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The cost of providing electricity to Africa

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ABSTRACT

Sub-Saharan Africa lacks electricity. We estimate the cost of providing electricity to the region. To do so, we build an optimisation model that links the electricity demand to the supply and links the supply to the generation, distribution and transmission of electricity between countries. To the best of our knowledge, such a model is novel in the literature.

We determine that the investment cost of providing electricity to Sub-Saharan Africa over a 10-year period is between 160 and 215 billion U.S. dollars, depending on assumptions for electricity access and the cross-country electricity trade. Although the electricity trade increases the investment cost estimate moderately, it provides a high return to African countries and is cost-efficient overall.

1. Introduction

Along with India, Sub-Saharan Africa is the region in the world with the lowest per capita consumption of electricity and the lowest rate of electricity access. The annual per capita electricity consumption in Africa is 518 kWh, which is equal to the electricity consumption over 25 days in the OECD (IEA, 2008). Two thirds of the population in Sub-Saharan Africa—585 million people—lack access to electricity (IEA, 2011). In rural areas of Malawi, Ethiopia, Niger, Chad and several other countries, less than 2% of the population have access to electricity.[1]

While Sub-Saharan Africa is struggling to bring electricity to its people, the region has ample undeveloped energy resources. Several countries are rich in hydropower resources. For example, in the Democratic Republic of the Congo, a single hydropower project (Grand Inga) has a potential of 40 GW.[2] Other countries with large hydropower resources include Cameroon, Ethiopia, Sudan, Nigeria, Guinea, Angola and Mozambique. Several countries house large reserves of natural gas, notably Nigeria and Angola. The Republic of South Africa has major coal reserves.

Evidently, a lack of natural resources does not explain the inadequate supply of electricity in Sub-Saharan Africa. But the resources are not put adequately to use. Investment in, e.g., a hydropower plant is a large undertaking for a poor country. The fact that the hydropower reserves are often located far from population centres adds further cost; there are vast areas to be covered by the grid.

Hence, cost is a definite problem, but donors are prepared to pick up a share of the bill.[3] But surprisingly, nobody knows with any degree of confidence what supplying electricity to Sub-Saharan Africa would actually cost. The funding implications of pursuing political targets for household access, or environmental targets, are not known either.

In this paper, we estimate the cost of providing electricity to Sub-Saharan Africa, as well as the costs of political interventions for trade and electricity access. To do so, we set up an optimisation model that, for each country of Sub-Saharan Africa, describes the electricity demand and the opportunities for electricity generation and trade with other countries. The model includes an extensive database of infrastructure stocks, fuel costs and investment and refurbishment costs for a range of technologies, including a long list of potential hydropower projects throughout the continent. This database is combined with data on electricity demand and information about targets related to electricity access. Because several countries are equipped

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[1] When no reference is given, data references in this paper are to Rosnes and Vennemo (2009) and references therein.

[2] 1 GW is 1000 MW. See, e.g., IEA (2008) Box 15.2 for a description of the Grand Inga project.

[3] See Eberhard and Shkaratan (2012) for detailed analysis of funding strategies.

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with abundant energy resources while others are not, it is also important to model trading opportunities in the form of transmission investments and their associated costs.

Having described the generation opportunities, the links between countries and the cost of distributing electricity to households and industries, the model estimates the cost of electricity supply in Sub-Saharan Africa with supply linked to demand and countries linked in a trading framework. An interactive version of the model is available at http://www.infrastructureafrica.org/tools/models/electricity-spending-needs-model.

We wish to analyse the impact of a 10-year expansion programme for electricity in Sub-Saharan Africa. To do so, we use our model to simulate the year 2015 and compare the results with our benchmark year of 2005. The year 2015 is the target year for the Millennium Development Goals, and energy access is important to achieve many of these goals. The year 2005 was chosen as the benchmark year due to the data availability. In a technical sense, the importance of the 10-year label is that economies, in most cases, have increased in size, and the population has grown by the period's end. In addition, it takes time to commission and build power plants and networks, and the time period allows for this. Most capacity additions that have come online since 2005 are included in the model as planned (exogenous) investments. Hence, the results are fairly representative of the next 10 years ahead.

Focusing on a 10-year investment window, we estimate the required investment for providing electricity to Sub-Saharan Africa will be 160–215 billion U.S. dollars (USD), depending on targets for electricity access, trade and other assumptions.[4] This amount will provide 100–120 GW of new and refurbished electricity generation capacity, plus associated distribution and transmission investments. Around two thirds of the additional capacity is new (“greenfield”) investment.

Compared to the GDPs of most African states, 160–215 billion USD is a very large amount.[5] However, it is misleading to compare a one-off investment to annual aid flows or the annual GDP. Our estimated *annualised* cost of meeting *additional* power needs in Sub-Saharan Africa is 28–37 billion USD. This amount is similar to the annual overseas development assistance to Sub-Saharan Africa.[6]

In this study, we pay particular attention to the gains from trade in Sub-Saharan Africa. We construct a benchmark scenario of free trade, which we compare with a scenario of the current capacity for trade. We find that trade requires an investment because new interconnectors must be built and also because a free trade scenario relies on capital-intensive hydropower. However, the investment has an annual expected return of 20–30% for the foreseeable future. In other words, trade is a better investment than most physical investment opportunities. Trade brings not only economic benefits but environmental benefits as well: 70 million tonnes of CO_2 may be saved annually if unrestricted electricity trade is allowed.

We also focus on the cost of scaling up electricity access. Again, we construct two scenarios: a benchmark scenario in which national targets for electricity access are implemented and a scenario in which there is constant access. We estimate that providing electricity access for an additional 300 million people will equal around a quarter of the benchmark cost of the electricity supply.

This paper also reports the sensitivity of the primary results to critical assumptions concerning the economic growth and oil prices. These analyses indicate the power of our model to handle a range of interesting policy questions.

To the best of our knowledge, our model is the first detailed model of the regional electricity system in Sub-Saharan Africa. However, there have been several attempts at modelling the system from other angles. The IEA, e.g., IEA (2011) uses a model that estimates the electricity provision to the whole of Africa as a by-product of a global energy demand and supply. Hence, the estimate is aggregate in nature, and electricity in Africa is not the main focus of the global energy assessment. Also using aggregate assumptions, the World Bank (2006) estimated the cost of providing electricity access to households and villages in Sub-Saharan Africa. This estimate ignored the electricity demands of industries and affluent households, as well as most of the grid cost. Nexant (2007) estimated the cost of electricity provision in the Southern African Power Pool, and Gnansounou et al. (2007) estimated this cost in the Western Africa Power Pool. These efforts also appear to ignore most of the grid cost. We compare our work to these studies in Section 6.

The volume of Eberhard et al. (2011) is a broad discussion of the power sector in Sub-Saharan Africa and draws on several sources, including Rosnes and Vennemo (2009). It does not emphasise the quantitative methodology, however.

Our model groups countries into four power pools. Currently, several countries cooperate closely to supply electricity to the region. For example, the SAPP (Southern African Power Pool) has a formal organisation. In other regions, e.g., Central Africa, there are currently no such organisations. The concept of a power pool is, nevertheless, useful in organising the discussion of results.

To explain the results, it is necessary to describe the theoretical model we use and the data that provides the model with its empirical properties. These issues are discussed next.

2. Model framework

To estimate the investment needs in each country, we have built a linear programming optimisation model that simulates electricity generation and investment strategies in response to the demand in the countries of Sub-Saharan Africa. The optimisation criterion is cost-minimisation subject to constraints; hence, we present the least-cost estimates of the electricity supply.

