Nicaragua: Policy Strategy for the Promotion of Renewable Energy: Wind Energy Integration Component

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Abbreviations and Acronyms

CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CNDC	Centro Nacional de Despacho de Carga
CNE	Comisión Nacional de Energía
ERPA	Emission Reduction Purchase Agreement
ICT	Information and Communication Technology
FIT	Feed-in Tariff
GHG	Greenhouse Gas
INE	Instituto Nacional de Energía
ISPs	Imbalance Settlement Prices
NO	Network Operator
PSO	Public Service Obligation
RE	Renewable Energy
RET	Renewable Energy Technology
RPS	Renewable Portfolio Standard
SIN	Sistema Interconectado Nacional
SO	System Operator
TREC	Tradable Renewably-generated Electricity Certificate
UoS	Use of System Charges

Preface

The objective of this study is to support Nicaragua's Comisión Nacional de Energía (CNE) in preparing and implementing new policy and strategy to encourage the private sector to participate in the development of electrical generation from geothermal energy. The study includes: (i) evaluation of the potential market for electricity generation via geothermal energy in Nicaragua, (ii) analysis of the existing barriers (legal, regulatory, financial, and so on) to geothermal energy development in Nicaragua and proposed options for the elimination of these barriers, and (iii) provide CNE with a policies and strategy framework that will serve as a basis for an implementation program to stimulate the development of geothermal electricity generation. This case study is one of three (geothermal, hydropower, wind) that assessed prospects and barriers for the most important renewable resources in Nicaragua, and served as the basis for the formulation of the overarching strategies delineated in the main ESMAP report.

Executive Summary

1. The recommendations for a 50–60 MW wind farm investment program are:

Size of tender scheme

2. CNE/INE implement a tender for a 12 year PPA for a 20 MW wind farm.

3. If CNE/INE decide on pluri-annual tenders for a total of 50–60 MW, the recommendation is to hold (i) an “open” tender for 20 MW the first year; (ii) a 20 MW tender the next year, from which the winner of the first tender (and any affiliates) are excluded from participating; and (iii) an “open” 10-20 MW tender the third year where the decision on whether 10 MW or 20 MW are accepted depends on the kWh price that is offered for 20 MW.

Supply side: conditions for bidders

4. The tender is for a 12-year PPA between the wind farm and the distribution company, Union Fernosa.

5. Bidders bid a single per-kWh tariff. The tender document fixes an upper lid on the accepted price per kWh, which is so tight that only wind farms making use of the CDM project opportunity become financially viable.

6. The tender material includes a formula, which translates the bid per-kWh tariff into a differentiated tariff structure with an on-peak and an off-peak tariff during the season of peak demand for non-hydropower; and a single tariff for the rest of the year.

7. 25 percent of the bid tariff (reflecting the share of the cost of production excluding annual amortization payments) is subject to a yearly inflation adjustment linked to the movement in the consumer price index.

8. Participating bidders are required to hold all necessary planning permits and documentation for ownership or long-term lease of wind farm land.

9. Wind farms contract thermal “reserva rodante” and “reserva de regulación” to cover the power system needs arising from the intermittent supply of wind farm production.

Demand side: how to impose the off-take obligations and compensate for surcosts

10. Depending on the interpretation of regulatory rules and regulations in Nicaragua—in particular as concerns the possibility to impose public service obligations on the distribution company—the scheme on the demand side can be introduced in one of two ways:

(a) Public Service Obligation scheme

(i) CNE via INE orders the distribution company to sign the 12-year PPA with the winner of the tender.

(ii) The surcost per kWh of the monthly purchase of wind farm electricity—the monthly difference between the total cost of wind farm-supplied electricity, and the value of that electricity according to recorded hourly power pool prices divided by the total kWh transported through the grid to the distribution company and to the large industrial customers—is calculated by the system operator.

(iii) The surcost per kWh of the monthly purchase of wind farm electricity, as calculated by the system operator, is imposed as a "RET system user charge" on the monthly power supply to large consumers, who purchase their power directly on the bulk market. The system operator transfers the raised revenue to the distribution company.

(b) Renewable Portfolio Standard (RPS) scheme

11. If the concept of public service obligation is not viable, CNE/INE can take recourse to the mandated fuel portfolio instrument.

(i) A wind farm RPS is imposed on the distribution company and the >2MW demand customers who contract their power directly from generators.

(ii) CNE/INE negotiate with the market operators on identifying the most cost-effective market scheme for achieving the RPS obligation, based on Union Fernosa signing the 12-year PPA.

(iii) The other operators with a RPS sign an "RPS quota delegation contract" with the distribution company.

(iv) The distribution company bills, on a monthly basis, the other market participants—according to their share of monthly power purchases—the monthly difference between the total cost of wind farm-supplied electricity and the value of that electricity according to recorded hourly power pool prices, which has been established by the system operator.

Incentive package other than the PPA tariff

12. If mixed credit finance is involved, the contract for the mixed credit may not give the donor country Government any priority rights for purchasing the CERs from the project.

13. The proposal made by CNE for state-financed incentives—a 10 year tax holiday and exemption from import duties and export duties—merits adoption by the Government

14. The framework of incentives for investments in wind farms is summarized in table 1 below.

Table 1: The Framework of Incentives for Investments in Wind Farms

Mecanismo de Financia-miento	Blanco de Subsidio		
	• Costo de Inversión	• Salida de kWh	•Costos O & M
Pagado por presupuesto del estado / contribuyente s	• Exención de impuestos de aranceles • Exención de impuestas de renta durante los primeros diez años		
Pagado por los consumidores de energía electrica	• Pago parcial del costo de connexión?	• Incentivo fijo sobre precio spot con tope de precio maximal • Tarifa fija mas alta que el precio spot	• Tarifa transmission estampilla • Ninguna penalizacion por costos adicionales de regulación
MDL		• bonos de carbon/kWh	
País Donante	• crédito mixto de financiamiento		

1

International Policies and Approaches for Promoting Wind Energy

Definition of Regulatory Scheme for Market Promotion

1.1 In this report, the term "regulatory scheme for market promotion of wind energy" is defined as:

> "the creation of a legal, institutional and incentive framework to stimulate and support large scale annual investments in wind energy in fulfillment of Government policy objectives for the energy sector."

Policy Objectives and Choice of Market Scheme

1.2 The objective of comparative analysis of international schemes for the promotion of grid-connected renewable energy technologies is to draw policy recommendations based on the perceived cost-effectiveness of alternative options in achieving specific policy targets.

"Mature" and "developing" RET technologies

1.3 The economic and financial costs of production per kWh are logical performance benchmarks for measuring the cost-effectiveness of alternative market schemes for promoting a "mature" renewable energy technology (RET) such as mini-hydro.[1] The economic cost per kWh outlines the least-cost resource path; the differential financial cost per kWh shows the subsidy cost to the public.[2] Static economic analysis identifies the recommended penetration level for "mature" RETs as the market share at which the economic cost per kWh of the marginal RET generator equals the economic value of the savings in replaced thermal power generation. At this penetration level, the incremental cost of the marginal RE project equals the avoided damage costs of replaced thermal power. Damage costs comprise (i) the environmental costs of thermal power and (ii) a risk premium reflecting the negative

[1] If done properly, the cost of production per kWh is the specific output cost of production of the RET net of any sur-costs (or savings), which the technology imposes on the power system, compared with production from thermal power.

[2] Thus, the expropriation of economic rents by the general public is an element of "financial cost effectiveness."

macroeconomic impacts of fluctuating prices in fossil fuels.[3] Positive employment impacts from RE generators may be monetized as well.

1.4 Once we analyze options to develop a market for a **"**developing RET,**"** such as wind energy,[4] the identification of cost-effectiveness becomes more complicated, as it takes on a time dimension. According to learning curve theory, the rate of productivity increase for a "developing technology" depends on the rate of increase of the annual market for the technology: as a rule of thumb, a doubling of market size leads to a 20-30% cost reduction.[5] An implementation strategy for a "developing RET" having higher upfront costs per GWh than an alternative option, but delivering a larger market volume, can be more cost-effective over time than the option with a lower upfront cost,[6] by accelerating the cost reductions of new vintages of the RET. Cost-effectiveness, in that case, depends on the discount rate of policy makers. Another implication of learning curve theory is the potential for reaping early mover advantages: companies in a country with a fast market development will, other things being equal, out-compete companies located in countries with slower market developments.[7] Cost-effectiveness in that case is a question of whether the initial "higher than average national support" to RET is compensated by the macroeconomic benefits gained from developing a new national industry.

[3] An alternative approach is incorporate the fuel risk directly in the cost of production per kWh by using a lower discount rate to deflate future fuel costs in annual O&M.

[4] The distinction between the two relates to the pace of technological progress as shown in longer term growth rates for annual productivity increases. The cost per kWh (net of changes in international fuel prices) of power plants using "mature" technologies declines at the normal industry wide 1% rate of productivity improvements; the cost of "developing" technologies declines faster than mature technologies, depending of the rate of the annual increase in the world market. Wind energy during the 1980s experienced average annual productivity increases of 8%, and of 5% during the 1990s. During the 2000–2010 decade a further annual productivity improvement of 3.5% is likely.

[5] The Wind Force 12 report (2202) in its year 2020 forecast foresaw a 30% reduction for each doubling of the wind energy market. The IEA assumes a more conservative 10% reduction in its report "Renewables for Power Generation - Status & Prospects," (2003), leading to a 25% cost reduction per decade during the next two decades. The IEA expects installed capacity to increase from 30 GW in 2003 to 130 GW in 2010.

[6] Expressed in supply curve terms: the upper position on the supply curve is compensated by the faster outward shift of the supply curve.

[7] The shining example is Danish wind turbine technology: in the year 2000, roughly 50% of installed capacity world-wide was of Danish origin. Early mover advantages do not last forever; latecomers can catch up quickly, using joint venture or direct company takeovers as a means to leapfrog any gap in technological know-how. Spain used its large-scale promotion of wind energy to build up a strong national wind turbine industry of its own. Gamesa, which originally was a joint venture with Vestas, bought out Vestas' 40% share to become totally independent; but in 2003 shrewdly established a technology development firm in Denmark, thereby keeping in touch with the know-how community in that country. In 2003, financially strong U.K. engineering companies have started the alternative strategy of buying up financially weak turbine manufacturers on the European continent and transferring production to the U.K.

Risk analysis and choice of policy

1.5 Policy makers in different countries attach different risk premiums to policy concerns.

- *Security of supply* is an issue for EU policy makers, as the EU is becoming 70% import dependent in fossil energy.
- *Fuel diversification* is seen by some as a worthwhile protection against macroeconomic shocks from fluctuations in internationally traded fuels. In addition it provides protection against the risk—a couple of decades down the road—of a permanent upward shift in oil and gas prices; international oil production is expected to reach its attainable all-time maximum sometime between 2020 and 2040.
- *Global warming* is an issue which policy makers in some countries are highly concerned about, while politicians in other countries show a lower willingness to pay.
- *Foreign exchange savings* are a policy objective in, above all, developing countries.

1.6 All four concerns increase the interest in wind energy. Although wind energy may not be on the lowest point of the national RET supply curve in individual countries, it is the unconventional RET technology with the most significant short-- to medium-term GW(h)-potential worldwide.[8]

Distributed generation in a centralized grid

1.7 Present power grids are optimized to link large-scale power plants—until recently the least-cost option for power generation—with distributed consumers. In the longer term, it is believed that distributed generation will become more cost-effective; the investment in and operation of transmission and distribution grids will adapt to its characteristics and needs. The present period is seen as a transitional period, where emerging distributed generation coexists with centralized generation under a power market scheme and a grid operation framework that is tailor-made to the latter. The suboptimal grid situation adds to the cost of an intermittent RET, such as wind energy. In some countries, the political position is that the "grid costs" of intermittent technologies reflect the outdatedness of grid operations just as much as an undesirable characteristic of the RET per se. For this—and security of supply—reasons, the costs are charged to final consumers as part of the transmission and distribution charge. In other countries, politicians see these "grid costs" as proof of the high cost of wind energy, and insist that they be charged to the wind energy generators.

What policy objectives are relevant in Nicaragua?

1.8 The virtues of internationally tested options depend on the policy objectives and visions of policy makers. Which ones are relevant for Nicaragua?

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[8] Thus, as a technology in a national strategy to reduce GHG emissions, the low CO_2-replacement effect per produced kWh is compensated by many GWhs.

1.9 Policy interests deducted from learning curve theory can be eliminated as the size of the national market is too small to make it relevant; Nicaragua discusses investments in MWs, not GWs. Overall, present lessons learned from international experience are of limited interest to Nicaragua: the tested options were for GW markets, and will be reviewed as such in the next section.

1.10 In view of the small size of the market, it is rational for Nicaraguan policy makers to look at wind energy as a "mature RET," and rank alternative market schemes according to their ability to provide the least cost economic and financial solution.

Cross-cutting Challenges

1.11 If the enabling framework is to allow a large-scale promotion of wind energy, it must be capable of (i) assisting the creation of an initial market for investments in wind farms, and (ii) sustaining large annual investment levels in the longer term, as "stop-go" market development policies are costly. To do this, the scheme must fulfill four concerns:

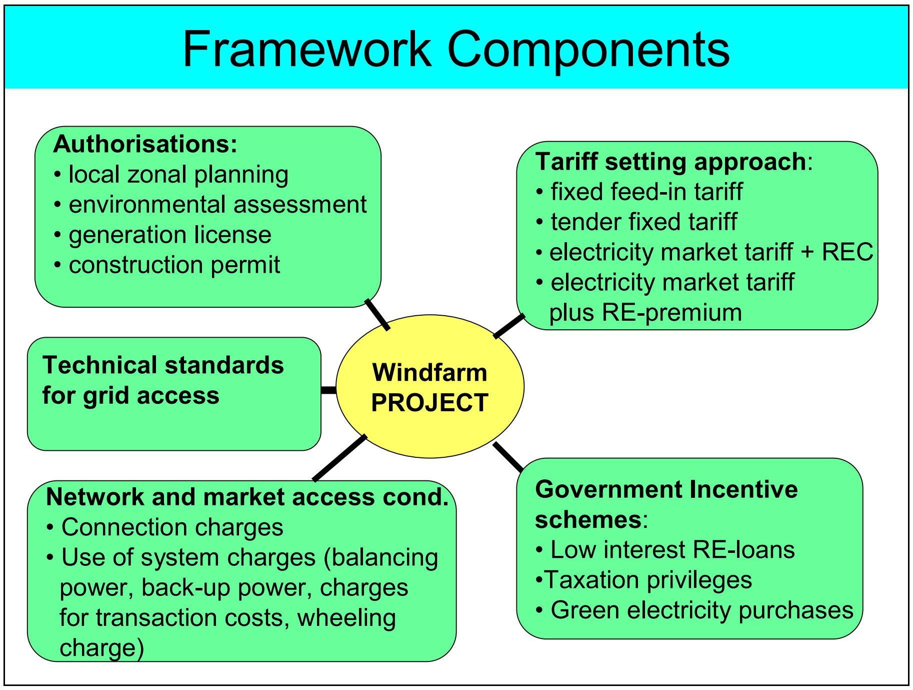
> (i) To promote a market for RETs, the scheme must first of all make projects using RET generators bankable. Even if existing incentives provide wind farm projects with a meaningful project rate of return that is not enough, if there is risk that the terms could be changed during the lifetime of the project. If banks perceive that there is a regulatory risk—that policy changes may decrease wind farm revenues or increase the annual charges levied on wind farm operation—they will be reluctant to lend.
>
> (ii) The scheme must keep the costs of wind farm incentives down to the minimum compatible with achieving the politically targeted penetration of wind energy on the power market.
>
> (iii) The scheme must allow an appropriate burden sharing of the extra costs associated with a large scale penetration of wind energy between the distribution companies/retailers purchasing the power and the national electricity consumers.
>
> (iv) The scheme must be compatible with the general market rules established for the power market, avoiding measures that distort the smooth operation of the bulk market for power. At low levels of penetration, this requirement may be waived, but as the market share of wind energy increases, compatibility with the rules of the market will become a key issue.

