CHAPTER 5

The Regulatory Treatment of Subsidies, Carbon Credits, and Advance Payments

> Show me the money!
>
> —Character in *Jerry Maguire*, a 1996 movie

> You cannot develop a long-term sustainable strategy based on subsidies and grants.
>
> —General Electric executive, World Bank Energy Day, 2012

> … like most principles, it is more easily expressed in abstract than satisfied in practice.
>
> —U.S. DOE (2007, 8-5)

Abstract

In chapter 5 we describe different subsidies that small power producers (SPPs) and small power distributors (SPDs) can receive, and ways to close an initial equity gap. We also explore the regulatory implications of capital cost subsidies and tariff cross-subsidies, explain how SPPs can earn carbon credits and how regulators should handle carbon credit revenues. Finally, we examine the regulatory issues that arise when receiving advance payments to provide equity financing.

Types and Sources of Subsidies Available to SPPs and Their Customers

A broad definition of a *subsidy* is cash or other transfer of something of value to an economic agent, whether it is a producer or consumer. Subsidies can be targeted at both SPPs and their customers. The subsidies provided to SPPs are usually referred to as producer or supply-side subsidies. Producer subsidies can benefit SPPs by lowering their costs or increasing their revenues.[1]

Subsidies provided to SPP customers are known as consumer or demand-side subsidies.[2]

The fact that a producer subsidy is targeted at an SPP operator does not mean that the benefits of the subsidy will stay with the SPP operator. SPP customers may also benefit from producer subsidies. For example, if a subsidy lowers an SPP's costs, the SPP may lower the tariffs charged to its customers. Or if it provides critical additional revenue that ensures the SPP's commercial viability, rural households will benefit by getting access to grid electricity that otherwise would not be available until the main grid arrives.

The two most common consumer subsidies are connection subsidies and consumption subsidies. A connection subsidy is a one-time grant that allows a household, business, or public institution to connect to an SPP system. A consumption subsidy (sometimes described as a quantity-based subsidy) is an ongoing subsidy that reduces a customer's cost of consuming electricity by reducing the customer's tariff. (Among countries that have set up explicit programs to subsidize both rural customers' connections and consumption, Peru has an especially clear and well-run program; see box 5.3, in a later section, for a description of the Peruvian program.)

Subsidies can be further distinguished by source. In other words, who funds the subsidy? As shown in table 5.1, subsidies received by SPPs usually come from one of four sources: national or subnational governments, external donors, other electricity consumers who are not in the SPP's service area, or other customers

Table 5.1 Types and Sources of Supply Subsidies Available to SPPs and SPDs

Type	*Source*
Subsidies that increase revenues	
Feed-in tariffs with premiums	Government/donors/buying utility's customers
External operating subsidies	Government/donors
Tariffs that exceed costs for other customers served by the SPP or for other non-SPP electricity consumers	Other customers from within a tariff class, from other tariff classes, or from customers whose tariffs are not regulated
Subsidies that lower costs	
Connection cost grants	Government/donors/other customers
Customer contributions in aid of construction	Customers
Discounted purchase price on bulk supply tariff	National utility/government/selling utility's other customers
Waivers of import taxes	Government/donors
Concessional/soft loans	Government/donors
Production tax credit	Government
Tax holidays	Government
Guarantees on SPP loan payments	Government/donors
Guarantees that national utilities will pay for electricity supplied by the SPP	Government/donors
Loan buy-down programs	Governments/donors

Note: SPD = small power distributor; SPP = small power producer.

of the SPP who are charged more than their cost of supply. The first two are external subsidies and the last two are cross-subsidies.

Key Observation

Subsidies available to SPPs and SPDs either increase revenues or decrease costs, and can come from the government, external donors, and customers.

Not all nontariff revenues received by SPPs are subsidies. For example, an SPP may earn additional revenues through the sale of carbon credits, which are not subsidies but payments for the provision of an additional service: a reduction in carbon emissions going into the atmosphere. Another closely related example would be "top-up" payments to feed-in tariffs (FITs), which have been proposed in the Deutsche Bank GET FiT program (Rickerson and others 2012) and is being implemented in Uganda. These are proposed grants for renewable generators that would be separate from any revenues earned from the Clean Development Mechanism (CDM)[3] or other carbon credit programs. The question that arises whenever an SPP receives additional nontariff revenues is: who should benefit from these revenues—the SPP operator, its customers, or both? And should the regulator have any say in that decision, or should it be left solely to the discretion of the SPP operator and those who provide these additional revenues?

Regulating Subsidies: The Key Recommendation

Governments usually mandate or authorize subsidies to meet a social objective such as promoting electrification or encouraging renewable energy. A government's decision to promote these objectives represents government policy making. Most recent regulatory statutes in Africa and elsewhere make it clear that the government's job is to make policy, and the regulator's job is to implement government policy—subject to any legal limits imposed by regulatory and other statutes.

Even if a regulator does not make the initial subsidy decision, its regulatory decisions will often determine whether the subsidy achieves its stated purpose. Ideally, a government should make its policy preferences clear by giving explicit policy guidance to the regulator on how to treat the subsidy. An example of such guidance can be found in the 2006 Rural Electrification Policy of the national government in India. The policy document states that: "If the State Government/State Electricity Regulatory Commission decides to permit a licensee to use assets created with subsidy, it must be ensured that the benefit of [the] capital subsidy is passed on to the consumers" (Government of India and Ministry of Power 2006, section 7.5). It is then the job of the state regulators in India to determine what specific tariff-setting actions are needed to implement this government policy directive.

Key Recommendation

If a subsidy is authorized, mandated, provided, or allowed by the government, the regulator should not take actions that would nullify or reduce the effect of the subsidy. Instead, the regulator should take regulatory actions that help to ensure that the subsidy is delivered to its intended target as efficiently as possible. The regulator, however, should periodically inform the government of the costs and benefits of the subsidy.

We now consider how this general principle could be applied for subsidies intended to reduce connection charges for rural households.

Subsidies for Connection Charges and Costs

It is widely recognized that the biggest single impediment to expanding electrification in Sub-Saharan Africa are connection charges: the payment required from new customers for their initial physical connection to an electricity supplier. (See box 5.1 for a discussion of connection charges versus connection costs.) A recent Africa Electrification Initiative survey found that the minimum connection charges for new on-grid customers served by the national utilities was above \$100 for nine Sub-Saharan African countries[4] (see figure 5.1) (Golumbeanu and Barnes 2013). The connection charges of national utilities in Africa are, on average, considerably higher than the connection charges of national utilities in Asia. In fact, in the survey conducted by Golumbeanu and Barnes (2013, 5), they found that "Sub-Saharan Africa had the highest number of countries with connection charges above \$100 per customer" for the lowest-available connection option.

Key Definition

A connection charge is the payment required from new customers for their initial physical connection to an electricity supplier.

When a connection charge is high, it acts as a real barrier to electrification because many poor rural households simply do not have the financial capacity to make a large up-front payment. Hence, the paradox is that rural households can generally afford the cost of electricity once they are connected and may see large drops in their monthly energy costs, but they are unable to pay the initial connection charge. Given the inability of households to make the up-front connection payment, it is not uncommon to see villages in Tanzania where only 10–20 percent of village households have signed up to be connected even though the village has been connected to the grid for five or six years (Sawe 2005).

Box 5.1 Connection Costs versus Connection Charges

Connection *costs* are the costs a traditional utility or an SPP incurs to connect new customers. Connection *charges* are the charges or fees that the new customer pays to the utility or SPP to be connected. Customer connection charges are often much lower than utility connection costs because the supplying utility may not charge a new customer the full cost of the connection when it receives a grant or subsidy that covers some portion of connection costs. Or the traditional utility may choose to recover the cost of connecting a new customer in the tariffs charged to all customers, new and existing. When this happens, the cost of connecting a new customer is cross-subsidized by existing customers. But this option is generally not available to a new SPP that proposes to build and operate an isolated mini-grid because all of its customers will be new customers.

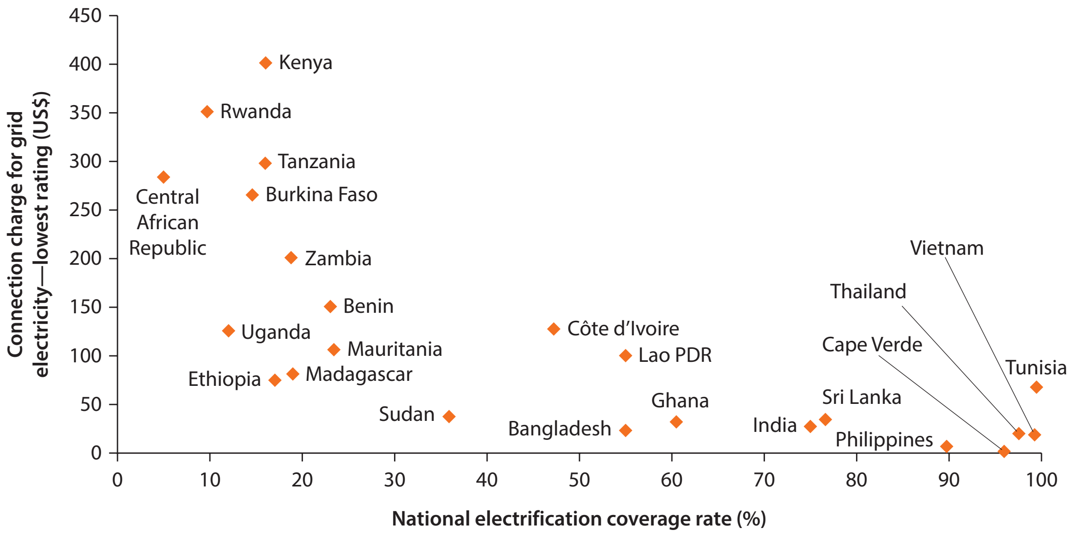
Connection costs can differ among African national utilities, for many reasons. The most obvious reason is that construction and equipment costs vary across countries. Also, utilities may simply use different definitions of what constitutes connection costs. For example, one utility may define it in basic terms: the service connection costs to a household, such as, the cost of dropping a wire, additional poles if necessary, a meter, and circuit breakers. Another utility may go further upstream and include an allocated share of the distribution transformer costs (that is, the neighborhood costs). Yet another utility may include the costs of any actual or expected expansion in the distribution or subtransmission networks. In this last case, the customer will pay the highest connection charge because it will pay a share of three cost components: the household, neighborhood, and network connection cost.

