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Regulatory reform and market development in power sectors of transition economies: the case of Kazakhstan

by David Kennedy

Abstract

Kazakhstan is at the forefront of power sector reform in the EBRD's countries of operations. Starting in 1996, a regulator was set up, the industry was unbundled, some distribution and generation companies were privatised, and the large user market was liberalised. A number of reform challenges remain, however, in the areas of privatisation, regulation and competition. This paper proposes that the remaining distribution companies be privatised with a view to raising the level of cash collection. Before this takes place, the industry would benefit from regulatory changes, strengthened independence of the regulator, and modified regulatory rules to improve risk allocations and strengthen incentives. On competition, the paper proposes enhancing the present market arrangements by introducing a balancing pool, and re-balancing transmission tariffs to reflect location marginal costs. Implementation of the proposed changes should yield substantial welfare gains for Kazakhstan. The broad challenges in Kazakhstan are characteristic of those in the sector throughout the region. The case of Kazakhstan shows that any country can embark on radical power sector restructuring irrespective of reform progress in the wider economy.

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1. INTRODUCTION

Starting in 1996, Kazakhstan has undertaken radical reform of the power industry and has progressed further in implementing such reforms than any other CIS country. Among the former communist countries, only Hungary has moved further in power sector transition.[1] Power generation, transmission and distribution have been unbundled, a regulatory body formed and substantial expertise developed, the private sector introduced in some areas, and the market for large users (including distribution companies) liberalised.

A number of reform challenges remain, however. Cash collection is low across the country, more so in regions where the private sector has not been introduced to power distribution. In the field of distribution company regulation, the legal and institutional framework and specific regulatory rules provide limited security for foreign strategic investors. In the absence of such investors in the remaining publicly owned parts of the industry, and given the very low levels of cash collection, financial viability of the sector is likely to remain weak. Regarding generation, there is inefficient dispatch because the market for contracts does not function perfectly (there are transaction costs, and informational and institutional constraints). From a geographical perspective, transmission prices do not reflect underlying costs thus incentives for underlying consumption and investment decisions are distorted.

It is particularly timely to confront these issues given the financial insolvency of the sector and the large investment needs, both of which are driving the Government of Kazakhstan to privatise remaining state-owned power firms. If progress can be made, then the sale price of assets – revenue to the government – in the forthcoming distribution company privatisations will be higher. In the longer term, finance for new investments is more likely to be available and at a lower price, and therefore the impact of investment on tariffs will be minimised. Once the private sector has been introduced, evidence from earlier power privatisations in Kazakhstan suggests that collections will improve. Regarding market operation, reform here will allow consumers to reap more of the benefit of private participation.[2] Reform now will set out the market rules prior to privatisation, thus reducing uncertainty.

The present paper outlines in more detail the reform challenges in the Kazakhstan power sector and proposes policy responses. The assumption throughout is that the objective of policy is to maximise economic welfare, equivalent to maximising consumer benefit from the consumption of power subject to the constraint that the industry is self-financing.[3]

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[1] The EBRD definition of power sector reform is embodied in the transition indicators published in the *Transition Report* (1999). Steps forward in power sector transition are laid out in Kennedy and Stern (2000). These include: commercialisation, unbundling, setting up of an independent regulator, privatisation, tariff rebalancing, and liberalisation.

[2] The extent to which this is the case depends on the regulatory and market rules. In the case of Kazakhstan, there are debates over whether consumers or shareholders have benefited from privatisation of the Almaty Power Company. In the case of the England and Wales power industry, Newbery and Pollitt (1997) suggest that efficiency gains benefited shareholders more than consumers, in the early years at least.

[3] In other words, the assumed objective is to minimise expected retail prices subject to the constraint that firms in the industry break even. The solution to this is the same as the welfare maximising price with the provisos that: (1) demand for power is not perfectly price inelastic/greater weight is attached to consumers' as opposed to producers' utility; (2) the shadow price of public funds is prohibitively high relative to the price elasticity of demand for power (i.e. there is no economic ground for subsidy).

Section 2 of the paper discusses company ownership. It argues that privatisation of distribution companies to international strategic investors should, within the right legal framework, lead to improved cash and revenue collection, something necessary to ensure financial viability of the sector, particularly as new investments are required. In addition, it contends that further joint ownership of generation and distribution should be prevented in order to ensure a level playing field for competition, and that regulatory reform should be carried out prior to privatisation in order to maximise sale receipts/minimise the cost of carrying out investments.

Section 3 discusses the elements of regulatory reform that would lead to an improved investment climate. From an institutional point of view, the key points are that the independence of the regulator could be strengthened, and that regulatory licences should be introduced to provide greater security for investors. Regarding regulatory rules, the paper proposes that while the existing mechanism should remain in place (forward looking price cap), some of the underlying assumptions should be changed. These include: moving from allowing a margin on cost to a return on capital employed; making assumptions about technical and commercial losses used in the tariff-setting process more realistic, with a view to supporting urgent investment; the regulatory body formally committing to pass through foreign (capital) costs, given the foreign exchange risk premium currently revealed in the Kazakhstani capital markets; lengthening the regulatory review period from the present three months, to improve incentives for efficiency gains.

Section 4 assesses alternative market rules and transmission pricing mechanisms. It argues that Kazakhstan is not yet ready to move to a fully competitive (either contract exchange or pool) market – largely due to the present non-payment problems, also to constrained institutional capacity – but that a balancing pool would probably bring benefits both in terms of efficient dispatch and system security. The second point is that cost-reflective (including congestion cost) transmission pricing would be both feasible and beneficial for Kazakhstan.

2. OWNERSHIP

In Kazakhstan, the industry has been partially unbundled. The national electricity transmission network is owned and operated by the state-owned Kazakhstan Energy Grid Operating Company (KEGOC). Power generation assets have largely been separated from transmission facilities and privatised, apart from the Ekibastuz GRES-2 plant, which is owned by KEGOC.[4] Only five of the regional distribution companies had been privatised at the end of 1999, with the majority remaining in state ownership and under the management of KEGOC.

