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The Economics of Renewable Energy Expansion in Rural Sub-Saharan Africa

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Abstract

Accelerating development in Sub-Saharan Africa will require massive expansion of access to electricity—currently reaching only about one-third of households. This paper explores how essential economic development might be reconciled with the need to keep carbon emissions in check. The authors develop a geographically explicit framework and use spatial modeling and cost estimates from recent engineering studies to determine where stand-alone renewable energy generation is a cost effective alternative to centralized grid supply. The results suggest that decentralized renewable energy will likely play an important role in expanding rural energy access. But it will be the lowest cost option for a minority of households in Africa, even when likely cost reductions over the next 20 years are considered. Decentralized renewables are competitive mostly in remote and rural areas, while grid connected supply dominates denser areas where the majority of households reside. These findings underscore the need to de-carbonize the fuel mix for centralized power generation as it expands in Africa.

This paper—a product of the Environment and Energy Team, Development Research Group—is part of a larger effort in the department to assess options for cleaner energy in developing countries and overcoming barriers to their adoption and sustainability. Policy Research Working Papers are also posted on the Web at http://econ.worldbank.org. The authors may be contacted at udeichmann@worldbank.org, cmeisner@worldbank.org, smurray@worldbank.org and dwheeler@cgdev.org.

The Economics of Renewable Energy Expansion in Rural Sub-Saharan Africa*

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1. Introduction

Lack of access to affordable electricity is a major determinant of poverty in Sub-Saharan Africa (SSA). Urban populations remain underserved by inefficient, unreliable systems, while many rural villagers have no access to electricity except for power provided to relatively affluent households by small, privately-owned generators. In this context, local renewable energy sources have strong appeal for two major reasons.

First, as Table 1 shows, most SSA countries have renewable energy potential, technologically feasible to exploit with current technology, that is many times their current energy consumption. In Namibia, which has the highest multiple, annual potential production from solar, wind, hydro, geothermal, and biofuels is about 100 times current energy consumption under realistic assumptions regarding technically feasible expansion potential. Senegal, Sierra Leone and Benin are near the median for SSA, with 10-12 times current consumption. Even South Africa, by far the most heavily-industrialized country in the region, has renewable potential that is 1.3 times current consumption (and this does not include the vast solar potential of Botswana, with a ratio of 22, which is already connected to the South African grid).

Second, we are moving into an era when zero- or low-carbon renewable energy will command a market premium based on its ability to reduce global greenhouse gas emissions (GHGs) by replacing fossil fuels. This premium may be realized directly, for example through imposition of carbon taxes on fossil energy sources in developed countries, or indirectly, through payments for "offset" emissions due to substitution of renewable for fossil fuel as implemented in the Clean Development Mechanism (CDM) within the UN's Kyoto Protocol for GHG control.

While SSA's technical potential for renewable energy is very large, the ability and willingness to pay remain critical factors for both expanded centralized service and decentralized service provision in a region where centralized services have remained

grossly inadequate. The recent history of telephone services shows how quickly decentralized services can develop in SSA under the right conditions. From 1960 to 2000, telephone landlines grew so slowly (3.2% per year) that coverage in 2000 was limited to 1.4 lines per 100 inhabitants. In contrast, mobile phone connections grew so quickly after 1993 (55% per year) that coverage had reached 22.5 per 100 inhabitants by 2007 (Figure 1).[1] The rapid expansion of mobile phones has made telephone service affordable for many poor households, through a variety of local expense-sharing arrangements.

In this paper, we assess the feasibility of a similar expansion of decentralized energy services in Sub-Saharan Africa. Using Ethiopia, Ghana and Kenya as case studies[2], we ask where decentralized service appears currently to be lower-cost than centralized network provision, and how this could be altered by likely changes in technologies and fossil energy prices. Our assessment employs a spatially-disaggregated model that estimates the comparative costs of network and decentralized electricity provision across each country. Among the decentralized power options, we focus particularly on renewable technologies such as solar, wind and biodiesel.

The remainder of the paper is organized as follows. Section 2 briefly reviews the rural electricity supply problem in Africa. In Section 3, we describe the energy options to be considered and the model we use to explore those options. Section 4 presents our comparative estimates for network and decentralized electricity provision under current and possible future conditions. Section 5 provides a summary and discusses the implications of our results.

[1] For comparison: Telephone landline coverage per 100 inhabitants is 40 in high-income countries, 22 in the East Asia-Pacific region, 17 in Latin America and the Caribbean (LAC) and 3.2 in South Asia (SAS). Mobile phone coverage per 100 inhabitants is 85 in high-income countries, 65 in LAC and 23.7 in SAS.
[2] We chose these three countries because high resolution data on renewable power potential (solar and wind) are available from SWERA (2001 and 2004). Renewable energy potential in these countries has long been recognized (see e.g., Edjekumhene et al. 2001). The analysis could be extended to other African countries using available data at somewhat lower spatial resolution.

2. Rural Energy Expansion and Economic Development in Sub-Saharan Africa

Figure 2 shows that Sub-Saharan Africa ranks last among global regions in energy consumption per capita when South Africa is excluded. Figure 3 and Table 2 document access to electricity for urban and rural households during 2003-2007 in three developing regions (DHS, 2009): Latin America and the Caribbean (LAC), South and Southeast Asia (SSEA), and Sub-Saharan Africa (SSA). The urban and rural distributions for SSA are so low that they hardly overlap with those of LAC and SSEA. Median rural access is 3% in SSA, 62.5% in LAC and 55.7% in SSEA. Among SSA countries the maximum rural access, 33.8%, is barely higher than first-quartile access in the other two developing regions.

The available evidence suggests that closing this gap would significantly reduce rural poverty in Africa. The World Bank (1996) has documented the economic and health benefits of switching from biomass fuels to electricity. According to another World Bank report (2001), "Efficient and clean energy supply is central to the reduction of poverty through many and varied linkages, as well as being important for economic growth." Barnes (2007) and World Bank (2008a) cite several of these linkages, while noting that supporting evidence remains largely anecdotal. Case studies from India highlight income generation potential for women, for example, thanks to nighttime lighting and sewing machines (Hiremath et al. 2009). One recent empirical study by Khandker et al. (2009) estimates income gains from electrification in rural Bangladesh between 9 percent and 30 percent. Small businesses, which rely heavily on family labor, can increase their production hours once electricity becomes available. Electricity access improves health by facilitating longer hours for clinics, and a strengthened cold chain for vaccines. Education levels improve, as electric lighting extends study hours. While empirical evidence from Africa on social benefits remains limited, there is no doubt that the private returns to rural electrification are substantial. Most households that can afford electricity become subscribers as soon as the service becomes available. Highly-valued private benefits include improved lighting and the ability to watch television.

The least-cost mix of centralized and decentralized power will depend on the cost of grid distribution, which is conditioned by geography (Parshall et al. 2009), and on the

relative costs of locally available energy sources. In the near future, these may be strongly affected by international measures to reduce carbon emissions, including international markets for carbon or low-carbon-energy credits and/or carbon taxes. In this paper we simplify the analysis by modeling the premium value for low-carbon energy as being determined by a hypothetical carbon tax applied to domestic fossil fuel uses. This is solely for analytical convenience rather than an endorsement of that policy instrument.[3]

Solar energy is a particularly-attractive renewable option for Africa because it is naturally decentralized, available in huge supply, falling steadily in cost as the technology advances, immune from supply or price uncertainty, and eligible for support from bilateral and multilateral institutions that are seeking to increase low-carbon energy production. As Figure 4 shows, Sub-Saharan Africa is richly-endowed with solar energy resources suitable for photovoltaic solar systems as well as for larger scale solar thermal facilities.[4]

Ultimately, as Figure 5 suggests, electrification is likely to be essential for eliminating rural poverty in Sub-Saharan Africa. The figure depicts the cross-country relationship between consumption of electricity (in kilowatt hours, kWh) and income per capita in 2000. When countries are divided into quintiles by energy use per capita, the highest income in each energy group is approximately equal to the median income in the next-higher group. This is not a one-way causal relationship, since demand for electric service is highly income-elastic. In addition, countries at the same level of development differ considerably in their efficiency of energy use. Nevertheless, it seems entirely plausible to assert that weak energy infrastructure imposes a fundamental constraint on African development (Ramachandran, Gelb and Shah, 2009).

[3] Payment from outside the country for carbon credits created by using renewables beyond "business as usual" essentially function as a kind of rebate for the costs incurred in the renewable investment. The same relative technology costs arise with our approach, but the imposition of a hypothetical domestic carbon tax confronts end-users with higher electricity prices than under the carbon credits system, implying differences in total electricity demand.

[4] Most of the region has average annual direct normal irradiance (DNI) that meets or exceeds 5 kWh/m2/day, the critical minimum level for efficient provision of power from solar thermal facilities.

3. Estimating Energy Delivery Costs

We estimate the costs of universal power supply in a given country through grid-connected systems and compare them with costs of providing the same level of electricity supply with different decentralized options. We compare these options at each step of a hypothetical investment schedule that progressively adds supply areas until the entire population of a country is covered. For grid connected supply we estimate the cost of extending transmission and distribution to all populated parts of the country. We also assume a scaling up of power production with the current fuel mix. Among decentralized options we estimate the supply costs for fully decentralized power provision to currently unserved customers, in which each household generates its own electricity, and for minigrid systems that provide power to tens or hundreds of households in order to satisfy the unmet demand. We assess the use of both fossil fuels (diesel generators) and renewables (solar, wind, biodiesel) for decentralized options. Other decentralized options, such as small-scale hydro, look promising, but data on their potential are scarce and thus we were not able to include them.

In comparing the resulting cost estimates, our primary interest is in the following questions:

- Spatial partition: Where is the optimal geographic boundary between grid-connected and decentralized provision, and what are the relative population shares supplied by each mode?
- Scale economies: How does the optimal spatial boundary change as decentralized provision moves from completely decentralized micropower to minigrids with some scale economies, thus increasing the relative economic advantage of larger scale electricity provision with renewables?
- Future costs: How will the configuration of cost-effective energy supply options change in the future as technical change lowers the cost of renewable energy sources, or as premium values for clean technology change relative fuel prices?

We develop our model with case studies for Ethiopia, Ghana and Kenya. We primarily use Ethiopia to illustrate our approach and results. Cost comparisons for Ghana

and Kenya are included in tabular form. The results are broadly comparable, suggesting some degree of generalizability to other parts of Africa. After describing the estimation of household demand, we discuss estimation of the cost of a centralized grid system that provides complete service coverage to all urban and rural areas. Following that, we describe the cost estimates for stand-alone household-level and minigrid options that exploit locally available non-renewable or renewable energy. Then we compare the levelized costs of each technology to determine the lowest cost options in each geographic area.[5] The result is a spatially-explicit set of expansion paths that delineate frontiers between centralized and decentralized service areas. We then introduce technological change and carbon mitigation economics. We incorporate learning rates to assess future costs and estimate the carbon tax rates necessary to make non-renewables competitive with grid supplied electricity in each part of the country. In these scenarios, we do not consider population growth, which would force a scaling up of supply, but would be unlikely to change relative supply prices; especially since most population growth will likely occur in high density areas where grid connected options dominate.

3.1. Household Demand for Electricity

In accord with a recent engineering feasibility study for Kenya (KMOE 2008), we assume that each connected rural and urban household consumes a fixed quantity of electricity, 120 kWh/month or 4 kWh/day. This is somewhat higher than the combined household and productive demand assumed in Parshall et al. (2008) for all but the most densely populated non-poor areas. Obviously the assumption of fixed average demand across households is a simplification. For our purposes, we are interested more in the question of whether households are connected or not than marginal changes in demand.

[5] Levelized cost is the cost of supplying a unit of energy over a system's lifetime that incorporates the initial investment in generation, transmission and distribution infrastructure; capital costs; and operations and maintenance costs including fuel costs. Levelized costs allow us to compare different technologies on the basis of the minimum unit price a user must pay for each system to break even.

In our model, between about 700 (Ghana) and 1000 (Kenya) settlements with known or estimated population represent spatially distributed electricity demand points.[6] These settlements are modeled as nodes in a transmission and distribution grid. Residual rural populations are identified from high resolution population maps (ORNL 2008). The residual populations are allocated to the closest settlements using a simple Thiessen polygon approach. Assuming that the entire population lives in settlements will yield a lower bound estimate for grid distribution costs at the margin, but does not significantly influence stand-alone cost estimates. Dividing population assigned to each settlement by average household size yields the number of households. Multiplication by the targeted energy supply provides the estimate of total demand at each location.

Our model estimates the costs of providing electricity to all households in a country. This must be the ultimate goal in any country, but is clearly unrealistic in the short or even medium term in Sub-Saharan Africa. The average access rate across sub-national areas in a sample of African countries is 23 percent, with half of all areas below 11 percent (DHS 2009). Current operational or policy goals are relatively modest. In one scenario (UN-ENERGY/Africa, 2007), USD 4 billion invested annually in the energy sector will supply approximately half of African households with electricity by 2030.

3.2. The Economics of Network Expansion

Previous modeling of electricity networks by Bergey, et al. (2003 a,b) has considered the optimal partition of a national monopoly grid into competitive power districts. We extend this approach to include non-grid service options. Also related are the approaches to optimal planning in Hongwei, et al. (1996), who focus on the locations and sizes of power grid substations; and Klose and Drexl (2005), who review more general algorithms for locating facilities and allocating customers in product distribution systems. Most closely related to our work are a study by Parshall et al (2009) and a companion paper by Zvoleff et al. (2009). They propose a comprehensive engineering-

[6] Settlement locations are from the Global Insights Plus v.6.1 database (Europa Technologies; www.europa.uk.com).

planning approach to operational grid expansion modeling in developing countries that is similar to the one developed here. In contrast to their work, our main objective is to compare the cost of grid connected electricity supply with a suite of decentralized—and particularly renewable — options under current and possible future cost structures.

Figure 6 illustrates the three basic components of electric power systems: generation, transmission and distribution. Generation occurs at power plants, which can have widely-varying scales of operation. Transmission involves the transfer of high-voltage (HV) electricity from a power plant to a substation or bulk supply point (BSP; using the terminology in Bergey et al. 2003a), where power is stepped down to medium voltage (less than 50 kV). From there, electricity enters the distribution system through medium-voltage (MV) lines to commercial or other bulk users, and via medium-to-low-voltage transformers (< 1 kV, often pole-mounted) to households.

In high-income countries, the electricity grid typically extends to all but the most remote users. Within supply areas, coverage rates are close to 100 percent. In low-income countries, however, electricity grids are often limited to areas with the highest population densities. Even within grid service areas, coverage rates are frequently low.

The key element driving the comparative economics of network expansion is the lumpy nature of the investments required for generation and transmission. Once demand exceeds a certain threshold, a new generation facility and/or a new bulk supply point (essentially a high to medium voltage transformer) have to be added. As the system expands, it serves progressively-smaller settlements whose sizes tend to follow a highly-skewed Pareto distribution.[7] The marginal service cost schedule slopes upward, because new fixed investments are spread across progressively fewer consumers as the system expands. This provides the economic rationale for minigrid and stand-alone electricity provision in outlying settlements or households. As the centralized grid expands into more sparsely-populated areas, the marginal cost of network provision is likely to be higher than the marginal cost of decentralized provision at some point.

[7] This is the well-known rank-size distribution of cities (e.g., Gabaix and Ioannides, 2004).

A Network Expansion Algorithm

Our model of network construction generates a transmission and distribution grid step-by-step, mimicking the progressive roll-out of power sector investments. The basic algorithm starts with n demand points (e.g., villages, towns and cities) and k power generation plants. Each demand point is a potential site for one of m substations or bulk supply points (BSPs) on the HV transmission grid. The system operates under the condition m (BSPs) $\leq$ n (demand points). Once selected as a site, each BSP serves all unconnected demand points within a threshold distance that is determined by the typical range of a medium-voltage (MV) line (about 120 km).[8] Distribution within towns and cities then follows, via local transformers and low-voltage distribution lines.

The design of a transmission and distribution grid is essentially a network optimization problem in which the total length (and thus cost) of transmission links is minimized (Hongwei et al., 1996; Bergey et al., 2003; Parshall 2009). Our algorithm implements a variation of the minimum spanning tree (MST) problem solved using a variation of Prim's algorithm—a so-called "greedy algorithm" in that at each step the option with the highest immediate payoff is selected. In sequential network expansion, each selection of a BSP (with associated assignment of nearby demand points) can be viewed as an investment stage. The algorithm assigns the first BSP to the demand point with the largest aggregate demand within its reach and connects it to the closest power generator. All demand points (settlements) within the technically-feasible threshold distance are assigned to this BSP, again assuming an MST derived grid. In each subsequent step, an additional BSP is assigned to the next-largest uncovered demand point and connected to the nearest existing BSP or generation facility. The algorithm terminates when all demand points are assigned to a BSP.

