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Abstract The paper looks at the development of the industry in the post-Soviet Russia, starting from the ealry 1990s. The main focus is on the last reform 2003-11 and the relationship of cost, prices and investment. In particular, the author examines the new designs for the electricity and capacity markets and their impact on incentives for short-run production and long-term planning and construction. The author defends the pro-competitve approach to the electricity industry reform in Russia and traces the roots of its success and failures.

Keywords Russian Electricity Industry, RAO EES, reform 2003-11, restructuring, market liberalisation, capacity markets

JEL Classification L11, L22, L43, L52, L94

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1. *Introduction*

The modern Russian electricity supply industry (ESI) has undergone a series of radical transformations in the last twenty years, yet its written history remains fragmented and scattered among relatively few sources and research publications. Many other reforms around the world have been studied extensively and then summarised, for example by Sioshansi and Pfaffenberger (2006)[1].The Russian case consists essentially of two reforms: transformation from a planned system into a state-owned monopoly in the early 1990s, followed by monopoly restructuring, together with market liberalisation, in 2003-11. The first reform consisted mostly of emergency measures in a fast-transforming environment and was therefore very unlikely to produce satisfactory results. By contrast, the second reform relied extensively on international experience and reform templates, and appears to have created a sensible industry structure and reasonable market design, although further policy decisions may have undermined some of the early-stage achievements. The key message that the second reform of the Russian ESI can offer to international observers is that restructuring and market liberalisation of a large-scale industry is feasible from both economic and political perspectives.

In the early 1990s, the Soviet electricity system was replaced by a vertically integrated monopoly. The new industry structure and market design led to inefficient decisions in production schedules and dispatching. The overall economic decline in the economy negatively affected the financial performance of the ESI. Eventually growing general dissatisfaction with the situation paved the way to a new reform: the preparatory stage included heated public debates, with reference to the Soviet experience and contemporary examples of ESI reforms around the world. The choice was made in favour of competitive markets for generation and retail supply, combined with natural monopolies for transmission and dispatch. The unbundling of the monopoly was undertaken in 2004-8, and the electricity

[1] The most recent volume by Sioshansi and Pfaffenberger (2013) also has a chapter on Russia

markets were liberalised from January 2011. The main events of the Russian ESI development are listed in the appendix and discussed further in the paper.

International experience already comprises a mass of ESI reforms, starting with the pioneering reform in Chile in 1982 and the now-textbook example of the reform in England and Wales in 1989. A reform typically consists of industry restructuring and market liberalisation, with varying degrees of advancement in an attempt, e.g., to overcome the inefficiency of the incumbent utility provider or to attract new investment. The California electricity market crisis in 1999-2000 demonstrated major reform failure at large financial cost, the roots and policy response of which have been widely studied (Borenstein et al., 2002; Wolak 2003).

While ESI reforms in most other countries, or markets, have been well-documented and examined, a review of the literature on the Russian ESI reveals the scarcity of research in this area. The number of papers published by international experts and institutions is quite limited, which could be partly explained by the language barrier. What is less expected is that the amount of ‘domestic’ research (i.e. in Russian) is also quite small[2]. Currently, there are two major strands of research: the first set of papers deals with the history of the industry in the 1990s, up to the recent reform; the second set of works examines the reform and its consequences.

Early reports by the International Energy Agency (1993, 1995) and somewhat later by the World Bank (1999) reviewed the Russian energy sector at the time, while Opitz (2000) provided an interim picture between the two reforms. To our knowledge, there has not yet been any work in Russian on the same period, so the international reviews sometimes serve as the only source of information, especially on the early 1990s.

The preparation for the second reform received much attention from the IEA (2003, 2005), as well as independent researchers (Yi-Chong 2001; Kennedy 2003; Tompson 2004). After the reform was largely completed, a few papers presented brief summaries of the modern market structure[3]. Later works by Solanko (2011) and Gore et al. (2012) discuss in greater detail the

[2] Solanko (2011) makes a similar observation, p. 16: “Given its magnitude and its relative success in attracting the necessary new investments, the reform has attracted surprisingly little attention both in domestic political discussions and in the international community”.

