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Competition in the power sectors of transition economies

by David Kennedy

Abstract

Radical reform of the power sector is under way in a number of EBRD countries of operations. This paper is concerned with the introduction of competition to the power sectors of transition economies. In particular, the paper focuses on the reform path from vertically integrated state-owned monopoly to liberalised industry, and on the appropriate model of competition. The message of the paper is two-fold: first, the model of competition adopted should fit the sector context; second, if the wrong reform path is chosen then mistakes can be hard to undo. The sector should be restructured before the private sector is introduced, Independent Power Producers (PPs) should be limited prior to liberalisation, and the single buyer model may provide a stop-gap while tariffs are rebalanced and (cash) collections improved. In the longer term the most suitable arrangements would be open network access backed by pools.

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INTRODUCTION

Contrary to a once common belief, power industries are not natural monopolies.[1] Though there are aspects of production – namely wires networks – where to have more than one supplier would lead to wasteful duplication of cost, there is scope for competition in generation and supply. Economic theory suggests,[2] and evidence backs this up,[3] that the introduction of competition between private sector entities to an industry formerly operated as a state-owned monopoly leads to reductions both in costs and in tariffs to consumers. Whereas inefficient producers may prevail in a regulated market, producers that do not perform in a competitive environment cannot survive.[4] Thus competition – within the correct regulatory framework – provides the best incentive for producers to behave in an efficient manner.

This paper takes for granted that, given the correct institutional setting, the introduction of competition will yield benefits. In the case of EBRD countries of operations, the assumption is that competition between existing generating plant based on fossil fuel technology,[5] and new entry (based on Combined Cycle Gas Turbine technology for example) to displace existing inefficient and/or unsafe generating plant (based on nuclear technology for example) will bring the best combination of price and quality from the consumers' point of view. The focus is on the ways that competition might be introduced to the power sector in EBRD countries of operations.

The message of the paper is two-fold: first, the model of competition adopted should fit the sector context; second, if the wrong reform path is chosen then mistakes can be hard to undo. The sector should be restructured before the private sector is introduced, Independent Power Producers (IPPs) should be limited prior to liberalisation, and the single buyer model may provide a stop-gap while tariffs are rebalanced and (cash) collections improved. In the longer term the most suitable arrangements would be open network access backed by pools.

The paper is organised in four sections. Section 1 outlines power industry structures that support competition, covers some of the timing issues related to industry restructuring, and reviews progress in this field across the region. In Section 2, alternative models for competition in the power sector are reviewed. Section 3 discusses the relationship between privatisation and the introduction of competition, and proposes contract structures at privatisation that are consistent with market liberalisation. Section 4 considers other issues including the construction of new capacity, and the role that use of system charges and end user tariffs play in market entry decisions. Examples from EBRD countries of operations are presented throughout.

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[1] The standard definition of monopoly is presented in Farrer (1902). The modern interpretation of this definition focuses on the presence or absence of scale economies in determining whether an industry is a natural monopoly. For a discussion of historical attitudes towards the power sector see Foster (1992).

[2] For a neoclassical statement of this view see, for example, Hart (1983), Holmstrom and Tirole (1989), Kamecke (1993), Vickers (1995).

[3] See for example Domberger (1987), Domberger, Meadowcroft and Thompson (1986), Kennedy (1995). For the power sector, see Newbery and Pollitt (1997).

[4] For an intuitive (Austrian type) exposition see Blaug (1996).

[5] Potentially competitive fossil fuel based generating plant is smaller in proportion to total capacity compared with other countries around the world (due to the larger than average presence of nuclear, hydro and CHP plant), but still significant.

1. POWER INDUSTRY RESTRUCTURING

The potentially competitive aspects of the power industry are generation and supply (metering and billing). Natural monopoly elements (i.e. where to have more than one supplier would lead to wasteful duplication of investment due to the presence of scale economies) are transmission (national, high voltage networks) distribution (local, low voltage networks) and dispatch. Competition works by allowing all generators equal access to transmission and distribution networks in order that they may transport power to consumers downstream.

The power industry structure that best supports competition is vertical unbundling; that is, generation, transmission and distribution are separately owned in the early stages of liberalisation.[6] By extension, this point applies equally to combined heat and power (CHP) plants and distribution networks.[7]

Vertical integration of generation with either transmission or distribution could act as an obstacle to the evolution of competition. There are various ways by which a vertically integrated generator can foreclose the market:

- The integrated company purchases from its own generator at an uncompetitive price. Though one way around this is to open large user markets, residential customers still remain captive, and the potential market for entrants remains small relative to the case with no integration. Benchmarking can mitigate this risk, though only to a limited extent when markets are undeveloped and information flows are far from perfect.
- The integrated company obstructs rivals' access to the transmission and/or distribution network. The integrated firm has an incentive to act in this way to gain increased market power upstream.
- The integrated company raises the costs of rival generators by charging a high price for network access. This price may be sufficiently high so that, given downstream prices, there are no profitable entry opportunities. Again, the integrated firm has an incentive to act in this way to gain increased upstream market power.
- The integrated company's access charges are regulated. The company has better information regarding its own cost structure, however, than has the regulator. Costs incurred by rival generators during production and supply are allocated by the integrated company to the regulated part of the business. This raises the network access price for any competitor. As above, this could deter entry.

These points apply equally to situations where integrated companies keep separate accounts (for example, for power generation and distribution): the fact that a regulator cannot know as much about a regulated firm's costs as the firm does gives scope for manipulation of the cost

[6] For a detailed discussion of issues relating to structure, see MMC (1996), also Kennedy (1997a). Vertical integration becomes less of a problem as regulators gain experience and full competition sets in. For example, vertical integration would be unlikely to undermine competition in the context of tried and tested pool, a competitive contracts for differences market, competition for large users; see Section 2 of this paper for discussion of these models. In very small systems, transaction cost arguments may be sufficient to outweigh the case for vertical unbundling.

[7] If CHP were "must run" plant all the time, then integration would not be a problem. The fact that CHP plant operates in different modes opens up the potential for inefficiencies. See the discussion in Section 3 of this paper.

structure in the manner above to foreclose the market.[8] Regarding accession to the EU, it is sufficient that integrated companies keep separate accounts, as opposed to having separate owners, though, to reiterate, such arrangements only lead to a second-best outcome (for details on the EU Power Directive see Annex 1 of this paper).

