Principles of Clean Energy Regulation in the ECOWAS Region

Working Draft

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Principles of Clean Energy Regulation

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Acronyms

ACG	Avoided Cost of Generation
ARE	Cape Verdian Agência de Regulação Económica
CCGT	Combined Cycle Gas Turbine
CRSE	Senegalese Commission de Régulation du Secteur de l'Electricité
ECOWAS	Economic Community of West African States
EREP	ECOWAS Renewable Energy Policy
EC	Ghanaian Energy Commission
ECREEE	ECOWAS Regional Centre for Renewable Energy and Energy Efficiency
ERERA	ECOWAS Regional Electricity Regulatory Authority
FIT	Feed-in Tariff
IPP	Independent Power Producers
LRMC	Long Run Marginal Cost
NAURC	National Association of Regulatory Utility Commissioners
NREAP	National Renewable Energy Action Plans
NREP	National Renewable Energy Policies
PURA	Gambian Public Utilities Regulatory Authority
PURC	Ghanaian Public Utilities Regulatory Commission
PPA	Power Purchasing Agreement
SE4ALL	Sustainable Energy for All
SO	System Operator (also TSO or DSO)
SPP	Small Power Producer
STC	Specific Technology Cost

Objective and Purpose of the *Principles of Clean Energy Regulation in the ECOWAS Region*

The following *Principles of Clean Energy Regulation* has been produced within the USAID-NARUC West Africa Regional Regulatory Partnership as part of the USAID Climate change and Development strategy 2012-2016. USAID's strategy recognizes the importance of establishing low carbon energy systems, "increasing the incorporation of renewable energy and low-carbon fuels" as well as "improved energy efficiency" in existing energy markets. The strategy acknowledges that "large-scale investments in clean energy will require an enabling environment that includes appropriate policies, laws, regulations, and institutions; and successful adaptation efforts have long been rooted in participatory, stakeholder-driven processes."

The National Association of Regulatory Utility Commissioners (NARUC) has worked with the ECOWAS Regional Electricity Regulatory Authority (ERERA), the West African Gas Pipeline Authority (WAGPA) and the ECOWAS Center for Renewable Energy and Energy Efficiency (ECREEE) to assess clean energy regulation in selected ECOWAS countries and to identify the existing needs and the foreseeable challenges of regulators in the region in the coming years.

In 2012, ECOWAS organized several projects to promote the establishment of a regional framework for the implementation of the Sustainable Energy For All (SE4ALL) initiative in the region. Those projects particularly focused on the enhancement of renewable energy and energy efficiency practices in energy markets. Within this process, in October 2012, ECOWAS Energy Ministers adopted a regional-scale action plan, a policy document that sets renewable energy targets in the region, pushing for the introduction and consolidation of renewable policies and strategies at member states level. Some states have already introduced or are in the process of introducing specific clean energy support mechanisms. Regulation will play a major role in transforming energy and electricity markets in the ECOWAS countries.

The *Principles of Clean Energy Regulation* seeks to complement and support this process by providing ECOWAS regulators with a document that will serve as a practical guide to facilitate the integration of clean modern energy practices into evolving traditional energy markets.

The document will support regulatory agencies and policy makers, providing an inventory of fundamental assumptions, approaches, mechanisms, tools, best practices, and national experiences on key issues in the field of clean energy. The *Principles* will reflect best practices based on local context and will be designed as a resource for the ECOWAS region, taking into account energy markets, natural resources, social and environmental priorities and other region-specific factors.

An initial focal group of five electricity regulatory bodies has been identified as leaders in clean energy regulation in the ECOWAS region: the Cape Verdian Agência de Regulação Económica (ARE), the Ghanaian Public Utilities Regulatory Commission (PURC), the Ghanaian Energy Commission (EC), The Gambian Public Utilities Regulatory Authority (PURA) and Senegalese Commission de Régulation du Secteur de l'Electricité (CRSE). The document combines NARUC's international experiences in clean energy policy and regulation with specific case studies coming from selected ECOWAS countries. The document was enriched by the outcomes of two technical workshops held in Praia, Cape Verde, in May 2013 and in Accra, Ghana, in October 2013.

Developing policies and market mechanisms to favor clean energy development is a relatively new challenge worldwide. Most of the electricity systems in ECOWAS countries are vertically integrated, with national companies providing electricity services at all levels of the system: generation, transmission, distribution, metering and sale. The introduction of clean energy policies often also coincides with the opening up of vertically integrated markets to independent power producers (IPP). This process needs to elaborate a legal framework that goes beyond the integration of renewables into existing electricity markets to regulate the access of IPPs at least in the generation sector. It implies the development of specific secondary level legislation and regulation to make the integration possible. Each state adopts a country specific primary legislation and subsequent secondary level legislation and regulation will be different in each case. While this results in energy and electricity markets being very different from country to country and contrasting mandates of regulatory agencies, some countries are more advanced than others in the adoption and implementation of renewable-friendly legal frameworks and their regulatory experience may be of value for newcomers.

No matter how encompassing their mandate is regulators always have the duty to advise, support, collaborate and share their knowledge with policy makers, market players, consumers and other stakeholders as contribution to establish the most efficient electricity market within a given context. Although this document is based on the specific experiences of four countries, there is not a single best receipt to develop clean energy regulations. A good legal framework is always the outcome of many different local, national, regional ingredients, market designs, priorities, challenges and governance structures. Yet, exchanging experiences and technical knowledge among policy makers, institutions and market players is a prerequisite for the establishment of an efficient and effective clean energy market. We hope that other ECOWAS national regulatory bodies may find those experiences a starting point for adapting similar measures within their own political and regulatory context.

Key Principles

Policy Environment

- The development of renewable energy is recognized as a national economic and energy policy objective that has positive impacts on national employment, local industry, security of supply and environmental issue, with particular reference to climate change. Such recognition has also been expressed at ECOWAS level.

- Investment in renewable energy today will strongly determine tomorrow's electricity market. Decision may be effectively supported by running consultation processes before their implementation. Most relevant decision may be accompanied by impact assessment.

- Implementation of renewable regulation is a new and challenging activity for national authorities. It is important to devote sufficient financial and human resources to complete this task.

- A complete legal framework needs to be based on some basic features and a clear identification of the competent body for the management of each of them. Coordination among ministry, regulator and system operators (SO) is a precondition for an effective renewable energy market.

- Promotion of national industry is often a priority associated with the development of renewables. Specific incentive schemes may be tailored to this objective. By contrast favorable import measures facilitate the development of renewable technologies. It is better to avoid that regulation becomes a sort of trade restriction and combine the advantages and disadvantages of different option. Renewable added value is not only in the technology components.

- There is a wide range of possible incentives to favor renewable development. Incentive may be both economic and technical. Renewables national legal framework is introduced by Governments, regulators are called to support and implement policies in electricity markets. In some cases regulatory decision may deliver implicit incentives to renewables.

- When renewables need economic support to develop, incentives have to be weighted with other national priorities, and they have to be proportional to real technology costs without delivering excessive remunerator to investors. Regulatory agency may be called to design and to monitor the implementation of incentive schemes.

Economic Regulation

- Renewable electricity may be remunerated through feed-in tariff or market mechanisms such as green certificate systems. Considering the existing and the evolving legislation in ECOWAS countries, feed-in tariff looks like the most appropriate mechanism to remunerate green electricity.
- At cost parity, renewables should be preferred to fossil fuel energy sources. Yet, existing electricity markets need some transformation to better integrate renewables. Regulation and policy makers should take that into account.

- There is a number of possible methodologies to set feed-in tariffs. The two main ones are based on Avoided Cost of Generation and on Technology Specific Cost. The first remunerates renewable as much as generating system cost, the latter sets a different feed-in according to the specific cost of renewable technologies. Both methodologies have advantages and disadvantages. A clever legislator and regulator is able to combine national energy priorities and objectives with the most effective incentive scheme.

- Allowing IPPs to enter the market means achieving some opening up in the generation sector. This may still coincide with a vertically integrated electricity industry. When markets are vertically integrated the regulator is called to facilitate the integration of renewables into the existing markets, in particular in connection issues preventing discriminatory practices by the incumbent.

- The largest part of renewable energy production's final costs are capital investments. Therefore renewables are very exposed to risks. There are markets and regulatory risks. Regulatory risks should be reduced as much as possible by promoting a complete regulation. A complete regulation is understandable and easily accessible to market participants. It gives market operators all present e future elements to make their market analysis and assumption.

- When market players perceive a too high risk, they do not invest capitals or they ask a high capital cost to invest. That is a common barrier for renewable development.

- As renewables investments are paid back in over a decade, stability is vital to create investor confidence. Nevertheless policies have to be able to adapt to changing circumstances and include price signals into markets. Experiences suggest that performing regular regulatory reviews can work effectively. By contrast retroactive policy change deter investments.

- Regulation has to optimize between the market need to change and the renewable energy investor to be stable. Investor will accept lower capital remuneration in markets they fell confident in investing in. If the final objective is the development of RES, it is sometime most cost effective to reduce investment risk rather than to regulate on a strict cost basis principle. Balancing cost may be an example.

- The development of renewable capacity is especially achieved by the commissioning of a number of small power plants, of different technologies, in different area of a country endeavored with renewable potentials, and not only be the installation of large power plants. This development pattern is better followed by allowing IPPs to access the generation sector and by the adoption of an easily accessible grid code.

Technical Connections

- The existing transmission network has been mainly built for the dispatching of fossil fuel generation. Definition of connection rights and connection costs (shallow or deep costs) is one of the most difficult activities for Regulators. A correct practice should balance between a fully cost reflective approach and the necessity to socialize some of the cost to reform existing infrastructure in order to make them more suitable to dispatch renewable future potentials.

Harmonization

Introduction of Countries

Regulatory agencies are tasked with designing clean energy markets rules and remuneration mechanisms with different mandates, roles and responsibilities. Primary legislation in each country sets out policy objectives, targets and the main legal framework.

In some cases regional policies and directives influence national legislations strongly, as is the case in the EU, for example. In other cases, such as the ECOWAS region, the regional level provides some guidance and introduces some non-mandatory clean energy targets but countries are free to choose what kind of policy instruments and incentive mechanisms they want to introduce.

The four leading countries Cape Verde, Ghana, Senegal and The Gambia are all following a different approach to advance clean energy policies:

Cape Verde

Cape Verde is possibly the most advanced renewable market in the region in terms of clean energy capacity installed. The installation of renewable energy in most archipelago islands has been strongly promoted by national policy given the high cost of fossil fuel and the abundance of renewable resources (wind and solar). Existing power plants have been constructed on a PPA agreement signed between the IPP and the national electricity company. The PPA defines the long term purchasing price, an updating methodology and the connection cost. The purchasing cost (avoided cost of generation for the national electricity company) is hence translated into the final tariff by the regulatory authority. Connection parameters have been agreed upon by the parties. The island TSO manages the system balancing directly with the plant operator. The overall involvement of the regulatory agency has been limited so far. The intention to reach ambitious renewable targets in the future is now calling for a new legislative framework for clean energy. Electricity remuneration and methodology to pay back investments into clean energy as well as grid and balancing rules have to be defined and the mandate of the regulatory agency is still uncertain. The development of further renewable capacity in Cape Verde introduces new challenges: Balancing renewable energy, the necessity to develop different renewable technologies, the opportunity to develop storage infrastructure, the integration of renewables with water treatment processes: These challenges suggest the introduction of advanced tariff schemes. Cape Verde's legislation also includes a net metering option for small power produces [reference], however the mechanism has been delayed by missing connection rules and a lack of assigning responsibilities in the management of the mechanism.

