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Issues and options for restructuring electricity supply industries

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Issues and Options for Restructuring Electricity Supply Industries

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Until recently the Electricity Supply Industry (ESI) was typically vertically integrated with a franchise monopoly to be the sole supplier of electricity in each region. It was, with few exceptions, under public ownership, either by the state and/or municipal governments. The past decade has seen a dramatic change in views about how the ESI should be owned, organised and regulated (Newbery, 1997a; 2000). As a result, there is a growing list of experiments in restructuring and reform to study. We are now in a better position to reflect on the lessons learned, to identify the most important issues that need to be addressed, and the options that should be considered. Perhaps the most important lesson is that models which appear to work well in some circumstances and places may not be easily transferable to countries facing different circumstances. The performance of particular models needs to be interpreted in the light of their special circumstances. Choosing the right reform strategy is more challenging than early optimists claimed. The experiences of California, South East Asia, and Brazil, have been salutary, and underlines the importance of careful analysis of what works, what can go wrong, and why.

1. Pressures for electricity reforms

1.1 The UK electricity reforms and their influence

The reform and privatisation of the ESI in the UK starting in 1990 demonstrated that it was possible to replace state-owned vertically integrated franchise monopolies with privately owned, unbundled and regulated successor companies without the lights going off. The UK actually offered three models of restructuring to compare and contrast. In England and Wales the Central Electricity Generating Board (CEGB) was unbundled into three generating companies and the grid, thus separating transmission from generation. The 12 distribution companies were privatised, and a wholesale market - the Electricity Pool - created. Eligible customers above 1 MW were free to buy in the wholesale market. Scotland, with its different political, legal and institutional history, chose to retain intact the two vertically integrated regional utilities but to privatise them.

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They could both trade in the English Pool, whose prices provided a benchmark for regulatory purposes. Northern Ireland, at that time isolated from the mainland and from the Republic of Ireland to the south, with a population of only 1.5 million, adopted the Single Buyer Model. Distribution and transmission were retained within a franchise monopoly, NIE, while the three main generating stations were sold to three separate private buyers holding long term Power Purchase Agreements (PPAs) with NIE.

Over the next few years, an increasing number of developed and then developing countries decided to reform and restructure their ESIs. Norway liberalised without changing the ownership structure, but unbundled transmission from generation and created a wholesale market and various financial markets. The state of Victoria in Australia followed the model of England and Wales, appropriate for an industry based almost entirely on coal, as in Britain. Chile had started reforming in the 1980s with a cautious programme of tariff rebalancing, legislative reform, the creation of regulatory institutions and eventual privatisation. That example was undoubtedly important in persuading Argentina that the benefits of reform and privatisation were not confined to developed countries.

The lessons from Britain and other early reformers were eagerly studied by those concerned with the reform process elsewhere. Newbery and Pollitt (1997) and Pollitt (1997, 1998) have completed social cost-benefit analyses of the three different models adopted by the UK, with striking and intuitively plausible results. The restructuring of the CEGB immediately introduced daily competitive price bidding for each power station. All generating companies dramatically increased productivity and drove down costs, including the state-owned Nuclear Electric. The audit of the first five years was that the social benefits amounted to a reduction of costs of six per cent for ever compared to the counterfactual, equivalent to a 100% return on the sales price. These benefits were almost entirely captured by companies, for profits rose as costs fell and prices remained stubbornly high until continued and aggressive regulatory intervention forced extensive divestment of capacity. By the end of the decade the dominant duopoly had evolved into a relative unconcentrated industry. Entrants and incumbents operated efficient combined cycle gas turbines, a range of international generating companies bought divested plant, and the modern nuclear stations had been privatised.

Scotland was a different story. In 1990 electricity prices were 10% lower than in England, but the lack of competitive pressure meant that by the end of the decade prices were some 5% higher. The very modest benefits of privatisation were entirely absorbed by the costs of restructuring, delivering no net benefit. Northern Ireland gives a mixed picture. The long-term PPAs provided powerful incentives for increased plant availability and cost reductions, so that the improved generator performance outstripped that of the CEGB by three times. However, these PPAs retained the benefits with the generating companies and consumers were only able to benefit by aggressive price reductions on the non-generating elements of cost, combined with Government subsidies to reduce the embarrassing price gap between Northern Ireland and Britain.

The lessons from UK electricity restructuring are clear. Increased competitive pressure on generation is needed to reduce costs and that requires separating generation from transmission and distribution. Whether these benefits will be passed on to consumers depends upon the intensity of competition - particularly the number of competitors and the existence of an open access wholesale market. Unrestructured industries, even if privatised, appear to deliver few benefits. Efficiency improvements in transmission and distribution require tough regulatory price controls. Improvements in the first five years under the initial price controls were modest, with most of the price cuts, efficiency gains, and transfers to consumers confined to the second and subsequent regulatory reviews (Domah and Pollitt, 2001). The evidence suggests that regulators have to work hard to transfer efficiency gains into lower consumer prices. They also need to take positive steps to counteract market power in the potentially competitive sectors, possibly including further divestment of capacity, if consumers are to gain from restructuring.

The lesson that unbundling is necessary has been taken to heart in restructuring choices around the world, and particularly in Europe. The European Commission, with its mission of creating a single market for goods and services, was anxious to tackle the national monopoly electricity industries that allowed very disparate prices for electricity to prevail in neighbouring countries. After several years of intense negotiation, the Electricity Directive (EC/96/92) came into force on 19 February 1997 to be transcribed into national legislation by 19 February 1999. The Directive required functional unbundling of generation from transmission (though neither legal nor ownership separation), and at least 33% opening of the market, so that eligible customers could choose their supplier (see Bergman et al. (1999).

It offered three models for the structure of the industry - regulated Third Party Access (rTPA), negotiated TPA, or the Single Buyer Model. Under rTPA, the transmission company would publish transmission tariffs and access conditions, so that generators would be free to transact directly with customers. Under nTPA, generators would have to negotiate with the transmission company, which might have ownership interests in competing generators. The SBM was consciously designed to mimic the effects of rTPA, in that the Single Buyer would buy electricity from generators and sell to final consumers, but had to pass on the purchase price with a regulated transmission tariff to final consumers. New generation could either be authorised (that is, allowed to enter the industry providing that it satisfied planning, license and environmental conditions which were to be applied in a transparent and non discriminatory fashion), or by tendering, thought to be appropriate to the SBM.

The European Commission had been much influenced by the experience of liberalisation in the UK, and had so designed the options to make authorization with rTPA the natural choice, which was indeed adopted by almost all countries (Bergman, et al, 1999). Experience in the few years following the Directive suggested that further more pro-competitive steps were required to integrate the electricity market. In March

2001 the Commission presented more radical reforms to be incorporated in a proposed new Directive. This would require legal separation (though still not full ownership separation) of transmission and generation, would insist on rTPA and remove the other options. It would require sector regulators (Germany still had none), and complete supply liberalisation by 2005. France, who missed the deadline for enacting the earlier Directive, and has done the minimal restructuring and market opening, opposed the proposals, arguing that it was too soon to deem energy liberalisation a success. Germany, with its preference for negotiated TPA and vertical integration, also opposed the proposals, particularly the requirement for an independent regulator. Pressure for reform from consumers and those countries that have liberalised continues, but for the present the reforms are stalled.

The emerging European consensus is that unbundling and introducing competition has been a success. The main problems have been to create and sustain adequate competition, and to prevent market abuses. Prices have fallen almost everywhere, although this is largely due to decreasing fuel costs. Even there, electricity liberalisation was influential in reforming other energy markets, particularly coal in Germany and Britain, and gas the Britain (and more slowly on the Continent). It is, however, important to appreciate the favourable circumstances that supported the reform process.

Britain, and Europe generally, started with substantial excess capacity, itself the outcome of the collapse in demand growth after the oil shock of 1974, at a time when a large but much delayed investment programme in large coal and nuclear plant was under way. Europe had already built up a dense network of transmission capacity, though interconnections between countries were less satisfactory. Electrification was complete, and the distribution networks needed little investment. Finally, the development of high efficiency combined cycle gas turbines (CCGTs) reached maturity just as Britain was liberalising its ESI. The rapid development of gas pipeline systems and the increasing availability of cheap gas in Western Europe and the United States provided a fuel at a cost that made entry by CCGTs attractive against incumbents. The "dash for gas" in Britain resulted in investment in new generation amounting to one-quarter of the existing (and perfectly adequate) capacity (as well as virtually eliminating the deep-mined coal industry). A cheap new fuel source that stimulated investment and increased competition did much to smooth the transition to a market-oriented customer-focused structure.

With such favourable circumstances and outcomes, the pressure to replicate the early reform example was understandable. The old vertically integrated utility model no longer looked like a desirable or even inevitable equilibrium form. Technical progress (CCGTs) may have played a small part, but arguably for electricity and gas the destabilising force was mature or excess capacity that unsettled the regulatory compact (Gilbert and Newbery, 1994). If the utilities had little need for investment to finance expensive capacity, then consumer interests saw the merits of pricing closer to avoidable costs, letting the market expropriate at least some of the returns to capital. As most of the

ESI was in state hands, this expropriation was largely invisible, though in Germany, where there were private owners, restructuring was more modest (and has been followed by a merger wave and considerable industrial consolidation).

In the US, the reform process has been considerably complicated by ensuring that stranded assets would be compensated, though initially there was great confidence that a new deal could be struck that was beneficial to all parties. With unfortunate timing, just when the European Commission was pressing for further reforms, events in California shook political confidence in the liberalisation agenda.

1.2 The Californian example

California originally reformed and liberalised its electricity market because of dissatisfaction over high consumer prices. However, average wholesale prices in 2000 were more than three times those of 1999, and 2001 started with rolling blackouts, stage 3 alerts,[2] and the major public utility, PG&E, filing for Chapter 11 bankruptcy protection (see Joskow, 2001). California shows that poor market design coupled with inappropriate regulatory and political intervention, can rapidly produce extremely unsatisfactory outcomes when capacity is tight, particularly if the shortages are unexpected. The Californian experience has certainly alarmed European politicians and caused several academic energy specialists to reconsider the merits of deregulation. In the words of the pseudonymous Price C Watts (2001) "It is clear that deregulation is a high-risk choice. Those jurisdictions that have not yet deregulated electricity generation need to think long and hard before they go ahead. Those that have done so need to figure out how to minimize the downside potential of the journey on which they have embarked."

What were the various contributory factors to this unhappy outcome? First, California (and the neighbouring states) had for a long history of under-investment in generation, partly because of disputes over nuclear power plant costs and safety, environmental objections, and misconceived long-term Power Purchase Agreements (PPAs) with Qualifying Facilities, QFs, typically owned by "non-utility generators". This was sustainable because California imported extensively from the Pacific Northwest, making use of the apparently abundant and cheap surplus hydroelectric power from the Columbia River. Second, after generation was unbundled from transmission and distribution, distribution companies were strongly dissuaded from signing long-term contracts for electricity or hedging. This regulatory restraint was caused by the California Public Utilities Commission's poor experiences with earlier excessively-priced PPAs from the QFs. The Commission recognised the spot market price as the principal measure of wholesale electricity costs, and utilities were required to trade all their power through the Power Exchange (PX).[3]

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[2] when reserve margins fall below 1.5% so that disconnection is essential to protect system integrity.

[3] In addition, the utilities considered that the contract prices offered were unacceptably expensive,

Finally, NO emissions were capped by region (and in some cases by plant) on an annual basis. In the (not particularly) hot summer of 2000, gas demand for generation greatly increased, and pipeline capacity and storage were frequently inadequate to meet the demand. Californian gas spot prices more than doubled (coming on top of high prices caused by the doubling of crude oil prices), as did the contract prices from many QFs, which were indexed to gas prices.[4] The price of tradable NO permits also rose to unprecedented levels as the annual quota became inadequate, with permits trading at $80,000/ton at their peak, compared with $400/ton on the East Coast (Laurie, 2001). Electricity prices rose, not just in California, but in the whole western interconnection in that wholesale power is traded. Thus the average price for the *whole year* at the Mid-Columbia hub in the northwest (i.e. not in California) was $137/MWh compared with £27/MWh in 1999, higher than in California (where it averaged $91/MWh on the PX). California's largest distribution companies were unable to pass on the high wholesale prices, precipitating a financial shortfall as revenue fell far short of cost.

High plant utilization in the summer and autumn induced by high spot prices necessitated greater scheduled maintenance downtime in the normally quieter winter period. Unfortunately, the combination of a dry winter in the Columbia River Basin lowering hydro output potential, with higher demand due to the colder weather, and plant outages in California, caused a severe shortage of capacity and energy, leading to higher prices, defaults, and bankruptcy. Inept price caps caused generators to export to neighbouring states, rather than sell in California, while the non-utility generators refused to supply for fear of not being paid. The repeated interventions of the State Governor arguably made a bad situation far worse, as threatened seizures, price caps, and regulatory hurdles prejudiced investment in generation. Poorly designed trading arrangements, with caps on some markets that encouraged participants to under-contract in the day-ahead market and diverted power to the real-time market at very high prices amplified market power (Wolak and Nordhaus, 2000).