Furthermore, generation should be horizontally unbundled, that is, split into a number of separate and potentially competitive companies. For regulatory purposes, distribution should also be split into a number of companies, something that is typically implemented on a regional basis.

Without horizontal unbundling of generation, there would be one incumbent producer, subject to the possibility of new entry, but with sufficient market power to make sure that this never actually happens (through predatory pricing, consumer loyalty, etc.).[9]

The initial conditions in many of the EBRD's countries of operations were power industries organised as monolithic companies (generation, transmission, distribution and supply were integrated) and working as branches of government ministries. The first step in moving from this state to an unbundled structure is to corporatise the integrated power company, typically achieved in these countries through the setting up of a joint-stock company wholly owned by the government. This is followed by the setting up of subsidiaries within the corporatised company and along the lines of the vertically and horizontally unbundled structure.

Before wide-scale privatisation through divestment of assets, it is desirable that a regulatory body has been set up and that regulatory rules are in place. If the private sector is introduced before the regulatory arrangements are in place, then there will be a high degree of uncertainty over future revenues. In the face of such risk, assets to be transferred to the private sector will sell at a price well below their value (whether measured by book value or discounted cash flow), more so where investors are risk averse, and finance for new investment will either not be forthcoming or will be forthcoming only at high prices and short maturities. The trade-off here is the degree of urgency as regards the privatisation, driven often by governments' need for revenue to finance budget deficits. In the absence of a regulatory framework, it is unlikely that finance will be available for investment (in system upgrades, etc.) after privatisation.

The present paper is not about the optimal institutional framework for regulation[10] (the extent of regulatory independence, whether regulation is price cap or cost plus or a hybrid). Suffice to say that in the context of industry liberalisation, there should be a grid code which specifies the terms and conditions of network access for generators. In order that there is a level playing field for competition, all generators should have equal access to transmission and distribution networks. A system of regulated and published network access charges promotes such access in a transparent manner.

It is unlikely that competition could work without the introduction of the private sector.[11] State-owned firms are not oriented towards profit (and instead pursue political objectives), are typically cushioned by soft budget constraints, do not have the discipline exerted by take-

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[8] See Cave and Martin (1994).

[9] See OFTEL (1985) for a discussion of possible entry deterring tactics by a dominant incumbent.

[10] Levy and Spiller (1996) discuss various regulatory frameworks with respect to associated regulatory discretion and risk.

[11] This view is articulated in Glaister (1992), Shughart and Van Boening (1994), and Vining and Boardman (1992).

over and bankruptcy threats, and often have limited access to capital markets. These factors reduce incentives to perform, whether in a competitive environment or not. Though it may be possible in general for public sector firms to operate efficiently, this is unlikely to be the case in EBRD countries of operations given the initial conditions in the industry (see below).

There are various ways to introduce the private sector, some more appropriate than others according to circumstances. Before an industry has been restructured, and where there is urgent investment, the private sector can be introduced through the issuing of concessions. In power generation, this is done by issuing power purchase agreements to privately owned companies, termed IPPs. The agreements typically specify formulas for, *inter alia*, capacity payments and power off-take payments, to be made from the national power purchaser to the IPP. There are strong arguments to limit the number of IPPs prior to privatisation relating to competition and the stranding of costs; these are discussed in Sections 3 and 4 below. Regarding full-scale privatisation through divestment of the majority of assets to the private sector, this should take place only when the industry has been restructured (i.e. corporatised and unbundled): experience (for example, in the British gas industry) has demonstrated the great difficulty in restructuring after divestment of assets.[12]

Regarding timing, where cash collection is a problem (often the case in CIS countries) the private sector should be introduced first to distribution. Cash collection problems cannot be solved through privatisation of generation, because links between generators and non-paying customers are (at the most) very limited. Privatisation of generation is likely to fail – the purchase price of assets will be low and finance for new investment will be restricted – where cash collection is a problem because this renders generating assets valueless (or of negative value where generating companies continue to operate at a loss). The problem stems from the fact that state-owned distribution companies are pressured to ease up on collections and disconnections relating to state-owned enterprises. The solution here is to first privatise distribution: private sector distributors are given an incentive to collect cash and will do so given that the right framework is in place (i.e. there is a social safety net and cutting off non-paying customers is allowed by law).

Progress in power sector reform in EBRD countries of operations is presented in Table 1. There has been a varying degree of progress across the region with only a small number of countries yet to embark on the reform process (that is, to have corporatised the power company as a minimum) and 11 countries involved in radical restructuring (unbundling, privatisation and liberalisation), six of which have already implemented structural changes. Of the countries that have advanced furthest – Hungary and Kazakhstan – the drivers of reform were different in either case:

- In the case of Hungary, the objective was to raise revenue to finance the government budget deficit. To this end, the institutional arrangements (such as setting up a regulator) were put in place prior to the introduction of the private sector.
- In the case of Kazakhstan, the objective was to secure private finance for the sector in the face of low system security. The regulatory arrangements were not developed at the time of privatisation and, coupled with low tariff collection, this showed up in the low sale prices of assets. Without innovation, however, it is unclear whether the sector will have access to private finance: sector risk stemming from uncertainty over future regulatory

[12] Cave and Martin (1992) discuss costs associated with de-merging.

decisions (because of gaps in the framework), compounded by country risk, may be perceived by investors as being prohibitively high.[13]

Where progress has been more limited, this is usually because there has been a lack of urgency as regards investment: countries are meeting power needs from inherited capital stock. Such a cushion allows governments to succumb to political pressure and delay costly and time-consuming legal and institutional reform. It allows also postponement of politically unpopular tariff increases associated with introduction of the private sector.

Table 1. Progress with reforming power

Reform stage	Countries
No reform – integrated state-owned monopoly retained.	Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Kyrgyzstan, Lithuania, Slovenia, Tajikistan, Turkmenistan, Uzbekistan.
Reform limited to concessions for private investors to sell to state-owned supplier of wholesale electricity.	Croatia, Slovak Republic
Reforms implemented with private sector participation but market dominance by state-owned transmission/ generation company; self-generation and third-party access allowed.	Czech Republic, FYR Macedonia
Radical reform being considered with enabling legislation enacted or in progress	Bulgaria, Estonia, Latvia, Moldova, Romania
State-owned monopolist unbundled but little divestiture to the private sector; concessions allowed to sell directly to distribution companies and large users of electricity.	Poland, Russia, Ukraine
Reform progressing radically through unbundling, independent regulator, divestiture and concessions, and nascent competition in wholesale supply.	Georgia, Hungary, Kazakhstan

A contributing factor to delayed reforms is that the only finance available in EBRD countries of operations has been at high rates of interest and with loan tenors that are short relative to the life of assets. Where this was particularly true of CIS countries prior to the Russian economic crisis, it applies more generally since then. This may have added extra weight to the case for delaying reform: governments may have put off restructuring in the hope of an upturn in the market.

