4 European Low-Carbon Strategies in Liberalized Electricity Industries: Some Lessons on the Efficiency of the Market Paradigm

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Socially efficient policies for reducing the environmental footprint of a power system, from generation through to consumption, cannot be developed without taking into account the new market regime in the power industry. There are two reasons:

- In a market regime for a vertically de-integrated system, it is expected that the market price will indicate to producers in a timely way the socially efficient technological choice for generation. However, with a market regime, there tend to be significant investment risks that must be borne exclusively by producers. This discourages the development of clean and non-carbon approaches because they are more capital intensive. Accordingly, to encourage and protect investment it is necessary to implement special arrangements that violate the principles of competition, such as auctioned long-term fixed-price contracts or vertical integration.
- In energy and environmental policymaking, market-based instruments (tax, cap–and-trade instruments, or subsidies) are adopted to internalize the negative (or positive) externalities associated with each activity of the electricity chain. These are consistent with the market regime in the energy sector, as opposed to 'command-and-control' policies involving, for example, emissions norms, energy efficiency measures, closures of polluting facilities, and mandatory development of clean and green technologies. However, market instruments such as cap-and-trade tend to add price and regulatory risks to new market risks, which increases the need for special arrangements for the development of non-emitting technologies.

In contrast, a regulated utility-monopoly regime limits investment risks for producers by enabling cost pass-throughs on tariffs. It also allows programming and strong governmental coordination of generation investment based on integrated resource planning, which takes environmental externalities into consideration.

This chapter focuses on the development of climate policies in electricity industries under market regimes. Their ultimate aim is to reduce CO_2 emissions by encouraging technology shifts in centralized and decentralized generation and by improving efficiency in electricity use, spontaneously reducing the environmental footprint of an electricity system. European low-carbon strategies developed in the electricity industry under the market regime serve as an example. The case of the European Union is instructive, given that the dominant paradigm of regulation of the economy in general, and of complex industries in particular, is the market model; any other types of social coordination for long-term efficiency are perceived as a source of regulatory imperfections. It informs the European Commission and the most market-oriented member states (in particular, the United Kingdom, the Nordic countries, and the Netherlands) in the creation of new legislation for electricity markets and the formulation of environmental policies. European climate policy has been set up as a cap-and-trade regime for the large emitting industries, including electricity industries. Its goal is to design complementary measures to boost the deployment of green technologies (renewables) and promote energy efficiency in a market-oriented way (for instance, tradable green certificates rather than purchase obligations under feed-in tariffs for the renewables in electricity generation).[1]

This chapter has two purposes: to show that an institutional regime in the electricity industry is far from neutral in terms of policy efficiency and to argue that the design of a policy is as important to its social efficiency as are the theoretical principles on which it is based (for example, command and control, norms, tax and subsidy, or quotas in cap and trade). The objectives of the European energy and climate policy to 2030 are presented, followed by the electricity reforms that successive European laws (so-called directives) impose on member states and a discussion of how they contrast with Ontario reforms. This leads to an analysis of the tension between the competition regime proposed for the near future and the environmental policies that require the development of capital-intensive, clean, non-carbon facilities. Next, there is a review of the market-oriented policies implemented or under discussion by the European Union regarding CO_2 emissions reduction and the promotion of renewable production in the market environment. The chapter ends with a summary of the virtues of a hybrid regime, intermediate between the regulated utility regime and the decentralized market regime.

Prospects for the Development of Non-carbon Technologies in the European Union under Market Instruments

In the European Union, more than 50% of electricity generation is based on fossil fuel (more than 30% on coal). According to the new official scenarios of the European Commission (European Commission Directorate-General Energy and Transport 2008), the proportion of fossil fuel generation will decrease steadily with the development of decentralized renewables, large hydro resources are limited, and nuclear development is politically restricted in a number of member states. Emissions from electricity generation could increase by 70% by 2030 if no determined corrective measures are adopted.

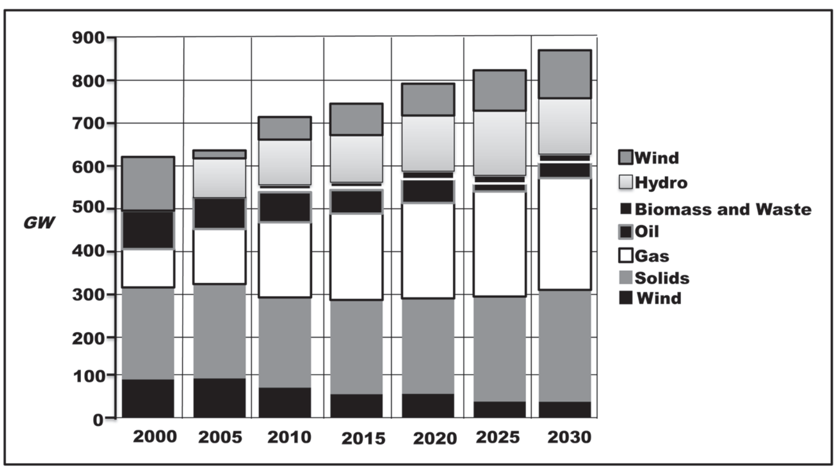
Examination of the new baseline scenario of the European Commission through 2030 (which assumes that present policies will be applied in a business-as-usual future) shows that technological changes in power generation may be important because most existing equipment will need to be replaced over the next three decades. This projection does not take into account investment risks. It assumes that capital costs are the same as before the market reform and that there is no risk aversion to investing in capital-intensive equipment; however, as noted, it incorporates political restrictions. The share of nuclear generation (15% in 2005) will drop over the projection period, reaching 10.6% in 2030 (about half of the 2000 share), owing to the incomplete replacement of units to be decommissioned and the phase-out policies followed by certain member states. Combined cycle gas technology (CCGT) will continue its penetration, attaining a share of 23.5% in 2030 because of its moderate level of carbon emissions (half of those from coal generation); steam turbines using fossil fuels (coal, gas, and fuel oil) will have a decreasing share, declining to 30% of total capacity in 2030.

However, market conditions (prices for coal being lower than those for gas and fuel oil) and emergence of supercritical, high-efficiency thermal power generation will enable the limited re-emergence of coal-based generation in the long term. European climate and energy policies could eventually rely on carbon capture and sequestration (CCS), currently in the research, development, and demonstration (RD&D) stage. A recent European Parliament report (Davies 2008) recommends that new coal equipment built after 2015 should be capture ready and that 90% of the CO_2 emissions must be captured and stored by 2025. However, this recommendation is not taken into account in the baseline scenario.

A discussion of renewable energy sources in electricity (RES-E) begins by noting that, owing to the already high exploitation of suitable sites in the European Union, hydropower capacity will expand much less than total capacity. Under the hypothesis of current policies and fuel prices, wind power is expected to grow throughout the planning period, attaining a capacity 3.6 times higher in 2030 than in 2005, which will correspond to 15% of total capacity. The generation capacity of renewable energy, including biomass and waste plants, will account for 34% of total power capacity in 2030, up from 22% in 2005. Decentralized renewable energy capacity will account for 17% of the total in 2030, up considerably from 2% in 2000. The high penetration is driven mainly by the development of wind and biomass power plants. Wind power is projected to attain a capacity of 146 Gw by 2030 (129 Gw onshore and 17 Gw offshore).

However, the 70% increase in carbon emissions in the baseline scenario (that is, without a determined climate policy) is inconsistent with the ambitious objective of reducing the total emissions of the European economy by a factor of four by 2050. In the alternative scenario, which

Figure 4.1. Power generation capacity by type of main fuel used in the EU-25 in GW



Source: European Energy and Transport – Trends to 2030 Update 2007 (May 2008) incorporates an increasingly restrictive climate policy, the goal of the European Union will be a 20% overall reduction in emissions between 2005 and 2030. The European Commission evaluated the effects of a market-oriented policy that was designed to reach this target, based on a uniform carbon price, and found that the economic position of emitting technologies in all sectors will be dramatically weakened by the increasing carbon price; it will have to increase in stages to €47 per tonne (t) of CO_2 in 2030 to reach the target.

A comparison of emitting sectors (electricity, industry, transportation, and construction) shows that the electricity industry will have to reduce its emissions by 40% in this stringent scenario because it is more flexible than are the transportation and construction sectors. Nuclear technology and clean coal technologies (CCS) will expand slightly through 2030, constrained by political restrictions and learning processes, respectively, but growth will be more significant during the period 2030–2050.

