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Conference Edition

Ghana: Mini-Grids for Last-Mile Electrification

Exploring Regulatory and Business Models
for Electrifying Lake Volta Region

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ACRONYMS AND ABBREVIATIONS

AC	Alternating current
AEA	Arthur Energy Advisors
AMADER	Agence Malienne pour le développement de l’Energie Domestique et de l’Electrification Rurale (Mali’s rural electrification agency)
APS	Alternative private supply (of electricity)
ASER	Agence Sénégalaise d’Electrification Rurale (Senegal’s rural electrification agency)
Average cost to serve	The total costs of a system divided by the total energy supplied
BOT	Build operate transfer model
C-RT	Cost-reflective tariff
CA	Concession agreement
CAPEX	Capital expenditures
CBMM	Community based management model
CRSE	Commission de Régulation du Secteur de l’Electricité (national electricity regulator, Senegal)
CSP	Competitive selection process
DC	Direct current
DSCR	Debt service coverage ratio
DSM	Demand-side management
DU	Distribution utility
EC	Energy Commission
ECA	Economic Consulting Associates
ECG	Electricity Company of Ghana
EPIRA	Electric Power Industry Reform Act (Philippines)
ERC	Energy Regulatory Commission (Philippines)
ERIL	Electrification Rurale d’Initiative Locale (Locally Initiated Rural Electrification; Senegal)
EUEI	European Union Energy Initiative
EWURA	Energy and Water Utilities Regulatory Authority
FIT	Feed-in Tariff
GEDAP	Ghana Energy Development and Access project
GEF	Global Environment Facility
GH¢	Ghanaian Cedi
GIS	Geographic information system
GoG	Government of Ghana
HV	High voltage
IFC	International Finance Corporation
IRR	Internal rate of return
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelised cost of energy
LV	Low voltage
Marginal cost to serve	The cost of serving one additional unit of energy
MoEP	Ministry of Energy and Petroleum
Micro-grid	A mini-grid with under 100 kW of installed generation capacity

MoP	Ministry of Power
MW	Megawatt
NEDCo	Northern Electricity Distribution Company
NES	National Electrification Scheme
NPC-SPUG	National Power Corporation—Small Power Utilities Group (Philippines)
NPV	Net present value
O&M	Operations and maintenance
O&M&M	Operations, maintenance and management
OBA	Output-based aid
OPEX	Operating expenses
PAD	Project appraisal document
PPA	Power purchase agreement
PPP	Public-private partnership
PSP	Private sector participation
PSPI	PowerSource Philippines Inc
PURC	Public Utilities Regulatory Commission
PV	Photovoltaic
PwC	PricewaterhouseCoopers
QTP	Qualified third party
RE	Renewable energy
RE Act	Renewable Energy Act
REA	Renewable Energy Authority or Rural Energy Agency (Tanzania)
RECP	Renewable Energy Cooperation Programme
RED	Renewable Energy Directorate of the Ministry of Power
REF	Renewable Energy Fund
REPO	Renewable energy purchase obligation
SADC	Southern African Development Community
SADC RERA	SADC Regional Electricity Regulators Association
SAGR	Subsidised approved generation rate
SAIDI	System average interruptions duration index
SAIFI	System average interruptions frequency
SHEP	Self-Help Electrification Programme
SHS	Solar home system
SPD	Small power distributor
SPP	Small power producer
SPPA	Standardised power purchase agreement
SREP	Scaling up renewable energy
TANESCO	Tanzania's state-owned electricity utility
TASF	Transaction advisory services facility (Tanzania)
TCGR	True cost generation rate
TEDAP	Tanzania Energy Development and Access Project
TOR	Terms of reference
UC-ME	Universal Charge—Missionary Electrification
UNT	Uniform national tariff
USAID	United States Agency for International Development
WACC	Weighted average cost of capital
WATSAN	Water and sanitation
WTP	Willingness to pay
\$	United States Dollars

All currency in United States dollars (USD or US\$), unless otherwise indicated.

EXECUTIVE SUMMARY

Ghana has been remarkably successful in extending its national grid into the rural areas. According to the Ministry of Power, around 80% of communities with more than 500 people have access to grid electricity. The main remaining frontier is to bring electricity to communities living on islands in Lake Volta and in isolated lakeside locations. The objectives of the study are to assist in this in four main areas: delivery models, tariff frameworks, policies and a regulatory framework, and arrangements for the rollout of mini-grids.

This summary highlights first some areas where clear recommendations have emerged, and then presents the areas where there are choices to be made between options with different advantages and disadvantages.

TASK 1: DELIVERY MODELS

Five delivery models, incorporating different combinations of responsibility for generation (G) and distribution (D) in mini-grids, are considered in the report and evaluated according to various criteria. The main advantages and disadvantages of the different models are as follows:

- **Public model** (public sector provides G&D)—highly reliant on cross-subsidies, no role for private sector; customers have low tariffs.
- **Private model** (public sector provides G&D)—less reliant on subsidies, but high revenue risk (from negotiation of tariffs and non-payment) and high transaction costs, so limited interest to date. Likely to require higher, cost-reflective tariffs.
- **Public generation, public distribution, private management** (Mixed model 1)—possible conflicts over long-term regarding responsibility on re-investments; lack of precedents.
- **Private generation (on the basis of a power purchase agreement or PPA), public distribution** (Mixed model 2, also known as the “**PPA model**”)—clear division of responsibilities; requires recurrent subsidies (can be through cross-subsidies), but customers have low tariffs.
- **Community**—community buy-in but serious concerns regarding technical and managerial capacity in and around Lake Volta.

No single model emerges as being universally superior. The communities might be best served by the fully public model, as the utilities (ECG or NEDCo) have the capacity to provide reliable service and will do so at the low uniform national tariff. Community ownership could also be beneficial for consumers, but only if the community has the capacity to sustainably operate the mini-grid.

Amongst the other models that involve varying degree of private sector participation, preference will be expressed by the private sector participant. Under the PPA model, the utilities can purchase privately-generated power at a cost-reflective tariff and sell this at the uniform national tariff, accommodating the higher costs through cross-subsidies from their other customers.

In the spirit of ensuring electricity reaches remote communities at the earliest possible date, any willingness by the private sector to provide electricity to remote communities is to be welcomed, irrespective of the delivery model that the operator prefers.

TASK 2: COST OF DELIVERY, TARIFFS AND FINANCING

Costs and Tariffs

Lake Volta communities would like to have access to electricity at the same price as their urban cousins in Ghana's cities that is at the uniform national tariff (UNT). The Government of Ghana would similarly like to make sure that domestic customers anywhere in the country should pay the same tariff.

However, supplying remote communities is inherently expensive and application of the UNT therefore requires subsidies. Subsidy resources in any year are limited. Therefore, a policy trade-off must be made between maximising the speed of electricity access roll-out (with mini-grid tariffs higher than the UNT) or leaving communities without electricity until such time as the subsidies available in that year are sufficient to allow a mini-grid to be established that charges the UNT.

The consultant team's observation is that people want electricity more than they want low tariffs. This is because, in the absence of access, they pay a higher proportion of their income for inferior forms of energy. This defines their willingness to pay (WTP). The model developed during the study was used to analyse the average cost recovery tariffs for a 140 kW solar PV mini-grid with a 100 kVA diesel backup. This exercise indicated that subsidies of over 50% of the capital costs would be needed to ensure that mini-grid electricity can be supplied at the level of community WTP. In order for the mini-grid to provide electricity at the UNT, on-going recurrent cost subsidies would be needed in addition to a 100% capital cost subsidy.

Retaining the UNT or allowing higher tariffs in mini-grids (as has been done in Tanzania) is a major policy issue. The team recommends that the uniform national tariff should **not** be required for any site, but particularly for those sites operated by private entities. Having remote, generally poor communities pay higher electricity tariffs than their urban counterparts is patently 'unfair', but a greater lack of fairness is to establish a framework in which communities will have to wait years, if not decades, before they gain access to electricity. At the same time, approaches used in other countries (such as Greece and Spain) connecting a minority of their population in more isolated areas have successfully retained uniform national tariffs, absorbing the higher costs across those in the population already connected.

Current policy and legislation is not explicit on this, but non-uniform tariffs should be allowable without requiring a change in either policy or legislation. Monthly flat rate charging mechanisms (see below) are likely to be a way of providing access to electricity in a sustainable (cost recovery) manner, while being acceptable to both consumers and politicians.

Financing and Subsidies

In view of the above, the primary focus in financing mini-grids is the allocation of subsidies from public sources (government revenues or development partner contributions). The team makes the following recommendations in respect of mini-grid subsidies:

- **Capital rather than recurrent subsidies**—one-off subsidies are more transparent than on-going subsidies, dependence on which could threaten sustainability.
- **Subsidies catalysing complementary financing** from beneficiaries and project developers.

Wherever possible, **incentive-based** subsidy approaches should be deployed. These provide incentives to ensure that the best use is made of public resources made available for subsidy purposes. In the context of the mini-grids, this can be achieved by:

- **Competition for capital subsidies** for mini-grid development through the tender procedures already identified above. The procurement process to be established will lead to efficient leveraging of private sector financing.
- **Output-based subsidies**, which would be suitable for providing incentives for expansion of an existing mini-grid through offering cash payments for each new certified connection.

The output-based approach, also referred to as **results-based subsidies (RBSs)**, is less suitable for the investment in mini-grid generation and distribution, because payment of an RBS can only be made on project completion, which implies that the initial investment has to be entirely pre-financed by the developer.

TASK 3: PERMITS AND POLICIES

The key policy principles have already been enunciated in the key recommendations section. The main implications of this are:

- **Tariff levels:** legislation already grants PURC the discretion to approve tariffs above the UNT.
- **Small mini-grids** to be exempt from formal licensing and tariff regulation (less than 100 kW is recommended)
- **Larger mini-grids:** streamlined licencing
- **Charging mechanisms:** allow operators to charge fixed monthly rates for energy services of for power consumption capped by load limiters.
- **Technical standards:** operators can only connect their assets to the main grid, or sell their distribution assets to the utility, if they are built to main grid standards on voltage, safety, security and reliability. However, lesser standards should be allowed in order to reduce costs, providing only that safety is adequately catered for.

TASK 4: SUPPORT REQUIRED FOR ROLLOUT

In the future, the Renewable Energy Act makes provision for the establishment of a Renewable Energy Authority (REA) that will oversee the implementation of renewable energy activities, execute renewable energy projects initiated by the State or in which the State has an interest and manage the assets in the renewable energy sector on behalf of the State.

One of REA's roles would be to take charge of the mini-grid roll out in the Lake Volta region. The main challenge is to organise and manage the competitive procurement process. Before REA is formed, it is envisaged that the Energy Commission will take on this responsibility. The EC is well placed in several respects, including being the custodian

of the Energy Fund, through which the Government's subsidy resources for mini-grids can be channelled.

The report discusses the following forms of support:

- **Technical support**—at the start of the rollout, this may be needed by the utilities and, to a lesser extent, by the EC. The REA/Ministry could both provide and receive input. This could include support on technical design tools such as HOMER.
- **Pricing methodology**—the Retail Tariff Tool is to be handed over to the Ministry, PURC, EC and other interested parties during an extended training course at the end of this project.
- **Procurement and private sector engagement**—some assistance will be needed in preparing the first tender and managing the evaluation and selection process.

Overarching Recommendations

In response to the imperative to provide electricity as soon as possible to remote communities, the study provides some over-arching recommendations:

- **Principles:** Wherever possible, **procedures should be streamlined** for the establishment of mini-grids for Lake Volta communities and the **simplest regulatory requirements** imposed that are consistent with the safe provision of electricity.
- **First right of refusal** should be granted to the **incumbent utilities** to supply power to the targeted communities. Alternatively, the incumbent utilities may be **required** to seek solutions to supply power to the targeted communities.
- **Tendering:** Should the utilities choose not to serve the communities, either the utilities or a central agency should tender the sites to qualified third parties.
- **Technology openness:** All tenderers should nominate how they choose to provide electricity to the identified communities, from main grid power, mini-grids, micro-grids (defined to be under 100 kW, including DC-based systems) and solar home systems (SHS).
- **Subsidies** should be made available for the main grid and mini-grid options. It is recommended that tenderers bid for the minimum subsidy to provide service at a given tariff, service level and specified number of connections.
- **Private operators** should not be restricted by either the utilities' first right of refusal or the competitive procurement process from **opportunistic development of mini-grids, micro-grids or providing SHS.**
- **'Light-handed' regulation** should apply to such systems. This means the system will be required only to meet grid standards on safety, but not on reliability or security.
- **Licensing:** the only requirement will be for such operators to obtain a license from the Energy Commission (EC).
- **Self-finance:** no subsidies will be offered for such private operators. Subsidies will only be offered in competitive tender processes.

1 | INTRODUCTION

About 1.2 billion people currently lack access to electricity and according to Independent Evaluation Group, if the pace of new connections made during 2000–2010 continues for the next 15 years, and population growth is taken into account, the number of people without access in low-access countries would rise by an additional 40 percent by 2030. IEA also forecasts that in Africa, the number of unelectrified people will probably even increase from 589 million to 689 million in contrast to the other regions listed. This estimate is mainly caused by population growth being higher than the increase in the electrification rate. To turn this trend around and to meet the *Sustainable Energy for All* goal of universal energy access by 2030, mini-grids are expected to play a critical role.

While mini-grids have a long history and were an integral part of the power sector development of many of the current high income countries, they are only now emerging as a scalable option for meeting the energy demand in Sub-Saharan Africa, South and East Asia and Small Island Developing States. In these areas, according to the IEA, mini-grids are a least-cost and timely option for more than 120,000 villages and towns.

In the past, acceleration of mini-grids in low income countries as a widespread credible option was constrained by a number of factors but not limited to: (a) limited proven business models that are viable for replication, (b) gaps in policies and regulations, (c) absence of long-term financing (d) high upfront capital costs, low capacity factors, (e) often higher residential tariffs compared to central grid consumers (f) insufficient

financing support and investment, (g) technology failures, (h) lack of effective institutional arrangements to ensure reliable and efficient operation and maintenance over time (i) lack of mechanisms to address grievances, and (j) uncertainty in the face of possible future central grid extension. Well-designed policies and appropriate institutional arrangements along with effective financing mechanisms can address many of these challenges and enable the successful and sustainable deployment of mini-grids.¹

However, recent technological and institutional innovation, combined with an overall cost reduction have made them an attractive alternative. In rural areas, mini-grids now have the potential to provide high quality energy for productive uses to communities that otherwise might be waiting for years for grid connections. And as decentralized generation, electrical storage systems, smart meters and efficient appliances continue to come down in price, independent power producers will find innovative ways to bring electricity services to new customers at affordable cost. For example, in Tanzania, small power producers are now able to sell to customers without going through a lengthy licensing process. In India, remote mobile phone towers, which would otherwise be powered by stand-alone diesel generators, are serving as ‘anchor customers’ for new clean energy mini-grids.

1.1 BACKGROUND

1.1.1 Need for Mini-Grids in Ghana

Ghana has been remarkably successful in providing electricity access and the access rates for urban (85%) and rural (41%) shows the government’s commitment.²

However, the challenge remains in bringing electricity to the communities living on islands in Lake Volta and in isolated lakeside locations. According to the SREP investment plan, as many as two million people live in such isolated areas where grid is unlikely to reach within next 10 years due to difficulties associated with the extension of conventional grid electricity.

Under the World Bank-funded Ghana Energy Development and Access project (GEDAP)³ the option of mini-grids is being explored in pilot mini-grid projects being developed for four island communities situated in Lake Volta. The challenge confronting the Government of Ghana regarding the implementation of these pilots and possible future mini-grids developed in the Lake Volta region is the uncertainty about the adoption of an appropriate business model(s) and applying the necessary policy and regulatory regime. This report focusses on the barriers to scale up mini-grids as a viable solution to provide quality and reliable energy access and some of the potential solutions vis-à-vis technology choices and standards, tariff determination and regulations.

1.1.2 Mini-Grids as Viable Solution for Providing Energy Access

The choice between the connection to the main grid and the development of a mini-grid in a rural or isolated area depends on various economic, financial, social, environmental and technical parameters. Grid connection or extension remains the preferred method of electrification worldwide, mainly because of the economies of scale that curtail power supply costs. Customers might have lower cost power, generally on a much more reliable and stable basis than those buying electricity from mini-grids. A much wider range of end-uses is also possible when a centre is grid connected. However, grid extension also has its limitations in reaching rural and isolated communities, where the consumers are

forced to rely on sub-standard energy solutions and fuels for energy access, for example, kerosene, diesel generators etc. A solar PV mini-grid, for example, is not suited to providing power for industrial-scale thermal and mechanical processes.

Mini-grids can provide cost effective alternative solution for rural electrification if the volume of power consumed and the lower costs of electricity supply from the mini-grid infrastructure outweigh the high fixed capital cost of the connection to the grid. This might be the case in geographical areas where settlements are a large distance from the main grid and there is potential to develop local power sources. Alternatively, the driver for the development of mini-grids may be a failure by the main grid to extend the network to rural areas despite the economic and financial benefits of doing so, or unreliable power supplies from the main grid. Renewable and hybrid energy mini-grids hold significant potential for the African energy sector, not only for increasing energy access, but also by enabling the increased use of renewable energy in the continent, with its benefits for local employment and economic development. Mini-grids are technically and increasingly also economically viable modern energy provision solutions in off-grid areas, and the hybridization of existing fossil-fuel based mini-grids can result in substantial savings—not only for consumers, but also for governments and state owned utilities.

1.1.3 Ghana's Uniqueness When It Comes to Mini-Grid Policy and Regulation

Ghana's achievement in attaining a high rate of electrification for the rural population is an important part of the context for this study. The electrification drive has taken place in the framework of a Universal National Tariff (**UNT**), thereby setting the precedent that all Ghanaians should not just have access to electricity, but that the price should be the same whether a household is in a remote rural area or is located in the capital city of Accra.

The problem this approach raises is that the costs of mini-grid electricity in many cases are inherently much higher than they are for main grid-supplied electricity. In order for all Ghanaians to have electricity access at the same price, either **all prices will need to increase to provide cross-subsidies, and/or there will have to be external subsidies.**

A UNT for electricity is underpinned by the **social justice** precept that rural low income dwellers should not be burdened with a cost of electricity that well exceeds that paid by more affluent Ghanaians living elsewhere in the country. This precept is endorsed strongly in Ghana, as it is in most sub-Saharan African countries, but there are other aspects of social justice that need to be considered. Until rural households gain access to electricity, they pay significant proportions of their household income for smaller quantities of inferior forms of energy. Such households may well prefer some form of electricity, even if it is at a higher price than that paid by households in the capital city. If the adherence to a UNT restricts the development of power supplies for these communities by reducing the potential of more responsive private sector engagement and increasing the cost either for the Government or other power customers, then it is vital to ask the question whether the policy is really in the best interests of those communities.

While other African countries also aspire to apply a UNT, low electrification rates in those countries imply the need for unaffordable large subsidies. The bigger social inequity in such countries is that most households lack access to electricity and continue to pay higher prices for lower quality energy than their grid-connected counterparts. In Ghana, the subsidy issue is manageable because relatively few people remain unconnected to an electricity supply, but the challenge of rolling out mini-grids is still large enough for

private sector participation (PSP) to provide some of the capital costs as well as technical and managerial skills.

The above discussion can be summed up in the notion that **people need electricity more than they need low tariffs**. This is an important framework statement when contemplating PSP. To attract the private sector into mini-grid projects requires as simple, transparent and predictable a policy and regulatory environment as possible.

1.2 STUDY OBJECTIVES

The purpose of this assignment is to explore the most feasible business models for mini- and micro-grids for Ghana's island and lake-side communities, together with a pragmatic policy and regulatory regime that will reinforce the development of such systems.

Specific objectives include the development of:

- 1 | **pragmatic policies** for the development of mini/micro grid electrification in Ghana;
- 2 | **sustainable business model(s)** for the development of mini/micro grid electrification in Ghana;
- 3 | appropriate **financial models and tariffs** for the recommended business model(s);
- 4 | pragmatic **technical and pricing regulations** for the development of mini/micro grid electrification in Ghana; and
- 5 | Appropriate **technical assistance** and **capacity development** for the sustainability of mini-grids in Ghana.

The potential output of this assignment is inform and guide the relevant sector institutions on their roles and responsibilities regarding the successful deployment of mini/micro grid electrification systems in Ghana.

This report is informed by the international experiences and comparative international case studies. This report also draws upon from few brief country case studies which provide examples of effective regulations and procurement processes, and tariff setting approach for mini-grids. The remainder of the report addresses specific objectives listed above.

- **Section 0** presents analysis and discussion of the various options for delivery models of mini-grids.
- **Section 2** | presents analysis and discussion of the costs of mini-grid delivery, tariff calculations and financing options.
- **Section 3** | presents review and proposals for required policy, legislation, regulations, permits, and institutional arrangements.
- **Section** | presents review and recommendations for necessary technical assistance to implement the delivery of mini-grids.



The Annexes to the report contain international case studies, licence and concession agreement templates and a note on Quality of Service, Technical Specifications and Monitoring.

1.3 DEFINITION OF 'MINI-GRID'

For the purposes of this report, a **mini-grid** is defined as an electricity system that is:

- technically separate and distinct from the main national electricity grid,
- sources power from its own power generation, and
- has two or more customers who are separate legally from the ownership of the system.⁴

A **micro-grid** is defined as a mini-grid with less than 100 kW of installed generation capacity, and including those operating with DC power. Unless clearly stated otherwise, anything we discuss for mini-grids also applies to micro-grids. And, a small-scale distribution system sources its power from a connection to the main grid as a **Small Power Distributor (SPD)**, and not as a mini-grid. At this stage, for this assignment, we are discussing options for mini-grids that may eventually convert into SPDs, but not the development of new SPDs.

1.4 INTERNATIONAL PERSPECTIVES

The most successful mini-grid schemes have been developed where the mini-grid design has carefully considered local economic, social and environmental conditions; where sustainable financial models have been developed; and where the national policy and regulatory context is sensitive to the requirements of building mini-grids. Many of these factors are very context specific.⁵ Today, holistic business models are already being piloted around the world. Mini grid developers in East Africa and South Asia are innovating by taking different stakeholder demands into account and catering to various types of customers, leveraging managerial expertise and employing solid financial planning.⁶

This report draws upon from mini-grid case studies in different case studies and each of these case studies has innovative features and/or lessons learned, related to either the regulation or procurement for mini-grids that can be of value to this project. Table 1.1 presents a summary of these noteworthy features for each country case study.

Table 1.1 | Summary of Annex Case Studies

Country Case Study	Noteworthy Features
Uniform National Pricing for Island Systems	
Greece	<ul style="list-style-type: none">• Most islands in the Aegean (between Turkey and Greece) are not interconnected. The networks on the non-interconnected islands are owned by PPC (Public Power Corporation) and operated by DEDDIE (the PPC distribution service company subsidiary).• Private investors own and operate renewable generators on the islands.• End-use tariffs are uniform in Greece, but the additional cost of the non-interconnected islands (arising from high reliance on fuel oil, diesel, etc.) is explicitly recovered through a 'PSO levy' on mainland customers.

(continues)

Table 1.1 | Continued.

Country Case Study	Noteworthy Features
Spain	<ul style="list-style-type: none"> • Until 2012, the Balearic Islands were not connected to the Spanish peninsula and comprised of two smaller-sized isolated subsystems, Majorca-Menorca and Ibiza-Formentera. • Tariffs were (and remain) the same in Balearic Islands as in the Spanish peninsula. The tariff structure comprises a fixed charge and an energy charge that varies according to consumption. • There is currently no explicit levy on consumers' tariffs to recover the cost of islands interconnections and these costs are partially recovered through the fixed and energy charges. Therefore, there is an implicit cross subsidy from the consumers of the peninsula to the Islands' consumers.
Regulation	
Tanzania	<ul style="list-style-type: none"> • Tanzania's Small Power Producer (SPP) Framework provides clear and reliable guidance on system registration and tariffs, providing security to investors. • Standardised tariff methodology and standardised power purchase agreements have assisted developers to conclude agreements with the national power utility (TANESCO). • The Rural Energy Agency (REA) was set up to provide grants to ensure commercial sustainability of mini-grid projects. It works effectively with the regulator, EWURA, on licensing issues, including tariff approvals. • REA is working with the IFC to establish a Transaction Advisory Services Facility (TASF) to assist project developers in negotiating the various stages of mini-grid project development. • Good example of effective light-handed regulation. • High degree of transparency in the regulatory process. • Context is of low electrification (15–20%), and mini-grids are in large part an interim solution before the main grid arrives.
Procurement	
Philippines	<ul style="list-style-type: none"> • In 'unviable' areas, where the utility is unwilling to provide power without an external subsidy, it becomes open to public tender by Qualified Third Parties, who then bid with the utility for a given subsidy, thus achieving the best value for money. • Good example to illustrate how competition in the procurement process can lead to the most cost effective outcome. • Mini-grids are being adopted to reach the minority of the population not yet served by other connections. • The involvement of multiple agencies has contributed to delays and a lack of implementation. In particular, distinguishing between the institutions promoting development, allocating subsidy finance, setting tariffs and setting technical standards has increased coordination costs. • Context is of high access (greater than 80%).

Country Case Study

Noteworthy Features

Mali

- Procurement for mini-grids is done through concessions granted for 12 or 15 years, while ownership of the fixed assets remains with the State.
- The granting of concessions is either done by soliciting bids for the electrification of areas and making a selection based on lowest tariff proposed or by selecting projects based on promoters' ability to develop with a fixed investment subsidy.
- Investment subsidies are limited to 75% of capex costs, while there are no subsidies for energy consumption or operating expenses.
- A single dedicated agency for rural electrification, AMADER provides technical assistance and financial support (investment subsidies) and ensures the successful completion of the procurement process.
- While electrification is low, mini-grids may be considered an optimal long-term solution for isolated but densely-populated areas.
- Context is national access of around 30%.

Senegal

- Procurement of rural electrification is done both through formal top-down identification and formalisation of concessions and tendering processes, and developments by entrepreneurial mini-grid developers in 'mini-concessions', called ERIL projects (Electrification Rurale d'Initiative Locale—Locally Initiated Rural Electrification).
- Top-down concessions are bid on a maximum subsidy basis (80% of capex costs), with bidders to state the number of connections they can achieve within three years.
- Connections can include extension of the main grid.
- Subsidies are paid on an OBA-basis.
- Bottom-up operators work with three different agencies for development permission.
- Operators are allowed to charge a cost-reflective tariff, approved by the national regulator CRSE (Commission de Régulation du Secteur de l'Electricité), but there is government pressure to charge no more than the national grid tariff.
- Operators use flat-rate charges for capped capacity, e.g. 50W, 90W, 180W, which can give effective per unit tariffs of as much as \$ 0.73/kWh.
- Context is approximately 50% electricity access.

1.5 GHANA'S SPECIFIC CIRCUMSTANCES

As compared with the international case studies, Ghana has a higher electrification rate than Tanzania, Mali and Senegal, but lower than the Philippines (>80%). Mini-grids are being considered in Ghana as a long-term alternative to grid connection for the minority remainder of the population not yet connected to the main grid, and in this respect is similar to the Philippines, although main grid connections to some of these communities should not be ruled out. Tanzania and Mali largely view mini-grids as a 'quick-fix' or 'interim' solution prior to the main grid arriving. This is particularly so in Tanzania, which is planning major grid extensions to reach most of its population eventually. In Mali, there are some communities that are both remote and concentrated, and in these cases the mini-grids can be an optimal long-run power solution. In Senegal, the situation is slightly in between the two positions, as mini-grids are considered alongside main grid connections for particular concession areas, dependent on economic drivers, but also allowed in more remote areas outside the concession areas as the 'quick fix' or 'interim' solution.

It is beyond the scope of this study to undertake detailed field research to determine the preferences of Ghanaian beneficiaries of the mini-grids. This report is based on discussions with key stakeholders, in particular ECG and NEDCo, and on secondary information provided by other studies.⁸

Key information on Community Perspectives from the PwC Report

- For powering radios, over 85% of households in all communities used dry cell batteries.
- There was limited use of solar energy in the seven communities; only 5% of respondents had solar PVs installed in their homes and this was mainly for lighting and to charge mobile phones for community members at a fee.
- None of the sampled households in all seven communities interviewed had a solar powered lamp.
- Over 90% of households interviewed were unwilling to use solar energy for any purpose. They actually bemoaned the so-called “limited” ability of solar energy, saying “... *aside lighting and charging of mobile phone, solar cannot be used for anything* . . .”.
- In all, 237 commercial activities were identified in all the communities, under four broad categories: *hair salons* (34 hairdressers and 27 barbers); *tailoring* (50 dressmakers); *entertainment* (18 video centres); and *convenience outlets* (70 mini retail shops and 4 drug stores).
- Current expenditure is equivalent to GH¢ 2.48/kWh (**\$ 0.56/kWh**).
- Over 78% of households in all the communities on the average spend at most GH¢10/month (**\$ 2.27**) on electrical energy services while less than 10% spending more or equal to GH¢ 50/month (**\$ 11.33**) on electrical energy services.
- All the communities opted for a Community Based Management Model (CBMM) for the facilities, citing reasons such as:
 - already existing high and strong commitment and interest in access to electricity;
 - strong commitment to quality of service;
 - operation and efficiency of facility; and
 - having real presence in the community to manage it;
- thereby ensuring sustainability and long life-span for the mini-grids. They also cited basic knowledge in electrical systems, such as generator operation and management as their reason for preferring the CBMM and using already existing WATSAN committees.