Our model covers the following 43 Sub-Saharan African countries:

- The Southern Africa Power Pool (SAPP) consists of Angola, Botswana, the Democratic Republic of the Congo (DRC), Lesotho, Mozambique, Malawi, Namibia, South Africa, Zambia and Zimbabwe.
- The Nile Basin–East Africa Power Pool (EAPP) consists of Burundi, Djibouti, Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania and Uganda.
- The Western Africa Power Pool (WAPP) consists of Benin, Burkina Faso, Côte d'Ivoire, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Mauritania, Niger, Nigeria, Senegal, Sierra Leone and Togo.
- The Central Africa Power Pool (CAPP) consists of Cameroon, the Central African Republic, Chad, the Republic of the Congo (Br), Equatorial Guinea and Gabon.
- Cape Verde, Madagascar and Mauritius are included as island states.

Each country is represented by a demand side and supply side. The demand is formulated outside the optimisation model. The supply is determined by the optimisation model based on assumptions concerning available technologies and capacities with the associated costs. The model minimises the cost of producing and distributing electricity, given the demand. The costs include production as well as the investment and refurbishment costs for generation; the investment costs of new cross-border transmission lines; the investment, refurbishment and operation costs of domestic distribution lines; and the cost of new connections to the power grid.

Each country has two demand centres or nodes: urban and rural. For the urban nodes, it is assumed that 70% of the electricity consumption occurs during peak periods. The rationale for this is that most of the industry is located in densely populated areas. For rural

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[4] Here and elsewhere, we use the 2005 value of the USD.

[5] Current Gross National Income in Sub-Saharan Africa was 706 billion USD in 2006 (World Bank, 2009).

[6] According to the organisation One, development assistance to Sub-Saharan Africa amounted to 27 billion USD in 2005 and 40 billion in 2010, see One (2012).

nodes, there is a 50–50 split between the peak and off-peak periods. Peak and off-peak periods are of equal length.

A mathematical formulation of the model is given in the Appendix. The numerical model is implemented in the GAMS programming language (Brooke et al., 1998).

2.1. Supply system

The supply system consists of power generation plants, the transmission grid (between and within countries) and the distribution grids (within countries). The transmission grid is defined by the two highest voltage levels available in a country.

2.1.1. Generation

Each generation technology is described in terms of capacity and cost; we use the countries' existing assets (as of 2005) as a starting point. The existing power plants (bottom-up data) are aggregated into technology-specific categories. The available technologies for power generation are hydropower (i.e., large-scale, including pumped storage, and small-scale), thermal (i.e., fuelled by coal, natural gas, diesel or heavy fuel oil), nuclear, solar photovoltaic (PV) and geothermal power. In addition to the grid-based electricity supply, the off-grid supply provided by mini-hydro, diesel and solar PV is an option in rural areas.

Large-scale hydropower differs from mini-hydro in terms of the production flexibility and investment potential. We assume that all mini-hydro power is run-of-river and has no reservoirs, which means that mini-hydro production remains constant day and night. For large-scale hydro, the reservoirs provide flexibility: it is possible to shift production from a low-demand (off-peak) period to a high-demand (peak) period. This flexibility varies from country to country.

Production in each technology is limited by a maximum number of production hours during a year. For thermal technologies, the maximum number of hours per year that a power plant can run is limited by the need for maintenance and other planned outages. For hydropower and solar PV, the number of hours per year will be limited by factors including the water inflow and available sunlight. Consequently, the number of available production hours per year will be considerably lower than for the thermal technologies.

Capacity expansion is possible through investment, but the maximum investment in each technology is exogenous for each country. This is particularly important for hydropower generation, as the hydropower potential varies significantly from country to country. Similarly, investment in thermal technologies is limited by the availability of fuel. An exogenous minimum investment describes thermal power projects that are being developed but are not yet online.[7] These projects are part of our least-cost solution, regardless of whether they have a higher cost than the alternatives.

Given costs and other constraints, the model endogenously determines which investments (both technology and location) are profitable. In addition, refurbishment can extend the lifespan of the existing capacity; hence, our model has two investment categories: new ("greenfield") investment and refurbishment.[8]

The concept of cost includes the capital cost and the variable operating cost. The variable operating cost is the cost of fuel, operation and maintenance.

[7] The OCGT plants in South Africa that came online in 2007–2009 are included in this manner.

[8] Refurbishment refers to major refurbishments: either to prolong the life of an outdated plant for which the operating life is coming to an end by restoring it to full operational status or to repair generation assets that have been seriously damaged, for example, due to war. Refurbishments do not include costs for ordinary maintenance and repair work.

2.1.2. Transmission and distribution

Investments must be made to extend the distribution and transmission grids, and maintenance of these grids is necessary to keep them in working condition. These investments are determined endogenously in the model as part of the least-cost solution. Again, we distinguish between new capacity and refurbishment.

Trade flows are also part of the optimisation. In other words, electricity trade is *not* based on an extrapolation of today's trends but is the outcome of the optimal development of generation resources in the region and expansion of the cross-border grid. Hence, in comparison to today, the trade flows in the future may be much larger or may even change direction.

Transmission losses are accounted for by assuming an exogenous percentage loss when electricity flows from one node to another. The transmission loss depends on the nodes and the direction of the flows. Distribution losses (in the low-voltage grid) are set as a percentage of the net demand for each node.

We proceed to describe the data that form the parameters of the model.

3. Demand side data

The demand side of each country consists of the three categories market demand, suppressed demand and new connections. *Market demand* for electricity is defined as the demand resulting from economic growth and structural change; that is, the growth in the existing consumers' demand. *Suppressed demand* is that portion of the existing customers' electricity demand that is currently not met due to blackouts and brownouts. *New connections* refer to social targets for new electricity access. The three categories of demand are added to form our country-specific demand projection:

$$\begin{aligned}\text{Demand} = {} & \text{market demand} + \text{suppressed demand} \\ & + \text{new connections}\end{aligned}$$

Market demand and suppressed demand are located in the urban node, while new connections are distributed between the urban and rural nodes.

Below, we explain the methodology for and parameters used in projections of the market demand and new connections. We refer to Rosnes and Vennemo (2009) for a description of suppressed demand but note that suppressed demand is country specific. The average downtime across the countries of WAPP (22%) and CAPP (10%) is much higher than in EAPP (5%) and SAPP (4%).

3.1. Market demand

There are few econometric models of electricity demand in Sub-Saharan Africa (see Khanna and Rao, 2009 for a survey), and we find it useful to explain the model estimated for this project. We model market demand, measured as *annual per capita electricity consumption*, as a log-linear function of real gross domestic product (GDP) per capita and of the agricultural and manufacturing shares of the economy. In addition, we follow Fay and Yepes (2003) and include country-specific fixed effects and time trends to proxy for prices and technological innovation.

We implement the econometric model on a panel covering 11 Sub-Saharan countries.[9] For the remaining countries, the data are either unreliable or missing. The estimation is based on 30 years (1970–2000), which, along with the data for the 11 countries, yields 330 observations.

We allow for first-order autocorrelation and panel correlation in the residuals to control for unobserved factors that may affect the electricity

[9] Benin, Côte d'Ivoire, Cameroon, Ghana, Kenya, Mozambique, Nigeria, Senegal, the Republic of South Africa, Tanzania and Zambia.

demand and may be correlated over time or across countries. All variables are in natural logarithms; in this way, the estimated coefficients can be interpreted as elasticities. We estimate the model with feasible generalised least squares (FGLS), using the econometric software Stata 9.

The estimation results are reported in Table 1.

