61811 v1

AICD
AFRICA INFRASTRUCTURE COUNTRY DIAGNOSTIC

BACKGROUND PAPER 5 (PHASE II)

Powering Up: Costing Power Infrastructure Spending Needs in Sub-Saharan Africa

Orvika Rosnes and Haakon Vennemo
Econ Pöyry, in association with Norplan and Power Planning Associates

MARCH 2009

Africa's Infrastructure | A Time for Transformation

1818 H Street, NW
Washington, DC 20433 USA
Telephone: 202-473-1000
Internet: www.worldbank.org
E-mail: feedback@worldbank.org

A publication of the World Bank.

The World Bank
1818 H Sreet, NW
Washington, DC 20433 USA

About AICD

This study is a product of the Africa Infrastructure Country Diagnostic (AICD), a project designed to expand the world's knowledge of physical infrastructure in Africa. AICD will provide a baseline against which future improvements in infrastructure services can be measured, making it possible to monitor the results achieved from donor support. It should also provide a better empirical foundation for prioritizing investments and designing policy reforms in Africa's infrastructure sectors.

AICD is based on an unprecedented effort to collect detailed economic and technical data on African infrastructure. The project has produced a series of reports (such as this one) on public expenditure, spending needs, and sector performance in each of the main infrastructure sectors—energy, information and communication technologies, irrigation, transport, and water and sanitation. *Africa's Infrastructure—A Time for Transformation*, published by the World Bank in November 2009, synthesizes the most significant findings of those reports.

AICD was commissioned by the Infrastructure Consortium for Africa after the 2005 G-8 summit at Gleneagles, which recognized the importance of scaling up donor finance for infrastructure in support of Africa's development.

The first phase of AICD focused on 24 countries that together account for 85 percent of the gross domestic product, population, and infrastructure aid flows of Sub-Saharan Africa. The countries are: Benin, Burkina Faso, Cape Verde, Cameroon, Chad, Côte d'Ivoire, the Democratic Republic of Congo, Ethiopia, Ghana, Kenya, Lesotho, Madagascar, Malawi, Mozambique, Namibia, Niger, Nigeria, Rwanda, Senegal, South Africa, Sudan, Tanzania, Uganda, and Zambia. Under a second phase of the project, coverage is expanding to include as many other African countries as possible.

Consistent with the genesis of the project, the main focus is on the 48 countries south of the Sahara that face the most severe infrastructure challenges. Some components of the study also cover North African countries so as to provide a broader point of reference. Unless otherwise stated,

therefore, the term “Africa” will be used throughout this report as a shorthand for “Sub-Saharan Africa.”

The World Bank is implementing AICD with the guidance of a steering committee that represents the African Union, the New Partnership for Africa’s Development (NEPAD), Africa’s regional economic communities, the African Development Bank, the Development Bank of Southern Africa, and major infrastructure donors.

Financing for AICD is provided by a multidonor trust fund to which the main contributors are the U.K.’s Department for International Development, the Public Private Infrastructure Advisory Facility, Agence Française de Développement, the European Commission, and Germany’s KfW Entwicklungsbank. The Sub-Saharan Africa Transport Policy Program and the Water and Sanitation Program provided technical support on data collection and analysis pertaining to their respective sectors. A group of distinguished peer reviewers from policy-making and academic circles in Africa and beyond reviewed all of the major outputs of the study to ensure the technical quality of the work.

The data underlying AICD’s reports, as well as the reports themselves, are available to the public through an interactive Web site, www.infrastructureafrica.org, that allows users to download customized data reports and perform various simulations. Inquiries concerning the availability of data sets should be directed to the editors at the World Bank in Washington, DC.

Contents

Acknowledgments

The authors wish to thank the following individuals for excellent research assistance: Halvor Aarrestad, Ryan Anderson, Sarah Carter, Jonathan Hedgecock, Sudeshna Ray, Ståle Skrede, and Fredrik Wilander. We also thank Vivien Foster of the World Bank for her patience and astute comments, and Steven Kennedy for improving the language. Their efforts significantly improved the report.

Abbreviations and acronyms

African Development Bank	ADB
Agence Française de Développement	AFD
Africa Infrastructure Country Diagnostic	AICD
Central Africa Power Pool	CAPP
Clean Development Mechanism	CDM
certified emission reduction credits	CERs
Nile Basin–East Africa Power Pool	EAPP
Energy Information Administration	EIA
gross domestic product	GDP
gigawatt	GW
gigawatt-hour	GWh
heavy fuel oil	HFO
high voltage	HV
International Energy Agency	IEA
independent power producer	IPP
kilovolt	kV
kilowatt-hour	kWh
long-run marginal cost	LRMC
low voltage	LV
megawatt	MW
New Partnership for Africa's Development	NEPAD
operations and maintenance	O&M
Southern Africa Power Pool	SAPP
solar photovoltaic energy	solar PV
transmission and distribution	T&D
terawatt-hour	TWh
United States Agency for International Development	USAID
United States Department of Agriculture	USDA
Western Africa Power Pool	WAPP

Summary

Sub-Saharan Africa will require substantial investments in the power sector—on the order of 4 percent of the region's gross domestic product (GDP) annually before 2015—if it is to meet the demands of economic development, keep pace with population growth, and expand electrification beyond the 2005 regional average of just 34 percent. Developing a regional power-trading market that exploits the vast hydropower potential of the subcontinent may be the best way to bring those costs down while also protecting against increases in oil prices and curbing carbon emissions. Expanding electrification is a daunting challenge, but the costs associated with extending the transmission network are minor in comparison with the investments in generation needed to accompany the demand of Africa's growing economies.

A model to inform energy policy decisions

Nowhere in the world is the gap between available energy resources and access to electricity greater than in Sub-Saharan Africa. The region as a whole is rich in oil, gas, and hydropower potential, yet 66 percent of its population lacks access to electricity, with coverage especially low in rural areas. National authorities and international organizations have drawn up plans to increase access, but key policy choices underpin these plans. Which type of power generation is right in which settings? Should individual countries move ahead independently, or should they aim for coordinated development? What are the benefits of regional trade in power, and who are the main beneficiaries? How should major global trends, such as rising oil prices and looming climate change, affect decisions about power generation in Africa? How rapidly can Africa electrify? How sensitive are power investment decisions to broader macroeconomic conditions?

To answer these questions, we developed a model to analyze the costs of expanding the power sector over the course of 10 years under different assumptions. The model simulates optimal (least-cost) strategies for generating, transmitting, and distributing electricity in response to demand increases in 43 countries of Sub-Saharan Africa, grouped into four power pools. The Southern Africa Power Pool (SAPP) consists of Angola, Botswana, Democratic Republic of Congo, Lesotho, Mozambique, Malawi, Namibia, South Africa, Zambia, and Zimbabwe. Within SAPP, South Africa clearly occupies a dominant position, accounting for 80 percent of overall power demand. The Nile Basin–East Africa Power Pool (EAPP) consists of Burundi, Djibouti, Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania, and Uganda. Here, Egypt is the driving force, accounting for 70 percent of power demand within EAPP. 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. In WAPP, Nigeria dominates, with two-thirds of electricity consumption in the region. The Central Africa Power Pool (CAPP) consists of Cameroon, the Central African Republic, Chad, the Republic of Congo, Equatorial Guinea, and Gabon. In CAPP, the Republic of Congo and Cameroon are the major players, sharing 90

percent of power demand. Finally, Cape Verde, Madagascar, and Mauritius are included in our study as island states.

The exercise begins with a projection of power demand over 10 years, 2005–15. Demand consists of (a) *market demand* associated with different levels of economic growth, structural change and population growth; (b) *suppressed demand* created by frequent blackouts and ubiquitous power rationing; and (c) *social demand*, as expressed in political targets for increasing access to electricity. Based on historic trends, demand is projected to grow at 5 percent per year in Sub-Saharan Africa, reaching levels of 680 terawatt-hours (TWh) by 2015. Demand is projected to grow at 4–5 percent per year in SAPP and EAPP to reach levels of 400 and 170 TWh, respectively. The other regions have even higher electricity demand growth: 7 percent per year in CAPP, 9 percent per year in the island states and 12 percent per year in WAPP. The absolute demand levels, however, are lower in these regions: 20 TWh in CAPP, 3 TWh in the island states combined, and about 100 TWh in WAPP. In all cases except the islands, market demand accounts for the great bulk of demand growth over the period.

The model then looks for the least costly way of meeting the new demand based on investments in electricity generation, transmission, and distribution. Those investments include refurbishment of existing capacity for electricity generation and construction of new capacity for cross-border electricity transmission. Our analysis covers four modes of thermal generation (natural gas, coal, heavy fuel oil, and diesel) and four renewable generation technologies (large hydropower, mini-hydro, solar photovoltaic [PV], and geothermal). Minihydro, diesel, and solar PV are off-grid alternatives; that is, they are not connected to the central power grid. Operation, but not new investment, of current nuclear power is considered.

The main value of the model is that it can be run under a number of different scenarios to highlight the implications of various policies. For example, by comparing a “trade-stagnation” scenario under which no further cross-border transmission capacity is built with a trade-expansion scenario under which all economically viable cross-border transmission capacity is developed, we can quantify the gains from trade. The model can also be used to evaluate the feasibility of alternative electrification targets, ranging from maintaining constant access rates, to raising electrification to a uniform level over ten years, to pursuing a range of national electrification targets. The impact of higher oil prices, higher investment costs and lower rainfall can be gauged through their effects on the relative cost of different generation technologies, while the consequences of slower economic growth on power sector investment needs can also be readily quantified.

A high price tag

How much will it cost to meet market demand for power in 2105 while eliminating power shortages and achieving national policy targets for access to electricity?

It is clear that these achievements will require substantial investments in the power sector, demanding about 82,000 MW new generation capacity in total. This entails almost a doubling of current capacity, which for the whole of Sub-Saharan Africa stands at 87,000 MW (2005 data).

Since many power installations in Africa are old, much of the capacity operational in 2005 needs to be refurbished before 2015. In the SAPP region, a 2005 capacity of 48,000 MW is expected to be reduced to 17,000 MW, and some 28,000 MW of generating capacity will have to be refurbished (Table A, column "National targets for access rates"). In addition, more than 33,000 MW of new generating capacity will have to be built, an increase of about 70 percent over the 2005 level. In EAPP, the needs for refurbishment are minimal, but 26,000 MW of new generation will be required, essentially doubling the installed capacity of the region. The investment requirements are even larger in WAPP and CAPP: 18,000 MW new capacity will have to be built in WAPP, corresponding to 180 percent of current capacity, while CAPP requires investments of more than 2.5 times 2005 capacity, or 4,400 MW in total. More than half of current capacity must be refurbished both in WAPP and CAPP (7,000 MW and 900 MW, respectively).

It is clear that each region, particularly West and Central Africa, require significant investment. The good news is that economic growth drives most demand. Therefore, at least according to the projections, the financial strength to finance investments should emerge alongside new investment needs.

The *annualized capital investment costs* in Sub-Saharan Africa are 2.2–2.4 percent of the region's GDP in 2015. There is, however, considerable variation between the different regions. The annualized capital investment costs are 2 percent of GDP for the SAPP region, and 2 to 3 percent of GDP for the EAPP and WAPP regions, but below 2 percent in CAPP (table B).

The costs of *operating* the entire power system are similar to investment costs, around 1.7–2.1 percent of GDP in total. The variation between regions is even more pronounced here: the costs are just under 2 percent of GDP for the SAPP region, and about 3 percent of GDP in the EAPP region, while they are about 1.5 percent in WAPP and a negligible amount in CAPP (0.2–0.4 percent of GDP).

Thus, *total spending* amounts to 4.2–4.4 percent of GDP in Sub-Saharan Africa. The total spending is about the same magnitude in SAPP and WAPP, but around 6 percent of GDP in EAPP and 2 percent in CAPP. Around two-thirds of overall system costs are associated with generation infrastructure, and the remaining third with transmission and distribution infrastructure.

Table A Generating capacity in Sub-Saharan Africa in 2015, under various trade, access, and growth scenarios

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
Generation capacity (MW)	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Southern Africa Power Pool					
Installed capacity [a]	17,136	17,136	17,136	17,136	17,136
Refurbished capacity	28,029	28,035	28,046	28,148	28,046
New capacity	31,297	32,168	33,319	32,013	20,729
Hydropower share (%)	33	33	34	25	40
Eastern Africa Power Pool					
Installed capacity [a]	22,132	22,132	22,132	22,132	22,132
Refurbished capacity	1,369	1,375	1,375	1,381	1,375
New capacity	23,045	24,639	25,637	17,972	23,540
Hydropower share (%)	49	47	46	28	48
Western Africa Power Pool					
Installed capacity [a]	4,096	4,096	4,096	4,096	4,096
Refurbished capacity	5,530	6,162	6,972	6,842	5,535
New capacity	15,979	16,634	18,003	16,239	17,186
Hydropower share (%)	82	79	77	73	80
Central Africa Power Pool					
Installed capacity [a]	260	260	260	260	260
Refurbished capacity	906	906	906	1,081	906
New capacity	3,856	4,143	4,395	3,833	3,915
Hydropower share (%)	97	97	97	83	97
Island states					
Installed capacity [a]	282	282	282	282	282
Refurbished capacity	83	83	83	83	83
New capacity	189	369	368	368	353
Hydropower share (%)	25	19	19	19	20
Total Sub-Saharan Africa					
Installed capacity [a]	43,906	43,906	43,906	43,906	43,906
Refurbished capacity	35,917	36,561	37,382	37,535	35,945
New capacity	74,366	77,953	81,722	70,425	65,723
Hydropower share (%)	48	47	47	36	52

a. "Installed capacity" refers to installed capacity as of 2005 that will not undergo refurbishment before 2015. Existing capacity that will be refurbished before 2015 is not included in the installed capacity figure, but in the refurbishment figure.

Table B Estimated annualized cost of meeting power needs of Sub-Saharan Africa under two trade scenarios (national targets for electricity access)

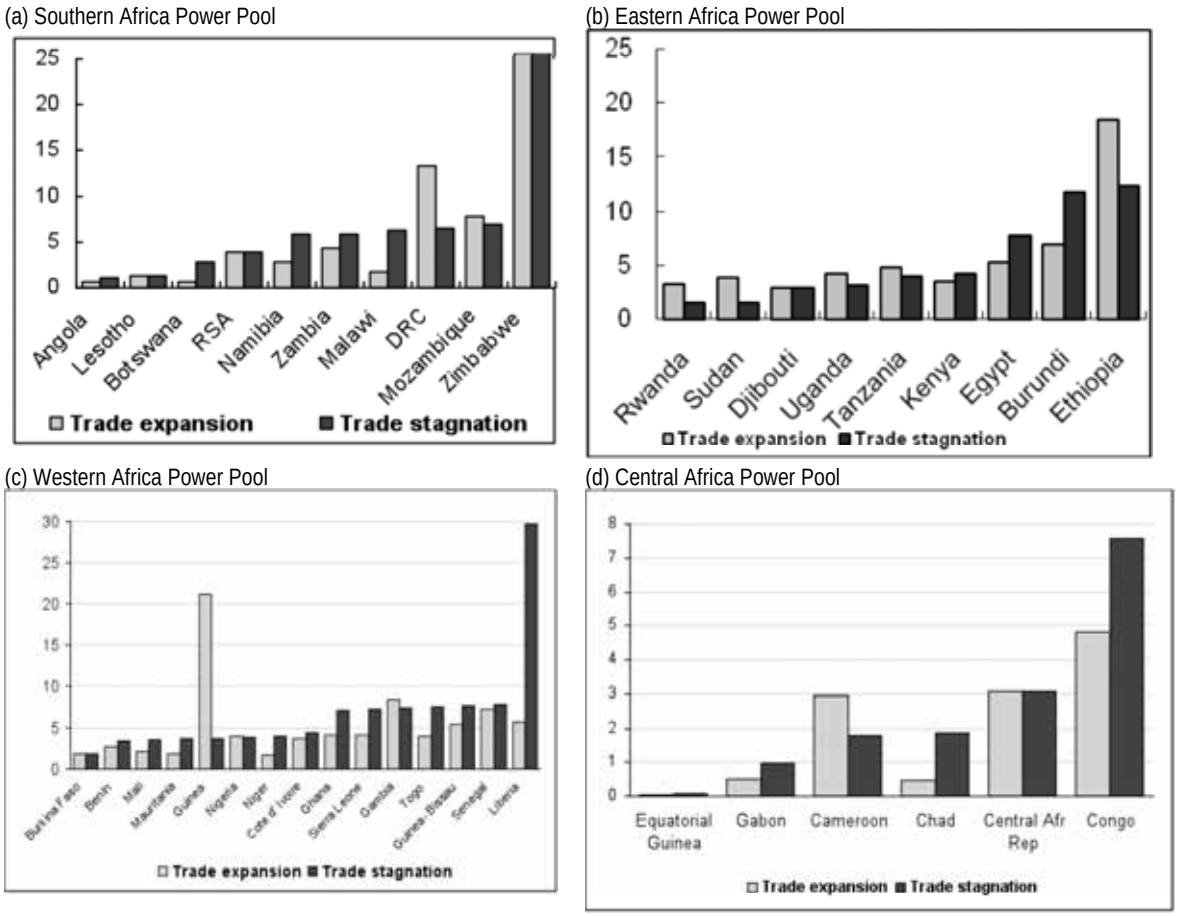
US$ billions and % of GDP	Southern Africa Power Pool		Eastern Africa Power Pool		Western Africa Power Pool		Central Africa Power Pool		Island states		Total Sub-Saharan Africa	
Trade expansion												
Total estimated cost	18.4	3.7%	15	5.7%	12.3	4.2%	1.4	2.0%	0.6	3.1%	47.6	4.2%
of which total												
Capital costs	10.0	2.0%	8.2	3.1%	8.2	2.8%	1.2	1.8%	0.2	1.4%	27.9	2.4%
Operating costs	8.4	1.7%	6.8	2.6%	4.0	1.4%	0.2	0.2%	0.3	1.7%	19.7	1.7%
of which total												
Generation	11.1	2.2%	10.5	4.0%	6.5	2.2%	1.0	1.4%	0.4	2.0%	29.5	2.6%
Transmission and distribution	7.3	1.5%	4.5	1.7%	5.8	2.0%	0.4	0.6%	0.2	1.1%	18.1	1.6%
Trade-stagnation												
Total estimated cost	19.5	3.9%	16	6.0%	12.7	4.4%	1.5	2.2%	0.6	3.1%	50.3	4.4%
of which total												
Capital costs	10.0	2.0%	6.3	2.4%	8.0	2.7%	1.1	1.6%	0.2	1.4%	25.6	2.2%
Operating costs	9.4	1.9%	9.7	3.7%	4.8	1.6%	0.4	0.6%	0.3	1.7%	24.7	2.2%
of which total												
Generation	12.6	2.5%	11.6	4.4%	7.1	2.4%	1.2	1.7%	0.4	2.0%	32.8	2.9%
Transmission and distribution	6.9	1.4%	4.4	1.7%	5.7	1.9%	0.3	0.5%	0.2	1.1%	17.5	1.5%

Note: Subtotals may not add up to the totals because of rounding.

The overall cost of developing the power system appears high, but not unattainable relative to the GDP of each regional trading area. But both GDP and power investment requirements are very unevenly distributed within the regional pools. As a result, under certain scenarios, some countries face power spending requirements that are burdensome relative to the size of their economies (figure A). In SAPP, depending on the electrification target and other variables, spending requirements may exceed 6 percent of GDP in the Democratic Republic of Congo, Mozambique, and Zimbabwe. In EAPP, countries such as Egypt, Burundi, and Ethiopia may require similar levels of spending. About half of the countries in WAPP have investment requirements of almost 10 percent of GDP, and Guinea and Liberia stand out at almost 30 percent. In CAPP, only the Republic of Congo requires investments of more than 5 percent of GDP. Some of these countries have the potential to become major exporters of power, provided they receive cross-border injections of capital to develop their power infrastructure. The necessary capital is not likely to materialize, however, unless trade in power expands.

Figure A Overall power spending needed to reach national targets for electricity access under alternative trade scenarios by country

% of GDP in 2015



What is the cost of expanding electrification?

We considered the impact of raising electrification levels from 2005 access levels to a uniform level across each region or to the levels specified in national electrification targets. The regional target levels roughly add 1 percent access every year over a ten-year period.

Due to relatively low power consumption by households, the impact of expanding electrification is quite modest. For instance, if national access targets are reached across Sub-Saharan Africa, the region's power generating requirement (in terms of MW) will only increase 10 percent, or $4 billion per year. The development of transmission and distribution networks, however, would require significant additional investment amounting to $5 billion per year across the region. The cost of transmission and distribution for access is particularly high in EAPP.

As a result, raising electrification levels to meet national electrification targets would entail a commitment of $9 billion per year, or 0.8 percent of GDP of Sub-Saharan Africa. There are, however,

regional differences. In SAPP and CAPP the cost would be 0.3 and 0.4 percent of GDP, compared to 1 percent in WAPP and as much as 1.5 percent in EAPP.

The 0.8 percent of GDP needed to increase access is included in the 4.2 percent estimate that we gave above on the cost of providing electricity for market and social needs. This shows that the majority of electricity needs is driven by market demand needs.

How sensitive are power investments to economic growth?

Economic growth creates greater demand for electricity, while also providing some of the resources needed to pay for it. Lower growth reduces demand. We explored a low-growth scenario in which economic growth per capita was assumed to be 50 percent lower than assumed in our base case. In SAPP, the largest reduction in power demand would occur in South Africa, where investments in new coal-fired plants would be put on hold. In EAPP, lower demand growth would first reduce investments in gas-fired power plants in Egypt. Hydropower investments would be only slightly reduced under the low-growth scenario, implying that even with slower economic growth the market remains large enough to justify the expansion of almost all the hydropower capacity considered in the base case. In WAPP, less of the old gas-fired capacity in Nigeria would be refurbished and less of the hydropower in Côte d'Ivoire would be exported to Ghana. In CAPP, hydropower investments in the Republic of Congo would be reduced by almost 30 percent, but imports from Cameroon would increase to partly replace them.

Overall, the reductions in annual power spending needs resulting from lower growth are 10 percent in EAPP and CAPP, about 15 percent in WAPP, and almost 25 percent in SAPP. For all of Sub-Saharan Africa the reduction is 20 percent. The cuts may seem modest compared to a 50 percent cut in economic growth per capita, but keep in mind that economic growth for the country is much higher than economic growth per capita since the population is continually increasing. In fact, the low growth scenario lowers spending needs more than it lowers GDP, and spending needs as a share of GDP would decrease from 4.2 to 4.0 percent.

Why trade power?

African countries have different endowments of natural resources: some have abundant hydropower resources, while others have domestic resources of coal or natural gas. Some have no domestic energy resources but depend on imported diesel fuel to generate power. Trade with neighboring countries enables power production from the cheapest sources in the region. By stimulating the development of hydropower, expanded regional trade in power would lower the generation costs, reduce carbon emissions from power plants, and insulate countries from hikes in the price of fossil fuels. Expanded trade would also encourage investment. For example, the optimal size of a new hydropower plant is often so large that domestic demand cannot absorb the large capacity expansion, so the new plant will not be built.

Further development of power trade will incur significant infrastructure costs to develop cross-border transmission capacity. It is estimated that some 12 GW of needed interconnectors are lacking in SAPP and 14 GW in EAPP. The interconnector needs are less in the other areas: some 5.5 GW in WAPP and only 800 MW in CAPP. Building those lines would cost around $380 million per year in SAPP, $130 million in EAPP, $120 million in WAPP, and $40 million in CAPP.

The benefits of building the interconnectors would be substantial, reducing annualized power system costs by between 5 and 11 percent in the trading regions. The savings would be the largest in CAPP at 11.5 percent, compared to 7–8 percent in SAPP and EAPP and 5.1 percent in WAPP. Keep in mind, however, that operation of existing equipment contributes to the annual cost in 2015. The cost of running this equipment adds to the annualized system cost, but it cannot reasonably be expected to be influenced by future trade.

Power trade would save Sub-Saharan Africa an estimated $2.7 billion annually, or 5.3 percent of the annual cost of meeting power needs (or 7.2 percent of the cost when the operation of existing equipment is deducted; see table B). The savings come largely from substituting hydro for thermal plants, which substantially reduces the operating cost of the power system, although it requires more investment in the short run. For example, power trade would provide operating cost savings of 1 percent of the area's GDP in EAPP and almost 0.5 percent of the area's GDP in CAPP. In EAPP and WAPP the hydropower plants substitute for gas-fired power plants, while in CAPP the new hydropower replaces thermal power fueled by heavy fuel oil (HFO), which is more expensive and more polluting than gas-fired plants.

The savings on operating costs can be considered a return on the additional capital investments made under the trade scenario. In SAPP, the additional investment cost under trade is recouped in less than a year, yielding an annual return of 167 percent. The return is lower in the other three regions, but still generous at around 20–34 percent; the additional investment cost of the trade scenario is recouped over three to four years. For Sub-Saharan Africa as a whole the return on trade investment is 27 percent.

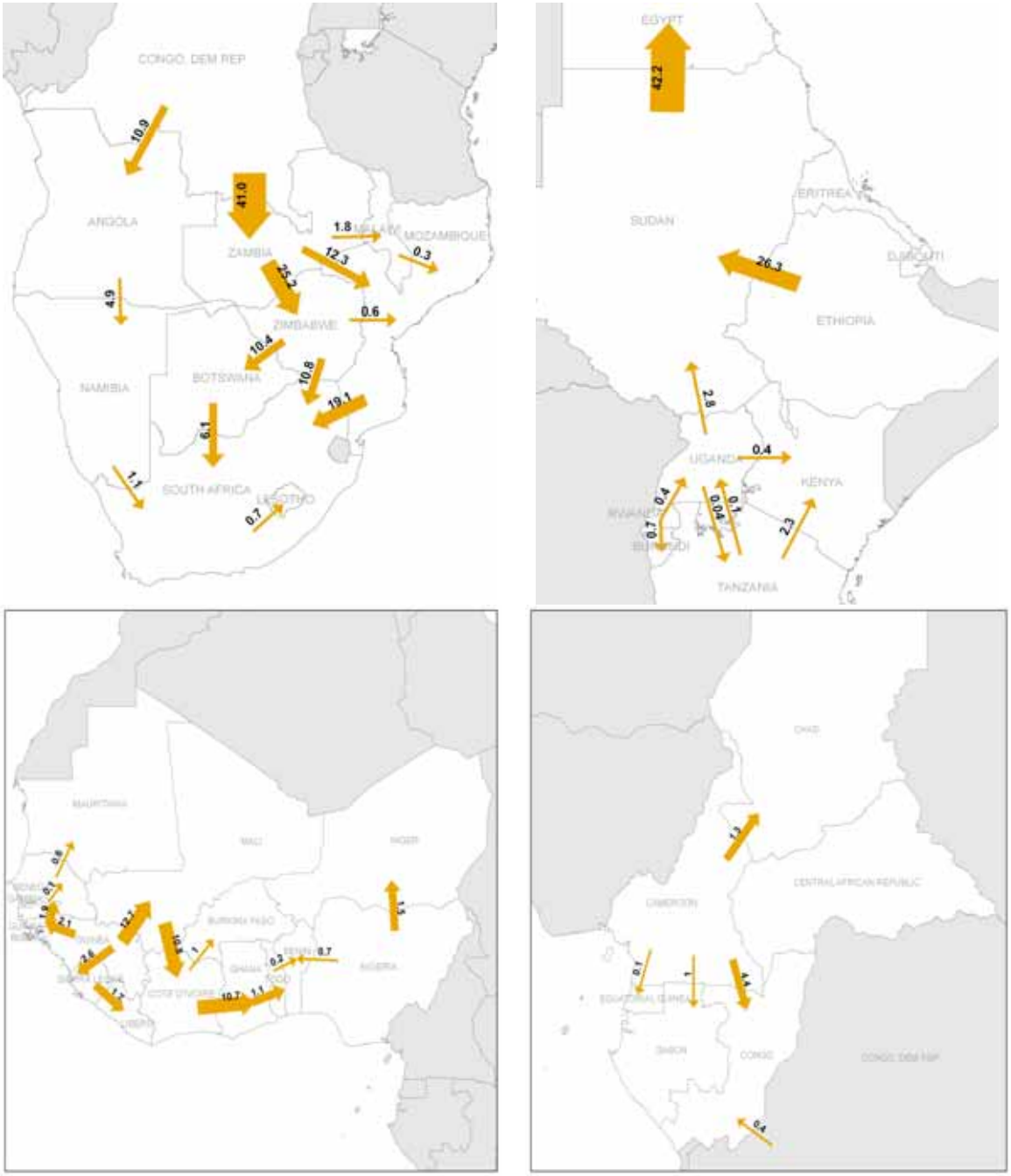
Moreover, the gains from trade increase as fuel prices rise, since trade reduces the use of thermal power plants and thus saves fuel. As fuel prices rise, hydropower projects become more profitable. At an oil price of $75/barrel (instead of $46/barrel in the base case), the gains from trade in EAPP amount to almost $3 billion annually.

What patterns of trade would emerge?

The expansion of power trade, as in our trade-expansion scenario, would allow countries with significant hydropower potential to develop their capacity and meet demand elsewhere.

In SAPP, the hydropower share would rise from 25 to 34 percent of the generation capacity portfolio. The Democratic Republic of Congo becomes the major exporter of hydropower, exporting three times as much as its domestic consumptions, while Mozambique continues to be a significant exporter. Hydropower from the Democratic Republic of Congo flows southward along three parallel routes through Angola, Zambia, and Mozambique (figure B). Countries such as Angola, Botswana, Lesotho, Malawi, and Namibia would become reliant on imports to meet more than 50 percent of power demand. In addition, South Africa would import large volumes of power, which would still account for only 10 percent of domestic demand.

Figure B Maximum potential for cross-border power trading in Sub-Saharan Africa, 2015 (TWh)



A similar shift from thermal to hydropower would occur in the EAPP region, pushing hydropower from 28 to 48 percent of the generation capacity portfolio and displacing gas-fired power capacity in Egypt and Kenya. Ethiopia and Sudan would become the major power exporters, trading more than what they produced for domestic consumption and sending their power northward into Egypt (figure B). While Egypt and Kenya would import significant volumes of power, Burundi would be the only country to become largely dependent on traded electricity.

In WAPP, the increase in trade would not significantly increase reliance on hydropower, but hydropower in Guinea would replace hydropower projects dispersed throughout the other countries. Also, trade would reduce the development of gas-fired power plants in countries such as Ghana, Benin, Togo and Mauritania. Guinea would emerge as the major exporter of hydropower, exporting more than 5 times domestic consumption.

In CAPP, the share of power production from hydropower would increase from 83 percent to 97 percent. Cameroon emerges as the major power supplier in CAPP, exporting about half of its production. Hydropower capacity in Cameroon replaces the HFO-fired thermal capacity in the other countries, in addition to some hydropower in the Republic of Congo. The other countries in the region, except Central African Republic, import a considerable share of their consumption: Chad and Equatorial Guinea import all of their power from Cameroon, while the Republic of Congo imports about one third and Gabon almost half of its consumption.

The Central African region borders the Democratic Republic of Congo and therefore could be expected to benefit from hydropower development there. In this study, the Democratic Republic of Congo is part of the SAPP region and only the 2005 level of imports from the Democratic Republic of Congo to the Republic of Congo was included in the base case. Even if higher imports from the Democratic Republic of Congo to the CAPP region are possible, Cameroon still remains the major supplier in CAPP (depending on the level of imports from the Democratic Republic of Congo). Instead, investments and production in the Republic of Congo are replaced by the increased imports.

Who gains most from power trade?

There are substantial differences in the long-run marginal cost (LRMC) of power across power pool areas, and those differences are differentially affected by trade (table C). The SAPP and CAPP regions have considerably lower average LRMC ($0.07 per kWh) than the EAPP and WAPP regions: the average LRMC of power in the EAPP region is around $0.12 per kWh and $0.18 per kWh in WAPP. The LRMC is also quite high on islands, between $0.14 and 0.19 per kWh. Of course, these numbers are estimates, with a considerable degree of uncertainty at the country level. The range within each power pool is also wide, though trade tends to narrow that range.

Two types of countries benefit from trade. Countries with very high domestic power costs can obtain significantly cheaper electricity by importing. Perhaps the most striking examples are in WAPP, where Guinea-Bissau, Liberia and Niger each can save up to $0.06–$0.07 per kWh by importing electricity. Countries in other regions also benefit from considerable savings: Angola in SAPP, Burundi in EAPP, and Chad in CAPP can all save up to $0.04–$0.05 per kWh by importing electricity. But even countries with smaller unit cost differentials, such as Burundi, Malawi, Ghana, Sierra Leone, and Togo, can generate important savings by moving from self-reliance to heavy imports.

On the other hand, countries with very low domestic power costs can also generate substantial revenues by exporting power. The most salient examples are the Democratic Republic of Congo for SAPP, Ethiopia for EAPP, Guinea for WAPP, and Cameroon for CAPP. Power export revenues could amount to 6 percent of GDP for Ethiopia and 9 percent of GDP for the Democratic Republic of Congo.

Table C Long-run marginal costs of power in Sub-Saharan Africa

U.S. dollars per kWh	Trade expansion	Trade-stagnation	U.S. dollars per kWh	Trade expansion	Trade-stagnation
SAPP average	*0.06*	*0.07*	*WAPP average*	*0.18*	*0.19*
Angola	0.06	0.11	Benin	0.19	0.19
Botswana	0.06	0.06	Burkina Faso	0.25	0.26
Congo, Dem. Rep.	0.04	0.04	Cote d'Ivoire	0.15	0.15
Lesotho	0.06	0.07	Gambia	0.08	0.07
Malawi	0.05	0.05	Ghana	0.10	0.10
Mozambique	0.04	0.06	Guinea	0.07	0.06
Namibia	0.11	0.12	Guinea-Bissau	0.09	0.16
South Africa	0.06	0.07	Liberia	0.08	0.14
Zambia	0.08	0.08	Mali	0.25	0.28
Zimbabwe	0.08	0.09	Mauritania	0.14	0.15
EAPP average	*0.12*	*0.12*	Niger	0.25	0.30
Burundi	0.11	0.15	Nigeria	0.13	0.13
Djibouti	0.07	0.07	Senegal	0.43	0.47
Egypt	0.09	0.09	Sierra Leone	0.09	0.10
Ethiopia	0.19	0.16	Togo	0.10	0.11
Kenya	0.12	0.13	*CAPP average*	*0.07*	*0.09*
Rwanda	0.12	0.12	Cameroon	0.07	0.06
Sudan	0.13	0.13	Central African Republic	0.11	0.11
Tanzania	0.10	0.08	Chad	0.07	0.11
Uganda	0.12	0.11	Congo, Rep.	0.06	0.08
Island states			Equatorial Guinea	0.08	0.10
Cape Verde	0.19	0.19	Gabon	0.07	0.07
Madagascar	0.14	0.14			
Mauritius	0.18	0.18			

Note: In some cases power exporting countries report higher LRMC under trade expansion. Even if the cost of meeting domestic power consumption may be higher with trade than without, the higher revenues earned from exports would more than compensate for that increment.

How will less hydropower development influence the trade flows?

In the trade-expansion scenario, cheap hydropower from Guinea supplies much of the power in the WAPP region (except Nigeria). But it might be unrealistic to develop such a huge amount of hydropower in one country in a short time span. In a reduced hydropower development sceanrio, we assume that only three projects, 375 MW in total, can be completed in Guinea before 2015 (instead of the 4,300 MW in the base case).

If hydropower development in Guinea is restrained, new trade patterns emerge in the WAPP region. Côte d'Ivoire emerges as the major power exporter, while Ghana increases domestic production considerably to reduce net imports. Mauritania and Sierra Leone also become exporters.

Hydropower investments in Côte d'Ivoire only increase by just below 200 MW, but production from existing gas-fired power plants also increases, so total power production increases by 3 TWh. Production in Ghana almost doubles to 16 TWh. Like in Côte d'Ivoire, the increase comes partly from new gas-fired power plants and partly from existing plants.

Total annualized costs increase by only 3 percent (just above $300 million). There is, however, a huge trade-off between lower capital costs and higher variable costs: while capital costs are $500 million less (mainly due to lower generation investments), variable operation costs of production are $850 million (30 percent) more. This clearly illustrates the trade-off between hydro and thermal capacity. With less hydropower capacity, more of the existing thermal capacity is used with lower efficiency and higher costs than new plants.

What are the environmental impacts of trading power?

Trade in power also offers potential environmental benefits. In the SAPP region, our model predicts that trade would increase the share of hydropower generation capacity from 25 to 34 percent, reducing CO_2 emissions by about 40 million tons. In the EAPP region, CO_2 emissions would drop by 20 million tons, even as power production rose by 2.4 TWh. In the WAPP and CAPP regions, the CO_2 savings are smaller, 5.2 and 3.6 million tons respectively, since the regions' total production is smaller.

The combined savings are 70 million tons of CO_2 annually. By comparison, the Energy Information Administration (EIA) estimates current emissions from power and heat production in Africa to be 360 million tons. The savings from trade is therefore 20 percent of this volume. Our estimates do not, however, include greenhouse gas emissions from hydropower in the form of methane from dams.

How would CDM affect generation technology choices?

Created pursuant to the Kyoto Protocol, the Clean Development Mechanism (CDM) allows industrialized countries that have made a commitment under the protocol to reduce greenhouse gases to invest in projects that reduce emissions in developing countries instead. The investment covers the difference in cost between a polluting technology and a cleaner but more expensive alternative. The CDM difference in cost is divided by emissions saved to work out the cost of certified emission reduction credits (CERs) associated with a given project. Focusing on SAPP, we analyzed the potential for CDM in the power sector of Sub-Saharan Africa, operating under the trade-expansion scenario.

CDM has not been widely used in the power sector in Sub-Saharan Africa. An illustrative simulation shows that at a CER price of $15/ton CO_2, investments in the Democratic Republic of Congo, Malawi, Zambia, and Namibia would lead to the development of an additional 8,000 MW (producing 42 TWh) of hydropower.

A CER price of $15 has the potential to reduce CO_2 emissions by 36 million tons—equivalent to 10 percent of Africa's emissions from power and heat production. That amount is significant but still less than the carbon reduction brought about by trade, which reduces CO_2 emissions by 40 million tons in SAPP. Trade and CDM are not mutually exclusive, of course. Starting from a trade-stagnation position, moving to a trade-plus-CDM position could reduce CO_2 emissions by 76 million tons.

One facet of the CDM model limits its contribution. System costs for Africa after CDM finance are still higher than before CDM finance. The reason seems to be that transmission and distribution costs increase after CDM (because hydropower plants are located far from consumption centers), but those costs are not addressed by the mechanism.

How might climate change affect power investment patterns?

By affecting weather patterns and making hydropower less reliable, climate change could increase the costs of generating and delivering power in Africa.

Focusing on the EAPP region, we performed an illustrative analysis to examine some of the key issues posed by climate change. Because exact numbers are lacking, we performed simulations in which climate change was assumed to reduce so-called firm hydropower production (in GWh per MW of installed capacity) by up to 25 percent. The reduction was assumed to apply both to existing capacity and to new capacity.

Lower firm power would increase the unit cost of hydropower, causing gradual substitution away from hydropower and increasing the total annualized cost of the power sector. It is perhaps some comfort that a reduction of 25 percent in firm hydropower availability would increase the annual costs of satisfying the region's power needs by only 9 percent. But it is decidedly not comforting that climate change would increase East Africa's dependency on thermal power—production in gas-fired power plants would increase 40 percent in EAPP. In other words, the solution to the power supply problem brought about by climate change implies an acceleration of the climate problem.

1 Introduction

The aim of this study is to analyze the investment requirements and costs associated with electrification in Sub-Saharan Africa, grouped into the Southern Africa Power Pool (SAPP), the Nile Basin–East Africa Power Pool (EAPP), the Western Africa Power Pool (WAPP), and the Central Africa Power Pool (CAPP). The island nations of Cape Verde, Madagascar, and Mauritius are also included.

We have analyzed the power sector investments necessary for three different scenarios (defined by the share of the population with access to electricity): (a) keeping electricity access rates constant at the 2005 level; (b) increasing them to an average of 35 percent in SAPP and EAPP, 44 percent in CAPP, and 53 percent in WAPP; and (c) increasing them to the national target rates of individual countries. In addition, we assess the potential gains from electricity trade. We also provide sensitivity analyses of our findings' robustness.

In the analysis, we use a least-cost expansion model developed for the project. The model is populated with data from 43 Sub-Saharan African countries, grouped into regions (as shown in table 1.1). The model will be available online for use by researchers.

Table 1.1 Countries covered in the study

Southern Africa Power Pool	Nile Basin–East Africa Power Pool	Western Africa Power Pool	Central Africa Power Pool	Island states
Angola	Burundi	Benin	Cameroon	Cape Verde
Botswana	Djibouti	Burkina Faso	Central African Republic	Madagascar
Democratic Republic of Congo	Egypt	Côte d'Ivoire	Chad	Mauritius
Lesotho	Ethiopia	Gambia	Republic of Congo	
Mozambique	Kenya	Ghana	Equatorial Guinea	
Malawi	Rwanda	Guinea	Gabon	
Namibia	Sudan	Guinea-Bissau		
South Africa	Tanzania	Liberia		
Zambia	Uganda	Mali		
Zimbabwe		Mauritania		
		Niger		
		Nigeria		
		Senegal		
		Sierra Leone		
		Togo		

Each country is represented by a demand side and supply side. The demand side consists of market demand, suppressed demand and social demand. Market demand for electricity is defined as the demand resulting from economic growth and structural change; that is, the growth of existing consumers' demand due to increase in income. Social demand is related to social targets for new electricity access. Suppressed

demand is that portion of electricity demand not currently met because of blackouts and brownouts. The next chapter presents the data and methodology used to estimate demand. These projections are then used in the least-cost expansion model.

The supply system consists of power generation plants and transmission (between and within countries) and distribution grids (within countries). The available technologies for power generation are hydropower (large scale, including pumped storage, and small scale), thermal (fueled by coal, natural gas, diesel, heavy fuel oil [HFO], and nuclear), solar photovoltaic energy (solar PV) and geothermal power. In addition to grid-based electricity supply, off-grid supply (provided by minihydro, diesel, and solar PV) is an option in rural areas.

Each technology is described in terms of capacity and cost. We take the countries' existing assets (as of 2005) as a starting point. Capacity expansion is possible through investment. In addition, refurbishment can extend the life span of existing capacity. Costs consist of the capital cost and variable operating cost (that is, the cost of fuel and operation and maintenance).

Investments are also necessary to extend transmission and distribution grids. These grids also require refurbishment to keep them in working condition.

Chapter 2 presents the demand-side data. Chapter 3 presents the supply-side data for generation, as well as for transmission and distribution. Chapter 4 gives an overview of the least-cost expansion model.

Chapters 5 and 6 present the results of the analysis. Chapter 5 contains results of the major scenarios for electricity access and trade. Chapter 6 investigates sensitivities with respect to demand and economic growth, fuel prices, investment unit costs, clean development mechanism (CDM) finance, the impacts of climate change, and other barriers to hydropower development.

Annex 1 (separately bound) contains detailed country-by-country outputs. Four appendixes accompany this report. Appendixes 1–3 present details of input data for the supply side. Appendix 4 compares results of this study with those of a recent study on the Southern African Power Pool, Nexant (2007).

2 Estimating demand

This chapter presents the methodology used to estimate demand for electricity in 2015. Demand consists of (a) *market demand*, associated with different levels of economic growth, structural change and population growth; (b) *suppressed demand*, created by frequent blackouts and the ubiquitous practice of power rationing; and (c) *social demand*, as expressed in political targets for increasing access to electricity. Together they form our country-specific demand projection:

Demand = market demand + suppressed demand + social demand

These projections are used in the least-cost expansion model.

Market demand

This section estimates market demand in Sub-Saharan African countries in 2015. We define market demand growth as the "organic" growth resulting from income growth and structural changes in the economy. First, we present different specifications of the econometric model for electricity demand, discuss the robustness of the model, and explain our choice of the model for projections of future demand. We then use the model to project future electricity demand. The estimation model is used for each country analyzed.

Econometric model of demand

We model the market demand, measured as *annual per capita electricity consumption*, as a log-linear function of real gross domestic product (GDP) per capita (a proxy for income), and of the agricultural, manufacturing, and construction 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. For the remaining countries, data are unreliable or missing. While there is usually a benefit to basing quantitative analysis on large data sets, adding more data can lead to biased estimates from the econometric model if the additional data are plagued by measurement error.[1] The data sources are presented in table 2.1. The estimation is based on 30 time periods that together with data for the 11 countries yield 330 observations.

Table 2.1 Data sources for econometric model

Variable	Source
Electricity consumption	International Energy Agency Database
Population	Penn World Tables
Real GDP per capita	Penn World Tables
Structural shares of economy	United Nations Statistics Division, National Accounts
Population growth	United Nations World Population Prospects

[1] In a multiple linear regression framework it is well known that measurement error in the explanatory variables can cause them to be biased toward zero.

We allow for first-order autocorrelation and panel correlation in the residuals to control for unobserved factors that may affect electricity 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 generalized least squares (FGLS), using the econometric software *Stata 9*. Our prior assumption is that the coefficient on GDP per capita (that is, the income elasticity) is positive and not too far from unity. One could also posit that the sectorial shares coefficients are negative for agriculture and positive for manufacturing (as in Bogetic and Fedderke, 2005).

The estimation results are reported in table 2.2.

Table 2.2 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

Source: Authors' original research.
Note: Variables in logarithms. Manufacturing includes mining sector. Residuals assumed autoregressive and panel correlated.

The results from the model agree with our prior assumptions and earlier results. Fay (2001) estimates an income elasticity of 1.1, while Bogetic and Fedderke's (2005) estimate is somewhat higher.

Turning first to the *coefficient on real GDP per capita*—our estimate of the income elasticity—we see that it is close to unity, and similar to the elasticity reported in Fay and Yepes (2003), while somewhat lower than the elasticity reported in Bogetic and Fedderke (2005). An F-test that the quotient of the coefficient divided by elasticity is equal to unity cannot be rejected. The *coefficients on the sectorial shares for agriculture and manufacturing* are consistent with the results in Bogetic and Fedderke (2005).

The results are also robust to alternative specifications and sample sizes, with two major exceptions:

- 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 frequently not robust. We include it in the above specification, but exclude it from the projections of future demand.
- The coefficient on income, representing income elasticity, drops from about 1.1 to 0.5 if one includes *urbanization* in the regression. The coefficient on urbanization is highly statistically significant and slightly below unity (0.9). The reason for this effect is the omitted variables bias. Since urbanization is positively correlated with both real income per capita and electricity consumption (because people in urban areas use more electricity than in rural areas), omitting it from the regression raises the

coefficient on income.[2] We chose to proceed with the model with higher income elasticity, since projections of future urbanization are highly uncertain.

In order to increase the robustness of the demand projections, we chose to omit construction and urbanization from the forecasting model. The resulting forecasting model is based on the results in table 2.2.

$$\%\Delta\text{Electricity consumption per capita} =$$
$$-9.415 + 1.07\%\Delta\text{Income} + 0.13\%\Delta\text{Manufacturing} - 0.25\%\Delta\text{Agriculture}$$

Projections of explanatory variables

In order to complete a forecast of electricity demand, we need to project the explanatory variables—more specifically, the percentage change in the explanatory variables—from 2006 to 2015.

Projected values of real GDP per capita are taken from the international macroeconomic data set of the United States Department of Agriculture (USDA) Economic Research Service and World Development Indicators database.