Ghana

Ghana approved the Renewable Energy Act (Renewable Act) in 2011. According to Art. 5 of the Act, the regulator is in charge of setting renewable tariffs. The primary legislation has not specified which methodology or what level of tariff should be introduced nor does it set a deadline for the approval of a renewable tariff. Ghana's Public Utilities Regulatory Commission (PURC) and the Energy Commission have built up a feed-in tariff scheme for different renewable energy sources and have carried out consultation processes on the proposed renewable tariff. In July 2013, PURC published tariff levels for the first period. Some implementation rules are still missing and are under discussion. PURC also approved a grid code in 2009(?). It does not include specific provisions for renewable plants. Ghana is talking about the introduction of a market for reserve and regulation of renewable energy fluctuation and balancing may be included in the discussion. Ghana has approved an advanced policy for promoting energy efficiency; the policy has been accompanied by a consultation process and some impact of regulation assessment. This may be a best practice for other ECOWAS countries.

Senegal

Senegal is possibly the first country in the ECOWAS area to have adopted a specific law to support renewable energy penetration into the electricity market; this took place in 2009. The law postpones the approval of specific support mechanism details to other future pieces of legislation. In the meantime - for a period of 2 years since the law was approved - the Ministry is designated as the counterpart for renewable energy PPAs with private enterprises.

Regulatory authority is called upon to define connection rules based on the non-discriminatory grid access code (article 13) as well as to define the purchasing price of electricity, whereas the purchasing rules have to be defined by legislation (article 14). The law also introduces a fiscal exemption of renewable technologies and introduces the right with no restriction to produce electricity from renewable energy sources for auto-consumption. Still, the final legal framework to favor renewable integration into the existing electricity market needs to be defined.

The Gambia

Finally the Gambia is currently considering the adoption of a renewable law and a final draft has been prepared, which defines most of the necessary elements for a favorable legal environment for renewable energy. The methodology used is based on avoided cost of generation as the long term marginal cost of a new oil power station. The methodology to update the tariff, a renewable energy capacity threshold and the overall renewable energy penetration percentage are defined by the legislation. The regulatory authority is mainly in charge of applying the ACG formula within defined deadlines. The legislation already includes connection and PPA contract templates. The legal framework also includes a net metering option and introduces international technical standard for connection of renewable energy capacity. The law is currently under discussion.

Harmonization

It is recognized that the development of a renewable energy market is better achieved in larger regional markets than national ones. Regional energy markets have some technical, economic and policy advantages:

- A regional market is a precondition for grid integration. With higher interconnection it becomes easier to access larger renewable potentials even if they are unevenly distributed among countries; balancing the system becomes possible with higher penetration of intermittent renewable energy.
- A regional market is able to introduce a standard legal framework establishing some common principles for renewable energy. This accelerates the legislative process at the country level, facilitates the sharing of experiences and the identification of common barriers, offering standard solutions to them.
- A regional market supports smaller and less advanced member states in the introduction of clean energy policy by providing them a standard set of policies, rules and target. More advanced countries' experiences can be more easily accessed and adopted by late comers.
- A larger area for the development of renewable energy technologies is an international market advantage, making ECOWAS a larger counterpart on international markets and offering a wider opportunity for new local enterprises in the sector.
- A larger market also better attracts foreign investment into the entire region. Small markets are not attractive to foreign investors as the learning cost to enter the market is too high compared to the limited opportunities. When a certain level of harmonization is reached, investors will find a favorable environment to operate.

Energy markets also benefit from an overall economic integration of the ECOWAS area. Specifically the harmonization of fiscal and import rules will facilitate better access to renewable and energy efficiency technologies. The process of convergence toward a stronger monetary integration will result in a more stable electricity tariff and will assure a safer investment environment.

ECOWAS has already taken some steps toward the integration of energy and electricity markets., specifically:

- The approval of the ECOWAS Energy Protocol in 2003 (A/P4/1/03) in order to establish a legal framework to promote the long-term co-operation in the energy field.[1]
- The establishment of the ECOWAS Regional Electricity Regulatory Authority (ERERA) to facilitate the adoption of a number of provisions to establish appropriate legal and institutional frameworks for the development of the electricity sector in West Africa and regulate regional cross-border trade of electricity in West Africa[2].
- The constitution of a Regional Centre for Renewable Energy and Energy Efficiency (ECREEE) for the ECOWAS region[3]
- The constitution of the West African Power Pool (WAPP) covering 14 of the 15 countries of the regional economic community to ensure Regional Power System integration and realization of a Regional Electricity Market.[4]
- The approval of a specific ECOWAS Renewable Energy Policy (EREP) by the Authority of ECOWAS Heads of State and Government in July 2013, aimed at increasing the share of renewable energy in the region's overall electricity mix to 10% in 2020 and 19% in 2030[5].
- The adoption of an action plan within EREP to allow all fifteen ECOWAS countries to adopt National Renewable Energy Action Plans (NREAPs) and policies (NREPs) by the end of 2014, which will contribute to the achievement of the regional ECOWAS targets by 2020 and 2030.

The development of renewable energy itself may also be seen as an opportunity for a faster integration and harmonization of ECOWAS energy markets. Energy policy, and specifically renewable energy policy, though, may not anticipate the larger process of market and policy harmonization within ECOWAS countries. This process will take time and might not always be possible. However, the lack of harmonization should not be taken as a cause to delay the development of renewable energy markets in each country.

[1] http://www.comm.ecowas.int/sec/en/protocoles/WA_EC_Protocol_English-_DEFINITIF.pdf
[2] http://www.erera.arrec.org
[3] http://www.ecreee.org
[4] http://www.ecowapp.org
[5] http://www.ecowrex.org/document/ecowas-regional-policy-renewable-energy-0

Integrating Renewable Energy into Existing Electricity Markets

Roles and Responsibilities

Renewable Energy policies are strongly determined by the national electricity market structure and support mechanisms have to be tailored according to market fundamentals.

The mandate of the regulatory agency ranges from the definition of specific technical and economic aspects of the renewable energy market to a wider involvement in the development of the renewable energy policy and support mechanisms. There is not a specific model to be followed and each state takes a different path in forging its renewable strategy, dependent on local market characteristics, the level of liberalization of the generation segment in the electricity market, the previous existence of renewable energy, the existing institutional framework and the power balance between the government and the authority.

However, a complete legal framework needs to be based on some basic features and a clear identification of the responsible body for the management of each of them. Coordination among the ministry, the regulator and the system operators (SO) is a precondition for an effective renewable energy market.

As the introduction of renewable incentives often coincides with at least a partial liberalization of the generation sector and the introduction of independent power producers, a cascade of necessary steps need to be taken by the regulators. It necessitates the introduction of a series of new rules and codes to integrate the new power generating units into the existing electricity market. This may require the regulating authority to establish a renewable office or department to strengthen renewable policy implementation and to integrate renewable energy regulation with market mechanisms and technical rules.

The clear identification of roles and responsibility within the national legal framework is possibly one of the most crucial characteristics of a successful renewable energy legislation.

Table 1: Roles and Responsibility Checklist

Action	Responsible Body Involved
Dispatching priority is a basic requirement in a renewable energy supportive market. Renewable energy investors need to be sure the system will accept their electricity when the renewable source is available.	Usually the dispatching priority principle is introduced by legislation and implemented by regulation
A **final buyer for electricity generated by renewable energy needs to be identified;** it may be the local public utility, the TSO, a single buyer or a final customer, according to the structure of the electricity market.	Legislation identifies the final buyer and sets obligations. The regulator monitors the system.
The economic value of the electricity generated from renewable energy needs to be defined. In a fully liberalized market this corresponds to the market price. Some incentive, premium, quota mechanisms to support renewable energy is often added to the electricity price. In partially liberalized markets and in monopolies it is necessary to define at what price renewable energy production is purchased.	Normally legislation chooses what kind of incentive scheme to adopt. Regulators are called to build methodologies to set prices to purchase electricity.

The economic value of electricity varies with time and a **mechanism to update purchasing price** has to be identified. The updating mechanism may include many variables and follow different priorities. It has to be clear, when, how often and who is in charge of updating the tariff.	Mostly in charge of the regulator. Legislation may give the general framework and deadlines and give mandates to the regulator to update the tariff.
Also it is important to specify whether the changes are affecting old generation of renewable energy plants or new ones.	Usually part of primary legislation.
Market players are not always welcoming the introduction of new producers. The publication of a reference **standard Power Purchasing Agreement (PPA)** regulating the contractual aspects between the seller and the buyer may help to avoid unnecessarily delays of the commissioning of renewable energy plants.	Regulator may prepare a standard PPA if it is not done by the legislator.
According to the electricity market structure **a mechanism to pay back renewable energy** buyers has to be in place. Resources are normally coming from the electricity tariff.	Regulator to build up the mechanism and to manage it, introducing a tariff component on tariff if necessary.
The renewable energy buyer needs to be financially stable. In countries where final electricity tariff are not cost reflective, it is important to assure long term financial stability of the final buyer.	Legislator to define general rules. Regulator may establish safe and clear procedures.
Access to the grid needs to be regulated from a technical and economic perspective. **The right** is supported by a **transparent grid** code. Technical grid connection parameters for IPPs have to be known and accessible.	The regulator together with the SO. Grid code approved by regulator and published.
Rules to pay connection costs have to be introduced. A general framework on future grid development strategy has to be known. Cost of new grid development and reinforcement should be identified and shared among market players	Legislator may define the principles. Regulators have the largest role in producing methodologies and procedures for connection costs.
Grid capacity may be limited. **Rules to assign connection rights** need to be defined.	Regulator is usually asked to define rules
Intermittent renewable energy plants may cause **fluctuations** on the system. Rules to contain fluctuations within a safety margin need to be introduced. A comprehensive strategy to integrate intermittent renewable energy needs to be in place.	Legislator to define general principles and strategy. Regulator to introduce adequate market instruments to improve network stability
Curtailment of renewable energy plants has to be regulated both technically and economically.	Legislator to define general principle. Regulator to implement curtailment procedures
A second level support mechanism may be introduced for some specific renewable energy system, such as small power producers (SPP) in net metering mode. In some cases this may be directly introduced by regulation.	Legislation introduces the option. Regulator may consider net metering as a tariff option and regulate without specific mandate.
The technical counterpart (the DSO) involved in the definition of the technical connection requirement, metering and tariff methodology	Regulator and DSO
A standard format for net metering contract to be produced to facilitate connection of SPP.	Regulator initiative to facilitate renewable energy, no need of

	legislative mandate
A consultation process to be in place to collect contributions from all players and improve the knowledge and the consensus on renewable energy.	Regulator internal procedure
An impact assessment process to be run on main supporting decisions for both renewable and energy efficiency policy to evaluate long term costs and benefits of intended policies.	Regulator internal procedure

It is very difficult to see all implications at the beginning of the process and the establishment of a *steering committee* of the three main players (government, regulator and SO) may be useful. This will accompany the introduction of the new legislation, recognize the barriers and identify the most competent body to close the missing gap.

The implementation of the feed in tariff scheme in Ghana has seen the establishment of an *implementation committee* composed by personnel from the main stakeholders. The committee was nominated in 2012 during the tariff setting process, following training in Kenya. The objective of the committee is to advise the Ghana PURC and other key stakeholder institutions on policy, socio-economic, technological and environmental concerns of the uptake of renewable energy, and carry out the various processes leading to a speedy and efficient implementation of the feed-in tariff.

The specific tasks of the implementation committee are:

- Identify any policy gaps which might hinder the smooth implementation of the feed-in tariff, and make appropriate recommendations.
- Draw up a time frame for the various stages, processes and implementation of the feed-in tariff, and a budget to cover activities of the committee.
- Make recommendations to PURC and other key stakeholders on findings from the stakeholder consultations (to be organized by the PURC), to incorporate genuine concerns of interest groups, where necessary.
- Design FIT implementation training needs.