The results are robust in terms of alternative specifications and sample sizes, with two exceptions. First, the coefficient on construction is sensitive to changes in specification, the use of alternative estimators and changes in sample size. It is close to zero in many specifications and is frequently not robust. We include it in the specification below but exclude it from the projections of future demand. Second, the coefficient on income, representing income elasticity, drops from approximately 1.1 to 0.5 if one includes urbanisation in the regression. The coefficient on urbanisation is highly statistically significant and slightly below unity (0.9). The reason for this effect is the omitted variables bias. Because urbanisation is positively correlated with both real income per capita and electricity consumption (because people in urban areas use more electricity than those in rural areas), omitting it from the regression raises the coefficient on income. We chose to proceed with the model with higher income elasticity because projections of future urbanisation are highly uncertain.

3.2. New connections

Because electricity access rates are very low in many countries, conscious interventions are needed to raise access. New connections refer to the social targets for new electricity access. To model the different targets for electricity access, one needs to specify the average consumption per household and the number of new connections.

In arriving at an estimate of *average consumption per connection*, we utilise an extensive data set collected in Tanzania (Econ Pöyry, 2006; see also Rosnes and Vennemo, 2009). The weighted average monthly consumption for rural and urban areas is 50.4 kWh and 114.7 kWh, respectively. The corresponding average daily maximum demand is 0.29 kW for rural households and 0.64 kW for urban households. We cross-check our estimates with those of the global review of rural electrification programmes performed by Zomers (2001) and those of the IEA (2011). Zomers arrived at an average monthly consumption of 81.75 kWh and an average maximum demand of 0.4 kW. Zomers' estimate may be slightly higher because it is global, with only a few observations from Sub-Saharan Africa. Our estimates are somewhat higher than those of the IEA (2011), which assumes an annual consumption of 250 kWh in rural households and 500 kWh in urban households in the first year of connection, gradually rising to the national average. This assumption is based on an a priori judgement of what is needed per day to cover basic needs (IEA, 2011, Box 13.1). Our estimates of 50.4 and 114.7 kWh correspond to 604 and 1376 kWh per year, respectively.

The *number of new connections* depends on the targets for increasing households' access to electricity. The targets are considered exogenous variables and discussed below. Targets must be compared to current access rates. We develop country-specific rates of current access for urban and rural areas. In total for Sub-Saharan Africa, we find a current access rate of 16% in rural areas and 65% in urban areas, resulting in a weighted total of 34%. The main source for this data is the World Bank World Development Indicators, based on the United Nations Statistical Office Annual Energy Questionnaire. For countries for which the data were missing, we used other sources, including the IEA (2006) and ECOWAS (2006). See Rosnes and Vennemo (2009) for details and individual country estimates.

Table 1
Econometric model for market demand: estimation results.

Regressor	Coefficient	Standard error	Z	$P>z$
Income	1.071	0.056	19.08	0.000
Agriculture	−0.255	0.047	−5.42	0.000
Manufacturing	0.127	0.053	2.38	0.017
Construction	−0.074	0.032	−2.34	0.019
Constant	−9.415	0.488	−19.28	0.000

Variables in logarithms. Manufacturing includes mining sector. Residuals assumed autoregressive and panel correlated.

4. Supply side data

On the supply side, we collect data for variable costs, unit investment cost and potential capacity levels for generation technologies, transmission and distribution.

4.1. Generation technologies

The starting point is the set of existing generation assets in 2005, characterised by the generation capacity and variable costs (e.g., fuel, operation and maintenance). We distinguish the assets that will need refurbishment before 2015, either because they need refurbishment by the benchmark year 2005 (due to war or previous mismanagement) or because they will need it in the years 2005–2015. If no specific information about the current state is available, we assume that the refurbishment needs are based on the asset age. Refurbishment can extend the lifespan of existing capacity at a cost considerably lower than that of greenfield investments.

We also assess the potential for greenfield investments for each country. It is useful to examine the main generation technologies and options in turn.

4.1.1. Hydropower

Hydropower costs are generally site-specific. We build our estimate of hydropower cost and capacity from the bottom up, going through project information country by country. In total, 227 hydropower projects in Sub-Saharan Africa were examined for their investment cost, capacity, firm energy production, age and, when available, refurbishment cost. The list of projects is not exhaustive, but a subset where good data could be obtained. We excluded projects smaller than 10 MW.

Hydropower plant information for the EAPP, SAPP and WAPP regions was mostly derived from the regional master plans prepared by the WAPP and SAPP power pools, the East African Union and the Nile Basin Initiative through the Nile Equatorial Lakes Subsidiary Action Programme (NELSAP) and the Eastern Nile Subsidiary Action Programme (ENSAP). Plant information for the CAPP region is mostly derived from various internet sources and is therefore not as complete and coherent as the data for the other regions.

In this model, we use one estimate of the hydro unit investment cost per country. In the case that there are several potential hydropower projects, the unit investment cost is the weighted average of the investment costs of the potential projects in the country, and the weights reflect the planned capacity of the plants. Where riparian countries share the water rights to a project, the cost and potential of the project are allocated between the partners. The unit investment cost estimate varies between countries, and most fall in the range of 1000–2000 USD/kW.

Refurbishment normally requires the replacement of runners, rewinding of generators and partial replacement of transformers, as well as the replacement and upgrade of switchgear, control and protection equipment. An increase in production capacity can be achieved by using more modern equipment. Heavy siltation can reduce the lifespan of dams considerably unless sufficient desiltation is provided. Several of the countries incorporated in this study have undergone civil wars; consequently, many hydropower stations have been more or less destroyed, requiring additional funds for reconstruction. Other countries have been so strapped for funds that normal maintenance has not been performed. Such negligence leads to the rapid deterioration of the installation, which, in turn, increases the repair cost ten-fold. Still, refurbishment is usually much more economical than a new installation, and typically costs approximately 300 USD/kW.

4.1.2. Thermal power plants

In contrast to hydropower, thermal power plants can be built almost anywhere. Nevertheless, the availability of fuels limits the feasibility of certain investments. Therefore, we allow for investments in natural gas-fired power plants in countries that have domestic gas reserves or that are (or will be) connected to a gas pipeline (such as the West Africa Gas Pipeline). Investments in coal-fired power plants are reserved for countries that have domestic coal resources. Oil products (e.g., diesel and heavy fuel oil) are assumed to be available in most countries. No new nuclear power is allowed, but the existing nuclear capacity in South Africa continues the operation.

Thermal power plant technologies are generic. The unit cost of investment is therefore similar across countries. Due to market pressures, costs increased in recent years until the global economic downturn of 2008–2009. We use unit cost estimates that are in line with the accepted international values from several sources (see Rosnes and Vennemo, 2009): 1100 USD/kW for coal, 670 USD/kW for natural gas and 335 USD/kW for small diesel units. Refurbishment costs are assumed to be 15% of the investment costs, with the exception of coal, for which the costs are relatively higher at 272–300 USD/kW (based on estimates in the literature and a detailed analysis of South African coal plants).

The cost of operating thermal power plants depends on the fuel cost. For coal, a world market price of 52 USD/tonne is our benchmark, based on a projected price for 2015 from EIA (2006). The prices of diesel and heavy fuel oil (HFO) are related to the world market price of crude oil. The price of oil has been highly volatile in recent years: six years prior to 2005, it was 10 USD/barrel; since 2006, it has gone from 35 USD to 150 USD, then back to 35 USD/barrel again, then up to 125 USD… Our scenarios are based on a price of 47 USD/barrel. The sensitivity in terms of oil price assumptions is discussed in Section 5.5. The world market price is also adjusted for transport costs. For the EAPP and SAPP regions, we use country-specific data provided by Metschies (2005). For the CAPP and WAPP regions, we use data provided by Arthur Energy Advisors (2007).