1.12 To design a scheme capable of achieving all this is a complex challenge. All schemes, therefore, are constantly being adjusted as problem areas meriting attention are identified. Some changes are micro-adjustments to improve the working of an otherwise accepted scheme. Major changes are triggered by a political push to reduce the financial and economic costs of an existing scheme, or by a need to adjust the scheme to a major reorganization and liberalization of the power market.

Components of a Regulatory Regime for Grid-Connected RETs

1.13 The chart below shows that the regulatory regime for grid-connected RETs is composed of five elements.

Figure 1.1: Regulatory Regime for Grid-Connected RETs



1.14 One could also reduce the number of components to three, by combining tariff policy, Government incentive schemes and network access conditions into a single element called "economic/incentive regime."

2

Basic Market Schemes for Large-scale Wind Energy

Major Design Decisions and International Trends

2.1 It is probably impossible to find two countries with identical RET market promotion schemes. But whereas the schemes show large variations at the level of details, the general trend for all countries is towards a regulatory regime that makes wind energy fit harmoniously within the overall market scheme for bulk electricity. This trend away from separate—parallel—market rules for RETs reflects the gradual maturing of wind energy as a power technology that can compete on the free power market.

2.2 There are two major choices in designing a regulatory regime for grid-connected RETs:

(i) Whether to use a variant of the "mandated market" approach (economic conditions for wind farms defined in individual commercial contracts) or of the "mandated tariff" approach (economic terms for off-take and connections defined by law and confirmed in standard contracts).

(ii) The balance between "taxpayer pays" and "electricity consumer pays" subsidy instruments.

"Consumer Pays" or "Taxpayer Pays" Support Schemes

2.3 The table below shows the financial support instruments used to cover the gap between the financial cost per MWh of (unsupported) wind farm-generated electricity and the free market price for bulk electricity from fluctuating resources. It identifies three financing mechanisms: subsidies paid by taxpayers, subsidies paid by electricity consumers, and CO_2 payments; and three subsidy targets: investment subsidies, kWh subsidies, and subsidized charges for grid and electricity market operations. Most—or all—countries use a mixture of supporting instruments.

2.4 The general international tendency is:

- a shift in the subsidy burden from taxpayers to electricity consumers;
- replacement of direct investment subsidies to wind farms ("per MW capacity" subsidies paid by the state budget) to subsidies linked to the output (per kWh subsidy);

- elimination of “windfall” subsidy payments (to avoid creating artificial producer surpluses)
- RE generators are increasingly charged the full cost for market access services provided by grid operators and system operators.

2.5 Broadly speaking, the complexity of the support package reflects the political ambitions as to the size of the market. In particular the German incentive package comprises a broad mix of “taxpayer pays” and “electricity consumer pays” instruments, making it understandable why 40% of world-wide wind farm capacity is installed in Germany (12 GW out of 30 GW installed as of end-2003). In addition to favorable feed-in tariffs, German wind farm investors get low interest rate loans and a 70–100% write-off on their investment during the first year of operation. [9]

Table 2.1: Financial Support Instruments

Financing Mechanisms	Subsidy Targets		
	Cost of investment	**Price of output**	**Charges for Operations**
Taxpayer pays	• direct capital subsidies • soft loans • VAT exemption • Import duty exemption • Accelerated depreciation • Tax holidays on income • Subsidies to exporters of RET equipment • Subsidies to R&D&D	• topping-up premiums to producers • topping-up premiums to consumers • VAT/excise duty exemptions • Green electricity purchases for public institutions	
Electricity consumer pays	• Grid reinforcement (deep connection costs) paid by utilities • Part of (shallow) connection costs paid by utilities • R&D&D of power utilities on wind energy/electricity system interfaces	• Premium feed-in tariffs for RET electricity • Renewable portfolio standards with or without RETs • Green tariffs • Eco-taxes on alternative fuels	• Wheeling tariff below the true opportunity cost of utility • Balancing costs charged to consumers not to generators • Use-of-system charges fixed below cost
CO_2 credits		• CO_2 certificate • CER revenue/kWh	

2.6 In Italy, eligible RE generators get “RE certificates” plus “CO_2 certificates,” which are both sold on the market separately from—or together with—their electricity output. The CO_2 credit instrument—CERs (certified emission reductions) in developing countries—is, strictly speaking, not a subsidy, but payment for a side product of power generated by an RET. It has, however, the same effect as a topping-up subsidy payment per kWh of output. The “RE certificate,” although marketed as paying for an attribute of RET-generated power, is actually a “pure” subsidy instrument.

[9] This is due to the general tax regime for German “GMBH” companies (Gemeinschaft mit beschränkter Haftung, a form of company unique to Germany), which is normally used for wind farms).

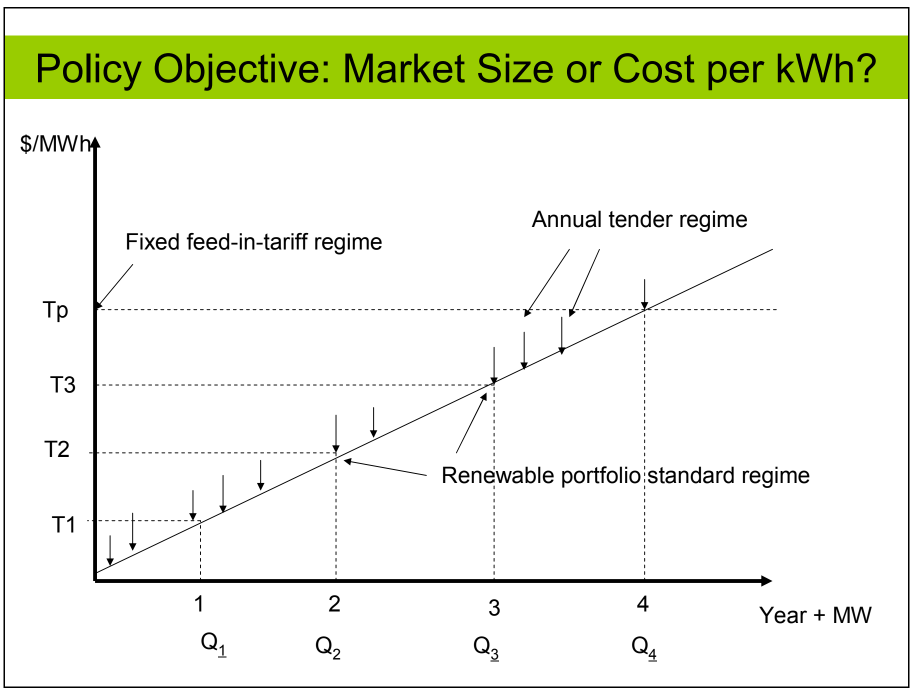
2.7 The limited scope for investments in wind farm capacity in Nicaragua—making it a "once in a decade" opportunity—reduces the range of feasible options. To what extent taxpayer-based instruments are politically feasible has to be verified.

"Mandated Tariff" Versus "Mandated Quantity" Regimes

Relative subsidy cost-effectiveness of mandated market schemes[10]

2.8 Much discussion in international literature has centered on the supposed superior subsidy cost-effectiveness of mandated quantity regimes over mandated tariff regimes (see Annex I). Studies financed by the EU Commission have, in addition, underlined the higher allocative efficiency of an EU-wide "RE certificate" scheme, as it allows member countries with high RE ambitions to invest in "RE certificates" from RE projects in other EU countries where costs are lower.[11] The origin of the higher subsidy cost-effectiveness of mandated quantity regimes is illustrated in Figure 2.1 below.

Figure 2.1: The Origin of the Higher Subsidy Cost-Effectiveness of Mandated Quantity Regimes



2.9 The small arrows indicate the location of individual RET projects along the RET-supply curve. We look at the impact over four years for a policy target of Q_4. In

[10] Mandated market schemes are defined to include any scheme where there is an obligation to connect, a right to recover costs from consumers, and a target.

[11] Once political economy is taken into account, the picture becomes less rosy. The Netherlands has shown political willingness to import "green electricity." In Spain, Germany, and Denmark, however, the strong political support for green electricity would likely evaporate if it meant investing in RE plants outside the national territory.

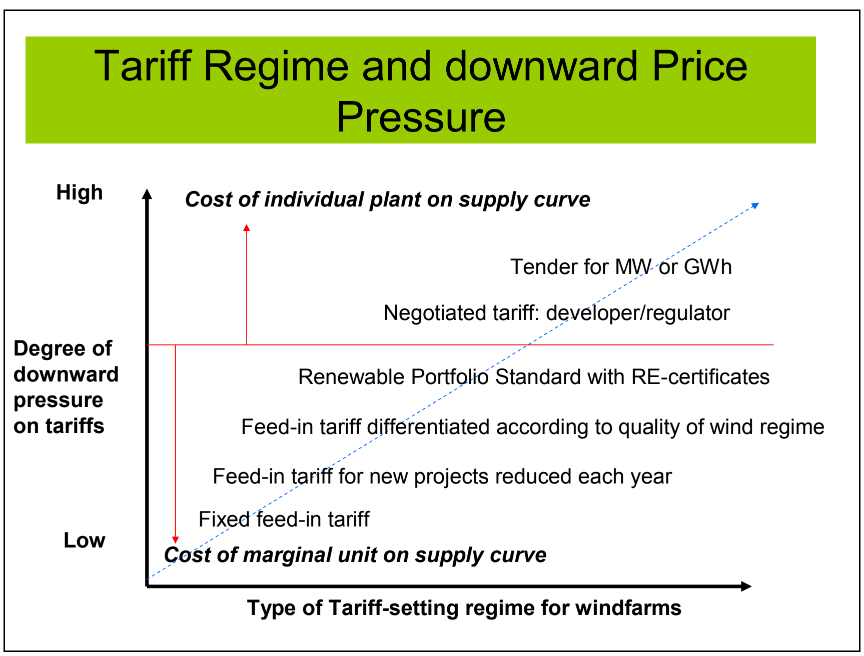
a fixed feed-in tariff regime, a tariff of Tp is offered to all projects, allowing a quantity of Q_4 to be reached, either at the end of the four years or before. In a renewable portfolio scheme, a quantity of Q_1 would be required in national power supply in year 1 (all projects paid the market clearing price of T_1), Q_2 in year 2 (all year 2 projects paid the market clearing price of T_2), Q_3 in year 3 (all year 3 projects paid the market clearing price of T_3) and Q_4 in year 4 (all year 4 projects paid the market clearing price of T_4). In an annual tender regime, a quantity of Q_1 would be tendered in year 1, of $Q_2 - Q_1$ in year 2, of $Q_3 - Q_2$ in year 3, and of $Q_4 - Q_3$ in year 4. All projects would be paid the specific price they bid in the tender. Hence, the conclusion is that the tender regime results in the lowest RE tariffs/subsidies, and the feed-in tariff regime in the highest.

2.10 The real life differences in the "subsidy cost-effectiveness" of the three schemes are smaller than indicated by the introductory analysis in 2.3, because policy makers adjust the details of the three approaches to address their specific weaknesses. The year 2004 versions of the feed-in tariff have largely eliminated the creation of subsidy-financed producer surpluses by using more complex formulas to calculate more individualized tariff levels. This trend is illustrated in the chart in 3.3.2.

Type of tariff regime and degree of downward pressure on tariff level

2.11 Figure 2.2 ranks the "subsidy cost-effectiveness" of different schemes, not taking potential differential dynamic impacts on technological progress into account. The red line in the chart marks the dividing line between tariff regimes that seek to hit the specific cost of production of individual wind farms (eliminating subsidy-financed producer surplus altogether) and those that tend towards pricing according to the cost of the marginal wind farm.

Figure 2.2: Tariff Regime and Downward Price Pressure



2.12 Details are provided in following sections of this chapter.

The feed-in tariff and its variations[12]

2.13 The feed-in tariff (FIT) is the "ultimate" instrument for promoting a rapid development of a market for wind farms. The FIT allows best sites and less attractive sites to be developed simultaneously in a given year; unlike the stepwise development under the renewable portfolio standard (RPS), which develops the best sites during the initial years and the less attractive sites during later years. The downside is that the cost of an FIT scheme—to reach, say, a 10% RE penetration on the electricity market by 2010—risks being more expensive per annual GWh than alternative schemes, at least when its superior impact on technological progress is not taken into account.[13] The relatively generous tariff levels, adopted to allow the less attractive sites to be developed, provide developers of better sites with a subsidy-created economic rent.

2.14 The strong market expansion created by the FIT in Spain, Denmark and Germany let the financial impact of the FIT on average retail tariffs be felt quickly. Neither the German nor the Danish scheme took the rate of technological progress into account: whereas the cost of production of new wind farms decreased substantially during the 1990s, the FIT remained unchanged. The explosion in economic rent benefited, above all, owners of wind-rich land, who extracted high lease payments from wind farm developers for use of their land. The unequal regional penetration of wind energy—utilities located in wind-rich regions were purchasing a much higher percentage share of total supply from wind farms[14] than distribution companies located in less windy regions—compounded the need to intervene.

2.15 The first reaction under both schemes was to define more equitable burden sharing arrangements. In Germany a hardship clause shifted the financial burden of the extra costs imposed by wind farms onto the neighboring utility as soon as a distribution company had reached a 5% share of wind-generated electricity. Energy intensive industries paid a smaller surcharge on their kWh bills than other consumers. Denmark introduced a 10 øre/kWh subsidy (eurocents 1.2) paid by the State budget. Later the administration of the subsidy scheme was transferred to the transmission system operator as a public service obligation (PSO), the cost of which was included in the transmission tariff.

2.16 Later reforms of the German and Danish FIT schemes reduced the "economic rent" impact of the FIT. The feed-in tariff is paid only during initial years until a given production level had been achieved. In the Danish FIT, wind farms were paid the premium rate during ten years or for the first 25,000 "full operating hours"

[12] EU countries applying FITs include Germany, France, Spain, the Netherlands, Greece, Portugal, Denmark and Luxemburg.

[13] Use of static analysis will conclude that the German, Danish and Spanish FITs are more expensive than an alternative bidding scheme or RPS scheme. In dynamic analysis—including the impact of rapid market growth on technological progress—the conclusion is less evident. Without the FIT in the three countries, wind energy would not have reached its low present production costs.