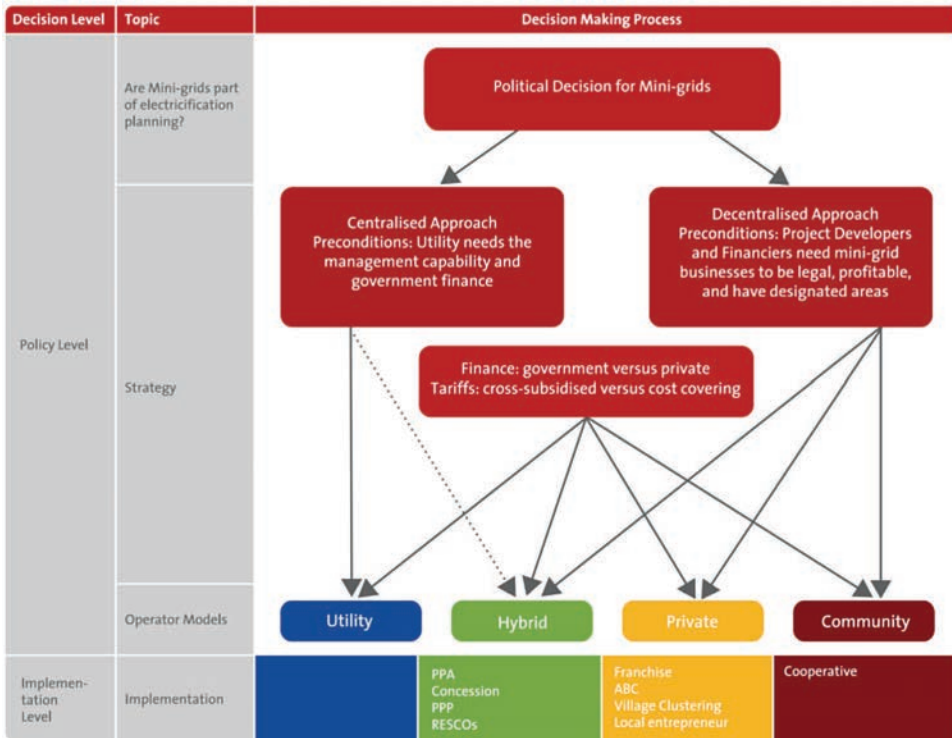
An Assessment of Delivery Model Options This section describe a selection of the delivery models that may be utilised for mini-grids. The choice of delivery model has implications for a range of outcomes, notably the speed of delivery and the tariffs that need to be charged (and as a result, the funding required for development and/or for subsidies).

Important decisions have to be made prior to the choice of the mini-grid operator model. These decisions relate the management approach, the method of financing the capital costs, and the type of tariffs that will be charged. These decisions are important in determining the optimal mini-grid operator model.

The decision making process for the operator models is illustrated in Figure 1.1.

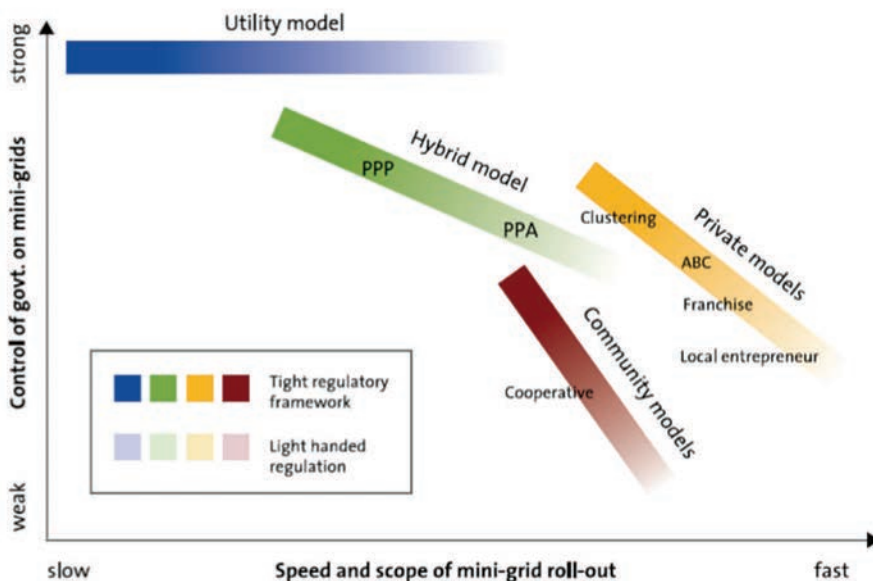
Figure 1.2 introduces some of the potential mini-grid delivery models that are being considered for deployment in Ghana. Each is located as a spectrum against axes representing the Government's control of mini-grid development, and the speed of system delivery.

Figure 1.1 | Decision Path for Selecting a Mini-Grid Model



Source | EUEI/RECP 2014, Mini-grid policy toolkit.

Figure 1.2 | Mini-Grid Delivery Model Options (Control and Speed of Delivery)



Source | EUEI/RECP 2014, Mini-grid policy toolkit.

As shown in Figure 1.2, the four basic options present different outcomes for Government control and speed of delivery. Each option is discussed further in the remainder of this section.

1.6 DETAILED OPTIONS

This section outlines the various options in more detail. The information in this section is guided by the detailed Terms of Reference, and incorporates our experience from similar programmes in other countries in Africa and other parts of the world, secondary analysis of other programmes, and our own analysis of the situation in Ghana. We also draw on some of the conclusions outlined in the 2012 report by PwC, 'Final report: Socio-economic study for mini-grid electrification of island communities'.

1.6.1 Fully Public

Under this option, the full costs of the distribution network and generation assets for systems to supply villages and towns with more than 500 residents will be met by GoG resources. Within this option, the construction and operation may be undertaken either by the Government, or by selected private sector partners. The most likely vehicle for ownership, and for delivery, should the Government choose to retain management control, will be the two distribution utilities, NEDCo and ECG.

Because of the Government funding, the mini-grid will have a lower cost of capital than for a private concessionaire. Some of the highest-level administrative costs may be lower than for private concessions given economies of scale in NEDCo's/ECG management. However, the overall impact on mini-grid costs will be minimal.

The tariff path is anticipated to follow that of the UNT. Tariffs will be indexed based on power cost of the entire system (grid and off-grid) and therefore indexation of mini-grid tariffs is likely to be lower than the increase of mini-grid costs.

Tariffs for public models based on the UNT are unable to cover the cost-recovery tariffs based on the levelised cost of energy. Therefore, to ensure the utility can cover its cost of capital, it must either cross-subsidise the costs from other customers, or seek an external subsidy. This can be accommodated by calculating the UNT based on the costs of the whole network, including mini-grids. This approach will generate positive project and equity NPVs, and project and equity IRRs no lower than the weighted average cost of capital (WACC) and cost of equity respectively. However, there will be a high economic return to customers who will be paying much less than they have been spending on alternative energy sources.

If the UNT is below the cost to serve, each unit of energy sold will generate a loss for the utility. While the tariff structure should accommodate this in aggregate through cross-subsidies, the utilities will still have little financial incentive to serve these customers. Therefore, it will be important under this model for the utilities to adopt minimum service level guarantees. These could take the form of monitoring the performance to the 'worst customer served', or by requiring utilities to guarantee some form of compensation to customers not served power, both of which have been used by Ofgem in the United Kingdom.

1.6.2 Fully Private

Under the fully private model, a private developer and operator will source all the finance for the development and retain ownership of the assets, as well as supplying electricity and charging for the service. Private financiers will have a higher cost of capital than public owners, and likely have higher administration costs as they do not benefit from economies of scale in administration of sites, but otherwise costs are expected to be the same as for the public model.

Tariffs will be guided by the levelised cost of energy (LCOE) in order to recover all costs, including the costs of capital. If this level is higher than the customers' willingness to pay (for each customer category), then the private concessionaire must receive a subsidy in order to provide power. This subsidy could be given either through a capital subsidy, effectively reducing the amount of capital costs to recover through the tariff, or by covering the gap between the willingness to pay and the levelised cost. The source of the subsidy is not relevant to the returns of the project.

If the Government or PURC requires tariffs lower than the LCOE, whether at the UNT or at some other level, they will also be required to offer financial compensation (a subsidy) to meet the funding shortfall. Our analysis (in the Executive Summary) indicates that the requirement for a UNT may make it impossible for tariffs to cover operating costs, let alone a recovery of capex, and that 100% capex subsidies will be needed in order to develop a mini-grid. In such a case, there will be **no space for private investment in mini-grids in Ghana.**

The Government has made large financial contributions to support the extension of the main electricity grid into rural areas in Ghana. The same principle of supporting rural electrification could be adopted to enhance the financial viability of private mini-grids.

Tariffs can be indexed to real cost increases, although the only cost that may be anticipated to increase in real terms is the fuel cost (typically diesel). Diesel costs are relatively small compared to others (particularly the recovery of capital costs), so tariffs are not expected to increase significantly from their initial levels.

With tariffs set to cost recovery levels, the project and equity NPVs will be positive and project and equity IRRs no less than the WACC and cost of equity respectively. With customers paying higher tariffs than under the public model, there is a lower economic benefit to customers. If the tariff is less than the willingness to pay, then customers still gain an economic return relative to their position without electricity. If the willingness to pay is below the tariff, then an external subsidy will be required to cover the difference in present value terms. This can be paid either as a capital sum up front (reducing the cost to serve), or as an on-going amount to cover the difference between the willingness to pay and the cost-reflective tariff.

The private entity's financing structure will be determined based on the costs of equity and debt, and the riskiness of its cash flows. As cash flows are not anticipated to be particularly stable, at least in the project's early years, financing should be provided through more flexible equity, or through debt with a grace period on interest and repayments.

A concern of the private model is the preference of the concessionaire to supply power to those customers most willing and able to pay, rather than to all customers who would

be supplied under a public model. This issue should be addressed with appropriate incentives and contractual requirements.

Private operators have developed mini-grids of various sizes very efficiently in other countries in Africa (e.g. micro-grids by Devery and a mini-grid Rift Valley Energy, both in Tanzania). Therefore, they can be an appropriate delivery model for both large areas under concessions and small sites under ‘bottom-up’ procurement approaches.

There are various options under a fully private model:

- **Complete privately built mini-grid systems:** Under a broader concession agreement, the private developer would be expected to build and operate the distribution network and generating assets in accordance with the terms of the bidding documents and concession agreement.
- **Privately built micro-grid systems:** In some small communities, private companies would provide electricity or energy services through small DC networks (with or without conversion to AC power), typically in communities of less than 500 households with estimated loads of less than 100 kW. While these systems would provide few benefits of economies of scale, they would be able to provide basic electricity services, usually on the basis of a monthly fee—as opposed to a kWh tariff—using pre-payment meters or load limiters (as in Senegal, see Annex A4.3), and renewable and/or hybrid generating technology. The micro-grid networks are not likely to be built according to normal 230V distribution network standards and therefore would not comprise an asset that can be assumed by the utility in the event that the grid reaches the community. Such systems would usually distribute DC electricity and supply the consumers with suitable DC-based appliances for a fee. While the price per kWh of such micro-grids will be high per unit, the specific monthly payment will be tailored to provide better energy services at the same or lower cost than households are paying currently for kerosene, dry-cell batteries, and candles. Micro-grid systems are currently in operation in Kenya and Tanzania.⁹
- **Build, Operate and Transfer (BOT):** under this system, a private firm will construct the hybrid mini-system, operate it for an agreed period, and then transfer the facility and its management to a local body, which they have trained to take over the system.

In addition to the fully private models, there are ways in which the public sector can have some engagement:

- **Private generation, supply and operation, public distribution network:** This option simply engages the public sector in the investment of the distribution network. Maintenance of the network will be the responsibility of the owner (likely to be either of the utilities, ECG and NEDCo). Depending on how the public owner pays for the distribution network, it may charge an access charge for using its network. This should reflect the capital and operating costs of the network, which would be the same as if it were the private operator who invested in the network, with the possible exception of the cost of capital and some administrative costs.

Experience shows that private sector involvement has been beneficial in various ways, including leveraging parallel financing and improving O&M of schemes (see Annex 0).

1.6.3 Public Ownership/Private Management

Under the first mixed model, the Government of Ghana finances and owns all the mini-grid assets, benefitting the project with its lower cost of capital. A private concessionaire will be granted the right to operate both the publicly owned generation and distribution assets, acting solely as distribution operator and supplier.

With a private supply of electricity, tariffs may either be fully cost-reflective, at costs below those for the fully private model to the extent that capital costs are not passed on to the customers, or set at the UNT. The discussion of who bears the costs and receives the economic benefit of this arrangement is per the discussion for the fully private model for cost-reflective tariffs, or the public model for the UNT.

Under this mixed model, the NPVs will be at least 0, with IRRs at least equal to the cost of capital for the public sector under a cost-reflective tariff. Under the UNT, the NPV should be at least 0, with the IRR also equal at least to the public cost of capital, but with higher tariffs across all other customers. A return to the private concessionaire cannot be calculated as there is no investment made against which to offset the positive cash flows from administration of the mini-grid.

The distribution companies ECG and NEDCo are not currently mandated to generate electricity. Consequently, some of the aspects of the mini-grid business such as generation must of necessity require a change in mandate, or be undertaken by a partner. As regards ECG, in other spheres the company has outsourced some aspects of its operations both nationally and in selected zones. The company performs an analysis to establish the cost effectiveness and operational efficiencies engendered by the segment of their operation before outsourcing. Currently most of its metering function and some collection have been outsourced. Additionally, its tariff structure has an element of cross subsidisation, which enables it ultimately to meet its revenue requirement for financial viability.

Under the mixed model 1, ECG has suggested to us that it will not cede its concession wholly to a private sector entity and would only allow the mini-grids in its sphere of operation on a public-private partnership (PPP) basis. It would need to ensure that the reasonable costs of the operation of the mini-grid are recovered fully.

It must be noted that GoG has commenced the restructuring of ECG with a view to breaking it up into concessions; this is in part to obviate the inefficiencies caused by the existing 'top heavy' large governance and management structure which negatively impacts on quick decision-making etc. This appears to be a departure from the Business Units Proposition that had been tabled in the past. Exact details of the concessions plan are unknown, but it is due for implementation before December 2016, when the relevant studies and action plans and strategy would have been concluded.

Communications with ECG suggest that **the company is emphatic about charging a cost-reflective tariff** rather than the UNT. It would also like to avoid subsidies since the history of management of subsidies schemes has more often than not proven unsatisfactory. Our analysis suggests the only way to accommodate this will be to adjust the UNT to include the costs of mini-grids, to be shared by all customers through a cross-subsidy.

ECG's suggested approach for pricing is to identify and provide a cushion for the poor as currently pertains in the normal tariff structure and a levelised tariff for all the other categories. The operations of the mini-grid will enable ECG to experiment with a simpler tariff structure, with a single band/category which some school of thought contends is most suitable—in that billing and collection is simplified and that it encourages conservation (DSM).

1.6.4 Private Generation/Public Distribution

In the second mixed model,¹⁰ a private generator sells power to ECG/NEDCo, which distributes and supplies power to customers. The private generator develops the generation assets with private finance, at a cost of capital that is higher than would have been achieved by the public utility, but lower than it would have achieved for the whole mini-grid as it is not bearing the supply risk of customers, instead of having ECG/NEDCo as the sole counterparty to its PPA. ECG/NEDCo distribution assets will be funded by the GoG at the lower capital cost. ECG is willing to make initial capital outlays but stressed that this should be recovered from the tariff or some form of GoG support.

The private concessionaire's administration costs will be lower than if it was managing the entire grid, as it will simply be running a generation plant without distribution costs. ECG/NEDCo administration costs will be lower than it would have been for a private supplier, and lower than its own costs for managing a whole mini-grid.

The private generator sells power to ECG/NEDCo either under a cost-reflective PPA or a standardised feed-in tariff, achieving cost recovery or capturing any efficiency savings itself under the standardised feed-in tariff. Therefore, it achieves positive NPVs and IRRs at least equal to its WACC. We refer to this MM2 model elsewhere as the 'PPA model'.

An autonomous agency (likely to be PURC) should be tasked with vetting the costs of operation as well as approving or setting the tariffs. Indeed this should be guaranteed by regulation, but the relationship must be contractual.

ECG/NEDCo may be required to sell power at the UNT, despite having purchased it at a higher cost, and incurred additional distribution expenses, including recovery of the capital cost of the distribution assets. Therefore, ECG/NEDCo will make a loss on every unit of energy sold, which must be recovered through some form of subsidy. An external subsidy may reduce the cost of the distribution assets, or a cross-subsidy from other customers (or external subsidy) can cover the margin loss between the national tariff and the costs to serve (including the cost of the PPA). The size of the systems and required amount for power purchasing is likely to be small relative to the companies' other costs, which suggests that they should be able to absorb the higher costs relatively easily.

As with other models where the cost to serve is higher than the allowed tariff, regardless of the size of the mini-grid, the utility will be required to conform to quality of service guarantee targets. This will provide incentives for the operator to serve customers which will incur a financial loss for each unit of energy sold, even if the average tariff is allowed to compensate for losses through a cross-subsidy.

1.6.5 Community/Cooperative Model

The community-based/cooperative model essentially operates the same as the fully private model, with cost-reflective tariffs, but some adjustments to the cost inputs. In

particular, its cost of capital may be higher than the fully private model, but it may also have lower administration costs. Similarly, it may have lower capital costs if the community is involved in its development, providing cheap labour through ‘sweat equity’, as is the case with community-based developments in other parts of the world, e.g. Sri Lanka.

1.7 SUMMARY OF OPTIONS

Five models have been considered in detail in this study. Key features are presented in Table 1.2. It should be noted that ownership and finance are inter-related issues because funding is either from the owner’s own resources or from loans and grants that depend on creditworthiness of the owner’s business plan to lenders and donors.

Table 1.2 | Summary of Viable Mini-Grid Delivery Models

Model	Generation	Distribution	Retail	Relevant Situational Factors	Financial Model Elements
Fully public	Ownership and O&M of assets by NEDCo or ECG Could have BOT by private developer/operator Not possible if utilities are unable to obtain generation licenses			Model used in various countries already	Public funds UNT Cross-subsidies
Fully private	Ownership of assets and O&M by vertically-integrated private firm or two or more private firms			Desired by NEDCo	Private investment Cost-reflective tariffs or subsidy
“Mixed model 1” or “Private management model”	NEDCo/ECG builds and owns systems; Operation outsourced to private sector either through concession or a management contract based on fee			Requires lower capacity in the utility	Public funds Operating costs versus contractual fees
“Mixed model 2” or “PPA model”	Private sector builds and owns the generation part and sells power under PPA.	NEDCo/ECG owns and operates the distribution element and retail of electricity		Existing policy/regulatory framework (FiT for off-grid stations)	Private investment FiT/PPA
“Community-based/ Cooperative model 1”	Community/cooperative builds, owns and operates the mini-grid Could have BOT by private developer/operator			Model encouraged by policy, potentially easier licensing procedures	Private investment Subsidies Electricity tariffs

Source | ECA.

Box 1.1 | Definitions and Interpretations of Licenses, Permits, and Concessions

There is no definition of the three terms in the Ghana energy sector laws or in the Interpretations Act of Ghana.

Licenses and permits in the Ghanaian context are distinguished by usage. For instance the EC Act and the RE Act indicate the sector activities for which a license is required. Permitting is provided under third-tier guidelines issued by the EC, such as the siting permit requirements under the Commission's facilities Siting Guidelines, or the Bulk Customer Permit, which allows entities that consume a large quantity of electricity to shop for their supplier. A license is required for **virtually every commercial activity** and with no room for the substitution of a permitting system.

With regards to **concessions**, the EC is authorized to delineate the zone or area to be covered by a distribution license and that grants the licensee the exclusivity rights to such zone or area. This will apply by extension to mini-grids. Under a concession, there is **no requirement for government ownership of assets** although traditionally the assets have been government owned. There is currently at least one investor-owned distribution entity (Enclave Power Company) which procured and installed, owns and operates the network under license issued by the EC.

The main advantages and disadvantages of the different models are as follows:

- **Public model**—highly reliant on cross-subsidies, speed of delivery limited by capacity of utilities, no role for private sector unless under BOT (this could speed up delivery); customers can have low tariffs.
- **Private model**—less reliant on subsidies, but high revenue risk (from negotiation of tariffs and non-payment) and high transaction costs (permits, procurement, etc.); interest may be limited without careful project preparation.
- **Mixed model 1**—possible conflicts in long-term regarding responsibility on re-investments; lack of precedents.
- **Mixed model 2 (PPA model)**—clear division of responsibilities, customers have low tariffs; requires recurrent subsidies, requires firm commitment from generator (if using mobile assets).
- **Community**—community buy-in, potentially lower cost of capital (e.g. using 'sweat equity'), potentially higher customer payments; concerns regarding technical and managerial capacity in remote rural areas (BOT model may assist this).

We understand that licenses are required for all commercial power operations, with permitting not allowed. Therefore, this will apply to all operators in any model, including the utilities (which presumably already have licenses for power generation, distribution and supply), private operators and community-based schemes. Further information on our understanding of licenses, permits and concessions is presented in Box 1.1.

1.8 DELIVERY MODEL SELECTION

The discussion in the previous sections suggests that the ultimate choice of the delivery model is unlikely to be a single recommended approach. Indeed, there are differences in the preference of the two utilities despite the shared interest in ensuring that people

within their concessions receive electricity. There are also significant challenges resulting from the preference for or against the application of the UNT to mini-grids. In this section, we identify the considerations that should lead to an appropriate delivery model selection for a particular site, based on the following key factors:

- cost of delivery,
- speed of delivery,
- ability to fund the development, and
- implications for tariffs.

Table 1.3 below summarises pros and cons of each model from the perspective of different stakeholders.

Table 1.3 | Comparison of Mini-Grid Delivery Models

Delivery Models	Utility/GoG	Private Sector	Population	Strengths	Weaknesses
Public model	Model highly reliant on cross subsidies, increasing electricity prices for all ECG/NEDCo customers	No significant role for private sector, only ECG/NEDCo	Benefit of cheaper electricity (grid prices) for mini-grid communities, but higher costs for rest of the population	'Business as usual'; Lower customer tariffs for mini-grid customers; operator already known	Require larger subsidies and/or higher tariffs for other customers; financial burden on utilities; slower delivery
Private model	Cost reflective tariffs ease pressure on public funds or cross subsidy schemes; issue of affordability of tariffs	First movers needed; revenue collection risk; bankability is a concern; burdensome, unclear licensing procedures; unclear mechanisms for allocation of subsidies	More expensive electricity (but better than no electricity); private sector concession can be more involved in encouraging opportunities for productive use of electricity	Faster delivery; lower subsidy required; close contact with customers to increase demand for power	Tendering/marketing process required; no precedent of licensed operators; higher tariffs for customers
Mixed model 1 "private management"	If case of concession for operation, there is an opportunity for cost reflective tariffs, thus reducing burden on cross-subsidy schemes	Private exposed to revenue risk from collection of tariffs but does not need to recover capital investment	Same as private model above; tariffs potentially lower due to GoG developing and owning infrastructure	Lower cost of capital (slightly lower tariffs)	Possible conflicts over large maintenance works, re-investments and upgrades (especially relevant for capital-intensive hybrid systems)

(continues)

Table 1.3 | Continued

Delivery Models	Utility/GoG	Private Sector	Population	Strengths	Weaknesses
Mixed model 2 “PPA model“	Payment of PPA while charging national tariff to consumers will require subsidies from the GoG or cross-subsidy from other customers; on the other hand, private generation potentially more efficient (and cheaper) due to incentive of fixed PPA tariff; private sector leverage in rural electrification	PPA reduces revenue risk. Bankable “comparatively easier” permitting and licensing procedures; still lengthy process requiring specific PPA clauses for off-grid suppliers	Similar to public model; limited interaction of private with demand side	Suitable for pilot project; easiest way to involve private sector	No precedent of PPAs for suppliers to mini-grids yet
Community-based/ Cooperative Model	Cost reflective tariffs could ease pressure on public funds but community models known to be highly subsidised	Private sector can play role in shareholding or O&M; potentially easier licensing procedures	Community involvement in project	Design focuses on community needs; community incentives for maintenance	Sustainability is a concern (technical and managerial capacity, tendency to charge too low tariffs, requires clear maintenance and reinvestment planning)

The assessment of the delivery models is not a purely technocratic matter that can be left to outsiders. There are some embedded policy issues relating particularly to the current policy of a UNT, which imply that the delivery model decision is ultimately one for the Government of Ghana to make.

1.8.1 Cost of Delivery

There is unlikely to be any change in the cost of material delivery based on the business model, except in the cost of capital and some administrative costs. It is possible that the government can access cheaper capital, which, when incorporated into the tariff, can lead to a lower revenue requirement.

1.8.2 Speed of Delivery

We anticipate that models led by the private sector, including community-based approaches, will be developed faster than those led by the utilities for most sites, owing to their clearer internal procurement processes. Where the utilities are involved in the development process, particularly in site identification and preparation, we recommend strict timelines to ensure that they work efficiently for the delivery of electricity to communities. This is discussed further in [Section 0](#).

In addition, while not specifically a delivery model issue, allowing developers the option of developing DC-powered systems should increase the speed of delivery as they are less technologically complex in development, while still retaining suitable safety standards.

1.8.3 Ability to Fund the Development

This is discussed further in [Section 0](#). It is anticipated that private developers could fund this faster than the Government, but ECG is confident it can do this itself (presumably with external GoG support, as has been the case with the extension of the national grid into rural areas). Given ECG and NEDCo's challenges in meeting their costs to serve customers, and the resulting weaknesses in their balance sheets, we are not confident that they can handle the financial burden for delivering mini-grids within a reasonable period.

1.8.4 Tariffs

Due to their larger and more diverse customer base, we would anticipate that the utility would have a greater ability to absorb through cross-subsidies what are anticipated to be higher costs of delivery than private developers can achieve. If private developers develop a site, and they are required to charge a tariff below their cost to provide service, they will require an external subsidy. As is made clear in the Executive Summary, a requirement to charge the UNT may effectively preclude the private sector from financing anything other than generation assets (which is sold through a PPA).

1.8.5 Recommendations on Delivery Model

After an assessment of all possible structures and an analysis of the impact that each model would have on the level of tariff and on required subsidies, as well as an analysis of potential constraints in each case, for instance the level of education and exposure to technology as identified in the communities, we recommend three models:

- **Fully public sector model** allows the utilities to continue to serve the customers in these concession areas, and has the greatest potential for tariffs to be kept low through cross-subsidisation. This option may not be available if utilities are not able to obtain distribution licenses.
- **Fully private sector model** will likely give the quickest roll-out of grids, and is a preferred option for the operation, management and maintenance of the mini-grid models. It is, however, likely to require higher, cost-reflective tariffs.
- **PPA model** (Mixed model 2, in which the developer generates power which is sold to ECG or NEDCo for distribution to final end-users) is the fall-back if private operators are only prepared to do generation and do not wish to undertake distribution, if the

utilities are unable to obtain generation licenses, or if the UNT is required. The recurrent subsidy requirement can be funded through cross-subsidies from other consumers.

Our recommendation is supported by the report by PwC, whose recommendations also included the private sector-led approach, despite the preferences of the communities for community-based models. They support their view with the following observations:

- The technical requirements of mini-grids are likely beyond the capacity of the communities, for development and management, including tariff calculation, load management and maintenance, at least in the short term.
- Communities tend to become quite bureaucratic in making decisions, potentially delaying important decisions and increasing costs and/or maintenance requirements.
- Private sector developers will have better access to finance than communities.

As discussed above, under the private sector model, the developers will have full responsibility for generation and distribution. Such a model would maximise the role of the private sector and will involve the lowest level of subsidy. The private model would free up resources to be used to accelerate the attainment of the national goal of universal access to electricity.

