Module 9

Regulatory and policy options to encourage development of renewable energy

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

CONTENTS

1. MODULE OBJECTIVES

1.1. Module overview

Why support renewable energy? There are many answers to this question. Renewable energy can aid security of supply. Small-scale renewable energy projects can contribute to a government's social agenda, for example by increasing access to electricity. On a broader social and political level, the development of a renewable energy industry can create jobs and enhance technical expertise. Renewables can also deliver additional local, regional and global environmental benefits.

This module examines types of regulatory/support mechanisms for renewable energy and the design issues that are involved in these mechanisms. The module will also give examples of the mechanisms in practice and provide information on the pros and cons of each system. Most mechanisms of this type have only been functioning for a short while with very limited application in Africa. Consequently, conclusions on their success or failure are hard to draw. Sometimes the best solution is to use a combination of mechanisms to support renewable energy development in a country.

1.2. Module aims

This module has the following aims:

- To provide an overview of the different advantages that a clear renewable energy policy can provide, and its possible interaction with other policies;
- To explain what the key building blocks are when designing a regulatory/support mechanism;
- To give an overview of the different possible approaches;
- To show how these have been implemented in different African countries.

1.3. Module learning outcomes

This module attempts to achieve the following learning outcomes:

- To be able to explain that a renewable energy policy can provide advantages and support a range of environmental and other policies;
- To understand which design elements are key to the success of the regulatory/support mechanism;

- To understand different approaches to designing a regulatory/support mechanism;
- To be able to argue which regulatory or policy approach suits best, given the national or regional situation

2. INTRODUCTION

This module gives an overview of the most common regulatory and policy support mechanisms for promoting the deployment of sustainable energy technologies and encouraging increased capacity and output.

The mechanisms described in this module are usually applied where there is at least some degree of liberalization in the energy system (e.g. even if the major energy company is still a state-owned monopoly, other generators are allowed to enter the market): in non-liberalized systems, new technologies can be adopted by state-owned generators in response to government demands, rather than through the use of specific regulatory/support mechanisms to drive their uptake.

The mechanisms discussed can be divided into two categories, as follows:

1. Regulatory/support options that are immediately applicable to many sub-Saharan African countries[1]:
    - Establishing "standard" power purchase agreements (PPAs);
    - Ensuring long-term electricity generation licences and PPAs;
    - Developing a favourable tariff setting and adjustment formula;
    - "Light-handed" regulation;
    - Setting explicit targets for the share of renewables in the electricity generation mix;
    - Enacting explicit regulations that encourage local private participation in renewable energy development;
    - Providing subsidies to renewable energy-based power systems especially those located in rural areas (e.g. accessing existing rural electrification funds).
2. Other regulatory/support mechanisms implemented in developed countries that may be applicable to sub-Saharan African countries in the future:
    - Feed-in tariffs (such as those in Germany and Denmark);
    - Quota mechanisms (such as the renewable obligation in the UK and various other countries);
    - Tender schemes (Ireland);
    - Voluntary mechanisms such as green certificates (Netherlands);
    - Various hybrid schemes involving two of the above mechanisms (Spain).

[1]Because of its advanced industrial/technological status and strong internal economy backed by a sophisticated legal and regulatory regime, South Africa is an exception in sub-Saharan Africa as it can often successfully adopt regulatory/support mechanisms that are deployed in developed economies.

The main focus is on mechanisms used in electricity systems, as this is where the use of such mechanisms is currently most common. They can be used to drive capacity increases for electricity from renewable energy sources and combined heat and power (CHP), although in practice most schemes to date have been restricted to renewable energies. They could also be used to encourage the production of heat from renewable energy and CHP, although again to date, the focus has been on electricity. Finally, in theory the mechanisms could also be used to drive the adoption of sustainable energy technologies in other energy areas, for example the use of a quota obligation to promote renewable fuels in transport, or the provision of heat.

Although different examples of each mechanism have characteristics in common, it should be emphasized that no two schemes are identical. Differences arise because of different markets, energy systems and political intentions in different countries. The descriptions concentrate on the general characteristics of the mechanisms, rather than on specific details of how they are implemented in different countries (some of these country specific details are covered in the case studies).

In addition, each type of mechanism has different strengths and weaknesses, and will tend to encourage the development of sustainable technologies in a particular way. The extent to which weaknesses become serious defects depends to a great extent on the interaction between the mechanism and other policy efforts. These include for example, R&D support, capital grants, production tax credits and soft loans, as well as broader measures such as changes to planning regimes. Therefore where appropriate, the importance of other supportive mechanisms is also highlighted.

Many sustainable energy regulatory/support mechanisms—especially those discussed here—are relatively new policy and regulatory areas, so the evidence on their performance is not yet definitive. This is particular of sub-Saharan Africa where many of the regulatory options widely deployed in industrialized countries are yet to be tried. The purpose here is not to argue that a specific mechanism is the most effective model for any given country, or that the weaknesses demonstrated in the design of some support mechanisms in some countries mean that the actual mechanism is not a viable way of promoting the development of sustainable energy. Instead, the purpose is to give a broad overview of the different main mechanisms, and highlight some of the more significant generic strengths and weaknesses. The accompanying case studies enable specific issues to be followed up in more detail.

3. WHY SUPPORT RENEWABLE ENERGY?

The adoption of sustainable energy policies can bring advantages to both a country and an energy system:

- Renewable projects in particular can aid security of supply—both by reducing the need for imported fuels, and by increasing the diversity of a national generating portfolio—a key benefit to many sub-Saharan countries that are dependant on large-scale hydropower and thus exposed to drought-related energy risks.
- Small-scale sustainable projects—CHP or renewable—can contribute to a government's social agenda, for example by reducing fuel poverty, or by increasing access to electricity.
- Distributed generation (renewable electricity and CHP not connected to long distance transmission networks) offers benefits in terms of reduced losses over transmission wires and, in countries without major distribution and transmission networks, the possibility of avoiding the costs of building such infrastructure. This can increase the economic efficiency of systems, although this benefit is not always reflected in the prices offered for sustainable energy.
- On a broader social and political level, the development of a sustainable energy industry can create jobs and enhance technical expertise. Building a viable domestic energy supply chain can also offer export opportunities in a rapidly expanding international market.
- Renewable energy deployment can deliver additional local, regional and global environmental benefits.

However, many renewable energy technologies are relatively new, and still developing. Although costs of some technologies (especially wind) have fallen dramatically, they still need financial support to compete with established, conventional generation in most situations.

This problem is exacerbated by the fact that there is not a "level playing field" in the treatment of conventional and renewable energy technologies. This inequality notably includes the failure to take account of the costs of risks (higher oil prices and drought-related hydropower crises) associated with conventional generating technologies when costing generation. Conventional generators benefit from the failure to take these risks into account.

In addition, the different operating characteristics of some renewable energy technologies—for example, the intermittency of wind or some CHP projects—mean that they can conflict with the operating characteristics of established systems, which are designed for constant, predictable output from large-scale, centralized generating plants. The differences can, for example, lead to increased operating costs for distributors. Distributors may reflect these increased operating costs in the power purchase agreements (PPAs) they sign with generators, possibly at a level, which is in excess of the real system costs of intermittency. This effectively creates penalties for producing intermittent power.

Many of the issues ultimately relate to financial risks to investors: the financial risks of building and operating new, relatively untested technologies in liberalized systems mean that investors may be wary of financing new projects where the return on their investments is uncertain. They will be unwilling to put money into potentially risky renewable energy projects, if they have other less risky investment opportunities. The key question for evaluating the different mechanisms for supporting renewable energy technologies is therefore whether or not they will create sufficient investor confidence to develop projects (see box 1 below for perspectives of risks from the private sector).

Box 1. **Private-sector perspective**

"The three most important 'deal breakers' to private investors have been found to be:

- Insufficient legal protection and framework for protection of investor rights.
- Lack of payment discipline and enforcement.
- Too few guarantees from governments or multilateral institutions."

Regulation in Africa – Investors and Operators Regulatory Concerns, Mr. T. Horvei, Chief Executive , SAD-ELEC (Pty) South Africa, Report of the Proceedings of the 2nd Annual Conference of the African Forum of Regulators (AFUR), March 2005

Key regulatory risks experienced by investors

- Weak and ever-changing regulatory frameworks.
- Right of government to override regulatory decisions.
- Lack of clarity about power of regulator.
- Regulator without necessary minimum skills, capacity and competence.
- Unilateral regulatory decisions undermining project and investment returns.
- Playing field tilted in favour of dominant industry player (most often a state-owned enterprise).

(Extract from the AFUR discussion paper "Infrastructure Investment and Regulation in Africa – Investors and Operators' Regulatory Concerns" presented at the AFUR 2nd annual conference)

4. DESIGN ISSUES FOR REGULATORY/ SUPPORT MECHANISMS

As well as the need to encourage investor confidence, there are also other important factors for policymakers and regulators to take into account when evaluating different regulatory/support mechanisms. Some of these are summarized below:

- Will the scheme be effective in reducing investment risks to enable the deployment of renewable energy technologies, while encouraging investors? This is a fundamental requirement, although the advantages given to renewable technologies should not be disproportionately costly to consumers or taxpayers.
- Will these costs be spread fairly across business, individual consumers and government?
- Whether the mechanism is an effective means of meeting any target set for renewable energy generation.
- Whether the mechanism will encourage new renewable energy plants, or whether it just encourages the installation of new capacity.
- How will the mechanism interact with other energy policy measures such as R&D programmes or investment support schemes (in the few African countries where such programmes/schemes exist)?
- Will the mechanism encourage reducing prices for new technologies over time, through reducing or compensating for market failures or through technological development?
- Will it be sufficiently flexible to take technological developments and reducing costs into account in the future, so avoiding the potential for developers to make windfall profits?
- Will it offer the potential for commercial or technical opportunities, for example, the development of a domestic manufacturing industry?
- Whether it will encourage a range of renewable energy technologies, or whether it will concentrate only on one.
- Whether it will encourage new entry into electricity generation.
- Whether the scheme will be transparent for all users.
- Whether it will allow exports/imports of power.

The weight given to these design issues will obviously depend on the priorities and intentions of individual governments, and the final choice of mechanism will have to take them all into account. For example, if costs to consumers are a central concern, policymakers may want to implement a competitive mechanism such as the quota system. On the other hand, if achieving specific levels of output are a key driver, then less competition-focused mechanisms such as feed-in tariffs may be more appropriate.

In order for the scheme to be effective, those involved will also need a good understanding of the characteristics of renewable energy generation technologies, the workings of the broader electricity system, and broader issues such as the potential for innovation or declining technology costs.

5. TYPES OF REGULATORY AND POLICY SUPPORT MECHANISMS

This section gives a brief overview of the different characteristics of some of the main regulatory and policy support mechanisms. This is a generalized overview and it should be borne in mind that in reality the detail of different schemes can vary considerably. It should be read together with the more detailed descriptions of individual programmes, which are given in the case studies. The types of regulatory/support mechanisms are categorized into two: firstly, mechanisms that are immediately applicable to sub-Saharan African countries; and secondly, other mechanisms implemented in the developed world that may be applicable to the African region in the future.

5.1. Short-term regulatory/support mechanisms

The mechanisms discussed under this section are those that have either been implemented in some African countries or in other developing countries. These mechanisms to a large extent are relatively straightforward for African regulatory agencies to implement and may not need significant changes to the Electricity Act.

These include:

- Establishing "standard" power purchase agreements (PPAs);
- Ensuring long-term electricity generation licences and PPAs;
- Developing a favourable tariff setting and adjustment formula;
- "Light-handed" regulation.
- Setting explicit targets for the share of renewables in the electricity generation mix;
- Enacting explicit regulations that encourage local private participation in renewable energy development;
- Providing subsidies to renewable energy-based power systems especially those located in rural areas (e.g. tapping into rural electrification funds).

Establishing "standard" power purchase agreements (PPAs)

In principle, most sub-Saharan African countries are committed to private sector supply of power to the national grid. However, negotiations with the utility to purchase energy from small producers tend to be cumbersome and the tariff offered unattractive to develop renewable energy projects to their full potential.

This market uncertainty stands in the way of substantial investment in renewable energy-based electricity generation in the region. In South Asia (Nepal and Sri Lanka), market uncertainty was overcome by instituting a "standard PPA"—a "standard offer" from the national utility to purchase all energy produced by specific renewable energy-based independent power producers (IPP) at a pre-announced price. This is somewhat akin to the feed-in tariff legislation implemented in developed countries such as Germany. The absence of such a "standard offer" inhibits the scaling up of small renewable energy investments in the power sector to their full market potential (UNEP/GEF, 2006).

The lack of clear rules to allow the sale of power produced from sustainable energy systems discourages investment opportunities in renewable energy-based electricity generation. In particular, lack of commitment from the utility to purchase excess power produced at an attractive feed-in tariff can often limit the renewable energy project to a size, which is less than optimal in terms of the available resources. Similarly, lack of regulatory measures to encourage agro-processing industries to sell excess power to neighbouring rural communities results in sub-optimally sized projects.

Ensuring long-term electricity generation licenses and PPAs for IPPs

In most sub-Saharan African countries with IPPs, typically, generation licences are issued for varying periods of 7 to 15 years. This implies that the investors have a very limited period of time to recoup their costs and make a decent margin. Issuing longer-term electricity generation licences and PPAs to independent power producers (e.g. 15-30 years) can ensure that the feed-in price of electricity charged by the investors of sustainable energy systems is moderated. This is essentially because, longer-term agreements allow for sufficient time for the investor to payoff project financing debts as well as providing adequate amortization periods for the equipment.

Developing a favourable tariff setting and adjustment formula

The calculation of the feed-in tariff on the basis of the cost of the fuel can result in very low feed-in tariffs offered to renewable energy development as the cost of renewable fuel is often very low or sometimes free but with higher equipment costs. A more favourable tariff setting and adjustment formula is one that takes into account the "avoided cost" of installing competing thermal power plants. For example, in Mauritius, the Government set up a technical committee at the Ministry of Energy to address the issue of energy pricing and power purchase agreements for bagasse-based cogeneration. In the price setting mechanism, the committees worked on the basis of the cost of a 22 MW diesel power plant. On this basis, the utility was directed to determine the tariff at the "avoided cost" for the diesel power plant, which in turn became a standard feed-in price for electricity generated by the sugar mills.

"Light-handed" regulation

"Light-handed" regulation refers to the regulatory agency's deliberate action to either "ignore" or make less stringent provisions for a player or group of players. In this case, it would entail the regulatory agency explicitly exempting or significantly reducing the statutory requirements of investors in sustainable energy. For example, the regulatory agency may waive the need for licensing small to medium scale renewable energy investments below a certain threshold (in the case of Nepal, initially the threshold was 100 kW capacity but was eventually increased to 1 MW).

Setting targets[2] for the share of renewables in the electricity generation mix

To mitigate the negative trend of having an excessively large share of IPPs generating electricity from fossil fuel-based power plants or large-scale hydro plants (that can be prone to drought-related risks), the regulatory agencies in collaboration with the Ministries of Energy can set explicit targets for the share of electricity generation from proven renewable energy technologies such as hydro, wind, solar PV, biomass-based cogeneration and geothermal. Kenya provides a model example where such targets have been set. The Government of Kenya has set a target of 25 per cent of electricity generation to come from geothermal energy by the year 2020. Consequently, an IPP is actively exploiting this resource as part of a broad investment effort aimed at meeting the year 2020 target.

Enacting explicit regulations that encourage local private participation in renewable energy development

The examples of Kenya, Mauritius and Zimbabwe demonstrate the potential financial and technical capability and viability of local private investors in the power sector. This is corroborated by findings from recent AFREPREN/FWD studies which indicate that local private investors can own and operate small to medium-scale entities in the power sector, either on their own or with foreign partners (see

[2]Targets should not be confused with "quotas" which are discussed separately. "Targets" are usually set at the policy level, while "quotas" are often backed up by legislation and might imply certain consequences befalling a specified party for failure to meet the "quotas" or exceeding them.

Marandu and Kayo, 2004). Appropriate policy and financial incentives such as enactment of lower entry requirements, tax holidays and lighter regulation of initial public offers (IPOs) can encourage local private investment in a privatized electricity industry. The ideal entry point, as in the case of Zimbabwe and Mauritius, is likely to be in renewable energy systems such as small hydro and wind energy sources as well as through local cogeneration in agro-based industries.

Providing subsidies to renewable energy-based power systems

Although developing renewable energy-based power systems in rural areas can register poor returns on investment, linking decentralized renewable energy power plants to rural electrification provides local benefits and increases the sustainability of such projects. However, adding the rural electrification component increases capital costs and also lowers the overall load factor of the power plant by increasing demand during peak hours and using small amounts of power during the rest of the day. In order to provide a reasonable return on investment, the capital cost of rural electrification needs to be covered in part or fully by subsidies in the form of grants by the government sourced from rural electrification funds or from donors.

A number of governments (primarily Uganda but also Kenya and Tanzania) in the region have put in place grants for private companies that expand rural electrification services, particularly those using renewables for electricity generation. The Ugandan government under its Energy for Rural Transformation (ERT) Programme will pay the additional cost accrued to the private power developer for providing rural electrification. One example of this is the West Nile Rural Electrification Company, which in April 2003 was awarded the concession of the West Nile region. This company is investing in a 3.5 MW small hydro project with partial grant support from the ERT. Three other energy service companies (ESCOs) in Uganda are investing in new generation capacity on similar terms.

Review question

1. Name at least five regulatory/support mechanisms that can encourage renewable energy development in the African power sector in the short term.

5.2. Medium to long-term regulatory/support mechanisms

These support mechanisms are largely implemented in the developed world. Some of them require sophisticated implementation strategies and, in some cases, enactment of new laws or significant changes to the Electricity Act. As mentioned earlier, with the exception of South Africa and possibly Mauritius, few sub-Saharan African (SSA) countries have implemented these regulatory/support options. In many SSA countries, the sophisticated regulatory and legal prerequisites that are required are yet to be put in place.

Feed-in tariffs

Feed-in tariffs offer either a minimum guaranteed price for output or a premium on the market price for output. In either case, electricity utilities are obliged to allow generators to connect to the grid, and to buy all of a project's output at a pre-defined price.

Key features:

- The scheme can be open-ended, or can be put in place for a specified number of years.
- The tariff schemes can be banded for different technologies, with less developed technologies receiving higher prices for their output.
- The level of the tariff can be set by assessing several factors such as:

  The avoided cost to the utility of building its own new plant;

  The end price to the consumer;

  A more explicit political decision about the level of tariff necessary to stimulate renewable deployment.
- The costs of the tariff can be covered by a levy per kWh on consumers, or on taxpayers, or both.
- Tariff levels can be set to decline over the years, reflecting the potential for declining technology costs.

The level of the tariff tends to be set for several years at a time, often through legislation, meaning that there is a high degree of certainty for investors on the returns available, and a high level of confidence about the duration of the scheme. Schemes offering a minimum guaranteed price tend to provide more certainty for investors than those which offer a premium on the market price, this being due to the higher degree of predictability that this affords.

The level of deployment of technologies is not set in advance, but instead is driven by the level of the premium in the tariff price. In other words, the government sets the price for the output from renewable energy generators, but lets the market determine the level of output. This in turn means that the total costs of the scheme are not known in advance because the costs will depend on the success of the mechanism in driving new capacity. Having said that, it would be possible to make sensible predictions about the amount of new capacity likely to be stimulated and hence the costs, based on the prices set in the tariffs.

Similarly, the length of a scheme can mean that technological developments over the course of a few years allow participants to make windfall profits in the last few years. A degree of flexibility should therefore be designed in to any scheme to ensure that the tariffs are not set unreasonably high, especially in the later years of a scheme.

The design of a tariff scheme may have to take into account the availability of renewable resources. For example, areas of high wind will obviously prove more attractive to developers seeking to maximize their returns. This can mean that networks in areas with high wind resources are targeted by developers, which in turn means that the customers of the network in that area are potentially subject to higher prices than network customers in areas with less wind. The tariff scheme can be designed to minimize this by offering higher prices for wind output in areas with less wind resources, so encouraging developers to site projects there. Alternatively, in order to distribute the financial impact equally over consumers and to avoid significant differences in price, the levy to finance the feed-in scheme can be equally covered by all the existing networks (cf. Germany).

As well as the level to which the tariff is set, the success of such schemes can depend on:

- Access charges to the grid—transmission or distribution.
- Any limits set on capacity.
- The ease of siting projects—i.e. getting approvals through planning systems.

Quota mechanisms

Quota mechanisms, also known as renewable portfolio standards (RPS), are an obligation for electricity suppliers to take a certain amount of sustainable power, or for customers to source a proportion of their power from renewable energy sources.

Key features:

- The percentage can increase over time, driving increased deployment.
- Utilities can also choose to pay a penalty rather than buy their allocation of the obligation.
- No requirement for utilities to allow priority access to networks.
- The operation of the system is supported by tradable green certificates for the output, which certify that the supplier has actually bought renewables-based power. These certificates can be sold with the power, or traded separately. In either case, the value of the certificate adds value to the actual generation. Green certificate markets are discussed in more detail below.
- Certificates could be banked for use in future compliance periods. This banking period is usually limited (generally five years).

In contrast to tariff systems, the government sets the desired level of output, and allows the market to decide the price that will be paid for it. A quota system avoids the government selecting which technologies will receive the benefits, instead leaving the technical choices to the market.

The level of incentive for the utilities to comply with the obligation depends on the level of the penalty payment set—the higher the cost for non-compliance, the more incentive to buy renewables-based power.

The value of renewables-based power can be further enhanced by redistributing any of the money paid as penalties to companies who have met their obligation. Utilities decide how best to meet this obligation, and what projects they will contract with if they chose to buy renewables-based power. Not surprisingly, utilities will chose to contract with the cheapest forms of generation, so meeting their obligation in the most cost effective way. This will keep the cost to companies and consumers down. In addition, there is no requirement for utilities to sign long-term contracts with generators for their output. The short-term nature of the market can act as a disincentive to investment across the board.

The need to negotiate deals with utilities for their output implies a degree of expertise and resources for developers. This may limit new entry into the system, or at least limit entry to relatively large, well-resourced entities. In addition, new entry by smaller companies may be limited by the investment risks inherent in the mechanism, effectively meaning that only large companies with diverse portfolios are able to participate. Both of these problems can be addressed by ensuring the availability of consolidation services to allow smaller developers to pool their output, reducing individual participation costs and risks.

If certificates can be banked from one compliance period to the next, careful monitoring will be needed to ensure that no gaming takes place, and that there is not a tendency for the development of renewable energy to enter a "boom and bust" cycle.