Estimating the price of natural gas is particularly challenging because the price and availability of gas is highly dependent on the infrastructure, such as pipelines. We assume that for countries that have the potential to export gas (e.g., Nigeria), the price of gas is related to the world market price of oil (i.e., gas has an alternative value). For countries that have no infrastructure to export gas (e.g., Mauritania), the price of gas is related to the domestic production costs. We adjust the price of gas delivered to the power plant to reflect transportation costs; countries with domestic resources are assumed to have a lower gas price than countries that import gas through a pipeline (e.g., Benin, Togo and Ghana).

4.2. Transmission and distribution (T&D)

We distinguish between domestic transmission (lines with voltages of 66 kilovolts (kV) or greater), domestic distribution and international transmission lines.

4.2.1. Domestic

For domestic T&D infrastructure, we assume that the stock will grow at half the rate of market demand, an assumption commonly used by regulatory authorities. In addition, we assume that over the 10-year period, the original asset stock will depreciate at 3% per year.[10] Combined with annual variable costs of 2%, the relevant annual investment to maintain capacity over the 10-year period is 5% of the original T&D stock.

The refurbishment requirements are based on the asset age: lines older than 30 years are assumed to need refurbishment at a unit cost corresponding to 60% of the replacement value. In several countries, the transmission systems are quite old. For example, in Niger, 96% of the system is more than 30 years old; in Zimbabwe, 85%; in Zambia, 80%; and in the DRC, 61%. Distribution systems are younger on average.

4.2.2. International

Transmission investments are determined endogenously in the model. The total cost of a cross-country line depends on the unit cost per km per MW and the line length (in km). The unit costs, per km and per MW, of investing in transmission lines have been provided for each country. For cross-country lines, we have used weighted unit costs for which the weights have been based on the approximate share of the line built in the two countries. The line length depends on the distance between load centres in the two countries or between a load centre and a possible power plant location (where locations are known). For instance, the relevant distance for a line between Mozambique and South Africa is the distance from Cahora Bassa North to Johannesburg.

4.3. Supply side assumptions related to new connections

We assume that urban households connect to the grid, while 70% of new rural connections are covered by grid extensions; Deichmann et al. (2010) reach a similar conclusion. The rest are supplied by off-grid mini-hydro (20%), diesel (5%) or solar PV (5%).

4.3.1. Connection cost in urban areas

The connection cost in urban areas consists of strengthening and extending the low- and medium-voltage distribution lines as well as the lines to dwellings with the installation of credit meters, etc. USAID (2004) and Gaunt (2005) provide estimates of the costs of the urban electrification programmes in South Africa, which are approximately 420 USD and 350 USD per connection, respectively. The cost of urban electrification is, to a large extent, generic across countries, but other countries lack South Africa's economies of scale. We use a slightly higher figure of 500 USD per connection for the remaining countries.

Once urban households connect to the grid, they send an impulse to generate more power. The cost of producing power delivered through the grid is calculated by the generation module of the model.

4.3.2. Connection cost in rural areas

In rural areas the cost of *grid extension* is similar in type but more expensive than the cost for urban connections. Often, one requires the installation of low- and medium-voltage sub-transmission lines (for example, 11 kV and 33 kV, respectively). The cost per connection equals the contribution to demand for sub-transmission lines and a distribution network in addition to the actual connection cost.

The connection cost of *mini-hydro* equals that of grid extension. The generation costs of mini and micro-hydropower stations are included in the connection cost estimate.

The starting point of our estimates of cost per connection to the grid extension and mini/micro hydropower is the extensive global review of rural electrification projects and the studies by Zomers (2001), who arrives at an estimated grid extension cost of nearly 1500 USD per connection (distribution cost of 1200 USD, transmission cost of 125 USD, and service connection of 100 USD). These

[10] 3 % per year implies that 40 % of the asset is functioning after 30 years.

data correspond with the estimates from Tanzania by Econ Pöyry (2006), which provides detailed estimates of costs per connection for several districts in 19 different regions in Tanzania, each with different access rates and population densities. The resulting average unit cost per connection in the 19 different regions lies between 550 and 4300 USD. The average unit cost across all regions is 1547 USD. Studies from Zambia (Sanghvi et al., 2005) and Mozambique (Bergman and Davies, 2005) estimate a cost per connection at approximately 2000 USD. Based on Econ Pöyry's work and the findings of Zomers, it is assumed that large-scale electrification programmes would converge around a cost of approximately 1550 USD in most countries. The main exceptions are South Africa, which requires 350 USD even for rural connections, and the island states (2500 USD).

Moving on to off-grid alternatives, *diesel* generation involves a generator accompanied by a distribution network, generally with no need for transmission or sub-transmission lines. Thus, the relevant connection cost is simply the unit distribution and service connection costs. Here, Zomers' (2001) cost of 1325 USD per connection is used. The operation of diesel generation requires fuel and capital. The capital investment costs for small diesel units are derived from expert judgement and cross-checked for this study against data from producers of mini-diesel plants, such as Jacobsen, Caterpillar and others. The unit capital cost used in the model is 335 USD/kW.

The *solar PV* markets in most Sub-Saharan African countries have only recently been developed. As a result, prices have fallen considerably in most countries in recent years. CORE (2003) reports the results of Afrepren, which arrives at an estimated average price of 1100 USD for a 50 Watt-peak (Wp) system for the SAPP countries. However, the work performed by Econ Pöyry (2006) in Tanzania and Zambia, where the markets are undeveloped, revealed prices of 650–800 USD. Other more recent sources from South Africa, Ethiopia, Sudan, Kenya and Uganda reveal similar prices. Thus, country-specific cost data are applied for those countries for which it is available, while a conservative estimate of 800 USD is applied to the remaining countries.

5. Results: investment needs and costs

Having presented our methodology and data, we turn to the results of our analysis: what are the investment needs of Sub-Saharan Africa over this 10-year period and what are the costs of these investments? Investment needs and costs depend not only on the model and its data but also on the exogenous variables. Important exogenous variables include country-specific economic growth, targets for new connections and assumptions about the electricity trade. We introduce a benchmark scenario for these variables. Afterwards, we bring in the impact of alternative assumptions.

5.1. Benchmark scenario: Trade and national targets for new connections

The benchmark scenario is characterised by the following exogenous assumptions:

- Best guess for economic growth (which is an important driver of market demand for electricity, see Table 1). National annual growth rates range between 2% and 9%. Projections of economic growth from 2005–2015 are compiled from the World Bank (2009).
- Targets for household access to electricity in urban and rural areas as defined by the stated national policy targets in each country. On average, the targets imply that access rates are lifted to 67–100%, depending on the region. This translates to 62 million new connections.[11]
- Fully integrated regional power pools. At present, the level of integration and cooperation varies between the different regions. We allow further integration within the four power pools to seek out cost savings when electricity is supplied in the most cost-efficient way.

[11] Assuming five individuals per household, as Rosnes and Vennemo (2009) and IEA (2011) assumed, 62 million connections provides electricity to 310 million people. Because of population growth, however, we cannot conclude that the number of people without electricity is cut from 600 to 300 million.

Table 2
Demand for electricity before and after 10-year programme (TWh).

Region	Total net demand 2005	Market demand and suppressed demand 2015	Demand of new connections 2015	Total net demand 2015
SAPP	259	383	14	397
EAPP	101	145	24	169
WAPP	31	70	25	94
CAPP	11	17	3	20
Island states	1	2	2	3
Total Sub-Saharan Africa	403	616	68	683

Note: Total gross demand is larger than net demand because it includes transmission and distribution losses.