In respect of the fall-back PPA model, it is notable that from our interviews with and analysis of ECG, they are keen to do the distribution itself, as it feels it can absorb the costs through cross-subsidies. However, this would essentially put the costs on to their other customers, rather than on to those using the mini-grid. NEDCo is not keen to get involved in mini-grids at all. In addition, we have concerns about ECG's ability to fund its component of the development, although this should be mitigated through special targeted funding from the GoG, akin to its national electrification strategy funding.

Given this, we feel that the utilities should be given the option of developing the sites with a first right of refusal, given their interest in developing sites, and the national-level preference for keeping the UNT, which the utilities may be better placed to accommodate. This will come with strict timing conditions that, if breached, will serve to transfer their rights of development to an open tender. This is discussed further in [Section 0](#).

The participants at the Final Workshop went beyond first right of refusal, arguing that the utilities should be **required** to develop mini-grids for remote communities within their service areas. If this is adopted as policy, as a quid pro quo we would recommend that the utilities be allowed to tender out all or part of these projects, provided there is adherence to the guidelines for such tendering laid out in this report. This idea is elaborated further in later sections.

1.9 PROCUREMENT

1.9.1 Top-Down vs Bottom-Up Procurement

The procurement of developers for mini-grid site development may be framed as either **'top-down'** or **'bottom-up'**. A 'top-down' approach is administered by a central agency, usually a government body (or collection of bodies). The agency identifies sites for mini-grid development, and it leads the procurement of a developer for each site, or else the relevant distribution utility is required to develop the site and does so itself or initiates a procurement process. The increased likelihood of site development from intentional procurement, and communities receiving electricity, is a strength of this approach. In

addition, the approach should remove some of the transaction costs of development borne by a developer, including demographic analysis and some of the costs of negotiating agreements with the relevant government agencies (although some these negotiation costs can be minimised under a bottom-up approach through the use of template agreements).

Under the assumption that any site where power can be supplied in a way that is economically viable will be developed, and therefore that sites without development are economically unviable, a ‘top-down’ approach will require some form of incentive for developers. This may take the form of a subsidy, increasing the financial viability, and/or regulatory security, such as a concessionary right-to-serve guarantee for a given period, ensuring an operator can supply without threat of competition that might otherwise have made the area unviable. Any subsidy or protected concession incentive will also need to have certain conditions attached, through which regulations are applied. This approach is known as “pre-specified regulation by contract”.

A ‘bottom-up’ approach is more passive (and therefore should be less costly) for central agencies, and relies on developers taking the lead in site identification. While not necessary for successful mini-grid development,¹¹ a central agency may still have a role in managing regulatory frameworks for site development, but will not actively procure developers. There may not be any promise of a subsidy, nor any protection from competition through regulations, e.g. concession contracts, tariff-setting guidelines.¹²

Senegal and Mali both follow a combination of the two approaches. The appropriate government entities identify sites for development, but not to the exclusion of opportunistic developers who wish to identify and develop sites, pursuing the relevant permissions and financing themselves. In Senegal, developers have the option of connecting customers to the main grid, to a mini-grid, or with a SHS. Benefits of the approach see the private sector given the opportunity for inclusion in a top-down network planning process (increasing the options for development), but not restricted by the process if it is able to identify potential development opportunities on its own. It is an appropriate approach when the total area to be electrified is large, and a detailed planning process very costly and time-consuming.

Ghana should adopt a combination of **the top-down and bottom-up approaches** to maximise its chances of providing electricity to all its communities within a reasonable timeframe. Given the areas for electrification are easily identified, a top-down approach can coordinate efforts to ensure all areas are included in the electrification planning process, without incurring significant additional cost or taking too much time. At the same time, the process can be expedited by allowing opportunistic developers to identify and develop power supply to communities without the procedural delays that the top-down process will likely entail. Any developer can either register with, or apply for a license to, the EC in the short-term (but eventually the REA) to supply any area, at any time, but will only be able to access subsidy financing by going through the formal top-down process.

Section 0 highlighted that the choice of delivery model for a given site can be dependent on a range of factors. Given the lack of certainty around the feasibility of each site, a procurement process using public tenders can provide strong information on available development options sourced from market participants.

The Philippines **Qualified Third Party (QTP)** bidding process, described in more detail in Annex A2.1, provides guidance on a top-down approach that, if adapted and adopted

by Ghana, should lead to the unconnected island and lakeside communities getting electrified in a reasonable period of time. It should also ensure the electrification process is provided relevant market information on the costs to serve, and lead to optimal delivery of a power supply. This approach gives the incumbent utilities (in this case NEDCo and ECG) the first right of refusal to develop a particular site, within a limited timeframe. Should they deem it 'unviable', meaning they are unable or unwilling to provide power without an external subsidy, it becomes open to public tender, to both Qualified Third Parties and the incumbent utility (and potentially the other utility as well), who then bid on the basis of the subsidy they will require.

Competitive bidding for a concession under these models should achieve the best value for money. Sites could be fully prepared for bidders who compete to provide a fixed number of connections, specified minimum service levels¹³ at an agreed tariff level, on the basis of the smallest subsidy they would need to achieve the targets. Technical and financial assistance should be provided for this process to ensure that both short-term and long-term outcomes are achieved.

Competitive bidding should be used to minimise costs incurred by the public sector, but it is crucial that the bidding be through a transparent and fair process. The guiding principle to ensure non-discrimination between the different approaches on matters that affect the quality and cost of service to the end-user or customer is very important.

1.9.2 First Right of Refusal or Requiring Utilities to Develop Mini-Grids

As explained earlier, two options being considered are for the distribution utilities to be given the first right of refusal to develop particular mini-grids in their service areas, or else for the utilities to be required to develop these mini-grids. Either way, the main options for the utilities are to develop the sites entirely by themselves, or to develop and operate the distribution networks while having the power supplied by private generators. The generators may be procured through a competitive process, following the same principles as that for the procurement of fully-private site developers discussed hereafter.

Our discussions with NEDCo and ECG have indicated different preferences for developing mini-grids. NEDCo is reluctant to engage in mini-grid development and operation, while ECG would prefer to undertake the delivery themselves or in partnership with private sector parties. This gives an indication of how each might respond when given the first right of refusal to develop a mini-grid within their existing concession. Our analysis of the capacity of each utility suggests that financing the developments may be challenging, although external GoG support should aid this.

While ECG has the preference to develop sites themselves, the discussion in [Section 0](#) highlighted the public delivery models are likely to be slower than those led by private sector developers. Given the risks of delay in delivery, borne ultimately by the community beneficiaries, restrictions should be placed on the utility to act on their first right of refusal. To give forewarning of refusal to develop, utilities must abide by certain milestones:

- After **1 month** (or sooner), utilities should nominate any sites they know they will not develop.
- After **5 months**, utilities should be able to present a plan for undertaking pre-feasibility studies of all identified sites within their concession area, and an associated plan for financing developments.

- After **12 months**, utilities should be able to show evidence that they have completed a target number of pre-feasibility studies on sites identified in their pre-feasibility plan, including a coherent financing plan.

If the utilities fail to meet **any** of these targets, the EC should consider withdrawing their first right of refusal, and initiate the Qualified Third Party competitive bidding process. This will also automatically kick-in at any time that the utility declares that it does not want to develop a site, or else at the end of the above milestone period, which amounts to a **maximum of 12 months**.

If a policy of requiring the utilities to develop the mini-grids is adopted, a similar timetable should be adhered to, whereby the procurement process is completed for any project components that the utility is not best placed to undertake itself is completed within the **same maximum of 12 months**.

ECG and NEDCo have advantages over private sector developers in developing mini-grids through their knowledge of the areas to electrify, their established in-house engineering capability, and their ability to absorb and spread higher costs across their wider customer bases. However, their capacity to finance developments requires further scrutiny not possible through this analysis. Their challenges in raising sufficient revenue to meet creditor obligations impacts their ability to carry debt on their balance sheets, and therefore to raise new capital to invest in mini-grids. This requirement may be mitigated if they receive targeted new funds from the GoG, although this gives a very different complexion to the bidding process unless the funds are available to all bidders indiscriminately.

We do not anticipate that the development and operation of mini-grids will generate returns greater than an allowed cost of capital; this will be enforced as much as is possible through tariff regulation. Therefore, the utilities' involvement in supplying power will not produce additional remuneration to support other activities that may not be strong in recovering costs. It is more likely that the opposite may be targeted, where tariffs can be cross-subsidised from other activities (i.e. tariffs based on the utilities' total network expenditure, rather than a per site basis).

1.9.3 Speed of Delivery

The experience of Senegal shows that a top-down concession approach has the potential to be very slow (approximately 10 years), particularly as compared with the bottom-up process. This is because it requires fairly detailed mapping exercises, including demographic profiling and the identification of renewable energy resources, financial and economic calculations, permitting and the establishment of funding support. However, given the detail already known about the areas to electrify, as opposed to Senegal's much lower electricity access rate (80% in Ghana vs 50% in Senegal) suggests this should be less of a problem for Ghana.

Similarly, the experience of the Philippines shows similar difficulties in achieving an efficient process. In this instance, the delays were in part due to the lack of coordination between multiple agencies to enact the procedure. To avoid this potential problem, Ghana should give as much authority as possible to a single agency, ultimately, the REA. In the interim, tasks will need to be carefully managed between the other lead agencies: the RED, EC and PURC. The procedures should be as streamlined as possible; especially where other institution must undertake activities, for example, tariff setting by the PURC.

Through the simultaneous adoption of the bottom-up approach, some of the targeted communities should benefit from much quicker delivery of power supplies by allowing both public and private developers to take opportunities to develop sites without excessive regulations.

1.9.4 Allocation of the Subsidy

Allocating a subsidy on a competitive basis under the top-down process requires bidders to provide some form of assurance against a measurable objective. Various objectives are possible, e.g. number of customers, tariff level, connection cost, level of the subsidy, but in order to assess bids easily and on the most comparable basis, a single measure should be chosen to optimise, against fixed constraints on the others.

For this process, we would recommend that bidders offer a guarantee that they will:

- provide power to a **fixed number of customers,**
- for a **given quality of service,**
- at a **given tariff level,** and
- for a **given connection cost,**

and then suggest the subsidy they would require in order to do this.

The fixed number should approximate all potential customers on a given date. To say that all customers will be connected without giving a number may run the risk of additional potential customers appearing once they know that an area will receive power, and that their connection is effectively guaranteed, with the developer bearing the additional cost. However, the experience of Mali and its 'per connection' subsidy has shown that developers/operators may struggle to fund additional connections once a mini-grid is operational. Given the possibility of this eventuality, an additional per connection subsidy could be made available for developers/operators on an OBA basis. Alternatively, this could be represented by a bonus subsidy, offered for exceeding an agreed connection numbers target.

Fixing the number of customers is in line with the priority of the Government to provide electricity to all households in Ghana. Therefore, a bidder will have to estimate the cost of connecting all households, even those they may believe to be least viable (owing to their distance from the next customer, and/or their potential load and likelihood to pay).

1.9.5 Packaging of Sites

A larger scale of projects available for tender in a region packaged together will likely attract larger, more experienced, and more professionally managed investor teams, thereby increasing the likelihood of success of this programme. In addition, bidding on packaged projects would reduce mobilisation, overhead, and transactions costs.

Bidders for subsidy benefit on a package of sites would require detailed information on several elements of a program to reduce uncertainty, which may include the following:

- **Pre-Development:** locations of sites; studies on consumption patterns and details of the community income levels; local and national permits and approvals established or

granted to the winning bidders; community involvement, support, engagement, and approval to increase confidence that the systems will not be vandalized and electricity will not be stolen; guarantees on tariffs or payments to ensure that revenues will be received if electricity is generated and distributed.

Under the Government's Self-Help Electrification Programme (SHEP), communities can increase their priority for grid connection by procuring and erecting the low voltage electricity poles required for their distribution network. If communities are prepared to do the same for a mini-grid, this community willingness should be included in the pre-development packaging of sites.

- **Construction phase:** Equipment types, features, costs of approved mini-grid system types for both generation and distribution; estimates on the types of personnel required to install or set up mini-grid generation and distribution; recommendations on locally sourced vs internationally sourced equipment and/or staff to assist in construction.
- **Operation and Maintenance phase:** guidebooks or training on how to maintain a mini-grid technically and operationally; resources for spare parts.
- **Exit phase:** standards and terms and conditions on what happens if or when the main grid connects—what are the terms of a sale or transfer and how can this be accounted for at the outset in a manner that will be sustainable over a 5 year or longer period of time.

1.9.6 Recommendation on Procurement

Following from the above discussion, our recommendations for the top-down procurement process are as follows:

- **Step 1**—Inventory of sites: population, grouping, economic viability of a mini-grid, generation technology identified, GIS maps required, estimated date for grid connection.
- **Step 2**—Packaging of sites and obtaining approvals—sites suitable for development under the top-down approach need to be packaged and the necessary approvals obtained, as these will be needed by any developer.
- **Step 3**—Utility first right or utility mandate: Under the first option, if the utility declares it will not develop a site, or else fails to commit to developing the site within a maximum of 12 months (this relatively long period allowing for feasibility studies to be carried out), the site goes to open tender. Under the model of the utilities being required to develop the mini-grids, they initiate and manage the procurement of any components that they do not themselves have the capacity to undertake or are not best placed to undertake.
- **Step 4**—Qualified third parties: potential QTPs are invited to submit their credentials to the EC (or REA in the future), or to the utilities if they have initiated the procurement process, in an expression of interest exercise that covers technical and financial track record, business model, O&M capabilities etc.
- **Step 5**—Open tender: utility and/or QTPs bid for packaged concessions, with approvals for mini-grid development already in place. The bidding is on the basis of the **lowest subsidy** to deliver specified levels of access and service standards, which may include access via the main grid, a mini-grid, micro-grid or SHS. We do not recommend openly soliciting 'bottom-up' proposals as observed in Mali as the top-down process is better suited when areas are smaller and more easily defined.

2 | COST OF DELIVERY, TARIFFS AND FINANCING

2.1 PRINCIPLES OF PRICING

The key principle of mini-grid cost of delivery, pricing and tariff regulation for mini-grids is that there are certain costs involved in developing and operating a mini-grid system that must be recovered one way or another in order for the system to operate sustainably. The choice of business model, form of regulation and other Government-level decisions have little direct impact on the absolute level of costs. Therefore, the choice has to be made, ultimately by the Government (through its delegated representatives), how these costs should be funded.

Costs of mini-grids may be classified as either **capital** costs or **operating** costs:

- **Capital** costs are those that are largely incurred at the start of the development, and relate to the development of the fixed assets, or any asset that is expected to last more than one year. Examples include wires connecting houses, power generation equipment (including a diesel generator) and any replacement of an asset after more than one year.
- **Operating** costs are those that are incurred on a recurring basis, or for the purchase of assets that last less than one year. Examples include the salaries of staff, routine maintenance of equipment and fuel for a diesel generator.

Both capital and operating costs for a mini-grid need to be funded. The primary sources for funding are:

- **Tariffs** from customers purchasing electricity.
- **Cross-subsidies** from the mini-grid operator, sourced from customers of their other operations.
- **External subsidies** from other parties.

It is possible for tariff income to pay for capital costs occurring before the income is received through financing from external sources, which is repaid over time from the tariff income as it is collected. If the average tariff for all customers is set at such a level that it covers all costs, it is said to be **'cost-reflective'**; in such circumstances, no additional subsidy will be needed.

Whether a cost-reflective tariff is applied to individual customers is a matter of policy choice. It may be possible for the operator to differentiate customers so that some pay below the cost-reflective tariff, while others pay above the level, resulting in an average tariff that is cost-reflective, and there is no requirement for additional subsidies for that system.

Alternatively, an operator with multiple sites, or indeed different businesses, can choose to have an average tariff for a single system set below the cost-reflective level, and meet the funding gap through the transfer of cash from the other sites or businesses. This is noted above as a cross-subsidy. Finally, the operator may receive funding from a source external to its business, allowing it to meet the gap between the tariffs it has set and the costs to serve.

2.2 MODEL

2.2.1 Purpose

A Retail Tariff Tool, accompanying this report, has been developed to provide a reasonably simple means of determining an average tariff level that covers the cost of supply. It can give mini-grid operators confidence that they are operating sustainably and their lenders confidence that financing costs can be met. Mini-grid operators could publish their tariff calculation (using this tool) as a way of giving consumers confidence that they are paying a fair price for electricity.

The model undertakes detailed analysis of the financial and economic aspects of mini-grid delivery and is rather generic and not site specific and it serves as a completed template for later use and replication by the relevant stakeholders(s). Even though the model incorporates high level, best estimate 'dummy' number to allow calculations, these have been sourced from reliable institutions and are therefore relatively accurate.

Our retail tariff tool is primarily economic rather than technical. As such, it will rely on inputs supplied by technical experts, likely to come from the project developers (utilities and/or private developers). Other mini-grid models, such as the HOMER Model, focus on technical aspects of mini-grids, and work in complementary fashion with our model. For example, the HOMER Model is used in many countries to determine the least cost generation configuration (e.g., pure solar, solar combined with batteries, solar/diesel hybrid) for a mini-grid at a particular location. Our retail tariff tool takes the technical information, including the LCOE that is generated from a technical model and determines how this can be translated into an appropriate tariff, taking into account project financing and customer willingness and ability to pay, factors not included in the HOMER Model.

2.2.2 Structure

The model allows detailed estimates of the costs to serve customers under the different delivery models, for each site. It comprises:

- **a cover page**
- **an inputs page including all the assumptions and parameters for the calculations:** this sheet will be the one on which users spend most of their time. Inputs will be easily identifiable by category: operational costs, capital costs, financing costs and other relevant costs. We use colour coding of cells to allow easy identification of those input assumptions that can be changed manually. Where appropriate, input assumptions can be selected from a drop-down menu.
- **a calculation page:** most users should not need to look at the calculations on these sheets, although the more competent users will be fully aware of the process for these calculations. For those revising or auditing the model, the calculations in these sheets will follow a clearly structured and transparent logic path, with calculations spread across lines where possible. Unless absolutely necessary, the model will not use macros as they are difficult for basic users to audit, and problematic to fix if broken.
- **a tariffs page** calculating the revenue requirement; the sheet contains a series of necessary outputs e.g. tables, graphs. Users may be able to change the style of these outputs to make them fit for purpose, but should not change their content
- **a cash flows page** showing the operating, investing and financing cash flows and the debt service coverage ratio (DSCR).

The general structure of the mini-grid financial and economic model is presented in Figure 2.1.

The Retail Tariff Tool provides the framework and mechanism for calculating tariffs, but not the input data. Because the costs of investing in and operating mini-grids are location and system specific (as we describe above), mini-grid developers/operators must provide their own costs and system characteristics for the tool.

The tool comprises two main components:

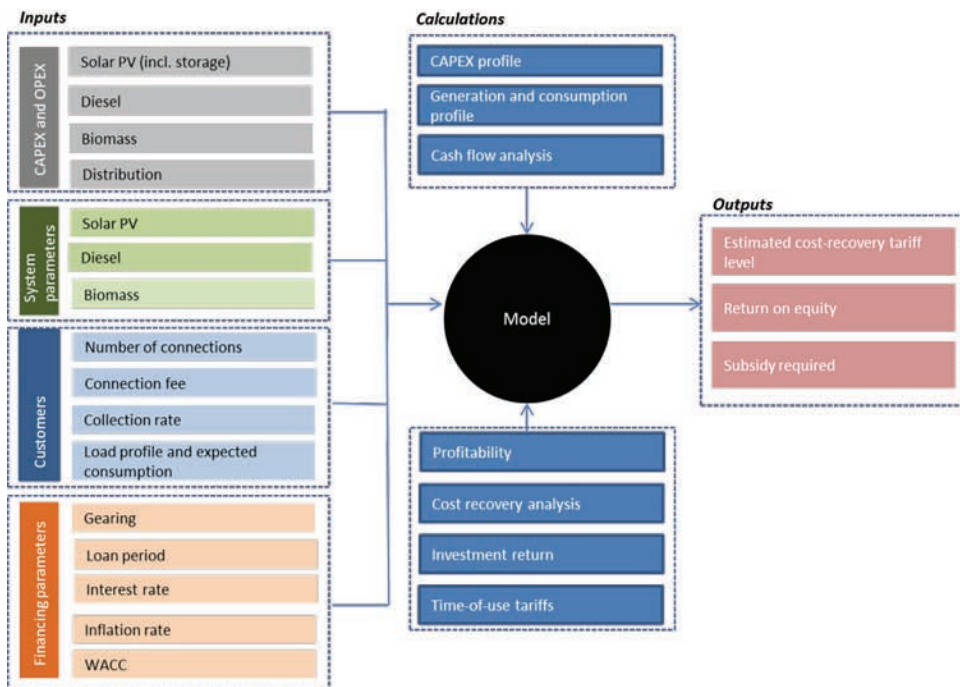
- an **asset base** calculation to determine sustainable tariff levels over the long-term;
- a basic **cash flow analysis** to check that financing costs can be met in the initial years of operation.

We discuss each of these components below. Because the Retail Tariff Tool is intended to be used as a training material, it is important that it be easy to understand and use. It is not being used to regulate prices and therefore does not need to be overly prescriptive; rather it should focus on the key issues that mini-grid operators need to consider.

Inputs should be changed to reflect the specific circumstances of the site for which the model is used, or to test the sensitivity of the model to changes in the inputs.

The flow of the model is from inputs, through calculations to outputs, including the tariff calculations and the cash flow analysis. The outputs can be useful not only to private developers (to ensure cost- recovery), but also to the Government (i.e. to get an estimate of future energy consumption and connection numbers) and the utility (primarily financial indicators to ensure cost-recovery).

Figure 2.1 | Structure of Mini-Grid Tariff Model



2.2.3 Types and Cost Structures of Mini-Grids

Mini-grids are typically classified by their energy source. A common classification separates these either into renewable (e.g. hydro, wind, solar, biomass) or fossil fuel (typically diesel).

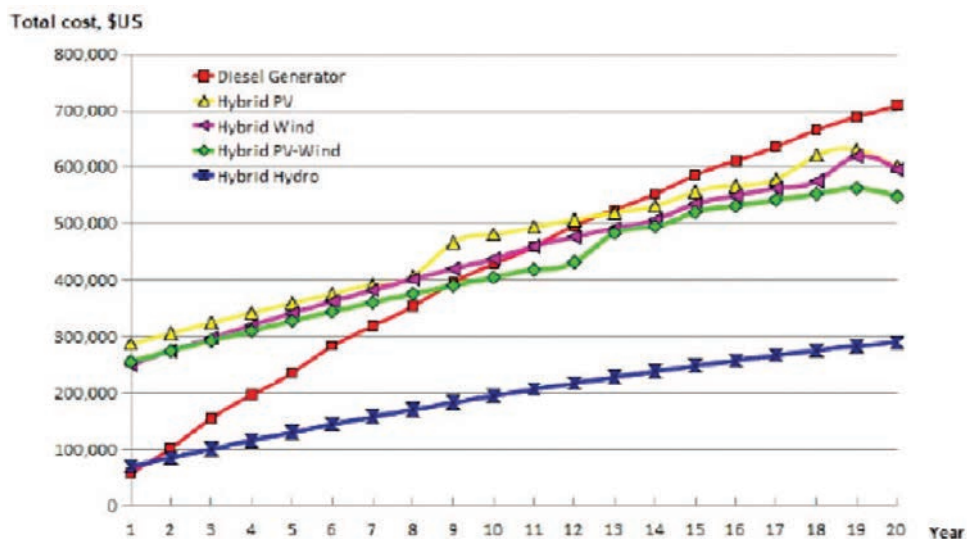
When comparing the economic advantages and disadvantages of the two types of mini-grids, the most important factors are the **cost structure** of the system and the **reliability** of the service. Here, the typical classification is a little unhelpful; fossil fuel energy sources can also be termed **‘thermal’**, but ‘thermal’ can also include biomass and biogas. Thermal mini-grids typically have a low initial capital investment requirement, compared to that of the other renewable technologies, but their operating costs are higher due to the fuel costs. For our discussion of cost structures, we do not include biomass in the category of renewable energy, but rather as being akin to fossil fuel-based systems, and therefore under the label ‘thermal’.

A comparison of the total accumulated cost of each mini-grid system is shown in Figure 2.2.

Thermal systems generate energy on demand, matching the level of generation to the required consumption. However, in a rural context, this also depends on the ability of operators to **purchase or source the required fuel** to run the thermal generator. Remote and inaccessible areas have difficulty in procuring large amounts of fuel and prices can be higher at retail levels for mini-grids that are further away from the port. Similarly, biomass or waste (for waste-to-energy plants) can be seasonal, or available in variable quantities.

On the other hand, renewable energy mini-grids are subject to **daily and seasonal variability**, depending on the weather conditions and technical aspects of the system, and must rely on a battery bank to store surplus energy so that electricity is available when the renewable sources cannot generate enough electricity. Given that they cannot

Figure 2.2 | Comparison of Lifetime Costs between Renewable and Thermal Mini-Grids



Source | USAID 2011, Hybrid mini-grids for rural electrification: Lessons learned.

easily match the power demand, as is the case with thermal generators, renewable energy mini-grids need to have a large generation capacity in that is higher than expected peak demand, which is often not possible. However, increasing the capacity of the system will reduce battery lifetimes. Without a thermal generator backup, generation will deviate a lot from the daily load profile and adverse weather conditions might cause the system to collapse.

Energy storage is a critical issue to ensure reliability of renewable energy mini-grids. It can be relatively cheap in the case of hydro power plants and thermal biomass plants, with the main fuel being water and feedstock, but **storage becomes very expensive** in the case of solar PV panels, where electricity has to be stored. The cost of storage over a battery's lifetime range is usually between \$ 0.20 and \$ 0.50/kWh, which doubles the LCOE of solar electricity.¹⁴

Another important aspect relates to **environmental consideration**. Thermal mini-grids are very polluting and have an adverse impact on the health of those located close to the generators, particularly those fuelled by diesel.

'**Hybridisation**', substituting part of the fossil fuel based generation with renewable energy generation has become very popular in sub-Saharan African countries, such as Tanzania and Mali (see Section A1 and A4 respectively). In a typical hybrid mini-grid, renewable energy generates 75%–99% of total generation, while the thermal generator is used during periods of high loads or low renewable capacity. The battery backup size can be lower than in 100% renewable mini-grid system, which highly reduces operating costs. Hybrid systems often provide the least-cost solution for rural electrification, with their most common application being that of solar PV generator with a diesel generator.

The model has flexibility to include a range of generating technologies, but is reliant on information from technical partners. For example, if the thermal generation in a mini-grid is based on biomass or waste-to-energy, the user can simply accommodate this by changing the parameters of the thermal generation (capital costs, fuel costs, O&M). For our calculations, we have used a diesel generator. To calculate costs based on other forms of generation requires quite site-specific technical information beyond the scope of this assignment.

2.2.4 Inputs

The inputs sheet allows users to choose among four types of mini-grid models, namely solar PV with thermal, wind with thermal, hydro-only and thermal-only systems. In the excel model that is attached to this report, we model a 140 kWp solar mini-grid, with 1 MWh battery bank and 100 kVA diesel back-up, for indicative purposes.

Our calculations of the generation and sale of electricity derive from manual inputs in demand growth. These will ultimately come from the developer, to be verified by the user of the model. The developer will design the capacity of the system to meet this demand, with system specifications inputted manually. In our model, we assume total annual generation of approximately 240 MWh in year 1, increasing to over nearly 385 MWh by year 26. We assume 150 customers in year 1 when the system first becomes operational, increasing to 245 by year 26. This calculation assumes average energy consumption of approximately 130 kWh/month.

After choosing the desired technology, the relevant cells to fill are shaded accordingly.

Capital Costs

Capital costs are divided into technology specific ones and expenses common for all technologies. Technology specific costs for solar PV generation include solar PV modules, structure, cabling and PV inverters, while costs for the battery bank include batteries and battery inverters. Expenses that are independent of the choice of technology include civil and electrical works, logistics, engineering and consulting services, distribution network and initial connection costs. Capital costs needed to be reinserted once the assets' life has passed.

Users are required to insert both initial capital costs as well as reinvestments during the project life cycle.

Operating Costs

For the operating costs, we have made the assumptions shown in Table 2.1. Users can change these assumptions, from the drop down menu, based on actual figures.

Forecast Output

Users are required to enter output values, which will result from an energy model that is designed to match energy demand. For solar/wind systems with a significant penetration (e.g. 50% of load at any time), we assume a battery bank has been sized and priced accordingly, in order to maximise utilisation of the RE source. If total energy output minus losses is above energy demand, then it will be assumed that it is the RE output (solar or wind) that is not used.