The European Commission also tested scenarios with complementary policies based on quantitative objectives in renewable energy sources (RES) development and in overall energy efficiency: 20% of the primary energy balance from renewables; 20% reduction in energy intensity. The RES objective is shared among the twenty-seven member states according to resource endowment and the level of prosperity. In electricity generation, this complementary policy increases the share of renewables from 15% in 2005 to 40% in 2030, instead of the 25% in the baseline scenario (350 Gw, instead of 170 Gw, to be installed between 2010 and 2030). It is worth noting that by boosting RES development to a higher level than that reached under the sole influence of carbon price, this policy tends to decrease the demand for CO_2 permits by emitting producers, who would be obliged to develop RES-E technologies at a higher level. Consequently, the policy focusing on RES will depress the CO_2 price that must be reached to limit overall emissions, by €3/t CO_2 in 2030.

To sum up, a European carbon policy that has an ambitious reduction goal (20% from 2005 to 2020) will be structured by market instruments that will impose an increasing carbon price. The price will have to rise progressively, reaching a high of \$50/t CO_2 by 2030, but in order to overcome barriers to the deployment of RES technologies, it will be complemented by RES policy focused on quantitative objectives (to reach specified shares of the primary energy balance and the electricity balance).

Contrast with the Ontario Carbon Policy

In Ontario, public policies dedicated to reducing the environmental impact of the electricity system are shaped by the public utility regulation culture. Environmental measures and political decisions, in particular those addressing CO_2, renewables, and energy efficiency, are not based on market-oriented instruments. Examples include

- the decision to eliminate coal generation capacity (6.4 Gw out of 34 Gw, that is, 20% of the installed capacity) before 2014;
- the program for developing new renewables production in large centralized units or small decentralized facilities (an additional 7.4 Gw by 2025);
- the development of new connections with Manitoba and Quebec to import more hydroelectricity as a replacement for emitting technologies; and
- the ambitious electricity conservation program whose target is the equivalent of 5 Gw electricity savings by 2025.

The closure of coal plants is typical of this non-market orientation. In Europe, although directives have been issued for sulphur dioxide (SO_2) and nitrogen oxides (NO_x) emissions regulation, the closure of coal generation facilities has to be encouraged by the allocation of CO_2 permits, either in the form of a free allowance with increasing restrictions or of allocation by auctions, as is the plan after 2012. This approach gives an implicit price to carbon. The market-oriented approach is based on the following logic: imposing a price on carbon affects the decision of every agent at the same time; and consumers of end products pay for the indirect impact of their consumption through the successive internalization of carbon costs along the path of production. Thus, rather than regulatory structures reflecting command-and-control decisions about specific technologies, change will be effected by decisions of decentralized agents which react to price signals after internalization of environmental costs.

Determining the Trajectory of European Electricity Market Reforms

With its successive directives on electricity markets, the European Union attempts to follow the textbook market model for a decentralized electricity market, based on the following principles:

- vertical separation of competitive and regulated monopoly activities to facilitate competition and regulation;
- horizontal restructuring to create an adequate number of competing producers and suppliers in wholesale and retail markets;
- designation of an independent system operator (ISO) to maintain network stability and facilitate competition, supported by market mechanisms for receiving offers of ancillary services (the ISO could be the owner-operator of the transmission system after the system has been completely unbundled from generation and supply activities);
- application of transparent regulatory rules to promote access to the transmission network;
- establishment of market rules for access to distribution networks and to ease competition at the retail level, after suppression of regulated electricity tariffs;
- creation of an independent regulatory agency with adequate staff and powers to implement incentive regulation and promote competition.

In addition to governmental decisions, a power exchange must be developed, either by the regulator and the ISO if it is a mandatory power exchange[2] or by private players. Its role is to facilitate hourly transactions and complement the market with financial contracts. In Europe, wholesale markets are decentralized, and power exchanges complement contractual sales. Whatever the nature of the power exchange, price setting is radically different from that of the historic tariff regulation, which was based on average cost price. Market prices are determined in hourly markets by marginal offers in order to equilibrate supply and demand on the power exchange. They are quite volatile, in particular, during peak periods.

Privatization of former public monopolies may occur after some vertical and horizontal de-integration, and preferably after market liberalization. However, in Europe, as in the rest of the world, the industrial structures of liberalized electricity markets differ significantly, especially in terms of horizontal restructuring to create an adequate number of competing generators, vertical separation of competitive businesses in generation and supply, and unbundling between the distribution network and supply.

A key issue is whether the restructuring of a country's power sector is ideologically and politically motivated, or whether it is forced upon a country by a higher authority, for instance the European Union and its member states, or the World Bank and less developed countries; the latter case often leads to a half-hearted and unstable approach. In Europe, such reforms run afoul of loyalty to public service (for example, in France and Germany) and cultural scepticism about market virtues, in particular, concerning the realization of capital-intensive, large-scale equipment programs (for example, nuclear programs in France). Differences of opinion continue to exist regarding key market design issues – for instance, the choice between a mandatory and a decentralized day-ahead market, the degree of separation of ownership of transmission and distribution network activities from competitive activities, the rules of network access, and the degree to which the industrial structure must be horizontally and vertically de-integrated.

More generally, public acceptance of reform can also be undermined by the price shocks resulting from the transition from regulated tariffs based on average costs to market prices aligned with hourly prices on the volatile power exchange, as occurred in Ontario. In a number of European countries, retail market liberalization, which was supposed to be completed by July 2007, remains severely restricted by price regulation designed to protect consumers, including even medium-sized industrial consumers, who are vulnerable to the first price hook and the effects of wholesale price volatility. Moreover, the development of systems based on an optimal mix of technologies has not been submitted to market tests, owing to overcapacity at the time of the reform. Nonetheless, given aging equipment and new investment cycles in various EU countries, reinvestment in generation is inevitable. In this context, public policies requiring capital-intensive investment and energy conservation actions on electricity demand could conflict with the decentralized market paradigm.[3]

Europe has the opportunity to learn from the U.S. and UK market culture in the design of electricity reforms and in the choice of public policy instruments compatible with the market environment. In contrast to the U.S. and Canadian federal governments, the European Union has the power to impose market liberalization on its member states even if they are reluctant because the raison d'être of the European Union is to stimulate trade and exchange among member states and to pursue economic integration in the context of political integration. Accordingly, directives and *règlements* can impose market rules on national electricity industries, such as the directives of 1996, 2003, and 2008 (European Commission 2003, 2008). The European Commission receives yearly benchmark reports that assess the state of competition in each member state (see table 4.1) and has the mandate to supervise

Table 4.1. Comparison of Horizontal Concentration in European Electric Markets

	Generators with capacity share of >5%	Capacity share of top 3 generators	Retailers with market share of >5%	Market share of top 3 retailers
Austria	5	45%	7	67%[a]
Belgium	2	96%[b]	3	53%
Denmark	3	78%	6	38%
Finland	4	45%	4	33%
France	1	92%	1	90%[c]
Germany	4	64%	3	50%
Greece	1	97%[c]	1	100%[c]
Ireland	1	97%[c]	1	90%[c]
Italy	4	69%	4	72%[b]
Netherlands	6	59%	7	48%
Portugal	3	82%	1	99%[c]
Spain	4	83%	4	94%
Sweden	3	90%	3	47%
UK	8	36%	10	42%

[a]First seven
[b]First two
[c]First one
Source: European Commission, 2005a, *Annual Report on the Implementation of the Gas and Electricity Internal Market*

the application of directives and to propose new legislation to bring competition to the level of the agreed targets.

Although the European Commission (encouraged by the precedent set by the United Kingdom and the Nordic countries) is eager to follow decentralized market principles, the directives are compromises among member states. The reluctance of major players (in particular, Germany, influenced by its two large energy companies, and France, influenced by its technocrats) has produced directives with imperfect and incomplete market rules. The fundamental issue is that the European Commission has no power to impose privatization and vertical or horizontal de-integration unless member states agree on the changes by voting for a directive, such as the new 2008 directive sanctioning the legal unbundling of the transmission system operator. In exceptional circumstances, the European Commission could act on industrial structures in the case of mergers and acquisitions, by requiring divestitures, but competition policy cannot replace industrial policy; the principles of a decentralized market model require the latter.