[3] See, for example, Oksanen et al. (2009) or Doeh et al (2009).

outcomes of the reform, with a focus on the new industry structure and market design, in particular the design of the capacity markets.

It appears that no work has yet attempted to link the two historic periods of the industry. The present paper aims at comparing the main components of the last reform with the changes in the 1990s, in order to outline successful steps and persistent problems that still need to be addressed. The paper is organised as follows: the next section provides a summary of the reforms with a focus on the main components; section 3 presents comparative statistics for the Russian electricity industry versus other national jurisdictions; section 4 deals with the development of the industry in the 1990s; section 5 outlines the problems that accumulated; sections 6 and 7 discuss the 2003 reform, with section 7 focussing specifically on the investment and capacity mechanism; the final section concludes.

2. Reforming an ESI – international theory and practice

Increasing efficiency is the broad aim of electricity industry reform. Theoretically, moving away from a monopoly to a pure competitive market is the best way to reduce prices, increase output and eliminate deadweight loss. Therefore, the key principle of electricity industry reform is to introduce competition where possible, i.e. in generation and retail supply, and maintain regulation where competition is not feasible, i.e. in transmission and distribution. This implies restructuring the industry, designing markets for competitive sectors and developing regulation for the non-competitive sector.

International experience and lessons to be learned are well summarised in many sources. General reviews can be found, e.g. in Littlechild (2006), Joskow (2006) or in a more recent paper by Pollitt (2012). A summary of various reforms around the world at the time was presented by Newbery (2003) while Pollitt (2009) looked at the European countries only.

A comprehensive list of steps for a successful reform can be broadly grouped into the following blocks[4]:

Restructuring: separating generation, distribution and retail; creating a sufficient number of generation and retail companies; creating an independent system operator;

[4] We do not discuss here environmental policy, e.g. support for renewable energy sources or emission trading schemes. These issues were raised later, when most competitive electricity markets were already in operation.

Market design: markets for electricity, ancillary services and (sometimes) capacity, markets for contracts, spot pool/exchange and financial markets; wholesale and retail markets, geographical zoning, rules for price determination, interaction between different markets;

Regulation: creating an independent regulatory authority; regulation of transmission and distribution, including transmission charges and rules for accessing the grid; regulation of generators and markets, if necessary (e.g. price caps).

The move from a regulated industry to a market-based one requires its own 'road map' and must be designed together with the main reform. The post-reform period inevitably has its own problems and issues to solve and requires an additional set of policies, or 'reform of the reform'. Various electricity market reforms show that a complex approach to reform is more convincing. Partial or poor implementation of some measures is more likely to lead to the reform failing.

The developing state of the economy complicates the design of any reform and may increase the risk of failure (at any stage), but it should not be regarded as an insurmountable obstacle to the reform per se. A developing country is likely to implement extra reforms that specifically address the developing character of the industry or economy. Measures might include improving the technical performance of the industry (e.g. developing the distribution network to reduce losses and increase connectivity), re-structuring upstream fuel markets (e.g. developing competition or improving fuel price regulation) or developing financial markets (e.g. for better and cheaper access to capital).

Restructuring

Good restructuring helps avoid many problems with competition once the reform is completed. A good industry structure would involve a sensible number of generation and retail companies that are not associated in any way with each other or with distribution companies through, for example, common owners. Newly created companies should not have significant asset concentration in a particular area, in order to minimise the risk of local market power, nor should one company have a technological advantage over its competitors (e.g. having only newer or more efficient plants).

A small number of generation companies creates obvious problems for competition and may lead to market power abuse. The early part of the reform in England and Wales in the 1990s gives a prime example: two generation companies created in the initial stages, National Power and PowerGen, appeared to have manipulated prices and consequently were subject to price caps and compulsory divestiture. Experience shows that it is important not only to create a reasonable number of companies, but also to sustain mergers and acquisitions, which end up inevitably being proposed.