[14] Under the feed-in laws distribution companies were forced to connect wind farms located in their territory and to purchase their output.

(nominal capacity of the wind farm multiplied by 8760)—whichever comes first—after which wind farms sell their output on the free power market. The stepwise tariff procedure has two advantages. (i) The best sites receive the high tariff for a lower percentage of lifetime production than less attractive sites; which reduces their economic rent. (ii) The cash flow matches the financing needs of wind farms: as loan maturity is shorter than the economic lifetime of a wind farm, investors need a higher cash flow upfront.

2.17 After 2000 Denmark and Germany undertook major overhauls of their FIT systems.

2.18 Germany introduced two innovations: the single FIT is replaced by three different rates according to the wind regime at the site, and all three rates are adjusted each year for new projects by a standard productivity improvement factor. The law still maintains the FIT for a pluri-annual period; but anticipating continued productivity increases for new wind farms, the FIT for new wind farm PPAs is decreased each year by 2% until 2012. Wind farms on low-wind sites are excluded altogether from the right to get the FIT: wind farms must achieve at least 65% of the benchmark production for low wind sites to qualify.

2.19 In Spain, wind farms can, at the start of each year, choose between two tariff regimes: (i) a FIT, currently 6.21 eurocents, which is changed each year;[15] (ii) to receive a "prima" per kWh, at a rate adapted each year, and sell their power into the power exchange receiving the daily market price.

2.20 Denmark decided in 1999/2000 to drop the FIT for new wind farms, replacing it with a tradable RE certificate scheme to begin in 2001. Existing wind turbines were to be paid the FIT until 2010, a decision which proved to be the kiss of death for the green certificate scheme: it reduced the annual volumes for traded RECs to insignificant levels, creating a market with too low liquidity to make it efficient. The REC was never implemented. Instead, as shown in the next chapter, Denmark introduced a variant of the "premium payment on top of market pool price" scheme.

The renewable energy portfolio standard

2.21 The renewables portfolio standard (RPS) support system is a requirement for consumers/ retail suppliers/ electricity generators to source a minimum percentage of their electricity consumption from eligible RET-generated electricity. RPS systems have been introduced in Australia, Japan, in at least 14 U.S. states, the U.K., Belgium (Flanders, Wallonia), and Sweden. Finland has a voluntary green pricing system in place, akin to a RPS system.

2.22 To add flexibility to parties with a RPS obligation and to reduce their compliance costs, a parallel system of Tradable Renewably-generated Electricity Certificates (TRECs) can be introduced to certify eligible RET generators and verify compliance with the RPS regulation. The administrative unit cost of a TREC tracking system can be kept very low per MWh of electricity by making it a Web-based electronic platform. Under competitive conditions, a TREC system can ensure

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[15] Under Spain's 1997 Electricity Sector Law, payment for renewable generation must be 80-90% of the electricity sales price nationwide.

minimum RPS compliance costs. Affected parties in areas with high marginal RET costs will source their TREC requirements in areas with lowest marginal costs, engendering by way of arbitration a trend towards equalization of the REC price across the whole support system area and, consequently, a trend towards minimization of overall system compliance costs.

2.23 Since commercial wind farm investments—once they get into the commercial 100–150 MW size range—are relatively lumpy, and it takes time to get all authorizations in place to develop a project, the RE investments during a year will either result in some overshooting (leading to low TREC prices on the market) or some underachievement (leading to high market prices for TRECs that give investors a substantial economic rent. For this reason, the schemes introduce flexibility by allowing (i) some banking of surplus TRECs and (ii) allowing retailers with insufficient TRECs the option to pay a penalty; which serves as a ceiling for the market price of TRECs. Minimum certificate price provisions can reduce the investor uncertainty on profit margins under RPS systems.

2.24 In the U.K.'s "renewable obligation" scheme, electricity suppliers must buy an increasing amount of their power from allowable green energy sources, rising to 10.4% by 2010; plans are to introduce a 15% target for 2015 and a 20% target for 2020. Suppliers unable to meet their requirements must buy ROCs at £30 per MWh, a price well above 2003 electricity wholesale prices of about £23/MWh. The money raised is distributed back to electricity suppliers according to how well they meet their targets. During 2002 and 2003, the elasticity of supply in the U.K. was not sufficient to enable the annual penetration targets to be reached. In 2002, companies missed the requirement for renewable energy purchases by about 40%. The result was high prices for ROCs and for RE supply contracts, as electricity companies, to avoid paying cash to rivals, paid more than £45/MWh for ROCs.

2.25 It should be underlined that there is no requirement under an RPS to have a TREC scheme, nor that the RPS can be applied only to competitive markets. In a single buyer regime, for example, it is easy for the Government to impose an RPS on the single buyer. Even in a competitive market, an important tradeoff is whether the transaction costs of setting up and managing a TREC scheme are less than the benefits from encouraging more efficient trading. If the benefits of trading are sufficiently attractive, a TREC would spontaneously emerge under open market conditions.

The MW tender scheme—the British NFFO and Irish tenders

2.26 The tender approach is attractive if (i) the goal is to keep PPA prices down to the absolute minimum, and (ii) the Government wants to promote a specific portfolio of RETs.

2.27 The government fixes a long-term target for the penetration of wind and other renewable energy technologies on the market, and divides the long-term target into targets for annual achievements subdivided into technology-specific tranches. On this basis, annual tenders are organized for 10–20 year PPA contracts for a specified volume of eligible RE generation. Although the aim is to acquire MWhs, the tender asks for installed MW capacity, the required number of MW being calculated backwards from a GWh-target using the estimated capacity factor for the tendered RET. The project developers bidding the lowest kWh prices are awarded the contracts. The tender documents define the price-setting method for the PPA tariff if the tender leads to more than one bidder being accepted. Either:

- each winning bidder is paid the bid PPA tariff ("bid pricing" method); or
- each winning bidder is paid the PPA tariff of the most expensive of the accepted bids ("strike-pricing" method).[16]

2.28 Depending on the governance structure for the national power system, the tender is organized:

- by the regulatory authority;
- by the transmission company/system operator;
- by the system operator;
- by the system operator/single buyer, or
- by the single distribution company.

2.29 The British NFFO—see Annex I—was poorly conceived. It did result in low-cost PPAs. However, it implemented few MW, as many developers afterwards were unable to get the local permits for the construction of their wind farms. By favoring the selection of the very best wind sites, it led to a concentration of project proposals in a few areas, which led to resentment by the local population. Due to low investment volumes and the stop-go nature of the NFFO bidding rounds, the scheme had no positive impact on the development of manufacturing expertise in wind energy technology in the U.K. The scheme failed because lack of political will to promote a larger scale development of renewable energy had resulted in an absence of serious work being done on developing a coherent planning and regulatory framework for wind energy. The supplementary components of the framework—see the chart on the front page of the report—were not in place.

2.30 The competitive tendering system for wind farms (and other RE generation) operated under the Alternative Energy Requirement (AER) program in Ireland is an example of a successful government-administered competitive tender program.[17] Because a strong political will to promote a large scale penetration of renewable energy exists, the annual tenders call for a large-scale volume of investments, and the procedures for planning and implementation are well designed.

2.31 The Governance structure for AER involves four organizations: Department of Communications, Marine and Natural Resources (DCMNR), the Commission for Energy Regulation (CER), the Department of Environment, Heritage and Local Government (DEHLG) and the power company Electricity Supply Board Customer Supply (ESB CS). The role of each is as follows.

[16] If bid pricing is used, the average price is lower than in the RPS case, as each wind farm is paid a tariff corresponding to its specific location on the supply curve. In strike pricing, the resulting price should be similar to the price reached under the RPS approach, as wind farms are paid the marginal costs of new RE supply that year.

[17] The Alternative Energy Requirement (AER) program was launched in the mid 1990s. Under the program there have been six AER competitions to date.

- DEHLG defines the planning guidelines pertaining to wind.
- DCMNR administers the program by periodically inviting tenders for specified amounts and types of RES-E capacity from private developers at or below cap prices. The capacity threshold for each RET is fixed by the Minister and DCMNR awards the winning tenders.
- The CER defines the best new entrant price (most economic new thermal power plant).
- ESB-CS is the monopoly supplier to the portion of the power market that has remained closed to competition (called the franchise market). Once tenders have been submitted and adjudicated, DCMNR obliges the ESB-CS via CER, to contract to purchase all of the electricity output of each winning project for up to 15 years at the tender price. ESB CS recovers the premium (above the best new entrant price) paid for AER contract generation through a public service obligation levy imposed on consumers.

2.32 Key details of the tender scheme and the changes introduced over time include:

- Applicants to the tender submit bids up to a cap price designated for specific technology categories (i.e. wind, hydro, and biomass). The applicants with the lowest bids in each category are selected up to a capacity threshold.
- All applicants are required to hold planning permits for proposed developments
- The tender tariff is indexed to inflation. AER V offered 15 year power purchase agreements with ESB at the successful applicants' bid prices with 25% of the output attracting an annual inflation adjustment based on the consumer price index (CPI). Since AER VI (announced April 2003), the full bid price attracts annual CPI changes; in addition, the bidder can chose a front-weighting price provision that increases the price by 35% for the first 7.5 years of the contract and decreases the price by 35% for the remaining 7.5 years.

2.33 The nontariff financial incentives (support measures) of the AER comprise:

- The AER programme, since 2003, is supported through a public service obligation charge levied on all customers.
- Section 486B of the Finance Act 1998 offers tax relief for corporate investors in renewable energy projects.
- The Business Expansion Scheme (BES) allows individual taxpayers to write off qualifying investments against personal income where the investment is in renewable energy projects. This scheme is of particular interest to small scale projects.

The negotiated PPA Scheme

2.34 In the negotiated PPA scheme, the Government fixes a target for a certain RE quantity and invites developers to present their project proposals to the Government.

2.35 Often, such a scheme is introduced in reaction to unsolicited proposals by private wind farm developers, which start off a Government debate on the role of RE in the country's electricity supply. This debate then leads the Government to fix what it considers to be an economically justified level of RE penetration. A good example are the wind farm PPAs in Costa Rica; see the Costa Rica PPA in section 3.5 signed with the national power company, ICE.

2.36 In negotiated deals, politicians normally attempt to fix the price of wind farm supply at the specific cost of production of the wind farm, refusing to approve PPAs with wind farms if the cost is higher than the avoided cost of thermal power.[18] The price negotiations, therefore, tend to be tough, resulting in PPA tariffs close to the cost of production of the individual wind farm. The price, unless influenced by corruption, is therefore similar to the tariff that would result from a tender.

2.37 The approach is efficient when the potential wind farm market is small and there is little competition for setting up wind farms. It makes a "once-and-for-all" penetration of wind energy possible without need for introducing complex legal, regulatory and market access rules. It is easily implementable under a regime of a regulated national power company.[19] It is more difficult to implement under a free market regime for the supply of electricity.

2.38 The forced PPA is a special category of a "negotiated PPA." An example is the agreement reached between the Danish Government and the Danish power utilities during the early/mid-1990s, which the latter undertook to invest in a specified MW quantity of offshore wind farms.[20] These were high-risk investments and absolutely not price competitive on the free power market. However, almost all potential land sites in Denmark had already been developed. A continued expansion of wind energy, therefore, had to look at offshore sites, and practical experience was needed in developing the technology for offshore wind farms.

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[18] The market in that case is defined by the willingness of foreign donors to subsidize the surplus costs.

[19] However, if a liberalization of the power market is under preparation, the national power company signing off on the PPA risks being stuck with a "noncompetitive" source of power supply in its portfolio.

[20] In principle, it was a negotiation, but since the Danish Government, due to the complex legislation for directed management of the energy sector, had a large arsenal of enforcement instruments, it was a Mafia-style "offer you cannot refuse" type of negotiation.

3

Contract and Institutional Issues in a Free Market Regime

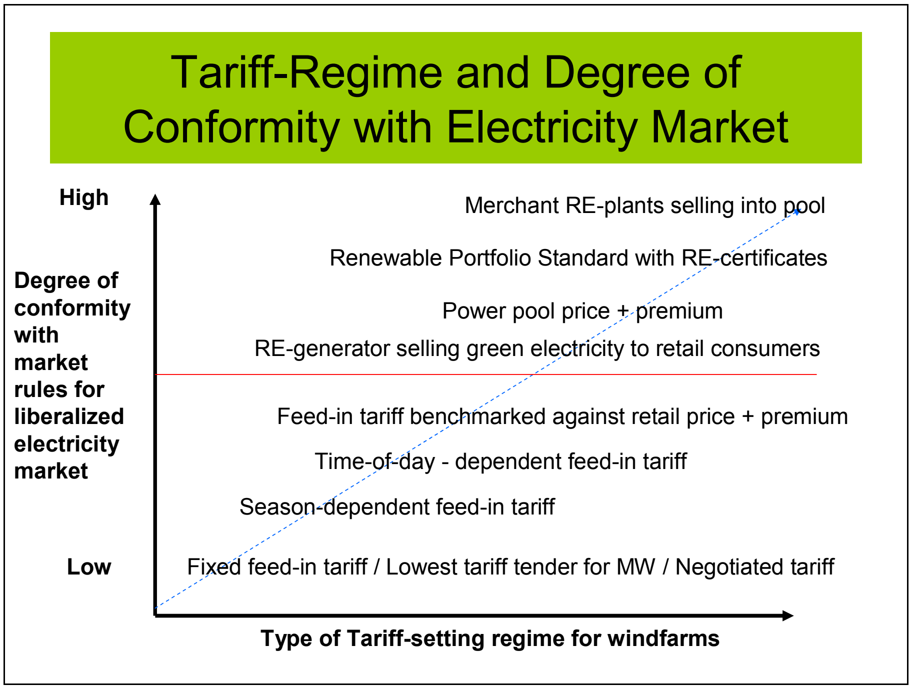
Getting Wind Energy Mainstreamed into the Free Power Market

3.1 PPA contracts and grid-connection contracts play a much smaller—less commercial—role in FIT schemes than in mandated quantity schemes:

- The economic terms and conditions of contracts in mandated tariff schemes are law-based, turning contracts between wind farms and other power market operators into formal confirmation of the economic conditions defined by law. Contracts may not even be used (as in the case of Denmark during the 1990s), or are standard documents, stating that "power off-take is paid according to terms defined by law."
- Mandated market schemes are contract based: the economic terms and conditions for power off-take, use of grid, etc., are not defined by law; they are the outcome of negotiated deals between two commercial parties. The economic terms for a wind farm, therefore, are defined in details in the commercial contracts that link the wind farm to the power market.

3.2 Other things being equal, mandated quantity schemes allow wind energy to be more seamlessly integrated within the normal rules of the power market. Thus, although the newest FIT schemes are subsidy-cost-effective, the nuisance of applying specific tariff rules to wind farms works against the survival of the feed-in tariff in the longer run. The exceptions from the rules irritate established market players and reduce the operational effectiveness of power pools. The trend is to make frameworks more compatible with the general operation of the power market.