In fact, the European Commission has not been able to impose a decentralized model. With the support of their governments, historic operators that are now privatized can preserve vertical integration between generation and supply by maintaining ownership of all their generation assets and can also preserve most of their retail market shares, domestic, commercial, and industrial. This has been the pattern in the majority of member states; the most dynamic operators have even acquired regional companies in other member states and in the gas industry.

Nevertheless, environmental and climate policies that require capital-intensive non-emitting equipment and important technological advances, both of which could incur some risk, can be developed in this market environment. Member states that preserve historic utilities and are reluctant to reform their electricity industries could find it advantageous to install large-scale non-carbon equipment (for example, the efficient nuclear plants built by EDF in France) or to implement a costly vertical gas strategy (for example, the international gas infrastructures developed by German players RWE and E.ON in joint ventures with geopolitical players such as the Russian Gazprom).

Contrast with Ontario Electricity Reform

As opposed to member states of the European Union, Canadian provinces have nearly total sovereignty over electricity sector institutions and rules, even those concerning trade between provinces. A province like Ontario typically remains under the influence of the public utility regulation regime, so electricity reforms are subject to the effects of electoral cycles and political instability. In Ontario there has been a succession of restructuring initiatives to dismantle the vertically integrated public monopoly, resulting in a competitive generation sector and liberalizing prices (Trebilcok and Hrab 2006). However, in 2002, confronted with the first price hike three months after the effective kick-off, the government decided to abandon market liberalization. Political consensus led to the rejection of partial or total privatization of Ontario Hydro. Almost all retail prices are defined under a type of cost-of-service regulation in which prices reflect average costs, rather than marginal prices (determined by the marginal offer of the most costly plant), in an hourly market over the year.

In this institutional environment the electricity system is coordinated by the government, which undertakes programming and planning. The creation of the Ontario Power Authority, charged with system planning, rate evolution, conservation policy, and promotion of renewables, institutionalized this style of coordination. The approach reflects a lack of confidence in the ability of market mechanisms to guarantee short-term efficiency and in the prospect that decentralized decisions of players investing according to market price signals will converge with long-term policy.

Tension between Policy Objectives and the Electricity Market Regime

In a decentralized market regime the producers are supposed to bear all the investment risks, while in the old cost-of-service regulation regime the risks were borne mostly by consumers via the pass-through of costs on the tariffs. Financial investors and pure producers have a preference for technologies that facilitate good market risk management through the correlation of electricity prices to fuel costs. However, in a non-carbon project requiring large capital investment it is impossible to manage market risk in this way.

Unfortunately, the market regime may not be compatible with climate policy objectives and, more generally, with other converging energy policy goals (energy security, energy reliability, and industrial and employment policy) affected by these technologies. This raises several crucial issues: How can the development of low-carbon or non-carbon generation equipment be encouraged? Should the production of new, non-carbon facilities be taken out of the market and allowed to benefit from the security of vertical arrangements that enhance the prospects of their development? Do integrated and large-scale companies provide advantages for developing investment strategies that can converge with policy goals?

Capital-Intensive Investment in Risky Electricity Markets

Decentralized markets involve sell-side risks arising from highly fluctuating power prices in the absence of storage and from the price inelasticity of real-time demand. Specific to the power sector, these risks discourage the development of long-term hedging products and increase the reluctance of large wholesale buyers (suppliers/retailers, major consumers) to contract on a long-term basis and share investment risks with new producers.

A fundamental aspect of risk management that handicaps capital-intensive investment decisions in de-integrated electricity industries is the difficulty of anticipating the price cycle, which is highly unpredictable in terms of the time, frequency, and amplitude of price spikes in competitive electricity markets (White 2006). Prices remain close to the variable cost of the technologies of the marginal producer until the hourly demand approaches the production capacity, at which time the prices increase dramatically to high levels, reflecting a scarcity rent (for instance, €1,000 per megawatt-hour (MWh) instead of €50/MWh in baseload hours). The net revenues (power price less fuel, operating and maintenance costs) during price spikes will contribute mainly to the capital cost amortization of the new equipment over a number of cycles. Consequently, for the developer of large and costly facilities such as nuclear equipment, the synchronicity of their commissioning with upcoming price spikes will have an important impact on the financial performance of the project, whereas long construction lead times make it impossible to anticipate upcoming price spikes.

The main problems with investing in capital-intensive equipment in a market environment are risk management and financing. There are high upfront construction costs but relatively low operating costs, while for gas-fired facilities the reverse is true. Nuclear investment combines huge fixed costs with political and regulatory risks. While the investment cost per kilowatt (kW) is three to four times higher than that for the smaller, more modular CCGT technology ($2,000/kW instead of $500/kW), the size of the equipment is two to five times larger (1,000–1,600 MW compared to 300–600 MW), which means that the investment unit is ten times larger. Three-billion-dollar to four-billion-dollar projects are a challenge for electric companies with market values of twenty billion dollars or less as their stock value may be affected by the long lead-time investment and significant construction risk. In a market environment and open political system, long construction times are also a disadvantage in themselves because they increase the risk that the market environment and political circumstances will change, making the investment uneconomic before the project is completed. In comparison, CCGT plants can be licensed and built much more quickly and benefit from standardization and series effects.

Investment in clean coal plants has a cost structure and a risk profile that are intermediate ($1,000–$1,500 per kW, $1 billion for a 700 MW plant, 50% of the cost per kWh due to fuel costs). Investment costs for clean coal plants will tend to be similar to those for nuclear facilities ($2,000 per kW) if they are developed with carbon-capture devices and CO_2 sequestration.

The climate policies that are currently being adopted are intended to give an economic advantage to non-carbon equipment (new nuclear projects, renewables, and eventually CCS coal plants) by internalizing the CO_2 externality, incorporating it into the cost of competing technologies (coal and gas). However, there is a large uncertainty in the long-term CO_2 price, resulting from the choice of a cap-and-trade instrument rather than a foreseeable long-term tax, and from the low predictability of long-term objectives. Whereas the CO_2 price was expected to give clean coal a definitive advantage over coal and gas plants, in fact, the risk in the CO_2 price reduces the incentive to invest in nuclear plants and clean coal plants in the near future.

Given its advantages in terms of both capital intensity and the possibility of hedging the risk, combined cycle gas turbine (CCGT) technology appears to be unduly favoured over other investment choices at the expense of more capital-intensive equipment, such as clean coal thermal plants, large RES-E equipment (hydraulic, and wind farms), and nuclear plants. The expected levelized costs for CCGT indicate a significant advantage in the future, under the different scenarios of increasing gas price evolution and CO_2 cost internalization. Risk hedging clearly favours CCGT since its cost structure is dominated by fuel costs and since there is a correlation between fuel prices and electricity prices because a gas generation facility tends to be the marginal unit on the hourly market during the major part of the year (see below). Gas importation risks from Russia, Algeria, and other developing countries are limited by long-term contracting and the credibility stakes for their governments in the trade relations with EU member states. Investments in technologies such as coal, hydro, nuclear, and wind power, which do not benefit from these risk correlations, are more risky for producers. Producers need to allocate part of their investment risks to suppliers or large consumers through vertical arrangements (long-term contracts at a fixed price, producer-consumer consortia, or vertical integration of supply and production).

However, in the de-integrated market model, which was and continues to be the reference point for electricity reforms, these arrangements are impeded by regulation for the sake of competition (to favour entrants) or undermined by the specific characteristics of competition in the wholesale and retail markets. For example, retailers confronted by the permanent risk of customers switching off if they do not follow the changes in the wholesale market price are reluctant to commit to long-term fixed price contracts with producers.

This situation does not favour the pursuit of climate policy goals in the electricity sector. Large-scale, capital-intensive non-carbon genera-

Table 4.2. Characteristics of Costs and Risks for Different Electricity Generation Technologies

Technology	Levelized cost CO_2 price of \$0-\$30/t CO_2	Capital size per unit (millions)	Lead time	Capital cost share	Fuel cost share	CO_2 cost	Fuel price risk
CCGT (400–600 MW)	\$5.6–\$6.7/kWh	Low (\$100–\$200)	Short	Low	High	Medium	High but correlated to electricity price
Coal (2 x 700 MW)	\$4.2–\$6.6/kWh	Large (€700–€1,000)	Long	High	Medium	High	Medium but low correlation with electricity price
Nuclear (1,500 MW)	\$5.5–\$6.7/kWh	Very large (€2,000–€3,000)	Long	Very high	Low	Nil	Low
Renewables (Wind farm/ 200 MW)	\$7–\$8/kWh	Medium (€300)	Medium	Very high	Nil	Nil	Nil

Sources: Deutsch and Moniz 2003; IEA/NEA 2005.

tion technologies (nuclear, very large wind farms, coal CCS, and new hydro) tend to magnify market risks owing to their capital intensity, indivisibility, long lead times, and long life cycles. Moreover, they are penalized by problems of acceptability (CO_2 sequestration, nuclear plant siting, nuclear waste management siting, hydro siting) and regulatory and political risks. Small-scale non-carbon technologies (for example, wind power, mini-hydro, wave) face some of the same problems (capital intensity) but also encounter specific market barriers because they do not benefit from scale effects on administrative costs and political risks.

