Privatization of the Electric Power Industry of the United Kingdom

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The Structure and Ownership of the UK Electricity Business Prior to Privatization

Prior to privatization, electricity in the United Kingdom was generated under monopoly by the Central Electricity Generating Board (CEGB). The CEGB was a vertically integrated, government-owned utility encompassing generation and transmission. The distribution of electricity, on the other hand, was assured through 12 so-called "Regional Area Boards." The pre-privatization structure of the CEGB is shown in Figure 1, where the CEGB's central role in generation and transmission is clearly visible, as is that of the non-overlapping, and thus non-competing, regional area boards in the case of distribution.

Electricity production by source, for selected years prior to privatization, is outlined in Table 1. As the information in this table makes clear, the British system was heavily dependent on thermal generation, which accounted for more than 70% of electricity production in the years preceding privatization. Over the same period, nuclear accounted for about 20% of production, while hydro sources were of relatively minor importance. Finally, the UK system had a total installed capacity of 65,800 MW in 1989, the last full year prior to privatization.

Table 2 reports 1988 data on generating plants compiled by the CEGB. As with most electricity-generation systems with ready access to both nuclear technology and natural gas reserves, the construction and fixed operating costs of nuclear capacity far exceeded that of gas turbines (here, by a factor of five on a £ per kW basis). Nuclear, however, had a clear advantage when it came to fuel costs: these were one-tenth the levels of gas turbines, on a

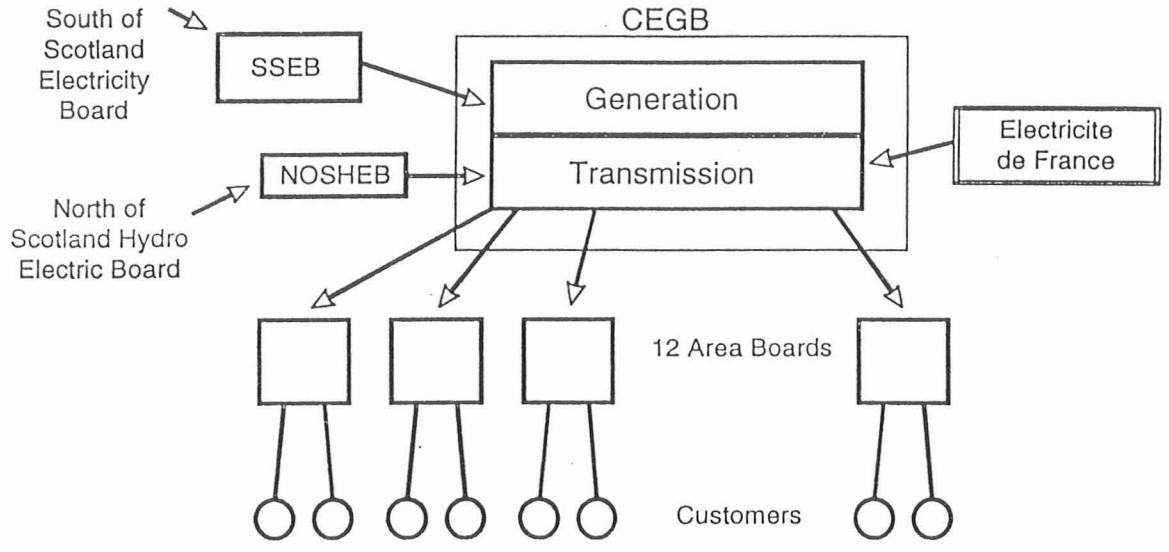

Figure 1: Pre-Privatization Structure of the UK Electricity Industry

Table 1: UK Electricity Production Prior to Privatization (TWh)

	Total	Thermal	Nuclear	Hydro
1985	280	205	50	3
1989	293	209	59	3
1990	300	219	55	4

Source: *Energy Business Review* (1991)

£ per MWh basis. Coal-fired plants, on the other hand, presented a more mixed offering: while construction costs per unit of capacity were about 60% of those associated with nuclear, both fixed operating and fuel costs were higher than nuclear's (unit fuel costs, for example, were more than twice as high for coal as for nuclear, but were still about one-fourth those associated with gas turbines).