Figure 3.1: Different Market Schemes According to the Market Compatibility Dimension



3.3 Originally, the market access rules were tailored to the needs and technical characteristics of wind energy. Now, the pendulum is swinging the other way: the regulatory framework for RET generators is adjusted to better match the needs and rules of the liberalized power market. Figure 3.1 ranks different market schemes according to the market compatibility dimension. The red line charts the dividing line between fixed and market-determined tariffs. It shows ways in which the fixed tariff regime is adjusted to "mimic" the outcome of free market forces. In Costa Rica, for example, the rate of the feed-in tariff depends on the time of day (higher during peak demand hours) and on the season (higher during the dry season, when hydroreservoirs are low).

3.4 The terms for using the transmission/distribution grid and for operating on the power market are also increasingly priced to reflect the higher costs of satisfying the needs of intermittent power supply.

Governance

3.5 The Danish system of power sector governance is complex. Powers are divided between the Energy Regulatory Authority, the Energy Authority, and the System Operators. In addition the market rules of the Nordic Power Pool apply. The Energy Authority is charged with oversight of licensing and the general economic regulation of the distribution network operators, while the objective of the ERA is primarily to undertake an inspection and complaints function in the field of energy. Day to day regulation of wind farms is mainly governed by the system operator to the extent that it is not covered by the extensive secondary legal regulation. Wind farms have priority producer status, offering them some protection from the general regulatory regime and from the demands of the market. Recently, however, the obligation of the system operator to sell the output of the wind farm in the pool on behalf of the wind farm operator (and before that the obligation of the local distribution company at whose grid the wind farm was connected to buy the wind farm's output) were abolished.

3.6 Germany differs fundamentally from other EU countries in that it has no distinct regulatory body; instead there exists a complex series of distinct regulatory and mediating bodies, backed by a body of law and the court system. As a result of this the German competition authority, the Federal Cartel Office (FCO), has a more significant role in regulation—and apparently a more proactive approach to becoming involved—than the corresponding competition authorities in other nations. The standard system of access foreseen in the energy law is negotiated third party access. A framework agreement on access prices and conditions (Verbändevereinbarung) forms the basis of policy, though this is not binding in law. This is backed by various codes, including the Distribution Code, which sets the technical and organizational conditions for use of, and access to, the distribution networks. The Ministry of Economics may issue a statutory ordinance if it is felt that the voluntary framework is not producing the expected results. One such ordinance, the Bundestarifverordnung Elektrizität (BTOElt), issued in 1990, sets down conditions for tariff charging for low voltage supply, insisting that tariffs be transparent and cost reflective. Tariffs generally, along with conditions for market access, were not regulated as a result of the 1998 liberalization, however, and these remain fixed within the Verbändevereinbarung. Grid charges are monitored by the FCO and by consumer groups. Most wind farms are given priority access to markets in that it is compulsory for the distribution companies to purchase electricity from renewable energy sources. The body of support to wind farms insulates them to some extent from the main body of electricity sector regulation.

3.7 In Spain, power industry planning is regulated by the Administracion General del Estado. The legal and substantive supervisory power is exercised by the Comision Nacional de Energía, which, while being a separate public law entity, must report to the Ministerio de Economía. The functions of Operador del Sistema and of Gestor de la Red de Transporte have by the Power Industry Act been conferred upon the Red Electrica de España (REE). REE operates the national high tension grid with tensions of 220 kV or more; medium and low voltage lines remain in the property and responsibility of the national and regional power companies. Each power company has the right to feed power into existing power lines and transport even if the lines are owned by a third party. The power market is organized by a power exchange managed by the Compañia Operadora del Mercado Español de Electricidad.

Scope of Required Contracts and Authorizations

Authorization to set up a wind farm

3.8 In Costa Rica, the feasibility study for a wind farm in the late 1990s was presented to *Agencia Reguladora de los Servicios Publicos, (ARESEP*) and the environmental impact study to the *Ministerio del Ambiente y Energía (MINAE)*, for approval. The wind operating concession is awarded for a 15–20 year period and was conditional on the initiation of construction within three years.[21]

3.9 In Germany, erection and operation of wind farms require public license. Authorization procedures for new capacity follow the same procedure as for an industrial plant. The permitting procedure for mainland sites is conducted at the state (Länder) level. Applicable rules depend on the magnitude of the project. One or two turbine projects are permitted by the local building committee pursuant to state construction laws. The application procedure for 3-5 turbine wind farms is similar but regulated under the Federal Emission Control Act. Larger farms must go through a public hearing. The Federal Emission Control Act embodies all permits otherwise required to be obtained from other state and federal agencies. The municipality within which the project is located must be heard in the permit proceedings, but once a permit is given it cannot be appealed. Offshore wind farms are subject to the same rules as inland sites as long as they are located within the 12 mile zone defining German territorial waters. Outside territorial water but inside the German Exclusive Economic Zone radically different permit procedures apply.

3.10 In Spain, there is no catch-all application process under which all administrative prerequisites are reviewed and one single permit is issued. The developer files an application for a building permit to the municipality and at the Consejeria de Industria of the District Government, and an application for granting public interest status ("Declaración de Utilidad Pública"). If there are competing projects, the regional Ente Regional de la Energia informs the Direccion General Industria, Energía y Minas, which decides in favor of one project developer. The decision is forwarded to the Servicio Territorial Industria Comercio y Turismo. The Declaracion Publica is published, allowing complaints to be lodged. A joint planning committee enters the conclusive decision on the project application. The procedure for approval of the EIA is similar. The wind farm developer needs the "Autorización Administrativa de la Instalación de Generación" by the Provincial Authority.

Interconnection contract

3.11 The interconnection contracts between the wind farm and the transmission company/distribution company define the technical specifications and power quality of supply obligations which the wind farm has to fulfill. In countries where no separate feed-in agreements are signed, the connection contract also contains the procedures and payment schedules for metering and other services, which the net operator provides for the wind farm.

3.12 The increased penetration of wind energy in European grids has led to more stringent quality criteria being imposed on the wind farms, in particular concerning reactive power issues and contribution to grid stability. The requirements have gone hand in hand with international technological progress in wind technology, which more and more enables wind farms to perform on power grids like fossil fuel-based generators.

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[21] The "initiation of works deadline" for keeping an awarded concession was copied from the hydropower sector.

Feed-in agreement, PPA, energy sales agreement

3.13 No separate feed-in agreements—in addition to the grid-connection agreement—were concluded under Danish and German FIT laws. In Spain, a formal PPA has been signed. See end of chapter 3

Pricing Policies of Grid Operators and System Operators

Connection costs and use-of-system charges in transmission

3.14 The policy issue for connection charges is whether to apply deep connection charges (charging the generator all costs to the grid, including grid reinforcement to absorb the output from the wind farm) or shallow connection charges (charging only the cost of connecting the wind farm to the nearest substation). The deep connection charge includes the use of system charge with respect to capital assets but not the use of system charge related to transporting the kWh through the grid; shallow connection charges include neither.

3.15 Some countries have specific connection rules for renewables (although they may not fix prices); in others (i.e. the U.K. and the Netherlands) wind farms connect under general connection rules.

3.16 In Denmark, wind farms located within a planning zone for wind farms pay the cost of connection investments up to the edge of such a zone. The distribution utility pays for all further investments, which are passed on to its consumers. Wind farms established outside such planning zones must pay the full cost of the connection.

3.17 Germany also applies shallow connection charging. The Renewable Energy Law (EEG) dictates that wind farm developers cover only the costs of connecting their plant to the grid; the network operators must provide any necessary grid extension, as long as this does not entail excessive cost. The reinforcement costs paid for by the grid company are recouped through their addition to the Regulatory Asset Base (RAB) of the grid operator; the use-of-system charge (UoS)[22] paid by customers is related to the RAB.

3.18 In Spain grid access fees are regulated in the Royal Decree 2820/1998 within the rules set forth in the Power Industry Act. Shallow charges are applied.

3.19 Connection charges in the Netherlands' shallow tariff system are regulated below 3MVA, subject to negotiation or regulated in the 3–10MVA range, dependent on circumstances, and negotiated over 10MVA.

Use-of-system charges in power pools

3.20 Use-of-system charges (UoS) refer to payments by the wind farm to the system operator/market operator to cover his costs in integrating the supply of power from wind farms into the market: administrative costs, market transaction costs, additional balance costs, and costs for additional reserve capacity.

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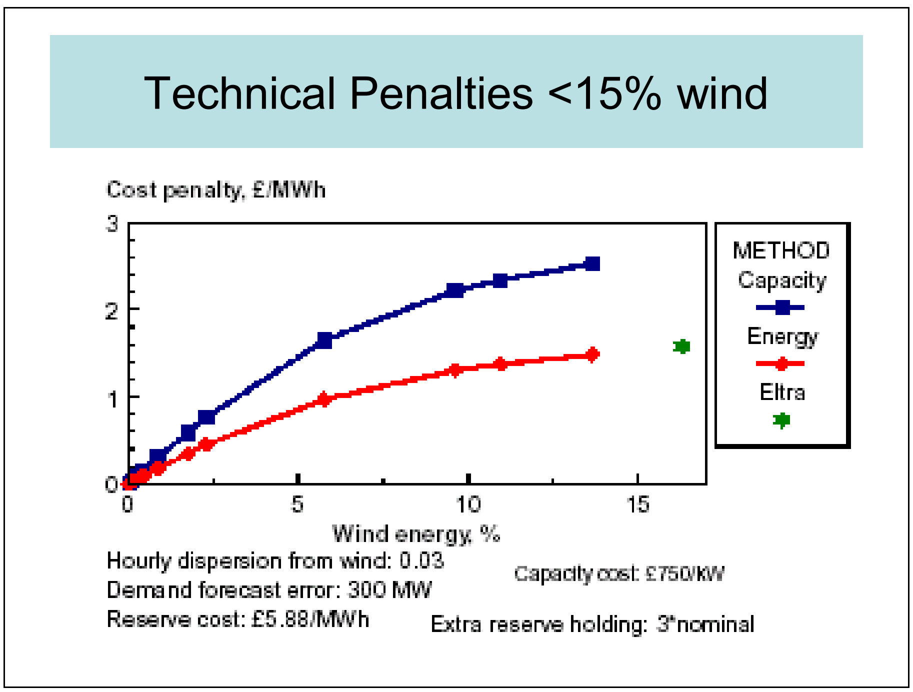
[22] Use-of-system charges in transmission refer to payments for wheeling of electricity, metering and others.

3.21 The Danish utilities participate in the Nordic Power Pool, along with the power companies of Norway, Sweden and Finland. In the Nordic power market, retailers/distribution companies typically secure about 70% of annual power needs through bilateral contracts with generators. The rest is purchased on the Nordic power pool, which is a spot market with the normal forward financial hedging instruments attached to it. The pool pays energy payments (kWh prices), and no separate payments are made for capacity, except for daily spinning reserve and stand-by capacity.

3.22 In pool systems, an intermittent power technology like wind farms gives rise to increased costs, both on the balancing market and on the market for reserve power. The balancing market is used by the market players to settle surplus sales to the pool and deficits in supply (compared to what they were contracted to supply). Since the system operator attempts to economically motivate the market players to bid and deliver their precise amounts, generators who supply too much are paid the pool price for the hour minus a penalty; while generators failing to supply the contracted quantity are charged the pool price for the hour plus a penalty. The size of these costs as shown in Figure 3.2 below, from David Millborrow's paper for a U.K. parliamentary committee, increases with the size of the penetration of wind energy in the national power system.

Figure 3.2: Pool System Technical Penalties



3.23 Under the rule for new wind farms adopted in Denmark, wind farms must sign a contract with a so-called "balance-responsible generator" to sell their power into the power pool. The latter is a private operator who takes care of selling the power, contracting back-up power, paying balancing prices, etc. A large number of wind farms were out of the FIT system or had had more than 10 years in operation (or produced more than 25,000 full operating hours). The system operator, ELTRA, had by law been forced to perform the "balance-responsible" function for these wind farms, charging the full cost of this service to the wind farms. ELTRA's charges for this cover the following costs:

- *Administrative costs* for making wind-production forecasts, selling the electricity from wind farms in the pool, and for fees paid for trading on the Nordic power pool and balancing market.
- *Costs for balancing*, calculated once per month, by dividing the balancing costs of ELTRA for wind farms with the number of kWh supplied by the wind farm during that month. Eltra, being "balance-responsible" for wind farms, pays the balance costs each day on the balance market, settling the difference between what the turbines produced at the specified hours of the day, and what ELTRA—using wind-forecasts—had informed the Nordic Pool would be produced during that hour 24 hours before the start of the operating day. If the actual output of the wind farms is greater than the forecast production, the surplus electricity is sold on the balance market at prices equal to or less than the market price for that hour. If actual output is less than the forecast production, the deficit in energy is purchased on the balancing market at prices equal to or higher than the market price for that hour.

3.24 During 2002 ELTRA's cost of administration averaged 0.5 øre/kW (0.07eurocents) while the average balancing cost was 1,8 øre/kWh (0.24 eurocents); leading to a total cost of 2.3 øre/kW (0.30 eurocents). The balancing costs, as seen in the monthly 2003 prices in Table 3.1 below, vary substantially depending on the wind regime and on the price for balancing power.

Table 3.1: Administrative Costs and the Costs for Balancing

	Administration Øre/kWh	Balancing Øre/kWh	TOTAL Øre/kWh	TOTAL Euro-cents/kWh
January	0,3	2,9	3,2	0.4
February	0,3	3,0	3,3	0.4
March	0,3	3,2	3,5	0.5
April	0,5	1,6	2,1	0.3
May	0,5	2,1	2,6	0.3
June	0,5	1,7	2,2	0.3
July	0,5	1,5	2,0	0.3
August	0,5	2,0	2,5	0.3

3.25 The use-of-system costs can be charged to the generators or to the consumers. In the end consumers pay in any case, as balancing costs are included in the bid price of generators. But by charging the generators, they are economically motivated to provide forecasts of their supply that are as accurate as possible. In Germany, the balancing costs of wind farms are charged directly to final consumers. The reasoning is that the stochastic nature of wind farm output is outside the influence of wind farm operators. Charging the specific balancing costs of wind energy to the wind farms instead of directly to consumers would increase the costs of transaction without yielding desired behavioral effects. In Denmark, the argument is also accepted that the higher than average balancing costs of wind farms are an unavoidable negative side effect of the positive fuel-diversification service that wind farms provide to power supply. But, the position is that the market operation of wind farms should be the same as for other operators. Wind farms—no longer included in the FIT scheme—are required to contract a system balance responsible to settle all costs on a purely commercial basis on their behalf. In order not to penalize wind farms economically, the system operator pays wind farms within and outside the FIT scheme a fixed compensation of 2.3 øre per kWh (0.3 eurocents), which is expected on average to cover the system balance costs.[23] The cost of the compensation is recovered by the system operator through his fees charged to consumers.

3.26 In the California BPA balance charges cost roughly $1/MWh. Payments depend on the size of the supply error. There are three categories. Band 1: free allowed error of either 1.5% of supply or 2 MW; Band 2: an error of 7.5% or 10 MW, whatever is lower, leads to payment of 110% of market price for underproduction, and of 90% for overproduction; Band 3: errors larger than that are fined $1–1.89/MWh.