Investment in renewable energy today will strongly determine tomorrow's electricity market. Decisions may be effectively supported by running consultation processes before their implementation. Most relevant decision may be accompanied by an impact assessment.

In the early implementation phases of a new policy it is not immediate and easy to identify potential stakeholders and to have them involved in a consultation process. In monopolies and vertically integrated markets most activities and decisions are restricted to public utilities and policy makers. Other stakeholders may be found in consumers and environmental organizations; however the interest in the design and regulation of electricity markets is usually limited. Opening the market to renewables and IPPs offers an opportunity to involve new stakeholders, to access new technical skills, managerial competences and financial resources. New stakeholders may be identified in financial institutions, banks, potential national and international investors, large energy consuming companies, commercial activities with consistent electricity back up units, consumer cooperatives, municipalities, professional and engineering organizations and so on. They may not be used to take part in consultation processes and at the beginning their participation may need to be stimulated through adequate information. In order to accelerate participation of stakeholders it is also possible to recognize an economic compensation. In Massachusetts, for instance, accredited stakeholders sending relevant feedbacks on consultation documents published by the Regulator are paid for their participation.

Remuneration of Renewable Energy

In order to develop renewable energy capacity it is necessary that the market pays producers enough to cover investment costs and allow a *satisfying* remuneration of invested capital. Electricity sale revenues have to be at least equal or higher than the levelized cost of energy (LCOE) for a given plant during its lifespan. (see Box 1).

In some cases such level of remuneration may be assured without the introduction of specific economic incentives, as the electricity market price is high enough to sustain renewable energy investments. In other cases economic incentives are needed (see Box 3).There is a wide range of support instruments the legislator may choose from. Not all incentive mechanisms are compatible with all electricity market structures. The overall levels of incentives are given by the combination of a number of variables the policy makers need to carefully evaluate. It is possible to combine different incentive mechanisms (from tax exemption to feed-in tariffs) but it is also important to ensure that the level of support does not deliver improper remuneration to investors.

In partially liberalized and in vertically integrated electricity markets the most common remuneration is based on a feed-in mechanism. When electricity is injected into the grid, each kWh is paid for by a buyer - who is normally under a regulatory obligation to purchase – at a price that is defined by regulation. In fully liberalized markets a quota obligation system based on a green certificate mechanism may also be introduced. A green certificate system is normally recommended solely in fully liberalized large markets with regional harmonization perspectives.

Box1: Levelized Cost of Energy (LCOE)

The levelized cost of energy is a widely used formula to calculate the generating cost of electricity of different power technologies. The generating cost of a single unit of electricity (kWh) of a given power plant over a period of years is given by the total of the cost supported by the owner each year discounted in time and divided by the total of the electricity produced by the power plant discounted in time.

The LCOE formula is thus as follows:[6]

$$C_{Lev} = \frac{\sum_{j=0}^{n} \frac{Expenses_j}{(1+i)^j}}{\sum_{j=0}^{n} \frac{Quantities_j}{(1+i)^j}}$$

where

C_{Lev} = levelized cost
n = lifetime of the project
i = discount rate

For renewable power plants where most of the costs are concentrated in the first year, the formula may be simplified as follows:

$$\text{LCOE} = \frac{\text{CAPEX + NPV of total OPEX for a given period}}{\text{NPV of generated kWh for a given period}}$$

Where:

- CAPEX is the capital investment cost, generally supported the first year when the power plant is commissioned. The regulator has limited influence in the definition of CAPEX, whereas the national legislation and the relevant renewables market dimension may significantly modify investment costs. A favorable fiscal policy for renewable energy technology imports and a strong market integration between ECOWAS countries may significantly reduce CAPEX. The regulator role may be more relevant in the definition of renewable energy connection costs, thus influencing the total CAPEX. For the estimation of CAPEX it is possible to consult international literature sources, run national market analysis and consultation processes.
- OPEX is the operational and maintenance cost. It is usually very limited in renewable energy technologies with the exception of biomass plants. OPEX in renewable energy may be calculated as a percentage of CAPEX costs. OPEX costs are discounted in time as the costs are supported year by year. The regulator plays no relevant role in the definition of OPEX.
- NPV is the net present value. Weighted Average Capital Cost (WACC) can be used to calculate NPV. WACC is the cost of capital of a company that can use both debt and equity to finance its investments. It is the company remuneration on investment. WACC is highly influenced by risk. The higher the risk the higher interest is asked on debt and the higher expectation the investor has on equity. The risk

[6] Renewable Energy Source and Climate Change Mitigation, Special Report of the Intergovernmental Panel on Climate Change, Annex II, Methodology, page 976;

may be lowered by a complete regulation that covers as many market and regulatory risks as possible. In particular as discussed in the *Principles* the following provisions are useful to lower risk:

- Clear connection costs and connection deadlines defined by regulation
- Clear formulas to update FIT, specifying inflation and exchange rate
- Clear dispatching rules and priority dispatching rights
- Clear rules for balancing costs and exclusion of balancing costs for non-predictable renewable energy technologies
- Financial solvability of PPA counterparts and clear timing for payment specified on PPA contracts
- Definition of curtailment compensation in case the grid is not reliable to dispatch electricity

The period to calculate LCOE is chosen by the policy maker. It may correspond to the technical lifespan of the renewable energy technology or may be reduced in time to accelerate the payback time of the investment. The shorter the period the power plant is paid back the higher the LCOE. Investors tend to prefer shorter payback time to reduce their investment risk and see their capital remunerated faster. Feed in tariffs are generally recognized for a period of 10-20 years.

The investor will commission the plant as long as the investor is reasonably confident the market will remunerate the electricity at the expected LCOE. The lower the risk, the lower the LCOE, and the lower the impact on final consumers costs.

Considering the existing and the evolving legislation in the ECOWAS countries, the focus of this document are feed-in tariffs. Some discussion on other renewable energy mechanisms will also be included to provide a complete picture.

Feed-in tariffs mechanisms are based mainly on two principles:

- The Avoided Cost of Generation (ACG) principle
- Specific technology cost (STC): rate of return principle

Avoided Cost of Generation (ACG)

The principle behind ACG is to pay renewable energy producers as much as the generation cost of the system. ACG should not necessarily be considered as an incentive but rather as an option for IPPs to enter the market as long as they are satisfied with the system price. This option is also often offered to auto-producers of electricity (from fossil fuels or renewables), who are willing to sell their excessive production to the grid.

The policy argument in favor of ACG is very strong: it does not conflict with other market priorities as it does not introduce additional costs for the consumers.

There are two main approaches to calculate ACG:

- Long-run marginal cost of generation
- Average cost of generation, or wholesale price

Marginal cost is the most favorable option for renewable energy producers as it is usually considerably higher than average cost. The two methodologies may also be combined together, for instance when the feed-in tariff is differentiated according to time of generation.

For a net-metering option, *retail price* is generally used as the ACG reference.

Regulators are often called to define how to calculate the ACG and to manage and update the mechanism once it's introduced. They also need to make sure there is a system in place to direct the resources earned from the electricity tariff to the renewable energy producers.

Methodologies to calculate ACG

Long run marginal cost of generation

Long run marginal cost (LRMC) of generation is usually the most used methodology to set ACG. LRMC corresponds to the cost that the public utility would pay to introduce additional capacity into the system and run it.

LRMC estimations are based on three main components:

- Investment cost of a reference technology, including capital remuneration
- Operations and maintenance (O&M) costs, both fixed and variable
- Fuel cost of generation (variable cost)

LRMC methodology is not suitable for markets experiencing a period of overcapacity as the introduction of new capacity will not be economically justifiable. However, this is not the case in ECOWAS countries.

To calculate the LRMC a reference expansion technology is chosen and reference parameters are set by the regulator: investment cost, fuel used, lifespan, O&M cost, fuel cost, cost of capital (usually Weighted Average Capital Cost), generation efficiency of generator and load factor. Parameters may be found by referring to literature data or by market assessment and/or through a consultation process. The three sources are normally checked and result confronted.

An example to calculate ACG on the LRMC may be offered by the Gambia's current experience with the feed-it tariff. Gambia has opted for the ACG methodology: *"on determining the setting of the renewable energy tariff for the Gambia, two different options were thoroughly explored. The first was to base it on an actual renewable technology cost-based approach. This would have allowed costs to be targeted to different technologies. This approach would require a high level of regulatory scrutiny during tariff setting intervals.*

The second approach to setting tariffs that was finally approved upon was the avoided cost methodology. This represents the avoided cost of an alternative form of generation, in our case, a potential mix of Heavy Fuel Oil (HFO) and Light Fuel Oil (LFO) mimicking the combination of both generation types available in The Gambia."[7]

The Gambia is now considering the introduction of a feed-in tariff based on the ACG where the reference technology is a 10MW oil fueled power plant that uses a mix of HFO and LFO. The variables under evaluation by the Gambian regulator are listed in the following table. The values are taken from international estimation adjusted by national circumstances.

Table 2 Reference fossil fuel power station to calculate Avoided cost of Generation in the Gambia

Technology	Units	HFO	LFO
Capacity	MW	10	10
Net thermal efficiency	%	40	36
Internal consumption	%	3	3
Calorific Value	Mkcal/sm^3	7837.5	8662.5
Scheduled Maintenance	Days/year	25	25
Forced Outage	%	10	10
CAPEX	USD/kW	1,400	1,100
Years under construction	year	2	2
Investment throughout years	%	45-55	45-55
Useful life	year	25	25
O&M	USD/MWh	7	7
Fuel Cost	USD/toe	624	850

In addition to the technical parameters the Gambian Authority has assumed the following financial inputs:

- Project financing: 25 years
- Depreciation period: 20 years
- Income tax and VAT: 0%
- Debt-equity structure: 50-50
- Loan features
    - Tenor 6 years
    - Rate 12%

The ACG is hence calculated assuming three different scenarios of internal rate of return on the investment at 10, 12 and 15%.

The resulted calculated ACG tariff is at 8,4 D /kWh (22c$/kWh).

In some circumstances, especially in countries where marginal generators are oil fueledl ones, LRMC may be enough to pay back renewable energy investments, and the ACG methodology proves to be effective for renewable energy development.

[7] The Gambian Public Utilities Regulatory Authority (PURA), Accra, Ghana, USAID-NARUC workshop: integrating renewables into electricity market from policy to practice, 16-17 October 2013

Renewable energy technologies are not producing uniquely during peak hours; they also generate electricity during base and mid load. In fact, they are not necessarily replacing the marginal technology. It is possible therefore to correct LRMC by choosing a set of different technologies and fuels (reflecting national generation share and representing technologies at base load, mid merit and peak load) and then average the respective costs. In other cases it is possible to estimate the ACG as the wholesale price of the market, if available, or the generation cost recognized by the regulator to the incumbent. Those methodologies, however, often do not recognize attractive capital remuneration on investment and are generally introduced to deter renewable energy development.

LRMC recognizes an implicit incentive for renewable energy. This principle is generally welcomed in the early stages of the renewable energy market, in countries willing to develop renewable energy capacity. An impact assessment may help the regulator in making the decision. If LRMC seems to introduce excessive system costs for consumers, the best choice may be to limit the renewable energy capacity eligible for the feed-in tariff, rather than reducing the feed-in level by using average cost methodology.

Box 2: Calculation of ACG in Tanzania for grid connected and mini-grid renewable energy connected systems, advanced features of ACG calculation

The Tanzanian regulatory authority proceeds with two different ACG calculations on an annual basis: one is for national grid connected renewable energy power plants[8] and the other for renewable power plants connected to mini-grids[9].