Maintaining links between a generator and distribution company (e.g. via a common holding company as in Chile) prevents fair access for other generation companies to the network or fair access for customers to generators other than those affiliated with the distribution. Links between a generator and retail supplier might create some economy of scale, although this should not compromise competition, either in the generation sector or the retail sector[5].

In Russia, the first reform of the 1990s was implemented with much haste, and a vertically integrated monopoly was established, in order to maintain state control of the industry. The second reform took a pro-competitive approach so that many generation companies (above 20 in total) were created in lieu of the former monopoly. The new companies were endowed with assets in such a way as to ensure equal starting positions, but also to avoid local market power.

Creating an independent system operator is usually never a disputed choice. However, the first Russian reform shows (as section 4.3 discusses) what happens when the dominating vertically-integrated utility, which competes with smaller independent power producers (IPP), is in charge of the dispatch operation. The result was the inefficient dispatch from the utility provider's power plants, which often had higher production costs than the power plants of the IPPs.

In addition to reform of the electricity industry, changes might be required in fuel supply markets. In the UK, British Gas was privatised prior to the electricity industry reform in England and Wales, but the regulators still had to deal with the inefficient coal industry. Chile, after the main industry reform was completed, experienced problems with gas supply from Argentina, on which it was dependent. The Russian case is probably one of the most difficult, as the gas supply industry is still a public monopoly and the gas tariffs appear to be greatly distorted in comparison with European gas prices.

Market design

[5] Joskow (2006) "Introduction to Electricity Sector Liberalization: Lessons Learned from Cross-Country Studies" p. 27. (In Sioshansi and Pfaffenberger, 2006)

Market zoning provides a basis for price determination and the pricing of transmission congestion. A relatively compact country with a developed network may have a single zone and consequently a single market price. When a transmission constraint is binding, extra generation or load shedding is paid for separately. If there are multiple zones, these can be geographically fixed (Sweden and Finland) or dynamic (Norway); they may be time-permanent or arise only during congestion. Locational or nodal pricing is a limiting case of multi-zoning and is implemented in the Pennsylvania-New Jersey-Maryland (PJM) market and the post-reform Russian market. A price differential between any two nodes reflects the transmission congestion cost and highlights potential bottlenecks in the grid.

The design of wholesale and retail markets represents two different tasks. Wholesale markets are usually introduced at the start of the main reform and typically include contract markets, day-ahead and spot-exchanges or pools to trade real-time imbalances. Contractual obligations might be voluntary or compulsory (e.g. to mitigate potential market power abuse). Low contractual cover (between generators and the retail supplier), hence higher incentives for manipulating available capacity and spot prices, is deemed one of the main reasons for the California electricity crisis 2000-01 (Borenstein et al., 2002).

To ensure smooth transition from a regulated industry to competitive markets, reformers sometimes use vesting contracts (e.g. in England and Wales, or Spain) or require generators to sell forward some of their output. Russia used vesting ("regulatory") contracts, although once they expired, voluntary contracting did not expand and remained at a low level. Perhaps in anticipation of this and to curb potential price manipulation, the government introduced a bidding code and required the companies to bid at a variable cost. To solve the "missing money" problem[6], a capacity market was put in place, but, as we discuss in section 7, it is subject to heavy regulation.

The design of retail markets is a more sensitive issue, as it concerns, at its fullest extent, any private household. Some jurisdictions (e.g. in England and Wales, the Nordic countries, parts of Australia) eventually open up the retail market to any final consumer; others limit the retail market to small commercial customers and maintain price regulation in the residential sector (as it is currently implemented in Russia). In the latter case, great care is needed to design the retail tariffs in order that they should match (somehow) liberalised wholesale prices.

[6] The "missing money" problem arises when the market operates as a uniform price auction and requires bidding at a variable cost so that the marginal, or peaking, plant earns just enough revenue to cover its variable cost and nothing to cover its fixed cost.