Wheeling charges

3.27 One incentive scheme used in India to promote wind farms is to allow industrial plants to invest in a wind farm in an area, and to "wheel" its production to cover power consumption at the industrial plant. The measured time-of-day output of the plant at the injection point is deducted from the electricity quantity measured at the point of consumption, when the monthly invoice is drawn up. The transmission company charges a wheeling charge for this service, which, dictated by state power agencies, is subsidized.

3.28 The scheme is a powerful instrument seen in the eyes of the investor. Yet banks, when doing their due diligence appraisal for a loan to such a project, will be concerned that the wheeling charge offered at the time of contract signature could be changed after a few years of operation.

Technical specifications

3.29 System operators define technical requirements for wind farms through formal routes such as "grid codes," replacing the use of more ad hoc technical regulations. Technological progress in wind energy technologies permits the grid company/system operator to impose ever stricter quality requirements on the output of wind farms.

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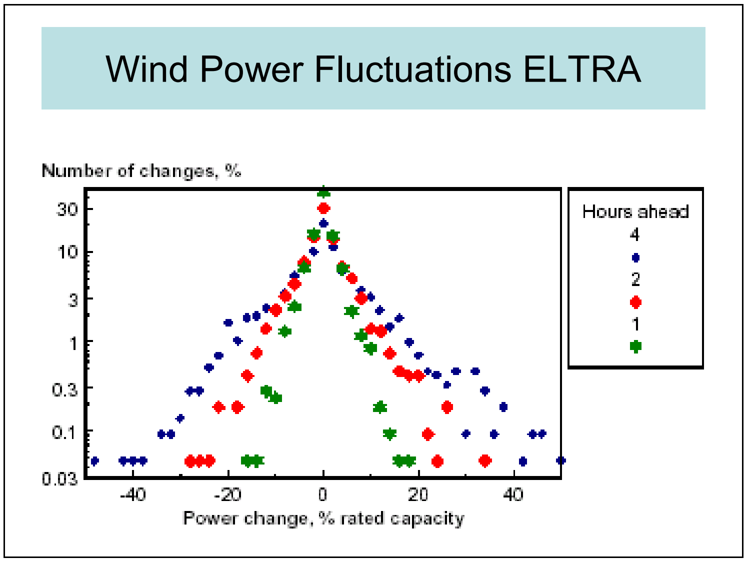
23 The 2.3 øre compensation is automatically deducted by ELTRA when the monthly bill for balancing services is sent to a wind farm under the FIT scheme for which ELTRA acts as balancing responsible.

Requirements for wind forecasting

3.30 The fluctuating wind resource imposes extra costs on the system, as additional reserve capacity and balancing power must be contracted. Both types of costs can be reduced, if the wind production output is predicted with greater certainty 1–24 hours ahead. Even from one hour to the next, variations in output—even if wind farms are spread over a large territory—can be quite substantial, as shown in the Danish example in following figure.

Figure 3.3: Wind Power Fluctuations



Source: David Millborrow

3.31 Forecasts help to reduce payments for capacity and the energy costs of standby capacity. With experience, the capacity of conventional generation operating at any time as backup for wind power can be reduced; the remaining conventional generation can then run closer to its optimum efficiency, increasing its energy efficiency. This will save fuel but increase the frequency with which conventional generators are started and stopped.

3.32 Better forecasting of wind farm production requires that the system operator—or the windfarm operators—have good software models for power prediction, and are able to get good meteorological data to provide the needed inputs to the model. In both areas, progress is being made. The number and the quality of suitable software models is improving, and research is going into developing better meteorological models tailor-made for wind farm requirements.

3.33 The forecasting can be entrusted either to the system operator or to the wind farms. The system operator is interested in keeping down the daily overall costs of system operation; wind farms in regimes where penalty payments are imposed on wind farms for deviations between “contracted/ forecasted delivery” and de facto delivery, get higher revenue when they improve their expected production forecasts. In Denmark, the system operator does the forecasting.

3.34 The California Independent System Operator (CAISO). Participating Intermittent Resources Program (PIRP) allows intermittent power producers (i.e., wind and other resources with an uncontrollable primary energy source) to schedule their energy in the forward market without incurring hourly or daily imbalance charges when the delivered energy differs from the scheduled amount. A key ingredient to implementing the new scheduling methodology is to develop near real time, state-of-the-art forecasts. Scheduling coordinators representing "Participating Intermittent Resources" will use these forecasts as the energy schedules submitted to CAISO. Participating wind generators will be exempt from the 10-minute settlement of uninstructed deviation charges and instead be assessed deviation charges based upon monthly net deviations between the metered and scheduled energy. The key is to have an unbiased forecast of energy production for every hour, which can result in a net energy deviation over an entire month that approaches zero or a very small number. The project covers all wind generators in any region regardless of their participation in PIRP and the availability of real-time per-project meteorological and production data.

PPA Design

U.S.-style PPA from Costa Rica

3.35 Under the late-1990s scheme for investments in wind farms, the output of the wind farms was sold to the national power company, ICE, under a 15-year PPA with possibility of extension for an additional 10 years. The developer was obliged to begin construction of the plant within two years after the signature of the PPA.

3.36 The PPA, summarized in table below is a classical U.S.-style PPA, which attempts to mimic real market price conditions as much as possible. The wind farm operator was offered a choice between two tariffs:

> (i) A Tariff 1 with a capacity payment and an energy payment. The guaranteed capacity of Tariff 1 is not a firm capacity in the classical sense of a thermal power plant; it is a guaranteed capacity factor for the season during the specific hours of the day (guaranteed number of kWhs that will be produced).[24] A hefty penalty is paid if the contracted capacity factor is not attained.
>
> (ii) A Tariff 2 with an energy payment only, which is higher that the energy payment of Tariff 1.

3.37 Both tariffs operate with two seasonal tariffs (high season, low season) that have different payments for off-peak and peak demand production. The PPA contains an inflation adjustment when inflation since the last adjustment has risen above 3%; and adjusts for devaluation of the colones versus the US$. The high season is the season when national hydropower production is relatively low (a large percentage of production comes from run-of-the-river hydropower plants).

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[24] The "contracted capacity" offered by the wind farm owner is his calculated expected "capacity factor" for the season and time of day (in the case of the 20 MW plant from which this PPA was taken it was: 10 MW for high-season/on-peak; 9.6 MW for high season/off-peak; low season/on-peak = 7.1 MW).

3.38 The developer's choice between the two tariffs depends on whether the expected gain from the capacity payments is large enough to offset the lower revenue from the energy payments and the losses from penalties for insufficient capacity. The choice of tariff is made at the beginning of each year. If an end-of-year comparison shows that the alternative tariff would have yielded higher revenue, the company can switch to that tariff the next year.

Table 3.2: PPA Tariffs in Colones/kWh December 1996 Officially Adjusted Prices

	High Season: January-August		Low Season: September-December	
	Peak period	Off-peak period	Peak period	Off-peak period
Tariff 2: Energy payment	18.59	12.60	14.35	7.63
Tariff 1: Energy payment Capacity payment[1)] Penalty payment:	 14.34 17.02 49.04	 12.19 8,26 4.17	 12.64 4.08 23.40	 7.63 0 0

Peak periods: Monday-Friday: 10.00 am –12.30 pm and 5.30–10.00 pm. Off-peak periods: all other hours. 1) Capacity payment is per season. The kWh is: guaranteed capacity * number of hours of the period.

3.39 The PPA gives ICE the right to disconnect the wind farm when the Arenal-Corobici plants are out of service between 8 pm and 10 am. During the high season, ICE may disconnect for up to 16 hours per month (128 hours) and during the low season, up to 244 hours per month (1220 hours) The impact of a full exploitation of the "curtailment" right is substantial, amounting to 15% of hours of operation per year. The impact on annual output and on revenues, however, is much lower even in the worst case scenario, as only off-peak production is affected.

3.40 The structure of the PPA is inspired by the "avoided cost principle" fixed in the U.S. PURPA Act. The time-of-day and season-dependent tariff is a strong economic incentive tool in the case of hydropower plants: the developer of a hydropower plant, when defining the economically optimal size of water storage, can increase it in response to the peak hour price incentive. In the case of wind farms it makes no economic sense: Wind farm owners do not have the technical means to store energy. The structure of the tariff, therefore, is of more psychological than real importance.

Spanish PPA

3.41 In Spain, the PPA signed between the wind farm and the local distribution utility is a short, simple, standard document adopted by the Direccion General de la Energía. It establishes the formal agreement of the local distribution utility to buy the output of the wind farm as required under the Régimen Especial.[25]

3.42 Since the PPA is not the result of a commercial negotiation between the wind farm developer and the distribution company; but a compulsory "public service obligation" imposed on the distribution utility as the result of the wind farm being registered as "Instalacion de Producción en Régimen Especial," the PPA does not define the economic conditions for the purchase of power. The economic aspect is dealt with in article 7: "El regimen económico de la energía entragada por el

25 Established by Real Decreto 2818/1998.

Promotor a la empresa de distribución será el que determine en cada momento la legislación vigente.”

3.43 Article 16 limits the duration of the PPA to five years, with possibility of extension if both parties agree. Article 12, furthermore, links the duration of the PPA to the length of the regimen especial: “En el caso de que la instalación de generacion perdiera la condición de instalación acogida al Real Decreto 2818/1998, el presente contrato quedaría automáticamente resuelto de pleno derecho. Asimismo, si se modificase la legislación vigente, dejando de ser obligatoria para la empresa de distribución la compra de la energía excedentaria de la instalación de generación, el presente contrato quedaría también automáticamente resuelto, salvo acuerdo en contra de ambas partes.”

4

Market Scheme for Wind Energy in Nicaragua

Governance Structure

Institutions

4.1 The three key policymaking and regulatory institutions for the power sector in Nicaragua are:

(i) *CNE (Comisión Nacional de Energía)* is the energy policy-making entity in Nicaragua*,*

(ii) *INE (Instituto Nicaragüense de Energía)* is the national regulatory authority for the power and hydrocarbon subsectors, responsible for applying energy policies adopted by Comisión Nacional de Energía (CNE). In the power sector INE approves tariffs, issues licenses to operators, adopts technical norms, and undertakes planning functions.

(iii) *CNDC (Centro Nacional de Despacho de Carga)* is an independent entity within the national integrated power system, responsible for the dispatching functions.

Legal framework and industry structure

4.2 The regulatory framework and the industry structure for the power sector is defined by Ley No. 272, Ley de la Industria Eléctrica (LIE) of 1998; [26] while *Ley de Reformas a la Ley Orgánica del Instituto Nicaragüense de Energía* of 1998 details the functions and administrative setup of INE.

4.3 LIE broke up the previous integrated national power company Empresa Nicaragüense de Electricidad (ENEL), introducing a horizontal separation between generation, transmission, dispatching, and distribution. LIE provides third party access to the transmission and distribution grids. The electricity transmission company, *ENTRESA*, remains public

4.4 Nicaragua's power generation assets, *Generadora Eléctrica Central* (Gecsa), *Generadora Eléctrica Occidental* (Geosa), and *Generadora Hidroeléctrica* (Hidrogesa), are being privatized by the state privatization agency, URE. In 2002,

[26] The key implementing legislation to LIE is provided by *Reglamento a la LIE* publicado en la Gaceta Diario Oficial No. 116 del 23 de Junio de 1998, mediante *Decreto No. 42-98*, y sus reformas mediante el *Decreto No. 128-99* publicado en la Gaceta Diario Oficial del 16 de diciembre del año 1999.

Coastal Power, a subsidiary of El Paso, acquired GEOSA and its two thermal power stations, Nicaragua and Chinandega, with a combined installed capacity of 114 MW. Bids for the country's hydropower plants were rejected, while the Gecsa power stations have yet to attract any bidders.

4.5 The distribution assets, Disnorte and Dissur, were acquired by the Spanish power utility Union Fernosa, which enjoys a monopoly on distribution and retail supply except for final consumers with a power demand higher than 2 MW, who can contract directly with generators if so they wish.

Regional Perspectives

4.6 The Central American countries have not established a liberalized, regional power pool. Even so, transmission investments allowing increased cross-regional trade are being made. The *Sistema de Interconexion Electrica para America Central* (SIEPAC) project entails the construction of transmission lines connecting 37 million consumers in Panama, Costa Rica, Honduras, Nicaragua, El Salvador, and Guatemala. SIEPAC will cost an estimated $320 million and is scheduled for completion in 2006. A second goal of the project is to integrate Mexico with the Central American electricity market by constructing a 62.5-mile, 400kV transmission line between the substations of Tapachula, Mexico and Los Brillantes, Guatemala. On May 20, 2003, Mexico and Guatemala signed an energy integration accord to develop this interconnection. The line is expected to be operational by 2005. The third goal of the project is to link Belize's electricity network with the Central American system. The project entails constructing a 122-mile, 230kV power transmission line between substations in Santa Elena, Guatemala and in Belize City. The initial stages of construction were tentatively set to begin in 2003.[27]

4.7 The SIEPAC project will be governed by two new regional institutions, the Regional Electric Interconnection Commission (CRIE) which will regulate the wholesale market, and the Regional Operating Agency, which acts as administrator of regional power transactions.

4.8 One would expect a region-wide power pool to become operational within the next ten years. In view of this perspective, the framework for RET in Nicaragua should be made as future-proof as possible to avoid stranded costs when more liberal power competition is introduced.

Power Market Demand and Financial Situation of Union Fernosa

Power demand

4.9 Between 1995 and 2001, demand for power increased an average of 6 percent per year. CNE expects for the next ten years an average growth rate of 5.4%. Maximum demand in 2002 reached 422 MW. Generation fed into the integrated national power system (SIN) was 2415 GWh in 2002; final sales amounted to 1575 GWh (excluding isolated grid systems). The difference between the two figures indicates a staggering 35 percent of system losses (technical + nontechnical).

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27 Source: DOE, "Regional Indicators: Central America," 2003.

Structure of power market

4.10 The power market is made up of the "mercado de contratos": the long-term PPAs, which Union Fernosa had to take over from ENEL when it acquired the distribution assets, and the "mercado spot." The average price from the two yields the price of the "Mercado Mayorista" which Union Fernosa is allowed to pass on to final consumers through its tariffs.

4.11 Existing market rules require distribution companies to have PPA contracts equal to a minimum 80 percent of forecast demand for the next year and of 60 percent for the following year. Future PPA contracts signed by the distribution company are to be secured via international tender.

4.12 At present, the "mercado de contratos" covers 80 percent of demand.

System losses and financial position of Union Fernosa Nicaragua

4.13 Since privatization was supposed to increase the operational efficiency of the power system in Nicaragua, the high level of system losses represents a disappointment. Union Fernosa at privatization was forced to take on all staff of the two privatized distribution entities. Apparently, it takes longer than expected to weed out old inefficiencies. The result, however, has been a significant weakening about of the financial position of Union Fernosa's registered daughter company in Nicaragua, as INE refuses to approve tariff increases covering all system losses. Union Fernosa Nicaragua, therefore, is not very creditworthy, and the parent company refuses to provide financial assistance.