In Almaty (the largest city and former capital) power generation and distribution companies are owned by a subsidiary of the Belgian power company Tractebel. In Karaganda (Kazakhstan's second-largest city) power generation and distribution facilities are controlled by a holding company owned by Great Britain's National Power and a subsidiary of the Israeli company Ormat. In the Altai (north-eastern Kazakhstan) region, which encompasses approximately one-quarter of all land in Kazakhstan, virtually all power generation facilities are owned (or managed under long-term concessions) by subsidiaries of AES Corporation, and some power distribution facilities in the region are managed by AES. In addition, an AES subsidiary owns the large Ekibastuz GRES-1 generating plant, though this is presently operating at about one-quarter capacity, due primarily to lack of demand for electricity. All remaining state-owned distribution companies are presently scheduled for privatisation by the end of 2000. In addition, the Kazakhstani government plans to separate Ekibastuz GRES-2 from KEGOC, thus allowing KEGOC to focus on its core business of transmission and dispatch.

The introduction of strategic investors to remaining publicly owned distribution and generation companies should improve performance both on the cost and revenue sides. Regarding costs, a strategic investor should break old insider relationships, bring new know-how and mobilise finance.[5] On the revenue side, where non-payment is allowed to persist for political reasons and due to corruption, in the right legal environment[6] – with sufficient penalties including as a last resort cutting off for non payment – then introduction of a strategic investor would be expected to improve payment discipline. This has been the experience in Kazakhstan after privatisation; in Karaganda, prior to privatisation (in 1997) collections were 20 per cent, rising to 85 per cent (30 per cent in cash) in the year to September 1999.

Regarding joint ownership of generation and distribution companies, this is not the first-best outcome in the real world situation of asymmetric information on the costs of regulated companies.[7] Joint ownership in a context of market liberalisation provides scope for anti-

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[4] The Kazakhstani news media announced in late December 1999 that a 50% interest in Ekibastuz GRES-2 had been transferred to UES Rossia, a major Russian energy company. The transfer is reportedly a step towards the establishment of a joint Russian-Kazakhstani energy enterprise uniting Kazakhstani coal mines, Ekibastuz GRES-2 and Russian Urals region power generating plants.

[5] See Commander, Dutz and Stern (1999) for theory and evidence on alternative privatisation methods and the relationship with company performance.

[6] See Section 3.2 below: the present legal framework does not penalise non-payers sufficiently to encourage payment.

[7] Newbery (1999) is a strong advocate of this point of view.

competitive behaviour (e.g. manipulating cost allocation between integrated companies in order to foreclose the market, even if integrated companies hold separate accounts[8]). In the case of Kazakhstan, previous privatisations resulted in integrated companies (Almaty, Altai and Karaganda); to the extent that accounts do not reflect underlying costs, this is a second-best outcome. As part of the regulation process distribution companies are benchmarked in order to ensure that their purchases from generators are competitively priced. Given distortions in transmission pricing, such benchmarking does not ensure economic purchase (see Section 4 below).

To the extent that there are scope economies between generation and distribution[9] that give integrated companies an advantage in a competitive market, then there is an economic rationale either to force separation of existing integrated companies or, if this is not feasible, to allow integration in future privatisations to ensure that the playing field is level. It is sometimes argued that allowing integration provides stronger incentives to improve payments discipline, the rationale being that a separate distribution company keeps only a proportion of any extra revenues collected, whereas an integrated company (with the generator supplying the distribution company) keeps all extra revenues. This holds true only where the cost of metering is low relative to the present value of future revenues that would otherwise remain uncollected. In addition, it requires a counterfactual (no investment in increasing revenue) where the burden of sector losses falls on generators i.e. distribution companies do not make payments to generators and do not run up payables.[10]

Evidence from elsewhere in the region emphasises the importance of having a well organised (by an international privatisation adviser) competitive bidding process in order to select the most efficient bidder and to ensure that there are not substantial bidding surpluses at the expense of tax revenues foregone or higher tariffs.[11] Furthermore, the regulatory framework should be in place before assets are sold. The importance of these points is illustrated in the case of both Almaty and Karaganda, whose power companies were sold in a highly uncertain environment and for substantially less than their discounted cash flow.

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[8] Kennedy (1999) elaborates these arguments. Presence of a strategic investor alone is not enough to guarantee finance. This depends also, *inter alia*, on the institutional legal and regulatory framework and the regulatory rules, see Section 2.

[9] Evidence suggests that these are small, see for example Gilsdorf (1994).

[10] A separate distribution company paying the generator or running up payables has the same incentive to invest in measures to increase collection as an integrated company; in either case, the benefit to the investing party is all extra revenue gained, to be set against the cost of metering and the effort of enforcing payments discipline.

[11] Even with such a privatisation process, evidence from the region suggests that there has been limited investor interest in the region e.g. Georgia, Moldova.

3. REGULATION

This section follows the distinction made by Levy and Spiller (1996) between regulatory institutions and regulatory rules. Regulatory institutions focused on in Section 3.1 below are the independence of the regulatory agency, and the legal basis of relations between the regulator and the regulated company. Regulatory rules discussed in Section 3.2 relate to assumptions underlying the tariff formula, particularly with regard to assumptions on technical and commercial losses and asset valuations.

3.1 REGULATORY INSTITUTIONAL FRAMEWORK

The framework for natural monopoly regulation in Kazakhstan was established by the Law on Natural Monopolies, adopted in July 1998. The Law states, *inter alia*, that an authorised agency selected by the Kazakhstani government is responsible for industry regulation. In the case of power, the authorised agency is called the Agency for Regulation of Natural Monopolies, Protection of Competition and Support of Small Business (the “Anti-Monopoly Agency”). The Law defines the functions of the authorised agency, which largely consist of the setting of tariffs (see Section 3.2 below for more details), approval of investments and determination of allowable costs. The form of the secondary legislation (decree, resolution, instruction) provides little security for investors, both because it is easy to change and because the primary legislation (as it relates to tariffs, see Section 3.2 below) would permit a change for the worse.

As is true with the relevant legislation in many transition economies, the Law is silent with respect to the terms and conditions for the appointment and dismissal of key members of the Anti-Monopoly Agency (AMA), and the basis for funding of the regulator (whether from the government budget or industry revenues).[12] The regulator has no obligation to consult (industry players, for example) prior to making a decision and has no obligation to justify any decision that it makes, hence there is more scope for the exercise of regulatory discretion with antecedent regulatory and political risk. The more recent Law on Electricity, dated 16 July 1999, does not address these areas. The AMC functions at national and local levels, the former developing the policy framework and the latter actually carrying out regulatory price reviews. There is a high degree of political interference at both levels with frequent politically driven reorganisations (six between the beginning of 1998 and the end of 1999).