5.1.1. Demand

With these assumptions, the demand for electricity at the end of the 10-year programme (2015) is 70% higher than before the programme starts (Table 2). Three quarters of the additional demand is associated with economic growth (market demand), and one quarter is associated with new connections. The Southern Africa Power Pool is the largest region of demand and the source of half of the increase over time. However, the relative weight of Southern Africa declines over time. The Western Africa Power Pool has the highest percentage of growth, more than 200%. One reason for this is that suppressed demand is particularly high in the WAPP region.

5.1.2. Investment needs

By model simulation, we determine the need for capacity addition to meet demand in this scenario to be approximately 80 GW in Sub-Saharan Africa. This entails almost a doubling of its current capacity, which, for the whole of Sub-Saharan Africa, was 87 GW in 2005. In addition, almost 40 GW of today's capacity will be refurbished. Almost half of the total available capacity at the end of the investment programme is hydropower.

5.1.3. Investment costs

We estimate that the investment cost of the expansion programme comes to approximately 215 billion USD (Table 3). Only approximately half of this amount is related to generation. To carry the new generation to market, substantial amounts of new transmission and distribution lines are required, as well as new connection points. The cost of these items makes up the other half of the total.

Although refurbished capacity is one third of the total in physical terms, the cost of refurbishing generation capacity is only one tenth

Table 3
Investment costs in Sub-Saharan Africa over 10 years (billion USD).

	SAPP	EAPP	WAPP	CAPP	Islands	Total
Generation						
Investment cost, new capacity	32.2	32.7	27.0	6.6	0.4	99.0
Refurbishment cost	7.6	0.4	1.5	0.3	0.0	9.8
T&D and new connections						
Investment cost, new capacity	23.7	27.4	29.8	2.3	1.3	84.5
–Cross-border transmission lines	3.1	1.0	0.9	0.3	0.0	5.3
–Distribution grid	12.7	3.1	11.9	0.3	0.1	28.1
–Connection cost (urban)	4.0	5.7	7.6	1.0	0.4	18.8
–Connection cost (rural)	4.0	17.6	9.3	0.7	0.7	32.4
Refurbishment cost	9.8	3.3	6.1	0.2	0.1	19.5
Total	*73.3*	*63.8*	*64.4*	*9.5*	*1.8*	*212.7*

of the cost of new capacity. This shows that the unit cost of refurbishment is significantly lower than the unit cost of new capacity.

It is interesting to note the differences between the regions. The EAPP stands out due to its large expenses on connections in rural areas and low expenses on the distribution grid. One reason for this behaviour is that the countries of the EAPP have particularly high access targets and aim for 14 million new connections in rural areas. The WAPP stands out for having high expenses overall. The investment cost in the WAPP region is almost on par with the EAPP and comparable to the SAPP, even though the WAPP region is a much smaller power pool. However, we previously observed that capacity expansion in the WAPP is similar to the EAPP. It adds to investment costs that several of the main hydropower projects in the WAPP are relatively expensive to build. We also note that the investment cost in the CAPP is much smaller than in the other power pools, which is due to the fact that the CAPP is a much smaller pool and the estimated capacity additions are also smaller.

5.1.4. Annualised cost of system expansion and operation

A description of investment costs does not capture variable costs of fuel, maintenance and operation associated with generating electricity. Moreover, the economic significance of the investment cost depends on the lifetime of the investment asset and the discount rate of the capital.[12] To incorporate both the variable costs and the annual equivalent of the capital costs, we introduce the concept of the *annualised cost of system expansion and operation*. The annualised cost of system expansion and operation is the entity that our model seeks to minimise by combining transmission, distribution and generation technologies. The system in question consists of generation, transmission and distribution assets that are refurbished or added over the course of the investment period, plus the assets operating at the initiation of the investment period. Hence, the annualised cost of system expansion and operation consists of the following three elements:

Annualised cost of system expansion and operation = Annualised capital cost of new and refurbished assets + variable cost of new and refurbished assets + variable costs of pre-existing assets not needing refurbishment.[13]

Note that the annualised cost of expansion and operation refers to a cost that continues for as long as one operates the system. Hypothetically, if the system is operated into eternity, the cost will stay on into eternity as well.

We estimate that the annualised cost of system expansion and operation associated with the investment programme of this scenario is approximately 48 billion USD (Table 4). However, almost 12 billion USD is used for operating pre-existing assets that do not need refurbishment. Hence, the relevant entity for assessing the *additional* strain on the economy of Sub-Saharan Africa is 36 billion USD. 80% of this additional strain is comprised of annualised capital cost.

There are interesting differences between the regions. Variable costs are particularly low compared to the annualised capital costs in the WAPP and CAPP regions; specifically, it is the variable cost of generation that is low. This finding indicates that hydropower is particularly important for generation in the WAPP and CAPP regions. A cross-check with the generation mix confirms the finding. In the WAPP, the share of hydropower in the least-cost mix is 77%, and in the CAPP, it is as high as 97%. In the EAPP, the variable costs of running the transmission and distribution system are particularly high. The transmission and distribution asset stock is large in this region, due to the large distances within and between countries.

Table 4
Annualised costs of system expansion and operation in Sub-Saharan Africa, benchmark scenario (billion USD).

	SAPP	EAPP	WAPP	CAPP	Islands	Total
Generation						
Investment cost	4.5	4.4	3.5	0.9	0.1	13.4
Refurbishment cost	1.3	0.1	0.3	0.0	0.0	1.7
Variable cost (fuel, O&M)	5.3	6.0	2.7	0.1	0.3	14.4
– New capacity	2.1	5.4	0.3	0.1	0.3	8.1
– Existing capacity	3.2	0.7	2.5	0.0	0.0	6.3
T&D and new connections						
Investment cost	2.9	3.3	3.7	0.3	0.2	10.4
–Cross-border	0.4	0.1	0.1	0.0	0.0	0.7
–Distribution grid	1.6	0.4	1.5	0.0	0.0	3.5
–Urban connection	0.5	0.7	0.9	0.1	0.1	2.3
–Rural connection	0.5	2.1	1.2	0.1	0.1	4.0
Refurbishment cost	1.2	0.4	0.8	0.0	0.0	2.4
Variable cost (existing capacity)	3.1	0.8	1.3	0.1	0.0	5.3
Total						
Capital cost	10.0	8.2	8.2	1.2	0.2	28.0
–Investment cost	7.5	7.7	7.2	1.2	0.2	23.8
–Refurbishment cost	2.6	0.5	1.0	0.1	0.0	4.1
Variable cost	8.4	6.8	4.0	0.2	0.3	19.7
Total	*18.4*	*15.0*	*12.3*	*1.4*	*0.6*	*47.6*
–of which existing assets	6.3	1.5	3.8	0.1	0.0	11.6
–of which new and refurbished assets	12.1	13.5	8.5	1.3	0.6	36.0

5.2. What will targets for electricity access cost?

Recall that the benchmark scenario assumes 62 million new household connections. How much of the cost is derived from this target? We contrast the benchmark scenario of nationally derived access targets with the *constant access scenario*. Together, the two scenarios span a range for access developments in Sub-Saharan Africa over the next few years.

The constant access scenario implies that access rates are kept constant at the 2005 levels. Due to population growth, the constant access scenario does imply 17 million new connections, mostly in urban areas, and 85 million more people are given access to electricity. Still, we consider it a scenario of low ambition.

The constant access scenario carries an investment cost of approximately 160 billion USD (Table 5), which is roughly 25% lower than the benchmark scenario. Based on this result, we believe that the main cost of providing electricity to Africa does *not* depend on providing electricity access to new customers. The main cost depends on meeting the market demand associated with the economic growth.

Table 5
Investment costs in Sub-Saharan Africa over 10 years in different scenarios (billion USD).