- For grid connected renewable energy systems, the ACG feed-in tariff is calculated as the average between the LRMC and the generation cost of existing generating infrastructure of the national public utility (TANESCO). The resulting value is then differentiated between the dry (August-November) and the wet season (December-July) through the introduction of a premium coefficient of 1.2 in the case of the dry season and a reduction factor of 0.9 when electricity is generated during wet season.
- For mini-grid connected renewable energy systems, the ACG is the average between the LRMC of TANESCO and the calculated generating cost of a 1MW diesel generator.

The methodology adopted in Tanzania contains many other advanced features (premium for medium voltage connection, moving average adjustment, floor and cap price) that can be introduced in a feed-in mechanism.

The calculated ACG tariff is corrected by an avoided transmission cost: *'SPPs are connected to the medium voltage network of TANESCO. Electricity produced by SPPs would be distributed through the medium and low voltage networks, thus saving high voltage transmission losses otherwise incurred by TANESCO to produce electricity at the main power plants and transfer to the medium voltage network. The avoided cost calculated will be adjusted upwards to reflect the avoided transmission losses'*.

Subsequently in order to smoothen out the annual variations, the calculated tariff is corrected by the moving average of the last three years calculation. The following table reproduces the Tanzanian methodology to set ACG.

Table 3: Methodology to set ACG in Tanzania, step sequence, values in Tanzanian Shillings

[8] The full methodology for grid connected RES systems can be downloaded from the Tanzanian Regulator (EWURA) website: http://www.ewura.go.tz/pdf/SPPT/Tanzania%20STM%20for%20Main%20Grid%20under%20SPPA%20-2009.pdf

[9] The full methodology for mini-grid connected RES systems can be downloaded from the Tanzanian Regulator (EWURA) website: http://www.ewura.go.tz/pdf/public%20notices/Tanzania%20STM%20for%20Mini-grids%20under%20SPPA-2009.pdf

(approx. 1600TZS per $)

Step 1		**Step 2**		**Step 3**		**Step 4**	
Calculation of ACG		**Adjustment for avoided transmission cost**		**Adjustment with moving average of 3 years**		**Wet season and dry season ACG**	
LRMC	133,98	Average ACG	124,08	Calculated ACG	130,53	Dry season (ACG x 1.2)	145,36
Generation cost	114,85	Correction factor	5,2%	Past two years ACG	108,80 123,06	Wet season (ACG x 0,9)	109,09
Average ACG	124,08	Adjusted ACG	130,53	Adjusted ACG	121,13		

The ACG methodology has the advantage to be reasonably simple from a regulatory point of view and to introduce a cost, after all, in line with the current one.

Nevertheless using the ACG methodology means to pay back a technology (renewable energy) whose cost are mostly fixed (capital) with the ACG of a technology whose costs are mainly variable (fuel). This may generate some complications. There are two different approaches to manage this problem:

- Each renewable energy plant is linked to the AGC of the year of commissioning. The ACG is used for the entire lifespan of the plant. In this case a significant gap between the estimated ACG at year one and the real future generating cost, strongly influenced by the international price of fossil fuel, may emerge. If the ACG is not updated, a renewable energy plant in the future may be remunerated significantly lower or higher than the future actual ACG, thus, nullifying the underlying principle of ACG (to keep renewable energy costs closer to system cost).

- The ACG is estimated each year and all renewable enrgy plants get the same price irrespective of their year of commissioning. In this case if the ACG is constantly updated to follow real ACG, the capital risks for renewable developers may be perceived as too high.

In both scenarios, it is very likely that the regulator will be called to constantly update the ACG, compromising between those two diverging factors. In some cases the regulator is given instructions by the primary legislation how to do it, in others the mandate may not be very clear. Rules for updating tariffs, the institution in charge of, and the timing to do it, are fundamental variables to accompany the ACG methodology.

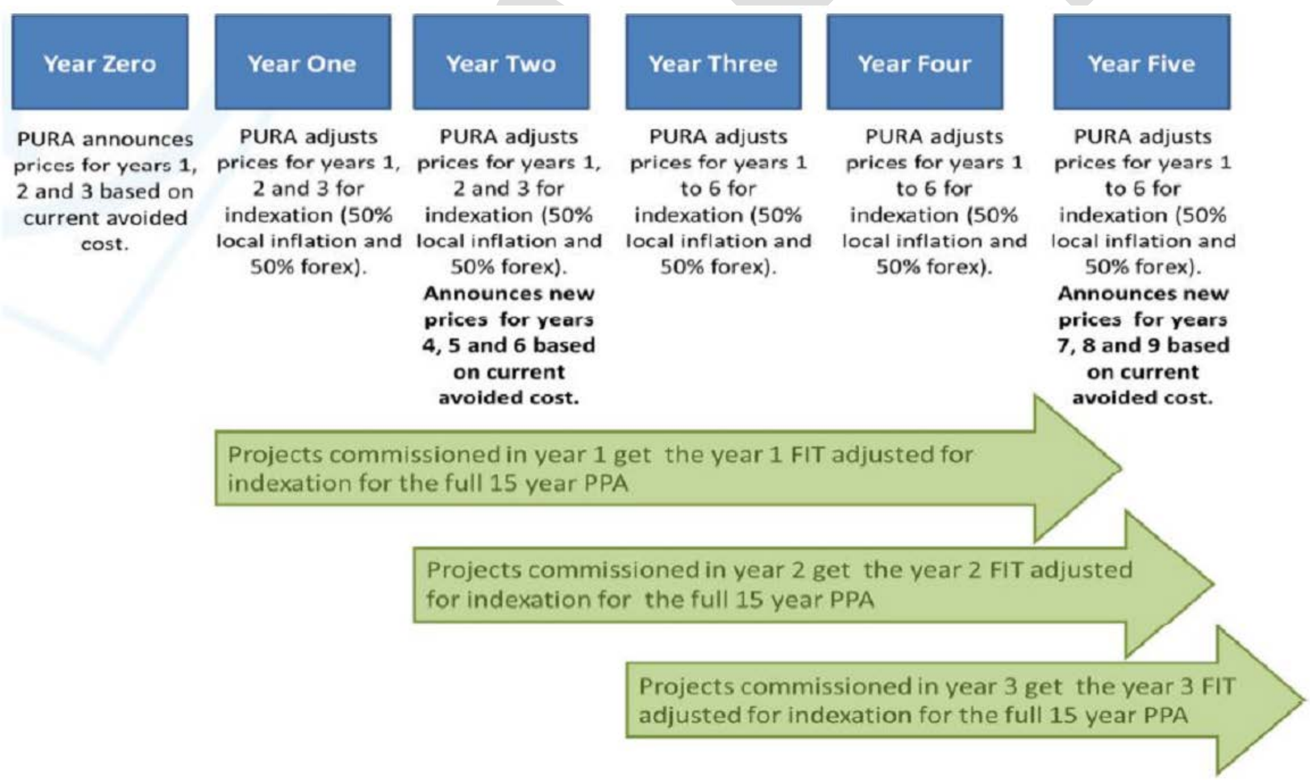
One of the following options is normally used to compromise:

- A cap and a floor price for ACG are introduced. For instance if at year one the ACG is 100, a +/-20% bundle may be introduced in order to reflect some of the fossil fuel price variation into renewable energy purchasing prices while investments are protected and over-remuneration is avoided.

- A moving average of fossil fuel costs over many years may be used for ACG calculation. AGC is calculated on the average cost of reference fuel for a period of 5-10 years. Some variation of fossil fuel price is introduced but the effect is mitigated by the moving average.
- A different AGC is calculated each year (or period of years) and applied to the new renewable energy plant generation. Each plant commissioned during each period will use the same ACG for its entire lifespan but new installations will be remunerated with the new ACG, according to their year of commissioning (The Gambia used this option.).

The Gambia PURA is setting up a clear mechanism to regulate the ACG tariff update. The first calculated ACG (year zero) will be recognized to the renewable energy power plant been commissioned within three years period. The plants commissioned on the 4th year will be remunerated with a recalculated ACG. The regulator is supposed to recalculate ACG every year considering updated reference parameters (oil price in particular) and to announce the new calculated AVG three years in advance. Each renewable power plant will hence be remunerated with the year of commissioning calculated AVG for a15 year period. The AVG, as explained later in the document, is annually updated according to inflation and exchange rate fluctuation parameters. The following graph explains the mechanism in practice.

Figure 1: Calculation of ACG in the proposed Gambia feed-in tariff, mechanism to update tariff to fuel cost[10]



For instance, a renewable energy plant starting to produce in year two will be paid with the feed-in tariff announced in the first year (as seen in table 1) for 15 years, yearly updated according to inflation and forex

[10] The Gambian Public Utilities Regulatory Authority (PURA), Accra, Ghana, USaid-NARUC workshop: integrating renewables into electricity market from policy to practice, 16-17 October 2013

exchange fluctuation. On the contrary, a plant starting to produce in year four will be remunerated with the ACG announced in year two. With the proposed design the Gambian mechanism combines different needs of renewable energy investors and mechanism design, in particular it combines the need of the investors to know the remuneration of the electricity produced (the tariff is known three years in advance and is updated to inflation and forex exchange), and the need of the mechanism to incorporate the variation of fuel costs within the calculation of the ACG.

The advantages of the ACG methodology are:

- Easy regulatory evaluation and methodology
- Remuneration costs in line with existing generating costs, strong policy argument in favor of renewable energy
- Good opportunities in most ECOWAS countries where oil fuel is still the reference marginal technology
- Possibility to correct methodology distortions by introducing mitigating measures such as cap and floor or moving average

The disadvantages are:

- Entry level renewable energy costs may be higher than ACG and some technologies may not be willing to risk entering the market. Some technologies may be more expensive in the early development phases but highly competitive in the long run. This is often the case in emerging markets where knowledge and experiences are limited. Renewable energy technology may have a very fast learning curve but it needs an initial period of incentives.
- With time it is difficult to keep ACG close to the real system cost. A compromise between cost adherence and investment risk is normally introduced.

As one of the main advantages of ACG is to have renewable energy feed-in tariffs in line with system generating cost, the long term potential decoupling between the updated tariff and the system cost risks to nullify the supposed advantage.

The ACG methodology is the most effective in mini-grid cases. In those contexts the reference price of a diesel generator is generally high enough to assure the pay back of most renewable technologies. In fact, in some cases it is even possible to reduce the calculated ACG cost to better reflect the real costs of the renewable energy system real. This is to say that in some off-grid cases the renewable energy cost may be considerably below the ACG of a diesel generator.

Often given the limited economic resources of people (consumers) living in rural areas, it is difficult to ask them to pay a higher kWh price than the national tariff in order to reflect off-grid generating costs. In some cases it is advisable to approximate the electricity final tariff of mini-grid system to national levels and to equalize the cost within the public utility budget. The regulator is normally called upon this duty.

In some cases the ACG is combined (for example in the U.S.) with quota obligation mechanisms and renewable portfolio standards. Public utilities have the obligation to buy a given quantity of renewable energy within their energy mix at a given minimum price.

Specific Technology Cost; Rate of Return Mechanism

The principle behind the *specific technology cost (STC)* mechanism is to introduce a different feed-in price according to the estimated cost of different renewable technologies. The purchasing price will be different for electricity generated from hydro, solar, wind and biomass. This leads to a balanced development of renewable energy sources.

Rather than focusing on the cost of a single reference technology as in the ACG case, the regulator is involved in estimating renewable energy generating costs for different technologies. In some cases the technologies are also differentiated according to their size.

For example, the feed-in tariff published in Ghana in July 2013 is based on a specific technology cost approach. The regulator has calculated the cost for each renewable energy technology and has derived a feed-in tariff accordingly. For hydro two different feed-in tariffs are considered according to the size of the power plant. This means that the regulator has recognized a higher tariff for smaller hydro given the higher cost of the technology. The tariff schemes also sets capacity development limits for wind and photovoltaic technology given their impact of grid stability. No capacity limits have been set for biomass and hydro. When limits are imposed, as discussed later, a project selection criteria has to be in place.

