Available online at www.sciencedirect.com
SCIENCE DIRECT®
Energy 31 (2006) 769–787
ENERGY
www.elsevier.com/locate/energy

Electricity deregulation in OECD (Organization for Economic Cooperation and Development) countries

A. Al-Sunaidy, R. Green*

Business School, University of Hull, Hull HU6 7RX, UK

Abstract

This paper discusses the spread of electricity deregulation in OECD countries since the early 1990s. England, Wales and Norway were the pioneers, but almost all OECD countries have now introduced some degree of liberalisation, and several have free entry to generation while allowing all electricity consumers to choose where they buy their power. The paper discusses some of the issues raised by competition in generation and in retailing (or supply), and the need to have appropriate regulation for the transmission and distribution systems, which will continue to be monopolies.

1. Introduction

Electricity is vital for any modern economy. Traditionally, most countries have obtained their power from vertically integrated utilities with monopolies in their service areas. Electricity prices fell in real terms for most of the industry's first century of existence, but rising fuel prices, troubled nuclear programmes and other problems led to rising prices in many countries from the middle of the 1970s. By that time, the intellectual trend in a number of countries was starting to favour deregulation as a means of improving economic performance.

In the US, the Public Utility Regulatory Policies Act (PURPA) of 1978 required utility firms to buy electricity from 'qualifying facilities' of co-generators and small power plants. In the same year, Chile set up a wholesale market pool in which generators would sell their power to retailers, and introduced a law in 1982 allowing large end users to choose their retailer and negotiate their prices freely. In 1990, the industry in England and Wales was restructured and privatised. The Electricity Pool was established as the setting for competition between generators, while the plan

* Corresponding author. Tel.: +44 1482 465 720; fax: +44 1482 466 216.
E-mail address: r.j.green@hull.ac.uk (R. Green).

0360-5442/$ - see front matter © 2005 Elsevier Ltd. All rights reserved.
doi:10.1016/j.energy.2005.02.017

was that all electricity consumers would be able to choose their supplier (retailer) by 1998. In 1991, Norway gave customers a choice of supplier and established its electricity pool, which was extended in 1996 to incorporate Sweden in what was thereafter called Nord Pool, the world's first multi-national electricity market. The Australian state of Victoria set up a pool in 1994, followed by New South Wales in 1996, the year that the Wholesale Electricity Market of New Zealand was established.

By the late 1990s, almost every US State had considered the possibility of electricity deregulation, and a number had moved to allow retail competition. California was among the most prominent, and that state's well-publicised disaster in 2000–2001 made several states that had been moving towards deregulation reconsider their policies. At the time of writing, however, there are well-functioning markets in the Pennsylvania–New Jersey–Maryland Interconnection (PJM), New York, New England and Texas, and retail competition is taking place in those states as well.

The European Union has also required its Member States to adopt a number of deregulatory policies. Some, such as the UK, Sweden and Spain, were already enthusiastic early adopters, while others seem to have complied reluctantly at best. Nonetheless, Commission Directives of 1996 and 2003 are requiring states throughout the Union to create competitive electricity markets. It is thus clear that a large number of policymakers in the OECD consider deregulation to be the best hope for achieving the dual goals of economic efficiency and security of supply.

What do we mean by deregulation? In many ways, re-regulation would be a better term, since the transmission and distribution networks continue to be natural monopolies, and are best regulated. Deregulation is therefore generally limited to the activities taking place at each end of these networks, generation and supply. It may involve liberalisation, allowing companies to enter the market in competition with the incumbents. It may involve restructuring, separating incumbent companies vertically (such as splitting transmission from generation) and/or horizontally (creating several competing generators, for example). The danger of liberalisation without restructuring is that the incumbents may have the ability to discriminate against entrants and make competition less effective. It may be limited to generation, which Steiner [1] points out is generally the first stage of reform. Many countries start by allowing entry by Independent Power Producers with long-term contracts, and creating an active wholesale market comes later in the process. Extending competition to retailing also generally comes later—a choice of retailer would be almost meaningless if generation was a monopoly, of course.

This paper considers the current state of electricity deregulation in the OECD. We adopt a thematic, rather than geographic, approach, and do not attempt to mention every country. Section 2 discusses moves to restructure generation. Various designs of wholesale markets are the subject of our third section, while the fourth section discusses changes to the regulation of the remaining natural monopoly sectors. Section five looks at the issue of separating transmission from the rest of the industry. The sixth section considers competition in supply, at slightly greater length than the other sections, since no other papers in the special issue focus on supply. We offer some conclusions in Section 7.

This paper can only act as an introduction to a large topic with an ever-increasing literature. Stoft [2] is an excellent introduction to electricity wholesale markets. Lévêque [3] considers the problems involved in regulating electricity transmission companies. Glachant and Finon [4] is a collection of papers discussing recent developments in the European electricity markets. Griffen and Puller [5] is a collection with a largely US focus.

2. Restructuring generation

The first move towards electricity deregulation was probably made by the United States. The Public Utility Regulatory Policies Act (PURPA) created a special class of non-utility generators who could build small power plants and co-generation facilities, known as 'qualifying facilities'. The utilities had to buy electricity from these QFs at their own avoided cost, a rule that should promote efficient entry decisions. In general, QFs only entered where long-term contracts were available [6] as investors were reluctant to commit their capital in return for an avoided cost tariff that could change over time. Where the contracts were too attractive, large numbers of QFs entered. To regain control of the process, some utilities offered long-term contracts, including contracts for larger plants, awarded on the basis of competitive bidding. The Independent Power Producer (IPP) was born. Today, nearly every country in the OECD allows independent power producers to build and run power stations, and IPPs are operating in many other countries around the world.

The next step was to extend the market to existing generating companies, which raises the question of whether it would be necessary to restructure the industry to ensure adequate levels of competition. In 1990, when the market known as the 'Pool' was established in England and Wales, the government-owned Central Electricity Generating Board (CEGB), which was responsible for generation and transmission, was split into three separate generation companies and a transmission company. Two of these generators, however, owned all the price-setting conventional plant, and had the ability to raise prices to undesirable levels. It took 10 years, and a lot of regulatory pressure, before the wholesale market became properly competitive [7]. The UK was the first OECD country to restructure its electricity industry, and Table 1 shows that most of the others have now followed. It gives the dates of the principal piece of legislation, which usually pre-dates the actual start of liberalisation by a year or two.

