Energy Policy 39 (2011) 215–227

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The economics of renewable energy expansion in rural Sub-Saharan Africa

Uwe Deichmann [a,*], Craig Meisner [b], Siobhan Murray [a], David Wheeler [c]

[a] Development Research Group, World Bank, MSN MC3-300, 1818 H Street NW, Washington, DC 20433-0002, USA
[b] Europe and Central Asia Department, World Bank, USA
[c] Center for Global Development, Washington, DC, USA

ARTICLE INFO

Article history:
Received 20 April 2010
Accepted 21 September 2010
Available online 13 October 2010

Keywords:
Energy supply modeling
Africa
Geographic analysis

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. We 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. Our results suggest that decentralized renewable energy will likely play an important role in expanding rural energy access. However, 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 decarbonize the fuel mix for centralized power generation as it expands in Africa.

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, i.e., 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 grid-connected supply has 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 land lines grew so slowly (3.2% $year^{-1}$) that coverage in 2000 was limited to 1.4 lines per 100 inhabitants. In contrast, mobile phone connections grew so quickly after 1993 (55% $year^{-1}$) that coverage had reached 22.5 per 100 inhabitants by 2007 (Fig. 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.

* Corresponding author. Tel.: +1 202 473 6400.
E-mail address: udeichmann@worldbank.org (U. Deichmann).

[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.

0301-4215/$ - see front matter © 2010 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2010.09.034

Table 1
Potential annual production of renewable energy relative to current annual domestic energy consumption.
Source: Buys et al. (2007), Table 10.

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	CapeVerde	0.9
Botswana	22.4	Ethiopia	8.5	Rwanda	0.7
Gabon	20.3	Zimbabwe	8.0	Comoros	0.2

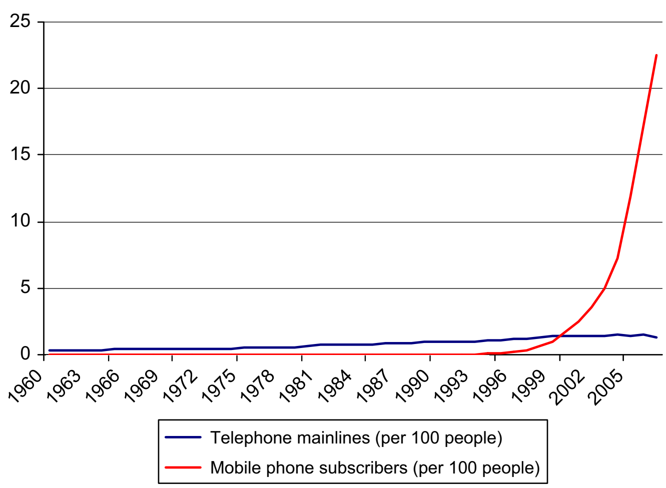

Fig. 1. Coverage of land lines and mobile phones in sub-Saharan Africa, 1960–2007.
Source: World Bank, World Development Indicators.

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.

2. Rural energy expansion and economic development in Sub-Saharan Africa

Fig. 2 shows that Sub-Saharan Africa ranks last among global regions in energy consumption per capita when South Africa is excluded. Fig. 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 (2008) 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% and 30%. 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. At the macro level, Pasternak (2000) and Martinez and Ebenhack (2008) argue that the link between per capita energy consumption and the Human Development Index is even stronger than with GDP. 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

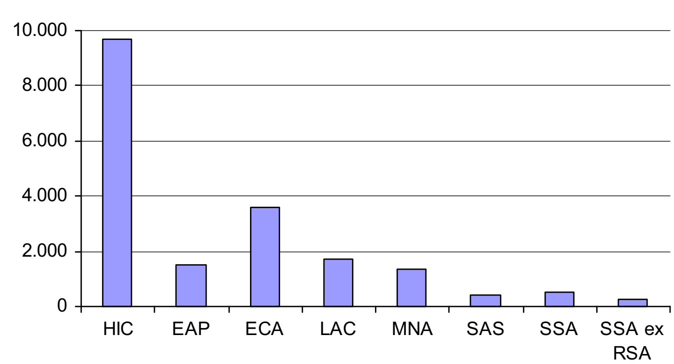

Fig. 2. Electric power consumption (kWh per capita), 2005. HIC: High-income countries; EAP: East Asia and Pacific; ECA: Eastern Europe and Central Asia; MNA: Middle East and North Africa: SAS: South Asia; SSA: Sub-Saharan Africa; and RSA: Republic of South Africa.
Source: World Bank, World Development Indicators.

[2] We chose these three countries because high resolution data on renewable power potential (solar and wind) are available from SWERA (2001, 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.