We also need projections for the agricultural and manufacturing shares of the economy. Such data are not available to our knowledge, but can be estimated from time-series data. One way is to simply extrapolate the time-series data on agriculture and manufacturing for each country. Alternatively, one can base a projection of future agricultural and manufacturing shares of the economy on the strong correlation between economic growth and structural change. The reallocation of labor from agriculture and into service and manufacturing that follows economic growth has been documented for both developed and developing economies (see, for example, Kongsamut, Rebelo, and Xie, 1997). Given the correlation present in our sample of SAPP countries, we estimate future sectorial shares based on the coefficients from two linear fixed-effects regressions of agricultural and manufacturing on (a) real GDP per capita and (b) projected future real GDP per capita.[3]

Projections of market demand

Using the econometric panel data models and projections for the future development of the explanatory variables, we estimate the increase in *market demand for electricity* in the four regions of Sub-Saharan Africa and in the island states.

---

[2] The decrease in income elasticity from the inclusion of urbanization can be understood in the light of omitted variable bias. Formally, suppose the correctly specified equation is $y = \alpha + \beta_1 x_1 + \beta_2 x_2 + \varepsilon$. Omitting x_2 from the regression leads to the following expectation of b_1, the least squares estimate of β_1:

$E[b_1] = \beta_1 + (x_1' x_1)^{-1}(x_1' x_2)\beta_2$. Hence the bias in the coefficient on x_1 from omitting x_2 depends on the correlation between x_1 and x_2 and the correlation of x_2 and y (which determines the sign of β_2).

[3] These equations are: $\Delta Manufacturing = 0.88 + 0.28\% \Delta GDP/capita$; $\Delta Agriculture = 8.8 - 0.82\% \Delta GDP/capita$. In other words, the manufacturing share increases 2.8 percentage points when GDP per capita increases 1 percent. (For EAPP the figure is 3.2 percentage points.) The agricultural share decreases 8.2 percentage points from GDP per capita growth, but the base is positive and the net effect depends on the economic growth assumed. In all normal growth scenarios, when growth is sufficiently high, the agricultural share declines. The equations forecasting sectorial shares should be revisited in future work.

The assumptions for population growth and GDP growth and the resulting projections for demand growth are shown in table 2.3. Electricity demand per capita, as estimated by the model, has been multiplied by 2005 and 2015 populations. Hence the figures for electricity demand growth show an increase in total demand, not per capita demand.

In addition to the normal growth scenario, we also report a scenario with lower economic growth (GDP/capita growth reduced by 50 percent). The lower growth in electricity demand that results from slower economic growth is used in the low-growth scenario presented in chapter 6.

Table 2.3 Increase in population, income, and market demand for electricity in study countries, 2006–15 (%)

Country	Annual population growth	Base growth scenario Total (annual)		Low growth scenario Total (annual)	
		GDP/capita	Electricity demand	GDP/capita	Electricity demand
Southern Africa Power Pool					
Angola	2.8	84 (6.3)	130 (9.7)	42 (3.6)	75 (6.4)
Botswana	-0.4	56 (4.6)	58 (5.2)	28 (2.5)	21 (2.1)
Congo, Dem. Rep.	2.5	16 (1.5)	45 (4.2)	8 (0.8)	35 (3.4)
Lesotho	-0.3	53 (4.3)	55 (5.0)	26 (2.4)	20 (2.1)
Malawi	2.2	19 (1.7)	38 (3.6)	9 (0.9)	25 (2.5)
Mozambique	1.7	21 (1.9)	34 (3.3)	10 (1.0)	21 (2.1)
Namibia	1.0	48 (4.0)	62 (5.5)	24 (2.2)	30 (3.0)
South Africa	0.1	43 (3.7)	47 (4.3)	22 (2.0)	18 (1.8)
Zambia	1.7	24 (2.2)	38 (3.6)	12 (1.1)	22 (2.2)
Zimbabwe	0.6	30 (2.7)	34 (3.3)	15 (1.4)	14 (1.5)
Nile Basin–East Africa Power Pool					
Burundi	3.2	14 (1.3)	45 (4.2)	7 (0.7)	35 (3.4)
Djibouti	1.9	15 (1.4)	29 (2.9)	8 (0.7)	19 (2.0)
Egypt	1.8	26 (2.3)	41 (3.9)	13 (1.2)	24 (2.5)
Ethiopia	2.3	29 (2.6)	52 (4.8)	14 (1.4)	33 (3.2)
Kenya	2.6	16 (1.5)	39 (3.7)	8 (0.8)	28 (2.8)
Rwanda	2.2	31 (2.7)	54 (4.9)	6 (0.6)	22 (2.2)
Sudan	2.0	32 (2.8)	53 (4.8)	16 (1.5)	31 (3.1)
Tanzania	1.8	26 (2.3)	41 (3.9)	13 (1.2)	24 (2.4)
Uganda	3.8	13 (1.2)	51 (4.7)	7 (0.6)	43 (4.0)
Western Africa Power Pool					
Benin	2.5	19 (1.8)	40 (4.0)	10 (0.9)	29 (2.9)
Burkina Faso	3.0	4 (0.4)	28 (2.8)	2 (0.2)	25 (2.6)
Cote d'Ivoire	1.9	11 (1.0)	23 (2.3)	5 (0.5)	16 (1.7)
Gambia	2.7	13 (1.3)	36 (3.5)	7 (0.6)	28 (2.7)
Ghana	1.9	37 (3.2)	58 (5.2)	19 (1.6)	33 (3.2)
Guinea	2.6	17 (1.6)	41 (3.9)	9 (0.8)	29 (2.9)
Guinea-Bissau	2.0	2 (0.2)	14 (1.4)	1 (0.1)	12 (1.3)
Liberia	3.1	17 (1.6)	46 (4.3)	9 (0.8)	35 (3.4)
Mali	2.8	21 (1.9)	49 (4.5)	11 (1.0)	35 (3.4)

Country	Annual population growth	Base growth scenario Total (annual)		Low growth scenario Total (annual)	
		GDP/capita	Electricity demand	GDP/capita	Electricity demand
Mauritania	2.9	62 (4.9)	102 (8.1)	31(2.5)	61 (5.5)
Niger	2.9	3 (0.3)	25 (2.5)	1 (0.1)	23 (2.3)
Nigeria	2.4	38 (3.2)	65 (5.7)	19 (1.6)	40 (3.8)
Senegal	2.5	22 (2.0)	46 (4.3)	11 (1.0)	31 (3.1)
Sierra Leone	2.3	5 (0.5)	21 (2.1)	3 (0.3)	17 (1.8)
Togo	2.7	2 (0.2)	22 (2.2)	1(0.1)	21 (2.1)
Central Africa Power Pool					
Cameroon	2.2	22 (2.0)	41 (3.9)	11 (1.0)	27 (2.7)
Central African Rep.	1.5	16 (1.5)	26 (2.6)	8 (0.8)	15 (1.5)
Chad	2.9	8 (0.8)	33 (3.2)	4 (0.4)	27 (2.7)
Congo, Rep.	2.8	24 (2.2)	52 (4.8)	12 (1.1)	36 (3.5)
Equatorial Guinea	2.0	36 (3.1)	57 (5.1)	18 (1.6)	34 (3.3)
Gabon	2.0	13 (1.2)	27 (2.7)	6 (0.6)	19 (1.9)
African Island states					
Cape Verde	0.5	58 (4.7)	70 (6.0)	29 (2.3)	32 (3.1)
Madagascar	2.5	12 (1.2)	33 (3.2)	6 (0.6)	25 (2.5)
Mauritius	0.8	34 (2.9)	40 (3.8)	17 (1.5)	18 (1.9)

Source: Authors' original research.
Note: Market demand for electricity is one of three categories of demand for electricity, the others being social demand/access, and suppressed demand.

Suppressed demand

In most low-income countries, some people who want to consume more energy at the going price are unable to. The difference between so-called notional demand and availability at the going price is called *suppressed demand*. Suppressed demand arises for two primary reasons. First, there are people on a waiting list to get connected to the grid who are not captured in our market demand estimate. Second, due to old and run-down infrastructure, blackouts and brownouts are relatively common; therefore, consumption is reduced, while notional demand remains unchanged. All of this implies that suppressed demand will immediately absorb a certain amount of new production before income growth or structural economic changes does so. Note that suppressed demand as defined here does not include the possible positive effect of increased supply on economic growth. In our model that effect is categorized as market demand. In a country where economic activity is limited by electricity supply, the market-demand effect can be strong.

In our simulations, we account for the additional consumption of suppressed demand as follows:

Waiting list. Since this is a direct result of slow expansion of new connections, we assume that this source of suppressed demand is picked up by social demand in each scenario. In fact, the pace of expansion is what determines our three expansion scenarios.

Blackouts. In order to estimate the amount of suppressed demand from blackouts, we rely on the results of the World Bank's enterprise surveys, which include estimates for blackout duration and

frequency. (For most countries, one to two data points are provided for the period 2003–6. For countries where no data is available, the regional average of the sample is applied.) This provides an estimate of the number of hours that an average household/business in a given country spends in blackout. The estimate for number of hours is then divided by 8,760 (the number of hours in a year) to convert the estimate into a percentage of the year. Then, electricity demand in energy terms (gigawatt-hours, GWh) is adjusted accordingly (table 2.4).

Table 2.4 Summary of blackout data and suppressed demand in study countries

Country	Average duration (hours)	Outages (hours per year)	Down time (% of a year)	Suppressed demand in 2005 (GWh)
SAPP				
Angola	19.31	1780.8	20.3	435
Botswana	1.86	38.9	0.4	11
Congo, Dem. Rep.	3.63	659.2	7.5	351
Lesotho	7.65	177.9	2	8
Malawi	4.27	328.1	3.7	49
Mozambique	6.08	350.4	4	450
Namibia	2.32	46.1	0.5	13
South Africa	4.15	24.5	0.3	602
Zambia	5.48	219.9	2.5	157
Zimbabwe	6.08	350.4	4	512
Average for available sample	*6.1*	*350.4*	*4*	
EAPP				
Burundi	10.34	1461.5	16.7	25
Djibouti	5.88	456.4	5.2	12
Egypt	2.48	43.3	0.5	417
Ethiopia	5.88	456.4	5.2	109
Kenya	8.2	702.6	8	366
Rwanda	4.47	346.9	4	5
Sudan	5.88	456.4	5.2	168
Tanzania	6.46	435.9	5	208
Uganda	6.55	463.8	5.3	84
Average for available sample	*5.88*	*456.4*	*5.2*	
WAPP				
Benin	2.72	505	6	34
Burkina Faso	1.61	196	2	11
Cote d'Ivoire	5.94	1101	13	365
Gambia	6.86	1961	22	29
Ghana	12.59	1465	17	979
Guinea	6.78	2759	31	224
Guinea-Bissau	17.94	1978	23	14
Liberia	5.94	1101	41*	123
Mali	2.44	453	5	21
Mauritania	2.89	129	1	3
Niger	0.5	124	1	6

Country	Average duration (hours)	Outages (hours per year)	Down time (% of a year)	Suppressed demand in 2005 (GWh)
Nigeria	5.94	1101	64*	10803
Senegal	5.67	1052	17*	250
Sierra Leone	5.94	1101	82*	189
Togo	5.94	1101	13	73
Average for available sample	*5.94*	*1176*	*22*	
CAPP				
Cameroon	4.03	613	7	241
Central African Rep.	5.2	950	10.8	11
Chad	5.2	950	10.8	10
Congo, Rep.	4.33	924	10.6	616
Equatorial Guinea	5.2	950	10.8	3
Gabon	5.2	950	10.8	134
Average for available sample	*5.2*	*889*	*10.2*	
Island states				
Cape Verde	5.3	797	9	4
Madagascar	2.67	221.1	2.5	21
Mauritius	7.23	1321	15.1	35

Source: World Bank Enterprise Surveys. * WAPP Emergency Power Supply Report (2007).

Note: Due to a lack of data, regional sample averages are applied to the following countries: Mozambique, Zimbabwe (SAPP); Ethiopia, Sudan and Djibouti (EAPP); Benin, Cote d'Ivoire, Liberia, Mali, Nigeria, Senegal, Sierra Leone, and Togo (WAPP). For CAPP, data is available for Cameroon and Republic of Congo only; for the other countries, regional average is applied.

Social demand

Social demand for electricity is composed of the expected demand of all new connections in the household sector in 2015. We develop three scenarios for electricity access:

- The *2005 access scenario* assumes that access rates are kept constant at their 2005 level. Because of population growth, even the current access scenario implies that a number of new connections are added and, hence, a higher demand level (measured in kilowatt-hours, kWh).
- The *regional target access scenario* aims to increase access by roughly 1 to 2 percentage points per year in each region. Based on stakeholder discussions, the scenario appears to be a moderately ambitious, yet realistic, access target.
- The *national targets scenario* reflects ambitions set by national governments for urban and rural electricity access. The relevance of this scenario lies in the fact that it is based on national aspirations.

These scenarios provide for a reasonable lower-bound estimate (2005 access rates) and particularly ambitious estimate (national targets), together with a realistic yet ambitious target (regional targets) used by international organizations such as the World Bank in planning and strategy documents.

We then arrive at our estimate for social demand in two steps: (a) we estimate the weighted average consumption per new connection, and (b) we estimate the number of new connections in the three scenarios. Let us describe the steps in turn.

Average consumption per connection

To estimate the total additional generation capacity required to satisfy the demand of new connections, we must first estimate the average demand per connection. We assume that all commercial demand is captured in market demand, and that social demand is thus made up of household connections.[4]

In arriving at an estimate of average consumption per connection, we use an extensive data set collected in Tanzania,[5] and cross-check our estimates with those of the global review of rural electrification programs carried out by Zomers (2001). The resulting 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.

These estimates correspond well with other international estimates, including those of Zomers's global review of rural electrification projects (2001), which arrived at an average monthly consumption of 81.75 kWh and an average maximum demand of 0.4 kW. The fact that Zomers's estimate is slightly higher corresponds with the fact that it is global, with only a few observations from Sub-Saharan Africa.

Estimating the number of new connections

We build the estimation of the number of connections in rural and urban areas around three variables: (a) the 2005 electricity access rates, (b) future population growth, and (c) targets for future electricity access rates.

Population statistics and projections for rural and urban areas in 2005 are taken from the United Nations's *World Population Prospects* and reported in table 2.5 (assuming that there are 5 persons per household).

---

[4] Some new connections, especially in urban areas, may come "organically" from market demand growth. Thus, by adding our estimates for social and market demand, there is a risk that the consumption of some new connections is counted double. But it is expected that this double counting is rather insignificant for two reasons. First, the historical data on which we base our market demand projections demonstrate very little access expansion—connection rates remain low in most African countries. This implies that our market demand estimate does not pick up significant new connections. Second, we do not count any commercial connections in our measure of social demand, although other social demand forecasts include those. Thus, it is expected that the neglect of commercial connections in social demand counteracts the potential double counting of residential connections, and the overall bias in the estimate, whether over or under, is limited.

[5] These consumption figures are calculated as follows. Our firm's survey of a large number of potential grid extension programs found that about 90 percent of all connections are households. We combine this estimate with DECON/SWECO (2005) estimates for income-class prevalence rates and expected-income class take-up rates. Using these distributions we calculate the distribution of connections across household income levels and commercial connections (for example, for a given 100 connections). We then combine this with DECON/SWECO's (2005) specific consumption data to arrive at a weighted average consumption per connection for urban and rural, which was used in the model.

Table 2.5 2005 and projected population in study countries

	No. of households 2005			No. of households 2015		
	Total	Urban	Rural	Total	Urban	Rural
SAPP						
Angola	3,188,200	1,186,010	2,002,190	4,189,400	1,881,041	2,308,359
Botswana	353,000	185,325	167,675	338,000	194,350	143,650
Congo, Dem. Rep.	11,509,800	3,769,000	7,740,800	14,770,600	6,201,000	8,569,600
Lesotho	359,000	65,338	293,662	348,800	73,248	275,552
Malawi	2,568,800	441,834	2,126,966	3,197,600	709,867	2,487,733
Mozambique	3,958,400	1,504,192	2,454,208	4,702,600	2,280,761	2,421,839
Namibia	406,200	136,077	270,123	449,600	178,941	270,659
South Africa	9,486,400	5,492,626	3,993,774	9,580,400	6,006,911	3,573,489
Zambia	2,333,600	858,765	1,474,835	2,768,200	1,129,426	1,638,774
Zimbabwe	2,602,000	934,118	1,667,882	2,760,800	1,142,971	1,617,829
Total SAPP	36,765,400	14,573,284	22,192,116	43,106,000	19,798,515	23,307,485
EAPP						
Burundi	1,571,800	157,180	1,414,620	2,244,600	303,021	1,941,579
Djibouti	160,800	138,449	22,351	190,200	170,419	19,781
Egypt	14,986,400	6,438,200	8,548,200	17,635,000	7,916,800	9,718,200
Ethiopia	15,486,000	2,502,200	12,983,800	19,431,000	3,844,400	15,586,600
Kenya	6,851,200	2,852,600	3,998,600	8,839,000	4,576,800	4,262,200
Rwanda	1,807,600	393,600	1,414,000	2,252,200	912,600	1,339,600
Sudan	7,246,600	2,955,000	4,291,600	8,807,000	4,340,000	4,467,000
Tanzania	7,665,800	2,874,600	4,791,200	9,130,200	4,272,000	4,858,200
Uganda	5,763,200	716,000	5,047,200	8,383,800	1,191,800	7,192,000
Total EAPP	61,539,400	19,027,829	42,511,571	76,913,000	27,527,840	49,385,160
WAPP						
Benin	1,529,872	613,479	916,393	1,964,237	876,050	1,088,187
Burkina Faso	2,698,347	493,798	2,204,550	3,628,240	827,239	2,801,001
Cote d' Ivoire	3,459,608	1,556,824	1,902,784	4,176,910	2,080,101	2,096,809
Gambia	319,017	171,950	147,067	415,923	257,040	158,883
Ghana	4,405,136	2,105,655	2,299,481	5,295,010	2,917,551	2,377,460
Guinea	1,890,534	623,876	1,266,658	2,448,382	932,833	1,515,548
Guinea-Bissau	282,689	83,676	199,013	345,071	107,317	237,754
Liberia	580,054	337,011	243,043	783,743	507,866	275,878
Mali	2,275,877	694,143	1,581,735	3,010,905	1,098,980	1,911,925
Mauritania	617,372	249,418	367,954	818,215	352,651	465,564
Niger	2,432,571	408,672	2,023,899	3,230,390	623,465	2,606,925
Nigeria	25,753,154	12,413,020	13,340,134	32,669,214	18,262,091	14,407,123
Senegal	2,372,086	986,788	1,385,298	3,041,419	1,359,514	1,681,905
Sierra Leone	1,173,485	477,608	695,877	1,473,488	710,221	763,267
Togo	1,079,998	433,079	646,919	1,412,145	669,357	742,788
Total WAPP	50,869,800	21,648,997	29,220,804	64,713,292	31,582,276	33,131,016

	No. of households 2005			No. of households 2015		
	Total	Urban	Rural	Total	Urban	Rural
CAPP						
Cameroon	3,452,293	1,884,952	1,567,341	4,277,460	2,681,968	1,595,493
CAR	847,541	322,065	525,475	979,141	395,573	583,568
Chad	1,931,414	488,648	1,442,766	2,579,209	786,659	1,792,550
Congo, Rep.	720,454	433,713	286,741	950,719	600,855	349,865
Eq. Guinea	105,807	41,159	64,648	128,759	52,920	75,839
Gabon	278,861	233,128	45,733	340,578	298,687	41,891
Total CAPP	7,336,370	3,403,665	3,932,704	9,255,866	4,816,660	4,439,206
Island states						
Cape Verde	83,645	47,928	35,716	88,103	56,650	31,453
Madagascar	3,721,200	1,005,200	2,716,000	4,762,600	1,463,200	3,299,400
Mauritius	246,120	104,355	141,765	265,688	117,168	148,519
Total islands	4,050,965	1,157,484	2,893,482	5,116,390	1,637,018	3,479,372
Total SSA	160,561,935	59,811,259	100,750,676	199,104,549	85,362,310	113,742,239

Source: United Nations, *World Population Prospects*

Three targets for electricity access

Tables 2.6 (electricity access rates) and 2.7 (new connections) summarize the assumptions related to social demand in the three access scenarios.

2005 access

2005 access rates were obtained from the World Bank (*World Development Indicators*), based on the United Nations Statistical Office Annual Energy Questionnaire. In our opinion, this is the most comprehensive compilation of electricity access rates in Sub-Saharan Africa, and we have therefore relied on it to the largest extent possible. Where data are missing, we have turned to other sources, listed in the notes at the bottom of the tables showing current and projected population and access rates.

Then, the number of new connections needed to maintain 2005 urban and rural electricity access rates is estimated. This represents new connections needed to keep up with population growth in rural and urban areas. It should be noted that the higher access rates in urban areas—along with urbanization trends—generally imply a slight increase in countrywide access rates. In addition, in those cases where population is projected to fall in rural areas, we assume zero expansion.

Regional targets for access

This ambitious yet realistic target lies between that of the other scenarios and is based on stakeholder discussions. In SAPP and EAPP countries, this involves increasing the regional average access to 35 percent. In SAPP countries, the target implies an average annual increase of 1.2 percentage points. In the EAPP it implies an annual increase of 2 percentage points, excluding Egypt. Given Egypt's current access rates of 100 percent in urban areas and 87.5 percent in rural areas, it is assumed that the country will achieve 100 percent access, even in rural areas. In CAPP, the regional target is 44 percent and in WAPP,

the regional target is 53 percent access (implying an annual increase of 1.2 percentage points in both regions).

National targets

This scenario reflects the electricity access targets as defined by the national authorities.

For SAPP, the number of new connections required to meet national governments' electrification targets is estimated. Various adjustments or approximations have been made for those countries with a target set for a year other than 2015. For the Democratic Republic of Congo and Zimbabwe, no national targets could be identified; we thus approximated these by adding the average increase in access rates implied by the national targets of the remaining countries.

For the Nile Basin–East African countries, the new connections needed to attain national urban and rural access targets were estimated. Stated national targets were applied to the greatest extent possible. It is assumed that Egypt will achieve 100 percent rural access by 2015 (as noted, urban access is already universal). For Ethiopia, the national target of 50 percent access by 2012 implies an expansion rate that would lead to 60 percent access by 2015. For Kenya, the national rural target of 20 percent access by 2010 is applied in the same way, while the regional urban target is 100 percent access. For Rwanda, the growth rate implied by the national target of 20 percent access by 2020 is employed, with urban access just keeping up with very rapid urban population growth. Sudan's stated national target of 90 percent access "in coming years" is used. For Uganda, the growth rate implied by the rural target of 10 percent by 2012 is used, while the regional target of 100 percent urban access is applied. For Djibouti and Burundi, no national targets have been set. Accordingly, the regional average increase in access in percentage points during the period is applied to these two countries.

For WAPP countries, ECOWAS targets are used (ECOWAS, 2006).

Table 2.6 Targets for electricity access under various scenarios (percent of population)

	2005 access			Regional targets			National targets		
	Total	Urban	Rural	Total	Urban	Rural	Total	Urban	Rural
SAPP									
Angola[a]	14	26	4	24	42	9	46	84	15
Botswana	30	45	9	40	59	14	100	100	100
Congo, Dem. Rep.	8	16	2	20	37	8	39	76	12
Lesotho[b]	6	23	1	17	68	4	35	121	13
Malawi	7	29	1	18	76	1	15	56	3
Mozambique	14	26	2	23	41	5	20	37	5
Namibia[c]	37	75	12	45	86	19	53	95	25
South Africa[c]	71	80	50	79	87	66	100	100	100
Zambia	20	45	3	29	57	11	29	50	15
Zimbabwe	41	87	8	49	99	14	67	100	44
Total SAPP	26	45	11	37	60	17	51	79	27
EAPP									
Burundi	6	45	0	25	100	13	31	67	25
Djibouti	31	34	5	50	54	11	53	56	29

	2005 access			Regional targets			National targets		
	Total	Urban	Rural	Total	Urban	Rural	Total	Urban	Rural
Egypt	93	100	87	100	100	100	100	100	100
Ethiopia	15	76	0	32	100	16	60	100	50
Kenya	27	48	4	42	72	10	67	100	32
Rwanda	16	39	1	29	66	4	18	39	4
Sudan	34	56	12	50	77	23	60	100	21
Tanzania	13	27	1	30	63	2	29	38	22
Uganda	8	44	2	27	100	15	25	100	13
Total EAPP	35	64	19	50	84	31	60	88	45
WAPP[d]									
Benin	25	50	6	35	68	9	50	100	11
Burkina Faso	9	40	0	20	84	1	23	100	6
Cote d'Ivoire	54	86	23	63	96	30	73	100	46
Gambia	59	82	21	66	88	31	79	100	37
Ghana	55	82	21	62	89	30	76	100	37
Guinea	21	54	2	31	77	3	40	100	3
Guinea-Bissau	14	41	2	25	74	4	33	100	6
Liberia	1	0	2	13	1	4	66	100	6
Mali	15	37	2	25	60	5	39	100	7
Mauritania	23	50	3	34	73	4	46	100	6
Niger	7	37	0	18	93	1	20	100	1
Nigeria	59	84	28	67	89	40	82	100	49
Senegal	34	69	6	44	88	9	51	100	10
Sierra Leone	41	82	2	46	91	4	51	100	6
Togo	21	41	2	30	58	5	50	100	8
Total WAPP	45	75	16	53	85	23	66	100	34
CAPP									
Cameroon	61	85	21	68	90	31	71	84	49
Central Afr Rep	3	8	0	15	36	1	34	84	1
Chad	3	9	0	15	46	1	26	84	0
Congo, Rep.	22	35	0	33	52	0	53	84	0
Equatorial Guinea	11	26	0	22	54	0	35	84	0
Gabon	82	85	54	92	93	83	91	84	82
Total CAPP	35	59	8	44	73	12	53	84	19
Island states									
Cape Verde	55	72	24	62	80	31	84	100	54
Madagascar	18	48	5	36	91	12	36	89	13
Mauritius	100	100	100	100	100	100	100	100	100
Total islands	23	52	9	40	92	16	40	90	17

Source: World Bank, *World Development Indicators*; IEA, *World Energy Outlook 2006 – Electricity Access*; UNEP (2002).

a. Data are for total-access rates only; the rural rate is based on average spread between the total and rural rates in Sub-Saharan Africa, which also yields an implicit estimate for urban electrification.

b. Private Solutions for Infrastructure in Lesotho (Country Framework Report 34354, World Bank).

c. Power Sector Reform in Africa: Assessing Impact on Poor People (ESMAP report 306/05). d. ECOWAS (2006).

Table 2.7 New connections under various scenarios

	2005 access			Regional targets			National targets		
	Total	Urban	Rural	Total	Urban	Rural	Total	Urban	Rural
SAPP									
Angola	189,517	177,270	12,247	626,062	495,006	131,056	1,544,540	1,270,679	273,861
Botswana	4,082	4,082	0	36,618	31,052	5,566	239,160	110,534	128,626
Congo, Dem. Rep.	405,946	387,713	18,234	2,158,523	1,681,848	476,675	4,986,424	4,118,393	868,031
Lesotho	1,834	1,834	0	41,612	34,804	6,808	104,828	73,248	31,580
Malawi	80,533	76,926	3,608	417,587	412,275	5,312	319,224	270,837	48,387
Mozambique	200,355	200,355	0	621,455	546,922	74,533	514,437	445,893	68,544
Namibia	32,212	32,148	64	69,050	51,026	18,024	103,186	67,936	35,250
South Africa	411,428	411,428	0	1,219,077	854,276	364,801	3,189,412	1,612,810	1,576,602
Zambia	126,822	122,068	4,754	386,443	255,967	130,476	380,456	177,410	203,046
Zimbabwe	182,538	182,538	0	396,442	313,325	83,117	896,805	326,552	570,253
Total SAPP	1,635,267	1,596,360	38,907	5,972,869	4,676,501	1,296,368	12,278,472	8,474,292	3,804,180
EAPP									
Burundi	68,320	66,212	2,108	473,983	231,661	242,322	610,986	132,306	478,680
Djibouti	10,887	10,887	0	46,190	45,142	1,049	52,787	48,058	4,729
Egypt	2,498,342	1,478,600	1,019,742	3,746,409	1,478,600	2,267,809	3,746,409	1,478,600	2,267,809
Ethiopia	1,033,168	1,022,756	10,411	4,316,696	1,937,724	2,378,972	9,699,988	1,937,724	7,762,265
Kenya	830,330	818,995	11,335	2,179,612	1,934,176	245,436	4,426,566	3,221,815	1,204,751
Rwanda	201,891	201,891	0	483,356	446,265	37,092	239,596	201,891	37,705
Sudan	798,611	777,563	21,048	2,198,508	1,677,706	520,802	3,110,220	2,681,012	429,208
Tanzania	382,227	381,490	737	1,944,457	1,895,796	48,661	1,839,775	823,674	1,016,101
Uganda	260,351	208,876	51,475	1,845,192	877,476	967,716	1,680,515	877,476	803,039
Total EAPP	6,084,126	4,967,270	1,116,856	17,234,404	10,524,545	6,709,859	25,406,842	11,402,556	14,004,287

WAPP									
Benin	139,684	130,235	9,449	338,376	290,292	48,084	635,693	571,764	63,929
Burkina Faso	133,569	132,376	1,193	508,094	496,918	11,176	636,793	631,201	5,592
Cote d' Ivoire	493,151	449,496	43,656	871,445	660,116	211,329	1,285,820	742,790	543,030
Gambia	72,255	69,774	2,481	102,539	84,114	18,424	155,214	116,041	39,173
Ghana	685,300	669,002	16,298	1,088,276	852,221	236,055	1,792,067	1,182,491	609,576
Guinea	169,952	166,219	3,733	400,901	379,423	21,478	621,287	597,188	24,099
Guinea-Bissau	10,156	9,575	581	49,891	45,852	4,039	77,215	73,428	3,786
Liberia	621	128	493	96,202	6,238	89,964	512,237	507,613	4,624
Mali	157,054	149,790	7,264	458,506	403,796	54,710	886,285	842,148	44,138
Mauritania	53,747	51,306	2,440	142,323	132,492	9,832	240,357	228,690	11,668
Niger	79,566	78,400	1,166	441,127	429,473	11,654	479,434	474,300	5,134
Nigeria	5,228,457	4,930,767	297,690	7,762,673	5,726,037	2,036,636	12,518,720	7,797,915	4,720,806
Senegal	274,605	256,809	17,796	583,312	519,770	63,542	785,043	679,618	105,426
Sierra Leone	205,924	204,913	1,011	277,461	269,994	7,466	345,993	332,753	13,240
Togo	99,647	97,346	2,301	230,519	212,066	18,453	510,621	490,928	19,693
Total WAPP	7,803,687	7,396,135	407,552	13,351,645	10,508,801	2,842,844	21,482,781	15,268,867	6,213,913
CAPP									
Cameroon	680,187	674,275	5,912	977,402	810,180	167,222	1,112,508	658,183	454,325
CAR	6,055	5,881	174	122,722	115,646	7,076	308,692	306,516	2,176
Chad	28,363	28,013	350	327,974	317,986	9,988	616,852	614,860	1,991
Congo, Rep.	57,978	57,911	66	163,163	162,836	326	354,860	354,444	416
Eq. Guinea	3,021	3,017	4	17,875	17,839	36	33,922	33,893	29
Gabon	55,792	55,791	1	90,583	80,555	10,028	86,592	52,504	34,089
Total CAPP	831,395	824,888	6,507	1,699,718	1,505,042	194,675	2,513,427	2,020,401	493,026
Island states									
Cape Verde	6,290	6,280	10	12,899	10,596	2,303	31,655	22,142	9,513
Madagascar	249,261	218,924	30,337	1,107,461	855,885	251,576	1,099,554	821,762	277,792
Mauritius	19,567	12,813	6,754	19,567	12,813	6,754	19,567	12,813	6,754
Total islands	275,118	238,017	37,101	1,139,928	879,295	260,633	1,150,776	856,717	294,059
Total SSA	16,629,592	15,022,670	1,606,922	39,398,563	28,094,184	11,304,379	62,832,299	38,022,833	24,809,466

Source: Authors' original research.

Total demand in 2015

Our demand projections for 2015 are summarized in table 2.8. The social demand figures refer to the national targets scenario, which will form the basis for the trade versus no-trade scenarios that are discussed below. In some countries, growth in market demand overwhelms social demand (Mozambique, South Africa, Egypt), whereas the situation is the opposite in other countries (Burundi, Ethiopia, Mali, Central African Republic, Chad).

Table 2.8 Demand in study countries (TWh)

	Total net demand in 2005	Market demand 2015*	Social demand with national targets 2015	Total net demand 2015
Southern Africa Power Pool				
Angola	2.1	6.0	1.9	7.9
Botswana	2.4	4.0	0.2	4.2
Congo, Dem. Rep.	4.7	7.4	6.2	13.6
Lesotho	0.4	0.8	0.1	0.9
Malawi	1.3	1.9	0.4	2.3
Mozambique	11.2	15.7	0.7	16.4
Namibia	2.6	4.2	0.1	4.3
South Africa	215.0	316.0	3.2	319.2
Zambia	6.3	9.0	0.4	9.3
Zimbabwe	12.8	18.0	0.8	18.7
Total	258.8	383.0	14.0	396.9
Nile Basin–East Africa Power Pool				
Burundi	0.2	0.3	0.5	0.7
Djibouti	0.2	0.3	0.1	0.4
Egypt	84.4	119.9	3.4	123.3
Ethiopia	2.1	3.4	7.4	10.7
Kenya	4.6	6.8	5.2	12.0
Rwanda	0.1	0.2	0.3	0.5
Sudan	3.2	5.2	3.9	9.2
Tanzania	4.2	6.2	1.7	7.9
Uganda	1.6	2.5	1.7	4.2
Total	100.6	144.8	24.2	169.0
Western Africa Power Pool				
Benin	0.6	0.9	0.8	1.7
Burkina Faso	0.5	0.6	0.9	1.5
Cote d'Ivoire	2.9	4	1.4	5.4
Gambia	0.1	0.2	0.2	0.4
Ghana	5.9	10.8	2	12.8
Guinea	0.7	1.3	0.8	2.2
Guinea-Bissau	0.1	0.1	0.1	0.2
Liberia	0.3	0.6	0.7	1.3
Mali	0.4	0.6	1.2	1.8

	Total net demand in 2005	Market demand 2015*	Social demand with national targets 2015	Total net demand 2015
Mauritania	0.2	0.5	0.3	0.8
Niger	0.4	0.6	0.7	1.2
Nigeria	16.9	45.6	13.6	59.2
Senegal	1.5	2.5	1	3.5
Sierra Leone	0.2	0.5	0.5	1
Togo	0.6	0.8	0.7	1.5
Total	31.3	69.6	24.8	94.3
Central Africa Power Pool				
Cameroon	3.4	5.2	1.2	6.4
Central African Rep.	0.1	0.1	0.4	0.6
Chad	0.1	0.1	0.8	1.0
Congo, Rep.	5.84	9.8	0.5	10.3
Equatorial Guinea	0.03	0.1	0.05	0.1
Gabon	1.2	1.7	0.1	1.8
Total	10.7	17.1	3.1	20.2
Island states				
Cape Verde	0.04	0.1	0.04	0.1
Madagascar	0.8	1.1	1.4	2.6
Mauritius	0.2	0.4	0.02	0.4
Total	1.1	1.6	1.5	3.0

Source: Authors' original research.

Note: * Assuming all suppressed demand is met.

3 Estimating supply

We now estimate electricity supply, which consists of power generation plants, a transmission grid and a distribution grid. In addition to a grid-based supply of electricity, rural areas may have off-grid supply.

The available technologies for power generation are hydropower (large-scale, small-scale and pumped storage), thermal (fueled by coal, natural gas, diesel, heavy fuel oil as well as nuclear power), solar PV and geothermal power. We describe each technology in terms of its capacity and cost. The starting point is the existing generation capacity as of 2005. Capacity expansion is possible through investments. In addition, refurbishment can extend the life span of existing capacity. Costs consist of capital and variable operating costs (that is, the cost of fuel and operations and maintenance, O&M).

Investments are also necessary to extend the transmission and distribution grid, and refurbishments are necessary to keep the existing assets in working condition.

The following sections outline assumptions for (a) installed capacity, refurbishment requirements and costs, the investment potential of different generation technologies, as well as costs of generation, based on fuel prices; (b) transmission and distribution assets; and (c) the supply side of social demand.

Generation capacity

Installed capacity, refurbishment requirements and costs

The stock of operating generation assets in 2015 is assumed to equal installed (design) capacity in 2005, minus the assets that must be refurbished by 2015 to continue effective production.

Refurbishment refers to efforts to either prolong the life of an outdated plant whose 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.

Table 3.1 reports the existing generation capacity (as of 2005) and refurbishment requirements in 2015. (Note that the column for refurbishment in table 3.1 also includes capacity that was installed but not operational in 2005, but can be brought online before 2015.) For further documentation, see appendixes 1 and 2. The amount that is refurbished will be determined within the least-cost expansion model.

For *coal-fired power plants* we base the assumptions for refurbishment costs on estimated costs of planned refurbishments of South African coal plants. The estimated average refurbishment cost of these plants is $272/kW. This figure will be used for South Africa. We cross-checked the estimate against international sources of refurbishment costs for thermal plants of similar age. The figure fits well with

other international experiences from both Europe and Asia.[6] Therefore, as an estimate for refurbishment costs of coal-fired plants in the remaining countries we will use $300/kW.

For *gas-fired power plants*, which carry a significantly lower overnight investment cost, a figure of $300/kW would be too high for refurbishment, as it would constitute almost half of the costs of new investments. We estimate the overnight refurbishment costs of gas-fired power plants to be 15 percent of the investment costs, or $100.5/kW.

Hydropower refurbishment costs are to a large extent site-specific; see appendix 2 for further documentation.

Table 3.1 Asset stock and refurbishment requirements for electricity generation in study countries

Country	Installed capacity, 2005 (MW)			Refurbishment requirements (MW)		
	Hydro	Thermal	Total	Hydro	Thermal	Total
SAPP						
Angola	830	320	1,150	306	103	409
Botswana	0	132	132	0	12	12
Congo, Dem. Rep.	2,451	0	2,451	2,455	0	2,455
Lesotho	72	0	72	0	0	0
Malawi	252	21	273	100	0	100
Mozambique	2,157	204	2,361	100	80	180
Namibia	240	144	384	0	120	120
South Africa*	2,242	33,232	35,474	600	21,432	22,032
Zambia	1,838	90	1,928	1,670	0	1,670
Zimbabwe	750	1,295	2,045	760	1,075	1,835
EAPP						
Burundi	26	5	31	18	0	18
Djibouti	0	85	85	0	0	0
Egypt	2,804	16,475	19,279	0	2,093	2,093
Ethiopia	1,115	76	1,191	335	0	335
Kenya	641	520	1,161	383	77	460
Rwanda	32	20	52	24	0	24
Sudan	1,623	1,129	2,752	0	133	133
Tanzania	553	332	885	305	0	305
Uganda	441	106	547	191	0	191
WAPP						
Benin	31	165	196	31	90	121

[6] The International Atomic Energy Agency (2002) reports on energy supply options in Poland and estimates the rehabilitation costs of Polish power plants. Poland has an aging fleet of coal power plants (in 1996 coal-fired power plants constituted more than 95 percent of installed capacity). The age structure is similar to South Africa in that more than half of the installed capacity was constructed in the 1970s. The Polish Power Grid Company estimated rehabilitation requirements to be in the range of $50–$350 per kW of installed capacity. The Indian Ministry of Power issued guidelines in 2004 for undertaking life extension (LE) works on its thermal units, where the cost guidelines were to restrict the cost of LE works between 0.8 and 1.25 crore rupees/MW, which is, at current exchange rates, approximately $178–$278/kW. The Ministry of Power's *Performance Review of Thermal Power Stations* (2006) reported a life extension/rehabilitation of 106 thermal units with combined generating capacity of 10,413 MW at a total cost of 9,200 crore rupees, or approximately $200/kW.

Country	Installed capacity, 2005 (MW)			Refurbishment requirements (MW)		
	Hydro	Thermal	Total	Hydro	Thermal	Total
Burkina Faso	33	183	216	63	117	180
Cote d'Ivoire	601	612	1,213	601	114	715
Gambia	0	103	103	0	81	81
Ghana	1,198	705	1,903	160	30	190
Guinea	103	108	211	28	64	92
Guinea-Bissau	0	22	22	0	22	22
Liberia	64	9	73	64	9	73
Mali	150	108	258	46	20	66
Mauritania	30	110	140	0	73	73
Niger	0	105	105	0	105	105
Nigeria	1,900	6,014	7,914	2,850	5,003	7,853
Senegal	66	496	562	0	291	291
Sierra Leone	50	66	116	0	55	55
Togo	31	60	91	31	60	91
CAPP						
Cameroon	722	222	944	596	98	694
Central African Republic	18	24	42	18	24	42
Chad	0	29	29	0	29	29
Congo, Rep.	99	28	127	129	28	157
Equatorial Guinea	0	44	44	0	34	34
Gabon	163	244	407	163	244	407
Island states						
Cape Verde	0	78	78	0	78	78
Madagascar	82	187	269	82	0	82
Mauritius	59	618	677	0	483	483

Source: Authors' original research. See appendixes 1 and 2 for further documentation.

Note: Refurbishment figures may exceed the original installed capacity, since capacity is often increased in the course of refurbishment.

* Thermal capacity includes nuclear (1,800 MW) in South Africa.

Generation investment: Unit cost and potential

Investments in conventional thermal power plants (fueled by coal, natural gas, heavy fuel oil or diesel) and hydropower are determined endogenously in the model.[7] In addition, it is possible to invest in solar PV, diesel and minihydro plants in rural areas. These will be discussed further under supply side assumptions related to social demand.

Hydropower unit cost and potential

Hydropower potential and investment costs are largely site specific.

[7] Investments in nuclear power are not included in the model. In general, nuclear power investments are more expensive than alternatives. In some countries nuclear power is chosen for political reasons (for example, energy security). In other countries, nuclear power is not an option for political reasons.

Our unit investment costs for each country are based on estimated investment costs for actual planned hydropower projects in the country. Where there are several planned projects, the unit investment costs used in the least-cost expansion model is the weighted, average-unit investment cost of planned projects in the country, where weights reflect plants' planned capacity. We want to emphasize that this is not an exhaustive list of planned hydropower projects in any region, but a subset for which good estimates of investment costs could be obtained. Some countries have no potential for larger hydropower plants, and thus no planned investments.

The investment cost estimates are documented in appendix 2.

Thermal power unit cost and potential

Thermal power plant technology is generic. The unit costs are therefore similar across countries. For thermal power unit investment costs, we rely on values used in the power market models developed by our firm, Econ Pöyry. These values agree with accepted international values from several sources (table 3.2).

Table 3.2 Unit investment costs for thermal power generation

Source	Unit cost, gas ($/kW)	Unit cost, coal ($/kW)
International Energy Agency—Projected Costs of Generating Electricity (2005)	400–800	1,000–1,500
U.S. Energy Information Administration (2005)	580	975
Royal Academy of Engineering—The Costs of Generating Electricity (2004)	570	1,400
Actual value used	670	1,100

Note: At current exchange rates.

The capital investment costs for small diesel units are derived from earlier project work carried out by Econ Pöyry and Power Planning Associates from Sub-Saharan Africa, and cross-checked against producers of mini-diesel plants such as Jacobsen and Caterpillar. The unit capital cost used in the model is $335/kW.

Nevertheless, fuel availability limits the feasibility of certain investments. Therefore, we allow for investments in natural gas-fired power plants only 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). Similarly, investments in coal-fired power plants are limited to countries that have domestic coal resources. Oil products (diesel and heavy fuel oil) are assumed to be available in most countries.

Fuel price assumptions

For *coal*, the world market price of $52/ton is the benchmark for fuel costs, based on the projected price for 2015 from the U.S. Energy Information Administration's Annual Energy Outlook 2006 (EIA, 2006). The world market price indicates the alternative value of domestic coal resources, that is, what the country could earn by selling the coal in the world market instead of using it for domestic electricity production.

The price of *oil products* (diesel and HFO) is related to the world market price of crude oil. Our base case scenario is based on the oil price of $47/barrel.[8] The world market price must, however, be adjusted for transport costs. For EAPP and SAPP, we use country-specific data for all countries, as provided by

[8] Sensitivities that analyze the impact of different oil prices are presented in chapter 6.

Meschies (2005). For CAPP and WAPP, the transport cost assumptions are based on Arthur Energy Advisors (2007).

Estimating the price of *gas* is particularly challenging, since the price and availability of gas depends heavily on infrastructure, especially pipelines. First, we assume that only countries with domestic gas reserves or countries that are connected to a gas pipeline can invest in gas-fired power plants. Second, we assume that for countries that have potential to export gas (for example, Nigeria), the gas price is related to the world market price of oil (that is, gas has an alternative value); for countries that have no infrastructure to export gas (for example, Mauritania), the gas price is related to domestic production costs. Third, we adjust the final price of gas (delivered to the power plant) to reflect the transportation costs: countries with domestic resources are assumed to have lower gas price than countries that import gas through a pipeline (such as Benin, Togo, and Ghana).

Transmission and distribution

Existing assets, refurbishment requirements, and costs

The existing stock of transmission and distribution (T&D) lines in each country are shown in table 3.3. Transmission lines are those with voltages of 66 kilovolts (kV) or greater, while the rest are defined as distribution lines. The refurbishment requirements are based on the asset age: we assume that lines older than 30 years need refurbishment at a unit cost of 60 percent of replacement value. In some countries, transmission systems are quite old. For example, in Niger, 96 percent of the system is more than 30 years old; in Zimbabwe, 85 percent; in Zambia, 80 percent, and in the Democratic Republic of Congo, 61 percent. Distribution systems are younger on average. For documentation of data sources for transmission and distribution, please see appendix 3.