Deductible Income

Deductible income refers to any income that is earned from utilising the system assets but is recovered from charges other than the retail tariff. This may include connection and disconnection fees, metering charges, rental of land/properties etc.

Table 2.1 | Assumption for Operating Costs

Type of Operating Costs	Unit	Assumption
Thermal energy cost	\$/kWh	0.50
Real fuel cost increase	% p.a.	0%
Thermal unit O&M	% of capex (thermal) pa	10%
Solar unit O&M	% of capex (solar) pa	1.5%
Hydro unit O&M	% of capex (hydro) pa	1.5%
Wind unit O&M	% of capex (wind) pa	1.5%
Maintenance of distribution network and connections	% of capex (distribution) pa	2.0%
Risk insurance	% of project cost per year	0.10%
Admin costs	\$/customer/year	100
Collection rate	% of customers/year	100%

Table 2.2 | Assumption for Financing Costs

Financing Costs	Unit	Assumption
Gearing	%	70%
Loan period	Years	10
Interest rate (nominal)		
Nominal	%	27%
Real	%	10%
Pre-tax return on equity		
Nominal	%	37%
Real	%	20%
Weighted average cost of capital (pre-tax real)	%	13%
Inflation rate	%	17%
Subsidy (% of capex)	%	0%

Financing Costs

The user inputs financing terms, including the initial gearing (i.e. the percentage of investments financed using debt), the loan period, the interest rate on the loan, the interest rate during construction, and the investor's pre-tax return on equity. The following assumptions have been made regarding the financing costs.

The inclusion of a subsidy as a % of capex allows the user to calculate the impact on levelised costs and tariffs through the inclusion of a capital subsidy. This reduces the revenue requirement from tariffs through a reduction in the return of capital (through depreciation) and the return on capital (through the weighted average cost of capital multiplied by the asset base). However, it assumes that all future capex will be subsidised at the same rate, therefore removing the requirement to recover capital costs in preparation for future capital expenditure. Subsidies are discussed further in [Section 0](#).

2.3 OUTPUTS

The key outputs of the analysis are:

- The **end user tariffs** are equal to the LCOE, which shows the levelised costs without subsidies. Tariffs are updated in the model every 5 years and during that period they remain constant. These average cost recovery tariffs differ between mini-grid models because of differences in capital and operating costs. They are calculated based on forecast output levels that are provided by the developers. Even though these calculations are independent of the level of demand, we assume that the forecast output levels are based on the forecast levels of demand.
- The mini-grid retail tariff tool provides a **full cash flow analysis** over the tariff period (20 years is assumed as the default, although this can easily be modified). The 'bottom line' is the return to the equity investor. An example of the cash flow analysis is provided in the table below.

2.3.1 End User Tariffs

This calculation is done on a forward-looking basis; the mini-grid operator enters forecasts costs and energy output for a period of up to 20 years. The Tool then calculates tariff levels such that, so long as the operator achieves the forecasts, it will fully recover its costs over the next five years.

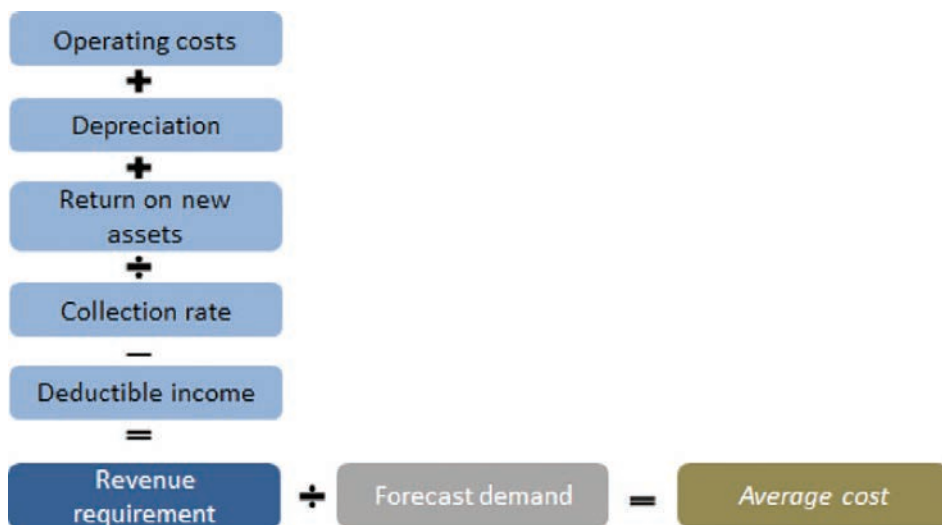
As shown in the figure below, the operator's 'revenue requirement' is a simple sum of parts. We refer to this overall approach as an 'asset base calculation' because it includes depreciation and a return on assets (calculated as the cost of capital multiplied by the value of assets) rather than the actual year-on-year financing costs. This approach is used internationally to price infrastructure assets because it smooths the effects of 'lumpy' investment costs (thereby avoiding consumers paying tariffs that vary significantly year to year). Over time, the operator will still fully recover the costs of its investments, however the timing of its cash flows does need to be considered and tariffs adjusted accordingly if necessary (as we discuss below).

The asset base approach to pricing suits mini-grids because the system's assets have long lives (typically much longer than the terms of debt financing) and require on-going and regular investment.

Other features of the calculation include:

- The calculation determines the **average cost of supply**, but does not detail the tariff structure (such as the fixed/energy/demand charges and choice of customer categories). As evidenced by practice around the world, tariff structures are based on a balance of financial, economic, and social considerations that are specific to each network and customer base. Large mini-grids may opt to apply complex tariff structures, while small mini-grids may apply a simple energy only charge (which is equal to the average cost of supply). In the model, adding a subsidy into the financing structure adjusts the effective LCOE, although the correct definition of the LCOE should not include subsidies.

Figure 2.3 | Asset Base Calculation



- The calculation depends on the **technology of power supply**. In the inputs sheet the user selects the mini-grid technology (i.e. solar PV and thermal) and fill in the relevant information that is colour coded.
- Forecast **collection rates** gross up costs, thereby ensuring that the operator will recover the cost of its bad debts.
- **Deductible income** is subtracted from the operator's costs. This refers to any income earned from utilising the system assets but is recovered from charges other than the retail tariff.
- To keep the calculation of **depreciation** simple, the operator enters an average asset life for each asset category, which calculates an accelerated depreciation rate (a percentage of the asset value each year).
- **Return on capital** ensures that the operator can recover its cost of debt and earn a return on equity, calculated as the depreciated asset value multiplied by the weighted average cost of capital (real, pre-tax).
- Forecasts are all in real terms, i.e. they **exclude inflation**. Both nominal and retail tariffs are presented at the end of the calculation.
- The figure below shows an example of the results of the asset base calculation. In this example, the average tariff is updated every five years and decreases over time due to increasing demand and a largely fixed cost base.

Figure 2.4 provides an example of the resulting cost recovery tariffs that will be applicable until 2041.

In the retail tariff tool example of a 140 kW solar PV mini- grid, with 1 MWh battery storage and a 100 kVA diesel backup, the LCOE over 25 years is \$ 0.97/kWh.

The average cost recovery tariffs for the period 2016 to 2041, assuming that the tariff is revised every 5 years and remains constant during each sub-period, are shown in the Table 2.3.

Figure 2.4 | Example Result of Real Cost Recovery Tariff

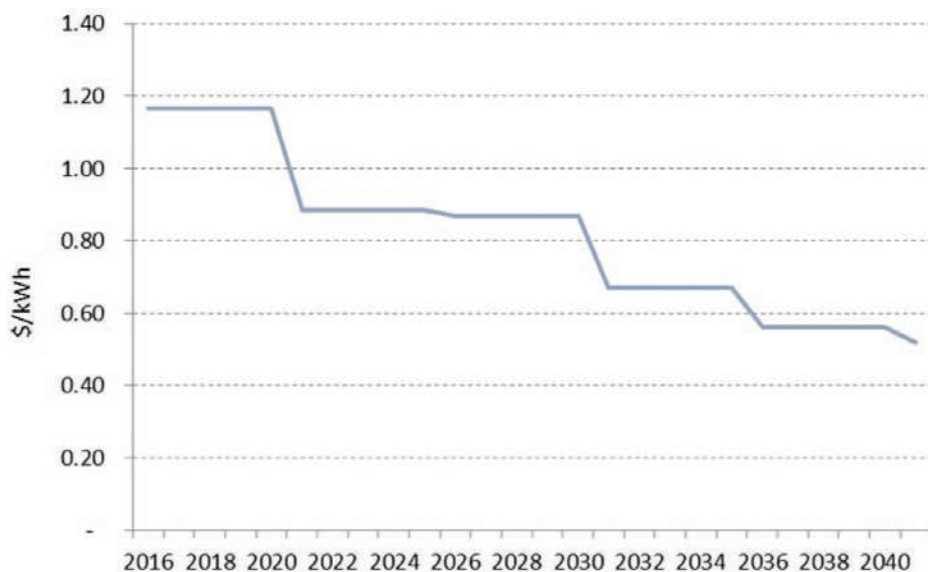


Table 2.3 | Average Cost Recovery Tariffs for a 140 kW Solar PV Mini-Grid

	Years					
	2016	2021	2026	2031	2036	2041
Tariff (\$/kWh)	1.16	0.88	0.87	0.67	0.56	0.52

Willingness to Pay

If the estimated tariff is higher than the UNT or the willingness-to-pay (WTP), the difference must be covered with subsidies, either through the tariff as a reduction per kWh, or through a percentage of the capex in the first five years.

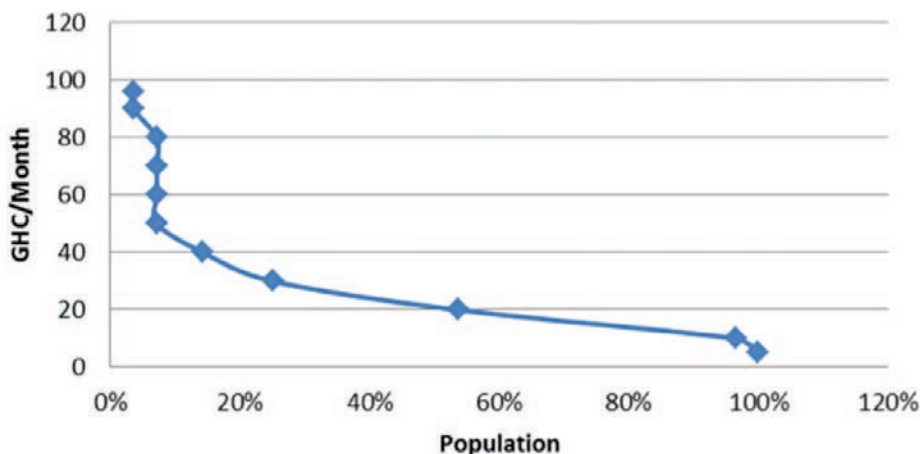
A WTP calculation is outside the scope of this study, but evidence from a World Bank report suggests that the average WTP for electricity in Ghana is at \$ 0.53/kWh.¹⁵ The same study also found that the WTP for solar lighting is equivalent to \$ 1.93/kWh.

Another study conducted by PwC found that households in all the seven island communities in the Volta region that were included in the analysis, spend on average, GH¢ 28.10 (\$ 7.31) for a consumption of 11.32kWh per month equivalent of energy on lighting and powering appliances. This translates to GH¢ 2.48(\$ 0.645) /kWh equivalent of electric energy.¹⁶

The WTP for electricity in Aglakope was found to be between GH¢ 5.00 (\$ 1.27)/month and GH¢ 96 (\$ 24)/month. It was also found that almost every household in Aglakope spent at least GH¢10 (\$ 2.52)/month on electrical energy services while half of these households spend more or equal to GH¢ 20 (\$ 5)/month on electrical energy services.¹⁷

According to these results, using the current expenditure from the islands (\$ 0.645) as the proxy for WTP and using the average end user tariffs from the mini-grids retail tariff tool, the required subsidy level will be approximately \$ 0.51/kWh in 2016, and reducing below the WTP by 2041.

Figure 2.5 | Willingness to Pay in Aglakope



Source | PwC/ KITE 2012, Socio-economic study for mini-grid electrification of island communities.

Table 2.4 | Cost Recovery Tariffs Adjusted by Subsidies (\$/kWh)

Subsidy Level	Years					
	2016	2021	2026	2031	2036	2041
0%	1.16	0.89	0.87	0.67	0.56	0.52
25%	0.92	0.72	0.72	0.58	0.50	0.47
50%	0.67	0.56	0.57	0.48	0.44	0.43
52%	0.65	0.55	0.56	0.48	0.44	0.43
75%	0.42	0.40	0.42	0.39	0.39	0.39
100%	0.17	0.24	0.27	0.30	0.33	0.35

Based on this analysis, we can adjust the cost recovery tariffs we calculated in Table 2.3 by adding subsidies, to the point where they are at a level that customers are willing to pay, and also observe the subsidies needed to match the UNT. The subsidy adjustment is made to the funding for initial development, reducing the revenue requirement from the return on capital invested (as this is much lower) and depreciation. Operating costs and other variables remain the same. These results are presented in Table 2.4.

This analysis shows that a subsidy of 52% is needed in order just to meet the WTP of communities on the islands. It also shows that for the tariff level to be the same as the current UNT (at \$ 0.05/kWh for the lowest consumption customers (0–50 kWh/month) and \$ 0.10/kWh for the next consumption category (51–300 kWh/month)), a subsidy of more than 100% of the capital costs is necessary (therefore requiring an operating subsidy).

Cash Flow Analysis

The asset base calculation will potentially create cash flow problems for small investors in new mini-grids during their initial years of operation, especially for new undercapitalized mini-grid developers. These investors potentially face high upfront financing costs (given loan terms are usually much shorter than the life of the assets) and small investors will often lack the capital resources to manage loan repayments in these initial years.

We accompany our asset base calculation with a simple cash flow analysis. If this identifies any potential cash flow issues, then the operator can adjust the tariff profile to ensure that financing costs are met, front-loading higher tariffs in earlier years to generate more cash. Over the long-term, investors should be able to refinance and maintain an optimal capital structure, so cash flow should not be such a concern.¹⁸ For this reason, the simplified cash flow analysis contained in the Retail Tariff Tool focuses on the first 10 years of operation only.

The cash flow analysis essentially takes revenues collected and deducts operating costs and interest payments to determine operating cash flows. Investment costs and financing costs (i.e. loan repayments less loan proceeds and equity contributions) are then deducted from operating cash flows to determine the cash available at the end of the year. If this drops below zero in any year, then the tariff profile needs to be adjusted to

boost cash flow in that year. Tariff adjustments should ideally be revenue neutral, that is, increases in one year to address cash flow issues should be offset by commensurate decreases in future years.

Another key indicator that the Retail Tariff Tool calculates is the debt service coverage ratio (DSCR). The DSCR is defined as the ratio of operating cash flow over loan repayments and gives lenders an indication of the ability of the investor to meet its loan commitments. A DSCR greater than 1.2 is a rough guide of a healthy DSCR.

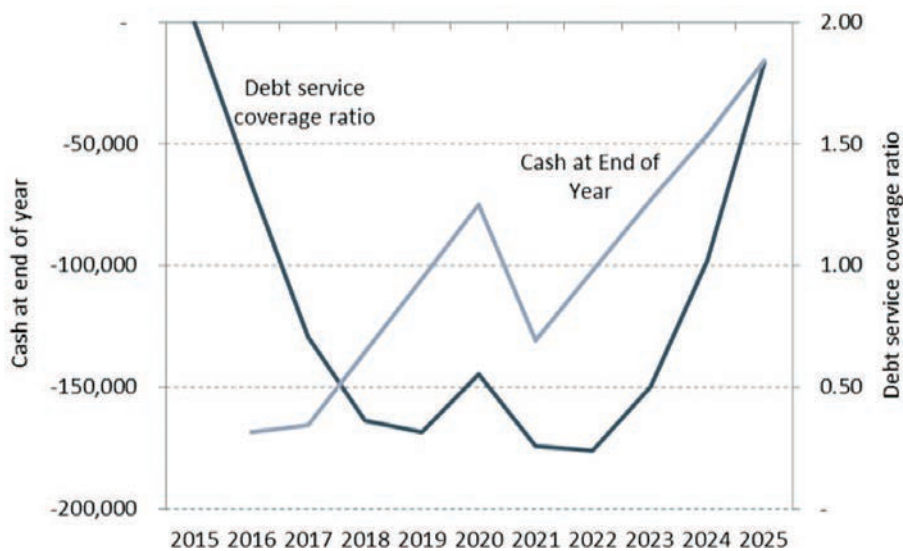
The figure below shows an example of the cash flow analysis produced by the Retail Tariff Tool. In this example, it shows that, if the financier requires repayment of the loan in the first three years of operation, the operator will still not have returned to a positive cash position after 10 years. If this is the case, the profile of the tariff determined in the asset base calculation may need to be adjusted accordingly. If the developer is granted either a longer repayment period, or a repayment holiday for at least two years, they should be in a stronger cash position to meet repayment requirements.

2.3.2 Connection Charges

Even though connection fees are important to guarantee commitment of the electricity customers and cover the costs related to connection, they have to be affordable.

Many customers cannot afford to pay the full one-time connection charges that are equal to a couple of month's income. Ghana currently offers a subsidy for connection charges to alleviate affordability issues, which should be available on the same or similar non-discriminatory basis for mini-grid developments. In addition, reducing the connection charge, by, for example spreading half of the connection fees over a given period (and including them in the tariff) will provide an incentive to customers to connect to the mini-grid and will likely increase the electrification rate.

Figure 2.6 | Cost Recovery Tariffs Adjusted by Subsidies (\$/kWh)



2.4 IMPACT OF THE CHOICE OF DELIVERY MODEL

As discussed, the choice of delivery model will have little impact on level of cost-recovery tariffs. The choice of technology, and the input cost assumptions for capex and opex, are independent of the delivery option; we don't assume any developer to have any advantageous access to particular technologies under any model.

The only costs we anticipate as potentially being different between delivery models are the cost of capital and some administrative costs. Public utilities may have access to cheaper sources of capital by virtue of being government entities. However, this advantage may be reduced if private developers are large international entities rather than small-scale developers, and therefore have greater ability to access low-cost capital. Similarly, the administrative costs for managing customers and systems can benefit from the economies of scale in networks that the utilities enjoy.

We have also noted that it is possible that the larger utilities (ECG and NEDCo) may be able to charge lower tariffs than private developers by virtue of the ability of their larger customer base to absorb the additional costs, which are probably higher per unit than the national grid. The extent to which this is possible is dependent on the total costs and customer base of the utilities, information to which we do not have access, and the calculation of which is beyond the scope of this assignment.

2.5 FUNDING OPTIONS

In the mini-grid sector, there are several possible or contemplated financial interventions to support the recommended model for the development of private sector mini-grids.

The mechanisms of interventions may include collaboration with donors, government, utility resources, in collaboration with development finance institutions, local banks, regional private equity or infrastructure investment firms, private grant making institutions, or other sources of capital active in a region.

They include but are not limited to the following:

■ Debt financing

- **Commercial debt**
- **Flexible fund:** an investment fund that invests alongside mini-grid developers and their financial backers that provides co-investment in either debt, equity, or both to enable a project to become viable.
- **Concessionary debt:** an investment facility, often in collaboration with a commercial bank that provides low or zero percent interest debt and takes the risk of default without recourse.

■ Results-based financing

- **Top up tariff scheme:** a scheme whereby the price of power sold to the consumer is kept low and a development partner facility remits cash payments on the output of power provided to consumers to the level upon which private investment is feasible.

- **Performance grants:** cash grants from a development partner to a mini-grid developer per each household or electricity consumer to cover the costs of development. Such performance grants are also called output-based aid (OBA).
- **Capital cost reimbursements:** another instance of OBA where cash payments are made to developers to cover the costs of development, wayleave payments, or other hard costs in the development of a mini-grid, with the payments being made once the mini-grid is in operation. Up-front payments are also possible, but this would not fall under the rubric of results-based financing.
- **Competition for concessionary financing**
 - **Challenge fund:** evaluating, selecting proposals, and providing grants and concessional loans, and other support based upon the quality of proposals and the team's ability to execute.
- **Other mini-grid financing mechanisms**
 - **Guarantee mechanisms:** a programme where a development partner provides a guarantee for a developer in the event of a default on a commercial loan. This can also be used to guarantee payments by buyers for wholesale power purchase by mini-grid power providers; there is a programme for this in Uganda, but to date, this has not been used.
 - **Development capital subsidies:** payments to developers for third party costs of environmental impact, detailed design, and other project preparation tasks prior to construction.
 - **Consumer connection loans:** microfinance or concessional loans to the household consumers to assist them in paying the total unsubsidised cost per connection of a mini-grid.
 - **Third party collateralization:** a program where a development partner would provide in country collateral to enable a mini-grid developer to qualify for corporate finance from a local bank.
 - **Non-performing debt buyouts:** similar to a guarantee program whereby a development partner commits to buying non-performing debt in mini-grids from commercial banks to reduce the credit risk to the commercial bank in lending to mini-grids.

In Tanzania, the World Bank has been working with commercial banks in the Tanzania Energy Development and Access Project (TEDAP) to help them develop a credit line for supporting small-scale energy projects. Tanzania and TEDAP target private sector developers, and allow a cost-reflective tariff structure that attracts financing for companies selling a majority of their power to the grid (>90%) and have received significant additional subsidies (>50% subsidy or grant). Given the subsidy, tariff and a clear regulatory framework, private investors have developed projects and more are in the pipeline, with debt made available through local banks in collaboration with World Bank interventions. To date, four projects are operational, eight have signed PPAs with TANESCO, and a further 19 have signed Letters of Intent. The total existing and potential investment is around \$ 250 million, of which around \$ 160 million is debt and \$ 90 million is equity. One of the operational projects is already selling retail power, and two of those with signed PPAs intend to do so.

Our analysis of the delivery model options, and our assessment of the financing options available in Ghana provides the following observations:

- **Private, Mixed Model 2 (PPA Model).** There are few focused private investor groups interested in small-scale energy projects in Ghana on the equity side. This is largely

a consequence of Ghana's successful main grid extension, leaving little opportunity for small-scale project development. This is particularly in comparison to more active countries such as Tanzania. Similarly, no commercial bank in Ghana has been involved in any small-scale energy projects, so will lack the experience necessary to negotiate such a deal (even if the capability is present).

In addition, recent currency volatility in Ghana, the lack of bankable offtake (by utilities) and a lack of readily realisable collateral would act as significant deterrents to any commercial investor. Perhaps the most significant deterrent would be the challenge to sufficient financial returns if the UNT is set for mini-grids by the PURC; in such an instance, the likelihood of receiving any interest from private investors is very low, including impact investors.

- **Public, Mixed Model 1, and Community Models.** The likely funding options for such models are unclear—it is possible that the Government may fund the developments with its own separate funds, rather than requiring the utilities to raise capital themselves. If the cash necessary for project development can be raised, then several professional groups are likely to tender to construct a mini-grid without operating it. However, there are fewer groups that would be interested in tendering to run it on a contractual basis. For private operators to show interest, the Government would have to take on the risk of payment by the end users but could establish service levels that the operator could abide by.

2.6 SUBSIDIES

The discussion in Section 0 showed that the costs to develop and operate a mini-grid must be met from customer tariffs and/or from subsidies, and that these subsidies may come from the operator other customers (cross-subsidies) or from outside the operator's business (external subsidies). Section also highlighted that the decision on whether to subsidise is primarily one for policymakers. The decision should be based on whether to allow operators to charge cost-reflective tariffs, and whether these would be beyond the willingness and/or ability of customers to pay. By implication, a decision not to allow cost-reflective tariffs is a decision to require the operator to subsidise its costs to serve. In doing so, the policymakers must also determine whether the shortfall between the costs to serve and the tariffs can be met through cross-subsidies, or whether external subsidies are required.

As noted in this report, the Government of Ghana has been very successful at extending the reach of the national grid into rural areas. This has largely been on the back of significant capital subsidies. We recommend that this approach be adopted for the isolated areas under a similar funding approach, to the extent that the Government is willing to finance such developments, or in order for such developments to be financially viable.

External subsidies can target either consumers or producers, and can be either recurrent or for capital expenses (more 'one-off' expenses). Examples of each, and their strengths and weaknesses, is presented in Table 2.5.

2.6.1 Funding of Mini-Grids and Subsidy Policy

Policy options for efficient subsidy delivery include the setting up of special funds (rural and renewable energy funds, carbon finance, funds to promote specific technologies, consumer finance, and micro-finance), tax credits and other investment incentives, guarantees and other risk mitigation instruments.

Table 2.5 | Strengths and Weaknesses of Subsidy Options

Subsidy Type	Description	Strengths	Weaknesses
Consumer Recurrent	A subsidy in the cost of each unit of electricity, lowering the price below the cost-reflective level, distributed to the operator based on the units sold	Easy to calculate value; seen as directly helpful for poorer customers	Beneficiaries difficult to target; difficult to administrate; requires regular budget support; may appear to discriminate against existing customers
Consumer Capital	Covers a portion of the (one-off) cost of connecting the customer to the mini-grid	Addresses financing issues for customers	May require on-going funding
Producer Recurrent	Covers a portion of the costs of fuel (for a thermal mini-grid), or the salaries of operators	Should be easy to target	Difficult to administrate; requires regular budget support; difficult to target
Producer Capital	Covers the initial costs of setting up the mini-grid, e.g. the earthworks for a mini-hydro scheme	One-off, so no on-going funding requirement	Cost assessment can be difficult; follow-up capex may not be covered

Source | ECA.

To ensure the most efficient and equitable use of resources available for subsidies, it is important for subsidy policies for mini-grids to be developed and clearly enunciated. Recommendations on subsidy policy for mini-grids are:

- **Capital, not recurrent subsidies:** Subsidies should be limited to one-off capital subsidies, as this will enable many more mini-grid users to benefit than concentrating providing recurrent subsidies to those few mini-grid beneficiaries lucky enough to already have access to electricity. This is in line with the suggested approach from the World Bank's Project Appraisal Document.¹⁹

Subsidies are best if non-discriminatory and used as a once-off grant and the project tariffs are set at a level that covers operation and maintenance including depreciation and investment returns. Subsidies should also be designed so as to be results-based, as is discussed further below.

- **Subsidies to catalyse complementary financing:** Where there are opportunities for private developers of mini-grids, subsidies from public and concessional resources should as far as possible leverage capital contributions from beneficiaries and project promoters, reducing project risk by reducing the capital across which project cash flows need to be shared, thereby allowing as many mini-grid projects as possible to be supported. Where a private project promoter is seeking a commercial bank loan as part of the project financing, it may be necessary or expedient for the public subsidy-granting entity to provide a partial risk guarantee for the project.

Wherever possible, **incentive-based** subsidy approaches should be deployed. These provide incentives to ensure that the best use is made of public resources made available for subsidy purposes. In the context of the mini-grids, this can be achieved by:

- **Competitive Selection of Subsidy:** As discussed in Section 0, there are essentially two main approaches:
 - Offer a fixed subsidy and tariff for a mini-grid and ask bidders to compete on the number of connections and the level of service that they will provide.
 - Set a fixed number of connections and tariff and specified minimum service levels and ask bidders to compete on the basis of the smallest subsidy they would need to achieve the targets.
- **Output-based Aid (OBA) or Results-based Subsidies (RBSs):** As mentioned above, whenever possible, subsidy provision is to have in-built performance incentives. This is achieved by an OBA approach whereby the recipient only receives the subsidy on proof of a tangible output being achieved. OBA subsidies can be applied to the initial project development, but the classic use of OBA is to provide incentives for operators to increase the number of customers connected to the mini-grid. A fixed subsidy amount is provided for each new customer who is connected and purchases electricity (as a consumer capital subsidy), the subsidy only being paid when the connection and its use has been verified.

The main problem with OBA subsidies is that the investments have to be financed up-front by the developer, with the subsidy being paid only when there is evidence of the investment being out to use. This makes the results based approach suitable for distribution extensions to increase the number of households with access to the mini-grid, but less suitable for the original development of the mini-grid itself. However, the pre-financing problem may be obviated through banks extending credit for the pre-finance, which security being provided by the OBA provider.

2.6.2 Subsidy Delivery Vehicle

There is not yet any organised system of subsidies in Ghana's power sector. To ensure greater efficiency in the use of public financial resources, existing subsidy mechanisms need to be tightened to make them **results based. There are currently both recurrent and capital subsidies through:**

- Recurrent cross subsidization by customer class, implemented under the existing PURC tariff structure, with inadequate monitoring of the extent to which the cross-subsidies achieve public policy goals.
- Capital subsidies through, for example, the National Electrification Scheme, whereby the government provides the funds for distribution and transmission grid extensions and strengthening. The government interventions will continue to be implemented by the Ministry of Power, but in future should be structured on results-based principles in order to provide incentives for efficient and timely project execution.