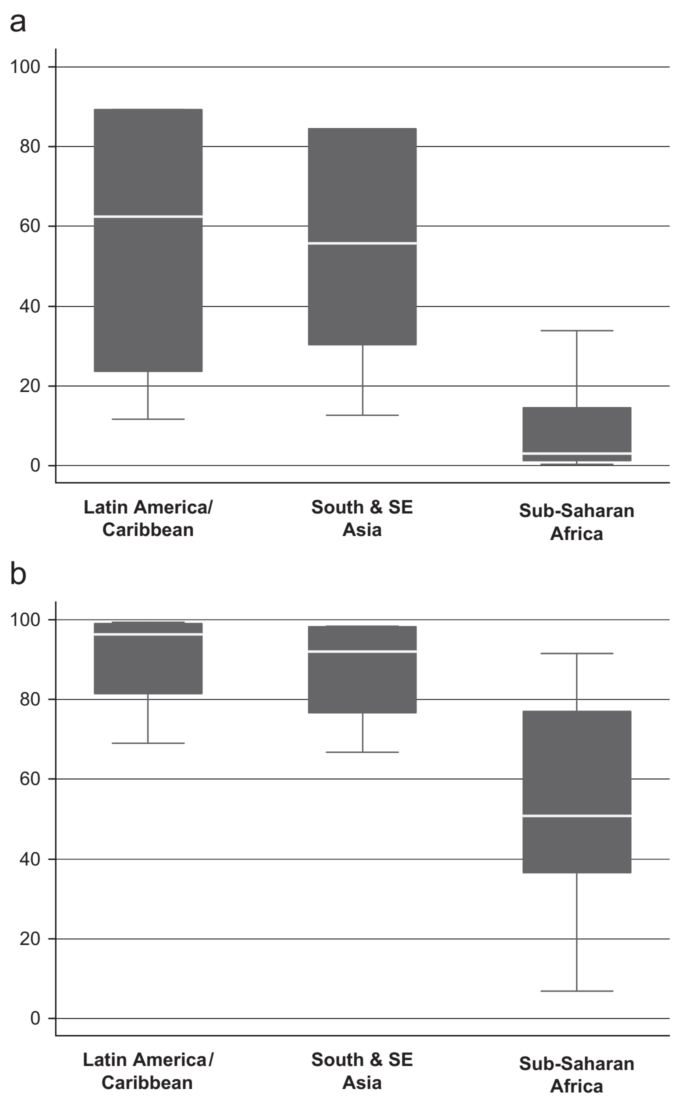

Fig. 3. Percent of households with electricity, 2003–2007. (a) Rural and (b) urban. *Source*: DHS (2009).

Table 2
Percent of households with access to electricity, 2003–2007.
Source: DHS (2009).

	Min	*Q1*	*Median*	*Q3*	*Max*
Rural					
Latin America and Caribbean	11.7	23.7	62.5	89.3	89.3
South and 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 and Caribbean	68.9	81.5	96.3	99.0	99.3
South an 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

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

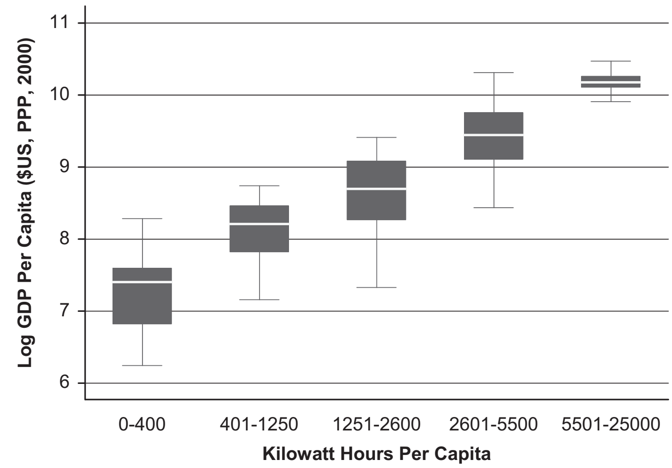

Fig. 4. GDP per capita (PPP) versus electricity consumption, 2000. *Source*: World Bank, World Development Indicators.

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 data from the US National Renewable Energy Laboratory shows, Sub-Saharan Africa is richly endowed with solar energy resources suitable for photovoltaic solar systems as well as for solar thermal facilities. Most of the region has average annual direct normal irradiance (DNI) that meets or exceeds 5 kWh/m^2/day, the critical minimum level for efficient provision of power from solar thermal facilities.

Ultimately, as the above cited literature suggests and Fig. 4 shows, 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 kWh (kilowatt hours)) and income per capita. 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 et al., 2009; Kebede et al., 2010).

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

[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.

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.[4] 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. (2009) for all but the most densely populated non-poor areas. Obviously the assumption of fixed average demand across households is a simplification. Demand is likely to increase with increasing wealth, but will be constrained by centralized generation capacity or by the size of stand-alone systems. In this analysis, we are interested more in the question of what it will take to provide electricity connections to households that satisfy a minimum acceptable level of demand, rather than modeling a dynamic process that includes marginal changes in demand in response to increasing incomes. On the other hand, projects that provide solar PV systems to low-income households often deploy smaller systems that are affordable by households but cannot power more than a few light bulbs and a radio. To ensure consistency in our scenarios that aim at significantly raising living standards at the household level, we therefore base them on the operational demand estimates outlined above for both grid and decentralized supply.

