annual fuelwood demand in Uganda



(Sources: The Biomass Energy Strategy for Uganda, MEMD 2013, and A. Sebbit)

Demand for electricity and petroleum products (LPG and kerosene) are shown in Figure 4. For electricity the Base Case demand is assumed to grow at 4.9 percent while the high case has it growing at 7.4 percent. In the Base Case LPG and kerosene grow at 4.8 percent.

Figure 4. Scenarios of projected demand of electricity and petroleum products in Uganda



(Sources: Based on information from various resources, including UETCL Annual Power System Report 2012, RPSMP 2011, Sebbit et al., 2004, and personal communications with A. Sebbit)

2.3.3. Electricity System Operation Parameters

Capital and Operations and Maintenance (O&M) costs for the different technologies are given in Annex I, covering large hydro, mini-hydro, nuclear, fuel oil (Combined Cycle Gas Turbine or CCGT), fuel oil (diesel), solar (land-based Photovoltaic or PV), geothermal and bagasse. O&M costs are expected to vary over time and this is captured in the data provided.

Annex I also reports estimates of the reserve margin and transmission and distribution losses from 2010 to 2050 based on local sources.

2.3.4. Fuel Price Projections

For a range of petroleum products as well as gas and uranium for nuclear plants projections are taken from the US-EIA (United States Environmental Impact Assessment), the BP statistical review and a number of other sources.

For the export price of electricity and unmet electricity demand the figures are based on local sources. According to the Electricity Regulatory Authority of Uganda "the economy could lose nearly US$50 cents per unit of load shedding". This figure, which referred to 2013 has been used to derive an estimate of unmet demand for that year, from which future year values are taken to increase with per capita GDP. In the case of the export price of electricity this is based on the marginal cost of generation.

For biomass the estimate of price is based on local sources. Unmet demand is assumed to be valued at the cost of meeting that demand from imported wood fuel. Imported fuel is assumed to have a 30 percent premium over the indigenous cost.

Details for each of these are given in Annex I.

3. BASE CASE MODELLING RESULTS WITHOUT IMPACTS OF CLIMATE CHANGE

In the Base Case we have a situation in which there is, as expected, a huge gap between supply and demand for wood (Figure 5). As indicated wood demand continues to grow but supply does not match that growth and electricity access does not expand sufficiently to enable meeting this demand using electricity. Figure 5shows the overall picture for energy demand and how it is met. There is a large amount of unmet wood demand starting from 2020 and reaching about 1,870 petajoules by 2050 (equal to nearly two-thirds of energy demand). In such a situation one can expect poor households to take desperate measures to find alternative sources of energy, including further loss of forests through illegal logging and measures to reduce demand. In this study we value the unmet demand at the amount households are paying and will pay for wood. With this valuation a total social cost of demand of energy can be estimated and this is shown in Figure 6. Such a cost defined as the sum of the costs of supply of electricity, wood, kerosene and LPG as well as the cost of any unmet demand (in this case wood). As the figure shows the total rises very sharply over time, from less than US$4 billion in 2020 to around US$17 billion in 2050. The total is dominated by the social cost of unmet wood demand, which makes up 37 percent of the total social cost.

As far as electricity is concerned, the base programme is sufficient to meet demand. In fact the proposed investments are more than enough to meet demand in the Base Case, and if the system is run to operate at least cost the entire needs for electricity can be met by hydropower and bagasse, with no contributions from geothermal, solar or nuclear. Figure 7 shows the least cost operating mix for the Base Case. It is dominated by large hydropower plants. The cumulative generation, over the period 2010-50, is 245 TWh (211 TWh after losses). The annual electricity consumption per capita is 127 kWh in 2050, compared to 47 kWh/cap in 2010 (both figures less transmission and distribution T&D losses).

Figure 5. Base Case (DBSBWB scenario) – Final energy demand in Petajoules (PJ) per year

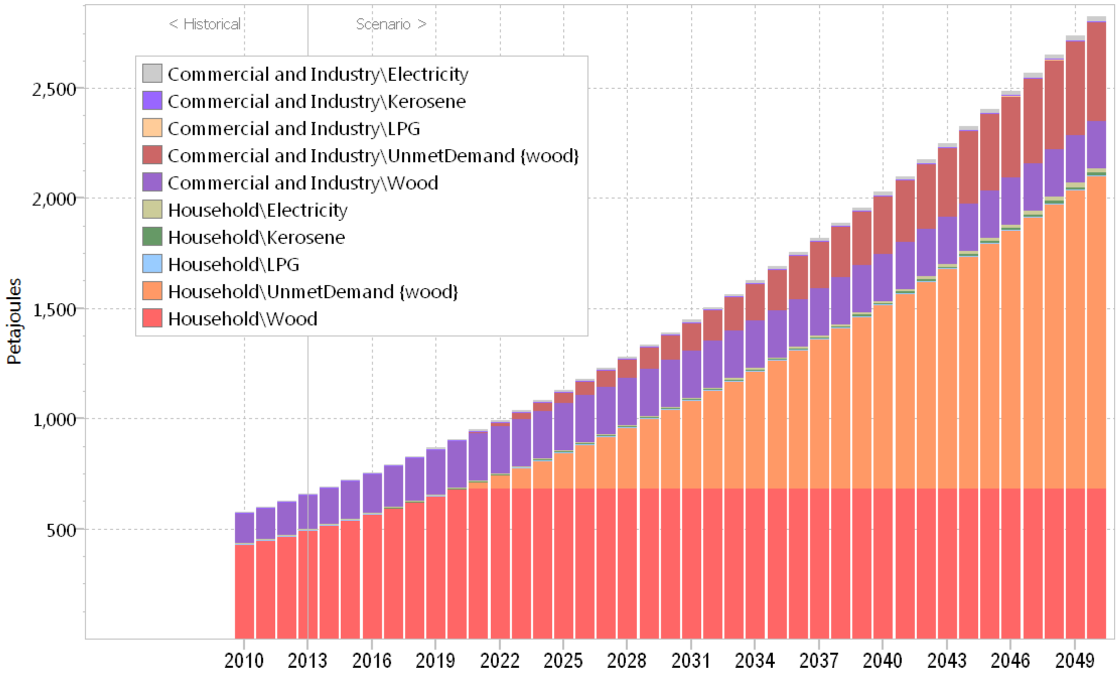


Figure 6. Base Case – Social costs of the 'proportional to available capacity scenario'

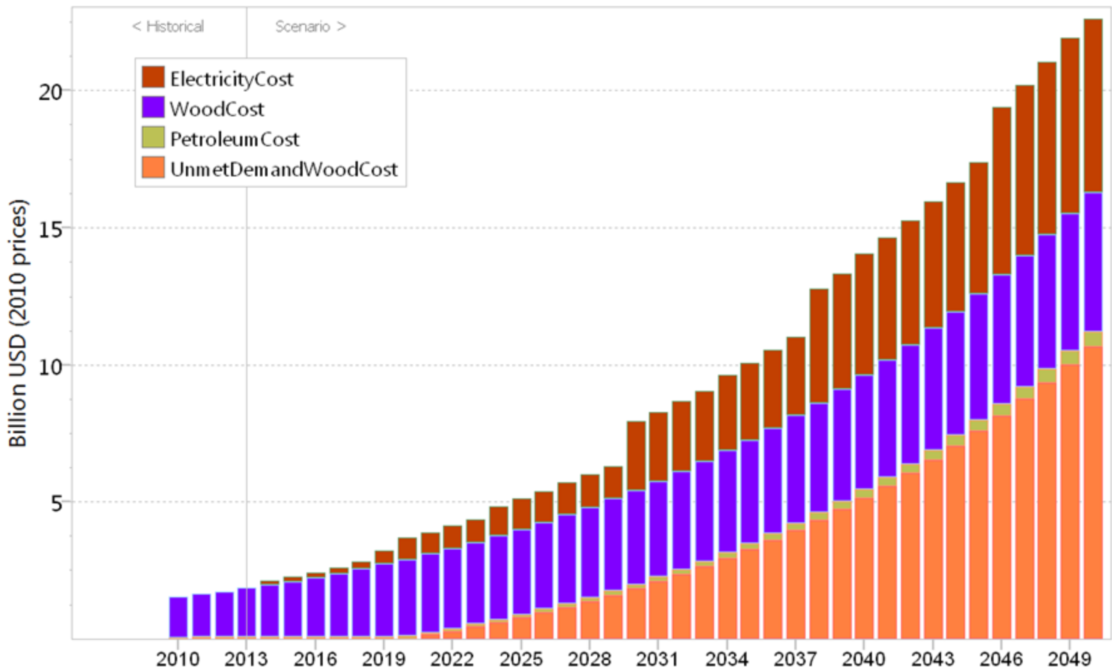
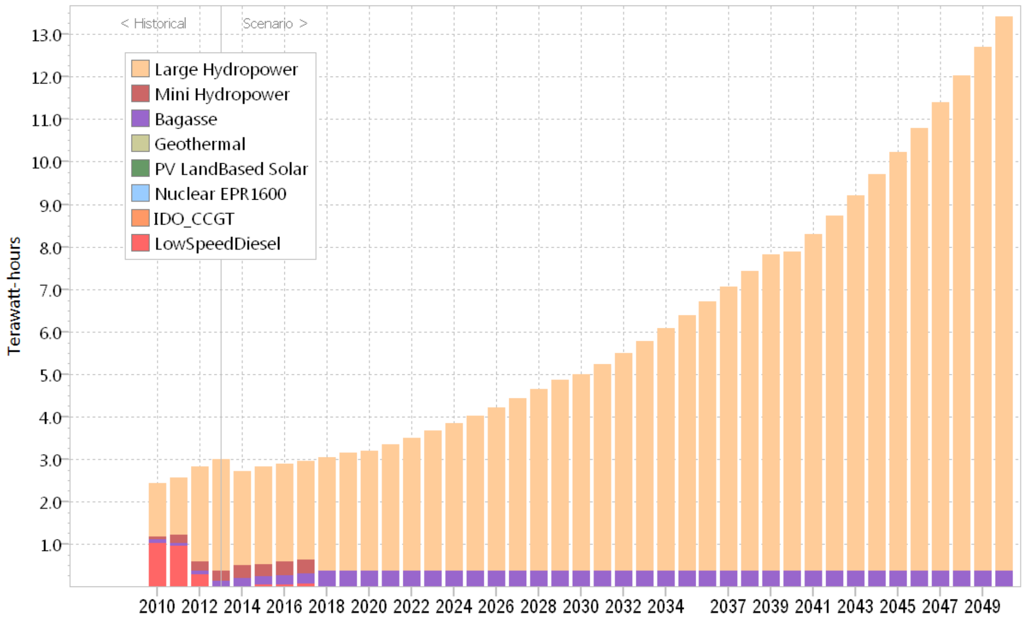


Figure 7. Base Case – Electricity generation in TWh/yr of the 'least running cost scenario'



While it makes sense to operate the electricity system at least cost, that is not the only way in which it might be run. We also look at two alternatives: one of which has dispatch proportional to available capacity and the other uses all capacity to its limit. In the first case nuclear plants are used to generate an increased share of total electricity, accounting for 50 percent of the total cost of production in 2030 and reaching 69 percent by 2050. This option, however, is considerably more expensive than the least cost – cumulative generation cost over the period 2010-2050 is about US$11.5 billion or about 11 percent greater. In the second case we also have all plants operating and total generation is well in excess of Base Case demand. In the period 2010-2050, 808 TWh of excess electricity are generated. This could be used to expand the grid (to cover some of the unmet wood demand) or it could be exported. It is also an expensive way of meeting that demand. Compared to the least cost operating option, costs are nearly double – increasing by US$94 billion for the period 2010-2050.

Lastly we look at CO_2 emissions from electricity and petroleum products. Emissions from consumption of fuelwood cannot be calculated without knowing how much is based on sustainable use of wood resources (i.e. whether the wood that is extracted is replaced by new plantation or not). In the Base Case least cost operating option emissions are dominated by kerosene (accounting for nearly 80 percent of the total). Yet total emissions are still very low – less than 0.1 tonnes per capita in 2050. Even with other operating options these emissions remain very low – the maximum they go up to is less than 0.35 tonnes of CO_2 per person. This compares to the world average of CO_2 emissions in 2010 of 4.9 tonnes per capita.