Table 4: Published feed-in tariff based on specific technology cost, maximum allowed capacity per technology in Ghana

	Feed-in tariff GHp	Maximum allowed capacity	Maximum allowed capacity for single developer
Wind	32.10	300 MW	50 MW
Solar	40.21	100 MW	20 MW
Biomass	31.46	No limit	
Hydro > 10 MW	22.74	No limit	
Hydro < 10 MW	26.55	No limit	

The published prices represent the maximum feed-in price the public utility should pay renewable energy electricity. Distribution utilities have the obligation to purchase renewable energy electricity below the approved prices and quantities. The utilities will recover their costs from consumers tariffs as approved by the regulators. To meet their Renewable Energy Purchase Obligations, all distribution utilities shall procure their requirements through international competitive bidding in line with guidelines approved by PURC in consultation with the Public Procurement Authority (PPA), to be published.

Investment costs, O&M cost, capital cost, lifespan and load factor for different renewable energy systems are estimated through market assessment, literature, consultation process. The methodology is the same as calculating the LCOE. When setting STC, the regulator aims at recognizing a *fair* capital remuneration for the IPP. The concept of *fair* is clearly very difficult to define and it implies different variables, last but not least taking into account country specific market risks on investment.

Not only is it difficult to set a *fair* price when introducing a STC feed-in tariff, but it is even more difficult to monitor the coherence between the estimated price and the real technology cost in the future. Technology cost may change for a number of reasons that it are not possible to predict: the technology specific learning curve, increased efficiency and, hence, higher load factors, cost of raw material on international markets, exchange rates and so on.

Most STC mechanisms need to be periodically updated to follow the real technology cost and keep renewable energy remuneration in line with the expected rate of return. A deadline for tariff updates (every two, three years, for instance) is usually introduced in the mechanism rules. This gives market participants a precise deadline for commissioning their installation they have to comply with if they want to access *that* level of feed-in tariff. An alternative approach is to cap the access to feed-in tariffs with a given overall quota (MW). Once the quota is reached the regulator will update the tariff based on the experience of the first period.

In some cases, the STC feed-in tariff already includes a regression factor and tariffs are reduced by a given percentage each year. The reduction is based on the regulator's learning curve expectation for a given technology and it gives plant developers the incentive to speed up plant commissioning in order to get a higher incentive rather than a reduced tariff.

For instance, the feed-in tariff in Germany includes different regression factors for different renewable energy technologies. The regression factor may be applied yearly such as in hydro, biomass and wind cases or be announced for a future period such as for wind offshore and geothermal technology. The table reports initial tariffs, regression factors and feed-in years also as reference.

Table 5: Feed-in tariff in Germany in 2012 - Regression factors and size differentiation

Technology	Size	Initial tariff	Regression factor	Year of feed-in
Hydro	<50 kW	12.70	1%	20
	<2 MW	8.30		
	<5 MW	6.30		
	<10 MW	5.50		
	<20 MW	5.30		
	<50 MW	4.20		
	>50MW	3.40		
Landfill gas	<500 kW	8.60	1.5%	20
	<5 MW	5.89		
Biomass	<150 kW	14.30	2%	20
	<500 kW	12.30		
	<5 MW	11.00		
	<20 MW	6.00		
Geothermal	All	25.00	5% from 2018	20
Wind off-shore	Initial tariff	12.00	7% from 2017	12[11]
	Basic tariff	3.50	7% from 2017	8

[11] The initial period of 12 years at higher feed-in tariff may be prolonged according to specific plant characteristic. For instance it is extended by 5 months for each full nautical mile beyond 12 nautical miles that the installation is located from the shore and by 1.7 months for each full meter of water depth over 20 meters. Those additional premiums may be used to meet other policy priorities, for instance environmental ones or, in the case of ECOWAS country they may be combined with energy access strategies. Feed-in tariffs may be for instance prolonged if RES plants are built in areas currently not reached by electricity services.

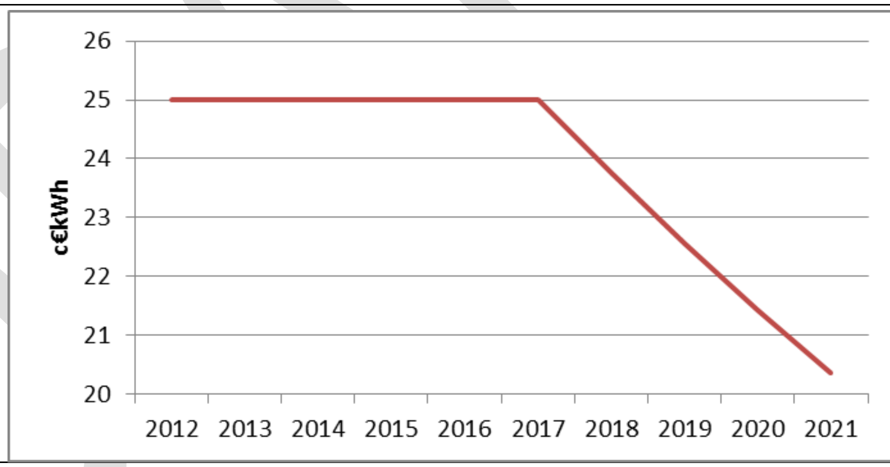
	Acceleration model	19.00	Not applicable	20
Wind on shore	Initial tariff	8.93	1.5%	5 years[12]
	Basic tariff	4.87		15 years
	<50 kW	8.93		20 years

The intent of the German legislator is to differentiate the feed-in tariff in relation to the size of the power plant. It means the German renewable strategy is based on the objective to develop all renewable potential and not necessarily the most competitive ones. In the case of hydro, for instance, the feed in price for small installation is nearly 4 times higher than for large ones. This implies on one side the calculation of rate of return for all different cases and on the other an accurate impact assessment the calculate, according to small hydro potential, the possible impact of final tariff of feed-in costs.

In the following table it is possible to observe the effect of the introduction of a regressive coefficient over feed-in tariffs in order to stimulate early investments.

Table 6: Feed-in tariff for geothermal plant in Germany, effect of delayed regressive coefficient (5% from 2018 onward)

Year	Feed-in tariff
2012	25
2013	25
2014	25
2015	25
2016	25
2017	25
2018	23,75
2019	22,56
2020	21,43
2021	20,36



In the case of geothermal power, the German law anticipates the intention to introduce a yearly regressive factor of 5% from 2018 onward. The effect of the regression on the incentive is visible in the graph. The legislator has allowed a 5 years' time to develop the technology at high incentive but has also clarified the intention to make the geothermal technology more competitive in the long term. The example may be very useful for those countries where there is no experience of renewable energy technologies and the introduction of a technology may be more expensive compared to international standards. In that case the feed-in tariff may allow a high incentive at the beginning but after a few years the tariff will be quickly aligned to international standard thanks to the introduction of a regressive coefficient.

12 The initial tariff level normally granted for 5 years may be prolonged according to the annual load factor compared to the standard load factor. In case production has been lower than expected the initial tariff period is prolonged accordingly. A similar approach may be used to regulate curtailment of RES power plant in case of grid instability (see curtailment paragraph)

This methodology may be adopted in those countries where national policies aim at the development of a national renewable industry. The regression factor may be successfully adopted in emerging markets where the entry level cost of a technology may be significantly higher than the *real* technology cost. There are a number of factors, such as lack of experience, scarcity of skilled and trained personnel, import procedures of plant components, connection rights and procedures still not established, that may cause high initial technology costs. The initial incentive cost may be compensated by the development of a renewable energy national industry and the availability of technologies that may prove to be less expensive than conventional generation in the long run (See impact assessment).

In some cases STC feed-in tariffs may be structured by two components: the ACG and a premium proportional to different renewable energy technology costs.

In liberalized markets the AGC may correspond to the electricity market price. In that context the renewable producers will sell their electricity into the market and receive a premium incentive separately. The premium is generally dispensed by an independent body managing a renewable fund. The fund is fed by a specific tariff component introduced and constantly updated by the regulator to follow the renewable energy mix and the consequent system cost.

STC feed-in tariffs are very common in the EU where the legislator is pushing for a balanced development of renewable technologies.

When an incentive is introduced, and this is normally the case with STC, it is necessary to specify the rules and the mechanism to access it. There are three main principles of access: unconstrained access, a first come first served approach, and the auctioning of access rights. Those three principles will be discussed in the section on connection rights as the methodologies to assign access to tariffs and access to connection rights are substantially equivalent.

The advantages of STC feed-in tariffs are:

- All technologies may access the electricity market. This incentivizes a balanced development of renewable energy and may be combined with specific policy objectives. If STC are not updated to inflation they may also has potential positive effects on inflation reducing its impact on electricity prices.
- The tariff may speed up the development of renewable technologies whose entry level cost may be higher than ACG but whose long term potential may overcome initial costs.
- Renewable energy costs are decoupled from oil and fossil fuel cost. The electricity produced by STC plants has a stabilizing effect on final electricity costs delinked from fossil fuel cost fluctuation.

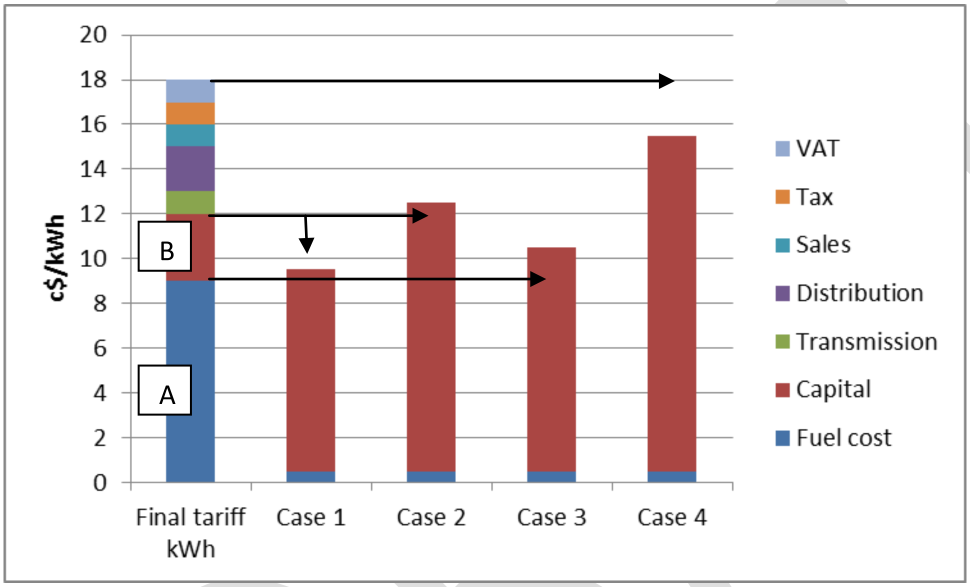
The disadvantages of STC feed-in tariffs are:

- It requires a greater regulatory effort to calculate STC and to update them. A more complicated tariff structure to pay back the IPP may be needed.
- It is normally associated with the introduction of incentives and therefore additional cost to the system.
- If not well designed the methodology risks not following real technology costs in the future and become excessively expensive for the system.

There is not a best methodology option to develop a feed-in tariff. ACG and STC both have some advantages and disadvantage that a clever legislator/regulator has to be able to adapt to the specific country characteristic and priorities. Running impact assessments of proposed options may be useful to compare the two systems in the long term.

Box 3: Generating cost in conventional fossil fuel power plant, composition of final electricity costs, and integration of renewable energy

Final electricity cost per kWh as illustrated below is given by the sum of different components. Those are: capital cost of generating infrastructure, variable cost of generation (OPEX, notably fuel cost in conventional generating plants), transmission costs, distribution costs, sale and metering service costs, taxes and duties, VAT. The cost of generation (capital and fuel costs) is only a percentage of final electricity cost, usually ranging between 50-70% of final cost.