Wholesale markets can trade only energy (Hogan 2005) or electricity and capacity separately (Crampton 2005). Most electricity market reforms were conducted in industries with an adequate reserve margin or excess spare capacity. As demand is growing and existing power plants are ageing, the problem of adequate capacity becomes more and more serious. In all probability, the key issue is not to separate traded commodities, but rather to create correct price signals for investing in new capacity. An energy-only market relies on price spikes that have a very short duration (e.g. only a few hours per year), but are politically and socially unacceptable. Capacity trading is therefore a potential solution to the "missing money" problem and seems an inevitable option for long-term development. Capacity markets are part of some US markets, but are virtually absent in Europe (although capacity remuneration mechanisms can be found in most European countries).

Regulation

Active regulation of the industry is inevitable, due to the presence of natural monopolies, namely in transmission and distribution. Regulation can also apply to markets and specific generators or suppliers, e.g. in the form of price caps or individualised tariffs. The very absence of a regulatory authority can impede industry reform, as the German case demonstrates. A regulator might be used to create suitable incentives or to support political objectives. Whatever form of regulation is implemented, it has to be carefully analysed against other alternatives in terms of social welfare.

Regulation of natural monopolies typically deals with transmission charges, rules for connecting to the grid and network development. Transmission charges can be based on a cost-plus methodology or performance-based schemes. The latter approach has the advantage that it incentivises cost-saving and the use of better technology, and is implemented, by way of example, in the UK. In a developing country, an incentive-based mechanism is perhaps a better option, as it can be used to improve drastically the technical performance of the network in a short period of time (e.g. to reduce losses) and, as such, to demonstrate the benefits of reform.

Russia's network and distribution grid has traditionally relied on cost-plus tariffs. As part of the second reform, the cost-plus method was replaced with a regulatory-asset based (RAB) approach, with the particular goal of helping the network and distribution companies to finance extensive investment programmes of expansion and refurbishment. The RAB method allows higher return rates on capital, but leads to higher transmission tariffs; the tariffs, however, are fixed for several years. Companies thus have a stronger incentive to complete their investment programme sooner and lower the overall cost, while for consumers tariffs actually decline in real terms over time (rather than being indexed against inflation, as in the cost-plus method).

Network development typically follows a regulatory approach when decisions are made by the transmission company and are approved by the regulator (in most countries, including Russia). Two other schemes have also been developed: merchant interconnector lines (within a single country) and the public contest method[7]. Merchant interconnectors were built in Australia, but the lines turned out to be less profitable than expected (due to a large entry in the high-price area) and it was necessary to switch to a regulatory regime. The public contest method used in Argentina specifies that the users who will directly benefit from a new line pay for its construction; the method was carefully designed and proved to be efficient in developing the transmission system.

In some instances, a regulator is required if a competitive market is not in put in place, e.g. there is a single-buyer model instead of retail competition. The regulator then has to decide how much energy to buy and at what price, given a certain forecast of energy consumption. A mistake in future quantities and tariffs can be very costly to consumers and potentially to regulators (not to mention political forces). In the USA, regulators, both the FERC and some state regulatory authorities, only approve price agreements between a utility company and its customers, rather than nominating tariffs.

When deciding on a suitable regulatory regime in the industry, developing countries might require, first of all, the very establishment of a regulatory body, or the re-enforcement of an existing one. Re-enforcement might mean independence from the government and stronger authority in decision-making, better qualified staff and improvement of informational support.

[7] Littlechild (2011) offers a detailed discussion of both models.

3. *Overview of the Russian ESI*

This section provides a statistical summary of the industry, first providing data on the electric efficiency of the Russian economy, together with international comparison, and then discussing output/capacity relations and the development of the transmission system.