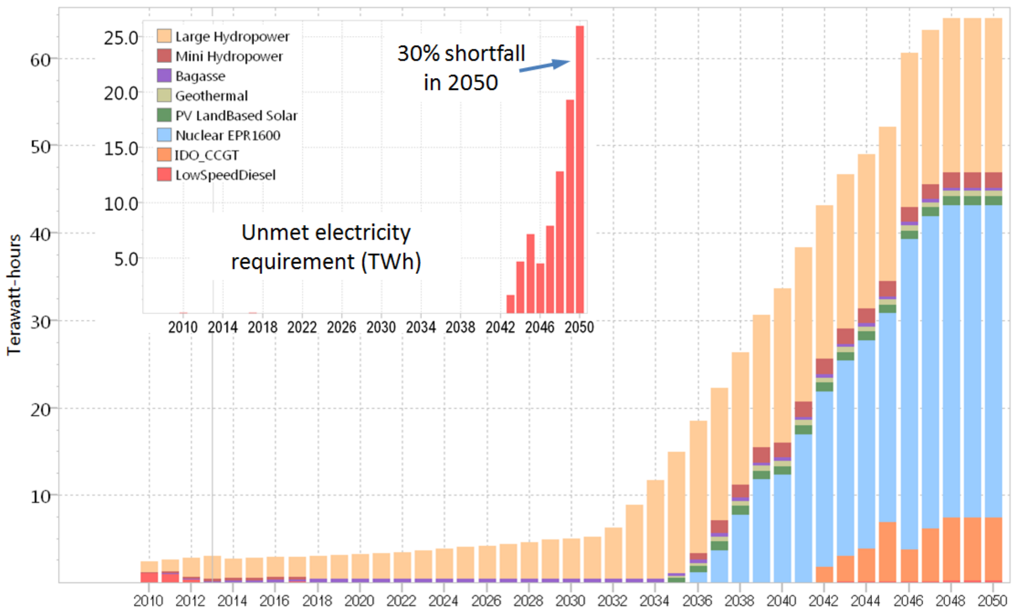
4. BASE CASE VS. OTHER SCENARIOS WITHOUT IMPACTS OF CLIMATE CHANGE

4.1. Scenario results for Low Wood Demand with Fuel Switch (least running costs)

In this section we consider the second scenario in Table 2 (DBSBSWL) in which wood demand is reduced significantly through a series of measures that include improved efficiency in the use of biomass, a switch to LPG and a greater extension of the grid to supply electricity. It is assumed that any unmet demand that was identified in the Base Case is met using LPG as well as electricity (on an equal energy basis). Kerosene is imported as before to meet demand at a price that goes from US$23/GJ in 2010 to US$36/GJ in 2050. Demand for kerosene, however, is not increased in this scenario compared to the Base Case. The substitution cost of electricity is based on the production cost, whereas the price of LPG varies from US$39.8/GJ (2010) to US$62.6/GJ (2050). One tonne of wood has an equivalent energy of 15 GJ.

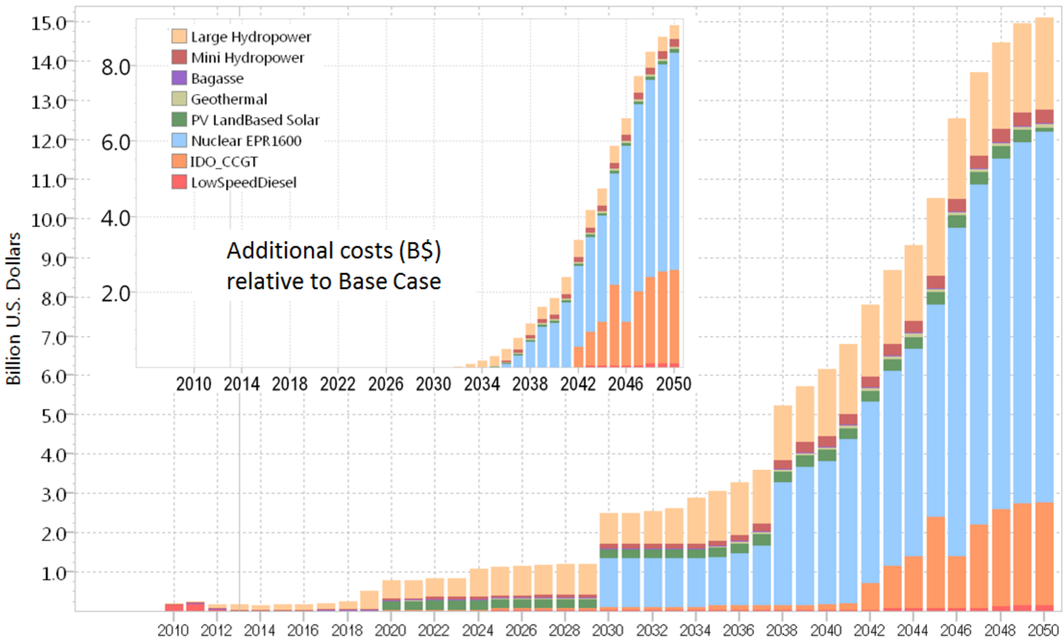
In this case the planned expansion of the power system does not meet total demand because of the significant demand increase from biomass users who are switching to electricity or being connected to it for the first time. Over the period 2010-50, there is a supply shortfall of 73.5 TWh (84 TWh before losses), which is about 9 percent less than demand. The cost of unmet electricity demand reaches US$45.5 billion in 2010 prices (the unmet cost of electricity per MWh varies between US$368 in 2010 and US$552 in 2050). After 2047, all generation facilities have to run at full capacity. The combinations of different plants operated and the unmet electricity demand are shown in Figure 8.

Figure 8. Low Wood Demand with Fuel Switch – Electricity generation in TWh per year



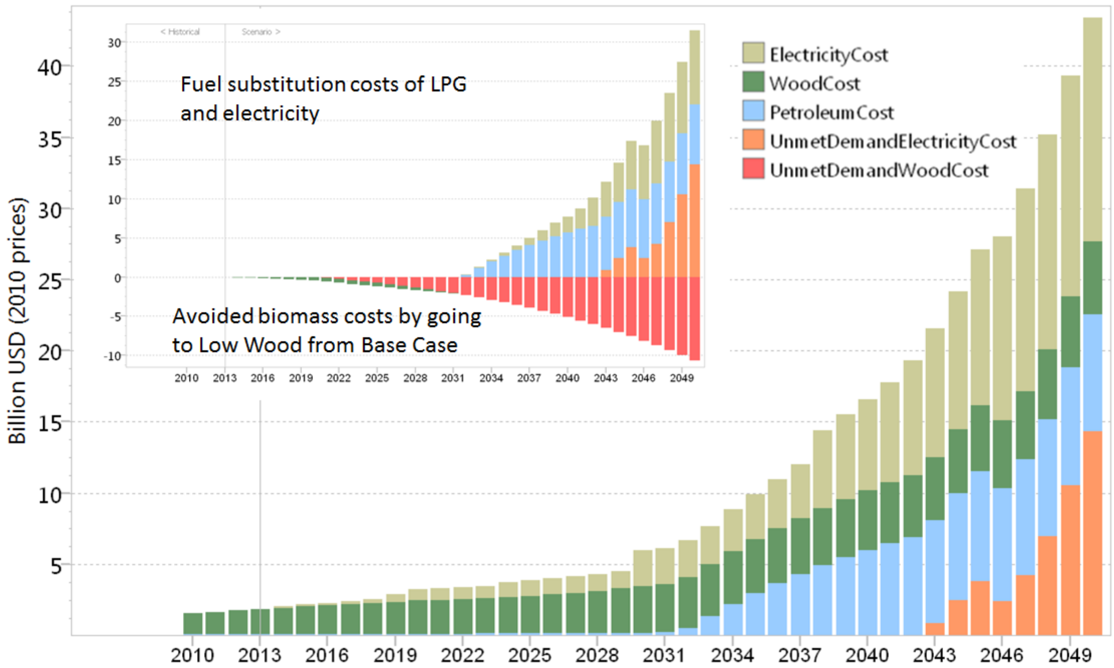
The electricity production costs for this scenario compared to the Base Case are shown in Figure 9. The additional electricity cost of production is US$67.5 billion (2010 prices), or 68 percent, higher than the generation cost of the Base Case (see insert in Figure 9). Nuclear contributes 54 percent of the cumulative total. The cost share of fossil fuels increases to 18 percent of the annual cost in 2050, which is more than that the share of hydropower.

Figure 9. Low Wood Demand with Fuel Switch – Electricity production costs per year



Following this path to meet demand, however, results in a lower total social cost. Compared to the Base Case, the cumulative social cost has risen slightly but the unmet demand for wood has been eliminated. In the comparison presented biomass consumers who had unmet demand fill it with electricity and LPG as substitute fuels. Electricity shortages begin in 2043 and contribute 10 percent to the total cost. Social costs of meeting energy demand are shown in Figure 10.

Figure 10. Low Wood Demand with Fuel Switch – Social costs



Finally we note that under this scenario emissions of CO_2 have increased significantly compared to the Base Case scenario predominantly on account of increased emissions from use of LPG and electricity (fuel oil, mostly). Cumulative emissions (2010-50) reach 176 million tonnes (vs. 20 Mt in the Base Case), of which LPG, electricity and kerosene contribute, respectively, 63 percent, 28 percent, and 8 percent. Per capita emissions are six times higher in 2050 relative to the Base Case, but are still comparatively very small.

4.2. Scenario results for Low Wood Demand with Fuel Switch and Imported Wood (least running costs)

In this scenario, biomass demand is met using indigenous supply (89.4 percent of total requirement) plus imported wood (3.5 percent, or 86 million tonnes), and through LPG + Electricity fuel substitution (6.7 percent). The price per tonne of imported wood (2010 prices) varies between US$52 (2010) and US$115 (2050).

If wood imports are feasible at the level indicated above then electricity supply meets demand. There is a 30 percent reduction in generation with a 22 percent lower production cost compared to the case when there is no wood import. Cumulative CO_2 emissions are 33 percent below estimates under the scenario with no wood imports.

The cumulative social cost is US$373 billion, nearly 20% below the cost estimate shown in Figure 10. Import of biomass begins in 2032, and accounts for 2.3% of the total social cost (2010-50).

Figure 11 shows the energy mix in this scenario and Figure 12 shows the social costs of generation.

Figure 11. Low Wood Demand with Fuel Switch and Imported Wood (DBSBWLFI scenario) – Final energy demand in PJ per year