When the cost of generation of fossil fuel (capital (B) + fuel cost (A)) is higher than the renewable energy LCOE (case 1), the introduction of an ACG methodology is the easiest as renewable energy is competitive compared to fossil fuel generation.

When the renewable energy LCOE is higher (case 2), it is necessary to introduce some incentive. A premium has to be recognized over the ACG. The most common approach in this case is a Specific Technology Cost feed-in tariff.

Not always, though, in order to keep electricity tariffs at a low level, the capital cost component is recognized to the public utility and the tariff is barely able to recover fuel cost only. Despite the ACG is (A+B) in some cases only (A) is paid to the utility. This lets the public utility run the power generation units but not pay back capital investment. When it happens, and tariffs are not cost reflective, it is difficult for renewables to seem competitive compared to fossil fuel (case 3). In fact fossil fuel generating assets are paid somehow by public money and in the ACG calculation it is necessary to add capital and fuel cost. In other cases fossil fuel supply to power generation benefit of public incentive. Again it is important to calculate the real ACG to understand when renewable energy is competitive.

Finally when the renewable energy system is installed by end users the reference avoided cost is the final electricity price including, transmission, distribution, sales and taxes. This is considerably higher than generating cost. *Retail cost* is generally used to calculate *net metering* options. Normally fiscal component are not paid for the kWh exchanged in *net-metering.*

Other Options for Feed-in Tariff (ACG and specific cost)

Feed-in tariffs may also be modulated into time of generation tariffs. This will link renewable energy remuneration to the different economic value of the electricity according to the time of the day or the season of the year it is produced. Time of generation tariffs may be applied to all renewable plants or uniquely to those technologies that can be predictable such as hydro, biomass or biogas. It is possible to structure feed-in tariffs into base-load and peak-load prices on a daily or seasonally basis. For the ACG methodology a reference peak load and base load technology can be chosen for the calculation. Alternatively, it is possible to introduce a premium (coefficient) to correct the reference tariff price for the electricity produced during peak hours.

Time-tariff have the effect to incentivize renewable production when the system is producing electricity at higher costs. This will promote the construction of programmable renewable energy rather than non-programmable ones. Two different systems may coexist: flat and time of generation tariff.

The Tanzania feed in tariff (Box 2) provides an example of a seasonally modulated feed-in tariff. The introduction of a simple coefficient gives a price signal to the power generator:

- 1.2 for dry season when electricity is scarcer and more expensive to generate given the water shortages in hydro plants
- 0.9 for wet season when hydro electricity is more abundant

Auction systems may be put in place in order to assign access to feed-in tariff rights when the overall capacity is constrained. Total capacities (MW) for each technology as well as the opening price (i.e. the tariff to be recognized to the RES for a given period of time) are set. Potential developers bid and development rights are given to the highest bidders.

Ghana, for instance, has introduced a feed-in mechanism based on maximum feed-in prices the public utility may pay IPPs. The public utilities are hence asked to purchase renewable electricity through an international competitive bidding (ICB) process defined in specific guideline approved by the electricity regulator (PURC) in consultation with the Public Procurement Authority.

In some cases the competitive bidding process may introduce additional complications and delay the commissioning of renewable energy installations. The benefit in terms of reduced incentive mechanism costs may be very limited compared to the transaction costs generated by running competitive actions.

For photovoltaic systems, rather than running competitive auctions it may be more efficient to introduce a size limit for the construction of power plants (i.e. 2 MW) and assign the available capacity on a first come first served principle. Larger power plants may have better chances to win the auction but will pose higher balancing problems to the national system thus introducing hidden additional costs. For this reason the construction of large photovoltaic systems may need lengthy technical feasibility studies to evaluate potential grid impacts of the installation, thus further delaying the implementation of a renewable energy favorable mechanism. This is the case in Burkina Faso and to some extent in Ghana. For photovoltaic technology the economic benefit of introducing a tendering system are negligible as the marginal saving on additional kW for large systems (> 2 MW) are very limited. Moreover the installation of a larger number of smaller photovoltaic plants does not only offer benefits in terms of better system balancing but also higher employment rates per kW installed, as opportunity of experiences for national engineers and technicians are greater.

For other technologies, such as wind, the potential grid balancing problems are compensated by the relevant investment cost reduction per kW according to the size of the power plant. In that case the auction mechanism may deliver higher system benefit. When an auction is run to assign feed-in access rights, precise arrangements have to be introduced in order to assure that plants are commissioned within a given period of time and that bidders are financially sustainable. For this purpose, in some cases, feed-in tariffs are progressively reduced if plant developers delay the installations and a financial deposit is asked to participate in the auction.

In Italy, for instance, the legislator assigns feed-in rights on a competitive basis. The available capacity is defined by decree for each renewable energy technology (see table 7). Once the contender has won the auction there is a maximum time to complete the installation. Once the expected commissioning time has expired the feed-in tariff is reduced by 0,5% each month for a maximum allowed delay of 24 months. Participation to the auction is conditional to a financial deposit. If maximum time is not achieved, the deposit is lost.

Table 7: Deadline rules for renewable energy plant commissioning to complement feed-in tariff rights auction mechanisms, Italy

Technology	Allowed capacity in 2013 MW	Expected commissioning time months	feed-in tariff reduction for any month of delay	Maximum allowed delay months
Wind onshore	500	28	0,5%	24
Wind offshore	650	40		
Hydro	50	40		
Geothermal	40	40		
Biomass	470	40		

The auction system has the advantage of combining an administrative tariff setting process with some economic efficiency provided by a competitive allocation process. Yet, often transaction and administrative costs may be higher than expected economic efficiency improvements. Sometimes keeping the feed-in system as simple as possible proves to be the best choice.

Another option may be offered by accelerated cost recovery feed-in tariff. In the following case, for instance, the German legislator let the IPP decide between a 20 years feed in tariff and a higher tariff for 12 years only. The reason for the introduction of the accelerated option is to encourage early movers in the development of new technologies. A higher tariff for a shorter period of time is an additional incentive for plant developers given the lower risk and the faster break-even point of the investment.

Table 8: Example of acceleration feed-in model in Germany for off-shore technology

5.3. Offshore wind energy

Degression rate until 2017: 0.0 %, from 2018: 7 %

Duration of tariff payment 20 years (acceleration model: 12 years)

year of commissioning	basic tariff in ct/kWh 13)	higher initial tariff in ct/kWh	initial tariff in acceleration model
2012	**3.5**	**15.0**	**19.0**
2013	3.5	15.0	19.0
2014	3.5	15.0	19.0
2015	3.5	15.0	19.0
2016	3.5	15.0	19.0
2017	3.5	15.0	19.0
2018	3.26	13.95	-
2019	3.03	12.97	-
2020	2.82	12.07	-
2021	2.62	11.22	-

13) the higher initial tariff for offshore wind energy is paid for the first 12 years from the date of commissioning of an installation. The period is extended by 5 months for each full nautical mile beyond 12 nautical miles that the installation is located from the shore and by 1.7 months for each full metre of water depth over 20 metres. In the case of the acceleration model the same tariff as for the "normal" tariff model shall be paid for the extension period calculated using distance from the coast and water depth (Section 31(3) sentence 2).

Feed-in Updates

Other parameters should also be considered when developing a feed in tariff (ACG and STC): inflation and foreign exchange rates. Specific mention to those two variables should be included in the main legal framework to make plant developers able to evaluate their long term investment remuneration.

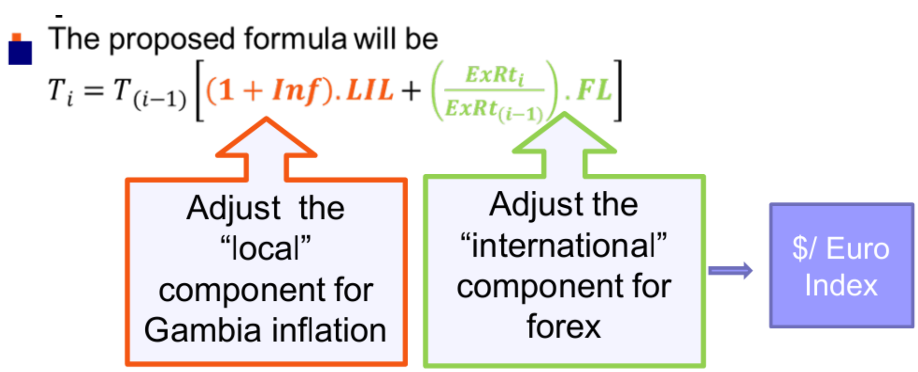
Inflation: the inclusion of inflation in the feed-in tariff formula will keep renewable energy remuneration constant to real terms over the period. As renewable energy investments anticipate all capital at year one, in principle inflation should be included in feed-in tariff. In ACG inflation correction should be applied uniquely over the capital cost component of the reference technology. Fuel costs, if updated yearly, are an independent variable that already includes inflation. Often national electricity tariffs do not follow inflation and full inclusion of inflation for renewable energy tariffs may be seen as an excessive privilege for renewable energy developers. In some cases only a percentage quota of inflation is included.

In principle, it is advisable to only adjust feed-in tariffs for existing plants to inflation. For new plants, the feed-in level calculated in the past should not be inflation adjusted as renewable energy technology costs are often decoupled from inflation. Renewable energy technology costs may significantly decrease when inflation is increasing. If the feed-in tariff is updated also for future plants this may incentivize investors to postpone plant commissioning to gain benefit from the spread.

In some cases foreign exchange variation against €/$ is considered in tariff updates as most technologies are purchased on international markets. When inflation is fully included in the tariff update this should generally already compensate the foreign exchange variations. Still to increase investors' confidence it is possible to include part or full foreign exchange fluctuation in the tariff adjustment.

Again it is possible to use the formula proposed in the Gambia feed-in scheme to see the principle in practice[13]. The formula serves only as an example for the methodology as the proposal has not been approved yet.

Figure 2: The Gambia: Proposed updating formula for ACG feed-in tariff, inclusion of inflation and exchange rate fluctuations.



Where:

- T_i tariff for the period 'I'
- $T_{(i-1)}$ Tariff in previous period (i-1)
- Inf is the local inflation
- LIL is the deemed local inflation link (percentage)
- FL is the deemed foreign exchange link (percentage)
- $ExRt_i$ Exchange rate GMD/€ for the period 'I'
- $ExRt_{(i-1)}$ is the exchange rate GMD/€ for the previous period (i-1)

Assuming the starting ACG in The Gambia is GMD8.4/kWh. One year later the inflation has been 5% higher and the forex rate has moved from GMD40 to GMD45 for one €. The Gambia mechanism recognizes 50% of inflation variation (LIL) and 50% of forex variation. The resulting formula being:

T_i = GMD8.4/kWh x [(105%) x 50% + (45/40) x 50%] = 8.4 x (52.5% + 56.3%) = GMD9,14/kWh

In year two, the corresponding updated ACG to be awarded to new and renewable energy power plant commissioned in year one is GD9.14/kWh[14].

Finally it might be useful to specify some minimum technical standard to avoid the installation of outdated renewable energy systems.

Green Certificate

An advanced option to support renewable energy is to introduce a quota obligation system combined with a green certificate (GC) market. The obligation is normally placed on electricity supplying companies. In some

[13] The Gambian Public Utilities Regulatory Authority (PURA), Accra, Ghana, USAID-NARUC workshop: integrating renewables into electricity market from policy to practice, 16-17 October 2013

[14] The values do not correspond to reality. The calculation is done for demonstration purpose only.

examples the obligation has been imposed on generating companies (Italy) or final consumers (Sweden). The obligation consists of demonstrating to have a minimum percentage of green electricity of total electricity sales each year. The percentage is progressively increased each year until the renewable energy policy development target is reached. Electricity suppliers can demonstrate to have complied with the obligation by redeeming a number of green certificates corresponding to their obligation quota. For example if company A is selling 100GWh of electricity each year and the green certificate obligation is set at 5%, the company has to redeem 5 green certificates (i.e. 1 certificate = 1MWh of green energy) in order to demonstrate it has complied with the obligation. The following year the obligation will be 7% and the company has to find an additional quota of certificates.