Prior to privatization, the industry provided lower prices to large power consumers under the "Large Industrial Customer Scheme" (LICS). At the same time, subsidies were also provided to British coal production in two ways. Coal was guaranteed a minimum annual supply contract to the UK's coal-fired plants, and prices paid for British coal were considerably above world-equivalent levels.

Table 2: UK Electric System – Summary of Plant Data Prior to Privatization[1]

	Nuclear	Coal[2]	Gas Turbine
Construction (£/kW)	1260	770	240
Interest During Construction (yrs)[3]	4.2	3.2	1.9
Plant Size (MW/station)	1175	2 x 900	250
Availability (initial 5 yrs)	62%	60%	90%
Availability (thereafter)	75%	75%	90%
Economic Life (yrs)	40	45	45
Fixed Operating Costs (£/kW/yr)	19.6	23	3
Fuel Costs (£/MWh)	4.5	11	45

1/ Data based upon Hinkley Point C Evidence (Jenkin 1989).

2/ Based upon an imported coal price scenario (with the assumption being that British coal prices will converge to international prices by 1995) of US $50 per tonne, delivered to the UK in 1995 (converted at an exchange rate of US $1.7/£ to give a fuel cost of £11/MWh and increasing at 1% per year thereafter)

3/ Number of years during the construction period for which interest is applied to the capital cost (at the specified discount rate)

Source: CEGB (1990, p. 20)

Structure of the UK Electricity Business after Privatization

A 1988 government with paper entitled: "Privatizing Electricity" began the process of privatizing the CEGB. The *Electricity Bill* was passed in July 1989, and the new privatized industry was formed on April 1, 1990. A major policy objective identified at the time was to introduce private ownership and competitive pricing of generation into the British electricity supply industry, while maintaining the operational efficiency of a large integrated transmission and distribution system with centralized dispatching.

Proponents of the change in ownership structure cited a number of benefits of privatization and the associated introduction of a competitive electricity supply market. They argued that the resulting change in structure would:

- provide a source of funds to reduce government debt through the sale of assets;
- encourage "popular capitalism," whereby shares would be offered to the general public ("share shops");
- improve the operational efficiency of the electricity industry;
- yield a more competitive power supply, and hence reduce prices to end users through innovation and greater discipline;
- assist in the development of an exportable national industry;
- increase opportunities for employees of privatized companies of securing more diversified, fulfilling and rewarding jobs; and finally,
- improve the quality of customer service.

As the government proceeded with the privatization, the UK electricity industry was transformed, and its new structure is presented in Figure 2. National Power and PowerGen were sold in 1991 by share offerings to the public and to institutional an foreign markets. Potential investors were allowed to apply only for a combined minimum purchase of 186 shares of National Power and 114 shares of PowerGen. Initially, 17.1% of the two companies was offered to the general public and an additional 12.6% was earmarked for the public, if demand warranted. In the end, all of these shares were indeed purchased by the public; the government retained a 40% equity position in the two companies, while the remaining shares were picked up by institutional and foreign investors.

The government also sold South of Scotland Electricity and North of Scotland Hydro Electric (see Figure 1; these companies are now known as "Scottish Power" and "Scottish Hydro Electric," respectively) and all 12 regional area boards (now called "regional electricity companies"–RECs), but retained 100% of Nuclear Electric. As Table 3 shows, total proceeds to the government of these asset sales reached £10.2 billion (approximately CDN $21.9 billion at 1994 prices).

Power Generation Structure

Since privatization, Nuclear Electric (and other non-fossil generation) is subsidized through a fossil fuel levy on all sales of electricity. The levy was initially set at 10.6%, raised to 11% and then reduced to 10% by April 1993. Current plans call for this levy to be phased out by April 1, 1998.

As Table 4 makes clear, prior to privatization, National Power and PowerGen had 48% and 30% of the market, respectively. Nuclear Electric had 16.5%. By March 1995, new independent generators had secured a 7.4% market share, National Power and PowerGen's market shares had fallen to 33.9% and 25.9%, respectively (a 23% drop), while Nuclear Electric's share had increased to 22.3% (a 35% increase). (Note that Scottish Power and Scottish Hydro Electric are included under "Interconnectors.")