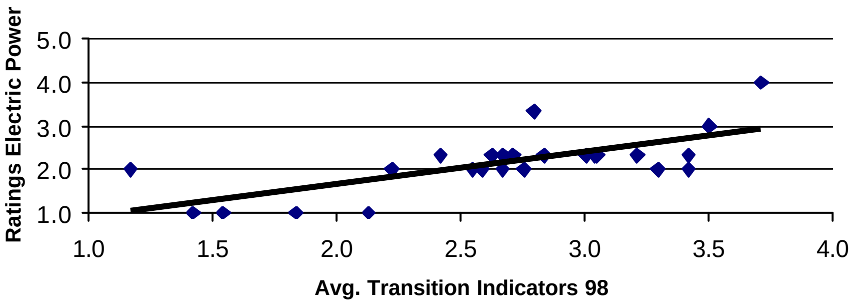
Reform cannot, however, be delayed forever. Given the limits to availability of sovereign finance, then tariffs will have to rise in order to finance new investments. Assuming that the private sector is more efficient than the public sector, then the tariff increases necessary to finance new investments will be less if the private sector is introduced.

[13] Having said this, the regulatory risks in all EBRD countries of operations are relatively high. In light of experience, it is probably unrealistic to expect the introduction of a truly independent regulator with full price-setting power and limited discretion to be in place prior to privatisation. Interim arrangements that provide some security are, however, feasible.

The fact that there has been power sector reform in countries as diverse as Hungary and Kazakhstan shows the potential for progress in all other countries in the region. Though reform has been delayed in some countries, the demand for power sector investment from the EBRD's countries of operations, and the need for private sector involvement, are likely to be large in coming years. The reason for this is years of under-investment resulting in a situation where much of installed generating capacity is redundant, losses in transmission and distribution systems are high by Western standards, and inadequate metering and billing systems hamper efforts to increase cash collection.

There is a strong correlation between general progress in transition and advances in the power sector. This is indicated by the relationship between the EBRD index of overall transition (see *Transition Report* 1998 for definition and country ratings) and the EBRD index of transition in the power sector (presented in Annex 2) of each of the Bank's countries of operations for 1998, which is shown graphically in Box 1. For example, Hungary has made most progress in general transition and is rated highest in power sector reform. Belarus and Turkmenistan, on the other hand, score low in general and in the power sector. The most notable outlier is the case of Kazakhstan, where reforms in the power sector have moved at a faster pace than general economic reform.

Box 1. Transition in the power sector correlates with transition in general



The correlation between general progress in transition and progress in power does not imply causality. It does indicate, however, that lack of progress in power is often symptomatic of lack of government commitment to reform in general. Lack of general reform need not hold back power sector reform (as the case of Kazakhstan illustrates). Countries that have moved forward with general reform should not fall behind with reform in the power sector. The most successful reform in the power sector has been achieved against a background of progress in general reform, which has fostered economic stability.

2. MODELS FOR COMPETITION

One way to introduce competition in the power sector is through the setting up of a pool; this was the path followed in Chile and England and Wales.[14] This is a wholesale market for power which works on the basis of a bidding process. Power generators declare their capacity available for production and then bid to supply power to meet demand that is forecast by the pool operator for particular time slots (usually a day ahead, though the time between bidding and supplying can be longer). On the basis of bids, a merit order is formed (in other words, a ranking of the cheapest combination of plant to fulfil given demand) from which plant is dispatched to fulfil forecast demand. In more sophisticated systems, large consumers may also bid into the pool the price that they would be prepared to pay for marginal consumption. This prevents the dispatch of plant where the bid by the generator exceeds the bid by the consumer, in other words, it prevents the dispatch of plant which adds negative net benefit (benefit minus cost) to the system. In practice, there has been very little demand-side bidding in power pools.

Any producer that declares plant available may receive a capacity payment, usually related inversely with the total amount of available capacity relative to forecast demand (i.e. system security). This payment plays a dual role: it signals to producers the need for new plant when capacity is short relative to demand; given that the capacity payment is passed on to the consumer, it rations available capacity and preserves system security (if prices were not to rise in response to a shortfall in capacity, then the frequency of system outages would increase).

For producers who own plant that is dispatched, an additional payment is made. This can be set equal to the bid made by the producer which, under conditions of competition, should equal the producer's marginal cost. It might alternatively be equal to the bid made by the last unit of plant to be dispatched, termed the "System Marginal Price", equal under conditions of competition to the marginal cost of that unit of plant. This latter mechanism has been criticised in the case of England and Wales on the basis that it provides gaming opportunities for major market players.

Payments in a power pool can in practice be highly volatile. Risk-averse generators and/or distributors can insure against this by signing futures contracts, sometimes called contracts for differences, which specify payments between contracting parties relative to the pool price. In effect this sets the price at which power will trade in the future irrespective of what the pool price is (though expectations about future pool prices will determine the prices specified in contracts).[15]

The benefit of the type of pool above is that it allows supply-side competition, something that should encourage low-cost production which is passed on to consumers in the form of low tariffs. Furthermore, it can provide a useful bridge in transition economies where prices remain unbalanced: a pool allows for price averaging to support cross subsidy. Though from an economic point of view cross subsidy is not desirable, from a practical point of view tariff re-balancing may have to be phased.

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[14] For analysis of the pool in England and Wales see Green (1996), Green and Newbery (1992), Von der Fehr and Harbord (1993), Kennedy (1997b).

[15] Green (1991) discusses contracts for differences in the case of the England and Wales industry.

Problems with power pools are:

- Bilateral relations between power generators and large consumers are limited relative to the situation in a fully competitive market. The economic losses resulting from this are two-fold: potential efficiency gains in billing and metering are not made; and distortions in the price structure (cross subsidy between groups of consumers) may be sustained.
- In the absence of demand-side bidding, and the presence of capacity payments, uneconomic new entry may take place, and uneconomic plant may be dispatched in the sense that the marginal value is exceeded by the marginal cost; see Annex 3 for discussion.
- Lack of transparency associated with pools allows for the possibility of dispatch that is not consistent with the merit order.
- The fact that all cash in the industry may pass through a pool provides scope for corrupt behaviour that threatens the financial viability of generating companies. This point does not apply if there is central settlement but not central payment. Where there is a deficit of cash, this may be allocated through the pool to generators in a manner that is not consistent with the power that they supply. This point applies also when there is central settlement but not central payment.