From a customer's perspective, the total cost of a connection will be the connection charge of the utility or SPP *plus* the additional costs of installing internal wiring within the house. One recent study in Tanzania estimated that the cost of internal wiring in a rural household would range from $175 in a one-room house to $435 in a four-room house. Hence, in 2011 the total cost of connection for a rural household in Tanzania living in a three-room house located within 30 meters of existing TANESCO facilities would be approximately $680 ($300 for the connection and $380 for the internal wiring) (NRECA 2012, 28).

One way to reduce the cost of internal wiring is to use readyboards—prefabricated electricity distribution boards that typically contain one light point and one outlet point. These eliminate the need to install internal wiring because the two usage points are located on the board and the board itself is placed at a central location in the room. Readyboards are much easier to install in traditional rural houses that have mud, stone, or wood walls. A readyboard might cost $50–75 to install versus $175 for wiring of the same room. A newly connected household might initially use a readyboard and then move to internal wiring in one or more rooms at a later time. Readyboards were the norm in the successful South African program to electrify poor households in urban townships.

Sources: Authors' analysis and NRECA 2012.
Note: Some authors may also include in the definition of connection costs the expenses incurred by the household (for example, internal household wiring expenses) to make use of the new connection (Golumbeanu and Barnes 2013, 2).

Figure 5.1 Minimum Average Connection Charges and Rural Electrification Rates



Source: Golumbeanu and Barnes 2013.
Note: The reported numbers are not comparable because they are based on reported data from different years (2005–10). Also, in some countries, they may reflect the cost of a short connection (for example, less than 30 meters), while in other countries the numbers may represent an average of connection charges for dwellings both near and far.

Village electrification (that is, an electricity supply source is available to the village) does not automatically lead to household electrification.[5]

Key Observation

Even after the main grid has arrived in a village, many rural households will not be able to connect because of the high connection charges established by national utilities. Many rural households in Africa cannot afford to make the up-front payment for a connection even though they are able to afford the cost of electricity once they are connected.

Connection Charges in Tanzania: The National Utility versus Mini-Grid Operators

In Tanzania the national utility's connection charges are especially high. In 2011 rural households located within 30 meters of existing distribution facilities that requested a basic single-phase connection consisting of a dropline and a prepaid meter were charged almost $300 by the Tanzania Electric Supply Company (TANESCO),[6] an amount that is about 43 percent of the annual median rural income in 2007 (NRECA 2012). Moreover, TANESCO will not undertake a connection unless it receives the payment up front and in full.

In contrast, mini-grid operators in Tanzania are offering considerably lower connection charges. For example, the LUMAMA project, a micro-hydropower mini-grid in western Tanzania built with assistance from the Asociación de Cooperación Rural en Africa y América Latina (ACRA), an Italian NGO, does not impose any connection charge on new households—they pay only a T Sh 2,000 ($1.25) fee for processing the application form. LUMAMA also helps with household wiring costs by providing a loan for 50 percent of the household wiring costs, payable over six months through payments that are added to the customer's monthly electric bill (Todeschini 2011).

The Mwenga Hydro project in southern Tanzania charges a connection cost of T Sh 180,000 ($113) for the first 2,600 single-phase connections, and T Sh 385,682 thereafter (Mwenga Hydro Limited 2012). For customers for whom T Sh 180,000 is a barrier, there is an option to make a partial payment of T Sh 100,000 ($63) and then pay off the remainder through a zero-interest loan, with payments spread out over time. Basic household wiring typically costs around 90,000 T Sh ($56) and is not subsidized, but the operator offers so-called readyboards with three prewired electrical outlets at a cost of 60,000 T Sh.

These two examples would seem to imply that mini-grids in Tanzania are more efficient because they are able to connect new customers at lower cost than TANESCO. But this may not be true. It may simply reflect the fact that the mini-grid operators have access to larger grants from donors on a per household basis than the grants that are available to TANESCO. We would need more detailed information on gross connection costs (that is, unsubsidized costs) to reach any firm conclusions about the relative underlying connection costs of TANESCO versus the mini-grid operators.

Two Approaches to Recovering Connection Costs

Among electricity distribution entities, there are two basic approaches to recovering connection costs.

In the first approach, the connection charge is thought of as simply a *service charge* to the new customer, and is kept low to get more households to sign up. The service charge is not intended to recover all capital costs incurred by the utility in connecting the new customer; instead, the connection capital costs are intended to be recovered from all customers (new and existing) over time through tariffs. This seems to be the philosophy of electricity suppliers in many Asian countries (Bangladesh, India, Sri Lanka, Vietnam, Thailand, and the Philippines)—by rolling the capital costs into the regulatory asset base used in setting general retail tariffs, they recover the connection costs from all customers (see figure 5.1).

One can see examples of the same commercial strategy in the mobile-phone sector. In many countries, mobile-phone companies will sell a new smartphone at a low price if a customer is willing to sign a contract to take a minimum amount of monthly service for two or more years. In the United States, a new customer can purchase a 16 GB iPhone 5 for $199 if the customer is willing to sign up for a two-year contract with an obligation to pay for prespecified minimum monthly voice and data usage; however, if the customer wishes to buy an unlocked iPhone 5 without any contract, the purchase price jumps to $649. This is because the mobile company sees no point in offering a large discount if the customer can easily transfer his or her mobile-phone usage to another company or another country, as the $450 subsidy would then never be recovered.

Electricity service is, however, different from mobile-phone service. Most new electricity customers do not sign up for a multiyear contract with a specified minimum, monthly usage. Also, though the customer is not "locked in" by a contract, there is very little risk that he or she will find another supplier unless the country suddenly adopts retail competition. So once the customer signs up, the electricity supplier has a *de facto* monopoly for at least several years. If the electricity supplier opts for the service charge approach, the unrecovered capital costs of the new connection are rolled into the supplier's regulatory rate base for tariff-setting purposes. *This means that the capital costs associated with new connections would be recovered as one element of the retail tariffs charged to all customers (new and old)*. To the extent that the tariffs of existing customers are calculated to include the capital costs of connecting new customers, there is a cross-subsidy from existing customers to new customers.

Under the second approach, the cost of connecting a new rural household is recovered in full from the individual customer in a separate connection charge that is paid for by that customer in a single up-front payment or paid over time in separate charges added to the new customer's monthly bill. Most African utilities have opted for this second approach, the full-cost recovery approach.

The second approach is typically justified on two grounds. First, it is pointed out that the retail tariffs for national utilities in most African countries do not recover their overall capital and operating costs. So under current conditions, there is a high risk that any connection costs rolled into overall capital costs used to determine retail tariffs would never be recovered. Instead, the costs for connecting new customers would simply widen the gap between incurred costs and collected revenues. Second, some of the connection costs (for example, droplines and meters) are not common or shared costs—they are incurred to supply one particular customer. Therefore, it is argued that these should be recovered only from those customers whose requests for connection produced these costs.

These are the reasons most often voiced by many African utilities as to why they favor full, up-front recovery of all connection costs. But there is another (often unspoken) reason as to why this is preferred—it is because the utilities' retail tariffs may fall far short of recovering the expected operating costs in rural areas. If a utility doubts that the government will make up the revenue shortfall in serving poor rural households, it will have an economic incentive to drag its feet in signing up new rural customers. Thus, high connection charges (such as those shown in figure 5.1) may simply be an indirect way of discouraging new users from signing up. (This is discussed further in the next section.)

Key Observation

Electricity providers generally adopt one of two strategies to recover the costs of connecting new retail customers. The first, *the service charge approach*, offers low initial connection charges to encourage more customers to sign up. Under this approach, the connection charge does not recover the provider's costs of connecting the new customer. Instead, the provider's connection capital costs are recovered from all customers (new and existing) over time through tariffs. The second strategy, *the full-cost recovery approach*, establishes connection charges that are designed to recover the provider's full cost of connecting new customers, either in a one-time, up-front charge or over time as separate charges added to the customer's monthly bill or prepayment card.