In addition to the above, the following three funds are currently being managed by the EC, which makes it the default subsidy delivery institution:

- The **Energy Fund**, established under section 41 of the EC Act, active since the 1980s under the defunct National Energy Board Law, then transferred to the EC when the Fund was re-established under the EC Act in 1997/98. The fund had a closing balance of GHc 85,000 at the end of 2013, having received income of approximately GHc 6.25 million (\$ 1.7 million) in the 2013 financial year, GHc 4 million of which came from fees from permits and licenses. The fund will be insufficient to meet the funding requirements of the mini-grid development programme as discussed (especially if the UNT is to be adopted for all developments).
- The **Renewable Energy Fund**, created under section 32 of the RE Act. The fund was opened on March 17, 2015, but as yet it does not hold any funds. The fund is to be financed from a portion of the existing Energy Fund, and is designed to support on-going solar PV and off-grid schemes being implemented by the EC.

As the latter is not yet operational, the only current vehicle for delivering subsidies could be the Energy Fund. At this stage, it seems there is insufficient funding in the Energy Fund to support the mini-grid development programme. However, following the lead of other countries such as Mali (with AMADER) and Tanzania (with the Rural Electrification Fund, managed by REA), we advise that any pool of subsidies for mini-grid development be managed by the same entity managing the programme. This will greatly assist project coordination from the perspectives of both the GoG and project developers. In Ghana's case, this is currently the EC, but will eventually be the new REA. This may necessitate the establishment of a new fund.

2.7 OPTIONS AND FEASIBILITY FOR ELECTRICITY SUPPLY MODELS

Box 2.1 presents an example of a calculation for grid connection versus isolated generation development for an island grid.

The initial GIS scoping exercise proposed should identify on a spectrum the viability of main grid connection for each site. Combined with this, the planning process should present a date by which each identified community that may be connected should be connected. This will allow the developers to factor into their feasibility studies the likely implications of grid arrival. The options for mini-grid operators at the arrival of the main grid are discussed further in [Section 0](#). For such sites, we recommend that developers retain the option of connecting households to DC-based mini-grids and SHS.

In addition, through sharing the capital costs of the transformers and the transmission and distribution lines amongst several islands and lakeside communities, grid connection could become an attractive alternative to separate mini-grids for the individual islands. We recommend that during the planning of the rollout that, where possible, opportunities for **clustering** a number of sites that are close to the existing main grid are examined and the idea of supplying these sites through shared grid extension is analysed. Pediatorkope is an example of such an opportunity for clustering, with two main settlements on the island, but at different ends.

An important distinction to be made is between those communities where grid connection might eventually be justified and those where it will not. The developers of minigrids in the former category may want to ensure compatibility with grid standards, so as to be

Box 2.1 | Costs of Grid Connection for Peditorkope

The undertook two site visits to Peditorkope (before and after the pilot project implementation), an island near the coastal mouth of the Volta River, identified as one that could be served by a mini-grid. The island is approximately between 200 m and 500 m from the mainland, where grid power runs right to the river's edge (including to a resort). It would seem particularly expensive and inefficient to develop a mini-grid on such a site if the costs to connect a local grid on the island to the mainland (as opposed to connecting a local grid to a local generation source) are low enough.

A hybrid mini-grid pilot project has gone ahead on Peditorkope (wind, solar PV and diesel back-up) because it can easily be monitored by MoP officials. With other communities close to the shore in mind, it is nonetheless interesting to consider the main grid alternative that could have been pursued for the electrification of Peditorkope. The costs of connecting an island community over water should not in fact be significantly more than the cost of connecting a village over land, depending on such things as the shipping traffic and river or lake-bed surface structure; e.g. clay is very easy for laying cables. For Peditorkope, with other islands between it and the mainland for part of its length, the greatest distance over which a line would need to pass without land is less than 200 m, with other gaps of around 70 m and 20 m between islands.

Using an estimate of \$ 15,000/km for cables over 250 m of land, \$ 30,000/km under 250 m of water, and a transformer of \$ 15,000 gives a **total main grid connection cost of \$ 26,250**. The **hybrid mini-grid capital cost is of the order of \$ 800,000**, including the distribution grid, but some of this high cost is due to features of the pilot project which would probably not be included in subsequent projects. Nonetheless, the gap is very significant. O&M costs of the hybrid mini-grid will be much higher than main grid supply. In the immediate future, the mini-grid would be more reliable for customers, but in due course, when national power supply-demand is restored, main grid supplies should be more reliable and versatile.

able to sell on their assets, but the alternative would be for the developers to anticipate recovering their investment costs before the main grid arrives. This judgment is to be made by the developers, and should not be subject to regulatory dictate.

Consistent with this approach, we recommend that the tendering of concession sites **not restrict the option** for electrification to mini-grids, but also allow developers to opt for investing in a main grid connection, as is the case with Senegal. While the feasibility of grid connection should have been assessed in the scoping process, the variables involved in this calculation can shift (costs, demand, etc.), and this will give developers the opportunity to explore this option further, with little cost to other parties. This should ensure that the developer of each concession would choose that connection type that is most economic for the customers.

At the other end of the scale to grid connection is a **solar home system (SHS)**. In designing projects to achieve universal household access to electricity, the SHS option should also be allowed as an electrification option. A SHS is likely to be optimal for households with low consumption (i.e. lights, mobile device charging, television), and some distance from other customers (requiring a dedicated low voltage connection). In some of the scattered communities on the islands, it may prove to be more economic and effective to give many of the households access to electricity through SHSs, while having a **'core' mini-grid** in the commercial and social centre of the settlement. This

concept would be applicable in communities where energy-using activities are located close to one another in a central area, such as a clinic, school district office, or a business centre (e.g. shops, mobile phone charging, mills, bars, internet café, photocopying). In such circumstances, low marginal connection costs, combined with the higher power loads, would justify a core mini-grid.

The firm thus recommend that SHS are included in the electrification options, at least as a short-term measure, but without subsidies for such connections. The affordability of SHS across Africa, including recent growth of sales by SHS companies within Ghana, has shown that subsidies are not necessary for the majority of SHS customers.

3 | PERMITS AND POLICIES

This section describe the existing policy, legal and institutional framework in electricity/ renewables and identify gaps as they relate to mini-grids. Drawing on international best practice, we then discuss options for the future framework that needs to be put in place, making the case for light-handed regulation to apply in order to accelerate private sector participation.

3.1 EXISTING FRAMEWORK

3.1.1 Policy, Legislation, and Regulation

Electrification Policy

The 2010 Energy Policy notes a target to increase electricity access from the current level of 66% to universal access by 2020 by extending the reach of electricity infrastructure to all communities by 2020. To meet this objective, the policy notes (in Section 2.6) that the Government will pursue the following policy actions that are relevant to this assignment:

- Increase funding from Government and other multilateral and bilateral sources for the National Electrification Scheme;
- Support private sector co-financing with Government for grid-extension to designated franchised zones;
- Establish a sustainable internally generated funding mechanism for rural electrification;
- Support new service connections for electricity in rural areas;
- Address institutional and market constraints that hamper increasing electricity access to the poor; and
- Promote productive uses of electricity as an integral part of the Rural Electrification Programme.

There is no specific mention of mini-grids in the policy statement, but it appears that there may give scope to consider mini-grids as one of the options for achieving universal access by 2020.

This idea is reinforced by a statement from the World Bank's GEDAP PAD from 2007, which discusses the promotion of off-grid alternatives to grid-based electrification:

On the institutional side, the Government is planning to allow both grid-based electrification and **off-grid alternatives** to co-exist and complement each other. In addition through innovative credit facilities, the Government wants to promote renewable energy alternatives in areas that are outside the reach of the national grid. For example, one of the mechanisms of this new approach, in remote rural areas, will be to find ways of reducing the upfront cash cost of **solar lighting equipment** for consumers and improve the business environment for entrepreneurs to develop **small solar energy businesses**.

While the term 'off-grid alternatives' is generally taken to mean self-contained systems such as SHS, it would seem unreasonable if mini-grids were not considered a viable solution.

Uniform National Tariff

Under the Government's Energy Policy (Section 2.7), the objective is to ensure that electricity pricing is efficient and competitive while providing rates that are affordable. The Policy states the intent to pursue the following measures with respect to pricing and the setting of rates for electricity:

- Uniform electricity tariffs throughout the country;
- Support the implementation of cost recovery pricing in electricity supply;
- Provide special rates for the needy in society (lifeline tariffs);
- Regulate pricing of transmission and distribution services to achieve financial sustainability of the utility companies as well as ensure consumer protection.

Tariffs have traditionally been uniform since the advent of the grid some four decades ago. There is guidance of the policy from the PURC Act (Act 538), where Section 20 provides that the PURC **may**, having regard to:

- the population distribution of the country;
- the need to make the best use of any natural resource of the country;
- the economic development of the whole country, fix a uniform rate throughout the country, any region or district for any service provided by a public utility.

The same Act also enjoins PURC to prepare rate-setting guidelines, to take into account the following:

- consumer interest;
- investor interest;
- cost of production of the service;
- assurance of the financial integrity of the public utility.

Following from the above (and possibly with encouragement from the other sectors such as the petroleum products, which sell at uniform prices country-wide), PURC has included the policy of uniform pricing in its Electricity Tariff Setting Guidelines.

Consequently, based on these provisions of the PURC Act and the Tariff Guidelines, the PURC has employed the policy of uniformity of tariffs for the entire country. Therefore, our understanding is that when read together, the above provisions **promote the uniform tariffs but do not prohibit differentiated or special tariffs where it can be justified**. Our understanding also extends to say that the **PURC Act is adequate in giving sufficient capacity to the PURC to determine the tariffs it shall set or allow for mini-grids, and no additional legislative change is necessary**. Such a justification for differentiated or special tariffs may include where a mini-grid supply is comparatively cheaper than other existing sources, even if it is more expensive than the UNT, which we anticipate finding under a fully-private delivery model.

Renewable Energy

There is a requirement for distribution utilities and bulk customers to purchase a certain percentage of their power from renewable sources. This may help major utilities, but it is unlikely to help small diesel mini-grids.

The literature and legislation would seem to place the renewable energy purchase obligation (REPO) on grid-connected entities. Consequently, a self-generator or standalone diesel plant would be exempt from the renewable energy purchase obligation. There had been discussions about the possibility of establishing a Rural Electrification Agency to oversee aspects of rural electrification, in particular the non-profitable operations. That idea seems to have been discarded and under the Renewable Energy Act, the establishment of a Renewable Energy Authority has rather been contemplated. Section 53 of the RE Act, provides as a transitory measure that until the RE Authority is established, the Renewable Energy Directorate under the Ministry of Power will:

- 1 | oversee the implementation of renewable energy activities in the country;
- 2 | execute renewable energy projects initiated by the State or in which the State has interest; and
- 3 | manage the assets in the renewable energy sector on behalf of the State.

The RED (or REA, when established) must take over the oversight of mini-grids. If this is not done, the traditional electricity or grid-connected regulatory approach will be extended inappropriately to cover evolution of the mini-grid.

Mini-Grids

There is no specific mention of mini-grids in the current legislation except under section 32 of the RE Act where it is stated that mini-grids could receive support from the RE Fund. Section 11 of the EC Act provides that, no person shall engage in any business or any commercial activity for, among others, distribution or sale of electricity without a licence. A similar provision is found in sub section (1) of section 8 of the RE Act. In the light of these provisions, the EC (licensing and technical standards regulator) and PURC (economic regulator) were minded to extend the existing traditional approach to mini-grid operations as a transitional arrangement pending the evolution of the rules for the development and operation of mini-grids.

Regarding FITs, section 25 of the Renewable Energy Act 2011, Act 832 gives the Public Utilities Regulatory Commission (PURC) the responsibility to set the Feed-in Tariff (FIT) as the pricing mechanism for Renewable Energy Technology in Ghana.

3.1.2 Permits and Licenses

There is no definition of the permits, licenses or concessions in the Ghana energy sector laws or in the Interpretations Act of Ghana.

Permits and licenses in the Ghanaian context are distinguished by usage. For instance the EC Act and the RE Act indicate the sector activities for which a license is required. Permitting is provided under third-tier guidelines issued by the EC, such as the siting permit requirements under the Commission's facilities Siting Guidelines, or the Bulk Customer Permit, which allows entities that consume a large quantity of electricity to shop for their supplier.

Anyone engaging in a commercial activity in the electricity sector and the renewable energy industry must have a license (section 8 of the Renewable Energy Act). This also applies to companies selling SHS. The licensing authority is the EC, which has developed a licensing manual for renewable energy technologies.

According to the licensing provisions, an applicant must be a Ghanaian citizen or a corporate body duly registered in Ghana. The application must be accompanied with information requirement that includes the technology and size of installation and the expertise available to the would-be licensee.

Similar to the procedure in respect of all licences, the EC is obliged to grant the licence within 60 days of submission of a complete application and person dissatisfied with the decision of the EC may complain to the Minister who must render a decision within 30 days failing which the applicant may appeal to the courts.

The licensing process is favoured by the governmental agencies and the EC in particular because it considers the information requirement essential for its national and indicative planning needs and also to ensure that basic siting and technical standards are adhered to at the inception phase. Licensing is therefore:

- Considered a means of compelling the registered entity to share information—through a data submission process.
- To ensure the systems being established are robust and meet the technical standards and to possibly aid the post installation monitoring.

The EC is currently developing the framework for licensing mini-grid and there as yet no specific licensing requirements. As a transitional measure and until the licensing process for mini-grids is established, EC proposes to licence mini-grid development as a **RE Installation and Maintenance** activity.

3.1.3 Concessions

With regards to **concessions**, the EC is authorized to delineate the zone or area to be covered by a distribution license and that grants the licensee the exclusivity rights to such zone or area. This will apply by extension to mini-grids. Under a concession, there is **no requirement for government ownership of assets** although traditionally the assets have been government owned. There is currently at least one investor owned distribution entity (Enclave Power Company) which procured and installed, owns and operates the network under license issued by the EC.

3.1.4 Institutions

Ministry

The Ministry of Power (MoP) is responsible for formulating, monitoring and evaluating policies, programmes and projects in the energy sector. It is also the institution charged with the implementation of the National Electrification Scheme (NES), which seeks to extend the reach of electricity to all communities in the long term.

Within the MoP, the RED has been established to, amongst other things, oversee the development of the mini-grid programme until the establishment of the REA.

Regulator(s)

- **Energy Commission (EC):** Responsible for setting and regulating standards of technical operations and the issuance of licenses for operations.

The Energy Commission, in addition to being responsible for technical regulations in the power sector, also advises the Minister for Energy on matters relating to energy planning and policy.

The EC has prepared a Distribution Code. This is widely considered the technical standards, which will apply to grid connected RE technologies and mini-grid systems.

- **Public Utility Regulatory Commission (PURC):** Independent multi-sector economic regulator responsible for regulating tariffs of the Transmission and Distribution Utilities in the Power Sector (and also in the Water Sector).

PURC will assess tariffs regarding the operations of mini-grids. The PURC Act requires the commission to publish guidelines on the tariff approval process. The guidelines for mini-grids are yet to be developed.

Utilities

- **ECG:** The Electricity Company of Ghana is a limited liability Company wholly owned by the Government of Ghana and operating under the MoP. As noted previously, GoG is seeking by the end of 2016 to restructure ECG into a number of concessions.
- **NEDCo:** Northern Electricity Distribution Company (NEDCo) is an electricity distribution utility company in Ghana. The company is a subsidiary of the Volta River Authority, the main electricity generation company. NEDCo is responsible for supply power to all the three Northern Regions of Ghana, namely Northern Region, Upper East Region and Upper West Region and part of the Asante and Volta Regions, while ECG supplies power to the other regions.
- **Enclave Power:** generates, purchases and distributes electricity power. It operates in Tema Free Zone.

3.2 FUTURE APPROACH

3.2.1 Policy, Legislation, and Regulation

Private Sector Participation in Generation and Distribution

Current legislation does not adequately address the mini-grids sector. The default measures involve the adaptation of the traditional regulatory mechanisms for licensing, pricing and technical regulation. The EC is currently preparing the licensing regime that will specifically target mini-grid operations. PURC has also indicated its willingness to develop tariff guidelines to support mini-grids as it is required by law to do.

While these future interventions will help clarify the policy and regulatory framework for mini-grids, the regulators have indicated their willingness to support investors in development of mini-grids within the limits of the existing framework pending the introduction of mini-grid specific regulations.

Allowing Private Suppliers within the ECG/NEDCo Concessions

The EC is mandated under the EC Act to designate the zone or area covered by the distribution licences. Consequently, the introduction of mini-grid licences within the concessions of ECG and NEDCo will involve an amendment to the distribution licences. The EC may exercise such discretion in favour of the private supplier.

It would be important for EC to elaborate a solicitation and evaluation criteria to promote fair competition in the mini-grid sector as a medium to long-term consideration.

Another issue arising is whether or not the distribution utility may itself engage in mini-grid developments. The existing law does not prohibit them from participation in mini-grid operations; however, they like other entrants will need permits for such operations. More significantly, the articles of incorporation of the distribution utilities, which are registered limited liability companies though wholly owned by GoG, will need to be amended to allow power generation.

Process for Drafting Policy

Energy policy is developed first and foremost by the Ministry of Power. It provides the general direction that the sector agencies develop further for implementation. The EC is required to, among others, recommend national policies for the development and utilization of indigenous energy sources and advise the minister on national policies for the efficient, economical, and safe supply of electricity having due regard to the national economy. The Ministry prepares an initial draft, possibly with inputs from the sector agencies, which also provide feedback on the draft before it is finalised. It is important that before any major policy decisions are made they receive the approval of the Cabinet.

Process for Drafting Regulations

Drafting of regulations as subsidiary legislation is initiated by the regulatory agencies, which have rule making powers in their legislation. Draft legislation from the Energy Commission are routed through the Minister responsible for energy and lodged with the Attorney General as drafting instructions. The reviewed draft is submitted to the EC for its comments/no objection and then laid before Parliament to go through the processes of becoming law. PURC draft subsidiary legislation is submitted directly to the AG and then it goes through a similar approval process.

3.2.2 Institutional Roles

The institutional role of existing institutions (Ministry, regulatory bodies and utilities) in the context of mini-grids will be:

- **MoP:** Overall guidance on policy, legislation and regulation preparation.
- **Regulatory bodies:** Energy Commission will award concessions and oversee the preparation and application of technical standards.

The pricing mechanism within the concessions will be subject to the approval of the PURC.

It is to be noted that under section 18 of the PURC Act, a utility may, with the approval of the commission, demand and receive a special rate agreed between the utility and its customer for the services provided by the utility.

- **Utilities:** Primary concessionaires with first right of refusal on site development, or else required to develop the mini-grids, but with the right to tender out aspects of the projects which they are not best placed to undertake themselves.

In the future, as mentioned earlier, the Renewable Energy Act makes provision for a **Renewable Energy Authority (REA)** to be established which will oversee the implementation of renewable energy activities, execute renewable energy projects initiated by the State or in which the State has an interest and manage the assets in the renewable energy sector on behalf of the State. In Tanzania, the establishment of the Rural Energy Agency (REA) had a catalytic and positive effect on scaling up renewable mini-grid projects and renewable energy development more broadly (see Annex A1.1).

The RE Act also provides that until the establishment of the REA, the RE Directorate of the Ministry shall undertake these functions.

Despite these institutional arrangements as specified in law, the Ministry has directed the EC to oversee the development of RE technologies, including mini-grid development and operation as an interim measure. Indeed the GoG announced in February 2015 (President's State of the Nation Address) the establishment of the RE Fund to be financed from a portion of the existing Energy Fund. The fund was opened on March 17, 2015, but as yet it does not hold any funds. The fund is designed to support on-going solar PV and off-grid schemes being implemented by the EC.

The indications are therefore that the EC will handle all aspects of mini-grid development in the short to medium term, in addition to the technical regulatory function. GoG is looking to establishing the REA as a long-term measure.

3.3.3 Light-Handed Regulation

The recommended regulatory provisions for mini-grids from the landmark study on African mini-grids by Tenenbaum et al.²⁰ can be summarised in six actions:

- Exempt small system operators from licensing and prior tariff approvals.
- If prior tariff approval is required, do not mandate that the operator must charge the same tariff as the national or state utility. This also allows operators to charge fixed monthly tariffs for bundles of energy services or for unlimited consumption with a capped power load.
- Allow operators to cross-subsidize between customer classes (usually, but not always, by charging businesses more than households).
- Allow operators to sign power sales contracts with businesses without requiring prior regulatory approval of contract terms.
- Specify what rights the operators have “when the big grid connects to the little grid.”
- Allow operators to make loans to potential and actual customers to connect and to buy appliances and machinery.
- The principles of **light-handed regulation** should be adopted to the extent possible under both top-down and bottom-up procurement. While a formal procurement process for identified sites will incur certain costs in establishing concession contracts and distributing subsidy finance, these should be designed to optimise or reduce the regulatory requirements to enable private sector investment to provide electricity in a safe manner as quickly as possible.
- In operational terms, this implies that, for those sites developed opportunistically outside the formal procurement process, a simple form of registration with the Energy

Commission for mini-grids below a certain threshold size, and formal licensing only for larger mini-grids, should suffice. The threshold proposed in this report is 100 kW, which would imply that the majority of mini-grids developed by opportunistic developers in Ghana would not be subject to detailed regulatory oversight.

- The principles should also apply to the formal procurement process, with flexibility in tariff setting allowing differences from the UNT, and light requirements for security and reliability standards. All such regulations should be established and detailed in the procurement process; this approach may be known as **“pre-specified regulation by contract.”**
- Communities would have the right of recourse to EC or PURC in cases where they are dissatisfied with either the quality or service or the price, but experience in other countries indicates that such complaints would be very rare. Clustering mini-grid projects, thereby reducing the transaction costs of site development, may make small systems attractive for private sector investments.
- By contrast, heavy-handed regulation will either put off the private sector altogether or raise the costs of mini-grid projects. However, it is important to note that the light-handed regulatory approach does not only make sense for attracting private investors and keeping down the costs of PSP mini-grid projects, but also from the viewpoint of the scope of the work of national agencies. Detailed regulatory oversight of hundreds of small mini-grids would be disproportionately time consuming and costly, and might also distract from the primary focus that EC and PURC have on national-scale entities in the electricity sector.
- For that part of our recommendation that concerns a top-down approach, we suggest using concession agreements.
- Box 3.1 describes how light-handed regulation is applied, and tariffs are set, in Tanzania.
- It appears that the Kenyan electricity regulator is adopting a similar approach to Tanzania: issuing permits rather than licenses for small mini-grids. However, while

Box 3.1 | Mini-Grid Framework in Tanzania

In the interests of social justice through enhanced access to electricity, Tanzania has abandoned a rigid commitment to UNTs for mini-grids. In its second generation small power producer and mini-grid rules issued in April 2014 by EWURA, the Tanzania electricity regulator, a mini-grid operator (under 10 MW) is allowed to charge the UNT only if it can demonstrate that charging the UNT will “ensure commercial sustainability of the project”.²¹

In respect of ‘light-handed’ regulation, in Tanzania, a generator producing and selling retail electricity with a capacity of generation of less than 100 kW is not subjected to price regulation unless more than 15% of the consumers complain, and the regulator determines that the prices being charged exceed what might be “reasonably” expected in a cost-recovery tariff. An overview of Tanzania’s mini-grid regulations is provided in Annex A3.1.

Another slightly stricter (but still light) regime of regulation applies for systems between 100 kW and 1 MW, and above 1 MW, the rules come closer to those imposed on the national grid. Systems in this size range are exempt from applying for either a generation or distribution license. Instead, they must simply register with the regulator so that the regulator is informed of their existence.

Source | EWURA.

there are intentions towards allowing cost-reflective tariffs, on a transparent basis supported by reliable information, evidence suggests that the Kenyan national regulator, the Energy Regulatory Commission, is more inclined towards only allowing the UNT, and this is proving to be a significant constraint on the development of minigrids to provide electricity to off-grid communities.

- To reiterate the point made earlier, Ghana has every reason to be proud of achieving an 80% electricity access rate, leaving only a relatively small proportion of communities and households still needing to be connected. The mini-grid issues Ghana is grappling with can nonetheless be usefully informed by the decisions that have been made in other countries. Further international perspectives are provided in [Section 0 below](#).

The main argument behind these recommendations is that mini-grid customers need electricity much more than they need low tariffs. Regulation should therefore be as light-handed as possible. In particular, tariffs for small mini-grids should not be directly regulated. It may be seen as unfair for mini-grid customers to pay more per kWh for power than main-grid customers, but the real unfairness is for people in remote centres not to have electricity at all.

While all mini-grids should have to show compliance with safety standards, licensing procedures (and tariff negotiation) should be streamlined and simplified for small²² mini-grid projects in order to reduce transaction costs and promote private investment. Light-handed regulation also reduces the burden for the regulator as illustrated in the Tanzanian example (see Annex A3.1). In Tanzania the abolishment of licence requirements for Small Power Producers (SPPs) has greatly reduced the bureaucratic burden and associated transaction costs and had a profound impact on the financial viability of mini-grid projects.

Senegal and Mali are examples of countries aggressively pursuing rural electrification through private concessions. Both countries have dedicated agencies for rural electrification, ASER and AMADER respectively, which by the end of 2010 had to supervise almost 100 concessions each.²³ In the specific case of Mali, which has been researched for this study (see Annex A4.2), the tariffs negotiated between the operators and AMADER are different for each concession. While there is no policy of a uniform tariff, there is still significant pressure to keep electricity prices low and substantial subsidies are granted to private operators to overcome the gap between the cost-reflective tariff and the approved tariff.

The Key Elements of the Arguments Made in Chapter 9 of Tenenbaum *et. al.*'s Book Are:

- In order for small power producers (SPPs) that operate isolated mini-grids to exist as commercially viable entities, they must be allowed to charge tariffs that are higher than the uniform national tariff (p 275)
- Rural household customers can afford cost reflective tariffs if they are allowed to pay for the initial connection cost in small monthly payments over time. Once they get over the connection cost hurdle, they can afford to pay electricity tariffs that will produce monthly expenditures equal to or less than their prior expenditures on non-electricity energy sources (kerosene, candles, batteries). Electricity has the added benefit of producing better energy services: higher quality lighting, better access to information, and health benefits (p 278)

As demonstrated in the case study analysis for Mali (Annex A4.2), the key lesson learned is that careful design of performance monitoring is necessary to avoid introducing perverse incentives.

The discussion above shows that a light-handed approach to regulations strikes a clear balance between those regulations that are absolutely necessary (i.e. safety and basic technical requirements) and those that are not strictly necessary but can impose costs on customers that are more difficult to spread across lower numbers of customers and lower volumes of electricity. The example from Tanzania, with a handful of mini-grids operating under the SPP Framework, shows that **light-handed regulation can be adequate for developing mini-grids**; customers receive power, operators are financially sustainable, and mini-grids function safely.

Based on this discussion, the recommendation is that Ghana adopt a similar approach for its mini-grids, and that this is adopted in the drafting of Ghana's mini-grid regulations. Not doing so may have two likely outcomes:

- a longer process to develop mini-grids for the unconnected communities, meaning effective economic losses to these communities while they wait for connections, and
- more costly tariffs once the mini-grids arrive—as with all other costs involved in development, regulatory costs must be recovered from customers.

This approach can apply to the bottom-up, opportunistic and unsubsidised development of sites by developers. However, the top-down formal procurement approach will, by necessity, involve increased regulatory procedure and interaction, particularly around the conditions of the concession agreement and the subsidy delivered. Here, the regulations should complement those in the general light-handed framework, and be implemented in the concession and subsidy agreements, in an approach we can refer to as “pre-specified regulation by contract.”

Concerns about whether a light-handed framework may lead to reckless development are not justified as safety and basic technical standards will still apply. The light-handed approach to tariff-setting as it has applied to customers in Tanzania has met with little resistance from customers, and where it has caused issues, customers have been able to take up their right to complain to their relevant regulator. Tanzania has the advantage though that with poor access rates across the country, comparison with national grid tariffs is rarely appropriate. In Ghana, such a comparison may be more realistic, and therefore protests at higher tariffs more plausible.

The framework will need to include the requirement for interested parties to obtain licenses in order to become QTPs. So as not to deter interested parties, this should not be too expensive or complicated a process to go through.