Table 3.3 Asset stock and refurbishment requirements related to transmission and distribution in study countries

Country	Type	Line (km)	Asset value ($ thousands)	Percentage of assets older than 30 years (weighted average)	Refurbishment cost ($ thousands) (Asset value x Assets older than 30 years x 60%)
Southern Africa Power Pool					
Angola	Transmission	—	—	—	153,998
	Distribution	—	—	—	153,794
Botswana	Transmission	2,664	280,258	43	72,516
	Distribution	3,560	184,172	35	38,428
Congo, Dem. Rep.	Transmission	3,050	421,477	61	154,279
	Distribution	5,295	367,875	69	152,942
Lesotho	Transmission	550	48,527	14	4,203
	Distribution	3,980	57,115	37	12,578
Malawi	Transmission	1,944	171,219	29	30,214
	Distribution	810	46,453	44	12,240
Mozambique	Transmission	3,116	416,713	35	87,187
	Distribution	4,680	272,221	46	74,733

Country	Type	Line (km)	Asset value ($ thousands)	Percentage of assets older than 30 years (weighted average)	Refurbishment cost ($ thousands) (Asset value x Assets older than 30 years x 60%)
Namibia	Transmission	7,813	1,145,190	51	351,935
	Distribution	10,457	503,848	29	88,043
South Africa	Transmission	68,704	13,337,276	30	2,411,721
	Distribution	404,861	26,858,652	25	4,032,881
Zambia	Transmission	5,213	783,970	80	374,012
	Distribution	20,645	810,452	58	280,102
Zimbabwe	Transmission	6,717	1,401,851	85	717,069
	Distribution	36,900	1,586,107	60	570,999
					Nile Basin–East Africa Power Pool
Burundi	Transmission	270	31,962	20	3,835
	Distribution	860	31,152	30	5,607
Djibouti	Transmission	5	354	0	0
	Distribution	579	15,534	20	2,026
Egypt	Transmission	34,897	3,681,478	52	1,149,869
	Distribution	19,725	1,309,630	30	235,733
Ethiopia	Transmission	6,488	595,482	91	326,145
	Distribution	17,480	1,273,742	46	353,166
Kenya	Transmission	2,615	362,005	39	83,834
	Distribution	34,927	1,727,075	29	303,628
Rwanda	Transmission	349	38,839	42	9,875
	Distribution	657	37,253	26	5,832
Sudan	Transmission	3,400	416,960	53	131,913
	Distribution	41,200	1,152,698	31	215,774
Tanzania	Transmission	5,511	643,218	52	201,698
	Distribution	14,550	328,675	44	87,040
Uganda	Transmission	1,169	82,825	88	43,777
	Distribution	13,412	540,190	56	182,514
Western African Power Pool					
Benin	Transmission	532	37,136	60	13,369
	Distribution	6,899	540,641	32	103,803
Burkina Faso	Transmission	1,161	201,774	50	60,532
	Distribution	6,396	321,447	32	61,718
Cote d'Ivoire	Transmission	4,396	701,106	41	172,472
	Distribution	32,177	895,940	36	193,523
Gambia	Transmission	–	–	–	–
	Distribution	704	18,382	50	5,515
Ghana	Transmission	5,374	562,819	53	178,976
	Distribution	10,390	949,872	17	96,887
Guinea	Transmission	415	64,611	10	3,877
	Distribution	1,817	43,967	50	13,190

Country	Type	Line (km)	Asset value ($ thousands)	Percentage of assets older than 30 years (weighted average)	Refurbishment cost ($ thousands) (Asset value x Assets older than 30 years x 60%)
Guinea-Bissau	Transmission	–	–	–	–
	Distribution	348	8,496	50	2,549
Liberia	Transmission	420	29,719	–	–
	Distribution	1,763	41,959	–	–
Mali	Transmission	956	114,123	45	30,813
	Distribution	6,135	574,830	36	124,163
Mauritania	Transmission	300	35,937	–	–
	Distribution	1,780	135,065	50	40,520
Niger	Transmission	910	213,096	96	122,743
	Distribution	325	18,284	41	4,498
Nigeria	Transmission	10,919	2,236,773	51	684,453
	Distribution	184,880	7,370,061	36	1,591,933
Senegal	Transmission	1,530	168,661	14	14,168
	Distribution	448,928	5,794,945	30	1,043,090
Sierra Leone	Transmission	308	36,534	-	-
	Distribution	1,435	36,171	50	10,851
Togo	Transmission	820	86,737	37	19,256
	Distribution	555	33,654	20	4,038
Central African Power Pool					
Cameroon	Transmission	1,860	274,834	48	79,152
	Distribution	14,635	412,998	31	76,818
Central African Rep.	Transmission	195	30,695	50	9,209
	Distribution	624	9,205	50	2,762
Chad	Transmission	–	–	–	–
	Distribution	355	14,156	37	3,143
Congo, Rep.	Transmission	1,128	131,398	–	–
	Distribution	4,148	73,367	–	–
Equatorial Guinea	Transmission	–	–	–	–
	Distribution	218	7,140	50	2,142
Gabon	Transmission	556	58,454	50	17,536
	Distribution	5,748	67,836	50	20,351
Island states					
Cape Verde	Transmission	80	14,154	50	4,246
	Distribution	146	4,760	50	1,428
Madagascar	Transmission	138	7,639	50	2,292
	Distribution	1,783	82,321	28	13,830
Mauritius	Transmission	252	21,759	20	2,611
	Distribution	5,060	322,019	20	38,642

Source: Authors' original research. See appendix 3 for details and data sources.

Note: The weighted average asset age is the average percentage, across voltage levels, of assets older than 30 years. Weights correspond to the fraction of a voltage level's asset value to total asset value.

Investments in transmission and distribution

Here we present assumptions for transmission and distribution costs related to *market* demand. Subtransmission and distribution costs related to *social* demand are described later.

Domestic transmission and distribution

For *domestic* T&D infrastructure, we have assumed that T&D stock will grow at half the rate of market demand, an assumption used by the regulatory authorities in both Norway and Great Britain. In addition, we have assumed that the original asset stock will depreciate at 3 percent per year before 2015.[9] Combined with annual O&M costs of 2 percent, we assume that the relevant annual investment to maintain capacity over the next ten years will be 5 percent of original T&D stock.

Cross-border transmission lines

Investment volume in *cross-border transmission* is an endogenous decision variable determined by the model.

The set of potential cross-border transmission lines is exogenous. For example, we exogenously determine the feasibility of building a line from Angola to Zambia.

Cross-border transmission can be built in two high-voltage levels—namely, the two highest voltage levels historically used in a given country. These have different unit costs and different average line ratings in MW. The average line ratings have been used to set upper limits for the capacity that may be built between countries. Finally, since the maximum capacity varies among countries (since they are using different voltage levels for transmission), the maximum capacity (in MW) for a line between the two countries is assumed to be determined by the *highest* capacity of the two countries.

The unit costs—per km and per MW—of investing in these lines have been provided for each country. The unit costs are country specific (refer to appendix 3 for documentation). For lines between countries, we have used weighted unit costs, in which the weights are based on the approximate share of the line built in each country.

The total cost of a cross-border line depends on the unit cost per km per MW and the line length (in km). The line length depends on the distance between load centers in the two countries, or between a load center and a possible power-plant location (where plans are known). For instance, the relevant distance for a line between Mozambique and South Africa is the distance from Cahora Bassa North to Johannesburg. Similarly, the Mmamabula power plant in Botswana will most likely be connected to the South African transmission grid in the vicinity of the Matimba power plant in South Africa; therefore, the distance between the two is the relevant distance.

Based on the total cost of a line (that is, unit cost per km per MW, multiplied by the line length in km), the model decides how much capacity to build between the countries.

---

[9] This is based on a 30-year lifetime, assuming that technological improvements will allow for slightly cheaper alternatives.

Supply-side assumptions related to social demand

Some aspects of the model are particular to social demand, such as the connection cost for grid-connected and off-grid technologies, the distribution of social demand connections across grid-connected and off-grid technologies, and distribution among off-grid technologies.

This section presents the assumptions and data related to the supply side of social demand.

Technology mix for social demand: New connections

New *urban* connections are assumed to be connected to the grid.

New *rural* connections are covered either by grid expansion (70 percent), minihydro (20 percent), diesel (5 percent), or solar PV (5 percent). The basis for these assumptions is professional judgment; allowing the model to determine the technology mix for new connections endogenously would rest too much on insignificant differences in unit costs and could result in coincidental outcomes. To compare the associated costs, we assume the same shares in all simulations.

Urban connection costs

The urban population in Sub-Saharan Africa is growing rapidly; in fact the region has the highest urban growth rate in the world (Karezeki and Majoro, 2002).

For urban electrification, the majority of costs are the result of connection to existing low-voltage distribution networks and the installation of credit meters. Econ Pöyry (2005) and Modi (2004) both estimate connection costs at $100 per connection.

The additional costs of low- and medium-voltage distribution lines are substantially lower per customer (given the higher population density and electrification rates in urban areas). USAID (2004) and Gaunt (2005) provide estimates of unit costs of urban electrification programs in South Africa of approximately $420 and $350, respectively. We use a similar but slightly higher figure of $500 per connection for the remaining countries, since the cost of urban electrification is to a large extent generic.

Rural connection and generation costs

We allow for four technical solutions for rural electrification (grid extension, mini- and microhydro, diesel generation, and solar PV) and estimate the connection costs for each (table 3.4).

Grid extension and mini- and microhydro

These technical solutions both require the installation of low- and medium-voltage subtransmission lines (for example, 11 kV or 33 kV) to deliver the electricity to the local grid. Thus, the cost per connection in both cases includes subtransmission lines, a distribution network, and actual connection costs. Note that the generation costs of mini- and microhydro stations are included in the connection cost estimate.

It is difficult to estimate the cost per connection for a large-scale and relatively effective rural electrification program. First, this cost depends on area-specific characteristics such as population density, distance from the grid, and terrain. Additionally, there are relatively few successful large-scale rural electrification programs in Africa from which we can extract data.

Probably the most successful program is in South Africa, where Gaunt (2005) estimated that between 1995 and 2001, approximately 500,000 new connections were made annually, and costs fell from ZAR 3,600 in 1995 to ZAR 2,600 in 2001 (less than $350 at current exchange rates). But recognizing country-specific challenges—whether geographic or institutional—this is probably a low estimate. Our estimates for cost per connection are based on the extensive global review of rural electrification projects and studies by Zomers (2001), who arrives at an estimated grid extension cost of nearly $1,500 per connection (distribution cost of $1,200, transmission cost of $125, and service connection of $100). This corresponds with the estimates produced in a particularly ambitious study on the costs of grid-based rural electrification in Tanzania by Econ Pöyry (2006), which provides detailed estimates of costs per connection for several districts in 19 different regions in Tanzania, all with varying access rates and population densities. The resulting average unit cost per connection in the 19 different regions lies between $544 and $4,336. The average unit cost across all regions was $1,547. Studies from Zambia (Sanghvi, 2005) and Mozambique (Bergman and Davies, 2005) estimate a cost per connection of around $2,000, while a World Bank Project Appraisal Document from Nigeria arrives at an estimate of $1,000.

Based on Econ Pöyry's work, the findings of Zomers, and discussions with World Bank staff, we assume that the cost for large-scale electrification programs converges to approximately $1,550 in most countries (see table 3.4 for exceptions).

Diesel generation and isolated grids

This technical solution involves a diesel generator accompanied by a distribution network, generally with no need for transmission or subtransmission lines. Thus, the relevant connection cost is simply the unit distribution and service connection costs. Here, Zomers's (2001) cost of $1,325 per connection is used.

Solar PV

The solar PV markets in most Sub-Saharan African countries have only recently begun to be developed. As a result, prices have fallen considerably in most countries over recent years. CORE (2003) reports the results of Afrepren, which arrives at an estimated average price for a 50 Watt-peak (Wp) system of $1,100 for SAPP countries. But work carried out by Econ Pöyry in Tanzania and Zambia, where the markets are undeveloped, reveal prices of $650–$800. Other more recent sources from South Africa, Ethiopia, Sudan, Kenya, and Uganda reveal similar prices.[10] Thus, country-specific cost data are applied for those countries where it is available, while a conservative estimate of $800 is applied to the remaining countries (see table 3.4).

[10] For South Africa, see http://roo.undp.org/gef/solarpv/forum/fileattachments/Discussion_Solar_PV_Forum_-_Disgest_1_Jan_2004.doc. For Ethiopia, Sudan, Kenya and Uganda, http://roo.undp.org/gef/solarpv/forum/fileattachments/ACFE91.doc.

Table 3.4 Summary of costs per connection in study countries ($)

	Urban	Rural		
	Grid extension	Grid extension or minihydro	Minigrid (diesel)	PV (50 Wp)
General assumption	500	1,550	1,325	800
Exceptions:				
EAPP				
Burundi	500	1,000	1,325	670
Djibouti	500	1,550	1,325	750
Egypt	500	1,550	1,325	670
Ethiopia	500	1,550	1,325	750
Kenya	500	1,000	1,325	550
Rwanda	500	1,000	1,325	670
Sudan	500	1,550	1,325	650
Tanzania	500	1,550	1,325	650
Uganda	500	1,000	1,325	730
SAPP				
South Africa	350	350	1,325	500
Islands				
Cape Verde	500	2,500	1,325	1,100
Madagascar	500	2,500	1,325	1,100
Mauritius	500	2,500	1,325	1,100

Source: Authors' original research.

4 Least-cost expansion model

In estimating the investment needs in each country, we used a *least-cost expansion model* that simulates optimal electricity generation and investment strategies in response to demand increase in African countries.[11]

The endogenous decision variables in the model are:

- Electricity generation (gigawatt-hours, GWh)
- Electricity transmission (GWh)
- Refurbishment of existing capacity for electricity generation (MW)
- Investments in new capacity for electricity generation (MW)
- Investments in new capacity for cross-border electricity transmission (MW)

Model assumptions and simplifications

Time assumptions

The model simulates *one year*. The year consists of two periods, one *peak* and one *off-peak*. The peak period represents all days in the year between the hours of 8 A.M. and 8 P.M.

Demand assumptions

Demand is modeled by using *demand centers*, hereafter referred to as *nodes*. Each country consists of one *urban* and one *rural* node.

Demand is *market driven* or *social*, and is located in one of the two nodes per country. Market demand is located in the urban node, whereas social demand is distributed between the urban and rural nodes. Total demand is the annual total sum of market driven and social demand.

Input data for market demand are provided by the econometric model described in chapter 2. Data for suppressed demand are added to the original 2005 market demand figures. Social demand determined by electricity access targets creates additional demand for electricity. This social demand entails extra costs, as new households must be connected to the electricity grid in order to increase the access rate.

For the urban nodes, it is assumed that 70 percent of electricity demand occurs during peak periods. The rationale for this is that most of the industry is located in densely populated areas. For rural nodes, there is a 50–50 split in demand between peak and off-peak periods.

Power generation assumptions

Existing and potential generation capacity can be located in all nodes in the model.

[11] AICD intends to make the model available on its website.

Generation capacity is divided into an exogenous set of technology types. Hydropower capacity is split between large-scale hydro (including pumped storage) and minihydro. Thermal capacity comprises power stations or generators based on coal, gas, diesel, HFO, nuclear, and geothermal. In addition, photovoltaic production equipment (solar power) can be built off-grid.

Production in each technology is limited by capacity and 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, however, the number of hours per year will be limited by factors such as water inflow and sunlight. Consequently, the number of available production hours per year will be considerably lower than for the thermal technologies.

Large-scale hydropower differs from minihydro in terms of production flexibility and investment potential. It is assumed that all minihydro is run-of-river without the possibility of storing water in reservoirs. This means that minihydro production remains constant day and night. For large-scale hydro, the model allows for flexibility so that it is possible to shift production from the low-demand (off-peak) period to the high-demand (peak) period. This flexibility varies from country to country.

Investments in new capacity in the different technologies are determined by the model, but upper and lower limits for investments in each technology are set exogenously. This is particularly important for hydropower generation, as hydropower potential varies significantly from country to country. Similarly, investments in thermal technologies can be limited by availability of fuel (as described in chapter 3). Lower limits are used for thermal power projects that are being developed but are not yet online.

Transmission and distribution assumptions

Electricity can flow freely between urban nodes within the countries of the model, limited only by the maximum cross-border transmission capacity (measured in MW). This maximum capacity can be increased by building new lines *between two urban nodes in two countries*. The set of potential transmission connections between countries is set exogenously, as well as the upper bound (in MW) for new transmission investments. Only transmission lines (two highest voltage levels available in a country) can be built between countries.

All export to and import from outside the model countries is assumed to be exogenous.

Urban nodes are connected to the national grid and can export or import electricity, depending on transmission capacity. Rural nodes “import” a predetermined share (70 percent) of electricity from the urban node of the same country. The rest (30 percent) of electricity demand in rural nodes is met by off-grid technologies (minihydro, diesel and solar PV). The rural nodes cannot import from or export electricity to other countries, nor is it possible to build additional transmission lines between the urban and rural nodes in the model.

Investments in the *domestic* distribution and subtransmission grid are not explicitly modeled as decision variables (in contrast to investments in transmission grid between countries). Instead, the distribution and subtransmission grid within a country is assumed to grow with increasing market and social demand according to a predefined rate.

Transmission losses are assumed to occur when electricity flows from one node to another. This loss depends on the nodes and the direction of the flows. Distribution losses (in the low-voltage grid) are set as a percentage of net demand for each node.

The mathematical formulation of the model

The approach used is a linear programming model, in which all the decision variables are modeled as continuous positive variables.

Objective function and model constraints

The model minimizes the cost of producing and distributing electricity to meet a certain demand level. The costs include production as well as investment and refurbishment costs for generation; investment costs of new cross-border transmission lines; investment, refurbishment, and operation costs of domestic distribution lines; and costs of new connections to the power grid.

Expression (1) is the objective function, which is to be minimized:

$$\begin{aligned}\min Z = &\sum_{t=1}^{T}\sum_{i=1}^{I}\sum_{k=1}^{K} p_{ikt}\cdot v_{ik} + \sum_{i=1}^{I}\sum_{k=1}^{K}\left[I_{ik}\cdot FC_{ik} + R_{ik}\cdot RCost_{ik}\right] + \sum_{t=1}^{T}\sum_{(i,j)\in U} y_{ijt}\cdot Tr_{ij} \\ &+ \sum_{z=1}^{Z}\sum_{(i,j)\in U}\delta_{ijz}\cdot TG_{ijz} + \sum_{t=1}^{T}\sum_{i=1}^{I} DistCost\left(MD_{it}, SD_{it}\right) + \sum_{i=1}^{I} GridRCost_{i}\end{aligned} \tag{1}$$

It consists of the following:

- Variable costs of electricity generation
- Costs of investing in new generation capacity and refurbishing the existing capacity
- Costs of electricity transmission between endogenous nodes
- Costs of investing in transmission grids between countries for all voltage levels
- Costs of connecting new households to the low-voltage distribution grid (this includes the distribution and subtransmission cost of social demand)
- Cost of expanding the distribution and subtransmission grid to accommodate increased marked demand
- Costs of refurbishing the distribution and subtransmission grid

The objective function is subject to several constraints that will be explained below (refer to the list of endogenous and exogenous variables below).

Expression (2) is the power balance constraint. For each time period and node, the sum of electricity imports from other endogenous nodes, imports from exogenous countries, and internal electricity generation (left-hand side of the constraint) must be large enough to cover market demand, social demand, exports to other endogenous nodes, and exports to exogenous countries (right-hand side of the constraint).

$$\sum_{\substack{j=1,\\(j,i)\in U}}^{I} y_{jit} + \sum_{y=1}^{Y} imp_{iyt} + \sum_{k=1}^{K} p_{ikt} \geq MD_{it} + SD_{it} + \sum_{\substack{j=1,\\(i,j)\in U}}^{I} y_{ijt} + \sum_{y=1}^{Y} e_{iyt}, \forall i,t \tag{2}$$

Expression (3) reveals that the electricity flow on a given line between two endogenous nodes (in either direction) must not exceed the transmission capacity (in MW) multiplied by the number of hours during time period *t*, LB_t.

$$y_{ijt} \leq I0_{ij} \cdot LB_t + \sum_{z=1}^{Z} \delta_{ijz} \cdot LB_t, \forall t, (i,j) \in U \tag{3}$$

Expression (4) states that investments in new generation capacity of technology *k* in node *i* must not exceed the potential maximum capacity (in MW). Expression (5) states that investments in new generation capacity of technology *k* in node *i* must be at least as high as a certain minimum capacity (MW).

$$I_{ik} \leq IMax_{ik}, \forall i,k \tag{4}$$

$$I_{ik} \geq IMin_{ik}, \forall i,k \tag{5}$$

Refurbishment of existing generation capacity of technology *k* in node *i* must not exceed a certain maximum capacity (MW, expression 6).

$$R_{ik} \leq RMax_{ik}, \forall i,k \tag{6}$$

Annual electricity generation (in GWh) by technology *k* in node *i* must be lower than the upper bound for generation (right side of expression 7), and higher than an exogenously set minimum generation level (right side of expression 8).

$$p_{ikt} \leq \left[Cap_{ik} + I_{ik} + R_{ik}\right] \cdot FLHours_{ikt}, \forall i,k \tag{7}$$

$$p_{ikt} \geq \left[Cap_{ik} + I_{ik} + R_{ik}\right] \cdot FLHours_{ikt} \cdot MinLoad_{ikt}, \forall i,k \tag{8}$$

Investments in new high-voltage grid capacity (in MW) of voltage type *z* between two countries cannot exceed the maximum potential for high-voltage grid capacity (expression 9).

$$\delta_{ijz} \leq G_{ijz}, \forall i,k,z \tag{9}$$

Sets

U represents all *possible* transmission connections between endogenous nodes; *I* is the set of endogenous nodes; *K* is the set of all electricity generation technologies; *Y* is the set of exogenous countries; *T* is the set of time periods.

Endogenous (decision) variables

p_{ikt} is the generation (GWh) in endogenous node *i* using technology *k* during time period *t*.

I_{ik} represents investment (MW) in generation technology *k* in endogenous node *i*.

R_{ik} is refurbishment (MW) of generation capacity of technology *k* in endogenous node *i*.

y_{ijt} represents the electricity transmission flow (GWh) from endogenous node *i* to endogenous node *j* during time period *t*.

δ_{ijz} stands for investment (MW) in transmission capacity of voltage *z* between endogenous nodes *i* and *j*.

All endogenous decision variables are assumed to be positive and continuous variables.

Exogenous variables

v_{ik} is the variable cost of producing one energy unit (GWh) with generation technology *k* in node *i*.

FC_{ik} is the annualized fixed cost per MW of investing in generation technology *k* in node *i*.

$RCost_{ik}$ is the annualized fixed cost per MW of refurbishing existing generation technology *k* in node *i*.

Tr_{ij} is the variable transmission cost of sending one energy unit (GWh) from endogenous node *i* to endogenous node *j*.

TG_{ijz} is the annualized fixed cost per MW of investing in transmission lines of voltage type *z* between endogenous urban nodes *i* and *j*.

$DistCost_i(SD_{it}, MD_{it})$ is the cost of expanding the domestic electricity grid in the model. This cost is assumed to be a function of market demand and social demand (new connections).

MD_{it} is market demand (GWh) in node *i* in period *t*.

SD_{it} is social demand (GWh) in node *i* in period *t*. Social demand equals the number of new households connected to the grid in node *i* with the expected annual consumption per household. The number of new connections varies between the scenarios.

$GridRCost_i$ is the fixed annualized cost of refurbishing the internal electricity network in node *i*.

imp_{iyt} is the amount of power imported (GWh) from exogenous country *y* to endogenous node *i* in time period *t*. The level of imports is set exogenously.

e_{iyt} is the amount of power exported (GWh) from endogenous node *i* to exogenous country *y* in time period *t*. The level of exports is set exogenously.

$I0_{ij}$ is the original transmission capacity between endogenous nodes *i* and *j*.

LB_t is the number of hours during time period *t*.

$IMax_{ik}$ is the upper bound for investments in new generation capacity of technology *k* in endogenous node *i*.

$IMin_{ik}$ is the lower bound for investments in new generation capacity of technology *k* in endogenous node *i*.

$RMax_{ik}$ is the upper bound for refurbishment of existing generation capacity of technology *k* in endogenous node *i*.

Cap_{ik} is the existing generation capacity of technology *k* in node *i* which does *not* need refurbishment to operate.

$FLHours_{ik}$ represents the average numbers of full load hours for generation technology *k* in node *i*.

$MinLoad_{ikt}$ is the minimum production level of technology *k* in node *i* and time period *t* (as a percentage of the maximum production level (GWh) in that period).

G_{ijz} is the maximum potential transmission capacity (MW) between nodes *i* and *j* for lines with voltage type *z*. The maximum potential capacity is exogenous but a function of the voltage or size. For instance, the upper bound for a 400 kV line is 1,440 MW (which is an average line rating for 400 kV lines).

5 Results: Spending needs through 2015

In our case scenarios, we have analyzed the costs of achieving three levels of access to electricity 10 years from now. The cases are:

- Keeping the access rates constant at 2005 level (*2005 access rate scenario*)
- Increasing the access rates by 1 to 2 percentage points in each country to reach a regional average (*regional target access rate scenario*)
- Increasing the access rates to the national targets for access rates of individual countries (*national access targets scenario*)

A scenario with *lower growth* would help explain how lower GDP growth might affect outcomes. The low-growth scenario is discussed in the next chapter, but data are included in the tables presented here. The next chapter also presents several sensitivities that test how vulnerable the results are to assumptions about various parameter values.

We wish to analyze the impacts of a ten-year expansion program for electricity. The starting point for all scenarios is 2005; therefore, the costs discussed in this chapter refer to the costs of expanding the power system from 2005 to 2015. The terms used are defined below.

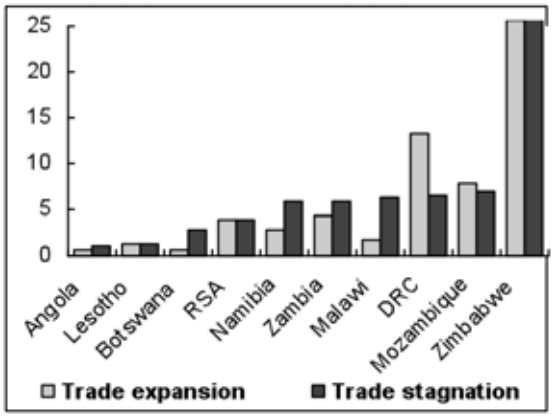
The overall cost of developing the power system appears high, but not unattainable given the GDP of each of the regional trading areas. But both GDP and power investment requirements are very unevenly distributed within the regional pools. As a result, under certain scenarios, some countries face power spending requirements that are very burdensome relative to the size of their economies (figure 5.1). In SAPP, depending on the electrification target and other variables, spending requirements may exceed 6 percent of GDP in the Democratic Republic of Congo, Mozambique, and Zimbabwe. In EAPP, countries such as Egypt, Burundi, and Ethiopia may reach similar levels. About half of the countries in WAPP have investment requirements of almost 10 percent of GDP, and Guinea and Liberia stand out at almost 30 percent. In CAPP, only the Republic of Congo requires investments of more than 5 percent of GDP. Some of these countries have the potential to become major exporters of power, provided they receive cross-border injections of capital to develop their power infrastructure. The necessary capital is not likely to materialize unless trade in power expands.

The next sections survey the investment requirements and costs in the four African regions (SAPP, EAPP, WAPP, and CAPP). More detailed output tables for each country (including the island states) can be found in annex 1 (separately bound). The section on each region follows the same basic outline, which we present below. Included in the outline are definitions of key terms used throughout the chapter.

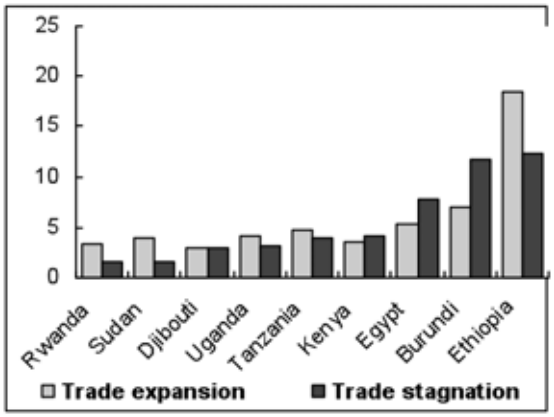
Figure 5.1 Overall power spending needs to reach national targets for electricity access under alternative trade scenarios by country

% of GDP in 2015

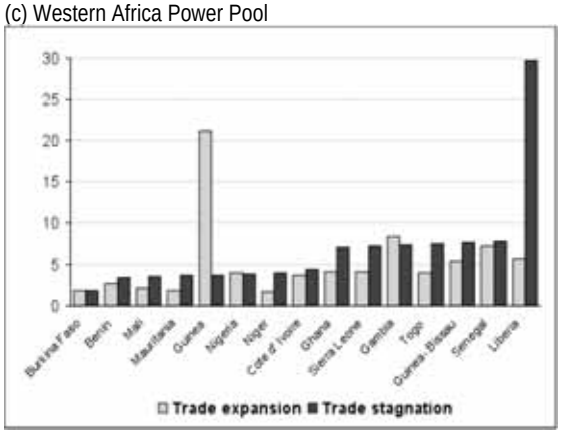
(a) Southern Africa Power Pool



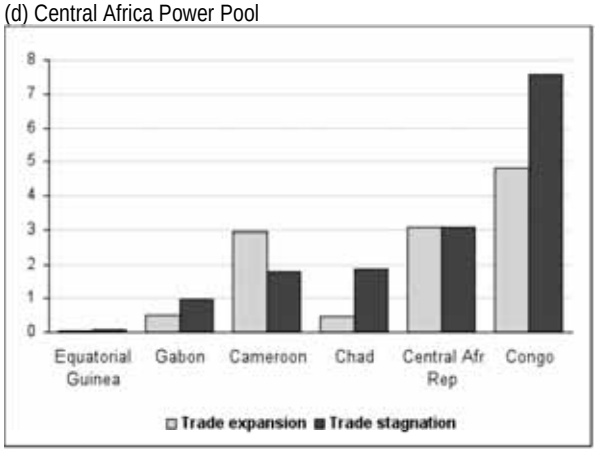
(b) East Africa Power Pool



(c) Western Africa Power Pool



(d) Central Africa Power Pool



Maintaining electricity access at 2005 rates

We begin the discussion of each region by looking at the investment needs and costs of the least-ambitious target scenario—where access rates are kept at the 2005 level. The types of costs are as follows:

Investment needs

This includes both investment in new capacity and refurbishment of existing capacity. Refurbishment consists of (a) power plants that were operational in 2005 but will exceed their economic lifetime before 2015 and will need to be refurbished to stay operational and (b) power plants that were not operational in 2005 because they were in such a bad state. This estimate is based on information about facility ages and conditions that we have assembled for this project.

Overnight investment costs

Generation costs: The investment costs of expanding the generation system between 2005 and 2015.

Transmission, distribution, and connection costs: The additional costs needed to bring power from power plants to consumers—the costs of transmission, distribution and new connections.

Total overnight investment costs: The total cost of expanding the power system, including both new investment and refurbishment costs. This is the total investment needed to meet market demand and provide electricity in 2015 to the same share of households as in 2005. It does not include variable costs.

Annualized costs

Annualized investment (capital) cost: The capital amount that must be spent annually to reach the access target. The annualized capital cost does not, however, equal the total overnight investment cost divided by 10 years. The cost takes into account both the discount rate and the different economic lifetimes of the investments. For example, we assume that the economic lifetime of hydropower plants is 40 years, compared to 30 years for coal-fired power plants and 25 years for natural gas fired power plants. The formula used for annualizing investment cost is the following:

$$\textit{annualized capital cost} = OIC * r(1-(1+r)^{-T})$$

where

OIC is the overnight investment cost,

r is the discount rate, and

T is the economic lifetime of the investment.

Annual variable costs: Includes fuel costs and variable costs of operation and maintenance of the system. The system includes both existing capacity as of 2005 that is still operating in 2015 and new capacity added over the ten year period.

Total annualized cost of system expansion: Includes the *annualized investment cost* and the *annual variable costs* of operating the new capacity. The variable costs of operating the existing capacity are not included in this figure.

Total annualized cost of system expansion and operation: Includes the *total annualized cost of system expansion* and the *annual variable costs* of the existing system.

Cost effects of raising access rates

This section discusses the increased costs needed to meet the more ambitious *regional* and *national targets for access rates* for each region.

The effects of trade

In this section we compare the effects of trade expansion and trade stagnation in each region. In the scenarios described above, we assume that trade will expand wherever it is worth the cost—that is, wherever the benefits of trade outweigh the costs of the additional infrastructure needed to support expanded trade. This is the *trade-expansion* scenario. Optimal trade expansion requires close regional cooperation in financing and institutional arrangements. Well-functioning power pools, mutual confidence, and stability are critical if trade is to yield its economic benefits. Exporters of power must be confident that they will have access to other countries' markets. Without that confidence, they will not take the risks of investing in exportable capacity. Importers, on the other hand, must be sure that they will

receive the power they need. In the absence of such assurance, policy makers will rely on self-sufficiency, regardless of its economic and environmental costs. Therefore, achieving optimal power trade will require important political, legal, and economic commitments from the cooperating countries.

In our *trade-stagnation* scenario, on the other hand, we assume that no new transmission lines will be built between countries. The existing cross-border lines can, of course, be used. In all scenarios, trade flows and volumes are determined endogenously, and the trade flows along the existing lines can change (increasing if there is spare capacity or even changing direction).

We only consider trade stagnation in the context of national targets for access rates, but the impact of trade is more or less independent of the target access rate.

We also discuss the costs and gains of trade expansion in each region. Trade allows for the development of the cheapest power resources in the region, taking into account the costs of investing in generation and necessary transmission lines. Trade-stagnation therefore leads to economic loss. While hydropower infrastructure is expensive to build (due to higher capital costs), it is cheap to operate once built. Thermal power plants (coal, gas, and HFO-fueled power plants), on the other hand, have higher variable costs from fuel. Additionally, hydropower has a longer economic lifetime than thermal power plants. Therefore, replacing thermal power with hydropower requires greater up-front investments but lower operating costs. This replacement takes place under trade expansion.

Returns on investing in trade. The gains from trade can be regarded as returns on investment, which we estimate for each region.

Long-run marginal cost. Differences in long-run marginal cost can also illustrate the gains from trade. The long-run marginal cost reflects the shadow cost of a marginal increase in net demand (consumption) in 2015,[12] or in other words, the least-cost option for meeting increased demand: increased generation in existing plants (domestic or through imports), or generation capacity expansion, together with the necessary investments in distribution and cross-border transmission lines.

The costs considered when determining the long-run marginal cost are marginal variable costs (fuel and O&M costs) of either existing or new capacity in 2015, marginal investment and refurbishment costs of generation, marginal cost of imports (through transmission loss), and marginal costs of investments in domestic T&D and cross-border transmission lines. Since the marginal costs of social demand (new connections) are driven by nonmarket considerations, they tend not to equalize with trade. Therefore, they are not considered in the long-run marginal cost calculation.

The model seems to indicate that trade benefits the importing countries. But the financial flows and agreements (on prices, for example) that are necessary to implement the least-cost solution are outside the scope of the model. It is these flows and agreements that will determine the allocation of the benefit.

The costs of T&D investment and refurbishment reflect the costs of a domestic grid and are not passed on to the importing countries. These costs are therefore the same under trade stagnation and trade expansion.

[12] Mathematically they are multipliers of the “supply equals demand” equations of the linear programming model.

SAPP

Maintaining electricity access at 2005 rates

Investment needs

The SAPP region needs almost 31,300 MW of new capacity by 2015 to keep up with the demand growth resulting from general economic development and population growth. In addition, 28,000 MW of existing capacity must be refurbished. Table 5.1 provides an overview of generation capacity in 2015, refurbishment and investment volumes over the ten years, and the resulting capacity mix for all scenarios.

Table 5.1 Investment needs and generation mix in SAPP in 2015

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation capacity (in MW)					
- Installed	17,136	17,136	17,136	17,136	17,136
- Refurbishment	28,029	28,035	28,046	28,148	28,046
- New investments	31,297	32,168	33,319	32,013	20,729
Generation capacity mix (%)					
- Hydro	33	33	34	25	40
- Coal	60	60	59	66	52
- Gas	0	0	0	2	0
- Other	7	7	7	7	8

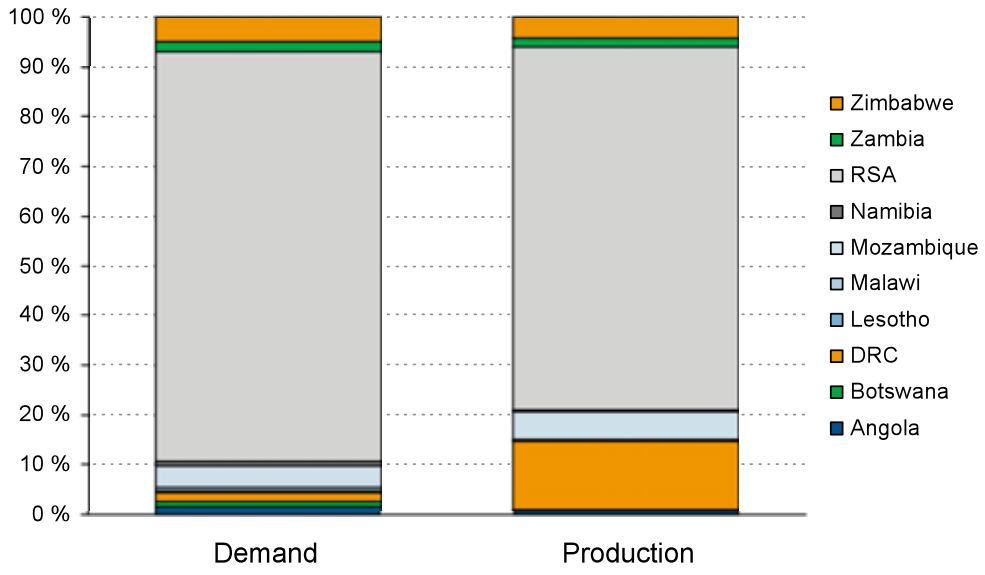
Source: Authors' original research.

Note: Installed capacity refers to capacity in place in 2005 that is not refurbished before 2015. Existing capacity that is refurbished before 2015 is not included in the installed capacity figure, but in the refurbishment figure.

South Africa accounts for about 80 percent of electricity demand in SAPP. Therefore, development in South Africa is an important driving force for the rest of the region. Figure 5.2 shows demand and production in the different countries in SAPP as a share of the region's total.

Figure 5.2 Demand and production in SAPP in 2015

Current access scenario; percentage of regional total



In the 2005 access rate scenario, power generation investments in South Africa amount to 18,700 MW (60 percent of total); in addition, 21,700 MW of capacity is refurbished in South Africa. The largest share of investments in South Africa is in coal-fired power plants; the rest include 3,000 MW in open-cycle gas turbine generators (that are already committed and thus included exogenously in the model) and 2,000 MW in hydropower and pumped storage.

In addition to domestic investments in South Africa, large investments take place in countries that are rich in hydropower: the Democratic Republic of Congo (7,200 MW), Mozambique (3,200 MW), and Zimbabwe (2,200 MW). While development in Zimbabwe meets domestic demand (the country imported 14 percent of its electricity as of 2005), exports from the Democratic Republic of Congo and Mozambique supply power to the rest of the region, with net exports of 50 TWh and 6 TWh, respectively.

Overnight investment costs

Generation costs are almost $38 billion (table 5.2). The largest share of this total is investments in new capacity ($30.3 billion), while the cost of refurbishment is only $7.5 billion. Even though refurbishment contributes about the same amount (in MW) to the total capacity as new capacity, refurbishment of existing capacity is much cheaper. Coal power plants in South Africa are an exception here; the cost of refurbishing them is almost as expensive as investing in new plants.

Transmission, distribution, and connection costs are lower than the costs of building new power plants: $26 billion is needed for investments in the expanded grid and refurbishment of the existing grid (table 5.2). Investments in new transmission and distribution lines account for more than half of this sum ($16 billion).

The direct cost of connecting new customers to the grid is only a fraction of the total grid cost: $0.7 billion is needed to maintain the access rate at the 2005 level (aligned with population growth) (table 5.2). More than 90 percent of this would be spent in urban areas.

Total overnight investment costs are slightly less than $64 billion in the 2005 access rate scenario.

Table 5.2 Overnight investment costs in SAPP, 2005–15

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	30,277	31,103	32,242	34,644	18,589
Refurbishment cost	7,572	7,574	7,577	7,587	7,577
T&D and connection					
Investment cost	16,384	19,422	23,711	20,653	16,606
- Cross-border transmission lines	3,009	2,991	3,058	0	3,082
- Distribution grid	12,674	12,674	12,674	12,674	5,544
- Connection cost (urban)	643	2,210	3,995	3,995	3,995
- Connection cost (rural)	58	1,547	3,985	3,985	3,985
Refurbishment cost	9,775	9,775	9,775	9,775	9,775
Total	*64,008*	*67,874*	*73,304*	*72,659*	*52,546*

Source: Authors' original research.

Annualized costs

The *annualized capital cost* of meeting market demand and maintaining current access is almost $9 billion: $3.2 billion in transmission, distribution, and connection; and $5.6 billion in generation (table 5.3).

In addition, the *annual variable costs* of operating the system amount to $8.3 billion. About $2 billion of this total is related to operating new power plants, while the rest is related to operating existing and refurbished power plants ($3.2 billion) and the grid ($3.1 billion).

The *total annualized cost of system expansion* is equal to 2.2 percent of GDP of the region in 2015 in the current access rate scenario (table 5.4). Adding the variable operation costs of existing capacity, the annualized costs of system expansion and operation are equal to 3.4 percent of GDP.

There are, however, large differences between costs in different countries. First, the costs of generation capacity expansion are high in countries with large hydropower development: 5.8 percent of GDP in the Democratic Republic of Congo, 6.2 percent in Mozambique, and 8.5 percent in Zimbabwe. Second, grid-related costs (investments, refurbishment, and operation) are significant in countries such as Zimbabwe, Zambia, Namibia, and the Democratic Republic of Congo. Third, even though generation-capacity expansion requires only 0.7 percent of GDP in 2015 in South Africa, the variable costs of the new coal-fired power plants amount to 0.6 percent of GDP.

Detailed country tables can be found in annex 1 (separately bound).

Table 5.3 Annualized costs of system expansion in SAPP

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	4,267	4,386	4,544	4,899	2,536
Refurbishment cost	1,340	1,340	1,341	1,342	1,341
Variable cost (fuel, O&M)	5,184	5,230	5,259	6,341	3,978
- New capacity	1,986	2,049	2,084	2,953	257
- Existing capacity	3,199	3,181	3,175	3,389	3,722
T&D and connection					
Investment cost	2,034	2,411	2,944	2,564	2,061
- Cross-border	374	371	380	0	383
- Distribution grid	1,573	1,573	1,573	1,573	688
- Urban connection	80	274	496	496	496
- Rural connection	7	192	495	495	495
Refurbishment cost	1,213	1,213	1,213	1,213	1,213
Variable cost (existing capacity)	3,100	3,100	3,100	3,100	3,100
Total					
Capital cost	8,855	9,351	10,042	10,018	7,152
- Investment cost	6,301	6,797	7,488	7,463	4,598
- Refurbishment cost	2,553	2,554	2,554	2,556	2,554
Variable cost	8,284	8,330	8,359	9,442	7,078
Total	*17,139*	*17,681*	*18,401*	*19,460*	*14,230*

Source: Authors' original research.

Note: We assume that there are no variable costs related to the new T&D assets.

Table 5.4 Annualized costs as a share of GDP in SAPP in 2015

Percent

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	Current access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	0.9	0.9	0.9	1.0	0.6
Refurbishment cost	0.3	0.3	0.3	0.3	0.3
Variable cost (fuel, O&M)	1.0	1.1	1.1	1.3	1.0
- New capacity	0.4	0.4	0.4	0.6	0.1
- Existing capacity	0.6	0.6	0.6	0.7	0.9
T&D and connection					
Investment cost	0.4	0.5	0.6	0.5	0.5
- Cross-border	0.1	0.1	0.1	0.0	0.1
- Distribution grid	0.3	0.3	0.3	0.3	0.2
- Urban connection	0.0	0.1	0.1	0.1	0.1
- Rural connection	0.0	0.0	0.1	0.1	0.1
Refurbishment cost	0.2	0.2	0.2	0.2	0.3
Variable cost (existing capacity)	0.6	0.6	0.6	0.6	0.7
Total					
Capital cost	1.8	1.9	2.0	2.0	1.7
- Investment cost	1.3	1.4	1.5	1.5	1.1
- Refurbishment cost	0.5	0.5	0.5	0.5	0.6
Variable cost	1.7	1.7	1.7	1.9	1.7
Total	*3.4*	*3.6*	*3.7*	*3.9*	*3.4*

Source: Authors' original research.

Note: We assume that there are no variable costs related to the new T&D assets.

Cost effects of raising access rates

Regional targets for access rates: Electricity access of 35 percent on average

Compared with the 2005 access rate, meeting the regional target for electricity access—35 percent access on average— requires an additional investment of almost $3.9 billion. This figure corresponds to about $0.5 billion in annualized capital costs (see tables 5.1–5.4).

The largest contributors to this increase are the costs of transmission, distribution and connection: connecting new households to the grid involves extra costs of about $3 billion ($380 million in annualized costs). About 40 percent of this amount is spent in rural areas, compared with only 10 percent in the current access scenario.

Some additional power generation capacity is also needed to meet the increased demand: investment costs are $0.8 billion higher ($120 million in annualized costs) than in the current access rate scenario. The additional costs of operating the new capacity (variable costs) are much less—$50 million annually.

The annualized costs of system expansion correspond to 2.3 percent of GDP in 2015 for the region. Including variable costs of existing capacity increases the total annualized cost of system expansion and operation to 3.6 percent of GDP.

National targets for electricity access

Meeting national targets requires $9.3 billion more than keeping the access rate constant at 2005 rates. This corresponds to almost $1.3 billion in annualized costs (see tables 5.1–5.4).

The largest contributors to this increase are the costs of transmission, distribution and connection. For example, connecting new households to the grid involves an extra cost of about $7.3 billion ($0.9 billion in annualized costs). About half of this is spent in rural areas, compared with only 10 percent in the 2005 access rate scenario.

The national targets scenario also requires additional power generation capacity to meet increased demand: investment costs are $2 billion higher ($280 million in annualized costs) than in the 2005 access rate scenario. The additional costs of operating the new capacity (variable costs) are much less—$75 million annually.

The annualized costs of system expansion are 2.4 percent of GDP in 2015 for the region. Including variable costs of current capacity increases the total annualized costs of system expansion and operation to 3.7 percent of GDP.

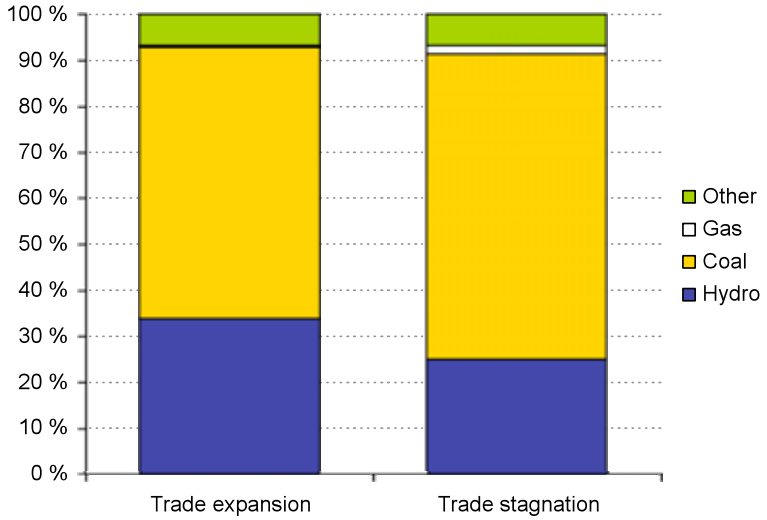
The effect of trade

Detailed figures are reported in tables 5.1–5.4.

Thermal power substitutes for hydropower

The most visible effect of restricting investments in cross-border transmission lines is reduced hydropower development, especially in the Democratic Republic of Congo (7,640 MW of forgone investments). The trade-expansion scenario leads to a generation mix with a higher proportion of renewable energy and less coal: only 25 percent of total capacity is supplied by hydropower under trade stagnation, compared to 34 percent in the trade-expansion scenario (figure 5.3).

Figure 5.3 Capacity mix in SAPP in 2015 with different trade assumptions

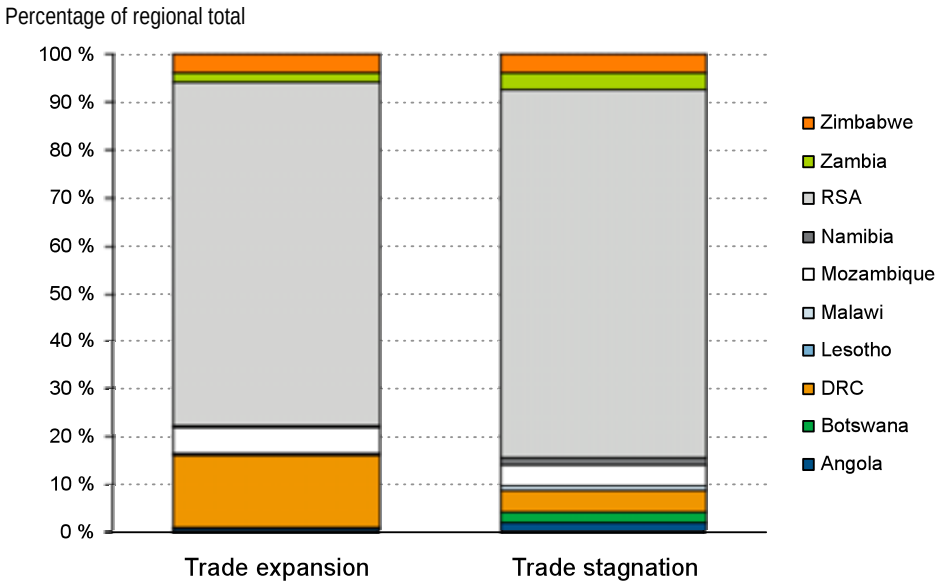


Power production in individual countries (as a share of total production in the area) would change with different assumptions about trade. For example, if trade were to expand, the Democratic Republic of Congo would produce and export more power (figure 5.4).