In general, the statistics reveals poor starting conditions of the economy and the industry. The Russian economy was characterised by high energy efficiency as compare to other developing countries or countries with similar northern climate. Price regulation in the industry was inconsistent, with the regulated tariffs often below production cost. Even such low tariffs were difficult to collect due to widespread non-payment of bills.

As a result of the economic decline and the inevitable decrease of the electricity demand, the reserve margin in the industry was quite high which had two implications for investment decisions. On one hand, the high reserves meant there was no need for new investment (which could not be paid for anyway with low energy tariffs and the bills non-payment). On the other hand, the economic revival that finally followed, coupled with ageing of the equipment, meant that significant investment would be needed both in construction of new capacity and in refurbishment of the existing power plants.

3.1. Some (in)efficiency measures

As the Russian economy was sharply declining in the early 1990s, so was the demand for energy: electricity production decreased by23%, from 1068 TWh in 1991 to 826 TWh in 1998. In the same period, GDP dropped by nearly 40% in real terms, meaning that the electricity intensity of the economy deteriorated significantly (see figure 1a). This case contrasts with that of many Eastern European countries, where the electricity production per \$1 GDP has remained the same or decreased (figure 1b). Apart from Russia, only Bulgaria has a similarly high level of intensity (0.6-0.8 kWh per \$1 GDP); other countries have 0.5 kWh or below.

The high electricity intensity of the Russian economy is combined with low per-capita GDP and low per-capita electricity consumption. This observation contrasts with that of developed economies with low intensity and high income (figure 1c). Moreover, compared to the countries of Northern Europe with similar climate conditions, Russia has a much lower GDP per capita. The developing stage of the Russian economy cannot explain the electricity inefficiency, either: other CEE countries with similar levels of per-capita GDP have lower intensity (figure 1d).

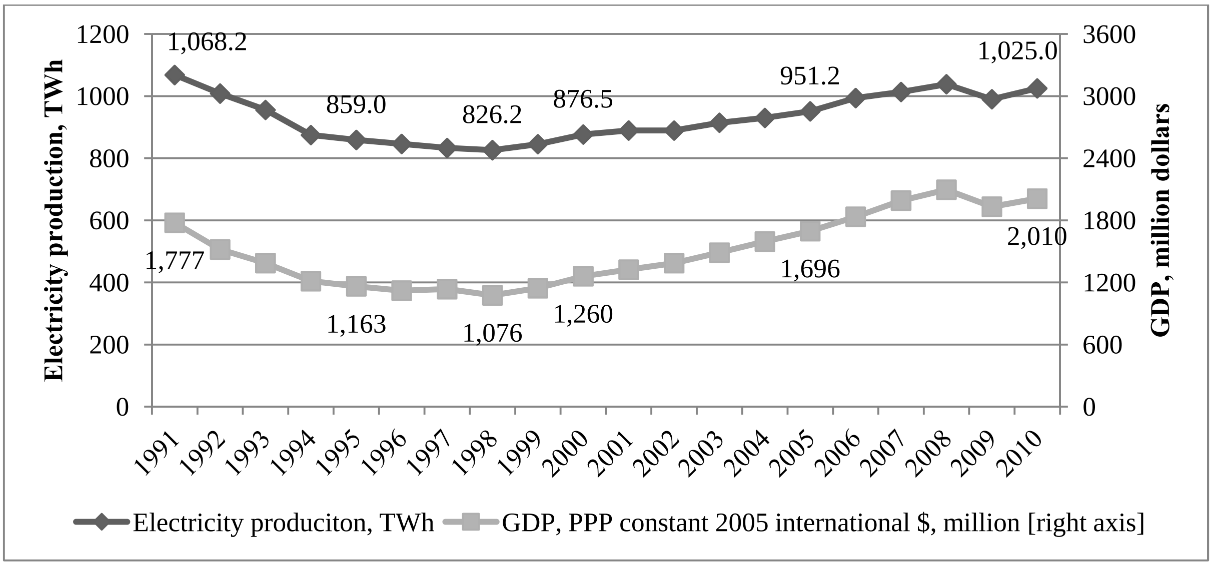

Figure 1a.GDP and electricity production in Russia, 1991-2010.