	Benchmark	Constant access rate	Trade stagnation	Low growth
Generation				
Investment cost	99.0	87.0	85.5	81.2
Refurbishment cost	9.8	9.6	9.8	9.6
T&D and new connections				
Investment cost	84.5	42.6	79.2	69.6
–Cross-border transmission lines	5.3	5.7	0.0	5.3
–Distribution grid	28.1	28.1	28.1	13.2
–Connection cost (urban)	18.8	7.4	18.8	18.8
–Connection cost (rural)	32.4	1.4	32.4	32.4
Refurbishment cost	19.5	19.5	19.5	19.5
Total	*212.7*	*158.7*	*194.0*	*180.7*

[12] The annuity formula we use is *annualised capital cost = investment cost* $* \, r(1-1(1+r)^{-T})^{-1}$. Based on professional judgement, we use a real discount rate of 12 % p.a. The life-time T differs between assets. We assume a life-time of 40 years for hydropower plants, 30 years for coal and 25 years for natural gas.

[13] By "not needing refurbishment" we mean no refurbishment during the 10-year period studied.

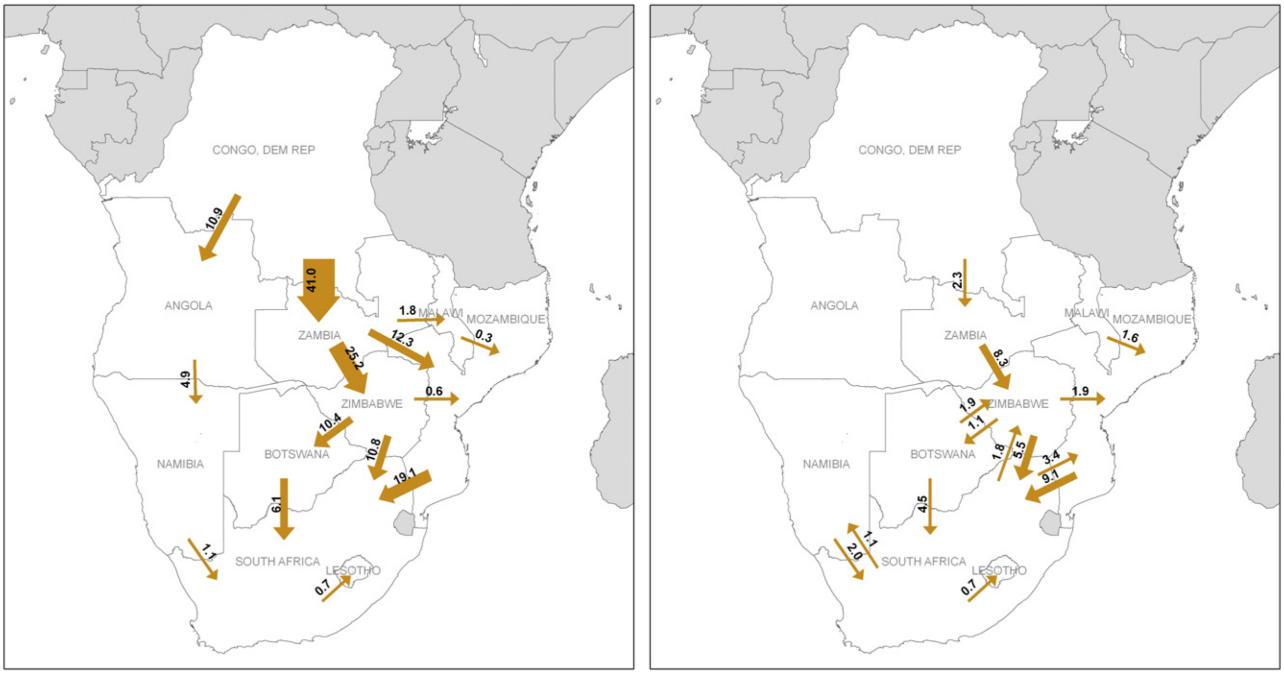

Fig. 1. Trade flows with trade expansion (left) and trade stagnation (right) in the SAPP after 10-year programme (TWh). Note: In the trade stagnation scenarios, the capacity on interconnectors equals the 2005 actuals, but the direction of trade flows may differ.

We also examined the total annualised cost of the system expansion and operation; even this variable differs by approximately 25% from the national targets scenario.

5.3. The benefits of regional integration

In the benchmark scenario, we have allowed for imports and exports of electricity within a power pool whenever it is economically beneficial. It was determined that it is cost-efficient for all power pools to make extensive use of trading possibilities. In the SAPP, for example, the DRC emerges as a huge exporter of electricity.[14] The DRC's net export is almost four times larger than its domestic consumption, and it supplies hydropower through Zambia, Zimbabwe and Botswana into South Africa. South Africa becomes an importer of 10% of its domestic consumption, trading with all neighbouring countries: Namibia, Botswana, Zimbabwe, Mozambique and Lesotho (Fig. 1).

A main supplier nation emerges in each of the power pools. The WAPP is, to a large extent, supplied by Guinea; the CAPP supply is driven by Cameroon; and the EAPP supply is driven by Ethiopia, followed by Sudan. These few countries, led by the DRC, are the main supply bases in regionally integrated power pools.

In reality, of course, trade in such an essential commodity as electricity requires significant cooperation and coordination among countries. Hence, achieving optimal power trade will require a range of important political, legal and economic commitments. It is beyond the scope of this paper to discuss the nature of the commitments needed to secure trade. This paper focuses on the benefits of trade, which is represented by the cost difference between trade expansion and trade stagnation.

The *trade stagnation scenario* assumes that no new interconnectors between countries are built in any power pool. The existing interconnectors can be used, and trade flows and volumes are determined endogenously. Hence, it is the opposite extreme to the benchmark scenario of trade expansion and serves to illustrate the range of possibilities in terms of trade.

A vivid illustration of the difference between the two scenarios is given in Fig. 1. The trade stagnation scenario obviously foregoes extensive trading opportunities and forces countries to cover their electricity demand using their own means.

From this observation, the benefits of trade emerge. It is important to realise that trade must be viewed as an investment. We find that it requires approximately 19 billion USD in additional investment costs (see Table 5). First, trading requires an investment in interconnectors, which amounts to approximately 5 billion USD. Second, trading allows hydropower to substitute for thermal power; this is more economical overall, but the investment cost is higher. The total generation investment is 14 billion USD higher in the trade expansion scenario.

5.3.1. Gains from trade

What is the return from this investment? We find that annual savings in variable cost amount to 5 billion USD. It is clear that 5 billion USD is quite a good return on an investment of 19 billion USD. The profitability of an investment is often indicated by the internal rate of return. The internal rate of return depends on market conditions, such as prices, and the depreciation profile of the investment. As a benchmark, assume an eternal lifetime of the investment and unchanged market conditions. In this case, five billion becomes a constant annual stream, and the internal rate of return is 27%. More cautiously, one could deduct 5% as depreciation and maintenance and claim a rate of return of 22%, which would still remain a good investment.

The gains from trade differ between power pools. In the SAPP, the additional investment is repaid in less than a year, and the internal rate of return is 168%. In this region, the required additions to transmission lines are low, and hydropower investments (mostly in DRC) have relatively low unit costs. Simultaneously, there are ample opportunities for hydropower to replace coal-fired power in South Africa. In the other regions, the benchmark internal rate of return varies between 20% and 33% (Table 6). By far, the largest reshuffling of generation occurs in the EAPP. Trade allows the EAPP to utilise

[14] Due to its large hydropower resources and central position, the DRC could, in the future, become supplier to the EAPP and CAPP, as well as the SAPP.

Table 6
Savings and costs when there is trade (billion USD).