In our model, between about 700 (Ghana) and 1000 (Kenya) settlements with known or estimated population represent spatially distributed electricity demand points.[5] 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%, with half of all areas below 11% (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. (2003a, 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-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

[4] 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.

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

renewable options under current and possible future cost structures.

Electric power systems have three basic components: 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%. 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 or rank-size distribution of cities (e.g., Gabaix and Ioannides, 2004). 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.

Table 3
Cost components for the grid expansion model.
Source: KMOE (2008).

	Unit costs		
	Kenya	**Ghana**	**Ethiopia**
Generation mix			
Capital, O&M and fuel cost ($/kW)[a]	3006.89	2306.85	2617.46
Levelized cost of production (¢/kWh)[a]	10.70	7.23	5.80
Transmission			
HV transmission lines			
132 kV line ($/km)	90,000		
220 kV line ($/km)	192,000		
Bulk Supply Point (2-bay configuration)			
Transformer ($/kVA)	10		
Static var compensator (SVC) ($/100 MVAr)	10,000,000		
Breaker switched capacitor (BSC) ($/100 MVAr)	1,500,000		
HV-MV transformers			
3 phase HV/MV transformers ($/kW)	35,371		
Distribution			
MV transmission lines			
132 kV line ($/km)	106,154		
33 kV line ($/km)	23,000		
11 kV line ($/km)	20,000		
MV-LV transformers			
200 kVA 33 kV/LV ($/unit)	60,000		
100 kVA 33 kV/LV ($/unit)	50,000		
50 kVA 33 kV/LV ($/unit)	33,656		
25 kVA 33 kV/LV ($/unit)	21,818		
200 kVA 11 kV/LV ($/unit)	50,000		
100 kVA 11 kV/LV ($/unit)	41,818		
50 kVA 11 kV/LV ($/unit)	28,182		
LV transmission lines (household connections)			
LV line 4 wires ($/km)	10,611		

[a] Base costs before any learning effects.

3.2.1. A network expansion algorithm

Our model of network construction generates a transmission and distribution grid step-by-step, mimicking the (idealized) 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, including 11 and 33 kV lines) line of about 120 km. 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., 2003a, b; Parshall et al., 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 population distribution favors grid expansion.[6] Inclusion would not change the evaluation of later investment stages, which are the focus of our study.

3.2.2. 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). 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.

[6] For instance, in Kenya, as of late 2007, approximately 1 million of 8 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).

Table 4
Current operational generation capacity > 8 MW in Ethiopia, Ghana and Kenya (MW) (% in parentheses).
Source: UDI World Electric Power Plants Data Base, March 2006. (www.gisdata.platts.com); CC—combined cycle; CT—combustion turbine; Note that only large (> 8 MW) 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.

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

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. After conversion to levelized costs we add these to levelized transmission and distribution costs. In computing levelized costs we follow convention and apply a discount rate of 10%.

Generators and BSPs are connected by high voltage (HV; 220 and 132 kV) transmission lines with length estimated as the shortest, most direct distance between them. For the MV network estimate, we inflate straight-line distances between settlements by 30%. 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.

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.[7] 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.

3.2.3. Illustration of the expansion algorithm

Fig. 5 shows the application of our methodology to sequential construction of a centralized grid for Ethiopia. Fig. 5a shows the distribution of almost 1000 settlements (dots) of known population size along with the locations of large power sources (blue rectangles). Fig. 5b shows 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 (Fig. 5c). The settlements connected to a given BSP form a supply area (Fig. 5d).

3.2.4. 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

[7] 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 m from a line (KMOE, 2008). So the required number of lines (N) is $W/(48\times2)$, plus two additional lines for closing and cross-connection. Total transmission line length for a settlement is NW.