Not every country has seemed to absorb the lesson that market power can be a problem. The Spanish government, for example, allowed Endesa, the largest company, to merge with two of its smaller competitors shortly before it was privatized. Sweden, however, avoided the potential problem caused by Vattenfall's 50% share of its domestic market by uniting with Norway to form Nord Pool at the moment of liberalisation. Finland and Denmark have subsequently joined Nord Pool, and when the market is uncongested, it is generally very competitive. At times, however, congested transmission lines split the market into smaller areas, and competition within these can be limited.

As competition spread through some European countries, the European Union decided to adopt a pro-competitive framework that would bring the electricity industry within the single European market. The first directive on the internal market in electricity [8] allowed countries to choose between authorising generation—letting the market decide how much to build—and a transparent tendering procedure based on regular forecasts of capacity need. Countries did not need to create a wholesale market, as they were allowed to require generators to sell all their output to a single buyer. This had to be implemented in a way that would be equivalent to a system of third party access to the transmission system, however, so that generators could effectively sell indirectly to eligible (large) customers. In practice, only Portugal adopted the tendering procedure and the full single buyer model. A second directive [9] required all the countries to use authorisation as their primary mechanism, although tendering was allowed as a fall-back where there were worries about security of supply. Portugal is now joining with Spain to create an Iberian electricity market [10].

Table 1
Electricity liberalisation and markets

Country	Liberalisation	Electricity market	Consumption (TWh), 2002
Australia	Electricity Industry Act for Victoria (1994)	National Electricity Market (1997), Victoria Pool (1994)	196
Austria	Law of Electricity Supply (1998)	Energy Exchange Austria (EXAA) (2002)	55
Belgium	Law for the Organisation of the Electricity Market, April 29, 1999	None	79
Canada	Alberta—Electric Utilities Act (2001), Ontario—Energy Competition Act (1998)	Alberta Pool (1996) Ontario Market (2002)	487
Czech Republic	The Energy Act (2000)	Operátor trhu s elektrinou (2002)	55
Denmark	Ammendment to Danish Supply Act (1996, implemented 1998)	Nord Pool (1999 East Denmark; 2000 West Denmark)	32
Finland	Electricity Market Act (1995)	Finnish Electricity Exchange (1995)	79
France	Law No. 2000-108 (2000)	Powernext (2001)	415
Germany	Act on the Supply of Electricity and Gas(1998)	European Electricity Exchange (2000)	513
Greece	Electricity Law, 21 December, 1999	None	47
Hungary	Electric Power Act (2001)	None, but EEX used as reference	36
Iceland	Electricity Act (2003)	None	8
Ireland	Electricity Regulation Act (1999)	Trading and Settlement Market (2000)	22
Italy	Bersani Decree (1999)	Electricity Market (2004)	294
Japan	Amendments to Electric Utility Law (1995)	None	971
Korea	Act on Promotion of Restructuring of the Electric Power Industry (2000)	Korea Power Exchange (2001)	267
Luxembourg	Law of 24 July 2000 on the organisation of the electricity market	None—most power imported from neighbours	6
Mexico	IPPs allowed, no further liberalisation	None	190
Netherlands	The Electricity Act (1998)	Amsterdam Power Exchange (1999)	101
New Zealand	Energy Act and Companies Act (1992)	Electricity Market Company (1996)	36
Norway	Energy Act (1990)	Norwegian Power Pool (1991), Nord Pool (1996)	107
Poland	Energy Act 1997	Polish Energy Exchange (2000)	117
Portugal	Decree Laws 182/95, 183/95, 184/95, and 185/95 of July 27 1995.	Iberian electricity market (2004)	42
Slovakia	Law on Energy (1998)		24
Spain	Electricity Act (1994)	OMEL (1997), Iberian electricity market (2004)	218
Sweden	Law for the Supply of Electricity 10/95	Nordpool (1996)	138
Switzerland	Act defeated in 2002 referendum	None	55
Turkey	Electricity Market Law (2001)		118
United Kingdom	Electricity Act (1989),	Electricity Pool of England & Wales (1990), NETA (2001)	344
United States	PURPA (1978), Energy Policy Act (1992)	PJM (1998), ISO-NE (1999), NewYork (1999), ERCOT (2002)	3660

Sources: [1,33] and authors' research.

Further liberalisation has also taken place in the United States. The Energy Policy Act of 1992 recognised the situation of IPPs, and a number of rules from the Federal Energy Regulatory Commission have required utilities to open their transmission systems to third parties. The initiative for further steps has been left to state regulators. The states that have deregulated have done so in a variety of ways, and many states have not chosen to deregulate—particularly those that had below-average prices before deregulation. The legal basis of regulating privately owned utilities in the US meant that utilities could have blocked policies that appeared to confiscate assets, even though the aim of deregulation was to produce lower prices than cost-based regulation. The solution adopted in many states was to give the utilities one-off payments for their stranded costs—the costs of prudently incurred investments which did not appear likely to be recoverable in a deregulated market. In states such as California, this was part of a broader compact, which required the major investor-owned utilities to divest their fossil-fuelled generation plants to other companies in order to create a more competitive generation sector. The utilities then invested some of the proceeds in power plants in other states—many large utilities now have unregulated 'affiliates'.

California's restructuring turned into a disaster. For the first 4 years, or until the stranded costs had been paid off, the retail price remained regulated. A large margin between retail and wholesale prices was expected, and once the stranded costs were paid off, retail prices would follow wholesale prices, minimising risks for the retailers. In the summer of 2000, however, high demand and low rainfall reduced imports of hydroelectric power from neighbouring states. The price of gas rose, as did the price of emissions permits. Generators had far more market power in the tight market, and raised prices above even their much higher costs. The utilities, buying at prices well above their selling prices, were in an unsustainable position. Some generators may have refused to sell to them; others may have been unable to buy fuel; others may have needed repairs after intensive operation during the summer. In any case, generation could not meet demand and there were several power cuts in the first 3 months of 2001. Federal regulators intervened in a manner that seemed to make things worse, shutting down the state's main power market, and the state government started buying large amounts of electricity on long-term contracts at high prices. Prices only fell when the regulators imposed a price cap on the entire western market [11,12].

California had created electricity markets run by two separate organisations, and traders were able to manipulate the 'seams' between them. Some traders also took advantage of geography, exporting power from the state in order to re-import it at a higher price, out of the jurisdiction of state regulators. While the other factors would have produced a disaster in any case, the market design made things worse. We thus turn to market design as our next topic.