Source: World Bank WDI.

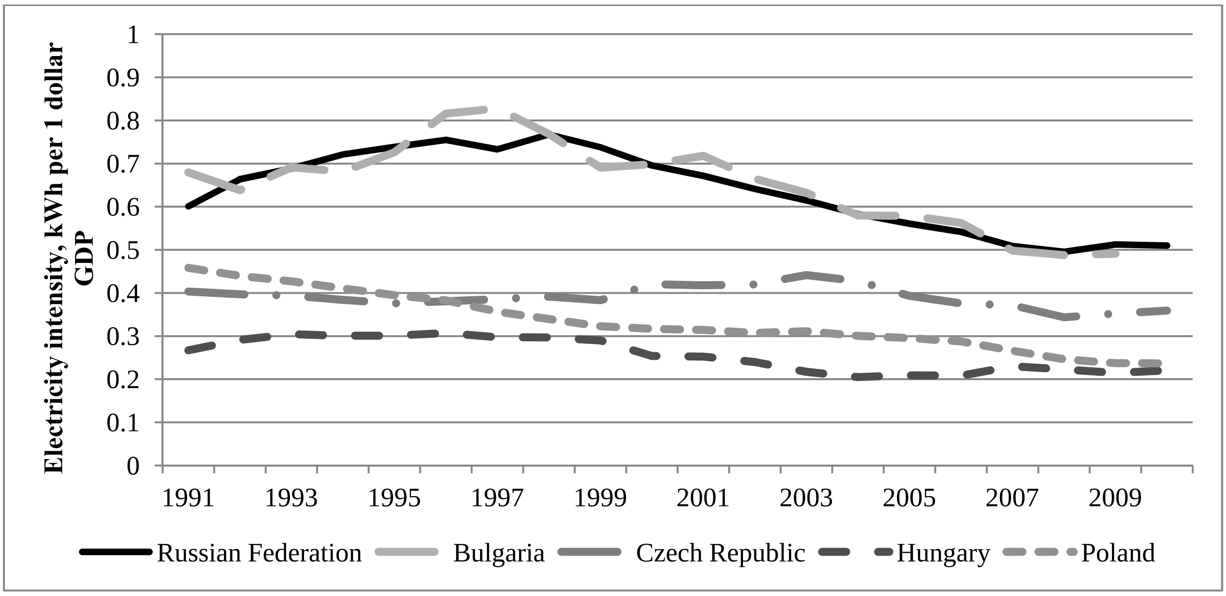

Figure 1b.Energy intensity, kWh per 1 dollar GDP (PPP constant 2005 international dollars). Central and Eastern Europe, 1991-2008.

Source: Author's calculations based on 'Electricity production' and GDP series by World Bank WDI.