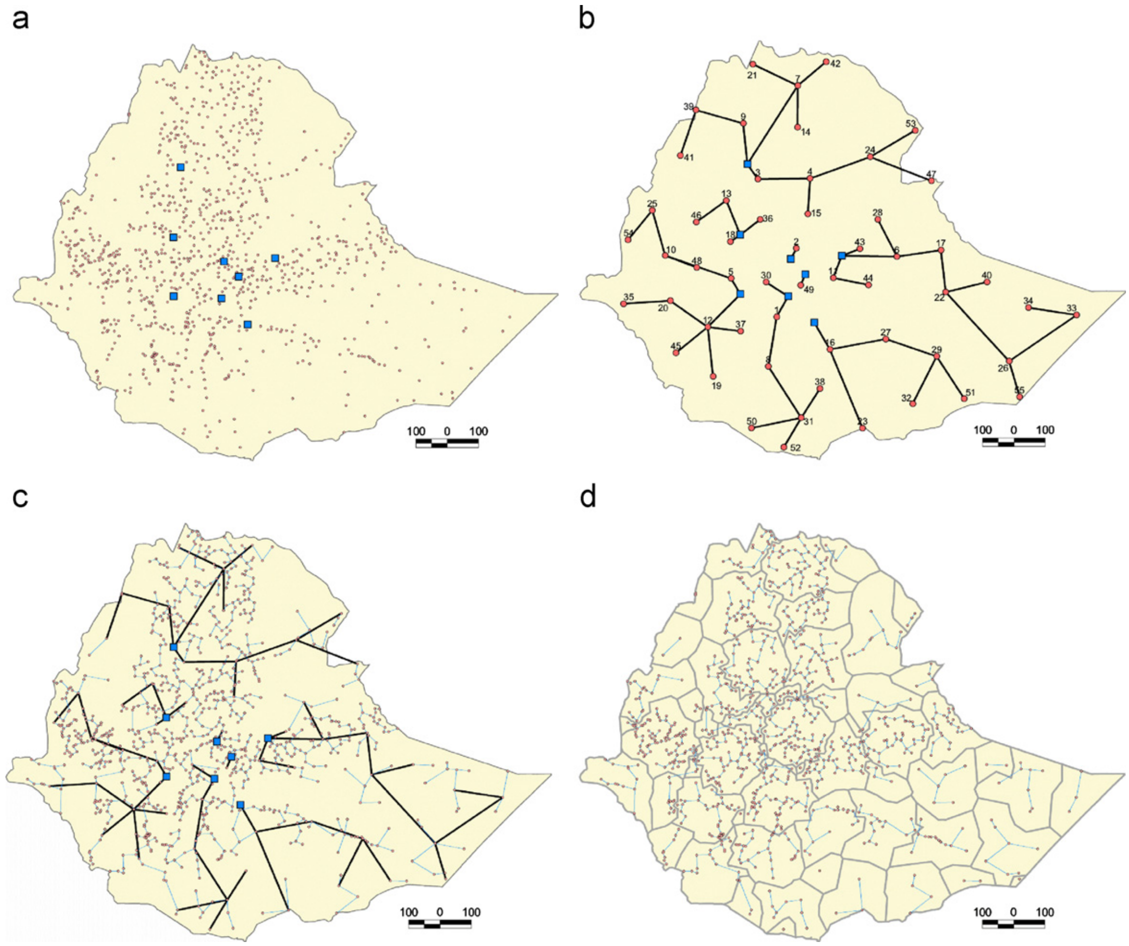

Fig. 5. Modeling grid connections.

(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 10 m hub height and 14–16 m/s at a 50 m height) are limited to certain regions, sometimes in fairly remote areas. We estimate that areas with promising wind potential include 34.1% of households in Ethiopia, 6.3% in Ghana and 5.5% 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; ESMAP, 2007).[8] This reduces the amount of required electricity storage which can reduce the cost per watt.

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 km^2.[9] 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.

3.3.1. *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

[8] PV-wind hybrid systems typically consist of one or more wind turbines (5–100 kW), PV modules of varying capacity, a control unit and a storage system. Estimated costs per installed kW vary from US$ 6400 for a 300 W system to US$ 5420 for a 100 kW system (ESMAP, 2007, Annex 3).

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

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.

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. Table 5 provides an overview. To facilitate comparisons, these figures are then translated into levelized costs per kWh.

3.3.2. 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. Figs. 8 and 9 present graphical and map summaries for Ethiopia. In the following sections, we summarize results for baseline scenarios, technical change and carbon taxes.

4.1. Baseline scenarios

The top two insets in Fig. 6 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, etc. 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% of the country's population, while the last 20 include only 2.5% (see Fig. 8).

Estimated levelized marginal costs of grid supplied electricity are between 16 and 50 cents/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 Fig. 7. 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/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 Fig. 7). Cost estimates are represented by circles in the charts. The cost of wind-supplied electricity varies between 23 and 29 cents/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

Table 5
Cost assumptions for distributed generation.

Technology	Power rating (kW)	Capital cost of system ($/kW)	O&M ($/kW)	Fuel costs ($/kW)
PV[a]				
Stand-alone	1	12,000	1956	–
Minigrid	25	7200	1558	–
Minigrid	100	6500	990	–
Wind[b]				
Stand-alone	1	5320	1721	–
Minigrid	100	2780	1263	–
PV-wind hybrid[a,b]				
Stand-alone	1	6440	2129	–
Minigrid	100	5420	2084	–
Diesel[b]				
Stand-alone	1	680	532	2863
Minigrid	100	640	3281	1182
Bio-diesel[a,b]				
Minigrid	30	1637	1768	2863
Minigrid	100	1215	1497	1182

[a] *Source*: KMOE (2008).
[b] *Source*: ESMAP (2007).