Solutions Other Than the Decentralized Market Model

Electricity producers, wholesale buyers, and consumers could normally manage price volatility if they were able to develop the contractual arrangements necessary for efficiently allocating the risks among generators, intermediaries, and consumers. Market risks could be transferred from the producers to other stakeholders (suppliers, large consumers) through long-term contracts at entry cost and eventually through options contracts. However, the reality is more complex.

The Intrinsic Difficulty of Hedging Investment with Long-Term Contracts

The decentralized market model supposes that pure producers easily protect supplier and consumer interests by hedging their own risks. 'Consumers,' that is, suppliers and large consumers, compete to buy electricity by entering into bilateral forward contracts with different generators, including new entrants, and by managing their risks through portfolio strategies on the power exchanges. Downstream, suppliers have to manage a portfolio of different types of contracts with time spans and price formulas adapted to different clientele segments, with volume risks inherent in the ability of customers to switch suppliers. They are supposed to harmonize risk management between the sourcing portfolio and the sales contract portfolio.

However, in the real world, wholesale buyers do not want to reveal their hedging strategies, which involve long-term contracts with specialized generators at fixed prices to avoid opportunity costs when the market price drops below the contractual price, and to limit the risk of losing market share. In the more concrete terms of risk management for a retailer, risks are not manageable by developing a portfolio of long-term contracts with new generators, or even by acquiring shares or buying bonds from different specialized generators, all of which are possibilities in ideal electricity and financial markets (Roques, Newbery, and Nuttall 2006). Given this problem, pure producers fail because it is difficult to establish long-term contracts at a fixed price (or an indexed price) with creditworthy buyers for developing new equipment, since retailers are averse to making long-term commitments. In the deintegrated market model, a generator cannot rely on long-term contracts to hedge its new generation investment. This could be regarded as a market barrier because of the impossibility of securing long-term revenues for new generation equipment in the pure market model.

Possible Solutions

Overcoming the difficulty of finding non-reluctant and creditworthy contractors in the long term requires a two-pronged solution. Contracts involving large consumers require capacity development in joint ventures with horizontal arrangements between associations of large consumers and producers. Retailers must either have an existing base of loyal consumers attached to historic suppliers or a remaining franchise for the supply of households (Green 2004; Newbery 2002); otherwise they must adopt Joskow's approach, which uses last-resort supplier provisions to maintain a large segment of loyal consumers (Joskow 2007), allowing retailers to pass on the price differential of their wholesale market purchase contract through their retail prices. Under these scenarios, historic suppliers will retain a large fringe of inactive consumers to which they can transfer part of the sourcing risks because these consumers have no interest in switching.

Finally, although vertical integration has been opposed by regulators, there are advantages to investing in a mix of generation layers. The vertically integrated generator controls the risks associated with asymmetrical changes in profit margins at each stage under the effect of market price fluctuations; what is lost by one unit is recaptured by another. From the perspective of the integrated supplier, this also stabilizes and secures the terms of its wholesale purchases, even if it does not completely control volumetric and price risks in resale. The advantage becomes even clearer when vertical integration is organized within a historic supplier that benefits from a large segment of core consumers, to whom some of the project and market risks can be transferred.

This suggests that imperfect market reforms which have preserved the essentials of the vertical and horizontal integration of historic utilities (aside from the unbundling of transmission systems from vertical companies) might appear to be more socially efficient than is usually presumed by liberal reformers. They allow the development of capital-intensive equipment at lower capital cost, with less risk aversion, and within the project management capability of large-scale companies.

New Risks with Market-based Policy Instruments

The next section examines problems arising from the choice of cap-and-trade instruments for non-carbon investment.

The Risk Inherent in a CO_2 Cap-and-Trade System

European governments and the European Commission have preferred to act on climate policy through a market instrument that fixes emission quantities and allows the exchange of permits to determine a carbon price rather than through imposing a carbon tax. There are two reasons: the political unacceptability of a tax and a strong belief in market virtues.[4] In 1995 a European eco-tax was promoted by the European Commission before the establishment of the Kyoto Protocol, but it failed because of opposition from a number of member states influenced by industrial groups that feared loss of competitiveness. Finally, before signing the Kyoto accord, the member states agreed on a binding strategy with a quantitative objective (−8% between 1990 and 2010), sharing the burden among them (Germany, −21%; United Kingdom, −12.5%; Spain, +15%; France, 0%). This was followed by the adoption of the cap-and-trade instrument for the large industry sector contained in the 2003 EU Emission Trading System (ETS) directive, implemented in 2005, and by the introduction of a carbon price. During the first three years, the spot market and future prices were very high (around €25–€30) until April 2006 and then retreated rapidly to very low levels when operators and speculators understood that too many permits had been issued for this period.

The use of a tax is clearly much more attractive to investors. With a cap-and-trade instrument, carbon prices are subject to market forces, and thus much of the price uncertainty is typical market uncertainty. Unauthorized banking between periods artificially increases price volatility, rendering short- and mid-term prices more chaotic. Moreover, the lack of long-term price history implies that there is no sound basis upon which to anticipate future prices. Although investors may be aware of the CO_2 policy risk, they cannot assess the risk of low CO_2 prices in the absence of meaningful historic trends for CO_2 prices. They are likely to

Box 1. Main Characteristics of the European Union's Emission Trading System during the First Two Periods (2005–2007 and 2008–2012)

Seven industrial sectors are regulated by the system: the energy and electricity industry (including the combined heat and power of self-producers' steam boilers, and coke ovens), oil refining, glass, ceramics, cement, pulp and paper, and steel production (aluminum and non-ferrous metals are excluded). The number of installations affected is around ten thousand, 65% belonging to the energy sector and 20% to the mineral industry.

The system is defined on a periodic basis: three years for the first period, and five years for all the others. The agents do not know what the target will be for subsequent periods.

Banking and borrowing of permits is not authorized between periods.

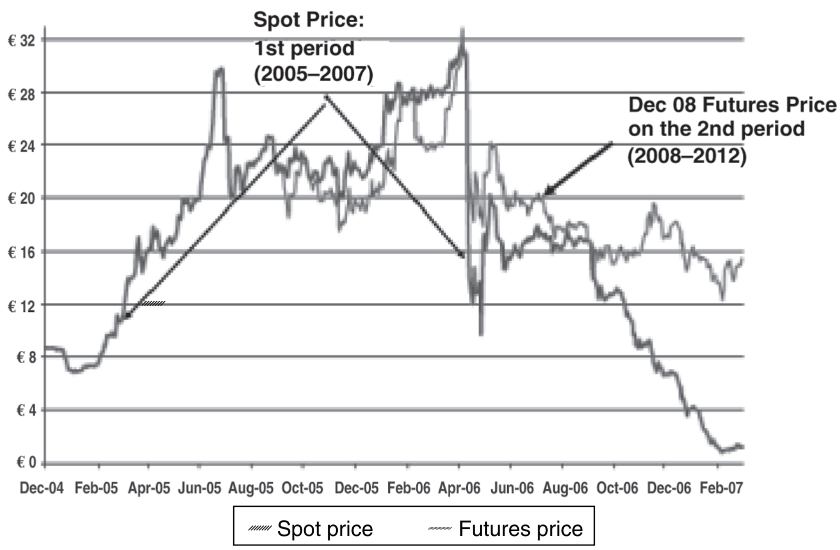
Allocation by grandfathering: the permits are free, and the allocation of permits to an industrial agent is determined according to its past emissions, decreased by a fixed reduction. There are two other rules: free allocations for new projects, and cancellation of initial allocations following plant closures. Entrants with new equipment must either buy permits on the market or benefit from special allocations from a reserve at no cost, in order to help competition.