The Law provides a route for appeal, though this is not to a third party (e.g. a competition authority), but rather back to the agency. Though there is a route for recourse to the judiciary, in practice the courts do not have the experience to make the detailed judgements necessary on regulatory issues.[13] Furthermore, given the looseness of the legislation, it is not clear upon what basis any judgement would be made. Tighter specification than in the sector Law could be achieved through writing tariff formulas into privatisation contracts and making these subject to international arbitration.[14]

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[12] For a detailed discussion of these and other conditions for regulatory independence, see Stern (1997).

[13] The *Transition Report* 1999 assigns the following rating to the judiciary in Kazakhstan: judicial support of the Law is often inadequate or inconsistent. Though this is a description of the commercial law, there is no reason to believe that the courts would perform any better in the field of natural monopoly regulation.

[14] In a sense this was the case in Almaty, where Tractebel of Belgium had recourse under its privatisation contract with the Government of Kazakhstan to go the International Chamber of

Best practice is based on the idea that regulatory regimes should allow regulated firms to confidently predict that they will continue to cover all their costs including the cost of capital (return on equity plus interest on debt[15]) under an assumption that they operate efficiently,[16] if investors feel more certain about the future, then they will be prepared to finance projects at a lower cost. Regarding privatisations, investors will be prepared to pay more for assets in a more certain – as opposed to uncertain and therefore risky – regulatory environment. From the point of view of the relevant government, taxpayers/consumers gain if uncertainty is reduced (in terms of privatisation receipts/retail power prices). From a global economic point of view (taxpayers, consumers, producers) this is a pure welfare gain because there is no offsetting reduction in (ex ante) profits.[17] Turning this around, if there is too much uncertainty, privatisation receipts will be low, finance for necessary investments might not be forthcoming and, if it is, it is likely to be at a higher price that will be passed on to the consumer. This idea motivates the following proposed changes to the regulatory regime in Kazakhstan.

One step forward, particularly relevant given the number of times that the AMA has been reorganised, would be to change the primary legislation to strengthen the independence of the AMA. This would require a statement in the Law regarding the fixed term to be served by AMA key personnel, criteria for dismissal of key personnel, and a provision for financing regulation through licence fees rather than the central budget. Other countries in the region have adopted primary legislation that embodies these aspects (e.g. Armenia, Bulgaria, Georgia, Poland and Romania).

One way to make a regulatory regime more predictable is to put relations between the regulator – whether this body is independent or politically influenced – and the regulated company on a contractual basis.[18] However good the regulatory rules are, if they are not on a contractual basis, an investor will be aware that the rules could be changed and that they would have no recourse, and this will be factored into investment decisions.[19]

The form of the contract is typically a regulatory permit. This is a contract that specifies, *inter alia*, conditions relating to average tariffs (e.g. the tariff formula), conditions to ensure security of supply, conditions relating to economic purchasing. Contract conditions can be changed with the agreement both of the regulator and the regulated company or after a referral by the regulator to a neutral third party e.g. international arbitration. In the case of Kazakhstan, recourse to international arbitration would seem preferable to the domestic judicial system.[20] Taking a lesson from the case of Almaty Power Company, the contract should be as complete as possible within the chosen regulatory regime (e.g. incentive regulation). Regarding the actual contract conditions, a good basis for the regulatory permit

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Commerce in Sweden over tariff decisions. The problem in this case was one of enforceability because the contract was not sufficiently well specified.

[15] These based on market prices, not transfer prices from parent companies.

[16] See Levy and Spiller (1996) for characterisation of the optimal regulatory institutional framework.

[17] As uncertainty decreases, tax revenues increase / retail prices fall, the more so as investors are risk averse / the regulatory regime is not credible.

[18] Contracts are typically incomplete, providing parameters to restrict regulatory discretion.

[19] See Levy and Spiller (1996) for cases where governments have changed the rules of the game at the expense of investors.

[20] See footnote 11 on the judicial system in Kazakhstan.

would be (an amended version of) the existing administrative order relating to tariff setting in the power sector (see Section 3.2 below).

One alternative would be to write regulatory conditions into privatisation contracts. Although this would be acceptable for those companies to be sold in the next round of privatisation, it would not provide adequate security in the case of those assets that have already been sold. This could lead to problems – high prices or limited finance – for new investments in the Altai and Karaganda regions and for this reason would be second best.

3.2 REGULATORY RULES

The Law on Natural Monopolies states that "prices must not be lower than the costs incurred during the provision of the services and must provide the possibility for the natural monopoly entity to gain profits". This statement is consistent with best practice in the sense that it allows tariffs which cover operation and maintenance costs, amortisation of (existing) fixed assets, interest on borrowed funds, and a return on equity that is sufficient to provide safe and efficient operation of entities within the sector, etc. It does not, however, guarantee such tariffs: a large range of retail tariffs would be consistent with the legislation, hence the primary legal framework leaves a high degree of uncertainty for investors. The important factor here – given the risk opened up by the primary legislation – is the tariff rule specified in the secondary legislation.

Secondary legislation relating to tariff regulation was drafted by the Anti-Monopoly Agency in the form of administrative Order No. 03-2 ? ? , "On Approval of the Instructions Concerning the Special Procedure for Calculating Costs Included in Prices (Tariffs) on Production and Rendering of Services (Goods, Works) by Natural Monopolist," dated 15 August 1998, which is based on Resolution No. 1171, "Concerning Regulation of Prices of Natural Monopolist's Product," dated 19 October 1994.

Under Resolution No. 1171 prices are set to cover most costs (though some costs, for example, insurance, are excluded) plus profit, the latter defined as revenue net of all expenses including interest payments and depreciation. In practice, profit is allowed for in the tariff calculation through a gross margin between 10-30 per cent at the discretion of the regulator. This methodology is not necessarily consistent with financing the cost of capital (which requires tariff setting to allow a rate of return on the asset base[21]). The methodology would benefit, for purposes of attracting new finance, by allowing a rate of return on equity that reflects the relative risk of the sector.[22] Moving to this new methodology would be feasible without changing the existing primary legislation.

On losses, the Anti-Monopoly Agency assumes that technical losses are equal to an industry norm and that there are no commercial losses (i.e., that revenue collection is 100 per cent and there is no theft from the system). Though these assumptions provide incentives for loss reduction (companies can increase profits by reducing costs and increasing revenues), they are both unrealistic: technical losses are at 15 per cent compared to the assumed 4.6 per cent;

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[21] Not to be confused with traditional rate of return regulation; incentive regulation has a rate of return component.