A pool has been introduced in the Ukraine power sector and some of the above problems have occurred there (Box 2).

Box 2. Ukrainian power sector restructuring and the pool

The power sector in Ukraine has been restructured in recent years, including the vertical unbundling of the generation, transmission and distribution functions. A power pool was introduced and operates as follows: the Energomarket purchases wholesale electricity from thermal, nuclear, hydro and CHP plants for resale to LECs, independent suppliers and industrial customers. Generators are compelled to sell to the Energomarket if capacity exceeds 20 MW. Each generating company provides hourly bids for each of its units a day ahead to the Settlement System Administrator (SSA). The SSA forms a merit order that is used (after revisions for transmission system constraints) as the basis for dispatch. In theory, generators are paid system marginal price if they are dispatched and a capacity payment – proportional to total system capacity available – irrespective of whether they are dispatched.

In practice, dispatch has not always been according to least cost principles. Payments are often not forthcoming or are in the form of barter (including promissory notes and offsets). Cash passing through the pool is allocated to generators in a non transparent manner. This creates problems for generators who are short both of working and investment capital. As a result, much of the installed capacity is not available (either due to poor maintenance or lack of cash to pay for fuel) and there has been minimal private sector entry in generation. The underlying cause of this is the low level of cash collection in the system, something that has been allowed to persist through the failure to privatise distribution companies.

One alternative to the pool arrangements is the single buyer model. Here the rule is that all output in the power system must be sold to a single buyer – usually the state-owned transmission company (or trading arm of the transmission company) – that then sells on to downstream users. This is implemented through off-take contracts, termed “Power Purchase Agreements” (PPAs), signed between generators and the single buyer.

Much as in the case of the pool, payments under the agreements relate to available capacity and output delivered. In contrast to the pool, the merit order for dispatch is not formed on the basis of competitive bidding. Rather, the single buyer forms an estimate of the merit order according to its estimate of generating costs for each unit; for plant that is dispatched, it pays a fixed price that moves over time according to an agreed formula which incorporates factors such as inflation, fuel price movements and exchange rate movements.

In terms of economic efficiency, whereas a pool gives the incentive to make ongoing efficiency improvements and to pass these on to consumers, there are weaker incentives to perform better under a single buyer and, in addition, performance gains show up in the form of higher profits rather than lower prices. The reason for this is that there is continuous competitive pressure in a pool, but in a single buyer situation there is only one round of competition (when contracts are first awarded). On other shortcomings, the single buyer model shares with the pool that there are limited (none in the case of the single buyer) bilateral relations between generators and downstream firms, and the single buyer carries the credit risks associated with the flowing of all cash in the system through a central body. However, the single buyer model can have a role to play in an interim period before full liberalisation, providing security for private investors within a new and untested regulatory framework and when tariffs have not been fully rebalanced. The case of Hungary illustrates the short-term efficacy of the single buyer model (Box 3).

Box 3: Hungarian power sector restructuring and the single buyer model

Hungarian power sector restructuring began in late 1995. Around this time, seven generation companies, some with investment undertakings, were sold to the private sector, in addition to all power distribution companies and a minority stake in the transmission company. One aim in this privatisation was to raise revenue to finance the government budget deficit. This being so, the industry was privatised on the basis of the single buyer model with its associated restrictions on competition. The arrangements were that the (state-owned) transmission company would have a monopoly on the sale and purchase of electricity and electricity generating capacity. This was implemented through long-term contracts between generators and the single buyer specifying capacity payments and unit power prices and formulas for price changes (indexing on fuel prices, etc.). Under the terms of the agreements, plant has been dispatched on the basis of a merit order relating to the underlying incremental cost of plant.

There is a hybrid called the “French Single Buyer Model” which emerged in the EU Power Directive (see Annex 1 for more details). Under this model, generators and large power consumers may agree to trade power of a specified quality at a specified price. The single buyer (the transmission company or its trading arm) is obliged to purchase power from the generator at the specified price, net of a transmission charge. The single buyer then sells the power to the large user at the specified price. In other words, the company buys the power from the generator and pays a transportation fee to the transmission company, something which is equivalent to the alternative model permitted under the EU Directive, third-party access. The problem with this model is that it provides commercially sensitive information to the single buyer. This information could be used in an anti-competitive manner: the single buyer would know the price necessary to undercut its rivals.

Under third-party access, the model adopted in the Kazakhstan power sector (see Box 4), generators compete to sell power to large users. Terms and conditions of access to the transmission network – including payment for the use of transmission capacity – will usually be specified in a grid code. Of the various alternatives for the access price (negotiated access, etc.) the most transparent is one which is published. In order that maximum consumer benefit derives from competition, the access price should be regulated (otherwise industry liberalisation could just result in an increase in the profits of the transmission company).

Box 4. Kazakhstan power sector restructuring and liberalisation

The Kazakhstan power industry was restructured from 1995 through the separation of distribution, transmission and generation. By 1998 most of the generating capacity had been sold to the private sector, as had a number of distribution companies. Vertical integration between privately owned generation and distribution was allowed (for example, in the Almaty and Karaganda regions). The national transmission company remains under state ownership and acts as a power wholesaler. It is not, however, a single buyer: direct contracting between generators and large users based on the third-party access model is allowed and has actually occurred.

Problems remain because of the haste with which the sector was privatised: the regulatory arrangements for distribution are such that the future level of tariffs is unpredictable; rules for access to the grid prevent competition from flourishing; there are cash collection problems in the distribution companies that have not been privatised; there are system imbalances due to the lack of reserve arrangements underpinning the contract market.

The benefit of the third-party access model over a simple pool is that the former allows the interaction of supply and demand, should result in prices which reflect underlying costs, and should enable minimum achievable costs in both generation and supply. There is scope for combining the two models to deal with the problem of energy imbalance that occurs when demand for power exceeds that supplied under bilateral contracts. Generators offer to supply power to the pool here in the manner discussed above: a merit order is formed on the basis of bids and least cost plant is dispatched until all residual demand has been catered for. The reason that imbalances between power demand and contracted supply occur is because contracted plant may not always be available, and because it is not economic for large users with uncertain demand (particularly distribution companies) to contract in advance sufficient capacity to meet demand in all eventualities. Rather, the optimal arrangement is to have system-wide capacity available which can be dispatched around the network according to the pattern of residual demand.