On the production side renewable operators generate electricity and receive an equal amount of green certificate.

The electricity is sold on the market at market price whereas the certificate may be sold bilaterally to the utilities under obligation or through a green certificate market.

GC mechanisms respond to the policy objective to have a determined share of renewable energy in a given period of time through a competitive mechanism where renewable energy costs are not defined by the regulator through a complex administrative process, but by the market. Within a green certificate mechanism the duty of the regulator is limited to market monitoring and assuring the obligations are met.

The GC mechanism in practice has often proven to be more complex than expected. In most experiences, the combined risk on electricity and green certificate remuneration, the market power of some operators, the exclusive development of some competitive technologies have persuaded the legislator to correct the mechanism, in fact, nullifying its alleged advantages.

The enforcement of the mechanism has also proven to be difficult. The introduction of non-compliance fines (buy out option) for those operators not able to redeem a sufficient number of certificates corresponds to a price cap of the mechanism. When the fine is too high, it is difficult to enforce. When too low, companies prefer to pay the fine rather than develop new renewable energy plants.

It is recognized that GC schemes can only be successful in large electricity markets (regional markets) with high level of competition both in generation and supplying sectors. In fact the two largest markets of GC (Italy and UK) have now turned back to feed-in tariffs managed through auction rights. Box: classification of renewable incentive

Financial sustainability of Renewable Energy Electricity Buyer

The financial sustainability of the renewable energy electricity buyer under obligation may be another obstacle to renewable energy development. Often obligation is set upon national public utilities. Investors may be worried about the long term capacity and willingness by the public utility to pay renewable energy generated electricity. The enforcement of the obligation to purchase renewable energy electricity may be difficult when final tariffs are not fully cost reflective.

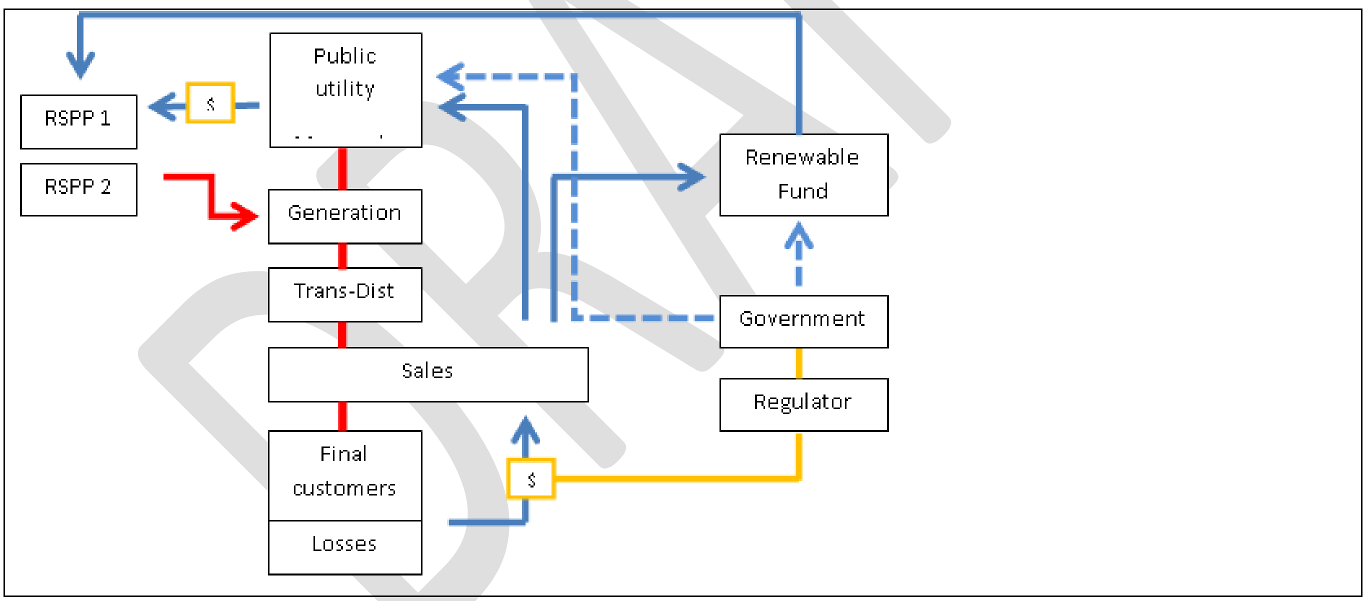
The concern is legitimate when final tariff are not able to collect enough money to pay back full cost of public utilities (see box 3) which, in turn, will not be able to pay renewable investors. In other cases the incumbent and the regulator may be involved in tariff and cost revision disputes and the former may delay payments to renewable energy producers until the dispute is over.

To overcome this situation it is possible to establish a renewable fund where a portion of the money collected through final electricity tariffs are deposited before being transferred to renewable energy producers The Renewable Fund costs may be covered by the electricity tariff or by the national budget (or a combination of both). Also international funds may be directed to the Renewable Fund.

When a Renewable Fund is introduced, the regulator is called to calculate the annual forecasted cost of the renewable energy feed-in mechanism and introduce a specific component (RC: renewable component) into the final tariff to collect an equivalent amount of money. When tariffs are collected the money corresponding to the RC are directly deposited into the Fund. In this case the PAA is signed between the IPP and the Renewable Fund which is responsible for the payments.

In many countries the high level of non-technical losses is one of the main reasons for concerns about the public utilities long term financial sustainability. Ghana has introduced an effective regulation to reduce non-technical losses through the introduction of quality standards to be respected by the public utilities.

Figure 3: Establishment of a Renewable Fund to mitigate financial sustainability risk of renewable energy buyer under obligation



Grid Access

Grid access rules and connection costs are a legal framework component and as important as the regulation of electricity remuneration.

- Location and size of renewable plants are determined by the local availability of renewable sources. Plants may be located far away from the existing grid infrastructure and/or the primary consumers of electricity. Connection costs for renewables constitute a significant part of final development costs especially for small scale renewable energy systems.

- The SO is not used to renewable energy plants, the system has probably been designed for conventional power stations and renewable energy may constitute a complication in the short term. In vertically integrated electricity systems, the national company may not be happy to connect potential competitors on the generation side.

The regulator has to make sure a transparent and non-discriminatory procedure to connect the plants is in place. The procedure should be based on some minimum requirements:

- Connection rights for IPPs have to be established and connection principles clearly defined.
- In case of constrained grid access a methodology to assign grid connection rights has to be in place.
- A methodology to pay connection costs has to be introduced.

Connection Rights

The non-discriminatory grid access right prescribes that the national SO has to allow the connection of any IPP willing to feed its electricity into the national grid. Exceptions are:

- The IPP is not able to meet some specific technical standards.
- The distribution/transmission lines the IPP wants to connect to are congested and the available capacity is limited.

An effective way to ensure that the right to grid access is respected is to publish a grid code. The grid code contains technical standards for any production unit willing to connect. The technical requirements are normally defined jointly between the regulator and the DSO/TSO and are made publicly available through a regulatory order. A grid code sets parameters for high, mid and low voltage connections. Anyone respecting those parameters may access the grid without restrictions. The grid code also indicates measuring and protection devices necessary for installation and electronic testing time and procedures for the first connection. A standard form for connection requests may be attached to the grid code and a deadline to reply is given to the SO.

When non-discriminatory rights are in place, the SO may refuse connections only on the basis of proven transmission capacity constraints. Obsolete transport capacity, network design and limited interconnection may significantly reduce the access of renewables in some parts of the country. The regulator may ask the SO to communicate available connection capacity for each area and make this information available to the market. The regulator may also ask to keep records of all refused applications to be taken into consideration in future grid development plans.

Renewable incentive schemes have been mainly tested in mature electricity market where grid constrains have emerged only once a considerable penetration of renewable energy has been achieved. In emerging market it may be advisable to accompany renewable energy production with mechanisms to adequately remunerate renewable energy related network investments from the beginning.

This is not an easy area to regulate. Large areas of the country may have not yet been reached by electric networks and a significant percentage of the population may have no access to electricity service at all. Future grid investments should be directed there. However, those areas may not coincide with those that have large renewable potentials. The regulation to support renewable energy has to be balanced and consider renewable energy potentials, electricity access priorities and a realistic development of networks. Specific schemes to favor the development of small size renewable energy plants and net metering options may be more compatible with the priority of extending the grid to increase electricity access, especially in the short-run.

When the grid is accessible, renewable energy penetration will likely not pose significant problems in the early stages of development and unconstrained access to the grid may be granted to renewable energy developers. The SO will be in charge of renewable energy connections and monitoring, promptly communicating to the regulator potential congestion risks. When necessary the regulator introduces rules to access limited connection capacity and establishes a queue management procedure.

The two main methodologies for queue management are:

- First come first serve: The renewable energy developer request grid access to the SO, who will accept applications as long as capacity is available without any selection based on economic criteria.
- Tendering system: Available capacity is auctioned among renewable energy plants developers. They may be called to offer a discount on the electricity they will sell if they are granted a connection right. Alternatively they may be asked to pay a one-off connection fee. The revenue may be directed to new grid investment or socialized through the electricity tariff.

Both queue management systems need to be complemented with a deadline for plant commissioning. When capacity is scarce renewable energy developers may also be asked for a deposit. It is important that assigned capacity is used within a reasonable period of time not to unnecessarily delay renewable energy development. To avoid speculation, assigned capacity rights should not be transferred or sold.

The starting up of a renewable energy market necessitates a simple environment to flourish and if it is not strictly indispensable it is advisable not to introduce constrained rights. This may be done in a second step once the start-up phase is over.

Connection Costs

The total connection cost of a new power plant is determined by two components:

- Direct cost of connection: The line from the power station output meter to the closest network substation.
- Indirect cost of connection: Costs generated by the necessity of reinforcing the grid following the connection of new production units.

The most commonly adopted principle is to ask renewable energy developers to pay only for direct connection costs. This practice is called *shallow connection regime.*

When an IPP decides to build a new line to reach the grid, it is possible the SO is willing to be the owner of that line as it may be functional to its future expansion strategy.

For this reason it may be useful to introduce a double options connection cost regime. In the first case it is the plant developer who builds the line and bears its entire costs. Still it will be necessary to:

- Make technical connections for low, medium and high voltage specification available.

- Specify, by regulation, the maximum time allowed by the network operator for system and line inspection and testing.
- Set a maximum cost for the necessary modifications at the public utility connection point.

In the second case the SO has to comply with some specific time deadlines for the construction of the new line. The time assigned may vary depending on the complexity of the work needed to be carried out and according to the total line length. A reference maximum time should be defined for all cases by the regulation.

The SO is normally asked to reply to the plant developer's connection request within a given period confirming:

- The availability of the requested capacity
- The intention to build the new line as SO. In this case it should also specify the kind of work to be done (complex or ordinary), the expected time for connection, and the quotation for the connection cost.

When the line is built by the SO, the plant developer will bear only a fraction of the total connection cost. The introduction of a lump sum payment, proportional to the length and the capacity of the requested connection, is probably the easiest regulatory option to be adopted.

In a vertically integrated market the cost of new connections and grid upgrades are combined with the planning of the new generating infrastructure and translated into the tariff. Generation, transmission and distribution infrastructure are part of the same strategy. However, when new plants are introduced by IPPs their location may not have been planned by the TSO/DSO and the new production unit may add additional cost to the system, which needs to be reconfigured.