[22] Something in excess of the interest rate on debt for the sector. Depending on the currency denomination of assets (see below), the required return could be estimated from data on sale prices of assets in Kazakhstan and elsewhere in the region. See Burns and Estache (1998) on information required to calculate the cost of capital. The Kazakhstan stock market is not sufficiently developed to provide valuable information for the regulatory process.

revenue collection is well below 100 per cent in every region. For example, collections in Altai in 1999 were 70 per cent, in Karaganda the 1999 collection ratio was about 85 per cent. It is not feasible for companies to move to 100 per cent collection given the legal framework (penalties for non-payment are small), political resistance at the local level, and technical constraints (lack of metering, billing, inability to cut individual non-payers off in practice).

At present the industry can continue to run on these assumptions because assets were privatised at prices reflecting a fraction of their book value: revenues exceed operating costs and provide for a return on the initial outlay. The industry would continue to be sustainable with new investments that reduce (operating plus capital) costs (e.g. investments in loss reduction). There could also be problems, however, as new investments are required (e.g. network rehabilitation to improve system security). Such investments, while economically beneficial, could at the same time increase a companies' costs (operating and capital) and justify a price increase. A tariff increase calculated to cover the additional cost under an assumption of no commercial losses would not actually cover the cost increase; there would be a shortfall equal to the additional cost multiplied by the level of commercial losses. In this situation, no investments would be forthcoming (nobody would be prepared to provide finance), even though they would be of benefit to consumers. Best practice here would be to assume technical and commercial losses close to *actual* levels in calculating tariff increases relating to new investment. Having said this, such investments should be made only in cases of extreme urgency, because finance would involve cross-subsidy from paying to non-paying customers. In all other circumstances that would involve price increases; investments should be delayed until collection improves.

On the valuation of assets for regulatory purposes, this is at book value. The stated policy of the AMA is to fully depreciate assets, though this has not always been applied in practice, particularly following the consequences of the economic crisis in Russia (late 1998). It has delayed passing through movements in real exchange rates on affordability grounds. When prices were adjusted (three months after the exchange rate movement), only assets purchased abroad were revalued.

In any regulatory regime, there is always a choice in the case of existing assets whether to value them at book value, replacement value, marked down book value, etc. This choice is important for the investor because it will determine their return (allowed rate of return multiplied by the asset base) and the level of depreciation. The differences between alternative methods of valuation show up in the sale price of the assets e.g. assets valued at book value will sell for more than assets valued at a fraction of book value. Best practice[23] would not point to one method of valuation over another, only that there is an announcement of the chosen method prior to privatisation in order to reduce the degree of uncertainty over future tariffs and thus increase privatisation sale receipts.

The choice over the currency denomination of assets is important because it affects both privatisation receipts and future prices. Asset valuation in local currency[24] should yield lower privatisation receipts than valuation in international currency (because of the possibility of decline in the value of local currency resulting in reduced dollar returns and dollar

[23] Vass (1997) and Newbury (1997) discuss alternative asset valuations.

[24] Local currency is taken to mean that assets are not revalued following a real exchange rate movement. International currency is taken to mean that assets maintain their international value following a real exchange rate movement.

depreciation[25]). The converse of this is that valuation in local currency reduces the extent of future tariff increases contingent on real exchange rate depreciation. As time goes on and new investments are undertaken, the associated cost of capital (debt and equity) will be higher for local currency denominated assets, the more so as exchange rate depreciation is expected and investors are risk averse.

The important thing from an economic point of view in regard to currency denomination of asset value, is to achieve the optimal risk allocation between consumers and investors. Evidence from the region – the lack of local currency finance both in general and specifically in the power sector[26] – would suggest that investors are unprepared to bear foreign exchange risk at the moment, or will only do so at a premium that exceeds expected exchange rate movements. It follows that assets should be denominated in an international currency (or local currency with revaluation following currency movements against (say) the US dollar, in tandem with an allowed cost of capital based on international currency denominated investments). Local currency denomination need not be ruled out and might be the chosen option, subject to a market test. For example, in the sale of assets, bidders might make a bid for assets denominated in international currency, and a variant on this for local currency. The information revealed would allow inference of the magnitude of risk premium associated with exchange rate uncertainty, and provide the basis for a decision over currency denomination of assets.[27]

The regulatory review period is presently three months. This undermines incentives for cost reduction within the price cap framework that is in operation. Incentives could be strengthened[28] either by lengthening the regulatory review period (five years would be a typical length here) or by introducing some sort of profit-sharing mechanism[29] between the regulated companies and their consumers. For example, prices might be indexed on the real exchange rate for a five-year period irrespective of efficiency gains, balancing prices and costs at the end of the five-year period. Alternatively, companies and consumers might share any efficiency gains 50:50, possibly beyond a certain threshold. Either mechanism would strengthen incentives for cost reduction – to be passed on through reductions in tariffs – without increasing the extent of uncertainty relative to the present situation.

[25] Under the assumption that Uncovered Interest Parity does not hold for purposes of regulation – rates of return and interest rates assumed by the regulator do not move to reflect expected exchange rate movements – and/or investors are risk averse.

[26] Even when regulatory rules pass exchange rate risk to the consumer, strategic investors typically participate through subsidiaries with weak balance sheets and without guarantees from the parent. For portfolio investors, the foreign exchange risk premium in Kazakhstan at present is well in excess of expected exchange rate movements. This is borne out in the 7% return on 3-month dollar denominated bond issue in December 1999, against the 16.6% return on 3-month tenge denominated bonds issued simultaneously, and when there was a widely held belief in the market that the currency would depreciate by 2% in the first quarter of 2000.

[27] The regulatory regime could allow for a changing risk allocation over time in respect of foreign exchange rate risk.

[28] See O Neill and Vass (1996) for a detailed discussion of incentive regulation.

[29] Burns, Turvey and Weyman Jones (1998) and Mayer and Vickers (1996) discuss profit sharing regulation.

3.3 Summary of proposed innovations to the regulatory framework

- Regulatory independence should be strengthened through moving the finance of the regulator away from the central government budget and by appointing the head of the office for a fixed term with specified events for contract termination.
- The relationship between the regulator and the regulated companies should be given a firmer legal underpinning through the introduction of regulatory licences subject to international arbitration.
- Tariffs should be formed on the basis of applying the sector cost of capital to the asset bases of the regulated companies, rather than allowing a gross margin.
- More realistic assumptions on losses should be used in order to facilitate investment. Assumed losses should be below actual losses in order to provide incentives for improved performance. All but the most urgent investments should be postponed until collection improves, in order to avoid distorting prices.
- A decision should be taken over whether to mark assets down from book value. Asset values should be linked to the value of international currency, in order to avoid large risk premia which would be passed on to consumers.
- The regulatory review period should be increased from three months to (say) five years in order to allow firms to reap the benefits of improved performance before these are passed on to consumers.

