The Russian Power Market

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Introduction

The Russian power market remains in a restructuring phase whereby former state-owned vertically integrated monopolies have been unbundled and are partly privatized. However, the network companies, system operator, and nuclear and hydropower plants are still state-owned and the government also have stakes in several territorial and wholesale generation companies through the state-controlled utility, Gazprom.

The restructuring is occurring in the two price zones which consume most of the power generated. The Europe-Urals zone includes six hubs and the Siberian zone includes two (Figure 1). In addition there is an isolated area and non-price zones (regulated market). Locational marginal pricing (LMP) is used in a day-ahead auction with aggregated bids that are arranged via a complex mathematical model for approximately 3,000 locations in the European zone and 6,000 locations in the Siberian zone. Several time zones are incorporated, a result of the country's vast geographical area diversity.

The two price zones exhibit different geographical characteristics and have different fuel mixes. The European zone has a high share of thermal power plants while the Siberian zone is home to most hydroelectric generation. Around half of the electricity trades now at unregulated prices, but they are set to increase to 90% by 2011, with the exception of household consumption. The unregulated electricity prices are relatively low compared to European levels (around 21€ and 15€ per MWh), but wholesale consumers (buyers) must pay for availability in the form of capacity payments (Abdurafikov, 2009). Otherwise, investments in new generation capacity may be unprofitable, because it may be impossible to recover the capital costs. With increasing price risks, a power exchange is currently being established so market players can hedge risk. Additionally, the government plans to support renewable generation and ancillary services and curb emissions.

The Wholesale Electricity Market

Wholesale electricity trade is complemented with ex ante capacity trade which is traded separately, yet all market players can act both as sellers and buyers. LMP is utilized to determine prices and quantities for wholesale trading. The locations are the supply points or groups of points where generation connects to the grid.

Figure 1: The Wholesale Market (Abdurafikov, 2009).

The LMPs differentiate electricity by location by considering production costs, transmission congestion and transmission losses. Investors in generation and transmission are thus incentivized by market signals. The market operator (ATS) employs a complex mathematical model of the power system to calculate LMPs and the planned hourly generation and consumption. All bilateral contracts including regulated are settled against the LMPs. Market players are required to notify the system operator (SO) about maximum consumption, minimum and maximum generation (including self-consumption), planned exports and imports and other necessary data. Generators also notify the SO about their start and stop costs as well as maximum bid prices in the day-ahead and balancing markets. Based on the submitted information the SO performs a unit-commitment (power plant scheduling) calculation which is subsequently forwarded to ATS for the day-ahead market clearing. The day before physical delivery the market players can submit price bids for hourly or block contracts to ATS. The bids must cover the available capacity of the generators so as to prevent withholding of capacity. The day-ahead zone prices (aggregated LMPs) exhibit cyclical fluctuations and high volatility caused by demand and supply shocks. The large geographical distances and time zone differences present some challenges in terms of hub or index prices since peak or offpeak prices will differ depending on the time zone. This is solved by defining these hours by local time and then averaging the LMPs.

Electricity is traded both at regulated and market prices. In isolated regions where there is lack of competition, regulated prices are used in regulated contracts. Uncontracted volumes are left for the day-ahead market, balancing and

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bilateral contracts.

Trading of regulated contracts requires a volume calculation by the Federal Tariff Service (FTS) and the ATS whereby companies' tariffs are set by cost plus profits divided by volume. The regulator issues forecasts of electricity consumption and generation capacities for generators and forecasts of monthly total and peak consumption. These forecasts (called FTS balances) are being used in the transition phase to a competitive market such that the regulated volumes are gradually being reduced, excluding household consumption. As a result, minimum and maximum regulated volumes are established. The maximum regulated volume comprises current year's volumes allocated to households. The volume is further profiled by using 60 typical load periods within the year. Finally, the market operator determines the counterparties to regulated contracts and volume traded. The matching process considers technical (instantaneous power balances) and cost constraints. The regulated price is set so that the average price of regulated contracts does not exceed the electricity tariff set by the FTS for the relevant region.

Since 2008, generators' tariffs are calculated by using the preceding year's tariff indexed by a public formula depending on forecasted inflation, fuel prices, water taxes for hydropower plants, etc., including deviations of actual values from forecast (ex post).

As an outcome of the matching process, buyers hold a portfolio of regulated contracts. They are allowed to reduce their regulated volumes of electricity and (or) capacity within the minimum and maximum volumes.

As of July 1 through December 31, 2009, 50% of electricity from the FTS balance and consumption volumes for 2007 have been sold at non-regulated prices. By 2011, all electricity will be sold at non-regulated prices, again with the exception of electricity sold to households (at regulated tariffs until 2014) (see Figure 2).