Conclusions of "Caso de Estudio: Situación y Perspectiva de la Energía Eólica"

Power demand and supply balance

4.14 The PPAs as well as other short term contracts provide Union Fernosa Nicaragua with supply more than sufficient to cover demand until 2005. Other existing contracts, especially those for the geothermal plants Momotombo and Tizate (together almost 90 MW), can cover needed demand until 2006.

Economic potential for integration of wind farms in power supply

4.15 CNE in consultation with private wind farm developers estimates that the high-class wind energy potential in Nicaragua allows 200 MW to be installed.

4.16 Simulations of the impact of wind energy in the Nicaraguan system show that up to 60 MW of wind farm capacity can be brought into the system between 2006 and 2010 without major increases in cost. These 60 MW amount to about 10% of peak demand and 20% of night demand in 2006. The power generation from wind would represent about 7% of estimated power generation in 2006.

4.17 Higher penetration levels would be uneconomical, as power production from wind farms during some off-peak days would be higher than power demand.

Evaluation of legal and regulatory framework for wind energy

4.18 The present framework for wind energy was found wanting:

(i) The key framework laws and regulations for the power sector, Ley de la Industria Eléctrica No. 272, and Decreto No. 42-98 "Reglamento a la Ley de la Industria Eléctrica del 23 de junio de 1998; both from 1998, contain no references to the promotion of renewable energy and their incorporation in the power market.[28]

(ii) The Ley General del Medio Ambiente y los Recursos Naturales (1996), requires that power generation projects with more than 5 MW and transmission projects with voltages above 69 kV require preparation and approval of EIA.

(iii) The Acuerdo Presidencial No. 279-2002, Política Específica para el Desarrollo de los Recursos Eólicos e Hidroeléctricos a Filo de Agua, and its "reglamentación," issued by INE in its resolution 07-2003, establish the legal basis for providing preferential treatment to RE generators. The decree stipulates the following:

> On top of the price obtained in the spot market, RE-generated electricity is paid a premium equal to 70% of the difference between the "precio mayorista" and the "precio del mercado spot."[29]
>
> The premium is paid provided it does not lead to an increase in final consumer prices.
>
> A ceiling is fixed for RE-generated power of 5% of power supply.

4.19 The decree and its implementation regulation are found not to be implementable without changes. First, no methodology is defined for translating the price of the Precio Mayorista (established for a day or longer periods) as an hourly price, as spot prices are established hourly. Second, since a premium above the spot price is paid to wind farms, it is not known how to interpret the meaning of *"el incentivo se pagará siempre y cuando no cause un recargo a las tarifas finales.*" Third, it is not indicated who will pay the premium: whether a charge is raised pro rata on final consumer demand, or on the rest of the generators. Fourth, whereas a ceiling of 5% for the penetration of wind energy makes sense—it being an intermittent source of supply—it is not understandable why hydropower is included in the ceiling.

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28 The key legislation specifically directed at the operation of the electricity market comprises (i) Normativa de Concesiones y Licencias Eléctricas (1999), (ii) Normativa de Tarifas (2000), (iii) Tomo de Normas de Operación Comercial (2000), (iv) Tomo de Normas de Operación Técnica (2000)

29 The precio mayorista includes the price of the "mercado" spot plus the price of the existing power contracts, and of ancillary services, such as payments for reserve capacity and balancing power.

Power market rules and use of system prices

4.20 According to prevailing norms in Nicaragua, wind energy, being an intermittent source of power supply, is not entitled to any capacity payment, neither in the "mercado de contratos" nor in the "mercado de corto plazo de capacidad," which is settled daily.

4.21 Market operation rules require that each generator provides a spinning reserve equal to 5% of his dispatched capacity.[30] If a generator does not dispose of such capacity himself, he needs to contract a capacity equal to 5% of his daily generation.[31] Since wind farm generators have a lower average capacity factor than thermal power plants, the reserve requirement is a financial burden.

4.22 The transmission company charges a postage stamp tariff of about US$4.2/MWh.

4.23 Future PPA contracts signed by the distribution company are to be secured via international tender. No specific requirements and rules are defined for generators making use of RETs.

Cost of production of wind farms in Nicaragua

4.24 The financial analysis, summarized in the Table 4.1 is based on an assumption of a 17% rate of return on equity, shows that the cost of production of wind farms in Nicaragua varies between US$50–66/MWh depending on the quality of the wind resources, the ability to sell CERs (certified emission reductions),[32] and the introduction of the proposed 10 year tax holiday for income from wind farms.

Table 4.1: Cost of Production of Wind Farms in Nicaragua

Velocidad Viento (m/s)	Factor de Planta	Generac. Media (GWh)	Tarifa Media Requerida		
			sin CO_2 (US$/MWh)	con CO_2 (US$/MWh)	+Tax Holiday (US$/MWh)
8.5	0.40	70.1	66.0	63.0	62.0
9.0	0.44	77.1	60.0	57.0	56.0
9.5	0.47	82.3	56.0	53.2	52.5
10.0	0.49	85.8	54.0	51.0	50.0

4.25 The cost of production does not include the cost of balancing power.

Spot market prices and cost of required subsidies to wind farms

4.26 The average power market prices between November of 2000 and June 2003 varied:

- between US$34–59/MWh for the "*precio spot,*" with an average of US$46.5/MWh, and
- between US$60–71/MWh for the "*precio mayorista.*"

30 Artículo TOC 9.81 de las reglas de operación comercial. The Centro Nacional de Despacho de Carga has a goal of a minimum of "5% de reserva rodante" and of "2.5% de reserva de regulación." At present it is not possible to have a reserva de regulación of 2.5% when the hydropower plants are not generating.

31 Artículo TOC 9.8.8.

32 An emission reduction of 0.8 ton CO_2/MWh and a price of US$5/ton CO_2 give a revenue of US$3/MWh.

4.27 The comparison of the spot market prices with the cost of production estimates results in a required subsidy of between US$3.5–16.5/MWh in the scenario that the tax holiday is not introduced.

4.28 The subsidy depends on the future oil prices. Spot market prices in Nicaragua depend strongly on the international price of oil, as the spot market is supplied largely by diesel generators. A crude price assumption of US$25/barrel results in an average spot market price of US$48/MWh until 2007 and of US$45/MWh for the 2008–2014 period. A price of US$30/barrel would increase spot prices to about US$53.5/MWh. In the latter case, wind farms operating under wind conditions with average wind speeds of 9.5 m/second would not need subsidies.

4.29 Judging from the spot market figures, the Presidential decree would have given wind farms a premium payment fluctuating between US$6–19/MWh (70% of the difference between the Mercado spot and the Mercado Mayorista prices) with the average being US$12/MWh.

4.30 Pulling all figures together, the report estimates that the incentive payments to a wind farm of 20 MW would increase the average generating cost in the interconnected system by 0.7 per cent and proportionally more, if 40 MW or 60 MW of wind farms were to be set up.

Policy recommendations

Incentive Regime

- To adopt either one of two options for the pricing of power output from wind farms:
    - To pay a RE premium of US$10/MWh to wind farms provided that the monthly average revenue of the sport market price plus the premium does not surpass US$65/MWh. According to the spot market prices from November 2000 to June 2003, the average income of the wind farms would be $56/MWh.
    - To pay wind farms a fixed tariff of $56/MWh.
- To finance the subsidy/incentive payment cost by a charge imposed on final consumer demand. To impose a Renewable Portfolio Standard on distribution companies, starting with the requirement that, for example, 30% of future growth in demand should be covered by RET generators secured through tenders.
- To exempt wind energy from the requirement to provide reserve and balancing capacity.
- To implement the incentive scheme for RETs prepared by CNE, which eliminates various import and export duties and gives a 10 year tax holiday to revenue from RET generators. According to the financial calculations done for the wind farm study, the value of the benefits equals US$3/MWh.

Penetration Target

- To install not more than 50–60 MW of wind farm capacity
- Before authorizing each new wind farm project, a detailed study should be carried out by CNDC to establish the impact of additional wind farm capacity on the transmission system and on the absorption capacity of the power market.

Status Quo for Wind Energy in Nicaragua as of December 2003

Planned wind farm projects

4.31 Three wind farm projects, each in the 20-25 MW category, are in an advanced stage of preparation in Nicaragua. The wind regimes for the three projects seem to be of similar quality.

4.32 One of the three projects combines the investment in the wind farm with investment in pumped water storage. This developer, therefore, offers a higher-value product than the other two: the hydro/wind hybrid offers greater stability and predictability in supply and higher supply during peak hours. The terms offered to winning bidders in the tender must adequately compensate higher-value supplies for any additional market value they provide.

4.33 Since CNE/INE seems to have agreed initially to prepare a tender for a 20 MW wind farm only, the competitive situation for the first tender is strong, providing an ideal background for a competitive tender.

PPA defined in generation license

4.34 Negotiations in December 2003 between CNE and INE led to an initial agreement to organize a tender in 2004 for a 20 MW wind farm. The authorization to set up the wind farm would be awarded to the bidder asking for the lowest tariff. INE would issue a generation license to the developer which defined the terms of his PPA.

4.35 The agreement, which in the end broke down, introduced an international innovation: a "generation license-based economic regime" for wind farms. Being a novelty, it represented an additional risk element for the financing community. International banks asked to provide project finance would need a careful explanation. The legal implications of the proposal were unclear, including who would sign the PPA with the wind farm. A generation license represents the supply side only; it cannot force the demand side to accept the terms without further legal sanction.

4.36 It was agreed that development would not stop with the 20 MW wind farm. Additional wind farms could be set up in future years. But authorization for a new wind farm would require that the developer, as part of his project proposal, finance a system impact study to prove that the wind farm could be economically absorbed by the integrated power system.

4.37 How to implement the concept of having future wind farm developers finance a system impact study was not explained. It is doable if the idea is to avoid future tenders and award new licenses through direct bilateral negotiations between CNE/INE on the one hand and the project developer on the other. Asking a developer to pay the system impact study for a wind farm project that is tendered afterwards does not seem attractive to the developer. Also, if future wind farms are to be tendered, then it is more rational to ask CNDC to prepare the system impact study. The cost can be recuperated by charging the winning bidder or be included in the system fees charged by CNDC.

Recommended Scheme for Nicaragua

Size of tender

4.38 The initial tender would be for a 12 year PPA for a 20 MW wind farm.

4.39 If CNE/INE decide on pluri-annual tenders for a total of 50–60 MW, the recommendation is to organize:

- an "open" tender for 20 MW the first year;
- a 20 MW tender the next year, from which the winner of the first tender (and any affiliates) are excluded from participating;
- an "open" 10–20 MW tender the third year; whether 10 or 20 MW are chosen should depend on the kWh price that is offered for 20 MW.

4.40 The procedure ensures strong competition among project developers for all three tenders. In the third year tender, for example, the developer of the present three who have invested in preparing a wind farm project will face strong competition from the two 20 MW wind farms who may be interested in expanded their farms by another 10-20 MW.

Policy choice: fixed tariff or pool price tariff with premium?

4.41 The worldwide trend as noted in chapters 2 and 3 is to design frameworks for wind energy that are as "free market-compatible" as possible. That trend reflects the free competitive power regime in those countries. Due to the structure of the power market in Nicaragua, where a monopsonist[33] on the demand side faces a monopolistic structure on the supply side, as only one wind farm will be tendered in the beginning, and also because a more competitive regional market is still in the making, there is no compelling need for Nicaragua to follow the trend.

4.42 A free market price for electricity from wind farms—power pool price supported by a premium—raises the risk of wind farm operations, and thereby the cost of finance compared to a system of fixed prices for wind-generated electricity. As CNC, INE and the Presidential decree put emphasis on reducing the cost of wind farm subsidies to consumers, the political willingness to pay a premium price for a "free market mimic" does not seem to exist. Also, power market regulations in Nicaragua impose on distribution companies—in practice Union Fernosa Nicaragua—the requirement to secure 80% of forecast demand for an upcoming year through the

[33] A *monopsony* is a market with only one buyer. This can be compared to a *monopoly* in which there is only one seller. The demand side in Nicaragua consists of the distribution company—Union Fernosa Nicaragua—and of industrial consumers with a minimum demand of 2 MW, who are eligible to contract power from generators. The latter consumers represent only 7% of power demand in the integrated national power system.

"mercado de contratos." To let wind farms sell their output to the pool is not easily reconcilable with this requirement, and would put a strong downward pressure on pool prices, as daily wind farm supply, without storage facilities, is price-insensitive.

4.43 Reduced volatility in power prices—protection against fluctuations in the international price of crude oil and derived oil products—is one of the benefits of increasing the penetration of RET-generated electricity in national power supply. A power pool price + topping up premium scheme is less effective in reducing the fluctuations in average power prices than a fixed tariff regime.

4.44 For these three reasons, the recommendation is to adopt a fixed tariff regime for the initial 20–60 MW wind farms in Nicaragua, with the level of the tariff being determined by tender.

Length of PPA and signing party

4.45 It is recommended to sign a 12-year PPA with the wind farms. The length allows investors to secure long-term project finance, yet pushes the wind farms on to the free market within a reasonable number of years.

4.46 As the distribution company Union Fernosa represents 93% of the demand side, it is logical that the PPA contract with the wind farm be signed by Union Fernosa, despite the fact that Union Fernosa is at present in a financially weak position. Since Union Fernosa Nicaragua is in a weak financial situation; its signing the PPA is not ideal. Banks asked to provide project finance to a wind farm investor look at the creditworthiness of the purchaser for the electricity when evaluating lending risk. However, there is no logical alternative agent on the market. Also, the financially weak situation of Union Fernosa—being caused by its huge system losses—may improve in the future: it is unlikely that its management is incapable of implementing an effective loss reduction program.

Surcost imposed by the PPA on the signatory party from the demand side

4.47 The surcost of the monthly purchase of wind farm electricity is equal to the monthly difference between the total cost of wind farm-supplied electricity and the value of that electricity according to recorded hourly power pool prices.

4.48 The value of the surcost divided by the total kWh transported through the grid to the distribution company and to the large industrial customers gives the surcost per kWh bulk electricity.

4.49 The monthly surcost per kWh is calculated by the system operator under the regulatory oversight by INE.

Policy choice: PPA imposed on the demand side through public service obligation or through RPS?

4.50 The key legal-regulatory issue on the demand side of the market scheme is how to impose any RE off-take obligations on the market players and how the market players can recoup the surcosts imposed on them by the scheme.

4.51 The scheme on the demand side can be introduced in two ways, depending on the interpretation of existing regulatory rules and regulations in Nicaragua, in particular as concerns the possibility to impose public service obligations on the distribution company.

(a) Public Service Obligation scheme

4.52 Under the Public Service Obligation scheme, ENE (requested by CNE, or according to negotiated deal with ENE) would order the distribution company to sign the 12-year PPA with the winner of the tender as a public service obligation.

4.53 The surcost per kWh of the monthly purchase of wind farm electricity, as calculated by the system operator, is imposed as a "RET system user charge" on the monthly power supply to large consumers, who purchase their power directly on the bulk market. The revenue raised by the system operator is transferred to the distribution company.

(b) Renewable Portfolio Standard (RPS) scheme

4.54 If the concept of public service obligation is deemed not viable under Nicaraguan regulations, CNE/INE can take recourse to the mandated fuel portfolio instrument.