Quota mechanisms are relatively new, so there is limited evidence on their performance. However, it appears that the emphasis on the market can have two particularly significant impacts for generating technologies:

- Only the cheapest forms of generation will receive contracts.
- Less developed—and therefore riskier—technologies will not receive contracts, so limiting their future development and deployment.

If a government wants to support a diverse portfolio of renewable energy technologies, including developing technologies, other support mechanisms (such as capital grants) will be required to compensate for the short-term nature of the market.

Review question

What are the main differences between a feed-in tariff system and a quota system?

Tender schemes

Under a tendering scheme, competitive bids are put forward to government for individual renewable energy projects, following a call for tenders launched by the government.

Key features:

- Suppliers are obliged to buy a certain amount of renewable power at a premium price.
- Although specific characteristics vary, it is likely that the government will:
  - Set an overall target for renewables-based generation, adding specified limits for individual technologies within that.
  - Set a specified time for contracts for the generation, during which time they will receive a premium price.
- The winning contracts are selected by the government, usually on the basis of cost, although in some schemes other factors such as technical quality and socio-economic aspects also play a role.

- Successful projects can either:

  Receive the price they have bid, or

  A “strike” price based on an assessment of developers needs.

- Can be banded to encourage the development of newer technologies.

Because there is a guaranteed premium for a set period of time, tender schemes can increase investor confidence in renewable energy projects. This is, of course, highly depended on the length of the contact and the price offered. However, the bureaucracy of the schemes and the government tender processes can act as a disincentive to put projects forward, as this implies significant project development costs without a guaranteed contract.

In addition, tender schemes tend to be stop/start, with months or even years between different bidding rounds. This can create a “boom and bust” environment for developers, who may be active for some periods, but without new projects for others. This in turn can discourage the emergence of a domestic renewable manufacturing industry, as there is no certainty about the frequency of the periods of “boom”.

Voluntary mechanisms

Green certificates

As well as operating with a quota system, green certificates can be used in voluntary markets to support renewable-based generation. The certificates can be traded separately from the power and sold to consumers who are willing to pay the additional cost to support sustainable energies. However, in the case of voluntary markets, the success of the scheme will rely on consumer awareness and willingness to pay the additional cost. Voluntary schemes pre-suppose a high-level of environmental public awareness—which is virtually absent in most of sub-Saharan Africa.

Because of their voluntary nature, green certificate schemes do not necessarily provide confidence to investors to develop new projects. Green certificate schemes therefore rely heavily on the success of other support measures (e.g. grants, soft loans, tax credits) in order to provide this confidence and to keep costs low enough to make sustainable generation attractive to consumers. Other strategies, such as the disclosure of the generating source and green power marketing can complement voluntary green certificate markets—these are outlined below.

Disclosure

In addition, green certificates schemes can be supported by policy measures such as the disclosure of the generation source of electricity on consumers' bills. Disclosure is based on the assumption that in a competitive market, consumers may chose to buy their power from less environmentally damaging forms of generation rather than solely allowing their choice to be dictated by the price. Disclosure requirements can include information on the type of generation, the amount of carbon dioxide emitted per kWh or the amount of radioactive waste produced.

Green power

A related issue is selling "green" power to consumers in markets where consumers can chose their supplier. This assumes the presence of a retail competitive power market—this has yet to be tried in Africa. This is again based on the premise that some consumers would include environmental performance in their choice of power supplier.

Green power schemes offer a way for suppliers to differentiate their product, and often to charge a premium for it over market prices for "brown power". In some markets, such as the UK, this has led to a situation where suppliers are obliged to provide a certain proportion of their power from renewable sources under the renewable obligation, but some have chosen to fulfil this obligation by marketing the green power separately from their standard product and to charge a premium for it. This approach allows them to offset any additional costs of contracting for renewable output—or even to profit from the fact that they are obliged to contract for it. Other companies have chosen to contract for green power in addition to any renewable obligation they might have.

Voluntary schemes rely on support from other measures to drive a viable market. Information provided to environmentally conscious consumers could act as a driver, as can the marketing opportunities of supplying green electricity.

Concerns have been raised that green power schemes do not necessarily encourage new construction, but rather maintain output from older schemes. This can be avoided by devising schemes, which explicitly state that revenue from a scheme will be used to build new renewable projects.

Various hybrid schemes involving two of the above mechanisms

Some countries—notably Spain and Belgium—have chosen a mixture of support mechanisms to drive renewable energy development. The strength of this approach is that it allows the strengths of individual mechanisms to be adopted, and for the weaknesses to be compensated for by other measures.

The flexibility of hybrid schemes also allows investors to choose which aspect of the scheme suits their finances and the type of project best.

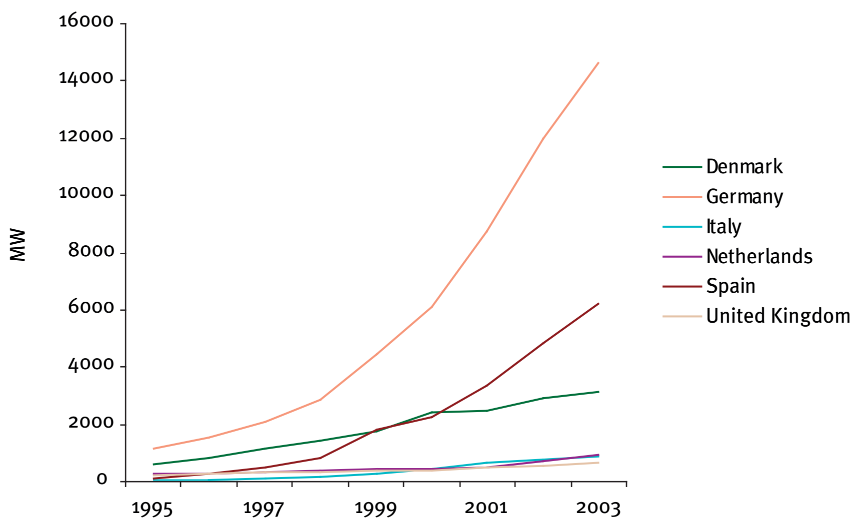
5.3. Regulatory and policy support mechanisms in practice

Regulatory/support mechanisms for renewable technologies are relatively new policy and regulatory measures, and have often been in place for only a few years. In Africa, the experience with such mechanisms is even more limited. Given the length of time it can take to develop new projects, evidence of their success or otherwise can therefore only be presented as indicative.

In addition, many of the support mechanisms in place have tended to concentrate on wind power, as this the most developed renewable technology. This means that other renewable technologies, which may be more appropriate in other countries, may have been neglected by the available support measures.

However, on the basis of the schemes to date, it appears that tariff schemes have been more successful than tender and quota schemes at encouraging the deployment of wind power in particular—installed capacity of onshore wind in Denmark, Germany and latterly Spain far outweigh installed capacity in other countries which have adopted more of the competitive tender and quota mechanisms (see figure I).

Figure I. Onshore wind cumulative installed capacity (MW)



In comparison, countries which have used quota or tender systems show a far lower level of development. This is not entirely unexpected, given the investor certainty ensured by fixed payment tariffs. However, it should be noted that there may also be local factors related to the design or wider policy contexts of specific schemes that have contributed to the different rates of development—it may not just be down to an inherent superiority of one type of mechanism over another.

So, for example, the ease of getting planning permission for projects or connecting projects to networks can directly affect the rate at which renewable energy projects are implemented. Similarly, the uncertainty created by the possibility of future changes to schemes can also reduce investor certainty. Some of these issues are highlighted in the individual case studies.

It is important therefore to remember that the interaction between the mechanisms outlined above and other policy measures in place to support renewable energy will play a vital role in the success of any programme to encourage the deployment of sustainable energy technologies.

Review question

Describe in short the main support mechanisms for renewable energy.

Discussion question/exercise

Given the particular situation in your country, which of the described support mechanisms might prove most useful? Describe the particular situation and give reasons for the support mechanism(s) chosen.

Bear in mind that investor confidence is a crucial aspect, and that you can combine aspects from different support mechanisms.

6. EXAMPLES OF REGULATORY AND POLICY SUPPORT MECHANISMS IN AFRICA AND OTHER DEVELOPING COUNTRIES

6.1. Mauritius: standard feed-in prices for bagasse-based cogeneration

Efforts have consistently been made over the past 40 years in Mauritius to exploit this bagasse-based cogeneration for energy generation. St. Antoine Sugar Factory became the first exporter of electricity to the grid in 1957, when around 0.28 GWh was sold to the Central Electricity Board (CEB)—the national electricity utility.

In early 1980s, two other bagasse-energy generation projects were implemented. The first one was a sugar factory located at Médine, with an installed capacity of 10 MW to supply around 6 MW to the grid. It was designed to generate what is termed as "continuous power" that is, using bagasse as feedstock for combustion, during the cane-crushing season only.

The second was in 1982 when another factory—FUEL—commissioned a power plant with 21.7 MW of installed capacity. This plant exported electricity all year-round, using bagasse as feedstock for combustion during the crop season and coal during the intercrop season. This arrangement was termed "firm power". With the successful operation of these two units, the amount of electricity generated from bagasse reached 70 GWh/year.

As the significant potential for cogeneration became apparent, there was a need to have a standard feed-in electricity price to avoid the need for each sugar factory to independently negotiate with CEB. Therefore, the Government set up a technical committee at the Ministry of Energy to address the issue of energy pricing as well as a power purchase agreement (PPA). To develop a price setting mechanism, the Committee worked on the basis of the cost of diesel plant of 22 MW capacity—the next planned installation by CEB. Consequently, the Committee determined the avoided costs and recommended the kWh price for electricity generated from cogeneration.

For the "continuous" power plants, the price of the electricity was set to about US$ 0.04 and was indexed to the price of oil. These plants have PPAs for 15 years with provisions for the supply of a minimum of 16 GWh every crop season, the export of 45 MW of power to the grid. Other provisions include a power intake of 3.5 MW daily during off-peak and a bonus/penalty for minimum power supply/default.

The “firm” power plants have slightly longer PPAs of 18 years to supply 180 GWh of energy per year. The minimum from bagasse is 45 GWh. During the crop period, the minimum power is 11 MW as semi-base load and 17 MW for two hours during evening peak. Power during the off crop season is 13 and 18 MW respectively. The kWh price is about 0.055 US cents, indexed to the price of coal and the exchange rate of the US$ and the euro.

Furthermore, there is a provision to ensure that the utility also buys intermittently available electricity from the sugar factories. However, the price for intermittent power is frozen at US$ 0.006 per kWh so as to discourage this highly inefficient mode of electricity generation. As the price setting mechanism has to provide for a value of the fuel utilized, the bagasse used for generation purposes is priced at Rs100 (or US$ 3.7) per tonne.

The overall effect of the standard feed-in electricity tariffs has been the gradual phasing out of intermittent electricity generation and shifting towards continuous as well as firm power. Tables 1 and 2 show the evolution of the electricity generated from bagasse/coal and equivalent amount of bagasse used over the 1988-1998 period. This is the period during which bagasse-energy development was a high priority issue in the Mauritian sugar industry. On the whole, electricity generated from bagasse has increased by more than three-fold over the ten-year period.

In parallel to the incentives for bagasse-based cogeneration, policy measures have been introduced to increase the efficiency in electricity production. Those measures include:

- A performance linked export duty rebate payable by millers related to their efforts in energy conservation to generate surplus bagasse and in energy generation, preferably, firm power.
- Income tax exemption on revenue derived from the sale of bagasse electricity, and capital allowances for investments in energy efficiency.

In response to these incentives and policies, the sugar industry has implemented a number of measures to efficiently use energy in sugar cane processing, e.g. improved sugar recovery, the enhancement of the calorific value of bagasse, reduction in power consumption in the prime movers of sugar manufacturing equipment, reduction in process heat consumption in juice heating and evaporation, adoption of continuous processes, factory computerization and process automation.

Table 1. Evolution of electricity production from the sugar industry (GWh) and kWh/tonne cane

Power	Fuel source	Year 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Firm	Bagasse	41	26	18	39	50	39	44	46	70	66	112*
	Coal	34	68	45	54	43	40	46	41	10	23	62
Continuous	Bagasse	19	20	24	21	28	27	28	30	33	53	109
Intermittent	Bagasse	12	10	11	10	6	4	4	5	7	6	4
Total GWh (bagasse)		72	56	53	70	84	70	76	81	110	125	225
Total GWh (bagasse and coal)		106	124	98	124	127	110	122	122	120	148	287
Total tonne cane (x 106)		5.52	5.44	5.55	5.62	5.78	5.40	4.81	5.16	5.26	5.79	5.78
kWh/tc		13	10	10	12	15	13	16	16	21	22	39

Source: Deepchand, 2003.

*Includes 30 GWh of electricity generated in 1999 from Crop 1998 stored bagasse.

Table 2. Evolution of equivalent tonnage of bagasse (X 10^3) used for electricity export

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Firm	93	58	40	88	114	90	100	104	160	149	254
Continuous	49	51	59	53	70	68	70	76	83	133	272
Intermittent	34	30	30	29	18	11	11	14	21	17	10
Total	176	139	129	170	202	169	181	194	264	299	536

Source: Deepchand, 2003.

6.2. Kenya: explicit target for share of renewables—case of geothermal energy

Starting in 1981, Kenya was the first country in Africa to exploit geothermal resources for electricity generation. After some inconclusive initial exploration at Olkaria in the 1950s, interest revived during the 1970s. A feasibility study carried out to evaluate Olkaria's potential for generating electricity found that the geothermal field covered 80 km² and could provide steam sufficient to provide 25,000 MW of generation capacity (assuming re-injection which would make it fully renewable). So far, 103 geothermal wells have been drilled in Kenya for exploration, production, monitoring and re-injection. Of these, 97 wells are in the Olkaria area and the rest in the Eburru field (Mariita, 2002; Mbuthi 2004).

The draft National Energy Policy provides a target for the contribution of geothermal electricity generation in Kenya. The policy provides that by the year 2020, the installed capacity of geothermal energy is expected to account for a quarter of the total installed generation capacity up from the current 9.7 per cent (Mbuthi and Andambi, 2004). Consequently, to encourage investment in geothermal development for electricity generation, the energy policy provides the following incentives (Republic of Kenya, 2004):

- Ten-year tax holiday for geothermal plants of at least 50 MW; seven years for plants in the range of 30-49 MW; and five years for plants between 29-10 MW.
- Seven-year tax holiday on dividend incomes from investments made from domestic sources.
- Duty and tax exemptions on the procurement of plant equipment and related accessories for generation and transmission during project implementation. In addition, the procurement of spare parts would be made free of duties and taxes.

Consequently, Kenya's geothermal energy developed has realized an installed capacity of 127 MW, of which 12 MW is exploited by ORMAT International, an independent private power producer (KPLC, 2003; Mbuthi and Andambi, 2004).

6.3. South-east Asia: standard PPAs for small hydropower development

Small hydropower development in Nepal

As a direct result of the liberalization in the power sector brought about by the Electricity Act (1992), international independent power producers (IPPs) invested in two medium hydropower projects in 1995: the Khimiti Hydro Electric Project (60 MW) and Bhote Koshi HEP (36 MW). The PPAs for these projects were negotiated on a case-by-case basis between the utility and the IPP. In October 1998, the government of the time announced that the national utility, Nepal Electricity Authority (NEA), would purchase all energy produced by small producers (5 MW or below) at a standard "power puchase agreement (PPA)"[3]. By early 1999, the first small hydro IPPs began to carry out feasibility studies and approach financial institutions with the standard PPA in hand. The first financial closure by local banks took place in 2000 and the Syange project (183 kW) was on line in January 2002 followed by the Piluwa Khola (3 MW) project October 2003.

Even after the standard PPA was announced, prospective IPPs remained skeptical about the credibility of the utility's offer. There was only limited confidence

[3]The rate was Rs 3.00 (4 US cents) for the dry season and Rs 4.25 (5.7 US cents) with an escalation of 6 per cent per year for five years on the local currency rate.

that small hydropower could be developed into a profitable sector at the rates being offered. Support was provided by Winrock International and GTZ to entrepreneurs and their engineering consultants by sharing feasibility costs, providing free technical reviews of feasibility studies and site construction, and by helping them negotiate with the utility, banks and insurance companies.

After the "standard PPA" was announced, over 50 feasibility studies were completed, 20 PPAs signed, 10 projects reached financial closure, and seven projects have commenced construction resulting in five completed projects. The projects that were financed after the "standard PPA" came into force are marked in bold in the table below. Once the barrier of market uncertainty for the produced electricity was removed through the "standard PPA" and developers gained confidence in the sector, hydropower has become attractive as an investment sector to both private developers and financing institutions, despite the ongoing insurgency in the countryside. All financing for these hydropower projects has come from local banks. Nepal has seen an investment by local banks of some US$ 47 million in new small hydropower projects in the last seven years, of which US$ 13 million has gone to smaller projects under the "standard PPA".

Table 3. Private sector investment in small hydro in Nepal

Projects	Size (MW)	Date of commissioning	Total cost (US$M)	Local financing (US$M)
Khudi	4.0	June 2006	6.36	4.47
Sisne	0.75	2006	1.4	0.99
Chaku	1.5	Jun 2005	1.64	1.15
Sun Koshi	2.6	Mar 2005	3.6	2.51
Rairang	0.5	2004	0.45	0.29
Piluwa	3.0	Oct 2003	5.5	3.16
Chilime	20	Aug 2003	30	19.86
Indrawati	7.5	2002	20.5	14.29
Syange	0.2	Jan 2002	0.3	0.16
Jhimruk	12	1995	20	Norwegian grant
Andhi Khola	5.1	1991	3.8	Norwegian grant

Note: Jhimruk and Andhi Khola have been privatized and are now operated by the Butwal Power Company.

Small hydropower development in Sri Lanka

In 1996, as part of the liberalization in the power sector started in 1994 by the Sri Lankan government, the Central Electricity Board (CEB) allowed the grid connection of private small hydro (<10 MW) and issued a "standard PPA" starting in

1997 and revised annually. The rate on the PPA was determined by the avoided cost of fuel at the CEB thermal plants and hence to the international price of petroleum fuel. The international fuel prices were averaged over three years to avoid large spikes which often occur in petroleum prices. This means that private small hydropower developers are paid only for the energy (MWh) they produced and not for the capacity (MW) which they also contribute to the system. Despite this, returns on investment were found to be attractive with simple payback periods typically of around 3-4 years or less. The published feed-in tariff is shown in the table below. It is likely that the persistent high price of petroleum products will help to contribute to continued and increased returns to investors.

Table 4. PPA feed-in electricity prices in Sri Lanka for small hydropower

	Dry season (Feb.-April) Rs/kWh	Wet season (balance months) Rs/kWh
1997	3.38	2.89
1998	3.51	3.14
1999	3.22	2.74
2000	3.11	2.76
2001	4.20	4.00
2002	5.13	4.91
2002	5.90	5.65
2003	6.06	5.85
2004	5.70	4.95
2005	6.05	5.30

US$ 1 = SL Rs 100, so the Rs can be read as US cents.

6.4. Photovoltaic energy service companies in Zambia[4]

Introduction

The following example is the result of a well-thought out scheme that has been implemented in the Eastern Province of Zambia. The programme of rural electrification in Zambia shows that the concept of ESCOs offers an interesting policy tool and could be replicated in other countries.

[4]Lemaire X. (2006) Case Study: Photovoltaic Energy Service Companies in Zambia. Centre for Management under Regulation, Warwick Business School.

Energy service companies (ESCOs)

The concept of ESCOs[5] was launched in 1998 in the Eastern Province of Zambia with the support of the Swedish International Development Agency (SIDA). In the first version of the project, the Zambian government would buy the photovoltaic solar systems that are lent to an energy service company, which could have up to 20 years to reimburse the loan from the government (initially a donation from the international agency).[6] The ESCO installs solar equipment in households and small shops and charges a limited fee. Then, the ESCO gets a monthly payment for the systems. A battery fund has been created to replace the batteries regularly.

Unlike conventional installers, these small enterprises are not paid for the installation of a product—the initial fee covers just a small part of the cost of installation—instead they are paid for the delivery of an energy service to their clients. In this scheme, ESCOs are given incentives to ensure a continued operation of the systems, as the customers pay only for the time that the service is provided. In fact, ESCOs are not operationally far from conventional utilities who would charge a low cost of connection to the grid and receive a monthly payment from their customers for the delivery of electricity.

Key ESCO aspects

The selection of the enterprises to become ESCOs was done in 1999. Now three autonomous ESCOs exist in the districts near the border with Mozambique and Malawi: one in Nyimba—operational in 2000 (NESCO), one in Lundazi—operational in 2001 (LESCO) and one in Chipata—operational in 2002 (CHESCO).

ESCOs are small structures with a director/project manager, two finance/administrative staff and 2-3 technicians. ESCOs photovoltaic systems include currently a 50 Wp panel with a 90-105 Ah battery. Each ESCO has its own history and faces specific constraints due to its location.

In Lundazi, LESCO has 150 systems, out of which 70 are currently operating. The other systems are not working mainly due to battery problems. The majority of battery failures are in the Zambia National Service Camp. LESCO is facing financial problems due to non-payment of the monthly service fee by this institution.

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[5]The project described in this case study is mainly funded by the Swedish International Development Agency (SIDA) with the technical assistance of the Stockholm Environment Institute and the University of Zambia.

[6]In 2005, the formal ownership of the solar systems has been transferred to ESCOs and it has been decided that the capital will have to be reimbursed in 10 years instead of 20 years, but with a 50 per cent capital subsidy. In the future, ESCOs will get a loan from a credit facilitator and buy directly the solar systems.

In Chipata, CHESCO has 150 systems, out of which 140 systems are currently working. CHESCO has faced a lot of difficulties with the tokens of a SIEMENS pre-payment system. Every time the charged tokens were not recognized, the client had to return to CHESCO's office in Chipata from sometimes as far as 60 km and CHESCO had to give them extra days of electricity as compensation.

In Nyimba, NESCO has 100 systems, 94 systems are currently working. NESCO was the first ESCO established, and now seems to have a good knowledge of the systems.

To establish comparisons, the cost of connection to the grid with ZESCO is 300,000 ZMK (US$ 91) in the capital Lusaka, 500,000 ZMK (152 US$) in Nyimba and 800,000 ZMK (US$ 244) in Lundazi. The monthly payment for grid electricity depends of course on the level of consumption, but is on average far less than the monthly service fee charged by ESCOs for solar energy, especially for the kind of appliances used. The low residential consumer monthly tariff of ZESCO is 18,000 ZMK (US$ 5). This is due notably to the fact that electricity from the grid is highly subsidized in Zambia.