In a system with third-party access or a pool it is important that there is a sufficient number of competing generators.[16] Where the number of generators is small (two for example) the degree of competition is likely to be limited, with industry liberalisation resulting in profits for power generators rather than price benefits for consumers. This problem has been highlighted in the England and Wales power pool where the two dominant generators had substantial price setting power (Box 5).

Box 5: limited competition in the restructured UK power industry

Privatisation of the electricity industry in England and Wales started in 1990. Old area boards were succeeded by regional electricity companies, each with a monopoly over electricity distribution. Competition for the large user market was phased in gradually, with the floor at 100 kW by 1994. Power generation was split into three companies, two of these fossil fuel, one nuclear. In addition to competing for the large user market, these companies compete to supply through the pool. New entry from IPPs was limited to a 10% market share by 1995, expected to rise to 20% by 2000. Most entry has been in baseload generation; in non-baseload, which sets system marginal price in the pool, the two incumbent generators will still have a market share estimated to be around 65% by 2000. The upshot is that there is market power in the pool and that this has been used to divert the benefits of privatisation and competition to firms as opposed to consumers. Divestment of assets in a more disaggregated structure for generation could have passed on benefits to consumers through more vigorous competition in the pool.

[16] This point is stressed in Green and Newbery (1992) and Green (1996).

To the extent that the single buyer model is ephemeral – it is used to play a bridging role until full competition is introduced – the number of players should be sufficiently large at the onset of full competition. Given that the process of new entry takes time, competition through new entry is unlikely to occur in the short term. If there are to be immediate benefits from the opening up of markets, the privatised structure, the extent of unbundling in generation in particular, and the contract structure (length and scope of PPAs) at privatisation, are crucial factors.

3. THE INTRODUCTION OF COMPETITION

Two important questions when restructuring a power sector are: first, "how far into the future after privatisation should competition be introduced?"; second, "what contract structure at privatisation maximises competition upon liberalisation and minimises the extent of problems associated with the financing of stranded costs?"

Before answering these questions, it is worth making the distinction between competition *for the market* and competition *in the market*. The former relates to situations where there is a competitive bidding process for a concession which, in the case of the power sector, is implemented through a single buyer tendering for new capacity, the owner of which will be given a power purchase agreement. Alternatively, the sale can be to the private sector, through a tendering process of companies with power purchase agreements. Competition in the market relates to the situation where there are no entry barriers so that producers are free to compete for custom. Thus the introduction of third-party access, which provides maximum incentives for (allocative and productive) efficiency, is designed to promote competition in the market.

Turning first to the question of when to liberalise, it is useful to assume that there is sufficient institutional capacity (a regulator and a grid code are in place, and technical standards have been achieved) to facilitate third-party access.[17] Then the decision over when to liberalise market entry involves the weighing up of a trade-off between revenues from the privatisation of existing assets and the economic gains from lower power prices to consumers in the future. The earlier the date for liberalisation, the greater the degree of uncertainty over and (due to either the possibility of future price reductions or loss of market share) the lower the expected value of future profits. On the other hand, the earlier that markets are liberalised, then the sooner that the resulting price reductions will ensue. In terms of balance, given that competition sets in upon liberalisation, the consumer benefit deriving from lower prices should outweigh the loss in revenue upon sale of assets.[18] This would suggest that competition in the market should be introduced as soon as possible.

If, for whatever (political or economic) reason liberalisation is to be delayed, and assets are to be privatised with PPAs, it is unlikely that there will be much competition in the market upon liberalisation if demand and capacity contracted under such contracts are approximately equal beyond the date of liberalisation. In this case, competition would only occur through new entry – as opposed to between existing producers – and would bring with it the problem of how to pay for stranded costs. The risk of such undesirable outcomes, and associated mitigating measures, should underpin design of the contract framework for privatisation.

For the case of IPPs, the fact that these are project-financed (i.e. off the balance sheet of project sponsors) means that they will typically require PPAs covering the majority of capacity throughout the life of the plant. Without such security, it is unlikely that anybody would be willing to finance an IPP in a transition economy given the multitude of other risks

[17] If this were not the case then it is unlikely that competition would work: there would be scope for anti-competitive behaviour, and the level of risk would be sufficiently high to restrict injections of finance to the sector by private investors.

[18] This is more the case as: price elasticity of demand for power is greater and there is sufficient capacity available; competition leads to cost reductions and service quality improvements. Losses to taxpayers are greater and prices lower as purchasers are more risk averse.

(macroeconomic risk, political risk, country risk, etc.).[19] To the extent that PPAs inhibit competition (by reducing the size of the competitive market), and can become stranded upon liberalisation, then the number of contracts signed between a single buyer and IPPs should be limited. This point is strengthened by the fact that IPPs typically require extensive and costly government performance guarantees if financial closure is prior to market liberalisation.

In the case of existing plant (which does not need rehabilitation), it is economically desirable to privatise generating companies without PPAs and to liberalise the market immediately. Investors will purchase uncontracted plant given that the sale price is sufficiently low (less than or equal to the expected profits from participation in the competitive market). Governments may be reluctant to follow this path because it reduces privatisation revenues relative to delaying liberalisation. In this compromise situation, it is important that PPAs awarded at privatisation do not conflict with the opening of the market. In the case of Belgium, there have been difficulties because distribution companies recently refused to accept their obligations under PPAs on the basis that they would rather shop around in the competitive market.

In order to promote competition upon liberalisation and avoid stranding of costs, PPAs for existing plant to be privatised should cover only a small portion of capacity after liberalisation, something that can be achieved through direct specification in the contract or through specification of events upon which contracts can be renegotiated (re-opener clauses, etc.). An example of a compromise, with PPAs that do not guarantee off-take beyond liberalisation, is the case of the power sector in Hungary (Box 6). The possibility that competition will be undermined and costs stranded currently has a high profile in discussions about implementation of the Bulgaria power sector restructuring (Box 7).