High Connection Charges and the Disincentive to Connect Rural Customers

Many reasons are given for the relatively high cost of household connections of large African national utilities. The most frequently mentioned are: use of costly European engineering standards (for example, oversized conductors for small rural loads), poor procurement practices, corruption in procurement, and the phenomenon of equipment suppliers charging high prices to state-owned national utilities because the national utility has a history of slow payment or nonpayment.[7] The underlying presumption is that the problem of high connection costs is largely one of design, construction, and procurement, and solving these would lead to lower connection costs and connection charges. This presumption ignores the fact that many state-owned utilities in Africa do not have a strong incentive to solve these engineering and procurement issues if they expect that "success" means that they will lose money selling electricity to newly connected rural customers. *So, expensive construction standards and faulty contracting methods may be symptoms of a more fundamental problem: the fact that many state-owned national utilities have few, if any, financial incentives to supply electricity to rural customers.*

Most state-owned African utilities do not have a financial incentive to connect new rural customers even if their initial capital costs are heavily subsidized. Since national utilities in Africa are often required to charge rural customers the same tariff that they charge their urban customers (that is, a uniform national tariff, as discussed in chapter 9) and most new rural household customers will also be eligible for an even lower lifeline or "social" tariff, national utilities will almost always lose money on every kilowatt-hour (kWh) that they sell to newly connected rural customers. An important but often ignored question is: *why would any rational business enterprise want to actively pursue new customers when they are almost certain to lose money on sales to these customers?*

With this question in mind, one might consider the widespread existence of high connection charges among state-owned utilities in Sub-Saharan Africa as a form of "passive resistance." No utility executives who want to keep their jobs at a state-owned utility are going to actively or openly oppose the government's efforts to expand rural electrification, even if they know that success in rural electrification will weaken their company's finances. Therefore, from their perspective, the hidden benefit of high connection charges is that they provide an indirect way of not complying with the government's mandate to electrify rural households.[8]

Even if connection costs for the utility and connection charges for new customers are significantly lowered by grants, such grants will not achieve sustainable electrification if the supplying utility expects that it will still lose money on almost every kWh that it sells to rural customers once the connection is made. This was clearly recognized in a recent memo of donor staff that described the failure of an electrification program in one African country. The memo stated that "[name of the utility] did not make an effort to roll out connections to poor households under this scheme as it had no incentive to connect them, *since actual connection costs were three times higher, and clearly these costs would not be recouped through the lower tariff revenue earned by serving low-income households.*" (Emphasis added.) In our view, it is unlikely that there will be significant acceleration in rural electrification through grid extensions unless national utilities can see a positive economic incentive to make electricity sales to rural customers after the physical connections are made.

Key Observation

The usually cited reasons for high connection charges in rural Sub-Saharan Africa are costly engineering and construction standards, poor or corrupt procurement practices, and overpriced contracts with equipment suppliers. While these are true, *national utilities may intentionally charge high connection fees to rural customers as a way to avoid compliance with government mandates on rural electrification. If the national utility has an underlying financial disincentive to connect new rural customers, lower-cost construction standards and better procurement will not solve the problem.*

In contrast, the incentives are likely to be quite different for SPPs. Unlike state-owned utilities that have a legal obligation to serve the public interest, privately owned SPPs will enter the retail electricity supply business only if they see a reasonable chance to cover their costs and make a profit. If regulators allow SPPs to charge tariffs that are cost recovering (as has been proposed by the Tanzanian regulator and discussed in chapter 9), the SPPs will have a strong incentive to increase the number of connected customers and the number of kWh that they sell to them. In addition, they will also have strong economic incentives to reduce connection costs and connection charges because they need connected customers to make sales. The difference, then, is that SPPs, if given positive economic incentives, will be seeking new customers rather than discouraging them.

Reducing Connection Charges

There are three basic ways to reduce connection charges. The first is to reduce the underlying connection costs that affect the level of connection charges, by undertaking engineering and procurement actions that can lead to lower-cost electrification. The most frequently discussed techniques include: the use of single-phase rather than three-phase distribution systems, single-wire earth return (SWER) shield wires on top of transmission lines to connect villages near transmission lines (avoiding the need to build expensive substations), and locally acquired materials.[9] The second way is for the national utility and SPPs to receive subsidies or grants from outside sources to lower the capital costs of connecting new customers. The third way is for the national utility or the SPP to establish a mechanism that allows new customers to pay for the connection charge in smaller payments over time rather than in one large up-front payment. In the discussion that follows, we focus on the regulatory decisions required for the second and third options.

Key Observation

The three basic ways to reduce connection charges, particularly for rural customers, are: reducing the underlying capital costs by adjusting engineering standards and improving procurement practices, providing subsidies or grants to the national utility and SPPs to reduce the capital costs of connecting new customers, and allowing customers to pay their connection charges over time in smaller monthly installments.

Grants to Lower Connection Costs in Africa

Outside funding for connection cost grants can come from several different sources: the national government, rural electrification agencies or funds, international donors, and the customers who have applied for a new connection and have paid a connection fee. If outside assistance is supplied by the national government or international donors, the assistance typically comes in the form of grants rather than commercial loans. (See box 5.2, describing the World Bank's Global Partnership on Output-Based Aid [GPOBA] program that has subsidized connection charges for new electricity customers in several developing countries.) The grant can be made in-kind or as a cash payment. For example, in Kenya the rural electrification agency builds new distribution facilities to serve previously unserved communities and then hands over these facilities at zero cost to the Kenya Power and Lighting Company (KPLC), the national distribution utility. In contrast, the Ethiopian Electric Power Corporation (EEPCO, the national utility) receives money for new distribution facilities that it builds on its own. The grants are an example of results-based financing: the full amount of the grant will be disbursed only upon independent verification that the household has been connected, with specifications set forth in the grant agreement.[10]

Box 5.2 GPOBA: Output-Based Aid at the World Bank

GPOBA and energy projects. An important program at the World Bank that has provided grants to subsidize the cost of new electricity connections is the Global Partnership on Output-Based Aid (GPOBA), which defines output-based aid as a subsidy payment linked to the achievement of a predefined output such as the installation of a working household connection. In a 2010 World Bank survey, 30 World Bank energy projects—involving both GPOBA and non-GPOBA projects—were found to contain output-based aid components (Mumssen, Johannes, and Kumar 2010). The most common subsidy was a one-off capital cost grant to bring down the initial cost of connection for poor households, but GPOBA has also provided grants for grid extension, installation of solar home systems, and the creation of mini-grids.

Of the 30 World Bank energy projects that were surveyed, 5 of the projects involved OBA subsidies for new mini-grids. The transaction costs of GPOBA or other donors providing OBA to an individual mini-grid operator are prohibitively high, so they reach existing and new mini-grid operators by channeling grant money through rural electrification agencies (REAs) that have ongoing programs to promote mini-grids.

GPOBA intends to use this approach in a major planned project in Uganda. Along with the Government of Uganda and KfW (the German development bank), GPOBA is expected to commit about $16 million to finance 102,000 poor households to become customers of six privately and cooperatively owned distribution entities. The donor grants, ranging from $125 to $167, will cover the costs of four types of "no-pole" connections and the entire estimated connection costs of the distribution entity. The newly connected customers will pay only for a security deposit and internal wiring, estimated to range from $90 to $116. The poorest households, who may not be able to afford the cost of internal wiring, will have a lower-cost option of receiving a readyboard with a load limiter for an up-front cost of $8.

Outputs. When GPOBA provides connection cost grants, the required output is typically defined as a verified working physical connection to the network. The network could be the main grid, a regional grid, or a new isolated mini-grid. In recent and new projects, the output definition has been expanded to include both access and service. An independent outside auditor verifies that a working physical connection was installed and that the newly connected household actually received electricity over the connections for a specified period of time. Ongoing supply and consumption of electricity are typically verified through billing and collection records. For example, in the case of main-grid connections made by the KPLC (Kenya's main distribution company) in the slum areas of Nairobi, the KPLC receives $125 upon independent verification of each household connection and then an additional $100 six months later upon verification that the connection is still in operation and electricity is still being purchased by the newly connected household.

Targeting. GPOBA must ensure that its grants reach the genuinely poor. Conducting surveys on household income to identify poor households can be costly and time consuming. In the proposed Uganda project, a proxy has been developed. A household is eligible to receive a connection grant if either the household has not connected for at least 18 months after grid connections were available in its locality or the household was identified as poor in a poverty mapping exercise for newly electrified areas.

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Box 5.2 GPOBA: Output-Based Aid at the World Bank *(continued)*

Grants and commercial sustainability. The OBA grant is designed to lower connection charges for new customers, but *the grant by itself does not guarantee the commercial viability of the enterprise*. That will largely depend on the retail tariffs that the enterprise is allowed to charge by the regulator, the REA, or some other entity that has ongoing tariff-setting responsibility over the grant recipient. GPOBA, like most grant-giving agencies, has only limited influence over the regulatory environment in which the grant recipient will operate. This point was emphasized in the 2010 World Bank survey of OBA initiatives: "OBA schemes are only as sustainable as the environment in which they operate … in order to provide sustainable service over time, tariffs need to be at appropriate levels and subsidies need to be minimized" (Mumssen, Johannes, and Kumar 2010). If the grant recipient's tariffs connect a large number of poor customers who are eligible to purchase electricity under a "lifeline" or "social tariff" that is not cost recovering *and* there is no other mechanism such as tariff cross-subsidies in place to cover the resulting revenue shortfall, then the grant program will increase the number of connections but may not achieve commercially sustainable electrification.

Tanzania's REA (which has received funding from the World Bank and other donors; see http://www.rea.go.tz) currently offers grants of $500 to SPPs for each new rural customer that is connected by suppliers (isolated or connected mini-grid operators) other than the national utility.[11] These grants are typically disbursed in tranches: 40 percent on signing the grant agreement, 40 percent on delivery of the connection materials to the village, and the remaining 20 percent on verification of the actual connections. Because the REA's goal is to maximize new customer connections, it does not distinguish between different sources of generation in giving these grants. In other words, the REA grants are provided on a per connection basis regardless of whether the electricity supplied comes from a renewable generator, a diesel generator, or a hybrid generating system.

A similar arrangement exists in Mali. The Malian Agency for Household Energy and Rural Electrification, AMADER, has provided grants of about $570 per new connection to the operators of more than 50 new isolated mini-grids. Almost all of these are privately owned and currently use diesel generation as their source of electrical supply (Adama and Agalassou 2008). The overarching mandate for AMADER and most other African electrification agencies is electrification. At present, renewable energy is a secondary consideration, especially if they believe that by subsidizing renewable energy they will have less money to subsidize new connections.[12]

If the grants are going to be effective in reaching genuinely poor households, care must be taken to ensure that there are no legal barriers that prevent such households from signing up for grant-subsidized connections. For example, in Bangladesh, it has been reported that in some locations only the head of the household is allowed to apply for a connection. This is a problem as many

Bangladeshi men work in the Gulf states (and send remittances home to their families), and the wife is not allowed to sign for a connection under the rules.