We model grid expansion based on the distribution of existing power stations, but do not explicitly incorporate the existing distribution grid. Where geographically detailed information is available, its inclusion would be straightforward. This would simply make the choice of the first few investment steps unnecessary. These are in areas where a dense

[8] Medium voltage includes 11 and 33 kV lines.

population distribution favors grid expansion.[9] Inclusion would not change the evaluation of later investment stages, which are the focus of our study.

Cost Estimation for the Grid Expansion Model

At each step—after a new BSP and its associated demand points have been identified—we compute total system cost as the sum of costs for power generation, transmission and distribution (Table 3). Generation, transmission and distribution unit cost estimates are largely drawn from a recent power sector study for Kenya's Ministry of Energy (KMOE, 2008) and also from a World Bank technical study of small-scale technologies (ESMAP, 2007).

Generation costs at large power plants are assumed to be fixed and proportional to the current generation fuel mix (Table 4).[10] By assuming a constant generation mix we avoid the more complex issue of when to bring online new generators and focus more on the transmission and distribution aspects of investment decisions. We calculate capital, O&M and fuel costs per kW for each of the currently operating generation technologies and convert the total into a per kW unit cost.[11] After conversion to levelized costs we add these to levelized transmission and distribution costs.

Generators and BSPs are connected by HV transmission lines with length estimated as the shortest, most direct distance between them.[12] For the MV network estimate, we inflate straight-line distances between settlements by thirty percent. These lines often follow roads, which tend on average to deviate from the shortest route between two points by that amount, and they are often routed around obstacles such as lakes or protected areas. This adjustment also partly compensates for the fact that real-world MV transmission systems include non-optimal configurations and redundant links.

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[9] For instance, in Kenya, as of late 2007, approximately one million of eight million households were connected to the national grid, largely in the areas of the largest cities: Nairobi, Mombasa, Kisumu and Eldoret (Parshall et al. 2009).

[10] Note that only large (> 8MW) operational units are included in computing the current generation mix. Plants that are in the planning phases, deferred without construction starts or deactivated are not included in the calculation.

[11] In computing levelized costs we follow convention and apply a discount rate of 10 percent.

[12] High voltage includes 220 and 132 kV lines.

We calculate connection costs within settlements by applying unit costs from KMOE (2008) to the estimates of lengths for low-voltage distribution lines and the number of required MV-LV transformers. We develop these estimates for each settlement using an optimal grid configuration for the settlement's area. We estimate the latter from the settlement's population, using a constant-elasticity model of the area-population relationship that we have fitted to a sample of African towns and cities whose areas and populations are known.[13] Once we have accounted for all transmission and distribution investments, we convert them to levelized costs and add the relevant levelized power generation cost to obtain total levelized supply cost per kWh.

Illustration of the expansion algorithm

Figure 7 illustrates the application of our methodology to sequential construction of a centralized grid for Ethiopia. Figure 7a depicts the distribution of almost 1,000 settlements (dots) of known population size along with the locations of large power sources (blue rectangles). Figure 7b illustrates the operation of the algorithm. Under our assumption of a fixed demand per household, the algorithm creates the first bulk supply point (BSP) in the town with the largest total demand within the reach of a MV distribution system (120 km). It connects the BSP to the nearest generator with a HV line. Then it creates the second BSP in the town with the largest total demand in the remaining area. It connects the second BSP to the first BSP or a proximate power generator, whichever is closer. The process continues until all towns in Ethiopia are within BSP coverage zones. Then the algorithm extends medium-voltage (MV) lines along least-cost paths to connect each BSP to all the settlements within its coverage area (Figure 7c). The settlements connected to a given BSP form a supply area (Figure 7d).

[13] Using a cross-country dataset for population (P) and area (A), we estimate the relationship $A=aP^b$. We then use the estimated parameters to project areas from known populations for settlements (demand points) in the case study countries. We assume that towns are square, so that settlement width (W) is equal to the square root of estimated area. Low-voltage lines must be configured so that each household is no more than 48 meters from a line (KMOE 2008). So the required number of lines (N) is $W/(48 * 2)$, plus two additional lines for closing and cross-connection. Total transmission line length for a settlement is $N * W$.

Average versus marginal costs

Our objective is to develop a geographically detailed assessment of lowest cost energy supply options. Our model for estimating grid connected energy supply costs works in stages. It captures the highest density areas—the "lowest hanging fruit" —first, then expands to areas with sparser population distribution. We express costs for both grid-connected and decentralized options as levelized electricity costs.

Costs depend on the pool of beneficiaries who share the benefits. In our model, where each additional bulk-supply point is an investment step, we have two choices: In an *average cost* approach we treat the entire system—the already-built regional distribution systems plus the newly-added one—as a single unit and distribute the costs evenly over all beneficiaries. Since each additional stage covers fewer households, this means essentially that early beneficiaries who reap higher economies of scale subsidize later ones. An alternative is the *marginal cost* approach: Since each new BSP represents a discrete expansion step, it benefits only the new beneficiaries, while previously connected households do not depend on it. So the denominator for cost computations includes only the newly- connected households, while the numerator is the cost of the newly-added system components. For our model, the marginal cost approach is appropriate. At each step, a planner needs to decide whether to extend the grid or select a decentralized option, which is by definition independent from previously installed capacity. Whether or not there will be a "cross-subsidy" across supply regions, total system costs will be minimized by selecting the lowest cost option at each investment step.

3.3. Calculating Decentralized Generation Potential

The decentralized options explored as comparators to grid options are those which exploit local resource endowments such as solar, wind and biodiesel potential. The model takes into account the spatial heterogeneity of these resources and calculates the levelized cost of serving household demand using stand-alone (single-household) and

minigrid technologies. For single-household systems, we evaluate photovoltaic (PV) solar and wind, as well as diesel generators as a non-renewable alternative. For minigrid systems, we evaluate wind, a combined solar–wind system, biodiesel, and, again, conventional diesel generators. Solar and wind options include backup batteries for intermittency and the resulting issues of dispatchability.

Solar and wind resource potential information are drawn from a recent resource assessment by the Solar and Wind Energy Resources Assessment Project for Ethiopia, Ghana and Kenya (SWERA, 2004). We translate minimum and maximum daily solar insolation data to power potential using energy conversion and efficiency factors from the National Renewable Energy Laboratory (NREL) (see Appendix 1 for details on the computation of decentralized energy costs).

Wind power potential from SWERA and specific wind turbine characteristics yield turbine performance (power) at varying wind speeds (Ethiopian Rural Energy Development and Promotion Center, 2007). It is worth noting that in all three countries, feasible wind speeds over Class 3 (i.e. 11-13 m/s at a 10m hub height and 14-16 m/s at a 50m height) are limited to certain regions, sometimes in fairly remote areas. We estimate that areas with promising wind potential include 34.1 percent of households in Ethiopia, 6.3 percent in Ghana and 5.5 percent in Kenya. Wind power can be deployed both at an individual household level and, with larger turbine size, as a minigrid option. As an additional option, we evaluate a combined solar–wind system that can at least partially offset problems of intermittent supply (see KMOE 2008).

Power from the production of biodiesel in nearby agricultural areas is another promising option for more remote areas. There is some debate on whether biofuels represent a viable energy source or whether competition over land will jeopardize food production. In this study we assess biofuel potential using the production of *Jatropha curcas* as a biodiesel minigrid fuel option and compare this with the other centralized and decentralized options. To estimate the potential of Jatropha, we identify non-agricultural areas proximate to population centers and assume that sufficient yields are possible to supply localized demand. Suitable areas are identified from land use data after removing

agricultural, urban and small areas under 10 km².[14] The distance from these areas serves as a proxy value for transport costs.

As a non-renewable decentralized power supply option, we include diesel generators, which are already widely used throughout the developing world. ESMAP (2007) and KMOE (2008) provide information on prices and energy conversion rates for power generation for conventional diesel fuel. Generators can be deployed at the household level, or, far more efficiently, as a minigrid system. Appendix 1 provides details.

Cost of decentralized generation

Meeting each household's demand requires a given system size for each stand-alone and minigrid option that depends on local renewable energy potential. For solar PV this is the number of panels necessary to produce enough power to meet demand. Power supply from wind turbines at a given wind speed depends on the hub height and the size of blades. Diesel and biodiesel generators exist in many different configurations. Small, household level systems typically have a size of only a few kW. Minigrid systems have larger capacity and can serve 50 or even 100 households at a time. In this study we compare the costs of single-household and minigrid options to understand how scale might play a role in increasing coverage rates.

Each of these power options is also associated with an efficiency rating that dictates the amount of energy that is actually produced. In this study we simulate both high and low scenarios to see the relative cost impact of adopting higher efficiency technologies, but to keep comparisons manageable, we report results based on today's average efficiency. Efficiency ratings and power configurations for each of the technologies is described in Appendix 1.

[14] Specifically, areas defined by the World Wildlife Fund ecoregions database as biomes of Deserts/Xeric Shrublands & Tropical/Subtropical Grasslands, Savannas, and Shrublands. See Buys et al. (2007).

The sum of household demand within each BSP demand area determines the total number of systems required. We add the cost of capital, O&M and, where required, fuel to calculate the total cost of each decentralized option. To facilitate comparisons, these figures are then translated into levelized costs per kWh.

Future trajectories

Innovation and development, driven by increased market demand, have reduced prices for renewable energy considerably in recent years. There is broad consensus that significant technical potential exists to bring prices down further. In addition to computing baseline comparisons between different electricity supply options, we therefore also present scenarios based on likely future costs.

Relative prices may be further influenced by measures that increase the relative value of renewables as a result of future climate change negotiations. The size of such a premium is uncertain. We therefore compute the implicit carbon tax required to reach grid parity for each decentralized renewable power supply option within each supply area.

Future cost trends are of particular importance because, with low coverage rates and therefore large backlog of investments in Africa, currently-planned programs will take a long time to implement. Cost comparisons may well change significantly during the operational roll-out phase. These systems also have a long lifespan and planners need to avoid lock-in of technology choices that may turn out to be more expensive in the future.

4. Cost Comparisons

We show a complete set of electricity supply cost comparisons for Ethiopia, Ghana and Kenya in the tables in Appendix 2. Figures 8 and 9 present graphical and map

summaries for Ethiopia. In the following paragraphs we summarize results for baseline scenarios, technical change and carbon taxes.

Baseline scenarios

The top two charts in Figure 8 show cost curves for the baseline estimates for individual household systems and minigrid systems, respectively. The levelized cost per kWh is shown for each of the 56 BSP demand areas in Ethiopia. Recall that these are assigned so that the first BSP has the largest aggregate demand, the second BSP the next largest, and so on. The curve for the marginal cost of grid-connected power is therefore upward sloping, since the large fixed costs for new transformer and distribution systems are distributed over progressively fewer households. In fact, the first 20 BSP areas account for about 90 percent of the country's population, while the last 20 include only 2.5 percent (see Figure 10).

Estimated levelized marginal costs of grid supplied electricity are between 16 and 50 cents per kWh for most demand areas, but rise steeply to more than one dollar for the most remote demand areas—these are the border areas in the first map in Figure 9. Both household-level solar and diesel generation are uncompetitive in all but the most remote regions of the country, which are home to about 50,000 households. The cost of solar PV generated electricity depends on the strength of local solar radiation. It therefore shows large variability across BSP areas from about 66 cents per kWh to more than one dollar. The cost of diesel is influenced by transport costs from the main port of entry (Djibouti in the case of Ethiopia, Accra, and Mombasa) and therefore also shows minor variation—between 60 and 70 cents in the baseline scenarios.

Wind is available in only some of the BSP demand areas in each country. For Ethiopia, areas with wind potential cover a region stretching from the central north to central south of the country (as seen in the map in Figure 9). Cost estimates are represented by circles in the charts. The cost of wind-supplied electricity varies between 23 and 29 cents per kWh. Wind is comparable to or cheaper than grid supply among household level systems in some parts of the country. However, wind resources are more

localized than demand areas, so in some of the BSP areas in which wind is most competitive, only a share of the households could feasibly be supplied with wind energy. We estimate that areas where wind is lower-cost than grid include less than three percent of all households in the baseline scenario.

Wind resources look far more favorable for minigrid systems, which deploy larger, more efficient, turbines. Costs drop to an estimated 14 to 17 cents per kWh. Localized areas in which minigrid wind systems are lower cost than grid include about 34 percent of all households. Costs for diesel and biodiesel minigrid systems are comparable at between 23 and 27 cents per kWh. Both provide lower-cost electricity than grid-connected options for about 9 percent of households. Production costs for combined solar PV and wind systems range from 29 and 122 cents per kWh. This is lower than grid supplied costs for less than one percent of households.

Technical change

Energy infrastructure tends to be long lasting. While traditional, fossil-fuel-based technologies are at a stage where further efficiency gains are limited, costs for some types of renewable energy systems have been falling rapidly. There is broad consensus about further scope for innovation that will lead to continued cost reductions. The learning curve describes the speed at which costs fall in response to engineering, construction, operational experience, improved material procurement, and manufacturing scale. It is defined as the percentage change in unit costs for each doubling of installed capacity.

The literature on technological experience curves and learning rates is extensive. In a review of the evidence for renewable energy technologies, Neij (2008) suggests plausible learning rates for various power generation technologies (see Table 6). Among renewables, we apply rates that vary from 2.5 percent cost reductions with a doubling of installed capacity for hydro and geothermal in the estimates of centralized power production, to 15 percent for decentralized wind and 20 percent for solar PV. Learning rates for some renewables appear high, but, with proper incentives for innovation and

deployment, some observers think that even higher rates are plausible (for instance as high as 30 percent for PV solar (Neij 2008)).

Applying these learning rates to the baseline estimates requires an additional step. Since learning rates refer to a doubling of capacity ("learning by doing" is the most important factor), we need estimates of future growth in globally-deployed renewable energy resources. We assume that the recent past gives some guidance for future trajectories. Table 6 shows estimates of growth rates over the last five to ten years. Annual capacity growth rates imply doubling times from less than two years to almost three years for solar, wind and biofuels. These, in turn, suggest the number of times the learning rate needs to be applied to current costs to yield an estimate of future costs. We implement a twenty year scenario of pure technological learning only—i.e., we apply learning rates only to the capital cost portion of levelized costs, not to O&M or other non-technical cost components.

Learning rates lower costs for all electricity supply options. But comparisons change significantly only for those technologies where the learning rates are higher than those for technologies used to generate grid supplied electricity. Solar PV-generated electricity costs drop from a range of 66-122 cents per kWh to between 19 and 35 cents. While cost differences narrow everywhere in Ethiopa, costs are lower than grid for only about 8 percent (1.15 million) of households. Both household-level wind and wind minigrid energy become lowest cost where available at 12-15 cents and 8-9 cents per kWh respectively, covering around one third of households in Ethiopia—about 5 million households in supply areas where sufficient wind resources are present. Finally, a combined solar and wind minigrid option is expected to generate power at 10 to 44 cents per kWh, cheaper than the grid for about 21 percent of households. Diesel and biodiesel comparisons remain unchanged, because cost reduction potential is similar to that of grid technologies. In each case they could supply electricity more cheaply than the grid for about 8 percent of households.

To illustrate an alternative way of assessing technical change impacts, Figure 11 plots the learning rate for each BSP demand area that is required to achieve grid parity

over a 20 year period. In contrast to the previous analysis, we now assume that learning will not only occur in production but also in deployment and O&M. This yields slightly faster cost reductions, but qualitatively similar results. Required learning rates for solar PV and combined solar-wind minigrid systems are well over 10 percent for most BSPs, and lower only for those demand areas that are relatively sparsely populated. Rates for biodiesel and wind, in contrast, are around 5 percent or lower, and in many demand areas negative where decentralized supply is already cheaper.

Premium for low-carbon energy

Energy choices in African countries will be affected in various ways by global climate policy agreements. In principle, Ethiopia could choose to participate in a global carbon tax system, perhaps with an efficient, fiscally-neutral approach that uses the revenues to reduce other fiscal distortions. Ethiopia also could participate in the Clean Development Mechanism if it can demonstrate that a portion of its renewable energy capacity increase goes beyond "business as usual" based on energy-equivalent costs of supply. Either way, the relative net cost of renewable energy would be lower. To explore the implications of such changes, we calculate the implicit carbon tax rates (in dollars per ton of emitted CO2) that would achieve levelized-cost parity between decentralized renewable power options and fossil-fired power delivered by the centralized grid.