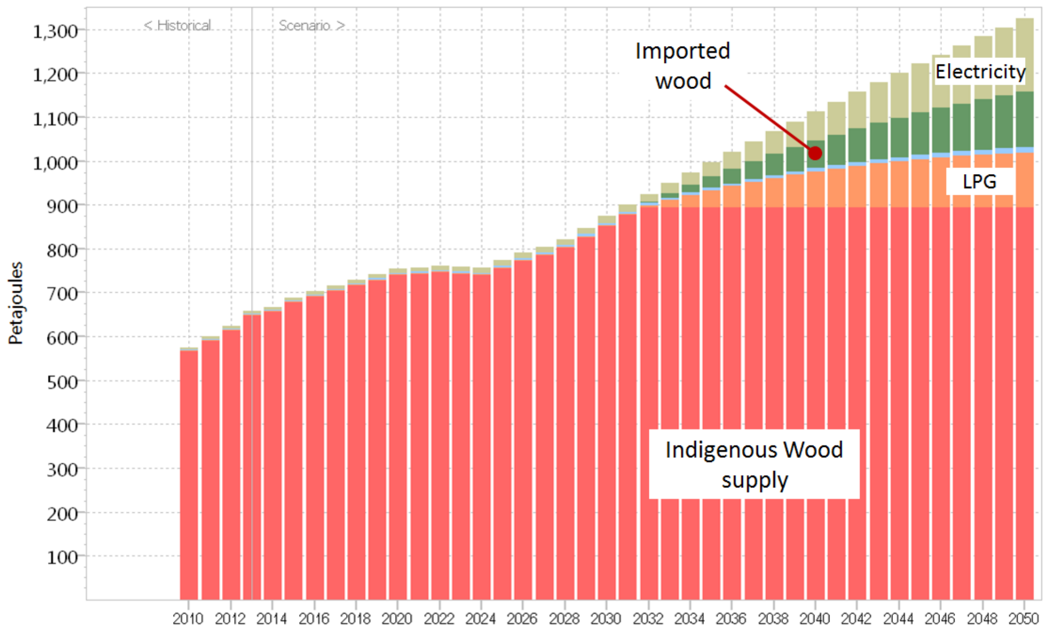
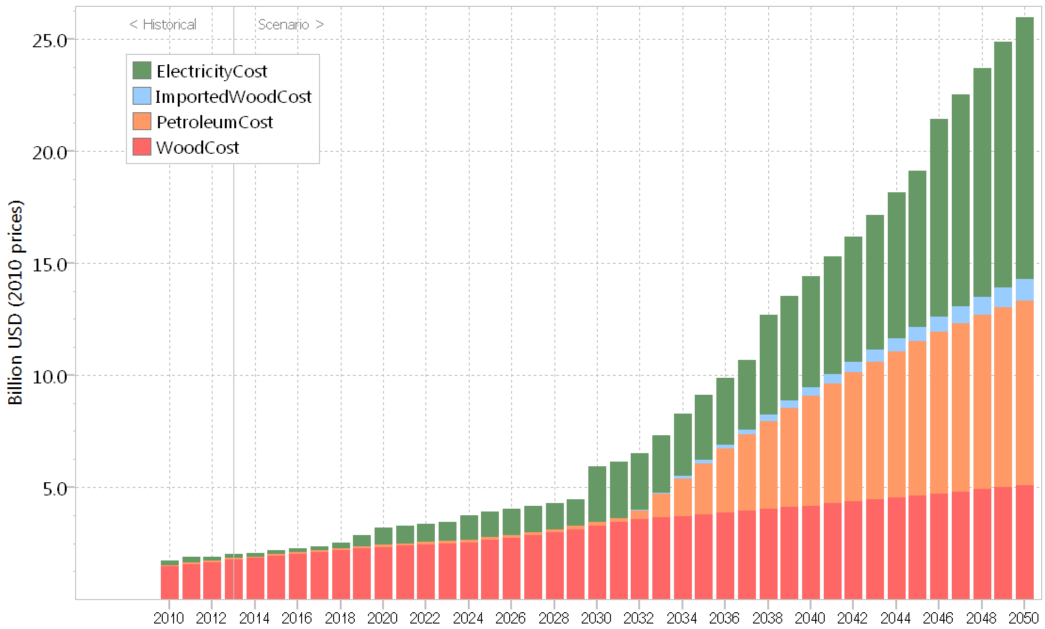


Figure 12. Low Wood Demand with Fuel Switch and Imported Wood – Social costs



4.3. Scenario results for High Electricity Demand with Low Supply Capacity (least running costs)

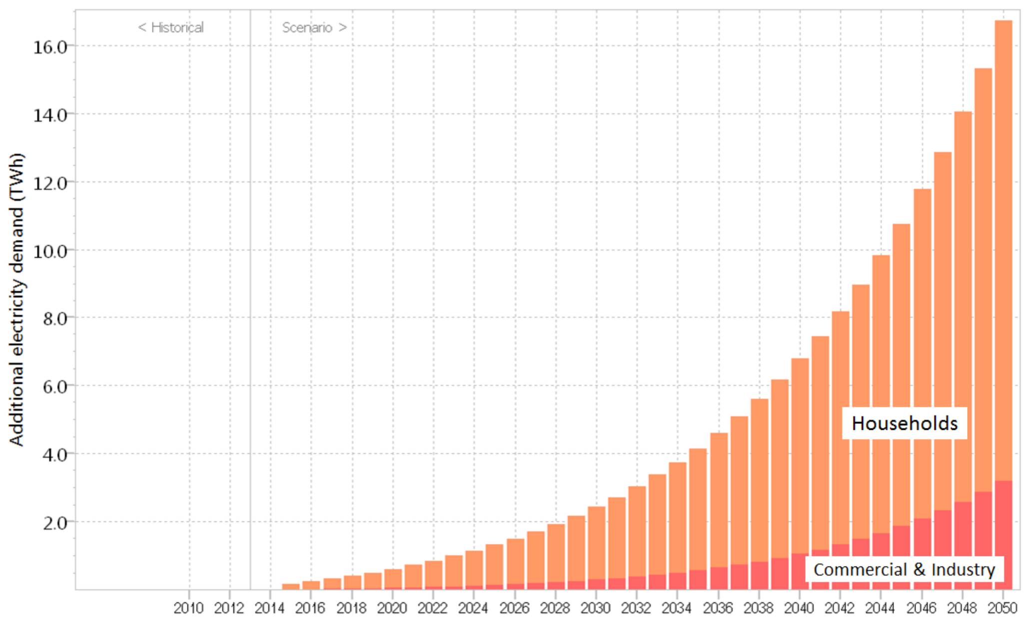
Under this scenario electricity demand is assumed to be considerably higher than the Base Case. There is an additional electricity requirement of 178 TWh over the duration under consideration (2010-50), which represents an increase of 84%. Thus as noted earlier electricity demand grows at an annualized rate of 7.4% vs. 4.9% in the Base Case. Demand for biomass and petroleum products remains unchanged. As in the earlier scenarios over the same time period, the annual average population growth is 2.6%, while GDP per capita grows at 4.9%. The real GDP growth rate is 6%. The additional demand or electricity (which is mainly from households) is shown in Figure 13.

In addition to the above, this scenario also assumed a slightly lower hydropower capacity. By 2050, the available hydropower capacity is 750 MW less than that in the Base Case (see insert). This leads to a supply loss of 38 TWh (10% reduction) between the years 2030 and 2050.

With such a growth in demand for electricity cumulative electricity production increases by 201 TWh (178 TWh after T&D losses) compared to Base Case. The decreasing supply of electricity from hydropower after 2030 is compensated mostly by nuclear generation with small (< 15%) increase in generation by renewables (see insert). Hydropower contributes 77% of the total supply, followed by nuclear with 15%.

There is no unmet electricity demand. The electricity cost of production is US$111 billion vs. US$99 billion for the Base Case (2010 prices). All other social costs (biomass, petroleum) remain constant. Carbon emissions increase by 2.3 million metric tonnes, 12% above emissions of the Base Case.

Figure 13. High Electricity Demand with Low Supply Capacity (DLSLWB scenario) vs. Base Case – Additional electricity demand in TWh per year



5. IMPACTS OF CLIMATE CHANGE

5.1. Background

The main impacts of climate variability and climate change on energy are through changes in biomass availability and changes in water flows, which alter the capacity of the system to generate hydropower

5.1.1. Impacts on Biomass

Climate variability may affect availability of biomass both directly or indirectly. The direct effects have been witnessed during periods of both prolonged droughts and prolonged rains. Forest fires due to prolonged drought directly destroy thousands of tons of biomass in a single incident. In early 2012, fires consumed over 100 hectares forest in Masindi district at Bujawe central Forestry reserve in Buseruka Sub County and Kyamugongo central forestry reserve. An example of damage due to heavy rains is the El Niño effects of 2007, which caused the inundation of woodlands around Lake Kyoga in central Uganda and areas around River Kanabelumu in Rakai district. Woodlands in these areas died off three years later due to prolonged water logging. Other examples include the floods in 1961/62, 97/98 and in 2007, which saw widespread infrastructure damage and inundation of biomass.

Forests have the potential to absorb one tenth of global carbon emissions into their biomass, soils, and products. However, some tree species do not tolerate high temperatures and moisture changes. Extreme weather and climatic events such as windstorms and flooding can destroy and kill trees on a massive scale as observed in Bwindi Impenetrable National Park. The heavy cutting and burning of the forest cover contributed to land and soil degradation. In such fragile ecosystems, deforesting and/or degrading forests makes poor communities susceptible to climate change disasters (e.g. landslides), exacerbates the severity of other disasters (e.g. floods and windstorm) and triggers an upward spiral of food insecurity and its associated consequences.

Indirect impacts of climate variability include those via crop failures, and problems of transportation. Crop failure as a result of climate variability results in shortages of agro-wastes. The 2012 prolonged rains with almost no dry season, for example, affected coffee yields in parts of western Uganda. The coffee plants could not flower due to lack of sufficient sunshine and thus could not produce coffee beans. This affected both coffee production and availability of coffee husks which are used as a source of thermal energy in the cement industry and the brick and tile industry.

Infrastructure damage (of roads and bridges) can also affect access to biomass. For example during the rainy season, charcoal availability is limited due to the difficulties of transporting charcoal to and from remote areas. When the rains get prolonged (above normal rainfall) the charcoal scarcity can lead to price hikes as was witnessed in the 2002 charcoal crisis.

Internal displacement of communities into camps as a result of climate variability results in centres with high population concentrations. Over-extraction of biomass in the areas immediately surrounding the camps can then result in biomass deficits or a need for people to travel long distances in order to access the biomass.

5.2. Impacts on Generation of Hydropower

The projections for water flow in Uganda due to climate change are uncertain. As part of this study estimates were made of changes in precipitation to 2050 and associated changes in water flows (Baastel Consortium, 2014). Under the Representative Concentration Pathway (RCP 4.5) the model predicts a decline of 5mm per month (mostly in the northern half of the country) and a decline of 10 mm per month (mostly in the southern half of the country). Rainfall over Lake Victoria is predicted to decline by up to 70 mm per month. These projections were combined with the WEAP model in the water sector report to arrive at an estimated decline in renewable water resources of 26 percent by 2050. (See the Water Sector Report for details).

There is, however, another set of projections, which indicate an increase in runoff and hydro capacity (Hamududu et al., 2009). They predict an increase in capacity of 17 percent by 2050. In this second case, but possibly also in the first, there will be impacts on hydropower infrastructure if extreme events become more common. Hence existing hydropower power dams will need to be strengthened to withstand the flood. The maintenance cost of small hydropower system could also increase due the increased levels of silting. Extreme events will also lead to damage of roads bridges and dams. That is if the effect of climate change was not considered during the design. In all the new and planned hydropower system, climate change should be incorporated in the design.

As far as the modelling of climate impacts is concerned it is difficult to quantify the effects of climate change on biomass but we consider a plausible reduction in available supply of 5-10 percent by 2050. The possible impacts of climate change on hydro power capacity are considered under two variants: one in which capacity declines linearly between 2025 and 2050 so that it is 26 percent lower by the latter date; and the other in which capacity increases linearly so that it is 17 percent higher in 2050 relative to 2025. Finally as far as possible damages to energy infrastructure due to extreme events are concerned these are estimated under the water and infrastructure extreme events assessments.

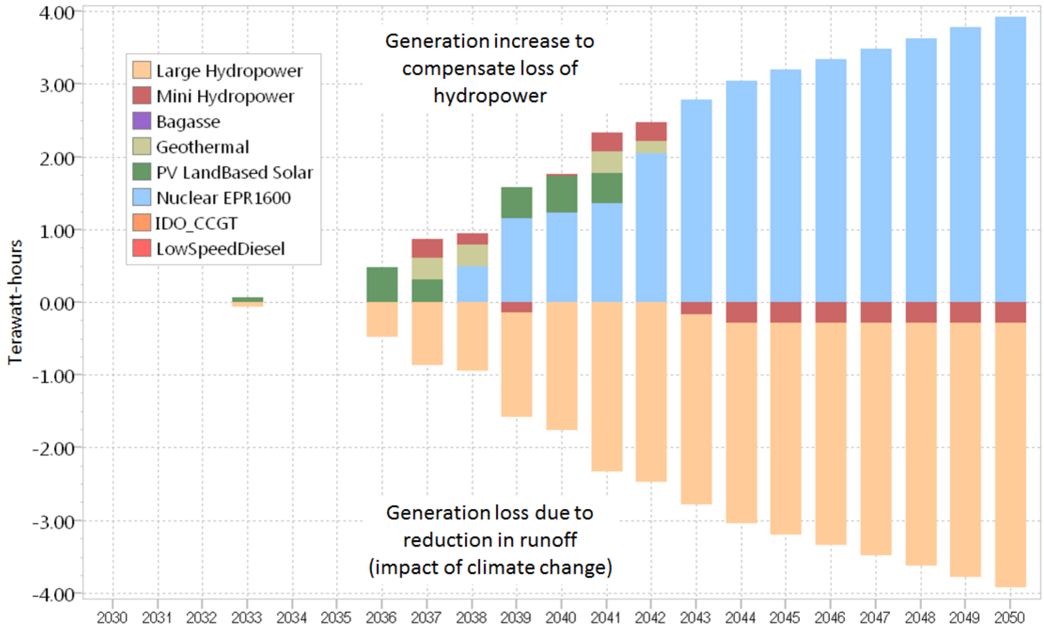
5.3. Scenario results for reduced runoff with fuel substitution (least running costs)

To recall, in this scenario, demand for electricity follows the high forecast, supply of electricity is 746MW less than in the Base Case and demand for wood follows the Base Case.