With trade stagnation, the Democratic Republic of Congo's exports are reduced from 41 TWh/year to 2.3 TWh/year. Reduced import possibilities in South Africa and Botswana are replaced by more coal-fired power plants. In Botswana the expansion of the Morupule plant becomes viable. (We assume the Mmamabula project will be built in both scenarios because of the short distance to the grid in South Africa). Gas-fired power plants and hydropower are built in Angola and Namibia to meet domestic demand in the trade-stagnation scenario.

Zambia imports electricity in the trade-expansion scenario and does not develop the domestic hydropower resources that are developed in the trade-stagnation scenario. This is because it is cheaper to develop hydropower resources in neighboring countries, and these resources (particularly in the Democratic Republic of Congo) are developed first in the trade-expansion scenario.

Figure 5.4 Production in SAPP in 2015 with different trade assumptions



Reduced hydropower development in Mozambique and Zimbabwe is partly offset by increased coal-power investments in these countries. This is because we have exogenously constrained the potential for hydropower development in these countries in the trade-stagnation scenario; it has been claimed that these investments are not viable without simultaneous development of regional transmission possibilities. According to unconstrained model results, however, at least some of these hydropower investments are necessary to meet the domestic demand. Despite the results of the unconstrained model simulations, it is possible that the exogenously constrained result—substituting hydropower with coal-fired power plants to meet domestic demand—is a reasonable outcome.[13] For instance, hydropower resources are located in the north of Mozambique, while domestic demand is located in the south. Hence, large investments in the domestic grid would be necessary to provide the south with the hydropower from the north. Since we do not model the domestic grid in detail, the costs of this grid development would have been underestimated in the model. Coal-fired power plants, on the other hand, can easily be built in the vicinity of demand centers. Therefore, the results illustrate the trade-off between investments in grid and generation, and between different kinds of generation capacity.

Under trade stagnation, power flows from the north to the south are replaced by more power exchange—that is, power flows in different directions in peak and off-peak hours. For instance, there is export during off-peak hours from South Africa to Mozambique, Namibia, and Zimbabwe.

[13] On the other hand, it is also possible that the assumed growth rates (that form the basis for electricity demand after ten years) are overestimated (especially for Zimbabwe).

The impact of trade stagnation on the individual countries' power balance is illustrated in figure 5.5 and table 5.5. One of the most striking effects, described above, involves the Democratic Republic of Congo, where net exports increase almost 20 times with trade expansion as other countries (Botswana, Malawi, Zambia) become net importers instead of net exporters. Under the trade-expansion scenario, only the Democratic Republic of Congo and Mozambique remain power exporters.

Trade from the north (especially from the Democratic Republic of Congo and Mozambique) to the south flows along several corridors (figure 5.5). The transit countries (Zambia, Zimbabwe, Botswana, Angola, and Namibia) are also net importers. This pronounced trade pattern requires sufficient investments in transmission lines throughout the region.

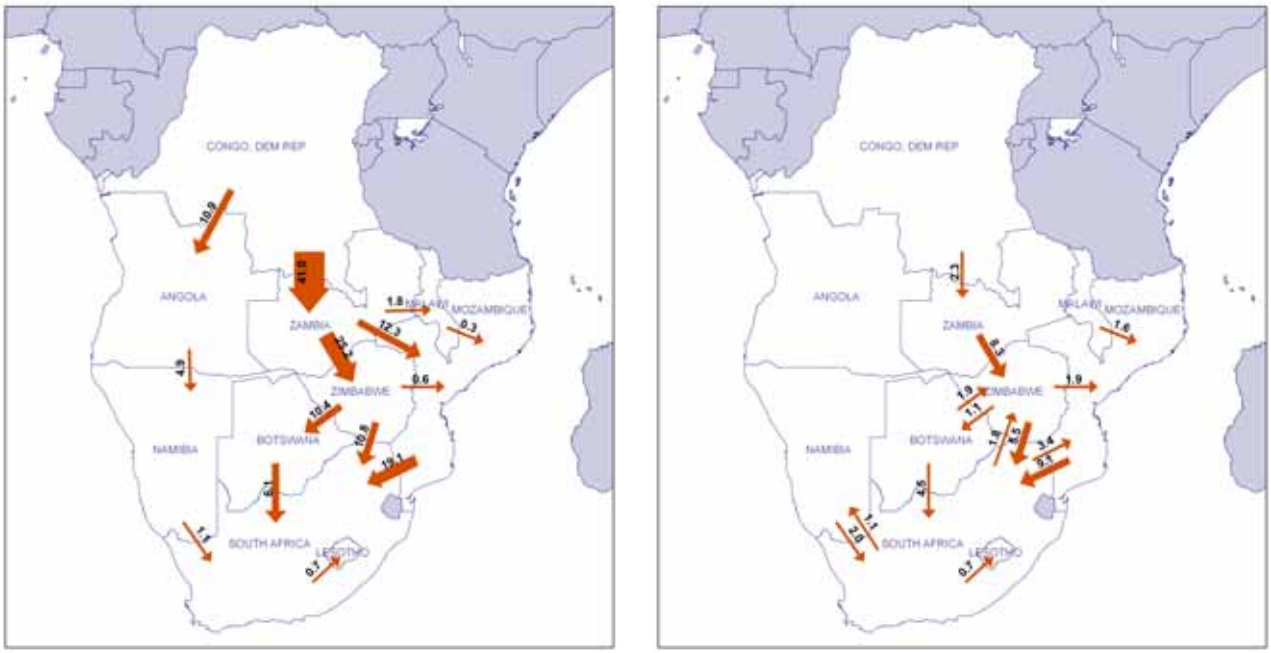
Table 5.5 Net imports (+)/exports (-) as share of domestic demand

Percent

	Trade-expansion scenario	Trade-stagnation scenario
Angola	65	0
Botswana	93	-117
Congo, Dem. Rep.	-369	-16
Lesotho	68	68
Malawi	58	-60
Mozambique	-33	-12
Namibia	72	-17
South Africa	10	4
Zambia	18	-62
Zimbabwe	17	18

Source: Authors' original research.

Figure 5.5 Trade flows with trade expansion (left) and trade stagnation (right) in SAPP in 2015, TWh



Source: Authors' original research.

Costs and gains

Overnight investment costs. Total overnight capital costs are $645 million higher in the trade-expansion scenario than in the trade-stagnation scenario. The costs related to transmission-grid expansion are about $3 billion higher with trade expansion. Yet, the costs related to investments in generation

capacity are $2.5 billion lower in the trade-expansion scenario despite the investment level being 1,300 MW higher. In other words, expensive capacity replaces cheap capacity when trade is restricted.

Annualized costs. The total annualized costs of system expansion in the SAPP region are more than $1 billion lower in the trade-expansion scenario than in the trade-stagnation scenario. Annualized investments costs are $25 million higher in the trade-expansion scenario. This reflects offsetting contributions from generation and transmission. Considerable cost savings stem from the operation of the integrated system: variable costs (that is, fuel costs and variable O&M costs) are significantly lower in the trade-expansion scenario. These cost savings stem both from using existing generation capacity more efficiently in the integrated system ($214 million), and the different capacity composition of the trade-expansion scenario ($868 million).

Returns on investing in trade. Recall that the capital costs in the trade-expansion scenario are $645 million higher than in the trade-stagnation scenario. On the other hand, the annual variable costs of the enlarged system in 2015 are more than $1 billion *lower*. This implies that the extra expenditure is recouped in a little more than half a year. This is equivalent to a return on investment of 168 percent. The savings from trade expansion are 8.2 percent of the annualized cost of expansion.[14]

Long-run marginal cost. Table 5.6 reports the long-run marginal cost of power in the SAPP countries under trade expansion and trade stagnation. The cost figures illustrate how the cost of power increases from production to consumption centers (see figure 5.4): The *cost of power generation* (column 2) is the lowest in the Democratic Republic of Congo; as the power is transmitted to the south, the need for international transmission lines creates additional costs for each country that is passed. Comparing this with the costs of generation in the trade-stagnation scenario (column 5) reveals that expanding domestic power generation capacity is much more expensive in countries that import during trade. In the case of the Democratic Republic of Congo, the difference in costs reflects the cost of international transmission lines that are necessary to export the power. The model seems to indicate that trade benefits the importing countries. But the financial flows and agreements (on prices, for example) that are necessary to implement the least-cost solution are outside the scope of the model. It is these flows and agreements that will determine the allocation of the benefit.

The costs of T&D investment and refurbishment reflect the costs of a domestic grid and are not passed on to the importing countries. These costs are therefore the same in both scenarios.

[14] Annual savings are $1,059 million. The cost of operation is $19,460 million, but that includes variable costs of current capacity ($6,489); $1,059 is 8.2 percent of the difference, that is, 8.2 percent of $12,971 million. Note that the discounted value of $1,059 into infinity at 12 percent discount is $8,825 million.

Table 5.6 Long-run marginal costs in SAPP

$ per MWh

	Trade-expansion scenario			Trade-stagnation scenario		
	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total long-run marginal costs	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total long-run marginal costs
Angola	18	46	64	59	46	105
Botswana	35	21	56	40	21	61
Congo, Dem. Rep.	14	24	39	11	24	36
Lesotho	36	22	58	48	22	70
Malawi	33	19	51	35	19	54
Mozambique	33	8	41	47	8	55
Namibia	36	73	109	47	73	120
South Africa	36	20	55	47	20	67
Zambia	29	46	75	33	46	78
Zimbabwe	32	46	78	39	46	85
Average	33	27	60	46	27	73

Note: Average is weighted by annualized cost. In some cases power exporting countries report higher LRMC under trade expansion. Even if the cost of meeting domestic power consumption may be higher with trade than without; the higher revenues earned from exports would more than compensate for that increment.

EAPP

Maintaining electricity access at the 2005 rate

Investment needs

About 23,000 MW of new capacity are needed in the EAPP region in 2015 to meet the demand growth resulting from general economic development and population growth. In addition, more than 1,000 MW of existing capacity must be refurbished. We may have underestimated the capacity potential for EAPP, which is much lower than that of SAPP. See appendix 2 for details.

Table 5.7 provides an overview of generation capacity, refurbishment, and investment costs in 2015, as well as the resulting capacity mix in all scenarios.

Table 5.7 Investment needs and generation mix in EAPP in 2015

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation capacity (MW)					
- Installed	22,132	22,132	22,132	22,132	22,132
- Refurbishment	1,369	1,375	1,375	1,381	1,375
- New investments	23,045	24,639	25,637	17,972	23,540
Generation capacity mix (%)					
- Hydro	49	47	48	28	48
- Coal	2	2	2	3	2
- Gas	47	48	49	64	45
- Other	2	3	4	5	4

Source: Authors' original research.

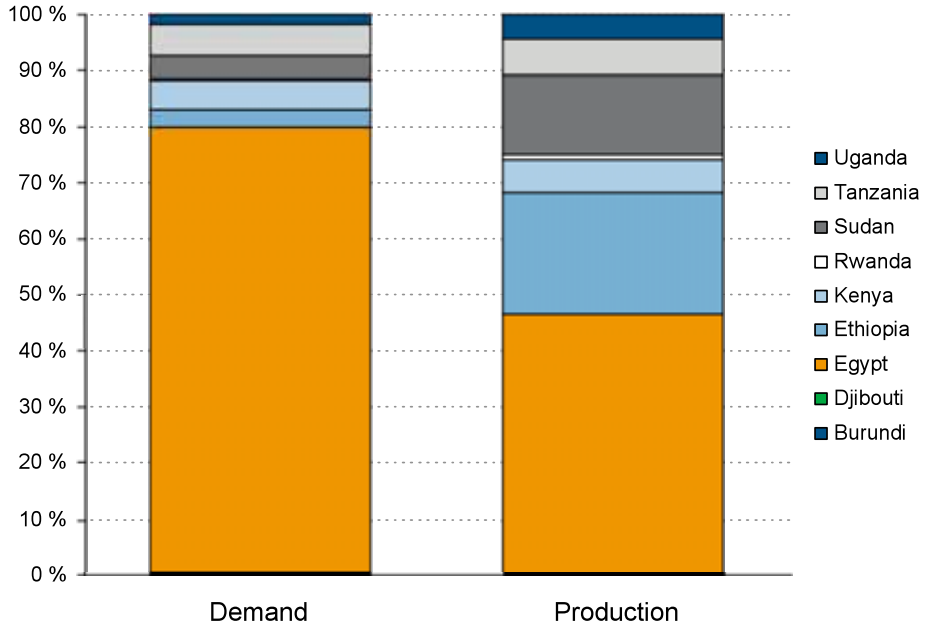
Note: Installed capacity refers to capacity in place in 2005 that is not refurbished before 2015. Existing capacity that is refurbished before 2015 is not included in the installed capacity figure, but in the refurbishment figure.

Egypt accounts for about 80 percent of total demand in EAPP with the 2005 access targets (figure 5.6). Since Egypt imports about 40 percent of its electricity (55 TWh), development in Egypt is of considerable importance for the EAPP region.

Egypt requires investment of almost 7,000 MW in natural-gas-fired power plants before 2015 to meet growing domestic demand. In addition, countries that have hydropower resources make substantial investments in hydropower: 8,150 MW in Ethiopia, 3,700 MW in Sudan, 1,200 MW in Tanzania and Uganda each, and 300 MW in Rwanda. In addition, Kenya and Tanzania invest in coal-fired power plants. Both Ethiopia and Sudan are large net exporters.

Figure 5.6 Demand and production in EAPP countries in 2015

Current access scenario; percentage of regional total



Overnight investment costs

Generation costs. Generation capacity must be more than doubled from its 2005 level to keep up with electricity demand growth. The costs of expanding the generation system over ten years are more than $29 billion (table 5.8). Almost all of this is due to investments in new capacity; the cost of refurbishment is negligible.

Transmission, distribution, and connection costs are about one-quarter of total costs ($11 billion).

Investments in the grid amount to $7.5 billion. Investments in transmission and distribution lines account for most of this total. Costs directly related to connecting new customers amount to about 40 percent of the total grid costs; $3 billion is needed to maintain the access rate at the 2005 level—that is, merely keeping in line with the population growth. About 80 percent of the connection cost is spent in urban areas. Refurbishment of the existing grid requires $3.3 billion.

Total overnight investment costs. The total overnight investment costs are $40.2 billion in the 2005 access rate scenario.

Table 5.8 Overnight investment costs in EAPP, 2005–15

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	28,913	30,802	32,667	18,621	31,275
Refurbishment cost	396	398	398	399	398
T&D and connection					
Investment cost	7,549	16,430	27,385	26,372	26,301
- Cross-border transmission lines	1,320	937	1,013	0	964
- Distribution grid	3,072	3,072	3,072	3,072	2,037
- Connection cost (urban)	2,484	5,263	5,702	5,702	5,702
- Connection cost (rural)	674	7,159	17,599	17,599	17,599
Refurbishment cost	3,342	3,342	3,342	3,342	3,342
Total	*40,200*	*50,973*	*63,793*	*48,735*	*61,317*

Annualized costs

The *annualized capital cost* of keeping up with GDP and population growth for ten years is about $5.3 billion. The share of households with access to electricity would remain the same as in 2005. The annualized cost of transmission, distribution, and connection is $1.3 billion and the annualized cost of generation capacity is $4 billion (table 5.9).

In addition, the *annual variable costs* of operating the system amount to $5.8 billion. Most of this ($4.4 billion) is related to operating new power plants (fuel costs and variable operation and maintenance costs), while the rest is related to existing and refurbished power plants ($0.7 billion) and the grid ($0.8 billion).

The *total annualized cost of system expansion* is equal to 3.6 percent of GDP of the region in 2015 in the 2005 access rate scenario (table 5.10). Adding the variable costs of system operation, the total annualized costs of system expansion and operation are 4.2 percent of GDP.

The costs of system expansion are relatively high in Egypt, the largest country in the region: 3.8 percent of GDP. The capital costs are only 0.9 percent, but since the new capacity is gas-fired, the fuel costs amount to as much as 3 percent of GDP. Ethiopia is the country with the highest outlay in terms of share of GDP—9.2 percent of GDP in total. But two-thirds of these costs are related to investments in generation capacity used for exports. In addition, some costs are related to investments in transmission and distribution lines and variable costs. The costs correspond to 1–2 percent of GDP in Burundi and Djibouti. In other countries, the costs are in the range of 2.5–3.5 percent of GDP.

Detailed country tables can be found in annex 1 (separately bound).

Table 5.9 Annualized costs of system expansion in EAPP, 2015

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	3,856	4,123	4,379	2,583	4,202
Refurbishment cost	70	70	70	70	70
Variable cost (fuel, O&M)	5,082	5,778	6,045	8,965	4,858
- New capacity	4,390	5,112	5,378	6,912	4,179
- Existing capacity	693	666	667	2,053	679
T&D and connection					
Investment cost	933	2,010	3,334	3,208	3,199
- Cross-border	164	116	126	0	120
- Distribution grid	381	381	381	381	253
- Urban connection	308	653	708	708	708
- Rural connection	79	859	2,119	2,119	2,119
Refurbishment cost	415	415	415	415	415
Variable cost (existing capacity)	762	762	762	762	762
Total					
Capital cost	5,273	6,618	8,198	6,277	7,862
- Investment cost	4,789	6,133	7,712	5,791	7,377
- Refurbishment cost	485	485	485	485	485
Variable cost	5,844	6,540	6,807	9,727	5,620
Total	*11,118*	*13,158*	*15,004*	*16,003*	*13,506*

Source: Authors' original research.

Note: We assume no variable costs related to the new T&D assets.

Table 5.10 Annualized costs as a share of GDP in EAPP, 2015

Percent

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	1.5	1.6	1.7	1.0	1.8
Refurbishment cost	0.0	0.0	0.0	0.0	0.0
Variable cost (fuel, O&M)	1.9	2.2	2.3	3.4	2.0
- New capacity	1.7	1.9	2.0	2.6	1.8
- Existing capacity	0.3	0.3	0.3	0.8	0.3
T&D and connection					
Investment cost	0.4	0.8	1.3	1.2	1.3
- Cross-border	0.1	0.0	0.0	0.0	0.1
- Distribution grid	0.1	0.1	0.1	0.1	0.1
- Urban connection	0.1	0.2	0.3	0.3	0.3
- Rural connection	0.0	0.3	0.8	0.8	0.9
Refurbishment cost	0.2	0.2	0.2	0.2	0.2
Variable cost (existing capacity)	0.3	0.3	0.3	0.3	0.4
Total					
Capital cost	2.0	2.5	3.1	2.4	3.6
- Investment cost	1.8	2.3	2.9	2.2	3.1
- Refurbishment cost	0.2	0.2	0.2	0.2	0.2
Variable cost	2.2	2.5	2.6	3.7	2.4
Total	*4.2*	*5.0*	*5.7*	*6.0*	*5.6*

Source: Authors' original research.

Note: We assume no variable costs related to the new T&D assets.

Cost effects of raising access rates

Regional target for access rate: electricity access of 35 percent on average

Meeting the international target for electricity access (35 percent on average) requires an additional investment of almost $11 billion compared to maintaining the 2005 access rate. This figure corresponds to about $1.3 billion in annualized capital costs (see tables 5.7–5.10).

The largest contributors to the increased costs are the costs of transmission, distribution, and connection: connecting new households to the grid involves extra costs of about $9 billion ($1.1 billion in annualized costs). About 60 percent of the connection costs occur in rural areas.

The increase in demand resulting from increased access rates will also require additional power generation capacity: investment costs are $2 billion higher ($270 million in annualized costs) than in the current access-rate scenario.

In addition, the variable costs of operating the system (fuel and O&M costs) are $700 million annually.

The total annual costs of system expansion and operation increase to 5 percent of the region's GDP in 2015. The costs of operating the existing system are only 0.5 percent of GDP. The costs of expanding the system amount to 4.4 percent of GDP.

National targets for electricity access

Meeting national targets requires $24 billion more than keeping access constant at the 2005 rate. This figure corresponds to about $3 billion in annualized capital costs (see tables 5.7–5.10).

The largest contributors to the *increased* costs are the costs of transmission, distribution, and connection: connecting new households to the grid requires almost $20 billion ($2.4 billion in annualized costs). About 75 percent of the connection costs occur in rural areas.

Additional power generation capacity is also needed to meet the resulting increase in demand: investment costs are $3.8 billion higher ($520 million in annualized costs) than in the 2005 access rate scenario.

In addition, the variable costs of operating the system (fuel and O&M costs) are $1 billion higher in the national targets scenario than in the 2005 access scenario.

The total annual costs of system expansion and operation increase to 5.7 percent in the national-targets scenario. Excluding the costs of operating the existing system, the costs of system expansion amount to 5.1 percent.

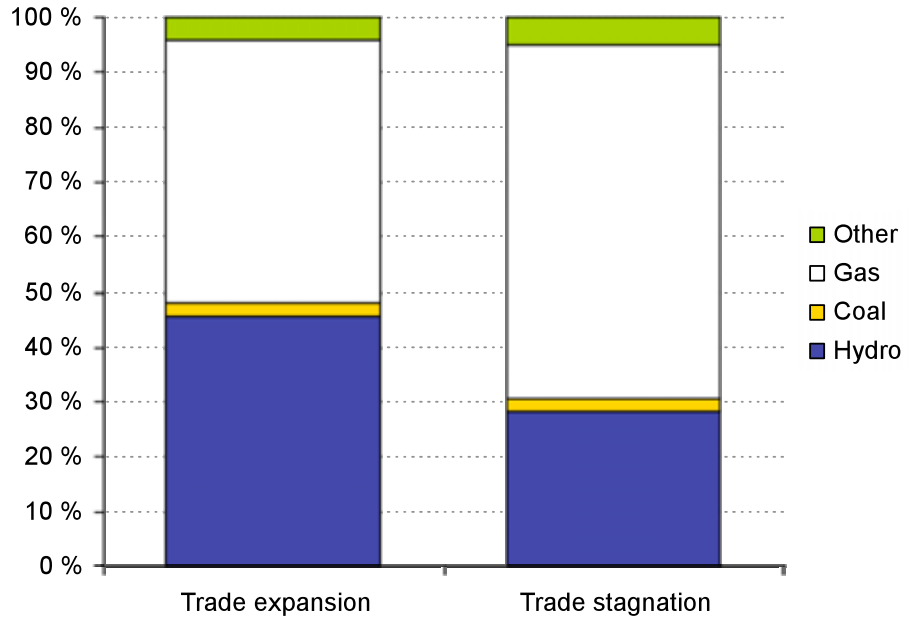
The effect of trade

Detailed figures are reported in tables 5.7–5.10.

Less total investment and less hydropower

The investment level is almost 7,700 MW lower in the trade-stagnation scenario. But investments in hydropower are 10,600 MW lower, while investments in gas-fired power plants are almost 3,000 MW higher. The share of hydropower in the region is reduced from 46 percent to 28 percent (figure 5.7). This difference in investment volume (in MW) is a result of gas having higher firm production capacity than hydropower.

Figure 5.7 Capacity mix in EAPP in 2015 with different trade assumptions



Most notably under trade stagnation, gas-fired power capacity and production is much higher in Egypt and Kenya, while less hydropower is developed in Ethiopia, Sudan, Uganda, and Rwanda. Egypt eliminates net imports (42 TWh), while Ethiopia, Sudan, and Tanzania cease to be net exporters.

Power production in individual countries (as a share of total production in the area) varies with different assumptions about trade. For example, under trade expansion, power production drops substantially in Egypt but soars in Ethiopia and Sudan (figure 5.8). Ethiopia and Sudan would become major power exporters, trading more than they produced for domestic consumption and sending their power northward into Egypt.

With the existing transmission network in the trade-stagnation scenario, there is very little trade. Exploiting the region's power resources in an optimal way results in huge trade flows from the south (primarily Ethiopia and Sudan) to the north (Egypt); see figure 5.9.

Figure 5.8 Production in EAPP in 2015 with different trade assumptions

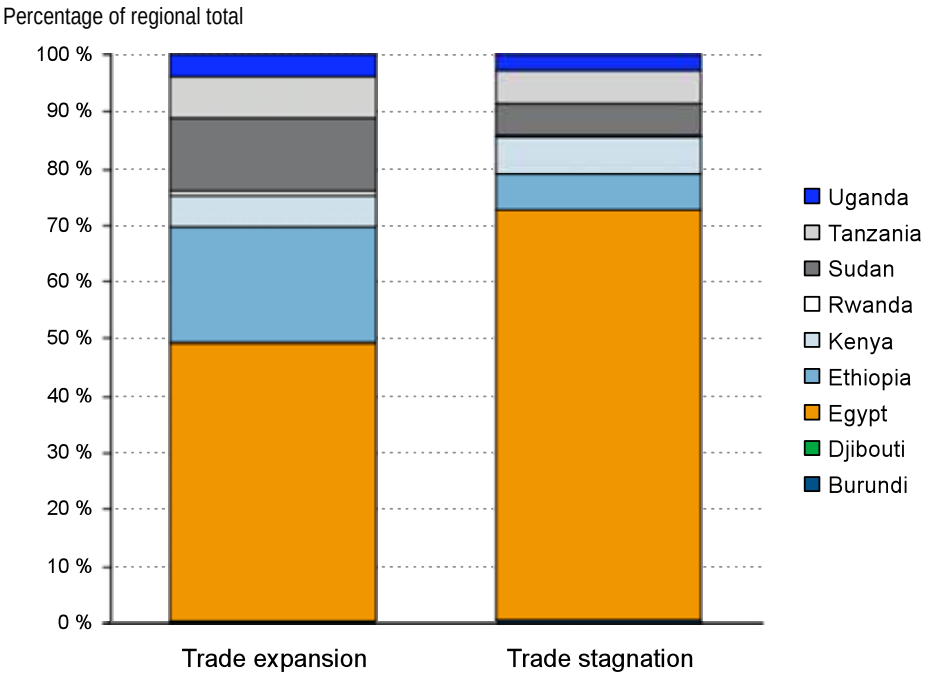


Figure 5.9 Trade flows with trade expansion (left) and trade stagnation (right) in EAPP in 2015, TWh

Source: Authors' original research.

Table 5.11 shows the impact of trade expansion on the individual countries' power balance: Ethiopia, Sudan, Rwanda, and Uganda become net exporters, while Egypt and Burundi become net importers.

Table 5.11 Net imports (+)/exports (-) as share of domestic demand

Percent

	Trade–expansion scenario	Trade–stagnation scenario
Burundi	78	0
Djibouti	0	0
Egypt	32	0
Ethiopia	–227	1
Kenya	22	3
Rwanda	–191	0
Sudan	–134	0
Tanzania	–22	0
Uganda	–61	–9

Source: Authors' original research.

Costs and gains

In contrast to SAPP, in EAPP it is not possible to switch expensive hydropower for cheap hydropower

Overnight investment costs. Total overnight investment costs are about $15 billion higher in the trade-expansion scenario than in the trade-stagnation scenario. The costs related to transmission-grid expansion are about $1 billion higher (since there are additional investments in cross-border transmission lines). The costs related to investments in generation capacity are $14 billion higher in the trade-expansion scenario.

Annualized costs. The total annualized costs of system expansion in the EAPP are about $1 billion lower in the trade-expansion scenario than in the trade-stagnation scenario (table 5.9). The annualized capital costs are $2 billion lower in the trade-stagnation scenario. There is a small savings ($126 million) from building less cross-border transmission capacity when trade is restricted, and a bigger savings ($1.8 billion) from building thermal instead of hydro. On the other hand, variable operating costs (including fuel costs) are $3 billion *higher* when trade is restricted. Trade expansion generates costs savings both from using the existing generating capacity ($1.4 billion), implying that an integrated system can use the existing system better, and from the different capacity composition ($1.5 billion). When import possibilities are limited, the new capacity has higher variable costs, and the existing (relatively old and expensive) capacity is used more.

Returns on investing in trade. The capital costs in the case of trade expansion are $15 billion higher than in the trade-stagnation scenario. On the other hand, the annual costs of the enlarged system (variable costs) ten years from now are about $3 billion *lower* in the enlarged system. This implies that the extra expenditure is saved in five years. This is equivalent to a return of 20 percent. Savings are 7.6 percent of the annualized cost of expansion.[15]

Long-run marginal cost. Table 5.12 shows the long-run marginal cost in EAPP countries with trade expansion and trade stagnation. Comparing these figures with figure 5.8, we see that the cost of power increases from production to consumption centers, for instance from Ethiopia via Sudan to Egypt or from Tanzania to Uganda and Kenya.

[15] Annual savings are $999 million. The cost of operation is $16,003 million, which includes the variable cost of current capacity ($2,815 million). $999 million is 7.6 percent of the difference between cost of operation and variable cost of current capacity, or $13,188 million. Note that the discounted value of $999 million into infinity at a 12 percent discount is $8,325 million.

Table 5.12 Long-run marginal costs in EAPP

$ per MWh

	Trade-expansion scenario			Trade-stagnation scenario		
	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total LRMC	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total LRMC
Burundi	68	46	114	103	46	149
Djibouti	66	6	72	66	6	72
Egypt	76	9	85	77	9	86
Ethiopia	69	122	190	40	122	161
Kenya	74	50	124	84	50	133
Rwanda	64	61	124	60	61	121
Sudan	75	52	127	74	52	126
Tanzania	65	32	97	45	32	78
Uganda	68	54	123	59	54	113
Average	74	47	121	75	47	122

Note: Average is weighted by annualized cost. In some cases power exporting countries report higher LRMC under trade expansion. Even if the cost of meeting domestic power consumption may be higher with trade than without; the higher revenues earned from exports would more than compensate for that increment.

Source: Authors' original research.

The most striking result of the EAPP analysis, however, is the much higher cost figures compared to SAPP. This is primarily due to the long distances that the transmission lines must cover. It also reflects the scarcity of cheap resources in EAPP. Even in the trade-stagnation scenario, where no international transmission lines are built, the generation costs in Ethiopia (the cheapest in EAPP) are four times higher than in the Democratic Republic of Congo, the cheapest generator in SAPP. There is, of course, uncertainty in these figures and comparisons, which ultimately build on project cost estimates in the individual countries, which incorporate exchange rate considerations and other quantities not precisely known.

Comparing the costs of generation in the cases of trade expansion and stagnation (columns 2 and 5 of table 5.12) reveals that relying on imports is much cheaper than expanding domestic power generation capacity in importing countries; in other words, the region benefits from gains from trade. In the case of the exporting countries Ethiopia and Tanzania, generation costs are greater in the trade-expansion scenario, reflecting the cost of international transmission lines necessary to export power. These countries may require compensation for the increased costs to trigger investments since the trade benefit accrues to the importing countries, not the exporters.

WAPP

Maintaining electricity access at current rates

Investment needs

Almost 16,000 MW of new capacity is needed in the WAPP region over ten years to keep up with the demand growth resulting from general economic development and population growth. In addition, more than 5,500 MW of existing capacity must be refurbished.

Table 5.13 provides an overview of generation capacity, refurbishment, and investment costs in 2015, as well as the resulting capacity mix in all scenarios.

Table 5.13 Investment needs and generation mix in WAPP in 2015

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation capacity (in MW)					
- Installed	4,096	4,096	4,096	4,096	4,096
- Refurbishment	5,530	6,162	6,972	6,842	5,535
- New investments	15,979	16,634	18,003	16,239	17,186
Generation capacity mix (percent):					
- Hydro	82	79	77	73	80
- Coal	1	1	1	1	1
- Gas	13	14	16	19	12
- Other	4	5	6	7	7

Source: Authors' original research.

Note: Installed capacity refers to capacity in place in 2005 that is not refurbished before 2015. Existing capacity that is refurbished before 2015 is not included in the installed capacity figure, but in the refurbishment figure.

Nigeria accounts for two-thirds of electricity consumption in the region. Hence, developments in Nigeria that influence electricity demand (such as economic development and the politically determined electricity access targets) have a large impact on the WAPP region's total costs of electricity sector development.

Nigeria does not, however, significantly affect the trade patterns and resource development in the rest of region. First of all, Nigeria is not centrally situated; therefore, any large exports would need large investments in transmission lines as well. Second, Nigeria meets domestic demand growth with large and relatively cheap hydropower resources. The ample gas resources that could be used to develop gas-fired power plants are more expensive than hydropower in other countries.

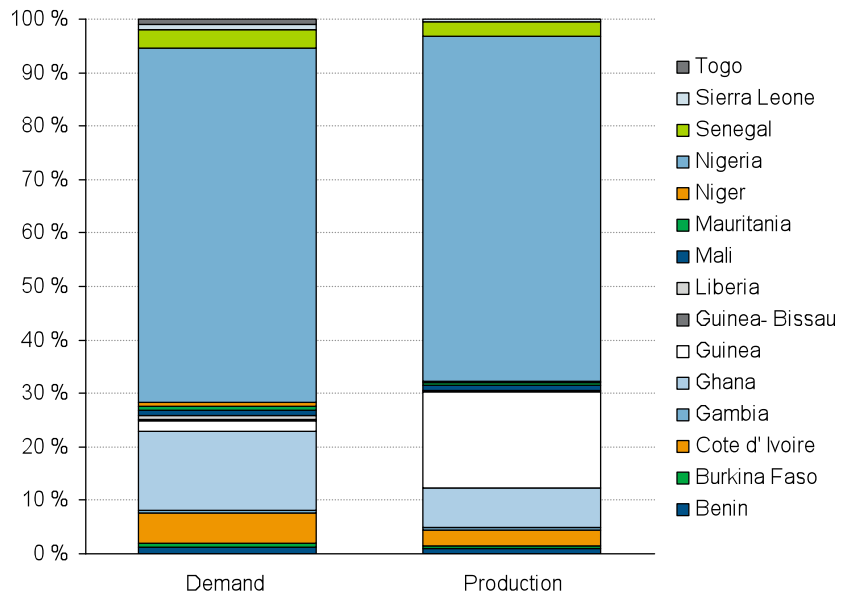
Ghana accounts for 15 percent and Cote d'Ivoire for 6 percent of the region's electricity demand. In contrast to Nigeria, these countries import about half of their electricity demand with 2005 access targets.

Guinea produces almost 20 percent of the region's power, exporting large amounts of hydropower, which has a competitive cost. Guinea exports more than eight times domestic demand.

Figure 5.10 shows demand and production in the different countries in WAPP as a share of the region's total.

Figure 5.10 Demand and production in WAPP countries in 2015

Current access scenario; percentage of regional total



In total, the WAPP region carries out 16,000 MW investments in power generation in the 2005 access scenario. Almost all of this is hydropower:[16] 10,290 MW in Nigeria, 4,290 MW in Guinea, 1,000 MW in Ghana, and 130 MW in Cote d'Ivoire. This means that Nigeria, Guinea, and Ghana fully exploit[17] their available hydropower resources.[18] In addition, Senegal builds one coal-fired power plant (250 MW) and some off-grid technologies in rural areas.

In addition to investments in new generation capacity, 5,530 MW of existing capacity is refurbished: almost 4,000 MW of hydropower (2,850 MW in Nigeria), 1,200 MW of natural gas-fired power in Nigeria, and 410 MW of HFO-fueled thermal power plants in various countries.

[16] In addition, there are minimal investments in off-grid technologies in rural areas.

[17] Note that "fully exploited" refers to the assumed maximum potential for hydropower in the model. In most cases, this maximum potential has been set equal to identified projects and plans, even though the full hydropower potential of a country may be much larger. The identified projects serve as a proxy for developments that are realistic in the time frame in focus here (the ten years before 2015).

[18] As we only use one (average) investment cost per technology per country, not individual costs per project, cheaper resources are often fully utilized in one country before the more expensive resources are developed in a neighboring country. The cost of building international transmission lines counteracts this to some extent.

Overnight investment costs

Generation costs. The investment costs of expanding the generation system between 2005 and 2015 are slightly more than $23.3 billion (table 5.14). The largest share of this by far is investment in new capacity ($22 billion), while the cost of refurbishment is only $1.4 billion.

Transmission, distribution, and connection costs are almost equal to the costs of new generation capacity: $23.3 billion in investment is needed to expand and refurbish the grid (table 5.14). Investments in new transmission and distribution lines account for most of this total (over $17 billion). Only 6 percent of this last figure is related to international transmission lines.

The direct cost of connecting new customers to the grid is less than 20 percent of the total grid cost: $4.3 billion is needed to maintain the access rate at the 2005 level (aligned with population growth) (table 5.14). Of this total, 86 percent would be spent in urban areas.

Total overnight investment costs. These are $46.6 billion in the 2005 access rate scenario.

Table 5.14 Overnight investment costs in WAPP, 2005–15

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	21,955	23,632	26,992	25,822	25,128
Refurbishment cost	1,363	1,429	1,511	1,496	1,366
T&D and connection					
Investment cost	17,241	22,399	29,813	28,872	23,206
- Cross-border transmission lines	1,022	968	941	0	912
- Distribution grid	11,909	11,909	11,909	11,909	5,332
- Connection cost (urban)	3,698	5,254	7,634	7,634	7,634
- Connection cost (rural)	612	4,268	9,329	9,329	9,329
Refurbishment cost	6,057	6,057	6,057	6,057	6,057
Total	*46,615*	*53,518*	*64,373*	*62,247*	*55,758*

Source: Authors' original research.

Annualized costs

The *annualized capital cost* of meeting market demand and maintaining current access over ten years is $6 billion, of which almost $3 billion is for transmission, distribution, and connection, and $3.1 billion for generation (table 5.15).

In addition, the *annual variable costs* of operating the system (that is, fuel and variable operation and maintenance costs) amount to $3.2 billion. About half of this is related to operating new power plants, while the other half is related to operating existing and refurbished power plants ($0.3 billion) and the grid ($1.3 billion).

The *total annualized cost of system expansion* is equal to 2.1 percent of GDP of the region in 2015 (table 5.16). Adding the variable operation costs of existing capacity, the annualized costs of system expansion and operation are equal to 3.2 percent of GDP.

This regional figure conceals large differences between costs in different countries with very different investment patterns. Guinea invests in hydropower for export purposes, and the investment costs are as much as 20 percent of GDP. In Gambia, the fuel costs of existing HFO-fueled capacity contribute to variable costs, which equal up 4.5 percent of GDP. In addition, the grid cost accounts for another 1 percent of GDP. In Senegal, both the grid-related (investment and variable) and variable generation costs lift the total to 7 percent of GDP.

Detailed country tables can be found in annex 1 (separately bound).

Table 5.15 Annualized costs of system expansion in WAPP, 2015

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	2,874	3,092	3,527	3,365	3,291
Refurbishment cost	237	247	258	258	237
Variable cost (fuel, O&M)	1,887	2,259	2,728	3,442	1,912
- New capacity	260	266	275	620	267
- Existing capacity	1,627	1,993	2,453	2,822	1,646
T&D and connection					
Investment cost	2,140	2,781	3,701	3,584	2,881
- Cross-border	127	120	117	0	113
- Distribution grid	1,478	1,478	1,478	1,478	662
- Urban connection	459	652	948	948	948
- Rural connection	76	530	1,158	1,158	1,158
Refurbishment cost	752	752	752	752	752
Variable cost (existing capacity)	1,320	1,320	1,320	1,320	342
Total					
Capital cost	6,003	6,871	8,238	7,959	7,161
- Investment cost	5,014	5,873	7,228	6,949	6,171
- Refurbishment cost	989	998	1,010	1,010	989
Variable cost	3,207	3,579	4,049	4,763	2,254
Total	*9,210*	*10,450*	*12,287*	*12,722*	*9,415*

Source: Authors' original research.

Note: We assume that there are no variable costs related to the new T&D assets.

Table 5.16 Annualized costs as a share of GDP in WAPP, 2015

Percent

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	1.0	1.1	1.2	1.2	1.3
Refurbishment cost	0.1	0.1	0.1	0.1	0.1
Variable cost (fuel, O&M)	0.6	0.8	0.9	1.2	0.7
- New capacity	0.1	0.1	0.1	0.2	0.1
- Existing capacity	0.6	0.7	0.8	1.0	0.6
T&D and connection					
Investment cost	0.7	1.0	1.3	1.2	1.1
- Cross-border	0.0	0.0	0.0	0.0	0.0
- Distribution grid	0.5	0.5	0.5	0.5	0.3
- Urban connection	0.2	0.2	0.3	0.3	0.4
- Rural connection	0.0	0.2	0.4	0.4	0.5
Refurbishment cost	0.3	0.3	0.3	0.3	0.3
Variable cost (existing capacity)	0.5	0.5	0.5	0.5	0.5
Total					
Capital cost	2.1	2.4	2.8	2.7	2.8
- Investment cost	1.7	2.0	2.5	2.4	2.4
- Refurbishment cost	0.3	0.3	0.3	0.3	0.4
Variable cost	1.1	1.2	1.4	1.6	1.3
Total	*3.2*	*3.6*	*4.2*	*4.4*	*4.0*

Source: Authors' original research.

Note: We assume that there are no variable costs related to the new T&D assets.

Cost effects of raising access rates

Regional target rate: Electricity access of 53 percent on average

Compared with the 2005 access rate, meeting the regional target for electricity access (53 percent on average) requires an additional investment of almost $7 billion. This figure corresponds to about $1.25 billion in annualized capital costs (see tables 5.13 to 5.16).

The largest contributors to this increase are the costs of transmission, distribution, and connection: connecting new households to the grid involves extra costs of over $5 billion ($600 million in annualized costs). Almost half of this amount is spent in rural areas.

Additional power-generating capacity is also needed to meet increased demand: investment costs are $1.7 billion higher ($200 million in annualized costs) than in the 2005 access rate scenario. The costs of operating the system (variable costs) are 12 percent higher—almost $400 million annually—since part of the new generation capacity is fossil-fueled (diesel in rural areas and refurbishment of gas-fired power plants in Nigeria).

The annualized costs of system expansion are 2.4 percent of GDP in 2015 for the region. Including variable costs of existing capacity lifts the total annualized cost of system expansion and operation to 3.6 percent of GDP.

National targets for electricity access

Meeting national targets requires almost $18 billion more than keeping the access rate constant at 2005 rates. This corresponds to about $3 billion in annualized costs (see tables 5.13 to 5.16).

The largest contributors to this increase are the costs of transmission, distribution, and connection. For example, connecting new households to the grid involves an extra investment of $12.5 billion ($1.6 billion in annualized costs). More than half of new connection costs are spent in rural areas, compared with only 15 percent in the current-access scenario.

Additional power generation capacity is also needed to meet the increased demand: investment costs are more than $5 billion higher ($650 million in annualized costs) than in the 2005 access rate scenario. The additional costs of operating the system (variable costs) are $850 million annually.

The annualized costs of system expansion are 2.9 percent of GDP in 2015 for the region. To include variable costs of current capacity increases the total annualized costs of system expansion and operation to 4.2 percent of GDP.

The effect of trade

Detailed figures are reported in tables 5.13 to 5.16.

Dispersed hydropower and gas-fired power plants substitute for hydropower in Guinea

The most visible effect of restricting investments in cross-border transmission lines is reduced hydropower development in Guinea (3,720 MW of forgone investments). As there are no lines from Guinea to neighboring countries today, Guinea will only produce enough to meet domestic demand (figure 5.12).

Countries that have no international transmission lines today—Guinea-Bissau, Liberia, Sierra Leone—cannot benefit from imports from Guinea and must be self-sufficient. These countries invest in domestic hydropower to compensate for the lack of imports.

In the trade-expansion scenario, electricity flowed from Guinea through Cote d'Ivoire to Burkina Faso and Ghana. Without this flow, Cote d'Ivoire increases investments (193 MW) and production (2 TWh) to export to Burkina Faso and Ghana on existing lines (figure 5.13). Similarly, Togo (a net importer in the trade-expansion scenario) now exports to Ghana and Benin. Also Senegal, Mauritania,

and Mali benefited from imports from Guinea in the trade-expansion scenario. In the trade-stagnation scenario, Senegal becomes a net importer from Mauritania and Mali.[19]

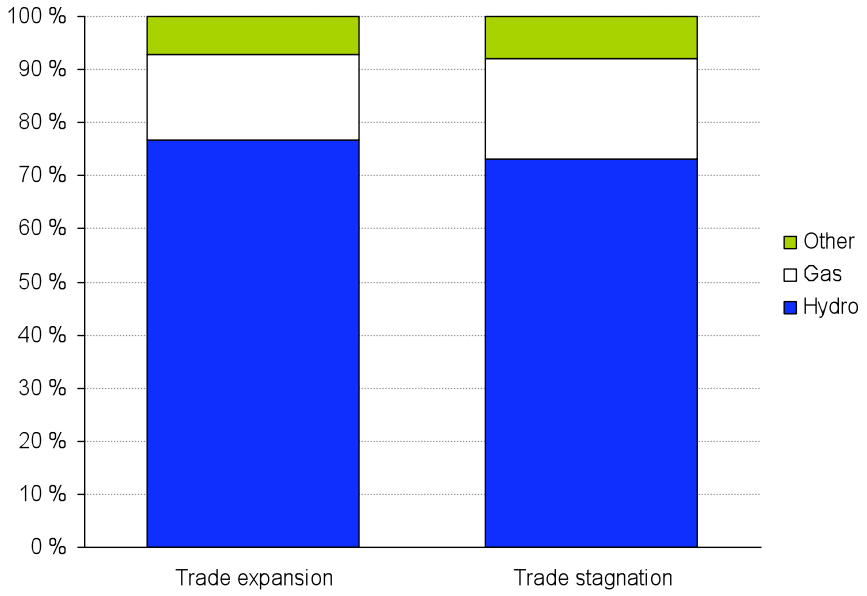
In total, hydropower investments increase 1,270 MW in countries other than Guinea, so the total decrease in hydropower capacity in the region is 2,450 MW.

More thermal power investments replace hydropower. Additional gas-fired power plants in Ghana, Benin, Togo, and Mauritania total 700 MW. Nigeria, on the other hand, reduces its exports to Niger and Benin and refurbishes fewer of its gas-fired power plants. Since thermal power plants can produce more power per MW installed compared to hydropower, total investments (measured in MW) are reduced by 1,700 MW. The total production, however, remains the same.

The trade-expansion scenario leads to a generation mix with a somewhat higher proportion of renewable energy: hydropower and natural gas supply 77 percent and 16 percent of total capacity, respectively, in the trade-expansion scenario, compared to 73 percent and 19 percent in the trade-stagnation scenario (figure 5.11).

Table 5.17 shows the impact of trade expansion on each country's power balance.

Figure 5.11 Capacity mix in WAPP in 2015, with different trade assumptions



[19] Imports from Mali include power from the Manantali hydropower plant (located in Mali but co-owned by Mali, Mauritania, and Senegal).