Connection Cost Grants and Extended Payment Programs: Regulatory Issues

Outside grants to bring down the costs of making connections to new households raise three issues for electricity regulators. The first issue is: will the regulator allow for cross-subsidies for the enterprise receiving the grant? Specifically, will the regulator approve higher tariffs for more-affluent households and business customers to cover the revenue shortfall produced by non-cost-recovering tariffs charged to lifeline customers? The second issue is how such grants should be treated in calculating an SPP's maximum allowed revenues (that is, the overall amount of revenue that the SPP will be allowed to recover through its retail tariffs).[13] For connection equipment financed by the grant, will the regulator allow the enterprise that receives the grant to earn an equity return, charge for depreciation, or do both? The third issue is how to treat administrative and financing costs that an SPP incurs when it allows new customers to pay for connection charges over time (with a loan at a subsidized or market interest rate) rather than in one lump-sum payment.[14] These programs are generally referred to as deferred or extended payment programs, and their administrative and financing costs are usually referred to as subsidy delivery costs.

Regulatory Issue 1: Cross-Subsidies

The politics and finances of cross-subsidies are discussed later in this chapter and in chapter 9. Our view is that tariff cross-subsidies will generally be needed, at least in the early years, to achieve commercial sustainability for most mini-grids. Presumably, any outside provider of connection grants will not want to provide grants to a mini-grid that is prohibited from cross-subsidizing among its current or expected customers because it would be the equivalent to giving a gift to an enterprise that is not likely to survive. We recommend that the grant-giving agency should satisfy itself that:

- First, the regulatory statute or rules give the regulator the authority to allow cross-subsidies in the tariffs charged by distribution entities, whether they are connected to the main grid, a regional grid, or operate an isolated mini-grid.
- Second, the regulatory entity has given a commitment (or at least strong indications) that it will use its legal authority to allow for cross-subsidies in the relevant tariffs.
- Third, it is economically realistic to expect that the overall revenue shortfall created by lifeline or social tariffs can be covered charging other customers tariffs that exceed their cost of supply.

Regulatory Issue 2: Capital Grants and Tariff Levels

How should outside grants be considered in the regulator's determination of an SPP's overall allowed revenue used to set retail tariffs? Outside grants are almost always used to finance capital investments. Once an operator makes a capital investment, it normally affects tariff setting in two ways: the depreciation allowed on the investment and the return or profit allowed on the investment. But the tariff rules should be different when the capital investment is funded with an external grant or subsidy. In this situation, we recommend the following general rule for calculating overall revenue requirements: *the SPP should be allowed to take depreciation, but should not be allowed to earn a profit or return on the equity provided by the grant.*[15]

This regulatory rule is justified on two grounds. The first is that any capital equipment (that is, generators, transformers, distribution poles, and wires) will eventually wear out and have to be replaced. By allowing the SPP to take depreciation on capital investments (whether funded from outside grants or the SPP's own funds), the regulator helps to ensure that the SPP will have money to replace the equipment when it wears out. Second, there is no need to provide the SPP with a profit on the outside grant, since it was given as a gift by an external party with no expectation that a profit would be made on the gift. In commenting on the specific case of Kenyan government grants for electrification, a government energy official observed: "If consumers have already paid for the facilities as taxpayers, why should they pay for the same facilities again as electricity consumers?" Hence, our recommended rule is that the SPP's retail tariffs should be set to allow a "return of" (that is, depreciation) but not a "return on" (that is, profit) externally provided capital. To make this recommendation less abstract, let us consider how outside contributions are treated by the electricity regulators of Tanzania, South Africa, and Peru.

The 2008 Tanzanian Electricity Law directly deals with the issue of outside grants. Section 23(2) of the law states that "costs covered by subsidies or grants provided by the Government or donor agencies shall not be reflected in the costs of business operation" (EWURA 2008). A weakness of the Tanzanian law is that the wording is too general. Specifically, the language of the law does not distinguish between depreciation and a return on capital; instead, it appears to prohibit the regulator from including either element in setting SPP tariffs.

South Africa seems to have taken a similar approach. In section 8.16 of the 2008 Electricity Pricing Policy, the South African government gives the following guidance to the electricity regulator:

> Any assets which are not financed by the distributors, but from sources such as: State grants, customer capital contributions and connection fees, developer networks handed to the utilities and networks transferred to new utilities debt free, shall be excluded from the asset base or the purpose of determining depreciation and return on assets and the same way these costs shall be excluded from COS [cost of service] studies. (Government of South Africa 2008)

But the South African government policy recognizes that there needs to be some provision for accumulating funds that can be used for the replacement of grant-funded equipment that wears out. So in the very next paragraph of the policy document, there is a clarification: "The provision for the replacement of these assets when it becomes due shall form part of the Licensee's revenue requirements …" (Government of South Africa 2008, section 8.16). This seems to be saying that the regulator must set tariffs so that they include a cost element that allows for the eventual replacement of grant-funded equipment, even if the regulator is not allowed to call it depreciation.

Of the three countries, Peru has taken the clearer and more straightforward approach. A Peruvian government decree issued under the Rural Electrification Law prohibits earning a return on outside capital but explicitly directs the regulator to use an annual depreciation allowance of 16.9 percent for any capital equipment provided to isolated mini-grids that was financed through a government grant (Government of Peru 2007, Article 25). The Peruvian approach is consistent with our recommended rule (see box 5.3).

Box 5.3 Peru: Three Subsidies for Rural Electricity Providers

In 2008 approximately 70 percent of rural households in Peru did not have grid-based electricity. To increase rural electrification, the Peruvian government established three types of subsidies for rural electricity providers. The key features of the three subsidies are:

- ***Initial capital cost subsidy ($100 million per year)***
  - Provided to isolated rural mini-grids (small power producers, SPPs) (less than 500 kW of installed capacity) and to small, grid-connected distribution systems (SPDs) outside the geographic concession areas of larger private and public utilities
  - Can be no higher than $1,000 per operator and the recipient must provide at least 10 percent of the initial capital cost
  - Selected based on bids for the lowest required subsidy per consumer based on prespecified maximum retail tariffs
  - Funded by the national budget, international loans, the rural electrification fund, and donor grants
- ***Operating cost subsidy ($36 million per year)***
  - Reduces the ongoing generation ($23 million) costs and distribution ($13 million) costs of rural providers
  - Bases the subsidy on the regulator's calculation of the distribution costs that would be incurred by an efficient distribution provider serving specified geographic areas with different customer densities
  - Funded by urban electricity customers
- ***Consumption subsidy ($31 million per year)***
  - Ensures that rural customers served by SPPs and SPDs pay tariffs that are similar to comparable customers in urban areas
  - Leads to a 50–60 percent reduction in the tariffs of SPP and SPD customers with monthly consumption of 30 kWh or less (for example, the subsidy reduces the tariff for 30 kWh customers from 17.42 cents to 11.91 cents in one low-density rural mini-grid)
  - Funded by a 3 percent surcharge on all consumers whose monthly consumption is 100 kWh or higher per month

box continues next page

Box 5.3 Peru: Three Subsidies for Rural Electricity Providers *(continued)*

The first two subsidies are producer subsidies designed to lower the capital and operating costs for rural providers. The third subsidy is a direct consumer subsidy that is a cross-subsidy because the funding comes from the 3 percent surcharge paid by higher consuming customers. OSINERGMIN, the national electricity regulator, calculates the amount required to be paid by each utility and the amounts to be received by each rural provider. To ensure the financial integrity of the system, the money is channeled through bank accounts that are not accessible to either the regulator or any other government official. Peru is able to offer these three subsidies because it is a richer country with a per capita income of $5,292 in 2010 (World Bank 2012) and its regulatory system has succeeded in setting retail tariffs at cost-recovering levels.

Source: Revolo Acevedo 2009.

Key Recommendation

If an electricity provider receives a grant from an outside entity to reduce its capital costs, the SPP should be allowed to take depreciation on the equity provided by the grant, but should not be allowed to earn a profit or return on this equity.

Regulatory Issue 3: Extended Payment Programs and Tariffs

The third regulatory issue involves how to account for the expenses incurred by an SPP or utility in delivering a connection subsidy to newly connected households. The most common mechanism for reducing the first-cost burden on consumers is to allow them to make an initial down payment for the connection and then to make installment payments on the remaining balance with little or no interest being charged. But most banks and microfinance institutions are reluctant to make such loans (or do so only at high interest rates) because the loan will be used for consumption rather than production that facilitates new income-generating activities. Therefore, by default, most deferred payment programs are typically operated by the electricity supplier—either the utility, an SPP, or an SPD.

We think that extended payment programs operated by mini-grid operators should be expanded beyond just connection costs. For example, “on-bill financing” could also be used to finance electrical equipment for productive uses (grain mills, and so on), to pay for internal household wiring, or even to make improvements to a potential customer’s house, such as adding a metal roof—which is sometimes a minimum requirement to receive electricity. Mini-grid operators in Tanzania have pointed out that giving them explicit authority to provide on-bill financing to customers for metal roofs would lead to a more rapid increase in the number of new connections because some poor households are unable to afford the cost of putting a metal roof on their house. Similarly, if mini-grid operators could also finance the purchase of productive-use machinery for their commercial customers, this, too, would lead to more sales. We think that expanding extended payment programs would lead to a win-win outcome because more rural households could be connected, more businesses could expand their income-producing activities, and the mini-grid operator would increase sales and be able to achieve financial viability sooner.