Even in the post-privatization world, the activities of generators are constrained by their relationship with the Electricity Pool of England and Wales (the "Power Pool"), whose role is summarized in Figure 3. All generators of over 50 MW must be licensed and sell their power into the Power Pool. Generators of less than 50 MW, on the other hand, can choose not to be licensed, and do not have to sell their power to the Power Pool. Irrespective of their size, generators signing contracts directly with customers must establish a supply arm, and

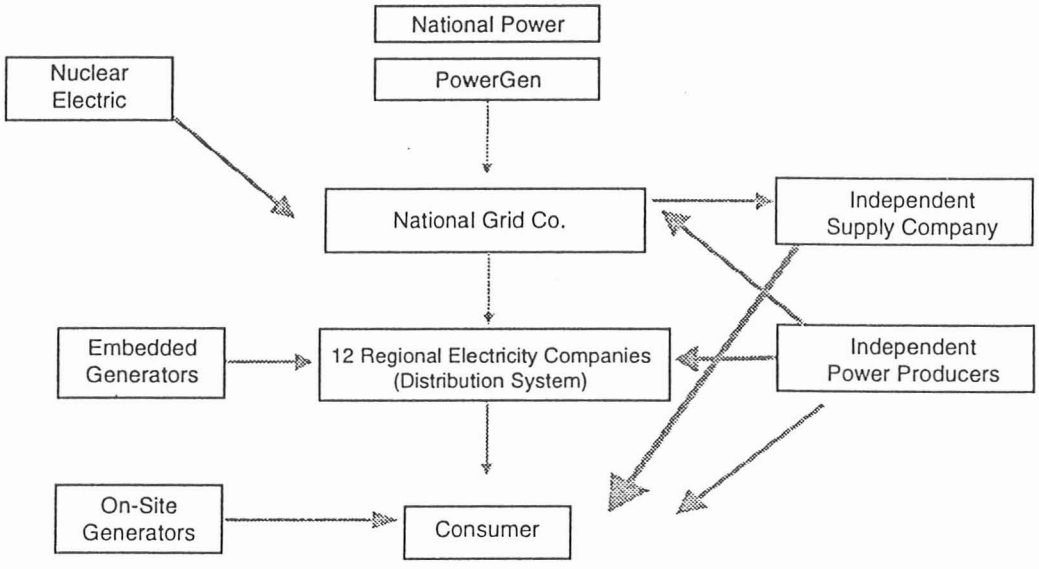

Figure 2: Post-Privatization Structure of the UK Electricity Industry

Table 3: Proceeds from Public Offerings (millions of 1994 CDN$)

Assets	Proceeds
National Power	2,864
PowerGen	1,756
South of Scotland Electric (Scottish Power)	4,185
North of Scotland Hydro Electric (Scottish Hydro Electric)	1,969
12 Regional Electricity Companies	11,091
Total	21,865

that arm must obtain a so-called "second-tier license" and join the Power Pool – National Power, PowerGen and Nuclear Electric have done precisely this. Finally, in addition to generators serving a supply function, there are also independent supply companies, which buy power from generators and resell it to users.

The Power Pool system is based on a merit order dispatch principle. Every morning, "major generators" (those of over 100 MW) give National Grid Company (NGC) an offer price for their power for the next day (the price at which they are prepared to operate each unit for each half hour of the next day). Based on this, the NGC prepares a "schedule" one day in advance specifying the order in which the stations will be dispatched the next day, with plants dispatched in order of increasing cost, and how much power each must supply.

Currently, there is no central planning with respect to generating capacity development. Development is strictly a commercial decision on the part of the developer. Within that context, National Grid Company can influence zonal charges and connection costs, while government consent is required to construct a power station. Indeed, as we will see later, some activities of the industry are tightly regulated.