3. Making markets

In the case of electricity trade, unlike other forms of utility trading, generation must closely match demand on a continuous basis. This is due to the fact that electricity cannot easily be stored and needs to be consumed as it is produced. The results of failing to do this were seen in the numerous power failures of the summer of 2003. The system operator (SO) is therefore an integral part of the regulatory infrastructure and is inherently a natural monopoly. Due to the special nature of electricity, one single system operator is needed to control the physical operations in each area, balancing demand and supply

and coordinating with nearby areas. Liberalisation does not change this physical reality, and electricity markets must be designed around it.

The first electricity markets, in Chile and in England and Wales, were gross pools. All generators have to sell to the pool, and all consumers' demand is met from it. This can ease the SO's task, as this single market covers all the resources available to it. Indeed, in England and Wales, the Electricity Pool was based on the operating procedures and software previously used by the integrated generation–transmission board, simply using generators' price bids to replace the internal cost information previously used in deciding which plants to schedule. These bids then determined the price in each half-hour, and all of the scheduled power was traded at those prices. The prices were often volatile, but buyers and sellers could hedge their risks with contracts for differences written around the pool price, which would lock in an agreed price for an agreed volume of power. Since the schedule was drawn up a day in advance, the SO had to make many adjustments on the day, and these were cashed out at prices based on the earlier bids of the generators involved [13].

The next electricity market, the Norwegian market (now Nord Pool), improved on the first designs in several ways. First, it was a net pool, and not all electricity had to pass through it. Companies that wanted to trade outside Nord Pool still had to inform the SO of their plans, but could agree a (physical) bilateral contract with no reference to the central market's prices. Second, it had a multi-stage format. The main market ran a day in advance, but there was a second market, the regulation market, which operated close to real time. The SO would accept bids and offers in this market to keep the system in balance. The main market's trades were firm, in that a company could not change its mind about its earlier trades without being charged for the cost of unwinding them in the regulation market. Because the regulation market accepted bids until shortly before real time, however, traders could react to changes in the balance between demand and supply, helping the market to send better price signals. Third, the bids were much simpler. Bids in England and Wales had to last for 24 hours. Since a thermal unit's cost would depend on its operating pattern, which could not be predicted until all the bids were assessed, units were allowed a multi-part bid. This greatly increased the complexity of the market. Units in Nord Pool can submit a different bid for every hour, which reduces the risk that they will find themselves having an uneconomic operating pattern. Most other markets are based on simple bids which can be changed frequently.[1]

The fourth advantage of the Nord Pool system is that it is a spatial market. If there are transmission constraints between one or more of the countries in the market, or between three regions defined within Norway, then a different price is calculated on each side of the constraint, treating each side as a separate market (while taking account of the fixed amount of electricity able to pass over the constraint). This gives better signals of the value of electricity in each area, and of where investment (in generation or transmission) might be required.

Constraints within a price area still have to be handled by the SO outside the main markets, by counter-trading. This involves selling power back to a generator unable to export it, and buying more from a generator in an import-constrained area. While the generators' bids to the main markets generally determine the prices for these transactions, consumers do not receive any price signals from them.

[1] In many markets, generators can submit more than one price–quantity pair per unit. In Australia, their prices must be fixed for an entire day, but the amount of energy offered at each price can be changed from hour to hour. In Spain, generators can submit additional constraints that can over-ride the results based on the hourly bids, so that their plants do not have to run in an unprofitable manner.

The way to send the correct price signals has been known since the 1980s, and is now called 'nodal pricing' [14]. When there is a transmission constraint, there could be a separate price for every node on the grid, depending on how a change in generation or demand at that node would affect flows over the constrained link(s). Chile's pioneering market had calculated a system-wide price as if all plants were in the same place, and then calculated nodal prices by scaling this up and down to take account of marginal losses (but not constraints). The New Zealand electricity market was the first to be fully based upon nodal pricing, followed soon after by PJM in the United States. In the late 1990s, other market designs were also being adopted in the US (California's failed market split the main market operator from the SO, while Texas has a zonal market), but some of these are now moving towards nodal pricing. The Federal Energy Regulatory Commission has proposed a Standard Market Design [15] based upon nodal pricing, and is attempting to persuade the states to adopt it—the politics of state-based regulation have made this an uphill struggle.

On the continent of Europe, a number of electricity exchanges have now been established, in Amsterdam, Leipzig, and Paris, for example. Energy is traded in increasing volumes at these exchanges, but the SOs are still responsible for keeping the system in electrical balance. This means that physical traders (generators and retailers with power stations and customers, as opposed to financial traders who must reverse their trades before real time to avoid taking delivery of the power) must have their own balancing arrangements with the SO. If there is a balancing market with liquid trading, this should be no problem for an entrant. If entrants can only buy balancing services from a dominant incumbent, or if the balancing market is very thin, this may act as a barrier to entry in generation. To reduce such problems in the US, most markets are run by independent system operators, and the market cashes out any imbalance between participants' trades and their physical positions.

One key subject of current debate concerns incentives for investment in generation. Can a market that only pays for energy give generators enough revenue to make it worth their while to build new plant in time to meet demand growth? In energy-only markets with sufficient competition, prices are close to marginal cost most of the time, which means that generators typically have to cover most of their fixed costs in the few hours when demand is close to capacity and prices can rise. The problem is that prices in those hours may need to be very high if they are to produce enough revenue to encourage investment, and regulators may be under pressure to cap the prices at lower levels. If generators fear that they cannot get enough revenue from the energy market, a separate market for available capacity may be an alternative source [16].

US wholesale markets such as PJM and New England include markets for capacity, which require retailers to procure enough capacity for their expected loads (plus a reserve margin) and are intended to ensure that the capacity is there when it is needed. Following an investment boom in the late 1990s, however, some of these markets have substantial spare capacity, and prices are presently low. That would seem to be the correct economic signal, but there have been political pressures to find ways of getting higher revenues in some of these markets.[2] If accepted, that could move the capacity markets in the direction of the Spanish capacity payment, which is a fixed payment to generators, largely unrelated to the balance between available capacity and demand.

[2] Source: Conference call with market monitors, University of California Energy Institute Electricity Camp 2004, Monday 28 June.