According to the definition of national allocation plans (NAPs), member states are responsible for determining the total number of permits, based on the present emissions of each sector and on the overall objectives, which differ from one member state to another. The plans specify the target assignments by sector and the cap assignments for the installations covered in each sector. The European Commission has the power to control the definition of NAPs to limit overly generous allocations by governments under the influence of industrial companies.

In the case of non-compliance, a penalty must be paid at the end of each year, which will increase in the future (€40/tCO_2 for the first period, then €100/tCO_2).

Exchanges have been established in different countries and tend to be increasingly connected.

Figure 4.2. Volatility of the CO_2 Price during the First Three-Year Period (2005–2007) of the EU Emission Trading System, in €/tonne of CO_2



Sources: for spot price, Powernext Carbon; for December 2008 futures price, European Climate Exchange

underinvest in low-carbon technologies that could be competitive and profitable if a stable carbon price could be anticipated.

Over several decades, utility companies have seen how regulatory and policy choices determine investment outcomes. When assessing investment choices, they are guided mainly by current policy frameworks, such as the evolving electricity market regime and the European Union's ETS (Trochet, Bouttes, and Dassa 2008). Current prices, forward prices, and existing policies are the dominant drivers of investment choices, and only credible commitments to changes in these policies will affect decisions. In the absence of strong guidance, some utility companies might continue with traditional investment approaches, focusing mainly on diversification within coal and gas operations.

A cap-and-trade scheme is much more exposed to problems of learning and design than is a tax; it cannot predict the long-term carbon price, nor can it influence the competition between the main emitting technologies (CCGT, and coal plants) and non-carbon technologies (nuclear reactors, large hydroelectric power stations, large wind farms, and CCS) if it does not provide market players with carbon price foreseeability. Another source of uncertainty arises from the progressive, phased enforcement of the EU ETS, because the emissions cap cannot be predicted in the long term. Players cannot anticipate the evolutionary target or the carbon price. A third source of uncertainty is the interaction of carbon credits issued in developing countries and former Soviet bloc countries with the trading of European permits. Only credible long-term commitments to CO_2 reduction targets and rules will affect investment decisions in favour of 'clean' but more capital-intensive technologies (Ellerman et al. 2007; Ellerman and Joskow 2008).

Another critical issue is that the design of the ETS instrument has not favoured efficiency during the first period, owing to the nature of its main rules. Free allowances for new projects and cancellation of initial allowances after the closure of a facility are counter-incentives to factoring the implied carbon cost into decision making. This gives emitting technologies an added edge over least emitting technologies. Moreover, the renegotiation of quotas every five years can encourage producers to retain emitting equipment and invest in higher emission technologies to benefit from free allocations from the preceding periods. Finally, an analysis of investment in generation equipment in the European countries since 2005 shows that the ETS instrument has had no real influence on decision making; there have been few closures of old coal generation plants, some development of new coal plants in Germany and Italy, and no marked renaissance of nuclear investment even though companies are aware that the carbon price could have a trigger effect if it becomes stable in the future. The development of renewables depends upon specific instruments.

Finally, it is important to consider the redistributive effect resulting from the free allocation of permits in the electricity system, which has raised the issue of social acceptability. While they are receiving free allowances, electricity generators incorporate the carbon cost into their bids on the hourly electricity markets. Their actions are tantamount to trading in a carbon opportunity cost (that is, as if they would rather resell their permits on the CO_2 market than run their equipment). The result has been a supplementary increase in the electricity market price throughout the year because coal or gas generators are always marginal technologies on the hourly market. It has been estimated that during the first two years of the first period the major companies received a rent of around €5 billion (Pointcarbon 2008), without any real effect on investment in non-carbon generation technologies. In other sectors such as the cement industry, which are subjected to the pressure of international competition from countries without binding climate policies, the effect on price has been negligible because only the real cost of small CO_2 permits is passed through in the price of cement.

All these flaws have been widely debated in Europe. Some of them will be corrected in the directive of 2008, which defines the rules for the next period (2008–2012). In particular, it is envisaged that CO_2 permits will be allocated to electricity companies by auction in such a way that the CO_2 rent will be transferred to the public budget of the member states and not to the pockets of the electricity companies as a windfall profit. Clearly, a cap-and-trade instrument is much more complex to implement, and it tends to add new risks to the difficult job of investors. This suggests that the most straightforward way to limit the CO_2 price risk is through the design of climate policy. One approach, proposed by Ellerman and Joskow (2008) based on the lessons learned from the sulphur dioxide quota system in the United States, is a long-term CO_2 quota system, rather than a time-limited, phased quota system.

Different Strategies for Allocating CO_2 Risk Away from Producers in the Decentralized Model

Grubb and Newbery (2008) suggested limiting the price risk via a government long-term price declaration. This could be achieved in the detailed definition of the allowance mechanisms with the direct implementation of a floor on the carbon price and budget compensation for non-emitting producers.

A more radical approach would be a government guarantee of a minimum CO_2 price through long-term CO_2 contracts for each new carbon-free facility. This could be implemented through fixed-price contracts for avoided emissions, or option contracts auctioned before decisions to develop nuclear, CCS, or large renewables units (Ismer and Neuhoff 2006; Grubb and Newbery 2008). Contracts would be auctioned for emissions reductions over twenty to thirty years, and winning projects would achieve reductions at the lowest cost because they would have the lowest capital costs. The attractiveness of this approach to investors depends on the credibility of the government commitment to a long-term target price or, more concretely, on government willingness to respect the options contracts during their long time span (Helm, Hepburn and Mash 2003).

However, it is fair to say that such arrangements are not yet envisaged in any country, particularly in the United Kingdom, where the nuclear renaissance is politically accepted but only under the condition that investors will receive no public support.

Alternative Policy Instruments for the Promotion of Renewables' Electricity Units

With the focus on environmental issues, it is important to ask whether there is a need to promote renewables in situations where economic policies internalize the environmental externalities of polluting energy technologies and, in particular, the carbon cost. In principle, solutions exist that internalize the environmental effects of using fossil fuels and thus circumvent the need for specific instruments that favour renewables, such as a tax on CO_2 emissions or the cap-and-trade system. A criticism of specific policies favouring renewables is that the costs of avoiding CO_2 emissions (for example, \$100–\$150/t CO_2) could dramatically exceed the estimated social damage from CO_2 emissions (\$20–\$30/tCO_2) (see, for instance, Newbery 2003; Fischer and Newell 2008).

However, there is a fundamental difficulty in imposing a sufficiently high CO_2 tax (or stringent CO_2 quota) that would encourage the replacement of fossil fuels with renewables and technological progress: there is no guarantee that even a high price for CO_2 emissions will lead to more extensive substitution of new clean technologies for fossil fuels than will the policies directly supporting clean technologies (see, for instance, the literature reviewed in Jaffe, Newell, and Stavins 2002). The two main reasons are (1) regulatory uncertainty over the price of CO_2 (which, as mentioned above in relation to the EU ETS, could follow when the period during which the quota applies is too short) and (2) entry barriers for renewable technologies.

Accordingly, the European Union decided to act on the deployment of RES-E before establishing climate policies and the ETS covering the electricity industry. It issued a first directive in 2000, which imposed voluntary objectives on member states, requiring an average of 22% of RES-E from large hydro by 2010, up from 14% in 1997 (this means 8% from small RES-E), with some differentiation between member states based on RES potential (European Commission 2001). While the more recent EU objectives defined in January 2008 for the new directive in the so-called third energy-and-climate package are not more ambitious (22% of the electricity system, including large hydro, to be reached by 2020), the objectives will be binding on member states because the 2010 objective has not been achieved (4% from small RES-E, instead of 8%).[5]

There is a long-standing debate within the European Union between countries adopting the tradable green certificate (TGC) quotas supported by the European Commission and the most market-oriented instruments and the proponents of feed-in tariffs (FITs) based on an RES-E purchase obligation at an administered fixed price for each new unit, guaranteed over the long term (Finon and Perez 2007). See table 4.3 and appendix 4.1 for the detailed design of the instruments chosen by the EU-15 member states. The proponents of the TGC system argue that its quality market incentive will increase efficiency and that FITs have higher costs for consumers. However, both TGCs and FITs are reasonable in light of recent experience.[6]

Table 4.3. Differences in the Choice of Instruments within the European Union

Countries with feed-in tariffs	Countries with tradable green certificates / quotas
Austria	United Kingdom
Denmark	Italy
Finland	Sweden
France	Belgium
Germany	
Greece	
Ireland	
The Netherlands	
Portugal	
Spain	

Note: Among the ten new member states, only Poland has adopted tradable green certificates / quotas.