Box 6. Liberalisation and the contract framework in Hungary

Long-term off-take agreements signed at the time of the Hungarian privatisation have clauses such that the level of contracted capacity is reviewed yearly. Contracted capacity can fall or rise according to demand from the Hungarian single buyer. This provides scope for market liberalisation without problems associated with the allocation of stranded costs: if there are stranded costs then these are borne by the owners of divested companies who, at the time of privatisation, made decisions about market risk and priced them accordingly in their bids for company ownership. The power market has not yet been liberalised in Hungary: construction of new capacity is centrally planned and constructed under contract awarded through tendering; there was a recent tender for 700 MW of new capacity. The market will, however, open in 2001 with an initial 15% open for competition and the possibility of an increase in this share later in the same year.

Box 7. Bulgaria power sector restructuring

The Government of Bulgaria recently adopted a 10-year Energy Strategy and 3-year Energy Sector Restructuring Plan. Proposals include: separation of generation, transmission and distribution; privatisation of specified generation as IPPs; later privatisation of generation and distribution; a single buyer model for an interim period; introduction of third-party access by 2005. The plan is quiet, in terms at least of concrete steps, on: the extent of IPPs; the horizontal structure of generation; the vertical structure as regards joint ownership of generation and distribution; the cover offered to investors through off-take contracts at privatisation; the problem of stranded costs that could occur in moving from the single buyer to the third-party access model. These issues are intended to be resolved as restructuring moves forward.

[19] At least in the early stages of market development.

There is some plant that should always be dispatched on the basis that its variable operating cost is the lowest in the system. Examples here are hydropower plant and combined heat and power (CHP) plant, the latter when operating in co-generating mode with heat production. This plant would be attractive to investors without PPAs; they would anticipate that it would be dispatched in a competitive market. However, privatisation of this type of plant with long-term PPAs consistent with economies of scale or scope is not economically undesirable.[20] Contracts extending beyond any economies (for example, power production from CHP plant at times when there is no heat being produced) reduces competitive pressure upon liberalisation and leaves prices higher than they might be in the absence of contract cover. Regarding contract prices in the case of CHP, there is a set of choices for allocating costs between heat and power production and between markets where there are concessions and those where there is competition. From an economic point of view, common costs should be allocated away from the competitive market – to the extent that CHP plant is able to compete – and to market segments where demand is least elastic.[21]

[20] New CHP plant will require PPAs for heat off-take given specificity to the heat distribution network. Without PPAs it is likely that investment would not go ahead due to the hold-up problem. For a discussion of the hold-up problem see Grout (1984).

[21] Brauetigam (1979) derives optimal cost allocation rules for firms operating in a number of markets, one of which is competitive.

4. OTHER ISSUES

Decisions to build new capacity can either be centralised or decentralised; the former where there is a single buyer that tenders for new capacity as required, the latter in an open market where anybody can construct new plant subject to obtaining a licence and will do so where there is sufficient demand. Under a single buyer model with tendering for new capacity, it is unlikely that the least cost method of meeting power demand will prevail. This is because the single buyer does not have the same incentives to strand costs as the market or the amount of information which is exchanged in the market. In other words, the single buyer could continue to purchase power from uneconomic plant and pass on the relatively high cost to the consumer. This is particularly important given the presence of plant that runs from high-cost fuel. Furthermore, in the absence of economic prices – a situation that may be sustained under the single buyer model – it is unclear that new plant can be justified on a cost benefit basis. These are additional arguments against the single buyer model; they add to the message in Section 2 that the single buyer model should only be in place for an interim period until full competition sets in.

To the extent that a government believes there will be market failure – for example, individual decisions of private companies lead to a situation of fuel dependence such that security of supply is under threat – there are various options for intervention. These include limits on the amount of a particular kind of capacity that would be licensed, and subsidies or tax levies according to type of capacity. To reiterate though, the danger is that intervention will result in an uneconomic solution. In situations where country and/or sector risk is such that there would be no new entry in a decentralised market, then the single buyer tendering for capacity backed by sovereign guarantees could be the solution for an interim period. However, there has been new investment in the fully decentralised Kazakhstan power sector even though country risk is high and there is a large degree of uncertainty as regards sector regulations. In such a situation, a balancing pool – and the information that this provides to distributors and generators as to relative scarcity of capacity – may be sufficient to encourage entry.

Turning to the issue of stranded costs, where the wrong contract structure is already in place, and the market is to be liberalised, the problem becomes one of where to allocate the stranded costs. The candidates here will typically be: commercial banks that have financed IPPs, owners of IPPs in (rare) cases where there is recourse for financiers, the single buyer, distribution companies, customers, taxpayers. Options include: scrapping or renegotiating long-term power purchase agreements (the financier or project sponsor pays); financing the difference between contract prices and market price through a tax or consumer levy. The solution in such a situation will typically be of a political – rather than economic – nature; such a situation has arisen in Poland (Box 8).

Regarding new entry, this will not necessarily be efficient (least cost) when there are distortions in the price structure such that prices do not reflect costs. In the case where there is subsidy, if this applies to some generators and not others, then the most efficient firm might be prevented from entering the market. In the case of implicit subsidy, arising from asset sales to the private sector at a price less than modern equivalent value, such a firm will price below the long-run cost of supply and prevent entry from producers operating greenfield plant. This is likely, however, to be consistent with the least cost plan, given that the costs of existing plant are largely sunk, and given that capacity constraints are not binding.

Box 8. Pre-privatisation power purchase agreements and Polish power sector restructuring

There is a large amount of generating capacity with long-term off-take contracts (the minimum take for 1999 is 61 TWh, from total production estimated at 112 TWh) awarded on the basis that rehabilitation was required and that this would only be financed if there was enough security. The problems here are: it is not clear that the plants with contracts fit the least cost plan; the prices specified in the contracts may afford excess profits to the generators. In either event, this plant would not be competitive at the contracted prices when the market is liberalised. In other words, the contracts could become stranded. This raises the issue of who should pay for stranded costs: commercial banks that financed plant rehabilitation, generators, the national electricity company, distribution companies, consumers or taxpayers. The constraints here are the Polish legal system and political considerations. Industry liberalisation cannot move forward until this issue has been settled. On existing plant, it would appear that this can be sold with little or no contract cover as regards off-take. A recent bid from National Power (NP) to purchase the PAK generating complex was rejected after NP demanded a 5-year power purchase agreement. It looks now that a consortium of domestic and international investors will purchase the plant without a PPA in a deal worth around US$ 250 million.