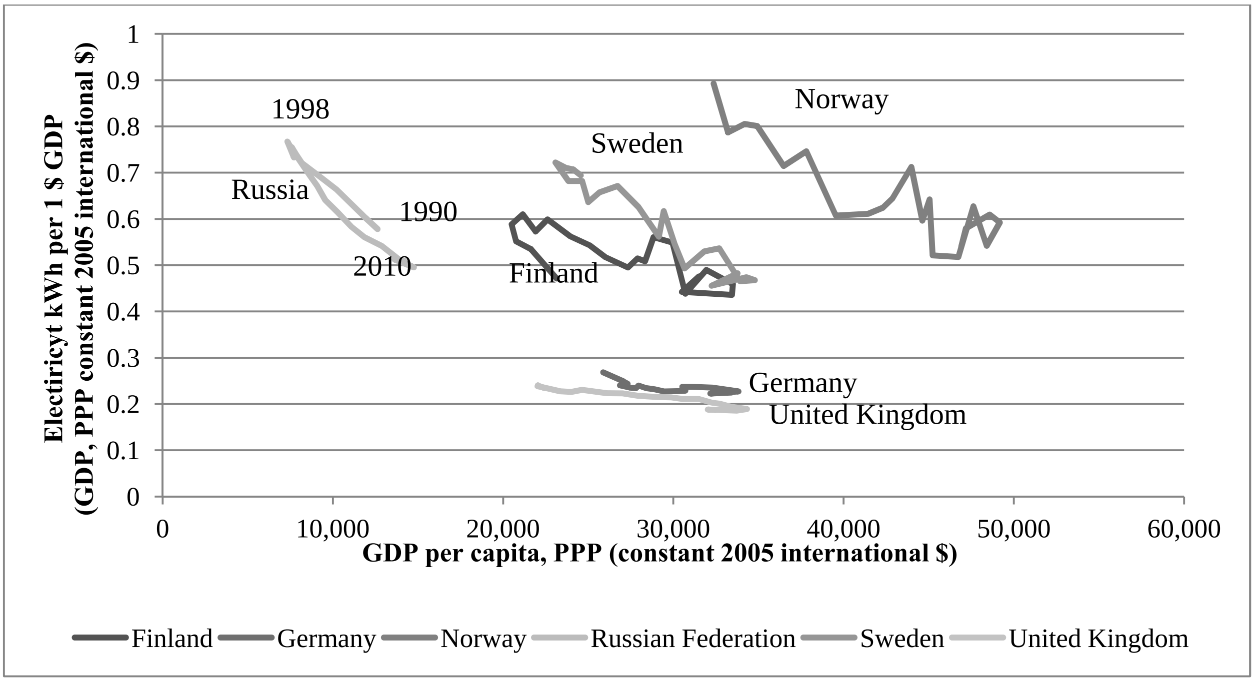

Figure 1c. GDP per capita vs. electricity intensity in Russia and Western Europe.

Source: World Bank WDI.