Some have argued that any loans that help to increase electricity usage in rural areas should be made through rural microcredit institutions or regular banks rather than the electricity provider. We disagree. While microcredit institutions should not be excluded from this activity, a rural electricity provider has two big advantages over a microcredit institution. First, it is relatively easy to add loan repayments onto an existing monthly prepaid or postpaid billing system. Second, if the customer fails to repay the loan, the electricity provider can simply turn off the electricity to that customer—an option that is not available to a microcredit institution or a bank.

The expansion of on-bill financing requires both regulatory changes and the availability of financing. Both are under consideration in Tanzania. The Tanzanian electricity regulator is considering a proposal that would allow SPPs to recover the interest subsidy and administrative costs of any expanded on-bill financing programs as a recoverable cost in tariffs. It has also been proposed to external donors in Tanzania that they consider providing grants or subsidized loan programs to mini-grid operators in addition to the grants that they currently provide for initial connections.

An ambitious connection-fee-financing program is being undertaken by EEPCO in Ethiopia, with support from GPOBA,[16] to connect more than 225,000 new households. While EEPCO is a traditional, vertically integrated utility supplier, the same regulatory issues would exist for SPPs that wish to provide extended connection payment plans for new customers. Under the EEPCO program, each newly connected customer is given the option of making a minimum down payment equal to 20 percent of the estimated cost of providing a new connection.[17] If the customer chooses this option, he or she will then pay for the remaining balance of connection costs, without any interest, in 60 equal monthly payments over a five-year period. The customer is, in effect, paying for the connection through an interest-free loan from EEPCO, which incurs both financing and administrative costs to operate this program. EEPCO must borrow money to on-lend money to its new customers. It also must have sufficient working capital to cover the lag between its payments (to acquire and install the equipment [for example, droplines, meters, and poles] to connect customers) and the reimbursement that will be received over time from newly connected customers. The GPOBA grant reimburses EEPCO for the cost of providing interest-free loans and two free compact fluorescent lights (CFLs) to its newly connected customers.

The basic lesson here is that the financing and installation costs of the lending program are real costs. The regulator should allow the operator, whether it is a large vertically integrated utility in Ethiopia or an SPP in Mali, to recover these costs in its retail tariffs if these costs have not been covered through an outside grant.[18]

Key Recommendation

If an electricity provider offers its customers the ability to repay their connection charge, the cost of internal wiring, the cost of improving their house to meet minimum electricity connection standards, and the cost of purchasing electricity-powered appliances and machinery through monthly on-bill installments, the regulator should allow the provider to recover both the financing and administrative costs that it incurs to provide these loans.

Cross-Subsidies in Tariffs

In most general discussions, cross-subsidies are defined to mean a tariff structure where some customers pay more than their costs of supply and other customers pay less than their costs of supply. In developing countries, the three most common forms of cross-subsidies are industrial customers subsidizing residential customers, high-usage residential customers subsidizing low-usage customers, and urban customers subsidizing rural customers.

Key Definition

A cross-subsidy is a tariff structure in which some customers pay more than their costs of supply to subsidize other customers who pay less than their costs of supply.

Economists often criticize cross-subsidies because they distort prices. They argue that cross-subsidies can lead to inefficient outcomes because customers do not see the true costs of being supplied electricity.[19] Similar statements are often made in official government policy pronouncements and laws. For example, India's National Electricity Policy states that: "Cross-subsidies hide inefficiencies and losses in operations. There is urgent need to correct this imbalance without giving tariff shock to consumers. The existing cross-subsidies for other categories of consumers would need to be reduced progressively and gradually" (Government of India and Ministry of Power 2005, section 5.5.3). (See box 5.4 for an example of conflicting language in the 2008 Tanzanian Electricity Law.)

The Politics of Cross-Subsidies in Africa

While cross-subsidies are discouraged in policy statements and prohibited in statutes, it is not uncommon for the policy statements and laws to be ignored

Box 5.4 Cross-Subsidies in Tanzania: The Regulator's Legal Dilemma

Even if a regulator or policy maker decides that the only viable tariff option for promoting small power producers (SPPs) is to allow cross-subsidies, there still may be legal barriers that will need to be addressed. For example, in Tanzania, the 2008 Electricity Law states that: "no customer class should pay more to a licensee than is justified by the costs that it imposes on such a licensee" (EWURA 2008, section 23 (2) (f)). Though this statutory language would seem to clearly preclude approval of cross-subsidies for isolated mini-grids, it has also been argued that this provision of the law cannot be read in isolation from other provisions of the law. In the very same section of the law (the section that specifies tariff-setting principles), there is also a requirement that: "tariffs should allow licensees to recover a fair return on their investment" (EWURA 2008, section 23 (2) (b)). Clearly, the two criteria are in conflict because SPPs will not be able to achieve financial viability by earning a fair return on their investments unless they are allowed to charge tariffs across customer classes that will produce sufficient revenues to earn such a return.

When two legally mandated tariff-setting principles are in direct conflict, it seems reasonable that the regulator should be guided by the government's principal stated policy objectives. In Tanzania the government has emphasized the overriding importance of achieving rapid rural electrification. This, then, would imply that cross-subsidies in SPP tariffs should be allowed because they will achieve commercial sustainability for SPPs that wish to supply rural customers on isolated mini-grids. Another justification for such cross-subsidies is that they are already allowed in the national utility's tariff structure for main-grid customers. Under the Tanzania Electric Supply Company's (TANESCO's) current tariff structure for its main-grid customers, a 2010 utility-sponsored tariff study clearly showed that its business customers cross-subsidized its household customers (Vernstrom 2010). So it seemed reasonable that operators of isolated mini-grids should be given the same pricing flexibility to make them commercially viable. When faced with this dilemma, the Tanzanian electricity regulator decided to accept cross-subsidies. In its June 2012 proposal for "second-generation" SPP rules, EWURA proposed the following rule: "To facilitate commercial sustainability, an SPP or SPD [small power distributor] may propose tariffs for specific customer categories or for customers within a single category, subject to the Authority's approval, that take account of the ability to pay of these customers" (EWURA 2012). This is one of four proposals made by EWURA to promote the financial viability of private- and community-owned isolated mini-grids in Tanzania. The four proposed regulatory actions are discussed in the section of chapter 9 titled "What Can a Regulator Do to Promote the Commercial Viability of Isolated Mini-Grids?"

in practice. It is worth taking a closer look at why this happens. The most plausible explanation is that cross-subsidies continue to be favored because they serve the political needs of presidents and prime ministers and the operational needs of government electrification officials. When it comes to actual implementation on the ground, politics usually takes precedence over policy.

Presidents and Prime Ministers

Presidents and prime ministers typically support uniform national tariffs and cross-subsidies in both public pronouncements and private conversations. In public speeches, they will state that basic fairness requires that everyone in the country should be treated equally. And "equal treatment" requires that every residential electricity consumer should pay the same tariff as any other consumer in the same tariff category or class, regardless of whether the residential consumer is located in the capital or in an isolated rural village. This then implies that there must be a uniform national tariff that eliminates all geographic differences in tariffs.[20] In addition, most presidents and prime ministers will state that the uniform national tariff should also include a lifeline or social tariff component because a low-price social tariff will help to alleviate rural poverty and promote affordable electricity for the poorest of the poor. The uniform national tariff, if combined with a social tariff for low-consumption customers, leads to two cross-subsidies: urban customers subsidizing rural customers and higher-consumption customers subsidizing low-consumption customers.

In private, off-the-record conversations a president or prime minister may also acknowledge three other political benefits produced by the cross-subsidies that are not mentioned in public speeches. The first is that cross-subsidies do not need to be financed through the government budget because the money that supports the cross-subsidies comes from the tariffs of other electricity consumers rather than from the government budget. The second is that cross-subsidies are largely hidden from public view and therefore get little or no attention in parliamentary debates. The third is that they help to produce votes from poor people, the principal beneficiaries of the cross-subsidies.

Government Electrification Officials

Government officials, who are involved in the day-to-day work of promoting rural electrification, support cross-subsidies for other reasons. From their perspective, cross-subsidies have three major practical (as opposed to political) benefits. First, even if the president commits to providing general subsidies from the government's general budget, the subsidies may not always be delivered as promised. Second, cross-subsidies are much easier to deliver because they simply require adjustments in an existing tariff system. They avoid the need to establish and administer a separate new subsidy delivery system. Third, without cross-subsidies, most isolated mini-grids will not be commercially viable because total revenues will fall short of total costs. And this is likely to be true even if the mini-grid operator receives grants to subsidize initial capital costs.

Why Cross-Subsidies are Needed (at Least Initially)

Our focus is on commercial sustainability—SPPs must be commercially viable or they will not be sustainable. Commercial viability cannot be achieved if costs exceed revenues on an ongoing basis. In chapter 9 we examine the likelihood of costs exceeding revenues for a hypothetical isolated mini-grid (Case 1: an isolated SPP that sells at retail) using typical real-world numbers from Tanzania. We simulate financial outcomes under different subsidy and tariff scenarios using a spreadsheet. Financial viability is measured using two key standard financial parameters: the debt service coverage ratio (DSCR) and the internal rate of return (IRR). We assume that the DSCR must be at least 1.44 and the IRR must be above 15 percent for the project to be viewed as commercially viable by potential lenders and developers. The simulations show that the only scenario that achieves these minimum thresholds is the scenario in which the mini-grid operator receives up-front capital-cost grants for more than 50 percent of its investment costs, is allowed to charge tariffs to all customers that exceed Tanzania's current uniform national tariff, and is allowed to charge higher tariffs to its commercial customers to cross-subsidize the tariff charged to its household customers. These simulation results are consistent with what Tanzanian developers have said in private conversations and public forums.

So the threshold decision for regulators and policy makers is: *should mini-grid operators be allowed to charge tariffs that exceed the uniform national tariff and to cross-subsidize residential customers*? In our view, the answer is yes, for three reasons.