Table A2-4 (baseline) and Table A2-5 (with 20 years of technical change) in Appendix 2 present the results for Ethiopia. Negative numbers for some technologies indicate that this energy source may be competitive even without carbon pricing. Overall, however, there are very few BSP demand areas where decentralized renewable energy would become competitive with grid supplied electricity under a realistic carbon tax. Implied taxes in areas where alternatives are uncompetitive today or in 20 years are generally far above the cost of traded European Union emissions allowances or charges suggested in policy debates.[15] So a realistic carbon tax or equivalent market premium for

[15] Nordhaus (2007b), Stern (2006) and others have estimated the carbon charges (or auctioned permit prices) consistent with different levels of emissions control. The underlying economic logic supports a

renewables, as with CDM, is unlikely to significantly expand the deployment of decentralized renewable electricity sources under this scenario, although it could alter the speed with which large-scale power producers adopt renewable options for the grid.

5. Summary and Conclusions

In this paper, we have tested the conventional view that renewable power remains too costly for large-scale applications in countries where poverty alleviation is the primary objective. To provide a more realistic test, we explicitly recognize the importance of spatial relations in power markets. Current power grids draw heavily on fossil power sources and are clustered in densely-populated areas, where fixed costs can be amortized over large numbers of consumers. However, the incremental cost of electric service rises rapidly as the grid is extended to settlements whose population falls along a standard rank-size distribution. In contrast, wind and solar power, exploitable in stand-alone units or minigrids, may be broadly distributed across rural areas. Diesel generator power is potentially available anywhere, at a cost that is affected by the distance from points of production or importation. Under these conditions, centralized grids are always subject to potential cost competition from local renewable or diesel power.

The implication is clear and cautionary: Generalizations about fossil power versus renewable power are inherently untrustworthy. Determining the scope for decentralized electricity production depends on information about the distributions of specific resources and populations, along with accurate representation of power production costs with alternative technologies, transmission costs, and distribution costs.

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charge that rises over time. At present, most damages are in the relatively distant future and there are plentiful high-return opportunities for conventional investment. Investment should become more intensive in emissions reduction as climate-related damage rises, and rising charges will provide the requisite incentive to reduce emissions. The optimal "ramp" for charges depends on factors such as the discount rate, abatement costs, the potential for technological learning, and the scale and irreversibility of damage from climate change (Nordhaus, 2007a). These factors remain contentious, so it is not surprising that different studies establish very different ramps. Nordhaus' preferred path begins at about $8/ton of CO2, rising to about $23/ton by 2050. Stern's initial charge is 10 times higher -- $82/ton – and his ramp is steeper. IPCC IV (2007) cites a variety of studies whose initial values average $12/ton, distributed across a range from $3-$95/ton.

Even if a renewable power source has a higher unit production cost than fossil power, it may be cost-competitive in many areas once its local costs are compared with those from extension of the centralized grid.

In the Ethiopian case, we find that decentralized wind power is already cost-competitive with power from an extended central grid in a large share of the country's area. Estimates for Ghana and Kenya—not discussed in the paper but summarized in Appendix 2—show similar patterns. We also find that solar photovoltaic power may become competitive in large parts of the country, as standard industry learning lowers the cost of solar modules.

But our scenarios, based on realistic unit costs, also show that for a majority of households, decentralized power supply is unlikely to be cheaper than grid supplies any time soon.[16] Levelized costs for wind energy are very low, but wind potential is limited to a relatively small share of each country. Solar PV would cover less than ten percent of all households under realistic technical change scenarios over the next 20 years. And electricity generated with biodiesel generators—as well as conventional diesel—tends to be more expensive than grid supplied power for most areas. Furthermore, where decentralized electricity generation is not already cheaper today or, after considering likely cost reductions, over the next 20 years, carbon taxes or equivalent premiums for renewable investments are unlikely to make the difference under realistic rates per emitted ton of CO2 avoided.

Our application is meant to be illustrative: We demonstrate the feasibility of spatially-explicit modeling of power supply scenarios at a national level, by applying it to specific scenarios which we believe to be realistic. The model also represents a flexible set of tools that can be used to test alternative assumptions about current and future energy supply costs. But even based on our specific scenarios and assumptions, we believe that two more general conclusions are warranted.

[16] This general conclusion, echoing the cautionary tone in work by others such as Wamukonya (2005), is likely to hold even if we adjust for probable underestimation of the cost of grid connections. Likely sources of underestimation include our assumption that all population resides in about 1000 settlements, and our use of minimum spanning tree configurations of power grids that typically have inefficiencies and redundancies built in.

First, stand-alone renewable energy technologies will be the lowest-cost option for a significant minority of households in African countries. These will be mostly in rural and more remote parts of the country, but stand-alone technologies are also an option for hard-to-reach pockets in more densely-populated demand areas that are otherwise grid connected. They may also be attractive as an alternative or complement for households that do not want to rely on poorly managed central utilities that may not be able to provide uninterrupted supply or may be slow to expand grid connections even in fairly densely populated areas. But the largest potential will be in rural and more remote areas in Africa where electrification strategies that follow western models of universal grid expansion are unlikely to be the most cost effective approach.

Second, the economics of grid-supplied electricity in more densely populated areas remain compelling, especially as the concentration of population in Africa is likely to increase rather than diminish (World Bank 2008b). From a climate change perspective, therefore, our analysis highlights the importance of reducing the carbon intensity of grid-supplied energy generation. For instance, concentrating solar thermal power (CSP, or solar thermal power) which is far less costly than solar PV, will be an attractive option for much of Africa (Ummel and Wheeler, 2008). At present CSP appears to require larger scale than the decentralized minigrid options discussed here, but recent industry developments suggest that smaller systems may be feasible. The same goes for larger-scale wind power generation, hydro electricity—where Africa is currently exploiting less than 10 percent of its potential—and geothermal energy in the Rift Valley and elsewhere.

In short, our analysis shows that decentralized renewable power expansion in Sub-Saharan countries cannot be a universal solution to universal access, but it will likely be an important component of any significant expansion in electricity access. We recognize that renewable power is not dispatchable power, because naturally-occurring conditions cause it to vary over the daily and annual cycle, however, with the appropriate storage options (included in the costs here), this is less of an issue for decentralized options. For larger configurations, cost-competitive power storage technologies are under development, but 24-hour power availability will require augmentation of renewable power by standby fossil or biofuel power until those technologies are

available. At the same time, the renewable power options considered in this paper have the advantage of permanently-available supply at a fuel source cost of zero. All things considered, our evidence suggests that the economics of decentralized renewable power may be compelling for large regions of rural Africa. Energy planners in Sub-Saharan Africa should therefore pay careful attention to opportunities for the expansion of renewable power now, not twenty years from now.

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Table 1: Potential Annual Production of Renewable Energy Relative to Current Annual Domestic Energy Consumption

Country	Total	Country	Total	Country	Total
Namibia	100.5	Burkina Faso	15.9	Kenya	6.5
Central Afr. Rep.	90.9	Madagascar	14.6	Malawi	6.4
Mauritania	86.2	Guinea-Bissau	14.2	Ghana	5.7
Chad	77.3	Tanzania	14.1	Uganda	3.1
Mali	58.4	Cameroon	12.7	Gambia	2.7
Niger	50.4	Senegal	12.5	Burundi	2.2
Congo	43.6	Benin	12.5	Nigeria	2.0
Angola	27.9	Sierra Leone	10.1	Swaziland	1.6
Sudan	27.6	Côte d'Ivoire	9.6	Lesotho	1.4
Zambia	25.2	Eritrea	9.5	South Africa	1.3
Congo, Dem Rep	24.7	Guinea	9.0	Equatorial Guinea	0.9
Mozambique	23.4	Togo	8.9	Cape Verde	0.9
Botswana	22.4	Ethiopia	8.5	Rwanda	0.7
Gabon	20.3	Zimbabwe	8.0	Comoros	0.2

Source: Buys, et al. (2007), Table 10

Table 2: Percent of Households with Access to Electricity, 2003-2007

Rural	Min	Q1	Median	Q3	Max
Latin America & Caribbean	11.7	23.7	62.5	89.3	89.3
South & Southeast Asia	12.6	30.4	55.7	84.4	84.5
Sub-Saharan Africa	0.3	1.3	3.0	14.6	33.8
Urban					
Latin America & Caribbean	68.9	81.5	96.3	99.0	99.3
South & Southeast Asia	66.8	76.6	92.0	98.1	98.3
Sub-Saharan Africa	6.9	36.6	50.8	76.9	91.4

Source: DHS (2009)

Table 3: Cost Components for the Grid Expansion Model

	Unit costs		
Generation mix	**Kenya**	**Ghana**	**Ethiopia**
Capital, O&M and fuel cost ($/kW) [1]	3,006.89	2,306.85	2,617.46
Levelized cost of production (¢/kWh) [1]	10.70	7.23	5.80
Transmission			
HV transmission lines			
132 kV line ($/km)	90,000	90,000	90,000
220 kV line ($/km)	192,000	192,000	192,000
Bulk Supply Point (2-bay configuration)			
Transformer ($/kVA)	10	10	10
Static Var Compensator (SVC) ($/100 MVAr)	10,000,000	10,000,000	10,000,000
Breaker Switched Capacitor (BSC) ($/100 MVAr)	1,500,000	1,500,000	1,500,000
HV-MV transformers			
3 phase HV/MV transformers ($/kW)	35,371	35,371	35,371
Distribution			
MV transmission lines			
132 kV line ($/km)	106,154	106,154	106,154
33 kV line ($/km)	23,000	23,000	23,000
11 kV line ($/km)	20,000	20,000	20,000
MV-LV transformers			
200 kVA 33 kV/LV ($/unit)	60,000	60,000	60,000
100 kVA 33 kV/LV ($/unit)	50,000	50,000	50,000
50 kVA 33 kV/LV ($/unit)	33,656	33,656	33,656
25 kVA 33 kV/LV ($/unit)	21,818	21,818	21,818
200 kVA 11 kV/LV ($/unit)	50,000	50,000	50,000
100 kVA 11 kV/LV ($/unit)	41,818	41,818	41,818
50 kVA 11 kV/LV ($/unit)	28,182	28,182	28,182
LV transmission lines (Household connections)			
LV line 4 wires ($/km)	10,611	10,611	10,611

Source: KMOE (2008)
1 – Base costs before any learning effects.

Table 4: Current operational generation capacity >8 MW in Ethiopia, Ghana and Kenya (MW) (Percent in parentheses)

Generator type	**Ethiopia**	**Ghana**	**Kenya**
Hydro	630.8	1157.8	672.7
	(91.9)	(53.8)	(59.5)
Oil/gas CC/CT		736.9	
		(34.2)	
Heavy Fuel Oil/Diesel	47.0	113.8	306.0
	(6.9)	(5.3)	(27.1)
Natural gas		145.1	
		(6.7)	
Geothermal	8.5		122.5
	(1.2)		(10.8)
Bagasse			17.5
			(1.6)
Biomass			12.5
			(1.1)
Total	686.3	2153.6	1131.2

Source: UDI World Electric Power Plants Data Base, March 2006. (www.gisdata.platts.com); CC – combined cycle; CT – combustion turbine

Table 5: Wind Energy Potential in Sub-Saharan Africa

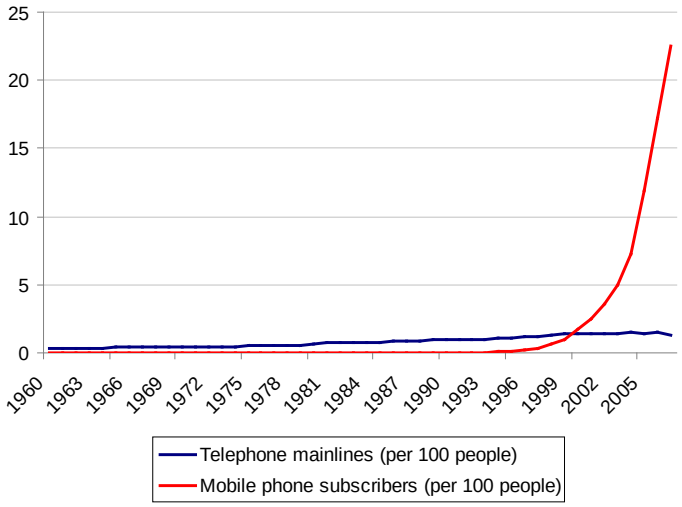
Subregion	Country	Annual Potential: Years of Current Energy Consumption
Central Africa	Angola	0.670
	Congo	0.444
	Congo, Dem Rep	0.019
Coastal West Africa	Cape Verde	0.857
East Africa	Sudan	1.126
	Tanzania	0.476
	Kenya	0.314
	Ethiopia	0.030
Indian Ocean Islands	Madagascar	3.833
	Comoros	0.400
	Mauritius	0.050
Sahelian Africa	Mauritania	5.000
	Chad	0.458
Southern Africa	Mozambique	1.775
	Namibia	1.000
	South Africa	0.018

Source: Buys, et al. (2007)

Table 6: Estimates of global energy production capacity growth

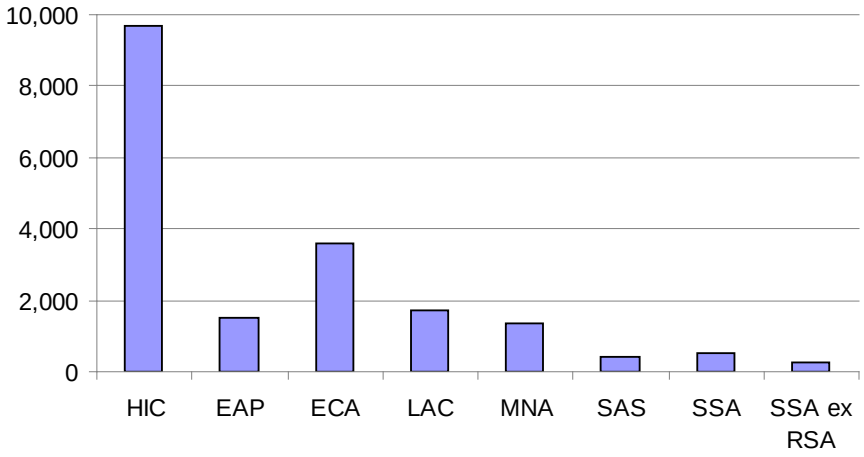
	Learning rate (%) (Neij 2008)	**Data period**	**Annual Capacity growth (%)**	**Doubling time (years)**	**Doubling per 20 years**	**Source**
Solar PV	20	2001-2008	42.1	1.6	12.1	Global Solar Photovoltaic Market Report (2009), www.thesynergyst.com
Wind	15	2000-2009	26.8	2.6	7.7	www.wwindea.org/home/index.php
Biofuel	5	2004-2008	25.3	2.7	7.3	Renewables Global Status Report 2009 www.ren21.net
Hydro	2.5	1978-2008	2.3	29.8	0.7	BP Statistical Review of World Energy 2009, http://www.bp.com/statisticalreview
Geo-thermal	2.5	1980-2008	3.5	20.0	1.0	Bertani 2005. World Geothermal power generation in the period 2001-2005. Geothermics 34: 65-69.
Oil/ diesel	2.5	1978-2008	0.8	88.0	0.2	BP Statistical Review of World Energy 2009, http://www.bp.com/statisticalreview
Gas CT/CC	4.0	1978-2008	2.8	24.7	0.8	BP Statistical Review of World Energy 2009, http://www.bp.com/statisticalreview

Figure 1: Coverage of land lines and mobile phones in sub-Saharan Africa, 1960-2007