The first independent power plant (IPP) to become operational after privatization was Lakeland Power (229 MW), completed in October 1991. By February 1994, there was a total of 3,200 MW of IPP generators in operation. At peak level of development activity, it was forecast that plant margin (excess capacity over demand) would reach 50%. The current outlook for prices, however, is such that many of the plants originally planned will not proceed. Closure of old coal fired stations may also reduce plant margin to a more appropri-

Table 4: Generator Market Shares – Percentage of Total Output

	1989/1990[1]	1990/1991	1991/1992	1992/1993	1993/1994	1994/1995
National Power	48.0	45.5	43.4	41.0	35.0	33.9
PowerGen	29.7	28.3	28.1	27.0	26.1	25.9
Nuclear Electric	16.5	17.4	18.8	21.3	23.2	22.3
Interconnectors and Pumped Storage[2]	4.82	7.7	8.4	8.7	8.4	9.2
New Entrants	0.0	0.1	0.3	1.1	6.2	7.4
Others[3]	1.02	1.0	0.9	0.9	1.1	1.3

1/ Pre-vesting output allocated on basis of subsequent allocation of plant

2/ Scottish Power and Scottish Hydro Electric (via the Scottish Interconnector), Électricité de France (via the French Interconnector) and National Grid Company (NGC) pumped storage business

3/ Mainly British Nuclear Fuels (BNFL) and pooled renewables

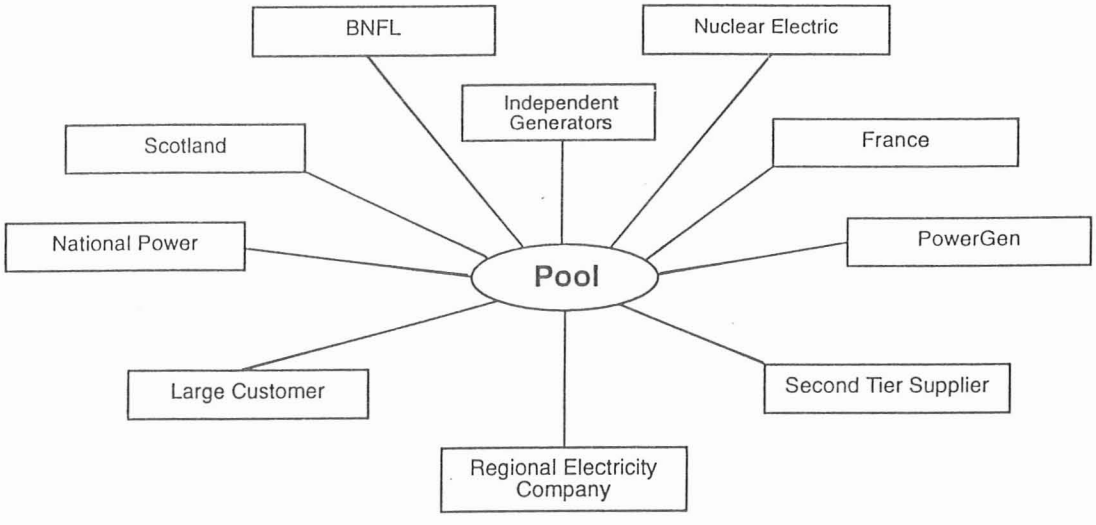

Figure 3: Post-Privatization Role of the Electricity Pool of England and Wales

ate level (i.e., closer to 20%).

The competitive market is being introduced in three phases. Starting in April 1990, the competitive market was set at sales in excess of 1 MW. Any consumer of more than 1 MW of power could purchase power directly from any licensed supplier. In April 1994, the franchise limit was reduced from 1 MW to 100 kW, bringing some 45,000 new customers into the competitive market. The franchise limit is scheduled to be eliminated on April 1, 1998 giving and estimated 22 million new customers access to the competitive market.

There is a great deal of speculation as to how a totally open direct purchase structure will affect the supply markets. One view is that it will have a dramatic effect on these markets, since there will then be a whole range of competing suppliers (12 RECs, generating companies and independent suppliers.) The second-tier market could become over-populated with suppliers, allowing only narrow margins to be achieved. If that were to be the case, then customers in the 100 kW to 1 MW range would be able to put pressure on suppliers by negotiating lower prices. In this context, the retail electricity market could become a commodity market just as it now is in the

greater-than-1-MW market. This would ensure the existence of a price-transparent market, such as a screen based trading market (i.e., natural gas in the US).

Another view is that the effect will not be dramatic. Indeed, by late 1994, only 10,000 of the 45,000 customers between 100 kW to 1 MW had sought competitive supply. The remainder, perhaps, find the process too complex. The 12 RECs have also approached their customers and offered them incentives to stay in return for tying them into two-year contracts. In this case, parallels with Canada's experience with the deregulation of natural gas supply would be evident.