	Additional investment cost	Savings in variable cost	Internal rate of return (savings over investment)
SAPP	0.6	1.1	168%
EAPP	15.1	2.9	19%
WAPP	2.1	0.7	34%
CAPP	0.9	0.3	28%
Total	18.7	5.0	27%

Note: There are no gains from trade in island states because they do not trade electricity.

hydropower resources in the Nile Basin, mostly in Ethiopia and Sudan. These resources replace the natural gas-fired generation in Kenya, Egypt and elsewhere. However, the demands on investments are also particularly heavy in this power pool, and the internal rate of return is lower than in the other pools.

It is perhaps expected that trade leads to savings in the variable costs of new capacity. However, savings also apply to the existing capacity. This means that some existing capacity is so inefficient that the variable and capital cost of new capacity combined is lower than the variable cost of the existing capacity. In particular, this is the case in the EAPP, where the import of hydropower is replacing the thermal capacity in Egypt.

5.3.2. Environmental benefits

In addition to economic gains, the electricity trade brings important environmental benefits to the table. We expect an annual saving of 70 million tonnes of CO_2. Of this, approximately 40 million tonnes will be saved when coal power in South Africa is replaced by hydropower from the DRC. Approximately 20 million tonnes will be saved when natural gas in Egypt and Kenya is replaced by hydropower from Ethiopia and Sudan. The rest is divided between a number of sources.

To put the estimate of 70 million tonnes into perspective, the IEA has estimated emissions from power production in Africa to be 405 million tonnes in 2009 (IEA, 2011). The savings from trade are equivalent to 17% of this volume. The numbers do not include greenhouse gas emissions from hydropower in the form of methane from dams, which could modify the estimate.

5.4. The role of economic growth

Although several countries of Sub-Saharan Africa have experienced healthy economic growth in recent years, the per capita growth forecasts are low for some countries (e.g., 0.2% for Guinea-Bissau ; 0.3% for Niger), and it is of interest to analyse the implications of lower economic growth for electricity supply costs. For simplicity, we assume that the annual economic growth per capita is cut to half in each country in the continent.[15]

Because of the positive relationship between electricity demand and economic growth, it must be expected that the investment requirement for electricity is reduced when growth is lower.[16] Market demand falls, but because the income elasticity is greater than one, the market demand falls less than economic growth. In addition, the suppressed demand and new connections are unaffected.

The net result of the experiment is a decrease in the additional capacity (investments plus refurbishments) from 119 to 102 GW and a decrease in the investment requirement from 215 to 180 billion USD (Table 5). Of course, the lower investment requirement is no easier to finance by domestic sources because the economies that are to shoulder the investment are smaller in this scenario. Somewhat contrary to our expectations, the share of hydropower is *higher* in this scenario than in the baseline. In other words, the hydropower investments are, to a large degree, sheltered from lower economic growth. Sufficient trading opportunities are available, even in a 15% smaller market, to carry the economies of scale required by hydro. This result powerfully supports the development of hydropower in Sub-Saharan Africa, despite uncertain market conditions.

5.5. The impact of oil prices

Few variables are surrounded with as much uncertainty as future oil prices. When considering a long-term investment in power production, it is the long-term average oil price that matters. In the simulations to test for the sensitivity of oil prices, we applied a crude oil price in the range of 25–75 USD/barrel. The consequences of an even higher oil price, for example, 125 USD/barrel, follow by extrapolation. We have used historical data to estimate the correlation between the crude oil price and the prices of other oil products and natural gases.

Sensitivities show that a higher oil price leads to a higher share of hydropower in the generation mix, a higher total investment, and higher annual costs of electricity supply. There are two mechanisms behind this result. First, higher oil prices cause investments in thermal power plants to be less attractive. Second, higher oil prices also cause the operation of existing gas-, oil- and diesel-fuelled power plants to be more expensive, thus contributing to the faster replacement of existing plants. Because hydropower has substantially higher investment costs than thermal power plants, the up-front investment cost is higher.

As hydropower resources are developed, however, the potential for replacing fossil fuels with hydropower is depleted. Further increases in oil prices will therefore have a diminishing impact on investments while the annual costs continue to increase.

Note that oil-based fuels (e.g., diesel and HFO) make up only a tiny share of the total electricity production capacity in Sub-Saharan Africa. The main technologies are hydropower and coal-fired power, counting for approximately one-half and one-third of total production capacity in 2015, respectively. Natural gas is important in several regions (i.e., Eastern and Western Africa), but we have assumed that gas prices are related to oil prices only in countries that export gas. Oil-related fuels have only 3% of the total production capacity and less than 2% of the production in Sub-Saharan Africa in 2015. However, these fuels can be important in isolated regions.

6. Comparison with the literature

As we mentioned in the introduction, there are already several projections of the cost of electricity provision in Sub-Saharan Africa. When comparing these projections to each other and to our work, one should note the following:

- Demand assumptions: Does the projection cover the market demand, new connections or both?
- Transmission and distribution assumptions: Does the projection cover transmission, distribution or both?
- Trade assumptions: Is trade based on optimisation or extrapolation of today's trends? Are investments in international transmission lines based on optimisation or on existing plans?
- Unit cost assumptions: How are unit costs of generation investments specified?

Other assumptions, such as fuel prices, are also important.

The IEA regularly publishes electricity demand forecasts for Africa as part of its World Energy Outlook. The main tool for these forecasts is the World Energy Model. Like our model, the World Energy Model considers economic activity and population as exogenous factors and

[15] This assumption was also chosen to imitate the impact of a shorter investment window than ten years at the original pace of growth.

[16] Economic growth can be a driver of electricity demand as well as a response to electricity demand. In our study, we have not discussed this issue, but we did note the historical correlation between the two as represented in our econometric demand equation.

derives demand on that basis. Supply depends on technology, and the whole energy sector is observed in context. The IEA (2011) concludes that 69 GW of power generating capacity will be added in the whole of Africa over the period of 2009–2020, which is approximately 85% of our estimate. Hence, the IEA's capacity projection for Africa is lower than ours. The IEA builds its demand forecasts by sector but states that economic growth is by far the most important determinant in demand. The main difference with our demand analysis seems to be the aggregate impact of economic growth on the electricity demand in Africa, i.e., the income elasticity. The IEA assumes an annual economic growth in Africa of 4.6% for the period of 2009–2020, but its electricity demand only increases 3.1% annually. Hence, its aggregate income elasticity in terms of the demand per capita is only approximately 0.7, while it is 1.1 in our analysis.

Another determinant of demand is household access rates. The IEA (2011) assumes that access rates increase from 31% in 2009 to 35% in 2015 and to 56% in 2030. In our national targets scenario, we assume a similar increase (to 59%) by 2015. In addition, we assume higher consumption per new connection, as discussed in Section 3.2. This also contributes to the lower IEA demand projections for 2015.

On the supply side, the IEA finds, as we did, that the investment cost of transmission and distribution is about as large as the cost of generation, approximately 45% of the total investment. However, the unit investment cost is 50% higher in the IEA analysis, which is approximately 3 USD million per MW in total compared to an average of roughly 2 million USD per MW across the technologies and countries included in our analysis. The reason is not that the IEA requires a higher return to capital; on the contrary, its return requirement seems to be lower.[17] Instead, the reason may simply be that the IEA uses PPP dollars, whereas we have used nominal dollars based on actual cost estimates.[18] In addition, we include a significant amount of refurbishment at a low unit cost.