Source: World Bank, World Development Indicators

Figure 2: Electric Power Consumption (kWh per capita), 2005

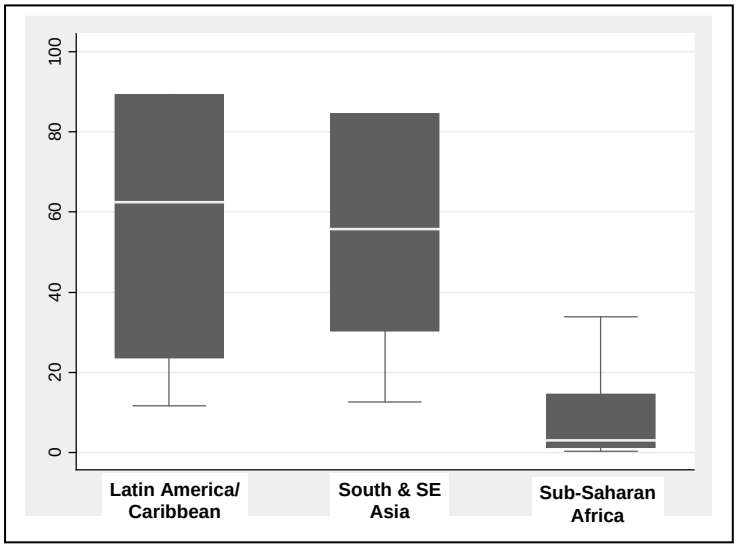


HIC: High-income countries; EAP: East Asia and Pacific; ECA: Eastern Europe and Central Asia; MNA: Middle East and North Africa: SAS: South Asia; SSA: Sub-Saharan Africa; RSA: Republic of South Africa

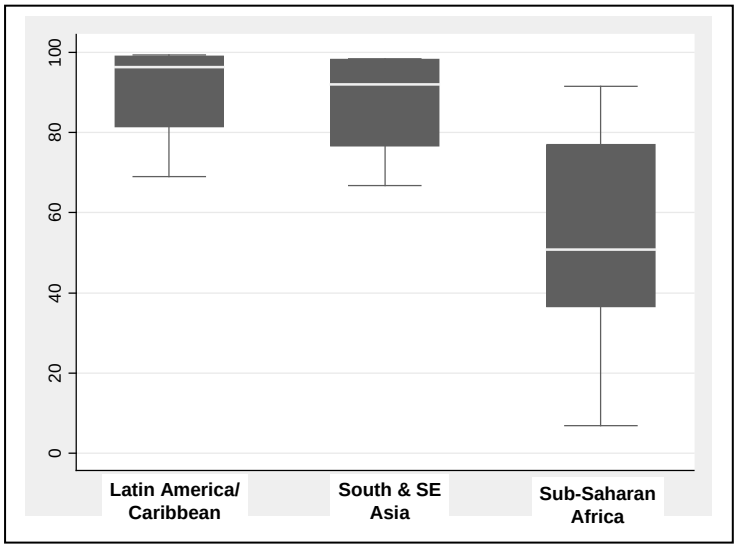
Source: World Bank, World Development Indicators

Figure 3: Percent of Households with Electricity, 2003-2007

a. Rural

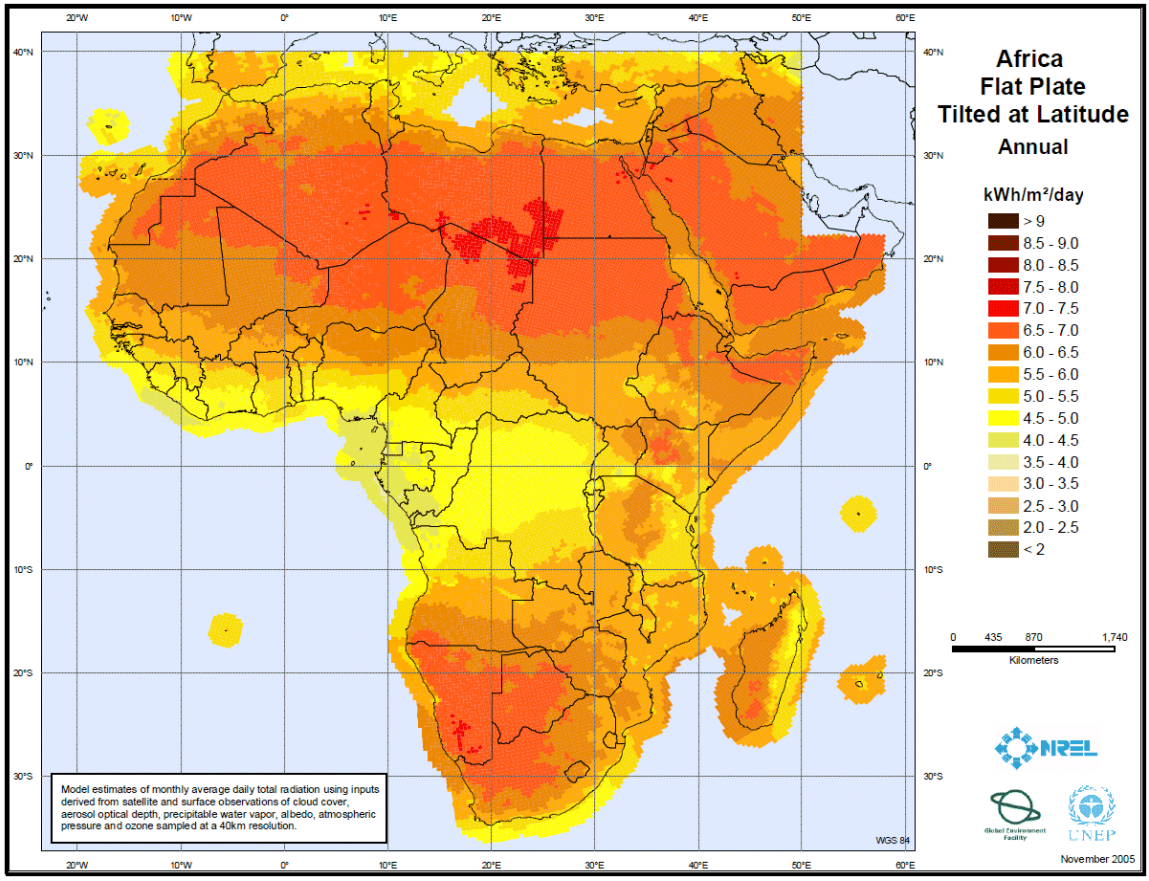


b. Urban



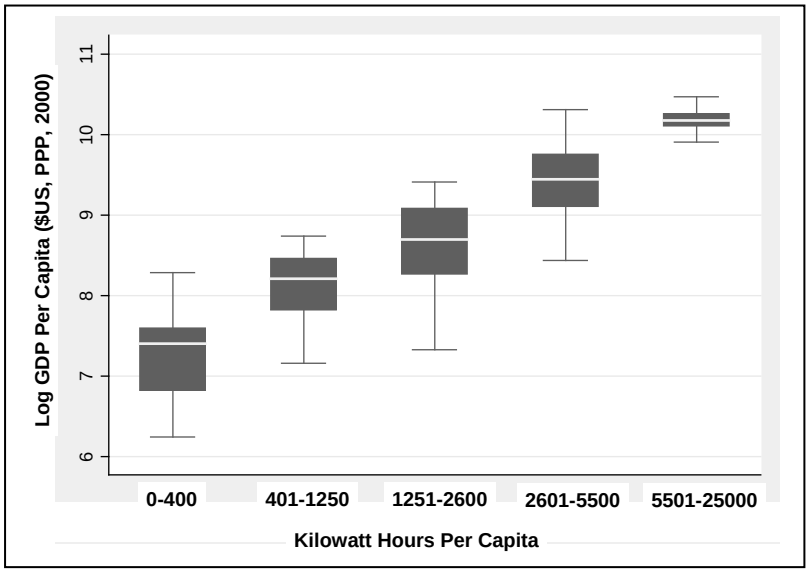
Source: DHS (2009)

Figure 4: Solar Radiation in Sub-Saharan Africa (kWh/m^2/day)



Source: US National Renewable Energy Laboratory

Figure 5: GDP Per Capita (PPP) vs. Electricity Consumption, 2000



Source: World Bank, World Development Indicators

Figure 6: Elements of a Power Transmission System

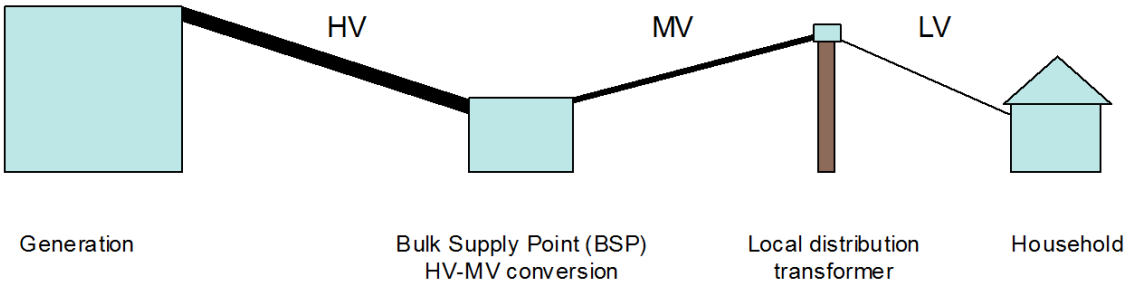
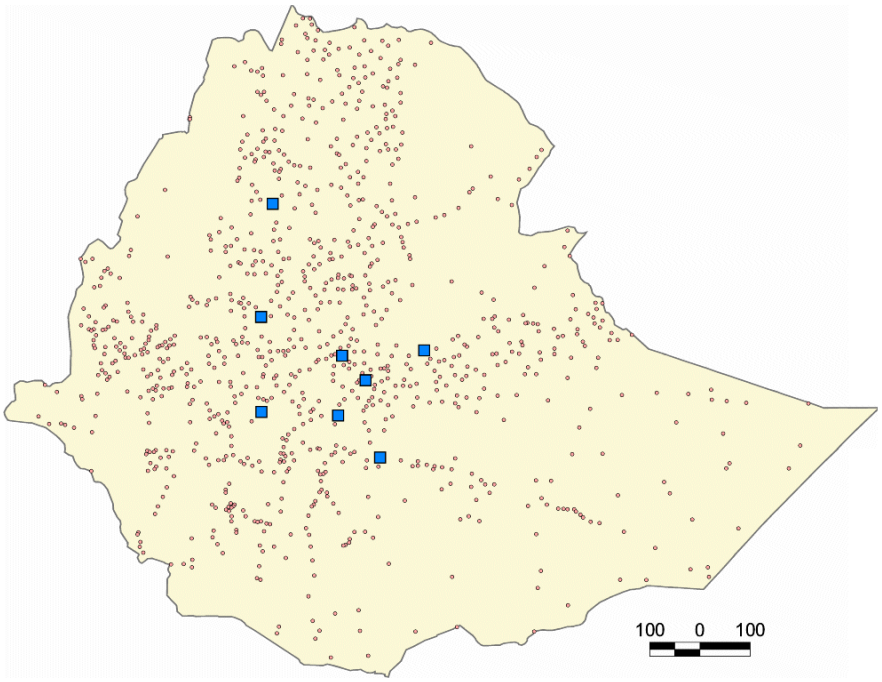
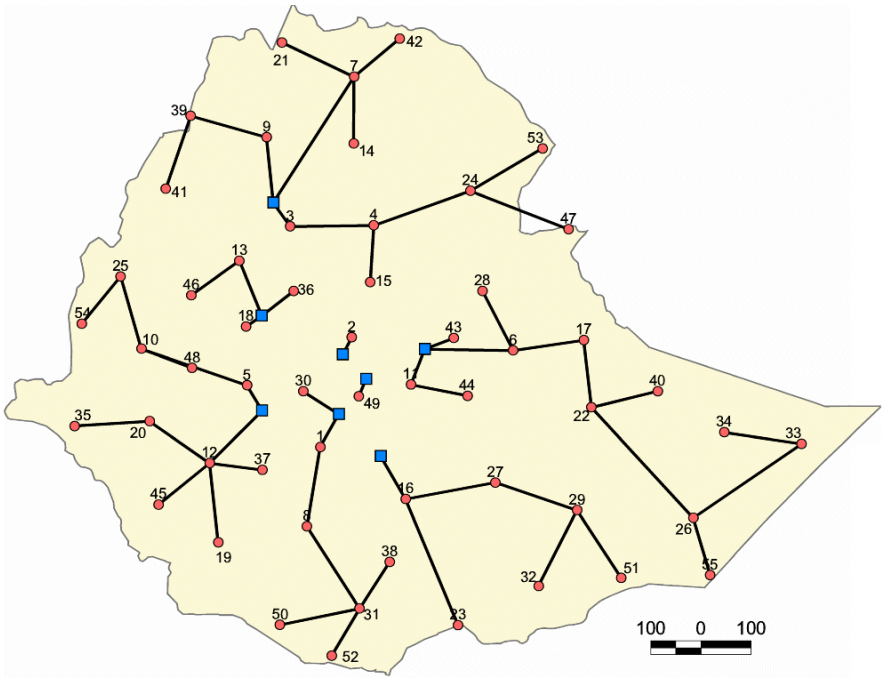


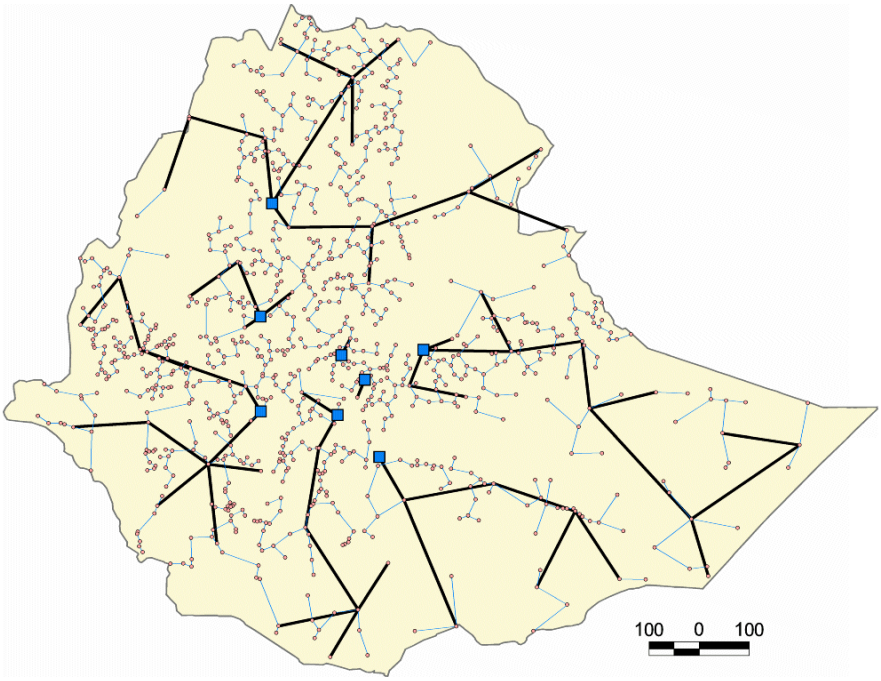
Figure 7: Modeling grid connections



a.



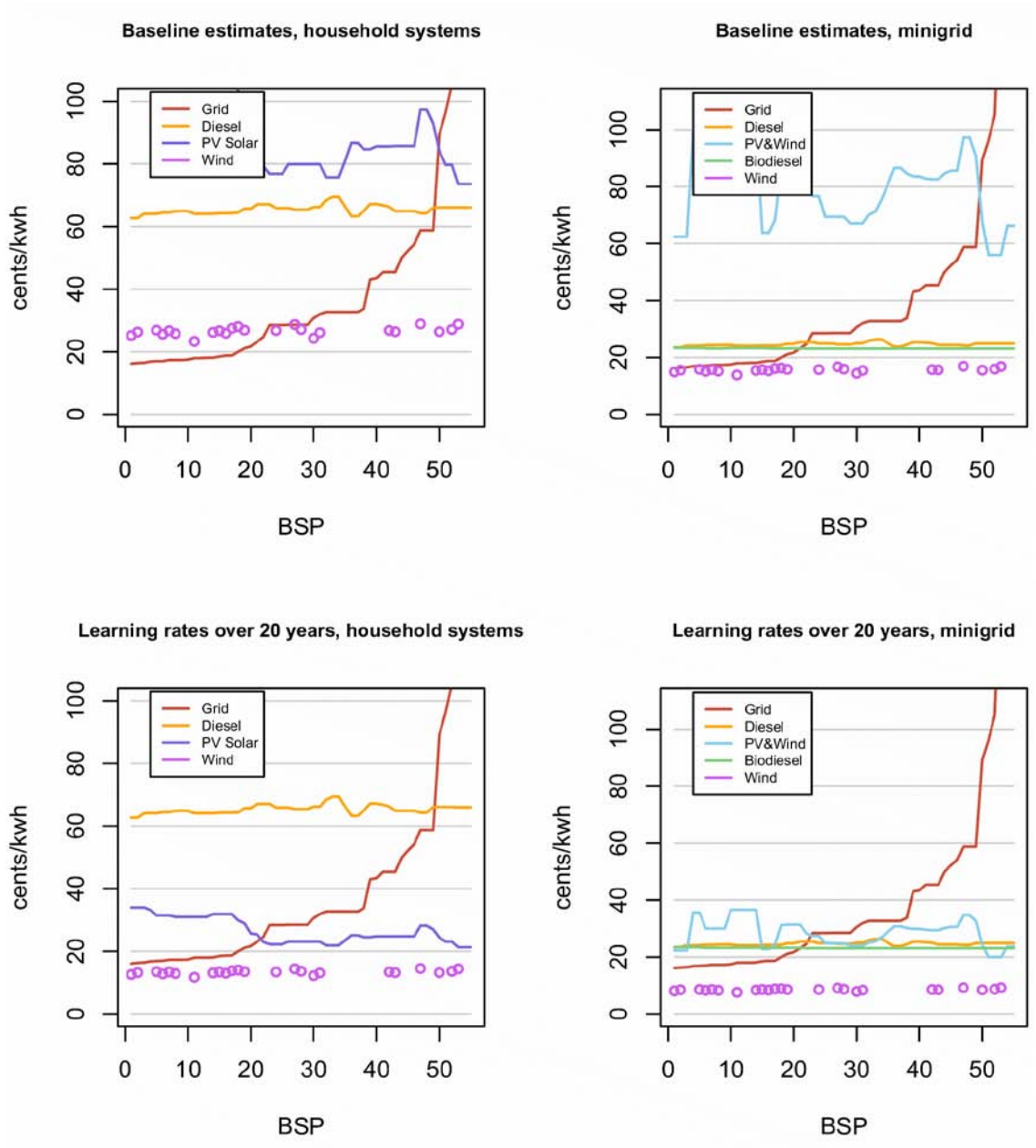
b.



c.

d.