The next section describes the characteristics of the two instruments and then discusses the lessons that can be drawn from the experience of some member states in promoting RES-E via these two instruments.

Salient Features of Feed-In Tariffs and Tradable Green Certificate Systems

A feed-in tariff is an obligation to purchase electricity based on renewable energy at a fixed (fairly high) price. Both the obligation and the price guarantee extend over a long period, for example, eight years in Spain, fifteen years in France, and twenty years in Germany. The purchase obligation is restricted to distributors-suppliers in the service area and applies to all new renewable power generation units. To promote the development of a diverse set of renewable technologies, feed-in tariffs are technology specific and differ across technologies. They reflect the generating costs of a typical renewable electricity unit (including some risk premium) and are not set on the basis of the avoided generating cost of the distributor-supplier (as was the case for RES-E and CHP units before 1995). Unless the supply curves for renewable electricity are known, the quantity of renewable electricity production resulting from setting feed-in tariffs is not known ex ante.

The recovery of the extra cost of renewable electricity incurred by mandated buyers can be accomplished in three ways: an increase in the price of every kilowatt-hour sold by the distributors, subject to a purchase obligation when such distributors have a legal monopoly; compensation among competing distributors-suppliers, given that they are obliged, irrespective of their own sales, to buy all the renewable electricity produced in the area of their distribution networks; or reimbursements financed by a tax on all electricity transmitted via the national grid. In the latter case, the extra cost of renewable electricity is paid by all electricity consumers. An alternative or complement to passing on the extra cost to electricity consumers is budgetary support for mandated buyers. Budgetary support could also be given to producers of renewable electricity to limit the level of feed-in tariffs and, thus, the cost to consumers; this could be achieved either through an eco-tax and/or a value-added-tax exemption, as in the Netherlands and Denmark, or tax credits for renewable electricity production, as in the United States.

Tradable green certificate systems designate economic agents that will be subjected to a rising renewable, or green, electricity quota (typically electricity suppliers or distributors/retailers), and identify eligible technologies and installations, generally including only new installations and possibly excluding new large hydro plants and waste incineration facilities. Since the different certificate markets are very small, no banding of technologies is considered. This is a serious limitation of the instrument, requiring that additional support be provided for the other technologies.

Designated agents, referred to as suppliers, can fulfil their quotas (expressed as a percentage of each supplier's annual electricity sales, rising over time) in different ways. They can produce renewable electricity, purchase it under long-term contracts from specialized producers, or purchase green certificates from suppliers who exceed their quotas or from specialized producers who choose to sell part of their renewable electricity in the market rather than directly, under long-term contracts.

The quota is complemented by a penalty to be paid in the case of non-fulfilment. This penalty could be seen as a price cap rather than as a threat to force suppliers to meet their quotas. Rather than fulfilling his quota, a supplier may opt to pay the 'buy-out price' (the UK term) for not meeting it, which could, in extreme cases, represent the full quota. In essence, the buy-out price puts a ceiling on the cost of renewable certificates. The last characteristic of the TGC design is the reallocation of the revenue from the penalties to agents who have strictly respected their quotas, which provides an added incentive to abide by them.

Lessons from Experience

The experience of EU member states in promoting renewable electricity production is now sufficiently well documented that lessons can be drawn on how various instruments have worked in practice (Finon and Menanteau 2003; Finon and Perez 2007). Insights can be derived from the experience gained through designing and applying various policy instruments and from an analysis of what they have achieved in terms of meeting policy objectives.

The first lesson is that the influence of a particular instrument cannot be isolated from other factors that foster or hinder the development of a country's renewable electricity resources.[7] Specifically, the success of an instrument depends not only on the level of support it provides but also on the protection it offers from the risks encountered in the planning and siting procedures, and on the rules that govern the recovery of both the balancing costs for intermittent production and the cost of connecting renewable power plants to the network. For example, in 2000, France adopted feed-in tariffs as generous and predictable as those in Germany, but investment in renewable generating capacity and its performance fell far short of what was achieved in Germany. In 2006, installed wind energy capacity amounted to only around 1,700 MW in France, in contrast to 20,000 MW in Germany.[8]

The second lesson is that differences in the risks associated with support for renewable electricity largely explain why some European countries were more successful than others in increasing the share of renewable electricity. Before the difference in results can be discussed, it is necessary to explain that TGC systems incorporate far more uncertainties than do feed-in tariffs, resulting in risk aversion and higher risk premiums which suppliers, producers, and financiers must take into account when embarking on renewable electricity projects; this raises the cost of such projects. Consider the revenue characteristics of a renewable electricity project under each of the two instruments. In the case of feed-in tariffs, revenues are fairly certain because there is a guaranteed price at which production can be fed into the network. In the case of TGC systems, revenues depend on the uncertain market price of electricity and the uncertain price of green certificates; electricity price risk contains green certificate price risk. Moreover, when the production of renewable electricity is difficult to schedule, as it is for wind energy, the electricity price risk is exacerbated by uncertainties arising from the balancing costs, which, in TGC systems, are borne entirely by the producers of renewable electricity. In TGC systems, the generation of renewable electricity must observe all electricity market rules, including those pertaining to the market balancing mechanism, which ensures the reliability of the whole power system (Mitchell, Bauknecht, and Connor 2004). In contrast, under feed-in tariffs, renewable power plants do not need to supply a specified load profile, and the balancing costs fall on obligated suppliers.

Revenue risk also arises from uncertainty as to how the quota will increase over time and, in particular, uncertainty as to the level beyond which it will cease to be raised. When the quota approaches its limit, investment in additional renewable electricity generating capacity may create an oversupply of green certificates, which will then drop in price. This increases the risk involved in renewable energy projects in a TGC system and, thus, their costs.

The differences between instruments can also be discussed in the context of onshore wind installations, so far the most successful, emergent, renewable electricity technology. Table 4.4 shows that there are large differences in wind power capacity and in growth of capacity among six selected countries. We use a meaningful indicator: the per capita installed capacity (in watts per capita) in wind power facilities installed between 2001 and 2007. In Austria, Germany, and Spain (countries that offer feed-in tariffs) and in Belgium, Italy, Sweden, and the United Kingdom (countries that offer TGC systems), we can assess the efficiency of the two support mechanisms for renewable electricity. If the level of installed capacity during a period is used as a measure of the environmental effectiveness of the underlying policy, then the countries with feed-in tariffs performed much better than did the countries with TGC systems.

Austria, Germany, and Spain have applied feed-in tariffs from 1998 to the present. Combined with low administrative barriers, this stimulated a strong, continuous growth in wind energy. In contrast, in the Belgium, United Kingdom, Italy, and Sweden, the transition from a tendering system or feed-in tariffs to a TGC system created substantial

Table 4.4. Comparison of Wind-Power Capacity of Selected Member States

	Instruments	Capacity end 2000 (MW)	Capacity end 2007 (MW)	Capacity increase 2001–2007 (MW)	Increase per capita (W/capita)
Germany	FIT*	6,113	22,247	16,364	200
Spain	FIT(variant premium)	2,235	15,145	12,910	290
Italy	TGC**/quota	427	2,726	2,299	38
UK	TGC/quota	406	2,388	1,982	32
Austria	FIT	77	981	904	110
Sweden	TGC/quota	231	653	419	45
Belgium	TGC/quota	194	287	93	9

*Feed-in tariff
**Tradable green certificate
Source: European Wind Energy Association Statistics (English version)

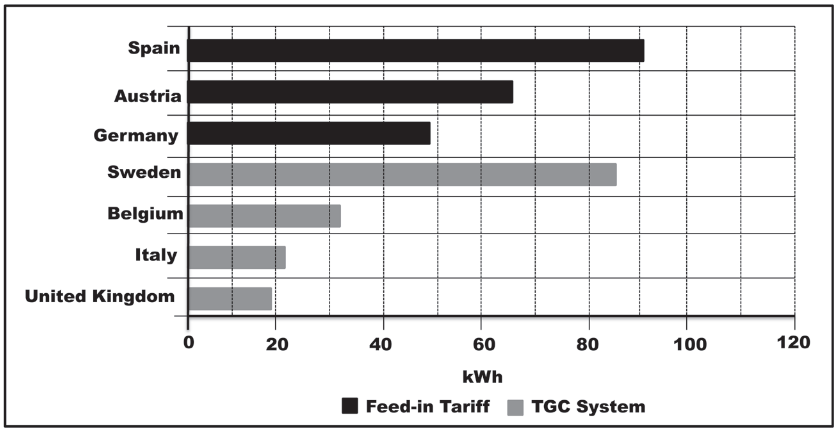
uncertainty. The indicator of installed wind-power capacity per capita shown in table 4.4 (last column) provides strong evidence for the hypothesis that TGC systems do not create an environment sufficiently secure to foster investment in renewable electricity generation.