4. MARKET RULES AND TRANSMISSION PRICES

This section of the paper starts by outlining general principles of competition in power sectors and pricing of transmission networks. The aim is to outline arrangements and mechanisms for aligning prices with marginal costs in generation and transmission, and optimal investment rules. The reader versed in these concepts might skip ahead to Section 4.3, which discusses the appropriate arrangements for Kazakhstan.

4.1 MARKET RULES: GENERAL

A straightforward way to introduce competition to the power sector is to allow third-party (transmission and distribution) network access and bilateral contracting between generators and wholesalers/large users; this is the minimum requirement under the EU Power Sector Directive. In this model, generators compete for custom from large users on the basis of equal access to transmission and distribution networks at regulated prices.

To the extent that contracts are not tradable, this model could result in a sub-optimal outcome, for example, contingent upon changes in relative fuel input prices or changes in demand. In theory, this can be solved by making contracts tradable. In practice, the extent of tradability could be limited by transaction costs, though these in turn could be limited by the existence of a contract trading exchange (a stock exchange for power contracts).

Regarding real time trading – as opposed to trading contracts ahead of time and closing the market prior to the realisation of power trade – this requires expensive data and communications and software equipment.[30] It requires also that lead times for turning up/down plant and adjusting load be short in order that producers and consumers can quickly respond to price signals. For both these reasons it may be justified to close the market prior to when production and consumption actually take place. The most high profile example of a tradable contract model in practice is the (proposed new) framework in England and Wales: the intention here is to have a tradable contracts market which closes four hours before real time supply.[31]

An alternative means of introducing competition to third-party access is trading of power in a pool. Various pool mechanisms have been used in practice in England and Wales (see Box 1), the United States, New Zealand, Scandinavia, Chile and Ukraine. The simplest pool model takes demand as given and dispatches on a least-cost basis sufficient plant to meet this. Asymmetric information between power generating companies and the pool operator is overcome through competitive bidding:[32] generators bid price-quantity pairs, which should, in a competitive market, reflect marginal operating cost. In addition to this, generators receive a capacity payment that varies in inverse proportion to the difference between demand and capacity and reflects consumption externalities associated with increased probability of system failure as the system operates close to capacity. The composite pool price (bid plus capacity charge) reflects the full short run (social) marginal cost of power, thus allocating existing capacity optimally, and providing the correct signals for investment in new capacity.[33]

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[30] Real-time trading is necessary for an efficient outcome given the difference between real time and both expected demand and, to a lesser extent, supply.

[31] See OFGEM (1999) for the proposed market arrangements.

[32] See McAfee and McMillan (1986) for an overview of the competitive bidding literature.

[33] See Green (1991) for analysis of the pool price mechanism.

Box 1: The England and Wales power pool

The power pool in England and Wales was introduced in the early 1990s and was a forerunner to some of the more sophisticated power pools that have emerged since around the world. The England and Wales pool was a wholesale day-ahead market for electricity, supplied by generating companies to meet demand from electricity supply companies and large industrial users.

Trading worked in the following way: each day was divided into (48) half-hour slots with associated forecast demand for which generator bid to supply. A bid comprised the price at which a generator would supply electricity to the pool the next day, the availability and operating characteristics of plant. There were 39 components to a bid including start-up price, no-load running price, three incremental prices relating to different uses of capacity, maximum generating price. A generator could make multiple bids relating to different sets of its plant.

For each half hour, bids were ranked according to price, the lowest bidder was chosen to supply electricity to the pool, then the lowest remaining bidder, and so on, until sufficient capacity was dispatched to meet demand forecast for the day ahead. This was carried out using an algorithm taking into account all permutations stemming from different components of bids.

Bidders were not paid the price specified in their bid, rather they received the highest bid price from among the selected bids, this called "System Marginal Price" (SMP). SMP was either *Table A* – when capacity was greater than demand and payment was at incremental price – or *Table B* – relating to other periods and where payment was at incremental price plus start-up price plus no-load price.

In addition to SMP, generators received a capacity payment. Capacity payments rose as available capacity fell relative to demand, based on the loss of load probability multiplied by the value of lost load, the latter derived from the marginal cost of new capacity under an assumed level of optimal system failure. Available capacity was based on the maximum offered and re-offered capacity of the previous week.

The sum of the SMP and the capacity payment was termed the "Pool Purchase Price" (PPP). The final price in the pool was called the "Pool Supply Price" (PSP), greater than PPP due to "Uplift", defined as the difference between the cost of operating an ideal, predictable and unconstrained system with the *real world* constrained system. Uplift payments related to: demand-forecasting errors, constrained on or off payments, unscheduled availability payments.

There were two types of contracts for differences. A *two-way* contract specified a fixed price at which a given quantity of electricity would trade at a date in the future. The contract was implemented by the generator (electricity supply company) paying the electricity supply company (generator) any positive (negative) difference between the pool price and the contract price. In this case, both parties to the contact were fully insured against risk. The alternative *one-way* contract specified an upper bound on the price an electricity supply company would pay a generator for a given quantity of electricity at a date in future. The contract was implemented by the generator paying the electricity supply company any positive difference between the pool price and the contract price. In this case, the electricity supply company was partially insured against risk, the generator foregoing outcomes associated with high pool prices relative to the contract price.

There are two problems with the pool as described above: calculation of the capacity charge requires assumptions on consumers' valuations of lost load in the event of system failure; taking demand as given, there may be sub-optimal dispatch, i.e. plant with marginal cost in excess of its marginal (consumer) benefit can be dispatched.[34] Both problems can be solved through the introduction of demand-side bidding: consumers bid price-quantity pairs that are factored by the pool operator into the dispatch decision. Demand-side bids help to ration

[34] A third problem is the possibility of gaming in the bidding process when there is too much market power in generation. This can be avoided by fully unbundling generation subject to constraints of minimum efficient scale. See Green and Newbery (1992).

scarce capacity when the system security is threatened, not by setting an administered social marginal cost price but through low-value consumers being bid out of the market. Likewise, the problem of sub-optimal dispatch is avoided because there is sufficient information revealed through demand-side bidding to implement the rule that a plant should operate only where it adds net benefit to the system. A demand-side pool requires greater institutional capacity, more investment in software, data and communications technology, particularly if trading is to take place in real time, rather than the simpler supply-side bidding-only variant.