Figure 8: Cost curves for Ethiopia



Note: Tukey's (running median) smoothing applied to cost curves.

Figure 9: Geographic distribution of levelized energy costs in Ethiopia

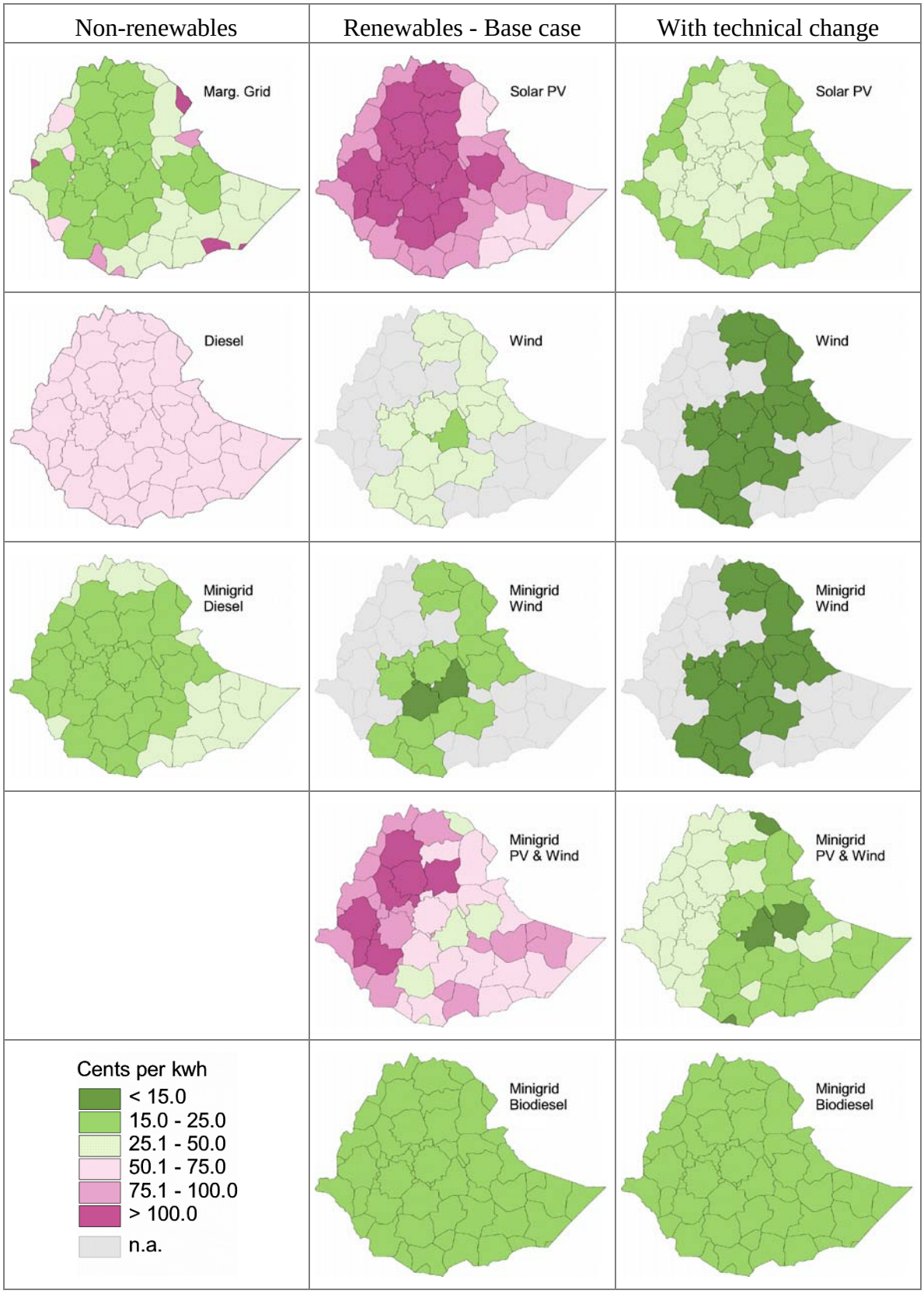


Figure 10: Cost curves (baseline) with households covered, Ethiopia

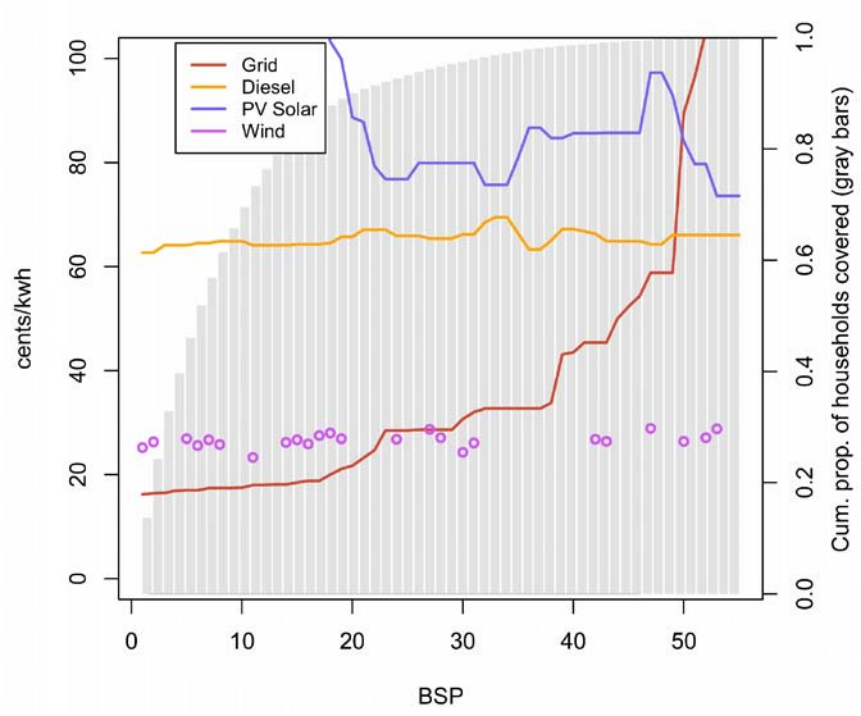
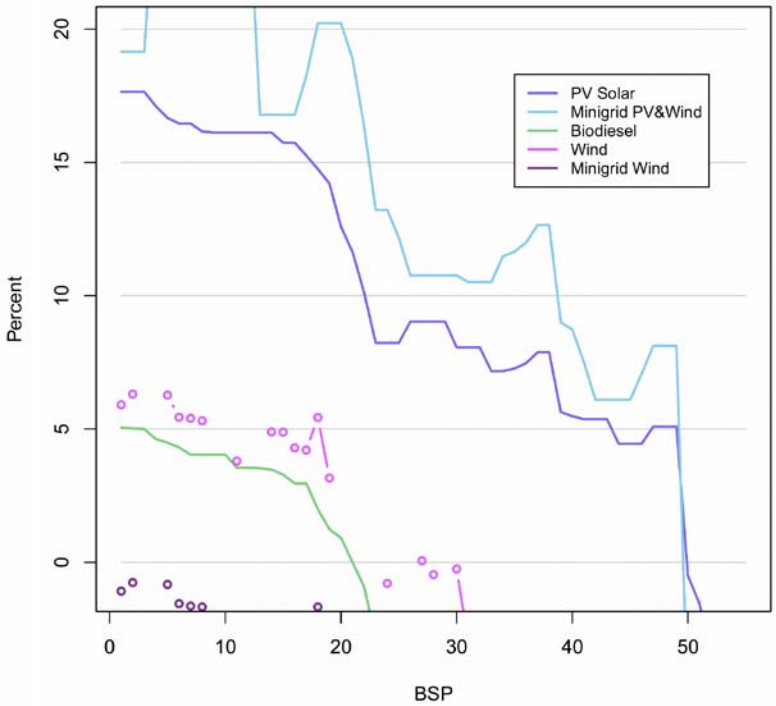


Figure 11: Learning rates required to reach grid parity, Ethiopia (20 year period, including learning effect for non-capital costs)



Appendix 1

Solar, Wind, Diesel and Biodiesel technologies

Solar power

Solar radiation varies from location to location, so it is necessary to establish a relationship between solar radiation (or insolation) and the power output of a solar PV panel. The conversion of radiation to power involves a complex set of assumptions. However, there are several convenient calculators that can simplify the computations. The one used in this paper is produced by the National Renewable Energy Laboratory (NREL), called PVWatts (http://www.nrel.gov/rredc/pvwatts/version1.html). The PVWatts Version 1 calculator uses hourly typical meteorological year (TMY) weather data and a PV performance model to estimate annual energy production for a crystalline silicon PV system. For locations in the United States and its territories, the PVWatts Version 1 calculator uses NREL TMY data. For other locations such as Kenya, it uses TMY data from the Solar and Wind Energy Resource Assessment (SWERA) Programme, the International Weather for Energy Calculations (Version 1.1), and the Canadian Weather for Energy Calculations. The following is a description of the study and resulting data for Ethiopia, Ghana and Kenya.

Solar and Wind Energy Resource Assessment (SWERA) High Resolution Solar Radiation Assessment for Kenya (2004)

The satellite-based high resolution solar resource assessment for Ethiopia, Ghana and Kenya is provided by DLR (Deutsches Zentrum für Luft- und Raumfahrt). The high resolution solar data (10kmx10km) provide country maps of the annual and monthly sums of hourly global horizontal and direct normal irradiance (GHI and DNI) for the years 2000, 2001 and 2002.

The PVWatts calculator uses these data in conjunction with a PV performance model to estimate annual energy production. Specifically, the calculator multiplies the nameplate DC power rating by an overall DC-to-AC derate factor to determine the AC power rating at standard test conditions (STC). The overall DC-to-AC derate factor accounts for losses from the DC nameplate power rating and is the mathematical product of the derate factors for the components of the PV system. For example, a system with a power rating of 1kW and a derating factor of 0.77 would produce 0.77kW after accounting for these system losses. In this study all the default parameter values were retained with the exception of the DC power rating which was set to 1kW for simulating household-level systems and 100kW for minigrid applications. The specific defaults for the derating factors were:

Table A1-1: Derate Factors for AC Power Rating at STC

Component Derate Factors	PVWatts Default	Range
PV module nameplate DC rating	0.95	0.80–1.05
Inverter and transformer	0.92	0.88–0.96
Mismatch	0.98	0.97–0.995
Diodes and connections	0.995	0.99–0.997
DC wiring	0.98	0.97–0.99
AC wiring	0.99	0.98–0.993
Soiling	0.95	0.30–0.995
System availability	0.98	0.00–0.995
Shading	1.00	0.00–1.00
Sun-tracking	1.00	0.95–1.00
Age	1.00	0.70–1.00
Overall DC-to-AC derate factor	0.77	0.96001–0.09999

Using the monthly output data from the calculator, the following regression was run so that solar energy potential at other sites in the country could be approximated by using only the available solar radiation information (note "AC" here refers to alternating current, not average cost):

AC Energy (kWh) = Constant + β * (Solar Radiation (kWh/m^2/day))

The resulting estimated coefficients were then used to calculate the monthly potential AC energy output for all locations in the country. For example, the regression for a 1kW DC nameplate rating yielded the following relationship:

AC Energy (kWh) = 16.60 + 18.20 * (Solar Radiation (kWh/m^2/day))

Thus, if solar radiation were 4.5 kWh/m^2/day, then the potential AC power output would be 98.49 kWh per month. The same procedure was repeated for 100kW systems for minigrid configurations. Below are some examples with alternative power ratings and solar insolation values, along with the associated assumptions on costs.

Table A1-2: Example solar PV configurations in the study

Configuration	**Stand-alone**	**Stand-alone**	**Stand-alone**	**Minigrid**	**Minigrid**	**Minigrid**
Data source (capital & O&M costs)	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**
Scenario (insolation)	**Low**	**High**	**High**	**High**	**Low**	**High**
Solar insolation (kWh/m2/day)	4.50	6.00	6.00	6.00	4.50	6.00
Constant	16.60	16.60	16.60	420.90	1,682.36	1,682.36
Coefficient for insolation	18.20	18.20	18.20	453.97	1,816.09	1,816.09
Power (kWh/month)	98.49	125.78	125.78	3,144.71	9,854.74	12,578.87
Power (kWh/day)	3.24	4.14	4.14	103.39	323.99	413.55
Power (kWh/year)	1,181.84	1,509.38	1,509.38	37,736.55	118,256.93	150,946.46
HH demand (kWh/month)	120	120	120	120	120	120
HH demand (kWh/day)	4	4	4	4	4	4
Configuration: Power rating (kW)	1	1	1	25	100	100
Population	500	500	500	500	5,000	5,000
# people per HH	5	5	5	5	5	5
Number of HHs	1	1	1	100	1,000	1,000
Solar system need (# systems)	124	97	97	4	13	10
Costs						
Capital cost of system ($/kW)	12,000	12,000	7,500	7,200	6,500	6,500
O&M ($/kW-yr)	324	324	324	259	164	164
Fuel costs ($/kW)	-	-	-	-	-	-
Discount rate	10%	10%	10%	10%	10%	10%
Life	20	20	20	20	20	20
Annualized capital costs (¢)	128,138	128,138	80,086	1,922,067	6,940,796	6,940,796
Annualized O&M costs (¢)	32,400	32,400	32,400	647,500	1,640,000	1,640,000
Annualized Fuel costs (¢)	-	-	-	-	-	-
Levelized capital costs (¢/kWh)	108.4	84.9	53.1	50.9	58.7	46.0
Levelized O&M costs (¢/kWh)	27.4	21.5	21.5	17.2	13.9	10.9
Levelized fuel costs (¢/kWh)	-	-	-	-	-	-
Total levelized cost (¢/kWh)	135.8	106.4	74.5	68.1	72.6	56.8
Total cost ($)	1,528,176	1,195,428	758,928	745,900	8,663,200	6,664,000
Average cost ($/HH)	15,282	11,954	7,589	7,459	8,663	6,664

Source: Data sources listed in second row; the remaining are the author's using the methods described above.

Wind power

The wind potential of an area is highly variable, due to the wind speed and turbine characteristics. In this study, wind power potential was estimated using wind power density (Watts/m2) information from the Solar and Wind Energy Resource Assessment (SWERA) Programme and another simple calculator that uses mean annual wind speed and turbine characteristics (Ethiopian Rural Energy Development and Promotion Center, 2007).