A positive commercial relationship with clients

400 clients are now paying a monthly fee to the ESCOs for solar photovoltaic electricity. Each ESCO has a waiting list of 400-500 clients. Solar systems enable small businesses to extend their hours of work and therefore to improve their income generation. For households, solar systems improve the quality of life by supplying basic needs such as light, TV and radio. The impact of a basic service such as light seems to be tremendous, especially for pupils who can study during the night. According to the latest available data, there has been a good payment record, no acts of vandalism and very few solar panels have been stolen, this being due to strong social control. Nevertheless, due to default of payment, a limited number of solar systems have been repossessed.

Technicians of ESCOs have to go every month to visit the clients and collect fees (except for prepaid systems). It means therefore that an inspection of the installation is conducted monthly. This also enables ESCOs to have regular feedback from their customers.

Persistent technical problems that are or can be solved

The main technical problem comes as usual from the batteries and the regulators. For various reasons, very few batteries from the first installations are still working. The initial design of the different systems and the quality of some batteries seems the issue. At the start, the ESCOs lacked the capacity and the necessary qualifications to maintain the systems. There could be also a tendency to overuse the systems, especially in businesses. Now, it seems that with a change of the kind of batteries used, the training of ESCO technicians in order to enable them to design the systems, and the dissemination of information to clients who are now more aware of the possibilities and limits of their solar system, these initial technical difficulties are about to be solved.

Financial uncertainty for ESCOs

ESCOs get a long-term loan that has to be refunded. ESCOs charge an installation fee that represents less than 10 per cent of the cost of the system (which is about US$ 900). The monthly fee is currently around US$ 10-13, which seems to be the maximum that clients are willing to pay. This covers the running costs (servicing, maintenance) of the ESCOs, but cannot cover all the capital costs. In fact, now that the ownership of the installations is progressively and officially transferred to the ESCOs, it has been agreed that 50 per cent of the capital cost will finally have to be subsidized for the first installations and 25 per cent for the new installations that the ESCOs will buy from now on (Swedpower, 2005, p. 5). Some uncertainty seems to remain on the future of the exemption of VAT for ESCOs.

Moreover, the inflation rate in Zambia is still around 20 per cent per year (compared to 400 per cent at the beginning of the 1990s).[7] ESCOs are importing all the components of solar systems that are paid for in US dollars while they are being paid in local currency by customers who cannot easily absorb successive increase of the monthly fee. This creates considerable distortion for ESCOs.[8]

Important points for replication

Even if ESCOs in Zambia are just starting to be fully operational, some lessons can already be drawn from this case.

The choice of location

In the Eastern Province of Zambia, the rural population is wealthier than in other parts of Zambia. The initial survey showed that 75 per cent of the respondents

[7]As the money invested in local currency is quickly devalued, some ESCOS have launched a small business (of soft drinks) to make money and keep the capital. The battery fund is deposited in US dollars.

[8]The current fee charged by ESCOs even after successive increases, is around 40-45,000 Kwacha. It should be at 52,000 Kwacha to match the initial fee value charged by the ESCOs the year they started to be operational based on exchange rate changes.

in this area were willing to pay US$ 5 per month for electricity (for an average monthly income of US$ 42 in 1998). In poorer places, the contribution capacity of households will be lower. Therefore, the possibility of replication seems to be limited for the moment to the relatively wealthier places in Africa.

The maintenance scheme also implies that solar systems are not installed into large area, so that ESCOs can regularly access all the systems for maintenance and to collect the fees. They need to have a sufficient number of clients (150-200) to be profitable. Another point to take into account is any planned grid extension that can affect the economics of ESCOs. However, competition from grid connected conventional electricity does not mean necessarily the bankruptcy of ESCOs working in the area, as ESCOs will have clients situated in the outskirts of the main towns who will never be connected (for example, the centres of Lundazi, Chipata and now Nyimba are connected to the grid while households on the outskirts are not).

The commercial scheme

Initially, only one kind of basic system chosen by the Department of Energy was offered: a 50 Wp panel with a 90-105 Ah battery to enable the connection of four bulbs and a power point for a small TV/radio. Now ESCOs tend to provide a more diversified range to meet the needs of their clients. It seems that there will be three standard sets:

- The current 50-70 Wp with a 100 Ah battery without inverter.
- 80-120 Wp and a 150 Ah battery with maybe a small inverter.
- 120-150 Wp for a system with a refrigerator.

It is also important to take into account the fact that for some groups of clients such as farmers, income can vary considerably during the year. Therefore, payment of the debt by ESCOs may have to be made on a basis other than monthly, e.g. quarterly or annually.

Providing electricity to institutions such as schools, health centres and the army may be a priority from a social point of view, but that raises the question of the capacity and the willingness of these institutions to pay the ESCOs on a regular basis.

Training, public awareness and the choice of equipment

As usual in solar energy, the fact that solar systems need to be sized to the consumption requirement of the users implies a good understanding by the clients of the possibilities and the limits of their solar systems. It appears that it is better to leave the choice of the system to the companies that can then build direct relations with the suppliers. Therefore, competitive tender at a governmental level for the purchase of photovoltaic systems, even if it can reduce prices by a bulk purchase, may have to be avoided. Moreover, competitive tenders tend to exclude local companies in favour of international companies. Direct purchase may favour the creation of a local network of solar companies.

The training of the technicians is also crucial to enable them to adjust the regulation of solar systems. Most of the problems linked to the batteries are not just linked to the product itself and could have been solved with correct training. Now that technicians are trained in the design of systems, ESCOs in Zambia will purchase their equipment directly.

Financial uncertainty and capital costs

Although technical problems are being solved, ESCOs in Zambia are still facing financial uncertainty due to macro-economic conditions, which are out of their control. This situation of excessive inflation is not specific to Zambia and proves to be quite damaging for small companies. Furthermore, the capital cost for solar electricity, as for conventional electricity, still needs to be subsidized as the purchasing power of inhabitants remains low and there are no local financial institutions ready to give loans to small rural companies.

Conclusion

The success of the market-driven concept of ESCOs demonstrates that with a suitable financing scheme, households and businesses can afford solar photovoltaic systems. Initial funding from the national government (supported by international agencies) is essential, but once provided, the concept of ESCOs seems to be capable of solving the eternal problems of up-front costs and maintenance. This example tends to prove that after enabling the establishment of a network of local entrepreneurs, solar systems can be maintained and can deliver a real service.

In a first phase, the initial funding can be worked out as a direct subsidy, a soft loan (to be reimbursed over a long period of time), tax exemptions, or a combination of those. Whilst it is most likely ESCOs will continue to depend at least partly on external funding, the aim should be to decrease ESCOs financial dependency towards the mid and longer term. One way to increase their income could be the broadening of their client portfolio and the diversification of the services offered.

The regulator should carry out reviews of the financial and operational performance of the ESCOs on a regular basis, and should come up with clear recommendations for the ESCOs, as is done in the case of Zambia by the Energy Regulation Board (ERB).

7. CONCLUSION

Renewable energy technologies tend to be less developed than “conventional” electricity generation technologies. The use of regulatory and policy support mechanisms is a necessity for driving the new technologies towards commercial viability by encouraging deployment and reducing investor risk.

LEARNING RESOURCES

Key points covered

These are the key points covered in this module:

- The advantages and benefits of supporting renewable energy through regulatory and policy measures.
- The main issues to address when designing a policy instrument to support renewable energy.
- The existing policy instruments to support renewable energy, including feed-in tariffs, quota mechanisms amongst others.
- The advantages and disadvantages for each of these policy instruments. Provision of information enabling the reader to consider, in a given country, which (or combination) of system(s) would suit their national situation best.
- Experiences from Europe, Africa and other developing countries.

Answers to review questions

Question: Name at least five regulatory/support mechanisms that can encourage renewable energy development in the African power sector in the short term.

Answer:

- Establishing “standard” power purchase agreements (PPAs)
- Ensuring long-term electricity generation licences and PPAs
- Developing a favourable tariff setting and adjustment formula
- “Light-handed” regulation
- Setting explicit targets for the share of renewables in the electricity generation mix
- Enacting explicit regulations that encourage local private participation in renewable energy development
- Providing subsidies to renewable energy-based power systems

Question: What are the main differences between a feed-in tariff system and a quota system?

Answer: A feed-in tariff system provides certainty on the price for green electricity, as this price is fixed over a certain period. A feed-in tariff system does not provide certainty on the level of green electricity that will be supplied. The fixed premium is the incentive for investors.

A quota system provides certainty on the level of green electricity that will be supplied, as the target is fixed, as well as a fine for non-compliance. A quota system does not provide certainty on the price for green electricity, as the price will be determined by supply and demand in the tradable certificate market. The target and the fine are the incentive for investors.

In theory, a quota system with tradable certificates is more efficient, as it stimulates the market players to develop the cheapest technologies. On top of that, the trade of certificates could improve efficiency between different regions or countries. On the other hand, the feed-in tariff system has proved very successful for wind energy on land in Germany and Spain, mainly thanks to the investor confidence that the system provides.

Question: Describe in short the main support mechanisms for renewable energy.

Answer:

A feed-in tariff system: see answer above.

A quota system: see answer above.

Tender schemes:

The government organizes tenders for individual renewable energy projects. The best proposal gets the approval to develop the project. The developer gets a lot of certainty about his project and about the income for his project (as a fixed premium for the green electricity will be paid by the suppliers). On the other hand, this system does not provide a continuous incentive for new renewable energy projects, which hinders the development of a full-grown green electricity market.

Voluntary mechanisms:

The system is based on customers' willingness to pay a higher price for green electricity. The system relies on the consumer's awareness of the advantages of green electricity and the disadvantages of other forms of electricity. The marketing and labelling of green electricity are key aspects in this support mechanism.

Hybrid schemes involving two of the mentioned support mechanisms:

A support scheme can make use of aspects of the different support mechanisms to correct a shortcoming of one of the individual support mechanisms.

For instance, when a quota system does not provide enough investor confidence because of a lack of a fully-grown certificate market, the government can introduce a minimum price for certificates to protect a developer from a cash flow problem should the certificate price decrease dramatically. This happened for instance in Flanders, Belgium.

To avoid this, in a feed-in scheme, the incentive for innovation would fade (because the price is fixed for a long period). The fixed premium can be decreased over time (for instance, five per cent per year for new projects) so the learning curve of the technology would not be harmed.

Exercise

What support mechanisms for renewable energy exist in your country? Are these directed towards electricity, heat or both? What have been the results so far and what suggestions would you make to improve the system?

Take into account that you should avoid changing the fundamental design of the system, as this would undermine investor confidence.

Write a 2-3 page essay answering these questions.

Presentation/suggested discussion topic

Presentation:

ENERGY REGULATION – Module 9: Regulatory measures for renewable energy

Suggested discussion topic:

Given the particular situation in your country, which of the described support mechanisms might prove most useful? Bear in mind that investor confidence is a crucial aspect, and that you can combine aspects from different support mechanisms.

Relevant case studies

1. Germany: feed-in mechanisms
2. Spain: support mechnisms for wind energy
3. Denmark: support mechanisms for wind energy
4. Ghana: status of renewable energy
5. Zambia: power sector reform and renewables
6. UK: renewables obligation

See annexes in separate files.

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INTERNET RESOURCES

The Global Regulatory Network (GRN) strengthens regional associations and promotes the understanding of complex regulatory practices: www.globalregulatorynetwork.org

Public Utility Research Center: www.purc.org

African Forum of Utility Regulators: www.afurnet.org

Centre of Regulation and Competition: www.competition-regulation.org.uk

European Renewable Energy Council (EREC): www.erec-renewables.org

European Energy Regulators (CEER): www.ceer-eu.org

Electricity Control Board of Namibia (ECB): www.ecb.org.na

Energy Regulation Board of Zambia (ERB): www.erb.org.zm

Kenyan Electricity Regulatory Board: www.erb.go.ke

GLOSSARY/DEFINITION OF KEY CONCEPTS

CHP, combined heat and power, cogeneration
A method of using the heat that is produced as a by-product of electrical generation and that would otherwise be wasted. The heat can be used for space heating of buildings (usually in district or community heating schemes) or for industrial purposes. Utilizing heat in this way means that 70-85 per cent of the energy converted from fuel can be put to use rather than the 30-50 per cent that is typical for electrical generation alone. Cogeneration schemes can be relatively of small-scale, for use at the level of a factory or hospital, or they can be major power stations. The term CHP is employed in the United Kingdom and some other parts of Europe, while the term cogeneration is employed elsewhere in Europe, the United States and other countries worldwide.

Consolidation services
Independent services enabling generators, including smaller generators, to combine their output and negotiate better terms for its sale.

Deregulation
The process of removing or reducing regulation. It is often employed in connection with the liberalization process for privatized industries.

Energy services
The provision of energy supply and measures concerned with end-use in a single package.

Energy services company (ESCO)
Companies concerned with maximizing efficient and cost-effective supply and end-use of energy for their customers. This can encompass a mixture of the following as appropriate: competitive purchasing of various fuels; CHP; end-use efficiency measures; consumption monitoring and management and others. ESCOs should be distinguished from energy supply companies whose main role is to supply units of gas, electricity or heat. ESCOs can also be distinguished from energy management companies whose main role is to supply energy efficiency services.

Liberalization
Technically, the removal of restrictions on the movement of capital. It has come to refer to a policy of promoting liberal economics by limiting the role of government in the operation of the market economy. Liberalization can include privatization and deregulation/re-regulation. Typically, it refers to the establishment of an industry structure to allow competition. The process includes the shifting of publicly-owned

companies into the private sector, such that provision of services is subject to greater competition or, in the case of natural monopolies to greater oversight with regard to economic efficiency.

Monopoly — The situation where one company has the market power to control the price or availability of a good or service.

Quota mechanisms — More generally known as a renewable portfolio standard or as an obligation mechanism.

Renewable energy — The use of energy from a source that does not result in the depletion of the earth's resources whether this is from a central or local source.

Renewable energy certificates (RECs) — A certificate that represents a unit of renewable electricity generated that can be used to verify the fulfilment of an obligation to source a certain percentage of renewable generation as required in renewable portfolio standard schemes. Trading may be allowed so that companies that underachieve their obligation can buy certificates from those who have overachieved.

Renewable portfolio standard — A market-based mechanism devised by Nancy Rader and Richard Norgaard for the American Wind Energy Association in 1996. It obliges supply companies or consumers to purchase a specific amount of electricity from renewable energy sources. The key goal of such a mechanism is to minimize the costs of increasing renewable energy capacity through the stimulation of competition to fulfil obligations. The RPS mechanism is also known as a quota or obligation mechanism. Examples of the RPS include the renewables obligation in the United Kingdom or the mandatory renewable energy target in Australia). The market may be operated through the creation and trading of certificates (renewable energy certificates).

Shallow connection charges — In essence these types of charges mean that generators pay only for the equipment needed to make the physical connection of their generation plant to the grid network, and that all other costs are the responsibility of the distribution network operator (DNO). This principle is usually introduced to stimulate distributed generation, and should be accompanied with the development of a transparent mechanism for the recovery of costs incurred by DNOs relating to the necessary reinforcement of the grid network (the "deep" cost elements).

Strike price	A reference price as agreed between electricity retailers (buyers) and electricity generators (sellers) in their "contracts for difference". If the resulting wholesale price index (as referenced in the contract) in any time period is higher than the "strike" price, the generator will refund the difference between the "strike" price and the actual price for that period. Similarly a retailer will refund the difference to the generator when the actual price is less than the "strike price". Market players use this type of contract to protect themselves from volatility in price and volume of electricity.
Tariff mechanism	A mechanism to encourage the growth of renewable energy generating capacity. Notable examples are Denmark and Germany. A tariff mechanism generally provides a particular rate per kWh of electricity generated and guarantees that payments will continue for a fixed or minimum period. The tariff can be fixed beforehand, can be fixed to reduce in specific gradations over time or can be linked to the average electricity tariff. Also known as a price mechanism.
Tender mechanism	A mechanism to encourage the growth of renewable energy where competitive bids are put forward to government for individual sustainable energy projects. Suppliers are obliged to buy a certain amount of renewable power at a premium price. Although specific characteristics vary, it is likely that in the framework of this kind of policy the government will set an overall target for sustainable generation, and then specified limits for individual technologies within that and also set a specified time for contracts for the generation, during which time they will receive a premium price. The government, usually on the basis of cost, selects the winning contracts although in some schemes other factors such as technical quality and socio-economic aspects also play a role.

ANNEX I. METHODOLOGY AND EXAMPLES ON HOW TO CALCULATE THE LEVEL OF FEED-IN TARIFFS

Methodology

Introduction

A feed-in tariff (FIT) is a pre-defined guaranteed minimum price or a guaranteed premium on the market price for every kWh of green electricity generated. The tariff scheme is usually differentiated for different green electricity production technologies, with less developed technologies receiving higher prices for their output. The scheme is usually defined for a specified number of years, but again this can vary depending on the technology.

Overall aim

The overall aim when designing a set of feed-in tariffs is to fix a premium tariff which:

- **Covers the extra cost** of electricity production using the given technology (thus stimulating investment)
- While at the same time **avoids over-subsidizing** the given technology (thus creating windfall profits and making the system more costly).

Relevant parameters

As is illustrated in table 1, the minimum to average generation costs for renewable energies vary widely among different technologies, and within the same technology, according to differences in the national market and resource conditions.

Table 1. Minimum to average generation costs for the main green electricity technologies in EU15[1]

Technology	Range of electricity generation cost (€/MWh)
Wind onshore	50-80
Small-scale hydro	40-140
Biomass using forestry residues	40-80
Agricultural biogas	60-100
Photovoltaics	> 450

[1]COM(2005) 627 final - Communication form the European Commission—The support of electricity from renewable energy sources—Annex 3 (December 2005).

The most relevant parameters are on the one hand plant-specific data, and more general parameters on the other. The most influential parameters when determining the generation costs are:

- Investment costs
- Full load hours
- Fuel price (in the case of biomass)
- Interest rate
- Expected return on equity

A non-exhaustive list of relevant parameters is presented below, as several tens of variables can be of influence depending on the given technology or on the country in question.

Plant-specific data:

- Investment costs
- Operational costs
- Energetic efficiency
- Full load hours
- Fuel price (in the case of biomass-fired plants)

General parameters:

- Depreciation time
- Interest rate
- Expected return on equity
- Tax regime

Other relevant parameters:

- Electricity price
- The level of support instruments (other than the feed-in tariffs, e.g. investment subsidies/tax incentives)
- The period during which the feed-in tariff is guaranteed

Because of the great amount of different variables, the renewable energy generation costs are generally calculated specifically. For this purpose a number of projects have developed mathematical models.[2]

A simplified calculation based on the most crucial parameters is presented in "Examples" lower in this annex.

[2]The Green-X and FORRES 2020 projects developed rather complex mathematical models to calculate generation costs. In the Netherlands a detailed methodology was developed by ECN to calculate the feed-in tariffs for new renewable electricity projects in 2004 and 2005 (www.ecn.nl).

Determine the feed-in tariffs

Once the generation costs per technology are known, the level of the feed-in tariff can be fixed accordingly.

Policy considerations

The level of the tariff can finally be influenced by the explicit political decision to stimulate renewable deployment. For instance a national government can decide to introduce higher feed-in tariffs to reach a certain share of renewable electricity by a given year, or to activate a virtually non-existent sector, or to establish the renewable energy policy as an umbrella policy aiming to improve on other policies such as energy poverty, education, health care and gender issues.

Examples

The following examples intend to illustrate the methodology to calculate the feed-in tariff for some of the green electricity production technologies, rather than describing in detail the existing mathematical models. The presented calculations are highly simplified in order to visualize the methodology, as they take into account only a few of the different relevant variables. It is stressed that further modelling is required when actually fixing the feed-in tariff levels for a given country.

On-shore wind energy

First thing to do is to determine what a typical wind energy project in the given country or region would look like. In this example a following typical project[3] is considered:

Capacity (kW_e)	1500
Full load hours/year	2000
Investment cost (€/kW_e)	1100
Operation and maintenance cost (€/kW_e/year)	40
Interest rate r (per cent)	6.5
Duration of support t (years)	10
Feed-in tariff (€/kWh)	?

[3]Only “investment cost” and “maintenance cost” could be seen as generally applicable. “Full load hours” depend on site-specific wind data and need to be measured on a case-by-case basis. A rough estimate can be made based on national or regional wind data, whenever available. “Interest rate” can vary depending on financial markets conditions. “Duration of support” is a design element of the feed-in scheme and can vary according to the technology. For instance the duration is typically 10 years for wind, and 20 years for PV.

The basis to calculate feed-in tariffs is the approach of net present value (NPV). NPV calculation is a standard method to consider whether a potential investment project should be undertaken or not. The interest rate is used to establish what the value of future cash flows is in today's money. A project is considered viable whenever the present value of all cash inflows minus the present value of all cash outflows (which equals the net present value), is greater than zero. This method is described in the following equation:

$$NPV = \sum{}^{*} [(INCOME/year – COST/year) / (1+ r)^t] - INVESTMENT\ COSTS$$

*∑ running over the duration of the support scheme.

Income/year

The feed-in tariff is considered to be the only form of income:[4]

⇨ 1500 (kW) * 2000 (hrs) * FIT (€/kWh)

Cost/year

As costs, the operation and maintenance cost are considered:

⇨ 1500 (kW) * 40 (€/kW) = 60,000 €

Investment cost

⇨ 1500 (kW) * 1100 (€/kW) = 1,650,000 €

Calculation of the feed-in tariff

$\sum [(3{,}000{,}000 * FIT – 60{,}000) / (1.065)^t] – 1{,}650{,}000 = 0$

⇨ FIT = 0.095 €/kWh = 95 €/MWh

The calculated FIT is slightly higher than could normally be expected for a typical wind energy project. This is mainly due to the fact that no other income than the feed-in tariff was considered in the simplified calculation. Usually investment subsidies, tax credits or the physical electricity sold to the market provide additional income. Also higher full load hours can significantly decrease the feed-in tariff. For instance coastal or typical hilly areas can reach up to 3500 full load hours.

[4]Depending on the case, additional income can be provided by investment subsidies or tax credits. The selling of the physical electricity to the electricity market needs to be taken into account as a form of income, depending on the design of the feed-in tariff scheme. For instance in Germany the feed-in tariff includes the value of the physical electricity, whilst in the Netherlands the feed-in tariff is calculated without taking into account the income from the selling of the physical electricity. In Spain, a green electricity producer can choose between a fixed premium per kWh and a premium that is calculated as a percentage of the average electricity price.