First, the decentralized track represented by mini-grids will be a viable and sustainable option only if mini-grids can achieve commercial viability. It is unrealistic to expect that governments and donors will be able to offer a credible commitment to cover any ongoing shortfall in revenues in addition to the up-front capital cost subsidies that they sometimes offer. If mini-grids are going to be commercially viable, their sustainability cannot be based on ongoing external subsidies.

Second, under the centralized track of extensions in the main grid, most national utilities are routinely allowed to cross-subsidize their residential customers by imposing higher (that is, non-cost-justified) tariffs on their commercial and industrial customers. So if a national utility is allowed to cross-subsidize across customer classes or categories, why should that same tariff strategy be denied to SPPs?

Third, when electricity arrives in rural areas, it is often first used for lighting that had previously been supplied by kerosene lanterns. And if the price of kerosene is subsidized, it could be argued on grounds of economic welfare that subsidizing the price of a substitute (that is, electricity) does not distort consumption choices. We recognize that the ideal would be to remove both subsidies over time. But if this "first-best" solution is not available, then allowing SPP operators to use cross-subsidies in their tariff structure seems like a reasonable second-best solution especially if it is the critical factor in determining whether an isolated mini-grid will be a "go" or "no-go" option for isolated villages.

Key Recommendation

Regulators should allow mini-grid operators to charge tariffs that exceed the uniform national tariff if the operators' costs exceed the uniform national tariff and to cross-subsidize residential customers. The three justifications for this recommendation are: it ensures the financial viability of SPPs; national utilities routinely cross-subsidize their residential customers by charging commercial and industrial customers higher tariffs, so that same opportunity should be available to potential mini-grid operators; and electricity is a good substitute for kerosene, which is itself often subsidized, so offering subsidized electricity would not distort consumption choices.

Revenues Earned from Carbon Credits through the Clean Development Mechanism (CDM) or Other Carbon Credit Programs

SPPs operating on both the main grid and isolated mini-grids have the potential to earn carbon emission reduction credits through the CDM, a carbon trading mechanism established under the Kyoto Protocol. For example, if an isolated mini-grid SPP can replace an existing fossil-fuel generator (such as a diesel generator) with a hybrid generating system, the SPP can make a credible argument that its planned operation will reduce carbon emissions and it should therefore be entitled to receive certified emission reduction (CER) credits. These CER credits can provide SPPs with an additional source of revenue, above and beyond the revenue that would be collected through the tariffs paid by its customers. As discussed earlier, CERs are not a type of subsidy; instead, they are payments for the provision of a service by the SPP: the reduction of global carbon emissions against a calculated "business-as-usual" benchmark.

Key Definition

Certified emission reduction (CER) credits are payments offered by the UN's CDM or other emission-abatement programs to entities that are able to offer a reduction in a specified and audited amount of carbon emissions against an estimated "business-as-usual" benchmark.

While the opportunity for an SPP to monetize the value of avoided carbon by earning CERs exists in theory, in practice, it would be prohibitively expensive and time consuming for one small, isolated SPP to submit and process a stand-alone application for a CER credit and to create and implement the required post-approval monitoring system required by the CDM board that approves such applications.[21] To date, the only SPPs that have succeeded in earning CERs are those that have applied jointly as individual projects within a larger SPP program. At this time, there seem to be two approaches that allow individual SPPs to be grouped together in a joint application. The first approach is a bundled application; the second, is known as a program of activity (POA) application.

Key Observation

Applying for CER credits is prohibitively expensive and time consuming for a single SPP. Therefore, individual SPPs can submit a joint application, using either a bundled application or a program of activity (POA) application.

Type 1: A Bundled Small-Scale Application

Bundled applications are feasible when the locations of the SPPs are known in advance and the SPPs will use a single generating technology whose aggregate size is below the threshold level required to meet the United Nations Framework Convention on Climate Change's (UNFCCC's) small-scale requirements. One of the first bundled SPP applications that succeeded in earning carbon credits was a community-based SPP program in the Northern Areas and Chitral (NAC) region of Pakistan. It was developed as an initiative of the Aga Khan Rural Support Programme (AKRSP)[22] over a four-year period, and was projected to create 90 isolated, run-of-the-river, micro- and mini-hydro facilities (Case 1 in chapter 2: isolated SPP that sells at retail) totaling about 15 MW of installed capacity at an average cost of $1,120 per kW of installed capacity. These small, village-level hydro facilities will help to replace existing or new diesel generators. In October 2009 the NAC program received approval from the CDM executive board after close to three years of effort in developing and obtaining final approval of the application. A significant portion of the application and project validation cost of the program was paid for by the World Bank Community Development Carbon Funds, and this cost was only partially recovered from subsequent carbon revenues realized.

With this approval, it is expected that the NAC project will receive CDM revenues that will almost double the average annual revenues attributable to each participating SPP project. The 90 village organizations will provide about 20 percent of the capital costs, mostly through in-kind contributions of labor. The villages agreed to sign over the rights to any carbon credit revenues to the AKRSP in return for ongoing and future technical assistance on the SPP project and other future rural development projects in their villages. Hence, the decision as to who would receive the CDM revenues was one component of a larger package that involved sharing of several different costs and benefits.

Type 2: A Program of Activity (POA) Application

A POA application is an alternative approach for grouping SPPs together in a joint application in situations in which the SPPs are operating under a common program but the mix of technologies and the locations of the SPPs are not known or finalized at the time of initial submission. This approach has been proposed in Tanzania for SPPs: (a) that will be using different generating technologies, (b) that will be operating as both grid and off-grid SPPs, and (c) whose location and technology are *not* known in advance. In Tanzania the REA, with assistance from the World Bank, is taking the lead in preparing the CDM application. The REA is the logical candidate for performing this role because it is already providing other forms of technical assistance to SPPs. In Tanzania, as in more than 15 other Sub-Saharan African countries, the REA is providing "connection grants" and guidance to develop project business plans. This assistance gives the REA detailed knowledge of SPP operations and technologies that can also be used to prepare a POA application.

Ultimately, an REA's decision to undertake a CDM application on behalf of an SPP depends on its projections of costs and revenues. The costs are principally the up-front costs of the application and of preparing initial documentation, the cost of preparing responses to questions received during the application process, as well as ongoing administrative costs such as those of the annual monitoring and verification required to validate that the SPPs are producing electricity as promised. The revenues are the future stream of carbon credit revenues and will depend critically on the market price of CERs at the time the application is approved, unless forward contracts (with or without delivery guaranteed) are obtained to provide certainty about future revenues. As of December 2013, the spot market price of CERs was about $0.50 per ton and there is a high level of uncertainty about future price levels, given the lack of global agreement about future carbon markets. If the price remains at this low level, the expected revenue levels may be too low and the transaction costs are likely to be too high to justify going ahead with an application.

The CER Calculation

In Tanzania it has been estimated that a hydro-based SPP that proposes to produce electricity to sell to an existing, isolated diesel-fired mini-grid would be eligible for 0.88 CER for every megawatt-hour (MWh) that it generates.[23] The assumption here is that the SPP's production of electricity will allow it to replace electricity that would otherwise be generated from the diesel generator. But if the SPP proposes to connect to the main grid, it will earn only 0.55 CER for every MWh that it generates, because the SPP's production will replace a less-polluting mix of the national utility's hydro and fossil-fuel generation. If one assumes that each CER brings in $12 of additional revenue, it has been estimated that the carbon credit revenues in Tanzania would increase an off-grid SPP's wholesale revenues by 4.3 percent per kWh sold and an on-grid SPP's wholesale revenues by 9.9 percent per kWh sold.[24] Even though an off-grid SPP will earn more CERs per kWh produced, the impact on the off-grid SPP's revenues, measured on a percentage basis, is smaller than for on-grid SPPs because the off-grid FIT (24 cents/kWh) allowed by the Tanzanian regulator is much higher than the on-grid FIT (6 cents/kWh) and the off-grid SPP operator may not be able to dispatch his plant as much as he would want because of technical constraints. For example, the diesel generator may have to satisfy minimum production levels to achieve minimum operating efficiency levels. Therefore, an SPP operating on an isolated mini-grid will probably have fewer hours of generation and sales than a comparable on-grid SPP facility (see chapter 8).

Table 5.2 provides estimates of the revenue impact of CER credits for main-grid-connected SPPs in Tanzania and three other African countries at different projected prices for the CER credits. Ideally, the revenue impact of CER credits should be measured as a percentage increase in the SPP's average tariff revenues (regardless of whether these revenues come from wholesale sales, retail sales, or a combination of the two). But since these numbers are not readily available,

Table 5.2 Potential Increase in Electricity Revenues from CDM Credits for Grid-Connected SPPs in Africa

			Carbon price ($\$/tCO_2e$)				
Country	*Measured entity*	*Unit of measure*	*5*	*10*	*15*	*20*	*25*
South Africa	Emissions factor	tCO_2e/MWh	1.0481	1.0481	1.0481	1.0481	1.0481
	Likely potential CDM revenues	U.S. cents/kWh	0.524	0.786	1.048	1.310	1.572
	National average tariff	U.S. cents/kWh	7.35	7.35	7.35	7.35	7.35
	CDM revenues as a percentage of the uniform national tariff	%	7	11	14	18	21
Tanzania	Emissions factor	tCO_2e/MWh	0.5	0.5	0.5	0.5	0.5
	Likely potential CDM revenues	U.S. cents/kWh	0.125	0.25	0.375	0.5	0.625
	National average tariff	U.S. cents/kWh	9	9	9	9	9
	CDM revenues as a percentage of the uniform national tariff	%	1.4	3	4	6	7
Kenya	Emissions factor	tCO_2e/MWh	0.63	0.63	0.63	0.63	0.63
	Likely potential CDM revenues	U.S. cents/kWh	0.158	0.315	0.4725	0.63	0.7875
	National average tariff	U.S. cents/kWh	17	17	17	17	17
	CDM revenues as a percentage of the uniform national tariff	%	0.9	3.5	5.2	6.9	8.7
Ethiopia	Emissions factor	tCO_2e/MWh	0.0034	0.0034	0.0034	0.0034	0.0034
	Likely potential CDM revenues	U.S. cents/kWh	0.001	0.0017	0.0025	0.0034	0.0042
	National average tariff	U.S. cents/kWh	16.62	16.62	16.62	16.62	16.62
	CDM revenues as a percentage of the uniform national tariff	%	0.01	0.01	0.02	0.02	0.03