What lessons can be drawn from the Californian experience for electricity reform? First, tight electricity markets, where the reserve margin falls below 10%, are likely to lead to volatile markets and high prices even if they are fairly competitive (meaning that there are four or more generating companies competing with each other at the margin of supply).[5] As demand tightens relative to supply, inelastic and

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compared to past experience, and were thus unenthusiastic about hedging. In the event the contract prices would have been extremely cheap compared to the subsequent spot prices.

[4] By the end of 2000 gas prices had risen to $15/MMBtu compared to a historic average of $2/MMBTu, and December electricity prices were estimated to be three times higher as a result. On one occasion after an accident disrupting deliveries on one of the major pipelines, spot gas reached $61/MMBTU, equivalent to an fuel cost in a reasonably efficient generator of $610/MWh (Bogorad and Penn, 2001).

[5] There are problems in using standard tests for market concentration, such as the HHI for either capacity or output, for what matters is the extent of competition between generators with bids near the

unresponsive demand[6] means that large price rises have little effect on demand, but each supplier has increasing and eventually very considerable market power. The large increase in price caused by any single company withdrawing a small amount of capacity is more than sufficient to compensate for the loss of profit on that volume of sales, making such withdrawals highly profitable in tight markets.

Second, any transition from a vertically integrated utility to an unbundled structure introduces price risks between generators and suppliers that previously cancelled out. High wholesale selling prices for generators gives profits upstream that are matched by the losses of downstream suppliers who have to buy at these high wholesale prices and sell at predetermined retail prices, unless these purchases are hedged by contracts. The transition to (and subsequent operation of) an unbundled industry therefore needs contracts and hedging instruments to insure against possible unexpected events that can have dramatic effects on spot prices, particularly when suppliers sell on fixed price terms. The British privatisation was accompanied by three-year contracts for both sale of electricity and purchase of fuel to reduce transitional risks.

Third, in an interconnected system operating under a variety of different regulatory and operational jurisdictions, spare capacity is a public good that may not be adequately supplied unless some care is taken to ensure that it is adequately remunerated. Fourth, it is even harder for a decentralised market under multiple jurisdictions to ensure adequate reserve capacity with a potentially energy-constrained hydroelectric system, particularly where reservoir storage is limited, and annual water volume variations are high. Finally, uncoordinated and injudicious regulatory interventions in such an interconnected system can have perverse local effects, and very damaging impacts on the efficient pattern of inter-regional electricity trade (Wolak and Nordhaus, 2000; 2001).

1.3 Pressures for reform in developing countries

Pressure for change in mature industrial economies grew with the emergence of excess capacity and the disillusionment with expensive and capital-intensive generation projects precipitated by the oil crisis of the 1970s. The circumstances in developing countries differ in important respects. Most countries have had very high rates of demand growth for electricity, at least in periods when their economies were expanding. Whereas investment needs were low in mature countries with excess capacity, they are high in many developing countries. Many countries have no spare capacity and excess demand, often with periodic blackouts. Market clearing prices in such cases would be politically unacceptable, and would likely derail any attempts at radical liberalisation. Finally,

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market clearing price.

[6] If consumers face prices unrelated to spot wholesale prices they will not reduce demand even if wholesale prices increase dramatically. All domestic and most commercial and industrial customers are in this position.

advanced industrial economies have developed commercial law and institutions to the point that private ownership of natural monopolies can be regulated in the interests of consumers while protecting the ability of the owners to finance investment. The ESI is capital-intensive, its assets are long-lived, and once invested cannot be relocated for use elsewhere. Electricity is a necessity and in urban areas at least an overwhelming share of the political constituency are directly dependent on the monopoly supplier, ensuring that regulated or government-set prices are politically inevitable.

The political demands for access and `fair' or non-exploitative prices means that investors must expect that after they have sunk their capital they will be limited in the prices they can charge, and subject to possibly onerous obligations to supply, to guarantee security, stability and safety. If these investors are to be induced to invest, they need the reassurance that future prices will be set at a sufficiently remunerative level to justify the investment. Once the capital has been sunk, the risk is that the balance of advantage would shift towards those arguing for lower and possibly unremunerative prices. Durable investments thus require the rule of law, and specifically the law of property, to protect owners, while network utilities, providing a public essential service, need the additional protection of fair and credible regulation to protect investments. In their absence, public ownership is the logical default option, and one that was widely adopted.

The post-war governments in most developing countries had been convinced of several things - electricity was vital to economic development, the ESI was a paradigm of the tightly centrally-planned successful socialist enterprise, the large investment required to increase penetration demanded the resources of the state, and the World Bank could be relied upon to provide the investment funds and the technical expertise to equip countries with state-of-the-art western technology. The standard model of a vertically integrated, state-owned, centrally planned ESI was therefore replicated throughout the developing world.

In the early days of rapid growth and young plant, prices could be set at cost recovering levels and even allowed to fall with the rapidly decreasing costs as economies of scale and new technology were exploited. Over time, and especially as inflationary and budgetary pressures increased, the margin between revenue and costs was squeezed, maintenance was delayed, management deteriorated, and over-manning through political patronage increased. Under-pricing to favoured groups in rural areas became politically more salient and more difficult to reverse, while theft and losses in urban areas further undermined the financial viability of the sector. The sector was in crisis, though for different reasons than those experienced in developed countries.

2. Systemic problems of state ownership

The public sector appears to find managing state-owned capital-intensive utilities difficult, and not just in developing countries. Part of the problem is that operating costs (mainly fuel) are only about half total costs, so that utilities can underprice while still covering operating costs. Managers and politicians alike have a shared interest in under-pricing to stimulate demand and secure political support. Excess demand signals the need for investment, which managers desire, and which politicians take as a sign of development. Maintenance has less appeal, because poor performance and worn-out plant underwrites the need for new investment. If plant breaks down, employment to maintain and keep the plant struggling on can be defended, and power companies are often remarkably overmanned as a result. The costs of overmanning appear modest relative to the fuel and capital costs, so there is little pressure to reduce staff, but overmanning tends to lead to inadequate salary levels, making it harder to recruit competent staff who could manage maintenance and operations more efficiently.

International agencies were happy to fund power sector investment as they were a visible sign of a successful transfer of technology, and obviously had high social returns. The cost of unserved power, even in poor countries, is high and can be plausibly quantified. Covenants on tariffs could be agreed, only to be abandoned as inflationary pressures were addressed by holding down public sector prices. The result was that over time real electricity prices declined as did profits (and hence the ability to self-finance investment). This was becoming increasingly evident by the 1990s, and a survey of 360 companies in 57 World Bank countries in 1989 found that the rate of return on revalued net fixed assets had declined to below 4% (World Bank, 1993), well below the 10% rate of return normally taken as the test discount rate by international agencies. Only 60% of power sector costs were covered by revenue (Besant-Jones, 1993), while self-financing ratios fell to only 12% of investment requirements in 1991 (World Bank, 1993, p12).[7] Newbery (1993) noted similar problems for Asian countries. Underpricing electricity resulted in a heavy fiscal burden estimated at $90 billion annually or about 7% of total government revenues in developing countries, larger than annual power investment requirements of about $80 billion, while technical inefficiencies caused true economic losses of nearly $30 billion annually (World Bank, 1994, table 6.7).

Several decades of studies of tariff reforms, covenants to improve pricing, and reports arguing that underpricing electricity was inefficient, fiscally harmful and distributionally unjust, appeared to have no effect. Without an alternative source of investment, aid agencies could be blackmailed into continued support, and the soft budget constraint reduced incentives to take politically unpopular pricing decisions. When first Chile, then Britain, followed rapidly by other countries, demonstrated that privatisation worked, it seemed like the obvious answer to the problem - how to instill

[7] The power sector would be able to finance all investment at an unchanged gearing ratio if the financial rate of return exceeded the rate of growth of capacity. The average annual rate of growth of power was about 7% p.a. for middle income countries between 1960-90, compared to an average *economic* (but not financial) rate of return on World Bank projects of 11% (World Bank, 1994, fig. 3 and table 1.2). Had the financial rate of return been raised to the economic rate of return, financing should not have been a problem.

financial prudence, management competence, and operational efficiency into the industry and at the same time relieve the government of the heavy investment costs.

2.1 Possible solutions to the problem

Power shortages are caused by inadequate investment and inefficient operation. The two requirements of providing incentives for efficiency and a mechanism for adequate investment are both satisfied in normal competitive markets with private ownership. Private owners pursue profit. They have every incentive to ensure that customers pay their bills or face disconnection. If firms have little influence over the market price, then the only way they can increase profit is to cut costs. Competition thus provides the spur to efficiency and solvency. Second, when more capacity is required, prices in competitive markets will rise to the marginal cost of expansion (including the return on investment). These prices will allow firms either to finance investment out of retained profits or to borrow against future profits. Private ownership provides motive, and competition provides the incentive for efficient pricing and investment. For that and other reasons, competitive enterprises should be placed in the private sector.

The obvious problem with the ESI is that the transmission and distribution businesses are natural monopolies and cannot be operated as competitive undertakings. The logical solution is to separate the potentially competitive generation and supply (or retailing) from the core natural monopoly networks. Generation and supply might then operate on competitive markets, and the natural monopoly would be regulated in a way that imitates the effect of competition. The regulated prices would be set at a level that enables the owner to finance operation and investment while providing incentives for efficiency. If the generation market is to be adequately competitive, then the transmission owner must have no ownership interests in any generation company, to prevent him favouring some generators over others.

The crucial restructuring question is how best to introduce competition into generation (and supply). The standard answer to date is that competition requires a market, and generation will therefore need a wholesale electricity market, either organised as a power exchange or Pool. That model has worked well when there is adequate capacity in generation, sufficiently numerous independent generating companies, and sufficient transmission capacity to ensure that each generator faces many competitors at all times. These conditions are very demanding, and may not easily be sustainable. Although many electricity industries have been restructured successfully, they all started with substantial spare capacity. As time passes, if prices remain low because of sufficiently strong competition, then entry will be unattractive and capacity will become scarce. In addition, incumbents are likely to wish to merge to increase their market power, and to act to deter entry by various means. One should therefore be rather cautious about the applicability of this solution. It may be sustainable where there is sophisticated regulation of competition, and where regulators can find a way of ensuring "over-investment" in transmission, to maximise the extent of the market (beyond that needed in a tight power pool under central dispatch). California reminds us that sophisticated regulation is a scarce commodity even in advanced countries.

2.2 Reform experience in developing countries

What may be termed the standard reform model for the ESI is one in which the potentially competitive parts are separated from the core natural monopoly transmission and distribution, with a regulatory agency setting the transmission and distribution tariffs. Competing generators offer electricity to the wholesale market, eligible customers are free to choose their supplier, and new entrants are free to build new capacity with non-discriminatory access to the grid and final customers. By that standard, in the developing world Latin America is not only where the first reforms started (in Chile), but where the standard model has been most influential and most widely adopted. How well has it worked?

According to Izaguirre and Rao (2000), in the period from 1990-9 Latin America took $77 billion out of a total of $193 billion of private electricity projects in developing countries. The ranking of countries in terms of private investment per capita very much follows the order of private sector involvement, with Chile leading, followed by Argentina, then Brazil, Panama, Columbia and other Central American countries. Chile's progress has been of enormous significance in demonstrating the feasibility of private sector involvement in the ESI of developing countries, and has provided lessons for subsequent reforms. Its progress was sensibly cautious, with restructuring and legislation introduced in 1982 and privatisation not starting until 1986. Given the obvious fears of expropriation by private investors, Chile had to create confidence by carefully identifying the rights of the investors in primary legislation that would be difficult to change. This had the advantage of creating shareholder confidence, but the disadvantage of creating a very inflexible structure that was ill-adapted to addressing problems of market abuse.

2.2.1 The experience in Chile

After the new electricity law was passed in 1982, the two state-owned integrated companies, ENDESA and Chilectra, were divided into separate generation and local distribution companies - thus ENDESA was divided into five separate generating companies and eight distribution companies. However, the interconnected transmission system was placed under ENDESA's umbrella, giving that generating company potentially preferential access, and storing up problems for the future.

The restructured companies were subsequently privatised and by 1991 there were 11 power generating companies, 21 electricity distribution companies and two integrated companies. Galal (1994) presents a social cost-benefit analysis of the privatization of Chilgener, one of a number of competing generators, and Enersis, a monopoly distribution company, both created out of Chilectra. Chilgener increased its profit, investment and productivity after divestiture. The increase in profit was due to a move to marginal cost pricing and increased capacity utilization, both due to improved regulation rather than divestiture. Galal's base estimate shows that the present discounted value of the simple sum of gains was Ch$4 billion, 21% of the private value of Chilgener. Of this Ch$4b, Ch$2.7b went to foreign shareholders, Ch$3.8b went to domestic shareholders, Ch$0.1b to employees, zero (ie no change) to consumers, and -Ch$2.7b (ie a loss) to the Government.