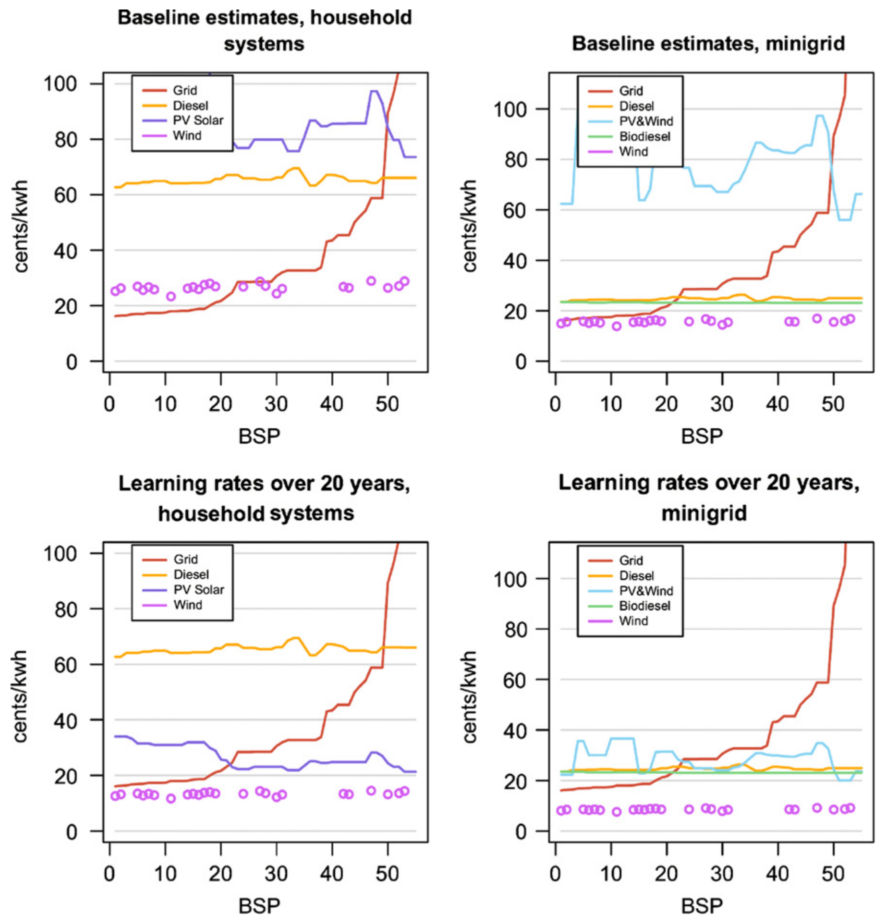

Fig. 6. Cost curves for Ethiopia. *Note*: Tukey's (running median) smoothing applied to cost curves.

lower-cost than grid include less than 3% of all households in the baseline scenario (Figs. 8 and 9).

Wind resources look far more favorable for minigrid systems, which deploy larger, more efficient, turbines. Costs drop to an estimated 14–17 cents/kWh. Localized areas in which minigrid wind systems are lower-cost than grid include about 34% of all households. Costs for diesel and biodiesel minigrid systems are comparable at between 23 and 27 cents/kWh. Both provide lower-cost electricity than grid-connected options for about 9% of households. Production costs for combined solar PV and wind systems range from 29 and 122 cents/kWh. This is lower than grid supplied costs for less than 1% of households.

4.2. 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% cost reductions with a doubling of installed capacity for hydro and geothermal in the estimates of centralized power production, to 15% for decentralized wind and 20% 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% 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 2 years to almost 3 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 20 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/kWh to between 19 and 35 cents. While cost differences narrow everywhere in Ethiopia, future costs are lower than grid for only about 8% (1.15 million) of households. Both household-level wind and