It is often presumed that feed-in tariffs offer more generous support for renewable electricity than do TGC systems and that this explains their greater environmental effectiveness. However, the predictability of feed-in tariff support is an important factor because, from the perspective of potential producers and investors, TGC systems involve considerable risks.

One consequence is that the revenue required to induce investment in renewables is higher under TGC systems than with feed-in tariffs. Empirical support for this hypothesis comes from Butler and Neuhoff (2004), which showed that the remuneration for wind energy is higher under the UK TGC system than with the German feed-in tariffs, which are often portrayed as excessively generous. More precisely, their study showed that the remuneration for wind energy ranges from €77/MWh to €100/MWh in the British mechanism, compared to €70/MWh with Germany's feed-in tariffs. Similar evidence was provided by Ragwitz et al. (2006), which estimated expected revenues for new producers of onshore wind energy.

Figure 4.3 shows that expected revenues are much higher in countries using TGC systems than in those relying on feed-in tariffs.[9] Sweden's success results from the specificity of its TGC system, which was not

Figure 4.3. Expected Revenues (€/MWh) for Onshore Wind Energy in Selected Member-States: Feed-In Tariffs vs the Tradable Green Certificate (TGC) System



Note: Estimates reflect levelized expected revenues.
Source: Ragwitz et al. (2006)

adopted until 2003 and replaced a system that offered large tax credits and investment subsidies; Sweden's statistics include existing installations and cheap technologies using biomass (for example, combined heat and power, and co-firing) in the portfolio of eligible technologies. It is reasonable to conclude that, in practice, feed-in tariffs do not provide exceptionally high revenues to producers and that the reliability and predictability of the policy and investment environment are crucial to the successful development of the market for renewable electricity.

The third lesson to be drawn on how various instruments have worked in practice is that governments must offer investment support (soft loans, tax allowances, and subsidies) to complement TGC systems. The need for such schemes seems to be greater in the case of TGC systems, whose objective is to foster not only the most technologically and commercially advanced renewable option but also to encourage options that lag behind.

In conclusion, in light of recent experience with competing instruments adopted to promote renewable electricity, it is not surprising that strong supporters of TGC systems have become more cautious, as evidenced by the evolving position of the European Commission (European Commission Directorate-General Energy and Transport 2005, 2008). Policymakers are increasingly aware, as they should be, of the complexity of the innovation process driving renewable electricity technologies. Once they have chosen an instrument, it is incumbent upon them to signal clearly that the support mechanism will remain in place long enough to ensure an acceptable return to producers. They must also assess the risk profile inherent to an instrument and understand its effect on capital cost, especially when combined with other project risks, in particular political and administrative risks. In other words, the cost of mitigating the risk aversion of developers and investors depends on the choice of instrument.

Conclusion: The Need for Hybrid Regimes for Sustainable Development

The electricity industry in Ontario is still under the influence of the former regulatory regime, exhibiting features such as the central position of the publicly owned Ontario Power Generation, the freezing of tariffs, coordination by Ontario Power Authority auctions for long-term contracts with entrants, the programming of renewables development and demand side management savings, and the phase-out of coal generation by 2014 to meet environmental objectives. These could facilitate planning, but they do not provide incentives for efficiency through market pressures or through the internalization of environmental costs, which gives realistic price signals to electricity producers and consumers.

Ontario is contemplating market liberalization in concert with an ambitious policy of CO_2 emissions reduction, which will diminish the environmental footprint of the electricity system. However, the European experience suggests that a better strategy is to adopt a hybrid model that

Table 4.5. Comparison of Electricity Regimes and Environmental Policy Design Based on Long-Term Effectiveness

	Market model	'Cost of service' regulatory model
Effectiveness	Risk aversion and slow development of non-carbon technology	Effective programming
Effects on investment risks and costs	Market risks and regulatory risks	Risk of uneconomic decisions

Table 4.6. Comparison of Market, Regulated Utility, and Hybrid Regimes

	Market model	'Cost of service' regulatory model	Hybrid model
Industrial structure	De-integrated firms	Vertical integration and supply monopoly	Variety of firms and vertical arrangements; oligopoly
Short-term coordination	Hourly market and short-term contracts	Engineer's merit order dispatching	Vertical integration; dispatchable contractual producer and some spot transactions
Generation capacity development	Decision of decentralized players	Investment programming, regulatory authorization, and prudency reviews	Coordination by programming and auctioning; long-term fixed price contracts; industrial and load-serving entity consortia
Type of environmental policy instrument	Market-based instrument. Market-oriented (tax)	Emission standards, technology substitution programming	Compatibility with the two types of instruments
RES-E development	Market-based (exchangeable quotas)	Purchase obligation on utility and feed-in tariff	Preferably feed-in tariffs
Electricity efficiency development	Price signals are assumed efficient	Demand side management and electricity efficiency schemes	Energy efficiency obligation on suppliers

incorporates market design and vertical industrial structures. These elements do not deter investment in capital-intensive equipment, because they avoid the risks created by reliance on the short-term market for the prices of electricity and environmental goods (see table 4.6).

It would be helpful to define a hybrid model. Imperfect power industry liberalization must preserve in part the former mode of coordination of the regulated monopoly. The main function of the electricity market should be to make short-term adjustments, but efficiency incentives should be created through competition, by encouraging an entry thread and facilitating competitive pressure on imports through the integration of regional markets. To orient market players' choices towards clean and non-carbon technologies, policy instruments in a hybrid regime must require price signals for environmental goods that are foreseeable and stable over the long term. This can be achieved with an increasing carbon tax in the climate policy and a feed-in-tariff for renewables. The Ontario electricity regime seems to be open to such a vision.

Appendix

Table 4.7. Promotion Strategies for RES-E in the EU-15 Countries in 2007

			RES-E TECHNOLOGIES CONSIDERED IN EU COUNTRIES		
	Major strategy	Large hydro	Small hydro	'New' RES (Wind on- and offshore, photovoltaic, solar thermal electricity, biomass, biogas, landfill gas, sewage gas, geothermal)	Municipal solid waste
Austria	FITs	No	Renewable energy act (Ökostromgesetz) 2003. Technology-specific FITs guaranteed for 13 years for plants that get all permissions between 1 January 2003 and 31 December 2004 and, hence, start operation by the end of 2006. Investment subsidies mainly on regional level. No decision yet on follow-up support after 2004.		FITs for waste with a high share of biomass
Denmark	FITs and premiums, net metering for photovoltaic	No	Act on payment for green electricity (Act 478): Fixed premium prices instead of former high FITs for onshore wind. Tendering for offshore wind. Biomass and biogas receive FITs of €80/MWh for the first 10 years, €54/MWh for the next 10 years. Net metering for PV used for individual houses		Subsidies available for CHP plants using waste.
France	FITs	No	Up to mid-2007, FITs for RES-E plant < 12 MW (wind plants are not subject to the capacity limit) guaranteed for 15 years (PV and Hydro for 20 years). Tenders for plant >12 MW. After mid-2007, no limitation of capacity for FITs, provided that the facilities are in specific zones decided by local communities and regional administrations (Energy act of July 2005). FITs in more detail: biomass, €49–61/MWh; biogas and methanization, €75–90/MWh, including premium for energy efficiency up to €120/MW, including premium for 'methanization' up to €140/MWh; geothermal, €76–79/MWh; PV, €300/MWh (20 years) including premium (for 'integration in buildings') up to €550/MWh; sewage and landfill gas, €45–60/MWh; onshore wind,[a] €28–82/MWh; offshore wind,[b] €30–130/MWh; hydro, €54.9–61/MWh.		FIT: €45–50/MWh
Germany	FITs	Only refurbish-ment	Novelty in German renewable energy act in 2004: FITs guaranteed for 20 years. FITs for new installations (2006) in more detail: hydro, €66.5–96.7/MWh (30 years); wind,[c] €52.8–83.6/MWh; biomass and biogas, €81.5–171.6/MWh; landfill, sewage and landfill gas, €64.5–74.4/MWh; PV, €406–568/MWh; geothermal, €71.6–150/MWh.		No
Ireland	FIT	No	FITs are granted for 15 years. Tariff level (2006): wind: €57–59/MWh; landfill gas: €70/MWh; other biomass, €72/MWh; small hydro, €72/MWh.		No
Netherlands	No support system	No	FIT scheme was abolished in summer 2006 since the government expects to fulfil the 2010 target set by the European Commission without further financial support, and RES-E support costs were higher than expected.		No
Portugal	FITs + investment subsidies	No	FITs (Decree Law 33-A/2005) and investment subsidies of roughly 40% (measure 2.5 [MAPE] within program for economic activities) for wind, PV, biomass, small hydro, and wave. Average FITs in 2006: wind,[d] €74/MWh; wave: n.a.; PV,[e] €310–450/MWh; small hydro, €75/MWh.		FIT for urban waste: €75/MWh