Figure 14 shows the impact of climate change on generation. The loss in hydro production due to reduced runoff (linear drop in available capacity between 0% in 2025 and 26% in 2050) is met through an increase in generation by nuclear and renewables (geothermal and solar). Nuclear accounts for 95% of the difference of the reduced yield (35.4 TWh). There is no change in delivered electricity by fossil fuels or bagasse. Finally CO_2 emissions increase slightly (+0.13 million tonnes).

The important points in this scenario are: (a) electricity generation meets the high demand, (b) the deficit in demand for wood is at least as much as in the Base Case (in fact, for the reasons given above the available biomass will probably decline and the unmet demand will be even higher) and (c) net cumulative cost of production is US$2.3 billion higher than the corresponding scenario without climate change, mostly due to the increased generation from nuclear.

Figure 14. Impact of climate change on electricity generation in TWh/yr under the scenario of reduced runoff assuming High Electricity Demand with Low Supply Capacity (DHSLWBC) vs. no impact of climate change



5.4. Scenario results for reduced runoff without nuclear energy (least running costs)

In this scenario we consider the case where, for one reason or another, the nuclear programme is not realised. The combination of reduced runoff and unavailability of nuclear capacity together contribute to an unmet electricity requirement of nearly 40 TWh or 36 TWh in unmet demand after T&D losses, which is 9% of the cumulative demand over the time 2010-50 (389 TWh). Switching to fossil fuels from hydro and nuclear generation leads to significant increases in carbon emissions: 60 Mt CO_2 or ten times more compared to the case when neither hydro nor nuclear capacity is restricted.

The net cumulative cost of production decreases by nearly US$40 billion (mostly from unbuilt nuclear). However, the demand cost of unmet electricity comes to US$22 billion (Figure 15), which gives a final cost savings of US$18 billion. Figure 16shows the generation losses resulting from this combination and how they are compensated. It also shows the unmet electricity requirement in TWh.

Figure 15. Impact of climate change on electricity production cost under the scenario of reduced runoff assuming High Electricity Demand with Low Supply Capacity and no nuclear vs. no impact of climate change

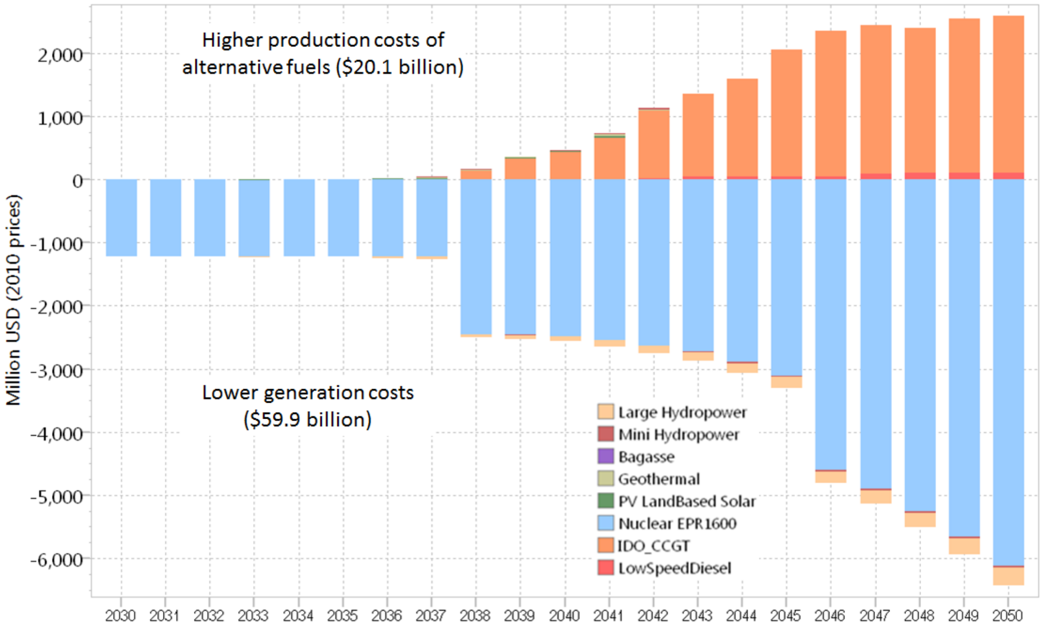
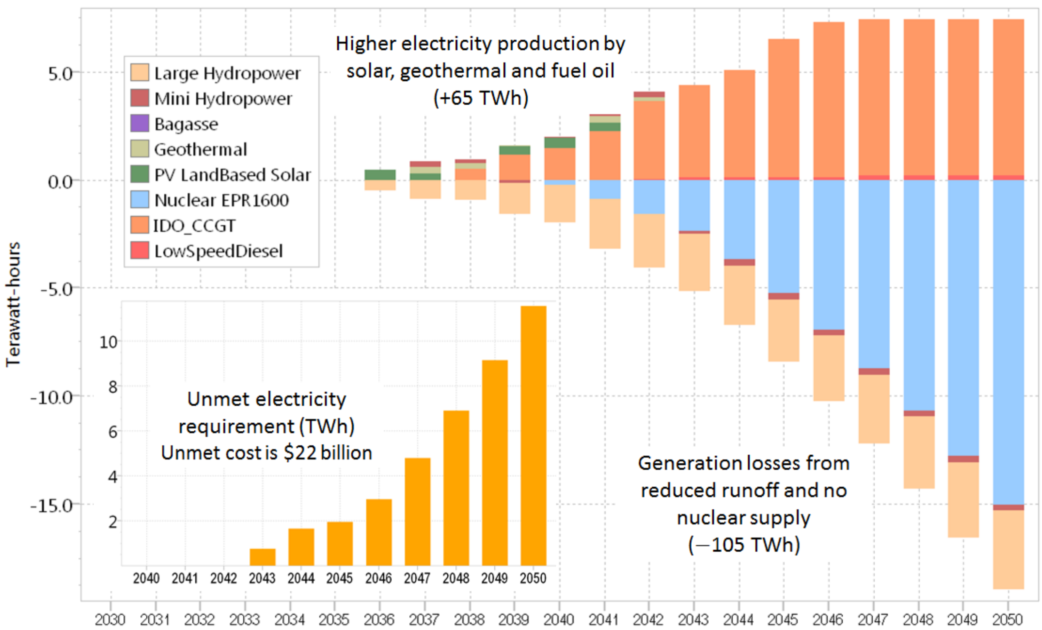


Figure 16. Impact of climate change on electricity generation under the scenario of reduced runoff with High Electricity Demand with Low Supply Capacity and no nuclear vs. no impact of climate change (DHSLWBCN)



5.5. Scenario results for increased runoff without nuclear energy (least running costs)

In this last scenario we consider an increase in hydropower potential in the period 2025-2050 owing to an increase in precipitation. In this case the "unrealized" nuclear generation is replaced by the additional hydro yield and use of fossil fuels, the latter contributing 67% of new generation. Compared to Figure 16, the unmet electricity requirement is nearly one-quarter (13 TWh), while CO_2 emissions have increased by 34 million tonnes.

The combination of changes, including more hydro and less nuclear, after accounting for the cost of unmet electricity (US$7 billion), brings cumulative cost savings of US$36.7 billion compared to the same scenario with nuclear but with no increase in runoff.

6. DISCUSSION OF SCENARIOS

A summary of the scenario results is given in Table 3. In scenarios that exclude climate change impacts we observe that after 2020 there will be a critical shortage of biomass, currently the main source of energy in Uganda. If demand for electricity grows at the Base Case annual rate of 4.9 percent, the government's planned expansion in generation is more than adequate to meet future demand. Electricity requirements can, in fact, be met from hydropower alone and other renewables and nuclear energy are not needed. This scenario, however, has a very high social cost because of the unmet biomass demand: for the period 2010-2050 the cost amounts to US$373 billion (third column Table 3 below)[6]. Furthermore it has major implications for deforestation and poverty, as it is the poorer sections of society that will be affected. Hence we conclude that it is not sustainable[7].

[6] The costs estimates in this table are undiscounted totals and are in 2010 prices.
[7] In Table 3 we do not include possible impacts of climate change on biomass supply. As mentioned these are uncertain but a range of 5-10 percent reduction is plausible. We consider these later in the discussion on adaptation options.

Table 3. Summary of cumulative results (2010-50) for scenarios defined in Table 1: Future demand and supply scenarios

Scenarios defined in Table 2		Base Case	Low wood demand (biomass substitution)	Low wood demand (substitution + imported wood)	High electricity demand with low hydro supply capacity	High electricity demand low hydro supply capacity reduced runoff	High electricity demand low hydro supply capacity reduced runoff and NO nuclear	High electricity demand low hydro supply capacity increased runoff and NO nuclear
Final energy demand		**NO Climate Change Impact**				**YES Climate Change Impact**		
Wood								
Indigenous	Million tonnes	2,314.5	2,198.6	2,198.6	2,314.5	2,314.5	2,314.5	2,314.5
Imported	Million tonnes	-	-	86.0	-	-	-	-
Unmet	Million tonnes	1,710.4	-	-	1,710.4	1,710.4	1,710.4	1,710.4
Electricity								
Consumption	TWh	211.3	696.8	491.6	389.4	389.4	349.4	376.2
Unmet	TWh	-	83.6	-	(*)	-	40.0	13.1
Petroleum products								
Kerosene	PJ	226.4	226.4	226.4	226.4	226.4	226.4	226.4
LPG	PJ	26.6	1,762.0	1,522.3	26.6	26.6	26.6	26.6
TOTAL energy	PJ	61,386	37,776	37,776	62,027	62,027	62,027	62,027
Wood	%	98.3	87.3	90.7	97.3	97.3	97.3	97.3
Electricity	%	1.2	7.4	4.7	2.3	2.3	2.3	2.3
Petroleum products	%	0.4	5.3	4.6	0.4	0.4	0.4	0.4
Electricity generation								
Fuel mix								
Hydro (large)	TWh	227.6	361.4	348.0	331.8	296.5	296.5	350.2
Hydro (mini)	TWh	2.0	26.6	21.3	12.9	11.4	11.4	12.9
Nuclear	TWh	-	322.0	153.8	68.2	101.7	-	-
Solar	TWh	-	15.4	12.5	11.4	13.6	13.6	10.2
Bagasse	TWh	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Geothermal	TWh	-	8.8	6.8	6.0	7.1	7.1	5.0
Thermal (HFO, IDO)	TWh	2.4	50.2	2.9	2.4	2.4	64.4	41.5
TOTAL generation	TWh	245.4	797.8	558.8	446.2	446.2	406.5	433.4
Production cost	$ billion	101.1	172.3	134.6	115.5	117.2	76.3	72.8
Carbon emissions								
CO_2								
Electricity	Million tonnes	3.8	50.1	7.3	6.2	6.3	60.2	40.1
Petroleum products	Million tonnes	16.1	125.7	110.6	16.1	16.1	16.1	16.1
TOTAL emissions	Million tonnes	19.9	175.8	117.9	22.2	22.4	76.3	56.2
CO_2 /cap (in 2050)	Tonnes/cap	0.010	0.16	0.10	0.012	0.012	0.08	0.08
Social costs								
Wood								
Indigenous	$ billion	139.2	133.4	133.4	139.2	139.2	139.2	139.2
Imported	$ billion	-	-	8.5	-	-	-	-
Unmet demand	$ billion	123.6	-	-	123.6	123.6	123.6	123.6
Electricity								
Supply	$ billion	101.1	172.3	134.6	115.5	117.2	76.3	72.8
Unmet demand	$ billion	-	45.5	-	-	-	21.8	7.3
Petroleum products	$ billion	8.7	110.3	96.6	8.7	8.7	8.7	8.7
TOTAL cost	$ billion	372.6	461.5	373.2	387.0	388.7	369.6	351.6

(*) In the case of NO nuclear capacity, there would be an electricity unmet demand of 21 TWh.