As Figure 4 suggests, generators compete for contracts to supply the 12 RECs, which are responsible for electric power distribution in separate geographical areas (the "wholesale market"). Generators can also enter into "Contracts for Differences," which are hedging financial instruments that can be negotiated with both the RECs and the second-tier suppliers (the independent supply companies).

Finally, it is important to note that the UK government has assisted the renewable energy industry through the establishment of "non-fossil fuel obligations," which require RECs to purchase a specified quantity of power generated from non-fossil fuel sources. These renewable energy set asides aggregated to 102 MW in 1990 and to 450 MW in 1991. The 1994 annual report of the UK Office of Electricity Regulation (OFFER 1995) suggested that an additional tranche of approximately 400 MW of non-fossil fuel obligations was under active consideration. As of the time of writing, however, no such initiative had been undertaken on this front.

Transmission and Distribution Structure

National Grid Company (NGC) was formed in 1990 by the disaggregation of the CEGB. It handles the transmission of power, organizes an efficient contract system between area boards and generators and ensures a minimum cost of dispatching power. Transmission, however, does not actually function as a free market system: NGC owns the transmission system, the 12 RECs own the regional distribution systems, and the 12 RECs also collectively own NGC. NGC's main business is the operation, maintenance and development of the transmission system, it coordinates the operation of the major power stations (of over 100 MW in capacity) to meet demand (the so-called "Scheduling and Dispatch" system). The subsidiaries of NGC (National Grid Settlements Administrator and the Power Pool) arrange for generators to be paid for the power they produce and for the suppliers (RECs) to pay for the power they use.

Transmission rates are subject to regulated price controls. To finance its business, NGC charges grid users for the services it provides. Specifically, the following charges are levied:

- entry and exit charges;
- system service charges; and
- infrastructure charges.

The distribution is done by the 12 RECs, which operate as monopolies. Distribution charges are subject to a price control formula. The increase in the average distribution charge per unit is restricted to RPI (inflation), plus or minus a fixed percentage amount (calculated for each REC). The cost incurred by the REC for supplying electricity to its customers, which include its power purchase costs, the fossil fuel levy, and transmission and distribution charges are passed on to the customer.

The Regulator

The regulatory body is called the Office of Electricity Regulation (OFFER) and is headed by a Director General, currently Professor Stephen Littlechild. The duties of OFFER are to encourage competition in generation and supply, and to protect consumers with respect to prices and standards of service. Some authority to intervene on electricity markets has thus been vested in the regulator. It is important to note that the relevant legislation does not require public hearings to precede any such intervention, nor does it provide for a mechanism through which decisions of the regulator could be appealed.