Figure 5.12 Production in WAPP in 2015, with different trade assumptions

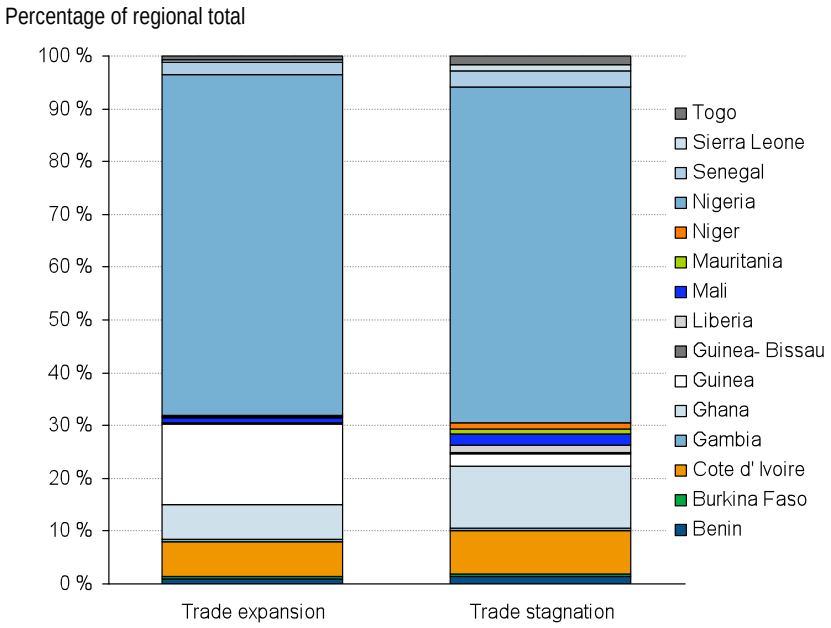
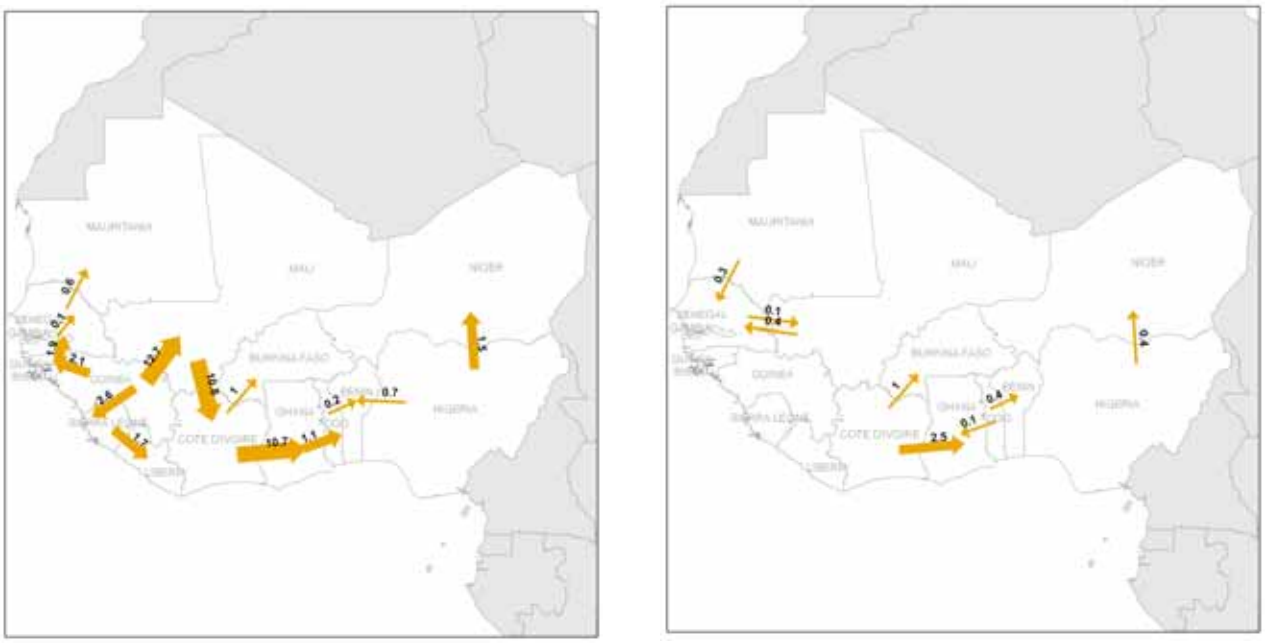


Figure 5.13 Trade flows with trade expansion (left) and trade stagnation (right) in WAPP in 2015, TWh



Source: Authors' original research.

Table 5.17 Net imports (+)/exports (–) as share of domestic demand

Percent	Trade-expansion scenario	Trade-stagnation scenario
Benin	45	18
Burkina Faso	58	58
Cote d'Ivoire	-12	-47
Gambia	-19	0
Ghana	52	14
Guinea	-564	0
Guinea-Bissau	77	0
Liberia	89	0
Mali	79	-14
Mauritania	55	-23
Niger	86	20
Nigeria	-3	0
Senegal	30	13
Sierra Leone	60	0
Togo	48	-27

Source: Authors' original research.

Costs and gains

Overnight investment costs. Total overnight capital costs are $2.1 billion higher in the trade-expansion scenario. The costs related to transmission grid expansion are about $0.9 billion higher (since there are additional investments in cross-border transmission lines), and costs related to investments in generation capacity are $1.2 billion higher.

Annualized costs. Although overnight investment costs are higher under trade expansion, annualized costs are lower since they account for savings on variable costs. While annualized *investments costs* are $280 million higher in the WAPP region under trade expansion, the total annualized costs of system expansion are almost $450 million *lower*. Both generation and transmission investments are higher in the trade-expansion scenario (due to investments in international transmission lines and the higher volume of hydropower investments required). But the *operation* of the integrated system in the trade-expansion scenario requires significantly lower *variable costs* (that is, fuel costs and variable O&M costs). These cost savings (over $700 million) stem from the greater proportion of hydropower in the trade-expansion scenario).

Returns on investing in trade. The gains from trade can be regarded as returns on investment. Trade-expansion requires $2.1 billion more in investment costs than the trade-stagnation scenario. Annual variable costs, however, are more than $700 million *lower* in the enlarged system. Therefore, the extra investment cost is recouped in three years. This is equivalent to an annual return on investment of 33 percent. Annual savings from trade expansion are 5.1 percent of the annualized cost of expansion.

Table 5.18 Long-run marginal costs in WAPP

$ per MWh

	Trade-expansion scenario			Trade-stagnation scenario		
	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total long-run marginal costs	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total long-run marginal costs
Benin	79	111	190	81	111	192
Burkina Faso	72	181	253	79	181	260
Cote d'Ivoire	69	78	147	76	78	154
Gambia	63	17	80	58	17	74
Ghana	73	23	96	80	23	103
Guinea	58	13	70	47	13	60
Guinea-Bissau	63	22	85	134	22	156
Liberia	66	15	81	126	15	141
Mali	64	182	246	97	182	279
Mauritania	69	67	136	78	67	145
Niger	79	168	247	136	168	304
Nigeria	76	52	128	76	52	128
Senegal	66	368	434	100	368	468
Sierra Leone	61	24	86	73	24	97
Togo	76	27	103	80	27	106
Average	72	111	183	80	111	191

Note: Average is weighted by annualized cost. In some cases power exporting countries report higher LRMC under trade expansion. Even if the cost of meeting domestic power consumption may be higher with trade than without; the higher revenues earned from exports would more than compensate for that increment.

Table 5.18 compares the long-run marginal cost of power in WAPP countries under trade expansion and trade stagnation. The cost figures illustrate how trade expansion increases the long-run marginal cost of power generation for exporters while the opposite is true for importers (see figure 5.12). For example, the *cost of power generation* (column 2) is lowest in Guinea (a net exporter); however, the costs of international transmission lines for each country through which power flows (for example via Sierra Leone to Liberia or via Cote d'Ivoire to Burkina Faso, Ghana, or Togo) adds to the long-run marginal cost.

On the other hand, countries that import in the trade-expansion scenario experience much higher long-run marginal costs of power generation (column 5) under trade stagnation due to the cost of expanding domestic power-generation capacity.

CAPP

Maintaining electricity access at current rates

Investment needs

To keep up with demand growth resulting from general economic development and population growth, 3,850 MW of new capacity are needed in the CAPP region over ten years. Virtually all new capacity investment is in hydropower:[20] 2,430 MW in Cameroon, 1,320 MW in the Republic of Congo, 85 MW in Gabon, and 25 MW in the Central African Republic. In this scenario, Cameroon fully exploits its available hydropower resources.[21]

In addition, more than 900 MW of existing capacity must be refurbished (600 MW in Cameroon and the remainder in Gabon, the Republic of Congo, and the Central African Republic).

Table 5.19 provides an overview of generation capacity in 2015, ten-year refurbishment and investment volumes, and the resulting capacity mix for all scenarios.

Table 5.19 Investment needs and generation mix in CAPP, 2015

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth Scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation capacity (in MW)					
- Installed	260	260	260	260	260
- Refurbishment	906	906	906	1,081	906
- New investments	3,856	4,143	4,395	3,833	3,915
Generation capacity mix (%):					
- Hydro	97	97	97	83	97
- Coal	0	0	0	0	0
- Gas	0	0	0	0	0
- Other	2	3	3	17	3

Source: Authors' original research.

Note: Installed capacity refers to capacity in place in 2005 that is not refurbished before 2015. Existing capacity that is refurbished before 2015 is not included in the installed capacity figure, but in the refurbishment figure.

The Republic of Congo accounts for more than half (54 percent) of electricity demand in CAPP in 2015, and Cameroon for one-third. Therefore, the development of these countries is an important driving

[20] There are very small investments in off-grid technologies in rural areas.

[21] The term "fully exploited" refers to the assumed maximum potential for hydropower in the model. In most cases, this maximum potential has been set equal to identified projects and plans, even though the full hydropower potential of a country may be much larger. The identified projects serve as a proxy for realistic development in the timeframe considered (before 2015).

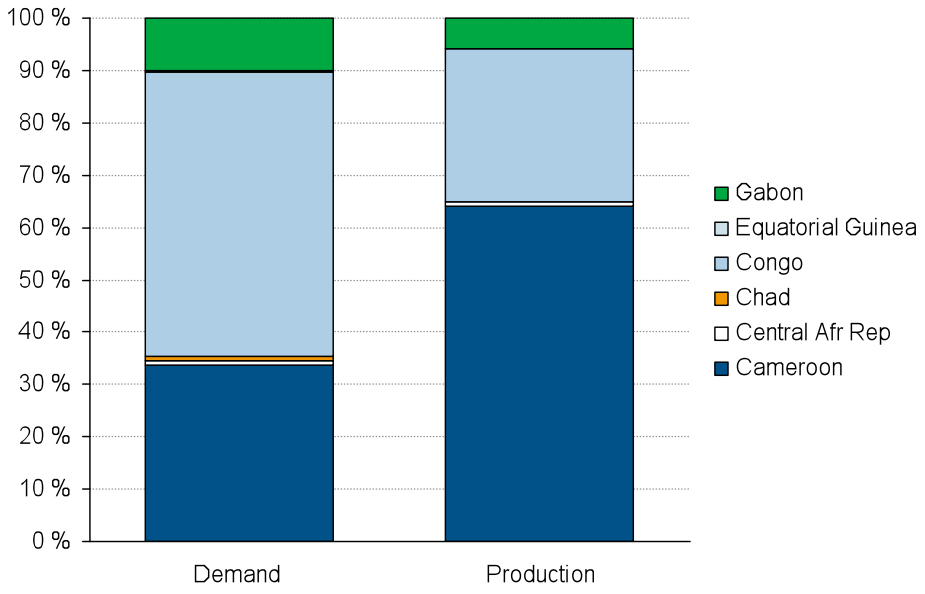
force for the rest of the region. Gabon has 10 percent of the region's total demand, while the other CAPP countries demand only small amounts of power.

Cameroon accounts for 64 percent of total electricity production in the region in 2015, compared to only 29 percent for the Republic of Congo. Cameroon exports more than a third (5.6 TWh) of its production to the Republic of Congo, as well as small amounts to Gabon, Chad, and Equatorial Guinea. We assume that imports from the Democratic Republic of Congo to the Republic of Congo remain at 2005 levels, although this is a small volume (less than 0.5 TWh/year).

Figure 5.14 shows demand and production in each CAPP country as a share of the region's total.

Figure 5.14 Demand and production in CAPP countries in 2015

Current access scenario; percentage of regional total



Overnight investment costs

Generation costs. The investment costs of expanding the generation system by 2015 are almost $6 billion (table 5.20), the largest share of which is investment in new capacity ($5.6 billion). Refurbishment accounts for only $0.3 billion of total costs.

Transmission, distribution, and connection costs are much lower than the costs of building new power plants, accounting for less than 20 percent of total investment costs: in the expansion and refurbishment of the existing grid requires $1.3 billion in investment (table 5.20). Investments in new transmission and distribution lines account for most of this sum (over $1 billion), of which a full third is investment in international transmission lines.

Maintaining the access rate at the 2005 level (aligned with population growth) requires $0.4 billion (40 percent of total grid investment) to cover the costs of connecting new customers to the grid, 98 percent of which would be spent in urban areas.

Total overnight investment costs. In the 2005 access rate scenario, the total overnight investment is slightly more than $7 billion: generation costs are $6 billion and grid-related costs are $1.3 billion.

Table 5.20 Overnight investment costs in CAPP, 2005–15

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	5,645	6,157	6,615	5,981	5,766
Refurbishment cost	272	272	272	301	272
T&D and connection					
Investment cost	1,057	1,648	2,348	2,036	2,311
- Cross-border	349	317	312	0	355
- Distribution grid	286	286	286	286	205
- Connection cost (urban)	412	753	1,010	1,010	1,010
- Connection cost (rural)	10	292	740	740	740
Refurbishment cost	222	222	222	222	222
Total	*7,196*	*8,299*	*9,457*	*8,540*	*8,570*

Source: Authors' original research.

Annualized costs

The *annualized capital cost* of meeting market demand and maintaining current access over ten years is almost $1 billion: this includes almost $160 million in transmission, distribution, and connection costs and $780 million in generation costs (table 5.21).

The *annual variable costs* of operating the system (that is, fuel and variable operation and maintenance costs) amount to $150 million. About $50 million of this is related to operating new power plants, while the rest is related to operating existing and refurbished power plants ($30 million) and the grid ($70 million).

The *total annualized cost of system expansion* in the 2005 access rate scenario is about $1 billion, or 1.4 percent of the region's GDP in 2015 (table 5.22). Adding the variable operation costs of existing capacity, the annualized costs of system expansion and operation are 1.6 percent of GDP.

The varied investment patterns of CAPP countries lead to different annualized costs. For example, countries with significant hydropower development have higher costs of generation capacity expansion: 3 percent of GDP in the Republic of Congo and 1.6 percent in Cameroon.

Grid-related costs (investments, refurbishment, and operation) in the Republic of Congo are 0.3 percent of GDP. This high total results from the new cross-border lines needed to accommodate the country's substantial imports. Cameroon also invests 0.3 percent of GDP in grid-related costs, composed mainly of the cost of connecting new customers to the grid and investments in domestic and cross-border grid.

Other countries in CAPP—Chad and Equatorial Guinea—do not invest in new generation capacity. Investment in these countries consists only of grid extension, maintenance, and new connection, the costs of which are quite low relative to new generation capacity. Annualized cost figures for the region are therefore lower than what might be expected.

Detailed country tables can be found in annex 1 (separately bound).

Table 5.21 Annualized costs of system expansion in CAPP, 2015

$ millions

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	734	800	860	798	751
Refurbishment cost	48	48	48	53	48
Variable cost (fuel, O&M)	84	88	92	347	84
- New capacity	51	55	61	259	51
- Existing capacity	33	33	31	89	33
T&D and connection					
Investment cost	131	205	292	253	287
- Cross-border	43	39	39	0	44
- Distribution grid	35	35	35	35	25
- Urban connection	51	93	125	125	125
- Rural connection	1	36	92	92	92
Refurbishment cost	28	28	28	28	28
Variable cost (existing capacity)	67	67	67	67	67
Total					
Capital cost	941	1,081	1,227	1,131	1,113
- Investment cost	865	1,005	1,151	1,051	1,037
- Refurbishment cost	76	76	76	81	76
Variable cost	151	156	159	414	151
Total	*1,092*	*1,236*	*1,386*	*1,546*	*1,264*

Source: Authors' original research.

Note: We assume that there are no variable costs related to the new T&D assets.

Table 5.22 Annualized costs as a share of GDP in CAPP, 2015

Percent

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Generation					
Investment cost	1.1	1.1	1.2	1.1	1.2
Refurbishment cost	0.1	0.1	0.1	0.1	0.1
Variable cost (fuel, O&M)	0.1	0.1	0.1	0.5	0.1
- New capacity	0.1	0.1	0.1	0.4	0.1
- Existing capacity	0.0	0.0	0.0	0.1	0.1
T&D and connection					
Investment cost	0.2	0.3	0.4	0.4	0.5
- Cross-border	0.1	0.1	0.1	0.0	0.1
- Distribution grid	0.1	0.1	0.1	0.1	0.0
- Urban connection	0.1	0.1	0.2	0.2	0.2
- Rural connection	0.0	0.1	0.1	0.1	0.1
Refurbishment cost	0.0	0.0	0.0	0.0	0.0
Variable cost (existing capacity)	0.1	0.1	0.1	0.1	0.1
Total					
Capital cost	1.3	1.5	1.8	1.6	1.7
- Investment cost	1.2	1.4	1.7	1.5	1.6
- Refurbishment cost	0.1	0.1	0.1	0.1	0.1
Variable cost	0.2	0.2	0.2	0.6	0.2
Total	*1.6*	*1.8*	*2.0*	*2.2*	*2.0*

Source: Authors' original research.

Note: We assume that there are no variable costs related to the new T&D assets.

Cost effects of raising access rates

Regional target for access rate: electricity access of 44 percent on average

Compared with the 2005 access rate, meeting the international target for electricity access in CAPP (44 percent on average) requires an additional investment of $1.1 billion. This equates to about $140 million in annualized capital costs (see tables 5.19 to 5.22).

The largest contributors to this increase are the costs of transmission, distribution and connection: connecting new households to the grid involves additional costs of about $0.6 billion ($80 million in annualized costs). Almost 30 percent of the total connection costs are spent in rural areas, compared to only 2 percent in the 2005 access scenario.

Meeting the regional target for access rates also requires additional power generation to satisfy the increased demand: investment in generation capacity is $0.5 billion higher ($66 million in annualized costs) compared to the 2005 access-rate scenario. Since some of the new generation capacity in rural areas is based on off-grid diesel generators, the additional costs of operating the system (variable costs) increase slightly.

The annualized costs of system expansion are about 1.6 percent of the region's GDP in 2015. Including variable costs of existing capacity lifts the total annualized cost of system expansion and operation to 1.8 percent of GDP.

National targets for electricity access

Meeting national targets for access rates requires $2.3 billion more in investment compared to maintaining the access rate constant at 2005 levels. This corresponds to $300 million more in annualized costs (see tables 5.19 to 5.22).

The largest contributors to this increase are the costs of transmission, distribution, and connection. For example, connecting new households to the grid involves an extra cost of about $1.3 billion ($165 million in annualized costs). More than 40 percent of this total is spent in rural areas, compared with only 2 percent in the 2005 access-rate scenario.

Investment in generation capacity is also almost $1 billion higher ($126 million in annualized costs) than in the 2005 access rate scenario to meet increased demand.

The annualized costs of system expansion are 1.8 percent of the region's GDP in 2015. Including variable costs of current capacity increases the total annualized costs of system expansion and operation to 2 percent of GDP.

The effect of trade

Detailed figures are reported in tables 5.19 to 5.22.

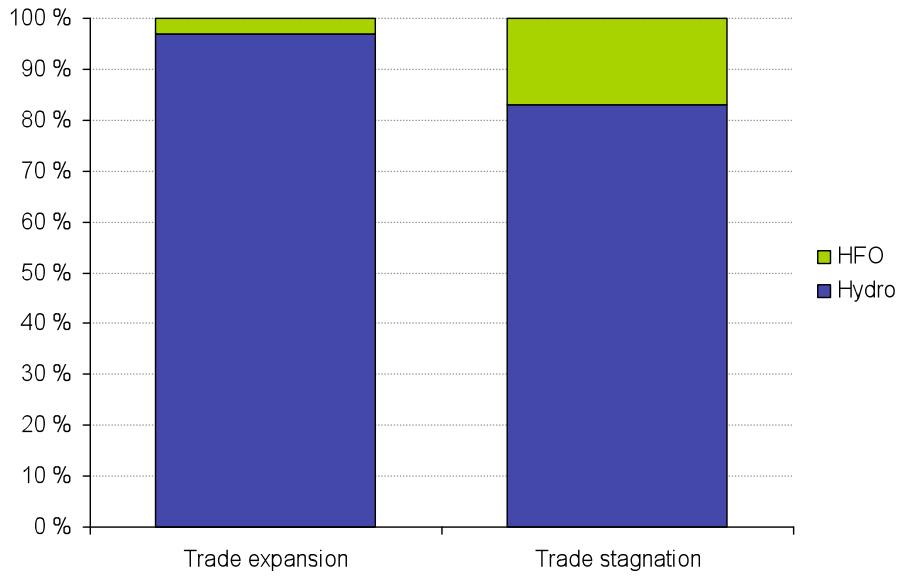
Thermal power substitutes for hydropower

In the trade-stagnation scenario, all CAPP countries must rely on domestic power generation. Therefore, the Republic of Congo, Chad, and Gabon increase their production considerably while Cameroon reduces production correspondingly (figure 5.16 and figure 5.17). The Central African Republic was self-sufficient in the trade-expansion scenario, and production therefore remains the same.

The most visible effect of restricting investments in cross-border transmission lines is reduced hydropower development, especially in Cameroon (1,450 MW of forgone investments). These investments contributed to exports to the Republic of Congo, Chad, Gabon, and Equatorial Guinea in the trade-expansion scenario. In the trade-stagnation scenario, CAPP countries cannot import power to meet demand. Therefore, investments in domestic generation capacity in the Republic of Congo, Chad, Gabon and Equatorial Guinea replace investments in exportable capacity in Cameroon. The new generation capacity is composed of HFO (over 700 MW new and refurbished capacity in the four countries combined) and hydro in the Republic of Congo (330 MW) and Equatorial Guinea (30 MW). In addition, production in existing HFO-fueled plants in Gabon increases considerably.

Total capacity is also reduced (400 MW), since thermal power plants produce more per MW installed than hydropower. Total production is unchanged since demand is the same in the trade-expansion and trade-stagnation scenarios.

Figure 5.15 Capacity mix in CAPP in 2015 with different trade assumptions



The trade-expansion scenario leads to a generation mix with a higher proportion of renewable energy and lower proportion of thermal energy: 97 percent of total capacity is supplied by hydropower and 3 percent by HFO in the trade-expansion scenario, compared to 83 percent and 17 percent, respectively, in the trade-stagnation scenario (figure 5.15).

The impact of trade on the individual countries' power balance is illustrated in figure 5.16 and table 5.23. Under trade expansion, Cameroon exports about half of its production, while Chad and Equatorial Guinea import all of their consumption. The Republic of Congo imports about one third of its consumption and Gabon almost a half. The Central African Republic is self-sufficient. Cameroon is the largest electricity supplier in the CAPP region.

Table 5.23 Net imports (+)/exports (-) as share of domestic demand

Percent

	Trade-expansion Scenario	Trade-stagnation scenario
Cameroon	-84	0
Central African Republic	0	0
Chad	102	0
Congo, Rep.	34	0
Equatorial Guinea	100	0
Gabon	42	0

Source: Authors' original research.

Figure 5.16 Production in CAPP in 2015 with different trade assumptions

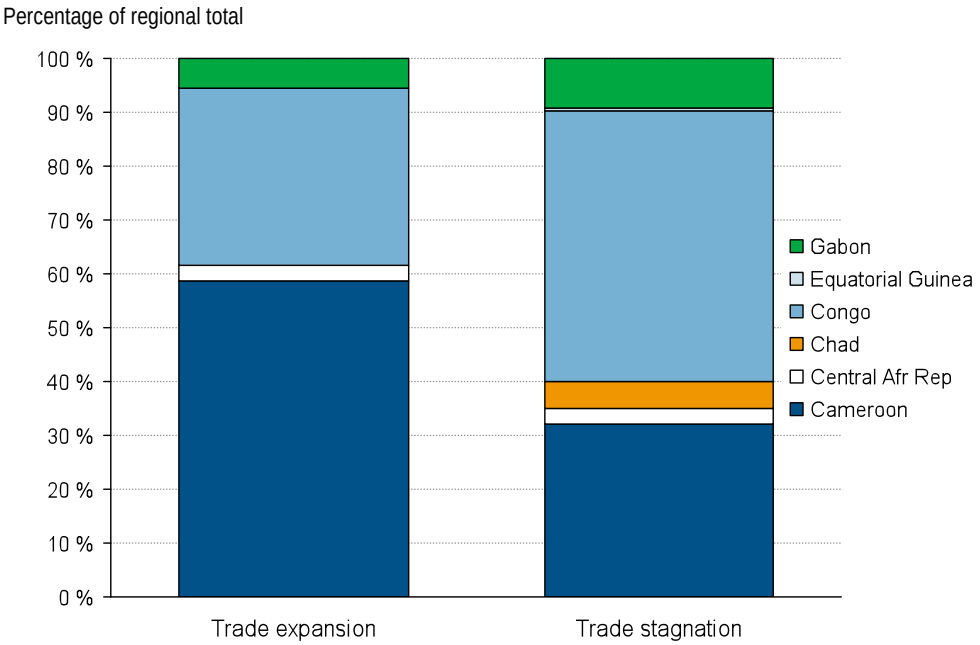


Figure 5.17 Trade flows with trade expansion (left) and trade stagnation (right) in CAPP in 2015, TWh

Source: Authors' original research.

Costs and gains

Overnight investment costs. Total overnight capital costs are $920 million higher in the trade-expansion scenario than in the trade-stagnation scenario. The costs related to transmission grid expansion are about $310 million higher (since there are additional investments in cross-border transmission lines).

The costs related to investments in generation capacity are $630 million higher in the trade-expansion scenario.

Annualized costs. Although overnight investment costs are higher under trade expansion, annualized costs are lower since they account for savings on variable costs. The total annualized costs of system expansion and operation in the CAPP region are $160 million *lower* in the trade-expansion scenario than in the trade-stagnation scenario. Annualized *capital costs* are $100 million higher in the trade-expansion scenario. Both generation and transmission investments are higher in the trade-expansion scenario (due to the higher volume of hydropower needed and the lack of international transmission lines in the trade-stagnation scenario). But the *operation* of the integrated system in the trade-expansion scenario requires significantly lower *variable costs* (that is, fuel costs and variable O&M costs). These cost savings ($255 million) stem from the higher proportion of hydropower in the trade-expansion scenario.

Returns on investing in trade. The gains from trade can be regarded as returns on investment. Capital costs in the trade-expansion scenario are $920 million higher than in the trade-stagnation scenario due to the costs of replacing thermal power with hydropower and constructing transmission lines. On the other hand, the annual costs of the enlarged system (variable costs) in 2015 are $255 million *lower* in the enlarged system. Therefore, the additional capital investment is recouped in less than four years through savings in variable cost expenditures. This is equivalent to a return on investment of 28 percent. Annual savings are 11.5 percent of the annualized cost of expansion.

Long-run marginal cost. Table 5.24 compares the long-run marginal cost of power in CAPP countries under trade-expansion and trade-stagnation. The cost figures illustrate how trade expansion increases the long-term marginal cost of power generation for exporters while the opposite is true for importers (see figure 5.17): the *cost of power generation* (column 2) is the lowest in Cameroon; however, the costs of international transmission lines needed to export power (which increase with distance) add to the long-run marginal cost.

On the other hand, countries that import in the trade-expansion scenario experience much higher long-run marginal costs of power generation (column 5) under trade stagnation due to the cost of expanding domestic power-generation capacity (especially Chad, but also the Republic of Congo and Equatorial Guinea).

Table 5.24 Long-run marginal costs in CAPP

$ per MWh

	Trade-expansion scenario			Trade-stagnation scenario		
	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total long-run marginal costs	Cost of generation and international transmission lines	Cost of domestic transmission and distribution	Total long-run marginal costs
Cameroon	44	24	69	40	24	64
Central African Republic	48	63	111	48	63	111
Chad	49	20	68	90	20	109
Congo, Rep.	54	2	56	79	2	81
Equatorial Guinea	48	27	75	70	27	97
Gabon	49	16	65	59	16	74
Average	49	22	70	70	22	91

Note: Average is weighted by annualized cost.

In some cases power exporting countries report higher LRMC under trade expansion. Even if the cost of meeting domestic power consumption may be higher with trade than without; the higher revenues earned from exports would more than compensate for that increment.

CO_2 emissions and their reduction in Sub-Saharan Africa

Throughout this study we have reiterated that least-cost trade expansion in Sub-Saharan Africa will result in the development of more hydropower plants, which have lower emissions than thermal power plants. Total reductions amount to about 70 million tons CO_2 annually in Sub-Saharan Africa (table 5.25). It is quite interesting that in the SAPP region, trade results in CO_2 reductions that are about as large as those that would be produced by the Clean Development Mechanism (CDM; see chapter 6).

Table 5.25 Difference in electricity production and CO_2 emissions in the trade-expansion and trade-stagnation scenarios

	SAPP	EAPP	WAPP	CAPP	Total
Production difference (TWh)					
Coal	-41.5	0.7			-40.8
Diesel	-0.3	0.3	-0.8		-0.8
Gas	-5.3	-42.4	-9.2		-56.8
HFO		0.4	0.2	-4.9	-4.3
Hydro	47.5	43.4	11.5	5.1	107.4
Total production difference (TWh)	0.5	2.4	1.6	0.3	4.7
Emissions savings (M ton)					
Coal	-37.8	0.6			-37.2
Diesel	-0.2	0.2	-0.6		-0.6
Gas	-2.7	-21.5	-4.7		-28.9
HFO		0.3	0.1	-3.6	-3.2
Hydro					0.0
Total emission savings (M ton)	-40.7	-20.4	-5.2	-3.6	-69.9

Source: Authors' original research.

Note: The emission factors are based on the carbon content of the fuel and on the efficiencies of different power plants as assumed in the model. The following emission factors have been used: coal 0.912 kg/kWh, diesel 0.788 kg/kWh, natural gas 0.508 kg/kWh, and HFO 0.745 kg/kWh. Emissions associated with hydro reservoirs are not calculated.

The International Energy Agency (2008) estimated that 2006 emissions from power and heat production in Africa were 360 million tons. The savings from trade expansion in Sub-Saharan Africa amount to 20 percent of this volume. Our estimate does not, however, include greenhouse gas emissions from hydropower in the form of methane from dams.

6 Sensitivity analyses

The accuracy of the results presented in chapter 5 depend heavily on assumptions of parameter values. We have therefore tested the sensitivity of our results to eight variables: low economic growth, higher fuel prices, climate change (assumed to affect the reliability of hydropower), the price of credits available under the Clean Development Mechanism (CDM), barriers to hydropower development, higher unit investment costs of coal-fired generation and hydropower, and more imports from the Democratic Republic of Congo to the CAPP region.

Low economic growth

This section presents a scenario in which each region experiences lower economic growth. Economic growth directly influences market-driven demand by raising income and indirectly by leading to structural adjustments (which then influence demand).

We examine the extent to which electricity sector investments will differ if per capita economic growth is reduced by 50 percent compared to the baseline scenario. Detailed results for this sensitivity analysis were included in the tables in chapter 5.

SAPP

A 50 percent lower rate of economic growth lowers electricity demand growth in the SAPP region, significantly reducing investment requirements (by almost 40 percent). The largest reduction is in South Africa, where 12,000 MW less is invested in new coal-fired power plants. South Africa's large impact on investments is expected—since South Africa accounts for about 80 percent of total power demand in the SAPP region, any change there will affect the region's power balance.

Hydropower investments in the region are reduced by only 400 MW, entirely in the Democratic Republic of Congo. The distance between the region's largest load center (South Africa) and the Democratic Republic of Congo is too large enough for cost-effective investments in hydropower and the accompanying transmission lines.

The result confirms that lower demand growth has a smaller effect on hydropower investments than investments in thermal power. About 97 percent of the hydropower capacity that is built in the normal growth scenario remains in the low growth scenario. The reduction of hydropower investments in the Democratic Republic of Congo is only about 5 percent of total investment. This result confirms the importance of trade: even if demand grows at a slower pace, power trading enlarges the overall market enough to make expansion of hydropower capacity preferable to thermal power options.

Intuitively, the model confirms that lower economic growth does not affect the refurbishment of aging infrastructure, which is usually the most economical way to increase generating capacity.

EAPP

In EAPP, lower demand growth reduces investments in gas-fired power plants in Egypt (by 1,921 MW) and in Tanzania (by 180 MW). Similar to South Africa in SAPP, Egypt is by far the EAPP's largest power consumer, accounting for 70 percent of the region's demand. Lower production in Tanzania also reduces net exports from there.

WAPP

In the WAPP region, 80 percent of the total demand reduction (14.6 TWh) occurs in Nigeria, and another 14 percent in Ghana.

Refurbishments of gas-fired power plants are reduced by 1,440 MW in Nigeria, resulting in a 13 TWh decrease in total production. Exports from Nigeria to Benin are also reduced (but are partly replaced by imports from Togo). Since Nigeria is a net exporter, lower domestic demand there does not influence investments in neighboring countries.

Hydropower investments are also lower by 800 MW in Cote d'Ivoire, accounting for a fall in production of 3.6 TWh. This production was exported to Ghana. In the normal growth scenario, Cote d'Ivoire was a huge transit country and a net exporter. With lower domestic investments, Cote d'Ivoire becomes a net importer. But power still flows through Cote d'Ivoire, mainly to Ghana and, farther out, to Togo and Benin.

Total capacity reduction is 2,250 MW in the WAPP region.

CAPP

Total electricity demand in CAPP is 9 percent (2.25 TWh) lower, mostly due to decreases in demand in the Republic of Congo (10 percent) and Cameroon (9 percent).

Lower demand growth reduces hydropower investments in the Republic of Congo by almost 30 percent (470 MW). The Republic of Congo replaces lower domestic investment with imported power from Cameroon, which has lower unit costs for hydropower and does not experience a change in investments or production, despite lower domestic demand. Exports from Cameroon to Congo increase by 0.8 TWh.

Total generation capacity in the CAPP region is 10 percent lower.

The impact of fuel prices in EAPP

The simulations presented in chapter 5 revealed large differences in investment patterns and costs in the trade-expansion and trade-stagnation scenarios; for example, more hydropower capacity is built in the trade-expansion scenario. Hydropower has substantially higher investment costs than thermal power plants; therefore, up-front investment costs are higher in the trade-expansion scenario. On the other hand, hydropower plants have longer economic lifetimes, so the investment costs can be spread over more years of operation. The difference in annualized capital cost is therefore less than the difference in investment cost.

Moreover, trade expansion leads to large savings in operating costs due to the higher share of hydropower. These savings are often large enough to justify hydropower's higher up-front investment costs. The total savings in operating costs depend on the fuel prices of thermal power plants. We use the price of crude oil as a signal of fuel prices for thermal power plants since it is closely correlated to the price of natural gas, heavy fuel oil and diesel.

In our base case (presented in chapter 5), we used a crude oil price of $46/barrel, based on 2005 prices. Oil prices are highly volatile, however, making them difficult to predict: by May 2008 the price of crude oil had risen far above $46/barrel, before falling below that mark in January 2009. Therefore, we found it important to check the sensitivity of our results to changes in oil prices. In our analyses, we used a crude oil price in the range of $25–$75/barrel, using historical data to estimate the correlation between the price of crude oil and the prices of other oil products and natural gas.

Running the least-cost expansion model for the EAPP region with different assumptions about crude oil prices reveals an interesting pattern:

- The total investment volume increases with the oil price during both trade expansion and trade stagnation (table 6.1)
- The total investment level is higher in the trade-expansion scenario than in the trade-stagnation scenario for all oil price levels
- The share of hydropower investments is higher in the trade-expansion scenario; investments in geothermal power also become more profitable with increasing oil prices

While higher oil prices make investments in thermal power plants less attractive, they also contribute to the faster replacement of existing gas, oil, and diesel-fueled power plants by making them more expensive to operate. The possibility of trade also encourages the development of hydropower capacity in countries that are rich in hydropower, avoiding expensive thermal power. Eventually, however, countries approach full exploitation of their hydropower resources, diminishing the potential for replacing fossil fuels with hydropower. Further increases in oil prices therefore have a diminishing impact on investments in hydropower.

Under trade expansion, hydropower is the least-cost choice for expanding generation capacity despite higher up-front costs. Therefore, total overnight investment costs are much more sensitive to oil price increases under trade expansion compared to trade stagnation (columns 2 and 3 of table 6.2). On the other hand, annualized costs are lower in the trade-expansion scenario for all prices of crude oil (columns 4 and 5). Since hydropower is a less feasible alternative to thermal power under trade stagnation, increases in fuel costs affect electricity *production* costs much more than under trade expansion. Therefore, the total annualized costs of expansion (which take into account both annualized capital costs and the annual costs of electricity production) also increase more rapidly under trade stagnation. Thus, the savings from electricity trade increase with the price of crude oil. Figure 6.1 plots the differences in overnight investment cost on the left axis and the *annual savings* on the right axis.

Table 6.1 Investments with different oil price assumptions

MW

Crude oil price ($/barrel)	Total investments		Hydropower	
	Trade-expansion scenario	Trade-stagnation scenario	Trade-expansion scenario	Trade-stagnation scenario
25	9,912	8,276	5,646	3,074
35	23,413	17,434	10,492	4,150
46	25,637	17,972	15,235	4,689
55	25,787	18,304	15,308	5,271
65	26,096	19,324	15,931	5,308
75	26,400	19,324	16,031	5,308

Source: Authors' original research.

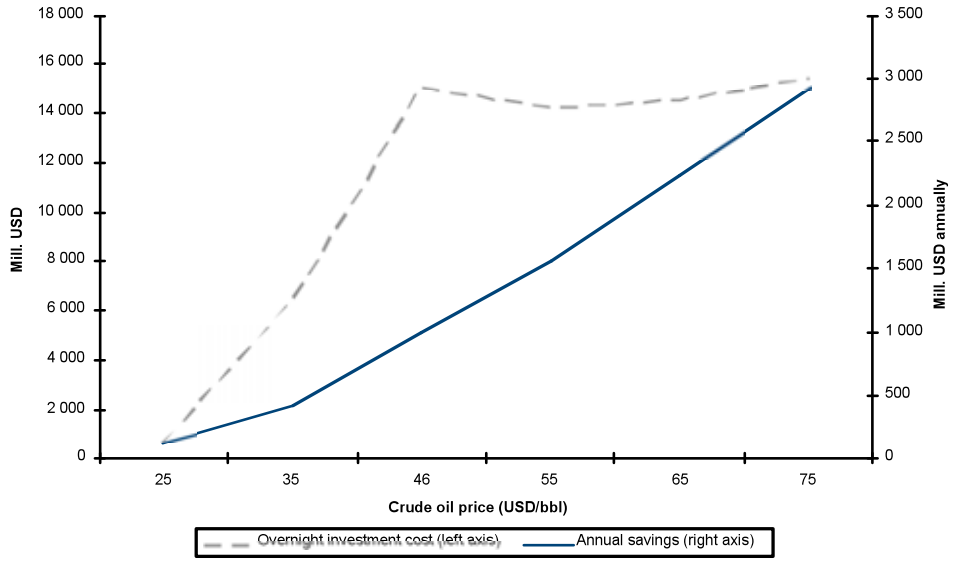
Table 6.2 Investment cost sensitivity to oil price

$ millions

Crude oil price ($/barrel)	Total overnight investment cost of expansion		Annualized cost of power system expansion and operation	
	Trade-expansion scenario	Trade-stagnation scenario	Trade-expansion scenario	Trade-stagnation scenario
25	47,392	46,726	11,454	11,587
35	59,898	53,500	13,296	13,721
46	69,928	54,870	15,004	16,003
55	70,570	56,392	15,957	17,513
65	72,129	57,597	17,101	19,333
75	73,020	57,597	18,201	21,115

Source: Authors' original research.

Figure 6.1 Difference in overnight investment costs and annual savings with different oil prices



Climate change and less reliable hydropower in EAPP

In this scenario we test how climate change—assumed to reduce the reliability of hydropower—influences the optimal (least-cost) investment solution in EAPP.

According to some, climate change will lead to more unstable weather patterns, including drought in some regions and more storms, heavy rainfall, and floods in others. It may not be possible to utilize the increased precipitation in some regions for hydropower production. According to the authoritative review by Boko and others (2007), East and West Africa will likely experience decreased water flow, while water flow will probably increase in southern Africa. The possible impact of climate change throughout Africa ranges from a 15 percent decrease to a 5 percent increase in water flows by 2050 compared to the 1961–90 baseline.

It is difficult to predict the short-term (before 2015) impact of climate change on water flows. Therefore, we conducted simulations in which climate change reduces firm hydropower production (that is, production in GWh per MW installed) of both existing and new capacity by between 5 percent and 25 percent.

The results of our simulation indicated that investments in natural-gas-fired power plants in Egypt and Tanzania replace investments in the less reliable hydropower in EAPP (table 6.3). Because natural-gas-fired power plants produce more energy (in GWh) per MW installed, the *total* investment level is reduced. As the gas resources in Egypt and Tanzania are almost fully exploited,[22] geothermal power in Djibouti becomes a more profitable option. In rural areas, diesel-fired power plants become an alternative to minihydro.

Table 6.3 Investments with different assumptions about hydropower availability

MW

Hydro-power availability	Total	Hydro-power	Natural gas-fired
Base	25,637	15,235	8,577
-5%	24,233	11,598	10,809
-10%	24,636	11,589	11,221
-15%	25,121	11,657	11,532
-20%	25,351	11,548	11,831
-25%	24,976	11,007	11,933

Source: Authors' original research.

Lower capacity investment and a shift away from hydropower reduces total overnight investment costs; as previously explained, hydropower is more capital intensive and requires larger up-front investments. Additionally, the lower investment in hydropower reduces the need for transmission lines, since thermal power plants can be built in the vicinity of load centers. On the other hand, as hydropower resources are increasingly more constrained, substitutes become increasingly expensive. Ultimately, investment costs are reduced, but only slightly.

On the other hand, when taking into account the operating costs and the shorter economic lifetime of gas-fired power plants, annualized costs increase steadily as hydropower investments are replaced by other technologies. According to our estimates, annualized costs increase 9 percent when hydropower availability is reduced 25 percent (table 6.4). A 9 percent increase is substantial, but, in light of warnings about the potential damage of climate change, it is in our view a surprisingly small effect.

Table 6.4 Power sector costs with different assumptions about hydropower availability

$ millions

Hydro-power availability	Total overnight investment cost of power sector ($ millions)			Annualized cost of system expansion and operation
	Total	Generation	Trans-mission	
Base	69,928	32,667	1,013	15,004
-5%	62,651	25,058	1,346	15,311
-10%	62,910	25,363	1,299	15,566
-15%	63,615	26,072	1,294	15,824
-20%	63,793	26,236	1,309	16,094
-25%	62,585	25,176	1,161	16,367

Source: Authors' original research.
Note: Investment cost of subnational distributional network not specified since it does not respond to hydropower availability.

Clean Development Mechanism (CDM) in the SAPP

More focus on climate change would increase the price of CDM credits and contribute to investments in emission-free technologies such as hydropower and solar PV.

The CDM is meant to cover the difference between the polluting, least-cost technology and the cost of the more expensive, clean project under consideration. The CDM difference is divided by emissions

[22] The potential for gas-fired power plants is assumed to be the same in all scenarios.

saved to calculate the cost of certified emission reduction credits (CERs) associated with the project under consideration.

The process can also be done in reverse: starting with the price of CERs, the admissible additional cost of a clean project, and subsequently the associated increase in clean technology, can be calculated. By doing this for several CER prices, it is possible to map the increase in clean technologies as a function of the CER price. We do this for the SAPP region, focusing on large-scale hydro. Off-grid technologies such as minihydro and solar PV are not considered.

In our simulations for the SAPP region, additional investments in hydropower replace investments in coal-fired power plants in South Africa (table 6.5). As expected, the increased investment costs in hydropower exceed the reduced investment cost in the coal-fired power plants (table 6.7). The difference is the macro equivalent of each project's CDM component.

Table 6.5 Investments with different assumptions about CDM prices

MW

CO_2 cost ($/ton)	Total	Hydro-power	Coal-fired power plants
Base	33,343	16,134	13,867
5	34,159	18,691	12,125
10	35,349	22,781	9,225
15	35,716	24,131	8,242

Source: Authors' original research.

Investments in hydropower increase in the Democratic Republic of Congo, Malawi, Zambia, and Namibia. In other countries with hydropower potential (Mozambique, South Africa, and Zimbabwe), hydropower resources were already fully exploited in the base case, although this is only a model assumption. In reality, the CDM could make additional investment in hydropower feasible. In all, the CDM generates 8,000 MW of additional hydropower (producing 42 TWh) at a CER price of $15/ton CO_2 (tables 6.5 and 6.6; figure 6.2).

We estimate that a CER price of $15 has the potential to eliminate 36 million tons of CO_2 (table 6.6). Note that greenhouse gas emissions other than CO_2 (for example, methane from hydropower dams) are not calculated. According to the International Energy Agency (2008), CO_2 emissions related to production of heat and power in Africa stood at 360 million tons in 2006. In other words, at a CER price of $15, CDM projects in SAPP alone are capable of reducing Africa's power sector emissions by 10 percent.

Table 6.6 Production change and CO_2 savings compared to base case (no CDM price)

	Production change (TWh)		
CO_2 cost (US$/ton)	Hydropower	Coal-fired power plants	CO_2 savings (M ton)
5	16	-15	-14
10	36	-34	-31
15	42	-39	-36

Source: Authors' original research.
Note: Excluding emissions from hydropower dams.

Table 6.7 Costs with different assumptions about CO_2 cost and CDM price

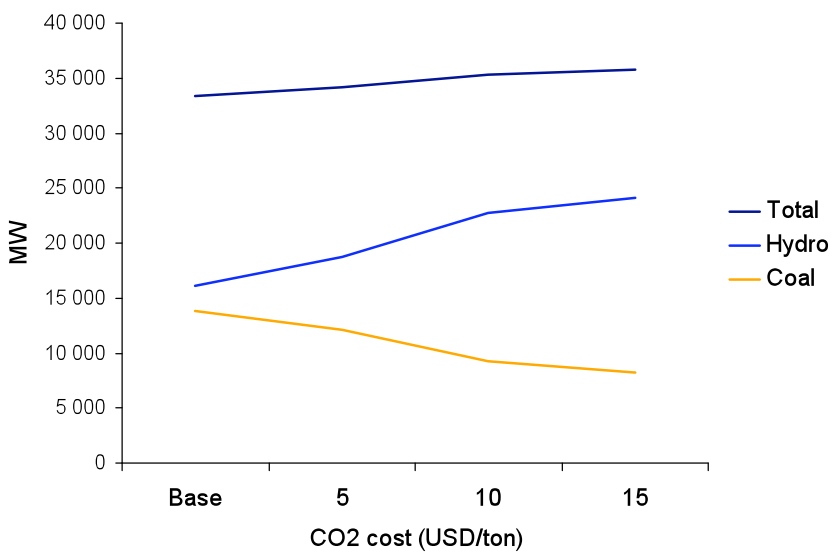
CO_2 cost ($/ton)	Total overnight investment cost ($)	Annualized cost of expansion and operation ($ millions)			
		Generation	Trans-mission	Total	Total excluding CER price
Base	98,638	4,554	380	18,500	18,500
5	101,161	4,508	722	19,800	19,100
10	104,893	4,715	944	21,100	20,800
15	106,271	4,802	1,014	22,300	21,700

Source: Authors' original research.