Finally, we briefly mention the New Electricity Trading Arrangements (NETA) in England and Wales, soon to be extended to Scotland. NETA replaced the original gross Pool with a centrally designed balancing mechanism, leaving companies free to trade in any market they chose, or with bilateral partners, until shortly before real time. Once close to real time, however, only the SO can trade with generators or suppliers in order to balance the system. Unlike most real-time markets, however, NETA is based on separate cash-out prices for companies that are short of power and those that have a surplus. The gap between these prices was intended to give companies an incentive to balance their positions before real time, but in practice, the volatility of the System Buy Price which is paid by any company that is short of power has given them an incentive to try to have a surplus at all times. Since the system as a whole cannot be allowed to have a surplus of power, this has made life difficult for the SO, and the rules have been changed to reduce the spread between the two prices [17]. Furthermore, NETA is a non-spatial market, and could not adopt spatial pricing without some fundamental changes.[3] It is hard to see it as falling within the mainstream of electricity market development.

4. Regulating the wires

Electricity transmission, like all other network industries, is usually a natural monopoly. They need not be state-owned (and are not in many OECD countries), but due to the element of economies of scale associated with them, they are often regulated. In the case of network industries, competition may not safeguard the market from any excessive price increases to consumers. The natural monopoly of electricity networks may also limit entry for small generators. Generally speaking, electricity transmission in the OECD is governed by a cost-based regulation. In this case, regulated firms can earn revenues equal to their historical costs including a return on investment corresponding to cost of capital. Some countries, however, such as Italy, Norway and the United Kingdom use a price- or revenue cap regulation for electricity transmission. The regulator here sets a cap with an incentive factor X, to induce lower costs, for a specified period of time. The complexity of such regulation relies in determining the value of X over interval periods of time. As the time period between reviews becomes shorter, this 'RPI-X' or price-cap regulation becomes closer to rate-of-return regulation [18]. Table 2 shows that the majority of OECD member countries choose a cost-based pricing method to regulate the wires. The challenge is to ensure that the companies come under sufficient, but not excessive, pressure to keep their costs down.

While most countries have a single transmission company, many have a number of distribution companies. This allows their regulator to compare their costs, and can lead to more efficient regulation. Mergers between distribution companies can threaten this advantage. In Finland, for example, the Electricity Market Act of 1995 allows the regulator to block any merger that would result in a single distribution network operator having a market share of 25% [19].

Practically all OECD countries now have a (relatively) specialised regulator for the electricity sector (and perhaps some other utilities). For many years, New Zealand had adopted a policy of light-handed regulation, and used only competition law rather than sector-specific regulation. In December 2000,

[3] NETA's imbalance prices are based upon the average of many trades made by the SO in a particular direction (buying or selling), while most other markets set prices at the marginal accepted bid or offer.

Table 2
Transmission unbundling and regulation

Country	Unbundling	Third party access	Price regulation
Australia	Ownership	Regulated	Price cap
Austria	Legal	Regulated	Benchmarked cost[a]
Belgium	Legal	Regulated	Cost-based
Canada[b]	Ownership	Regulated	Cost-based
Czech Republic	Legal	Regulated	Price cap
Denmark	Legal	Regulated	Ex post
Finland	Ownership	Regulated	Ex post
France	Management	Regulated	Cost-based
Germany	Legal	Negotiated	Not regulated
Greece	Legal	Regulated	Cost-based
Hungary	Legal	Regulated	Price cap
Iceland	Legal	Regulated	Cost-based
Ireland	Legal	Regulated	Price cap
Italy	Legal	Regulated	Price cap
Japan	Accounting	Negotiated	Cost-based
Korea	Legal	Regulated	Cost-based
Luxembourg	Accounting	Regulated	Cost-based
Mexico	None	None	n/a
Netherlands	Ownership	Regulated	Price cap
New Zealand	Ownership	Regulated	Ex post
Norway	Ownership	Regulated	Revenue cap
Poland	Management	Regulated	Cost-based
Portugal	Ownership	Regulated	Cost-based
Slovakia	Legal	Regulated	Price cap
Spain	Ownership	Regulated	Standard cost[a]
Sweden	Ownership	Regulated	Ex post
Switzerland	Ownership[c]	Regulated[c]	Not known[c]
Turkey	Legal	Regulated	Revenue cap
United Kingdom	Ownership	Regulated	Price Cap
United States	Varies[d]	Regulated	Cost-based

Sources: [1,34–36], and authors' research.

[a] Benchmarked cost and standard cost are variants of incentive regulation.

[b] Data are for Ontario; some other provinces have not restructured.

[c] Unbundling and third party access are not currently required, but a law requiring them is being drafted.

[d] Most wholesale markets have an Independent System Operator.

however, the government issued a statement requiring the industry to adopt a formal system of self-regulation, with the threat of government regulation should its efforts be inadequate. Traders and network owners voted for the resulting system of self-regulation in a referendum held in April and May of 2003, but 95% of consumer groups' votes were against it. The government then established an Electricity Commission, which took over formal regulation of the industry in March 2004. Germany also relied upon its competition authority when it first liberalised its electricity sector, but with disappointing results. The German electricity companies agreed a set of negotiated rates for using the transmission system, as allowed under the 1996 European Directive on electricity liberalisation. Although this model ensures equality of treatment between incumbent's own competitive activities and those of entrants

through transmission tariffs and enforced separation of transmission from generation and supply, it may be used to discourage entry by keeping transmission tariffs high and cross-subsidizing generation in order to prevent entrants. This appears to have happened in Germany, and in July 2004, the government gave its telecommunications regulator power to regulate the electricity sector. This fitted in with the 2003 European directive, which required countries to replace negotiated third party access with a system that regulated the methodology used to calculate tariffs, if not the tariffs themselves.

We agree that a sector-specific regulator is the best approach for the electricity industry. When liberalisation starts, the regulator often faces large companies, which may still be state-owned, and lobbying to preserve their position. Since a successful electricity market is likely to require that these companies give up some of their activities to spun-off divisions or even to competitors, it would be unfortunate if such lobbying succeeded. A separate regulator is likely to be better placed to make the independent decisions required. Furthermore, electricity is an extremely complicated industry, and a specialised body is required if the relevant expertise is to be developed. Finally, competition policy generally relies on ex post responses to problems, whereas regulators have ex ante tools such as price caps, which can protect consumers from the start. For example, there were price caps on retail electricity prices in the UK until the regulator was confident that competition was sufficient to protect consumers, whereas a competition authority would have to wait until it had accumulated evidence of actual harm.

Transmission tariffs are only relevant if there is Third Party Access (TPA), so that other companies can use the transmission grid. Market openness for electricity—of a given country—could be measured by how much network access is allowed for both local and foreign IPPs in that country. While TPA is usually a regulated function due to the monopolistic nature of these networks, some countries may choose a negotiated TPA (Table 2 shows a country comparison).