Enersis, unlike Chilgener, is not subject to competition, and its external regulatory regime did not change with privatization. Nevertheless, privatization encouraged the company to reduce losses from theft and improve returns on non-operating assets. The gainers were shareholders (Ch$42.9b, of which foreign shareholders received Ch$2.2b), and honest customers (Ch$17.5b), while the losers were non-paying consumers (Ch$9.8b), the Government (Ch$5.6b), and Chilean citizens (Ch$26.3b), who lost the opportunity to receive the shareholder gains in ENDESA (had they remained publicly owned) which were instead captured by Enersis and passed to its own shareholders. The net benefit to Chile was Ch$16.3b, and to foreigners Ch$2.2b, or together 31% of the private value of Enersis. Privatization was again costly to the Government, resulted in considerable redistributions (some desirable, from non-paying to paying customers), but more of the gains were captured domestically than in the case of Chilgener.

The sequencing of reform in Chile is instructive in that the reform of the regulatory system and the restructuring of state enterprises occurred first, to ensure that the new enterprises had some experience of the regulatory regime before privatisation. Privatisation proceeded slowly, avoiding some of the risks of underpricing with attendant larger transfers to shareholders, while wide share ownership created political support for the new system.

The benefits of restructuring and price regulation are that prices now reflect economic costs, being regionally differentiated and related to SRMC, as efficiency requires. In addition, although prices are close to marginal costs, the companies have made reasonable profits, and have been willing to invest in new hydro capacity as well as in transmission and distribution (Spiller, 1996). The worries lie largely on the degree of competition in the system, which will affect the costs used to set the prices. ENDESA has been strongly criticised for its monopoly over transmission, which allowed it to limit access by other generators. These generators also disputed the pricing of transmission. ENDESA also has dominance over current generation capacity (over 50% in the central system) and over access to water rights for future hydro power (over 40% of economically viable water). New generation plant has been small scale, built when needed rather than reaping economies of larger scale, suggesting that ENDESA may not be subject to much competitive pressure.

If Chile failed to deal adequately with competition concerns, it did place some constraints on the ability of generators to exploit their market power. The regulated part of the wholesale market relates the wholesale price to audited costs. The drawback is that this has led to endless arguments about the measurement of these costs. Similarly, Chile’s innovative attempt to regulate distribution companies on the basis of a hypothetical model distribution company provided strong incentives for efficiency improvements, but was relatively ineffective at passing these cost reductions through to final consumers. Between 1987 and 1998 wholesale prices fell by 37% but final prices fell by only 17%. The rate of return of the main distribution company rose from 10% to 35% over this period (Fischer and Serra, 2000).

2.2.2 Argentina's reforms

The next major reform was in Argentina, which learned much from Chile's mistakes. Reforms starting in 1992 transformed the structure, ownership and regulation of the ESI (Perez-Arriaga, 1994). Argentina had a population of 34 million, generation capacity of 16,000 MW, and consumption of 51 TWh (1994), though capacity availability was initially very low (at 45%). The generation mix was fairly balanced, with 44% hydro, 45% thermal and 11% nuclear. As in England, restructuring unbundled the industry into generation, transmission, and distribution. Distribution is regulated as a natural monopoly and the generating companies were so divided that no generator had more than 10% of capacity initially. By the end of 1993 there were 70 firms trading in the bulk supply market. By 1997 there were 40 generating companies, most of were by then private, and over 20 distribution companies, many of them provincial. The national grid and the three federal distribution companies were privatised, as were about half the provincial distribution companies.

The wholesale electricity market determines prices on the basis of bids that can only be changed every six months - reflecting a move away from the audited cost approach of Chile, but not to the daily bidding of the English Pool. The theory is that a bid that must remain valid for a longer period is less likely to be used to manipulate the market to take advantage of short-term opportunities (curiously, the 2001 reforms to Trading Arrangements in Britain have moved in the other direction from daily to half-hourly bidding).

The reforms had a very positive effect on plant availability (which increased from 45% to 72%) and power outages, while the pool prices are giving market signals not only for investment in generation but also in transmission. The monthly average price in the wholesale electricity market fell from about $45/MWh (with peaks over $70/MWh) steadily down to about $15/MWh in 1997. (The 1998 average was $24/MWh, in 1999, $26/MWh, and in 2000, just over $27/MWh, since when it has drifted back to about $25/MWh annual average.)[8] Despite the fall in prices, 4,927 MW net additional capacity was added to the system, while available capacity increased from 5,930 MW in 1992 to 13,530 MW in December 1997. More than half of the new capacity was hydro-electric (all commissioned before the reforms), though the trend demand for gas has

[8] Updates can be downloaded from http:/www.cammesa.com.ar

almost doubled over the period. CCGT increased from 144 MW in 1996 to 5011 MW in 2001, up to 23% of gross installed capacity in the main system (MEM). The availability of abundant cheap gas, as in Britain, greatly assisted the transformation of the electricity sector.

The wholesale electricity market appeared to be operating extremely competitively, though there were criticisms that regulatory constraints, methods of calculating prices, and price caps interfered with efficient functioning of the markets. Specifically, the capacity payments, set at $10/MW, did not reflect opportunity costs, and the system of smoothing prices for distribution companies discouraged them from contracting. The regulated prices failed to reflect costs. It would have been preferable to allow prices to track costs moment by moment, even though the underlying prices would be more volatile, and to encourage distribution companies to buy on contract to hedge these risks, rather than discouraging them by not allowing them to pass through any contract costs to final customers. The California experience suggests that it is most important to encourage contracting with distribution companies, mainly to alleviate problems of market power (that were not so important in Argentina), but also to signal the need for and willingness to pay for adequate capacity.

2.2.3 Colombia

Colombia, coming later, was more ambitious in reforming the wholesale market, and more closely followed the English Pool model. The reforms suffered from the delayed and incomplete privatisation of the distribution companies. They were under municipal ownership or *de facto* control, creating local patronage that was hard to oppose. They remained inefficient, overstaffed, corrupt, and with poor collection and high theft. The generators would not sign contracts with the clearly uncredit-worthy distribution companies, and the Power Pool was similarly unable to collect payment. When the Pool cut off major cities, the population blockaded highways until the Superintendent of Public Services forced the Pool to restore service (Millan, Lora and Micco, 2001), risking bankruptcy.

While the distribution experiences were unsatisfactory, the reform of generation also left much to be desired, as it repeated the British mistake of not creating adequate competition in the wholesale market. The 3-firm concentration ratio (i.e. the market share of the three largest firms) in Argentina is only 30%, but in Colombia and Chile is 50% (and substantially higher in most smaller countries). As a result, market power has been a continuing problem in many Latin and Central American countries.

2.2.4 Brazil

Brazil, like California, faces an electricity crisis, and like California, raises awkward questions and points to the cost of flawed and inappropriate reforms. Rather than repeat the full details of reform in the largest Latin American country, this brief account will just highlight some of the lessons that can be drawn from the attempt at reform. In common with many developing countries, the main argument for reform was to overcome problems of under-investment and the fiscal burden of financially poorly performing companies. Despite continuing rapid growth in demand, investment peaked at about $12 billion per year in 1982 (and again briefly in 1987) before declining steadily to $3 billion by 1999 (de Araujo, 2001). The reforms, started in 1990, were given more momentum by the Cardoso administration from 1994, and were heavily influenced by the English model of unbundling, competition and privatisation (with the possible exception of transmission).

The distinctive feature of Brazil that contrasts sharply with Britain is that it is dominantly (95%) hydro-based with large multi-year storage dams, and relatively recent access to gas, with an immature gas network and market. In contrast to almost all other countries, the long-run marginal cost of additional hydro investment is probably lower than that of CCGT. In addition, dispatching the dams gains considerably from basin-wide coordination (allowing perhaps an additional 20% firm power), while considerable rainfall fluctuations mean that it is advisable to maintain adequate water reserves, or face, as at present, severe and long-duration shortages when rains fail and dams have been depleted. Finally, the dams are multi-use, and managing them for irrigation and other water uses requires close coordination between the water management authorities and power dispatch.

These conditions are the least propitious for a competitive, privately owned generation market. Investing in multi-use hydro-electric projects that need coordinated regulation creates considerable private investor risk. Dams are entirely front-end loaded, with negligible running costs but massive investment costs. The gains from private operation (once built) are thus likely to be small, and the risks that prices will be held down in periods of tight demand high, while if water is spilled, prices may fall almost to zero in a competitive market. Investing in CCGT is equally unattractive, for although from a least-cost system expansion view point, some low capital cost flexible plant may be desirable, the financial economics look terrible. It would only operate in drought years, and the overall load factor would probably be less than 35%. Its average cost would exceed the LRMC of hydro, and if hydro prices are suppressed in periods of shortage, then the average *price* will be even lower, and hence unremunerative without special payments for its role as emergency capacity or reserve.

The uncomfortable conclusion is that it is unlikely that private ownership of generation is an efficient way to plan, develop and finance the generation sector in Brazil. It is an open question whether it would ever be in countries requiring large-scale multi-use river basis management schemes. The most favourable circumstances would be for dams whose sole use is for hydro-electricity, and where the price of electricity is set by thermal plant, as in Chile and Argentina. Private involvement in generation has a comparative advantage where timely construction and maintenance are required to deliver possible efficiency benefits, but is least likely to work in dominantly hydro systems.

In the past, Electrabras (the largest state owned generator) has, with considerable financial support from the international financial institutions (IFIs), been able to mobilise the required funds to finance hydro investment. Given the remit to plan a coordinated programme of transmission and generation investment, and the financial autonomy to undertake it, subject to proper regulation and audit, one would expect a competent and well-managed company to be able to finance and undertake such an investment programme. The main risk, which may be hard to protect against, is that the state or provincial government may be attracted by the large rents accruing to hydro systems, to transfer the funds for other uses - public finance, cheap electricity, patronage, etc. Highly capital-intensive industries like hydro-electric generation and long-distance transmission lines are vulnerable to such expropriation in periods of inflation or downturns in forecast demand, when the pressure to finance investment declines for a period. Putting in place the kind of indexed return on an inflation-revalued asset base requires a degree of regulatory sophistication that has only emerged gradually under the English system of RPI-X regulation of network utilities.

2.3 Addressing the systemic problems

What advice can we give to a country whose ESI is still in state ownership, and where there is genuine political commitment to reform? The first question to address is whether there is a logical sequence of reforms, and whether it is costly to undertake reforms in the wrong order. It is a good principle that any reform addresses the most important problems first, and that the early reforms should if possible create a momentum for future desirable reforms, while minimising the risks of failure and policy reversal. Reversible and less risky reforms can be undertaken more readily than irreversible (or costly to reverse) and more risky reforms. Some irreversible reforms may be necessary to commit the country to future desirable changes, and privatisation is often argued to be one such reform. Nevertheless, the principle that irreversible reforms require more careful design and assessment than reversible reforms holds good.

Fortunately there is growing evidence on what constitute robust, self-sustaining and desirable reform strategies, and what strategies are risky and may lead to undesirable outcomes. Privatisation itself is only reversible at high external cost (loss of reputation for foreign investment). Imperfectly designed privatisation can complicate subsequent reforms. Similarly, it is often hard or costly to reverse structural choices, such as the degree of vertical and horizontal integration.

2.3.1 Privatising and regulating distribution

The diagnosis presented earlier is that the current system of ownership, management and finance leads to unbalanced tariffs, unremunerative prices, often associated with a failure to collect bills or reduce theft, excessive costs, and hence an inability to sustain efficient investment. The logical place to break this vicious circle is with the key mechanism that sustains non-cost reflective tariffs - the distribution and supply end (usually combined) that collects revenue from final consumers. The best way to both start and sustain this reform is to separate the network monopoly of distribution from the rest of the ESI, privatise it, and subject it to price or revenue cap regulation.

There is a related question about whether to separate out the supply (or retailing) function from distribution, or at least to signal that this will take place in due course, as part of the larger programme of separating competitive from monopoly segments. This partly depends on whether it is expected that a supply franchise for smaller customers (perhaps all those taking less than 1 MW or possible 100kW) will continue. For various reasons discussed below, the case for full supply liberalisation is probably weak even in developed countries, and arguably even weaker in developing countries. If so, then the natural supplier to the franchise market is the distribution company, and the main requirement is to ensure that other suppliers to eligible customers have non-discriminatory access to the distribution network and meters. It would be sensible for this requirement to be written into the electricity legislation.

Privatisation is not feasible without a commitment to cost-reflective tariffs, which needs effective and independent regulation to be credible. On the principle of delaying irreversible reforms until the conditions are right, the government should state its intention to privatise as soon as the regulatory institutions command the necessary private sector confidence. That confidence will only be forthcoming if the government (and likely successor governments) are seen to be strongly committed to reform. If there is any doubt, then investors will be rightly cautious. There are many ways in which interest groups can derail or undermine reforms. Unless everyone believes that the government will be able to effectively over-rule or discipline these opponents, then privatisation will seem very risky. This will either make the distribution companies unsaleable, or only at such a low price that any subsequent profits will seem unjustified. In such cases it would be better to wait until there is credible commitment to reform. Testing private sector support is relatively straightforward - investment bankers will be able to assess whether they consider that a flotation would be successful at an acceptable price.