In both supply-side and demand-side bidding pools there is the possibility of price volatility resulting from underlying demand volatility (and to a lesser extent supply volatility, as regards available capacity). This can be hedged to the benefit of all market participants (and hence consumers) through financial contracts, termed Contracts for Differences, that specify payments to be made between contracting parties (generators and large consumers) contingent on the pool price. This effectively sets the price in advance for the quantity of power covered by the contract. With sufficient competition in the contract market, the outcome is such that the contract price equals the expected price in the pool.[35]

4.2 Power transmission network pricing: general

As part of more general sector reform, many countries around the world have re-balanced power transmission prices. The rationale for this is to provide the right signals for investment (whether industry should locate near power generators and vice versa) and consumption decisions (e.g. whether to consume power or gas, or to consume locally or distantly generated power, or not to consume); these would come from prices reflecting underlying marginal costs.

Marginal cost in an unconstrained transmission network relates to power losses. In a constrained system, short-run marginal cost relates to power losses plus congestion costs. In the long run, congestion can be eased through new investment; this is reflected in long-run marginal cost, which reflects power losses plus costs associated with system expansion.

Practical implementation of these principles requires knowledge of some basic physics regarding power flows in a transmission network. For the purposes of thispaper, the following two principles are sufficient to understand the discussion:

- Along one line, power losses depend on line length and line load (current flowing down the line).[36]
- There are parallel flows between nodes in a network.[37] Between two nodes, losses depend on direct flows and indirect (via other network nodes) flows. Congestion costs based on capacity constraints must be calculated on the basis of parallel flow.

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[35] This requires an assumption that the contracting parties are risk neutral. For risk averse agents, the contract price will vary around the expected pool price according to relative risk aversity of the contracting parties. See Green (1996) for analysis of the electricity contracts market.

[36] Losses on a power line are defined as the rate that energy is given off (joules per second). Substitute into this the following: potential difference is defined as the rate of change of energy per unit charge; current is defined as the rate of flow of charge; Ohm's law (potential difference is current multiplied by resistance). This gives power losses as the multiple of the load squared and resistance. In turn, resistance is a function of line length. Hence transmission costs depend both on load and distance.

[37] Imagine a power network comprising three nodes, A, B, C linked such that the transmission network forms the shape of a triangle. Say that power is generated at A and consumed at C. In such a network,

Bearing in mind the types of marginal costs in power transmission systems (i.e. losses, congestion, forward-looking investment), and the two basic rules of power flows above, the following pricing regimes are now discussed with respect to their economic properties: postage stamp, distance-based, location marginal and zonal pricing. In addition, market mechanisms for hedging transmission price volatility, and for new investment in transmission capacity, are considered.

Postage stamp pricing

Postage stamp transmission tariffs allocate total system costs to consumers on the basis of load share: a customer pays a transmission charge equal to the total system cost-weighted according to their consumption divided by total consumption. This is straightforward to administer, but does not yield transmission charges that reflect marginal costs.[38] Typically the postage stamp methodology raises charges above marginal cost because it incorporates historical fixed cost, something that is not marginal.[39] Abstracting from historical fixed cost, given that the relationship between load and losses/congestion is not linear, then the postage stamp methodology cannot reflect underlying short-run marginal costs, more so when there is congestion (the methodology averages congestion costs across the system as a whole rather than charge them to consumers who actually cause congestion). A tariff structure allocating short-run costs on the basis of the postage stamp methodology would contain cross subsidy in the sense that some users would be charged less than their avoidable cost.[40]

Distance-based pricing

This charging methodology allocates costs on the basis of the distance between the point of input of power to the transmission network and the point of consumption. This is not optimal where the costs to be allocated include historical costs (as in the postage stamp methodology above). Abstracting from historical fixed costs, the distance-based pricing methodology cannot reflect short-run marginal costs because it picks up the non-linear relationship between power losses and load, and because it does not reflect congestion costs or parallel power flows that occur on most real world transmission networks.

Location marginal pricing

An advance on distance-based pricing is to model the relationship between demand and load flow[41] in the transmission network and then to price each location in the network according costs imposed on the system through location marginal consumption; this is known as *location marginal* or *nodal* pricing.[42] If there were a need to recover investment costs,

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power flows from A to C directly and from A to C via B. By Kirchoff's Law, power flows along different lines in inverse proportion to line resistance. See Hogan (1992) for elaboration.

[38] Except in special circumstances e.g. where all generators are equal distances from load, where the load on each line is equal, and there is no congestion, and capacity is fully divisible.

[39] Forward-looking capital costs may form part of the optimal price; see the discussion of long-run marginal cost pricing below. Forward-looking capital costs are, however, highly unlikely to be equal to historical costs.

[40] See Faulhaber (1975) for analysis of cross subsidy in utility pricing.

[41] This could be a.c. or d.c. according to whether there are voltage constraints and thus whether reactive power is a problem, see Hogan (1993).

[42] Implementing such charges in a context of congestion requires information about consumers' willingness to pay; see discussion later in the section.

minimum departure from first best (measured as the reduction in consumer surplus) would be through a two-part tariff with a fixed component relating to the fixed cost to be recovered and a variable component relating to losses. Regarding allocation of common costs,[43] the economic optimum is to charge a price inversely related to elasticity of demand (*Ramsey pricing*), though this is difficult to implement in practice given the information requirements. Also it is more conventional to allocate costs along accounting lines (e.g. according to share in total consumption); such conventional allocations can have perverse economic implications.[44]

Nodal versus zonal prices

Nodal pricing requires a price for consumption at every node in the network. Whether this is optimal – or some kind of averaging would be desirable – depends on the associated transaction costs. These include complex settlement arrangements, the wide disparity in locational prices, which could be problematic in a context of increasingly liberalised markets, and the data and communications and software requirements for real-time trading.[45] The alternative is to have zonal prices, which apply to locations in the network where transmission costs are roughly equal; this system thus picks up the majority of differences in locational costs. Whether nodal or zonal pricing is optimal depends on network-specific spatial distributions of generators and consumers, the level of demand and existing transmission capacity (in absolute terms and as regards network density).[46]

Congestion charging

The discussion above is abstracted from how to deal with network congestion. There are actually various mechanisms in place around the world – both non-market and market – which attempt to do this. One possibility, where there is congestion, involves constraining off low-cost plants that would ideally produce power for export, and constraining on local high-cost generating plants. An alternative would be to constrain off certain users in the case of, say, a region with a transmission constraint and limited local generating capacity. This approach does not use pricing to ration scarce capacity and could be problematic because typically it does not take into account willingness to pay. Therefore this approach may constrain on plants that should not from a cost-benefit point of view be dispatched, and might also constrain off high-value users in favour of low-value users.