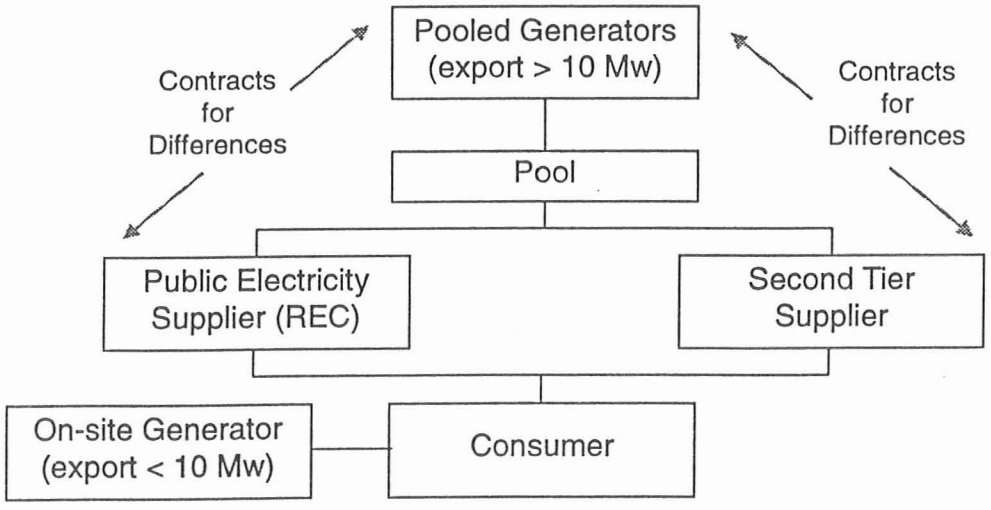

Figure 4: Financial Structure of the Post-Privatization Electricity Industry

All in all, OFFER remains a relatively small operation, funded through the £10 million (approximately CDN $21.6 million) licensing fees it collects annually. In 1994, it employed 200 people to oversee the electricity market in a country of more 50 million people. As a point of comparison, the Ontario Energy Board employed 50 people and had an operating budget of CDN $5.5 million in 1994.

Effect Of Privatization on Power Prices

As noted earlier, in the wholesale bulk electricity market (the Power Pool), a spot price is determined every half hour through competitive bidding by generators. The sellers are the generators, and the buyers are distribution companies (RECs), other licensed suppliers and large consumers buying directly from generators. The Power Pool pays generators the Pool Purchase Price (PPP), which is the system marginal price (SMP) plus a capacity payment. The buyers pay the Pool Selling Price (PSP), which is the Pool Purchase Price plus an "uplift" to cover additional system costs.

Pool prices in the first year of operation followed movements in demand quite closely, and were about 25% lower than had been predicted at the start of the privatization process. However, increases in Pool prices were substantial in March of 1992 and 1993 as well as between September and December of 1994. As Table 5 indicates, the average Pool Selling Price was about £18.34/MWh (3.67 CDN cents /kWh) in 1990/91. In the second year after privatization (late 1991), this price increased by 22% to £22.43/MWh (4.48 CDN cents /kWh). More price spikes have also been observed since privatization. For instance, the peak half hour price on December 11, 1991 reached £370/MWh, when NGC was at peak demand. On a similar note, an extremely high capacity price was reached in December 1994, due to outages of several plants resulting in a narrower gap between demand and available supply. On the other hand, there have been a few occasions where sufficient generation has been bid in at zero resulting in a zero Pool price. The generators scheduled to run did so for no payment, perhaps, to avoid fuel take-or-pay penalties. On a similar note, in the first three months of 1992, Pool prices fell 16% over 1991, due in part to a better-than-average performance realized by Nuclear Electric.

For many direct purchase consumers, prices are determined by contracts, and are not

Table 5: Electricity Pool Prices 1990/91–1994/95

Pool Settlement–Key Data	1990/91	1991/92	1992/93	1993/94	1994/95
Payments (£M)					
Total Pool	5122.27	6298.63	611.49	7326.4	7963.52
Average daily	14.03	17.21	18.11	20.07	21.82
Increase/Decrease (%)		23	5	11	9
System Marginal Price (SMP) £/MWh	17.37	19.5	22.64	24.16	20.7
Increase/Decrease (%)		12	16	7	-14
Pool Purchase Price (PPP) (£/MWh)	17.42	20.82	22.8	24.44	24.0
Increase/Decrease (%)		20	10	7	-2
Pool Selling Price (PSP) (£/MWh)	18.34	22.43	24.19	26.62	26.38
Increase/Decrease (%)		22	8	10	-1

linked to Pool prices. However, over 1,000 large customers have Pool price contracts where they pay the Pool price only. For most large customers there were nominal price reductions of 9% in 1990, then increases of 4% in 1991, 3% in 1992 and 7% in 1993.

The net effect for most large customers is that, since privatization, prices paid are actually lower after inflation. However, large consumers did incur large Pool price increases in April of 1993 and in October-December of 1994. The reaction to the price increase of April 1993 led a Government Select Committee to recommend, in February 1994, that steps be taken to reduce the influence of the two major generators, National Power and PowerGen. In the aftermath of the sharp price increases of April 1993, OFFER concluded that prices in the Pool were artificially lowered, but that by April 1993, prices were increased above the avoided costs of the two generators. Within that context, OFFER's greatest concern was that the two generators had too great an influence over Pool prices. In its February 1994 report entitled: "Decision on a Monopoly and Mergers Commission Reference," OFFER ruled that National Power and PowerGen had to cap their prices over the next two years (1994 and 1995) at the levels prevailing in October 1993. This was designed to have the effect of restricting Pool prices to a 7% decrease over 1994 and 1995 compared to the levels prevailing at the beginning of 1994. As a further way of curbing the influence of the two generators, the ruling by OFFER also specified that independent generation would be increased by the sale of 6,000 MW of plant capacity by National Power and PowerGen. (Note, however, that this sale had not occurred at the time of writing.)