Transmission access becomes most difficult to organise when more than one country is involved. There is a real danger of 'pancaking'—forcing companies to pay transmission charges to every operator whose system they use—which would make desirable cross-border trades uneconomic. Alternatively, the 'contract path fiction' meant that a company would make arrangements with a small number of system operators on the direct (or possibly indirect) route along which it wished to trade power, and could ignore the owners of neighbouring systems that would also be affected by loop flows resulting from the trade.

In Nord Pool, the issue has largely been resolved by forming an international market—where there is congestion on a national border, the market is split into areas with different prices and companies trading across the border pay (or are paid) the difference. Some other interconnectors, such as the one between Germany and the Netherlands, are the subject of regular auctions. These at least produce a market signal of the value of transmission, although since the transmission auctions take place some time before the electricity is actually traded, the interconnector price does not efficiently arbitrage the national prices on each side of it [20].

ETSO—the European Transmission System Operators' association—has been working on the issue of cross-border flows, and in particular on the issue of loop flows. The main aim has been to minimise the risk of pancaking. From March 2002, there was a single charge of €1/MW h on all cross-border flows, to be put into a fund to compensate for loop flows. This payment was abolished in January 2004 for countries in ETSO's central core, although peripheral countries still pay an export fee. ETSO still calculates compensation payments between system operators, based on the use which is made of their system for transit flows, but any payments due from core countries are made from their operators' general revenues [21].

5. Unbundling transmission

As discussed earlier, transmission wires are usually a natural monopoly. Due to the technical nature of the electrical system, transferring electricity from one side where it is generated to the side where it is consumed, there are many potential constraints on the movement of power. Such limitations can affect the price offered at each location in the grid network, and the amount of power that generators can sell, again depending upon their location. It is almost impossible for an outsider to second guess the decisions of the transmission system operator, which gives the operator a lot of scope to favour some generators and disadvantage others. It is therefore a common practice in most of the OECD countries and elsewhere that early stage reforms start with the separation of the vertically integrated activities of generation and transmission to ensure that the transmission operator has no particular incentive to discriminate between generators.

Ocaña [22] presented four approaches to separating transmission and SO activities from generation. The first two are referred to as 'behavioural measures' while the second two are 'structural measures'. *First*, accounting separation requires the utility to charge itself and others the same set of prices to use the grid, and to keep financial records that compare its costs to these revenues. *Second*, functional separation requires the utility to keep staff working on transmission, and proprietary information about the system, away from other parts of the business. *Third*, operational separation means that a separate unit is fully responsible for transmission decisions, but is still owned by the utility. *Fourth* is divestiture or ownership separation, where distinct legal entities are formed for each of the two functions, with little or no common ownership.

Different OECD countries choose different forms of separation, as shown in Table 2. For example, Denmark requires 'corporate unbundling', in practice similar to accounting separation, by creating separate legal entities for generation and transmission while keeping common ownership [22]. In Sweden, it is a legal requirement to separate generation from transmission, while in Norway and Finland, accounting and management must be separated [23].

In the UK, the transmission system is owned and operated by the National Grid Company (NGC) which is now a publicly traded company.[4] The company, however, is not allowed to perform down or upstream activities [24]. The Electricity Act 1989 obliged NGC to develop, maintain and operate the transmission system in an economic, coordinated and efficient way. However, as the UK power sector moved from a pool wholesale market to the NETA, the responsibilities of NGC changed and the company is now required to trade electricity in order to balance the market. In 1990, retailing to small consumers was bundled with distribution to the extent that the same regulatory licence covered both activities. Over time, however, the position changed, and companies were first allowed to separate distribution and supply (several sold their supply businesses to other companies) and then required to do so. All distribution businesses in the UK have now been operationally unbundled from generation and retailing.

In Italy, the Transmission System Operator (TSO) is a public company created in 1999 with the aim of operating and carrying out the required maintenance and development work of the national grid. One of the main activities of the state controlled company of Gestore della Rete di Transmissione Nazionale

[4] It was originally owned collectively by the distribution companies, through a holding company designed to ensure its independence, but its flotation in 1995 guaranteed this.

(Italy's TSO) is to deal with the concern of the interest that ENEL may have to discriminate against non-integrated rivals. The concern arises from the fact that ENEL and the transmission company are vertically integrated by ownership. The government of Italy was urged by the Energy Authority and the Antitrust Authority to separate ownership [25].

For the energy intensive economy of the Czech Republic, using 2.3 times as much energy per unit of GDP as the average in the EU, transmission is under common ownership with the CEZ a.s. Through its wholly owned subsidiary (CEPS a.s.), CEZ is the country's largest power producer with a share of 64% in the year 2000. But CEZ is not a totally privatized company. The National Property Fund owns 67% of the shares [26]. In the case of the Czech Energy Act operational since 2001, producers of over 10 MW are allowed to access the grid at regulated tariffs starting year 2003. Here, the Act specifically states that the system operator must not discriminate on access between the different generators. The SO, however, could deny access to interconnection in cases of lack of capacity or threat to system reliability [26]. It is needless to say that the SO must be closely mentioned by the regulator. Even though the Czech Electricity Transmission System (CEPS a.s.) was separated from CEZ in 1999, it is still a 100% subsidiary of the nation's main power producer CEZ. Here, it would be rather essential for CEPS to be fully separated from CEZ, in order for CEPS to take the role of a fully independent Transmission System Operator.

The European Union's first electricity directive required accounting separation, and that decisions on transmission issues were taken by managers independent of the rest of any vertically integrated companies. Its second directive went further, requiring full legal separation, but confirming that this did not require ownership separation [8,9].

6. Supply competition

The final stage in the electricity industry is retailing, or supply. Traditionally, dealing with consumers was not thought of as a distinct activity separate from distribution. Since distribution is a natural monopoly, the implication was that supply was one as well. Once the transmission network was seen as a place where competition between generators could take place, however, it became apparent that retailers could compete over the distribution network in a similar manner. This does not mean that competition in supply has to accompany competition in generation, and a number of countries have liberalised generation without liberalising supply, although it is hard to imagine effective competition in supply unless there is a market in which suppliers can buy generation.

If a policy of allowing competition in supply is adopted, a number of further choices follow. Which customers should be allowed to choose their supplier? It is commonest to start with large (mostly industrial) customers. The transactions costs of organising competition in supply are lowest (per kilowatt hour) for these customers, since they are buying large amounts, which also gives them the incentive (and ability) to make their decisions with care. If only some customers are to be allowed to choose their supplier, however, how is the line drawn? It is quite possible that customers who can choose their supplier will get better deals than those who cannot, which is likely to lead to pressure from customers left just outside the competitive arena. In many jurisdictions, the customer's maximum demand is used to determine their eligibility, but the rules for measuring this must be clear—can several consumers on a single site, or two adjacent sites owned by the same customer, add their demand to meet the threshold?