Probably the most likely case of inefficient entry through price structure distortions would be when there is cross-subsidy between groups of customers. In the EBRD countries of operations, the inherited price structure typically exhibits cross-subsidy between industrial and residential consumers such that the former pay a price above cost and the latter a price below cost. In a liberalised market, this will lead to cherry-picking.[22] Entry would not always be efficient (consistent with the least cost plan) in situations where the incumbent producer was constrained in their price response to competitive pressure. Such constraints do exist in practice (incumbents' price reductions are constrained to give an advantage to new entrants, price increases in loss-making parts of the market are barred). If inefficient entry is to be prevented, ideally tariffs should be rebalanced to reflect costs prior to market liberalisation. In any event, incumbent producers should be allowed to adjust prices (industrial and residential) in the face of competition. Without the ability to change prices in the face of competitive threat, the incumbent company would not be financially viable. This is undesirable because the incumbent would still be left with the responsibility to supply residential consumers.

The price structure as regards network access could also potentially allow inefficient entry. This would be the case, for example, if prices were based on national cost averaging that did not reflect the underlying cost of transporting electricity between two points in the network.[23] For example, the more that transmission prices exceed the marginal cost of transportation, the more the playing field is tilted in favour of local production, even when this might not be least cost. In such a situation, the outcome could be the building of new power stations close to markets when, in fact, it would be economically desirable not to build and instead to draw on capacity already existing within the system. The risk of uneconomic production is partially mitigated in this case by the fact that transmission costs are a small part of total costs.

The optimal price for power transmission is based on the underlying cost which in turn is the sum of the variable cost plus the (average) net incremental cost of adding to transmission

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[22] See Armstrong, Cowan and Vickers (1994).

[23] See Newbery (1996).

capacity.[24] This rule assumes that the capacity of the system is optimal, something which is unlikely to hold in the EBRD countries of operations because past investment decisions were not made on an economic basis. Where there is excess capacity, then a price less than long-run marginal cost, bounded below by short-run marginal cost, should prevail until either demand grows to the level of capacity or capacity needs to be renewed.

Where there is a deficit of capacity, if the price for transmission is less than or equal to average incremental cost, then there will be system failure. For as long as demand exceeds capacity, the price charged should be such as to guarantee a chosen level of system security. Formally, the price in this situation should equal the expected value of lost load. To the extent that the price-setting authority may not have the information to implement this pricing rule, one option is to have repeated auctions of network access slots. Data from this type of auction would reveal the marginal value of congested capacity and would provide a signal to a regulator of when, from an economic point of view, new capacity should be constructed. An alternative to repeated auctions would be trading of network access slots. This has the feature that it would yield profits for slot holders any time that there was excess demand for network access. For the case of repeated auctions, this would yield excess profits for the owner of the transmission network in situations of capacity deficit. Three things are important here. First, the time period for re-auctioning slots is consistent with any PPAs that are in place. Second, a decision must be made about the allocation of the excess profit.[25] Third, given that the incentive is for the transmission network to preserve the capacity deficit, the grid code should specify the rules for construction of new capacity.

[24] See Turvey and Andersen (1977).

[25] Excess profit occurs because of delays in building and due to discontinuities in the cost function for power transmission.

5. SUMMARY

- The aim of this paper was to outline ways to introduce competition to the power sector, drawing on examples from the EBRD countries of operations.
- The supporting structure required for competition involves vertical and horizontal separation of operating units. Vertical integration of generation and distribution is a second-best structure. Horizontal unbundling of generation is paramount if the aim is to promote competition.
- Industry structure should be in place before wide-scale privatisation: restructuring is difficult once assets have been sold to the private sector and vested interest created.
- There has been varying progress in reform in the EBRD countries of operations. Few countries have yet to embark on the reform path. Radical reform in Hungary and Kazakhstan has led the way for the rest of the region.
- A power pool allows supply-side – and not demand-side – competition, may be non-transparent and manipulated through corrupt behaviour. A pool is preferred to the single buyer model where there are problems associated with non-transparency and, in addition, incentives to reduce costs and/or tariffs are limited. Maximum incentives for cost and tariff reductions are present in the third-party access model with bilateral relations between power generators and consumers.
- Competition in the market is preferable to competition for the market. From the economic point of view, power markets should be opened to competition as soon as is technically feasible. This would benefit consumers in excess of any associated loss incurred on taxpayers. In practice, competition may be delayed in order to raise tax revenues from asset sales. The trade-off here will be determined according to political factors.
- The contract structure should be consistent with proposed liberalisation. The number of IPPs should be limited until the market is opened. For divested assets, PPAs should cover only a part of capacity from the date of liberalisation. Failure to organise the contract structure in this way would limit competition at liberalisation and possibly result in stranded costs and the problem of who should finance them.
- Construction of new plant should be decentralised on the basis that a central authority has neither the information nor the incentive to implement a true least cost plan.
- Retail and access prices should reflect costs. Formally, the pricing rule should be that prices equal the higher of net incremental cost or marginal social cost. Without this pricing rule there are incentives for inefficient entry.

ANNEX 1: EU POWER DIRECTIVE

The European Electricity Directive resulted from discussions taking place from 1992 and was finalised in July 1996. The aim of the Directive is to liberalise access to electricity markets in Europe. This is seen as a logical extension of the European single market under the European Union Treaty. The Directive allows member states to choose between alternative models for electricity industry liberalisation, reflecting a preference for subsidiarity, which is necessary to harmonise political differences between member states, in this context at least. In form, the Directive comprises 29 articles, the more important of which, from an economics point of view, are now summarised.

Article 3 states that alternative systems must achieve equivalent results. This article also gives member states the option to restrict liberalisation where this would conflict with public service obligations. Public service obligations may relate to: system security, including security of supply, regularity, quality and price of supplies and to environmental protection. Restrictions on liberalisation must not work against the interest of the Community, defined, among other things, as the development of competition in parts of the electricity market.

Article 4 states that new electricity generating capacity may be secured either by an authorisation procedure or a tendering procedure. Each procedure must be based on objective, transparent and non-discriminatory criteria.

Article 5 sets out the rules for authorisation of new capacity. Under the rules, a state’s refusal to authorise the construction of new capacity must be well founded and duly substantiated and there must be an appeals procedure.

Article 8 states that dispatch of generating capacity will be determined by the transmission system owner according to non-discriminatory rules, taking into account all available capacity, including interconnected capacity.

Article 14 states that there will be separate accounts for integrated (generating, transmission, distribution) companies; the aim of this is that integrated companies will act as if they were separate companies.