This problem can be addressed at a cost if major steps are taken to switch from biomass use to LPG and electricity ("low wood demand scenario", 4th column in Table 3). Under this solution total costs of meeting demand are about 25 percent higher, but the energy provided is cleaner (hence health effects are less) and poor households do not face energy shortages. On the negative side, however, the electricity capacity, even if it is used to the full, cannot meet demand in this scenario – there is an unmet electricity demand of 84 TWh, equal to about 9 percent of the total.

This social cost can be reduced further wood is imported to fill the gap in demand or biomass. An import of some 86 million tonnes (equal to 4 percent of the Base Case demand for wood fuel), combined with a partial switch to LPG and electricity, would be enough to ensure that there is no unmet electricity demand and the total social cost of the system declines to US$373 billion (5th column in Table 3), almost the same as in the Base Case but no with no unmet demand. The option of importing wood to meet demand, however, needs further examination. At this stage it is only a possibility that should be studied further. Another option may be to import electricity from neighbouring countries, which would also need further study.

The last case considered in the no climate change scenarios is one in which electricity demand grows at a faster annual rate of 7.4 percent and hydro capacity can only increase by 2,470MW, some 746MW less than in the Base Case, reflecting possible problems with development of some of the hydro plants. In spite of this reduction, electricity generation can still meet requirements as long as there is no additional demand to switch from biomass to electricity. The social cost of the scenario is higher by US$14.5 billion (or 1 percent) than the Base Case because more electricity is being generated and it is being generated from more expensive sources.

Overlaid on these scenarios are the impacts of climate change. We observe that such change will almost certainly reduce biomass availability, although it is difficult to quantify by how much. Hence if the country follows the Base Case biomass track and climate change impacts are taken into account, the gap between supply and demand will be even bigger than shown in Table 3.

The other major impact of climate change will be in terms of power generation from hydro. Climate models do not agree on the effect that climate change will have on runoff and two alternatives are considered: one in which hydro capacity declines by 26 percent by 2050, starting from no decline in 2025; and the other in which it goes up from 2025 to 2050 so that it is 15 percent higher by the end of the period. The scenarios examined that include climate change are the ones with the high demand growth for electricity and the limited hydro capacity increase of 2,470MW, but similar conclusions would hold with the other scenarios. With the decline in hydro power capacity due to reduced water flow, more power has to be generated from higher cost sources, principally nuclear, resulting in a total social cost that is US$1.7 billion greater than with no climate change. This figure can then be said to be the cost of climate change impacts that are included in this scenario. Since the development of the nuclear programme is still at an early stage and there may be difficulties in realising it, we also consider what would be the impact of climate change if there was no nuclear power in the system. In that case, thermal power is used to make up the gap but since thermal power is slightly less costly than nuclear the total cost of generation falls by around US$19 billion.

On the other hand, if runoff increases then more power can be generated from hydro sources and the total cost of meeting demand declines by about US$18 billion relative to the case where there is no increase in run off.

7. EVALUATING ADAPTATION OPTIONS

Part of the adaptation to climate change for the energy sector will come from reducing dependence on traditional biomass. As the above analysis shows, there is already a critical situation with respect to biomass in the country and by 2020 supply will not meet demand even without climate change. If we add the expected reductions in supply due to climate change more households will have to switch to other sources. Here we assume that the fall in biomass starts from zero and grows linearly to be between 5-10 percent by 2050. In that case an additional 557-1114 PJ of energy have to be found by 2050. The cost or meeting that demand will depend on the source. If it is met from imported wood the present value of the cost will be between $600 million (5% loss) and $1.3 billion (10% loss). If the gap is to filled by LPG the cost will be much higher – around $5-10 billion. And finally if it is filled from electricity the cost will be similar to those of LPG (the exact cost depending on what source is developed).

The results indicate an adaptation cost for replacing lost biomass of between US$5 and US$11 billion over the period 2020-2050 at a 10 percent discount rate[8]. Doing the same with electricity would cost even more – the marginal cost of electricity is around $28/gigajoule while that of LPG is $37/gigajoule To be sure these are high costs as the replacement energy is more expensive than the biomass it replaces. At the same time, electricity and LPG are cleaner than traditional biomass and have important health and other social benefits.

[8] For the period 2020-2030 the corresponding figures are US$1.8 billion and US$3.6 billion.

8. CONCLUSIONS AND ADAPTATION SIGNATURES

8.1. Costs of Inaction

Energy use in Uganda is dominated by traditional biomass, with electricity and other fuels playing a very small role. The current balance between supply and demand for biomass, however, is very fragile and predictions from the modelling are that if no action is taken there will be a huge deficit of biomass (1,710 million tonnes) over the period 2010-2050. The cost of the unmet demand for biomass over this period amounts to US$139 billion and the whole scenario has a total (undiscounted) cost of US$373 billion. In this Base Case inaction scenario the national power sector generation expansion plan, does, however, meet the demand for electricity if it is realised in a timely manner. The main dependence for future electricity in this case is for hydropower, with large new hydro plants coming on stream in 2018 and 2019 (Isimba and Karuma respectively), and then in 2024 (Ayago).

From the above the report concludes that a Business as Usual scenario for growth in biomass demand is not sustainable and a solution is needed to address the predicted deficit.

A number of alternatives are considered to fill this gap even with no climate change impacts. One would be to increase biomass efficiency and make available LPG to households who cannot be connected to the grid. Another would be to look for an alternative to LPG, based on imported biomass. These options need further analysis.

These problems are exacerbated by climate change in two ways. First there is a potential decline in biomass production and second a decline in electricity generation owing to a fall in precipitation. Climate change effects on biomass are both direct and indirect. The direct effects occur through periods of both prolonged droughts and prolonged rains as well as through temperature and moisture changes, which affect growth for some species. Indirect impacts include those via crop failures, and problems of transportation. Crop failure as a result of climate variability results in shortages of agro-wastes. Infrastructure damage (of roads and bridges) can also affect access to biomass. For example during the rainy season, charcoal availability is limited due to the difficulties of transporting charcoal to and from remote areas. When the rains get prolonged (above normal rainfall) the charcoal scarcity can lead to price hikes as was witnessed in the 2002 charcoal crisis. A plausible range of decline in biomass owing to these effects is 5-10 percent by 2050.

The effects of climate change on hydropower capacity are considered under two variants: one in which capacity declines linearly between 2025 and 2050 so that it is 26 percent lower by the latter date; and the other in which capacity increases linearly so that it is 15 percent higher in 2050 relative to 2025. The decline of 26 percent is based on the climate projections generated as part of this study combined with hydrological modelling using the WEAP model. The increase is based on the results of an alternative model.

The consequences of climate change on the energy situation are twofold. First the biomass decline makes the situation even more difficult, with an increase in biomass deficit of 5-10 percent. This would require an additional expenditure to meet demand and if that were done via imported wood the additional costs in present value terms would be around $600 million-$1.3 billion. If it were done by LPG, the increase in expenditures in present value terms would be in the order of US$5-11 billion over the period to 2050. Other options for meeting the increased demand are available and their cost is likely to somewhere in between these two ranges.

The second main impact of climate change relates to the availability of water resources for hydropower generation. In the case of a possible decline of 26 percent by 2050 the analysis shows that the government's current expansion programme for the power sector is sufficient to cover the hydropower deficit, as long as the other components of the programme are implemented according to the proposed schedule. It is important to remember, however, that this is a very ambitious programme, which will demand large financial resources as well as highly skilled manpower that is able to operate a much more sophisticated electricity system than the one that Uganda has at present. The estimated additional capital investment in hydro, nuclear and other generation from now to 2050 is around US$83 billion. According to these plans, in the period 2015-2020 the country will need to invest around one billion dollars in the electricity system, or around US$200 million per year, a sum which is equal to about one percent of national GDP. In future years the amounts increase very sharply.

8.2. Adaptation Signatures

The Government of Uganda's NCCP Costed Adaptation Strategy document (Government of Uganda, 2012) responds to many of the priorities discussed above, in terms of focussing heavily on reducing dependence on biomass, but it also gives importance to promoting energy conservation and efficient utilisation of energy to reduce GHG emissions and to protecting watersheds for the generation of hydropower. The programme proposes a number of strategic interventions for which a cost is given; they are presented in Table 4, where questions of timing and priority are summarised. The following conclusions emerge from our analysis of those proposed interventions:

1. It is very important that those components focussing on reducing biomass demand (namely strategic interventions 4, 6 and 9) are implemented effectively and urgently given the critical nature of the problem. In addition to those strategic interventions, we would expand the programme to increase electricity connections and to extend the supply network for some alternative fuel to biomass. LPG is one option but imported biomass or kerosene are other. These alternatives need further investigation but a preliminary analysis indicates that the benefits of developing an alternative fuel program (in terms of reducing unmet demand) are well in excess of costs[9]. Given that some poor households will not be able to afford the alternative fuel, some kind of support (e.g. "address the high upfront costs of acquiring these technologies through household subsidies or tax waivers" as proposed in strategic intervention 9) needs to be factored into the programme.

2. The components dealing with energy efficiency are similar to others that have been implemented in many developing countries by many national and international agencies (interventions 4, 6, 7, 8 and 9). Reviews of such programmes indicate a high level of cost effectiveness in promoting energy efficiency and reducing Green House Gases (GHGs). Item 7 ("Enforce building codes to reduce energy consumption") has worked well in other countries and should be a priority but its effects will be felt gradually as new construction takes place. For items 4, 6, 8 and 9 the main difficulties arise when the programme requires an up-front expense by the user and when the user has limited resources. In Uganda similar considerations will apply: energy efficiency programmes designed with care, taking account of lessons learnt from other countries in a similar situation, should yield high benefits relative to costs.

[9] Although in energy equivalent terms LPG is not much more expensive than wood (currently wood is around US$45 per gigajoule while LPG is around US$43 per gigajoule) some support may be needed to acquire the infrastructure for its use and that should be part of the programme to extend the use of the fuel. These and other alternatives need further analysis.

3. In addition to such programme, a number of other measures can be taken to improve biomass productivity. The full list was provided in Table 1. From that list the following have been highlighted in other reviews and are especially important in the light or recent experience:
   - Choose tree species and forestry practices less vulnerable to flooding, storms and fires.
   - Increase rates of afforestation and reforestation through measures involving a wide range of stakeholders.
   - Enhance the capacity of rural households to effectively and efficiently utilise the same piece of land to produce both food and the needed biomass. This calls skills in utilizing waste material for both energy purposes and improvement of soil fertility, knowing the right species to plant for energy needs (especially fast-growing shrubs) and employing practices that will not compromise food production (e.g. planting shrubs along boundaries and as hedge-grows).
   - Reduce rates of deforestation by strengthening the forestry legal framework, law enforcement and governance to stop illegal logging, deforestation, and land degradation.

   These measures have to be implemented at the local level and can only be evaluated in economic terms at that level.

4. As far as electricity is concerned the main impact is on water resources for hydropower and the situation is more complex. In relation to extreme events measures to strengthen structures of small dams are already needed and will be needed even more if such events increase in intensity. Water catchment protection is also a part of the current development plans and this will become more important. Afforestation and reforestation measures to protect watersheds that supply major hydroelectricity generating sources are a key part of such protection. Items 1 and 2 address these problems and need to be initiated now, but with a longer time horizon in mind.

5. Regarding the availability of water resources for hydro generation there is a possibility that capacity will decrease due to a fall in precipitation, but that is not certain. If it happens the analysis shows that the government's current expansion programme can handle the fall, as long as the other components are implemented according to the proposed schedule. Responding to such possibilities needs more information and that is what item 5 addresses. This is a high priority item but one that will yield results over the medium term.

6. It is important to remember that the country's power generation expansion program is very ambitious and demanding of a large amount in financial resources as well as in human skills to operate a much more sophisticated system than we have at present. The estimated additional investment in hydro, nuclear and other generation from 2015 to 2050 is around US$83 billion. These are undiscounted 2010 dollars.