Photovoltaic energy—autonomous

A typical example is considered below:

Capacity (kW_p)	2
Full load hours/year	1250[5]
Investment cost (€/kW_p)	10.000[6]
Operation and maintenance cost (€/kW_e/year)	0[7]
Interest rate *r* (per cent)	6.5
Duration of support *t* (years)	20
Feed-in tariff (€/kWh)	?

Income/year

Following the same approach in the wind energy case, the income is:

⇨ 2 (kW) * 1250 (hrs) * FIT (€/kWh)

Investment cost

⇨ 2 (kW) * 10,000 (€/kW) = 20,000 €

Calculation of the feed-in tariff

$\sum [(2{,}500 * FIT) / (1.065)^t] - 20.000 = 0$

⇨ FIT = 0.72 €/kWh = 720 €/MWh

Photovoltaic energy—grid connected

The same example considered as a grid-connected system (instead of an autonomous system[8]) offers the following result.

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[5]An average of 800 full load hours is typical for a country such as Germany. In Morocco full load hours can be as high as 1500, and in some specific regions in the world (like deserts), even 2000 full load hours are possible. See "Energy from the Desert", www.iea-pvps.org. The maintenance cost is very low for a PV installation, and is therefore neglected in the example.

[6]The investment cost can vary significantly depending on the specific situation, on the use of batteries or a diesel generator to decrease intermittency. For more details on costs of PV systems, see European Roadmap for PV R&D, PVNET, paris.fe.uni-lj.si/pvnet/files/PVNET_Roadmap_Dec2002.pdf #search=%22PVNET%22.

[7]The maintenance cost is very low for PV installations, and is therefore neglected in the example.

[8]A grid-connected system does not need a battery and battery charger.

Capacity (kW_p)	2
Full load hours/year	1250
Investment cost (€/kW_p)	6500
Operation and maintenance cost (€/kW_e/year)	0
Interest rate *r* (per cent)	6.5
Duration of support *t* (years)	20
Feed-in tariff (€/kWh)	?

Income/year

⇨ 2 (kW) * 1250 (hrs) * FIT (€/kWh)

Investment cost

⇨ 2 (kW) * 6500 (€/kW) = 13.000 €

Calculation of the feed-in tariff

$\sum [(2.500 * FIT) / (1{,}065)^t] - 13.000 = 0$

⇨ FIT = 0.470 €/kWh = 470 €/MWh

Biofuel

An example of a 10,000 kW_e installation is considered using biofuel (palm oil)[9] in a condensing steam turbine.

Capacity (kW_e)	10,000
Full load hours/year	6000[10]
Investment cost (€/kW_e)	800
Operation and maintenance cost (€/kW_e/year)	120
Fuel cost (€/GJ)	10[11]
Interest rate *r* (per cent)	6.5
Duration of support *t* (years)	10
Feed-in tariff (€/kWh)	?

[9]ECN-C—05-016 – Small-scale independent electricity installations using biomass (2005), www.ecn.nl. VITO – Onrendabele toppen van duurzame elektriciteitsopties in Vlaanderen (2005), www.energiesparen.be

[10]In principle even higher full load hours (>7000) are reachable, provided there is a continuous fuel supply (generally guaranteed through contracts). In reality, such installations do not always run at full capacity yet and need regular stops for maintenance.

[11]The price of crude palm oil in January 2007 was circa 360 euros/ton CPO (www.mpoc.org.my). If then an energy content of 37 GJ/ton is assumed, the cost per ton comes at circa 10 euros.

Income/year

Following the same approach as above, the income is:

⇨ 10,000 (kW) * 6000 (hrs) * FIT (€/kWh)

Cost/year

Fuel cost: 10 €/GJ

Electricity production: 60,000,000 kWh = 540,000 GJ
(1 kWh = 3.6 MJ, efficiency of energy conversion assumed at 40 per cent)

⇨ Fuel cost/year: 5,400,000 €

⇨ Operation and maintenance cost/year: 10,000 * 120 = 1,200,000 €

Investment cost

⇨ 10,000 (kW) * 800 (€/kW) = 8,000,000 €

Calculation of the feed-in tariff

$\sum$ [(60,000,000 * FIT – 1,200,000 – 5,400,000) / $(1.065)^t$] – 8,000,000 = 0

⇨ FIT = 0.127 €/kWh = 127 €/MWh

Small-scale hydro[12]

Capacity (kW_e)	100
Full load hours/year	6000
Investment cost (€/kW_e)	2500
Operation and maintenance cost (per cent of investment)	3
Interest rate *r* (per cent)	6.5
Duration of support *t* (years)	10
Feed-in tariff (€/kWh)	?

Income/year

Following the same approach as before, the income is:

⇨ 100 (kW) * 6000 (hrs) * FIT (€/kWh)

Cost/year

Operation and maintenance cost /year: 100 (kW) * 2500 (€/kW) * 0.03 = 7500€

Investment cost

⇨ 100 (kW) * 2500 (€/kW) = 250,000 €

[12]State-of-the-art of small hydropower – European Small Hydro Association – www.esha.be

Calculation of the feed-in tariff

$\sum$ [(600,000 * FIT –7500) / $(1.065)^t$] – 250,000 = 0

⇨ FIT = 0.063 €/kWh = 63 €/MWh

ANNEX II. STRUCTURE OF THE ELECTRICITY PRICE

The price for the supplied electricity finally paid by the end-consumer is significantly higher than the generation cost. The price structure for electricity generally consists of four components:

- Generation cost
- Transmission and distribution cost
- Taxes and levies
- Profit and return on equity for investors

Generation costs

The generation costs are the costs necessary to produce the electricity, as described above (e.g. investment costs, fuel cost, operation and maintenance cost, etc.).

Transmission and distribution costs

The transmission and distribution costs are the costs related to the transport of the electricity to the end-consumer. The supplier needs to pay the transmission and distribution grid operator for using the grid. The supplier integrates these costs in electricity bills to the end-consumer.

Taxes and levies

As for any product, tax needs to be paid for supplied electricity. In most cases, additional levies are applied by the government, usually as a percentage per supplied kWh. These levies can include contributes to finance:

- The operation of the energy regulator
- The treatment of nuclear waste
- Social and environmental public obligations

Other components can influence the price of electricity, for instance the balancing costs (especially for wind energy).

Transmission and distribution costs, taxes and levies are applicable for any type of electricity generation, both fossil-based, nuclear and renewable energy. Therefore these costs do not influence the level of the feed-in tariff, and should not be included in the feed-in tariff calculations.

Profit and return on equity for investors

Finally a profit and return on equity component is part of the electricity price.

Case study 1.

GERMAN FEED-IN MECHANISMS

CONTENTS

1. INTRODUCTION

Germany currently has more installed wind energy capacity than any other country. In late 2003, Germany had a total of 14000 MW of installed capacity (WPM, 2004). It has had a very rapid deployment rate, though this is now slowing as good onshore sites become rarer. Before 1990 Germany had invested significant funds in renewable energy R&D with little practical results. Since 1990, the use of particular financial mechanisms, most notably the long-term availability of a tariff mechanism, has seen the strong practical results indicated by the statistics for increasing wind energy exploitation. Germany has employed a number of support mechanisms in the last fifteen years, each of which has supported renewable energy technologies including biomass, solar power, hydropower, geothermal energy and energy derived from landfill gas, sewage treatment and coal-bed methane from coal mines (Federal Ministry for the Environment 2000). Different levels of compensation apply with regard to each technology. This case study will primarily deal with support mechanisms as they have applied to wind energy as this provides the best example of an applied policy engendering positive results.

2. REGULATION IN GERMANY

It is worth noting that regulation in Germany has until recently relied upon interpretation of legislation by either the courts or by the Federal Cartel Office (FCO)—or both. A regulatory agency was established in 2004 but the full range of its powers has not yet been brought to bear. The lack of a regulator has meant that support mechanisms for RE have been subject to some drawn out court cases as utilities have tried to avoid costs.

3. ELECTRICITY FEED-IN LAW 1991

Germany's first significant mechanism for encouraging wind energy exploitation came with the introduction of the *Stromeinspeisungsgesetz* or Electricity Feed-In Law (EFL) on 1 January 1991. This forced German distribution network operators (DNOs) to purchase all electricity offered to them from a range of renewable sources, with wind-generated electricity to be paid a price equal to 90 per cent of the average price charged to end-users over the year. The price was paid by the local company and was passed on to local consumers. This was an example of a "renewable energy feed-in tariff" (REFIT), mechanism. Under the EFL, each DNO had an effective catchment area within which it was obliged to pay the tariff to the generators of renewable-based electricity from any qualifying projects within that area.

The EFL laid down that the actual connection of the generator to the grid be paid for by the project developer, with the utility responsible for arranging and financing its own affairs in order to be capable of utilizing the electricity delivered to its grid network. The main sticking point that arose was that the DNOs, opposed as they were to the law overall, submitted excessive bills for grid connection. The EFL was supported by a 100 MW subsidy programme, which was rapidly extended to a 250 MW programme as a result of the high-level of response it encountered. The programme provided an additional operating subsidy of €0.031/kWh on top of the EFL-mandated price, at the time equal to €0.084/kWh.

The resulting €0.151/kWh available was thus very substantial. Anderson for example makes a comparison with the rates of around €0.046-0.051/kWh that were available to American projects at the time and with which they were able to operate profitably (Anderson, 1995). The result in Germany was that the programme was heavily oversubscribed. Anderson suggests that by applying a lower level of remuneration, considerably more capacity could have been incentivized without any greater cost having to be borne by the consumer. Setting the level of remuneration can be regarded as one of the key problems with the tariff mechanism—setting it high means that investors can earn an unnecessarily high rate of return whilst setting it too low means the mechanism will fail to stimulate investors.

4. THE RENEWABLE ENERGY LAW 1998

The EFL was changed to some degree in 1998 to become the Erneuerbare Energien Gesetz (EEG), which has been commonly translated as the "Act on Granting Priority to Renewable Energy Sources", though it literally translates as "Renewable Energy Law". The change in the legislation on renewables took place at the same time as the new German legislation regarding the liberalization of the German energy market (Mallon 2000). The EEG effectively acted to bring the EFL into line with the new legislation introduced to reform the energy sector. The immediate effect of the EEG was to place a cap on renewables, such that they may not supply more than 10 per cent of electricity in Germany.

The new tariff scheme, detailed in the EEG law, was adopted in 2000. The EEG lays down pricing mechanisms for the support of a range of renewable energy technologies, with a specific pricing mechanism applied to each. It also redefines the regulations regarding the financial and institutional support of wind energy.

The EEG law restates the obligation on distribution network owners regarding connection of renewable energy generators to the grid where such a connection is requested. The nearest grid owners to a proposed site are obliged to connect a new generator to their grid. Whilst the generator owner is liable for the costs of connection to the grid, the bill submitted to the generator for this function is made subject to oversight by the Federal Cartel Office (FCO) to ensure that the cost is a reasonable reflection of the actual costs. The grid owner is liable for any costs relating to the upgrading of the grid to facilitate the new generator. That is, the German system uses shallow connection charging for renewable electricity generation.

The EEG Act compels the grid owners to purchase electricity produced by the renewable energy generators within the pricing mechanism laid down within the Act. The new act also contains provision to address one of the most contentious aspects of the old EFL Act, establishing a national equalization scheme. The national equalization scheme makes compulsory the payment of compensation to those distribution and transmission network owners which bear above average costs of paying for renewable energy sources from those which make purchases below the average. This removes the system set up under the EFL, whereby the costs borne by local network operators could only be passed on to their own consumers. This socialization of costs is administered by the network operators themselves, with the law enabling network operators to require each other be independently audited to assess the actual costs of purchasing renewable electricity (Bechberger and Reiche 2004).

The EEG also changed the mechanism for calculating the base price paid for wind-generated electricity. The previous flat payment of 90 per cent of the final consumer tariff is replaced by initial fixed payments of €0.088/kWh for the first five years, with the potential for an extension of this period dependent on the actual performance of the turbine. Wholesale electricity prices in Germany are typically €0.02/kWh.

This has the effect of producing a scale of payment dependent on the quality of the location of the wind turbine and, it is hoped, ensuring that efficiently operated turbines can be run profitably, while inefficiently run turbines can not. The effects of this may well be an increase in the number of sites that can be profitably operated, and, it is speculated, may act to increase the further penetration of turbines to sites further from the coast. Regardless of when the higher payments cease, the turbines should, at least in theory, continue to be paid at a rate of €0.059/kWh for a minimum period of twenty years. Whilst the lower rate is below that paid under the old EFL mechanism, which had dropped to around €0.08/kWh by early 2000, the initial higher rate exceeds it significantly. This approach should act to provide more of a return during the early stages of turbine operation, thus aiding in obtaining capital. Turbines already in operation will also switch to the new tariff scheme, though with an amendment to reflect their status as already having received some subsidy.

The EEG also draws offshore wind projects into the payment mechanism specifically, placing support for offshore installations alongside onshore projects, but with the initial rate of €0.088/kWh available for the first nine years of operation. It would appear that the nearest distribution network owners to offshore installations will be compelled to provide connection to the national grid, as with onshore installations (German Federal Environment Ministry, 2000). As with onshore wind, the network operators will be reimbursed for costs under the equalization provision of the EEG. The EEG is estimated to add €0.001/kWh to German electricity prices.

The results of the new law were positive and expansion of German wind energy capacity has continued up to 2004. However, the mechanism has been subject to a much-delayed review since January 2003. The result is likely to see further changes in the level of tariff paid across the board for renewably generated electricity. Current proposals would see a slight drop in onshore payments, from €0.088/kWh to €0.087/kWh guaranteed for the first five years, with €0.055 thereafter instead of €0.059. Offshore wind would receive a slightly higher tariff of €0.091/kWh with a guaranteed availability of twelve years instead of nine provided turbines are in place by 2010. Turbines already installed are subject to the tariff in place when they were first brought online. Such guarantees are important for ensuring the security of income and to avoid discouraging new investment.

Those technologies which are currently less mature receive different rates than wind. The highest rate is currently that paid to photovoltaic generation of electricity, which currently attracts compensation of €0.434/kWh. Other technologies currently attract similar rates to onshore wind energy. Lindenberger and Schulz estimate that the overall costs of the EEG will rise as shown in table 1. It should be noted that these figures do not take into account the implicit cost savings relating to electricity purchase from sources which are displaced by the RE sources. Nor do they take into account any system costs and benefits associated with the operation of increased distributed generation on electricity networks.

Table 1. Projected annual subsidy within the EEG

Year	Hydropower Mio €	Windpower Mio €	Biomass Mio €	PV Mio €	Total Mio €
2000	348	692	67	17	1125
2001	426	952	132	30	1540
2002	443	1565	170	54	2232
2003	460	1993	201	76	2731
2004	476	2331	232	98	3137
2005	493	2598	263	118	3472
2006	510	2822	293	137	3762
2007	527	3040	323	155	4045
2008	544	3263	353	172	4331
2009	560	3502	382	189	4633
2010	577	3764	412	205	4957

Source: Lindenberger and Schulz, 2003.

5. OTHER MECHANISMS TO SUPPORT RENEWABLES IN GERMANY

Initial efforts in German RE policy were also aided with the application of capital grants in the period 1990-1996. Efforts are currently being assisted with the use of two tax-related instruments:

- Income tax relief: the Income Tax Enforcement Decree allows a deduction to be made against production costs resulting from investment in RES in buildings.
- Ecological tax reform: this increases taxes on various motor fuels and on electricity. This benefits biofuel production, though adds costs to electricity from renewable energy sources, due to the difficulty in differentiating such electricity once it is in the system. To compensate for this, the German Government has introduced the Market Incentive Programme, which acts to provide investment subsidies and additional low-rate loans to various renewable sources. (Bechberger and Reiche 2004).

The central mechanisms for the support of renewable energy in Germany are further bolstered by various other mechanisms at the regional level. Since the 1990s these have included additional low-rate loans and other investment subsidies available within specific regions.

6. CONCLUSION

The German feed-in laws and associated mechanisms have been very successful at stimulating growth in wind energy deployment. The early phases of these laws could be criticized for having imposed high costs on consumers although subsequent revisions have reduced the level of subsidy and hence costs.

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Case study 2.

SPAIN: SUPPORT MECHANISMS FOR WIND ENERGY

CONTENTS

1. INTRODUCTION

Spain is the country that has seen the greatest expansion of wind energy utilization of recent years. Spain currently has the second largest installed capacity of electricity generated from wind, with a capacity of 5780 MW installed by late 2003, with the large majority of this expansion occurring since 1995. The main expansion of Spain's wind generation occurred following the introduction of a tariff mechanism in 1994. The level of this expansion is demonstrated in table 1:

Table 1. Spanish installed wind turbine capacity

Year	MW
1995	115
1996	221
1997	512
1998	834
1999	1530
2000	2099
2001	3335
2002	4830
Late 2003	5780

Spain began the 1990s with a stated target for further installation of wind energy equal to 275 MW of capacity to be in place by 2000. This objective was exceeded in 1997. The current target for wind in Spain is to have 8974 MW installed by 2010, as part of the effort to reach the 12 per cent target for renewable energy set by the European Union (McGovern 2000). In general, estimates of likely rates of expansion have fallen short of the actual rates. The IEA, for example, expected that installed capacity could be as high as 750 MW by 2000 in a report published in 1998 (IEA, 1998), the same year that figure was actually exceeded.

2. GOVERNANCE OF SPANISH POLICY

Responsibility for Spanish policy relating to renewable energy lies with the Institute for the Diversification and Conservation of Energy, (Instituto para la Diversificación y Ahorro de la Energía—IDAE), a "semi-autonomous" organization operated through the Ministry of Industry.

The main regulatory body for all energy sources in Spain is the National Energy Commission (Comisión Nacional de Energía—CNE). CNE is attached to the Ministry of Economy. It acts to set budgets, to ensure that licences are complied with and to settle any disputes arising from regulation. CNE is responsible for oversight of the legislatively mandated payments made to renewable energy sources.

2.1. Spanish renewable energy policy

Spanish policy at the national level has been founded on the twin pillars of a REFIT-style subsidy scheme and of generous capital subsidies. However, regional policies have also played an important role in both making wind energy projects economic and in encouraging the growth of new turbine manufacturers.

One important aspect of Spanish law, which already favoured renewables in the mid 1990s, was the existence of an obligation introduced in 1987 via Royal Decree, on distribution companies to purchase all electricity from independent power producers at a fixed rate. The intended effect of this being to minimize any problems that Spanish wind turbine owners might face from utilities hostile to the use of renewables.

Spanish wind energy development, and renewable energy development generally, is under the purview of a national renewable energy plan, which forms one aspect of the Energy Savings and Efficiency Plan (PAEE).

A wide-ranging national policy on renewables effectively began in 1994 with Royal Decree 2366/1994. This formed the legal basis for the provision of feed-in tariffs for electricity from renewable sources with a capacity under 100MW. The decree instituted a tariff at a rate of 80-90 per cent of the average final consumer price paid for electricity, with the specific rate calculated on an annual basis. Until the late 1990s this was typically calculated to equal 88.5 per cent. In 1994, application of this rate amounted to an increase in the tariff available to wind from the 10 peseta/kWh (€0.063/kWh) rate typically paid to IPPs, up to 11.57 pta/kWh (€0.073/kWh). The tariff was guaranteed to be paid for a five-year period in order to provide increased stability to the market and to thus help encourage investment.

A 1997 adjustment altered the payment scheme, effectively offering developers a choice of two payment schemes. They could opt to receive either a fixed price, in 1997 this being equal to €0.066/kWh, or a variable price based on the average price paid by consumers for all electricity consumed domestically in Spain, plus an environmental bonus. In 1997 this variable price worked out to €0.034/kWh, with an environmental bonus of €0.032/kWh, making the two practically the same, though this was not a matter of deliberate policy (Wind Directions 1999). This figure was also intended to include a consideration for those avoided costs for the distributor, which would otherwise be incurred in the process of purchasing from traditional large-scale generators (Cerveny and Resch, 1998). Controversially, the payment was reduced, by an average of 5.48 per cent, at the end of 1999 as part of a round of government cuts (WPM 2000).

The adjustment made in 1997, introduced as part of a general electricity law through Royal Decree 54/1997, included the codicil that the new payment regime would apply only to those installations with a maximum generating capacity of 50 MW. Any problem which this might have presented to new large-scale projects appears to have been circumvented through the breaking down of projects into pieces resulting in components with generating capacities less than this limit and presenting them as being separate, even where they are practically adjacent. Further regulation concerning payments stems from Royal Decree 2818/1998.

In addition to the creation of a REFIT-style support mechanism, the 1994 decree also divided electrical distribution from generation as well as establishing a moratorium on nuclear plant construction. Alongside the REFIT-style mechanism for subsidizing electrical production from wind generators, there is a second policy pillar aimed at supporting growth in the use of wind energy, and growth of an industry to exploit it. The IDAE oversees the allocation of capital grants to projects intending to install less than 20MW of wind turbine capacity, with public capital invested with the aim of attracting private capital to meet the majority of any costs.

In 1997, IDAE made US$ 70.6 Million available to such projects, offering up to 40 per cent of costs. Funding was announced to be preferred for those projects in remote areas with poor levels of grid connectivity.

2.2. Changes to Spanish policy

The Spanish government has proposed changes to the way that wind is subsidized in Spain in 2004. The new law will see the premium option—where the payment is related to the electricity market price—changed to instead offer generators the chance to trade on the open market for electricity. The price they achieve will then be supplemented with a premium payment equal to 40 per cent of the electricity sector's average billing price per kWh for the entirely of its supply for the year (known as the Average Electricity Tariff—AET). (McGovern 2004). The total cost for electricity in Spain in 2002 was around €0.13/kWh before tax and €0.155/kWh after tax. (Eurostat 2003)

The fixed price choice is also subject to change. The subsidy available had previously been held between 80-90 per cent of the AET, tending towards the 90 per cent figure. However, there always remained the potential for a review to see this reduced to 80 per cent, with obvious economic implications for investors. The new law will fix payments at 90 per cent of the AET for the first five years of plant operation, dropping to 85 per cent for the next ten years and then 80 per cent for the remainder of the plant's life. This new set-up is intended to stabilize security of investment in new projects.

A third option allowing generators to stick with the old arrangements will also be open to generators until 2007.