Despite the increase in Pool prices in 1993 and 1994, domestic (residential) electricity prices have not, over the five years since privatization, increased faster than the rate of inflation, as indicated in Table 6. This is due mainly to the price controls imposed by OFFER, which had their effect spread over 1994 and 1995 average prices. Other factors have also contributed to limited cost increases. In particular, the RECs have reduced the cost of their distribution services substantially through the elimination of thousands of jobs, thus increasing operational efficiency.

Analysis of Restructuring: Upside and Downside

The Upside

The positive reasons for privatization, which appear to have been achieved to a degree, are:

- reduction of government borrowing and deficits through asset sales;
- "popular capitalism" – wide share owner-

Table 6: Prices Charged to Typical Standard Domestic Tariff Customers (pence/kWh)

	1989/1990	1990/1991	1991/1992	1992/1993	1993/1994	1994/1995
Avg. Nominal of 12 RECs	7.26	7.95	8.81	8.96	8.6	8.53
Avg. Real (89/90 prices)	7.26	7.2	7.56	7.38	6.99	6.76
% (real)	–	-0.8	5	10.8	-4.9	-15

ship;
- improved operating efficiency;
- reduced labour costs;
- a change in business culture from engineering to marketing and finance which implies long-term benefits through greater entrepreneurial innovation;
- improved customer service.

Fuel cost savings, through the removal of the obligation to buy from British Coal, were also achieved. British Coal intends to charge a world-equivalent price for coal by the end of 1995. In the meantime, relative prices have favoured natural gas, and this fuel has indeed replaced coal in many thermal generation operations.

Prices for many large consumers (which are able to negotiate direct purchase contracts with generators) have actually declined after inflation. Others, however, have experienced price increases due in part to the abolition of the electricity price subsidies that existed prior to privatization. To counter the upward pressure on prices caused by the increase in returns required by investor-owned companies, other policy changes were introduced:
- relaxing restrictions on the use of natural gas for generators;
- increasing competition in natural gas supply;
- reducing the capacity reserve margin; and
- encouraging industrial users to generate their own power (and sell any surplus).

Since privatization, Nuclear Electric has made impressive improvements in operating efficiency: productivity has increased from 2.9 to 5.76 GWh per employee, as Table 7 indicates. On a similar note, National Power improved productivity by reducing its staffing from 17,500 to 7,000 in three years, while PowerGen has gone from a workforce of 9,000 to one of 4,500.

As noted earlier, the UK government to date has earned £10.2 billion (approximately CDN $21.9 billion at 1994 prices) from the proceeds of privatization. Still to come are proceeds from its 40% interest in National Power and PowerGen and from its 100% ownership of Nuclear Electric, subject to buyers being found for these assets.

It can also be argued that privatization has resulted in a more entrepreneurial electricity industry in the UK. The generation supply businesses have developed a more entrepreneurial culture than was evident prior to 1990, and even the transmission and distribution businesses, which are still monopolies, are now involved in numerous competitive ventures.

The Downside

One of the major disadvantages of the system is that the market is extremely complex. Due to the phasedin nature of the privatization process and to the ensuing restructuring of the industry, the market will continue to evolve as users get familiar with it.

In the privatization process, the government pursued a number of objectives simultaneously, and some of these acted to slow the arrival of competition. For example, there initially was to be support for the British coal industry by seeking to ensure that it would retain 30% of the fuel market for thermal electricity generation. This objective was effectively abandoned as the restructuring proceeded, such that coal's share is now estimated to be about 20%, and will decline further as old plants are retired and replaced by gas-fired combined cycle plants. The government's intention to support the franchise market until 1998 for the RECs has also slowed down competition.