7. The assessment made here is at a national level and does not look at individual projects for adaptation at the local level. The latter is necessary to get a full evaluation of the benefits relative to the costs and should be part of a programme for preparing adaptation actions. Some examples of such local assessments will come from the case studies being prepared.

Table 4. Strategic Interventions for the Energy Sector in Uganda 2015-2030

	Strategic Intervention*	Outcome	Additional Cost (US$Mn.) *	Timing and Critical Decisions	Comment
1	Promote and participate in water resource regulation so as to ensure the availability of water for hydropower production.	Better management and protection of water resources for hydropower	54.0	Short term priority that needs urgent action	Not evaluated quantitatively except to note that current power shortages indicate the seriousness of the problem.
2	Promote and participate in water catchment protection as part of hydroelectric power infrastructure development	Protection of water resources should make more available for hydropower.	60.3	Start now but has a longer term horizon with major outlays after 2020.	The problem of power deficits is a noted and this will contribute but over the medium term
3	Diversify energy sources by promoting the use of alternative renewable energy sources (such as solar, biomass, mini-hydro, geothermal and wind) that are less sensitive to climate change	Ensures that power generation is not so affected by reductions in hydropower.	74.0	Medium to long term strategy.	Present projections for hydro are uncertain so it is desirable to keep options open for more information (see Item 5). Some renewables are cost effective and should be developed right away.
4	Promote energy-efficient firewood cook stoves, solar and liquefied petroleum gas (LPG) cookers	Reduced demand for biomass	128.2	Programme is absolutely critical and needs highest priority. Needs to be coordinated with item 8.	Efficiency increases in use of wood fuel are critical even without climate change and more so with it. If well implemented benefits will be very high relative to costs but problems arise with take up.
5	Conduct research to determine the potential impacts of climate change elements on the country's power supply chain	Makes planning for future energy supply more effective	71.8	Programme is a high priority	This is a key requirement, given the lack of knowledge and the importance of information on likely future impacts on supply of energy
6	Promote the development of energy conservation and efficiency projects in all sectors; for example, to promote the use of	Decreased demand for biomass	29.2	Program justified under present	Efficiency increases in use of wood fuel are critical even without climate change and more

	Strategic Intervention*	Outcome	Additional Cost (US$Mn.) *	Timing and Critical Decisions	Comment
	stabilised bricks and efficient brick kilns in the building sector			conditions and should be a high priority.	so with it. If well implemented benefits will be very high relative to costs
7	Enforce building codes to reduce energy consumption	Reduced consumption of energy	71.8	Effects will take time to be realised but needs to start now	In other countries enforcement of building codes is a cost effective way to reduce energy use if implementation can be assured. (Markandya et al., 2014)
8	Promote the use of energy-efficient technologies such as compact fluorescent and other commercially available high-efficiency lamps	Reduced consumption of energy	1.9	Program justified at present and can be promoted.	Benefits of adopted are high relative to costs but problem here is take up. Some programs make little impact on this and other involving subsidies are not cost-effective. Care needs to be taken in selecting the right promotional measures
9	Promote efficient firewood/charcoal stoves and solar and LPG cookers, and address the high upfront costs of acquiring these technologies through household subsidies or tax waivers	Reduced demand for biomass	5.3	Needs to be coordinated with item 4 as a high priority item	Success depends on high take up rates at modest subsidy payments.

Source: Government of Uganda, 2012, Own Calculations

* from the NCCP Costed Implementation Strategy

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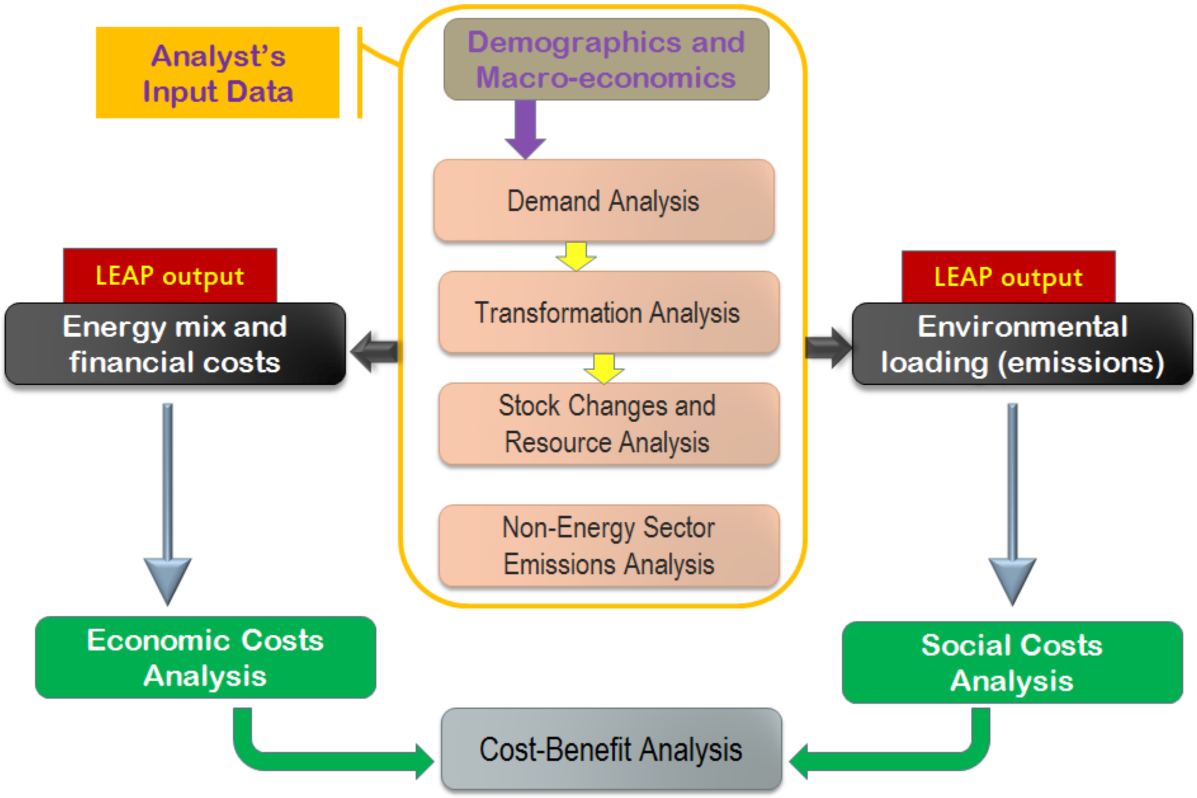
ANNEX I: THE LEAP MODEL

LEAP provides a range of accounting and modelling approaches to determine how an energy system might evolve over time, its energy and resource requirements, its social and environmental implications, and its costs and benefits. LEAP uses a long-range scenario analysis in which the analyst defines future trajectories (storylines) based on assumptions about technology evolution and build capacity, energy system characteristics, and socio-economic projections affecting both energy supply and demand. LEAP also supports optimization modelling, which allows the construction of least cost models of electric system capacity expansion and dispatch, potentially subject to climate policy and/or air pollution constraints.

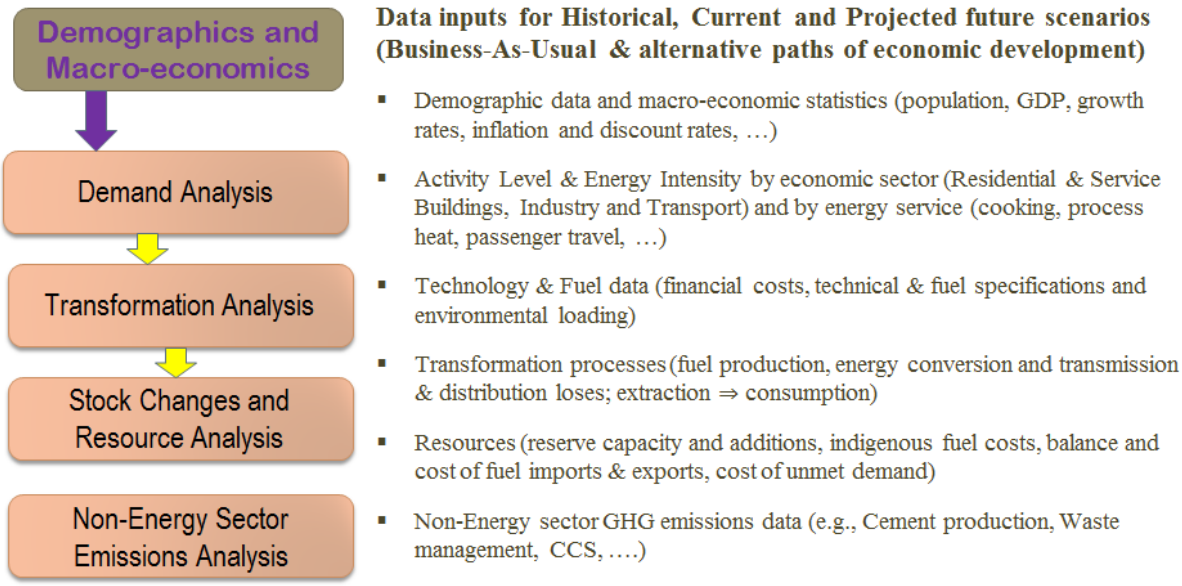
Figure 17. LEAP calculation flowchart



Uses of LEAP include: Energy outlook and balance analysis, Resource planning, GHG mitigation analysis, Environmental impact assessment (emissions and "external costs"), Non-energy sector emissions/sinks analysis due to changes in land use for biomass and renewable resources, Capacity expansion and plant-dispatch analysis, Stock turnover in transportation and Cost-Benefit Analysis. The geographical applicability of the model ranges from the local- to the regional-level. The time scale it covers is the medium to long-term (20 to 50 years is a typical analysis period), with unlimited annual time steps.

Data requirements vary with the complexity of the analysis, but initial data needs are low. LEAP includes a built-in Technology and Environmental Database (TED) with costs, technical specifications and environmental loading data (emission factors) for many types of current and future energy technologies. Of course, it is always best to collect and use data that reflect local technology and fuel characteristics and we have tried to do that as much as possible.

Figure 18. LEAP input data



As indicated in Figure 18, LEAP uses a hierarchical input data structure "tree", which includes information on socio-economic, technological, and environmental parameters which impact energy production (supply) and consumption (demand). The overall activity[10] level is specified at the top of the tree, with disaggregated inputs provided at lower levels:

Sector → Sub-sector →End-use → Fuel → Emissions

Main sectors include: demand, transformation, resources, and non-energy sectors. Demand sub-sectors include: buildings, industry, transportation and agriculture. Fuels include: fossil fuels, nuclear, renewables, and hydropower (note, however, that LEAP is not a water resource planning software).

The Transformation and Resources branches contain details on fuel production, costs, energy conversion (heat, electricity or CHP), and transmission losses (Figure 19). Calculations are linked to demand needs, which vary over time (Figure 1. Energy planning framework).