It is likely that the market option will allow companies more revenue, though with fewer guarantees than are available with the fixed price option due to the risk that the generator may not be able to sell its electricity. The mixture of mechanisms in this way allows generators to choose the support that best suits their project, as well as allowing the Spanish Government to incentivize companies towards acting competitively and removing the prioritization of the electricity from renewable sources and thus reducing the level of interference that they offer to free market trading of electricity generally. Effectively, having the choice will allow generators to take into account their own need for security of revenue against the potential for greater revenue at greater risk. It is likely that generators will have the opportunity to switch between options on an annual basis.

The viability of the market scheme will depend on how capable the generators prove to be within the market, as well as on the particular conditions applicable within the market relating to the ability of the wind generators to effectively deliver power to a schedule, and the penalties that apply for failure to do so. What these conditions will be are not yet clear.

3. CONCLUSION

Using a feed-in scheme plus some other support systems, Spain has been successful in increasing its wind energy utilization. The changes announced in 2004 will bring in a hybrid support scheme that offers a middle way between feed-in/tariff schemes and obligation/certificate schemes, that is likely to be of interest to many other countries looking to balance the costs and benefits of each type of support mechanism.

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Case study 3.

DENMARK: SUPPORT MECHANISMS FOR WIND ENERGY

CONTENTS

1. INTRODUCTION

Denmark can be regarded as a leader in both policies to increase the generating capacity of wind energy, and in the manufacture of wind energy technology. It currently has enough capacity in place to generate 18 per cent of its electricity in an average wind year.

Denmark has a long history of utilizing wind energy for energy generation purposes. Both World Wars saw Denmark develop electricity generation as a substitute for the fossil fuels to which it lacked access. The late 1970s and 1980s saw Demark look to wind energy again as a possible energy source which would enable it to take more control over its energy security and reduce the environmental impact of its energy use. Government efforts in R&D were matched with an interest from an environmental movement seeking an alternative to nuclear power. This led to both a grass roots movement interested in developing the technology and government policies to encourage the use of wind generators. Increases in Danish wind energy capacity are shown in the table.

2. INITIAL POLICIES FOR DENMARK

Table 1. The Danish domestic market, 1983-1990

Year	MW capacity – Denmark domestic market sales	Number of turbines sold to Danish domestic market
1983	20.6	919
1984	7.2	216
1985	23.1	326
1986	31.7	358
1987	33	311
1988	82	457
1989	65.7	469
1990	81	432

As Danish capacity was produced domestically, sales can be taken to correlate with total installed capacity in those years. (FDV, 1999)

Karnøe attributes this growth to the following changes in the national institutional set-up that acted to increase the profitability of wind power projects:

(a) The increased reimbursement of energy excise tax (1984) due to falling oil prices.

(b) New prices for sales to the grid.

(c) A 20 per cent direct subsidy to dispersed installations (reduced from 30 per cent) but a 50 per cent subsidy to installations in wind farms.

(Karnoe, 1990)

3. THE LAW FOR WIND TURBINES 1992

The Law for Wind Turbines, enacted in 1992, was the first Danish policy to introduce a full subsidy mechanism. It established a fixed tariff rate to be paid by the utilities for any wind generated electricity.

The Act also formalized the allotment of responsibility for meeting the costs of grid connection for wind turbines, an issue that had previously engendered considerable controversy. The law stipulated that turbine owners would henceforth be responsible for costs of grid connection, with the distribution utilities responsible for strengthening the grid so that the connection was workable. In fact, this actually set up a system of shallow connection charging with utilities having to strengthen the grid in the specific area in which the wind farm was to be constructed, and thus bearing the majority of the cost burden. While the agreement originally applied only to turbines under 150 kW, then under 250 kW, it was later relaxed to apply across the board (Gipe, 1995).

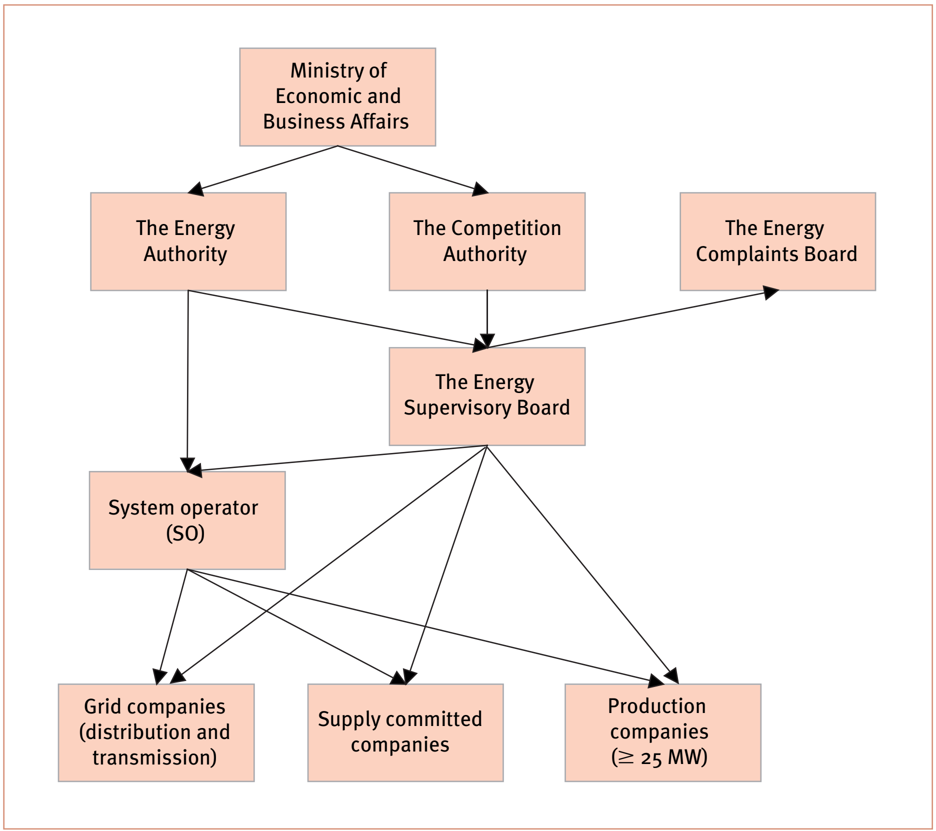
The Act fixed the amount the utilities had to pay for wind-generated electricity at 85 per cent of that charged to a local, average retail consumer with an annual consumption of 20,000 kWh. This amounted to €0.044/kWh, but turbines received up to DKK €0.081/kWh by the end of the scheme in 2000 as the result of the addition of a CO_2 tax compensation of €0.014/kWh and an energy tax compensation of €0.022/kWh (Kjær, 1999). This price compares with the price of €0.028/kWh that electricity could attract with the Nordic power exchange in 2003.

Further measures to increase the available sites include a Government mandate to each region. This has resulted in the identification of more potential onshore sites than was expected, with the likelihood that these will be developed in the next few years.

4. ENERGY REGULATION IN DENMARK

The regulatory structure for the electricity sector in Denmark is shown in figure I below. The Energy Authority regulates the distribution network operators (DNOs) and deals with any complaints. The Minister grants licences. The system operators are responsible for prioritization relating to renewables on the grid and for balancing the system.

Figure I. Regulatory governance bodies within the Danish electricity supply sector



5. CHANGES IN DANISH ENERGY POLICY

Danish energy policy, including that relating to wind energy and other renewable energy sources was brought up to date with Energy21, published in 1996. This laid down Danish targets for onshore wind energy of 1500MW to be in place by

2005 (Danish Energy and Environment Ministry, 1996). Danish onshore capacity moved beyond the projected 1500 MW onshore capacity in 1999 (WPM, 2000). Additional capacity gains are being made as smaller turbines are replaced with larger ones. Energy21 also laid down an offshore wind target of 4 GW. Denmark currently has the world's largest offshore farm, 160 MW at Horns Rev and has granted contracts for a number of others to be constructed.

Fixed-price tariffs remained as the central pillar of subsidization until 1 January 2000, when they were set to be displaced by a renewable portfolio standard (RPS). In addition to the higher price paid during the life of the tariff, wind was also exempted from—or rather compensated for—the imposition of energy and CO_2 taxes. Both of these measures helped to make wind more competitive with respect to conventional electricity generators.

However, the attempted adoption of the market-based RPS undermined the perceived security of investment in wind energy in Denmark. Sales of turbines immediately dropped to zero in 2000, threatening both Danish targets for renewable installation and the Danish manufacturing industry, which had come to dominate its domestic market sector.

At this point it is worth noting that the Danish turbine manufacturing industry, with the advantages it gained from its historical experience and a bottom-up approach to developing its technology was best placed to capitalize on the continuous expansion of the worldwide wind energy industry in the 1990s. The wind turbine manufacturing industry is now Denmark's third largest export industry. Also, aside from wind energy Denmark relies on coal for much of its energy and so has relatively high greenhouse gas emissions on a per capita basis.

The Danish Government could not afford to ignore either the undermining of the home market for wind or the effect this would have on Danish environmental commitments. The Government rapidly readopted the tariff-based mechanism in 2001, albeit with some changes to reflect the improved nature of the technology and to reduce the rising level of overall costs within the tariff mechanism. A parliamentary hearing in September 2001 led the Government to conclude that re-attempting to adopt the RPS mechanism was impracticable at that stage.

After 2001, the reformed support mechanism for wind energy in Denmark provided a fixed price system with an environmental premium per kWh in addition to the market electricity price. The system became somewhat more complex as the result of efforts to cut down on the overall costs of subsidies to wind. Settlement prices changes such that they had several components:

- Base Price: €¢4.42/kWh. In cases where turbines were no longer entitled to the base price, they were effectively compelled to seek a price on the market.

- Subsidy 1: €¢1.34/kWh
- Subsidy 2: €¢2.28/kWh
- Special Price: By arrangement
- Green Certificates: Subject to the future development of a green market. Until that point entitlement to subsidy 1 as a default position.

Entitlement to each of these components is related to ownership, plant capacity, plant age and historical plant output. An overview of entitlement is shown in table 2.

Table 2. Settlement of wind turbines

	Settlement price
Utility owned	
Grid connected before January 1, 2000	Market price plus a variable subsidy adding up to 8.04 €-cents. An upper limit of the variable subsidy of 6.43 €-cents has been imposed. Grid connected after January 1, 2000 The base price, subsidy 1 and 2 are given until further notice.
Owned by collective supply companies	
Grid connected before January 1, 2000	Subsidy 1 is given until further notice
Grid connected after January 1, 2000	The base price, subsidy 1 and 2 are given until further notice.
Non-utility owned	
Existing turbines	Turbines less than 10 years old are entitled to the base price and subsidy 1. The base price and subsidy 1 were given as a minimum until January 1, 2003. Furthermore, subsidy 2 is given until the full-load hours share has been used but not later than 2012. If the full load share has not been used within 10 years the subsidy is reduced to 1.34 €-cent/kWh. Turbines that are no longer entitled to the base price, subsidy 1 and 2 are entitled to Green Certificates.
New turbines connected to the grid before December 31, 2002	Base price until 22,000 full-load hours have been produced. In addition, the turbines are entitled to green certificates.
New turbines connected to the grid after December 31, 2002	Green certificates
Offshore turbines	Base price, subsidy 1 and 2 until further notice.

Source: Techwise, 2002.

Notes: 1) "Until further notice" means until the European Commission has defined new rules for grid connection and settlement of renewable production facilities. 2) Collective supply companies are defined as: Distribution companies, Supply-committed companies, Transmission Companies and SR-Companies. 3) Existing turbines are defined as turbines bought on a binding contract before December 31, 1999 and which are requested to be grid connected before August 21, 2000. 4) The full-load hour share is defined as 25,000 hours for turbines with a capacity of 200 kW or less, 15,000 hours for turbines with a capacity between 201 and 599 kW and 12,000 hours for turbines with a capacity in excess of 600 kW.

The average domestic electricity price in Denmark for small-scale consumers in 2003 was €0.2558/kWh after tax, making it the most expensive in the European Union. However domestic energy use is heavily taxed in Denmark and the pre-tax price of €0.134/kWh is comparatively low for the EU. (Eurostat, 2003) The prices available within the tariff were effectively 30 per cent lower for new turbines than the prices paid for turbines already generating. (ECN, 2003).

It was planned that Denmark would attempt to switch over to a green trading mechanism from 1 January 2003, however, this deadline was not met, and instead a scheme wherein wind turbines erected after 1 January 2003 receive the market price plus ~€¢1.34/kWh was instituted. The scheme includes a maximum allowable price of €¢4.83/kWh. Turbines that qualify for the subsidy are eligible to receive it for up to twenty years. (Techwise, 2002).

Electricity from biomass maintains the feed-in tariff of 8.1 ct/kWh. The premium for renewables is financed as an addition to the electricity price per kWh, shared equally among all electricity consumers in relation to their electricity use. The result of the return to the more stable tariff mechanism was a boom year for installation and sales of wind turbines in Denmark, with over 400 MW of increased wind capacity.

Denmark typically has a spinning reserve[1] of around 20 per cent of the load and this has generally been sufficient to cope with any fluctuations in the output of wind power. Interconnection with Norway and Sweden, both with large amounts of hydropower has proved to complement the Danish system, with output from hydropower easily able to be altered to respond to windpower output. Nevertheless Denmark has had to be at the forefront of developing new technology to deal with balancing the distribution and transmission grids with high levels of intermittent generation. Neilsen gives consideration to the technical problems associated with this (Neilsen, 2002a; Neilsen, 2002b).

6. CONCLUSION

The Danish renewables support mechanisms have led to the substantial development of wind power and its use of feed-in type mechanisms (with guaranteed prices and connection agreements) has also favoured small-scale wind development much of which was undertaken through community ownership. Even in 2004

[1]Generating capacity which is currently unused but is synchronized with the network such that it can be brought on line to respond to system needs instantaneously.

around 75 per cent of wind power in the country is produced by turbines owned by communities and individuals. Attempts to change the mechanisms have caused setbacks and the current (2004) system can be seen as attempting to incorporate elements of feed-in and certificate/obligation systems to overcome the disadvantages of each.

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Case study 4.

RENEWABLE ENERGY IN GHANA

CONTENTS

1. BACKGROUND

1.1. Energy generation

Ghana's first major generation project was the Akosombo hydroelectric dam, commissioned in 1965 with an initial output of 588 MW. Prior to this, several small diesel plants were in operation, providing services to local communities, mines, industries, hospitals and educational institutions around the country. These smaller and more expensive plants were phased out as cheap electricity gradually became available through the national grid. Power output from Akosombo was increased to 912 MW in 1972; followed in 1982 by the addition of 160 MW from a second hydroelectric plant located at Kpong, downstream from Akosombo.

In 1998, poor rainfall in the catchment area of the Akosombo dam led to sharply reduced output from the plant, and two foreign companies, Cummins Ltd. and Aggrekko Ltd. were contracted to run two 30 MW diesel power plants to feed power directly into the national grid. These plants were classified as "Emergency Power Producers" and were eventually shut down in 2000 when the electricity supplied by Volta River Authority (VRA) increased to normal levels. However, a 30 MW diesel plant, commissioned in 1992, is run by VRA in Tema.

Further expansion took place in 1999 with the completion of a 330 MW-combined Cycle Thermal Plant at Aboadze in south-western Ghana. Output at the Aboadze plant was increased in 2000 with the addition of a 220 MW simple cycle thermal generator using waste heat from the original turbines. The expanded plant is jointly owned by the Volta River Authority and CMS Energy of Michigan, USA. In 2000, the Government purchased a 125 MW power barge to generate electricity from natural gas from the Tano fields but this is yet to be commissioned. Table 1 shows the installed capacity of electricity generating plants in the country in 2005.

Table 1. Installed capacity of generating plants (2005)

Generation plants	Type of plant	Fuel	Capacity (MW)
1. Akosombo	Hydro	Hydro	1,038
2. Kpong	Hydro	Hydro	160
3. Takoradi thermal plant	Thermal	LCO/gas	330
4. TICO (CMS/VRA plant at Takoradi)	Thermal	LCO/gas	220
5. Tema diesel plant	Thermal	Diesel	30

Ghana's electricity grid is interconnected with those of the neighbouring countries of Benin, Burkina Faso, Côte d'Ivoire and Togo. Before 1995, Ghana had a surplus of electric power, allowing VRA to export electricity to Compagnie Ivoirienne d'Électricité (CIE) of Côte d'Ivoire and Communaté Électrique du Bénin (CEB) of Togo and Benin. However, as demand grew within Ghana, the country began to face an electricity deficit. VRA now augments electric power supply by buying from Côte d'Ivoire, which has expanded its generation capacity. VRA imports up to 250 MW of power from Côte d'Ivoire, and transmits power onwards to Togo and Benin.

Power purchases from CIE have been mixed, with VRA having to import more power during times of crises, for example, during the 1998 drought, which led to a drastic fall in hydro-capacity from Akosombo. Table 2 below shows the source of power supply by VRA to the Ghanaian market in 2005.

Table 1. Power supply to the Ghanaian electricity market by VRA in 2003[1]

Generation source	Electricity generated (GWh)
Hydro	3,884
Thermal	2,015
Purchased from CIE	940
Total	6,839

There is also some standby generation capacity available. Notably, mining company Anglogold-Ashanti has a 21 MW diesel plant at Obuasi, and the Tema Oil Refinery operates a 6.5 MW diesel plant at Tema. The Volta Reservoir received substantially above-average inflows during 1999, enabling output from Akosombo and Kpong to be raised from 3,830 GWh in 1998 to 5,169 GWh in 1999. By 2003, the water level in the lake fell again to as low as 237 feet in July and about 247 feet in November. The minimum operating level of the dam is 248 feet.

1.2. Transmission and distribution

VRA owns and operates the nationwide transmission system and the distribution system for northern Ghana. The distribution system in southern Ghana is managed by the Electricity Company of Ghana (ECG). As of December 2003, the existing transmission network system comprised of 36 substations and approximately 4,000 km of 161 KV and 69 KV lines. This includes 129 km of double-circuit 161 KV interconnection to Togo and Benin. There is also a single 220 km circuit, being a 225 KV inter-tie with Côte d'Ivoire's transmission network. The distribution system comprises 8,000 km of sub-transmission lines, 30,000 km of distribution networks with 22 bulk supply points and 1,800 MVA of installed transformer capacity.

[1]VRA Annual Report, 2003.

1.3. Energy consumption

In 2004, Ghanaians consumed a total of 5,158 GWh of electricity supplied by VRA. VRA has two main customers: the Volta Aluminium Company (VALCO), which is the largest industrial customer, and ECG, the largest non-industrial customer. VRA also supplies power to some mining concerns and other industries. In 2002, VALCO took up to 32 per cent of the power sold by VRA. Production at VALCO was closed in May 2003, following a breakdown in negotiations between the government and VALCO's parent company Kaiser Aluminum at the end of VALCO's energy contract. Extra electricity became available to VRA as a result of the smelter shutdown. In October 2004 VALCO was bought by the Government of Ghana and subsequently reopened on a reduced scale in September 2005 under a joint venture agreement with the US company ALCOA.

ECG distributes power to households and industries in the heavily populated southern part of Ghana. The utility presently has about 1.1 million customers, of which about 80 per cent are residential and the remaining 20 per cent include industrial customers, the military, and other public facilities. The distribution network has relatively high losses of about 26 per cent, including about 15 per cent non-technical losses. This indicates that a significant amount of distributed power is lost through illegal connections and wastage.

2. ENERGY REGULATION IN GHANA

2.1. Institutional structure of the energy sector

The energy sector in Ghana is managed at different levels by the organizations detailed below. For simplicity, the various institutions are grouped under policy, regulatory, operational and support institutions. Some of their roles overlap—for example the roles of the Energy Commission and the Environmental Protection Agency in licensing petrol filling stations.

Policy institutions

- The Ministry of Energy: As part of the executive arm of Government, the Ministry is the ultimate body responsible for development of energy policy for Ghana. The ministry is responsible for developing and implementing energy sector policy in Ghana, and also supervises the operations of the agencies associated with the sector.

Regulatory institutions

These include:

- The Energy Commission (EC): An independent agency responsible for licensing, regulating and monitoring private and public entities operating in the energy sector. The commission also collects and analyses energy data and contributes to the development of energy policy for Ghana. EC was established in 1997 in accordance with the recommendations of the Power Sector Reforms Commission (PSRC).
- The Public Utilities Regulatory Commission (PURC): An independent agency set up as recommended by the Power Sector Reforms Commission (PSRC) to oversee the performance of the public utilities. PURC is mandated to protect the interest of consumers and to examine and approve the rates chargeable by the utilities.[2]
- Environmental Protection Agency (EPA): Responsible for establishing, monitoring and enforcing environmental policies for the country. EPA has oversight responsibility in any activity that is likely to have an environmental impact. EPA monitors the activities involved in the production and use of energy.

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[2]Public Utilities Regulatory Commission Act, 1997 (Act 538).

- National Petroleum Tender Board: Supervision of international competitive bidding and award of contracts for the procurement of crude oil and petroleum products for Tema Oil Refinery.

Operational institutions

- The Volta River Authority (VRA): This wholly state-owned entity is responsible for generation and transmission of electricity in Ghana. VRA was established in 1961 under the Volta River Development Act (Act 46) to generate electric power by means of the water in the river Volta, and to supply electricity through a transmission system.[3]
- The Electricity Company of Ghana (ECG): 100 per cent state-owned entity responsible for distribution of electricity to consumers in southern Ghana, namely in the Ashanti, Central, Greater Accra, Eastern and Volta Regions. Established in 1967, ECG, the nation's main electricity distributor, is responsible for providing line connection to domestic and certain categories of industrial consumers. ECG is responsible for billing and maintaining a reliable supply of electricity to its customers.
- The Northern Electrification Department (NED): Established in 1997 as a subsidiary of VRA, it is responsible for power distribution in northern Ghana, serving the Brong-Ahafo, Northern, Upper East and Upper West Regions.
- Tema Oil Refinery (TOR): Responsible for the importation of crude oil and petroleum products. Also undertakes the refining of all the crude oil imported into the country and bulk sale of petroleum products to OMCs and bulk consumers. TOR was incorporated in 1960 under the companies' code of Ghana.

Support institutions

- The Energy Foundation (EF) Ghana: Established in November 1997 by the Private Enterprise Foundation in collaboration with the Government of Ghana, the Energy Foundation is a non-profit institution with the goal of promoting sustainable development and efficient consumption of energy as a key strategy to manage Ghana's growing energy needs in a sustainable manner. The Foundation offers energy efficiency and renewable energy advice and support to residential, industrial and commercial energy consumers in Ghana.
- Ghana National Petroleum Corporation (GNPC): Established by law in 1983 to promote the exploration and development of petroleum resources in Ghana,[4] GNPC is currently responsible for oil and gas exploration and production.