The obvious difficulty is that if privatisation is unattractive to politically powerful groups, then their best strategy is to derail the creation of regulatory institutions. Knowing this, the government has various options, none of which are very attractive, and some of which are definitely high risk. One strategy is to press on with privatisation and setting up regulation in parallel, perhaps putting in place strong contractual commitments to the distribution companies that will run until the regulator is fully operational and effective. A variant of this is to choose other governance structures short of full privatisation, such as management contracts, or limited-term renewable concessions with carefully designed contracts. The experience of management contracts is not encouraging - they were tried and abandoned in Orissa (see Box 1).

In Chile, privatising distribution solved the problem of theft, as noted above. In Colombia, continued municipal ownership or control which failed to address problems of low collection derailed much of the rest of the reform, showing how critical it is to address the retailing stage before attempting the remaining reforms. However, high theft and losses create another difficulty with privatisation and regulation, and that is to determine the extent to which the new owner is to bear the risk of eliminating or failing to eliminate theft and corruption.

> The first Indian State to start reforming was Orissa in 1993, with 2,900 MW of generation supplying 1.3 million consumers, of whom less than half were metered. Losses exceeded 50%. The Orissa Electricity Regulatory Commission (OERC) was created in 1995, and the Orissa Electricity Reform Act came into force in April 1996. The Act unbundled the State Electricity Board, and eventually created four distribution companies. The first was initially operated under a management contract or Distribution Operations Agreement, awarded to the Bombay Suburban Electricity Supply Company (BSES) in October 1996. It was revoked in April 1997 when it became clear that corporatisation under a management contract had not worked. Part of the problem was that the employees remained with Gridco, the State-owned transmission company, and management continued to be subject to continued political interference. It became clear that the more radical reform of privatising the distribution companies was required. That step was completed in 1999.

Box 1 Management contracts in India

Again, Orissa provides salutary lessons. After the failure of the management contracts (Box 1), the Government of Orissa invited competitive tenders to strategic investors for 51% of the shares of each of the four distribution companies in late 1997, with 49% remaining with Gridco, the transmission company, under state ownership. Bids were submitted in the second half of 1998, and after a certain amount of negotiation, three discos were awarded to BSES in April 1999 and the fourth, Cesco, was awarded to AES Corp (USA) in September 1999. These investors paid a premium of 40% over the revalued book value of the assets.

The regulator, OERC, holds open annual tariff hearings that result in revisions to the bulk supply tariff (BST) and to the tariffs set by the discos. There were tariff orders in March 1997, November, 1998 and December 1999 (the first after privatisation). One of the key issues in setting the tariffs is the level of losses that is assumed in determining the revenue requirements of the companies, and this has been gradually forced down to provide incentives for the companies to reduce losses.

The experience of these early tariff revisions has been mixed. OERC has insisted on keeping uniform tariffs across the state despite differences in costs, and has differentiated the BST charged to each disco to compensate. OERC kept down the lifeline tariff (on the first 100kWh/month) after the 1998 cyclone, and denied interest payments on bonds raised to securitise payables and raise working capital. In the words of the Frontier Economics report, this totally undermined the financial recovery plan which had been recently prepared for Gridco. (Frontier Economics, 2000, 1.2.1).

Subsequent developments were not encouraging. Gridco still owns 49% of the distribution companies, and is itself effectively bankrupt. The regulator (and perhaps the companies) made over-optimistic estimates of how rapidly theft and losses could be controlled, so that the distribution companies failed to achieve the target allowed revenue. On July 18, 2001, AES filed arbitration proceedings in the Orissa High Court, claiming that Gridco owed Cesco $45 million, and threatened to sell out and quit the country.

Clearly, it is difficult to devise a sensible regulation system for the transition from a corrupt, theft-prone and loss-making distribution company to a viable privately owned and efficiently operated company. If the regulator is too optimistic in assuming that losses will decline, then the distribution company is likely to refuse to pay the generating company (or single buyer, as would frequently be the case, and was in Orissa). If, on the other hand, the company is allowed to pass on any losses in reduced payments, there would be little incentive to reduce losses. If they are allowed to keep all or most of the revenue previously stolen or not collected, their profits may reach unacceptable levels - as has been the one of the main criticisms in Chile. How this might be done is discussed below in the section dealing with tariff regulation.

2.3.2 Regulating distribution

Satisfactory regulatory institutions need to be in existence and to have the confidence of the private sector for successful privatisation. Private ownership requires a credible and effective system of regulation if potential owners are to be willing to pay fair market value for the assets and are to be persuaded to invest efficiently. Price-cap regulation provides superior incentives for efficiency, but requires periodic resetting if the efficiency gains are to be passed through to consumers. It may also need to be reset at the request of the utility if it is not able to finance needed investment.

Buyers need to know how the price-cap will be reset at subsequent periodic reviews if they are to properly value the company, so this will also need to be set out in the legislation or the licence or concession contracts with the operators. Given the high stakes involved in resetting prices, which transfer rents from one side of the market to the other, a satisfactory dispute resolution procedure is also required and needs to be specified clearly in advance of privatisation. Finally, price-cap regulation provides strong incentives for cost-cutting. To prevent cost-cutting lowering the quality of supply, minimum quality standards will need to be set, with penalties for failure (payable to those suffering the poor quality).

Price-cap regulation is more demanding than traditional cost-of-service or rate-of-return regulation, where the procedure for rate-setting can be more carefully codified, leaving less discretion to the regulator, and hence providing more assurance to the utility. However, rate-of-return regulation runs into the problem that the rate of return required by an investor in a developing country with a poorly developed capital market may be politically unacceptable. Certainly some investors have preferred properly indexed price caps precisely because they conceal from public discussion the likely rate of return. This problem is only temporarily avoided by price-cap regulation, because when it comes to resetting the price caps, the return on the asset base is needed to determine the allowed price. The asset base must be indexed, uprated by new investment, and then the required rate of return to elicit future finance determined before prices can be reset. Typically the required rate of return is public information, and will be subject to critical scrutiny.

The requirement to set in place proper regulation is now widely recognised as necessary, and its absence from the legislation, licences and rules under which the various institutions operate will be clearly signalled by bankers, financial advisors and consultants. Let us suppose for the moment that privatisation of distribution looks promising, and probe more deeply into the details and problems of setting the tariffs.

2.3.3 Setting cost-reflective tariffs

The first step is to identify the efficient costs of distribution (and similar principles apply to transmission). These will include interest on and depreciation of the asset value (or Regulatory Asset Base, RAB - see Newbery, 1997b), as well as the efficient level of operating costs and distribution losses. The efficient operating costs may be substantially below what can realistically be achieved in the near term, raising questions of how best to motivate improvements without greatly increasing the risk placed on the company. One appealing but risky strategy is to specify in detail how tariffs will be set over a realistic time horizon (4-5 years) and how they will be revised periodically thereafter, and then invite bids for the right to these revenue streams. This avoids one problem - that of determining the speed with which the company is able to drive costs down to the efficient level, but creates several others: the problem of determining the initial asset value, the greater problem of how to reset the tariff, and the related risk of receiving a relatively low privatisation sales price and/or granting a politically unacceptably high return to the buyers.

The issue of the initial RAB can be partially finessed by determining the politically acceptable level of tariffs, predicting a realistic revenue stream, deducting a predicted path of operating costs (starting at the current level, and converging on the efficient level), determining a required rate of return to finance new investment, and then discounting future profits to determine the initial RAB. This may bear little relation either to the (revalued) book value or to the sales price, and in any case is primarily a device for determining depreciation, and uprating its value for new investment for resetting the price cap at the next review. It still runs into the problems of determining the required rate of return (or the Weighted Average Cost of Capital, WACC), and the risks attached to forecasting future costs and revenues.

There are a variety of methods that have been tried to address these risks. In Chile, the method of determining the WACC is prescribed in legislation and is related to the performance of the local stock exchange. That may be reasonable where there is a liquid capital market and where most distribution finance is locally sourced (with a large share of debt). It is less plausible where these conditions are absent. Some of the risk can be shared by variants of sliding-scale regulation, where if the costs or revenues deviate from the value specified by the regulator (or in the prospectus), the deviations are shared between the consumers and utility. Thus if revenue were 20% less than specified, but costs were as specified, and the sharing rule were 50:50, the utility would be entitled to increase tariffs by enough to raise the revenue to 10% less than forecast. Often these bands are capped, so that deviations outside the band fall entirely on or solely benefit consumers, limiting the downside risks to the owner. The shortfall in profits might have to be underwritten as a claim on the initial privatisation sales receipts, where there is little confidence in the ability of the regulator to secure tariff and specifically consequential revenue increases.

Here is not the place to speculate on how best to address these various problems, which will be better illuminated in due course as experience accumulates. Chile has been commended and criticised by basing distribution tariffs on a hypothetical distribution company. One advantage is that it allows a determination of the unit total cost (including the return on capital) with strong incentives to outperform, but it suffers from either high realised rates of return (the current criticism) or excessive risk and/or inadequate returns to underwrite investment (to avoid which the tariffs may have to be set so high as to risk the first objection).

One possibility is for the buyer to tender not just for the amount to be paid, but the required rate of return to equity. The company with the cheapest net cost of distribution would then be chosen. The required return might be based on an assumed 50:50 equity:debt and made a function of the credit rating of the country (or some other measure of the cost of capital on the international market, which can change for better or worse over the likely future). The more dimensions across which bids need to be judged, the harder it is to ensure a transparent and fair tender auction. Often the rate of investment in new connections, metering, and possible refurbishment may also be components on which the bid is judged, and some of these may need to be predetermined to reduce the dimensionality of the bid.

There is relatively little experience in resetting tariffs (apart from the very unsatisfactory annual revisions in Orissa), so it remains to see whether the system described earlier, which has been tried and tested in the UK and is being tested in The Netherlands, will translate to developing countries (or to which ones). Several other issues have to be addressed in resetting tariffs, most obviously inflation but also the sensitivity to various cost drivers. Thus the UK distribution revenue control takes the form RPI - *X*, with 50% fixed (in proportion to a predetermined projection of customer numbers) and 50% varying with the volume of demand (Ofgem, 1999). Thus if the initial revenue is 100, the price level (RPI) increases by 12%, *X*, the efficiency factor, is set at 2%, and demand (kWh) grows by 8%, total revenue is allowed to rise in money terms by 100 x (1.12 - 0.02) x (1 + 0.5*0.08) = 110 x 1.04 = 114.4, and the real distribution cost per unit will have fallen by 5.4%.

2.3.4 Tariff structure and setting the final price

The distribution company will then need to decide how to set the various tariffs (Distribution Use of System, or DUOS charges) for HV, MV and LV and other tariff categories to collect this revenue. The company will have an incentive to make these tariffs cost-reflective, for the formula for total revenue has been designed to cover total costs, so if one tariff is set above cost some other tariff will be below cost, and increases in sales under this tariff will result in losses. The same steps will be needed for setting the Transmission Use of System charges for the use of the high tension transmission system or grid, together with charges for power losses and for any ancillary services provided by the grid company.

Once the wholesale (or ex-power station) price is determined, the main elements will then in place to determine the final prices of electricity delivered to franchise customers. This will be the wholesale price plus the TUOS (including other transmission services) and DUOS charges, and the amount needed to cover the cost of supply (billing, meter reading, contracting, etc). If there is a single buyer, this process is relatively simple, but if distribution companies are free to contract with generators, then the final price for captive customers may need further regulation. On the one hand, the distribution company should be encouraged to achieve high levels of contract cover (to signal demand and mitigate possible generator market power). On the other hand, the ideal is to encourage efficient contracting and discourage sweetheart deals with subsidiaries. In The Netherlands, the regulator allows the distribution company to pass on a weighted average of the company's own contract costs and that of the rest of the companies, all of whom have to deposit full contract details with the regulator. This has good incentive properties but can expose companies to considerable purchase or contracting risk, depending on the weight attached to the share of other companies. Given that competitive contracting is likely to be associated with more mature and sophisticated markets, the added complexity may be reasonable in such cases.

The main mistake to avoid is regulating prices which contain volatile elements without some means of passing through or insuring against fluctuations in uncontrollable components, of which the most important is the wholesale price. If the final price is capped, and the wholesale price free to increase sharply, and if the suppliers are not hedged with contracts, they will rapidly become bankrupt, as in California. Provided the distribution companies are not prevented from rebalancing their tariffs, and providing supply companies can pass through all the costs in the chain (the wholesale electricity price, TUOS, ancillary services, DUOS) with an adequate margin, then distribution companies can be privatised without necessarily waiting for a full restructuring of generation. The converse, of privatising generation before setting in place the full mechanism for sustainable pricing of the downstream elements, is unwise and may be very costly, as will be argued below.