The underlying assumption of the CDM is that CDM finance should neutralize the higher generation costs of cleaner projects. This would imply that system costs do not increase after deducting CDM finance and the price of CERs. The results of the model, however, suggest that system costs increase substantially even after deducting CDM due to the greater transmission and distribution costs needed for the cleaner hydropower projects. These costs are unaccounted for by the mechanism. There are savings on maintenance, but cost additions are higher than the cost deductions. The model is able to reveal the hidden costs of CDM because it treats generation, transmission,and distribution in an integrated way.

There are two interpretations of the increase in expansion and operation costs after deducting CDM. First, Africa should be paid more for its CO_2 reductions, and the rest of the world underpays for the benefit of reduced emissions. This is a valid point since our simulations show that Africa does indeed end up with a higher bill after CDM than before. Second, the cost of a given CDM reduction is higher than suggested by generation costs in isolation. Therefore, the given price of CERs should lead to fewer projects and lower CO_2 savings. This is also a valid point since each unit of CO_2 reduction is more expensive when taking into account all costs than when only considering generation costs.

Figure 6.2 Investments with different CO_2 costs



Barriers to hydropower development in WAPP: Less hydropower in Guinea

In our trade-expansion scenario, cheap hydropower in Guinea supplies much of the power in the WAPP region (except in Nigeria). Yet most of Guinea's hydropower capacity was undeveloped as of 2005. Therefore, this sensitivity analysis examines a scenario in which Guinea is unable to develop its maximum hydropower potential originally assumed in the model. Which other producers emerge when exports from Guinea are limited?

As of 2005, Guinea had 103 MW of hydropower capacity and 108 MW of thermal power capacity. A portion of this will require refurbishment before 2015, so we assume that only 119 MW of Guinea's capacity will be operational capacity at that time.

According to estimates, however, Guinea has economically profitable hydropower potential of about 6,000 MW. Based on our review of all planned hydropower projects in the country, we originally included a maximum potential of 4,287 MW hydropower in the model. Since the assumed unit cost of hydropower in Guinea is among the lowest in the region, all of this potential is exploited in our base case model runs and Guinea becomes a large exporter of power in WAPP.

This is a huge amount of hydropower to be developed in one country over such a short time horizon (ten years). Therefore, we tested the effect of constrained hydropower investment in Guinea on development in the WAPP region. In this modified scenario, we include two power plants (Kaléta I and Sambangalou) with a combined capacity of 165 MW that are scheduled to come online in 2008–9. Among the other planned hydropower projects in Guinea, we assume that only Kaleta II (210 MW) can be completed before 2015. In other words, we reduce the maximum amount of hydropower that can be developed in Guinea to 375 MW.

In this scenario, new trade patterns emerge in the WAPP region. Guinea becomes a net importer, despite being a significant exporter in the base case. Côte d'Ivoire emerges as the major power exporter, while Ghana increases domestic production considerably to reduce net imports. Mauritania and Sierra Leone also become net exporters.

Hydropower investments in Côte d'Ivoire increase by just under 200 MW, but production from existing gas-fired power plants also increases; total production increases 3 TWh. Production in Ghana almost doubles, increasing to 16 TWh, although only 370 MW new capacity comes online. New (gas-fired) power plants and increased production in existing plants supply the additional power. Sierra Leone invests over 500 MW in hydropower and Mauritania 85 MW in gas-fired power plants to export to neighboring countries.

Total annualized costs increase by only 3 percent (just above $300 millions). There is, however, a huge trade-off between lower capital costs and higher variable costs: while capital costs are $500 million lower (mainly due to lower generation investments), variable operation costs of production are $850 millions (30 percent) higher. In addition, more of the existing lower-efficiency thermal capacity is put into use.

Unit investment cost of coal-fired power generation in SAPP

The unit investment (capital) cost of coal-fired power generation has increased recently. In particular, the unit cost of new coal-fired power plants in South Africa is more likely $1,500/kW than the $1,100/kW assumed in our main scenarios.

We perform a sensitivity analysis to test how a higher investment cost of coal-fired power plants in SAPP would influence the results in the trade-expansion scenario; more specifically, the unit investment cost of coal generation is raised from $1,100 to $1,500/kW. The increase applies to all countries, but only South Africa invests in new coal capacity in the original scenario, while South Africa, Mozambique, Namibia and Zimbabwe refurbish their existing coal capacity.

We find that with higher coal prices, coal investments in South Africa are reduced by 33 percent, from 13,900 MW to 9,300 MW. Incidentally, the 36 percent increase in cost results in a 33 percent decrease in investment.[23] Refurbishment is not affected. Since demand is inflexible to price, the shortfall in investment must be covered elsewhere: hydropower investments in the Democratic Republic of Congo, Zambia, and Malawi increase 6,500 MW. This leads South Africa to depend more heavily on imports from these countries, which increase by 32 TWh. New transmission lines are also needed to transport power from the Democratic Republic of Congo, Zambia, and Malawi to South Africa.

The environmental implications of this scenario are positive and similar to an increase in the cost of coal or a decrease in the price of hydropower for CDM-related reasons.[24]

Financially, the increase of the unit capital cost of coal-fired power plant increases overnight capital costs by $9.5 billion, a 15 percent increase. This increase is perhaps lower than expected, given that in the original scenario 60 percent of new capacity in SAPP is coal-fired, and 60 percent of 36 (the unit cost increase) is 22 percent. Out of the $9.5 billion increase, generation investments account for almost $6 billion.

Finally, annualized costs of expansion and operation in SAPP increase from $18.4 to $19.0 billion, an increase of only 3 percent. The reasons include the savings in fuel costs generated by replacing coal with hydropower. Also, annualized costs of expansion and operation include several fixed items such as maintenance of the distribution network, distribution, and connection costs of social demand, which prevent any single parameter from reducing annualized costs by a significant margin.

How robust are model results to a parameter such as the unit investment cost of coal-fired power plants? Macro results, in particular the annualized cost of expansion and operation, are robust. But the closer one moves to the area of the model surrounding the parameter, the more vulnerable the results become. In this case, investment in coal-fired power plants in South Africa and imports to South Africa are two vulnerable aspects of the model.

---

[23] There is no supply curve for coal in the model, so this—close to the Cobb-Douglas supply curve—is brought about by the links and constraints of the simultaneous system.

[24] In this and similar discussions, it is important to remember that when demand is price insensitive, the *level* of production is not affected by cost increases (for example, in coal production). But the shares of production covered by coal and other technologies are affected. Also, from a least-cost perspective, it is the sum of annualized capital costs and operating costs that matters.

Unit investment cost of hydropower in WAPP

Hydropower development costs are project-specific but are still influenced by the world market conditions. Construction costs have risen lately and there is always the risk of cost overruns. We have tested to what extent the investment and trade pattern in the WAPP region depends on the costs of hydropower development.

We have chosen to increase the unit cost of hydropower in all countries by 50 percent. In this way, the model retains the relationship between hydropower development costs in the different countries, but hydropower becomes relatively more expensive than thermal power compared to in the base case scenarios.

With hydropower relatively more expensive, net exports from Guinea, the large hydropower supplier in the WAPP region, fall from 17.4 TWh to 5.4 TWh. Exports to Guinea-Bissau and Sierra Leone remain almost the same, but exports to Mali fall from about 13 TWh to 1.2 TWh. While in the base case, power flowed through Mali to the other WAPP countries (via Côte d'Ivoire to Ghana and farther), these power flows now cease completely and Guinea only supplies its closest neighbors. In this scenario, it is no longer profitable to invest in hydropower and the associated transmission lines while thermal power can be built closer to consumption centers. Just 1,600 MW of hydropower investments are carried out in Guinea (compared to 4,300 MW in the base case), in addition to some 65 MW of refurbishments of HFO-fueled power plants.

Instead of relying on Guinea, countries in the eastern part of the WAPP region—Nigeria, Côte d'Ivoire, and Togo—increase their exports, and Ghana develops more of its domestic resources.

Due to the relatively higher cost of hydropower, gas-fired power plants completely replace hydropower investments in Côte d'Ivoire, Ghana, and Togo. In addition, more gas-fired power plants are refurbished in Nigeria and Côte d'Ivoire.

In total, hydropower capacity is 5,200 MW lower and gas-fired capacity 1,800 MW higher than in the base case.[25] The capacity share of hydropower falls from 77 percent to 66 percent.

This switch of investments increases annualized costs by 10 percent ($1.2 billion). The savings related to lower investments (in generation and transmission lines) are only 4 percent (less than $300 million), while the variable costs of generation increase by a significant 55 percent ($1.5 billion). While a 10 percent increase in annualized costs is fairly high, it may be lower than expected given the 50 percent unit cost increase in 77 percent of the system.

More imports from the Democratic Republic of Congo to CAPP

The Central African region (the Republic of Congo and Central African Republic) borders the Democratic Republic of Congo and could thus be expected to benefit from hydropower development

[25] As thermal power plants can produce more kWh per MW installed, less capacity is required to produce the same amount of power. But with lower power flows, power losses are also smaller. Therefore, total production is slightly (2 percent) lower in the sensitivity with higher hydropower costs.

there, especially from the Inga project, which is located relatively close to Brazzaville. In this study, the Democratic Republic of Congo is part of SAPP and a large hydropower development will indeed benefit the SAPP region, with exports of 52 TWh.

This sensitivity analysis illustrates how imports from the Democratic Republic of Congo might influence the power balance in the CAPP region. Since demand in the CAPP region is relatively low compared to that of SAPP, the Democratic Republic of Congo could redirect some exports to the north (to CAPP) while exporting to the south. (Additional investments are of course possible, but this is outside the scope of this sensitivity analysis.) Note, however, that we cannot test whether importing from the Democratic Republic of Congo is more profitable than developing the domestic capacity in CAPP countries.

We tested a scenario in which the Republic of Congo can import 5 TWh (equal net imports from other CAPP countries to the Republic of Congo in the base case) from the Democratic Republic of Congo.[26]

Imports of 5 TWh to the CAPP region reduce hydropower investments in both Cameroon (550 MW less, due to less exports to the Republic of Congo) and the Republic of Congo itself (300 MW less). Imports from Cameroon completely replace hydropower investments in Gabon.

Even though imports from Democratic Republic of Congo to the Republic of Congo replace imports from Cameroon to some extent, they do not eliminate them: Congo still imports 1.3 TWh from Cameroon. Instead, the new imports replace production and investments in new capacity in the Republic of Congo.

Allowing the Democratic Republic of Congo to export to the CAPP provides overall annual savings of $220 million. Of this total, $180 million arises from reduced investment in generation capacity in the CAPP region, while the rest is due to lower operating costs and less cross-border transmission investments. Note, however, that we do not account for costs incurred in the Democratic Republic of Congo.

[26] Note that in the base case, current imports (0.4 TWh annually) from the Democratic Republic of Congo to the Republic of Congo were included. These imports are included in the 5 TWh of the sensitivity.

References

This section lists references cited in the main document. Additional references to official websites and master plans made in the annexes are not included here.

Arthur Energy Advisors. 2007. "WAPP Emergency Power Supply Plan to Curtail Power Shortages Faced by ECOWAS Member States." Draft Study Report. August 2007.

Bergman, S., and I. Davies. 2005. "Mainstreaming Low-Cost Innovations in Electricity Distribution Networks." Study prepared for Energy Sector Management Assistance Program, World Bank, Washington, DC.

Bogetic, Z., and J. W. Fedderke. 2005. "Forecasting Investment Needs in South Africa's Electricity and Communications Sector." World Bank Policy Research Paper 3829, Washington, DC.

Boko, M., I. Niang, A. Nyong, C. Vogel, A. Githeko, M. Medany, B. Osman-Elasha, R. Tabo, and P. Yanda. 2007. "Africa." In M. L. Parry, O. F. Canziani, J. P. Palutikof, P. J. van der Linden and C. E. Hanson (eds.), *Climate Change 2007: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* (433–467). Cambridge: Cambridge University Press. http://www.ipcc.ch/pdf/assessment-report/ar4/wg2/ar4-wg2-chapter9.pdf.

CORE. 2003. "Issues and Options for Rural Electrification in SAPP Member Countries and Rural Electrification Planning in Lesotho." Unpublished desk study.

DECON/SWECO. 2005. "Tanzania Rural Electrification Study."

Econ Pöyry. 2005. "Reform and Development of the Angolan Electricity Sector." Discussion document prepared for the Angolan Ministry of Energy and Water.

———. 2006. "Tanesco Pre-Feasibility Grid Project." Report prepared for Tanzanian Ministry of Energy and Mines.

ECOWAS. 2006. "White Paper for a regional policy geared towards increasing access to energy services for rural and periurban populations in order to achieve the Millennium Development Goals." ECOWAS/UEMOA.

EIA. 2006. Annual Energy Outlook. http://www.eia.doe.gov/

Fay, M. 2001. "Financing the Future: Infrastructure Needs in Latin America 2000–05." Unpublished paper, World Bank, Washington, DC.

Fay, M., and T. Yepes. 2003. "Investing in Infrastructure: What is Needed from 2000 to 2010?" World Bank Policy Research Working Paper 3102, Washington, DC.

Gaunt, C. T. 2005. "Meeting Electrification's Social Objectives in South Africa, and Implications for Developing Countries." *Energy Policy* 33: 1309–1317.

International Energy Agency. 2005. "Projected Costs of Generating Electricity." Paris.

———. 2008. "CO_2 emissions from fuel combustion, 2008 Edition." Paris.

Karezeki, S., and L. Majoro. 2002. "Improving Modern Energy Services for Africa's Urban Poor?" *Energy Policy* 30: 1015–1028.

Kongsamut, P., S. Rebelo, and D. Xie. 1997. "Beyond Balanced Growth." NBER Working Paper W6159. National Bureau of Economic Research (NBER), Cambridge, MA.

Meschies. 2005. "International Fuel Prices 2005." 4th edition. Report commissioned by Federal Commission for Economic Cooperation and Development, Germany.

Modi, V. 2004. "Energy and Transport for the Poor." Paper commissioned for the Millennium Project Task Force 1.

Nexant. 2007. "SAPP Regional Generation and Transmission Expansion Plan Study." October.

Royal Academy of Engineering. 2004. *The Costs of Generating Electricity*. London.

Sanghvi, A. 2005. "Rural Electrification: Costs of Connection, Willingness and Ability to Pay." Presentation at Consultative Workshop on Public Private Partnership in Rural Electrification.

World Bank. 2006. "An Investment Framework for Clean Energy and Development."

UNEP. 2002. Widening access in the context of power sector reform – an overview of the institutional challenges in Africa. Power sector reform and sustainable development. Brainstorming meeting of UNEP and IEA, May 21-22, 2002, Paris.

USAID (U.S. Agency for International Development). 2004. "Innovative Approaches to Slum Electrification." Washington, DC.

Zomers, A. 2001. "Rural Electrification." PhD dissertation, University of Twente.

Appendix 1 Documentation of asset stock and refurbishment needs of thermal power generation

This appendix gives an overview over the existing asset stock and refurbishment needs of thermal power generation in Sub-Saharan Africa. These assumptions are used in the Least Cost Expansion Model.

Refurbishment refers to major refurbishments, to prolong the life of an outdated plant whose operating life is coming to an end by restoring it to full operational status, or to repair generating assets that have been seriously damaged due to for example war. We do not include costs for ordinary maintenance and repair work. We will here describe the assets that need to be refurbished. The actual amount of refurbishment will be determined as an endogenous variable in the Least Cost Expansion Model. However, due to the lower costs per MW of refurbishment (compared to new investments), all assets in need of refurbishment are usually refurbished.

CAPP Region

Cameroon

98.2 MW of total capacity to be refurbished before 2015.

Table A2.1 Thermal Generation in Cameroon (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Limbé	Diesel	2004	85	85
Bassa	Diesel	2002	24.6	9.6
Logbaba	Diesel	2002	17.6	17.6
Mefoue	Diesel	1980	13	13
Oyomabang (old)	Diesel	1980	19.6	19.6
Oyomabang (new)	Diesel	2002	16	16
Bafoussam (old)	Diesel	1979	12	12
Bafoussam (new)	Diesel	2002	4.7	4.7
Garoua	Diesel	1980	19	19
Isolated mini generators	Diesel	1980	10	10
Total Cameroon			221.5	206.5

Central African Republic

The entire capacity of 24 MW is to be refurbished before 2015.

Table A2.2 Thermal Generation in Central African Republic (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Bangui	Diesel	1980	18.2	18.2
Many small ones	Diesel	1983	5.8	5.8
Total CAR			24	24

Chad

The entire capacity of 29 MW is to be refurbished before 2015.

Table A2.3 Thermal Generation in Chad (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
N'Djamena	Diesel	1980	22	22
Other	Diesel	1980	7	7
Total Chad			29	29

Republic of Congo

The entire capacity of 28.4 MW is to be refurbished before 2015.

Table A2.4 Thermal Generation in Republic of Congo (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Pointe-Noire	Diesel	1980	19	19
Brazzaville	Diesel	1980	9.4	9.4
Total Republic of Congo			28.4	28.4

Equatorial Guinea

Out of the total capacity 34 MW is to be refurbished before 2015.

Table A2.5 Thermal Generation in Equatorial Guinea (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Punta Europa	Gas	1999	10.4	10.4
In Malabo (name unknown)	Diesel	2000	30	30
Name unknown	Diesel	1980	4	4
Total Equatorial Guinea			44.4	44.4

Gabon

The entire capacity of 244 MW is to be refurbished before 2015.

Table A2.6 Thermal Generation in Gabon (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Owendo	Diesel	1980	33	33
Name not known	Diesel	1995	203	203
Other	Diesel	1980	8	8
Total Gabon			244	244

EAPP – Nile basin region

Burundi

No thermal refurbishment is expected in Burundi. Almost all electricity generated in Burundi is hydropower provided either by the national Regie de Production et Distribution d'Eau et d'Electricité (Regideso) or the three nation cooperation Société Internationale des Pays des Grands Lacs that operates hydropower generation with supply to Burundi, Rwanda and DRC. There is also the Direction Generale de l'Hydraulique et des Energies Rurales (DHER) that independently develops rural electrification projects.

There is installed back-up capacity of 5.5 MW diesel generation in Bujumbura. These diesel generator sets are mostly from 1996, and we assume that they are still operational in 2015.

Djibouti

No thermal refurbishment is expected in Djibouti. The publicly owned Electricité du Djibouti, EdD, is responsible for power generation, transmission and distribution in Djibouti. All generation capacity (85 MW) is thermal, mainly oil-fired. The World Bank has provided grants and loan for the establishment of a transmission interconnection from Ethiopia to Djibouti in 2009, so that future hydropower from Ethiopia can replace Djibouti's expensive oil-fueled generation. It is further planned a geothermal capacity in Assal of 30 MW, and Djibouti is preparing a BOO scheme for this.

The government has also sourced financing from the Arabic countries to replace aging rural diesel generation with renewable energy (photovoltaic and wind) for water pumps. The residual electricity from these installations will be used for limited rural electrification.

Egypt

Egypt's thermal generating capacity, under the supervision of Egyptian Electricity Holding Company (EEHC) is divided into four regions: Cairo, East Delta, West Delta and Upper Egypt. While much of the thermal generating capacity is old, Egypt has recently completed an ambitious program enabling a large majority of old oil-fired power plants to run on natural gas. This reduces the refurbishment requirements of these older units. We will go through each region below, highlighting refurbishment requirements. The total installed thermal capacity is 16,475 MW, of which 2,093 MW must be refurbished before 2015.

Table A2.7 Cairo Region: Installed thermal capacity

Plant	Fuel	Commissioning date	Installed capacity (MW)
Shoubra El-Kheima	Nat. gas/HFO	1984–1988	1260
Shoubra El-Kheima	Nat. gas/HFO	1986	35
Cairo West	Nat. gas/HFO	1966–1979	350
Cairo West Extension	Nat. gas/HFO	1995	660
Cairo South I**	Nat. gas/HFO	1957–1989	570 (700)
Cairo South II	Nat. gas	1995	165
Cairo North	Nat. gas/HFO	2004	750
Wadi Hof	Nat. gas/HFO	1985	100
Tebbin*	Nat. gas/HFO	1979	46
Tebbin*	HFO	1958–1959	45

* To be replaced by a new 750 MW plant. Funding secured from World Bank.
** To be replaced by 2*350 MW.

For the Cairo region, all thermal plants except parts of the aging Tebbin plant now run on natural gas. The Tebbin plants are, however, to be replaced by a new plant at the same site, therefore we will remove it from the 2015 available capacity. The largest plant is Shoubra El-Kheima, which has been in operation for 20 years. However, Siemens recently won a major contract to rehabilitate and upgrade the 1,260 MW plant and therefore we estimate that it will not need any further refurbishment. Three remaining power stations were commissioned prior to 1995 and could be in need of refurbishment: the Cairo West station (4*87.5 MW), the Cairo South I (3*110 MW + 4*60 MW), the Wadi Hof (3*33 MW). The Cairo West station will be partly refurbished by Alstrom but we estimate that half of the capacity in that plant would need refurbishment prior to 2015. Alstrom also recently announced (January 2007) that they will supply 2*350 MW gas turbines to the Cairo South power plant, raising the capacity of that plant. It would be natural to assume that the aging units in that plant would be retired and we will therefore count the plant as having a 700 MW capacity in 2015 but not needing refurbishment. Also the Wadi Hof Station is to be partly refurbished by Alstrom, who won a contract in 2006 to rehabilitate one of the three 33 MW gas turbines that are installed. The station is old and with a load factor of 10% in 2005 the plant can be said to be a peak load plant. We still assume that 66 MW will need refurbishment prior to 2015.

Table A2.8 Upper Egypt Region: Installed thermal capacity

Plant	Fuel	Commissioning date	Installed capacity (MW)
Walidia	HFO	1992–1997	600
Kuriemat	Nat. gas/HFO	1998–1999	1254
Assiut	HFO	1966–1967	90

In Upper Egypt two of the plants, Walidia and Kuriemat, are relatively modern and according to information in the EECH Annual Report for 2004/2005, they seem to be working well (high

availability factor, 85% or higher). The aging Assiut plant had a major refurbishment in 1996. Therefore we envision no refurbishment requirements for this region and the full installed capacity will be available in 2015.

Table A2.9 East Delta Region: Installed thermal capacity

Plant	Fuel	Commissioning date	Installed capacity (MW)
Damietta	Nat. gas/LFO	1989–1993	1125
Talkha*	Nat. gas/LFO	1979–1989	284
Talkha* 210	Nat. gas/LFO	1993–1995	410
Ataka	Nat. gas/LFO	1985–1987	900
Abu Sultan	Nat. gas/LFO	1983–1986	600
Shabab	Nat. gas/LFO	1982	100
Port Said	Nat. gas/LFO	1977–1984	64
Arish	HFO	2000	66
Oyon Mousa	Nat. gas/LFO	2000	640
Suez Gulf (BOOT)	Nat. gas/HFO	2002	682.5
Port Said East (BOOT)	Nat. gas/HFO	2003	682.5

* Replaced by a new 750 MW plant at the existing site
Note: Excluded are the old power plants in Sharm El Sheik and Hurghada which are not in use.

In the East Delta Region, the plants Arish, Oyon Mousa, Suez Gulf and Port Said East (the last two are IPPs) are relatively new and are not estimated to need refurbishment. The Talkha plant is to be decommissioned and replaced by a new 750 MW plant at the existing site. We will therefore remove the current plant from 2015 available capacity, but add 750 MW of capacity instead and assume no further refurbishment requirements of this plant until 2015. The Ataka and Abu Sultan plants have received refurbishment during the past few years (2002 and 2004 respectively). The contract for rehabilitating the Abu Sultan power station went to Honeywell while Emerson landed the Ataka project. They are not assumed to need further refurbishment. Finally, the aging Shabab and Port Said plants with a total capacity of 164 MW we assume need refurbishment prior to 2015.

Table A2.10 West Delta Region: Installed thermal capacity

Plant	Fuel	Commissioning date	Installed capacity (MW)
Kafr El-Dawar	Nat. gas/HFO	1980–1986	440
Mahmoudia I	Nat. gas/LFO	1981–1982	135
Mahmoudia II	Nat. gas/HFO	1983, 1995	308
Damanhour 300	Nat. gas/HFO	1991	300
Damanhour Extension	Nat. gas/HFO	1968–1969	195
Damanhour (old)*	Nat. gas/LFO	1960	30
Damanhour CC			153
El-Sieuf	Nat. gas/LFO	1985–1995	200
El-Sieuf	HFO	1981–1984	113
Karmouz	LFO	1980	25
Abu Kir	Nat. gas/HFO	1983–1991	900

Abu Kir*	LFO	1983	25
Sidi Krir 1&2	Nat. gas/HFO	1999–2000	640
Nubari	Nat. gas/LFO	2005	500
Matrouh	Nat. gas/HFO	1990	60
Sidi Krir 3 & 4 (BOOT)	Nat. gas/HFO	2002	682.5

* Retired

The West region has several old thermal plants with poor operating performance (Egyptian Electricity Holding Company Annual Report 2004/2005). While the Mahmoudia II, Damanhour CC, Abu Kir, Sidi Krir and Nubari plants are either new or refurbished, Kafr El-Dawar, Mahmoudia, Damanhour Extension and El-Sieuf power plants are assumed to need refurbishment prior to 2015, based on age and low availability factors and/or efficiency factors. Total refurbishment requirements are thus 1,105 MW. The Abu Kir LFO plant has been retired, and the Matrouh plant was not in operation in 2005. These plants will be taken out of 2015 generating capacity, as will the old oil-fired Karmouz plant.

In addition Egypt has over 50 isolated thermal power plants with an Installed capacity of 280 MW. The majority is older diesel units and although some of the isolated plants were strengthened in 2003/2004, we still estimate that many of these isolated plants would need to be replaced before 2015. A conservative estimate would be 100 MW.

Ethiopia

The bulk of Ethiopia's generating capacity is hydro, but there are also about 43.3 MW of thermal (diesel) capacity spread out over 12 plants and one 7.3 MW geothermal plant connected to the grid. In addition, there are 25.1 MW of stand-alone diesels.

The Ethiopian Electric Light and Power Authority (EELPA) official homepage acknowledges that due to aging of plants the available capacity is lower than the installed capacity (approximately 84%). The table below presents a list of the thermal units in Ethiopia.

The installed thermal capacity is 76 MW, but due to aging of the plants the available capacity is lower. We estimate that the newer Aluto Langano, Adwa, Awash 7 Kilo and Kaliti plants will be operational in 2015, as well as 10 MW of the stand-alone diesel plants. Available capacity in 2015 is thus 51 MW.

Table A2.11 Thermal power plants in Ethiopia

Plant	Type	Commissioning Date	Installed capacity MW
Aluto Langano	Geothermal	1999	7.3
Alemaya	Diesel	1958	2.3
Dire dawa	Diesel	1965	0.3
Adigrat	Diesel	1992-95	1.1
Axum	Diesel	1972,92	0.55
Adwa	Diesel	1998	3.0
Mekele	Diesel	1984,91,93	1.3
Shire	Diesel	1975,91,95	0.8
Jimma	Diesel	-	0.1
Nekempt	Diesel	1984	1.7
Awash 7 Kilo	Diesel	2004	22.4
Kaliti	Diesel	2004	9.0
Ghimbi	Diesel	1962,84	0.3
Stand Alone Units	Diesel	1967-1998	25.1
Total			75.7

Source: Ethiopian Electric Light and Power Authority (EELPA) official homepage

Kenya

Kenya has 10 thermal power plants with a total installed thermal capacity of 520 MW and an operational capacity of approximately 470 MW. Below we present more detailed information on the plants:[27]

- Kipevu (steam), the currently installed units with capacity of 63 MW were installed in 1972 and 1976, the actual capacity is 26 MW.
- Kipevu (diesel), commissioned in 1999. Installed capacity 73 MW, effective capacity 70 MW.
- Kipevu (gas), two gas turbines commissioned in 1987 and 1999. Installed capacity 63 MW, effective capacity 60 MW.
- Nairobi South (gas), commissioned in 1972. Installed capacity 13.5 MW, effective capacity 10 MW.
- Iberafrica (diesel), IPP commissioned in 1997. Installed and effective capacity 57 MW.
- Westmount (gas), IPP commissioned in 1997. Installed capacity 46 MW; effective capacity 43 MW.
- Tsavo (diesel), IPP commissioned in 2001. Installed capacity 75 MW, effective capacity 74 MW.

[27] SNC Lavalin (2005): "Strategic/Sectoral, Social and Environmental Assessment of Power Development Options in the Nile Equatorial Lakes Region"; Kengen official home page; Eberhard, A. and K. Gratwick (2005): "The Kenyan IPP Experience", Working paper University of Cape Town

- Olkaria I (geothermal), 3*15 MW commissioned in 1981, 1982 and 1985. Installed and effective capacity 45 MW.
- Olkaria II (geothermal), commissioned in 2000-2001. 70 MW installed and effective capacity.
- Olkaria III / OrPower4 (geothermal), commissioned in 2001. Installed capacity 13 MW, effective capacity 12 MW.

The IPPs are new and modern and do not need refurbishment. Also the geothermal plants are according to the above-mentioned sources fully functioning. We estimate that the aging Kipevu steam plant and Nairobi South gas-plant needs refurbishment prior to 2015. Available capacity is then 434 MW and refurbishment requirements are 76.5 MW.

Rwanda

Rwanda has only two thermal stations with combined installed capacity of approximately 20 MW.[28] Both run on diesel.

- Gatsata (diesel), originally three old 850 kW units with one 4.77 MW diesel unit added in 2004.
- Kigali (diesel), 12.2 MW of which 8 MW was installed in 2004 by Lahmeyer.

The Kigali plants have been extended with new units as a part of a 2004 Government Fast Track Emergency Project. We remove the three aging diesel units in Gatsata from generating capacity so available thermal capacity in 2015 is approximately 17 MW.

Sudan

Sudan's National Electricity Corporation (NEC) operates 15 grid-connected thermal plants and 14 stand alone diesel systems. In addition there is a newer IPP plant commissioned in 2004. Below we provide information on the power plants.

Table A2.12 Thermal generation in Sudan

Plant	Type	Commissioning Date	Installed capacity (MW)	Available capacity (MW)
Grid Connected:				
Sherief Steam 1	Steam	1984	60	53
Sherief Steam 2	Steam	1994	120	103
Atbara	Diesel	1985	17.2	10.4
Girba	Diesel	1984	7	4
Kassala 1	Diesel	1982	4	2
Kassala 2	Diesel	1990	3.5	2
Kassala 3	Diesel	1990	4.8	3.9
Fao	Diesel	2004	12.6	10
Sherief Gas 1	Gas	1986	20	14
Sherief Gas 2	Gas	1986	50	30
Kuku 1	Gas	1986	15	8

[28] SNC Lavalin (2005): "Strategic/Sectoral, Social and Environmental Assessment of Power Development Options in the Nile Equatorial Lakes Region"; Lahmeyer homepage.

Plant	Type	Commissioning Date	Installed capacity (MW)	Available capacity (MW)
Kuku 2	Gas	1986	12	10
Garri 1	Combined Cycle	2003	210	172
Garri 2	Combined Cycle	2003	120	84
El Jaili	Combined Cycle	2004	73	73*
Dit Kilo X (IPP)	Diesel	2004	257	257*
Total Grid Connected			986	836
Stand Alone:				
Port Sudan	Diesel	1983, 1997, 2003	59	37
Wadi Halfa	Diesel	2004	1.8	1.5
Dongola	Diesel	1981	10.2	6.6
Karema	Diesel	2004	12.7	12
Elobied	Diesel	1987	3.2	2.9
Umrawaba	Diesel	1994	9.4	6.6
Nyala	Diesel	1985	11.24	7.05
ElFasher	Diesel	1983	3.12	2.24
ElGlnina	Diesel	1989	2	1.4
Aldaeen	Diesel	2004	2	1.6
Kadogly	Diesel	2004	2	1.6
Elnehood	Diesel	2004	2	1.6
Juba	Diesel	1986	5	1.6
Malakal	Diesel	2002	2.6	1.6
Wau	Diesel	1983	1.6	1.4
Total Stand Alone	-	-	142	94

Data missing, the new 2004 plants are assumed not to need refurbishment and full Installed capacity is available
Source: NEC official home page as of October 2006, Mbendi

The installed thermal capacity is thus 1,128.5 MW, of which 931 MW is available. Refurbishment requirements of natural gas and HFO plants amount to 133 MW. It is assumed that it is not feasible to refurbish the diesel units (65 MW); these can rather be replaced by new units.

Tanzania

Although the bulk of Tanzania's installed capacity is hydropower, the generating mix also includes gas and diesel fired thermal plants. The thermal plants connected to the system have an installed capacity of approximately 300 MW according to the East Africa Power Master Plan. The installed capacity can be divided into the newer IPP plants that are driven by natural gas from the Songo-Songo gas to electricity project and the diesel generators owned and operated by Tanesco:

- The Ubungo gas-fired plant with 120 (180/200) MW installed capacity (IPP)
- The Tegeta gas-fired plant with 100 MW installed capacity (IPP)
- Older grid connected diesel plants of 82 MW installed capacity
- Stand alone diesel units of 30 MW installed capacity

The Ubungo and Tegeta gas-fired plants are modern plants and have recently been refurbished when they were converted from diesel-fired to gas-fired plants. Therefore we do not consider them to be subject to major refurbishments before 2015.

The older diesel generators operated by Tanesco have effective capacity supply only half of their installed capacity, due to age, lack of spare parts and other problems, according to the information provided on Tanesco's official homepage. However, with the Songo Songo gas to electricity project, the objective is to retire the aging diesel fleet and use capacity at Tegeta and Ubungo instead[29]; therefore, we exclude the older diesel plants from current generating capacity in the Least Cost Expansion Model.

Uganda

Just a few years ago, Uganda relied almost exclusively on hydro-power, except the 10 MW thermal (bagasse cogeneration) plant in Kakari. Due to low levels of water in lake Victoria and resulting acute power crises, Uganda leases two 50 MW diesel plants from Aggreko, with plans of additional 50 MW.[30] The Kakari plant currently sells 6 MW to the grid and uses 4 MW for internal consumption. Installed thermal capacity is then 106 MW. The newly installed Aggreko plants are estimated not to need refurbishment prior to 2015.

SAPP region

Angola

Although hydropower is the main contributor in the supply of electricity in Angola, there is also thermal power generation capacity installed in the country. The thermal power situation is summarized below (the figures do not include the 82 MW new gas turbine in Benguela).

Table A2.13 Thermal generation assets in Angola

System (Main and Isolated)	Type	Installed capacity (MW)	Available capacity (MW)	Available capacity (%)
Main – North	Gas turbines	93.2	24.4	26
	Diesel plants	25.5	16.3	64
Main – Central	Gas turbines	33.8	0	0
	Diesel plants	38.9	22.3	57
Main – South	Gas turbines	-	-	-
	Diesel plants	16.5	12.9	78
Isolated Systems	Gas turbines	10.4	10.4	100
	Diesel plants	19.8	4.7	24
Total		238.1	91	38

Source: Power Sector Master Plan (2003) and cross-reference of Alfstad (2005) and EIA (2003)

[29] East Africa Master Plan (2005)
[30] First-Hand View of Africa's Power Crises, World Bank, November 2, 2006

The installed thermal capacity, 238 MW, described in the Power Sector Master Plan (2003) is well in line with the figures in Alfstad (2005)[31] and EIA (2003) which report 222 MW and 235 MW respectively. From the table we can see that a mere 38% of the installed thermal generating capacity is operational. We assume that it is not profitable to refurbish the broken-down diesel units. It is assumed that the 103 MW gas turbines can potentially be refurbished.

Botswana

Botswana Power Corporation (BPC) has installed capacity of 132 MW (4*33 MW) at the coal-fired Morupole Power Station, commissioned in 1985. In addition, there are approximately 20 MW of stand alone generating units, mostly diesel and solar. One example is the Ghanzi diesel power plant, run as an IPP, from which BPC obtains approximately 1-2% of electricity generation.

Total refurbishment requirement before 2015 is 12 MW.

Malawi

About 98% of the installed capacity in Malawi's generation system is hydropower. Escom, the national utility responsible for generation, transmission and distribution, operates three diesel units:[32]

- Lilongwe, 4.3 MW (1.3 MW and 3.0 MW diesel units), commissioned in 1972
- Mzuzu, 1.1 MW diesel unit, commissioned in 1980
- Chichri, 16 MW gas-fired back-up generator

The 2000 Escom annual report stated that the Chichri gas-fired generator was closed down for maintenance and is under repair by a UK firm. We assume that the ChiChri gas turbine is available without additional refurbishment also in 2015., while the diesel units are not refurbished.

Mozambique

Mozambique relies mainly on hydropower for electricity. The state-owned utility company EdM (Electricidade de Mozambique) has installed capacity of 204 MW of thermal capacity in 14 plants, but not one single plant was fully operational in 2005:[33]

- Angoche, 1.6 MW, diesel (available capacity 0.4 MW)
- Beira, 12 MW, gas (available capacity 0 MW)
- Inhambambe, 4.3 MW, diesel (available capacity 2.15 MW)
- Lichigonga, 1.3 MW, diesel (available capacity 0.9 MW)
- Lionde, 2.4 MW, diesel (available capacity 1.8 MW)

---

[31] T. Alfstad (2005): "Development of a least cost energy supply model for the SADC region", Master Thesis at University of Cape Town

[32] http://www.escommw.com/aboutESCOM/factfig.asp

[33] T. Alfstad (2005): "Development of a least cost energy supply model for the SADC region", Master Thesis at University of Cape Town; EdM official web-site (http://www.edm.co.mz/)

- Maputo, 111 MW, coal/gas (available capacity 62 MW)
- Tete, 0.4 MW, diesel (available capacity 0.3 MW)
- Mocuba, 0.8 MW, diesel (available capacity 0.4 MW)
- Nacala, 21 MW, diesel (available capacity 3.5 MW)
- Nampula, 6.5 MW, (available capacity 5.2 MW)
- Pemba, 8 MW (available capacity 6.7 MW)
- Quelimane, 6.9 MW (available capacity 6.4 MW)
- Xai-Xai, 2.6 MW (available capacity 1.4 MW)

In 2005, the available thermal power generating capacity was thus only 50% of the installed capacity, pointing to huge needs for refurbishment of thermal power plants in the war-torn country. We assume that the coal and gas-fired power plants will either be operational or considered for refurbishment (80 MW) ten years from now, while the diesel plants will not be refurbished.

Namibia

Namibia's thermal power generation resources amount to approximately 140 MW, summarized below.[34]

- Van Eck coal-fired power plant in Windhoek, 4*30 MW units, unit 1 and 2 commissioned in 1972, unit 3 commissioned in 1973 and unit 4 in 1979. Current operating peak load capacity is 76 MW.
- The Paratus diesel-fired stand-by plant in Walvis Bay, 24 MW, commissioned in 1976. Current operating peak load capacity is 18 MW.

The two thermal plants are high-cost options. They are currently in operation, mainly due the constrained supply situation in South Africa. However, the future supply plans of Namibia mainly concern gas-fired power plants and hydropower plants. The main projects are:

- Kudu Gas-to-Electricity project, which plans to use gas from the Kudu gas fields of the coast of southern Namibia to fuel an 800 MW gas-fired power plant,
- Two hydropower projects Epupa and Popa Falls.

It is likely that existing thermal plants will be replaced by the newer power sources. According to the SAPP 2005 Statistics Information from the SAPP official home page, it is expected that the Kudu project will be commissioned in 2009 and the two hydropower projects in 2015. Since these dates are associated with large uncertainty, we will include the 120 MW of the aging Van Eck coal plant as potential refurbishment in the Least Cost Expansion Model. We remove the Paratus power plant due to its very high generating cost from the generating capacity in 2015 in the model.

[34] Nampower generation information from official web-site (www.nampower.com.na)

South Africa

South Africa is the country with the largest thermal power generation capacity in the region. About 90% of generation capacity is coal-fired, the rest is nuclear (Koeberg, 1,800 MW), gas turbines and hydropower/pumped storage (2,240 MW in total).

ESKOM's power plants

ESKOM is by far the largest producer in the country. Let us start with an overview over ESKOM's power plants.[35]

Gas turbines

- Acacia Power Station: Gas turbine, 3*57 MW. Operational in 1976.
- Port Rex Power Station: Gas turbine, 3*57 MW. Operational in 1976.

Coal-fired power plants

- Arnot Power Station: Coal-fired, 6*350 MW units, to be expanded to 6*380 MW. Fully operational in 1975.
- Duvha Power Station: Coal-fired, 6*600 MW units. Fully operational in 1984
- Hendrina Power Station: Coal-fired, 10*200 MW units. Fully operational in 1976.
- Kendal Power Station: Coal-fired, 6*868 MW units (3,840 MW net maximum capacity). Fully operational in 1993.
- Kriel Power Station: Coal-fired, 6*500 MW units. Fully operational in 1979.
- Lethabo Power Station: Coal-fired, 6*618 MW units. Fully operational in 1990.
- Majuba Power Station: Coal-fired, 3*665 MW and 3*716 MW units. Fully operational in 2001.
- Matimba Power Station: Coal-fired, 6*665 MW units. Fully operational in 1988.
- Matla Power Station: Coal-fired, 6*600 MW units. Fully operational in 1983.
- Tutuka Power Station: Coal-fired, 6*609 MW units. Fully operational in 1993.

In addition, the following mothballed power plants are in the process of being recommissioned:

- Camden Power Station: Coal-fired, 1,520 MW.
- Grootvlei Power Station: Coal-fired, 1,128 MW.
- Komati Power Station: Coal-fired, 909 MW.

Most power stations are old, commissioned in the late 1960-ies to early 1980-ies, implying that by 2015 they are between 35 and 55 years old. Since coal plants have an estimated lifetime ranging from 30–40 years,[36] this implies that most of the power plants need refurbishment. Some plants are

---

[35] Net maximum capacity is usually lower than nominal capacity of a power plant. The overview here indicates the nominal capacity of the power plants, except for power plants where the net maximum capacity is significantly lower than the nominal capacity.

[36] The International Energy Agency assumes a 40 year economic life-time of coal-fired power plants in the *Projected Costs of Generating Electricity Report* (2005).

newer and some have been refurbished already. Plants that became operational 1990 or later are assumed not to need major refurbishment, while all plants commissioned before 1990 are assumed to need refurbishment, except those that have been refurbished. This includes five of the ten units at the Hendrina power plant that were refurbished in 1996–1997, and one of the units at the Duvha power plant which was refurbished after a mechanical breakdown in 2003. We estimate that remaining ESKOM power stations will need refurbishment before 2015, even though they are currently in full operation.

IPPs and municipal power plants

In addition to Eskom's generation capacity, there are also some municipal power stations and private power stations. With the exception of the Kelvin Power Station that was sold to an IPP in November 2001, the private power stations produce electricity exclusively for individual manufacturing companies. It is reasonable to assume that these companies keep their power plants in working order; hence, refurbishment needs of these plants will not be considered in the model.

The municipal power stations are listed below, with installed (design) capacity. Note that only Rooiwal, Pretoria West and Roggebaai are currently operational. All of them are estimated to need refurbishment before 2015.

- Rooiwal: Coal-fired, 300 MW (206 MW net maximum capacity)
- Pretoria West: Coal-fired, 170 MW (100 MW net maximum capacity)
- Athlone: Coal-fired, 180 MW (currently not operational)
- Kroonstad: Coal-fired, 30 MW (currently not operational)
- Swartkopf: Coal-fired, 240 MW (currently not operational)
- Bloemfontein: Coal-fired, 103 MW (currently not operational)
- Orlando: Coal-fired, 300 MW (currently not operational)
- Roggebaai: Gas turbine, 50 MW
- Athlone Gas: Gas turbine, 40 MW (currently not operational)
- Port Elizabeth: Gas turbine, 24 MW (currently not operational)
- Orland Gas: Gas turbine, 176 MW (currently not operational)
- Pretoria West: Gas turbine, 24 MW (currently not operational)

Zambia

Zambia relies mostly on hydropower.

According to information from the official web site of the national utility ZESCO, 99.1% of the utility's production came from hydropower sources. ZESCO's thermal power plants amount to 10 MW small diesel-fired power plants. Many of these units were installed in the 1980-ies and spare parts represent a problem. An intention is to replace these small diesel stations with a combination

of grid-extension and mini-hydro plants.[37] Therefore, we will not include them in refurbishment potential in the Least Cost Expansion Model.

The installed thermal capacity in Zambia is, however, larger than the few MW of small diesel-fired plants owned and operated by ZESCO, due to gas-fired turbines installed to provide electricity to the many copper mines in Zambia. The privately owned Copperbelt Energy Cooperation (CEC) is the largest such operator, and has around 80 MW of stand-by gas-fired generation turbines.[38] According to the company's web-site, the system is modern and maintained to the highest international standards. Consequently, we assume that these privately owned generation systems are in no need of refurbishment during the next ten years.

Zimbabwe

Zimbabwe's thermal generating capacity comes from the following coal-fired power plants

- Bulawayo, 120 MW
- Harare, 135 MW
- Munyati, 120 MW
- Hwange I, 480 MW (4*120) commissioned in 1984
- Hwange II, 440 MW (2*220MW) commissioned in 1986

Refurbishment requirements of the thermal fleet are large, due to the difficult financial position of ZESA, the state-owned utility company. For example, in October 2006, four generators at Hwange power station broke down, while the remaining two had been idle for several month due to lack of funds for repair/refurbishments.[39] The three remaining thermal plants, which are older than the Hwange system, have an available capacity far below the installed capacity and are in need of refurbishment. Therefore, before 2015 it is assumed that all of Zimbabwe's thermal generating capacity needs refurbishment

WAPP region

Benin

Out of the total installed capacity, 89.5 MW are to be refurbished before 2015. This includes all the existing plants except Cotonou, Vedoko and some small plants.

---

[37] Core International (2004)

[38] http://www.copperbeltenergy.com/

[39] IRIN News

Table A2.14 Thermal generation in Benin (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Cotonou (Akpakpa)	Combustion Turbines	1980	56	56
Natitingou 1	Diesel	1998	4.5	4.5
Natitingou 2	Diesel	2004	10.1	10.1
Parakou 1	Diesel	1998	7.8	7.8
Parakou 2	Diesel	2004	26.8	26.8
SIIF Porto-Novo	Diesel	2004	17.4	17.4
Small units (SBEE's)	Diesel	2000	8.5	8.5
Small units (SBEE's)	Diesel	2004	8.5	8.5
Vedoko (CEB)	Gas turbine	1998	25	20
Total Benin			164.6	159.6

Source: WAPP Key Performance Indicators 2005

Burkina Faso

Out of the total capacity 116.5 MW are to be refurbished before 2015.

Table A2.15 Thermal Generation in Burkina Faso (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Ouaga 1 G1/G2	Diesel	1991	6.8	5
Ouaga 1 G5/G6	Diesel	2003	6.8	5.2
Ouaga 2 G1	Diesel	1975	4	2
Ouaga 2 G2/G3/G4	Diesel	1978	19.8	12
Ouaga 2 G5/G6	Diesel	1982	19.8	12
Ouaga 2 G7/G8/G9	Diesel	1999	12.2	9
Kossodo G1/G2/G3	Diesel	2000	20.9	15.5
Kossodo G4/G5	Diesel	2003	16.2	16.2
Kossodo G6/G7	Diesel	2005	20.1	20.1
Koudougou G4/G5/G6 A	Diesel	1978	3.2	3.2
Koudougou G4/G5/G6 B	Diesel	1993	26.3	26.3
Bobo I G1/G2/G3/G4	Diesel	1976	7.5	7.5
Bobo II G1/G2	Diesel	1988	9.5	9.5
Bobo II G3/G4/G5	Diesel	1995	9.5	9.5
Total Burkina Faso			182.5	152.9

Source: Western Africa Regional Transmission Stability Study: Master Plan (2004)

Cote d'Ivoire

CIE, the company responsible for generation, transmission and distribution, operates three thermal plants with a total installed capacity 612 MW. 114 MW of this must be refurbished before 2015.