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[3]The Forty-Sixth Act of the Parliament of the Republic of Ghana (The Volta River Development Act, 1961).

[4]The Ghana National Petroleum Corporation Law (PNDC Law 64).

- Bulk Oil Storage and Transportation Company (BOST): Bulk Oil Storage and Transportation is a Government-owned, limited liability company that undertakes planning for storing and managing strategic stocks of petroleum products. BOST runs several storage depots in the port cities of Tema and Takoradi, and in seven other locations around the country. In addition, BOST is responsible for primary distribution of the products. Funding for maintaining the reserves comes from a special levy on petroleum products.
- Oil marketing companies (OMCs) and retail outlets: The oil marketing companies are responsible for distribution and marketing of petroleum products, mainly through small retail outlets countrywide.

2.2. Status of energy sector reforms, current policies

There have been a number of energy sector reforms in Ghana over the years, mostly focusing on the power subsector: expanding capacity and extending the electrical grid across the nation and to smaller communities. These efforts have been largely successful and have led to the electrification of all district capitals under the National Electrification Programme. Although renewable energy has not featured prominently in the reforms, its role has largely been to supplement the national grid by providing power as a stopgap measure and for providing electricity to inaccessible communities.

The most recent energy sector reforms were started in 1997, when the World Bank indicated that support would no longer be provided for electricity projects in developing countries unless there was a clear commitment by the Government to reforming the sector. While the reforms were undertaken primarily to secure an IDA credit for the construction of the 330 MW Takoradi thermal plant, there was also a view to secure private participation in the development of future electricity infrastructure. At the time that the reforms were instituted, there was very little external investment in energy, which led to poor quality service and poor financial performance by utilities. In broad terms, the reforms sought to achieve the main goals listed below:

1. Establish a new, effective regulatory framework;
2. Allow for competition in the generation and wholesale supply of power;
3. Commercialize existing state-owned power utilities, enhance their management and accountability, and secure private sector participation;
4. Unbundle the utilities;
5. Minimize the Government's role and use of public resources in the sector, particularly through subsidies;

6. Use available public resources to improve the cost effectiveness of transmission and distribution projects under the National Electrification Scheme.

These reforms were expected to lead to increased access to electricity in all sectors of the economy and increased efficiency in the delivery of power to consumers. Some achievements of the reforms include the conversion of the Electricity Corporation of Ghana into a limited liability company under the Statutory Corporations Act (1993). In addition, thermal power generation has been opened up for private sector participation and competition. The expected influx of private investment to the electricity sector has not yet occurred, in spite of the high growth in demand and the need for additional capacity. So far, there has been only one private sector power generation plant; the Takoradi International Power Company (TICO), with a 220 MW capacity. It was constructed in 2000, and is owned jointly by VRA (10 per cent) and CMS Energy (90 per cent). It draws its source from the Takoradi thermal plant, which is owned fully by VRA.

The reforms also led to the creation of a new classification of "bulk customers" by the Energy Commission. Beginning 2004, the EC defined bulk customers of electricity in the mining and manufacturing industries as those customers who are able to negotiate power supply contracts directly with VRA and ECG or any other licensed independent power producer with a framework of wheeling charges and other guidelines determined by the PURC. This is expected to give such customers more flexibility and better pricing based on their high levels of consumption.

The power sector reforms have also led to the introduction of the Embedded Generation Facility (EGF) concept. By definition, an EGF is a power generation unit supplying power at low to medium voltage to an electricity substation within a particular distribution system. For example, during the 1997-98 power crises, two private companies—Aggreko Ltd. and Cummins Ltd.—each provided 30 MW power from diesel generation sets directly into the 33 kV distribution network. The Embedded Generation Facility also allows for renewable energy power producers to supply power at local levels.

2.3. Rural electrification

Ghana's Government embarked upon the Economic Recovery Programme (ERP) in the 1980s. These reforms included the establishment of a National Electrification Scheme (NES) in 1989 with the aim of providing nationwide access to electricity by 2020. Under this scheme all communities with populations above 500 were to have access to electricity. Over the years, funding for NES has been mainly through grants, concessionary credit, government sources, and the national electrification fund levy. The levy of ¢1.7/KWh (US¢ 0.02/KWh) is paid by grid electricity consumers and generates about ¢9.8 billion (US$ 1.1 million) per year. However, heavy donor reliance has meant that specific electrification projects have been undertaken only when funding became available.

An extension to the NES for rural electrification is the Self Help Electrification Project (SHEP). SHEP allows for the electrification of communities not directly covered under NES but which are within 20 km of an existing or planned 11 kV or 33 kV transmission line. The community is required to provide a certain minimum contribution to the project, usually in the form of wooden poles for the distribution wires. Government would then provide additional assistance to complete the project. The average tariff for electricity for urban consumers is between 5.2-8.2 US¢/kWh, but rural subscribers pay about US$ 1.00 as a connection fee to the electricity supplier and then a subsidized lifeline tariff of about $2.00/month for consumption of up to 50 KWh/month. This amounts to about US¢ 4.0/KWh. The extra costs for connecting rural communities (transmission, distribution and service drop costs) are covered by Government under the NES.

Before the launch of NES in 1990, only 478 (11 per cent) out of 4,221 identified communities nationwide had access to electricity. Of the 110 district capitals at the time, only 46 were on the national grid. Between 1991 and 1994, the initial phases of SHEP 1 and SHEP 2 were completed, with the connection of 50 and 250 communities to the grid respectively. SHEP 3 was launched in 1995, and covered almost 1,400 communities nationwide. By the end of 1999, all 110 district capitals were electrified; and over 450 communities (52 per cent) also had power. By 2004, 3,500 communities had access to power, representing 65 per cent of the total. Presently, all communities with populations greater than 3,000 are connected to the grid. As a result of the ongoing electrification scheme, access to electricity in the country had reached about 48 per cent by 2003, which is among the highest in sub-Saharan Africa.

The rural electrification drive may receive a boost with the recent announcement by the Minister of Energy of the arrival of US$ 15 million worth of equipment, with an additional US$ 30 million earmarked to support the project.[5] Also, the Government recently announced its intention to shift the focus of the National Electrification Scheme (NES) to ensure that rural communities used the supplied power to boost economic activities.[6]

So far, many rural communities have benefited from the available electric power, even though power supply to the rural areas has been unreliable with frequent

[5] "All Set For Bui Dam To Take Off", Daily Graphic, October 28, 2005.

[6] "Government To Shift Focus Of National Electrification Scheme", Daily Graphic, Sept. 28, 2005.

power outages and low voltage situations. However, many households consider the current electricity tariffs as unaffordable.[7]

[7]Amissah-Arthur, Jabesh; Anamuah Amonoo, Jojo. *Study of the Social and Poverty Impacts of Energy Interventions on Rural Communities in Ghana*. Kumasi Institute of Technology (KITE), April 2004.

3. RENEWABLE ENERGY

Although several efforts have been made through feasibility and pilot programmes, there has not been a concerted policy regime that specifically targets renewable energy technologies (RETs). Moreover, none of the electrification programmes have included renewable energy as an alternative source of power. This has meant that renewables remain in the hands of individuals with little government support. In spite of the EGF facility introduced under the reforms, there is no process in place presently for individuals or cooperatives to feed the power generated from renewable energy systems into the national grid. Some of the significant initiatives with regards to renewables are outlined below.

The earliest effort to harness renewables came in the wake of the global energy crisis of the 1970s, when the Government of Ghana created a special committee on energy resources. This marked the beginning of the Government's interest in diversifying Ghana's energy sources, and pursuing a developmental programme in renewable energy technologies.

In 1983, the Government instituted the National Energy Board (NEB) by enacting a law (PNDC Law 62). The Board was to oversee the development of renewable energy resources. Also, NEB's scope of activities spanned energy conservation (electricity and petroleum) and demand management. A total of 135 projects were undertaken by NEB, 29 of them being in renewables.

The NEB was abolished in 1991, and until 1996 when another policy document was put in place, the activities of NEB were carried out by the Ministry of Mines and Energy. In 1996, the Energy Sector Development Programme (ESDP) was initiated.

Under the ESDP, the Renewable Energy Development Programme (REDP) was set up to promote the development of RETs and the renewables industry, as well as to build a database on renewable energy activities in Ghana. REDP supported a number of biomass and solar energy projects.

ESDP has been the overall policy regime regulating the development of RE technologies in Ghana to date. However, ESDP is to be replaced with the National Renewable Energy Strategy (NRES) being formulated with the support of the Danish International Development Agency (DANIDA). This is under the Strategic National Energy Programme (SNEP), which is intended to dictate the direction of the development of energy in Ghana from 2000-2020.

The current energy policy document is the Strategic National Energy Programme. SNEP is projected to span a twenty-year period, 2000-2020. In 2003, a technology catalogue for SNEP was published, in which the goal of SNEP was stated as:

> "... to contribute to the development of a sound and well regulated commercial energy market that will provide sufficient, viable, efficient and least cost energy services for social welfare and economic activities through the formulation of a comprehensive plan that will identify the optimal path for the development, utilisation and efficient management of the country's energy resources."[8]

The document identifies the following RETs as viable projects that warrant attention:

- Solar water heaters;
- Biomass—charcoal kilns, sawdust briquetting, biomass gasification, palletizing, biogas plants, pyrolysis;
- Grid/off grid solar systems;
- Grid/off grid wind turbines;
- Off-grid small hydro;
- Landfill gas power plants.

Renewable energy contributes an insignificant part of electricity supply in Ghana. For example, by 2001, the estimated over 4,000 off-grid PV systems installed nationwide had a total capacity of 1MW, compared to the grid capacity of over 1,700 MW in 2003.[9] Besides the major hydroelectric plants, electricity generated from RETs is used at the individual household or institution level, and does not enter the supply grid. The different renewable energy technologies and according case studies in Ghana are described below.

3.1. Biomass

The combustion of biomass is the primary means of energy for most of the Ghanaian population. In the rural areas, fuel wood for cooking accounts for 57 per cent and charcoal 30 per cent of energy consumption. Charcoal is also the fuel of choice for cooking in the urban areas. Efforts in the renewable energy field have focused on developing and deploying new technologies to make biomass combustion safer and more efficient.

More advanced uses of biomass involve the conversion of biomass into other forms before being used for energy generation. In ovens and furnaces, biomass is typically used in the form of charcoal, sawdust briquettes, and gas. Gas can be generated directly for use in a gasification plant, or in a biogas plant. A small number of biogas plants have been installed in Ghana, and the Kwame Nkrumah University of Science and Technology (KNUST) has built research prototypes of viable biomass converters.

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[8] Strategic National Energy Plan 2000-2020 Technology Catalogue, April 2003.

[9] Electricity Sector Overview; Ghana Energy Commission.

At least three palm-oil mills have biomass-fired power plants for generating electricity from palm fruit residues. These have a total generating capacity of 1.5 MW. Also, at least one sawmill runs a plant based on wood residue, while another such plant lies abandoned.[10] According to the technology catalogue of SNEP, there are many commercial biomass cogeneration plants available in Ghana, operating mainly in off-grid locations.

One of the most famous biogas projects in Ghana is the "Integrated Rural Energy and Environment Project" commissioned in 1990 at Appolonia in the Greater Accra region. This pilot project was to produce biogas from human and animal waste, and the gas used to produce electricity and also for cooking. The system provided electricity to five social centres, a school, 21 houses, and 15 streetlights. This project has shown itself to be unsustainable, and has come to a standstill.[11] Recently, worldwide interest has been directed at biofuels. A promising plant is *Jatropha curcas*, which grows in arid conditions and yields seeds that can be processed into biodiesel. This fuel has been shown to run in conventional engines. Currently, a Jatropha oil-extracting project is running on a pilot basis in Yaakrom in the Brong Ahafo region. In 2005, DaimlerChrysler and UNESCO announced funding for a research project, Jatropha Energy Development for Rural Communities in Ghana. The project will be undertaken by a team from KNUST and Cambridge University and aims to establish a small-scale industry for the development of Jatropha diesel to serve rural communities.[12] The authors are unaware of any company that offers any biomass technologies for sale at this time.

3.2. Solar electricity

Solar photovoltaics (PVs) are by far the most popular renewable energy application. Solar electricity has been shown to be technically viable, but due to the high initial costs there has not been a widespread application of PV systems nationwide. PV systems have been used to provide electric power mainly for health centres and for homes. Some PV systems have also been installed for commercial applications such as telecommunication repeater stations, water pumping, and battery charging. Furthermore, the solar lantern is quite well received, and had the cost been lower, would have been a viable competitor to the kerosene lantern. In the urban areas, PV systems are often used in electricity back-up systems in areas where grid reliability is low. Also, a few wealthy individuals invest in PV systems for their homes in order to diversify their energy sources.

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[10] *Renewable Energy Development Programme*, Draft National Renewable Energy Strategy, Ministry of Energy, Energy Commission, and DANIDA. October 2003.

[11] E. K. Ackom, *Technical & Economic Viability Analysis of Renewable Energy Technologies in Ghana*. PhD Thesis. Brandenburg University of Technology, 2005.

[12] www.mondialogo.org/106.html

Currently, there are a number of private companies offering renewable energy technologies and services in Ghana. Most of them are involved in solar electricity, and mainly sell to private urban households. The companies sell discrete components such as panels and balance of system (BOS) parts: batteries, inverters, chargers, solar lanterns, and submersible pumps. However, some companies offer full system design, installation and maintenance. A few companies offer installation and maintenance services only.

Recently, some opportunities were created for the private sector to supply large quantities of solar PV equipment. For example, in 2005, the Ministry of Education required 300 solar home systems for its Non-formal Education Division (NFED). The supply and installation of the pre-designed PV systems was put to a competitive tender.

Several projects have deployed solar PV systems to provide electricity services to off-grid communities. Notable projects are the Renewable Energy Services Project (RESPRO) in the East Mamprusi district. This project started in February 1999 and was originally expected to last three years after which RESPRO would become a public sector company providing rural energy services for a fee. Although the project phase formally ended on 31 March 2003, the Ministry has continued to support the programme.

RESPRO has installed and is operating solar PV systems in over one hundred communities in thirteen districts of the three Northern regions and Brong-Ahafo region. Table 3 shows the total number of installations under RESPRO.[13]

Table 3. Number of installations carried out under RESPRO

Solar home systems	2,200
School systems	42
Clinics systems	6
Water pumping system	1
Street lighting	24
Total	**2,273**

Another solar electricity initiative is the Solar Rural Electrification Project run by the Ministry of Energy between July 1998 and December 2000. More than 1,500 systems were installed in several communities in the Volta, Eastern, Upper West, Greater Accra and Northern Regions. Some of these communities have since been connected to the national grid, and the Ministry intends to relocate those PV systems to other districts where they are needed.

[13]Ministry of Energy: www.energymin.gov.gh

The Ministry has also installed a number of PV street/area lighting projects in the rural areas. This application of PV has been found to benefit the community as a whole, suggesting a higher social impact vs. cost ratio than individual home systems. For example, a single street or area lamp placed at a lorry station or the village centre extends hours of business for food vendors and bus operators. The maintenance of such projects can be put under the local authority or the transport union, and this can be more sustainable in the long run.

Table 4 summarizes the extent of PV deployment in Ghana. The RESPRO project is item 4 on the list, appearing as the Rural Energy Services Company (RESCO).

Table 4. List of PV projects in Ghana[14]

Organization	Project
Danida/MOH Solar Project	PV refrigeration, lighting, water pumping and heating, *Equip* rural or small health sectors with reliable tech.
CIDA-UR/UST Renewable Energy Project	Small-home-systems (SHS), battery charging, water distillation
UST/GTZ solar pump project	Radial flow centrifugal water pump
MOME [special unit, in close collaboration with the Volta Authority (VRA/NED)] UNDP/GEF	UNDP/GEF, GEF grant of $2.5 mil. Ghana Gov. $0.5 million for establishment of RE-based rural energy services company River (RESCO) to provide off-grid solar electrification to initially 13 villages
MOME	2 solar service centres Funding through a $185 million (306,177 million Cedis) syndicated loan provided by IDA, ORET of Netherlands, DANIDA, Nordic Development Fund (NDF) and Caisse Francaise de Developpement (CFD), the rest of 105,066 million Cedis was to be the local component of the programme
MOME Wachiau Project	2.1 kW solar battery charging centre Battery operated home systems (BOHS)
MOME Spanish Solar Project	Concessionary loan of the Spanish Government of $5 million for off-grid solar electrification of 10 villages, Home, school & community systems, water pumps, streetlights
MOME Solar Thermal Projects	Crop dryers for reduction of post-harvest losses Improve quality of agric. produce for high export prices
CIDA-University Of Regina, in collaboration with the University of Science and Technology of Ghana	Solar service centres (SSC), installed in rural communities since 3.1995 CN$ 1.24 , of which CIDA (Canadian International Development Agency) contributes $900,000 with the remaining amount donated by the participating universities
The Ghana Solar Energy society (GHASES)/GEF also Ghases/Women's World Banking	GEF Small Grants Project and Women's World Banking micro-credit scheme Training/marketing for improved charcoal stove; administration of a micro-credit scheme
Sun oven	Production and marketing of solar ovens

[14]www.areed.org/country/ghana/ghana.pdf

The estimated 4,600 PV projects are summarized according to application in table 5.

Table 5. PV systems in Ghana according to application

Application	Quantity
Lighting	4270
Vaccine refrigeration	210
Water pumping	80
Telecommunication repeater stations	63
Radio transceivers	34
Battery charging stations	20
Rural telephone systems	3
Grid-connected power generation*	1

*This unit, installed at the Ministry of Energy, is experiencing technical problems.

3.3. Solar thermal technology

Thermal applications of solar energy are limited to small systems for the provision of hot water from solar water heaters (SWHs). Solar water heaters have been installed in individual homes, hospitals and hotels, but this has been on a small scale because cheaper water-heating alternatives such as electric water heaters are available.[11]

Solar drying of foodstuffs is widespread and is the traditional form of storing many types of food, but this is usually rudimentary—foodstuffs are spread out in the sun or hung in barns to dry. A number of solar crop driers have been manufactured and trails have shown them to be a viable application of solar energy in Ghana.[10]

3.4. Wind energy

Ghana's wind resources are confined to narrow stretches along the eastern coastline and offshore; but the speeds are moderate. Even so, it is still expected that wind energy can be harnessed to provide electricity in commercial quantities[8, 11].

A number of private companies in Ghana sell small wind turbines (systems ‹ 50 kW have been advertised).

In 2004, Enterprise Works Ltd. launched the "Ghana Wind Energy Project", a demonstration project of 12 wind turbines (600-1,000 Wp) installed along the eastern coast of Ghana. The Global Environment Facility and the World Bank provided funding. Six of these wind turbines were locally manufactured, with the intention of developing local technical capacity in the fabrication of small wind turbine systems.

3.5. Mini/micro hydro generation

Studies conducted in Ghana over the past three decades have shown that there exists a theoretical availability of up to 25 MW of micro hydropower from 70 sites.[10] However, recent studies have shown that a number of these sites are fed from water sources that tend to dry up for a number of months in the year. Some of the other sites have been found to be economically unfeasible.[11] Currently, one of the feasible sites is being developed, and a 30 kW system expected to be established soon.[15]

[15]Personal communication with Mr. W. Ahiataku-Togobo.

4. CONCLUSIONS

The penetration of renewable energy technologies (RET) in Ghana could have been extensive by now if the barriers to the successful application of these technologies had been dealt with earlier. Some of the barriers had to do with the cost of the technology (which is rapidly reducing), but other barriers have to do with financial arrangements, government policies and customer education.

Many years of heavily subsidized petroleum and electricity costs have made RE options, especially PV, uncompetitive and therefore the sector was unable to attract sufficient private sector investment. The few companies dealing in RETs are unable to generate enough sales to keep them running, since the people who need their services most cannot afford them.

The Government launched a number of pilot projects, which subsequently failed. By their very nature, these projects could be seen as a “test of concepts” and therefore failure was an “acceptable” option. However, the authors are of the opinion that certain mechanisms could have been put in place to ensure the success of such projects. For example, the biogas project at Appolonia had certain difficulties with the provision of sufficient dung. Also, the tariffs paid by the consumers at Appolonia were insufficient and could not keep the plant running. Thus the facility has been out of use for considerable time, even though electricity continues to be provided by fuelling the generators with regular diesel fuel.

The RESPRO is also reported to have run into difficulties, where many of the installations have batteries that are run down but cannot be replaced due to lack of funds. Once again, it would appear that the tariff regime is unable to sustain the project.

The Ghana Wind Energy Project launched by Enterprise Works ran into technical difficulties when some of the electronic components at various sites were damaged during windstorms.

5. KEY RECOMMENDATIONS

Based on observations and interviews in Ghana, several key areas have been identified as needing attention. The areas listed below are not intended to be comprehensive, and do not take into account efforts that may be presently underway at the government level which were not made known to the authors during the course of their research.

Firstly, it is recommended that future energy policies be reviewed to incorporate renewable energy technologies as part of the energy mix. The present situation where large-scale grid electricity is planned separately from decentralized renewable sources has hindered the development of the sector and perhaps reduced the number of communities that could have been electrified.

As part of the planning process, it is recommended that firm numerical targets be established for the proportion of total electrical energy that will come from RETs. When a target it set, it will allow resources to be mobilized and foster policies and programmes to achieve this goal.

The present tax waiver on solar generating sets was found to be restrictive and has not led to the expected increase in the development of solar energy in Ghana. It may be worth considering the removal of these duty and tax waivers on RETs, and apply the funds instead to an RET fund to support viable renewable energy projects. Having a fund for renewable technologies will allow careful evaluation of projects for feasibility and economic benefit. The selected projects will also be fully funded and are likely to be on a scale that will be sustainable.

It would be necessary for the Energy Commission to clarify regulations regarding independent power producers and the Embedded Generation Facility to allow private operators to evaluate the opportunities present in the energy sector and make investment decisions. Lack of clarity may be preventing much needed investments. The regulator should also make provisions to make it easier for cooperatives to generate their own power using renewable resources. Furthermore it will be necessary to provide technical support to communities that have natural resources and are interested in establishing their own generation facilities. This particularly applies in the case of mini and micro-hydro resources.

The classification of energy producers should be refined to distinguish small operators from large ones. This does not necessarily mean compromising on environmental and performance standards, but it will allow smaller companies to be incorporated into the mainstream energy sector. Under the current situation, smaller energy service companies do not benefit from the resources of the Energy Commission because the barriers to recognition are too high.