Privatisation in this context is only likely to be effective if the majority ownership passes to commercial owners. Voucher privatisation, coupled with allocations to local authorities and only minority sales allowed to strategic investors (for example as followed in the Czech Republic and popular in Eastern Europe), may fail to create true owners concerned with and empowered to pursue profits by cutting costs. Partial privatisation without satisfactory governance may merely create vested interests opposing necessary further reforms, and essentially loses the option value of state ownership - where the option is to make major reforms without the need for excessively complex compensation arrangements to other owners.

2.3.5 Rebalancing and raising tariffs

Electricity consumption in middle and higher income countries is extremely price and income inelastic. Electricity is therefore an essential service whose price has important distributional implications. Subsidising electricity appears politically attractive as it can approximate a lump-sum grant, targeted in proportion to the number of household members. Conversely, raising the price of electricity appears like a lump-sum tax bearing heavily on the poor, those with large families, and, in cold countries, the vulnerable and old. Raising prices to households is highly politically sensitive, and the Conservative Government in Britain was defeated on an attempt to raise value added tax from the low to the standard rate (from 8% to 17.5%). The incoming Labour Government immediately implemented its election promise to cut the VAT to 5% (the lowest level allowed by the EU).

Countries in Central and Eastern Europe face similar strong political opposition and have found it very difficult to even maintain price increases for electricity in line with general inflation. Only very determined efforts such as those in Hungary have managed to restore real electricity prices to their pre-1989 levels, and even there they are still some way below the cost-reflective level. They can be kept down by not rewarding the capital embodied in the transmission and distribution networks, and paying generation the average rather than marginal cost of generation, again ignoring most of the capital value of the equipment. Generation prices may not have to move as much as might be expected from this description, as the average total cost of new gas-fired generation may be below the average variable cost of inefficient old coal-fired generation - as seems to be the case in Hungary and was certainly the case in Britain. Nevertheless, in many countries generation prices will have to rise if the wholesale price is to reflect the entry price of new generation.

The margin between wholesale and retail prices can be kept at a lower level in the medium run by effectively writing down the asset value and hence the Regulatory Asset Base, but over time as new investment is added to the RAB, the capital cost element in transmission and distribution will gradually rise. Such a gradual adjustment will be politically less painful than a sudden increase, but the cost will be reduced proceeds from the sale of the transmission and distribution companies. The value may be politically unacceptably low, in which case the regulatory formula may have an additional K factor (as in RPI - $X + K$ for the price cap), raising prices more rapidly to ensure adequate cash flow for new investment. This would increase the flotation value while preserving a smooth transition from current to equilibrium prices.

Other strategies are available to ease the transition to cost-reflective prices. Many countries offer a life line level of sales, under which the first 50 kWh per month may be provided at a subsidised rate, but levels above this pay the marginal efficient price. That way the rents associated with past investment in the network can be transferred selectively to households without removing incentives for efficient consumption at the margin. In some countries, commercial, regulatory, and eventually political pressures conspire to eliminate this lifeline element (Hungary is the most recent example in 1999). There would seem to be no reason for subsidising industrial and commercial customers, who together probably account for two-thirds of total demand. Agricultural users represent a politically intractable problem in some countries like India, where the inefficiencies of underpricing electricity are more serious: socially more expensive electric pumps for tube wells may displace perfectly adequate diesel pumps. It may be necessary to grandfather existing connections where pumps are already installed but to only offer new connections at commercially feasible tariffs. Existing grandfathered rights may have to be time limited to the expected life of a tubewell pump and lifeline rates with marginal prices at efficient levels may also be attractive. Whether any of these rather complex schemes are viable given likely levels of corruption and whether it is reasonable to impose them on privatised or franchised license holders (as commercial suppliers would not willingly offer such tariffs) is unproven. At best they offer a temporary transitional arrangement which should have a strong sunset clause to prevent future unnecessary complications.

Underpricing electricity in poorer countries is far less defensible on income distributional grounds. The main beneficiaries are invariably the richer urban dwellers, and the costs are felt indirectly by the poor, who may be deprived of the chance of electricity provision at all because of the inability to finance extensions of the system. Electric light is substantially cheaper than kerosene or other alternatives, and consumers are willing to pay high prices for a minimum level of consumption that provides light, TV and other modest appliance use. Unfortunately, political support may be concentrated in urban areas where consumption is highest. Even here, improvements in quality (avoiding blackouts and brownouts) may more than compensate for increases in prices.

Suppose that it is politically impossible to raise electricity tariffs to households in less than five or so years. Would it still be possible and desirable to privatise distribution companies? The evidence from Central Europe is that it can be done, with the advantage of launching the process of regulatory reform and restructuring that should eventually lead, with careful decision making, to a fully liberalised ESI. The main problem will be to maintain a low wholesale price of electricity for at least the household franchise while establishing regulated transmission and distribution charges and a cost pass through mechanism for the energy price.

Generating companies would then require contracts of a suitable duration (the length of the transition period) to deliver fixed amounts of power at low prices, though they might be freed to sell surplus power at the market clearing price. Prices to non-household customers could then be raised to efficient levels, and trading between eligible customers and generating companies introduced. The main problem with this arrangement is to provide credible and efficient price signals for the entry of new power generation. If most or all electricity passes through a bulk wholesale market or pool, or if the power exchange is sufficiently liquid to produce stable and transparent price signals, then household consumers can be protected by contracts while allowing the wholesale price to give efficient price signals. The main problem then lies in creating satisfactory wholesale markets, and resolving the structure of contracts between generators and suppliers. The objective is to protect or subsidise sensitive parts of the market without discouraging competition in generation and supply to eligible customers, and to end fiscal profligacy as soon as possible.

2.3.6 Options where privatising distribution is not yet viable

It may be that the prospects of early privatisation of distribution are so poor that there is no point in proceeding. Would it still be sensible to set up an independent regulatory agency when there is little immediate prospect of privatising distribution? The answer would appear to be yes. Among developed countries, Norway, has had a successful independent electricity regulator, in the presence of continuing significant state and municipal ownership (Jamasb and Pollitt, 2001). The Chilean example also suggests a positive answer, as part of a dedicated attempt by a specialist agency to reform and restructure tariffs, and devise incentives for improved performance. The obvious danger is that if the distribution company is politically powerful enough to resist the kinds of reform needed to make privatisation viable (reducing theft, sacking excess workers, etc), then it is likely to be powerful enough to sideline and discredit the regulator. Reform commitment requires adequate political power and support before it makes sense to start on the task.

Taking a pessimistic view that neither privatising distribution nor creating an independent regulator is currently feasible, the next question is whether it is possible to consider reforms elsewhere in the ESI, and specifically whether it is sensible to involve private investors and owners in generation.

3. Private involvement in generation

The private sector can be involved in generation in two ways. Privatisation normally means the sale of a majority controlling share in existing generation companies, possibly retaining nuclear power stations (and/or major multi-use hydroelectric dams) in publicly owned companies. If generation is to be privatised, then the state electricity company or board will need to be further subdivided into a large enough number of competing companies. The second way is to invite Independent Power Producers, IPPs, to tender to supply the (preferably restructured) state electricity company, thus bringing new private investment into the industry with more modest reform and restructuring.

In both cases, the logical first step is to separate transmission from generation and to create the conditions for regulated third party access (rTPA) to transmission. Again, transmission will need to be regulated (and similar principles apply as in distribution, but with fewer problems if, as seems sensible (at least for a transitional period), transmission remains in public ownership. That argument is defended below when transmission issues are considered in more detail. The argument for separation (preferably ownership separation) of transmission from generation are by now standard. A transmission company that has ownership stakes in generation is likely to favour its own generation over that of other owners. This may not be so serious where all new capacity is put up to tender auction, and the transmission company acts as the Single Buyer, described below. It creates far more serious problems if the intention is to create a competitive and less-heavily regulated wholesale market with free and contestable entry, as an increasing number of examples testify (see e.g. the problems in Chile and Scotland).

There are two quite different ways of introducing competition into generation. The first is to create a wholesale spot market (Pool) or a power exchange (PX) where generators can sell directly to suppliers and/or final buyers. The EU Electricity Directive requires that buyers taking more than 40 GWh (actually those accounting for at least 26.48% of total demand) should be free (eligible) to contract with generators from 19 February 1999, and that this threshold should drop to 9 GWh (33% of the market) by 19 February 2003. In many countries, this may only involve a few hundred, rising to a few thousand buyers, though clearly they account for a significant fraction of total demand. If distribution companies (more accurately, the supply businesses with the licence to supply non-eligible customers in the distribution area) are counted as eligible buyers, then all electricity would need to be sold to suppliers.

If eligible buyers are to buy from suppliers or generators, there must be a market or exchange where the buying and selling can take place. The parties will need access to the transmission and distribution systems to ensure delivery, best arranged under a system of regulated Third Party Access. This approach goes naturally with an authorization procedure for building new generation capacity, under which IPPs are free to enter the industry provided they obtain authorization (planning permission, environmental clearance, and satisfy any restrictions on the choice of fuel).

The second approach to introducing competition into generation is the Single Buyer Model (SBM), under which the transmission company (which may also be vertically integrated into generation and even distribution and supply, as was Electricité de France) is the single buyer of all public electricity generated. Competition takes the form of periodic tenders for new capacity, and the winners sign long term Power Purchase Agreements (PPAs) with the Single Buyer (SB).

The SBM is the only viable way in which IPPs can be invited to tender for long-term PPAs, which are likely to be a precondition of any private investment in generation in an otherwise not very reformed industry. The SBM can also work if the existing power stations are sold to a number of generation companies, and that was the model followed when restructuring and privatising Northern Ireland. As the SBM is the only viable model for partial electricity reform, or where the distribution companies have not yet been privatised, we consider that first.

3.1 The Single Buyer Model

The standard SBM is one in which the SB contracts directly with all generation companies for their entire output. In its extreme form, the SB is also the sole authorised seller of electricity, ruling out supply competition. The EU Electricity Directive insists on market opening, so that if buyers are not allowed to contract directly with generators and instead the SB buys on behalf of customers, then the transmission operator (TO) must publish non-discriminatory tariffs for the use of the transmission and distribution system. The SB is required to pay the producer a price equal to the price paid by the customer *less* the published transmission and distribution tariff (Article 18 (2).) The effect of this intentional restriction on the interpretation of the SBM is to make it functionally equivalent to rTPA, while leaving the SB with additional and relatively unattractive obligations. The intended result has been to make the EU version of the SBM very unattractive, with virtually no takers. The proposed reformed Electricity Directive would actually remove it as an option.

The standard interpretation of the SBM survives extensively in developing countries, and deserves more careful analysis before reaching the EU's view that it is an undesirable form of liberalisation. The obvious attraction is that it allows competitive tendering for the PPAs (securing which is likely to be a financial precondition for investing, even if it is not a formal requirement). An efficient PPA would specify the availability payment for capacity (payable per kW capacity when available for dispatch, possibly at different rates at different times of the year) and an energy payment, linked to the fuel price, per MWh generated. Given these (and other technical parameters), the SB can determine which of the tenders represents best value or least cost (given various constraints such as fuel diversity, import dependence, foreign exchange exposure, etc.). Competitive tendering can indeed considerably reduce the cost of generation, particularly compared to bilateral negotiations between the incumbent SB and a selected generation company (see Box 2).

Hungary invited tenders to build several conventional power stations of up to 200 MW capacity. Twenty-four bids were submitted and opened on 9 October 1998, with a gross capacity about six times the nominal capacity of the tender invitation. The winners were AES Fonix Kft with a 191 MW CCGT plant and Budapest Power Plant Ltd. with a 110 MW co-generation CCGT. The average total cost of electricity produced by AES FONIX will be 6.43 HUF/kWh, while that produced by the Kispesti plant will be 6.87 HUF/kWh (both assuming 7000 hours per year utilisation and indexed to January 1998). The average price deflated by the Producer Price Index to January 1997 would be 5.69 HUF/kWh (3.38 UScents/kWh). The average price paid to the early CCGT entrants (in prices of the same date) was 8.4 HUF/kWh (5 UScents/kWh), or some 45% higher, demonstrating the advantage of an open competitive tender. (see Bergman et al, 1999)

Box 2 Bidding in Hungary

Long-term PPAs appear to offer the attractions of permitting the rapid entry of private finance to meet growing electricity demands without the need for drastically restructuring the rest of the ESI. Indeed, in some cases, the tendering or negotiating process is just grafted on to a vertically integrated and otherwise unreformed ESI. The risks are, however, considerable. If the incumbent SB also owns generation, then it may preferentially select bids from its generation subsidiary (or bias the competition in favour of the subsidiary). Incumbents are loath to face the test of competition, which may reveal the high costs of current operations, and are well placed to disfavour attempts at entry by loading unreasonable conditions on entrants. Knowing this, potential entrants may be reluctant to undertake the considerable costs involved in preparing a credible bid, reinforcing the power of the incumbent and undermining the point of opening generation to outside investors.