Once renewable energy development becomes a country's priority it is normally accepted that some of the indirect costs of connection are socialized and they are absorbed into the tariff as ordinary network investments. Very rarely renewable energy developers are asked to pay *deep connection costs*.

Balancing the System

Renewables may be classified as dispatchable and non-dispatchable source of energy. Non-dispatchable renewable energy may pose some fluctuation problems to the system as they are weather dependent and are not able to operate as load-following entities.

Photovoltaic and wind systems show the highest fluctuation within limited time whereas other technologies such as biogas, geothermal, biomass and hydro are easily predictable. Intermittency, though, is an inherent characteristic of some renewable energy and fluctuation problems should not be considered a barrier for renewable energy development especially in the early stages of renewable energy penetration in the electricity markets.

As a general rule, up to 20% of penetration of intermittent renewable is normally not considered a problem. Therefore as long as the national capacity does not get close to this level no restrictions on renewable energy development should be introduced. Local weather conditions may prove that higher injection of electricity can be reached without jeopardizing grid stability. In Cape Verde, the stable wind regime allows the energy system to absorb higher percentages of wind production. Photovoltaic systems in Sub-Saharan countries may show less fluctuation than experienced in other countries with different sun irradiation regimes.

There are a number of instruments to strengthen the national system and allow it to cope with higher renewable penetration:

1. A better communication between plant operators and the SO improves system balancing. The renewable energy owners and the SO have to be incentivized to improve their weather forecasting skills and to promptly communicate any gaps.
2. Price incentive mechanisms may be introduced in order to motivate renewable energy generators to better utilize weather forecast data. A premium may be introduced for accurate day ahead forecasts or a cost may be added to producers to compensate unbalanced quantities. In sophisticated electricity markets renewable energy sources are asked to pay the cost of balancing the system for the quantities they are responsible for.
3. Electricity storage technologies may be promoted. Pumped storage and water reservoirs are typical storage solutions: water is pumped when there is an excess of renewable input and is discharged within seconds to produce electricity once required by the system. Electrochemical storages are now being introduced in some markets that have experienced high penetration of intermittent renewables.
4. Storage may be considered a production or a transmission (system security) infrastructure. In the first case (production) it is fundamental that the electricity market gives adequate price signals to remunerate storage infrastructures. Time of generation tariff, for instance, have to be in place. A specific market for reserve capacity will also help. In the second option (transmission and security infrastructure) storage costs are recovered through the tariff.
5. In some contexts intermittent sources of energy may be efficiently combined with some specific energy uses that can serve as storages: water industry, water treatment plants, water management. The water sector often benefits from discounted tariff options and incentives. The regulator may try to improve the overall system management by orienting tariffs to system efficiency. It may be possible to ask the water industry to offer balancing services in return for existing tariff privileges.
6. Demand response and load management is an efficient option to balance the system. Larger consumers may be willing to cut their load when required by the system if adequately compensated. The load service may be purchased by a forfeit compensation or on a time basis. The cost of such services are normally recovered through tariffs as system cost; in advanced markets demand loads may participate to capacity reserve market and get balancing system price for the service.
7. The more distributed the non-dispatchable renewable plants are, the lower is the risk of fluctuation. In principle the overall legislative framework should avoid the temptation to favor the commissioning for large size non-dispatchable renewable energy plants and prefer a smaller scale distributed pattern of plants being installed in different area of the country. It is generally better to have a number of small size plants being distributed throughout the country and insist on different balancing areas rather than have a big plant in a single balancing area.
8. Net metering options are a good instrument to promote distributed generation. An additional measure may be the introduction of an additional tariff component to be added to feed-in tariffs for power plants directly connected at low or medium voltage. The component corresponds to avoided transmission costs (including losses).
9. The larger the balancing area, encompassing different production and load units, the lower the fluctuation risk. Penetration of renewables benefit from investments in network development and integration. Interconnection of larger systems, including cross border connection, is the most efficient solution to absorb local fluctuation problems. An effective instrument to incentivize network expansion is to recognize a higher remuneration on investments in new lines as compared to existing capital remuneration of existing ones.
10. Increasing quick response reserve capacity is another solution to balance the system. Reserve capacity may be granted through administrative or market rules. Hydro basins or fossil fuel (hot reserve) may

be asked to keep a percentage of their capacity available for reserve. Alternatively reserve capacity may be purchased on a competitive market.

11. Finally, as overall system stability is given by the mix and the flexibility of all generating units connected to the grid, the commissioning of CCGT plants, able to quickly respond to grid requirements, make the system generally more flexible.

Curtailments

Curtailment of renewable energy (especially intermittent ones) may be necessary by system requirements or may happen following network outages. It is a good principle to regulate curtailment procedures especially in markets with fragile network systems. There are two main reasons for curtailment:

- Unpredictable sources of energy exceeds the 'safety' quota in the system. There may be many plants in the specific area, comprised of different sizes and belonging to different owners.
- Network instability or outages not caused by renewable energy generators. Renewable energy units will be automatically switched off by their protection systems and will be idle for the time the network parameters are not re-established.

Excess capacity may be determined by many variables renewable producers are not responsible for: lack of coordination between system monitoring and plant licensing offices, mistakes in demand forecasts, unexpected load reduction, delays in the construction of new network connections, etc. Defining curtailment rules reduces investment risk. Criteria for curtailment have to be known, whether the SO proceeds by curtailing one plant at a time (which plant?) or by reducing electricity inputs by all market participants (when technically feasible) by a percentage of their load. It is possible to establish a compensation for non-dispatched electricity following curtailments. The compensation may be introduced on all losses or only when losses occur for a significant period of time. Compensation for these economic resources may be taken from all renewable energy producers, non-predictable renewable energy producers, or socialized into tariff.

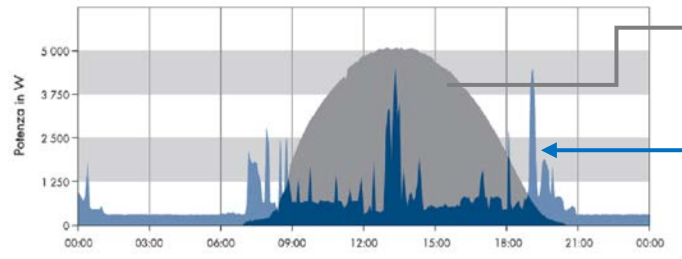
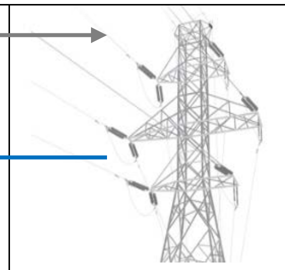
In the second case renewable energy producers are curtailed because of network problems. It is the SO that will have to fix the problem and it may take a longer time than needed. In vertically integrated markets the SO may have little or no incentive to repair a line an IPP is connected to. This situation may discourage investment of IPPs. In renewable energy plants investment remuneration is highly influenced by the plant load factor. Some compensation for non-dispatched electricity may be introduced especially when outages exceed a maximum period per year. Network quality standards are usually introduced to assure the SO receives the right economic signals to repair networks in time.

Net Metering

Net metering is a significant feature of renewable energy favorable electricity markets. Net metering is an exchange of electricity between a private producer, usually of small power plants (1-200kW), and the electric utility.

Figure 4: Net metering

Household PV generation (gray) and load (blue) profile	National grid	Net metering is the

		exchange of electricity between a small producer and the local utility for the quantity not simultaneusly absorbed by load (inputs) and the quantity consumed by the final user when PV production is not producing or not enough to supply loads (withdrawns)

Net metering is not an incentive; it is an option to feed the excess of electricity produced by independent small installations into the system and to regulate this exchange at net costs for the electricity bill and no cost for the system. In fact, net metering is a sort of borrowing between the small producer and the grid. In some markets incentives are added to the net metering option to further support the development of small scale renewable energy distributed generation. Net metering alone offers a good economic opportunity for small renewable energy installation (especially PV) as it values the electricity at retail price, including generation, transmission, distribution, metering, sale services and taxes.

Net metering usually requires the regulator to work on the following aspects:

- Technical aspects: net metering plants are connected at low voltage. The DSO has probably no experience in LV plant connection and two-direction metering. Technical connection rules have to be prepared and become national standards for all small renewable energy systems willing to apply to the net metering option.
- Economic aspects: The net exchange of electricity between the public utility and the power producer is regulated through the electricity bill. The regulator defines the rules for such exchange.
- Licensing: given their limited size a specific licensing procedure is normally not required for net metering installations. Technical certification of products respecting grid quality and security standards, though, need to be introduced.

In fact, as net metering does not necessarily introduce an incentive for independent producers nor is normally seen as a violation to production concession rules, it may be directly introduced by regulators without a formal piece of primary legislation being approved. It is, in fact, a tariff option.

System Monitoring, Registration and Certification

Regulators are normally not involved in the licensing procedure for electricity generators. Still the regulator may find it very helpful to keep track of the development of renewable infrastructure. Renewable energy plants normally have a specific tariff system. The system may generate additional costs for the electricity market. The regulatory authority needs to have a comprehensive vision of the renewable energy plants installed and the tariff they are associated with.

A registry of all renewable energy installation over 1kW and grid connected may be established. The registry should have an easy procedure for registration as not to add additional burdens on renewable energy developers.

It may be useful to certify electricity production. The certification may be used to monitor the system at the national level, to verify the proceeding of renewable energy legislation in case of regional targets being established and to sell green rights on potential international green certificate or CO2 markets. A precise definition of renewable energy technologies is needed to start up a certification process. The process would benefit from the harmonization of certification procedures at ECOWAS level.

Contract Format

IPPs need to sign a contract with the entity paying the electricity produced. Regulators may be asked to produce a standard contract format. A standard contract makes the mechanism more transparent and easier to manage. The absence of standard contracts has been reported as one of the possible barriers delaying renewable energy commissioning. The publication of a reference contract makes the application of the law clear and univocal for investors.

Signing a contract is the proof the developer will need to access feed-in tariffs. Often it is a precondition to access financing. The PPA is a contract between an electricity producer and a purchasing entity (usually a local utility) for the purchase of electricity generated by a power plant. A properly negotiated PPA is a critical part of a renewable energy project. It defines the price at which generated power is sold as well as various other obligations between parties. Negotiating an appropriate PPA is among the most complicated aspects of developing a clean power project therefore the publication of a standard PPA within one nation's support mechanism is very useful.

A number of information and standard PPA may be found online[15]. Contractual legal basis are different from country to county.

As a general rule a complete PPA is normally structured to include:

- ✓ Definition and identification of the parties
- ✓ Recall of the legal basis the PPA is built upon (whereas)
- ✓ List of the IPP licensing requirements (land, water right, environmental impact assessment)
- ✓ Description and identification of the power plant
- ✓ Definitions of terms and rules of interpretation
- ✓ Effective date of commencement and duration of the PPA
- ✓ Definition of the point of delivery, GIS coordinates
- ✓ Procedures for metering produced electricity eligible to feed-in tariff
    - Technical requirement of metering
    - Responsibility for metering
    - Inspection to metering devices

- ✓ Payment of electricity
    - Price per kWh [legal basis]
    - Updating of tariff [legal basis]
    - Timing and format of billing
    - Timing of payments
    - Management of delayed payments
    - Adjustment and balance of payments

[15] **http://www.retscreen.net/ang/power_purchase_agreements.php**;
http://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements

- Rules for curtailments

- ✓ Obligation of the parties
  - Communication between partners
  - Connection, quality and safety standard as required by the Grid Code
  - Rules for inspection and access to power plant by counterpart
  - Minimum standard for operation maintenance, communication of maintenance periods
  - Communication of modification of plant configuration

Impact Assessment and Consultation Process