Article 17 states that third parties may gain access to transmission networks through negotiation with network owners. As part of the negotiated access model, transmission network owners should publish indicative access prices, based on the average of the past year’s prices. Alternatively, member states may opt for the model of network access based on regulated and published tariffs.

Article 18 gives member states the option to appoint a single buyer of electricity. Power producers and certain consumers would, however, be able to trade electricity and would have to be allowed access to the transmission network. Access would be based on either negotiated or published tariffs. This article allows the possibility that the single buyer will be obliged to purchase contracted electricity at a single buyer (retail) price minus the published network access price.

Article 19 proposes a timescale for liberalisation. Retail competition is secured for all consumers with annual consumption above 100 GWh. In each member state the total share of the market open to competition must be equivalent to the proportional size of the market for customers consuming in excess of 40 GWh per year (this should equate to around 22% of the market). This threshold will fall to 20 GWh after three years and 9 GWh after six years. In order to purchase power in the liberalised market, a customer will have to be deemed “eligible” by its member states. In order to ensure that there is reciprocity between member states, where a customer is eligible in one market and not another, so in the latter state that customer is refused permission to trade, the Commission can over-ride refusal and force the member state to allow trade. Distribution companies in member states may potentially be eligible customers under the Directive.

Article 22 states that dominant position abuse should be prevented through, *inter alia*, regulation.

ANNEX 2: POWER SECTOR TRANSITION INDICATORS

The power sector transition indicators were constructed for the EBRD's countries of operations and were published in the *Transition Report* 1998 (see Box). They measure progress in reform from the initial situation in the power sector identified in the *Transition Report* 1996: abundant supply capacity at zero or low prices with little cash collection and service provision by entities more oriented to engineering than business. Countries were rated according to the degree of progress in reform: corporatisation, legal reform to facilitate unbundling, regulation and liberalisation; implementation of a restructuring programme; and a large scale of private sector involvement. Ratings were adjusted downwards for countries with very low levels of cash collection.

Power sector transition indicators

1. Power sector operated as a government department, political interference in running the industry, few commercial freedoms or pressures, average prices below costs with external and implicit subsidy and cross-subsidy, very little institutional reform with monolithic structure with no separation of different parts of the business.

2. Power company is distanced from government, for example, is a joint-stock company, though there is still political interference. Some attempt to harden budget constraint, but management incentives for efficient performance are weak. Some degree of subsidy and cross-subsidy. Little institutional reform, monolithic structure with no separation of different parts of the business. Minimal, if any, private sector involvement.

3. Law passed which provides for full-scale restructuring of the industry including: vertical unbundling through accounting separation, setting up of a regulator. Some tariff reform and improvements in revenue collection, some private sector involvement.

4. Law for industry restructuring passed and implemented with separation of the industry into generation, transmission and distribution and setting up of a regulator with rules for cost-reflective tariff-setting formulated and implemented. Arrangements for network access (negotiated access, single buyer model) developed. Substantial private sector involvement in distribution and/or generation.

4+ Business separated vertically into generation, transmission and distribution, an independent regulator with full power to set cost-reflective effective tariffs. Large-scale private sector involvement. Institutional development covering arrangements for network access and full competition in generation.

Scores for each country (.) were as follows: Albania (2), Armenia (2), Azerbaijan (2), Belarus (1), Bosnia and Herzegovina (2), Bulgaria (2), Croatia (2+), Czech Republic (2), Estonia (2), FYR Macedonia (2+), Georgia (2+), Hungary (4), Kazakhstan (3+), Kyrgyzstan (2+), Latvia (2+), Lithuania (2+), Moldova (2+), Poland (3), Romania (2+), Russian Federation (2), Slovak Republic (2), Slovenia (2+), Tajikistan (1), Turkmenistan (1), Ukraine (2+), Uzbekistan (1).

ANNEX 3: MARKET FAILURE IN POWER POOLS

The case of England and Wales is useful to illustrate the shortcomings of power pools. To recap, the pool in England and Wales works on the basis of capacity payments and volume-based payment at system marginal price.[26]

Capacity payments are supposed to ration existing capacity. In the absence of capacity payments (and without demand-side bidding) there would be outages in times of high demand relative to available capacity. This would not be economically optimal: in this situation low-value customers would impose costs on high-value customers in terms of reducing the security of supply. This is a typical case of externality, with the standard economic solution to charge a price equal to social marginal cost. In this case the social costs are related to security of supply and can be embodied in a variable termed the *value of lost load,* defined as consumers' willingness to pay in order to avoid a power outage.

Capacity payments are also designed to provide a signal upon which new entry decisions can be made. Optimal system capacity sets the value and capacity of cost equal at the margin. In other words, optimal capacity sets the expected value of new capacity (value of lost load multiplied by the probability of a power outage) equal to the marginal cost. If the value of lost load were known, then an optimal capacity payment would be feasible.

The problem is that the value of lost load is not known by the pool operator. Though there are methods for estimating lost load (for example, gathering data on costs associated with own generation in industry) these do not provide comprehensive information. As a result of this, rules of thumb are used for practical purposes. For example, the number of outages deemed to be acceptable is chosen and then the price set according to this target. If the resulting price is higher than the underlying value of lost load, then there will be suppressed demand (eroded consumer surplus) and too much new entry. If the price is below the underlying value of lost load, then there will be too many outages, and not enough new entry.

Turning to another problem, uneconomic plant can be dispatched in the pool because the link between consumption decisions and prices is not always strong. The fact that price is learnt by the consumer after consumption has taken place means that consumption cannot be adjusted in response to price changes. For consumers who do not purchase directly from the pool (i.e. all but the largest industrial customers) the distribution company may practice price smoothing across different periods. Again the consumption decision becomes divorced from the economic price.

One solution to both these problems – the chosen way forward in England and Wales – is to abolish capacity payments and allow demand-side bidding. Such a system should ration capacity according to economic principles and provide signals for new entry. In situations with high offer prices by generators, related plant would only be dispatched when warranted by marginal value (i.e. dispatch of uneconomic plant could be avoided).

One other innovation in the case of England and Wales is the introduction of tradable futures markets. These should provide security for market participants while at the same time allowing flexibility to respond to, for example, changes in relative fuel prices, changes in demand profile.

As regards the EBRD's countries of operations, it must be noted that the above-mentioned changes in England and Wales were due to be introduced around 10 years after privatisation, and that replication in central and eastern Europe and the CIS would require substantial further institutional development.

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[26] Also on the basis of uplift payments (for transmission losses, etc.), the subject of criticism, but not discussed here.

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