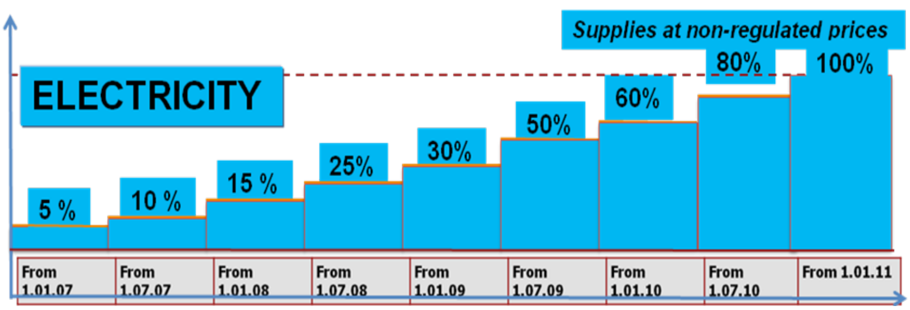

Figure 2: Gradual Opening of Russia's Electricity Market

The Russian Wholesale Capacity Market

A capacity market is employed as a mechanism to secure reliability of supply in the medium and long term (Abdurafikov, 2009). Available generation capacity should be able to meet peak demand. However, since peak demand may vary considerably on an annual basis due to electricity consumption cycles, some capacity will be reserved during lower demand periods. As a compensation for the costs incurred during these periods, the owners receive a capacity payment. Buyers of wholesale electricity are obliged to contract peak-hour availability (i.e., total peak load plus a reserve margin). The Russian capacity market is divided into 28 free transfer zones. In these zones annual long term auctions (4 years ahead) are conducted. Before these are fully implemented, however, the capacity market still follows the transitional market model described below.

Transitional market model

Before a liberalized capacity market was implemented, capacity was traded at regulated tariffs set by the regulator. The capacity payment was for fixed cost per installed MW capacity. From mid-2008 only available capacity was remunerated. On average, capacity payments account for roughly 60% of the generators' revenues as energy prices are insufficient to cover total generation costs including capital costs.

The SO determines the available capacity in every price zone. At the end of each year generators submit bids to the yearly capacity auctions. In advance the SO announces volumes, expected electricity consumption and capacity, planned reserve coefficients including a list of free electricity transfer zones and flow limits between them. The generator can submit bids for capacity which are limited to values as set by the regulator. Capacity is divided into new and old type where the price for the old capacity is set by the regulator and the price for new capacity is subject to a market council's approval. Information regarding any commissioning or decommissioning during the period is specified as well as technical parameters. Capacity is remunerated as pay as bid. The SO certifies the generator's volumes and parameters, including non-certified volumes to be purchased by the generators and delivered. The generator has supply obligations, and must keep capacity available by ensuring that technical standards set by the SO are fulfilled. In case of failure the capacity payments are reduced pro-rata and the failing generator compensates the other generators within the price zone.

Capacity can also be traded freely on the market as bilateral contracts, based on the auction's results for capacity delivered under "agreement of capacity provisioning. The three types of base and peak contracts are:

- Bilateral contracts for non-regulated volumes
- Contracts traded on commodity exchanges
- Contracts for new capacity

Since 2009, the capacity not sold by regulated and non-regulated contracts is offered on commodity exchanges bundled with electricity. Capacity as specified in bilateral contracts between non-regulated electricity transfer zones is constrained to the transmission capacity (capacity quota) between zones. Capacity not specified by regulated and bilateral contracts is shared among generators pro-rata according to their certified capacities. Any generator exceeding its capacity limit is charged a penalty equal to the difference between the auction price and the generator's price bid. The capacity quota may be traded among the generators. If a generator buys more capacity than allowed, the surplus can be sold in auctions. Buyers of capacity in the annual auctions pay for certified volumes equalling actual consumption times a reserve coefficient for the price zone. The volumes are partly covered by regulated contracts with older hydro and nuclear power plants while the remaining may be purchased as non-regulated bilateral contracts and in auctions. New capacity is traded on the market as capacity delivered under agreements of capacity provisioning. Newly developed generation capacity as part of the investment programmes may delay commissioning by 1 year without paying charges. After that non-commissioned capacity is not remunerated and is also charged a 30% fee of the auction price.

Long term capacity auctions

After the transitional phase, long term capacity auctions will be held in the free electricity transfer zones where certain generation technologies will be prioritized to achieve a fuel mix as laid out in the national energy strategy. In the new model there will be competition between generators for capacity payment to reduce costs and excess capacity, as well as give price signals for investments. Moreover, in the transition model the aggregate electricity and capacity costs may be overstated since the marginal electricity revenue does not reduce the capacity cost. Nuclear and hydro power plants are price takers and will not be compensated if their profits from the day-ahead market are sufficient to cover their fixed costs. Bilateral contracts will be concluded in advance of the auctions where volumes are price taking. Auctions for generation capacity are conducted for old and new capacity. Prices are capped by operation costs and operation costs plus return on investment, respectively. Capacity payments are guaranteed at the bid price for one year for old capacity and for a non-defined period (five to ten years) for new capacity. New capacity is treated as price taking and adjusted annually by inflation. Controllable load consumers will also participate in the capacity market. These consumers must qualify for a volume and technical certification. Prices are capped and demand curves are defined by reserve coefficients. Large-scale industry may undertake self-planning for four years at a constant value. If actual consumption deviates from planned, the consumers buy or sell capacity in the market. Volumes from bilateral contracts are limited for each buyer, to eliminate arbitrage and ensure fairness among consumers. A capacity buyer's volume will, therefore, be from bilateral contracts for old and new capacity and from auctions.