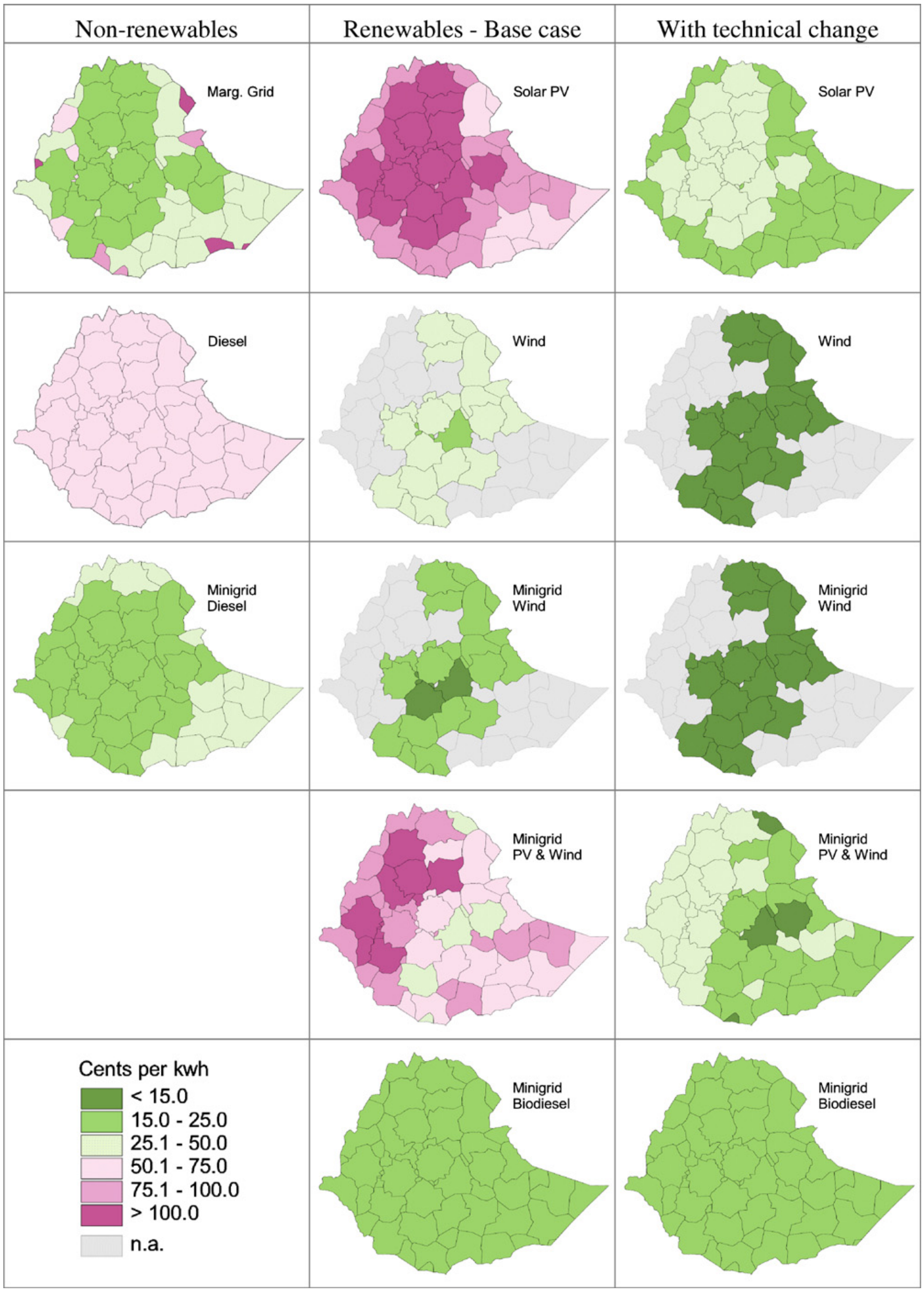

Fig. 7. Geographic distribution of levelized energy costs in Ethiopia.

wind minigrid energy become lowest cost where available at 12–15 cents and 8–9 cents/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 10–44 cents/kWh, cheaper than the grid for about 21% 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% of households.

To illustrate an alternative way of assessing technical change impacts, Fig. 9 shows 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% 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% or lower, and in many demand areas negative where decentralized supply is already cheaper.

4.3. Premium for low-carbon energy

Energy choices in African countries will be affected in various ways by global climate policy agreements. In principle, Ethiopia

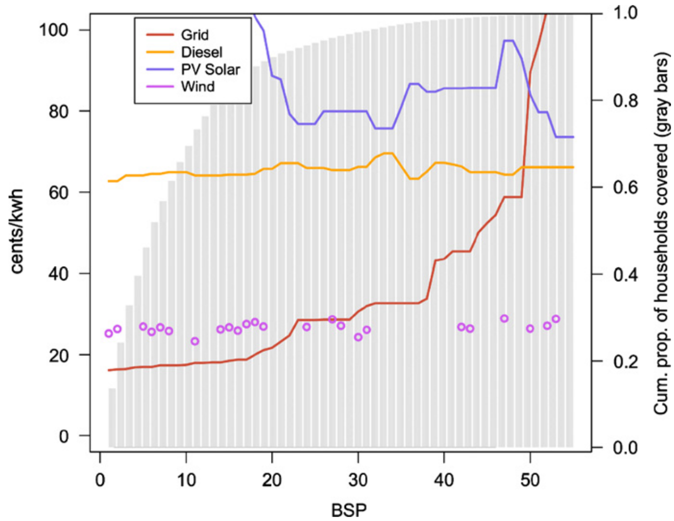

Fig. 8. Cost curves (baseline) with households covered, Ethiopia.