Exogeneous data for current and projected years (BAU and alternative scenarios) include:

- Feedstock (indigeneous or imported fuels), list of derived or secondary fuels, conversion technology data, production and resource costs (including the cost of unmet demand), and environmental loadings (lifecycle emissions inventory that includes lifecycle stages from "out-of-ground", processing and conversion, and use)
- Rules for use of output fuels, including how to deal with surplus (export or discard), shortfall (import), and priority use (domestic or export)
- Electricity generation technology data (endogeneous capacity, historical production, availability, efficiency, auxiliary fuels), costs (capital, fixed/variable O&M, amortized interest rate, salvage value,

[10] Total Energy Demand = Activity Level × Energy Intensity

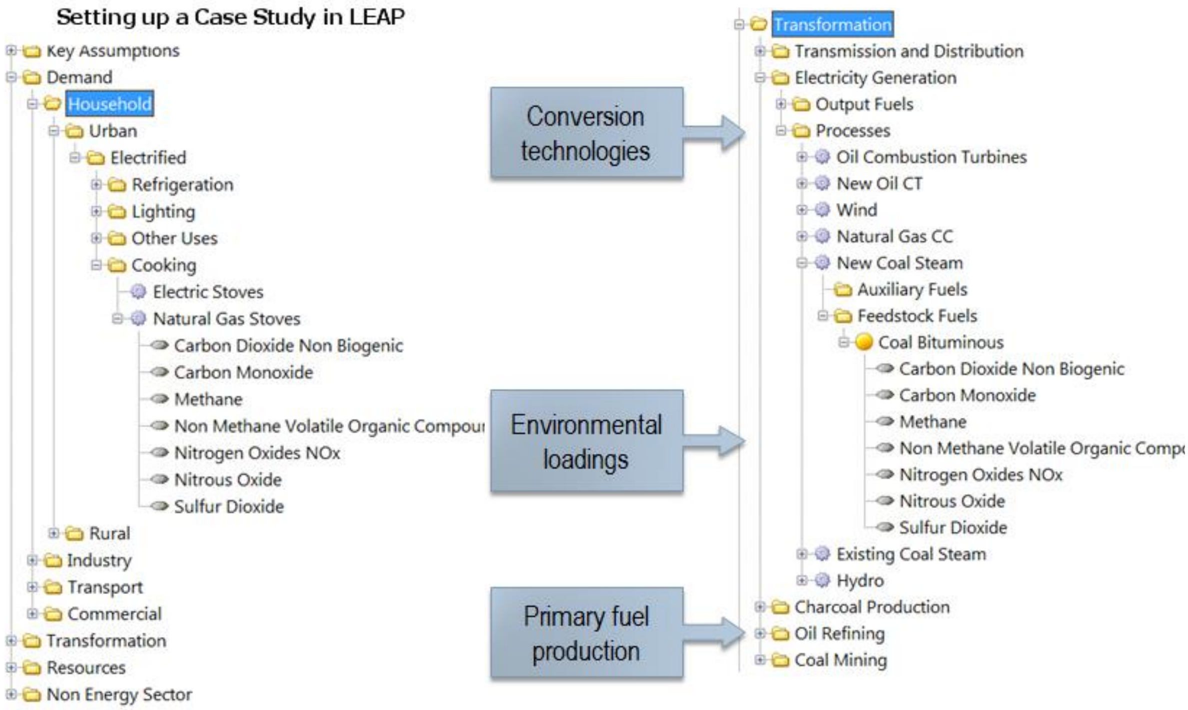
The activity level is a measure of the social or economic activity that consumes energy. Examples include: number of households, household consumption by end-use, biomass consumption per household, economic added value by sector, industrial output by sector (tonne of iron & steel and cement), commercial surface space (m²), freight and passenger transport levels (in terms of number of passenger or tonnes of freight transported per km), waste management (tonnes landfilled, incinerated), CO_2 disposal (carbon capture and storage, CCS), etc.

The energy intensity is the energy requirement per activity unit. It might have units: kWh electricity per household, GJ per tonne of steel, litres of fuel consumed per 100 km driven, GJ/GDP US$, etc.

lifetime), reserve margin, and dispatch (least running costs, full capacity, proportional to available capacity) or merit order (base-load or peak generation)

- Transmission and distribution losses

Figure 19. a- Hierarchical data structure (left). b- Transformation branch (right)



ANNEX II

This annex provides more details about the electricity generation options, including what plants are assumed to be available at different dates and other key technical data for running the LEAP model.

Electricity expansion options for Uganda to 2046.

Table AI-1 Planned electricity system expansion options

Plant (fuel type)	Capacity (MW)	Expected on-line time*
Base Case (see Figure 6)		
Maziba (mini hydro)	6.5	2016
Kakira (bagasse, capacity expansion)	32	2016
Kabaale (heavy fuel oil, HFO)	53	2017
Kinyara (bagasse, capacity expansion)	40	2018
Isimba (hydro)	183	2018
Nengo Bridge, Nyagak, Rwimi, Waki (mini hydro)	26.5	2018
Karuma (hydro)	600	2019
Kikagati (mini hydro)	16	2019
Siti, Nyamwamba (mini hydro)	19	2020
Solar, Land-based photovoltaic PV (4 × 125 MW)	500	2020
Industrial diesel oil (IDO, combined-cycle gas turbine, CCGT)	100	2020
Geothermal #1	30	2020
Geothermal #2	30	2021
Geothermal #3	30	2022
Nshungyezi (mini hydro)	39	2022
Ayago (hydro)	600	2024
Agbinika (mini hydro)	20	2025
IDO, CCGT (capacity addition, 2 × 100 MW)	200	2025
Muzizi (mini hydro)	44	2027

Namanve (HFO, retired)	50	2028
Agago-Achwa (mini hydro)	83	2030
Nuclear #1 (AREVA, EPR technology[§])	1,600	2030
IDO, CCGT (capacity addition, 2 × 100 MW)	200	2030
Murchinson Falls (hydro)	600	2034
IDO, CCGT (capacity addition, 2 × 100 MW)	200	2035
Nuclear #2 (AREVA, EPR technology)	1,600	2038
Rusumo Falls (mini hydro)	63	2039
Orianga (hydro)	400	2040
Bagasse #3 (replaces Kakira, end of lifetime)	52	2040
HFO (replaces Kabaale, end of lifetime)	53	2041
Bagasse #4 (replaces Kinyara, end of lifetime)	54	2043
Geothermal #4 (replaces unit #1, end of lifetime)	30	2043
IDO, CCGT (capacity addition, 2 × 100 MW, plus replace 100 MW unit added in 2020 due to end of lifetime)	300	2040
HFO (capacity addition, 2 × 53 MW)	106	2043
Geothermal #5 (replaces unit #2, end of lifetime)	30	2044
Geothermal #6 (replaces unit #3, end of lifetime)	30	2045
IDO, CCGT (2 × 100 MW)	200	2045
Nuclear #3 (AREVA, EPR technology)	1,600	2046
Total capacity by 2050	**9,971**	
Hydro (large + mini)	2,833 + 383	
Nuclear	4,800	
Solar-PV	500	
Bagasse	106	
Geothermal	90	
Thermal (IDO + HFO)	1,100 + 159	

* Based on past experience, on-line service dates of some power plants have been delayed compared to existing national electricity system expansion plans.

[§] EPR = Advanced nuclear pressurized water reactor (gen. III+)

(Sources: own elaboration based on information in RPSMP 2011 and MEMD, Energy and Mineral Sector Performance Report, 2012)

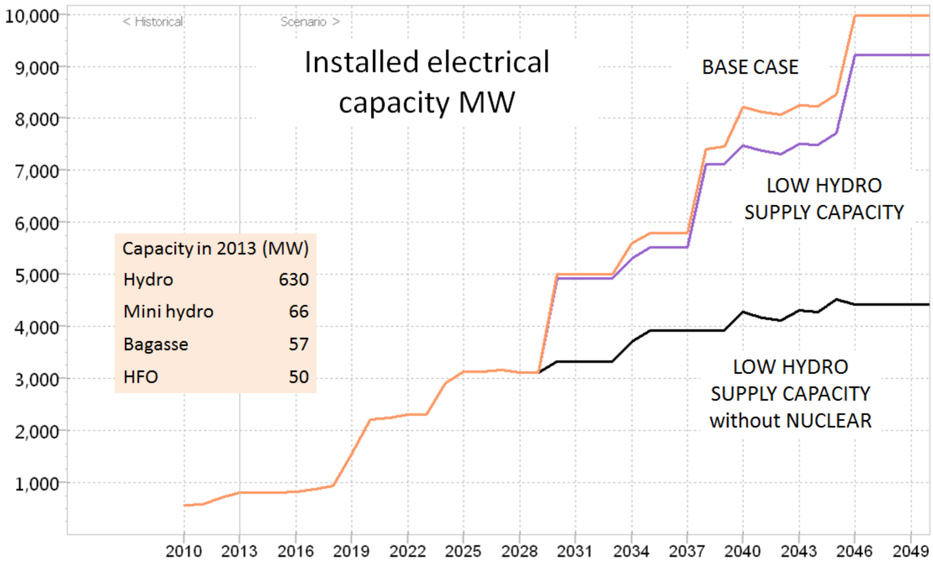
Table AI-1 (cont.): Planned electricity system expansion options

Plant (fuel type)	Capacity (MW)	Expected on-line time*
Low Hydro Supply Capacity		
Same as "Base Case" between 2016 and 2028		
Nuclear #1 (AREVA, EPR technology[§])	1,600	2030
IDO, CCGT (capacity addition, 2 × 100 MW)	200	2030
Orianga (hydro, replaces Murchinson Falls)	400	2034
IDO, CCGT (capacity addition, 2 × 100 MW)	200	2035
Nuclear #2 (AREVA, EPR technology)	1,600	2038
Bagasse #3 (replaces Kakira, end of lifetime)	52	2040
HFO (replaces Kabaale, end of lifetime)	53	2041
Bagasse #4 (replaces Kinyara, end of lifetime)	54	2043
Geothermal #4 (replaces unit #1, end of lifetime)	30	2043
IDO, CCGT (capacity addition, 2 × 100 MW, plus replace 100 MW unit added in 2020 due to end of lifetime)	300	2040
HFO (capacity addition, 2 × 53 MW)	106	2043
Geothermal #5 (replaces unit #2, end of lifetime)	30	2044
Geothermal #6 (replaces unit #3, end of lifetime)	30	2045
IDO, CCGT (2 × 100 MW)	200	2045
Nuclear #3 (AREVA, EPR technology)	1,600	2046
Total capacity by 2050	**9,225**	
Hydro (large + mini)	2,233 + 237	746 MW less than Base Case
Nuclear	4,800	
Solar-PV	500	
Bagasse	106	
Geothermal	90	
Thermal (IDO + HFO)	1,100 + 159	

* Based on past experience, on-line service dates of some power plants have been delayed compared to existing national electricity system expansion plans.

The installed capacities for electricity generation under different scenarios are shown in Figure 20.

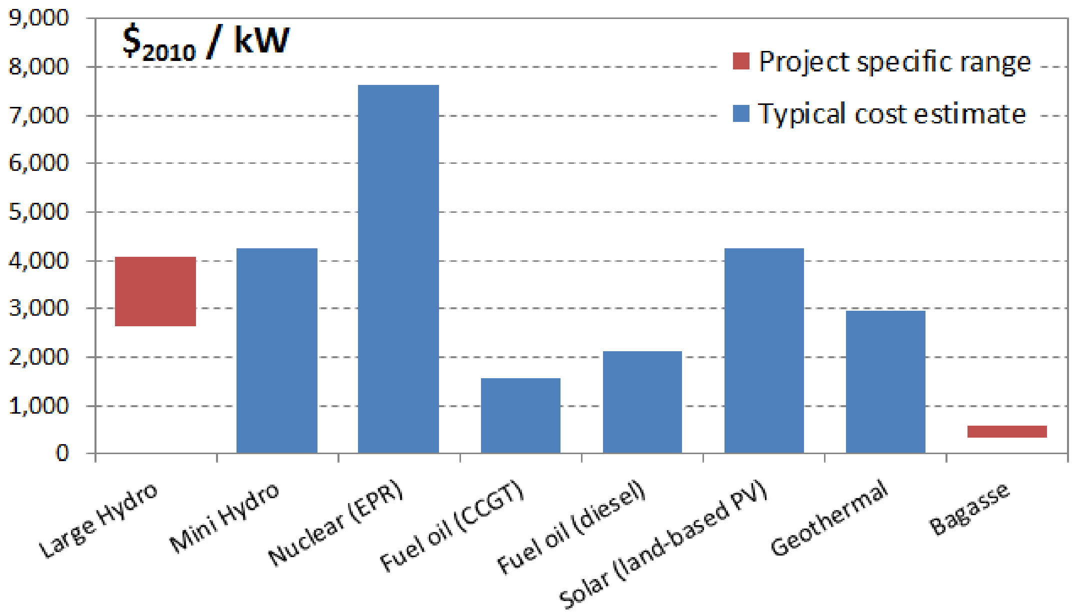
Figure 20. Installed capacity of electricity generation (MW) under different scenarios



Capital and O&M Costs for Different Technologies

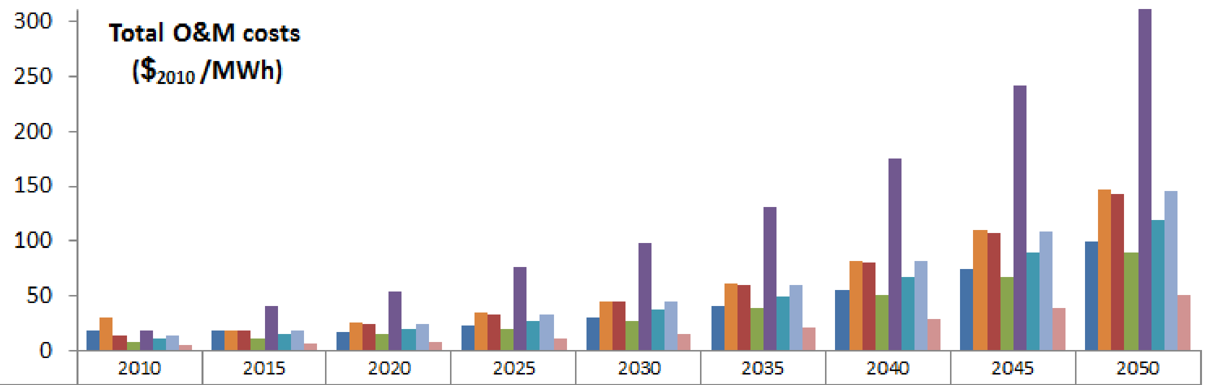
Capital and O&M costs for different electricity generation technologies are given in Figure 21 and Figure 22.