Table A2.16 Thermal Generation in Cote d'Ivoire (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Vridi 1 TAG 5000	Gas (CCGT)	1984	100	100
Vridi 2 Ciprel	Gas (CCGT)	1995	216	210
Azito IPP	Gas (GT)	2000	296	288
Total Cote d'Ivoire			612	598

Source: WAPP Key Performance Indicators 2005

Gambia

Gambia has a total capacity of 102.8 MW, of which 81 MW must be refurbished before 2015.

Table A2.17 Thermal Generation in Gambia (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Kotu G1	Diesel	1981	3.4	2
Kotu G2	Diesel	1981	3.4	2
Kotu G3	Diesel	1997	3.4	3
Kotu G4R	Diesel	2001	6.4	6.4
Kotu G5	Diesel	1990	6.4	6.4
Kotu G6	Diesel	2001	6.4	6.4
Kotu G7	Diesel	2001	6.4	6
Kotu G8	Diesel	1997	11	0
Other	Diesel	2000	56	56
Total Gambia			102.8	88.2

Source: WAPP Key Performance Indicators 2005

Ghana

30 MW of total capacity is to be refurbished before 2015.

Table A2.18 Table: Thermal Generation in Ghana (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Takoradi 1 (TapCo)	CCGT	1997	330	330
Takoradi 2 (TiCo)	CCGT	2000	220	220
Tema	Diesel	1970	30	30
Effasu	Diesel	2007	125	125
Total Ghana			705	705

Guinea

Out of the total capacity of 108 MW, only 44 MW is available till 2015. 64 MW of total capacity is to be refurbished before 2015.

Table A2.19 Thermal Generation in Guinea (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Tombo 1 - 13 G	Diesel	1997	11	1.5
Tombo 1 - 14 G	Diesel	1987	11	0
Tombo 1 - 15 G	Diesel	1989	11	0
Tombo 1 - 16 G	Diesel	1993	11	0
Tombo 2 - 23 G	Diesel	1997	6.8	0
Tombo 2 - 24 G	Diesel	1997	4	4
Tombo 3 - 31 G	Diesel	1997	11	11
Tombo 3 - 32 G	Diesel	1997	11	11
Tombo 3 - 33 G	Diesel	1997	11	11
Tombo 3 - 34 G	Diesel	1999	11	11
Isolated centres		1990	9.2	
Total Guinea			108	49.5

Guinea Bissau

The entire capacity of 22.2 MW is to be refurbished before 2015.

Table A2. 20 Thermal Generation in Guinea Bissau (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Bissau 1	Diesel	1980	8.3	8.3
Bissau 2	Diesel	1990	14	14
Total Guinea Bissau			22.2	22.2

Liberia

The entire capacity of 9 MW is to be refurbished before 2015.

Table A2.21 Thermal Generation in Liberia (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Monrovia	Diesel	1980	9	9
Total Liberia			9	9

Mali

19.5 MW of the total capacity must be refurbished before 2015.

Table A2.22 Thermal Generation in Mali (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Dar Salam	Gas	1999	20	20
Dar Salam	Diesel	1998	7	7
Dar Salam	Diesel	1998	6	6
Balingue IV	Diesel	1997	18.8	18.8
Balingue V	Diesel	1997	4.8	4.8
Mopti	Diesel	2001	6.2	6.2
Sikasso	Diesel	2001	6.0	6.0
Gao	Diesel	2001	2.1	2.1
Tombouctou	Diesel	2001	1.9	1.9
Other small diesel	Diesel	1995	15.3	15.3
Sugar refineries	Diesel		7	7
Compagnie Malienne de Dev Textile	Diesel		8	8
Huilerie Cotonnerie du Mali	Diesel		4.5	4.5
Total Mali			107.6	107.6

Mauritania

72.9 MW of total capacity is to be refurbished before 2015.

Table A2.23 Thermal Generation in Mauritania (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Nouakchott (Arafat)	Diesel	1980	42	30
Nouakchott (ksar)	Diesel	2000	10.5	7
Nouadhibou	Diesel	2003	22.1	12
Atar	Diesel	2003	3.7	1.2
Néma	Diesel	2003	1.5	0.4
Timbédra	Diesel	2003	0.8	0.4
Aîoun	Diesel	2003	1	0.6
Tintane	Diesel	2003	0.4	0.3
Kiffa	Diesel	2003	2.4	0.5
Geurou	Diesel	2003	0.8	0.3
Sélibaby	Diesel	2003	1.2	0.6
M'Bout	Diesel	2003	0.4	0.2
Tidjikja	Diesel	2003	0.8	0.3
M. Lahjar	Diesel	2003	0.6	0.3
Aleg	Diesel	2003	1.1	0.4
Boutilimit	Diesel	2003	1.1	0.7
Akjoujt	Diesel	2003	1.4	0.5
Other	Diesel	2004	18	18
Total Mauritania			110	74.1

Niger

The entire capacity of 105 MW is to be refurbished before 2015.

Table A2.24 Thermal Generation in Niger (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Niamey II	Diesel		36	36
Arlit	Coal		37.7	37.7
Other	Diesel	1999	31	31
Total Niger			105	105

Nigeria

In Nigeria, 5,003 MW of total capacity is to be refurbished before 2015.

Table A2.25 Thermal Generation in Nigeria (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Egbin/Lagos	CCGT	1986	1320	1147.8
Sapele	SCGT	1981	1020	104.7
Delta	SCGT	1989	912	393.5
Afam	SCGT	1982	623	221.2
Ijora	SCGT	1978	40	0
Oji	SCGT	1956	30	0
AES Lagos*	Gas	2005	300	300
AGIP Okpai	Gas	1986	480	262.3
Omoku	Gas	1980	150	100
Ajaokuta	Gas	1990	55	21.1
Geregu	Gas	2005	414	41
Omotosho	Gas	2007	335	335
Papalanto/Olurunsogo	Gas	2007	335	335
Total Nigeria			6,014	3,531.5

Senegal

290.8 MW of total capacity is to be refurbished before 2015.

Table A2.26 Thermal Generation in Senegal (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Bel Air C2	Steam	1961	51.2	41.6
Bel Air C2	GT	1999	35	30
Bel Air C1	Diesel	1990	9	0
Cap de Biches C3	Steam	1978	87.5	75
Cap de Biches C3	GT	1984	30	30
Cap de Biches C3	GT	1994	30	30
Cap de Biches C4	Diesel	1990	30.3	30.3
Cap de Biches C4	Diesel	1997	30.3	30.3
Cap de Biches C4	Diesel	2003	30.3	30.3

Cap de Biches, IPP GTI	Combined cycle	1999	52	52
Aggreko, Cap de Biches	Diesel	2005	48	48
St. Louis	Diesel	1979	6	6
Kahone	Diesel	1982	9.4	7
Kahone	Diesel	1988	9.4	7
Tambacounda	Diesel		7	7
Boutoude	Diesel	2006	15.2	15
Isolated Centers (25)	Diesel	1990	15.4	10
Total Senegal			496.1	449.6

Sierra Leone

54.5 MW of total capacity is to be refurbished before 2015.

Table A2.27 Thermal Generation in Sierra Leone (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
King Tom 1 K3	Diesel	1980	3	2
King Tom 2 S4	Diesel	1979	9.2	7.5
King Tom 3 S5	Diesel	2008	6	6
King Tom 4 C1	Diesel	2000	1.3	1.1
King Tom 4 C2	Diesel	2000	1.3	1.1
King Tom 4 C3	Diesel	2000	1.3	1.1
King Tom 5 M6	Diesel	1995	5	4.5
King Tom 6 M3	Diesel	2002	6.3	5.8
Bo	Diesel	1987	5	3.8
Private (mining firms)			28	28
Total Sierra Leone			66.3	60.9

Togo

The entire 60 MW of the total capacity is to be refurbished before 2015.

Table A2.28 Thermal Generation in Togo (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Lome	Gas	1980	20	20
Various plants	Gas	1980	40	20
Total Togo			60	40

Island states

Cape Verde

Cape Verde has only two thermal plants, one coal based and the other diesel. The Matiota plant is to be refurbished before 2015.

Table A2.29 Thermal Generation in Cape Verde (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Matiota	Coal	1980	0.8	0.8
Many small plants	Diesel	1991	77	77
Total Cape Verde			78	78

Source: Western Africa Regional Transmission Stability Study: Master Plan (2004).

Madagascar

Jirama, the state owned utility company, has 292 MW of installed capacity, 187 MW of which is thermal.[40] The generating capacity is divided between 112 small stand-alone diesel and mini-hydro stations, and three urban interconnected networks serving Antananarivo-Antsirabe, Toamasina and Fianarantsoa.

On a general level the thermal generating units are old and in poor condition and it is expected that a large number of the generating stations will be replaced before 2010. A World Bank Energy Sector Development Project between 1996 and 2005 modernized 82 small stand-alone units with a combined capacity of 20 MW.[41] In addition, six of the larger thermal plants were refurbished. Nonetheless, a World Bank Power/Water Sector Recovery and Restructuring Project plan for future (2007-2011) refurbishment of additional 4-5 power plants. We assume that no additional old diesel plants will be refurbished during the next ten years.

Mauritius

482.5 MW of capacity is to be refurbished before 2015.

Table A2.30 Thermal Generation in Mauritius (2005)

Plant	Type	Commissioning date	Installed capacity (MW)	Available capacity (MW)
Fort George	Diesel	1980	138	137
St Louis	Diesel	1980	113	77.4
Fort Victoria I	Diesel	1980	24	14
Fort Victoria II	Diesel	2005	18	18
Nicolay	Kerosene	1990	78	76
IPP	Cogeneration	2000	247	117.5
Other	Diesel		0	
Total Mauritius			618	440

[40] World Bank PAD Madagascar (2006)
[41] World Bank ICR 37163

Appendix 2 Documentation of hydropower refurbishment needs and investments

The objective of this appendix is to detail the assumptions, approximations and methodology adopted for deriving a simple and robust methodology for estimation of hydropower development costs at country level. These assumptions are used in the Least Cost Expansion Model.

Hydropower characteristics

Hydropower differs from thermal power generation in the sense that the investment costs are determined by site-specific, natural conditions. The "fuel cost", however, is zero provided the station does not compete with alternative water use as irrigation etc.

The fuel in a hydropower station, i.e. water, is a stochastic variable and the most used key figure for indication of the production capacity is the so-called *firm energy*. The definition varies, but is always linked up to the expected supply security, i.e. the probability of having enough water to supply the indicated amount of energy. However, paying main interest to firm energy does not mean that "excess energy" is worthless. In many situations such energy can replace other generation sources with high fuel cost. This is even more applicable for regions with cross boundary interconnectors and free power trade where difference in hydrological regimes, load patterns or generation mix can give opportunities for trade of excess energy. Hence, *average energy* production is also an important key figure.

A hydropower station with relatively modest storage capacity can also convert off-peak power to peak power if the generation capacity is increased, enabling it to produce more energy over a shorter time span. Pumped storage schemes develop this strategy to the extreme as they are pumping the water in off-peak hours in order to generate power in peak hours. Hence, their energy contribution is negative, but they refine low cost power to high value power.

Peak production capacity will decline with lower dam filling where such gives lower head for the turbines. This factor is very noticeable with low head schemes. Also, more water is needed per MWh produced energy when the reservoir level is low. However, a reservoir higher up in a river course can increase firm energy production in downstream power stations.

Some of the best hydropower sites are so big, difficult and/or costly to construct in steps that the domestic demand cannot absorb the large expansion of production capacity, making the cost per unit of actual produced energy high in the initial phase. In such situations, interconnectors that open a larger market can contribute to make the project financially viable.

The natural data that mostly influence the cost are meteorological, hydrological, topographical and geological conditions:

- Rainfall data together with run-off characteristics and size of catchment area determine the amount of water available for power production. Seasonal variations give less water available as firm energy. However, where favourable topographical conditions exists, storage dams can be established for a

reasonable cost and this can convert non-firm energy into firm energy by retaining water in wet seasons and releasing it in dry seasons.

- The amount of power generated from a water course is dependant on water volume and altitude variations (head). Large head over short distance give less expensive power stations whereas gentle sloping river courses increase the distance between the intake and outlet and hence the development costs. The scaling of the installations is normally a trade-off between the marginal increase in construction cost and the extra production potential. This determines which part of the river will be included in the hydropower scheme and which sort of storage facilities that will be developed.
- Construction of power stations involves tunnelling and/or construction of large civil structures such as dams and powerhouses. The costs of such installations depend heavily on geological and topographical conditions.

Being so dependant on site-specific conditions, the energy price can only be calculated by in situ determination of construction cost and production capacity. Sometimes the size of the installation can be adapted to the local demand, but downscaling of an installation leads normally to increased cost per unit. Care should also be taken not to block future development of an optimally sized power station.

Another factor influencing the cost is that a hydropower station must be located at a specific site often far from the consumers so large transmission costs may have to be added.

If the hydropower plant is part of an irrigation scheme, limitations on when the water can be released may reduce the firm energy capacity and increase the cost of produced energy. However, if hydropower is a side benefit to an irrigation scheme, marginal cost considerations can make cheap hydropower available.

Hydropower can have a large influence on the environment. Environmental costs are normally incorporated in the feasibility study and a project is, in this report, regarded as potentially environmentally acceptable if they are incorporated in a national or regional plan.

Determination of potential production capacity of new projects

As mentioned above, the production capacity of a hydropower site is basically a stochastic variable parameter, namely the run-off from the catchment area. This variable can to a certain degree be manipulated through storage reservoirs, through head variations created by selection of dam heights and by defining the project boundaries.

In order to predict the production capacity for a potential site one has to find the best methodology to simulate the run-off from the catchment area. Long series of historical data are necessary for that (series of at least 30 years are normally created).

The best accuracy is achieved if one has actual readings of water flow at the specific site over a long period, but if not, artificial series are created by statistical methods using regression analysis by comparison with similar rivers or catchments areas. The accuracy of the predictions is often amplified by taking into account rainfall recordings, evaporation measurements and other meterological information.

The resulting flow series are then used for simulations at various production scenarios taking into account various plant options (head to be utilised, storage possibilities etc.). The potential income from

the production scenarios is compared with the investment predictions for the same scenarios to establish the most economic development. Firm production capacity is usually given most emphasis but peak production capacity and non-firm production capacity also play a role.

For existing plants, the simulations are corrected by records of actual flow and productions, but the future production will also here be basically stochastic.

Operation, refurbishment and reconstruction

Hydropower stations have very low operation and maintenance cost; this is normally taken into account as 1.5–2 percent of the investment cost per year. In rivers with heavy silt loads, high wear on the turbine runners can increase the operation and maintenance cost.

The major civil structures in a hydropower project (dams, tunnels and powerhouses) have a life span in the range of 100 years and more, provided normal maintenance. Machinery (gates, hydraulic steelworks, turbines, generators and transformers) have a life span of 30–50 years whereas smaller equipment (breakers, control equipment, protection etc.) have a life span of 10–20 years. However, major overhaul and upgrading are normally performed every 20 years.

The nature of refurbishment work is such that it normally requires the replacement of runners, rewinding of generators, partial replacement of transformers and replacement and upgrade of switchgear, control and protection equipment. At the same time increase in production capacity can be achieved by using more modern equipment.

Heavy siltation can reduce the lifespan of dams considerably if not sufficient desiltation arrangement is provided.

Some of the countries incorporated in the study (e.g., Angola and Mozambique) have gone through civil wars and 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 taken place. Such negligence leads to rapid deterioration of the installation which in turn increases the repair cost tenfold.

Sources of data

As explained above, the hydropower data are never generic, but site-specific. That's why some sort of study must be available in order to estimate the potential and cost of a project. The normal study cycle is screening of potential, prefeasibility study of interesting sites and feasibility study of the best sites. As the costs for hydropower projects are site specific, a generation master plan is normally developed for a country or a pool area where specific hydropower projects are mixed with other generation project forming a least cost development plan.

A request for data and information from the utilities with a cover letter from the World Bank and follow-up by telephone failed to yield response. It was therefore necessary to base the study on information available in the public domain.

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

Data sets

In order to make the database manageable and not to overwhelm the respondents, only power stations larger than 10 MW are included in the study.

Where available, predicted firm production capacity is used. Where firm production capacity is not available, average production capacity is used instead, and if this is not available, 50% firm load factor is assumed (this means that mean firm energy production is estimated to be 50% of peak power potential).

Two economic key figures are calculated based on anticipated construction cost:

- USD per kWh annual production
- USD per kW peak power capacity

Our unit investment costs are based on estimated investment costs for actual planned hydropower projects for each country. Where there are several planned projects, the unit investment costs used in the least cost expansion model is the weighted average of investment costs of the planned projects in the country, where weights reflect the plants' planned capacity. Where riparian countries share water rights to a project, the cost and potential of the project are allocated equally between the partners.

We want to emphasize that this is not an exhaustive list of planned hydropower projects in any region, but a subset for which good estimates of investment costs could be obtained. It should also be borne in mind that the economic key indicators only illustrate different merits of the project. As the input data are of very variable quality, the key indicators can be used for overall generic planning but not for detailed investment planning.

The refurbishment needs are estimated based on year of construction, period of time from last known refurbishment and size of installation, if actual refurbishment information is not available.

The tables below give an overview over

- Potential and costs for new hydropower projects (tables A3.1–A3.5)
- Refurbishment needs and costs of existing hydropower plants (tables A3.6–A3.10)

Investment plans and costs for hydropower projects

CAPP region

Table A3.1 Investment Costs for Hydropower Projects, Central Africa Power Pool region

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ full utilization (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Cameroon						
Lom Pangar	56	50*	245.3	115	2054	4
Bini a Warak	75	50*	328.5	N/A	N/A	5
Memve'Ele	202	50*	884.8	160	793	1
Nachtigal	267	45	1060	318	1191	2,4
Njock	150	72	950	371	2473	2
Sonmbengue	900	50*	3942	N/A	N/A	3
Song Ndong	280	50*	1226.4	N/A	N/A	3
Kikot	500	50*	2190	N/A	N/A	3
Central African Republic						
Palambo	300	50*	1314	153	1500**	
Boali III	10	50*	43.8	N/A	N/A	5
Republic of Congo						
Sounda II	160	50	700	230	1438	1,5
Sounda III	750	50*	3285	N/A	N/A	5
Imboulou	100	74	645	200	2000	1,5
Kouembali	150	50*	657	N/A	N/A	
Nambili	28	50*	122.6	N/A	N/A	
Gamomba	14	50*	61.3	N/A	N/A	
Mpe	20	50*	87.6	N/A	N/A	
Kouli	180	50*	788.4	N/A	N/A	
Dijoue ext.	15	67	88	58	3867	1
Chollet	600	50*	2628	N/A	N/A	
Equatorial Guinea						
Name unknown	120	50	525.6	275	2292	
Gabon						
Two projects	90	50*	394.2	N/A	N/A	5

* Estimated 50 percent plant factor

** Assumed 1,500 USD/kW in the model simulations

References:

1 UNDP/World Bank - Energy Sector Management Assistance Programme (ESMAP); 2001; "Africa Gas Initiative"; ESM 240

2 UN Framework Convention on Climate Change

3 WB Project Appraisal Document for an Energy Sector Development Project, 2008-05-29

4 Direct communication WB Task Manager

5 Various internet sources

EAPP – Nile Basin region

Table A3.2 Investment Costs for Hydropower Projects, East Africa Power Pool region

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Burundi						
Ruzizi III (**DCR & Rwanda)	27	58	139.3	32	1171	1,2,6
Rusumo Falls (**Tanz. & Rwanda)	21	74	134.3	38	1839	1,2,6
Kabu 16	20	38	67	44	2200	1
Kaganuzi Complex	39	50	171	162	4154	1
Muele	17	26	39	38	2235	1
Jiji 03	16	24	33	49	3063	1
Mpanda	10	46	40	51	5100	1
Siguyaye	90	62	486	420	4667	1
Egypt						
Damietta Barrage	13	58	66	10	769	6
New Nagi Hammidi Barrage	64	83	464	386	6033	6
New Assuit Barrage	32	50*	140.2	42	1314	6
Ethiopia						
Beles	220	56	1086	294	1338	4,5,6
Chemoga Yeda (1&2)	281	57	1415	403	1434	4,5,6,7
Halele Wrabesa (1 & 2)	422	61	2245	474	1123	4,5,6,7
Karadobi	1600	61	8600	2040	1275	4,5,6,7
Baro 1	200	52	904	505	2525	4,5,6,7
Baro 2 + Genji	700	57	3505	502	717	4,5,6,7
Geba (1 & 2)	372	55	1788	361	418	4,5,6,7
Gojeb	153	39	520	287	1876	4,5,6,7
Neshe	43	58	220	69	1605	4,5,6
Alethu East I	186	49	800	438	2355	4,5,6,7
Alethu West	265	45	1050	561	2117	4,5,6,7
Genale III	258	53	1200	304	1178	7
Genale IV	256	45	1000	383	1496	7
Border	1200	57	6000	1626	1355	7
Mandaya	2000	69	12100	247	124	7
Kenya						
Ewaso Ngiro	220	32	609	493	2241	1,2,6
Low Grand Falls	140	58	715	455	3250	1,2,6
Magwagwa	120	64	669	383	3192	1,2,6
Mutonga	60	62	328	229	3817	1,2,6
Rwanda						
Nyabarongo	28	58	142	111	3964	1,2,6
Panzi (**DCR)	19	53	87.5	69	3632	1,2,6
Rusumo Falls (**Tanz. & Burundi)	31	74	201.5	57	1839	1,2,6
Ruzizi Div (**DCR)	135	55	650	160	1181	1,2,6
Ruzizi III (**DCR & Burundi)	27	58	139.3	32	1171	1,2,6
Sici 3 (**DCR)	87	58	441.5	203	2333	1,2,6
Sudan						

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Dal Low	340	65	1944	1096	3224	3,5,6,7
Dagash	285	59	1476	1048	3677	3,5,6,7
Shereiq	315	56	1546	1190	3778	3,5,6,7
Sabaloka	120	49	520	396	3300	3,5,6
Fula I	720	65	4119	1319	1832	3,5,6,7
Shukoli	210	77	1422	420	2000	3,5,6,7
Lakki	210	77	1415	429	2043	3,5,6,7
Bedden	400	79	2761	880	2200	3,5,6,7
Kabjar	300	53	1400	1125	3750	3,5,6,7
Morgat	240	65	1360	595	2479	3,5,6
Shirri	400	58	2020	549	1373	3,5,6
Roseires ext. + Dinder	135	29	341	173	1281	3,5,6
Tanzania						
Upper Kihansi	120	12	126	81	677	2,3,4
Stiegler Gorge I	344	86	2598	1899	5520	2,3,4
Stiegler Gorge II	600	13	693	388	647	2,3,5
Stiegler Gorge III	300	67	1754	637	2123	2,3,4
Ruhudji	358	57	1800	611	1707	2,3,6,7
Rumakali	222	60	1170	351	1581	2,3,4
Mpanga	144	68	863	191	1326	2,3,7
Masigira	118	51	528	157	1331	2,3,4
Mandera	21	59	109	42	2005	2,3
Ruzomo (**Rwanda & Burundi)	62	57	308			2,3,4
Songwe (**Malawi)	330	47	1352			2,3
Uganda						
Bujagali	200	97	1703	526	2630	1,2,5,6
Bujagali # 5	50	51	222	31	620	1,2,5,6
Karuma	180	81	1271	429	2383	1,2,5,6
Kalagala tot	450	64	2525	512	1137	1,2,5,6
Ayago North	304	99	2624	730	2401	1,2,5,6
Murchison Base 2	222	91	1773	397	1788	1,2,5,6
Bygoe	13	72	82	25	1923	1,2,5,6
Masindi I	360	83	2615	1347	3742	1,2,5,6
Masindi II	360	57	1798	1088	3022	1,2,5,6

* Estimated 50 percent plant factor

** Riparian country

References:

1 Power Development Options in the Nile Equatorial Lakes Region; SNC-Lavalin/Hydro Quebec; 2005

2 East African Master Plan; Acers; 2004

3 Long term Power System Planning Study, Sudan; ACRES, 1993

4 Ethiopian Power System Expansion Plan; ACRES, 2002

5 Various feasibility studies and master plans

6 Various internet sources

7 Odegard, World Bank, e-mail communication

SAPP region

Table A3.3 Investment Costs for Hydropower Projects, Southern Africa Power Pool region

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Angola						
Capanda II	260	66	1500	344	1323	1,2,3,6
Cambambe II	260	40	900	772	2969	1,2,3,6
Medio Kwanza	6700	50*	29346			1,2,3
Baine (**Namibia)	180	55	862	320	1778	1,2,3,6
Gove	60	50*	263	58	967	6
Dem. Rep of Congo						
Inga III	3500	75	22995	1730	494	2,3,6
Grand Inga 1	6000	50*	26280	4025	671	2,3
Grand Inga 2	6000	50*	26280	4025	671	2,3
Busanga	240	60	1261	300	1250	2,3,6
Ruzizi III (**Rwanda & Burundi)	82	58	418	105	1280	2,3
Zongo 2	150	50	657			2,3
Nzilo 2	120	50	526			2,3
Lesotho						
Muela II	110	9	90			2,3,6
Oxbow	80	59	410	155	1938	2,3,6
Montosa Pumped Stor.	1000		n/a	2666		6
Malawi						
Kaphichira Phase II	58	92	469	50	862	2,3,4,6
Fufu	100	61	530	141	1410	2,3,4,6
Kholombizo	240	71	1500	391	1629	2,3,4,6
Mpatamanga	260	55	1250	397	1527	2,3,4,6
Songwe (**Tanzania)	343	45	1352			6
Mozambique						
Mepanda Uncua Ph I	1300	80	9070	2000	1538	2,3,5,6
Cahora Bassa North	850	38	2835	771	907	2,3,5
Boroma	160	50*	701	150	938	2,3,5
Lupata	654	50*	2865	1215	1858	2,3,5
Mazingir	40	35	123	55	1375	2,3,5,6
Lurio	183	50*	802	339	1852	2,3,5,6
Mawuzi III	60	50*	263	119	1983	2,3,5
Namibia						
Baine (**Angola)	180	55	862	320	1778	2,3,6
Popa	23	50*	101		-	2,3
South Africa						
Bramhoek Pumped Storage.	1332		n/a	1400		2,6
Steelport Pumped Storage.	1000		n/a	976		2,6
Zambia						
Kafue Lower	600	57	3000	600	1000	2,3,6
Itezhi Tezi	120	64	676	142	1183	2,3,6
Batoka (**Zimbabwe)	800	65	4550	1250	1563	2,3,6

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Lulapula	950	50*	4161	1500	1579	2,3
Kalungwhishi	163	62	880	210	1288	2,3,6
Kariba North ext. (**Zimbabwe)	360	16	500	192	533	2,3,6
Mupata Gorge (**Zimbabwe)	300	50*	1314	454	1512	2,3
Devils Gorge (**Zimbabwe)	300	50*	1314	454	1512	2,3
Zimbabwe						
Gairezi	35	50*	153	35	1000	2,3
Condo	100	50*	438	100	1000	2,3
Victoria Falls (**Zambia)	390	50*	1708	590	1513	2,3
Batoka (** Zambia)	800	65	4550	1250	1563	2,3,6
Mupata Gorge (**Zambia)	300	50*	1314	454	1512	2,3
Devils Gorge (**Zambia)	300	50*	1314	454	1512	2,3
Kariba South Extension	300	19	500	200	667	2,3,6

* Estimated 50 percent plant factor

** Riparian country

References:

1 Planjemento Integrado do Setor Elétrico, Sondotécnia - Odebrecht, 2003

2 SAPP Priority Projects for Investor Consideration and Funding" presented on SAPP Executive Committee 21 November 2005

3 Various internet sources

4 Power System Development Study and Operation Study, Malawi; Lahmeyer, Knight Pieshold; 1998

5 EDM annual reports and information leaflets

6 Southern Africa Power Pool Study, Progress Report 4, Nexant, 2007

WAPP region

Table A3.4 Investment Costs for Hydropower Projects, Western Africa Power Pool region

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ Full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Benin						
Adjaralla (**Togo, 50%)	49	39	166.5			1,2
Adjaralla ext. (**Togo, 50%)	38.5	53	178	76.5	1987	1,2
Ketou	72	50*	315.4	302	4194	2,5
Olougbe	42	50*	184	210	5000	2,5
Assante	36	50*	57.7	287	7972	2
Batchanga	15	50*	65.7	75	5000	2
Burkina Faso						
Nounibiel (**Ghana, 80%)	48	39	162.4	228.8	4767	1,4
Diebuugo	12	50*	52.6	N/A	N/A	4
Cote d'Ivore						
Soubre	316	54	1500	471	1491	1,4,5
Louga	280	50*	1226.4	678	2421	1,2,5
Gibo-Popoli	112	50*	490.6	N/A	N/A	1
Boloubre	156	50*	683.3	N/A	N/A	1
Tayaboui	100	50*	438	N/A	N/A	1
Missouli	21	50*	92	N/A	N/A	1
Kokumbo	78	50*	341.6	N/A	N/A	1
Singrobo	80	50*	350.4	184	2300	1,2,5
Daboite	91	50*	398.6	269	2956	1,2,5
Malamasso	90	50*	394.2	245	2722	1,2
Abisso-Come	90	50*	394.2	N/A	N/A	1
Ndieliesso	90	50*	394.2	315	3500	1,2,5
Gambia						
Yelitenda	N/A	N/A	N/A	N/A	N/A	4
Ghana						
Bui	400	27	963	622	1555	1,2
Nounibiel (**Burkina Faso, 20%)	12	39	40.6	57.2	4767	1
Juale	193	50*	845.3	528	2736	2,5
Awisam	88	50*	385.4	174	1977	2,5
Abatumesu	63	50*	275.9	162	2571	2,5
Asouso	51	50*	223.4	150	2941	2,5
Kojokrom	36	50*	157.7	N/A	N/A	3
Hemang	54	50*	236.5	N/A	N/A	5
Sedukrom	26	50*	113.9	N/A	N/A	5
Jomuro	26	50*	113.9	N/A	N/A	5
Tanoso	30	50*	131.4	N/A	N/A	5
Guinea						
Kaléta I	105	98	900	143	1362	1,4
Sambangalou (**Senegal)	60	38	200	139	2317	1,2
Kaléta II	210	71	1300	209	995	1,2

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ Full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Kassa	118	45	463	93	788	1
Amaria I	300	55	1435	309	1030	1
Souapiti II	500	64	2825	605	1210	1,2,5
Amaria II	665	57	3325	835	1256	1,2,5
Balassa	181	30	470	171	945	1,3
Gozoguezia	48	62	259	110	2292	1
Morisanako	100	60	523	246	2460	1,2
Tiopo	120	56	590	296	2467	1,2
Bouréa	161	51	717	373	2317	1,5
Souapiti III	750	56	3667	1008	1344	1
Koukoutamba	281	35	858	440	1566	1,5
Diaoya	149	45	581	332	2228	1
Téné	76	30	199	122	1605	1
Fello Sounga	82	46	333	263	3207	1
Fomi	90	47	374	300	3333	1,2,5
Grand Kikon	291	26	656	637	2189	1
Guinea Bissau						
Salthino	20	50	88	82	4100	1
Liberia						
Manu River	45	47	187	N/A	N/A	1
Mount Coffee expansion	60	50*	262.8	N/A	N/A	5
Via Storage	142	50*	622	850	5986	2
SP2	214	50*	937.3	813	3799	2
SP-B1	120	50*	525.6	437	3642	2
Mano 1	180	50*	788.4	605	3361	2
Mano 2	74	50*	324.1	330	4459	2
Mali						
Kenie	56	36	178	100	1786	1,2
Feloue	62	61	330	84	1350	1,2,4
Gouina	95	54	450	160	1684	1,2
Tossaye	30	50*	131.4	330	11000	1,2
Baoule 3	24	50*	105.1	119	4958	2
Bagoe 2	36	50*	157.7	182	5056	2
Gaoulgo	300	50*	1314	814	2713	2
Labeanga	17	50*	74.5	211	12412	2
Niger						
Kandadji	125	52	564	359	2872	1,2,4,5
Gambou I	50	50*	219	N/A	N/A	1
Dyondyonga	26	36	82	69	2654	1,5
Nigeria						
Lakoja	1950	50*	8541	4463	2289	1,2,5
Makurdi	1062	50*	4651.6	1983	1867	1,2,5
Zungeru	950	50*	4161	N/A	N/A	1,4
Mambila	3900	50*	17082	2000	513	1
Onitsha	1050	50*	4599	N/A	N/A	1

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ Full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Ikom	736	50*	3223.7	N/A	N/A	1,4
Guara	300	50*	1314	N/A	N/A	1
Dadin Kova	34	50*	148.9	N/A	N/A	4
Katsina Ali	310	50*	1357.8	N/A	N/A	4
Senegal						
Sambangalou (**Guinea)	60	38	200	139	2317	1,2
Sierra Leone						
Bumbuna Ph II-III	275	58	1400	957	3480	1,2
Benkongor I-III	200	66	1164	511	2551	1,2
Kuse II	92	84	680	N/A	N/A	1
Kambatibo	53	58	269	N/A	N/A	1
Bitmai I – II	89	66	518	N/A	N/A	1
Manu River	45	47	187	N/A	N/A	1
Togo						
Adjaralla (**Benin, 50%)	49	39	166.5	N/A	N/A	1,2
Adjaralla ext. (**Benin, 50%)	38.5	53	178	77	1987	1
Tetetou	20	50*	87.6	132	6600	2
Tchala	90	50*	394.2	146	1622	2

* Estimated 50 percent plant factor

** Riparian country/shared power plant

References:

1 Nexant; 2004; "West Africa Regional Transmission Stability Study, Vol 2, Master Plan"

2 Sparrow, F.T., W.A. Masters, B.H. Bowen, Purdue University & Jeffrey C. Metzel AIRD; 2000; "Electricity Trade and Capacity Expansion Options in West Africa, Revised Draft"

3 UNDP/World Bank - Energy Sector Management Assistance Programme (ESMAP); 2001; "Africa Gas Initiative"; ESM 240

4 Various internet sources

5 Direct communication with World Bank Task Manager

Island states

Table A3.5 Investment Costs for Hydropower Projects, Island states

Country/ Project	Planned installed capacity (MW)	Plant factor = Firm production/ Full utilisation (percent)	Planned energy production (GWh)	Planned construction cost (mill. USD)	Cost/ peak power (USD/kW)	Reference
Cape Verde						
No candidates						
Madagascar						
No candidates						
Mauritius						
No candidates						

Refurbishment needs and costs of existing hydropower projects

CAPP region

Table A3.6 Assumptions regarding refurbishment of hydropower projects, CAPP area

Country/ Station	Refurbishment year	Capacity to be refurbished (MW)	Refurbishment cost (mill. USD/MW)	Refurbishment cost (mill. USD)	Reference
Cameroon					
Edea I, II and III	2009	263	0.3	61	1,3
Song Loulou	2010	387	0.3	96	1,3
Lagdo	2013	72	0.3	22	1,3
Central African Republic					
Boali I-II	2009	18	0.5	9	
Republic of Congo					
Djouel	2010	15	0.3	5	2,3
Maukaukoule	2012	74	0.3	22	2,3
Sounda	2014	10	0.3	12	3
Gabon					
Kinguélé	2010	58	0.3	17	3
Tchimbélé	2011	69	0.3	21	3
Poubara I & II	2015	36	0.3	11	3

References:

1 Nexant (2004): "West Africa Regional Transmission Stability Study, Vol 2, Master Plan"

2 UNDP/World Bank - Energy Sector Management Assistance Programme (ESMAP) (2001): "Africa Gas Initiative"; ESM 240

3 Various internet sources

EAPP – Nile Basin region

Table A3.7 Assumptions regarding refurbishment of hydropower projects, EAPP/NB area

Country/ Station	Refurbishment year	Installed capacity (MW)	Refurbishment cost (mill. USD/MW)	Refurbishment cost (mill. USD)	Reference
Burundi					
Rwegura	2015	18	0.3	5	
Egypt					
Aswan High Dam		2100			6
Old Aswan HPP		550			6
Esna		90			6
Naga Hamadi		64			6
Ethiopia					
Tis Abay I	2008	11	0.3	3	4,5,6
Tis Abay II	2009	73	0.3	22	4,5,6
Finchaa (I-IV)		134			4,5,6
Koka		43			4,5,6
Awash II	2010	32	0.3	10	4,5,6
Awash III	2011	32	0.3	10	4,5,6
Awash IV	2012	34	0.3	10	4,5,6
Melka Wakena	2007	153	0.3	46	4,5,6

Country/ Station	Refurbishment year	Installed capacity (MW)	Refurbishment cost (mill. USD/MW)	Refurbishment cost (mill. USD)	Reference
Gilbet Gibe I		183			4,5,6
Gilbet Gibe II		420			4,5,6
Kenya					
Turkwel Gorge	2009	106	0.3	32	1,2,6
Tana		14			1,2,6
Masinga	2010	40	0.3	12	1,2,6
Kamburu	2013	92	0.3	28	1,2,6
Gitaru	2010	145	0.3	44	1,2,6
Kiandurama		40		-	1,2,6
Kiambere		144		-	1,2,6
Sondu Miru		60			1,2,6
Rwanda					
Ntaruka	2010	11.5	0.3	3	1,2,6
Mukungwa	2012	12.4	0.3	4	1,2,6
Ruzizi I&II (**DCR & Burundi)		8.1	0.3	2	1,2,6
Sudan					
Roseires		280			3,6
Merowe		1250			3,6
Sennar		50			3,6
Jebel Aulia		30.4			3,6
Kashm Algirba		12.6			3,6
Tanzania					
Hale	2009	21	0.3	6	2,6,7
Pangani	2020	68	0.3	20	
Kidatu	2015	204	0.3	61	
Mtera	2010	80	0.3	24	
Lower Kihansi	2025	180	0.3	54	
Uganda					
Mboku III	2010	11	0.3	3	1,2,5,6
Nabuaale	2015	180	0.1	18	1,2,5,6
Kiira		250			1,2,5,6

** Riparian country

References:

1 Power Development Options in the Nile Equatorial Lakes Region; SNC-Lavalin/Hydro Quebec; 2005

2 East African Master Plan; Acers; 2004

3 Long term Power System Planning Study, Sudan; ACRES, 1993

4 Ethiopian Power System Expansion Plan; ACRES, 2002

5 Various feasibility studies and master plans

6 Various internet sources

7 SAPP Priority Projects for Investor Consideration and Funding

SAPP region

Table A3.8 Assumptions regarding refurbishment of hydropower projects, SAPP area

Country/ Station	Connected to	Refurbish-ment year	Capacity to be refurbished (MW)	Refurbish-ment cost (USD/MW)	Refurbish-ment cost (mill. USD)	Reference
Angola						
Mabubas	nat. grid	2010	18	0.3	5	1,3
Cambambe	nat. grid	2015	180	0.3	54	1,3
Capanda	nat. grid		520	0.3	156	1,3
Biopio	island	2010	23	0.3	7	1,3
Lomaum	island	2008	35	0.3	11	1,3
Luachimo	island	2008	10	0.3	3	1,3
Matala	island	2008	41	0.3	12	1,3
Democratic Republic of Congo						
Inga I	SAPP	2007	341	0.23	78	2,3,4
Inga II	SAPP	2007	1424	0.32	452	2,3,4
Zongo Songa	SAPP	2010	89	0.22	20	2,3,4
Nseki	SAPP	2009	262	0.21	56	2,3,4
Nzilo	SAPP	2009	108	0.26	28	2,3,4
Koni	island	2008	42	0.36	15	2,3,4
Mwadingusha	island	2010	70	0.43	30	2,3,4
Tshopo	island	2010	19	0.3	6	2,3
Mobay	island	2010	11	0.3	3	2,3
Ruzizi I (**Rwanda & Burundi)	Gr. Lack	2010	28	0.3	8	2,3
Ruzizi II (**Rwanda & Burundi)	Gr. Lack	2015	40	0.3	12	2,3
Solen II	island	2009	11	0.3	3	2,3
Budane	island	2009	10	0.3	3	2,3
Lesotho						
Muela	SAPP	2020	72	0.3	22	3
Malawi						
Tedzani	nat. grid	2008	90	0.13	12	
Kaphichira	nat. grid	2030	128	0.3	38	
Nkula Falls	nat. grid	2015	10	0.3	3	
Mozambique						
Corumana	SAPP	2020	14	0.3	4	
Mavuzi	SAPP	2009	62	0.32	20	
Chicambha	SAPP	2009	38	0.26	10	
Cahora Bassa	SAPP		2075	0.3	623	
Namibia						
Ruacana	SAPP	2020	249	0.3	75	3
South Africa						
Gariep	SAPP	2010	360	0.3	108	3
Van der Kloof	SAPP	2010	240	0.3	72	3
Zambia						
Kariba North (**Zimbabwe)	SAPP	2009	720	0.03	20	2,3
Kafue Gorge, Upper	SAPP	2009	900	0.02	20	2,3
Mulungushi	SAPP	2008	20	0.3	6	2,3
Lunsemfa	SAPP	2009	18	0.3	5	2,3

Country/ Station	Connected to	Refurbish-ment year	Capacity to be refurbished (MW)	Refurbish-ment cost (USD/MW)	Refurbish-ment cost (mill. USD)	Reference
Lusiwasi	SAPP	2010	12	0.3	4	2,3
Victoria Falls	SAPP	2025	108	0.3	32	2,3
Zimbabwe						
Kariba South (**Zambia)	SAPP	2009	760	0.3	228	2,3

** Riparian country

References:

1 Planjemento Integrado do Setor Elétrico, Sondotécnia - Odebrecht, 2003

2 SAPP Priority Projects for Investor Consideration and Funding

3 Various internet sources

4 Southern Africa Power Pool Study, Progress Report 4, Nexant, 2007

WAPP region

Table A3.9 Assumptions regarding refurbishment of hydropower projects, WAPP area

Country/ Station	Refurbishment year	Capacity to be refurbished (MW)	Refurbishment cost (mill. USD/MW)	Refurbishment cost (mill. USD)	Reference
Benin					
Nangbeto East (*Togo)	2010	31	0.3	9	1,2
Burkina Faso					
Bagre	2013	18	0.3	5	1,2
Kompienga	2008	15	0.3	5	1,2
Nounibiel	2010	30	0.3	9	1,2
Cote d'Ivore					
Ayame	2009	52	0.3	16	1,2
Kossou	2010	174	0.3	52	1,2
Taabo	2011	210	0.3	63	1,2
Buyo	2012	165	0.3	50	1,2
Ghana					
Kpong	2009	160	0.3	48	1,2
Guinea					
Donkea	2010	14	0.3	4	1
Grandes Chutes	2012	14	0.3	4	1
Liberia					
Mount Coffee	2011	64	0.5	32	1,2
Mali					
Selingue		46	0.3	14	1,2
Nigeria					
Kainji	2009	760	0.3	228	1,2
Jebba	2010	540	0.3	162	1,2
Shiroro	2011	600	0.3	180	1,2
Zungeru	2012	950	0.3	285	1,2
Togo					
Nangbeto West (*Benin)	2010	31	0.3	9	1,2

* Riparian country/shared power plant

References:

1 Nexant (2004): "West Africa Regional Transmission Stability Study, Vol 2, Master Plan"

2 Various internet sources

Island states

Table A3.10 Assumptions regarding refurbishment of hydropower projects, island states

Country/ Station	Refurbishment year	Capacity to be refurbished (MW)	Refurbishment cost (mill. USD/MW)	Refurbishment cost (mill. USD)	Reference
Cape Verde					
No hydropower					
Madagascar					
Mandraka	2011	24	0.3	7	1
Andekaleka	2012	58	0.3	17	1
Mauritius					
No refurbishment					

References:

1 Various internet sources

Appendix 3 Documentation of asset stock and refurbishment needs of transmission and distribution

The objective of this section is to detail the assumptions, approximations and methodology adopted for deriving a simple and robust methodology for generic cost estimation at country level of the transmission and distribution networks. The starting point for the analysis was to examine data which is available for those countries where the Consultant has had a direct involvement in transmission and distribution investment analysis, through other projects and activities.

A request for data and information from the utilities with a covering letter from the World Bank and telephone follow-ups failed to yield responses. It was therefore necessary to progress the study using information available in the public domain, some country specific projects and regional data.

It was observed that in each country there are various voltages, substation configurations, line constructions and ratings at transmission, subtransmission and distribution level, with the exception of a single voltage level for domestic supplies. The observations for the individual countries in the region are tabulated below. The countries can be grouped as follows:

- Group I: Two voltage levels at transmission and one or two voltage levels at sub-transmission.
- Group II: One voltage level at transmission and one or two at subtransmission.

It was also observed that there were a small number of unusual line voltages for a few lines (including interconnection lines) and double circuit line construction in some countries. The total route lengths of these lines were not significant.

Total line lengths and ratings at the higher voltages were noticeably higher than those at the lower voltages as expected because these lines are designed to transfer large amounts of power.

Table A4.1 Central Africa Group II-Utility Voltage Levels

Country	Utility	Transmission (kV)		Subtransmission (kV)		Distribution (kV)		Low Voltage (kV)
Cameroon	AES	n/a	225	90	n/a	30	11	0.4
CAR	Enerca							
Chad	STEE	n/a	161	69	n/a	33	11	0.4
Republic of Congo	SNE	220	n/a	n/a	n/a	20 & 10	6.6 & 5.5	0.38
Equatorial Guinea	SEGESA							0.38
Gabon	SEEG					20	5.5	0.38

Note: n/a denotes no other voltage at the level.

Table A4.2 Eastern Africa Group II-Utility Voltage Levels

Country	Utility	Transmission (kV)		Subtransmission (kV)		Distribution (kV)		Low Voltage (kV)
Burundi	REGIDESO	n/a	110	n/a	70	35 & 30	10	0.4
Djibouti	EdD	n/a	63	n/a	n/a	20	n/a	n/a
Egypt	EGELEC	220	n/a	132	66	33	11	0.4
Ethiopia	EEPCo	230	132	66	n/a	33	11	0.4
Kenya	KPLC	n/a	220	132	66	33	11	0.4
Rwanda	ELECTROGAZ	n/a	110	70	n/a	30	15	0.4
Sudan	NEC	n/a	220	110	66	33	11	0.4
Tanzania	TANESCO	220	132	66	n/a	33	11	0.4
Uganda	UMEME	n/a	132	66	66	33	11	0.4

Note: n/a denotes no other voltage at the level.

Table A4.3 SAPP Group I-Utility Voltage Levels

Country	Utility	Transmission (kV)		Subtransmission (kV)		Distribution (kV)		Low Voltage (kV)
DRC	SNEL	220	120	70		15	6.6	0.4
Mozambique	EdM	220	110	66	n/a	33	11	0.4
Namibia	NAMPOWER	220	132	66	33	22	11	0.4
South Africa	ESKOM	400	275	132	88	22 & 33	11	0.4
Zambia	ZESCO	330	220	88	66	33	11	0.4

Note: n/a denotes no other voltage at the level.

Table A4.4 SAPP Group II-Utility Voltage Levels

Country	Utility	Transmission (kV)		Subtransmission (kV)		Distribution (kV)		Low Voltage (kV)
Botswana	BPC	n/a	220	132	66	33	11	0.4
Lesotho	LEC	n/a	132	66	n/a	33	11	0.4
Malawi	ESCOM	n/a	132	66	n/a	33	11	0.4
Zimbabwe	ZESA	330	n/a	88	66	33	11	0.4

Note: n/a denotes no other voltage at the level.