To make RETs more practical and visible in the lives of ordinary people, it would be necessary to move emphasis away from pilot projects to viable and functional entities. The abundance of pilot programmes in the past has created the impression that renewable energy technologies are an exotic curiosity and far removed from the real world. By selecting proven technologies and establishing viable businesses around them, policymakers and industry can start to change this perception.

Finally, renewable energy technologies should be incorporated into the NEP and SHEP programmes as soon as possible. There should be a single electrification programme in which several alternative power sources are available. Communities and programme managers can together then choose the best options for each community. This will also prevent the situation where people on the grid are subsidized, but those who choose to use RETs are made to bear the full cost of their installations.

Case study 5.

ZAMBIA: INSTITUTIONAL FRAMEWORK AND STATUS OF RENEWABLE ENERGY

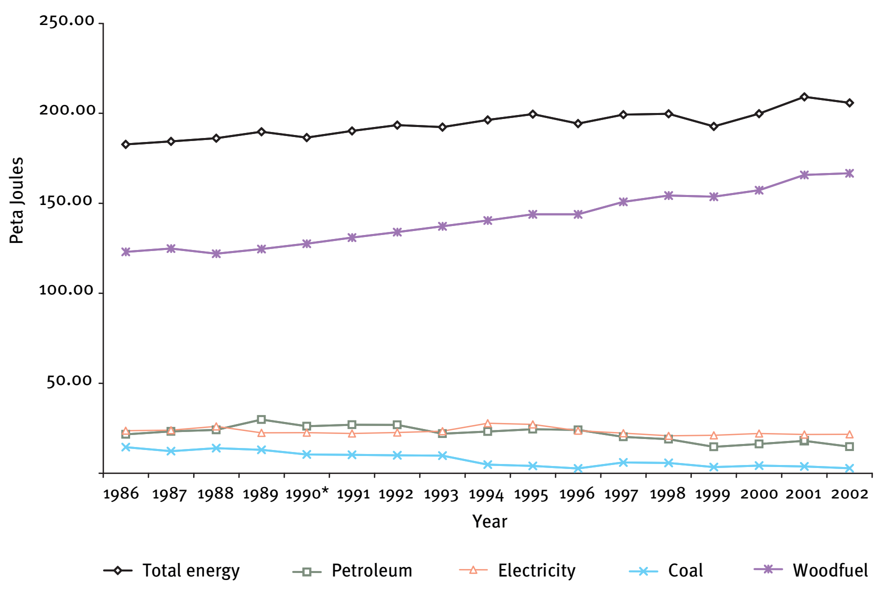
CONTENTS

1. BACKGROUND

1.1. Energy consumption

The overall energy consumption trends for Zambia between 1986 and 2002 are given in figure I.

Figure I. Energy consumption trends (1986-2002)



Source: Department of Energy, Energy Bulletin 1990-2003.

There has been a moderate growth in total energy consumption between 1986 and 2002. The increase has mainly been attributed to wood fuel utilization in the household sector as a result of increasing population.

However, petroleum and coal consumption trends witnessed a decline due mainly to a corresponding decline in economic activities, especially after 1991, when the country experienced industrial company closures following the privatization programme. The closures were mainly a consequence of opening the market to international goods and services, thereby making some local goods and services uncompetitive.

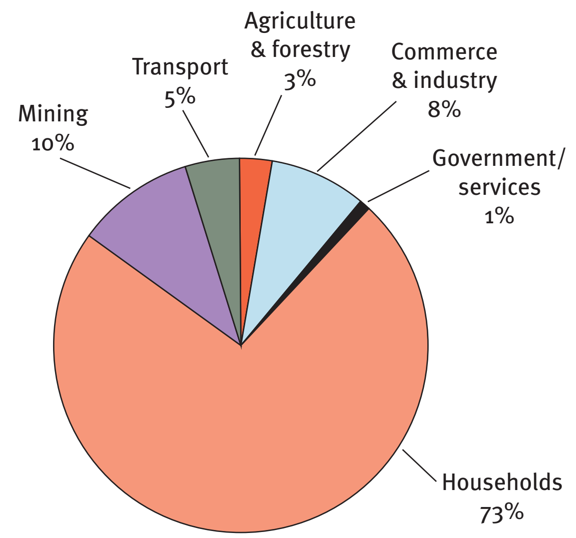
The overall energy consumption by sector for Zambia is illustrated in table 1 and figure II for the year 2000.

Table 1. Energy consumption by sector (year 2000)

Sector	Peta Joules	Per cent
Agriculture and forestry	5.75	2.8
Commerce and industry	17.06	8.3
Government/services	2.29	1.1
Households	150.56	73
Mining	20.99	10.2
Transport	9.67	4.7
TOTAL	206.33	100

Source: Department of Energy, Energy Bulletin 1990-2003.

Figure II. Sectoral energy consumption chart (2000)



The energy consumption pattern in Zambia is dominated by households and mining. As shown in table 1 and figure II, households account for 73.0 per cent of total final energy consumption in 2000. The largest share of energy consumption by households is attributed to firewood as illustrated in figure I, which indicates the overall importance of firewood in the provision of energy in Zambia. The mining sector, second in importance in terms of energy consumption, accounted for 10.2 per cent of total final consumption, followed by industry 8.3 per cent and transport 4.7 per cent.

1.2. Energy supply

Zambia is well endowed with hydropower resources. The main river catchment areas that have been developed are the Zambezi and Kafue. On the Kafue River, Zambia has developed the Kafue Gorge hydroelectric scheme (900 MW); on the Zambezi River, Kariba North Bank (600 MW) and Victoria Falls power station (108 MW). Small/mini-hydro power stations serve the rural areas. The significant ones are Lusiwasi (12 MW), Chishimba falls (6 MW), Musonda falls (5 MW) and Lunzua (0.75 MW). The main power stations are interconnected into the main grid via a 330 and 220 kV network. There is an untapped hydropower potential of about 6000 MW. Table 2 shows total installed electricity generation capacity in 2004.

Table 2. Installed electricity generation capacity (2004)

No.	Description	Capacity (MW)	Type
1	Kafue Gorge	900	Hydro
2	Kariba North Bank	600	Hydro
3	Victoria Falls	108	Hydro
4	Lunsemfwa and Mulungushi	38	Hydro
5	Small hydros	24	Hydro
6	Isolated generation	10	Diesel
7	Gas turbine (stand-by)	80	Gas
	Total installed capacity	**1760**	

The country also has large deposits of coal at Maamba in the south of the country, along the Zambezi valley with deposits estimated at 30 million tons. Other areas where coal deposits have been located are Lwangua North, Luano, Lukusashi, Chunga and Lubaba. These deposits are estimated at several hundred thousand tons each. Due to production constraints and lack of investment funds, the design output of 1.2 million tons per annum of beneficiated and saleable coal has drastically dropped over the last years. Coal only contributes about 6 per cent of the country's energy needs, mainly in the mining and industrial sectors. At domestic sector level, research has been completed aimed at developing suitable appliances that can use coal briquettes.

Peat is another potential source of energy in the country. A general cartographic analysis reveals that there are peat land areas along the Zambezi and Kafue river valleys. However, there has not been a systematic investigation of the resource to date, therefore its use in Zambia cannot be quantified.

Zambia receives a lot of sunshine, such that solar power presents itself as a substitute to other energy sources. It is competitive when remote areas are being considered, especially for water pumping, electrifying village communities and refrigeration in health clinics. The main constraint is the initial investment cost, which is quite prohibitive. The other form of renewable energy source is wind power. Today in Zambia its use is basically limited to water pumping.

Wood fuel and charcoal are estimated to meet the energy needs of about 70 per cent of the rural and urban population. The copper mines utilize nearly 2000 tons of charcoal annually in the refineries.

Petroleum is not indigenous to Zambia. This has to be imported as crude and refined into petrol, kerosene, diesel, aviation gas, and heavy fuel oil. Petroleum has to be imported at international prices, transported through a 1500 km pipeline to the refinery in Ndola. The refinery has a processing capacity of 1.0 million tons per year.

2. ENERGY REGULATION

The current institutional and legal framework for the energy sector is a result of the liberalization and reform process that started with the first ever National Energy Policy, released in 1994 (NEP1994). The Government's liberalization of various sectors of the Zambian economy at the beginning of the 1990s was the main driving force of the reforms in the energy sector. New laws, namely the Energy Regulation Act (1995), the Electricity Act (1995) and the Rural Electrification Act (2003) were enacted to facilitate liberalization and to ensure consistency of the energy sector with other sectors.

The Energy Regulation Act provides for the establishment of the sector regulator, the Energy Regulation Board (ERB), and defines its functions and powers. The ERB is the sole licensing authority for operators in the energy sector and is responsible for close monitoring and supervision of such operators. The ERB is also responsible for monitoring the level and structure of competition, market entry issues (i.e. the ease of market entry) and investigating and remedying consumer complaints. In order for the ERB to execute its mandate, the Board works with other statutory bodies such as the Environmental Council of Zambia, the Zambia Competition Commission and the Zambia Bureau of Standards. This therefore means that the legal and regulatory framework of the power sector also needs to recognize the legislation of these institutions namely: the Environmental and Pollution Act, the Zambia Competition Commission Act and the Zambia Bureau of Standards Act.

The Electricity Act provides the framework within which the electricity sector will operate. It abolished the statutory monopoly that the state-owned utility ZESCO Limited had enjoyed in the electricity subsector and provides for new entrants. The act sets out the rights and obligations of the electricity supply companies and those of the consumer.

The Rural Electrification Act established the Rural Electrification Authority, an institution responsible for implementing rural electrification, as well as defining its functions and establishing the Rural Electrification Fund.

Furthermore, a new awareness of the integrated nature of energy in economic development has prompted the review of the existing policy and the formulation of the 2005 National Energy Policy (NEP2005). The NEP2005 sets out the Government's intentions in the energy sector, these being aimed at ensuring that the sector's latent potential to drive economic growth and reduce poverty is fully harnessed. The NEP2005 is still under consideration by Government.

Some of the gaps in the current legal and regulatory framework include:

- Open access to the transmission grid by independent power producers (IPPs) is difficult to implement because the transmission system operator, ZESCO Limited, has a vested interest in maintaining control and owns most of the generating power stations.
- About 70 per cent of power sales in the country are covered under long-term agreements between ZESCO, CEC and the mines, thus reducing the scope for competition amongst new entrants.
- There is lack of an established and well-functioning electricity market for the sale and purchase of power. Consumers do not have power supply choices.
- The Framework Incentive Package for promoting private power investments is not backed by law.
- Sub-economic tariffs.
- Cross-subsidization in tariffs.

Since the promulgation of the Energy Regulation Act and the Electricity Act in 1995, two prominent private companies have entered the power sector, namely the Copperbelt Energy Corporation (CEC) and the Lunsemfwa & Mulungushi hydropower company. Both companies operate under licence from the ERB. However, the power tariffs were negotiated between parties under various long-term power purchase agreements.

The Rural Electrification Authority (REA) was also established following the promulgation of the Rural Electrification Act of 2003. The REA is still in its early stages of development. The REA is expected to spearhead the development and application of renewables for rural electrification in Zambia.

3. RENEWABLE ENERGY

Renewable energy sources are increasingly being used in Zambia but still remain insignificant in terms of contribution to the total national energy supply. Some of the past and current renewable energy initiatives are detailed in annex 1 of this case study. There is no specific legal framework dealing with renewable energy sources in their entirety, however, renewables are regulated under the Energy Regulation Act and when used for electricity generation, the Electricity Act also applies. These pieces of legislation, in their present state, are not adequate to regulate and promote renewable energy.

Although Zambia is endowed with many renewable sources of energy, efforts to harness these resources have been minimal. This is despite the fact that renewable sources of energy, particularly solar and wind energy, are widely available and have the potential to improve the living standards of rural population.

Some of the constraints to a wider use of new and renewable sources of energy include:

- Lack of awareness among the general population about the renewable sources of energy technologies;
- Lack of an institutional framework for resource mobilization, system planning and expansion;
- High initial costs;
- Inadequate adaptive research on NRSE technologies to Zambian situation;
- Lack of end-user acceptability;
- Inadequate demonstration projects;
- Lack of specialized training.

Some of the policies and regulatory measures that the Government has embarked on to promote renewable energy development are:

- Establishment of the Rural Electrification Authority (REA) is expected to effectively accelerate the implementation and mobilization of funds for renewable energy for rural areas.
- Government's deliberate policy to deal with the current inadequate information about available renewable energy resources and applicable technologies, poor dissemination of information, low literacy levels and a lack of awareness of potential business opportunities among entrepreneurs.
- Government's policy to ensure that energy prices reflect costs of providing energy and also to take into account principles of fairness and equity.

The above policy measures, which are contained in the proposed NEP2005, are adequate to promote the development and deployment of renewable energy if they are backed by the appropriate legal, regulatory and institutional frameworks. In addition, the government will need to take further deliberate measures to build the necessary capacity at various policymaking levels within both the government itself and the Energy Regulation Board and the Rural Electrification Authority in order to achieve an effective regulatory environment for the promotion of renewables.

4. CONCLUSIONS

The power sector in Zambia has been going through a dramatic change from a totally state-controlled business with vertically integrated subsector monopolies to a free market with competition and private sector investment. An appropriate legal and regulatory framework has been established through legislative instruments, such as the Energy Regulation Act and the Electricity Act. A sector regulator, the Energy Regulation Board, was established in 1997 as an independent and sole licensing authority for operators in the energy sector. A Rural Electrification Act was passed in 2003 and a Rural Electrification Authority established.

Zambia does not have a specific legal framework dealing with renewable energy technologies (RETs) in their entirety. However, these are regulated under the Energy Regulation Act and the Electricity Act. A specific framework for the promotion and development of RETs is necessary.

The major constraints to a wider use of RETs include: *(a)* lack of awareness about RETs; *(b)* high initial costs; *(c)* inadequate adaptive research on RE technologies to the Zambian situation; *(d)* lack of end-user acceptability; *(e)* inadequate demonstration projects; and *(f)* lack of specialized training.

The National Energy Policy of 1994 (NEP1994) clearly spells out policy measures needed to accelerate the development of renewable energy. These include:

- Promotion of education and training in renewable energy at various levels;
- Promotion of information dissemination about renewable energy;
- Promotion of renewable energy technological development.

The proposed National Energy Policy of 2005 (NEP2005) further recommends:

- Strengthening of the institutional framework for research and development of RETs;
- Application of appropriate financial and fiscal instruments for stimulating the implementation of RETs;
- Actively involve women in decision-making and planning in renewable energy programmes and activities;
- Promotion of biomass technologies for electricity generation.

The above policy measures are contained in the proposed new national policy (the NEP2005). Consequently the above policies have not yet been implemented a significant degree. However, it is expected that this situation will be addressed now that the Rural Electrification Authority has been established.

Zambia is currently undertaking a series of renewable energy projects such as the African Rural Energy Enterprise Development (AREED), Access to Energy Services (IAES), and ESCO projects. These are pilot projects from which important lessons have been learnt. The ESCO project in Eastern Province can for example now be extended countrywide given further financial and technical assistance. The same can be said about the other projects.

5. KEY RECOMMENDATIONS

Policy changes that would better promote renewable energy technologies can be summarized as follows:

- Deliberate and clear policy to build and strengthen awareness on renewable energy technologies (RETs) at the policymaker level through appropriate training and other capacity-building activities.
- Build capacity within the relevant regulatory agencies on the techniques to promote RETs through appropriate regulation.
- Minimize financial constraints and create attractive investment incentives for the private sector to participate in the provision of RET solutions to the energy sector problems by introducing tax incentives and smart subsidies for example. This would greatly compliment the Government's own funding and the current 3 per cent rural electrification levy.
- Strengthen institutions currently involved with the development of RETs including the Rural Electrification Authority (REA). Comprehensive capacity-building is required at REA at this stage.
- Ensure that electricity tariffs are cost reflective with a view to encouraging private investment.
- Build an effective communication infrastructure to ensure that there is adequate information available about RETs to the general public. Awareness of the business opportunities available to entrepreneurs.
- Ensure that experiences gained from some of the pilot projects that the Government has already undertaken (such as PV-ESCOs, AREED, and IAES) are used as examples of the application of renewable energy providing successful and sustainable solutions.
- Consider a renewable energy policy as an opportunity to address other policies such as employment, gender issues and energy poverty (especially in rural areas).

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ANNEX. CURRENT RENEWABLE ENERGY INITIATIVES

Energy service companies

The ESCO project was a new approach for providing electric light and other basic services to people in rural areas through solar photovoltaic (PV) systems. The approach was based on the Energy Service Company (ESCO) approach. The main objective was to create a sustainable market by which the people in rural areas would access the services provided by solar photovoltaic technology at a fee. The project was initiated by the Government of Zambia (through the Department of Energy) in 1998 with financial support from the Swedish International Development Agency (SIDA) and technical assistance from the Stockholm Environment Institute (SEI).

This project was executed in three phases: Phase I (June 1998–June 2000), Phase II (October 2001–December 2003) and Phase III (September 2004–September 2005). The project is currently at the reporting stage of Phase III.

AREED

The AREED Initiative is a multi-country initiative and was established in 2000 by a group of multi-lateral (UNEP and the UNF), international companies/NGOs (primarily E&Co) and national government partners (Ghana, Mali, Senegal, United Republic of Tanzania and Zambia). It is being implemented by E&Co and seeks to develop new sustainable energy enterprises that use clean, efficient and renewable energy technologies to meet the energy needs of the rural poor, thereby reducing the environmental and health consequences of existing energy use patterns.

The main objectives of AREED are:

- To create rural energy enterprises and to build the capacity of NGOs and institutions to facilitate enterprise development.
- To provide early stage funding and enterprise development services to entrepreneurs, build capacity in African NGOs to work with clean energy enterprises and work with financial institutions to assess the rural energy business sector as well as integrate enterprise investments into their portfolios.

In order to achieve the above objectives, AREED has the following components in its portfolio:

- Training and tools to help entrepreneurs start and develop energy businesses;
- Enterprise start-up support in areas such as business planning, structuring and financing;
- Seed capital for early stage enterprise development;
- Assistance in sourcing second stage financing.
- Partnerships with banks and NGOs involved in rural energy development.

The AREED initiative has begun operations in Botswana, Ghana, Senegal and Zambia. It is working in-country with a number of local partners, including ENDA in Senegal, KITE in Ghana, CEEEZ in Lusaka and the Mali Folkecenter.

Increased Access to Energy Services Project (IAES)

The Government, through the Ministry of Energy and Water Development (MEWD), recognizes the need for increasing rural and peri-urban access to electricity and information communication technology (ICT) as a strategy to reduce poverty in these areas. As part of the implementation strategy, the government embarked on the Increased Access to Energy Services Project (IAES) financed by World Bank, Global Environmental facility, other donors, and the Prototype Carbon Fund.

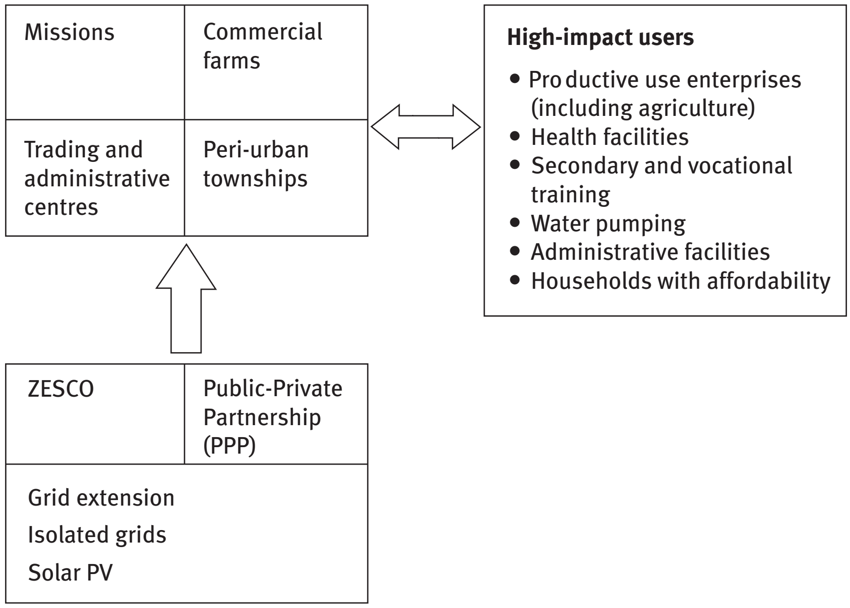
IAES project objectives and design strategy

The objective of the project is to provide for investment and technical assistance/capacity building activities to enable the scaling-up of access to electricity and ICT services in rural and peri-urban areas to maximize development impact: *(a)* income generation by SMEs through productive uses (farm and non-farm), and *(b)* improved quality of life emphasizing the effectiveness of social services (such as health, education) and administrative service.

The underlying approach of the IAES project is to expand access via public-private partnerships in a commercially oriented manner, i.e. with focus on cost recovery. It is recognized that there is a need for "smart" subsidies that address the up-front capital cost investment requirements and the initial transaction costs to encourage entrepreneurial activity while maintaining efficiency of operations and promoting output. The level and terms of the capital subsidy may differ according to project characteristics—including underlying prospects for economic growth and investment risks. GEF provided financial support will be available for developing local hydro and other renewable energy generation for sale to the grid and to independent grids.

The scale-up strategy for designing delivery mechanisms and targeting the limited resources (credit and grants) is driven by the consideration of maximizing the development impact on growth and poverty within the prevailing sectoral context and taking into account emerging changes that can be characterized as a "break from the past" in Government policies for the sector.

This means (see schematic below) geographically targeted introduction of electricity and ICT services at established centers of economic and/or social activities for the benefit of large numbers of people drawn to those centers from the respective catchment areas. Such concentrations of activity and centers of day-to-day life for most rural people are missions, farm blocks, trading and administrative centers (including postal centers) and peri-urban townships. As appropriate, they would also include community centers and zonal resource centers.



Finally, another key aspect of project design is consistent with the Government's emerging policy thrusts and initiatives that aim to engineer a "break from the past", by opening up key infrastructure sectors of the economy to new entrants while at the same time strengthening the existing parastatal players. In keeping with this, the IAES project aims to target a third of the IDA credit for rural electrification investments and the bulk of GEF grant resources for enabling rural electrification and renewable energy investments via public-private partnerships (PPP). Specifically, the project would develop and strengthen two parallel and complementary service delivery modalities and sector players: ZESCO and new entrants that are non-ZESCO sponsors. The latter potentially include sponsors of subprojects and investments such as mission groups, other private sponsors, and creditworthy NGOs as well as community-based organizations with bankable business plans.