The ethos of a light-handed approach will need to carry through to the concession agreements and standardised power purchase agreements (SPPA) as much as possible. The requirements of a concession agreement, by their nature, will impose additional cost and regulatory burden, but these need not be excessive, for the same reasons as discussed above. We present an example of the information that may be included in a

concession agreement in Annex A5.2. In summary, the sorts of sections that may be included in a concession agreement include:

- General conditions
- Service obligations
- Interior installation obligations
- Maintenance and replacement obligations
- Record-keeping obligations
- Various agreements around transfer of contract, acceptance of work, inspection and control
- Fees payable
- Tariff-setting rules and methodology, including approval process and rights of complaint (for operators and customers)
- Subsidy payments
- Insurance
- Rules around agreement modification and termination, including arbitration

Standardising as many terms of the SPPA as possible will minimise the transaction costs involved in negotiations between an SPP and the distribution company. Included in this is the tariff; some countries negotiate tariffs for each SPP, possibly capped at the utilities' avoided cost of supply, whereas many countries (e.g. Kenya, and more recently, Tanzania and Uganda) are moving towards standardised feed-in tariffs, particularly for renewable energy technologies. We recommend that Ghana adopt a similar approach. The key information that should be considered in a standardised SPPA include:

- Definitions
- Term
- Conditions precedent
- Interconnection with the buyer
- Commissioning and testing
- Delivery, sale and purchase of electricity
- Metering
- Record and confidentiality
- Undertakings and warranties of the parties
- Force majeure
- Default and termination
- Relationship of the parties, limitation of liability and indemnification
- Dispute resolution
- Miscellaneous provisions
- Description of the plant

- Standardised tariffs and escalators
- Designation of interconnection facilities and requirements
- Contents of seller's invoice
- Designated address and contact persons for each party

We recommend reviewing the SPPA templates in place in other countries in sub-Saharan Africa, notably Kenya and Tanzania. Kenya's SPPA template can be downloaded from: http://www.renewableenergy.go.ke/asset_uplds/files/Standardized_PPA_for_Small_Scale_Generators_less_than_10%20MW.pdf. Tanzania's SPP documents can be downloaded from: <http://www.ewura.com/newsite/index.php/sppmenu>.

3.2.4 Pricing/Tariff Regulation

As highlighted earlier in this report, costs that are not met by tariffs have to be met by subsidies either from other users or from the public finance system. Hence the choice around the applicable tariff for customers is fundamentally one of policy, with economic implications, rather than one of economics. The options are on a spectrum, guided at each end by:

- A **cost-reflective tariff (C-RT)**, encompassing all costs necessary to develop and operated a mini-grid in a specific location for a given period, which is likely to be in excess of \$ 1.00/kWh.
- The **UNT**, which is applied to all of the customers in the lowest consumption category, which is around \$ 0.05/kWh.²⁴ Mini-grid operators in other countries follow the same tariff level graduation as the national grid.

With the C-RT being much higher than the UNT, the choice is whether to apportion the difference to:

- Direct customers (increase towards C-RT).
- Indirect customers (operator cross-subsidy).
- Tax-payers (including non-customers) through GoG external subsidy.
- Donors through donor external subsidy.

The tariff eventually adopted could sit at a point between the two, in part acknowledging that the costs involved in providing power through a mini-grid is more expensive than via the main grid, but that fully cost-reflective tariffs may be beyond the willingness and/or affordability of most customers.

In Philippines, a Competitive Selection Process (CSP) is used to select the least cost generation option for electrifying an area. In order to calculate the power producer's allowed revenues, the True Cost Generation Rate (TCGR), approved by the Energy Regulatory Commission (ERC) is used. However, the power producer can only collect from customers a tariff based on the Subsidised Approved Generation Rate (SAGR), which reflects the customers' ability to pay. The difference between the TCGR and the SAGR is paid to the producer in the form of a subsidy. The procurement process for mini-grid development in Philippines is summarised in Annex A4.1.

The approach adopted by Tanzania’s electricity regulator, EWURA, as shown in our case study analysis in Annex A3.1, provides a strong option for Ghana.

- Under EWURA’s Small Power Producer (SPP) Framework, projects under 100 kW in capacity do not require tariff approval from EWURA unless the developer opts in to its regulation, or there is a complaint by customers.
- For those projects that have tariffs regulated by EWURA, the assessment is clear and balanced between the interests of operators and customers. Applicants submit their costs of operation, which are assessed by EWURA for their fairness, and used as a benchmark for the tariffs to ensure the operator recovers all reasonable costs (operating costs and recovery of capital costs).
- EWURA then assesses the affordability of the tariffs for customers, but **does not** assess the willingness of customers to pay the tariffs. Any difference between ability and willingness to pay tariffs is a risk borne by the developer.
- If 15% of customers are unhappy with the tariff set by EWURA, they can complain to EWURA and request a formal inquiry.

In countries such as Kenya where (although not explicitly stated in the policy) significant pressure from the regulator can be expected to reduce tariffs to levels similar to the grid, an adequate subsidy scheme will be needed to attract private investment.

Based on the discussion above, and as noted elsewhere in this report, we recommend that Ghana follow an approach of allowing cost-reflective tariffs that are affordable for customers. For systems under 100 kW, we recommend that tariffs are only reviewed ex post, that is, if customers complain, or if operators choose to license themselves under the framework that applies for systems 100 kW and above. For systems 100 kW and above, we recommend that tariffs are approved ex ante by the PURC, but still on a cost-reflective basis.

If the PURC chooses to adopt an approach that requires operators only to charge the UNT, and developments require capital subsidies to become financially viable (as we have recommended as being necessary for development), then any increase in the UNT subsequent to development may effectively transfer wealth to the operator who was in receipt of the subsidy. There is no straightforward way of recovering that part of the subsidy that has become a wealth transfer through the marginal increase in the tariff. This would argue against the application of the UNT to all mini-grids.

3.2.5 If the Main Grid Arrives

In designing the contractual arrangements for a mini-grid, it is important to consider what the arrival of the main grid would mean for the mini-grid. This topic has been explored in detail in the mini-grid regulatory handbook referenced earlier,²⁵ where five main options are identified:

- **Option 1:** SPP (small power producer) stops generating and becomes a SPD (small power distributor), if the mini-grid is built according to the national grid code.
- **Option 2:** SPP stops distributing and sells power to ECG/NEDCo. The SPP might need to be compensated for the non-depreciated value of assets that are made obsolete (i.e. batteries and battery inverters) but not for any substandard.

- **Option 3:** SPP operates as combined SPP-SPD (grid main source of electricity, existing generation backup and/or sale at prevailing feed in tariffs).
- **Option 4:** ECG/NEDCo buys the SPP (but is not able to operate it without a change to its constitution to allow generation).
- **Option 5:** SPP moves its assets to a new site, and/or abandons the distribution grid, which is possible if the assets are not built to grid standard, such as with a DC micro-grid.

In order to reduce the risk for private operators considering investing in mini-grid projects, which options may apply need to be specified in advance. For the two chosen delivery models:

- **Private Model:**

1. the operator should stop generating and become purely a distributor of electricity (if their mini-grid is built to main grid standards; Option 1), or
2. if grid supplies are unreliable, the generation equipment could be retained for use as back-up or for sale of power into the grid (with a connection at main grid standards; Option 3), or
3. if not at grid standard, no compensation is offered for the distribution assets (Option 5).

- **PPA Model:** for solar-PV based schemes, at prevailing feed-in tariffs selling to the national grid (Option 2) would not be attractive for a private operator, and purchase of the generator (Option 4) would not be attractive for ECG.

In the event of the grid arriving to a mini-grid system not built to grid standards (but to sufficient technical standards, as discussed in Section 0), the developer will not receive compensation for any distribution assets not assumed as part of the grid extension; they may remove them if they choose to. Therefore, the risk of loss at such time rests with the developer.

Requiring mini-grids to be built to main grid standards has two possible implications for the unconnected households as compared with allowing lighter (but sufficient) technical standards:

- Slower (or no) delivery of electricity (until the main grid arrives), as mini-grids built to sufficient (but not main grid) standards can be developed faster than mini-grids at main grid standard, and
- More expensive energy consumption, either from the mini-grid built to grid standard, or from reliance on their more expensive existing sources of energy.

The definition of the applicable option for a Private Model or PPA Model (and the details of what aspects are to be negotiated)²⁶ is a prerequisite for private investors. Adequate provisions need to be included in the standardised concession or power purchase agreements.

Additionally, financial issues need to be resolved before the utility enters the area. If the mini-grid operator has been charging a higher tariff than the utility (and the utility is ‘taking over’ the concession) the new tariff has to be agreed and any obligations due to the mini-grid operator to enable it to ‘close out’ its operations have to be met. If the mini-grid

operator will continue to operate the site, then new tariff, generation and distribution agreements and Feed in Tariffs may have to be negotiated or regulated.

3.2.6 Technical Standards Regulation

Quality of service, technical specifications and monitoring of mini-grids are summarised in Annex A6. We do not recommend overly-prescriptive technical requirements on the whole, provided basic minimum requirements are included, following the lead of the light-handed regulatory approach.

OSINERGMIN, the Peruvian electricity regulator has decided that quality-of-service standards should be lower for service providers in rural areas. Its rationale is that it is more difficult and costly to provide comparative service in rural areas at a price that is affordable to the generally poorer rural customers.

The protection of life and equipment is the minimum technical design requirement that must be enforced on all mini-grids regardless of size. Provided safety is adequately provided for, mini-grid systems could reduce costs by having lower technical standards. In particular, direct current (DC) distribution systems could be used in solar PV mini-grids, cutting out the costs and losses associated with inverters, but also limiting the range of end-use appliances that are available. The value of the assets of the mini-grid would be lower, and it would anyway not be eligible to be bought out if the main grid arrives, but in remote communities these would not be problems. Users would benefit from lower cost electricity.

Being overly prescriptive in the technological regulation of generation can preclude innovative and more efficient forms of generation. As there should be fewer safety concerns with generation, we recommend at least that a light-handed approach is taken to this aspect of regulation. Distribution assets are more standardised, and therefore regulation is less likely to preclude innovation, except perhaps in metering at the point of supply. Similarly, distribution assets (e.g. wires and poles) are more accessible to customers, and therefore safety regulations are of more relevance.

We recommend that the EC undertake assessments of the following key safety issues on a regular basis or on the occasion of a breach that results in an accident:²⁷

- The design and operation of equipment must be under authorised personnel who have attended and passed a course of instruction in safety regulations as certified by the regulator or a more experienced undertaker such as the main-grid operator;
- All equipment used and system designs must comply with applicable national and international standards;
- Physical barriers and warning signs to energised equipment must be provided to prevent accidental or intentional entry by all non-authorised personnel;
- Protective relays and interrupting devices must be provided and maintained in working conditions as certified by regular testing procedures;
- An adequate earthing system must be installed and maintained to ensure correct operation of protective devices and for protection of equipment and personnel during maintenance work;
- Adequate lighting must be provided for normal and emergency working conditions;
- Fire risk protection;

- Workmanship and cleanliness;
- Operating manuals and documents must be developed and updated regularly and users regularly trained in the use of the documents.

The regulator must publicise the findings of the assessments. Serious penalties must be provided to ensure compliance.

With regards to reliability, we recommend that the EC ensure that mini-grids provide a **consistent quality of supply and service** demonstrated by:

- Voltages and frequency maintained within the statutory limits during normal and emergency operation;
- Harmonic distortion limited to permissible levels as defined in the grid or distribution code;
- Keeping to service response times publicised in a customer charter, to be developed by the mini-grid operator and approved by the regulator, which must address such service issues as new connections, fault repair, call-centre performance, handling of complaints and queries, metering, billing and cash collection;
- Timeliness of performance reporting.

DC-based systems will only be required to apply the last two bullets of this list as the first two only apply to AC-based systems.

For a mini-grid to qualify for grid connection, the technical requirements of the main utility need to be met. These include overall network safety needs, frequency and voltage regulation, the integration of the distribution system into the utility system, whether the mini-grid system is able to ‘island’ in the event of grid failure, and whether it is used as a ‘dispatchable’ asset of the grid. However, as discussed earlier, these requirements should not be subject to regulation. It is for the developers of mini-grids that are likely to be absorbed into the main grid to ensure compatibility with grid standards, so as to be able to sell on their assets, but the alternative would be for the developer to anticipate recovering their investment costs before the main grid arrives. This judgment is to be made by the developers, rather than by regulators.

The likelihood of eventual grid connection will be a major determinant of the technical standard for any particular mini-grid. For this reason, ECG has pointed out that it would prefer that the technical standards of the mini-grid conform to the existing Distribution Code and for that matter the Renewable Energy Code without derogation or relaxation. Indeed, that position fits into their forward plans of incorporating the mini-grids into their systems when grid connection occurs. NEDCo would also maintain the existing distribution code standards but are amenable to other suggestions from the ministry and regulators.

3.3 RECOMMENDATIONS

The main objective of mini-grid development is that people in remote communities should gain access to electricity. People need private entrepreneurs to be prepared to provide electricity to their communities, and the operators are far more likely to be willing to make the big effort and take significant risks in supplying remote communities if they do not have to adhere to onerous regulatory requirements.

The experience of other countries, notably Tanzania, has shown that a light-handed approach to mini-grid regulation is adequate for protecting the interests of customers, particularly in terms of their safety, their reliability of supply, and the affordability of their tariffs. It is thus strongly recommended that the principles of a light-handed regulation approach be adopted, similar to the practice in Tanzania (see Section A3.1). This implies:

- **Exempting ‘small’ mini-grids from formal licensing and tariff regulation** requirements under the bottom-up, opportunistic approach—we recommend that any mini-grid that is less than 100 kW is classified as ‘small’. This applies to both AC and DC-based systems. Such mini-grids could still be obliged to register with the EC, but this would be purely for statistical purposes and the monitoring of safety. Only if communities appeal to the PURC would the economic regulator scrutinise tariffs. As noted above, the same basic safety standards will apply to small mini-grids; technical requirements should include the preparation of the customer charter and the timeliness of reporting.
- For larger mini-grids that are to be regulated, allow the operator to charge **scheme-specific tariffs** that are different to the UNTs. For those systems procured through the top-down process, the tariff may be set as a fixed constraint in the bidding process, but should still be allowed to differ from the UNT. Operators would need to be allowed to cross-subsidise between customer classes (for example, higher tariffs for businesses than for households).
- Allow operators to charge a **flat monthly rate for bundles of energy services**, or for **power consumption capped with load limiters** (with the implication that the effective rate per kWh may be higher than the maximum allowed per kWh tariff).
- Promote **small power producers** through a standardised SPP framework, including pre-determined technology-specific feed-in tariffs and a **standardised power purchase agreement**.
- To cater for the **arrival of the main grid**, adequate provisions need to be included in the standardised concession or power purchase agreements, as discussed in **Section 0**. This may include a clause within the agreement how the assets specified for the particular site will be treated.
- Operators wanting to be in a position to sell the distribution assets when the main grid arrives must adhere to main grid **technical standards**, but lesser standards should be allowed in order to reduce costs, providing only that safety is adequately catered for.

It is hoped that these principles will be incorporated by the EC and PURC in the drafting that they are undertaking of the licensing and tariff requirements for mini-grids.

4 | SUPPORT REQUIRED FOR ROLLOUT

This section addresses the capacity building needs to make the recommended mini-grids framework effective. The starting point of the analysis is further elaboration of the institutional structure involved with mini-grids, as it is the capacity of those institutions which need strengthening.

4.1 INSTITUTIONS TO BE INVOLVED IN THE ROLLOUT OF MINI-GRIDS

As highlighted in **Section 0**, when the Renewable Energy Authority has been formed it will assume overall responsibility and oversight of the renewable mini-grid sector. The RE Act also provides that until the establishment of the REA, the RE Directorate of the Ministry shall undertake these functions.

The main functions to be performed relate to the procurement process and the subsequent monitoring of the projects. The following aspects need to be covered:

The key institution that will in due course require capacity building is the REA, but no specific plan can be made as the formation of the REA is not yet programmed. Once the REA has been established, it will require technical assistance to assess and enhance its capacity to manage the mini-grids programme, covering the areas discussed in the remainder of this section.

The EC will have a significant on-going role in screening QTP candidates, registering small mini-grids, issuing licences for mini-grids that are larger than 100 kWp, establishing safety and technical standards and monitoring during the operational phase.

Before the formation of REA, the EC will be well placed to organize the procurement process for mini-grids.²⁸ Further in June 2011, GoG adopted a PPP policy and followed

Table 4.1 | Institutional Responsibilities

Item	Area of Intervention	Institution
1	Inventory of sites	RED (REA in long term)
2	Packaging of sites	RED (REA in long term)
3	Utility first right to develop/required to develop	ECG, NEDCo
4	Candidates achieve QTP status	RED (REA in long term)
5	Open mini-grid tender	RED (REA in long term) + PPP unit
6	Registration of small mini-grids or Concession agreement and licensing	EC (REA in long term)
7	Tariff approval for larger mini-grids	PURC
8	Management of subsidies (if new fund is established)	EC (REA in long term)
9	Supervision and monitoring	EC (and REA in long term)

Key: REA = Renewable Energy Authority, RED = Renewable Energy Directorate, EC = Energy Commission, PPP unit = Public-Private Partnership. Unit to be set up in Ministry of Finance.

it up with the establishment of the PPP Unit within the Ministry of Finance to provide facilitate the implementation of PPPs. The entity responsible for managing the development and management of mini-grids, whether the EC now or the REA in the long term, will be expected to work in close collaboration with the PPP Unit, which will have national-level PPP procurement capability.

In addition, the EC can take responsibility for the management of subsidy finance for mini-grids. It already has the legal mandate for management of the Energy Fund and the Renewable Energy Fun, so should be well positioned to manage a specific mini-grids subsidy fund. Once the REA has been established, management of the subsidy fund should be transferred to the REA. This combines the management of the mini-grid programme with the financing capacity, as is seen in other companies, notably Mali (through AMADER) and Tanzania (through REA).

The remainder of this section discusses various different areas of capacity building.

4.2 TECHNICAL SUPPORT

The utilities are not familiar with renewable mini-grids and would benefit from technical support and training at the start of the rollout.

Although this is also a new area for the technical regulator, EC has staff capable of taking this additional area of regulation as they undertake this role for the existing main grid network.

4.3 PRICING METHODOLOGY

If the recommendation that only mini-grids in excess of 100 kWp should have regulated tariffs is accepted, then the tariff methodology will only be needed for regulatory purposes for larger mini-grids. However, the tool will also be useful for scoping and planning purposes.

The Retail Tariff Tool that has been developed as part of this project is to be handed over to the Ministry, PURC and other interested parties in an extended training workshop (2 full days and 2 half days). The mode of transfer of models we have successfully developed in East and Southern Africa is to have a relatively long training course which starts with theoretical concepts relating to policy and regulation of mini-grids, together with discussion of experience elsewhere, including alternative business models, and critical assessment of the results of the study.

The training workshop will include deepening excel skills, and will introduce the model through a 'learning by doing' process of developing core elements of the model, progressively adding complexity, and culminating in the handover of the finished model. Exercises, readings and class presentations will be integral parts of the training process.

Electricity pricing is a technical activity already within the remit of PURC, and therefore we understand that the capacity to develop tariff models is already present for large-scale electricity systems. These skills should be transferable easily to mini-grids.

4.4 PROCUREMENT AND PRIVATE SECTOR ENGAGEMENT

Once the framework has been agreed, an awareness creation campaign should be mounted to inform potential mini-grid operators of the opportunity to invest and to encourage them to seek QTP status.

On the side of the agency running the procurement process, which is likely to be the Energy Commission until the establishment of the REA, help may be welcomed in preparing the tender, plus the evaluation criteria and process. The first round of procurement could be done with external assistance to EC/REA, and inputs from people with national PPP procurement experience, and thereafter EC/REA could run future procurements with confidence.

4.5 TEMPLATES AND GUIDELINES

In Annex A5 we include the basic structure of a mini-grid license and a sample concession agreement. Furthermore, we recommend reviewing the SPPAs used in Kenya and Tanzania, which can be downloaded from:

- **Kenya:** http://www.renewableenergy.go.ke/asset_uplds/files/Standardized_PPA_for_Small_Scale_Generators_less_than_10%20MW.pdf.
- **Tanzania:** <http://www.ewura.com/newsite/index.php/sppmenu>.

Overarching Recommendations

In response to the imperative to provide electricity as soon as possible to remote communities, the study provides some over-arching recommendations:

- **Principles:** Wherever possible, **procedures should be streamlined** for the establishment of mini-grids for Lake Volta communities and the **simplest regulatory requirements** imposed that are consistent with the safe provision of electricity.
- **First right of refusal** should be granted to the **incumbent utilities** to supply power to the targeted communities. Alternatively, the incumbent utilities may be **required** to seek solutions to supply power to the targeted communities.
- **Tendering:** Should the utilities choose not to serve the communities, either the utilities or a central agency should tender the sites to qualified third parties.
 - **Technology openness:** All tenderers should nominate how they choose to provide electricity to the identified communities, from main grid power, mini-grids, micro-grids (defined to be under 100 kW, including DC-based systems) and solar home systems (SHS).
 - **Subsidies** should be made available for the main grid and mini-grid options. It is recommended that tenderers bid for the minimum subsidy to provide service at a given tariff, service level and specified number of connections.
- **Private operators** should not be restricted by either the utilities' first right of refusal or the competitive procurement process from **opportunistic development of mini-grids, micro-grids or providing SHS**.
 - **'Light-handed' regulation** should apply to such systems. This means the system will be required only to meet grid standards on safety, but not on reliability or security.
 - **Licensing:** the only requirement will be for such operators to obtain a license from the Energy Commission (EC).
 - **Self-finance:** no subsidies will be offered for such private operators. Subsidies will only be offered in competitive tender processes.

ANNEX 1 | ISLAND MINI-GRID TARIFF REGULATION CASE STUDIES

A1.1 GREECE

Most islands in the Aegean (between Turkey and Greece) are not interconnected. The networks on the non-interconnected islands are owned by PPC and operated by DEDDIE (the PPC DSO subsidiary).

End-use tariffs are uniform in Greece, but the additional cost of the non-interconnected islands (arising from high reliance on fuel oil, diesel, etc.) is explicitly recovered through a 'PSO levy' on mainland customers.

There are private investors owning and operating renewable generators. The RES private producers, located on non-interconnected system receive preferential tariffs for some RES, as shown in Table A1.1.

The high FIT levels, especially for solar and biomass have attracted a lot of investment in the sector. From September 2011 to September 2015, the installed capacity of solar increased by a factor of 6.4 (Figure A1.1).

Table A1.1 | Feed-In Tariffs for Electricity Produced from RES

Electricity Production	Electricity Price (€/MWh)	
	Interconnected System	Non-Interconnected System
Wind energy onshore power > 50 kW	87,85	99,45
Wind energy onshore ≤ 50 kW	250	
Wind energy	108,30	
Hydraulic energy ≤ 15 MWe	87,85	
Solar energy utilized in solar thermal power plants	264,85	
Solar energy utilized in solar thermal power plants with a storage system	284,85	
Geothermal low temperature	150	
High temperature geothermal energy	99,45	
Biomass ≤ 1 MW (excluding biodegradable municipal waste)	200	
Biomass > 1 MW and ≤ 5 MW (excluding biodegradable municipal waste)	175	
Biomass exploited by stations with an installed capacity ≥ 5 MW (excluding biodegradable municipal waste)	150	
Landfill gas ≤ 2 MW	120	
Landfill gas > 2 MW	99,45	
Biogas from biomass (livestock and agro-industrial organic residues and waste) ≤ 3 MW	220	
Biogas from biomass (livestock and agro-industrial organic residues and waste) > 3 MW	200	
Other renewable energy (including municipal waste)	87,85	99,45
Combined Heat and Power High Performance (CHP)	87,85	99,45

Source | DEDDIE.

Figure A1.1 | RES Installed Capacity, Sept 2011–Sept 2015



Source | DEDDIE.

A1.2 SPAIN (BALEARIC ISLANDS)

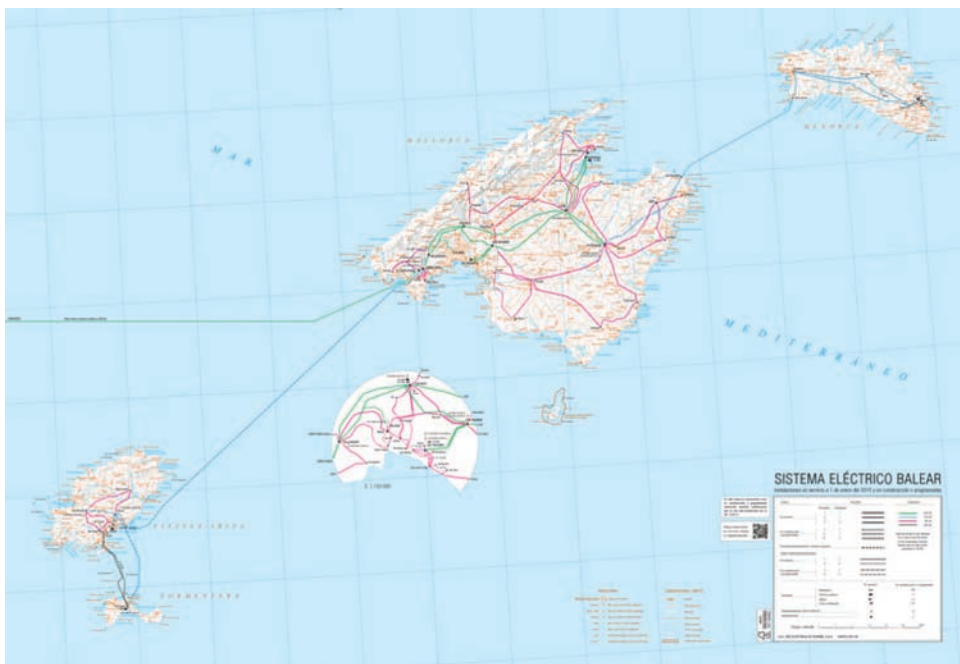
In July 2010, Red Eléctrica became the owner of 100% of the transmission grid in the Balearic Islands (Figure A1.2). Previously, the transmission grid was owned by a separate monopoly company, Gesa Endesa. Until 2012, the Balearic Islands were not connected to the Spanish peninsula and comprised of two smaller sized isolated subsystems, Majorca-Menorca and Ibiza-Formentera.

COMETA, an undersea electric power transmission system between mainland Spain and the island of Majorca, became operational in 2012, connecting Morvedre near Valencia and Santa Ponsa near Palma de Mallorca. The project was developed by Red Electrica. The total length of the cable is 247 km and it costed EUR 375 million. The project has had a positive impact on the Islands electricity generation market, in terms of higher competition and lower carbon emissions.

In 2014, Red Eléctrica started the construction of a second cable to connect Ibiza-Formentera to the Spanish main grid. The project is expected to be operational in 2016. Once operational it will have a length of 126 km and will be the world's longest submarine interconnection in alternate current and the deepest (800 m) of this kind. The cost of this project is EUR 225 million.

In 2011, a year before the commissioning of the submarine interconnection, the share of RES in total Balearic Islands' demand was only 1.9%. This is because most of the power generated in the Balearic Islands is from fossil fuels. This figure increased to 16% in 2013, since most of the electricity transmitted from the peninsula (22% of total inland demand) was generated by RES.

Figure A1.2 | Balearic Island Transmission Grid Map



Source | Red Electrica.

New Ibiza-Formentera Interconnection

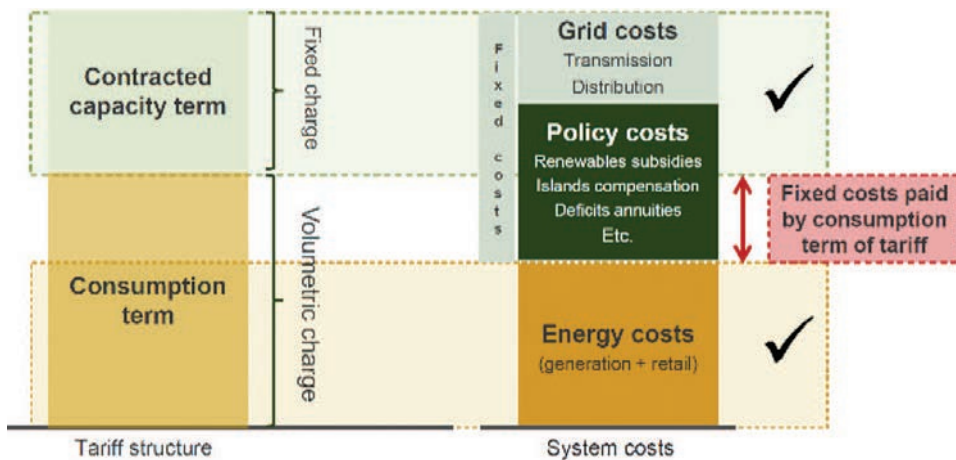
A new submarine electricity cable between Ibiza and Formentera will be constructed to strengthen the existing interconnection between the two islands. This will be 23 km in length undersea and a further 9.3 km on the land section. The project is expected to cost EUR 77.7 million.