Even where the SB genuinely opens competition to new entrants, and even if bribery and corruption can be prevented from biassing the outcome, the entrant will be selling to a monopsonist and will need strong assurances against *ex post* opportunism. That explains the necessity for long-term PPAs, and the frequent request that the contracts be guaranteed by the government, for the financial viability of the SB may be suspect. The problem to which private investment by IPPs is the solution is, after all, the financial inability of the incumbent ESI to finance the necessary investment, which must cast doubt on its ability to service the implicit debt (ie the capacity availability payments in the PPA, which have debt-like qualities).

The recent Asian financial crisis demonstrated the risks attaching to PPAs, and the details are set out in World Bank (1999). East Asia attracted over $US 80 billion into the power sector between 1994 and 1998, over half the total by developing countries in this sub-period, and substantially ahead of the only other major destination, Latin America with $53 billion. Five countries - China, The Philippines, Indonesia, Malaysia and Thailand accounted for virtually all the investment in East Asia. In 1996 68% of incremental power sector investment in East Asia was financed by private capital, and three-quarters of the investment was in green field projects, mostly in new generating stations (World Bank, 1999). In South Asia 95% of private investment was in green-field sites, accounting for 38% of incremental power sector investment in 1996. In contrast, most of the investment in Latin America was for the purchase of divested publicly owned assets, with only one-third for financing new green-field capacity. Nevertheless, in 1996 86% of incremental power sector investment was privately financed.

Reforming countries in Latin America restructured and unbundled their ESIs, and created wholesale electricity markets. In contrast, East Asian countries invited private investment into generation through IPPs, with negligible restructuring and reform. In South Asia, IPPs typically entered on the back of a PPA with the state-owned SB utility. The PPA typically involved payment in dollars, and required government guarantees as default proceedings against a state-owned utility are not normally allowed (see Box 3).

The state-owned Indonesian electricity company, Perusahaan Listrik Negara (PLN) had 21.3 GW capacity at the end of 1996, and 39 projects with 30 GW planned capacity under development or under construction. The US Energy Information Administration reported in Jan. 1999 that at least 26 private power projects with 24.8 GW capacity were at risk of bankruptcy. Most PPAs with PLN are in US$, and PLN was forecasting losses of $1-2 billion in 1999, and has not been able to meet its payment obligations. Hopewell Holdings declared *force majeure* and suspended work on the 1.32 GW Tanjung Jati-B project, started in 1996 and due early 1999. PLN's losses have in part been attributed to alleged corruption, and the government has agreed to independent auditing, as proposed by the IMF.
(see World Bank, 1999)

Box 3 Force Majeure in Indonesia

The financial crisis that started in South Asia in 1997 had a dramatic negative impact on GDP growth rates and hence on electricity demand, as well as on the exchange rate. Between the end of 1996 and the end of 1997, the exchange rate in the Philippines against the dollar moved from 26.3 pesos to 40 pesos, in Thailand from 25.6 baht to 47.3 baht, and in Indonesia from 2383 Rupiahs to 4650 Rupiahs. Whereas the currencies of Thailand and the Philippines stabilised between the end of 1997 and 1998, in Indonesia the currency fell further to 8025 Rupiahs (and in Sep 2001 stood at 9603 Rupiahs).

The collapse in currencies caused a doubling in the domestic cost of electricity under the PPAs, which the state-owned power company was reluctant to pass on to final consumers. Malaysia, which experienced a more modest devaluation from 2.53 Ringgits/$ at the end of 1996 to 3.89 Ringgits at the end of 1997, nevertheless faced PPAs as high as 8.5 UScents/kWh but charged consumers less than 2 cents/kWh after the crisis (World Bank, 1999, p20). These events created financial crises for the power companies and for the governments - for example in the Philippines the foreign debt of the National Power Corporation was more than 20% of the total national debt. (World Bank 1999 p.20). The fall in demand created strong pressures to renege on, delay or renegotiate PPAs, further amplifying the loss in confidence of foreign investors.

It became painfully clear that this form of private investment in power generation is equivalent to expensive foreign debt borrowed by the government. The true cost of the debt may be concealed by the terms of the PPAs, but the interest rates are inevitably high because of risk and the source of finance. Private investors inevitably borrow at higher rates of interest than institutions like the World Bank, even in stable markets, but the risk of lending to state-enterprises in corrupt economies is perceived by the foreign investor to be particularly high, particularly given recent events (see Box 4). Some governments attempted to repudiate the debts entered into by their predecessors, often on claims of corrupt dealing, while other governments had to reschedule if not default. Nor has this form of private involvement led to much restructuring of the sector, and has not addressed the underlying problem of non cost-reflective tariffs set at non-remunerative levels - if anything, the currency crisis seems to have made this worse.

> Pakistan's state power company, Wapda (Water and Power Development Authority) has contracts with 19 private power producers, together with the Hub power company, which is the largest private power plant in the developing world. The Government of Pakistan has been in dispute with these companies since 1997, and in July 1999, set up the 11th committee to attempt to resolve the dispute. The companies were accused of bribing Wapda to raise tariffs, but the formula for setting tariffs had still not been agreed two years later.

Box 4 Problems in Pakistan

3.1.1 Contrasts between the Single Buyer Model and a liberalised wholesale market

Contrast the effects of a currency crisis under the SBM with that under a well-functioning liberalised electricity market in which IPPs sell electricity spot and under contract to final consumers. If the IPPs have confidence in the continued competitiveness of the wholesale electricity market, and the liquidity of the contract market, they will not feel the need to sign very long-term contracts in order to protect their investment. It would be normal for them to sign a sequence of shorter-term contracts (1-3 years) with franchise distribution/supply companies. These franchise holders will in turn be concerned to contract for most if not all of their forecast demand, creating the right conditions for a viable contract market. (Of course, these conditions are only plausible where the distribution companies have reformed their tariffs and practices to ensure that they are credit-worthy.)

In the event of a financial crisis with a collapse in demand and of the exchange rate, much will then depend on how the IPP is financed. If the local capital market is reasonably well developed, and the IPP has issued local debt and purchases domestically produced fuel, it will be insulated against the currency change (though not fully if the fuel is internationally traded). A collapse in electricity demand will almost certainly lead to a fall in the (dollar) spot price of electricity, reducing the profits to the IPP, and possibly leading to attempts by suppliers to renegotiate contracts. If some suppliers declare bankruptcy, the financial plight of the IPP will be adversely affected, but there is no obvious reason why the government need guarantee the terms under which the IPP chose to enter the market. The fall in spot electricity prices will be beneficial to eligible customers buying on short term contracts and this will reduce the deflationary effect on electricity demand.

The natural monopoly transmission and distribution companies should not be particularly adversely affected by the shock, for their revenue will be indexed to inflation, and any fall in revenue should be matched by a comparable fall in operating costs. Although the competitive elements of generation and supply may face financial difficulties and even bankruptcy, the plant will remain after creditors have sorted out claims, while new suppliers can enter the industry and ensure the continued viability of the ESI as a whole.

3.1.2 The case for the SBM

The SBM can misallocate risks between foreign investors and the domestic electricity company where the latter remains in state ownership, and can be a poor substitute for traditional forms of financing electricity investment from multilateral sources. It risks stranding contracts that complicate further restructuring, and creates heavy debts instead of resolving the financial problems of the sector. Having said that, the Californian experience suggests that crises triggering bankruptcy are unlikely to be left to the market to resolve even where the wholesale market has been liberalised, as in the somewhat optimistic scenario just described. IPPs know that in turbulent markets random and ill-considered political interventions are to be expected, and will increase shareholder risk. They are very unlikely to invest in most developing countries without strong guarantees (of the kind long-term PPAs are designed to provide), unless they have unusual confidence in the sensible management of the host country. Such countries in turn are unlikely to experience poorly-managed foreign exchange crises (Argentina could be an exception). It is therefore little comfort to argue that SBM risks can be avoided by liberalised electricity markets, as too many countries lack the necessary preconditions to make that a plausible solution.

That raises the question whether there are any circumstances in which the SBM with IPPs holding long-term PPAs is part of a sensible reform strategy? Bangladesh provides an interesting test case. Recent PPAs signed with the state-owned Bangladesh Power Development Board with IPPs building high-efficiency CCGT burning low-cost indigenous gas look sensibly priced, although the distribution companies still need major reform to be able to pay for the power (Box 5). Some of the foreign exchange risk is hedged by indigenous fuel, though this is obtained under contract from International Oil Companies at prices linked to the international oil price. It would be open to Bangladesh to export surplus gas and provide a better foreign exchange risk. Meanwhile, the new IPPs provide power at lower cost than recent emergency measures and compared to the cost of unserved power, which may be 5-50 times as high.

> Faced with severe power shortages, the Government of Bangladesh invited competitive bids for four barge-mounted plants, which can be delivered to the site rapidly, though at relatively high cost. The first (oil-powered) plant of 110 MW, commissioned in 1998, delivered power at 9 cents/kWh, nearly double the *retail* price. The next two (gas-powered) plants sold power at just under 5 cents/kWh), also above the retail price.
>
> In contrast to these hasty and costly solutions, the AES Haripur CCGT plant, due to be commissioned in July 2001, will deliver 360 MW at about 3 cents/kWh, based on a gas price of $2.40/mmBTU (compared to state-owned power stations, which buy at $1/mmBTU), remarkably cheap by international standards. The next IPP at Meghnaghat of 450 MW is to deliver in 2003 at a reported levelized tariff of UScents2.8/kWh.

Box 5 Better PPAs in Bangladesh

These IPPs provide a benchmark against which to measure the performance of the state-owned generation, and put pressure on the supply chain to collect revenues to avoid bankrupting the single buyer. In theory, an SB owning transmission is ideally placed to ensure payment, for it would be hard to bypass, and provided it can enforce payment by disconnection without major civil unrest, its monopoly power provides the necessary credit-worthiness. On the other hand, the reform is so modest in its disruptive effect that it may allow the continuation of all the poor practices that precipitated the demand for reform in the first place, merely delaying the credit crunch for a few years by finding another sources of off-balance sheet *de facto* public sector borrowing.

What are the alternatives? Borrowing from IFIs is obviously cheaper than commercial borrowing by private companies operating in high credit-risk countries, even where the IPPs secure sovereign guarantees for their PPAs. High profile disputes, such as that involving Enron at Dabhol, Maharashtra, can only increase the cost of financing such borrowing. However, the IFIs are increasingly arguing that continued financial support to the power sector regardless of that sector's financial performance has similar effects as the "soft budget constraint" that undermined efficiency in Soviet-type planned economies. IPPs are a test of the commitment of governments to serious financial reform. As countries demonstrate their success in meeting the terms of PPAs, so the cost of those PPAs will decrease. Refusing to provide further loans except to assist sector reform forces the government to start the reform process. The risk is that reluctant reformers will do the least possible. Inviting in IPPs with offers of long-term PPAs with sovereign guarantees in an otherwise unreformed ESI is the least disruptive step, and delays the pain until the next financial crisis.

Is this a reasonable approach for the IFIs? The main difference lies in the terms of the loan (IPPs have higher interest payments over shorter time horizons). This has the advantage of delivering the penalties of reform failure more quickly and targeted more obviously on the failing sector, without necessarily removing the safety net of IMF/World bank support at the next financial crisis. It may lead to more imprudent borrowing by the state electricity company as the IFIs disengage with the sector, or are ignored as they bring only criticism, not cash, to the table. Bangladesh has embarked on an uneconomic coal mine to provide fuel for an high cost, low efficiency and uneconomic coal-fired power station, financed by Chinese supplier credit, rather than exploiting her indigenous low cost gas in high efficiency CCGT stations, though this may just be further evidence of mismanagement or worse of the state electricity board.

The SBM can make sense as part of a programme that reforms and privatises the distribution companies, though it makes sense that a reasonable fraction of PPAs are linked to domestic prices (and are financed in large part by domestic capital), using fuels that are also priced in domestic currency. It is a risky strategy if the distribution companies are not credit worthy, and have not reformed their tariffs to meet the terms of the new PPAs. It may precipitate further reforms, or it may plunge the sector into further financial distress, leading to further deterioration in plant as maintenance is delayed.

3.2 Restructuring generation and transmission as part of wider reforms

Let us return to the case in which a country is firmly committed to radical reform, and has signalled this by restructuring tariffs, has started to unbundle the industry, setting up the regulatory authority under suitable legislation, and is well on track to privatise the distribution companies. What additional steps need to be taken?

Many countries already have a number of separate distribution companies, organised on a regional basis (unless the country is very small), but it is quite common for the transmission company to be vertically integrated with generation. There are historically good reasons for this, as planning the location of new generation needs to be coordinated with building the necessary transmission lines. Central dispatch is also standard, and again requires close coordination between the transmission operator (TO) and individual power stations. Stations need to be brought on line in merit order (cheapest stations providing base load, followed by stations with higher avoidable cost providing mid merit and peaking power), but the TO must ensure that transmission lines are not overloaded. These transmission constraints may require the TO to dispatch stations out of merit order. The TO will also need to obtain ancillary services to maintain the stability of the system, and so needs to be able to call on or instruct stations to provide these services at short notice.