The calculator is a simple spreadsheet model which uses the mean wind speed to compute wind machine performance. It can be helpful to maximize the benefits of the SWERA-generated wind data, which provide an estimate of annual mean wind speed for any particular location. The user inputs project site-specific data (e.g. average wind speed, site altitude, anemometer height, etc.) and the wind turbine power curve data as provided by the manufacturer (see column 2 in the table below). The probability of wind speed (column 4) for the range of wind speeds is graduated into bins of 1m/s (column 1) starting from 0m/s up to 20m/s and calculated using the Weibull and Rayleigh probability distribution of wind speed and a shape factor, k. Instantaneous wind turbine power (column 5) is calculated by multiplying the corrected wind power on the turbine power curve (column 3) for each bin of wind speed by the Weibull wind speed probability (column 4). Details of each column calculation are listed below.

The output of the model is the annual mean wind speed at the hub height, air density factor (which is an input to correct the performance of the turbine curve for a specific site), average output power (which is the sum of instantaneous wind turbine power), daily energy output (the sum of the average power output of the turbine on a continuous, 24 hour, basis), monthly and annual energy output, and percent operating time (the time the turbine is producing some power). The definitions given for each calculated cell (and column) help the user to develop this model in an Excel spreadsheet.

An illustrative 1kW wind turbine system is provided, with the cost details in the table after the power calculation tables. The same calculation procedure was performed for a 100kW wind system for minigrid applications in the study.

Input data

Site Altitude - is the meters above sea level for the project site.

Anemometer Height - is the height at which the average wind speed is measured. If the SWERA generated annual mean wind speed is used; the value to input is 50 meters.

Mean Wind speed - annual average wind speed in meters per second at the height of measurement (at the anemometer height).

Weibull k - The probability distribution of wind speed where k is the shape factor. An excellent fit to the distribution curve is obtained for values of k ranging between 1.8 and 2.3. The Rayleigh distribution is a special case of the Weibull distribution where the value of k=2. If the Weibull k is not known, use k=2 for inland sites and 3 for coastal sites as a first approximation.

Wind Shear Exponent - The user enters the wind shear exponent, which is a dimensionless number expressing the rate at which wind speed varies with the height above the ground. A low exponent corresponds to a smooth terrain whereas a high exponent is typical of a terrain with sizeable obstacles. This value is used to calculate the average wind speed at the wind turbine hub height and at 10 m. The wind

shear exponent typically ranges from 0.10 to 0.40. The low end of the range corresponds to a smooth terrain (e.g. sea, sand and snow from 0.10 to 0.13). A wind shear of 0.25 corresponds to a rough terrain (i.e. with sizeable obstacles). The high end of the range (0.40) corresponds to a project in an urban area. A value of 0.14 (=1/7) is a good first approximation when the site characteristics are yet to be determined.

Tower Height - is the hub height of the turbine (e.g. 30 meters).

Hub Height - is the height of the turbine's hub height.

Turbulence Factor - is a derating for turbulence, product variability, and other performance influencing factors. Use 0.1 (10%) - 0.15 (15%) is most cases. Setting this factor to 0% will over-predict performance for most situations.

Outputs / Results

Hub Mean Wind Speed - extrapolated wind speed at the height of the turbine hub.

Air Density Factor - the reduction of air density at a given altitude from sea level.

Average Power Output - is the average continuous equivalent output of the turbine.

Daily Energy Output - average energy produced per day.

Annual and Monthly Energy Output - calculated using the daily value.

Percent Operating Time - sum of the time the turbine generates some power.

Table A1-3: Example using the BWC XL.1 wind turbine with 1kW rated power

Inputs:		**Outputs:**		**Calculations:**
A - Site Altitude (m)	2000	H - Hub Mean Wind Speed (m/s)	6.66	$H = C*(F/B)^E$
B - Anem. Height (m)	50	I - Air Density Factor	-0.18	I = -0.18
C - Mean Wind Speed (m/s)	7.89	J - Average Output Power (kW)	0.30	J = The value of the sum under Column 5 in the table below
D - Weibull K = 2	2	K - Daily Energy Output (kWh)	7.0960	K = J * 24
E - Wind Shear Exp.	0.14	L - Annual Energy Output (kWh)	2590.0401	L = K * 365
F - Tower Height (m)	15	M - Monthly Energy Output (kWh)	215.8367	M = L / 12
G - Turbulence Factor	0.1	N - Percent Operating Time	89.5171	N = Sum of Column 4 where the turbine is producing some power

Note: Air Density Factor - the air density ratio is about 0.82 at an altitude of about 2000m, meaning that air at that altitude is 82% as dense as air at standard temperature and pressure. (In other words, air density factor is -18%).

Table A1- 4: Example of wind energy yield estimation

Column 1 Wind speed (m/s)	Column 2 Power (kW)	Column 3 Corrected power (kW)	Column 4 Wind Probability (Φ_u)	Column 5 net kW@v
0	0	0.000	0.0000	0.00000
1	0	0.000	0.0351	0.00000
2	0	0.000	0.0665	0.00000
3	0	0.000	0.0912	0.00000
4	0.062	0.046	0.1074	0.00491
5	0.123	0.091	0.1143	0.01037
6	0.233	0.172	0.1127	0.01937
7	0.376	0.277	0.1042	0.02892
8	0.540	0.399	0.0911	0.03631
9	0.700	0.517	0.0757	0.03909
10	0.891	0.658	0.0599	0.03938
11	1.064	0.785	0.0453	0.03555
12	1.208	0.892	0.0328	0.02920
13	1.240	0.915	0.0227	0.02078
14	1.202	0.887	0.0151	0.01339
15	1.149	0.848	0.0096	0.00817
16	1.099	0.811	0.0059	0.00479
17	1.047	0.773	0.0035	0.00269
18	0.993	0.733	0.0020	0.00145
19	0.941	0.694	0.0011	0.00075
20	0.895	0.661	0.0006	0.00037
21	0.848	0.626	0.0003	0.00018
		Totals	0.8952	0.2957

Source: Values in column 2 are from the manufacturer's description of the turbines power curve for various wind speeds; the remaining columns were calculated according to the formulas described below.

Column 1: Enter numbers 0 to 20 as bins of wind speed. These are wind speeds in meters per second.

Column 2: Enter these values from the manufacturers' description of the turbines power curve for various wind speeds. In this example SW Whisper H40 wind turbine is used. See the manufacturer's information for the power curve.

Column 3: In each cell in Column 3 put the value obtained by multiplying the corresponding row of each cell in Column 2 by (1 - G) * (1 + I).

Column 4: In each cell in column 4 put the value obtained using the following formula:
(D/(1.123*H)) * (Column1/(1.123*H))^(D-1) * Exp(-((Column1/(1.123*H))^D))

i.e., Column1 means the corresponding row cell in Column 1.

Column 5: Multiply the corresponding row cells of Column 3 and Column 4 and put the product in each cell of Column 5.

Table A1-5: Example wind configurations in the study

Configuration	**Stand-alone**	**Stand-alone**	**Minigrid**	**Minigrid**
Data source (capital & O&M costs)	**ESMAP, 2007**	**ESMAP, 2007**	**ESMAP, 2007**	**ESMAP, 2007**
Scenario (wind power density)	**Low**	**High**	**Low**	**High**
Wind power density (W/m2)	300	400	300	400
Wind speed	7.88	8.68	7.88	8.68
Power (kWh/day) = Value of cell K	7.10	7.10	694.86	800.63
Power (kWh/year) = Power * # systems	147,632	172,881	14,710,203	14,611,406
HH demand (kWh/month)	120	120	120	120
HH demand (kWh/day)	4	4	4	4
Configuration: Power rating (kW)	1	1	100	100
Population	5	5	50,000	50,000
# people per HH	5	5	5	5
Number of HHs	1	1	10,000	10,000
Wind system need (# rated systems)	1	1	58	50
Costs				
Capital cost of system ($/kW)	5,370	5,370	2,780	2,780
O&M ($/kW-yr)	1,721	1,721	1,263	1,263
Fuel costs ($/kW)	-	-	-	-
Discount rate	10%	10%	10%	10%
Life	20	20	20	20
Annualized capital costs (¢)	57,342	57,342	172,174,454	148,426,253
Annualized O&M costs (¢)	18,377	18,377	78,221,703	67,432,503
Annualized Fuel costs (¢)	-	-	-	-
Levelized capital costs (¢/kWh)	22.14	18.91	11.70	10.16
Levelized O&M costs (¢/kWh)	7.10	6.06	5.32	4.62
Levelized fuel costs (¢/kWh)	-	-	-	-
Total levelized cost (¢/kWh)	**29.23**	**24.96**	**17.02**	**14.77**
Total cost ($)	7,091	7,091	23,449,400	20,215,000
Average cost ($/HH)	**7,091**	**7,091**	**2,345**	**2,022**

Source: Data sources listed in second row; the remaining are the author's using the methods described above.

Diesel and Biodiesel power

Diesel power options take into account both fuel and transport costs in producing power. In the Kenya study for this exercise, the main port of Mombasa, Kenya is used as the central delivery point of imported diesel and the distance to each city is calculated. Biodiesel options are modeled by using information on suitable land areas proximate to each city and where *Jatropha curcas*, one of the more promising fuels for rural areas, can be grown and produced.

Diesel fuel prices and associated energy conversion information are based on feasibility calculations performed under the Kenyan Rural Electrification Project (KMOE, 2008). Capital and O&M costs for the stand-alone options were from ESMAP (2007) and larger minigrid options from the KMOE (2008). The base price of diesel oil used in decentralized power plants is linked to the price of crude oil – which has varied extensively during the past few years. In defining the scenarios we take two extreme values of $30/bbl. and $80/bbl. to reflect the wide range of oil prices.

Biodiesel prices in this study are assumed to be approximately equal to that of regular diesel since recent field evidence in Kenya suggests that the profitability of Jatropha production for smallholder farmers is expected to be minimal unless farm-level production is accompanied by investments and policies promoting decentralized oil extraction and transesterification (Tomomatsu and Swallow, 2007). Thus, on the production side, Jatropha is only marginally cost competitive with other forms of energy and any potential cost savings comes in the form of minimizing transportation costs, since Jatropha can be grown more locally.

Distance to potential growing areas was estimated as the straight line distance to nearest area of biomass potential, defined using the World Wildlife Fund (WWF) biomes of Deserts/Xeric Shrublands & Tropical/Subtropical Grasslands, Savannas, and Shrublands. Agricultural and urban areas as well as patches < 10 km² were not included.

Table A1-6: Estimates of cost ranges for diesel and biodiesel production (US $ / litre)

Diesel fuel ex-factory, 2005	0.43-0.45
NYMEX futures heating oil cif New York, November 2007	0.60-0.65
Biodiesel from (imported) palm oil, Kenya	0.70-0.89
Biodiesel from Jatropha, China	0.42-1.43
Large scale Fischer-Tropsch diesel from imported biomass, Europe	0.56-0.69

Source: Baur *et al*., 2007

Fuel costs for diesel and biodiesel options are best described by way of an example. Suppose we have the following configuration and assumptions for a diesel option:

Stand-alone diesel generator: 1kW
Efficiency: 30%
Oil price: $80/bbl.
Exchange rate (Kenyan Shilling/$): 70

Diesel price (AGO) (Ksh/liter) = 74.40
Diesel price (AGO) (Ksh/MJ) = 2.71
Transport price (Ksh/1000 MJ/km) = 0.42

Transport distance (km to Mombasa) = 500

Transport cost (Ksh/MJ) = 500 / 1000 x 0.42 = 0.21

Transport cost ($/GJ) = (2.71 + 0.21) x 1000 (GJ to MJ) / 70 (Kenyan Shilling/$) = 41.71

Diesel conversion efficiency (%) = 50%
Engine efficiency (%) = 32%

Full load efficiency on LHV (Lower Heating Value) (%) = 50% (diesel conversion efficiency) x 32% (engine efficiency) = 16.0%

Fuel power heat rate (Btu/kWh) = 3,412 (Btu/kWh) / 16.0% (efficiency) = 21,325

Convert fuel power heat rate to (kJ/kWh) = 21,325 (Btu/kWh) x 1054.9 (Btu/J) / 1,000 (kJ) = 22,496

Fuel cost ($/kWh) = 22,496 (kJ/kWh) x 41.71 ($/GJ) / 1,000,000 (kJ/GJ) = 0.9384
Fuel cost (¢/kWh) = 0.9384 x 100 = 93.84

Fuel costs for biodiesel options are similarly calculated and tabulated in the below tables.

Table A1-7: Example diesel and bio-diesel configurations in the study

Configuration	Stand-alone Diesel	Stand-alone Diesel	Minigrid Diesel	Minigrid Diesel	Minigrid Biodiesel	Minigrid Biodiesel	Minigrid Biodiesel	Minigrid Biodiesel
Data source (capital & O&M costs)	ESMAP, 2007	ESMAP, 2007	ESMAP, 2007	ESMAP, 2007	KMOE, 2008	KMOE, 2008	KMOE, 2008	KMOE, 2008
Scenario	Low eff./ high price	High eff./ low price	Low eff./ high price	High eff./ low price	Low eff./ high price	High eff./ low price	Low eff./ high price	High eff./ low price
Power rating (kW)	1.0	1.0	100.0	100.0	30.0	30.0	100.0	100.0
Capacity factor (%)	30%	40%	80%	90%	55%	65%	65%	70%
Power (kWh/month)	219.0	292.0	58400.0	65700.0	12045.0	14235.0	47450.0	51100.0
Power (kWh/day)	7.2	9.6	1920.0	2160.0	396.0	468.0	1560.0	1680.0
Power (kWh/year)	2,628	3,504	700,800	788,400	144,540	170,820	569,400	613,200
HH demand (kWh/month)	120	120	120	120	120	120	120	120
HH demand (kWh/day)	4	4	4	4	4	4	4	4
Population	5	5	500	500	500	500	500	500
# people per HH	5	5	5	5	5	5	5	5
Number of HHs	1	1	100	100	100	100	100	100
Distance	500	500	500	500	500	500	500	500
Diesel system need (# systems)	1	1	1	1	2	1	1	1
Costs								
Capital cost of system ($/kW)	680	680	640	640	1,637	1,637	1,215	1,215
O&M ($/kW)	532	532	3,281	3,281	293 [1]	293 [1]	248 [1]	248 [1]
Fuel & fuel transport costs ($/kW)	2,466	1,233	2,715	1,146	4,202	1,862	2,051	828
Discount rate	10%	10%	10%	10%	10%	10%	10%	10%
Life	10	10	20	20	10	10	10	10
Annualized capital costs (¢)	10,061	10,061	683,401	683,401	726,584	726,584	1,797,597	1,797,597
Annualized O&M costs (¢)	7,871	7,871	3,503,500	3,503,500	880,020	880,020	2,480,600	2,480,600
Annualized Fuel costs (¢)	246,610	123,305	27,153,606	11,455,428	12,607,036	5,587,209	20,506,459	8,281,455
Levelized capital costs (¢/kWh)	3.83	2.87	0.98	0.87	5.03	4.25	3.16	2.93
Levelized O&M costs (¢/kWh)	3.00	2.25	5.00	4.44	6.09	5.15	4.36	4.05
Levelized fuel costs (¢/kWh)	93.84	35.19	38.75	14.53	87.22	32.71	36.01	13.51
Total levelized cost (¢/kWh)	**100.66**	**40.31**	**44.72**	**19.84**	**98.34**	**42.11**	**43.53**	**20.48**
Total cost ($)	3,678	2,445	663,636	506,654	367,961	113,782	351,371	229,121
Average cost ($/HH)	**3,678**	**2,445**	**6,636**	**5,067**	**3,680**	**1,138**	**3,514**	**2,291**

Source: Data sources listed in second row the remaining are the author's using the methods described above. 1 - O&M for Minigrid Biodiesel options are shown as annualized costs ($/kW-yr)

Table A1-8: Corresponding fuel cost calculations for the diesel and bio-diesel configurations in the study

Configuration	**Stand-alone Diesel**	**Stand-alone Diesel**	**Minigrid Diesel**	**Minigrid Diesel**	**Minigrid Biodiesel**	**Minigrid Biodiesel**	**Minigrid Biodiesel**	**Minigrid Biodiesel**
Data source (fuel prices and energy conversions)	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**	**KMOE, 2008**
Exchange rate (Kenyan Shilling/$)	70	70	70	70	70	70	70	70
Oil price ($/bbl)	80	30	80	30	80	30	80	30
Diesel price (AGO) (Ksh/liter)	74.40	27.90	74.40	27.90	74.40	27.90	74.40	27.90
Diesel price (AGO) (Ksh/MJ)	2.71	1.02	2.71	1.02	2.71	1.02	2.71	1.02
Transport price (Ksh/1000 MJ/km)	0.42	0.16	0.42	0.16	0.42	0.16	0.42	0.16
Transport distance (km to Mombasa)	500	500	500	500	5	5	5	5
Transport cost (Ksh/MJ)	0.21	0.08	0.21	0.08	0.002	0.001	0.002	0.001
Transport cost ($/GJ)	41.71	15.64	41.71	15.64	38.77	14.54	38.77	14.54
Diesel conversion efficiency (%)	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Engine efficiency (%)	32.0%	32.0%	77.5%	77.5%	32.0%	32.0%	77.5%	77.5%
Full load efficiency on LHV (%)	16.0%	16.0%	38.8%	38.8%	16.0%	16.0%	38.8%	38.8%
Fuel power heat rate (Btu/kWh)	21,325	21,325	8,805	8,805	21,325	21,325	8,805	8,805
Convert fuel power heat rate to (kJ/kWh)	22,496	22,496	9,289	9,289	22,496	22,496	9,289	9,289
Fuel cost ($/kWh)	0.94	0.35	0.39	0.15	0.87	0.33	0.36	0.14
Fuel cost (¢/kWh)	93.84	35.19	38.75	14.53	87.22	32.71	36.01	13.51

Source: Data sources listed in second row; the remaining are the author's using the methods described above.