These problems can be overcome by price setting that reflects congestion[47] associated with location marginal consumption.[48] In order to implement such a pricing mechanism, information about (generating and network [loss-related]) cost and consumers' willingness to pay is required. One option is to estimate these data; for example, cost may be estimated on

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[43] Which costs are common depends on the definition. From the point of view of avoiding cross subsidy, where it is possible to attribute a fixed cost to a certain group of customers (e.g. a transmission link to a particular area) then that group of customers should finance the cost.

[44] See Kennedy (1997) for analysis of the economic implications (over/under consumption) of alternative cost allocation mechanisms.

[45] See Henney (1998) for more details.

[46] See Harvey and Hogan (2000).

[47] See Walters (1961) for the classic article on congestion charging.

[48] Joskow and Tirole (1999) characterise the competitive equilibrium in the case of congested capacity and perfect information.

the basis of engineering studies, and demand estimates might be based on contingent valuation studies. This is problematic in the same way as are assumptions made about willingness to pay upon which generating capacity payments are then made: estimates are likely to be wrong and thus provide the wrong signal for consumption and investment. There are, however, alternative market mechanisms which bypass the need to make such estimates.

Actually, all information needed for location marginal pricing incorporating congestion costs is revealed in a pool with demand-side bids. Bids in the pool may be regarded as location specific, and a separate pool may be operated at any location where there is a binding capacity constraint (i.e. a merit order including imported power (to the extent that the constraint allows) is formed and dispatched according to local demand-side bids).[49]

Such information may not be available under alternative market rules; for example, competition based on contracts that are not fully tradable, or where information about contract prices is not available to the regulator (or whoever sets the network charges). In such cases, scarce capacity can be allocated on the basis of tradable physical rights. Under such a regime, consumption is only allowed at a congested node when backed with a physical right to use congested capacity associated with power flows to the node.

Physical rights may be allocated initially arbitrarily or auctioned; this is neutral from an economic point of view, though having different distributional properties. Under a lottery, congestion surpluses accrue to whoever receives the physical right, whereas in an auction, congestion surpluses accrue to whoever sells the right.[50] Provisos here are that the transmission company does not own physical capacity rights, bin order to avoid possible gaming (implementing dispatch in a way to maximise congestion rents), and that contracts are tradable (so that they may be owned by the consumers that value them the most). Finally, the application of such a physical rights model requires enforceability of property rights that may only be practically achieved in certain types of networks e.g. stringy or radial networks with controllable links.

Hedging transmission price volatility

Location marginal pricing with demand volatility could result in substantial transmission price volatility. Physical rights to congested capacity provide a partial hedge against volatility, to the extent that the holder of the physical right does not have to pay a congestion charge.[51] In the case of a pool, there is a parallel price hedge based on financial rights to rents from congested parts of the network. Though rents depend on the extent of congestion and thus vary according to demand, the owner of the financial right is in a position to contract with network users, offering to provide insurance to network users. In other words, the owner of a financial right can sign contracts with users that stipulate payments to (from) users when congestion charges are high (low). In a competitive market, this would result in an effective price equal to the network charge (reflecting losses) plus the expected congestion cost, much in the same way that a contract for difference between generators and consumers reflects expected pool prices.

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[49] See Hogan (1998) for more details, also Bushnell and Stoft (1996) and Woychik (1996).

[50] Under conditions of competitive bidding, the seller of the right will receive approximately the discounted value of the congestion rents; this is a central result in auction theory, see *inter alia* Wilson (1977).

[51] To the extent that physical rights are held by high-value users, then the transmission price is bounded above by the network charge (reflecting losses) plus the price of physical rights. To the extent that the latter varies, then there is still some residual price volatility.

Decentralised investment in transmission capacity

In a context where decentralised investment in new capacity is allowed, incentives for such investment are equivalent under the financial and physical rights models (assuming perfect tradability in the case of the latter). In either model, the motivation to invest is based on congestion charge savings. The signal to the potential investor is the congestion cost; which is offset by the marginal operating plus capacity cost.[52] Constructing new capacity when the congestion levels exceed the marginal capacity cost, requires the investor to apply the same methodology as the social welfare maximiser. To the extent that investment changes transmission prices, there could likely be network externalities, in the sense that investment by one user would benefit all other users in the form of lower congestion charges, and the result could be under-investment. The crucial thing here is the size of the investment: many transmission investments are sufficiently small that they do not change prices. When decentralised mechanisms do not result in optimal investment (e.g. where projects involve substantial fixed costs) then some kind of regulated coordination between industry participants may be brought into play.

Long-run marginal cost pricing

Under LRMC,[53] prices are set relative to a base case investment scenario and reflect the effects of marginal consumption, both in terms of operating costs and capital costs, the latter arising because permanent increases to consumption now require that future investments are brought forward in time. For example, if an investment is to be made in 20 years time, a permanent increase of sufficient magnitude in consumption now will involve extra operating costs, plus the costs associated with moving the investment programme forward one year, that is, the annuities investment cost, discounted over a 20-year time horizon; this will be close to the marginal operating cost. If an investment is to be made in two years, on the other hand, and there is a permanent increase in consumption now, such that the investment programme is brought forward by one year, then the marginal capacity cost (a function of the annuities value of the investment discounted over a two-year horizon) will drive a wedge between the short-run and long-run marginal cost. Under LRMC, if investment is not going according to plan, then the relevant price is short-run marginal cost encompassing both losses and congestion.

The long-run marginal cost model yields an equivalent set of prices and investments as the physical/financial rights models. Decentralised mechanisms may be deemed superior to LRMC on the grounds that, for certain market arrangements, they better reflect underlying costs and values (in the case of a contracts market with limited public information) and, more generally, to the extent that profit-driven investment leads to more efficient use of resources than centralised investment constrained by bureaucratic factors.

4.3 Application to Kazakhstan

The wholesale market in Kazakhstan is organised along principles of competition: generators have, at least in theory if not always in practice, open access to transmission and distribution networks and can enter into bilateral contracts with large users and electricity distribution companies for the sale or purchase of power. In practice, competition tends to be restricted in certain areas of the country due to economies of scale (e.g., hydro facilities in the Altai

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[52] If market-based expansion fails, the tradable value of physical rights provides information upon which centralised investment decisions can be made.