How should the customer's consumption be determined for the purposes of billing their supplier for energy? The price of electricity in the wholesale market is generally determined hourly or even half-hourly, whereas customers' meters are traditionally read once a month at most. Some large consumers had multi-rate tariffs, but this traditionally involved switching their current between a number of simple meters at pre-determined times, so that each meter measured the amount of power to be charged for at a given rate. If the supplier is to be charged for an appropriate amount of electricity on an hourly basis, something more is required. For large customers, it is cost-effective to install electronic meters that can record their consumption every hour (or half-hour) and communications equipment that can automatically send this information back to the market operators. For small consumers, the cost of similar metering equipment has generally been prohibitive,[5] and most countries use a system of profiles instead. Each customer is given a profile, which shows the typical load shape for customers of their type (e.g. household or small business), based on sampling a small number of customers with sophisticated meters. The customer's monthly metered consumption is then allocated to hours on the basis of their profiled load shape. If a customer takes 500 kWh in a month, and the profile implies that 0.3% of their consumption would come in a given hour, then their supplier will be charged for 1.5 kWh in that hour.

Should the competing suppliers sell energy or delivered electricity? In some countries, consumers continue to receive a bill from their distribution utility for the wires service, and get a second bill from the company which sells them energy. If the competing supplier sells delivered electricity, the customer receives a single bill, and the supplier must pay the distribution utility for the use of its system. To allow fair competition, this charge ought to be regulated. Similarly, the rebate that the customer gets when they buy energy from a competitive supplier—sometimes known as the 'shopping credit'—would need to be regulated to allow fair competition under the two bill system.[6]

How should the incumbent utility be regulated—assuming that it is in fact allowed to continue to supply consumers with electricity? One option is to have no regulation, and this is appropriate when the market can be regarded as properly competitive. Large customers generally have the ability and incentive to shop around, and it is usually safe to drop price regulation for these consumers soon after their market is opened to competition. Smaller consumers take longer to get accustomed to competition, on average, and so may need protection for longer. Should this take the form of a maximum price for the incumbent? If this is set too low, however, other companies may be unable to compete effectively, and competition may be stifled. The British regulator came under pressure in 1999 to scale back some proposed price cuts in order to help competition, and did so [27]. Incumbents in Texas were not allowed to undercut their regulated price during the first 3 years of retail competition unless they had lost at least 40% of their market share. If price caps are set, they need to be sufficiently flexible to allow retail prices to rise if wholesale costs rise, either by including fuel cost adjustments or the like, or by setting a series of short-term caps which do not run for longer than the period for which suppliers can hedge their purchases in the forward market.

Should there be a supplier of last resort? There need to be arrangements for customers to be continuously supplied, even if their chosen company goes out of business. When electricity suppliers

[5] Mass production and blanket installation can reduce these costs, however, and Enel of Italy is installing electronic meters, communicating through the power grid, for all of its 27 million customers.

[6] The debate in the US has generally centred on the size of the shopping credit, although it could also be framed in terms of the amount that a customer pays the distribution utility after the shopping credit, which is the equivalent of the use of system charge in the single-bill system.

have failed in the UK, other companies have so far been willing to acquire their businesses, but a regulatory backstop is a good idea. In some US states, there has been a distinction between the regulated utility's standard offer service, a continuation of its former regulated rate, and its default service, intended to be the provider of last resort. Customers who took a competitive supply would have switched away from the standard offer service, and would not be allowed to switch back to it. Should their competitive supplier go out of business (which has happened on a large scale in some states), they would have to go to the (typically less attractive) default service. This means that the utility does not suffer from

Table 3
Retail competition

	Retail market opening		Choice threshold, August 2004	Switching by consumers, 1998–2001	
	Started	Full		Large	Small
Australia	1994	n.a.	Varies by state[a]		12%[b]
Austria	1998	2001	All	20–30%	5–10%
Belgium	2000	2007	Varies by region[a]	2–5%	n.a
Canada	1996	n.a.	Varies by province		
Czech Republic	2002	2006	9 GW h		n.a.
Denmark	1999	2003	All		
Finland	1995	1997[c]	All	>50%[d]	5–10%
France	2000	2007	All non-domestic	10–20%	n.a.
Germany	1998	1998	All	20–30%	5–10%
Greece	2001	2007	1 kV	nil.	n.a.
Hungary	2003	2007	6.5 GW h		n.a.
Iceland	2003	2007	100 GW h		n.a.
Ireland	2000	2005	0.1 GW h	10–20%	n.a.
Italy	1999	2007	0.1 GW h	>50%	n.a.
Japan	2000		2 MW		n.a.
Korea			None	n.a.	n.a.
Luxembourg	2000	2007	All non-domestic	10–20%	n.a.
Mexico			None	n.a.	n.a.
Netherlands	1999	2004	All	20–30%	n.a.
New Zealand	1993	1994[c]	All	22%[e]	
Norway	1991	1991	All		
Poland	1998	2005	1 GW h	Nil	n.a.
Portugal	1999	2004	All	5–10%	n.a.
Slovakia	2002	2005	20 GW h	Nil	n.a.
Spain	1998	2003	All	10–20%	n.a.
Sweden	1996	1996[c]	All	100%[d]	10–20%
Switzerland			None	n.a.	n.a.
Turkey	2002	2011	9 GW h		n.a.
United Kingdom	1990	1999	All	>50%	30–50%
United States	1998	n.a.	Varies by state[a]		

Sources: [34,36–40].

[a] Some parts of the country have opened the market to all consumers.

[b] Data for Victoria, 2002–2003.

[c] Competition for small consumers initially based on meters.

[d] Customers who have switched or renegotiated.

[e] Data covers all customer classes, June 2003.

customers who have a one-way bet (buy from the utility when its prices are low compared to costs, buy from a competitor when the utility's prices are relatively high), but does increase the risk involved in switching away from the utility. Other countries allow customers to return to the incumbent utility on the same terms as those who have never left it, which reduces the risk in switching.