Appendix 2
Levelized Cost Estimates for Ethiopia, Ghana and Kenya

Table A2-1: Ethiopia - Baseline estimates of levelized cost for grid-connected, off-grid and minigrid options (US cents/kWh)

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
1	1996411	16.2	62.7	113.2	25.2	23.5	14.9	62.4	23.2
2	1546027	16.4	61.1	117.2	26.3	22.9	15.5	54.0	23.4
3	1262633	16.5	64.8	121.6		24.4		121.7	23.6
4	987967	17.0	64.1	114.7		24.1		114.7	23.4
5	942516	16.9	62.8	108.9	26.9	23.6	15.8	99.6	23.4
6	845727	17.0	64.5	103.1	25.6	24.3	15.1	38.0	23.2
7	720993	17.8	66.8	112.6	26.7	25.2	15.7	84.0	23.2
8	678826	17.4	64.5	103.0	25.8	24.3	15.2	47.7	23.2
9	627561	17.4	66.1	110.3		24.9		110.4	23.3
10	558701	18.8	64.9	105.9		24.4		105.9	23.1
11	548222	17.5	62.4	107.1	23.3	23.4	13.8	35.0	23.3
12	446110	18.0	64.1	102.5		24.1		102.5	23.3
13	385002	18.1	63.8	110.4		24.0		110.4	23.3
14	337621	18.1	65.2	113.3	26.2	24.6	15.4	59.9	23.3
15	270390	18.5	62.8	103.3	26.7	23.6	15.7	54.2	23.5
16	258246	18.8	64.3	110.1	25.9	24.2	15.3	68.2	23.2
17	214544	20.0	65.8	99.9	27.5	24.8	16.1	63.8	23.1
18	211971	18.6	62.7	110.1	28.0	23.5	16.3	92.9	23.4
19	178813	21.1	65.7	88.7	26.9	24.8	15.8	87.2	23.1
20	140251	21.7	64.5	114.9		24.3		115.0	23.3
21	117045	23.2	68.1	87.8		25.8		87.8	23.2
22	90932	24.7	67.1	79.3		25.4		79.2	23.1
23	89514	29.5	67.6	76.8		25.5		76.7	23.1
24	86879	28.5	64.9	73.7	26.8	24.4	15.7	69.0	23.1
25	85406	27.1	65.9	95.1		24.9		95.1	23.1
26	85323	32.5	68.5	69.5		25.9		69.4	23.1
27	83455	28.6	65.4	87.0	28.7	24.6	16.7	59.4	23.1
28	64116	28.1	64.5	79.9	27.1	24.3	15.9	67.1	23.1
29	61670	32.0	67.1	70.3		25.3		70.2	23.1
30	61373	24.8	62.1	119.6	24.3	23.3	14.4	74.8	23.3
31	60845	32.8	66.2	83.8	26.1	25.0	15.4	57.8	23.1
32	59452	30.7	68.5	66.3		25.9		66.2	23.1
33	52869	37.4	70.4	71.4		26.7		71.3	23.1
34	52440	32.7	69.5	75.7		26.3		75.6	23.1
35	49325	34.6	66.4	80.9		25.0		80.9	23.1
36	46739	27.1	62.6	101.5		23.5		101.5	23.7
37	32779	32.3	63.3	89.0		23.8		88.9	23.3
38	31652	33.8	65.0	84.7		24.5		84.6	23.2
39	26352	43.1	67.2	83.7		25.4		83.6	23.1
40	24550	43.5	69.5	82.9		26.4		82.8	23.1
41	22118	50.1	66.3	87.5		25.0		87.4	23.1
42	21155	45.4	66.8	85.6	26.8	25.2	15.7	31.2	23.1
43	21139	34.8	62.6	90.1	26.4	23.5	15.6	28.9	23.2
44	19137	50.0	64.9	84.6		24.4		84.6	23.1
45	18678	54.3	66.5	85.7		25.1		85.6	23.1
46	16820	52.3	64.3	97.3		24.2		97.3	23.1
47	14234	84.8	66.5	76.1	28.9	25.1	16.9	67.8	23.1
48	13532	58.8	63.7	107.3		23.9		107.3	23.2

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
49	12709	41.2	62.1	99.3		23.3		99.3	23.1
50	11162	89.5	66.1	84.1	26.4	24.9	15.5	50.5	23.1
51	8718	105.3	68.0	67.7		25.7		67.6	23.1
52	7083	96.4	66.1	79.7	27.1	24.9	15.9	29.6	23.1
53	5594	157.6	66.1	73.6	28.8	24.9	16.8	56.0	23.1
54	3891	178.4	65.8	99.7		24.8		99.7	23.1
55	1881	331.0	68.7	66.4		26.0		66.3	23.1

Table A2-2: Ethiopia - Estimates of levelized cost for grid-connected, off-grid and minigrid options (US cents/kWh), Learning rates over 20 years

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
1	1996411	16.1	62.7	32.8	12.6	23.5	8.1	22.3	23.2
2	1546027	16.3	61.0	34.0	13.2	22.9	8.5	19.3	23.4
3	1262633	16.4	64.8	35.2		24.4		43.5	23.6
4	987967	16.9	64.1	33.2		24.1		41.0	23.4
5	942516	16.8	62.8	31.5	13.5	23.6	8.6	35.6	23.4
6	845727	17.0	64.5	29.9	12.8	24.3	8.3	13.6	23.2
7	720993	17.7	66.8	32.6	13.4	25.2	8.6	30.0	23.2
8	678826	17.3	64.5	29.8	12.9	24.3	8.3	17.0	23.2
9	627561	17.3	66.1	32.0		24.9		39.4	23.3
10	558701	18.7	64.9	30.7		24.4		37.8	23.1
11	548222	17.4	62.4	31.0	11.7	23.4	7.6	12.5	23.3
12	446110	18.0	64.1	29.7		24.1		36.6	23.2
13	385002	18.0	63.8	32.0		24.0		39.4	23.3
14	337621	18.1	65.2	32.8	13.1	24.6	8.4	21.4	23.3
15	270390	18.5	62.8	29.9	13.4	23.6	8.6	19.4	23.5
16	258246	18.7	64.3	31.9	13.0	24.2	8.4	24.4	23.2
17	214544	20.0	65.8	28.9	13.8	24.8	8.8	22.8	23.1
18	211971	18.5	62.7	31.9	14.0	23.5	8.9	33.2	23.4
19	178813	21.1	65.7	25.7	13.5	24.8	8.6	31.2	23.1
20	140251	21.7	64.4	33.3		24.3		41.1	23.2
21	117045	23.1	68.1	25.4		25.8		31.4	23.2
22	90932	24.6	67.1	23.0		25.4		28.3	23.1
23	89514	29.4	67.6	22.3		25.5		27.4	23.1
24	86879	28.4	64.9	21.4	13.4	24.4	8.6	24.7	23.1
25	85406	27.1	65.9	27.6		24.9		34.0	23.1
26	85323	32.4	68.5	20.1		25.9		24.8	23.1
27	83455	28.5	65.4	25.2	14.4	24.6	9.1	21.2	23.1
28	64116	28.0	64.5	23.1	13.6	24.3	8.7	24.0	23.1
29	61670	31.9	67.1	20.4		25.3		25.1	23.1
30	61373	24.7	62.1	34.7	12.2	23.3	7.9	26.7	23.3
31	60845	32.7	66.2	24.3	13.1	25.0	8.4	20.7	23.1
32	59452	30.6	68.5	19.2		25.9		23.7	23.1
33	52869	37.3	70.4	20.7		26.7		25.5	23.1
34	52440	32.7	69.4	21.9		26.3		27.0	23.1
35	49325	34.5	66.3	23.5		25.0		28.9	23.1
36	46739	27.1	62.5	29.4		23.5		36.3	23.7
37	32779	32.2	63.3	25.8		23.8		31.8	23.3
38	31652	33.8	65.0	24.5		24.5		30.2	23.1
39	26352	43.0	67.2	24.2		25.4		29.9	23.1
40	24550	43.4	69.5	24.0		26.4		29.6	23.1
41	22118	50.0	66.3	25.3		25.0		31.2	23.1
42	21155	45.4	66.8	24.8	13.4	25.2	8.6	11.1	23.1
43	21139	34.8	62.6	26.1	13.2	23.5	8.5	10.3	23.2
44	19137	49.9	64.9	24.5		24.4		30.2	23.1
45	18678	54.2	66.5	24.8		25.1		30.6	23.1
46	16820	52.2	64.3	28.2		24.2		34.8	23.1
47	14234	84.7	66.5	22.1	14.5	25.1	9.2	24.2	23.1
48	13532	58.8	63.7	31.1		23.9		38.3	23.2
49	12709	41.1	62.1	28.8		23.3		35.5	23.1
50	11162	89.4	66.1	24.4	13.2	24.9	8.5	18.0	23.1
51	8718	105.2	68.0	19.6		25.7		24.2	23.1
52	7083	96.3	66.1	23.1	13.6	24.9	8.7	10.6	23.1

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
53	5594	157.5	66.0	21.3	14.4	24.9	9.2	20.0	23.1
54	3891	178.3	65.8	28.9		24.8		35.6	23.1
55	1881	331.0	68.7	19.2		26.0		23.7	23.1

Table A2-3: Ethiopia – 20-year learning rate (percent/year) required to reach grid parity

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV & wind	Biodiesel
1	17.45	5.91	-1.08	19.15	5.08
2	17.65	6.31	-0.76	16.74	5.00
3	17.95			29.63	5.02
4	17.10			28.16	4.49
5	16.67	6.27	-0.83	25.95	4.62
6	16.04	5.44	-1.55	10.99	4.31
7	16.46	5.40	-1.64	22.31	3.69
8	15.86	5.31	-1.67	14.04	4.04
9	16.49			27.11	4.08
10	15.37			25.19	2.91
11	16.16	3.80	-3.00	9.45	4.05
12	15.45			25.32	3.55
13	16.12			26.48	3.53
14	16.34	4.89	-2.09	16.79	3.48
15	15.26	4.88	-2.13	14.94	3.29
16	15.74	4.29	-2.64	18.24	2.96
17	14.21	4.21	-2.79	16.24	1.99
18	15.83	5.43	-1.67	23.23	3.17
19	12.59	3.16	-3.73	20.22	1.24
20	14.75			24.14	0.92
21	11.64			18.89	0.00
22	10.12			16.34	-0.92
23	8.23			13.22	-3.31
24	8.17	-0.79	-7.41	12.17	-2.84
25	10.92			17.69	-2.19
26	6.49			10.37	-4.56
27	9.64	0.06	-6.71	9.99	-2.86
28	9.03	-0.46	-7.12	12.00	-2.62
29	6.73			10.76	-4.36
30	13.89	-0.25	-6.80	15.42	-0.86
31	8.06	-2.93	-9.38	7.64	-4.69
32	6.58			10.51	-3.82
33	5.49			8.74	-6.40
34	7.17			11.48	-4.68
35	7.27			11.65	-5.40
36	11.52			18.69	-1.84
37	8.73			14.06	-4.38
38	7.88			12.65	-5.06
39	5.64			9.00	-8.19
40	5.48			8.73	-8.31
41	4.72			7.51	-10.07
42	5.37	-6.64	-12.87	-4.77	-8.86
43	8.18	-3.52	-9.94	-2.41	-5.41
44	4.45			7.07	-10.03
45	3.84			6.10	-11.05
46	5.26			8.39	-10.57
47	-0.89	-13.03	-18.93	-2.86	-16.33
48	5.09			8.12	-11.96
49	7.54			12.10	-7.61
50	-0.51	-14.68	-20.36	-7.17	-16.94
51	-3.58			-5.59	-18.78
52	-1.56	-15.18	-20.86	-14.24	-17.78
53	-6.10	-19.80	-25.24	-12.57	-23.14

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV & wind	Biodiesel
54	-4.69			-7.28	-24.43
55	-12.43			-18.84	-30.57

Table A2-4: Ethiopia - Carbon tax (USD/ton) required to reach grid parity; baseline

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV-wind	Biodiesel
1	3618	336	-118	4170	637
2	3758	368	-85	3392	633
3	3919			9500	640
4	3642			8825	580
5	3431	375	-95	7469	594
6	3208	320	-174	1895	555
7	3533	331	-193	5975	487
8	3194	317	-191	2741	526
9	3465			8395	532
10	3247			7864	395
11	3341	217	-330	1585	530
12	3149			7626	472
13	3440			8335	470
14	3547	300	-246	3773	465
15	3160	306	-256	3217	446
16	3406	267	-315	4465	403
17	2978	279	-354	3951	279
18	3410	349	-204	6711	430
19	2521	214	-484	5967	179
20	3474			8418	136
21	2411			5833	0
22	2035			4922	-145
23	1764			4264	-580
24	1686	-63	-1151	3658	-488
25	2534			6136	-366
26	1381			3336	-847
27	2177	5	-1068	2787	-493
28	1933	-36	-1098	3528	-447
29	1428			3452	-803
30	3536	-18	-937	4515	-137
31	1900	-250	-1575	2259	-877
32	1328			3207	-686
33	1267			3060	-1293
34	1601			3870	-872
35	1727			4177	-1041
36	2773			6715	-311
37	2113			5114	-814
38	1896			4587	-964
39	1514			3661	-1805
40	1470			3555	-1841
41	1395			3372	-2438
42	1496	-696	-2682	-1288	-2018
43	2063	-313	-1740	-538	-1049
44	1292			3123	-2426
45	1170			2830	-2816
46	1677			4061	-2634
47	-323	-2083	-6135	-1535	-5572
48	1807			4376	-3216
49	2166			5245	-1633
50	-201	-2355	-6683	-3526	-5999
51	-1402			-3403	-7426
52	-624	-2583	-7268	-6038	-6622
53	-3133	-4803	-12717	-9175	-12149

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV-wind	Biodiesel
54	-2934			-7107	-14027
55	-9867			-23905	-27810

Table A2-5: Ethiopia - Carbon tax (USD/ton) required to reach grid parity; with 20 year learning rates

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV-wind	Biodiesel
1	623	-130	-720	558	643
2	657	-118	-711	267	638
3	701			2443	646
4	608			2174	585
5	551	-123	-735	1697	599
6	481	-154	-786	-305	561
7	554	-163	-828	1107	492
8	468	-162	-808	-21	531
9	546			1996	538
10	446			1727	400
11	508	-214	-889	-441	536
12	438			1685	478
13	520			1935	476
14	550	-185	-870	302	470
15	427	-189	-892	80	452
16	492	-213	-934	512	408
17	335	-230	-1007	256	285
18	498	-169	-866	1325	436
19	173	-284	-1123	912	185
20	433			1752	141
21	88			746	5
22	-62			332	-140
23	-268			-182	-574
24	-263	-559	-1789	-340	-483
25	18			624	-360
26	-457			-685	-841
27	-123	-526	-1746	-655	-487
28	-180	-538	-1742	-361	-441
29	-430			-615	-797
30	371	-468	-1521	181	-132
31	-315	-733	-2197	-1090	-871
32	-425			-628	-680
33	-621			-1071	-1287
34	-400			-511	-867
35	-413			-510	-1035
36	88			832	-306
37	-241			-41	-808
38	-344			-318	-958
39	-699			-1185	-1800
40	-723			-1246	-1836
41	-919			-1695	-2432
42	-767	-1191	-3320	-3091	-2013
43	-322	-802	-2370	-2207	-1043
44	-947			-1779	-2420
45	-1096			-2134	-2811
46	-897			-1578	-2628
47	-2336	-2618	-6818	-5463	-5566
48	-1032			-1845	-3211
49	-461			-512	-1627
50	-2426	-2843	-7311	-6449	-5993
51	-3192			-7322	-7420
52	-2731	-3085	-7913	-7746	-6616