Sources: South Africa: http://www.erc.uct.ac.za/Information/Climate%20change/Climate_change_info3-Carbon_accounting.pdf; Tanzania: http://www.cd4cdm.org/tanzania.htm; Kenya: http://www.kplc.co.ke/ and http://cdm.unfccc.int/; Ethiopia: http://www.jiko-bmu.de/files/basisinformationen/application/pdf/subsaharan_ldcs_cdm_potentials.pdf.
Note: CDM = Clean Development Mechanism; kWh = kilowatt-hour; MWh = megawatt-hour; SPP = small power producer; tCO_2e = tonnes of carbon dioxide equivalent.

we used average retail tariffs for the national utility as a proxy for tariff levels within a country. Though this would be a reasonably good proxy for SPPs that are selling just to retail customers on an isolated mini-grid, it provides a low estimate of the revenue impact for SPPs that would be selling just at wholesale to the national utility on the main grid because one would expect that the wholesale FIT would generally be below the average national retail tariff.

Of the four countries, the expected revenue impact of CDM revenues will be greatest in South Africa for two reasons. First, South African SPPs that use renewable energy would be replacing electricity generation systems that currently use a lot of coal. South Africa's emission factor of 1.04 tonnes of carbon/MWh generated on the main grid is almost double the comparable value for Tanzania. Second, South Africa has relatively low average tariffs. Hence, any new CDM revenues will have a greater revenue impact in South Africa than in some other African country with a higher national average tariff.

In three of the countries—Tanzania, Kenya, and Ethiopia—the revenue impact of carbon credits at current CER prices is likely to be small, perhaps in the 0–5 percent range. And these are estimates of gross benefits. A more accurate estimate of the benefits of seeking CERs through the CDM program would require reducing the expected revenue stream by the cost of the mandatory annual monitoring and verification, after subtracting out the initial costs of CDM validation.

There is another possible source of outside revenues that could be larger than CDM revenues. It has been proposed that outside donors provide direct "top-ups" of the FITs of SPPs that are connected to the main grid (Hanley 2010). The top-ups would be calculated as estimates of the additional revenues required per kWh to make a proposed SPP commercially viable. Unlike CERs, top-up payments would not be justified on the basis of reduced carbon emissions. Instead, they would be justified in terms of increasing national security of supply, reducing vulnerability to fluctuations in fossil fuel prices, and reducing the likelihood of generation capacity shortages within a country. (See appendix G for a discussion of questions that would have to be resolved to implement a donor top-up program.) Uganda is considering a top-up program that would be an overlay to existing FITs. In its first round, the Ugandan program will offer about 2 cents/kWh for mini-hydro projects on top of an existing FIT of 9 cents/kWh. The proposed supplemental payments will increase SPP revenues by about 22 percent/kWh. At the time of this writing, top-up agreements have been signed with three SPPs with the expectation that a total of eight agreements will be signed in the first round, leading to 85 MW of SPP-installed capacity. (See www.getfit-uganda.org.)

CER Credits: Should They Affect Electricity Tariffs?

The central issue for electricity regulators is: how should carbon credit revenues be considered in setting retail or wholesale tariffs for an SPP? This general issue raises several subsidiary questions:

(a) *Who should decide how the revenues from carbon credits earned by an SPP project are allocated?*

(b) *If the regulator makes this decision, should the revenues be given to:*
- The owner of the SPP facility?
- Any party in addition to the owner that provided equity capital either through a monetary or in-kind contribution?
- The wholesale and retail customers of the SPPs?

Regulators have typically *not* been involved in the initial decision on how to allocate CER revenues—it is usually decided beforehand as one element in a larger agreement. However, a regulator has the *de facto* capability to overturn prior allocation decisions among project participants. For example, if a regulator decides that an SPP's customers, rather than the developer, should receive all carbon credit revenues, the regulator can simply reduce the allowed retail or wholesale tariff by an amount equal to the expected annual CER revenues. By doing so, the regulator would effectively "claw back" the CER revenues that would otherwise go to the developer.

Should a regulator change the allocation of CER revenues, either directly or indirectly, through offsetting adjustments to tariffs? *Our recommendation is that the regulator should not modify a previously agreed-to allocation of CER revenues.* It will usually be the case that the CER revenue allocation will be just one component of a larger package of benefits for which there will be various "*quid pro quos*." If the regulator attempts to change this, the whole package may unravel.[25]

Sometimes the regulator may be explicitly asked by one or all parties to pass judgment on the allocation formula. *We recommend that the regulator adopt the general principle that the revenues should go to those who supplied equity or who took the lead and assumed the risk in developing the project*.

Key Recommendation

Regulators should not modify a previously agreed-to allocation of CER revenues, and if they are asked to create or pass judgment on an allocation formula, they should adopt the general principle that CER revenues should go to those who supplied equity or who took the lead and assumed the risk in developing the project.

We recommend this principle for three reasons. First, it is expensive both in time and money to develop a successful CER application. No rational developer will want to incur the expense of preparing an application if there is an expectation that the regulator may, after the fact, turn over the CER revenues to the SPP's customers by reducing the allowed revenues to be recovered through tariffs by an amount equal to the expected or realized carbon credit revenues.

Second, it is likely that the SPP's retail customers will already be benefitting from subsidized tariffs through external grants received for the project's capital costs. Therefore, rather than further reducing already subsidized tariffs, we think that it would be preferable for the revenues to go either to the developer of the project or the rural energy agency that has provided connection grants to the project. If it is the latter, the revenues could be used to create the equivalent of an electrification "revolving fund" that could fund capital cost subsidies for new SPPs. But if the regulator decides that CER revenues should go to some entity other than the developer or the REA, then both entities need to know this right from the beginning so that the other entity that will receive the revenues should incur the risk and expense of making the application.

Third, if there is uncertainty as to how the regulator will deal with CER revenues when setting tariffs, the developer's application may not be approved. CER credits will only be awarded if the developer can make a convincing case that the CDM revenues are needed to achieve financial viability. This is usually referred to as the financial additionality requirement. But if it is unclear whether the national electricity regulator will allow the developer to retain the CER revenues, then it will become difficult (and perhaps impossible) for the developer to make the argument that CER revenues will help to ensure the project's financial viability.

Advance Payments to Close the Equity Gap

At present, SPP developers in many African countries face an equity gap. This means that SPP operators are unable to acquire sufficient up-front capital to make initial capital investments to get an SPP mini-grid up and running. The current reality is that SPPs are generally not able to finance the total capital cost of mini-grids from their own funds and outside grants. Therefore, if a government wants to develop an SPP program that goes beyond a few pilot projects propped up by major government and donor contributions, it needs to find some way for SPPs to gain access to loans from local commercial banks on a regular basis. But local commercial banks are generally reluctant to loan money to SPPs, unless the SPPs or their outside investors can provide a significant amount of up-front equity.

Key Observation

SPP developers face an equity gap in many African countries, in that they cannot secure sufficient up-front equity capital. This, in turn, makes it difficult, if not impossible, to obtain loans from commercial banks.

Minimum Equity Requirements to Obtain Commercial Bank Loans

In Tanzania commercial banks have stated that they will not provide loans to an SPP operator unless the SPP is able to provide 30–40 percent of its own equity for capital equipment. (See table 5.3 for an overview of possible sources of financing for Tanzanian SPPs.) While the Tanzanian bank's high equity requirements may be reduced in the future as the banks gain more experience with SPPs,

Table 5.3 Sources of Funding for SPPs in Tanzania

Funding source		*%*	*Comments*
Debt financing		70	Long-term debt from local banks enabled by the World Bank line of credit
Equity requirement (to be arranged by the project developers)	In-kind equity	5	Valuation of developer's efforts in getting water rights, land, preparatory works, and so on
	Cash equity	10–15	Typical amounts (based on actual data from several projects)
	Connection grants from REA	5	Advance payment of a portion of the $500 per new connection
	Equity gap	5–10	Advance payments of carbon credit revenues + donor grants

Note: REA = rural electrification agency; SPP = small power producer.

the current situation is that very few potential SPP operators in Tanzania can provide 30–40 percent of the overall capital costs of a mini-grid system from their own resources. The situation in Tanzania is not unique. Similar equity requirements have been reported in other developing countries. For example, one of our authors reports: "In Sri Lanka, reported debt-to-equity ratios have been between 50:50 and 80:20. There is no fixed ratio, but most projects are reported to be in the range of 60:40–70:30. A newcomer (small investor, no previous record with the bank) or a new type of SPP (the first wind plant) would be required by bankers to go on 50:50, whereas a good hydro site done by a strong company with other credit history with the bank would be offered 80:20. It's all a matter to be negotiated between the developer and the bank" (Siyambalapitiya 2012).