Figure 21. Capital costs (incl. interest during construction) of electricity generation technologies



(Sources: WNA 2014, US-EIA 2013, Mtunzi et al., 2012, RPSMP 2011, IEA-ETSAP 2010, NREL 2010, CASES 2010, PPA 2007, EPFL 2006 plus others)

Figure 22. Evolution of operation and maintenance O&M costs (combined fixed plus variable)



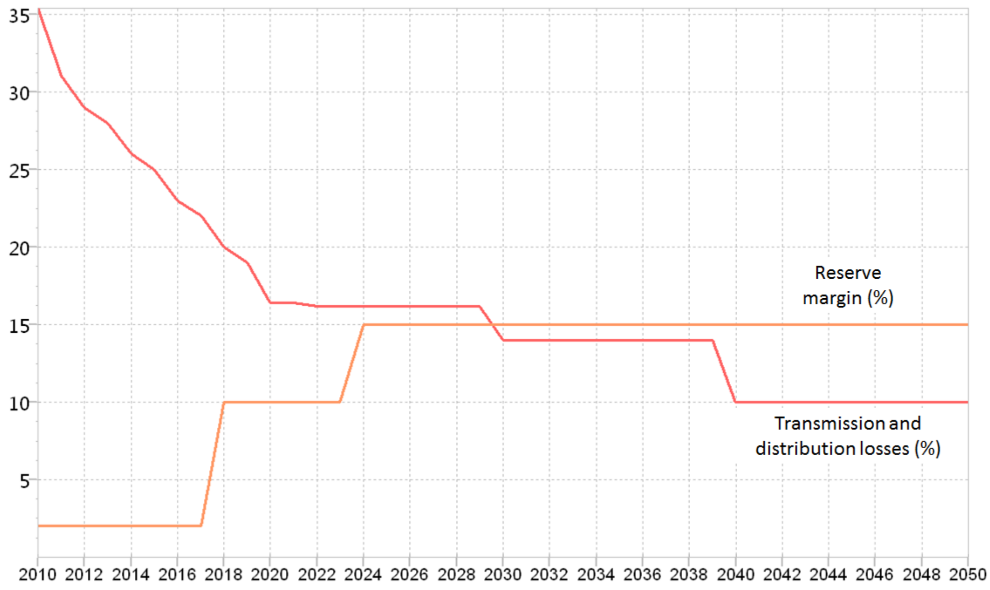
	2010	2015	2020	2025	2030	2035	2040	2045	2050
Large Hydro	18	19	17	23	31	41	55	74	99
Mini Hydro	31	19	26	34	46	61	82	110	147
Nuclear (EPR)	14	19	25	33	45	60	80	107	143
Fuel oil (CCGT)	9	12	16	21	28	39	51	68	90
Fuel oil (diesel)	19	41	55	77	98	131	176	242	315
Solar (land-based PV)	12	16	21	28	37	50	67	89	120
Geothermal	14	19	25	34	45	61	83	109	145
Bagasse	5	7	9	12	16	21	29	39	51

(Sources: WNA 2014, US-EIA 2013, Mtunzi et al., 2012, RPSMP 2011, IEA-ETSAP 2010, NREL 2010, CASES 2010, PPA 2007, EPFL 2006 plus others)

Reserve Margins and Transmission and Distribution (T&D) Losses

Reserve margins are expected to increase from around 2.5percent in 2010 to 15 percent by 2024 and remain stable thereafter. T&D losses are expected to fall from around thereafter percent in 2010 10 percent in 2040 and remain stable thereafter. The trends are shown in Figure 23.

Figure 23. Evolution of electricity reserve margin and T&D losses

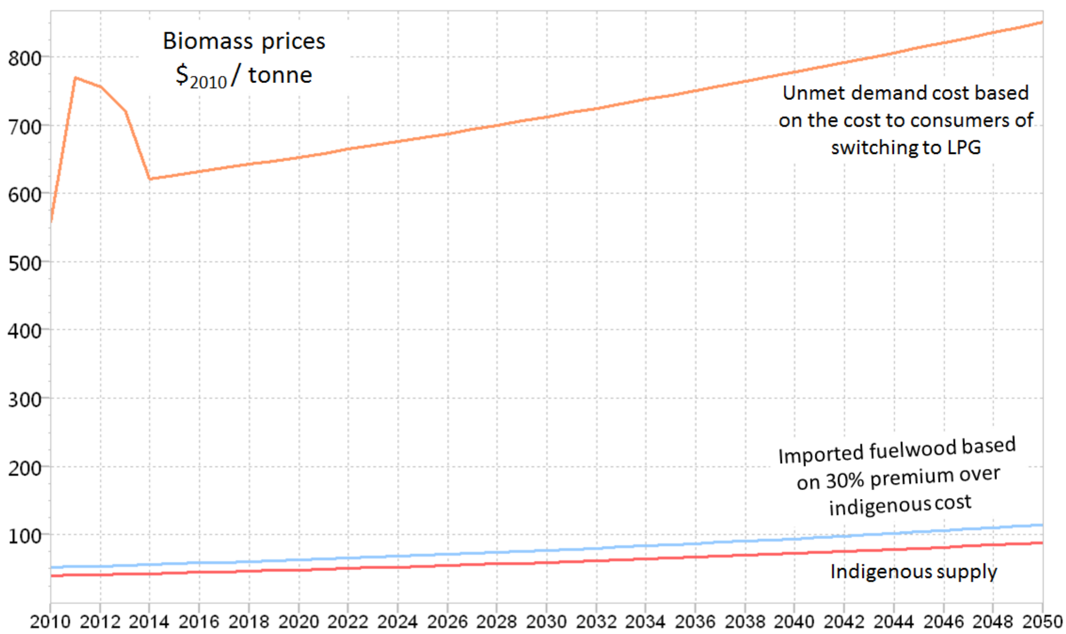


(Sources: Source: UBOS 2012, MEMD 2010, PPA 2007 and A. Sebbit)

Price Projections for prices and costs of unmet demand petroleum products, electricity and biomass.

Figure 24 to Figure 26 give the projections for petroleum products, electricity and biomass respectively.

Figure 24. Fuel prices in USD per GJ of energy consumed (2010 prices); the cost of petroleum products follows the trend of crude oil



(Sources: BP Statistical Review 2014, GTZ 2007 plus others, incl. US-EIA, Natural Resources Canada and A. Sebbit)

Figure 25. Export prices of electricity and costs of unmet demand

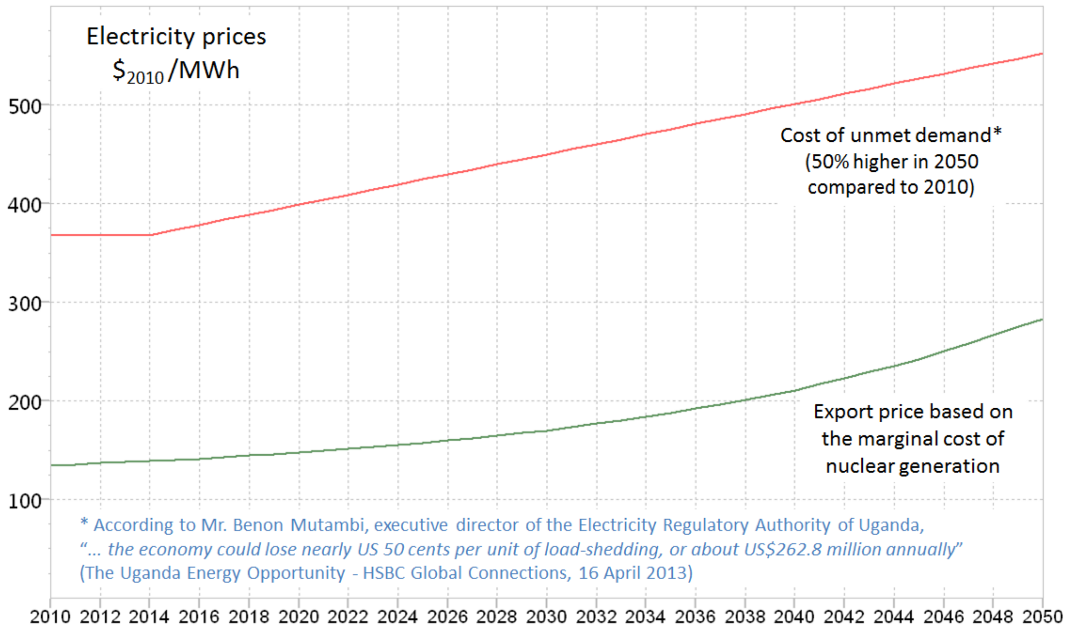
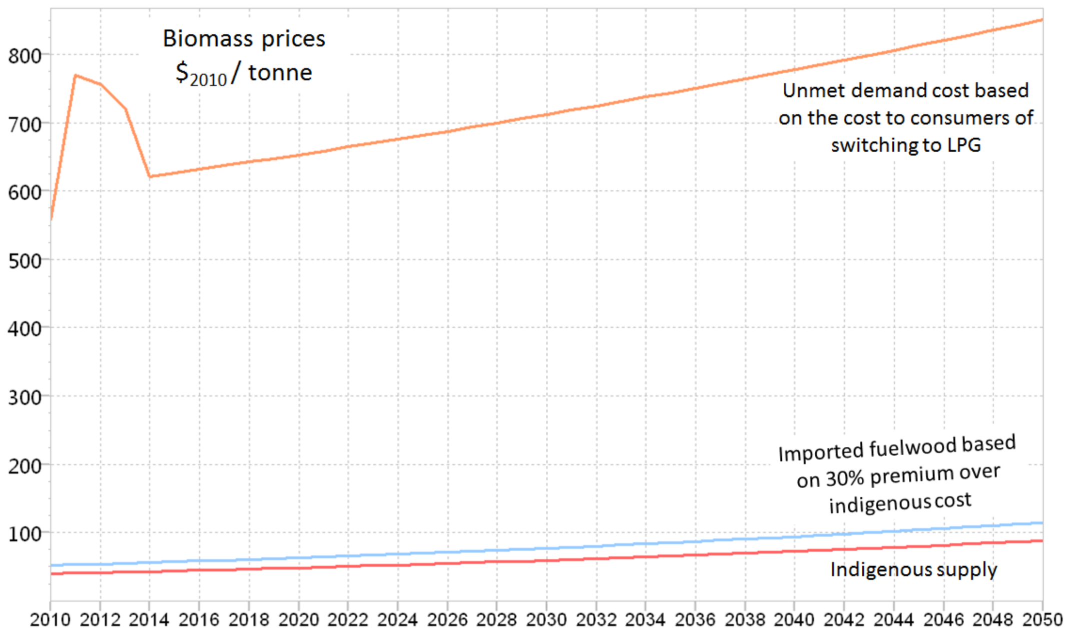


Figure 26. Fuel wood prices of indigenous and imported biomass, and costs of unmet demand



(Sources: IRENA 2012, GTZ 2007 plus others).