	Off-grid			Minigrid		
BSP	Solar	Wind		Wind	PV-wind	Biodiesel
53	-5079	-5336		-13397	-12419	-12143
54	-5572				-12887	-14021
55	-11623				-27748	-27805

Table A2-6: Ghana - Baseline estimates of levelized cost for grid-connected, off-grid and minigrid options (US cents/kWh)

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
1	1581666	18.1	61.5	64.8	26.8	23.0	15.7	61.4	23.4
2	921769	19.2	63.4	68.8	27.4	23.8	16.0	66.5	23.5
3	406925	22.8	66.2	66.6	27.6	25.0	16.1	64.6	23.1
4	384147	20.6	63.1	66.1		23.7		66.0	23.9
5	374217	20.1	61.9	64.7	25.6	23.2	15.1	59.8	23.2
6	193140	25.1	64.5	66.2	24.6	24.3	14.6	64.8	23.2
7	147049	26.9	66.7	68.0	25.9	25.2	15.3	67.5	23.1
8	128179	26.8	64.3	65.9	25.9	24.2	15.3	63.9	23.2
9	76138	26.9	65.7	67.4		24.8		67.4	23.2
10	51854	33.8	63.7	65.1		23.9		65.0	23.1
11	35777	36.7	64.1	68.3		24.1		68.2	23.8
12	34977	42.5	65.2	68.7		24.6		68.6	23.1
13	16537	42.2	61.5	62.5		23.0		62.4	23.8
14	11294	83.7	65.6	65.7		24.7		65.6	23.1
15	8280	88.0	64.6	70.9	23.7	24.3	14.1	26.1	23.3
16	6803	105.0	63.0	70.5	23.3	23.6	13.9	41.9	23.2
17	6371	102.7	62.1	60.3		23.3		60.2	23.3
18	3657	209.5	67.6	67.6		25.5		67.5	23.1
19	393	565.4	64.4	63.5		24.2		63.4	24.2

Table A2-7: Ghana - Estimates of levelized cost for grid-connected, off-grid and minigrid options (US cents/kWh), Learning rates over 20 years

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
1	1581666	18.0	61.5	18.8	13.4	23.0	8.6	21.9	23.4
2	921769	19.1	63.4	19.9	13.7	23.8	8.8	23.8	23.4
3	406925	22.7	66.2	19.3	13.8	25.0	8.8	23.1	23.1
4	384147	20.5	63.1	19.2		23.7		23.6	23.9
5	374217	20.0	61.9	18.7	12.8	23.2	8.3	21.4	23.1
6	193140	25.0	64.5	19.2	12.3	24.3	8.0	23.2	23.1
7	147049	26.8	66.7	19.7	13.0	25.2	8.4	24.1	23.1
8	128179	26.7	64.2	19.1	13.0	24.2	8.4	22.8	23.2
9	76138	26.9	65.7	19.5		24.8		24.1	23.2
10	51854	33.7	63.7	18.9		23.9		23.2	23.1
11	35777	36.6	64.1	19.8		24.1		24.4	23.8
12	34977	42.4	65.2	19.9		24.6		24.5	23.1
13	16537	42.2	61.5	18.1		23.0		22.3	23.7
14	11294	83.7	65.6	19.0		24.7		23.5	23.1
15	8280	87.9	64.6	20.5	11.9	24.3	7.7	9.3	23.3
16	6803	104.9	63.0	20.4	11.7	23.6	7.6	15.0	23.2
17	6371	102.7	62.1	17.5		23.3		21.5	23.3
18	3657	209.4	67.6	19.6		25.5		24.1	23.1
19	393	565.3	64.4	18.4		24.2		22.6	24.2

Table A2-8: Ghana – 20-year learning rate (percent/year) required to reach grid parity

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV & wind	Biodiesel
1	11.13	5.22	-1.80	17.20	3.58
2	11.13	4.72	-2.30	17.52	2.80
3	9.26	2.49	-4.39	14.47	0.18
4	10.14			16.37	2.07
5	10.15	3.19	-3.64	15.22	1.97
6	8.35	-0.22	-6.77	13.13	-1.08
7	7.97	-0.46	-7.06	12.71	-2.06
8	7.73	-0.41	-7.02	11.96	-1.94
9	7.89			12.65	-2.03
10	5.56			8.85	-5.06
11	5.28			8.40	-5.73
12	4.04			6.41	-8.00
13	3.29			5.20	-7.58
14	-1.98			-3.12	-16.17
15	-1.77	-15.69	-21.20	-14.61	-16.63
16	-3.24	-17.75	-23.11	-11.25	-18.69
17	-4.30			-6.70	-18.39
18	-8.92			-13.67	-26.07
19	-16.54			-24.74	-35.07

Table A2-9: Ghana - Carbon tax (USD/ton) required to reach grid parity; baseline

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV-wind	Biodiesel
1	258	48	-32	579	71
2	274	45	-42	633	57
3	242	26	-89	559	4
4	252			609	44
5	246	30	-67	531	41
6	227	-2	-140	531	-26
7	227	-5	-155	544	-51
8	216	-5	-154	496	-48
9	224			541	-50
10	173			417	-143
11	175			422	-172
12	145			349	-259
13	112			270	-247
14	-100			-242	-811
15	-95	-355	-989	-828	-865
16	-190	-451	-1219	-844	-1094
17	-234			-568	-1062
18	-784			-1899	-2493
19	-2772			-6716	-7240

Table A2-10: Ghana - Carbon tax (USD/ton) required to reach grid parity; with 20 year learning rates

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV-wind	Biodiesel
1	4	-25	-126	52	72
2	5	-30	-138	62	58
3	-19	-49	-186	4	5
4	-7			42	45
5	-7	-40	-157	18	42
6	-32	-70	-227	-25	-25
7	-39	-76	-247	-36	-50
8	-42	-76	-245	-52	-47
9	-40			-37	-49
10	-82			-141	-142
11	-93			-163	-171
12	-124			-240	-258
13	-133			-266	-246
14	-357			-806	-810
15	-372	-420	-1073	-1052	-864
16	-467	-515	-1302	-1203	-1093
17	-470			-1085	-1062
18	-1048			-2478	-2492
19	-3021			-7259	-7239

Table A2-11: Kenya - Baseline estimates of levelized cost for grid-connected, off-grid and minigrid options (US cents/kWh)

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
1	2149737	21.4	67.2	96.4		25.4		96.4	23.2
2	1925957	21.5	65.0	84.3	26.6	24.5	15.6	78.6	23.1
3	506415	23.3	66.3	103.7	25.0	25.0	14.8	96.7	23.1
4	449608	23.4	61.0	55.8		22.8		55.8	23.2
5	303893	23.5	67.8	105.0		25.6		105.0	23.1
6	280630	25.5	63.6	73.2	28.4	23.9	16.6	72.0	23.1
7	252172	24.1	66.4	93.6		25.0		93.6	23.1
8	234719	24.2	65.6	71.2	26.3	24.7	15.5	47.3	23.1
9	71713	44.7	67.8	65.2		25.7		65.2	23.1
10	71149	42.9	63.6	59.2		23.9		59.1	23.1
11	52346	36.9	68.9	67.6	27.6	26.1	16.2	60.6	23.1
12	51385	37.0	62.1	71.5		23.3		71.4	23.1
13	49525	35.8	65.2	79.3		24.5		79.2	23.1
14	45719	40.5	66.9	82.1	26.3	25.2	15.5	61.1	23.1
15	42749	47.8	62.6	55.5		23.5		55.4	23.2
16	36925	38.7	67.8	82.2		25.7		82.1	23.1
17	36029	45.9	65.6	59.3		24.7		59.2	23.1
18	33450	47.7	63.7	64.4		23.9		64.4	23.1
19	29525	60.7	69.1	64.9		26.2		64.8	23.1
20	23055	62.6	68.1	67.6	26.8	25.8	15.7	42.4	23.1
21	21641	65.2	69.1	75.1		26.2		75.0	23.1
22	19498	68.6	65.9	59.9		24.8		59.8	23.1
23	19460	69.8	68.8	71.5	27.2	26.1	15.9	63.4	23.1
24	16353	76.0	69.1	67.7		26.2		67.6	23.2
25	9595	107.9	69.1	74.0		26.2		73.9	23.1
26	5559	147.8	64.3	55.2		24.2		55.1	23.1
27	5047	124.4	61.2	55.0		22.9		54.9	23.3
28	4329	159.0	68.1	70.5	24.4	25.8	14.5	26.9	23.1
29	4242	198.4	69.1	67.3	24.2	26.2	14.4	26.7	23.1
30	3479	203.8	64.1	59.6		24.1		59.5	23.1
31	3399	132.7	69.1	81.4		26.2		81.4	23.2
32	2252	287.2	69.1	72.2	26.6	26.2	15.7	29.1	23.1
33	1736	369.4	67.3	66.5		25.4		66.4	23.1
34	590	963.9	63.4	60.8		23.8		60.7	23.1

Table A2-12: Kenya - Estimates of levelized cost for grid-connected, off-grid and minigrid options (US cents/kWh), Learning rates over 20 years

			Off-grid			Minigrid			
BSP	No. HH	Marg. Grid	Diesel	Solar	Wind	Diesel	Wind	PV-wind	Biodiesel
1	2149737	21.3	67.2	27.9		25.4		34.4	23.2
2	1925957	21.5	64.9	24.4	13.3	24.5	8.6	28.1	23.1
3	506415	23.2	66.3	30.0	12.5	25.0	8.1	34.5	23.1
4	449608	23.3	61.0	16.2		22.8		19.9	23.2
5	303893	23.4	67.8	30.4		25.6		37.5	23.1
6	280630	25.4	63.5	21.2	14.2	23.9	9.1	25.7	23.1
7	252172	24.0	66.3	27.1		25.0		33.4	23.1
8	234719	24.2	65.6	20.6	13.2	24.7	8.5	16.9	23.1
9	71713	44.7	67.8	18.9		25.7		23.3	23.1
10	71149	42.8	63.6	17.2		23.9		21.1	23.1
11	52346	36.8	68.9	19.6	13.8	26.1	8.8	21.6	23.1
12	51385	37.0	62.1	20.7		23.3		25.5	23.1
13	49525	35.8	65.1	23.0		24.5		28.3	23.1
14	45719	40.4	66.8	23.8	13.2	25.2	8.5	21.8	23.1
15	42749	47.8	62.6	16.1		23.5		19.8	23.2
16	36925	38.6	67.8	23.8		25.7		29.3	23.1
17	36029	45.9	65.6	17.2		24.7		21.2	23.1
18	33450	47.7	63.7	18.7		23.9		23.0	23.1
19	29525	60.6	69.1	18.8		26.2		23.2	23.1
20	23055	62.6	68.1	19.6	13.4	25.8	8.6	15.1	23.1
21	21641	65.1	69.1	21.8		26.2		26.8	23.1
22	19498	68.5	65.9	17.4		24.8		21.4	23.1
23	19460	69.8	68.8	20.7	13.6	26.1	8.7	22.7	23.1
24	16353	75.9	69.1	19.6		26.2		24.2	23.2
25	9595	107.8	69.1	21.4		26.2		26.4	23.1
26	5559	147.8	64.3	16.0		24.2		19.7	23.1
27	5047	124.3	61.2	15.9		22.9		19.6	23.3
28	4329	158.9	68.1	20.4	12.2	25.8	7.9	9.6	23.1
29	4242	198.4	69.1	19.5	12.1	26.2	7.9	9.5	23.1
30	3479	203.8	64.1	17.3		24.1		21.3	23.1
31	3399	132.6	69.1	23.6		26.2		29.1	23.2
32	2252	287.1	69.1	20.9	13.3	26.2	8.6	10.4	23.1
33	1736	369.4	67.3	19.3		25.4		23.7	23.1
34	590	963.8	63.3	17.6		23.8		21.7	23.1

Table A2-13: Kenya – 20-year learning rate (percent/year) required to reach grid parity

	Off-grid			Minigrid	
BSP	Solar	Wind	Wind	PV & wind	Biodiesel
1	13.25			21.59	1.10
2	11.94	2.80	-4.07	18.31	0.97
3	13.15	0.91	-5.75	20.32	-0.08
4	7.47			11.96	-0.09
5	13.18			21.47	-0.21
6	9.12	1.43	-5.42	14.45	-1.34
7	11.87			19.27	-0.56
8	9.31	1.07	-5.65	9.08	-0.66
9	3.17			5.01	-8.65
10	2.70			4.25	-8.12
11	5.14	-3.70	-10.17	6.65	-6.22
12	5.58			8.89	-6.26
13	6.78			10.85	-5.83
14	6.02	-5.46	-11.75	5.49	-7.40
15	1.24			1.94	-9.43
16	6.43			10.27	-6.80
17	2.14			3.35	-9.00
18	2.52			3.97	-9.47
19	0.56			0.87	-12.40
20	0.63	-10.45	-16.43	-4.95	-12.78
21	1.18			1.85	-13.22
22	-1.11			-1.76	-13.85
23	0.20	-11.54	-17.46	-1.24	-14.07
24	-0.94			-1.49	-15.01
25	-3.07			-4.79	-19.04
26	-7.82			-12.03	-22.45
27	-6.52			-10.08	-20.52
28	-6.50	-21.59	-26.74	-20.62	-23.23
29	-8.55	-23.90	-28.90	-22.95	-25.53
30	-9.66			-14.77	-25.80
31	-3.95			-6.15	-21.26
32	-10.79	-26.57	-31.47	-25.73	-29.20
33	-13.21			-19.98	-31.59
34	-20.42			-30.17	-40.03

Table A2-14: Kenya - Carbon tax (USD/ton) required to reach grid parity; baseline

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV-wind	Biodiesel
1	708			1714	41
2	593	48	-135	1305	36
3	759	16	-195	1678	-3
4	307			740	-3
5	770			1864	-8
6	451	28	-203	1064	-54
7	657			1589	-22
8	443	20	-200	528	-26
9	194			467	-494
10	154			371	-452
11	290	-88	-474	541	-316
12	325			785	-319
13	410			992	-291
14	393	-134	-572	471	-398
15	73			174	-563
16	411			993	-356
17	126			304	-523
18	158			381	-563
19	40			95	-860
20	47	-338	-1072	-463	-904
21	94			225	-961
22	-82			-200	-1040
23	16	-403	-1232	-147	-1069
24	-78			-190	-1207
25	-320			-777	-1939
26	-875			-2121	-2852
27	-655			-1589	-2313
28	-835	-1270	-3304	-3021	-3107
29	-1238	-1645	-4210	-3928	-4010
30	-1361			-3299	-4133
31	-484			-1174	-2504
32	-2030	-2460	-6209	-5903	-6039
33	-2860			-6930	-7919
34	-8527			-20654	-21513

Table A2-15: Kenya - Carbon tax (USD/ton) required to reach grid parity; with 20 year learning rates

	Off-grid		Minigrid		
BSP	Solar	Wind	Wind	PV-wind	Biodiesel
1	62			300	42
2	28	-77	-295	151	37
3	65	-101	-346	259	-2
4	-67			-78	-2
5	66			322	-7
6	-40	-106	-374	7	-53
7	29			215	-21
8	-34	-104	-359	-166	-25
9	-243			-489	-493
10	-242			-497	-451
11	-163	-217	-640	-347	-315
12	-154			-263	-318
13	-121			-171	-290
14	-157	-258	-731	-425	-397
15	-299			-640	-562
16	-140			-212	-354
17	-271			-565	-522
18	-274			-564	-562
19	-395			-856	-858
20	-406	-464	-1234	-1084	-903
21	-409			-876	-960
22	-483			-1078	-1039
23	-463	-530	-1396	-1077	-1068
24	-531			-1183	-1206
25	-816			-1862	-1938
26	-1244			-2929	-2851
27	-1024			-2395	-2311
28	-1307	-1385	-3453	-3414	-3106
29	-1689	-1759	-4357	-4319	-4009
30	-1761			-4173	-4132
31	-1030			-2368	-2503
32	-2514	-2585	-6370	-6328	-6038
33	-3306			-7904	-7918
34	-8934			-21544	-21512