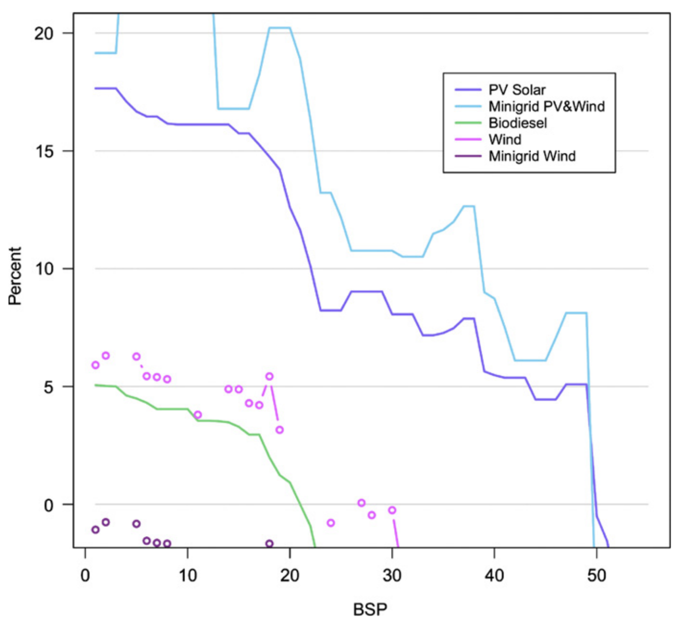

Fig. 9. Learning rates required to reach grid parity, Ethiopia (20 year period, including learning effect for non-capital costs).

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 CO_2) 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.[10] Therefore, a realistic carbon tax or equivalent market premium for 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. 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.[11]

[10] Nordhaus (2007b) and Stern et al. (2006) have estimated the carbon charges (or auctioned permit prices) consistent with different levels of emissions control. The underlying economic logic supports a 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^{-1} of CO_2, rising to about \$23 ton^{-1} by 2050. Stern's initial charge is 10 times higher – \$82 ton^{-1} – and his ramp is steeper. IPCC IV (2007) cites a variety of studies whose initial values average \$12 ton^{-1}, distributed across a range from \$3 to \$95 ton^{-1}.

[11] 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

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
Geothermal	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

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 10% 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 CO_2 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.

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, 2009). 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% 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-h 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.

Acknowledgements

This research was supported by the Knowledge for Change Program of the World Bank. Our thanks to Ken Chomitz, Thomas J. Cova, Govinda Timilsina, and Michael Toman for useful comments and suggestions. All remaining errors of fact or interpretation are our own. The findings, interpretations, and conclusions expressed in this paper are entirely those of the authors. They do not necessarily represent the views of the International Bank for Reconstruction and Development/World Bank and its affiliated organizations, or those of the Executive Directors of the World Bank or the governments they represent.

Appendix A. Supplementary material

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2010.09.034.

(*footnote continued*)
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.