[53] See Turvey (1976) and Turvey and Andersen (1977).

region), low-cost existing plants (e.g. coal-fired plants supplied by large open-pit mines in the Karaganda region), excess capacity due to the fall in demand for electricity since communism ended (as consumers begin to cope with having to pay their way), distortions in the structure of transmission prices (see below), and high transaction costs (there is neither a pool nor a contracts exchange) associated both with intra- and inter-regional trading.

Regarding transmission tariffs, these are presently regulated by the Anti-Monopoly Agency, and have two components: (1) the volume of energy transmitted and (2) the transmission distance. In other words, the present tariffs are a hybrid of postage stamp and contract path methodologies and (as explained above) they do not reflect underlying system costs. The network in Kazakhstan covers a large geographical area and is stringy as regards inter-regional links.

This section argues that the challenge to improve the functioning of the competitive market can best be met, in the short term at least, through the introduction of a balancing pool (see below), rather than moving to a fully competitive market based around either a contracts exchange or a pool. Later the section argues that welfare improvements would ensue through a move to zonal prices with tradable physical contracts for congested parts of the transmission network.

In theory, maximum economic benefit would ensue from moving immediately to a fully competitive market. This would require up-front investments relating to software, metering and training of personnel that might be justified if the market were to work ideally. The problem here[54] comes from the lack of payments discipline in Kazakhstan. Moving from the present situation of bilateral contracts to a more fully functioning market would expose generators to more payment risk, at least in the short term, and quite probably in the long term (depending upon market settlement mechanisms and disconnection policy). This is based on the possibility of losing a paying customer under the present arrangements and gaining a nonpaying customer under the new arrangements, since there are customers who do not pay and generators that do not recoup costs in the Kazakhstani power sector. In anticipation of this, generators would either not participate in the market – in which case system security would decline – or raise prices to factor in the possibility of non payment. In either case, this would make the job of raising revenue collection, the main challenge facing the sector, more difficult.

The preferred alternative would be to delay moving to more competitive arrangements until the payments problem has been solved through privatisation of the distribution companies. With higher effective prices in the sector there would be a higher probability that more sophisticated market arrangements would succeed, hence a stronger case for the associated outlays on a cost-benefit basis. The case for delaying investment is strengthened, because at the moment the price of limited credit available for this type of project does not reflect the market rate and, in terms of alternatives, there are other projects in the sector (e.g. transmission network rehabilitation) with higher economic returns. In the future, as the investment climate improves and the price of credit falls and availability increases, more projects in the sector will be justified.

Accepting a gradualist approach, the present arrangements could still be enhanced through the introduction of a fringe ("balancing") pool. This could involve generators trading contracted

[54] There could also be problems associated with the massive institutional change required. If these were to affect system security, then post-privatisation enforcement of payments discipline would become more difficult due to increased political resistance.

power to achieve the optimal dispatch. It would allow a mechanism for selecting efficient plants to supply non-contracted power, thus providing a cost-effective way to improve the system security. This might involve some demand-side bidding, from customers with good payments records, and caps on the ratio of power consumed from the pool relative to total consumption. Such a supply- and demand-side pool would be desirable, as it would introduce a market mechanism for non-contracted consumption. Feasibility, given the present infrastructure, would not be subject to the problems above associated with a full-scale pool because the industry core would continue to function on the basis of contracts as it does now.

Enhancements in the transmission price methodology could be easily adjusted to increase better signals for consumption (power trading between regions) and investment (in new generating plant, or in new industry). Modified prices should be based on load flow rather than distance, and would require development of a load flow model. Prices could be calculated on a nodal basis, and, for similarly priced locations, grouped into zones so as to simplify trading and settlement. Such averaging would capture inter-regional costs, which dominate total transmission costs in Kazakhstan, and provide a price system consistent with the current technology in the country.

Rather than the AMA attempt to set prices for congested parts of the network (on the basis of imperfect information), there is scope for the welfare-improving introduction of tradable physical capacity rights.[55] This would work such that in order to import power into a region subject to a transmission constraint, purchase of a physical right to use transmission capacity would be required; this is feasible given the network configuration in Kazakhstan. Rationing capacity this way would ensure maximum production efficiency and maximum value from consumption; this would be a welfare improvement from the present situation where there are social costs associated with congestion. In the correct institutional setting (relating to construction of new capacity), tradable physical rights would remove the need to employ a forward-looking methodology (based on centralised demand forecasting) in providing correct incentives for system expansion. At a minimum, application of the physical rights model would provide better information than presently exists for centralised investment decision-making, should market-based investment fail.

4.4 SUMMARY OF PROPOSED MARKET INNOVATIONS

- Developments in recent years mean that there are now market mechanisms for dispatch of generating and allocation of transmission capacity which can overcome informational and institutional constraints to result in an outcome that is efficient relative to that under a non-competitive structure. Implementation of market arrangements requires technology and institutional capacity.
- Present trading arrangements to be enhanced through the introduction of a balancing pool with demand-side bidding for large customers with a proven track record of payment and caps on the percentage of total demand to be purchased from the pool.
- The introduction of a fully competitive market with supporting institutions (contract exchange or pool) to be delayed until payment collection has been improved.
- Location-specific prices reflecting losses and congestion to be introduced, based on a load-flow model and physical rights for congested capacity. Such a set of prices and contracts is consistent with the network characteristics in Kazakhstan.

[55] Financial rights would not be feasible in the present contract-based market.

5. CONCLUSION

Though there has been much progress in power sector liberalisation in Kazakhstan, further benefits would accrue through enhanced market arrangements and re-balanced transmission tariffs. If further progress can be made in the areas of privatisation, regulation and liberalisation, then there should be significant benefits for Kazakhstan. Among the possible ways to capitalise on potential benefits are further privatisation of power distribution, strengthening of regulatory institutions, and changing some of the regulatory rules to provide the correct risk allocations and incentives, enhancing of market arrangements and rebalancing transmission prices. Though these detailed prescriptions are specific to Kazakhstan, the more general messages apply to the region in general. The case of Kazakhstan illustrates the point that radical reform in the power sector need not be constrained by progress in more general reform. Radical power sector reform is feasible for most countries in the region, where further privatisation, regulatory reform and liberalisation would yield substantial welfare gains.

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