4.55 Under this, a wind farm RPS is imposed on the distribution company and the >2MW demand customers who contract their power directly from generators.

4.56 CNE/INE negotiate with the market operators to identify the most cost-effective market scheme for achieving the RPS obligation, which is that CNE/INE organize the tender and that Union Fernosa signs the 12 year PPA on behalf of all demand side agents in the bulk power market.

4.57 The other operators on the demand side, who are subject to an RPS, sign an "RPS-quota delegation contract" with the distribution company.

4.58 The distribution company bills, on a monthly basis, the other market participants, according to their share of monthly power purchases, the monthly difference between the total cost of wind farm-supplied electricity and the value of that electricity according to recorded hourly power pool prices, which has been established by the system operator.

Who shall organize the tender and how?

4.59 In principle, the tender can be organized by the distribution company signing the PPA. However, since the distribution company signs the PPA also on behalf of industrial consumers purchasing their power directly from generators, it is recommended to let CNE/INE organize the tender.

4.60 Participating bidders are required to hold all necessary planning permits and documentation for ownership or long-term lease of wind farm land.

4.61 CNE via INE orders the distribution company to sign the 12-year PPA with the winner of the tender.

Tariff structure

4.62 It is recommended to introduce a Costa Rican-style tariff structure for wind farms in Nicaragua. The structure offers two advantages:

(i) The difference between on-peak and off-peak prices allows wind farm investors to optimize their investment, making use of economic opportunities for investing in pumped hydro-storage facilities.

(ii) The tariff structure has the psychological advantage of minimizing the differences between hourly pool prices and the tariffs paid to wind farm-generated electricity.

4.63 During the season of peak demand for non-hydropower, there would be an on-peak and an off-peak tariff. During the remaining year a single tariff may be sufficient; a study of the size of daily differences in hourly pool prices during that season can determined that issue.

4.64 It is recommended to base the structure of the tariff on an analysis of spot prices during the last two years. The analysis results in a formula for the tariff structure, which shows how much percentage-wise the three (or four) tariff rates deviate from the average kWh price.

4.65 The tender material includes the formula for the tariff structure. Bidders bid a single per-kWh tariff, knowing that the formula is used to translate the bid tariff into the three (or four) rates.

Inflation adjustment

4.66 At least 70% of the cost of wind farm production (or, of the NPV of annual expenses during the lifetime of the project) is composed of the cost of capital: the annual amortization payments on loans. These payments are not subject to inflation. It is, therefore, recommended that 25 percent of the bid tariff (reflecting the share of the cost of production excluding annual amortization payments) is subject to a yearly inflation adjustment linked to the movement in the consumer price index.

Compensation for payments for contracting spinning reserve

4.67 Present regulations in Nicaragua *for* "reserva rodante" and "reserva de regulación" obligations lead to an inefficient market for these ancillary services. Market participants are not charged according to the specific balancing/reserve costs of their power supply. That may change within a few years, particularly if a regional power pool is established. To prepare for that, it is recommended not—as in Germany—to exempt windfarms from the obligation to provide "reserva rodante" and "reserva de regulación."

4.68 One can discuss instead whether the wind farms—as in Denmark—should be paid a fixed compensation per kWh of wind farm electricity, covering the expected yearly costs for efficiently contracted balancing power. Paying wind farms a standard compensation per kWh reflecting the cost of efficient contracting of thermal spinning reserve and balancing reserves reduces the average wind farm tariff, narrowing the gap between power pool prices and the PPA tariffs paid to wind farms. The compensation would be paid by CDNC and its cost included in CDNC's "cost of operating" fee, which is charged to the distribution companies and to the larger than 2 MW consumers. The compensation rate, which is subject to approval by INE, would be fixed once per year by CDNC, based on a forecast of reasonable reserve and balance costs during the upcoming year.

4.69 However, since the wind farm market is so small, involving only two to three players, it is recommended not to introduce a special compensation scheme.

How to make wind farm projects eligible as CDM-projects

4.70 The CDM instrument (payments for CERs) is a "free gift" to the policy objective of promoting RET and to developers investing in RET. To avoid problems with the "additionality criterion" for CDM projects, the tender documents will fix an upper cap on the tariff per kWh, which is so low that projects are dependent on CER revenue to become commercially viable. Alternatively the tender could state that only CDM projects are eligible to be awarded a PPA contract. Otherwise, there is a potential risk—if the Government adopts a RPS for wind farms—that the wind farm investment is considered being part of the baseline when CDM eligibility is determined.

How to use soft credits to cofinance CDM projects

4.71 The mixed credit instrument is also a "free gift" to the Government objective of promoting investments in wind farms and to the developers investing in RET. According to OECD rules mixed credits must have a subsidy content of at least 35%, meaning that the net present value of the annual amortization payments (subsidized interest payments + repayment on principal) must be 35% lower than the NPV of annual amortization payments of a standard export credit. The subsidy element is registered by donors as development aid at the OECD's DAC (Development Aid Committee). Since the mixed credit is used to cofinance a CDM project, one must be sure that the arrangement does not contravene the Kyoto Protocol's Marrakech Agreement that "public funding of a project is not to result in a diversion of ODA (Official Development Assistance) from Annex-1 parties." Any funding for CDM is to be additional to—and not substituting for—funds flowing from Annex 1 countries to developing countries. When a project is submitted for registration to the CDM Board, the CDM Project Design Document requests inclusion of "an affirmation that public funding does not result in a diversion of development assistance." The PDD does not state which party is to affirm; thus either the donor country or the host country can sign that declaration. Only the donor country, however, can clarify what the situation is for "mixed credits." A qualitative check on the fulfillment of the non-diversion criterion could ensure:

- That there is no conditional link between the authorization of the mixed credit to a wind farm project and the signing of an Emission Reduction Purchase Agreement (ERPA) for the CERs from the project. Preferably the donor government should not purchase the CERs.
- That the CER price in the ERPA is not influenced by the aid support from the donor.

- That neither the mixed credit nor the CER revenue alone is sufficient to make the project commercially viable, eliminating the need for topping-up kWh subsidies.

Recommended taxpayer-pays incentive instruments

4.72 The proposal made by CNE for state-financed incentives—a 10 year tax holiday and exemption from import duties and export duties—merits adoption by the Government

4.73 The incentive package of tax-financed subsidies does not represent an undue burden for the state budget; yet narrows the gap between the financial cost of wind farm production and the spot market price. This reduces the tension which the financial gap creates among other market players.

Annex

Price-based or Quantity-based Approach to RE Market Development?[34]

Three basic categories of approaches to market development

A1.1 "Electricity consumer pays" support schemes for grid-connected renewable energy systems fall into three main categories, of which one is price-based[35] and two are quantity-based in their approaches:

a. Feed-in tariffs, used in Denmark, Germany, Spain, and France since 2001.

b. Bidding for long-term PPAs with the system operator/national transmission company, such as Ireland's "Alternative Energy Requirement" scheme.

c. Tradable green certificates schemes, used in U.K., Italy, Netherlands, Denmark, Belgium, Austria, and Sweden, where electricity suppliers[36] are obliged to supply a certain quota of renewable energy.

A1.2 Each category has a number of subcategories:

a. Among feed-in tariffs one can distinguish between "fixed price/uniform tariff," "declining scale tariff," and the Spanish "hybrid feed-in tariff/kWh subsidy" schemes.[37]

b. Tender schemes differ with regard to the mechanism used to fix the PPA price (marginal bid price given to all or each bidder is paid his bid price) and with regard to how the contracted quantity is established: the tender can fix the quantity to contract (bid prices define the financial cost of the

[34] Adjusted paper "Subsidy Schemes for Renewable Energy: Quantity and Price Base Approaches" by Wolfgang Mostert in NER Quarterly Journal, Volume 2, 2003.

[35] The upfront investment subsidy is another example of a price-based scheme. But this type of scheme is financed by the public budget, and used for cases of initial market development, not for major market penetration.

[36] Alternatively, or for major self-generators as a supplement, final consumers must consume a minimum quantity of green tariffs. Voluntary green electricity demand schemes are insignificant.

[37] Under the Spanish renewables pricing mechanism, generators, when signing the PPA, can chose between being paid a fixed wind energy tariff of €0.064/kWh or a kWh-subsidy ("la prima") of €0.029/kWh paid on top of the market price in the power pool.

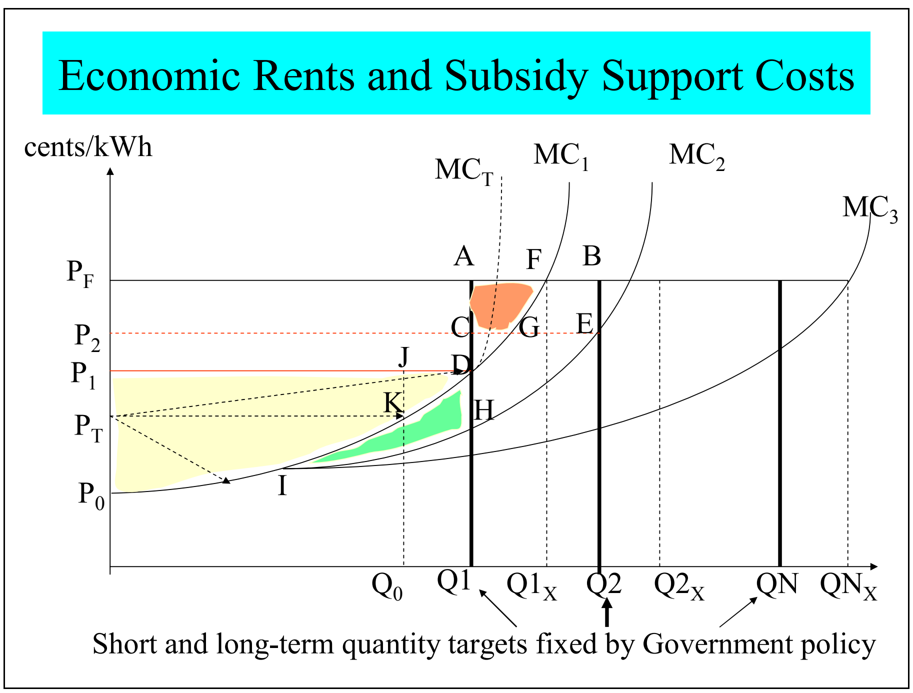
tender) or the subsidy amount (bids establish by how many MW(h) can be bought with the price support).

c. Tradable green certificates schemes can be stand-alone (wind farm revenue = electricity sales + TGC sales) or coexist with a separate CO_2-certificate market (wind farm revenue = electricity sales + TGC-sales + CO_2 sales).

Comparison of the three approaches under perfect information

A1.3 In figure A.1, Government RE policy has fixed a RE supply target of Q1 (MW or GWh) to be reached in period 1 and of QN for period N. When (i) all parties are in possession of perfect information, (ii) the transaction costs of the schemes are identical, (iii) the perceived risks are the same for investors and (iv) there is no technological progress or we look at one period only, then price-based and quantity-based schemes produce similar results. To reach the quantity Q1, the Government can either introduce a feed-in tariff of P_1 or fix a quota of Q1. The tradable green certificate (TGC) scheme leads to a market clearing "green electricity price" (market price of electricity + market price of green certificates) of P_1, which is also the "marginal quota fulfilling price" of a bidding process.

Figure A.1: Economic Rents and Subsidy Costs under Price- and Quantity-based Market Approaches



A1.4 As long as we look at one period only, the producer surplus is identical for feed-in tariff and TGC-schemes: P_1P_0D. In the real life case of pluri-annual programs with step-wise increasing penetration targets and long-term PPAs/TGC-purchases, the subsidy burden of the TGC-scheme is lower, if the supply side reacts efficiently. Let Q_0 represent the TGC market for year 1, and Q_1, the target for year 2, and let the three arrows indicate the position of the three least-cost RE projects on the RE-supply curve. In the feed-in tariff scheme, all three projects are paid the tariff P_1, and in the TGC scheme the first two projects are paid the tariff P_T. The producer surplus/subsidy cost is reduced by the rectangle P_1P_TKJ compared with the feed-in tariff scenario.

A1.5 The producer's surplus of the tender scheme depends on the pricing procedure. If all accepted bids up to the quota are paid the marginal quota fulfilling bid price, the tender scheme yields the same result as the TGC scheme: a tariff of P_T in year 1 and of P_1 in year 2. If each bidder is paid his specific bid price, the result is the average price P_T for the mandated quantity Q_1, on the "ignorant bidder assumption" that each producer bids the tariff reflecting his specific position on the supply curve. [38] The tender scheme, in that case, totally eliminates the producers' surplus.

A1.6 Thus, under perfect competition, the feed-in tariff imposes the highest subsidy burden, the "bidded price = tariff paid" variant of the tender scheme results in the lowest subsidy burden, and the TGC scheme falls in between the two.

Feed-in tariffs with variable rates according to GWh production per MW

A1.7 In order to reduce the producer surplus/subsidy cost of the feed-in tariff, in real life schemes, the "uniform tariff" is replaced by tariff rates that decline with the GWh output per MW. The variable feed-in tariff reduces the "wind resource producer surplus" of the best sites, yet still expands the market by paying wind farms located at less attractive sites a higher average rate per kWh produced. Two variants can be seen:

(i) In Denmark in the late 1990s, the high feed-in tariff was paid for the first 25,000 GWh per installed MW, after which wind farms had to sell their power into the power pool at the lower market prices.

(ii) Germany went a step further in 2003. Eligible projects are classified into three categories according to the quality of the wind resource at the project site. Wind farms located at sites having a "category 1" wind resource are paid the lowest tariff, which is valid during the first five years only. Projects at the other sites get their—higher—feed-in tariff until a defined GWh/MW production has been attained. Projects producing less than 60% of the "standard output" for a "category 3" wind resource site are not eligible for a subsidized feed-in tariff at all.

Impact of insufficient information on market size

A1.8 When information is less than perfect, policy makers may set the feed-in tariff too low to reach the quantitative target; a price of P_T results in the low quantity of Q_0. Or, the price may be set too high: the price of P_F leads to an oversupply of $Q1\text{-}Q1_X$, meaning, that a larger than expected financial burden for electricity consumers. The positive, "other side of the coin," aspect of overshooting is the fast development of the

[38] The extent of the reduction in the producer surplus depends on the extent of bidders' gaming and gambling on the outcome. In case of perfect information, the profit-maximizing "below-marginal-cost producers" would all bid a tariff just below the market clearing price and still be certain of getting their contracts.

market for wind energy, which is why policy makers who want a rapid penetration of renewable energy prefer the feed-in tariff.

Impact of regulatory voids on market size

A1.9 The tender scheme has the reputation of providing new RE supply at low-priced PPAs. However, a main reason for this is the smaller market size normally associated with the scheme: the tender scheme is primarily used by countries that are stingy with subsidies and renewable energy ambitions. The low demand from the tenders for RE allows wind farm investments to stay on the low-cost end of the supply curve, at least during the initial years; while the tender procedure enables only the least-cost projects to be implemented during early years: in order to win, projects are done in the windiest areas only. The problem with this is the high geographic concentration of projects on land, which leads to resistance by the local population in the area against the implementation of new projects.