Other Sources of Equity and Their Regulatory Treatment

To help close this equity gap, Tanzania's REA announced that it is willing to allow SPPs to treat the REA's $500 connection grants as if they were the SPP's own equity. But there is a difference between the REA grants and what might be termed "normal" equity that is supplied by the SPP operator or an outside investor. In the case of the REA grants, the grant is being given as a gift. In return for the grant, the REA expects that the SPP will connect a specified number of new rural customers, but does not expect to earn any returns. So the regulator should treat the grant like any other grant when setting tariffs: the SPP operator should be allowed to take depreciation on the capital financed by the grant, but would not be allowed to earn an equity return on the grant. This is different from the tariff treatment that would be given to "normal" equity supplied by an SPP operator or an outside investor in the project. In this latter case, neither the SPP operator nor the outside investor is providing the equity as a gift, but instead both are expecting a return on their investment. For this normal equity, the regulator should allow both a return on the equity supplied and depreciation on any capital equipment financed by the equity.

Another possible source of advance payments could be carbon revenues. Tanzania's REA and the World Bank are exploring the possibility of securitizing future carbon revenues. Again, this would be an advance payment that would give the developer more money to make up-front investments but unlike the REA connection grants, the securitized carbon revenues would not be a gift (table 5.3). Once the project is up and running, the SPP developer would receive a reduced amount of carbon revenues to reflect the fact that it received an advance payment of a portion of the carbon revenues. So in projecting the financial viability of the SPP, the regulator should project somewhat lower future carbon revenues to recognize the fact that some of the carbon revenues have been "securitized" (that is, received as a prepayment). At the time of this writing, it has been proposed that a "green generation grant" would provide an advance of 70 percent of the carbon revenues that are expected to be generated in the first eight years of operation.

Key Observation

To close the equity gap, two innovative funding mechanisms have been proposed: allowing SPPs to record REA and donor grants as their own equity, and "securitizing" future carbon revenues through a CER program—that is, receiving a larger sum of CER revenues up front, in return for decreased CER revenues later.

Notes

1. A full discussion of energy subsidies can be found in Reiche and Teplitz (2009).
2. An excellent introduction to the theory and practice of targeted consumer subsidies in the water and power sectors of developing countries can be found in Komives and others (2005).
3. A good introductory description of the CDM mechanism can be found at: https://cdm.unfccc.int/about/index.html.
4. These are the average official reported connection charges for large national utilities. The actual out-of-pocket costs for households may be higher if they have to pay a bribe to get to the front of the queue. For example, a villager pointed out, "They [households and businesses seeking a new connection] have to pay money to the engineers and the linemen … There are separate bribe rates for setting up a pole, a transformer, a wire and a connection" (Lakshmi and Denyer 2012).
5. In contrast, it has been reported that about 33 percent of village households have signed up to lease rechargeable lanterns and battery boxes from the Omnigrid Micropower Company (OMC) in the Indian state of Uttar Pradesh within 45 days after the system was put into place (see box 2.2). This is probably attributable to the fact that OMC's customers do not have to pay a connection charge or security deposit (see Raj 2012).
6. Households within 31–70 meters would be charged between $871; those located within 71–120 meters, $1,288. The higher charges reflect the cost of installing distribution poles. In January 2013, TANESCO reduced its connection fees by 30–75 percent in response to a directive from the Government of Tanzania (www.tanesco.co.tz).

7. Techniques for lowering these costs were discussed in several sessions at the Africa Electrification Initiative (AEI) Dakar workshop. See, in particular, the presentations at the session titled "Low-Cost Solutions for Electrification" (http://go.worldbank.org/WCEDP90SZ0). A comprehensive manual on low-cost electrification techniques can be found in Karhammar and others (2006).
8. The reluctance of state-owned utilities to sell to rural customers is not limited to Africa. The same is true in India. It has been estimated that state-owned enterprises lose, on average, about 8 U.S. cents per kWh supplied in rural areas (Dixit 2012). Therefore, it should not be surprising that even after rural villages are connected, state-owned utilities in India try to minimize the number of hours of electricity that they supply to rural customers so as to minimize their losses. It has been estimated that about 75 percent of grid-connected rural households in India average at least four hours per day of outages. The Central Government has issued statements and policies to try to overcome this "reluctance to supply." For example, the 2006 Rural Electrification Policy states that it will be "necessary that the distribution licensee follows [a] non-discriminatory approach towards the franchisees in case of power supply shortage" (Government of India and Ministry of Power 2006, section 9.11). But in the absence of credible positive incentives (profits) or negative disincentives (penalties) for compliance, it seems unlikely that these government policy directives will have much effect.
9. Engineering techniques for reducing connection costs are discussed more fully in Golumbeanu and Barnes (2013, appendix B).
10. But not all donors tie disbursement of their grants to independently verified connections of individual households or businesses. For example, the ACP-EU Energy Facility II: 2nd Call for Proposals of the European Commission requires that the project seeking a grant provide evidence that the new power lines (whether from a main-grid extension or a new mini-grid) will reach at least 30,000 beneficiaries. A beneficiary appears to be defined as a person who lives in the village. There is no requirement that the person must actually use electricity in her home. A beneficiary can be a direct beneficiary (that is, she and members of her household receive electricity in their home), or an indirect beneficiary (the household now has access to cold sodas in village shops or a computer in a village school). The fact that indirect beneficiaries are included in the output measure may create incentives to connect a village but not to connect poor, low-consumption households—with the result that the cost per achieved connection paid for by the grant may be very high (see http://ec.europa.eu/europeaid/where/acp/regional-cooperation/energy).
11. In Tanzania, it has recently been proposed that the level of the REA's connection grants should vary among rural energy providers. It has been pointed out that the capital costs of a shared solar micro-grid that provides low power levels of DC electricity at 24 volts to households in a village (www.devergy.com) will be much lower than the capital costs of a hybrid mini-grid (solar, diesel, and batteries) that provides AC electricity. Moreover, the shared solar DC electricity system provides a lower level of service. For example, the electricity that it provides cannot power the operation of most machines. Hence, in terms of the electrification ladder described in chapter 2, the shared solar micro-grid is providing electricity service at a lower step on the ladder. As a general rule, we think that connection grants should be keyed to the level of electricity that the mini-grid can provide using some variation of the electrification ladder framework rather than being based on an analysis of the capital costs of the provider's facilities. In other

words, the grants should be keyed to the outputs provided rather than to the inputs installed.

12. However, the Malian government is currently discussing a new program with the World Bank that would provide grants through AMADER to operators of the existing diesel systems to convert their systems to hybrid generating systems comprising diesel, solar, and battery components.
13. While our focus here is on outside grants, similar tariff-setting issues arise for customer capital contributions and customer connection fees.
14. This is not just a regulatory issue for SPPs. The same regulatory issue exists for large national utilities that have received outside grants and who use the grants to connect new customers either through grid extensions or new off-grid installations.
15. This assumes that an SPP's tariffs are set based on the SPP's actual costs. This need not be the case. Under Tanzanian law, EWURA has the authority to set tariffs on a generic basis. Section 23(4) of Tanzania's 2008 Electricity Law states that: "[EWURA] may prescribe maximum tariffs of a generic nature of simplified tariff methodologies, applicable to licensees or persons exempted under section 18" (EWURA 2008). Entities that are exempt under section 18 are SPPs with an installed generating capacity of less than 1 megawatt (MW) or SPDs serving an off-grid system with a total maximum demand of 1 MW or less. This section would give EWURA the authority to set SPP retail tariffs at the same level as the retail tariffs charged by the national utility (TANESCO), or by shared characteristics (for example, generating technology) of SPPs. (Further discussion of the theory and practice of retail tariff setting for SPPs is given in chapter 9.)
16. Programs that give customers the option of paying for connection costs in smaller separate payments spread out over time are operating or have been proposed by national utilities in Côte d'Ivoire, Senegal, and Kenya.
17. While EEPCO is not an SPP, the regulatory issues would be the same for an SPP.
18. This policy has been adopted by AMADER, the Malian REA. The annex to the concession agreement awarded by AMADER states that one component of the allowed electricity tariff should be "linked to the pre-financing by the operator of the cost of connection, customer interface (circuit breaker, energy meter, etc.) for interior installations, and electrical equipment such as lighting units" (AMADER, undated, article 7.3). Under Malian law, AMADER is both grantor and regulator for isolated mini-grids.
19. But if the consumption of a substitute product such as kerosene is also being subsidized, it is not clear that a cross-subsidy that lowers the cost of consuming electricity is necessarily inefficient.
20. Since it usually costs more to serve a rural customer, a uniform national tariff will lead to geographic cross-subsidies (that is, urban customers subsidizing rural customers).
21. At the time of this writing, it has been estimated that the cost of putting together a CDM application is about $500,000–750,000.
22. A good description of the project can be found in the project design document (PDD) filed with the CDM executive board. See http://cdm.unfccc.int/Projects/DB/DNV-CUK1204739473.81/view.
23. For an SPP that proposes to create an isolated, greenfield mini-grid, the CER would probably have to be calculated on the assumption that the SPP is mostly providing an alternative to kerosene lanterns.

24. If the value of the CER is $12, then an SPP operating on an existing isolated mini-grid would receive $10.56 per megawatt-hour (MWh) generated or $0.01056 per kilowatt-hour (kWh) generated. In 2010 the SPP received $0.246/kWh sold at wholesale on existing isolated mini-grids. Hence, the opportunity to earn CER revenues would increase its wholesale revenues by about 4.3 percent per kWh produced. The percentage increase would be 9.9 percent for SPPs selling on the main grid because the 2010 wholesale tariff for grid connected is much lower ($0.066 instead of $0.246). The overall increase in SPP revenues will depend on the price of the CER credits and the future feed-in tariff (FIT) prices allowed by the regulator for these two types of sales.
25. We would also recommend applying the same rule if an SPP receives top-up payments from donors to raise the effective price received under FITs. Such payments are designed to improve the commercial viability of renewable generation projects. If the regulator "claws back" such payments by reducing the base FIT, it is likely that top-up payments will not be given by donors in the future.

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