What has happened in OECD countries? Table 3 gives a summary of the extent of market opening, and the level of switching (where available). Great Britain was the first OECD country to start opening its retail markets to competition, starting in April 1990, when 5000 customers with maximum demands of more than 1 MW were allowed to choose their supplier—these customers represented about 30% of the country's electricity consumption. About two-fifths (by volume) chose a new supplier in the first year, and this proportion rose steadily. The market was opened to another 50,000 customers (20% of consumption) in April 1994 to those with peak demands of more than 100 kW. These customers also switched in large numbers, although at a slower rate than in the over 1 MW market. Price regulation was lifted in this market from the day it opened,[7] and this was an appropriate policy, although the market opening was marred by avoidable problems installing and registering meters and communications links [28].

When the time came to open the rest of the market, these problems were avoided by delaying the start in each region from April 1998 until the systems were ready, and by opening the market in stages (by post code area) to keep the number of switchers manageable at first. Five years after the last area was opened to competition, in June 1999, a majority of electricity consumers have now switched their supplier at least once, although about 10% have since switched back to the incumbent. About 80% of switchers now buy gas and electricity from the same company (the residential gas market was deregulated between 1996 and 1998), and British Gas now has the largest share of the residential electricity market. In general, British Gas and the local electricity company are not only the most expensive suppliers for gas and electricity taken together (by up to 5%), but also have the largest market shares. Marketing ability and customer familiarity seem to be more important than price.

Norway was the second OECD country to open its market to retail competition, and did so fully in 1991. To reduce transactions costs, a system of profiling was used from the start for small consumers, so that they did not need to buy expensive meters. Norway has a hydro-based market, with little intra-day price variation, which reduces the likely difference in the costs allocated via a profile and those that would be recorded by an hourly meter. Consumers face three types of contract—the traditional variable contract, which allows the retailer to change its prices each month (if it wishes to do so); fixed-price contracts which hold prices constant for a year or more, and a spot market contract which passes on the actual wholesale spot price for the period. While some customers have switched supplier, others have renegotiated their contract type while staying with their original supplier. This will have given them a rate that they prefer to their previous rate, but a renegotiation should probably be given less weight than a switch when measuring the customer reaction to competition [29].

New Zealand opened its market in two stages, in 1993 and 1994, and took the unusual step of opening the market to small consumers first, followed by larger consumers. The reason was that New Zealand had adopted a light-handed method of regulation that mainly relied on competition law rather than traditional regulation to keep prices down. Since the authorities realised that competition was likely to be stronger for large consumers than for small consumers, they wished to give the latter a head start, in

[7] Prices to customers with maximum demands of 1–10 MW were regulated (as part of a wider basket) until April 1993; customers with higher maximum demands faced unregulated prices from April 1990.

the hope that this would prevent companies from shifting costs onto the smaller consumers [30]. However, it was not until 1999 that small consumers were allowed to use profiles rather than meters, and switching became practical for them.

Australia is a federal country, and so decisions on electricity competition are mostly made by state governments. Victoria gave consumers with a maximum demand of over 5 MW a choice of supplier from December 1994. Consumers with a maximum demand of over 1 MW got a choice from July 1995, and the market was progressively opened until all consumers had a choice, from January 2002. Most of the other states have followed Victoria's lead, although not all have opened their markets to domestic consumers.

Finland opened its market for large customers in 1995, and for small consumers in 1997, although they had to buy an hourly meter before they could switch supplier. This made competition unattractive to small consumers until a system based on profiling was adopted in November 1998. Similarly, Sweden opened its entire market in 1996, when it joined the Norwegian wholesale market to create Nord Pool, but it was not until November 1999 that small consumers were allowed to choose a competitive supplier without installing an hourly meter [31].

By this time, the European Commission was advocating the benefits of electricity deregulation, and its 1996 Directive on the Internal Electricity Market included a timetable for partial market opening. Member States had to open their markets to consumers taking more than 40 GW h a year (about 26% of the EU market) from February 19, 1999. In February 2000, this threshold would fall to 20 GW h (28%), and in February 2003, it would fall to 9 GW h (33%). Belgium and Ireland were given an additional year, and Greece 2 years more, to implement the directive. Table 3 shows that all EU countries have now started to open their markets, and a number have opened them completely. A second directive, approved in 2003, has put the EU on course to open its markets for all consumers by 2007, subject to a review in 2005 [8,9].

Some Canadian provinces and American states have also adopted retail competition, starting with Alberta in 1996. Because of the federal nature of these countries, competition has been introduced in many different ways. California's reformers wanted every consumer to contribute to the industry's stranded costs (costs allowed under past regulation that were expected to exceed revenues in the competitive system). They set the shopping credit for taking a competitive retail energy supply exactly equal to the wholesale price. This left no margin for the retailers' costs, and so there was little effective competition before the reforms broke down in 2001. In Pennsylvania, Duquesne Light has lost more than 20% of its residential customers to competing suppliers, while Pennsylvania Power and Light has lost almost none—the difference can be almost entirely explained by the companies' rates. Duquesne's regulated prices were high enough for competing suppliers to undercut, while PPL had lower rates that left no margin for its rivals [16].

Few of the states that had not deregulated by the time of the California debacle did so afterwards, but one exception was Texas. This state opened a retail choice scheme for all consumers in January 2002, with 14% of residential customers, 19% of commercial and small industrial, and 35% of large industrial customers switching in the first 2 years [32]. These were typically the larger customers, so the 35% of large customers who switched actually accounted for more than 60% of this segment's load. Competitive programmes in some other states have faced problems as wholesale prices have risen, however, raising the entrant retailers' costs above the incumbents' regulated rates and driving a number of entrants out of business.

What determines the success of retail competition, and how should we measure it? Competition is not an end in itself, but a way of ensuring that customers pay no more (and no less) than they should for their

power. High switching rates may be interpreted as a sign that competition is putting incumbents under pressure to perform, but could also be evidence that the incumbents' prices have remained too high. Any correlations between prices and market shares can be complex, however. In a market where switching is difficult, incumbents may keep their prices high and still face little switching, while in another market, incumbents face a lot of switching despite low prices, because switching is relatively easy.

Nor is the level of prices itself a clear guide to the success of retail competition. If fuel input prices rise, then the price of electricity ought to rise. In the Nordic countries, the way in which retail prices adjusted to low rainfall in the autumn of 2002, and helped to reduce consumption, is seen as a benefit of competition [29]. The level of stranded costs from the past and the way in which they are recovered can affect retail prices. The clearest lessons so far are that large customers adapt most easily to retail competition, that many domestic customers will gradually do so, but that they must not be expected to acquire expensive meters if competition is to work.