To incentivize generators to develop peak load capacity, the national strategy suggests that generators should be remunerated with both energy and capacity prices. This peak load capacity will be capped in the day-ahead market by the energy price submitted in the auction, while generated electricity sold under bilateral contracts will trade freely on the day-ahead market. This suggested mechanism encourages trading under bilateral contracts, because auction trading would be more expensive for buyers, and generators could receive extra profits in the day-ahead market. If this new model is rejected, the model with inflation adjusted returns should incentivize investors sufficiently. When capacity shortfalls occur, the SO organizes tenders with starting price equalling twice the expansion costs for short construction time capacity. If no one participates in the tenders the government will invest in generation or transmission capacity.

Commodity (power) Exchange

From late 2007 trade of non-regulated bilateral agreements for the purchase of physically delivered power (SDD) has been conducted on the Arena stock exchange. From 2008 Arena has facilitated trade of simultaneous physically delivered power and capacity (SDEM). The spot price index by ATS is used as a settlement price for the contracts. The SDDs weekly and monthly agreements are settled against the hub indices for the first and second pricing zones. The SDEMs are traded in a fixed capacity amount and freely chosen power volume within a month depending on the shape of the supply. Financially settled SDEMS are also available from generation companies.

The current share of capacity and power traded at Arena is about 34% of the total free tradable volume. With increasing market opening, the volume is expected to increase also.

Balancing and Ancillary Services Markets

Planned and actual generation and consumption differs in real-time and the deviations are handled in the balancing market. Large industrial consumers and generators participate here. Hydro and pump-storage plants are price takers. Based on the submitted bids the SO runs its mathematical model and calculates minimum balancing prices for 3 hours ahead and in real time. The upward balancing price is calculated as the maximum of the day-ahead market price and the minimum balancing price, while the downward balancing price is the minimum of these two.

Ancillary services (major frequency and voltage) provide reliability and stability of the power systems. These services incur costs for the providers and must be remunerated. The ancillary services market was launched in 2009.

Bilateral Contracts and Hedging

Bilateral contracts allow participants to carry out long-term planning, lock in electricity prices, hedge the risks of performing obligations under regulated contracts and determine the terms and procedure of payments for electricity. Bilateral contracts can be concluded between market players located in a single price zone. The counterparties agree upon contract price and schedule of delivery (hourly volumes), and report to ATS which then calculates the delivery costs as reflected in LMP difference (costs of transmission losses and congestion). In addition to the injection and withdrawal locations, the parties specify an arbitrary reference location (location of delivery). If the reference location does not match the seller's or buyer's location, both of them will be exposed to LMP risk. Thus, a better solution is to settle the contracts against a liquid hub (weighted LMP) price. The LMPs have similar prices that do not deviate more than a specified value from the hub price. Four hubs are located within price zone 1 and two are within price zone 2.

Retail Electricity Prices

Suppliers in the retail market are energy supply companies, suppliers of last resort SLR) and generation companies. Each SLR operates in its assigned operation area. The SLR concludes a contract with each customer in line with the contract form approved by the government. It also sells volumes purchased from regulated and non-regulated contracts to retail customers under tariff and under non-regulated prices to other classes of retail customers. Households only buy from the SLR at regulated prices.

Electricity and capacity may be sold separately or combined. Retail electricity prices reflect energy and capacity components (non-regulated and regulated) as well as network tariffs, and SO and ancillary services tariffs including sales mark-ups. The mark-ups are determined by regional regulators and set by a cost plus principle. In general the regulated markups are around 1–3 €/MWh (Abdurafikov, 2009).

The levels of regulated regional prices are generally harmonized with the indicative prices set by the federal regulator and used in regulated contracts. As of 2008 prices (as determined by bilateral contracts, day-ahead and balancing markets) are modified by adjusting consumption downward by irregular variations. The most expensive generator volumes are compensated pay as bid while the lower demand results in lower clearing prices. Beginning in 2009 clearing prices are determined as the maximum of irregular consumption variations and exports from a price zone.

The energy component of electricity prices reflects the variable cost including the fuel cost of the marginal plant. In most cases coal and gas plants are price setting, backed up by hydro and nuclear plants which have substantially lower marginal costs.

The fuel markets in Russia are generally uncompetitive and dominated by vertically integrated companies.

From 2011 regional wholesale gas price for non-household customers are net backed such that the price in certain region equals a regional coefficient times the price in a (virtual) gas production location. This equates to average export price net of the costs for delivery (transportation, storage and sales), including customs fees and export duties. The export price is calculated as the average export price in the preceding base period which depends on long-term gas supply contracts indexed to oil with a time lag.

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