References

Barnes, Douglas F., 2007. The Challenge of Rural Electrification. Strategies for Developing Countries. Resources for the Future and Energy Sector Management Assistance Program, Washington, DC.
Bergey, Paul K., Ragsdale, Cliff T., Hoskote, Mangesh, 2003a. A simulated annealing genetic algorithm for the electrical power distribution problem. Annals of Operations Research 121, 33–55.
Bergey, Paul K., Ragsdale, Cliff T., Hoskote, Mangesh, 2003b. A decision support system for the electrical power districting problem. Decision Support Systems 36 (1), 1–17.
Bertani, R., 2005. World geothermal power generation in the period 2001–2005. Geothermics 34, 65–69.
Buys, Piet, Deichmann, Uwe, Meisner, Craig. That, Thao Ton, Wheeler, David, 2007. Country stakes in climate change negotiations: two dimensions of vulnerability. World Bank Policy Research Working Paper, No. 4300, August, Washington, DC.
DHS (Demographic and Health Surveys), 2009. Reported by Measure DHS STATcompiler. Available from: 〈http://www.statcompiler.com〉.
Edjekumhene, Ishmael, Bonsu Atakora, Sefa, Atta-Konadu, Rodney, Brew-Hammond, Abeeku, 2001. Implementation of renewable energy technologies—opportunities and barriers. Ghana Country Study. Kumasi Institute of Technology and Environment. Kumasi.
Ethiopian Rural Energy Development and Promotion Center, 2007. Solar and Wind Energy Resources Assessment (SWERA) Project: country background information, solar and wind energy utilization and project development scenarios. Final Report, Addis Ababa. Available from: 〈http://swera.unep.net/typo3conf/ext/metadata_tool/archive/download/EthiopiaSWERAreport_258.pdf〉.
ESMAP (Energy Sector Management Assistance Program, World Bank), 2007. Technical and economic assessment of off-grid, minigrid and grid electrification technologies. Technical Paper 121/07, December, World Bank, Washington, DC.
Gabaix, Xavier, Ioannides, Yannis M., 2004. Evolution of city size distributions. In: Henderson, J. Vernon, Thisse, Jacque-Francois (Eds.), Handbook of Urban and Regional Economics, vol. 4. Elsevier, Amsterdam.
Hiremath, R.B., Bimlesh Kumar, P., Balachandra, N.H., Ravindranath, Raghunandan, B.N., 2009. Decentralised renewable energy: scope, relevance and applications in the Indian context. Energy for Sustainable Development 13, 4–10.
Hongwei, Dai, Yixin, Yu, Chunhua, Huang, et al., 1996. Optimal planning of distribution locations and sizes—model and algorithm. Electrical Power and Energy Systems 18 (6), 353–357.
IPCC IV (Intergovernmental Panel on Climate Change), 2007. Fourth Assessment Report. Available from: 〈http://www.ipcc.ch〉.
Kebede, Ellene, Kagochi, John, Jolly, Curtis M., 2010. Energy consumption and economic development in Sub-Sahara Africa. Energy Economics 32 (3), 532–537.
Khandker, Shahidur R., Barnes, Douglas F., Samad, Hussain A., 2009. Welfare impacts of rural electrification. A case study from Bangladesh. Policy Research Working Paper, No. 4859. World Bank, Washington, DC.
Klose, Andreas, Drexl, Andreas, 2005. Facility location models for distribution system design. European Journal of Operations Research 162, 4–29.
KMOE (Kenya Ministry of Energy), 2008. Updating of the Rural Electrification Master Plan, vol. 1, prepared by DECON and Re-Engineering Africa Consortium for the Ministry of Energy of Kenya and Ministry of Foreign Affairs of Finland, Nairobi.
Martinez, Daniel M., Ebenhack, Ben W., 2008. Understanding the role of energy consumption in human development through the use of saturation phenomena. Energy Policy 36 (4), 1430–1435.
Neij, Lena, 2008. Cost development of future technologies for power generation—a study based on experience curves and complementary bottom-up assessments. Energy Policy 36 (6), 2200–2211.
Nordhaus, William, 2007a. Critical assumptions in the Stern Review on climate change. Science 317, 201–202.
Nordhaus, William, 2007b. The Challenge of Global Warming: Economic Models and Environmental Policy. Department of Economics, Yale University July 24.
ORNL, 2008. Landscan Population Database. Oak Ridge National Laboratory Available from: 〈http://www.ornl.gov/sci/landscan/〉.
Parshall, Lily, Pillai, Dana, Mohan, Shashank, Sanoh, Aly, Modi, Vijay, 2009. National electricity planning in settings with low pre-existing grid coverage: development of a spatial model and case study of Kenya. Energy Policy 37, 2395–2410.
Pasternak, Alan D., 2000. Global energy futures and human development: a framework for analysis. Report UCRL-ID-140773, Lawrence Livermore National Laboratory, Berkeley.
Ramachandran, Vijaya, Gelb, Alan, Shah, Manju Kedia, 2009. Africa's Private Sector: What's Wrong with the Business Environment and What to Do About It. Center for Global Development, Washington, DC.
Stern, Nicholas, et al., 2006. Stern Review on the economics of climate change. Available from: 〈http://www.hm-treasury.gov.uk/independent_reviews/stern_review_economics_climate_change/sternreview_index.cfm〉.
SWERA (Solar and Wind Energy Resource Assessment Project), 2001. Description available from: 〈http://swera.unep.net/〉.
SWERA, 2004. High Resolution Solar Radiation Assessment for Kenya, Final country report prepared by DLR. Available from: 〈http://swera.unep.net/〉.
Ummel, Kevin, Wheeler, David, 2008. Desert power: the economics of solar thermal electricity for Europe, North Africa, and the Middle East. Working Paper, No. 156, Center for Global Development, Washington, DC.
UN-ENERGY/Africa, 2007. Energy for Sustainable Development: Policy Options for Africa. United Nations, New York.
Wamukonya, Njeri, 2005. Solar home system electrification as a viable technology option for Africa's development. Energy Policy 35, 6–14.
World Bank, 1996. Rural Energy and Development: Improving Energy Supplies for Two Billion People. World Bank, Washington, DC.
World Bank, 2001. The World Bank's Energy Program: poverty reduction, sustainability, and selectivity. Energy and Mining Sector Board Paper. World Bank, Washington, DC.
World Bank, 2008. The Welfare Impact of Rural Electrification: A Reassessment of the Costs and Benefits: An IEG Impact Evaluation. Independent Evaluation Group, World Bank, Washington, DC Available from: 〈http://www.worldbank.org/ieg〉.
World Bank, 2009. World Development Report 2009. Reshaping Economic Geography. World Bank, Washington, DC.
Zvoleff, Alex, Selin Kocaman, Ayse, Huh, Woonghee Tim, Mody, Vijay, 2009. The impact of geography on energy infrastructure costs. Energy Policy 37 (10), 4066–4078.