Another shortcoming of the restructuring is that there were only two major private generating companies established as opposed to the

Table 7: Nuclear Electric's Turnaround

Performance Indicator	1989/90	1990/91	1991/92	1992/93	1993/94
Output: Total (TWh)	42.5	45.0	48.4	55.0	61.0
Market Share (%)	16.7	17.4	18.5	21.6	23.2
Income: Market Sales (£M)	2,044	1,007	1,167	1,426	1,732
Levy Premium (£M)[1]	0	1,195	1,265	1,280	1,230
Operating profit/(loss)[2]					
Market Sales Only (£M)	n/a	(1,009)	(783)	(564)	(224)
Total Income (£M)	n/a	186	482	716	1,006
Return on Capital Employed %		3.4	7.9	11.0	14.0
Staff in Post at Year-end	14,164	13,542	12,674	11,323	9,454
Productivity (GWh/employee)	2.9	3.2	3.6	4.5	5.7

1/ Subsidy paid to Nuclear Electric from fossil fuel levy.

2/ As restated to meet the requirements of Financial Reporting Standard No. 3, but before provisions for restructuring and before revision of previous year's nuclear provisions.

Source: *Power UK* (1994)

5-10 which should have been established to eliminate the possibility of prices being controlled by any one generator. In fact, the main criticism to date of the privatization exercise has been the fact that the two large generators exert too much influence on electricity prices.

The UK system of regulation also has its weaknesses. The regulator is a single person, not a tribunal, and the process is not open to the scrutiny of public hearings. For example, the regulator's decision to limit 1994 and 1995 prices to the October 1993 level was seen by many as an extremely detrimental move for power developers with projects under development. A number of potential new developments have been cancelled as a result of the Power Pool price intervention.

The regulator can also alter the licensing conditions of the regulated organizations (the generating companies and the RECs) and there is no judicial process for appealing these decisions. Despite this inherent weakness, the UK regulatory process is seen to be less drawn out and legalistic than the US and Canadian systems.

The new private companies are, of course, expected to earn higher market rates of return than the CEGB. The required real rate of return would be expected to be a risk free rate (say 3-4%), plus a risk premium (say 7-8%) for a risk-adjusted real rate of about 10 to 12%. That higher return would be expected to have two impacts on prices. First, discounting at a high rate would favour investments with lower capital, but higher operating costs. Second, higher revenue is required to achieve profit targets.

Privatization has also had negative employment effects. In particular, the declining market share of coal in thermal electricity generation is forecast to eliminate 30,000 "pit" jobs. Productivity improvements at National Power and PowerGen have eliminated 10,500 and 4,500 jobs, respectively, in a three-year period. Total employment of Nuclear Electric has fallen from 14,164 in 1989 to 9,454 in 1994, and employment by the RECs has also decreased substantially.

Lessons Learned

While it would be inappropriate to apply the British approach directly to Canadian utility restructuring, many valuable lessons can be learned from reviewing the UK experience.

- Due to the numerous other issues involved, the effects of privatization are impossible to isolate from the other agendas pursued by the Government.
- The UK example proves that privatization of

a large electricity utility can be achieved without significant power price increases.

- Utility privatization can be an effective means to promote the participation of the public in utility stock purchases.
- Both public share offerings under privatization were over-subscribed (National Power, PowerGen, and the RECs). Any public float of Canadian utilities should ensure a substantial allocation of shares for purchase by Canadians.
- The UK system is extremely complex, partly because of the numerous objectives the government endeavoured to achieve (e.g., protection of British Coal, support for Nuclear Electric, support for franchise market and support for renewable energy). Attempts should be made to focus on the central goals of electricity industry restructuring (e.g., attracting private investment, improving operational efficiency, increasing productivity through competition, etc.) and reducing electricity rates.
- Competitive bidding has been partly responsible for impressive improvements in productivity. National Power, PowerGen, Nuclear Electric and the RECs have all substantially reduced their labour costs.
- The use of a regulator to set prices can ensure that power prices do not substantially increase due to a privatization-related restructuring.
- A regulatory process that gives an individual the right to set some prices, but does not provide for an appeal mechanism of these decisions can result in investors seeking an additional risk premium, thus further restricting new generators from entering the system.
- When establishing new generation companies to sell into a competitive market, a sufficient number of new generators must be licensed to prevent price control by any single company, or small group of companies.

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