The World Bank (2006) estimates the cost of increasing access, corresponding to new connections in our terminology. They find that a total of 280 billion USD is required in the generation, transmission and distribution of electricity until 2030 to provide electricity to 100% of the population (i.e., 200 million new connections). While several of the assumptions regarding new connections and consumption per new connection are similar to those made in this study, the World Bank (2006) takes a more generalised approach to estimating costs. The World Bank (2006) assumes that 75% of all households connected by 2030 would be through grid connections. The low voltage distribution cost is assumed to be 500 USD per household until 35% of households are connected, 800 USD between 35% and 50%, 1000 USD between 50% and 75%, and 1500 USD thereafter. The off-grid connection cost is assumed to be 800 USD per household. Losses in generation and transmission are assumed to amount to 1.5 billion USD per GW. Despite differences in methodology, the end result of the World Bank (2006) exercise is comparable to our estimate of the marginal cost of new access connections. The 280-billion USD investment to obtain 200 million new connections averages 1400 USD per connection. Our similar estimate is 1200 USD per connection.[19]

Gnansounou et al. (2007) estimate the cost of the increasing electricity supply in the WAPP and study the cost advantages of the electricity trade. Their analysis is model-based, and the model is presented as a “least-cost techno-economic model”. Only grid-based electricity demand is considered, which emphasises the concept of market demand. An important difference from our study is that the cost of transmission and distribution investment in the WAPP only amounts to 3% of the total cost. By contrast, we find transmission and distribution to be approximately 50% of the total cost. From their presentation, it seems that Gnansounou et al. (2007) ignore national transmission and distribution, and their cost component for transmission and distribution is referred to as the “cost of adaption and expansion of interconnection lines”. This brings the numbers together because transmission makes up only 3% of the investment cost in our data, as well (Table 3).

Although the method is similar in principle, Gnansounou et al. (2007) find far greater benefits in the electricity trade in the WAPP than we do. In their analysis, trade brings about a reduction in the discounted total costs of electricity of no less than 38%. By comparison, we find a reduction in the annualised cost of system expansion and operation of 5.1%. They claim that the electricity trade reduces capital expenditures. We find that electricity trade increases capital expenditures due to more hydropower and more interconnectors. The difference here could be due to the different assessments of transmission and distribution costs. Gnansounou et al. (2007) compare their results to earlier studies, including Sparrow et al. (1999) and Graeber et al. (2005), which also estimate quite large benefits of the electricity trade.

Nexant (2007) is a regional generation and transmission expansion plan that assesses power investment requirements in the SAPP for the period of 2006–2015. The study is not based on an optimising framework, but calculates the costs of specific additions to the generation capacity as well as the specific transmission reinforcements needed to support the anticipated levels of trading (based on the individual TSO assessments). With this exception, the results of Nexant are quite similar to those of Gnansounou et al. (2007). The cost of distribution is ignored, and the cost of transmission is found to be small compared to the cost of generation. Trade leads to large (approximately 50%, 12 billion USD) savings in investment costs and small (approximately 4%) savings in the variable cost. By contrast, we find an increase in the investment cost of 0.6 billion USD in the SAPP and large (approximately 20%) savings in the variable cost. At a methodological level, the fact that Nexant (2007) does not require constrained optimality means that a non-optimal situation with trade is compared to a non-optimal situation without trade.

7. Conclusions

Sub-Saharan Africa demands large amounts of electricity, both to develop economically and to end the untenable situation in which nearly 600 million of its people do not have access to electricity. International finance institutions and bilateral donors are ready to work with the governments of Sub-Saharan Africa to increase the electricity supply, but nobody knows the cost of this endeavour. Our study has found that a realistic estimate for the region over a 10-year period is approximately 100–120 GW in terms of generation capacity investments and that the investment cost would amount to approximately 160–215 billion USD. The estimate includes a significant amount of refurbishment, which is more economical than greenfield investments. The cost of generation comprises half of the total, while transmission and, in particular, distribution comprise the other half. The annual cost of system expansion and operation, a concept that includes variable cost (e.g., fuel cost) and the annualised cost of capital, amounts to 39–48 billion USD. Approximately 10–12 billion of this amount refers to a cost-efficient operation of the existing electricity system. The lower end of the 39–48 billion range is associated with moderate access targets. The higher end of the range is associated

[17] The IEA (2011) does not state its return requirement explicitly, but from the background material, it appears to be 5–10 %. An annual cost reduction (“learning curve”) is also assumed. To us, 5–10 % seems quite low for African conditions and, as noted, we use 12 %.

[18] Generally, the PPP rate of dollar against poorer countries' currencies is lower than the nominal rate. This is to correct for a lower price level in the poorer countries. However, when equipment is imported to the poorer country, the use of PPP can be misleading. Consider a country with a nominal exchange rate of 10:1 versus USD and a PPP rate of only 1:1. If a machine that costs one USD is imported, it will cost 10 in local currency. When translated back to USD using PPP, the price suddenly becomes 10 USD.

[19] We develop our estimate by comparing the constant access and benchmark scenarios. There are 62 million new connections in the benchmark scenario of national targets, and 17 million new connections in the constant access scenario. The difference is 45 million connections, which creates an investment cost difference of 55 billion USD.

with national access targets and trade stagnation. The range is similar in size to current annual overseas development assistance to Sub-Saharan Africa.

The range of investment is spanned by ambitions in terms of providing electricity access to new households. The 160-billion USD estimate is obtained if one maintains the current access rates. Most of this cost is for satisfying the electricity demand from industry, the public sector and affluent households. The 215-billion USD estimate is obtained if one assumes that national targets for electricity access are met. Viewed as projections, the national targets may be optimistic, and the current access assumption may be pessimistic.

Economic growth is an important driver of the market demand from industry, the public sector and affluent households. We estimate an income (GDP) elasticity of 1.07. Still, cutting economic growth per capita by one-half only reduces the investment requirement from 215 to 180 billion USD. This relatively small reduction is partly due to the fact that the cost of new connections and eliminating suppressed demand is independent of economic growth. Moreover, population growth will, by itself, imply increased demand.

Even though we technically focus on the period until 2015, our estimates can be generalised to a later 10-year period, e.g., 2010–2020 or 2013–2023. On the demand side, there are two opposing developments. On one hand, the global economic recession starting in 2008 has reduced growth rates in Africa, although not as much as it has in other parts of the world. On the other hand, the population growth continues. On the supply side, many of the most advanced projects are delayed, while others are still on the drawing table.

There are significant economic benefits to linking the power systems of different countries and encouraging trade. In contrast to earlier studies, such as Nexant (2007) and Gnansounou et al. (2007), we have determined that allowing electricity trade in Sub-Saharan Africa will generate higher investment costs. The reason for our result is partly that trade will require strengthening the transmission lines and partly that trade will allow an expansion of capital intensive hydropower production at the expense of thermal power production. However, we find that the higher investment costs are counteracted by the lower variable costs. Therefore, viewed as an investment, trade in Sub-Saharan Africa carries an annual internal rate of return of 20–30%. In the SAPP, the pay-back time is less than a year, and the rate of return is above 100%. Trade also saves significant amounts of CO_2, which is interesting in its own right. For example, NGOs have sometimes claimed that trade is detrimental to the environment. Here is an example for which that is clearly not the case, at least for CO_2.

Rosnes and Vennemo (2009) report on a number of policy experiments that we have not related here, including the higher investment costs of critical technologies, CDM support to clean energy, and the impact of climate change.

Although our work provides considerable detail on the cost of electricity supply in Sub-Saharan Africa, there are aspects that could be improved upon in later studies. Demand is not price elastic; hence, there is no simultaneous determination of demand and supply. We are not convinced that price is an important equilibrating factor in several countries, but the current dichotomy between supply and demand is not satisfactory either. Another issue is that the categorisation of countries into one of four power pools has a degree of arbitrariness. In future work, we would like to analyse the integrated trade across the continent on one hand and the interaction between the physical possibilities for trading and political constraints on the other.

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Appendix A. Supplementary data

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