A1.10 The tender and TGC schemes only generate their subsidy savings if the supply side is efficient, which it is not if the procedures for site approvals and construction permits are wanting. The tariff policy for RE generators is only one of five major components that together make up the regulatory framework for RE investments. As always, the chain is not stronger than its weakest link.

A1.11 Due to a near absence of adequate planning and approval guidelines for the local authorization of wind farm projects, the U.K.'s NFFO scheme resulted in a large number of "virtual reality" wind farm projects: most winning bids did not afterwards pass the local site approval process for the project; so only a fraction of approved MW were implemented. The risk of undershooting is addressed in the design of the Irish Renewables Obligation scheme: only projects having all required permits in place can bid.

A1.12 The introduction of the RO scheme in the U.K. in 2002/03 was accompanied by the publication of developer-friendly planning guidelines for regional and local authorities. Nevertheless, due to uncertainty about the fate of the scheme beyond 2012, RE projects faced difficulties in reaching financial closure, as the financial community looked unfavorably at the long-term regulatory risk.

Insufficient information and the level of the subsidy burden

A1.13 Due to the inability of planners to set the feed-in tariff at the "correct" price of P_1 for reaching the targeted quantity of Q1, the adopted tariff P_F leads in period 1 to a producer's surplus of P_0P_FAD (for quantity Q1) + AFCG (for the "overshoot quantity" $Q1Q1_X$). Compared with the TGC option, the feed-in tariff increases the subsidy cost of RE by the amount of P_1P_FAD for quantity Q1 plus an "overpayment" of ACFG for the overshoot quantity $Q1Q1_X$; a TGC scheme would in period 2 have provided the quantity $Q1Q1_X$ at the lower price of P_2.

A1.14 Overshooting (impact on market size) is one reason why feed-in tariffs gained the reputation for being expensive; the other reason is the financial burden of the high "producer surplus/incremental rent" which producers reap under the uniform (fixed price) feed-in tariff scheme.

Impact of transaction costs and risks on MCCs and type of investor

A1.15 The feed-in tariff is ideal for investors: there is no market risk, the project can be implemented any time during the year as soon as financial closure has been secured, and the formal procedure for signing the PPA with the system operator/local utility is simple. The feed-in tariff scheme, therefore, is capable of attracting a broader scope (small and large, professional project developers and ad hoc project developers, utilities and IPPs) than the tender scheme.[39] This "agent" impact is another reason for the faster expansion of the market that takes place under a feed-in tariff: due to the larger number of investors, more projects get implemented.

A1.16 The tender scheme is at the opposite end: it attracts major players only. Thus, if you want to get small projects developed as well—the situation in Germany and Denmark where small stand-alone or mini-wind farms are scattered across the countryside—the tender scheme is not the way to go.

A1.17 Due to the inclusion of small players, at identical tariffs (feed-in-tariff = PPA of tender = total price for electricity under TGC), the potential size of the market developed by a feed-in tariff scheme is larger than for the other two schemes. The assumption, usually seen in graphic analysis, that the three schemes have identical supply curves is wrong: each scheme has its own unique MC curve.[40] The higher market risks of the TGC scheme increase the cost of project finance, and consequently, the RE cost of production; whereas higher transaction costs push up the cost of production of the tender scheme. In figure A.1, MC_1 is the MC curve of the feed-in tariff scheme, while MC_T represents the MC curve for the tender scheme. The position of the two is more or less identical at the low-cost end, which are large sites located at windy locations. But the MC_T curve is steeper due to increases in transaction costs per kWh when small marginal sites are developed. Due to the higher cost of production, the least attractive sites, which are still doable under a feed-in tariff scheme, are not commercially viable under a tender scheme. The quantity, which a tender PPA-scheme can develop, if the maximum tariff is fixed at P_F, is below $Q1_X$. The characteristics of the three options are compared in table below.

Table A.1: Impact of Market Scheme on Costs of Transaction and on Risks for Investor

Type of Scheme	Transaction Costs	Investor Risk	MC-Curve
Feed-in tariff	*Low*:	*Low*: no market risk	*Low-cost*
Tradable Green Certificate	*Medium*: fees for TGC dealers and brokers; costs for negotiated long-term PPA prices or for day-to-day power pool sales	*Medium*: risk of fluctuating market prices for electricity and for TGCs	Small inward shift in position
Tender	*Medium/High:* for Government (organization and implementation of tender) and for investor (preparation of bidding documents and time in waiting for tender to take place)	*Medium/High*: risk that project implementation is delayed several years until tender prices have gone up	Small initial inward shift turning steep for marginal sites

39 The TGC scheme is in between the two on both counts.
40 The "economic cost of supply curve" is the same, the "investor cost of supply" curves are not.

Impact of technological progress on market size and producer rent

A1.18 Technological progress, shown by the outward shift of the marginal cost curve MC_1 to MC_2 and later to MC_3 in figure A.1, reinforces the strong market dynamic as well as the "additional subsidy cost" of the uniform (fixed price) feed-in tariff scheme. The increase in productivity during period 1 from MC_1 to MC_2 affects the three schemes as follows:

- In the TGC scheme, the "green electricity" price for the mandated market Q1 is reduced to P_T and the producer surplus as well as the subsidy burden is reduced by P_1P_TDH.
- In the tender scheme, the marginal bid price is reduced from P_1 to P_T, while the average bid price falls below P_T, as all bid prices now fall within the P_0-P_T range.
- In the uniform feed-in tariff scheme, the price paid to the producer is not changed. The decline in the cost of production makes a number of previously unviable wind farm sites commercially viable. This expands the wind farm market and leads to an "overshooting" beyond Q2. The producer surplus for Q1 is increased by the amount IHD, while the difference between the subsidy cost of the feed-in tariff scheme and the TGC scheme is increased by the amount P_1P_TDH.

A1.19 The above mechanism explains the high price elasticity of demand for turbines witnessed in the markets using the uniform feed-in tariff: the "explosion" of the German, Danish and Spanish markets for wind energy. Cost reductions made less attractive wind sites financially viable, expanding the scope (geographic location) and the size of the potential market. A costly, but productive, interaction took place between the demand side (reacting to cost decreases with high price elasticity) and the supply side (reacting to the economies of scale generated by the increase in demand with further cost reductions). According to the premises of "learning curve theory,"[41] the level of the impressive productivity improvements/cost reductions in wind energy technology during the 1980s and 1990s would not have been attained had Spain, Germany and Denmark not applied the fixed feed-in tariff approach.

A1.20 A side effect of the higher producer surplus was an "explosion" in the prices for the lease of land for wind turbines. A high share of the higher rent did not benefit wind farm developers, but went into the pockets of landowners and speculators, who were fast in seeing the profit opportunities created by the uniform tariff and purchased early on lease rights at low prices from owners of "windy" lands.

[41] Theory for which new technologies show a close correlation between the doubling of market size and the level of productivity improvements. In the case of wind turbines, a doubling of the world market led to a 30% decrease in the cost of production per kWh of new wind farms.

Declining scale feed-in tariff: impact on producer rent and market size

A1.21 Feed-in tariffs with preannounced declining scales each year for investments in new wind farms have two subsidy-reducing impacts: they reduce the "incremental producer rent from technological progress," and keep the annual market expansion below the level that would be reached under a fixed feed-in tariff.

A1.22 These changes, without affecting the cost of transaction and low market risk advantages of the feed-in tariff, reduce the producer rent and subsidy cost of the feed-in tariff scheme down to the low levels of the tender and TGC schemes.

A1.23 Neither the "declining scale feed-in tariff" nor the "PPA tender" come out as a clear winner if the objective is to minimize the subsidy burden per installed MW: the feed-in tariff minimizes the financial cost of production of wind farms, while the PPA tender minimizes the producer's surplus, and through this, the tariff and subsidy level.

A1.24 That the TGC scheme is gaining ground in the EU—as witnessed by the support given to the pilot RECS scheme[42] and the replacement of the NFFO in the U.K. by a TGC scheme—has little to do with any superior allocative efficiency or higher cost effectiveness of the TGC approach. It has to do with three political factors. One is the political incapability of introducing cost-effective and timely adjustments to the feed-in tariff in the three pioneer countries, Germany, Denmark and Spain: the vested interests in the existing feed-in tariff schemes were too strong. The second is the promotion by the EU Commission of the TGC scheme. The Commission never liked the feed-in tariff scheme—by reducing the amount of free competitive thermal power supply on the national markets, it limits the potential for cross-border electricity trading, the size of which is a success benchmark for the Commission's internal market policy. The third is that the TGC scheme fits better into the free-market logic of the liberalized power markets.[43]

Impact of supply side conditions

A1.25 The graphic analysis assumes that markets are efficient and have the ability to react instantaneously to changes in market conditions: at the end of the period, prices and quantities have settled at the expected equilibrium levels.

A1.26 Markets, however, need time to adjust, and the effectiveness of different schemes depends on the quality of the supply side:

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42 RECS is the "Renewable Energy Certificate System." To ensure that national systems are harmonised, built to the same standards and compatible with each other, RECS members have developed and adopted a set of rules: the Basic Commitment (BC). RECS is administered within each geographical area by an Issuing Body (IB), which is unique to this area and independent of other members of RECS. All IBs are members of the international Association of Issuing Bodies (AIB), which guarantees the compatibility and adherence to the BC of the various national certificate systems. In addition, the commercial operations of each IB are subject to peer review by the AIB

43 The initial design of the feed-in tariff in Denmark and in Germany was weak in terms of burden sharing between the distribution companies. A mandated market scheme, on the contrary, imposes the same purchase burden on all retailers, while the TGC allows the amounts to be produced by the least-cost suppliers.

- A tender scheme operating under quasi-monopoly conditions will not generate the low prices of a fiercely contested tender.
- When there is an objective short-term scarcity of green power, prices under a TGC scheme will hit the ceiling established by the "penalty-payment escape clause."[44]

Type of approach and development of the market over time

A1.27 Figure A.2 illustrates the difference in market dynamics over time of four different market schemes: (i) uniform feed-in tariff, (ii) declining scale feed-in tariff, (iii) mandated market scheme, (implemented as a TGC scheme when there are many competing retailers on the market and as a tender scheme when there is a single buyer on the bulk market), (iv) set-aside scheme, where a specific politically determined amount of renewable energy is purchased each year by a tender.

A1.28 Market development under the uniform feed-in tariff is fast, the major reason being its generous level: it must make good as well as mediocre sites commercially viable. The wind resource potential in the country is, therefore, exploited very quickly as witnessed in Denmark, where the majority of potential on-land sites have been developed. Since 2001, investment in new wind farm capacity on-land is mainly in the form of replacement of old small wind turbines by large turbines.

A1.29 Under the declining scale feed-in tariff the development of the market is more gradual. Even so, it may be less predictable and more fluctuating than the development under a mandated market scheme.

A1.30 The mandated market scheme imposes on electricity retailers the obligation to secure a fixed percentage of their supply from renewable energy systems.[45] The quota grows each year until its politically fixed plateau is reached, making contracts for new investments each year a necessity. Growth in national power demand adds further demand for annual investments in renewables.

A1.31 Under a set-aside scheme, the Government may use a fixed MW(h) quantity for new annual RE supply, or let the contracted quantity increase steadily each year. The latter case is shown in figure A.2.

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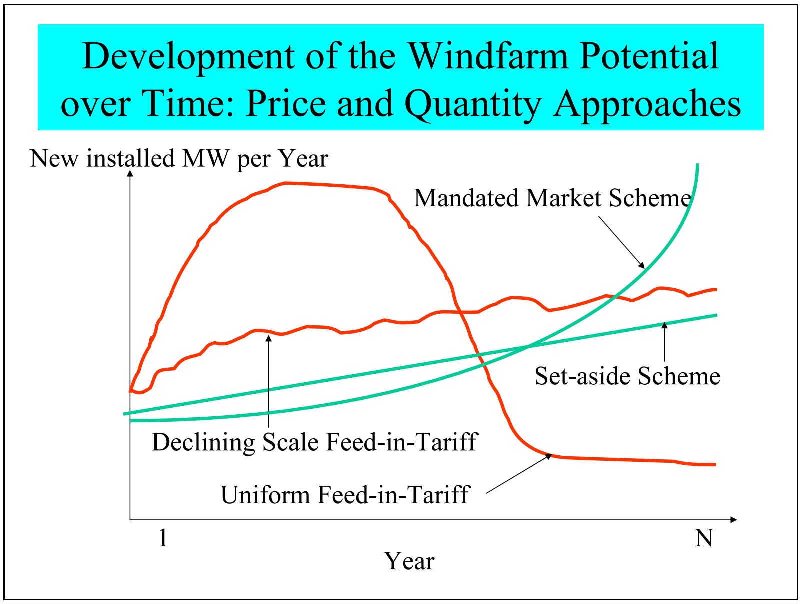
44 In the U.K., wind output was sold for as little as £0.02/kWh under the former NFFO tender scheme; under the Renewables Obligation scheme introduced in 2002, a TGC scheme, and prices hit £0.06/kWh.

45 Operators then have the possibility of generating the required amount of electricity themselves, purchasing it in the long term from a specialised renewable energy generator, or purchasing certificates for specific amounts of green electricity from other operators.

Figure A.2: Market Scheme and Profile for Market Development Over Time



A1.32 What are the economic consequences of the differences in the profiles shown in figure A.2?

A1.33 There is no doubt that the adoption of the feed-in tariff in Germany, Spain and Denmark was a major contributor to the spectacular improvements in wind farm technology during the 1980s and 1990s; none of the alternative schemes could have accelerated the technology equally fast. There are two reasons for this:

a. Other things being equal, a fast-growing market attracts more players than a slower-growing market. The scheme, in fact, provided an incredibly competitive supply side with many turbine manufacturers fiercely competing for orders.

b. The fast expansion of the international market for wind energy drove down the costs of wind energy, confirming the "rule of thumb" from learning curve theory that each doubling of market size for a new technology leads to a 30% reduction in unit costs.

A1.34 Yet, because the contribution of the domestic market of an individual country to the expansion of the international market is small—with the exception of Germany, Spain, U.S.A., Denmark, and now the U.K.—an individual country can neglect the "learning curve effects" in manufacturing. If it believes its national industry can be internationally competitive, the national market is of less importance except for providing an initially half-protected niche for building up national manufacturing capabilities.

A1.35 However, there are also drawbacks associated with being an early mover when the technology still has substantial cost reduction potential: a fast exhaustion of the national wind resource potential for wind farms leads to a large portion of installed capacity being high-cost. Wind turbines installed today will not benefit from the cost reductions which technological progress brings to later investments. Therefore, if the political target is to reach "X" MW of installed capacity by the year "Y," it pays to wait until the later years to install a large percentage of "X."

A1.36 In addition, a rapid market development has a negative impact on the capacity value of wind farms, if the speed in the growth of installed wind farm capacity is faster than expected. Wind farm capacity has a thermal power capacity replacement value only if the availability of wind farm capacity is taken into account in thermal power expansion planning. Otherwise, the impact is over-capacity in installed generation. In Denmark, for example, investments in new wind farm capacity during the 1990s had a capacity value close to zero; or, seen from a different angle, the new thermal capacity installed during the 1990s had a capacity value of zero.