Tariffs

The end of use tariffs are the same in Balearic Islands as in the Spanish peninsula. The tariff structure comprises a fixed charge and an energy charge that varies according to consumption. There is currently no explicit levy on consumers' tariffs to recover the cost of islands interconnections and these costs are partially recovered through the fixed and energy charges. Therefore, there is an implicit cross subsidy from the consumers of the peninsula to the Islands' consumers.

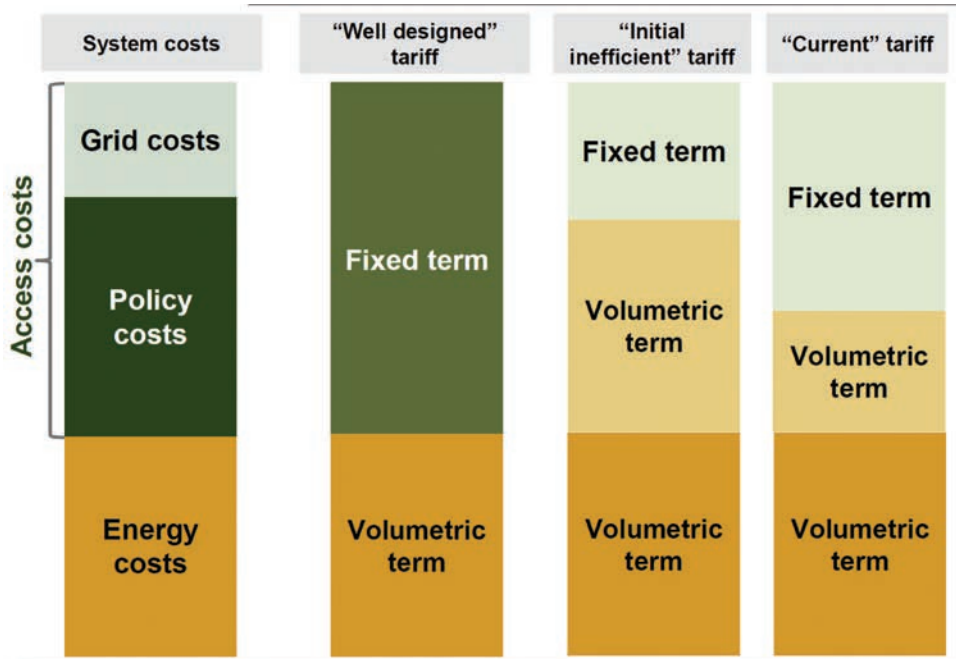
Since 2013, the tariff structure has changed, gradually increasing the weight of the fixed term on access costs (Figure A1.3), which include islands transmission network investments.

Figure A1.3 | Electricity Tariff Structure Spain



Source | IEA 2015.

Figure A1.4 | Electricity Tariff Structure in Spain Before and After 2013



Source | IEA 2015.

ANNEX 2 | MINI-GRID REGULATION CASE STUDY

TANZANIA

Tanzania has a large number of mini-grid projects at various stages of development, mostly promoted by local developers. This can largely be attributed to the effective regulations in place.

The Tanzania Rural Energy Agency (REA) and the Tanzania Energy Development and Access Project (TEDAP) have an impressive list of projects:²⁹

- Since the REA started in 2002, five renewable energy mini-grid projects have been completed totalling 22 MW—with all five closing in the last five years. Of these, three are biomass-based and two are hydropower. Four of five are grid-linked and benefit from feed-in tariffs on net power exported. One hydro project of 300 kW is isolated.
- Four projects are listed as ‘Tier 1’ by the World Bank (nearing financial closure). Three of these, at 28.5 MW, are grid connected hydro plants receiving feed-in tariffs. One is a 2 MW isolated biomass plant (Mafia Island). The World Bank states that any three of these will exhaust the remaining \$ 15 million in the TEDAP credit line available to projects.
- Eight hydro projects, totalling 25 MW, are listed as ‘Tier 2’ by the World Bank.
- 28 other projects were on lists provided by the REA and World Bank. This includes 22 hydro projects (17 MW), three biomass (9.6MW) and three solar PV (3 MW). Most of these latter projects have received matching grants and/or have signed Letters of Intent with the REA.

The slow pace of project development in Tanzania has a number of causes, such as inability of projects to reach financial closure, and unclear land, water, environmental and other regulatory issues. Power regulations have been cited as not being a barrier to mini-grid development. The Tanzanian government, its development partners, and others, are providing support to address these obstacles. This support includes:

- the provision of finance, guarantees and capacity-building for financiers;
- capacity building and technical assistance for project developers and implementing agencies; and
- technical assistance for the design of regulatory frameworks and plans.

Tanzania’s Small Power Producer (SPP) Framework is one of the most advanced policy and regulatory frameworks for small power projects supplying both the main grid and off-grid mini-grids in sub-Saharan Africa. This framework provides developers with clear and reliable guidance around issues such as system registration, tariffs and concession security.

Tariff Methodology

The Energy and Water Utilities Regulatory Authority (EWURA) has developed a standardised tariff methodology and standardised power purchase agreements and process guidelines that have assisted a number of developers to conclude agreements with the national power utility, TANESCO, to supply power using biomass, mini-hydro and solar power plants. However, the rate at which investment is taking place is too low to make a significant impact on electricity access and renewable energy development.

Cost Reflective Tariffs

Recently, the Tanzania regulator, recognising that cost-reflective tariffs for mini-grids are the most cost-effective solution for scaling up electricity access in many regions, issued the 'second generation' mini-grid rules. These rules allow mini-grid investors to charge tariffs that are higher than the national utility's tariffs, provided that this is required for commercial sustainability.

In cases where energy demand is small and there is little chance of connection to the national grid, prices may be negotiated directly between consumers and providers and they do not require approval from the regulator if the generator's installed capacity is very low (below 100 kW).

Institutional Framework

REA was set up to provide grants to support project development, as well as connection subsidies of up to \$ 500 per connection or up to 80% of the transmission and distribution costs. By 2010, 17 MW of off-grid projects based on small hydro and biomass were in various stages of development.³⁰

Also, REA developed TEDAP, with funding from the World Bank, which provides subsidies, collateral financing, special interest rates and technical assistance for main grid and off-grid projects.

Tanzania is also in the process of establishing a Transaction Advisory Services Facility (TASF) to support and promote the development of commercially viable mini-grid projects that will improve energy access in rural off-grid locations in Tanzania. The aim of this support is to strengthen their operating models, increase their commercial viability and, ultimately, bankability.

Light-Handed Regulation

Another key aspect of the regulation that aims to reduce the bureaucratic burden on Small Power Producers (SPPs) is that those with generation capacity of less than 1 MW are not required to obtain a licence but are required to register with EWURA, which conducts reviews of the tariffs upon complaint from 15% of their customers.³¹

Moreover, very small mini-grids, below 100kW, are exempted from all regulation altogether. Full exemption from obtaining a licence for very small mini-grids, reduces transaction costs and, therefore, increases the financial viability of projects.

Provisional licences, offer exclusive rights to the investor for a few years to allow time for the feasibility studies, financial structuring, land acquisition, construction, etc. They provide security to the developer and also make the process of obtaining general business documents (incorporation, tax registration, etc.) and building permits easier.³²

Transparency

In Tanzania all relevant regulatory documents are publicly available on the EWURA website and can be accessed at <http://www.ewura.go.tz/newsite/index.php/sppmenu>.

ANNEX 3 | MINI-GRID PROCUREMENT CASE STUDIES

The development of mini-grids often entails large capital costs and in many countries their viability depends on grants or subsidies. A careful design of the procurement process is necessary in order to promote the development of sustainable mini-grid markets.

This Annex provides an overview of the procurement process for mini-grid development in Philippines, Mali and Senegal, respectively.

PHILIPPINES

Qualified Third Party

The Philippines consists of 7,107 islands, and electricity generation, primarily based on diesel generators, is very expensive with the cost of generation reaching well over 20 pesos (\$0.45) per kWh. Until 2014, there were around 110 isolated diesel grids, from 46 operators, most of which are cooperatives. The Government is actively seeking to adjust regulations in order to attract private sector and community initiatives for mini-grid operations.

Almost a third of rural households are situated in areas not connected to the national transmission grid. Each distribution utility (DU) has a franchise area and is obligated to electrify all of that area. However, it is recognized that some areas may not be commercially viable to supply at the regulated tariff. The distribution utility can declare these areas unviable. The areas deemed as financially unviable for the distribution utility and a list of such areas has been published by the Department of Energy (DoE).

Once an area has been declared unviable and this has been approved, it becomes eligible for funding through the Universal Charge—Missionary Electrification (UC-ME). This is a levy on all customers that is used to provide a subsidy to electrification.

As part of the Government regulations, the National Power Corporation—Small Power Utilities Group (NPC-SPUG) is mandated to electrify unviable areas and, for this purpose, is paid the proceeds from the UC-ME. The amount to be collected is set annually by the Energy Regulatory Commission (ERC) on application by NPC-SPUG.

Since 2001, the Philippines has followed a general policy of privatisation. In the context of rural electrification, this has turned NPC-SPUG into a contractor rather than operator.

The Qualified Third Party (QTP) process has been used as the primary private participation model for providing off grid electrification in unviable areas and in areas where there is an existing non-NPC-SPUG distributor.

The potential investor has to:

- select the area where the RE project will be developed;
- propose it to the Department for Energy, and;
- upon approval from the DoE, get the required permits to develop the project.

Under this model, the power supplier is selected by the Department of Energy through a competitive tender on a least-cost basis (an existing entity can opt to continue under the QTP model or give its rights in which case a tender is conducted).

The winner signs a QTP agreement (for up to 20 years) with NPC-SPUG to serve the area. It then applies to ERC for approval of its tariff and its true cost of total service. The difference between these is paid by NPC-SPUG from the UC-ME. The tariff is currently, by default, set at the same tariff as the DU into whose franchise area the QTP falls. The true cost of the QTP is defined as its winning bid where a competitive tender was held or, where there was no tender or only one bidder is calculated by ERC on the assumption of a 12% return on its rate base.³³

PowerSource Philippines, Inc. in Rio Tuba, Palawan

To date, there is only one QTP operating in Philippines: PowerSource Philippines Inc (PSPI) in Rio Tuba, Bataraza, Palawan. The company has supplied power to the area since 2005, before the QTP rules were issued. A formal QTP Service contract for the supply of electricity was signed between PSPI and National Power (NPC) in 2008.

When the QTP contract was signed, PSPI was serving approximately 1,000 households with 24-hour electricity services, using two diesel generators with capacity of 250 kW each. PSPI was also using solar home systems in very remote locations.

Initial Problems

As part of the QTP rules, PSPI is obliged to charge the subsidised/approved retail rate (SAGR) and not cost reflective tariffs (TCGR). With the full cost recovery tariff at the time being \$ 0.44/kWh and the socially acceptable tariff set at \$ 0.18/kWh, the subsidy was equal to the difference between the two, i.e. \$ 0.26/kWh.

Due to the small size of the company and its limited financial capability, PSPI is dependent on the subsidy provided by NPC-SPUG to continue its operations of providing electricity in Barangay Rio Tuba. Difficulties arose in the first couple of years of operation after the signing of the QTP contract, due to NPC-SPUG delaying the payment of the subsidies and causing financial distress to the company.

In order not to cease operations PSPI had agreed with its customers in 2009 to temporarily charge cost reflective tariffs to customers until NPC-SPUG resumes the payment of the subsidy with the condition that the difference between the subsidised tariff and the cost-reflective one will be credited back to customers' accounts once PSPI starts receiving the subsidy from NPC-SPUG. However, the Energy Regulatory Commission (ERC) decided that the implementation of unapproved retail tariffs in the QTP Service Area that PSPI was operating was a violation of ERC rules.³⁴

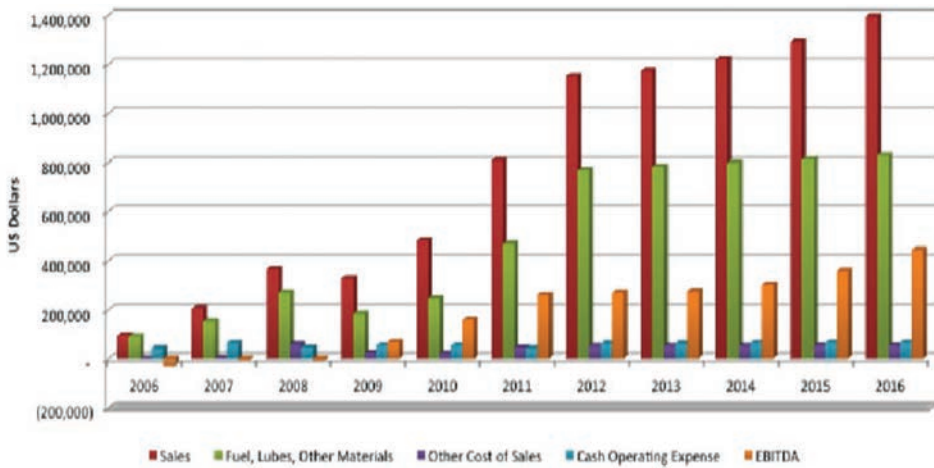
Recent Success

Once PSPI was able to collect its subsidy claims from NPC-SPUG, the company's earnings increased rapidly (Figure A3.1).

The number of household connections also increased rapidly reaching 1,450 customers in 2011 (Figure A3.2). A substantial increase in electricity demand was also reported, together with a high collection fee index of 97%.³⁵

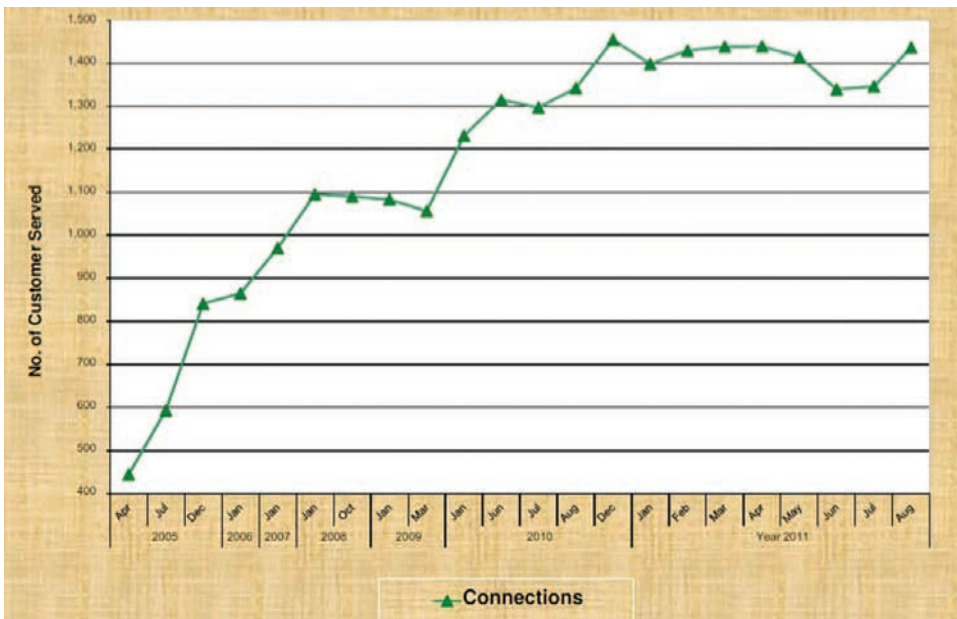
Since 2008, when the first QTP contract was signed, a number of QTP applications were submitted to the Department of Energy, including the Malapascua QTP project by PSPI in 2011 and the Semirara QTP Project in Caluya by the Semirara Mining Corporation in 2011.

Figure A3.1 | PowerSource Philippines Financial Highlights in Rio Tuba



Source | The PowerSource Group 2013.

Figure 3.2 | Customer Connections to PSPI in Rio Tuba Grid



Source | The PowerSource Group 2013.

Conclusion

While the QTP approach was positively greeted by private investors, the establishment of new QTPs has been very slow. This can largely be attributed to the bureaucratic nature of the regulatory agency and the subsequent difficulties in obtaining approvals for contracts and subsidy levels, since the DU, DoE, NPC-SPUG and ECA are all involved in the process.

In the case of ERC in particular it can take many years to approve a tariff and true cost during which, unless a temporary approval is given, the QTP cannot receive the UC-ME

subsidy (as was the case with PowerSource Philippines in Palawan). The ERC has also consistently set the allowed UC-ME below the amount requested by NPC-SPUG. While, to date NPC-SPUG has paid QTPs in full and borne the loss itself there is no certainty this will continue as the subsidy payments grow, adding a further risk.

The example of PowerSource Philippines in Palawan illustrated that the smooth functioning of institutions is a fundamental prerequisite to guarantee the financial sustainability of private providers and minimise the bankruptcy risk.

Even though the QTP seems to work in principle, a more effective process of approving permits, agreements and tariffs is needed to attract private investors. This may mean some form of standard formula or 'fast-track' approvals mechanism.

MALI

Context

The Malian rural electrification model is widely regarded as successful in the sub-region. It is partly a bottom-up model, driven by decisions from local private entrepreneurs/cooperatives to construct and operate small-scale mini-grids in rural areas based on their perception of the local market, but also combines this with a top-down aspect, and mini-grids operated by the national utility, Energie du Mali (EDM). The approach to rural electrification in Mali is a concession model (concessions granted for 12 or 15 years depending on the installed capacity). These concessions are managed and regulated by a dedicated agency for rural electrification, named AMADER (Malian Agency for Household Energy and Rural Electrification).

Investment subsidies from the Rural Electrification Fund (REF-AMADER) are designed to arrive at affordable tariff levels for rural customers and provide an acceptable financial rate of return for the private operators. Investment subsidies in new rural mini-grids were limited to 75 percent (average) of capital investment costs, with local private operators providing an average matching co-financing of 25 percent.

Subsidy allocation was based on objective criteria (including the number of customers to be connected during the first two years, the average tariff and the cost of investment by connected off-grid customers). No subsidies for energy consumption or operating expenses were provided. Existing mini-grids are mainly diesel-run.

For the mini-grids operated by EDM, tariffs are kept at the same level as those of grid-connected customers. Tariffs for the mini-grids operated by private operators are often much higher than those of EDM, at approximately \$ 0.50/kWh rather than the utility's approximate \$ 0.20/kWh.

A significant number of local private or community-based (communities, women associations) energy actors have emerged with the support from AMADER and the Rural Electrification Fund. More than 60 operators are currently active for about 190 mini-grids. The operators have tested, through their projects, both market appetite and different technical and institutional arrangements for rural electrification schemes. A tendency towards concentration of the sector can be observed.

Approach to Procurement and Development of Mini-Grids

In the process of granting concessions, Mali has a dual approach:

- **Top-down—Priority Electrification Zones (“ZEM”):** where AMADER solicits bids for the electrification of designated areas. Selection is done through direct competition among bidders. Promoters submit proposals in response to calls and projects are selected on the basis of lowest tariff proposed by promoters. In poorer rural areas, where sponsors are hard to come, REF finances feasibility studies and puts projects up for bidding.
- **Bottom-up—“spontaneous” private initiative (“PCASER”):** projects selected based on promoters’ ability to develop and operate a viable project with a fixed investment subsidy.

There are approximately the same number of top-down and bottom-up mini-grids. Minimum technical specifications and quality of service standards that a rural electrification operator must comply with are set in the contractual documents. Typically, private operators obtain authorizations to operate mini-grids for a period of 15 years. After analysis of their business plans, operators receive financing for investments under a financing agreement (“convention de financement”) with AMADER reflecting their commitments under the business plan. The two contractual agreements between AMADER and the rural operators (authorization contract and financing agreement) create concession-type arrangements.³⁶

Ownership of the fixed assets remains with the State, with the operator allowed compensation at the term of the contract for the non-depreciated portion of its contribution to the assets. Overall, these concession-type arrangements have proved fairly resilient, allowing mini-grids operators to continue to operate even faced with political instability, internal armed conflict, and rising fuel prices in 2012. Still, the exposure of rural operators to volatile and rising diesel prices remains a threat to their long-term viability and an obstacle to further expansion.

Institutional Framework

AMADER plays a central role as the agency responsible for developing household energy and rural electrification. In that regard the agency:

- 1 | promotes electrification in rural and suburban areas,
- 2 | works with all types of operators, national and international private operators, NGOs, decentralized groups, cooperatives, etc.,
- 3 | provides technical assistance and financial support (investment subsidies), and
- 4 | acts as de facto regulator in rural and suburban areas.

As part of its mission to monitor the implementation of concession-type contracts, AMADER authorizes electricity price adjustments for rural operators. The general principle established by the sector legislation is that electricity prices in rural areas are not regulated. The role of de facto regulator exercised by AMADER results from contractual stipulations with rural mini-grid operators and is reciprocation for the initial investment

subsidies. AMADER is responsible for analysing and selecting the initial business plans of operators, providing initial investment subsidies out of the Rural Electrification Fund (REF) and monitoring the operators.

SENEGAL

Senegal³⁷ has a mini-grids regulatory framework similar to that in Mali, based on a ‘two-pronged’ approach that adopts both a top-down concession approach for large areas, and a bottom-up “mini-concession” approach for private entrepreneurs, for so called ERIL projects (Electrification Rurale d’Initiative Locale—Locally Initiated Rural Electrification).

Top-Down Concession Approach

For the top-down approach, the areas of the country to be electrified were divided into areas designed to be compact enough, but also large enough to be commercially viable and attractive. Areas were put out to tender, where for a predetermined subsidy, and a three-year period, parties bid the maximum number of connections. The specification on connections **did not specify whether customers should be connected to an isolated mini-grid or the main grid**. Subsidies were paid on an OBA basis in order to ensure high quality connections were made. The value of the subsidy was set to ensure that monthly revenues from customers would cover O&M&M and at least 20% of the initial up-front capital costs, and allow a 20% return for operators on that return. Additional subsidies were available from the Global Environment Facility (GEF) for renewable generation sources, but these were not taken into account in the calculation of the number of connections proposed by bidders.

The winning bid for one of the areas was from ONE, a utility from Morocco. Their bid of customer connections was 21,800, more than double the 8,500 target set in the tender documents. In addition, ONE offered \$ 9.6 million of their own financing, which made up much more than the 20% minimum required; the subsidy amounted to just 40% of the total, rather than the anticipated 80%. It is anticipated that most connections will be made by extending the main grid rather than to isolated mini-grids.

Overall, while the top-down concession approach was considered a success, it was not without its challenges. In particular, KfW, through its involvement in this approach in Senegal and in Mali, and has spoken of the length of time involved in running a process, and the high transaction costs involved. Another company involved in the process in Senegal has mentioned that the planning process alone took 10 years, to reduce the number of concessions from 18 to 11 for economic viability reasons. Without going into detailed economic analysis, we can assume that the economic costs to unconnected communities during this time would have been very significant.

Bottom-Up Approach

Senegal’s bottom-up approach, which runs alongside its top-down approach, provides opportunities for private micro-utilities to develop ERIL projects, supplying power to individual remote communities. Responsibility for the political and regulatory issues are shared between three authorities, which has created additional complexity in managing the framework, due to the challenges of creating a stream-lined development process. Operators work with the Senegalese Rural Electrification Agency ASER (Agence Sénégalaise d’Electrification Rurale), and apply for a renewable contract with a 15-year licence

for electricity sales and a 25-year concession for electricity distribution which is issued by the Senegalese Ministry of Energy and the Development of Renewable Energies. To date, approximately 30 systems are operating in Senegal, owned and managed by numerous different private operators, with several hundred more in the pipeline.

A key success factor of the ERIL programme in Senegal has been the ability for operators to set their own tariffs, under the authority of the national regulator CRSE (Commission de Régulation du Secteur de l'Electricité), and a clearly-defined tariff calculation model. As a result, the tariffs for isolated mini-grids are significantly higher than the tariffs charged by the national utility.

Some mini-grid operators charge both flat-rate and per kWh tariffs. Flat-rate tariffs are based on a maximum load capacity in watts, which produces an effective control on the usage without the need for a meter. This reduced metering requirement also lowers the operating costs for the operator.

An example of the tariffs charged is presented in Table A3.1. Here, the S1 tariff is roughly equivalent to \$ 0.55–0.73/kWh, depending on the customer's total monthly consumption. The S4 tariff is set against the national grid tariff, and reflects the position of the government that it does not want mini-grid operators selling power at a per kWh charge that exceeds that charged to those connected to the national grid. However, this charge is lower than the mini-grid operator's cost to serve these customers, at \$ 0.27/kWh, meaning the operator effectively loses \$ 0.04 for every kWh sold to an S4 customer. Because of this scenario, no mini-grid operator will willingly take on any S4 customers.

This balance between flat-rate and per kWh tariffs has two unintended consequences for Senegal, which are presumably also undesired. Firstly, the poorer customers, being those on the S1, S2 and S3 tariffs, are paying more per kWh than the relatively wealthier customers on the S4 tariff. As a result, these customers will seek to move to the S4 category and pay a lower charge per kWh, thus decreasing the financial viability of the mini-grid operator. Secondly, there is no incentive for the mini-grid operator to connect high-consumption customers. These customers are likely to include businesses, which can provide wider economic benefits to the communities, and the development of which the government surely wants.

Table A3.1 | Mini-Grid Tariffs in Senegal

Tariff Category	Peak (watts)	Fixed Monthly Charge (\$)	\$/kWh
S1	50	4.68	n.a.
S2	90	8.62	n.a.
S3	180	16.16	n.a.
S4	180+	n.a.	0.23

Source | "Regulatory and Technical Issues in Operating Hybrid Mini-Grids," Assani, 2011.

ANNEX 4 | TEMPLATES

In the past in the power sector, terms and conditions have been spelt out in licences issued by the EC rather than in concession agreements.

In this Annex, we provide an outline of the contents of a licence and details of a concession agreement (CA) based on CAs from Mali for bigger systems than the Lake Volta islands. These are presented for consideration by the Energy Commission in particular.

Guidance is needed on the whether the licence approach is to be retained or a combination of a relatively detailed CA with a streamlined licence that refers to the CA. Once this is clarified, we will either flesh out the licence template or simplify the CA. Our recommendation is for a combination of a concession agreement and licence, with the licence being relatively stream-lined (focusing on general operating conditions), and a concession agreement containing more site-specific features. These features could be amended or updated directly or through schedules to the agreement, depending on the scale of the concession. This will be particularly applicable if large concession areas are identified, and the scale of power supply contains a significant degree of complexity, e.g. multiple islands and generations systems and technologies.

STRUCTURE OF A MINI-GRID LICENCE

- Type of licence and authorizations
- Description of concession area
- Applicable legislation
 - EC/PURC/EPA/RE Acts etc.
 - Standard of performance regulation/RE Grid Code
- Duration of licence
- Renewal and modification
- Suspension and cancellation
- Licence fees and charges
- Siting approval
- Construction permit
- Commissioning and start up
- Terms and conditions of licence
- Plans— maintenance/ environmental/decommissioning/emergencies
- Discontinuation and abandonment
- Guarantees and bonds
- Reporting requirements
- Complaints and dispute resolution
- Access to RE fund

SAMPLE CONCESSION AGREEMENT

Article 1 Definitions

“Concession holder” means, unless otherwise indicated, the . . . , party and signatory to this Contract.

“Interior installations” means installations to be used to meet the needs of individuals in the concession area or other collectively occupied premises.

“Declarant” means any operator whose installed power capacity is less than or equal to 50kW.

“Permit Holder” means any concession holder whose installed power capacity is more than 50kW and less than or equal to 250kW.

Article 2 Object of the Contract

The object of this Contract relates to the realization, by the concession holder, of the installations and equipment necessary to supply electricity to the localities specified in the annex to the Specifications, the connection of interior electrical installations and/or consumer equipment for customers, and the supply of electricity to these customers.

The supply may be delivered through:

- 1 | The means of production set up by the concession holder and serving a grid belonging to it, and the sale of any surplus to a third party;
- 2 | Individual systems, based on solar or any other renewable source of energy, which are installed by the concession holder.

GENERAL CONDITIONS FOR THE OPERATION OF THE SERVICE BY THE CONCESSION HOLDER

Article 3 General Operating Conditions

This Contract is concluded in relation to the commitment signed by the concession holder to provide, manage, and maintain electrical installations and sell services according to the conditions set out in the Concession Order and its annexes (this Contract and Specifications).

SPECIFIC OBLIGATIONS OF THE CONCESSION HOLDER

Article 4 Service Obligations

The concession holder agrees to supply electric power every day for at least seven (7) hours to each owner, tenant, or occupant of premises situated within the authorized perimeter of the locality on the electric power grid who so requests, provided that such service does not jeopardize the financial situation of the concession holder. The supply time of seven (7) hours a day shall change over time depending on the number of customers and the increase in the operator’s profits.