Table A4.5 Western Africa Group II-Utility Voltage Levels

Country	Utility	Transmission (kV)		Subtransmission (kV)		Distribution (kV)		Low Voltage (kV)
Benin	CEB	n/a	161	69	n/a	33	11	0.4
Burkina Faso	SNEB	n/a	161	69	n/a	33	11	0.4
Cote d'Ivoire	CIE	n/a	225	90	n/a	30	6.6	0.4
Gambia	NAWEC					33	11	0.38
Ghana	VRA	n/a	161	69	n/a	33	11	0.4
Guinea	EDG	n/a	110	60	n/a	30	11, 6.3, 5.5	0.38

Guinea Bissau	Electricidade et Aguas de Guinee Bissau						10 & 6	0.38
Liberia	LEC	n/a		69	n/a	12.6	7.2	0.24
Mali	EDM	n/a	225	90	n/a	30	11	0.4
Mauritania	SOMELEC	225	n/a	90	n/a	33	15	0.4
Niger	NIGELEC	n/a	132	n/a	n/a	33	11	0.4
Nigeria	NEPA	330	n/a	132	n/a	33	11	0.4
Senegal	SENELEC	n/a	225	90	n/a	30	6.6	0.4
Sierra Leone	NPA	n/a	110	66	n/a	33	11	0.4
Togo	CEET	n/a	132	66	n/a	33	11	0.4

Note: n/a denotes no other voltage at the level.

Table A4.6 Island States Group II-Utility Voltage Levels

		Transmission (kV)		Subtransmission (kV)		Distribution (kV)		Low Voltage (kV)
Cape Verde	Electra					20	15,13, 6, 6.3	0.38
Madagascar	LA JIRAMA	n/a	138	63	n/a	35	15	0.4
Mauritius	CEB	n/a	132	66	n/a	22	6.6	0.4

Note: n/a denotes no other voltage at the level.

Assumptions and approximations

In order to develop a simple and robust methodology for generic estimation of the cost of power system equipment, it is necessary to make assumptions and approximations. These assumptions and approximations will either be of a general or a specific nature at transmission, sub-transmission, distribution or low voltage level for all the countries, some which are country specific because of the diverse nature of the systems. Whilst these assumptions and approximations, which are made from knowledge of the region and various sources of data, will lead to a reduced order of accuracy, the resulting equipment costs will be adequate for the purpose of the investment study.

General assumptions and approximations for all network subsystems

The assumptions and approximations of a general nature applied at each voltage level are detailed below:

The line rating will always be greater than the demand to be supplied. The resulting excess line capacity and interconnection is the cost for the security of that supply.

Substation costs based on assumptions as to typical configurations and ratios of substations per unit length of transmission lines were factored into the transmission line costs.

At each system level, except for low voltage, the design is (N-1) security which includes interconnection.

Where there are more than two transmission or sub-transmission voltage levels in a country, the higher of the two voltages would be used for line investment as this is likely to be more cost effective.

Where several voltage levels are present in a country voltage levels are lumped to enable the estimation of the maintenance and refurbishment costs within the transmission and distribution categorization.

Interconnecting voltages will only be considered as a transmission voltage if there are other lines in the country under consideration.

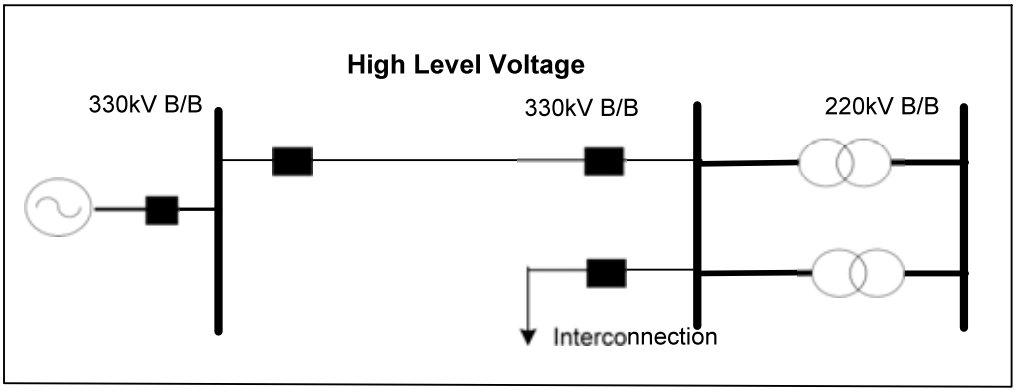
Transmission level assumptions

The assumptions that are applicable at the transmission level are detailed below.

Generator transformer and substation costs were considered to be part of the generation costs.

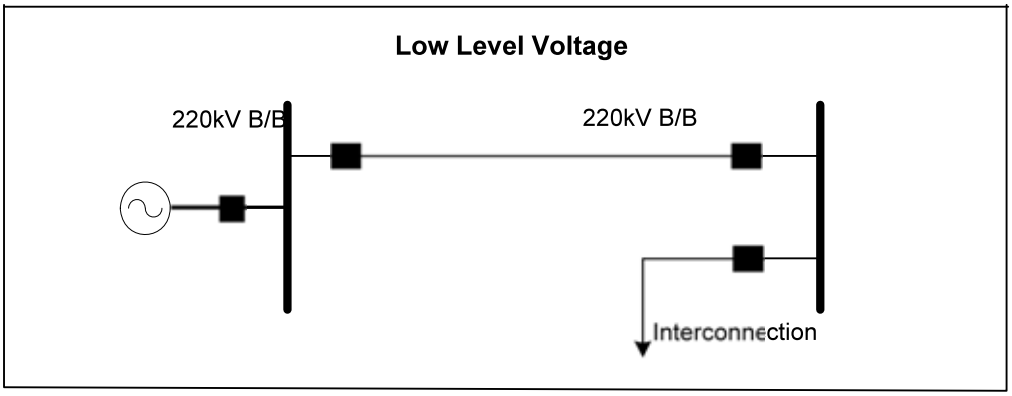
For cost comparison, if there are two transmission voltages, then the higher voltage line will have the cost of a duplicated HV line bay (extra line bay for interconnection), transformers of adequate rating including HV and LV bays, stepping down to the lower transmission voltage as shown in below. This is applicable to Group I Country Utilities.

Figure A4.1 Group I – Higher level voltage configuration



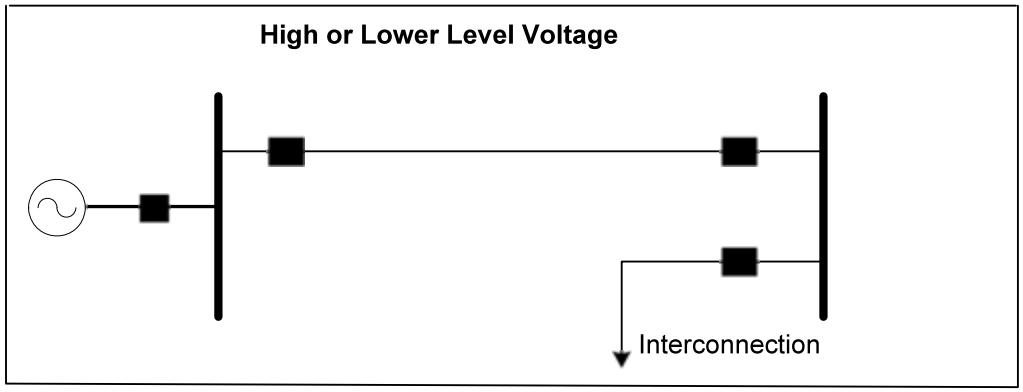
For Group I-Country Utilities, the lower transmission voltage line cost will comprise the line construction cost, two line bays plus the cost of an extra bay for the interconnection as shown in figure below.

Figure A4.2 Group I – Lower level voltage configuration.



For Group II-Country Utilities, the unit cost for the transmission voltage was determined separately for the two different sub-transmission voltages as shown in below. The subsequent sub-transmission line costs excluded the transmission substation costs but included two line bays on either end plus the actual line costs.

Figure A4.3 Group II – Higher and Lower voltage configuration



With the data available, the average transmission line length in each country differed from approximately 100 km to 200 km. This was calculated by ignoring very short lines which would have distorted the average. An average transmission length of line of 150 km was then calculated for all the countries. This line length is reasonable when considering investment costs as the countries have some infrastructure already in place and it should be borne in mind that the overall objective is to derive generic investment costing. If an investment were to be made which was say, twice the average country line length, this would mean duplicating the terminal equipment in the costing at the transmission voltage. This is acceptable as over the planning horizon there may be a requirement for an intermediate substation as the load increases with increased access to electricity.

The nature of investments on power systems is discrete in nature; this implies that the unit costs in kUSD/km/MW can only be used for the calculated average line rating for new equipment.

The decision to use the higher or lower voltage unit investment cost is based on the length of line, the power to be transferred and other investment parameters as well as any country standard voltage.

Some odd voltage levels were ignored as they were considered to be of special design (for example 765 kV in ESKOM.). Because of the very high line ratings inclusion of these circuits would lead to very low unit costs (kUSD/km/MW), which would distort the average unit investment costs.

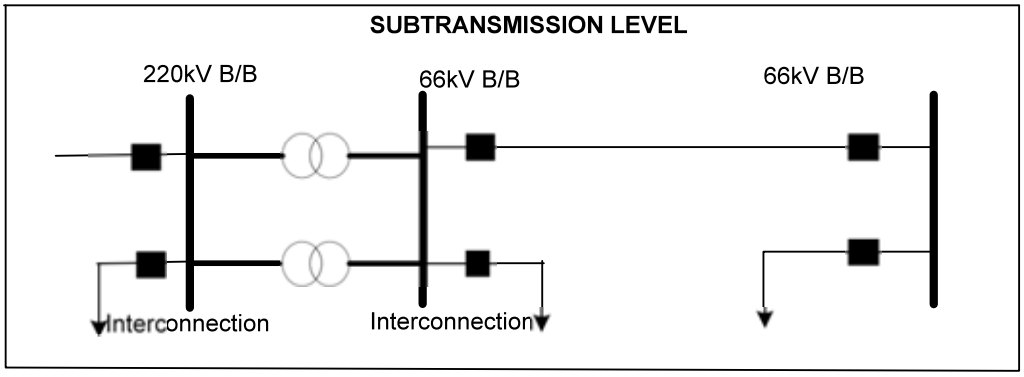
Subtransmission level assumptions

The assumptions that are applicable at the sub-transmission level, i.e. the second voltage transformation level after the generator transformer, are detailed below

With the data available and knowledge of the region, the average sub-transmission line length in each country was estimated to be 50 km.

For both groups of countries, the unit costs will comprise the line cost, two line bays, plus half the cost of the transmission substation. Half the cost of the substation is assumed as it would be expected that there will be at least two out going circuits.

Figure A4.4 Group I and Group II – Subtransmission voltage configuration



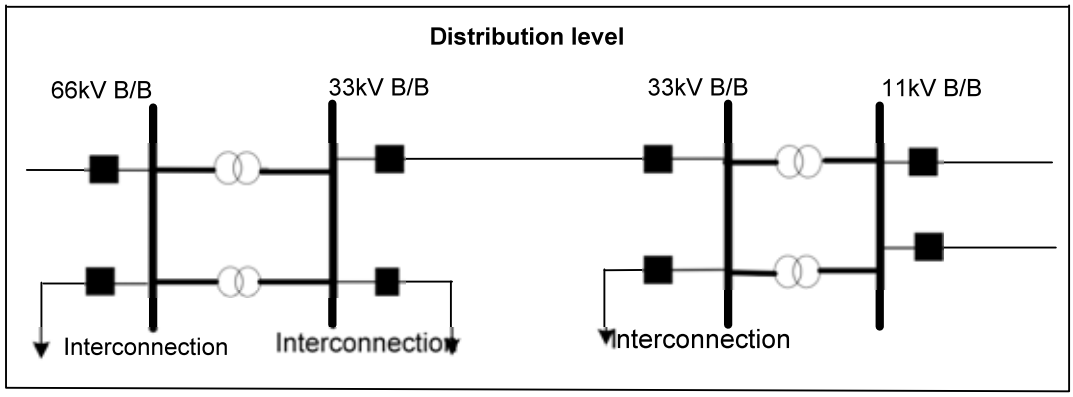
Distribution level assumptions

The assumptions that are applicable to the distribution voltage levels are detailed below.

With the data available, the average distribution line length in each country was estimated to be 30 km for the 33 kV and 5 km for 11 kV.

For 33 kV it was assumed that for the 33/11 kV substation there will be two bays at the 11 kV side. The cost of the distribution line was calculated as the total of half the cost of the subtransmission substation and the interconnection bay at the high voltage side plus the actual distribution line cost and the two LV bays. The exception was for SNEL in DRC where the use of 15 kV necessitates the use of a higher number of bays. This is applicable to both Group I and Group II Country Utilities.

Figure A4.5 Group I and Group II – Distribution voltage configuration



For 33/11 kV substations it was assumed that the 11kV side will be equipped with metalclad switchgear with on average six bays except for SNEL in DRC where there is use of 6.6 kV which will necessitate a higher number of bays.

For MV line material and transformers, there are small differences in price between lower MV levels of 6 kV or 11 kV and the higher 22 kV equipment

Domestic low voltage assumptions/approximations

An After Diversity Maximum Demand of 2.0 kVA was judged to be good average for each domestic supply.[42]

The average transformer size was taken as 200 kVA because from the data available the transformer sizes vary from 25 kVA to 630 kVA.

From knowledge of the region there are numerous conductor sizes and types for LV networks. In this study it only one size was assumed, which is 95mm^2 aerial bundled conductor.

It is assumed that the LV transformer will be 50% loaded to allow for load growth.

The LV line length was approximated to be on average no more than 500m with two lines per transformer loaded to about 50% to allow for load growth.

The total cost of the LV line included the pole mounted transformer and the cost of the 0.4 kV line including all tee-offs.

In the absence of country specific data, the same distribution data has been used for all the countries except for SNEL-DRC which has different system voltages. This was judged to be a fairly good assumption as the major source of power system equipment and materials for African countries is South Africa and there are several initiatives to standardize in the region.

CAPP: Country-specific assumptions and unit costs

There is very limited data and information on CAPP utility networks on the public domain or from specific projects in the region. Central Africa is the least electrified sub-region in Africa. CAPP has proposals for the interconnection of the CAPP countries and external interconnection with WAPP, SAPP and EAPP.

Group II – CAPP Country Utilities

Cameroon – AES

AES has one voltage at each level, transmission at 225 kV and subtransmission at 90 kV. Distribution is at 30 kV, 6.6 kV and 0.4 kV. No data has become available regarding interconnections, however, we believe that there are no major inter connection with Chad or Nigeria.

Central African Republic – Enerca

Very little information is available about the electricity system in the Central African Republic, which is likely to be limited in its extensiveness as only 3% of the population have access to electricity and the

[42] However, in many developing regions, notably Africa, supplies are at a much lower capacity, typically ranging between 5 A, 1.1 kW and 10 A, 2.2 kW. In South Africa a 550 W supply has been piloted, and is now the default option, with a design after-diversity-maximum-demand of 0.4 kVA (R. Stephen, personal communication, 1998). These limited-current supply options offer the potential to reduce the distribution infrastructure costs significantly in comparison with conventional 20 A or greater supply capacities. There are also significant advantages in terms of load factor, as the magnitude of domestic peaks is effectively reduced.

country has had an unstable past. There are no interconnections. CAPP have plans to interconnect the Central African republic with the Democratic Republic of Congo.

Information from the World Bank details a short 120 kV transmission line within the country. The lengths of the distribution system and lv system have been estimated from other similar countries based on the distribution length / net consumption of the country.

Chad – STEE

There is no significant network in Chad mainly due to the prolonged civil strife in the country. The network is concentrated in N'Djamena at 20, 15 and 0.4 kV.

Peak electricity consumption in Chad is less than 25 MW, of which about 20 MW is generated in N'Djamena, Chad's capital, the remainder being in three smaller urban centers (Moundou, Sahr and Abeche). There are about 7,500 electricity customers in a country of 7 million people. In other words, only 1.5% of Chad's population benefits from electricity. This electricity density rate is on of the lowest in the world.[43]

Republic of Congo – SNE

The power infrastructure was severely damaged during the conflicts which ended in 2003. Prior to the conflict there was transmission at 225 kV and 110 kV. Distribution was at 35 kV. There is a 225 kV transmission interconnection with DRC. CAPP have plans to connect the Republic of Congo with the Democratic Republic of Congo and Gabon. The length information provided by the World Bank from their 1996 source has been used in the tables as it is likely the system will be being reconstructed.

Equatorial Guinea – SEGESA

There are two networks, one on the mainland and one on Bioko Island, which are likely to be at distribution voltage level. There is no interconnection to other countries. CAPP have plans to connect Equatorial Guinea with Gabon and Cameroon. No information has been obtained about the electrical system, therefore the lengths of the distribution system and LV system have been estimated from other similar countries based on the distribution length / net consumption of the country.

Gabon – SEEG

Information about the transmission and distribution systems in Gabon has been obtained from the World Bank. There is transmission at 225 kV and distribution at 90 kV, 63 kV, 30 kV and 20 kV. There is no interconnection to other countries. CAPP have plans to interconnect Gabon with Cameroon, Equatorial Guinea and the Congo.

---

[43] World Bank: Chad—Critical Electricity and Water Services Rehabilitation Project. Report No. PID10962 February 25, 2002

EAPP – Nile Basin: Country-specific assumptions and unit costs

Group I – Eastern Africa/Nile Basin Country Utilities

There is very limited data and information on Eastern African utility networks on the public domain or from specific projects in the region, mainly because most of them have been privatized, with KPLC in Kenya being an exception. The only country with two levels of transmission voltages is Tanzania. This may be due to low load densities in most countries except Egypt.

Tanzania – TANESCO

TANESCO has two transmission voltages 220 kV and 132 kV, 66 kV at sub-transmission with 33 kV, 11 kV and 0.4 kV on the distribution system. Tanzania and Kenya have completed a feasibility study for linking Arusha to Nairobi by a 220 kV transmission line.

Group II – Eastern Africa/Nile Basin Country Utilities

Burundi – REGIDESO

There is only one voltage at each level in Burundi, transmission is at 110 kV and subtransmission is at 70 kV. Distribution is at 35 kV, 30 kV, 10 kV and 0.4 kV.

Burundi and Eastern DRC are connected at 110 kV.

Djibouti – EdD

In Djibouti there is only 5 km of 63 kV transmission lines and 245 km of distribution lines at 20 kV. There is a current project to connect Djibouti to Ethiopia at 230 kV.

Egypt – EGELEC

Egypt's utility EGELEC is the second largest in Africa after ESKOM, South Africa. The system has two transmission voltages 220 kV and 132 kV, sub-transmission is at 66 kV with 33 kV, 11 kV and 0.4 kV on the distribution system.

Egypt is connected to other countries through the 220 kV Libya-Tunisia interconnection which will soon be upgraded to 400 kV. Egypt is also connected to the Middle East through 500 kV/400 kV Egypt-Jordan interconnection and to the European electricity system through the Morocco-Spain interconnection.

Ethiopia – EEPCo

In EEPCo there is only one voltage at each level, transmission at 230 kV and subtransmission at 132 kV. Distribution is at 33 kV, 11 kV and 0.4 kV.

There are plans to interconnect:

- Ethiopia with Sudan by a 220 kV power line;
- Ethiopia with Djibouti with a 220 kV power line;
- Sudan with Egypt by linking Merowe hydropower station to the Aswan dam.

Kenya – KPLC

KPLC has one transmission voltage at 220 kV with subtransmission at 132 kV and 66 kV. Distribution is at 33 kV, 11 kV and 0.4 kV.

Kenya and Tanzania have completed a feasibility study for linking Nairobi to Arusha by a 220 kV transmission line.

Rwanda – ELECTROGAZ

In Rwanda there is only one voltage at each level, transmission is at 110 kV and subtransmission is at 70 kV. Distribution is at 15 kV, 6.6 kV and 0.4 kV.

Rwanda and Uganda are connected at the level of border towns in 30 kV, and there are plans to link the two countries by a 132/110 kV the transmission line.

Sudan – NEC

In NEC there is only one voltage at each level, transmission is at 220 kV and subtransmission is at 110 kV. Distribution is at 66 kV, and 33 kV, 11 kV and 0.4 kV. There seems to be no interconnection with neighbouring countries.

Uganda – UMEME

In UETCL &UMEME (the Ugandan Transmission and Distribution Company, respectively) there is only one voltage at each level, transmission at 132 kV and subtransmission at 66 kV. Distribution is at 33 kV, 11 kV and 0.4 kV. There is an interconnection with Kenya at 132 kV and Rwanda at 30 kV which provide adhoc cross border supplies.

SAPP: Country-specific assumptions and unit costs

This section deals with country specific data because of different voltages and transformation configuration at transmission and subtransmission level within the countries. The costs of distribution investments tend to be less installation specific and more generic than is the case for transmission investments. Distribution investments are influenced by the choice of primary distribution voltage levels to a degree, and in the SAPP countries the voltages are fairly standard

Group I – SAPP Country Utilities

South Africa – ESKOM

ESKOM is by far the largest utility by asset base in every category of the system as well as having a very complex system with numerous voltage levels and transformation, which includes 765(DC), 400, 275, 220, 132, 88, 33, 22, 11 and 0.4 kV.

From the available data and some knowledge of the system, it was assumed that the transmission voltages would be 400 kV, 275 kV and subtransmission, 132 kV and 88 kV, with distribution at 33 kV and 11 kV with 0.4 kV low voltages. Any line lengths at intermediate voltage (220 kV and 66 kV) are considered at the higher voltages in the estimates.

The data and information available did not include the large number of Regional Electricity Distribution Companies including the municipalities.

Democratic Republic of Congo – SNEL

There are numerous voltage levels and transformation configuration for the SNEL network which include at transmission, 220 kV and 132 kV, at subtransmission, 110 kV, 70 kV, 50 kV, and 15 kV. Distribution is at 11 kV, 6.6 kV and 0.4kV. With the data and information available it was assumed that the transformation will be 220, 70, 15, and 6.6 down to 0.4 kV. The 70 kV and 15 kV equipment and line cost were approximated to 66 kV and 11 kV respectively.

Mozambique – EDM

EDM has numerous voltage levels and transformation configuration for the network which included 400, 275, 330, 220, 110, 60, 33, 22, 11 6.6 and 5.5 kV. Some of the voltage levels are mainly for interconnection with other countries. There are two main transmission voltages, 220 kV and 110 kV, as well as 66 kV on the subtransmission and 33 kV, 11 kV and 0.4 kV on the distribution system. There are some 22, 6.6 and 5.5 kV network but the total line lengths are not significant.

Namibia – NAMPOWER

Nampower has two transmission voltages, 220 kV and 132 kV, subtransmission at 66 kV with 33kV, 22kV, 11 kV and 0.4 kV on the distribution system. Interconnection with ESKOM is at 400 kV and there is an odd 330 kV line. At distribution level there are various configurations, the data available indicated that 66 kV was a subtransmission voltage with significant lines and substations at 33 and 22 kV lines and for this study the higher voltage was used for the estimates.

Zambia – ZESCO

ZESCO has two transmission and subtransmission voltages 330 kV and 220 kV, 88 kV and 66 kV, with 33 kV, 11 kV and 0.4 kV on the distribution system. There are a few kilometres of line at 132 kV and this was not considered significant for the study.

Group II – SAPP Country Utilities

Botswana – BPC

BPC has one transmission voltage of 220kV and subtransmission at 132 kV and 66 kV, with 33 kV, 11 kV and 0.4 kV on the distribution system. There are some 22 kV cross border supplies with ESKOM but these are very short lines no more than 5km per connection.

Lesotho – LEC

There is only one voltage at transmission level of 132 kV, and subtransmission level of 66 kV. Distribution is at 33 kV, 11 kV and 0.4 kV. There are a few kilometres of line at 88 kV.

Malawi – ESCOM

There is only one voltage at each level transmission 132 kV, subtransmission 66 kV, and distribution at 33 kV, 11 kV and 0.4 kV.

Zimbabwe – ZESA

From knowledge of the system, ZESA has only 330 kV as the transmission voltage with subtransmission at 132 and 88 kV. There are some lines at 66 kV but the total line length is not significant. Distribution is at 33 kV and 11 kV with the low voltage at 0.4 kV.

WAPP: Country-specific assumptions and unit costs

Group I – Western Africa Country Utilities

There is very limited data and information on Western African Utility networks in the public domain or from specific projects in the region, mainly because most of them have been privatized. There are no countries in WAPP with two levels of transmission voltages. This may be due to low load densities in most countries except Nigeria, Ghana and Cote d'Ivoire. Generally the countries are small or they are on the fringes of the Sahara desert with sparse population.

Group II – Western Africa Country Utilities

All the countries in WAPP are Group II countries operating at different voltage levels.[44] There is an interconnector from Nigeria, Benin, Togo at 161 kV, this continues into Ghana and Cote d'Ivoire at 225 kV. There is a separate 225 kV interconnector from Cote d'Ivoire to Mali and Burkina Faso, from Mali the interconnector goes to Senegal.

Benin – CEB

In CEB there is one voltage at each level, transmission at 161 kV and subtransmission at 63 kV. Distribution is at 20 kV, 15 kV and 0.4 kV. There is an interconnection with Nigeria and Togo at 161 kV.

Burkina Faso – SNEB

Burkina Faso is interconnected with Cote d'Ivoire at 225 kV, transmission is at 132 kV and 90 kV. Distribution is at 15 kV.

Cote d'Ivoire – CIE

In CIE there is one voltage at each level, transmission at 225 kV and subtransmission at 90 kV. Distribution is at 33 kV, 11 kV and 0.4 kV. There is an interconnection with Ghana (VRA) and Burkina Faso at 225 kV.

Gambia – NAWEC

The Gambia does not have a transmission network. Distribution is at 33 kV, 11 kV and 0.38 kV. The OMVG interconnector project is planned for 2004–2011 and will connect The Gambia to Senegal at 225 kV.

[44] West Africa Regional Master Plan – Report June 2004

Ghana – VRA & EGC

In VRA & EGC there is one voltage at each level, transmission is at 161 kV and subtransmission is at 69 kV. Distribution is at 33 kV, 11 kV and 0.4 kV. There is an interconnection to Togo at 161 kV and at 225 kV with Cote d'Ivoire.

Guinea – EDG

Transmission in Guinea is at 110 kV with some Sub-transmission at 66 kV. Distribution is at 33 kV, 20 kV and 11 kV. Guinea is not presently interconnected, however the OMVG interconnector project is planned for 2004–2011 and will connect Guinea to Guinea-Bissau at 225 kV. There is also a planned interconnection as part of the LSG program to connect Guinea to Sierra Leone after 2011.

Guinea-Bissau – Electricitie et Aguas

Guinea-Bissau does not have a transmission network. Distribution is at 30 kV, 10 kV, 6 kV and 0.38 kV. Guinea-Bissau is not presently interconnected, however the OMVG interconnector project is planned for 2004–2011 and will connect Guinea-Bissau to Guinea and Senegal at 225 kV. Information about the lengths of the 30 kV and 10 kV systems have been provided by the World Bank.

Liberia – LEC

Liberia lost a large part of its electricity generation, transmission and distribution systems in the recent civil war. Prior to the war there was 69 kV subtransmission and 12.6 kV distribution. The system was 60 Hz, but has been converted to 50 Hz during the re-construction. The LSG program is planning the connection of Liberia to Sierra Leone and Cote d'Ivoire (East) after 2011. The lengths of the distribution system and LV system have been estimated from other similar countries based on the distribution length / net consumption of the country.

Mali – EDM

In Mali there is one voltage at each level, transmission at 161 kV and subtransmission at 63 kV. Distribution is at 20 kV, 15 and 0.4 kV. There is an interconnection with Nigeria and Togo at 225 kV.

Mauritania – SOMELEC

Mauritania is connected to Senegal at 225 kV as part of the OMVS project, there is a small amount of 90 kV system connecting generation in the south of the country. Distribution is at 33 kV, 15 kV and 0.4 kV.

Niger – NIGELEC

NIGELEC has 132 kV as the transmission voltage with subtransmission at 66 kV. Distribution is at 33 and 11 kV with the low voltage at 0.4 kV. NIGELEC has interconnections with NEPA at 132 kV.

Nigeria – NEPA

NEPA has 330 kV as the transmission voltage with subtransmission at 132 and 66 kV. Distribution is at 33 and 11 kV with the low voltage at 0.4 kV. NEPA has interconnections with NIGELEC at 132 kV and with Benin (CEB) at 161 kV.

Senegal – SENELEC

In Senegal there is only one voltage at each level, transmission is at 225 kV and subtransmission is at 90 kV. Distribution is at 30 kV, 6.6 kV and 0.4 kV. There is an interconnection with Mali at 225 kV.

Sierra Leone – NPA

Sierra Leone has some 161 kV transmission lines. Distribution is at 66 kV, 33 kV, 11 kV, 3.3 kV and 0.4 kV. There is presently no interconnection to other countries, however the LSG program is planning the connection of Sierra Leone to Liberia and Guinea after 2011. Information about the length of the transmission system was obtained from the World Bank. The lengths of the distribution system and LV system have been estimated from other similar countries based on the distribution length / net consumption of the country.

Togo – CEET

In Togo there is one voltage at each level, transmission at 161 kV and subtransmission at 63 kV. Distribution is at 20 kV, 15 kV and 0.4 kV. There is interconnection with Benin and Ghana at 161 kV.

Island states: Country-specific assumptions and unit costs

Cape Verde – ELECTRA

Cape Verde is a collection of islands in the Atlantic Ocean west of Senegal. Information from the World Bank suggests there is a small amount of transmission system on the islands; this has been assumed to be 110 kV. Distribution is a mix of 20 kV, 15 kV, 13 kV, 6.6 kV, 6 kV and 0.38 kV. For the purposes of this analysis estimates have been made for 20 kV and 6.6 kV based on the application of typical ratios of distribution length to net consumption from other countries.

Madagascar – LA JIRAMA

The network has one voltage at the transmission and subtransmission level, 138 kV and 63 kV respectively, but at the distribution level there is 35, 20, 15 6.6 and 0.4 kV.

Mauritius – CEB

Mauritius has a transmission system at 132 kV and sub-transmission at 66 kV. Distribution is at 22 kV and 6.6 kV. There are no interconnections.

Unit investment costs outputs and analysis

The analysis has been split into the three distinct regions to differentiate between the type of terrain and climate. Another major aspect is the availability of materials and High Voltage contractors within the country. It was assumed that because of the volumes of work on the distribution systems and judging from the knowledge available for SAPP utilities, distribution work could be done in-house or by local contractors.

Analysis of transmission unit costs

SAPP countries

Country unit investment costs indicate that by investing at the higher voltage, the unit investment costs are cheaper per MW of power transfer. Countries with similar voltages have comparable unit costs, the determining factor being the line rating.

Except for ESKOM, investing at a lower voltage is more costly because of the lower ratings. This is the expected result because the structural and construction costs are not significantly reduced for the lower voltage and single conductor line construction.

For ESKOM the line ratings for the lower voltage are significantly higher than those of other utilities due to enhanced design standards and this leads to almost the same unit costs for both voltages per MW of power transferred.

For all countries except South Africa it is highly likely that foreign contractors will be awarded the construction of the lines because of lack of local expertise and construction equipment. This together with the higher cost of materials results in the unit investment cost for ZESA and ZESCO at 330 kV being higher than unit costs for ESKOM 275 kV lines. Further, ESKOM has an added advantage that most materials are locally manufactured at prices which are competitive compared with the international market; this, coupled with an abundance of local contractors for construction, tends to significantly reduce the costs.

Central and Western Africa countries

The unit costs follow the same pattern as described for SAPP and with no detailed data and information on the utilities, it was impossible to cite specific issues that would differentiate the individual utilities or compare with other regions. There is no knowledge of the existence of local manufacture of materials and neither equipment nor High Voltage construction contractors.

The region has also very varied climatic conditions and terrain ranging from a rain forest and coastal countries (Cameroon and Nigeria) to arid desert (Mali and Chad).

Eastern Africa – Nile Basin countries

As highlighted for CAPP and WAPP countries, the unit costs follow the same pattern as described for SAPP. There is the same problem of no detailed data and information on the EAPP utilities. This made it impracticable to cite specific issues that would differentiate unit costs for the individual utilities or compare with other regions. There is also no knowledge of the existence of local manufacture of materials and neither equipment nor High Voltage construction contractors. The region also has very varied climatic conditions and terrain ranging from high rainfall region (Uganda and Rwanda) to arid desert (Sudan and Egypt).

Analysis of distribution unit costs

As highlighted before, the costs of distribution investments tend to be less installation specific and more generic than is the case for transmission networks; they are influenced by the choice of primary distribution voltage levels to a degree, and in the SAPP countries the voltages are fairly standard.

The major differentiating cost parameters associated with these standardized systems arise from whether networks are predominantly urban cabled systems, or whether they are largely rural systems utilizing overhead distribution lines. Urban networks are generally characterized by shorter distribution distances and higher costs per km of reticulation as compared with rural systems.

Distribution network investment cost estimates can be derived from generic system models which are designed to deliver standardized quanta of load using network and equipment configurations which ensure appropriate levels of supply reliability, taking account of standard equipment ratings and circuit configurations. In the absence of specific data for many of the countries it is considered accurate enough for the purpose of this study to assume standard distribution costs for all the countries by extrapolating from the countries for which data is available. However, the distribution costs for South Africa will be slightly lower because of the advantage of some materials being manufactured locally. The margin will not be significant because the other countries have local supplies of poles, labor and other materials which are a major cost component for distribution systems.

Refurbishment of existing structures

Infrastructure life spans

Infrastructure components have a life span ranging from approximately 10 years for mechanical metering (for electronic metering ~5 years) to 50 years for cables and transformers. The long life spans can render equipment obsolete before the end of its life due to changes in technology resulting in the non availability of spare parts.

A benchmark planning average of 30 years has been used in this study as the life span which the transmission and distribution infrastructure can be refurbished to full functionality or extend the life by another equal number of years.

The nature of refurbishment work is such that it normally requires the replacement and repair of transmission towers, the reconductoring of lines or the replacement of transformers and switchgear. The costs of carrying out these activities can be estimated as a percentage of the full installed costs of modern equivalent assets.

From operating experience in the region, economic refurbishment of the infrastructure cost is normally limited not to exceed 60% of the replacement cost. If the refurbishment cost exceeds 60%, the usual recommendation is to replace with either like for like equipment or with new technology with enhanced features.

Transmission and distribution infrastructure age data

A fair amount of data regarding the age of the infrastructure was available for the transmission system for all the countries, which was used for estimating the refurbishment costs. The amount of equipment that would reach the limit of 30 years within the planning horizon to 2015 was estimated and used for the study. For distribution there was very little infrastructure age data, except for Namibia which was available from a project undertaken by the Consultant.

Refurbishment factors

The major influences on whether transmission infrastructure needs to be refurbished are associated with:

- the age of the infrastructure;
- the rate of deterioration of the assets,
- due to normal wear and tear;
- due to the effects of a particularly harsh operating environment (e.g. a coastal location or high levels of pollution); or
- due to the operating and maintenance regime to which equipment has been exposed, e.g. frequent overloading due to rapid demand growth not being matched by adequate network investment, or the requirement to keep equipment in service in cases where continuity of supply is deemed to be more important than the need for preventative maintenance; and
- the possible need for asset replacement with equipment of higher capacity, recognizing the effects of demand growth on issues such as energy losses or the need for expanded substation capacity within the constraints of existing sites.

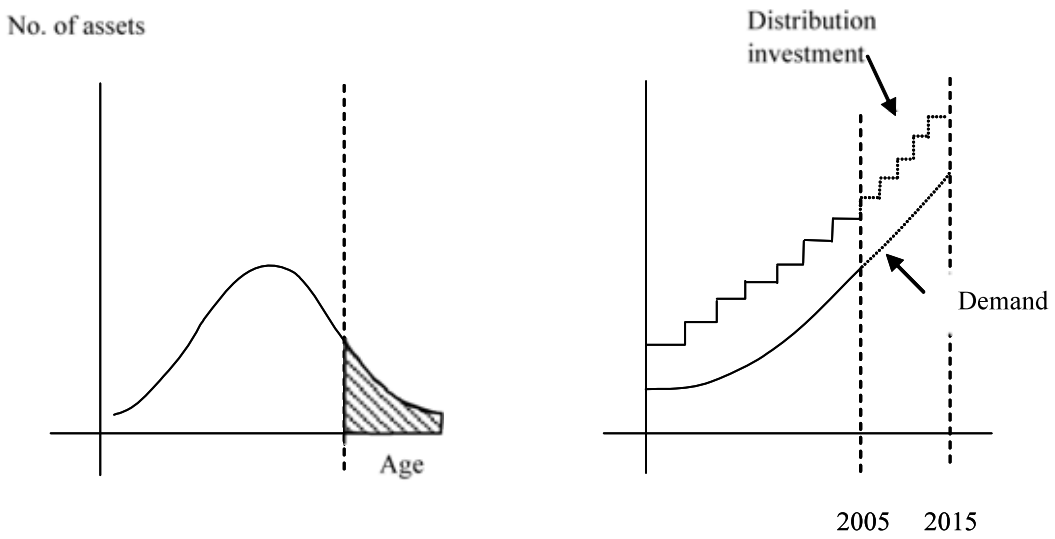
Distribution

In order to assess the costs of distribution refurbishment, similar considerations apply to those described above for transmission. Distribution refurbishment costs are less dependent on the costs of specific projects, however, and can be assessed on a broader basis. There are two key options available, depending on the quality of the data which can be obtained from the utilities:

- analysis can be performed with reference to the asset register for the distribution network, in order to identify the proportion of assets that are over a given age and which are therefore likely to require refurbishment over the next ten years, see figure below, or
- analysis can be undertaken with reference to the overall levels of distribution capacity utilization and investment that can be projected for the future, extrapolating from historical records of investment against demand growth, see figure below.

Figure A4.6 Optional approaches to distribution refurbishment evaluation

(a) Typical asset age profile (b) Typical profiles of demand growth and distribution system investment



The choice between these approaches is entirely dependent on the extent to which accurate information about the asset bases of the utilities is available. Neither method could be used for the systems under consideration, however, as there was no historical data on demand growth or age profiles for any of the countries except Namibia.

The age data of the transmission system was therefore used to estimate the age of the distribution data. Transmission investments are normally lumped to cover a 5% demand growth over a twenty year horizon. With the growth in demand, there will be more investments in distribution infrastructure lagging the original transmission investment over the planning horizon.

This result in a lower percentage of distribution equipment requiring refurbishment within the same planning horizon compared to transmission equipment. With the available transmission data and specific data for Namibia, the percentage equipment that would require refurbishment was estimated. The percentage will be slightly higher than reality because due to economic problems, forecast average load growth has not always been achieved. Further, investments in most of these countries are financed from loans which make the investments very discreet.

Maintenance of existing and new infrastructure

Overall approach

The derivation of maintenance costs per km for transmission and distribution network assets is approached by allowances for maintenance as a percentage of the capital cost of new lines and substation equipment. This is normal practice for the purposes of assessing future network investment needs.

A figure of 2% of the investment cost/km line is generally used for planning and this is the same level of O&M expenditure which are allowed for by the SAPP member utilities in planning transmission

system investments. However, to be conservative we will in the least cost expansion model use 5% of asset value, which is the same percentage that will be used at the distribution level.

It was considered unnecessary to differentiate rates which are used for operating and maintaining equipment in harsh environments or in terrain where access is difficult because an average percentage cost has been used. Further for unit investment costs for new equipment it was considered not necessary to differentiate costs depending on the environment or accessibility.

At the distribution level, there is much more activity because due to the nature of the distribution system and lack of automation there is more human interaction than for transmission systems. For distribution systems the rule of thumb is to estimate operations and maintenance costs to, on average, 5% of the investment cost/km line. Since this is an average cost for maintenance it is not necessary to distinguish between the maintenance costs of overhead lines that are close to the coast (and therefore subject to corrosion problems), and other lines. It will not be necessary to differentiate levels of maintenance cost/km across a broad range of line sizes and types since it is an average cost.

Conclusion

It can be concluded that the utilities that have been considered so far, excluding ESKOM, are highly likely to invest in transmission lines at their higher voltage which has a lower unit investment cost. For a particular transmission voltage the line rating can vary between countries, however, the spread of unit costs per MW is small and hence an average can be taken to derive a generic cost per MW for use where data is sparse.

The data and costs available do not indicate an adverse cost implication on terrain and accessibility in the different countries; however, this could have become clearer if the country utilities had provided the requested information.

For refurbishment, a rule of thumb of not exceeding 60% of the replacement cost is used in the study for transmission and distribution infrastructure. For operations and maintenance, the average cost for transmission and distribution is 5% of the cost/km of unit investment. Finally the assumptions, approximation and methodology adopted in the study yielded the desired outputs which are accurate enough for use to determine the investment needs given that there was very scant data for the infrastructure of the countries.

Appendix 4 Comparison of Econ Pöyry cost estimates with those of Nexant study

Here we compare our findings for the SAPP to those of a regional generation and transmission expansion plan drawn up by Nexant[45] that assesses power sector investment requirements in SAPP for the period 2006–25.[46]

There are two fundamental differences between Nexant's and Econ Pöyry's analyses: methodological approach and scope of the costs included. In addition, assumptions about fuel prices, unit cost of investments, demand growth etc. are crucial to the numerical analyses and are therefore potential sources for divergent results. Here we compare the results along broad lines.

Different methodologies: generic least cost model vs. costs related to existing plans

Nexant's analysis takes the existing generation expansion plans as a starting point and calculates the costs of specific transmission reinforcements that are needed to support the anticipated levels of trading. The Base Case is based on the existing generation and transmission plans for each of the 12 SAPP utilities. The generation plans are generally based on an assumption of moderate trade or self-sufficiency.

Econ Pöyry's least cost expansion model takes a more generic approach by estimating the costs of meeting a certain level of demand from the cheapest sources in the whole SAPP region. In other words, there is no requirement of national self-sufficiency.

An implication of the different methodological approach is that the two studies estimate the costs of different investment volumes. Nexant's study includes 93 projects or generic technologies. Many of the projects are also included in our analysis.[47] However, in our least cost approach, existing plans for generation capacity expansion are included as *potential* investments, among which the model chooses the least cost solution. Plants where the construction has already started or where the investment decision has been made are included as exogenous investment. Projects that are characterized as "very close to financial closure" are included as potentials: based on experience, projects can stay at this stage for a long time. Hence, Econ Pöyry's least cost approach enables an assessment and comparison of economic profitability of different projects.

Differences in the treatment of trade

Nexant compares two cases:

---

[45] Nexant (2007): "SAPP Regional Generation and Transmission Expansion Plan Study." October

[46] Nexant's study includes Tanzania, while Tanzania is included in EAPP in Econ Pöyry's analysis.

[47] However, since our study of SAPP was completed before Nexant's report was published in October 2007, we were not able to use inputs from the report in our work.

- A *base case* based on the existing generation and transmission plans for each of the 12 SAPP utilities. This scenario has a national focus, with most TSOs trying to cover domestic demand from domestic generation sources.
- An *alternative case* that considers various scenarios for the optimization of generation and transmission capacity additions assuming free trade, no constraints on the expansion of the interconnecting lines, and removal of the constraints within the utilities internal networks.

Therefore, Nexant's alternative case is methodologically more comparable to Econ Pöyry's study, while its base case is more comparable to our *trade stagnation* scenario. It should be noted, however, that Econ Pöyry's *trade stagnation* scenario limits the development of new international transmission lines, but trade within the limits of existing transmission capacity is allowed. Hence, the *trade stagnation* scenario does not take national self-sufficiency as its starting point (as in Nexant's base case), but allows for exploiting the cheapest resources in the region within the limits set by existing transmission lines. In some cases, the trade flows in the opposite direction compared to today's trade flows. Therefore, the resulting trade flows in the *trade stagnation* scenario do not necessarily coincide with the anticipated trade flows or levels in Nexant's base case.

Different scope: transmission, distribution and connection costs

The focus of Nexant's study is on transmission reinforcements that are required to accommodate the anticipated trade levels. The transmission costs appear to be a small portion of total expansion costs, "Transmission interconnection costs are a very small component of overall system costs, indicating that utility expansion plans are mostly based on self sufficiency requiring few new transmission interconnection lines" (p. 2-2 of Executive Summary).

Lower-level (e.g., distribution) grid costs are not included in Nexant's study, as far as we can see. These lower-level grid costs make up a substantial part of the estimated system expansion costs in Econ Pöyry's analysis. Grid costs include O&M costs during the ten-year period, investments in distribution grid that are necessary to meet demand growth due to economic growth and increased electricity access due to new connections. Finally, grid costs also include transmission grid expansion.

Since Econ Pöyry's analysis includes many additional and large grid costs that Nexant does not include, total grid costs in the Econ study make up a large share of total expansion cost. This is in contrast to the small share claimed by Nexant.

Comparison of results

Generation costs

Nexant's *base case* estimates the overnight investment costs in generation to be 25.9 billion USD during the 10-year period of 2006–2015. In the *alternative case*, the overnight generation investment costs are only 13.7 billion, indicating a more efficient exploitation of the region's resources.

Econ Pöyry's cost estimate is higher: 32 billion by 2015 (*Trade expansion with national targets for electricity access*). In addition, 7.5 billion are required for refurbishment of the existing plants. It is unclear whether the refurbishment requirement is taken into account in Nexant's analysis.

The following differences in assumptions explain the diverging cost estimates.

Demand. This large difference in cost estimates is largely explained by different investment volume: 21,600 MW are invested in Nexant's base case and 19,000 MW in the alternative case, while 33,300 MW are added in Econ Pöyry's analysis.

This difference in investment requirements is partly due to different assumptions about demand:

- Nexant (gross demand?): 386 TWh (includes Tanzania, ca. 5 TWh)
- Econ Pöyry's gross demand: 438.9 TWh, net demand 396 TWh (without Tanzania)

Our demand assumptions take into account demand growth due to economic growth and social demand (increased electricity access). In addition, the suppressed demand is assumed eliminated. Admittedly the targets for increased electricity access are quite ambitious. We haven't examined the reasoning behind the Nexant estimate.

Unit cost assumptions. As Nexant's study is based on existing plans, obtained from project developers, it is possible that the unit costs of investments are more precise than Econ Pöyry's assumptions (that are based both on actual project costs where available and on generic costs of different technologies). Cost estimates can differ due to different assumptions about discount rate and life-time of different assets.

It is worth noting that Econ Pöyry's investment cost figures include costs related to off-grid technologies as well (associated with increased electricity access in remote areas), which are quite expensive.

Fuel costs. Econ Pöyry's variable production costs (fuel and O&M) are higher in total. This is an obvious result, given the higher demand. Another source of difference may be assumptions about fuel costs. We haven't examined which fuel (coal and natural gas) costs are assumed in the Nexant's study. Econ finds, however, that there are large savings of variable costs with trade: the fuel and O&M costs are almost 20 percent lower in trade expansion scenario. In contrast, Nexant estimates these cost savings to be less than 4 percent. A possible explanation is that Econ Pöyry's analysis finds greater switch from thermal into hydro, which in turn is related to the factors mentioned above: different attitude to exogenous investment and different interpretation of what is meant by trade expansion.

Network costs: transmission and distribution

The big difference in the results is, however, in the costs of network expansion. As explained above, this is due to different scope of the costs included in the analysis: Distribution costs are omitted in Nexant's analysis.

Comparing the transmission costs only, the results are quite similar: the *alternative case* transmission investments are almost 4 billion. The comparable figure in Econ Pöyry's analysis (investments in cross-

border grid) is slightly more than 3 billion. In Nexant's *base case* the transmission investment costs are very low (due to focus on self-sufficiency). This is similar to Econ Pöyry's *Trade stagnation* scenario.

It is reasonable to assume that Nexant's study is based on more detailed information about specific transmission lines and reinforcement needs; hence, their estimates may be more accurate for some connections.