A key preparation activity is to prepare and offer on a competitive basis, the opportunity to undertake pre-defined rural and peri-urban electrification schemes, or "subprojects", designated as Priority Rural Electrification Projects (PREPs).

Case study 6.

UNITED KINGDOM RENEWABLES OBLIGATION

CONTENTS

1. POLICY AND INDUSTRY STRUCTURE

The lead government department on energy policy in the United Kingdom is the Department of Trade and Industry (DTI) and it is here that renewables policy is mainly developed. However, the Department for the Environment, Food and Rural Affairs (DEFRA) is the lead government department on climate change and environmental issues and it also has the lead on energy efficiency.

The electricity and gas industries were privatized in the United Kingdom in the late 1980s. There have been a number of changes in the energy market since privatization but the structure as at mid-2005 was as follows: six large integrated gas and electricity supply and generation companies and a number of smaller companies involved in generation and/or supply; nine electricity distribution companies (distribution network operators—DNOs) in England and Wales; a single gas transportation and electricity transmission company for England and Wales (that also does gas transportation in Scotland); two integrated electricity distribution, transmission and generation companies in Scotland, (they are also two of the gas and electricity suppliers that serve Scotland, England and Wales). The whole industry is regulated by the Gas and Electricity Markets Authority (more commonly known as the Office of Gas and Electricity Markets (Ofgem)) which is an independent regulator established by an Act of Parliament. There has been full retail competition since the late 1990s and price controls were removed from the household retail market in 2002. (Note that the situation in Northern Ireland is different where there is a separate market and regulator.)

The United Kingdom Government's Energy White Paper, published in 2003, makes a strong commitment to environmental as well as economic and social goals for energy policy. The United Kingdom is signed up to the Kyoto protocol (that requires greenhouse gas emissions to be cut by 12.5 per cent compared to 1990 levels by 2010) and has also set more internally demanding targets (20 per cent reduction by 2010) for reducing carbon dioxide emissions. It has a number of policies and programmes to foster the development of renewable energy and energy efficiency to help achieve a low carbon economy.

2. THE NON-FOSSIL FUEL OBLIGATION (NFFO)

The United Kingdom's first programme to support renewable energy was the Non-Fossil Fuel Obligation (NFFO) introduced in 1990. The NFFO was primarily established to subsidize nuclear power, which the Government had been unable to privatize along with the rest of the electricity industry, as the electricity generation companies would not have been viable as private companies if they included the nuclear power stations. However, the Government decided to broaden the obligation to include specified renewable energy technologies. The Electricity Act 1989, enabled the raising of a fossil fuel levy (i.e. on all fossil—coal, gas and oil—fuel generated electricity) to pay for the NFFO. The NFFO operated via bidding for support in various technology bands—developers of eligible types of renewable electricity generation bid for support and those who were successful received subsidy payments (which varied according to the technology) on top of the market price that they would otherwise be paid. However, this scheme stimulated only small amounts of renewable energy generation—up from 1.8 per cent of total electricity generated in 1990 to 2.5 per cent of electricity in 2000).

Following the election of a new Government in 1997, support for renewable energy was reviewed was the aim of overcoming three main problems with the NFFO:

- Limited development of renewable energy (some commentators have argued that this was largely due to the low-cost cap imposed on support via the NFFO rather than the nature of the mechanism itself);
- Ending the must-take or priority access contracts that renewable energy generators who received support via the NFFO received—these were felt to separate them too much from the reality of the marketplace;
- That a support mechanism shouldn't "pick winners" by giving different levels of support to different technologies.

(Mitchell and Connor, 2004)

The result of the review was the establishment of the renewables obligation.

3. RENEWABLES OBLIGATION

The renewables obligation was introduced in 2002 to boost the amount of electricity generated from renewable energy. The United Kingdom has set itself a target to generate 10 per cent of its electricity from renewable sources by 2010 and 15 per cent by 2015, as part of its commitment to reducing greenhouse gas emissions. The renewables obligation is the main policy instrument to achieve this and its main feature is that electricity suppliers (retailers) have to source a set percentage of the electricity that they sell to customers from renewable sources. This started at 3 per cent in 2002 and will rise to 15 per cent by 2015 in line with the national target.

The current main sources of renewable electricity generation that are eligible for the financial support provided by the renewables obligation are:

- Hydroelectricity power stations with a capacity of less than 20 megawatts;
- Wind farms both onshore and offshore;
- Electricity generated from landfill gas and sewage gas;
- Electricity generated by burning energy crops and other natural waste, and until 2016, electricity generated from power plants which co-fire such material with coal.

Over time generation from other technologies such as wave and tidal power plants, which are also eligible, is predicted to increase.

The 2010 target only includes electricity generated from sources eligible for the renewables obligation. It therefore excludes electricity generated by large hydroelectricity power stations and some forms of energy from waste (notably incineration).

The legal basis for the renewables obligation (RO) is contained in Section 32 of the Electricity Act 1989 (as amended in 2000) which enables the Secretary of State, by order, to impose an obligation on suppliers ("the Renewables Obligation"). This power has been devolved to the Scottish Executive in respect of suppliers in Scotland (Renewables Obligation Scotland (ROS)). The RO and the ROS came into effect on 1 April 2002 and are scheduled to stay in place until 31 March 2027. An obligation period runs from 1 April to 31 March each year. The Gas and Electricity Markets Authority (Ofgem) is responsible for the administration of the orders.

The orders place a legal obligation on each licensed electricity supplier to produce evidence that either it has supplied a specified proportion of its electricity supplies from renewable energy sources to customers in the United Kingdom, or that another electricity supplier has done so, or, that between them, they have done so. Section 32B of the Act allows for "green certificates" to be issued under section 32 orders. Such certificates certify that a generating station has generated from renewable sources an amount of electricity and that it has been supplied to customers in the United Kingdom. These are known as Renewables Obligation Certificates ("ROCs") (issued under the RO) or Scottish Renewables Obligation Certificates ("SROCs") (issued under the ROS). These certificates can be purchased separately from the electricity in respect of which they were issued. So suppliers can meet this obligation by contracting with renewable energy generators to buy their output directly (and receive "green certificates" for doing so), or by buying the ROCs separately from the renewable power generated. Alternatively, a supplier can discharge its Renewables Obligation, in whole or in part, by paying the buy-out price to a central fund. The proceeds of the buy-out fund are divided between those suppliers who have met the obligation by obtaining the required number of green certificates, so providing an additional value to ROCs.

In order for ROCs to be issued, the generating station that generates the electricity must be accredited by Ofgem as capable of generating electricity from eligible renewable sources. The participation of a generating station in the scheme is voluntary and there are certain criteria that need to be met before a station can be accredited. The orders set out what sources of electricity are eligible renewable sources and also specify the exclusion of certain types of generating stations, e.g. stations incinerating waste. Time limits for eligibility are placed on stations co-firing, i.e. burning biomass and fossil fuel to generate electricity.

Suppliers are required to produce evidence of compliance with their renewables obligation to Ofgem by 1 October each year. Evidence can be via ROCs or SROCs.

4. PRICES AND COSTS OF THE RENEWABLES OBLIGATION

Unlike the feed-in scheme in Germany, the renewables obligation does not guarantee connection nor specify the price that renewable generators will be paid for the electricity that they generate—this is set by the market for all electricity generation and is usually agreed in bilateral contracts between generators and suppliers. However, in addition to the market price for renewable electricity, generators can sell their ROCs/SROCs to suppliers who have to meet their obligations or pay the buy-out price. The buy-out price (which is set in the order and rises each year in line with the retail price index (RPI)) thus sets the basic price for ROCs—so long as demand for ROCs exceeds supply. However, as suppliers who meet their obligations via ROCs will also get extra revenue from the buy-out fund, this further increases what they are willing to pay for ROCs/SROCs. Together therefore, these features increase the market value of renewable generation. The following prices illustrate this.

Illustrative prices for renewable energy under the RO:

- The market price for the electricity (which can be sold separately from the ROC)—this has varied significantly since 2002 from around 1.5p/kWh to 4p/kWh.
- 3p/kWh for the ROC (the buy out price started at £30/MWh or 3p/KWh).
- 1.5p/kWh for the extra revenue from the recycled buy-out fund.

Thus the renewable electricity generators can obtain significant additional revenue from the RO.

The buy-out price is intended to act as a cap on the costs to be charged to consumers. In 2003/2004, the total renewables obligation across the United Kingdom was 13,627,412 MWh. The simple calculation of multiplying this by £30.51 gives a total cost to consumers of around £416 million.

Total public support for the renewables industry (through the renewables obligation, capital grants and research and development support) is expected to average £700 million per annum between 2003 and 2006. Around two-thirds of this will come through the renewables obligation, the cost of which is met by electricity consumers and will reach up to £1 billion per annum by 2010 (the equivalent of a 5.7 per cent increase in the price of electricity).

The cost of reducing carbon dioxide emissions through the renewables obligation is currently higher than other policy mechanisms which primarily incentivize energy efficiency. However, the renewables obligation is not just in place to meet the Government's climate change objectives. Its other goal is to promote diversity and security of energy supplies. It is recognized that technologies that are not mature will have higher costs, but that as they develop, these costs should come down.

Another cost issue is that the renewables obligation provides the same level of financial support for all eligible renewable projects. The Government adopted this approach to ensure that the most economic renewable energy projects are developed first, while minimizing Government intervention in the market. A consequence is that some projects using the lowest cost technologies (onshore wind and landfill gas) at the best sites receive more support from the renewables obligation than necessary to see them developed. The Department of Trade and Industry is looking at this issue for new sites in its review of the renewables obligation.

5. IMPACT OF THE RENEWABLES OBLIGATION

The renewables obligation has increased the total renewable electricity generating capacity in the UK from 1400 MW in 2002 to 2400 MW in 2004. A rough breakdown of this is as follows:

Onshore wind – 600 MW

Landfill gas – 600 MW

Co-firing – 500 MW

Biomass – 150 MW

Hydro (<20 MW net capacity) – 400 MW

Others (mainly offshore wind, micro-hydro, sewage gas) – 250 MW

At the end of the first obligation period (March 2003), there were 505 accredited generating stations and 616 at the end of the second obligation period. 257 of the accredited generation stations were landfill gas, with over 100 accredited for onshore wind and for hydro (those generating stations with a declared net capacity of 20 MW or below and which are not micro-hydro). However, the capacities accredited for landfill gas and onshore wind are very similar, which demonstrates that landfill gas generating stations accredited under the RO tend to be smaller in capacity than onshore wind generating stations. Sewage gas and micro-hydro generating stations are also generally smaller whilst co-fired and biomass generating stations are among the larger capacity generating stations Ofgem accredits, although the statistics for co-firing reflect an estimate of the renewable capacity based on the biomass element.

The distribution of ROCs issued is as shown in the following table:

Table 1. ROCs issued by technology

Technology	RO 2002-03 (percentage)	RO 2003-04 (percentage)
Landfill gas	48	40
Onshore wind	20	16
Hydro (< 20 MW)	9	17
Co-firing	8	10
Biomass	11	10
Other	4	9

Source: Ofgem, Annual reports on the renewables obligation.

As the following table shows, a significant proportion of the renewables obligation is being met by companies paying into the buy-out fund rather than contracting for renewables capacity. This has been one of the criticisms of the RO—that it is not stimulating as much renewable capacity as the total obligation figure suggests. However, by paying into the buy-out fund, the value of renewable capacity is increased and this may be making this capacity more secure.

Table 2. A comparison of RO compliance figures over the 1st and 2nd obligation periods

	2002/2003	2003/2004
Total obligation (TWh)	8,393,972	12,387,720
ROCs and SROCs produced (£ mlln)	4,973,091	6,914,524
Buy-out paid (£ mlln)	78,853,260	157,960,978
Buy-out not paid (£ mlln)	23,773,170	9,026,231
Percentage obligation met by ROCs or SROCs	59	56
Buy-out distributed and late payment fund (£ mlln)	79,251,930	158,466,502
Buy-out paid per ROC or SROC produced (£)	15.94	22.92
What a ROC or SROC was "worth" to a supplier (£)	45.94	53.43

Source: Ofgem, 2nd annual report on the renewables obligation.

6. OTHER SUPPORT FOR RENEWABLES

The fact that the RO does not pay different prices for different technologies means that suppliers tend to favour the least costly forms of renewables (currently landfill gas and onshore wind) which can be viewed as an advantage on cost-effectiveness grounds. However, this does mean that it may not promote as much diversity as schemes that pay higher prices for less mature technologies. The UK Government is tackling this issue via a range of other schemes of funding for renewables—typically capital grants to offset the extra costs of technologies such as offshore wind, biomass, wave and tidal power, and photo-voltaic. These include grants for large and medium-scale schemes and some grants for small and micro-scale technologies.

Examples include:

- Bioenergy has received £55 million in capital grants to support 22 projects, although not all of these are proceeding due to various difficulties in making them commercially viable.
- The offshore wind scheme has allocated capital grants of £117 million to 12 projects, two of which are now fully operational. The remaining projects are expected to come on stream in the next three years, providing total capacity of over 1,000 megawatts, enough to supply more than 600,000 households.

7. WILL THE UK MEET ITS RENEWABLES TARGET?

By April 2004 (two years after the introduction of the renewables obligation), the level of electricity supplied from eligible renewable sources was 2.4 per cent, significantly lower than the obligation level of 4.3 per cent. In the early phases therefore, the RO has been underperforming in terms of delivering new renewable electricity capacity. Various estimates have been made of whether the rate of growth will increase sufficiently for the 2010 target of 10 per cent electricity from renewable sources to be achieved. These range from 7.5 per cent (House of Lords Science and Technology Committee) to close to 10 per cent on the most optimistic of a range of estimates produced for the National Audit Office (NAO, 2005). According to the NAO the main challenges to achieving the 2010 target are:

- Whether revised planning guidance for England facilitates the planning process for new renewable energy sites;
- Whether the upgrading of the electricity transmission and distribution networks, required to accommodate new renewable generation, is planned, funded and installed on time;
- Whether investor confidence in the way the renewables obligation is working is maintained;
- Whether financial support provided through capital grants and the research and development programme fulfil their respective objectives.

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Comprehensive information on the renewables obligation including the annual report on progress is available on the Ofgem website (www.ofgem.gov.uk).

See also the website for the Department of Trade and Industry (www.dti.gov.uk/energy).

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Renewable Energy

Module 9:
REGULATORY MEASURES AND POLICY OPTIONS TO ENCOURAGE DEVELOPMENT OF RENEWABLE ENERGY

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Module overview

- Why support sustainable energy
- Design issues for support mechanisms
- Types of support mechanisms
- Support mechanisms in practice

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Module aims

- To provide an overview of the different advantages that a clear renewable energy policy can provide, and its possible interaction with other policies
- To explain what the key building blocks are when designing a regulatory/support mechanism
- To give an overview of the different possible approaches
- To show how this has been implemented in different African countries

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Module learning outcomes

- To be able to explain that a renewable energy policy can provide advantages and support a range of environmental and other policies
- To understand which design elements are key to the success of the regulatory/support mechanism
- To understand different approaches to designing a regulatory/support mechanism
- To be able to argue which regulatory or policy approach suits best, given the national or regional situation

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Why Support Sustainable Energy

- Environment
- Security of supply
- Decentralized production
- Links with socio-economic policy:
  - Fuel poverty
  - Gender
  - Employment
  - Capacity-building

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Design Issues for Support Mechanisms

- Effectiveness and efficiency
- Investor confidence is key
- Interaction with other policy measures
- Flexibility
- Stimulation of reducing prices over time

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Types of Support Mechanisms

- The mechanisms discussed can be divided into two categories:
  - Regulatory/support options that are immediately applicable to many sub-Saharan African countries
  - Other regulatory/support mechanisms implemented in the developed countries that may be applicable to sub-Saharan African countries in the future

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term

Establishing “standard” Power Purchase Agreement (PPAs)

- Eliminate cumbersome negotiations
- Institute a “Standard PPA” - a “standard offer” from the national utility to purchase all energy produced by specific renewable energy-based Independent Power Producers (IPP) at a pre-announced price
- Set clear rules to allow the sale of power produced to encourage investment in renewables

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term (2)

Long term Electricity Generation Licenses and PPAs for IPPs

- Currently generation licenses are issued for varying periods of 7 to 15 years
- Investors have a very limited period of time to recoup their costs and make a decent margin
- Issuing longer term electricity generation licenses and PPAs to IPPs (e.g. 15-30 years) can encourage investors
- Longer term agreements allow for sufficient time for the investor to pay off project financing debts and make a profit

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term (3)

Developing a favourable Tariff Setting and Adjustment Formula

- Calculation of the feed-in tariff on the basis of the cost of the fuel can result in very low feed-in tariffs offered to renewables
- Renewable fuel cost is often very low or sometimes free but with higher equipment costs
- A more favourable tariff setting and adjustment formula takes also into account the “avoided cost” of installing competing thermal power plants

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term (4)

"Light-handed" Regulation

- Deliberate removal of, or making less stringent, provisions for a player or group of players
- Explicitly exempting or significantly reducing the statutory requirements of investors in sustainable energy
- For example, waiving the need for licensing small to medium scale renewable energy investments below a certain capacity threshold

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term (5)

Setting Targets for Renewable Electricity Generation

- Set explicit targets for the share of electricity generated from proven renewable energy technologies such as hydro, wind, solar PV, bagasse-based cogeneration and geothermal
- The Government of Kenya has set a target of 25 per cent of electricity generation to come from geothermal energy by the year 2020
- IPPs actively encouraged to exploit renewables to meet targets

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term (6)

Encouraging local private participation in renewable energy development

- Local private investors can own and operate small to medium scale entities in the power sector
- Either on their own or with foreign partners
- Appropriate policy and financial incentives such as:
  - Enactment of lower entry requirements
  - Tax holidays
  - Lighter regulation of Initial Public Offers (IPOs)

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term (7)

Providing Subsidies to Rural Investments

- Rural electrification provides local benefits but has high capital cost
- Demand/usage of electricity in rural areas is low
- For a reasonable return on investment, the capital cost of rural electrification needs to be covered in part or fully by subsidies
- Usually grants financed by donors through rural electrification funds
- Used to finance rural electrification concessions (e.g. Uganda)

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Support Mechanisms Applicable in the Short Term (8)

Conclusions

- Relatively easy regulatory and policy initiatives can initiate renewable energy investments
- Some good examples available in Uganda, Kenya, Tanzania, Mauritius
- Such initiatives will:
  - Show opportunities and bottlenecks
  - Provide input for medium and longer term support instruments

Module 9

SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA

Questions/Activities

"Which of the described support mechanisms could be relatively easily implemented in your country to stimulate renewable energy investments?"

Discuss

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Support Mechanisms Applicable in the Medium to Long Term

Feed-in Tariffs

- A minimum guaranteed price for output or
- A premium on the market price for output
- High degree of certainty for investors
- Costs to be covered by a levy per kWh (on consumers, on taxpayers, or on both)

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Support Mechanisms Applicable in the Medium to Long Term (2)

Quota Mechanisms

- Obligation for electricity suppliers or customers
- Supported by tradable green certificates
- Penalty when there is non-compliance
- Government sets level of output
- Leaving choice of technology to the market
- Incentive to comply ~ level of the penalty

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Support Mechanisms Applicable in the Medium to Long Term (3)

Tender Schemes

- Government organizes competitive bids for RE projects
- Guaranteed premium ~ increase investor confidence
- Produces stop-go development

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Support Mechanisms Applicable in the Medium to Long Term (4)

Voluntary Mechanisms

- By means of green certificates
- Relying on consumer awareness and willingness to pay
- Disclosure
- Green power marketing

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Support Mechanisms Applicable in the Medium to Long Term (5)

Various Hybrid Schemes

- Involving two of the above mechanisms
- Example: Spain wind support mechanisms
- Possible to combine best of two (or more) worlds
- Avoid your system getting too complex

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Support Mechanisms in Practice

- Relatively new policy
- Thus far concentrated on wind power
- Tariff schemes seem more successful for wind power (so far)
- Still unclear for biomass

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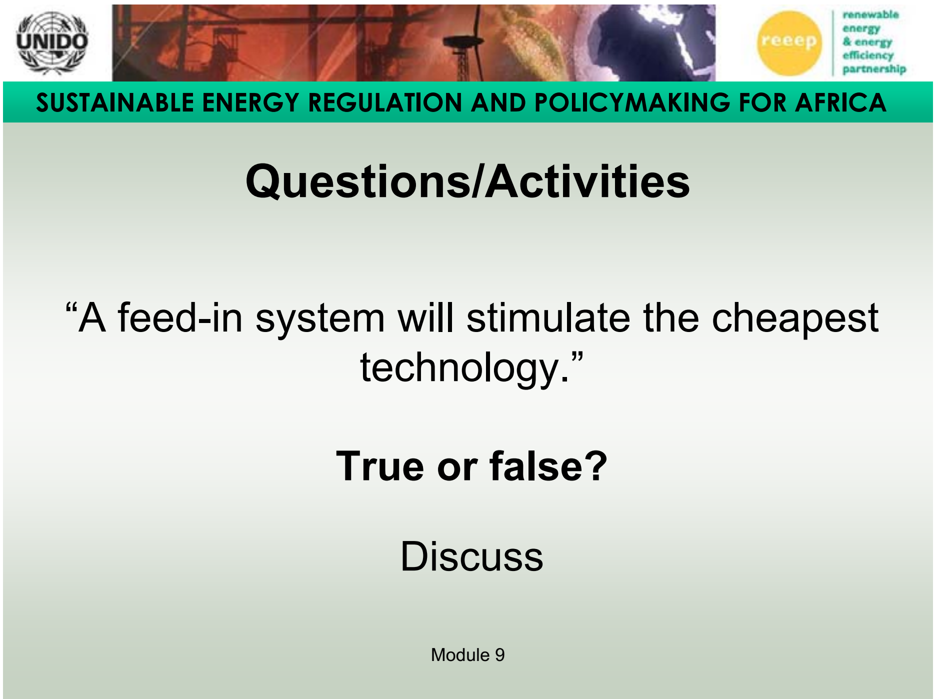
renewable energy & energy efficiency partnership
SUSTAINABLE ENERGY REGULATION AND POLICYMAKING FOR AFRICA
Questions/Activities
"A feed-in system will stimulate the cheapest technology."
True or false?
Discuss
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