[a]Stepped FIT: €82/MWh for the first 10 years of operation and then €28–€82/MWh for the next 5 years, depending on the quality of site.
[b]Stepped FIT: €130 /MWh for the first 10 years of operation and then €30–€130/MWh for the next 10 years, depending on the quality of site.
[c]Stepped FIT: In case of onshore wind, €83.6/MWh for the first 5 years of operation and then €52.8–€83.6/MWh depending on the quality of site.
[d]Stepped FIT depending on the quality of the site.
[e]Depending on the size: <5kW, €420/MWh; or >5kW, €224/MWh.

Table 4.7. (*Concluded*)

	Major strategy	Large hydro	RES-E TECHNOLOGIES CONSIDERED IN EU COUNTRIES Small hydro / 'New' RES (Wind on- and offshore, photovoltaic, solar thermal electricity, biomass, biogas, landfill gas, sewage gas, geothermal)	Municipal solid waste
Spain	FITs or fixed premiums	Depend ing on the plant size	FITs (Royal decree 436/2004): RES-E producers have the right to opt for a fixed FIT or for a premium tariff.[f] Both are adjusted by the government according to the variation in the average electricity sale price. In more detail (2006): wind, biomass, small hydro (<25 MW), geothermal, €68.9/MWh (fixed) and €38.3/MWh (premium); solar thermal and PV:[g] €229.8–440.4 /MWh. Agricultural and forest residues: €61.3/MWh (fixed) and €30.6/MWh (premium). Moreover, soft loans and tax incentives (according to 'Plan de Fomento de las Energías Renovables') and investment subsidies on regional level.	FIT: €53.6/MWh (fixed) or €23/MWh (premium)
			THE TGC/QUOTA SYSTEM	
Italy	TGC/Quota + FITs for PV	Included in TGC system	Quota obligation (TGC system) on electricity suppliers: 3.05% target (2006), increasing yearly 0.35% until 2008; TGC issued for all (new) RES-E (incl. large hydro and municipal solid waste) – with rolling redemption; no penalty; €12,528/MWh (2006) to purchase TGCs from the grid operator, but market distortions appear; feed-in tariff for PV and local investment subsidies from regional administrations.	Included in TGC system
Belgium	TGC/Quota + guaranteed electricity purchase	No	Federal: The Royal Decree of 10 July 2002 (in effect from 1 July 2003) sets minimum prices (i.e., FITs) for RES-E. On regional level promotion activities include – Wallonia: quota-based TGC system for electricity suppliers, increasing from 3% in 2003 to 12% in 2010. – Flanders: quota-based TGC system on electricity suppliers, increasing from 3% (no MSW) in 2004 up to 6% in 2010. – Brussels region: no support scheme yet implemented.	Included in TGC system (except Flanders)
Sweden	TGC/Quota	No	Quota obligation (TGC system) on consumers: increasing from 7.4% in 2003 up to 16.9% in 2010. For wind, investment subsidies of 15% and additional small premium FITs ('Environmental Bonus')[h] are available.	No
United Kingdom	TGC/Quota	No	Quota obligation (TGC system) for all RES-E: increasing from 3% in 2003 to 10.4% by 2010; buyout price is set at £32.33/MWh for 2005/2006. In addition to the TGC system, eligible RES-E are exempt from the Climate Change Levy certified by levy exemption certificates (LECs), which cannot be traded separately from physical electricity. The current levy rate is £4.3/MWh. Investment grants in the frame of different programs (e.g., Clear Skies Scheme, DTI's Offshore Wind Capital Grant Scheme, the Energy Crops Scheme, Major PV Demo Program, and the Scottish Community Renewable Initiative).	No

Source: Haas et al. (2008)

[f] In the case of a premium tariff, RES-E generators earn in addition to the (compared to fixed rate, lower) premium tariff the revenues from the selling of their electricity on the power market.
[g] In the case of PV, the expressed premium tariff refers to plants >100 kW. For small-scale plants (<100 kW), only a fixed FIT is applied.
[h] Decreasing gradually down to zero in 2009.

NOTES

1 With the help of different 'directives' to be transcribed in the national laws of member states, the European Union will influence national energy policies, the technological evolution of electricity systems, and the rationalization of energy use.
2 Jurisdictions can choose to create mandatory markets to optimize dispatching as in regional U.S. markets (for example, Pennsylvania-New Jersey-Maryland and New York).
3 When institutional economists consider telecommunications reforms (Levy and Spiller 1996), they must take into account the institutional and socio-political environment of an industry. The feasibility and the credibility of a competition-based reform model are different in different institutional environments. The feasibility of a reform (that is, the ability to implement it despite the influence of the losers on the decision-making process through access to the courts or the electoral rules) and the credibility of a reform (that is, the guarantee that the reform will not deviate from its course or prove abortive, and the predictability of market rules) rely on the compatibility of the characteristics of a particular reform model and the characteristics of the institutional environment of each country.
4 This choice was also supported on the basis of academic considerations of the merits of price instruments and quantity instruments (quota in a cap-and-trade), taking into account ignorance of and uncertainty in the cost curves for damage and reduction costs.

   Weitzman (1974) makes two points: A *price* mechanism is superior when the curve of marginal environmental damage is relatively flat; that is, in the case of quantitative variability, the marginal cost of damage shows little variation or uncertainty. A *quantity* mechanism is superior when the curve of the marginal cost of reduction is relatively flat; that is, when for the quantities emitted, the marginal cost of reduction shows little variation or uncertainty, which appears to be the case for the CO_2 problem.

   Pizer (2002) adds that the social efficiency of a quantity instrument in a context of uncertainty can be improved by imposing a price cap (a safety valve) and a price floor. In the first case, agents prefer to pay a buy-out price (which could also be called a penalty) rather than respect their quotas if their marginal reduction cost is high; in the second case, when the market price of the permit decreases below a threshold, the government would pay the difference. Both measures would give the carbon price a certain foreseeability.
5 In fact, the binding 20% objective also refers to the total of renewable

energies (biofuel, solar, geothermal electricity), but the detailed objectives in the official scenario amount to 22% for the RES-E.

6 Finally, after intensive debates from 1998 to 2000 before the adoption of the 2000 RES-E directive and again between 2005 and 2008 before the adoption of the 2008 RES-E directive, it was decided that the two directives should allow member states to choose their instruments without seeking harmonization throughout the TGC system.

7 There is extensive literature about the causal links between the diffusion of renewable electricity and the variation in the design and strength of policy instruments. Examples include Reiche 2005, Meyer 2003, and van Dijk et al. 2003.

8 Key obstacles to developing renewable electricity generation in France are fragmented planning procedures and problems concerning local acceptability. Effective planning procedures and network integration rules can help reduce project costs and risks, so they must be an integral part of a successful renewable energy policy. However, as is the case with renewable energy in general, the political backing they receive is no stronger than that for the underlying renewable technology. Moreover, they mirror social preferences for global environmental protection and energy security on the one hand and local environmental concerns on the other.

9 Nonetheless, the difference will probably decrease as institutional experience with the relatively new TGC instruments accumulates, but even if it does decrease, this would not reduce the risk premium associated with the production of renewable electricity under TGC systems.

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