These coordination benefits can still be obtained if generation is unbundled from transmission, and any small loss in these synergies ought to be more than offset by improvements in efficiency in generation resulting from competition. The evidence from England and Wales suggests that considerable improvements can also be wrung out of transmission companies with the sharper focus that a separate business provides.

Central dispatch can be maintained and certainly the TO will need to obtain and provide ancillary services, either through contracts, tenders, or by spot purchases in a balancing or reserve market. The main problem to resolve is the planning of new transmission lines, and designing a system to ensure efficient location of new generation plant. A variety of models are available, and their lessons are being closely studied (EEE, 1999). Whichever one is chosen, charges for using the transmission system will need to be set at a level that can finance network expansion (if necessary, not out of current cash flow, but out of borrowing secured on the future revenues that will be allowed once the investment is in place). Transmission charges may be spatially differentiated to encourage generators to locate efficiently, though this may be achieved by the capital charge for connection to the system.[9]

The difficulty in setting and regulating an efficient set of transmission charges provides one of the strongest arguments for vertically unbundling transmission from generation. Otherwise the incumbent TO will devise charges (particularly "deep" connection charges) which favour related incumbent generators and disfavour entrants, thus raising their costs and allowing existing generators to set higher wholesale prices. This unbundling is therefore one of the most important steps in restructuring and reforming the ESI.

[9] There are two different philosophies guiding the method of signalling location. If a new generator connection requires extensive reinforcement over the whole network, this may be charged to the new generator (as a "deep" connection charge) or it may be smeared over all generators ("shallow" connection charges), but in the latter case annual charges may be spatially differentiated to signal location decisions. England and Wales adopt this second approach.

3.2.1 Restructuring generation

If the generation companies are separated from transmission, they will need to be placed in a number of companies, with some revenue security if they are to be privatised. If the remaining transmission company is to become the single buyer, inheriting any existing PPAs with IPPs, and if the existing companies are to be sold, then they will need comparable and suitable PPPAs. This approach has been favoured in Cental European transitional countries as a means of financing refurbishment, and has both risks and benefits. If the aim is to created a fully liberalised wholesale market, then additional steps may be required.

> The Polish ESI was restructured and unbundled in 1990, and by the end of 1993 consisted of 18 system power plants, 24 combined heat and power stations, 33 distribution companies, and one national grid company, Polskie Sieci Elektroenergetyczne SA, PSE, acting as a strong single buyer (and retaining much of the expertise of the previously integrated power company). The generation companies had to borrow at rather high rates of interest to finance expensive refurbishment and pollution clean-up investment, which was secured against 24 long-term PPAs with PSE covering 65% of supply. These PPAs, many of which are effectively stranded contracts, are greatly complicating attempts to prepare the industry for privatisation.

Box 6 Stranded PPAs in Poland

In some cases the grid company or its predecessor power and transmission company may have existing PPAs with recently entered IPPs. If the grid company has been operating as a SB, then it may well have acquired a set of long-term PPAs, even where the generation companies remain state-owned (see Box 6). In each case it becomes important to decide whether, and if so how, to renegotiate any existing PPAs, and what contractual arrangements to put in place for any newly created generation companies.

The simplest case is where all generation is state-owned, in which case any existing PPAs can be renegotiated, with only bureaucratic obfuscation preventing a rational resolution of any problems. The first step is to determine a set of suitable contracts to be held between the generating companies and the suppliers. Even where supply is to be liberalised, it is unlikely that more than 33% of sales (to the larger customers) will be open to competition for the first three years, leaving 67% or more to be sold to the franchise market. The supply businesses associated with the distribution companies will therefore need licences with the obligation to supply all non-eligible customers in the franchise area. In Britain, these licences are termed Public Electricity Supply (PES) licences, and contain within them the obligations and regulatory conditions. The PES licence holders are the logical counterparties to generation contracts, and in Britain the Regional Electricity Companies or RECs who held the PES licences were given contracts of up to three year's duration before they and the generators were privatised. Note that the contract question will have to be settled before the distribution companies can be privatised, and so should be set in train as soon as possible.

3.2.2 Creating a competitive wholesale market

The detailed design of the contracts will depend on the design of the wholesale market, and need not detain us, except to note the considerable advantage of financial contracts over physical contracts. As the object is to create a competitive wholesale market for electricity, we can presuppose either a pool or a power exchange, in either case with a well-defined reference wholesale price at each moment. The natural choice of contract is then either a one-sided or two-sided Contract for Differences (CfDs). A one-sided CfD would have a price reflecting the value of the right but not the obligation to buy up to M MWh at a strike price c (similar to an efficient two-part PPA with a capacity and energy element). A two-sided CfD would have a price (possibly zero or negative) in return for the obligation to pay the strike price *less* the reference price (normally the pool price) times the specified number of MW to the contract holder, who earns the reference (pool) price if he is dispatched and receives the strike price *less* the reference price whether or not he generates.

Such contracts are needed to ensure a smooth transition to the new liberalised market, and to give stability to revenue forecasts of the contract holders (on both sides of the market), to allow them to be valued for sale. Contracts also reduce problems of market power in generation, as we shall discuss below. If past investments in generation have been financed by bank loans secured on PPAs with the SB, then these PPAs should be renegotiated into these new contracts. These are likely to be of shorter duration than the standard commercial PPA with a SB (perhaps 3-5 years, rather than 5-15 years for PPAs with the SB). They will be purely financial contracts (ie payments are not contingent on the dispatch of the underlying plant, or even its continued existence). The renegotiated PPAs will be then be equal to sensible (ie commercially viable) contracts, but may not be sufficient to underwrite the original debt. The difference between the capital value of the new contracts and the original debt is a measure of the size of the stranded contracts.

If these stranded debts are still significant, they will need to be dealt with before privatisation. The simplest solution is to transfer these remaining debts to the state, preferably at the same time renegotiating the entire original debt package to reflect the sovereign guarantee now explicitly underwritten by the government. When the government comes to sell the grid and the distribution companies, they can be furnished with a suitable amount of long-term debt to the government (in local currency), so that their debt-equity ratio is appropriate for a regulated natural monopoly (ie quite high, perhaps 50%). Effectively the government will have transferred the stranded debt component of the original PPAs to the grid and distribution companies, with the possible advantage of refinancing it on more favourable terms. Once the distribution companies are sold, the government should receive more than enough cash to liquidate any temporary increase in the national debt caused by this refinancing operation.

It may be objected that crystallising the debt component of the PPAs as a liability of the government will reduce the net sales value of the privatisation and thus make it less attractive to the government. This raises the question of how to value the natural monopoly elements (the distribution companies and the grid), and how the generation companies will be valued. Note the asymmetry in the two questions, for the value of existing generators in a competitive market into which entry is expected will be derived from the competitive price, which will be equal to the average cost of generation from new entrants.[10] Once the future wholesale price of electricity is known, the profits of operating the plant can be deduced from a knowledge of its fixed and short-run avoidable costs (which will determine how much it generates and at what price), and then the present value of its profits calculated.

The value of the natural monopoly elements will be determined by the amount of revenue that the regulator chooses to allow the companies. Here the government faces a classic trade-off. If the aim is to realise a certain target value for the grid and distribution companies, then this value is the logical choice for the regulatory asset base (RAB) on which the owners will expect to receive a rate of return, and which will be depreciated over some specified period (related to the average remaining life of the assets). The interest on and depreciation of the RAB will be a (possibly large) part of the allowed revenue, which will be recovered from TUOS and DUOS charges and which will directly affect the final price of electricity. The higher the desired sales value, the higher the RAB and the higher will final electricity prices have to be.

If, in contrast, the government is anxious not to increase final electricity prices too rapidly, it will have to specify a time path for prices (in real terms) from their present, presumably uneconomically low, level to a cost-reflective level at some future date. The implied time path of revenue (final sales revenue less the cost of purchasing power) will then be determined, as will gross profit, and hence the present value of the cash flows to the buyer. This present value will represent the most the buyer is willing to bid for the company. Lower electricity prices, or longer periods for their adjustment, will translate into lower sales values for the companies.

These calculations can be made completely independently of any stranded contracts or inherited debts. If these debts are to be recovered by higher total receipts, then prices will have to be higher (and consumers will pay for the past debts), whilst if prices are already politically determined, so is the total value of the assets against which the debts represent a liability.

Once the problem PPAs have be resolved and the generators and franchise suppliers provided with commercially sound contracts, the generators can be sold. The aim is to create a competitive wholesale market, which requires a sufficient number of

[10] Most developing countries expect rapid demand growth within a very short period, and even central and eastern europe, where there may appear to be excess capacity, is likely to experience entry, and/or is open to neighbouring markets where prices will be set by competition, and which can therefore be predicted.

companies competing with each other at each part of the market - valley, shoulder and peak hours of the day. Some countries like Argentina have gone to the logical extreme of making almost every power station an independent company, while others have grouped power stations into a smaller number of companies. The number required for a competitive outcome depends on the ease of entry and the degree to which the country is interconnected with other competitive markets. An isolated system should aim for at least four competing companies in each isolated region - and an isolated region is defined as one that is only interconnected to other regions by capacity-constrained transmission links.

While there may be sound reasons of river management to place tightly linked hydro stations on the same river in one company, different hydro systems should be in different companies as there are no economies of scale or scope from integration. Each company should either be small relative to the size of the (local) market or have a range of types of generation which is close to the margin when prices are both low and high (ie have avoidable costs which span the normal daily or seasonal price range). That way no company will have much influence over the wholesale price. Restructuring an ESI dominated by hydro raises additional problems, particularly if further hydro expansion is least cost, or if a large proportion of generation is located in multi-use systems, as the example of Brazil above illustrates. Whether or not privatisation is sensible in such cases needs careful analysis.

Market power can be further reduced by encouraging or requiring plant to be contracted, for then the benefits of manipulating the wholesale price are only captured by the uncontracted margin of plant - the returns to the contracted volume are predetermined by the strike price of the contract. If plant is 80% contracted, and there are 5 similar generation companies, each one has price-setting power equal to 20% of 20% or only 4% of the total market. Some countries adopt a belt-and-braces approach to controlling market power, by requiring bids to be based on audited marginal fuel costs, and constructing more or less elaborate systems of rewarding the fixed costs, and that may be desirable in smaller markets or as a transitional arrangement until the competitiveness of the market has been established.

3.3 Ownership of the transmission grid

The argument so far has been that privatising and regulating distribution companies is important for establishing sensible prices for electricity, and hence allowing generators to be paid viable prices. Privatising generation should wait until the wholesale market has been established and the terms under which electricity is sold to final customers has been clarified. Restructuring to separate generation from transmission should take place as early as possible. Of course, privatisation should not be considered until the legislative and regulatory framework is in place. So far, no mention has been made of privatising the transmission grid. There is considerably less agreement about the importance of privatisation, and the speed with which it needs to be completed if privatisation is decided to be appropriate.

Social democrat countries in Europe typically prefer to retain the national grid under public ownership (just as they often have a preference for keeping distribution companies under municipal or regional ownership). Such countries often have well established and mature networks that need little expansion, and whose costs are a very small part of the total final price of electricity (typically only 5%). In other cases, strengthening and extending the transmission grid may have high priority, and the efficient management of its expansion is critical to the costs of delivering power to final customers. If the national grid is also charged to provide the transmission systems operator, who organises dispatch and secures ancillary services, then these commercial functions are best supplied by commercially oriented owners. The success of the electricity wholesale market and consequently the extent and speed to which efficiency improvements are passed through in lower prices will depend critically upon the design and operation of the wholesale market. If the grid remains in public ownership, it will be crucial that the commercial activities of systems operation, market management and operation are placed in a commercial organisation. Again, there are continuing debates about whether this should be entrusted to act *pro bono publico* or should be incentivised as a for-profit organisation subject to careful oversight.

One of the most persuasive arguments for delaying the privatisation of the National Grid is that it is particularly hard to value the assets, as in most cases transmission was previously bundled with generation. This will be even more of a problem if the grid combines transmission operations and if these transmission operations are incentivised by some cost sharing formula. Many of the transactions between generators and the systems operator would previously have been internal transactions and would cancel out, but they will now become revenues for the TO and costs of the generation companies. There will be no history of accounts, let alone regulatory accounts, of the grid under its previous integrated form, so any projections of revenue will have to be taken largely on trust. These revenue forecasts will depend critically upon the way in which regulation operates and the extent to which costs can be reduced. Of course, the same is true of the distribution companies, but they have usually been separate companies before and so have a set of accounts setting out their costs, so there is rather less uncertainty in their case.