Article 5 Obligation Concerning Interior Installations

a) Solar

The concession holder must provide interior installations for customers, including at least two lamps which meet the prevailing . . . standards and are in accordance with the levels of service set forth in the Specifications.

b) Grid

The interior installations shall be paid for by the customer. In all cases, the operator shall verify the conformity of the interior installations before connecting them to the grid.

Article 6 Obligation Concerning Maintenance and Replacement

Installations for Production and Distribution

Installations and equipment for production and distribution as part of the concession must be maintained in good condition by the concession holder, who shall ensure their maintenance and replacement in accordance with good practice.

Individual Installations Based on Solar Power or Any Other Renewable Energy Source

The concession holder shall maintain the individual systems that it has installed and shall replace them at the end of their normal lifespan.

It shall also replace them if they are damaged as a result of an event which is not attributable to normal conditions of use or to an action by the customer.

Interior Installations

The concession holder shall include the completion of the interior installations for its solar customers in respect of the work for which it is deemed to be the certified installer. As long as the customer remains a customer of the concession holder, only the latter may maintain or modify these installations.

The customers shall become owners of the interior solar installations within a time period to be determined by the concession holder. The cost of these installations shall be included in the monthly cost of the service.

The concession holder shall also replace the interior installations if they are damaged as a result of an event which is not attributable to normal conditions of use or to an action by the customer.

In case of an accident, the customer must report it, with a written acknowledgement of receipt, within 48 hours, and an expert investigation shall ensue in order to determine liability.

Article 7 Replacement in Case of Theft or Deterioration Attributable to the Customer

The concession holder may not be held responsible for thefts and deterioration affecting individual installations falling within the concession.

In cases of theft or deterioration of such equipment attributable to the customer, the concession holder shall not be responsible for replacing them unless the customer pays an amount corresponding to the price of the equipment to be replaced as listed in the price schedule attached to the updated financial offer.

The concession holder shall charge the customer a monthly amount for the replacement costs of such equipment spread out over at least one year.

Article 8 Record-Keeping Obligations

The concession holder shall keep records on the customers, production, purchase, and sales of electricity, the purchase of fuel, and any other element referred to in the Specifications.

The concession holder shall also keep a record of incidents under the conditions set forth in the Specifications.

The concession holder shall keep general accounts and shall establish for each fiscal year a balance sheet and an income statement for its activities in the electricity sector. It shall also set up cost accounting in order to facilitate inspections by . . . or third parties representing it.

The concession holder shall make available to its customers a record of complaints, which may be consulted at any time by third parties who so request.

The duration of period of retention of record shall be (a)—months in respect of incidents; and (b)—months in respect of billing.

Article 9 Agreement to Negotiations for a Potential Transfer of Concession

The concession holder may, if need be, negotiate the transfer of its concession to the concession holder of the Priority Rural Electrification Project (PREP), which might subsequently cover its territory at the latter's request.

The transfer may not be completed unless just compensation has been paid to the concession holder.

Article 10 Acceptance of the Work

The date of provisional acceptance of the work shall be notified at least five (5) working days after the request is submitted by the concession holder. The date of acceptance may not exceed 15 working days after notification to the concession holder.

A statement of provisional acceptance of the work shall be signed by the authorized representative of . . . and by the concession holder or its duly authorized representative.

. . . shall announce the final acceptance of the work at the end of one year after the provisional acceptance for the electric grids and three (3) months for the individual systems.

Article 11 Inspection and Control of the Operation

. . . shall have a general power of control over the performance of the Contract in accordance with . . .

To that end, . . . shall receive from the concession holder all financial, accounting, technical, or legal documents pertaining to the operation.

. . . shall have access, by simple request, to all premises, installations, or sites of the concession holder or its corporate agent within 24 hours, barring unforeseen circumstances.

Without prejudice to the implementation of the relevant provisions in force, any opposition by the concession holder or by its agents or executives to the powers of inspection and control of . . . shall constitute a grave breach of the contractual obligations of the concession holder under the terms of this Contract.

Technical audits shall be conducted at the end of each six-month period as from the provisional acceptance of the work.

Unless otherwise stipulated in the Subsidy Agreement, accounting audits shall take place every year as from the start of the operation.

. . . shall bear the costs of inspection, control, monitoring, and auditing.

Article 12 Obligations of . . .

. . . agrees to make every effort to help obtain the administrative documents necessary for the execution of this Contract by the concession holder or its subcontractors, establishing the tax and customs regime applicable to agreements and contracts executed under the responsibility of . . .

FEES, CHARGES, AND RATE CONDITIONS AND THE RURAL ELECTRIFICATION FUND

Article 13 Fees and Charges

Any applicant for a preliminary permit or operating license shall pay a deposit, half of which may be reimbursed if a concession application file is submitted following the period of validity. This deposit shall be lost if the permit holder does not submit the concession application file. The deposit shall amount to G¢ . . .

A handling fee of G¢ per 5 kW unit shall be charged for all concession application files. If the concession and the financing are not granted, these filing fees shall definitively revert to the Rural Electrification Fund (REF).

Article 14 Regulation Fee

All operators shall pay a yearly regulation fee of 2 percent of the turnover of the operating and electrification activities governed by . . .

Article 15 Termination of the Concession and Change of Operator

Upon the expiry of the concession, the concession area shall be open to competition, and the former operator may itself compete to become its own successor.

. . . shall organize a pre-selection of applicants for the takeover of the concession and the repurchase of equipment on the basis of competence criteria. In a second phase, the successful applicants in the pre-selection phase shall be invited to bid for the repurchase of equipment. The applicant whose bid is the highest, at equal rates, shall be selected. The price received by the outgoing operator shall be reduced by the amount necessary for the possible rehabilitation of the equipment directly used for production and distribution under the control of . . .

If the outgoing operator has received subsidies from REF to finance its activities, . . . shall receive 25 percent of the gross bid price, which shall be deposited with REF.

Article 16 Prices, Rates

The concession holder shall charge customers served by an electric grid or equipped with individual installations a rate that is in accordance with the provisions of the Specifications annexed to the Concession Order.

The concession holder may disconnect the supply of electricity to users, including collective services, in cases of non-payment in accordance with the conditions set forth in the Specifications.

Article 17 Rural Electrification Fund and (REF) Renewable Energy Fund

A Subsidy Agreement defining the amount and means of payment of the equipment subsidy shall be concluded between the concession holder and . . .

The purpose of this subsidy is to contribute to the financing, through the concession holder, of the infrastructure investments necessary for the provision of electricity to the localities which the latter has agreed to serve within the period fixed by the Subsidy Agreement, [including] where appropriate, consumer equipment for users.

Article 18 Means of Payment of the Subsidy

The equipment subsidy shall be paid by . . . to the concession holder in accordance with the provisions of the Subsidy Agreement

Article 19 Guarantee Deposit

Before the entry into force of the Contract, the concession holder shall pay a guarantee deposit established by a local bank in an amount equivalent to [specify amount].

The amount of penalties and sums due to . . . by the concession holder in accordance with the Specifications shall be deducted from the deposit. Amounts paid out for measures taken, at the concession holder's expense, to provide the public service or the resumption of the operation if the work is temporarily carried out by a third party shall also be deducted from the deposit.

The concession holder shall also make available enough spare parts in the locality served in order to ensure the continuity of service.

Whenever any amount is deducted from the deposit, the concession holder shall replenish it within fifteen days.

Article 20 Insurance

Coverage of risks to persons and property and the loss of income owing to an insurable risk shall be mutualized among the operators coming within the purview of . . .

The aim is to prevent an insurable risk from jeopardizing the financial sustainability of the enterprise, since operators abandoning the enterprise do not have the means to replace equipment or compensate individuals or corporate entities for harm suffered.

MODIFICATIONS AND TERMINATION OF THE CONTRACT

Article 21 Modification of the Contract by Agreement between the Parties

. . . and the concession holder may at any time modify, by agreement, the terms of this Contract.

Article 22 Force Majeure

Definition of Force Majeure

Force majeure means any unpredictable, unavoidable event beyond the control of the parties, making it impossible to execute this Contract in whole or in part. Either Party's inability to fulfil any of the obligations set out in this Contract shall not be deemed a contractual breach if such inability is a direct consequence of a force majeure event within the meaning of this Contract.

Effects of Force Majeure

The Party affected by a force majeure event shall take every step to resume, as soon as possible, the complete fulfilment of its contractual obligations and limit the consequences thereof.

The Party affected by a force majeure event shall immediately notify the other Party, within a period not to exceed fifteen (15) days, of the occurrence or cessation of such event.

As from the date on which the Party concerned is notified of the occurrence of a force majeure event, the Parties shall together make good faith efforts to put an end to the situation created by the force majeure event and to limit and repair the consequences thereof. If the force majeure event persists, and in the absence of an agreement between the Parties, the Contract shall terminate thirty (30) days after the Party requesting the termination of the Contract notifies the other Party of this intention, provided, however, that the force majeure event or its consequences persist.

Article 23 Entry into Force and Termination of the Contract

This Contract shall enter into force on the date of its signature by the two Parties. It shall terminate fifteen (15) years from its date of entry into force. This Contract shall also terminate ahead of time if:

- A decision is made to abrogate the Concession Order;
- A mutual agreement is reached between . . . and the concession holder;
- Either Party fails to remedy a serious breach of its obligations within forty-five (45) days from the receipt of the notice of injunction to remedy it.

Article 24 Conditions Having Suspensive Effect on the Entry into Force of the Contract

This Contract may not enter into force unless the following conditions are met:

- (1) The registration of the concession holder as a company under the Companies Code;
- (2) Communication to . . . of the certificates of insurance required by the regulations in force;
- (3) Proof of payment of the guarantee deposit stipulated in this Contract;
- (4) Signature of the Concession Order by the Minister of Energy;
- (5) Signature of the financing agreement between the operator and . . .

Article 25 Costs

Each Party shall be responsible for any costs it may incur for the negotiation and signing of this Contract.

Article 26 Notices

All notices and communications must be in writing and delivered in person with acknowledgment of receipt or sent by facsimile or express mail to the following addresses:

[PROVIDE ADDRESSES OF THE TWO PARTIES]

Article 27 Applicable Law

This Contract shall be executed in accordance with the laws and regulations in force in [Country].

Article 28 Arbitration and Dispute Settlement

Amicable Procedure

The Parties shall make every effort first to settle by amicable agreement any disputes arising out of the execution of this Contract or the interpretation thereof.

Arbitration

Any dispute between the Parties concerning the application or interpretation of the Contract which has not been settled by amicable agreement within thirty(30) days after the receipt by either Party of the request for amicable settlement may be referred, by either Party, to an arbitration procedure under the ADR Act2010 (Act 798).

Article 29 Independence of Contractual Clauses

If a clause in this Contract should be found null and void in whole or in part, and to the extent that the applicable law permits, such nullity shall not affect the validity of the rest of this Contract.

Article 30 Contractual Documents

The contractual relations of the Parties shall be governed by this Contract. This Contract shall reflect all agreements between the Parties relating to its object.

Article 31 Final Provision

This Contract cancels and replaces all previous provisions signed between the Parties.

IN WITNESS WHEREOF, this Contract has been signed in three originals.

ANNEX 5 | QUALITY OF SERVICE, TECHNICAL SPECIFICATIONS, AND MONITORING

WHAT DIMENSIONS OF QUALITY OF SERVICE WILL BE REGULATED?

It is provided under section 30 (d) of the RE Act, the Minister [responsible for energy] may on the recommendation of the EC prescribe standards of performance for the development, management and utilization of renewable energy resources.

Good practice and established norms in other countries will be considered in order to define benchmarks for each dimension of quality of service. The indicators below are provided as examples, which will be refined and quantified during the study. The regulatory framework at all times needs to be appropriate for the scale of operation of the mini-grid and micro-grids being considered, and this will bias recommendations towards a minimum number of easily understood and applied benchmarks.

Product Quality

Acceptable range of voltage level and frequency:

- Nominal voltages: high voltage (HV) 11kV, 22kV
- Low voltage (LV) 240V, 415V
- LV variation range: steady state within +6%/–10%
- Nominal frequency: 50Hz
- Frequency variation range: within 5%; +/-2.5Hz

Load Balance

A supplier shall ensure that the connections are made to balance the loads on the three phases of the distribution system.

Voltage Fluctuations

A supplier shall ensure:

- Minimize voltage fluctuations on its distribution system, and
- Not connect customers whose loads are likely to cause voltage fluctuations at the point of common coupling.

Table A5.1 | Limits on Harmonic Distortion

Voltage at Point of Common Coupling	Total Harmonic Distortion	Individual Voltage Harmonics	
		Odd	Even
< 1 kV	5%	4%	2%
> 1 kV and < 34.5 kV	3%	2%	1%

Reliability of Supply (Load Shedding)

A supplier shall not shed load unless:

- Demand is likely to exceed supply as a result of a forced outage of a generating unit.
- It is necessary to preserve the security of the distribution system.
- It is necessary to reinforce or rehabilitate the distribution system.
- It is necessary for safety reasons.

Despite the above, a period of load shedding shall not exceed two months where the load shedding is necessary only to protect the supplier's overloaded distribution system.

Safety of Supply

A supplier shall ensure that its distribution system is safe and efficient for the supply of electricity to its customers and shall take the precautions necessary to avoid exposing the customer or the public to exposed live electricity cables.

Supply Quality

The first consideration is that higher supply quality involves higher costs and these costs must ultimately be borne by the consumer.

OSINERGMIN, the Peruvian electricity regulator has decided that quality-of-service standards should be lower for service providers in rural areas. Its rationale is that it is more difficult and costly to provide comparative service in rural areas at a price which is affordable to the generally poorer rural customers.

Technical and Commercial Quality of Service Standards in Rural and Urban Peru are shown below.

Table A5.2 | Targeted SAIFI & SAIDI Standards in Peru

Types of Service Area	SAIFI (Number of Interruptions per Year)	SAIDI (Hours per Year)
Urban high density	12	7
Urban medium density	16	9
Rural concentrated	25	10
Rural dispersed	40	10

Note | SAIDI = System Average Interruptions Duration Index; SAIFI = System Average Interruptions Frequency.

Source | Revolo Acevedo 2011.

Table A5.3 | Maximum Time for Making a New Connection-Days

		Without Network Adaptation	With Network Adaptation	With Installation of New Network Equipment
Urban	Up to 50 kW	7	21	360
	Above 50 kW	21	56	360
Rural	Up to 50 kW	15	30	360
	Above 50 kW	30	90	360

Source | Revolo Acevedo 2011.

For example, the first table shows the different required service levels for SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index) two measures of quality of supply in rural and urban Peru. SAIFI is a standard measure of the number of outages during a specified calendar period; SAIDI refers to the total duration of these outages measured in hours per year.

Customer Metering

A supplier shall provide, install and maintain a meter that will measure and record the amount of electricity supplied to the customer within specified accuracy of that meter's class.

- Ensure that facilities for the purchase of units for prepayment meters are available at all its customer service centers between the hours of 8:00 am to 5:00 pm each working day; and
- Provide weekend facilities for the purchase of units for prepayment meters in at least one customer service center in each operational area.

Issue and Delivery of Bills

A supplier shall, where the supplier adopts a monthly or bi-annual meter reading, issue an electricity bill every month to customers except those on prepayment meters, including the electricity usage and other charges.

A supplier shall issue a quarterly bill at each quarter meter reading, where the supplier adopts a quarterly meter reading.

Complaints and Dispute Resolution

A customer who is not satisfied with electricity supplied, may complain orally or in writing to the supplier.

The supplier shall deal with the customer's complaint in accordance with its complaints procedures.

Where the supplier fails to address the customer's complaints to the customer's satisfaction, the customer may lodge a complaint with the PURC in accordance with the Public Utilities (Complaints Procedure) Regulations, 1999 (L.I. 1665).

Restoration of Power Supply to a Disconnected Customer

A supplier shall restore electricity to a customer who has been disconnected for non-payment of electricity bill or undisputed arrears within:

- 18 hours in rural areas
- 12 hours in district capitals
- 6 hours in cities and industrial estates

after the customer has settled the bill or arrears.

Performance Reporting

The Utility shall provide information to the regulators, Public Utilities Regulatory Commission (PURC) and Energy Commission on the performance of their operations quarterly and annually in the form determined by the regulators.

The transitional requirement (LI 1935) is the submission to PURC and EC of separate quarterly technical and financial reporting—submitted not more than a month after the end of the quarter.

Targets for Timely Performance Reporting to the Regulator

Contents of report—minimum of the following:

- System average interruption frequency index
- System average interruption duration index
- Financial statements

IMPLEMENTATION

Who Sets the Standards?

Energy Commission of Ghana (EC) sets technical standards and monitors the standards through periodic audits of utility services and applies the set out penalties contained in the rules of engagement for deviations from the standards.

The Public Utilities Regulatory Commission (PURC) determines energy prices. There are public consultations on energy pricing involving all categories of consumers. Where the utility contravenes any obligation imposed under the Electricity Supply and Distribution (Technical and Operational Rules, 2005 (L.I.1816), the Commission may impose a penalty on the utility as specified in its schedules.

The standards are prescribed in Regulations issued by the Minister on the recommendation of the EC.

How Are the Standards Monitored?

Under the EC Act, the EC in consultation with PURC shall prescribe standards of performance for the supply, distribution and sale of electricity. The standards of performance include—voltage stability; maximum number of outages both, scheduled and unscheduled; number and duration of load shedding periods; and metering.

How Are the Standards Enforced?

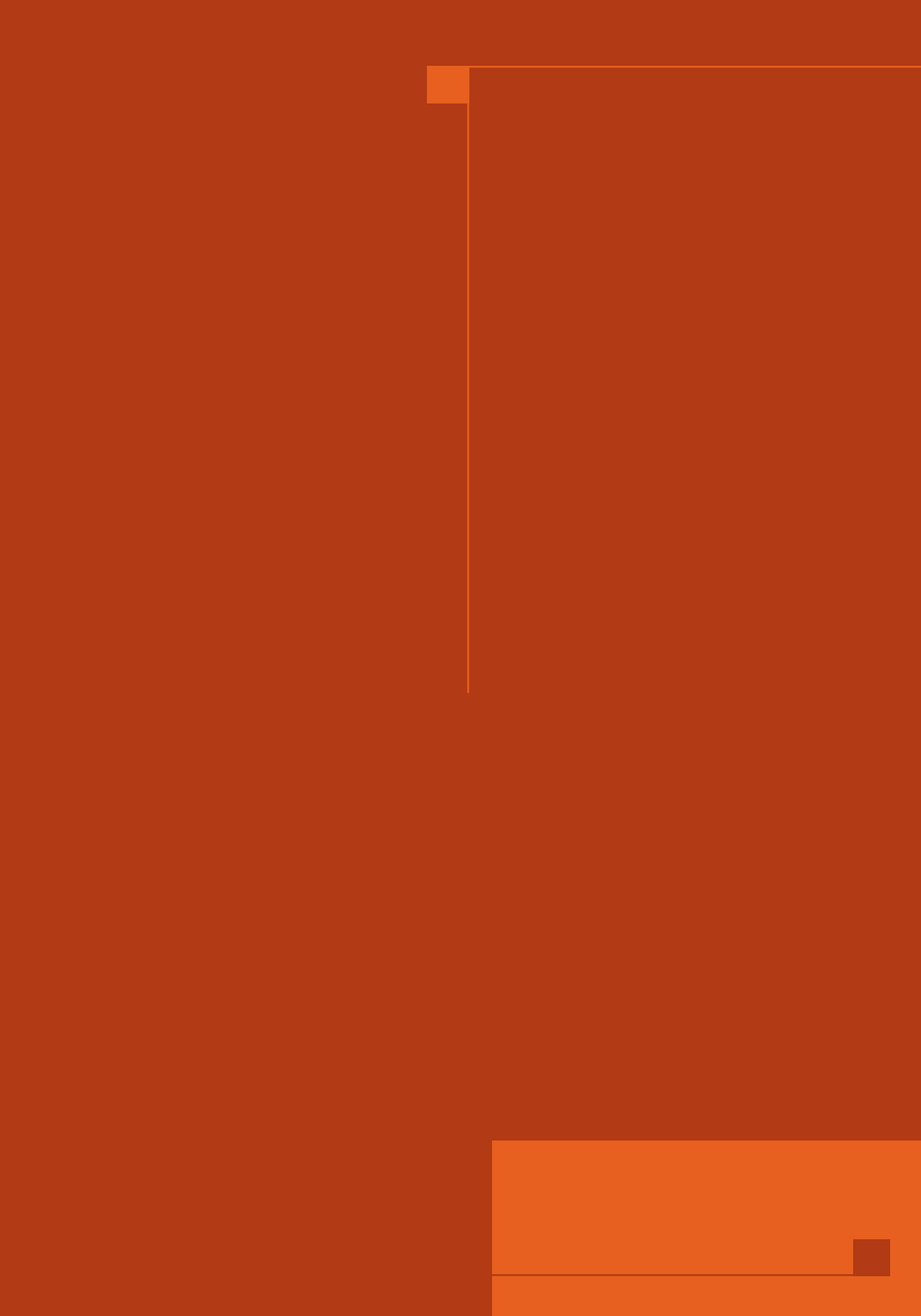
Current practice includes the following measures:

- Criminal prosecution under offences provisions
- Imposition of pecuniary penalty by PURC in consultation with PURC
- Order for payment of compensation to customer
- Withdrawal of license in extreme cases

ENDNOTES

- ¹ http://www.cleanenergyministerial.org/Portals/2/pdfs/Sustainable_Development_of_Renewable_Energy_Mini-grids_for_Energy_Access.pdf
- ² <http://data.worldbank.org/country/ghana>
- ³ <http://www.worldbank.org/projects/P120016/additional-financing-ghana-energy-development-access-project-gedap?lang=en&tab=overview>
- ⁴ For this study, we are not concerned with a change in definition for a maximum number of customers, e.g. if a system is classed as 'very small' or 'small' based on its customer numbers.
- ⁵ ESMAP. 2000. Mini-grid design manual. ESMAP technical paper. Washington D.C.: World Bank. 2007. Technical and Economic Assessment of Offgrid, Mini-grid and Grid Electrification Technologies. Washington D.C.: World Bank. Foster, Vivien, and Cecilia Briceño-Garmendia. 2010. Africa Infrastructure: A Time for Transformation. Washington D.C.: World Bank.
- ⁶ David Manetsgruber, Bernard Wagemann, Bozhil Kondev, Katrin Dziergwa: Risk Management for Mini-Grids—A new approach to guide mini-grid deployment.
- ⁷ Our consulting team spoke with Ebenezer Baiden, General Manager—Regulatory and Governmental Affairs at ECG, and John Nuworklo, Managing Director and Frank Akligo, Director of Operations at NEDCo.
- ⁸ The World Bank document for the GEDAP programme, including GEF Project Document from 2007. Final Report: Socio-economic study for mini-grid electrification of island communities' written by PwC.
- ⁹ Two private micro-grid operators in Kenya are Powerhive and PowerGen. In Tanzania, Deveryg operates micro-grids in five villages. All three companies have websites.
- ¹⁰ A third mixed model is possible with public ownership of the distribution network only, and private ownership of all generation and retail/supply assets, with private management of the whole system. This is functionally the same as a fully private system, with the potential for lower cost recovery based on how the public owner (anticipated to be the relevant utility) funds the distribution network capex. Tariffs shouldn't be markedly different from those under the fully private model. Given the insignificant differences, we do not discuss this model further.
- ¹¹ Indeed the success of Cambodia's mini-grid development, largely in the first half of the 1990s, was in the absence of either any lead institutional body or regulation. For more information, see the case study on Cambodia's mini-grids in 'The Potential for Alternative Private Supply (APS) of Power in Developing Countries', 2014, written by ECA and published by the Investment Climate Department of the World Bank Group.
- ¹² The 'heaviness' of the regulatory framework can be largely independent of the procurement approach. See Section 0 for more discussion.
- ¹³ This should include plant availability, energy sold, % of power generated from renewables, etc.
- ¹⁴ http://www.ruralelec.org/fileadmin/DATA/Documents/06_Publications/Position_papers/ARE_Mini-grids_-_Full_version.pdf
- ¹⁵ WB PAD, 2007, Energy Development and Access Project, p25.
- ¹⁶ PwC/ KITE 2012, Socio-economic study for mini-grid electrification of island communities, p8.
- ¹⁷ PwC/ KITE 2012, Socio-economic study for mini-grid electrification of island communities.
- ¹⁸ Assuming there are no hiccups with vandalism, theft, community issues, payments and collections, maintenance, etc.
- ¹⁹ See page 13 of the World Bank's GEDAP PAD 2007.
- ²⁰ Bernard Tenenbaum, Chris Greacen, Tilak Siyambalapatiya, and James Knuckles (2014): From the Bottom Up—How Small Power Producers and Mini-Grids Can Deliver Electrification and Renewable Energy in Africa, World Bank, Washington.
- ²¹ Rule 50(5). See <http://www.ewura.go.tz/newsite/attachments/article/165/The%20Electricity-Development%20of%20Small%20Power%20Projects%20-%20Rules%20-%202013.pdf>
- ²² The size threshold can and should be subject to review as mini-grid experience is gained by the regulator.
- ²³ By 2010, AMADER (Malian Agency for Household Energy and Rural Electrification) was in charge of supervision of 82 concessions. 59,000 connections had been achieved, bringing the rural electrification rate to 14.9%. Similarly for the ASER (Senegalese Agency for Rural Electrification), the first phase of their Renewable Energy for Senegal (ERSEN) project (implemented jointly by GIZ) brought electricity to 74 villages by the end of 2009.
- ²⁴ The lowest 'lifeline' tariff is currently set at GHP 20.5393/kWh (as of October 2014), up to 50 kWh/month. This increases to GHP 41.2072/kWh (\$ 0.10/kWh) for the 51-300 kWh/month category, and GHP 53.4790/kWh (\$ 0.13/kWh) from 301-600 kWh/month.
- ²⁵ See Chapter 10 of Tenenbaum et al, op cit.
- ²⁶ For example, the arrival of the grid will make certain assets obsolete (e.g. batteries and battery inverters). Investors will have to be compensated for the non-depreciated value of these at the time of arrival of the grid. This could be done by either allowing the SPP or SPD to maintain higher tariffs to recover this value or by buying out these assets.
- ²⁷ Taken from the 'Guidelines on Technology Choice and Technical Regulation', December 2013 for SADC RERA under EUEI-PDF funding, prepared by ECA and Practical Action.
- ²⁸ It is unusual for a regulator to do procurement, but in Ghana there is no legal barrier to EC procuring mini-grid operators. This can take place under the licensing regime, as part of EC's procedures in receiving and assessing applications for licences. It must be governed by guidelines issued and published for the purpose.

- ²⁹ Information compiled from REA-provided information, Richard Hosier (World Bank), David Ross (World Bank/TEDAP advisor), December 2013.
- ³⁰ http://www.ren21.net/Portals/0/documents/Resources/MGT/MinigridPolicyToolkit_Sep2014_EN.pdf
- ³¹ EUEI/RECP 2012 Mini Grid Policy Toolkit.
- ³² EUEI/RECP 2012 Mini Grid Policy Toolkit.
- ³³ ERC 2006, A resolution promulgating the rules for the regulation of qualified third parties performing missionary electrification in areas declared unviable by the department of energy http://www.spug.ph/PSP_articles/Res.No.22,S%20of%202006%20QTP.pdf
- ³⁴ ERC Case 2011, Implementing Unapproved Retail Rate in the Qualified Third Party (QTP) Service Area of Barangay Rio Tuba, Bataraza, Palawan. <http://lia.erc.gov.ph/documents/938>
- ³⁵ DOE 2011, 18th EPIRA Implementation Status Report, http://www2.doe.gov.ph/EP/18th_EPIRA_Status_Report.pdf
- ³⁶ An example of a concession agreement between AMADER and one of the private concession companies (Yeelen Kura) can be found in: <http://ppp.worldbank.org/public-private-partnership/sites/ppp.worldbank.org/files/documents/Mali11CONCESSION0CONTRACT0YK.pdf>
- ³⁷ Information for this case study has been sourced extensively from three reports on mini-grids: 'Hybrid Mini-Grids for Rural Electrification: Lessons Learned' by the Alliance for Rural Electrification (March 2011), 'Mini-grid Policy Toolkit: Policy and Business Frameworks for Successful Mini-grid Roll-outs' by EUEI-PDF and Inensus (2014), and 'From the Bottom Up: How Small Power Producers and Mini-Grids Can Deliver Electrification and Renewable Energy in Africa' by Tenenbaum, et al (2014).





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