7. Conclusion

While different countries have had different motives for restructuring the electricity supply industry, the fact remains that the deregulation wave has swept across most of the OECD. The OECD has a diverse range of policies and experiences, including good practice and bad. The countries all differ in detail, but there are some common themes in the process of successful reform. These include the need to ensure that the system operator is fully independent, typically by unbundling transmission from generation. Successful competition requires a suitable market structure, without dominant companies. The natural monopoly segments require an independent regulator, who can also act to promote competition in the other parts of the industry. Finally, we should point out that the impact of liberalisation on the long-term issues of investment and security of supply has not yet been fully resolved.

Acknowledgements

We would like to thank C.K. Woo for encouragement and helpful comments, and Toru Hattori, Scott Rogers, and participants at the SESSA conference on EU Electricity Enlargement, Technical University of Berlin, for providing information, subject to the usual disclaimer.

References

[1] Steiner F. Regulation, industry structure and performance in the electricity supply industry. OECD Econ Stud 2001;32: 143–82.
[2] Stoft SE. Power system economics: designing markets for electricity chichester. Chichester: Wiley; 2002.
[3] Lévêque F. Transport pricing of electricity networks. Dordrecht: Kluwer; 2003.
[4] Glachant J-M, Finon D, editors. Competition in European electricity markets: a cross-country comparison. Cheltenham: Edward Elgar Publishers; 2003.
[5] Griffen J, Puller S. Electricity deregulation: where to from here? Chicago: The University of Chicago Press; 2005.
[6] Gilbert RJ, Kahn EP. US Electric power regulation. In: Gilbert RJ, Kahn EP, editors. International comparisons of electricity regulation. Cambridge: Cambridge University Press; 1996.

[7] Newbery DM. Electricity reform in Britain: the quest for a satisfactory wholesale market design. Energy J, in press.
[8] European Commission. Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity. Brussels: Commission of the European Communities; 1996.
[9] European Commission. Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC. Brussels: Commission of the European Communities; 2003.
[10] Crampes C, Fabra N. The Spanish electricity industry. Energy J; in press
[11] Joskow PL. California's electricity crisis. Oxford Rev Econ Policy 2001;17(3):365–88.
[12] Blumstein C, Friedman L, Green RJ. The history of electricity restructuring in California. J Ind Competition Trade 2002; 2(1/2):9–38.
[13] Green RJ. Markets for electricity in Europe. Oxford Rev Econ Policy 2001;17(3):329–45.
[14] Schweppe FC, Caramanis MC, Tabors RD, Bohn RE. Spot pricing of electricity. Boston: Kluwer; 1988.
[15] Federal Energy Regulatory Commission. Notice of proposed rulemaking, docket No. RM01-12-000, issued July 31, 2002 (the 'Standard Market Design'). Washington, DC: Federal Energy Regulatory Commission; 2002.
[16] Joskow PL. The difficult transition to competitive electricity markets in the US. In: Griffen J, Puller S, editors. Electricity deregulation: Where to from here?. Chicago: The University of Chicago Press; 2005.
[17] Green RJ. Spot and contract markets for electricity. Oxford Rev Econ Policy 2005;21(1).
[18] Gonenc R, Maher M, Nicoletti G. The implementation and the effects of regulatory reform: past experience and current issues. OECD Econ Stud 2001;32:11–98.
[19] OECD. Regulatory reform in Finland; enhancing market openness through regulatory reforms. Paris: Organisation for Economic Cooperation and Development; 2003.
[20] Neuhoff K. Integrating transmission and energy markets mitigates market power, working paper CMI EP17. Cambridge: CMI Electricity Project; 2003.
[21] ETSO. CBT mechanism. Brussels: European Transmission System Operators; 2004.
[22] Ocaña C. Competition in electricity markets. Paris: OECD and the International Energy Agency; 2001.
[23] Amundsen ES, Bergman L. Will cross-ownership re-establish market power in the Nordic power market? Energy J 2002; 23(2):73–95.
[24] OECD. OECD reviews of regulatory reform. Regulatory reform in the United Kingdom. Gas and electricity and the professions. Paris: Organisation for Economic Cooperation and Development; 2002.
[25] OECD. Regulatory reform in Italy: regulatory reform in electricity, gas, and railroads. Paris: Organisation for Economic Cooperation and Development; 2001.
[26] OECD. Czech Republic: regulatory reform in electricity, gas, road and rail freight. Paris: Organisation for Economic Cooperation and Development; 2001.
[27] Littlechild SC. Electricity regulation. In: Vass P, editor. Regulatory review 2000/2001. Bath: Centre for the Study of Regulated Industries; 2000.
[28] Green RJ. Restructuring the electricity industry in England and Wales. In: Griffen J, Puller S, editors. Electricity deregulation: where to from here?. Chicago: The University of Chicago Press; 2005.
[29] von der Fehr N-H, Amundsen E, Bergman L. The Nordic market: signs of stress? Energy J; in press.
[30] Ministry of Economic Development. Chronology of New Zealand electricity reform. Wellington: Ministry of Economic Development; 2002.
[31] Bowitz E, Bye T, Rosnes O, Vennemo H. The Nordic electricity reform: economic and environmental consequences, working paper 3/00. Oslo: ECON Centre for Economic Analysis; 2000.
[32] Texas PUC. March 2004 report card on retail competition. Austin: Public Utility Commission of Texas; 2004.
[33] US EIA. Energy international annual. 2002 ed. Washington, DC: US Energy Information Administration; 2002. See also: http://www.eia.doe.gov/emeu/iea/elec.html.
[34] International Energy Agency. Energy policies of IEA countries. Paris: International Energy Agency; 2001.
[35] OECD. International regulation database. Paris: Organisation for Economic Cooperation and Development; 2000.
[36] European Commission. Third benchmarking report on the implementation of the internal electricity and gas market. Brussels: Commission of the European Communities; 2004.

[37] European Commission. Second benchmarking report on the implementation of the internal electricity and gas market. Brussels: Commission of the European Communities; 2002.
[38] Essential Services Commission. Review of effectiveness of retail competition in gas and electricity: public draft report of 30 March 2004. Melbourne: Essential Services Commission; 2004.
[39] Ministry of Economic Development. Electrical prices and retail competition. Wellington: Ministry of Economic Development; 2004.
[40] Burdett M. Old habits die hard for the CEECs. News feature on the Platts web site; 3 June 2004. See also: http://www.platts.com/Electric%20Power/Resources/News%20Features/EU%20Accession%20Members/