The experience of National Grid Company (NGC) in England and Wales is relevant here. NGC's shares were allocated to the Regional Electricity Companies, which were then privatised in 1990. The implied value of NGC at this flotation was about £2.3 billion (or £2.7 billion at 1996 prices, after allowing for new investment and depreciation). In 1996, NGC was floated on the stock exchange for £4.5 billion, suggesting that the initial underpricing was as high as 40%. It would clearly have been easier to value the revenue streams associated with NGC on the basis of several years' accounting results of the unbundled grid, as was possible at the second flotation. Instead, shareholders had to take the pro-forma accounts of the unbundled grid combined with the RECs, which also combined supply businesses with which there was very little commercial experience, and were clearly not able to reach a very accurate valuation.

NGC is responsible for providing various services including payments for transmission constraints. Originally the cost of these services were passed straight through as `uplift' - the difference between the payment to generators and the payment by suppliers. In the first few years of Pool operation the charges for uplift more than doubled. This raised concerns that NGC had inadequate incentives to reduce these costs. In 1994/95 NGC started to receive incentive payments for managing various controllable costs, under which it bore some fraction of the cost in excess of a target (and received some fraction of any shortfall).[11] In 1994/95 these incentive payments amounted to £26 million out of total uplift of £752 million. The effect of these incentives is to slightly increase the risk of NGC's income. Resolving the way in which costs will be controlled clearly has an effect on the value of the business, and should ideally be done ahead of sale.

The other unresolved issue at the time of the initial privatisation what resetting the pattern of locational transmission charges, where there had not been enough time to agree a satisfactory methodology before sale. Rather than delay flotation, the government announced that the initial (somewhat arbitrary) set of charges would be reviewed after two years. They were subsequently considerably revised and a new methodology for setting the charges was agreed and published. NGC's regulated revenue was capped in line with the forecast growth in system maximum demand, and therefore should not have been affected by any rebalancing of charges. Nevertheless, uncertainties about the charging methodology may have increased uncertainty about the value of the assets and so reduced the sales value.

The lesson is that it may take some time to develop a satisfactory set of regulated charges and incentives, and these may affect the reliability of revenue and cost forecasts. The main problem (at least in Britain) was the absence of reliable accounts for the stand-alone grid business, which the passage of time would rapidly resolve. There is no obvious danger in delaying its privatisation for several years after the privatisation of distribution and generation, and may well be positive advantages.

4. Problems of market power with excess demand

Where wholesale markets have worked well in developed economies it has been in large part because of excess generating capacity, modest demand growth, and the availability of cheap new plant which allows independent power producers to enter at modest scale,

[11] These included ancillary services, transmission constraints (under which generators required to either to not generate when their bid was competitive, or required to generate even though their bid was uncompetitive, are paid the difference between the pool price and the station bid), demand forecasting errors, and transmission losses. The maximum profit or loss that NGC can experience is capped at £50 million.

putting downward pressure on wholesale prices. California has demonstrated that tight demand, low contract coverage, and a liberalised wholesale market can lead very rapidly to high prices and bankruptcy. Dependence on storage hydro systems (very common in Latin America) exposes countries to risk of periodic shortage and prolonged period of high prices in liberalised markets.

That raises the obvious question, whether competitive markets can work as well in developing countries suffering from a shortage of capacity, current excess demand and forecast rapid demand growth? The answer will depend critically upon the existence of credit-worthy electricity buyers (ideally suppliers) willing to enter into longer term contracts on the back of which new investment in generation can be financed. This is turn requires satisfactory pricing of transmission and distribution to ensure that the power can be delivered from the generator to the customers. If capacity is scarce, then the spot price in a competitive market can rise to very high levels - prices of more than $150/MWh are common at certain times of the day and times of the year in the British pool, and prices have certainly exceeded $1000/MWh both in the UK and the US in periods of very tight market conditions.

Provided franchise customers are adequately covered by contracts, which can be imposed upon existing state-owned generators at the time they are unbundled, high spot prices have the desirable advantage of signalling the attraction of entry and encouraging consumers to sign contracts to support and finance entry. They also efficiently ration scarce supply to consumers most willing to pay the high spot prices, and motivate them to seek out more attractive longer term arrangements. They therefore provide finance at the margin where it is needed without necessarily raising average prices to all consumers. Markets, contracts, and well regulated transmission and distribution charges therefore represent a significant improvement on a situation of power interruptions, underpriced electricity and an inability to finance the generation that is needed.

Nevertheless, although market power may be restrained in the short term through contracts, it will reappear when these contracts are due for renegotiation, at least if the generators are privately owned and cannot be coerced to sign new contracts. Market power depends on the number of competing generators and the overall degree of market demand relative to capacity. If demand is inelastic, and if all remaining generators cannot meet that demand, the remaining generator has considerable market power. In a competitive wholesale market, each generator will be aware of that power, and will offer at least marginal output at a high price. Investment in response to the excess demand and high prices will reduce this market power if there are sufficiently many independent generating companies, but not if there are too few, at least until enough entry has taken place to alter the number of price-setting generators. The evidence from Britain suggests that this may take a decade or more even under ideal entry conditions, and the implication is that the restructuring should aim to create at least four independent generation companies, and preferably more, right from the start.

If generators have apparent market power, the temptation to choose the Single

Buyer Model in order to countervail against such market power will be strong. The SBM effectively forces generators to sign long-term PPAs to avoid subsequent unattractive contract terms, unless they can be credibly offered Most Favoured Nation clauses (under which they will be offered terms as good as the best currently or recently offered). Even this may be hard to enforce if contracts are confidential, and hence may be an unattractive alternative to a long-term PPA. Perhaps an independent agency (the regulatory office) could announce the results of subsequent PPAs, allowing PPAs to have a re-opener such that after an initial period (5-10 years) the subsequent contract has to match the terms of PPAs accepted in tender auctions.

The alternative is to place all new PPAs with the franchise market, which can provide the security for long-term contracts. If and when the industry evolves towards a liberalised wholesale market with authorised entry and rTPA (current EU best practice) then the existing portfolio of PPAs would gradually be replaced by shorter term contracting in the spot market. This evolution would presumably only occur when the capacity shortage had been overcome so that the spot market were pricing reliably on average at the entry price.

Relying on contracts alone may not be sufficient to address issues of market power, and it is important that the regulator has sufficient power to address market power issues as well as setting the price-caps or tariffs in the regulated natural monopoly sectors. At least some EU countries have liberalised their electricity industries under the requirements of the Electricity Directive but failed to write the required information-gathering and enforcement powers into their electricity legislation. It is most unlikely that such information will be voluntarily provided. A full-scale competition inquiry with the necessary powers to request information may take months, and fail to find evidence that would stand up to in court. If in addition generators are not required to hold a licence, regulators cannot follow the route open in Britain and modify the licence to prevent future abuse and to require provide necessary information to be routinely supplied.

The United States, with its more legalistic approach, is much clearer about the duties of regulators when liberalising. Under the Federal Power Act 1935, The Federal Energy Regulatory Commission, FERC, has a statutory obligation to ensure that wholesale prices are "just and reasonable". If an electric utility wishes to sell at market-determined wholesale prices, this will be only allowed providing "the seller (and each of its affiliates) does not have, or has adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry."[12] Even then, the authority to sell at market-determined prices can be withdrawn and replaced by regulated prices if there is "any change in status that would reflect a departure from the characteristics the

[12] *Heartland Energy Services, Inc*, 68 FERC & 61,223, at 62,060 (1994), cited by Bogorad and Penn (2001).

Commission has relied upon in approving market-based pricing."[13]

FERC therefore assumes that market pricing is "just and reasonable" so long as it is competitive. The reason for its concern to ensure that prices remain competitive is that any FERC-approved form of pricing greatly restricts the competition authorities from intervening. At the same time, existing antitrust laws are relatively powerless to enforce competitive outcomes in the energy industry as "the antitrust laws do not outlaw the mere possession of monopoly power that is the result of skill, accident, or a previous regulatory regime. ... Antitrust remedies are thus not well-suited to address problems of market power in the electric power industry that result from existing high levels of concentration in generation." (DOE, 2000).

This suggests a further contrast on the two sides of the Atlantic, reflecting the prior histories of the electricity industry on the two continents. Deregulation in the United States was in principle a cautious relaxation of regulatory control over prices, with considerable awareness of the potential problems of market power. Electricity restructuring in Europe has tended to overlook issues of market power, and instead has concentrated on introducing wholesale and often retail markets in the expectation that they will be naturally competitive. The dictum of confining regulation to the natural monopolies has often been taken too literally, paying too little attention to the unnatural, or at least undesirable, monopolies in generation. These two histories should be borne in mind when examining consultants' recommendations for restructuring. It is worth asking whether they are sufficiently familiar with the richer and longer history of US regulation, or whether they are relying on standard competitive market doctrine of the kind normally written into competition law. The latter may be a weak reed on which to rely.

5. Conclusions on ESI restructuring

The ESI is a highly capital-intensive industry, and its success depends critically upon the management of its investment programme. The main problem in most developing countries is that investment is poorly managed, poorly maintained, and often inadequate. These problems stem from an inability to finance investment from a sound cash flow, as well as poor incentives for efficient management and operation. Financial problems ultimately result from poor pricing decisions which can be seen as a reflection of inadequate regulation. Public ownership is a form of regulation, though one that confuses the issue of protecting consumers, owners and other interests. There are good arguments for separating regulation from ownership. It is a central argument of this paper that regulation must be carefully designed to provide efficient incentives and adequate guarantees to sustain investment and operations. Separating ownership and regulation is best done by privatisation, but privatisation will only deliver efficiency and benefits to consumers if regulation is well designed.

[13] *Heartland* 68 FERC at 62,066, cited as above.

The logical sequence of events, some of which can happen simultaneously, is to first create the legislative and regulatory framework and institutions, and to restructure the state-owned ESI. Unbundling and corporatising the generation companies, national grid, and distribution companies while they are still in public ownership can precede the legislation and setting up the regulatory agencies, but privatisation cannot. Unbundling generation from transmission will require a restructuring of any contractual relationships between the two. A timetable for tariff rebalancing is needed before the distribution companies can be privatised, and the system of regulating transmission and distribution charges is critical to the success of the whole reform programme.

The argument for privatising distribution companies as soon as all the previous elements are in place, stable, and have developed an adequate track record for valuation, is that private ownership clarifies and stabilises the process of price determination, and provides incentives to ensure bills are collected, and financial viability restored.

Once this step has been taken or is confidently predicted, then generation can be opened to private investment. The simplest model, which may be the only viable one for smaller or less mature economies, is by creating a Single Buyer to offer long-term PPAs with IPPs by competitive tender. In some countries there may be enough spare capacity (once refurbished and made available) and sufficiently benign entry conditions, to privatise existing generation and move to a liberalised wholesale market, as in many Latin American countries. Here the main issue is one of restraining market power, through long-term contracts, and if institutional conditions are right, by retaining adequate powers to ensure wholesale prices are not "unjust and unreasonable". Developing investor confidence that intervening to control market power is not expropriative will be challenging in many countries, and other means of striking the right balance between the interests of investors and consumers may then be required, such as cost-based bidding.

In the best of cases, if regulation is credible and effective, and the macroeconomic conditions in the country are stable and supportive of private enterprise, then entry of and competition between new entrants should drive down generation costs which will be passed through the final consumers. Private ownership of distribution will reduce losses and address problems of non-payment, lowering the costs of serving those customers who do pay. Investors will be confident of earning a satisfactory return on their investment in the regulated sector, and will be willing to take commercial risks in the competitive sector. Supply competition forces prices to align with costs, eliminates cross-subsidies, and should clarify the value of reliability and quality of service.

Even in the most favourable cases, though, it is unlikely that full supply liberalisation will be desirable. There are considerable advantages in retaining a franchise monopoly for smaller customers (up to 50-100kW, perhaps covering up to two-thirds of total demand). The main advantages are that there will then by a viable counterparty for medium to long term contracts which assist entry and mitigate market power. There are additional advantages that, provided final tariffs are intelligently regulated (for example by yardstick pricing of contracts), the costs of contracting are reduced without sacrificing the benefits of competition. In that case, supply competition will be more limited, and some cross-subsidies within the franchise market can be preserved. They may be politically necessary, though they may be less defensible. The case for further supply liberalisation should be based on a careful cost-benefit analysis of the advantages of (some) lower prices, reduced cross-subsidies and greater consumer-orientation, compared to the extra costs. Given that it cost the best part of $1.5 billion to end the domestic franchise in Britain, these extra costs can easily destroy the case for complete supply liberalisation (Green and McDaniel, 1998).

In other countries less ambitious reforms of generation, based on the Single Buyer Model, may be sustainable with adequate reform in distribution, and with access to low cost indigenous fuel. In other countries the plausibility that private ownership of generation is viable or sustainable at lower cost than public ownership may be very doubtful, in which case reform of the continuing state-owned ESI to improve autonomy, accountability, and financial viability, may be the only option. The fact that such reforms have failed in the past does not make it wise to encourage irreversible reforms of unproven worth, and privatisation in unpropitious circumstances may be even more costly than the unsatisfactory status quo.

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