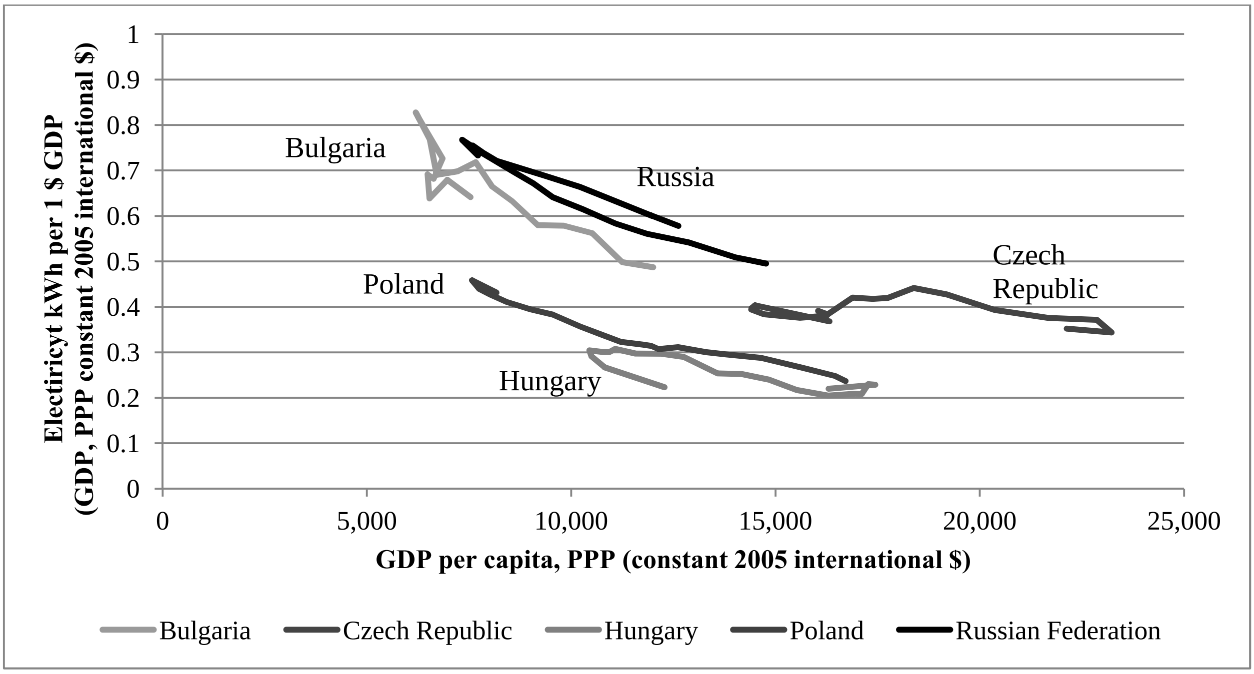

Figure 1d. GDP per capita vs. electricity intensity in Russia and Central and Eastern Europe.

Source: World Bank WDI.

3.2. Installed capacity and output

The total installed capacity of the industry in the year 1990 was around 213 GW; the break-down by type is shown on figure 2. Thermal generation capacity accounted for 70.2%, the shares of hydro and nuclear were 20.3% and 9.5%, respectively. There are neither public statistics on fuel used at the time, nor aggregate information on fuel-switching projects at the power stations in the '90s.

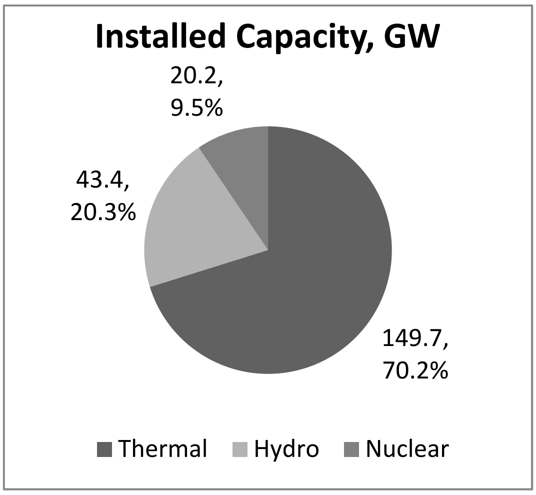

Figure 2.Installed capacity by type, year 1990.

Source: Russian Federal Statistics Service.

A notable characteristic of the Russian ESI is the presence of combined heat and power plants that comprise almost half of the thermal capacity. The CHP stations vary greatly in size (from just 17 MW up to 1800 MW), and often serve as base load in the winter period. Many stations are built within cities to supply heat and electricity to households. A small but noticeable fraction of the CHP plants (around 5% of the industry) belong to industrial users that need both heat and electricity as inputs, and might sell residual energy to local customers.

Hydropower generation contributes significantly to the overall output. Two clusters of larger hydropower stations are located in Siberia and on the Volga River. Further, two areas have a number of smaller stations: the Caucasian mountains in the south of Russia and the region of Karelia in the north (which borders Finland).

Nuclear generation is represented by ten power plants, the majority being located in the European part of Russia (one small station is located in the Far East of the country; no nuclear stations were built in Siberia). Throughout all the reforms, the nuclear generation sector has remained under government ownership and management because of safety requirements and technological links to the military industry.

In 2010, around 2/3 of the thermal capacity was gas-fired; the bulk of gas-fired power plants are located in the European part of Russia. Coal-fired plants comprise slightly less than 1/3 of the installed capacity; these are found predominantly in the Siberian part of the country. There are a few stations that use both types of fuel (e.g. two turbines are gas-fired; one turbine is coal-fired). The fraction of renewables in the mix is negligible- less than 1%.

The amount of installed capacity remained practically unchanged in the 1990s, with the main reason being decreasing demand. The reserve margin was quite high, above 30%, and reached a generous 41% in the year of the lowest demand, 1998 (see figure 3). Even correcting for the capacity that was unavailable due to routine maintenance and repair (approx. 10%), the reserve margin would still be in the range of 20-30%.

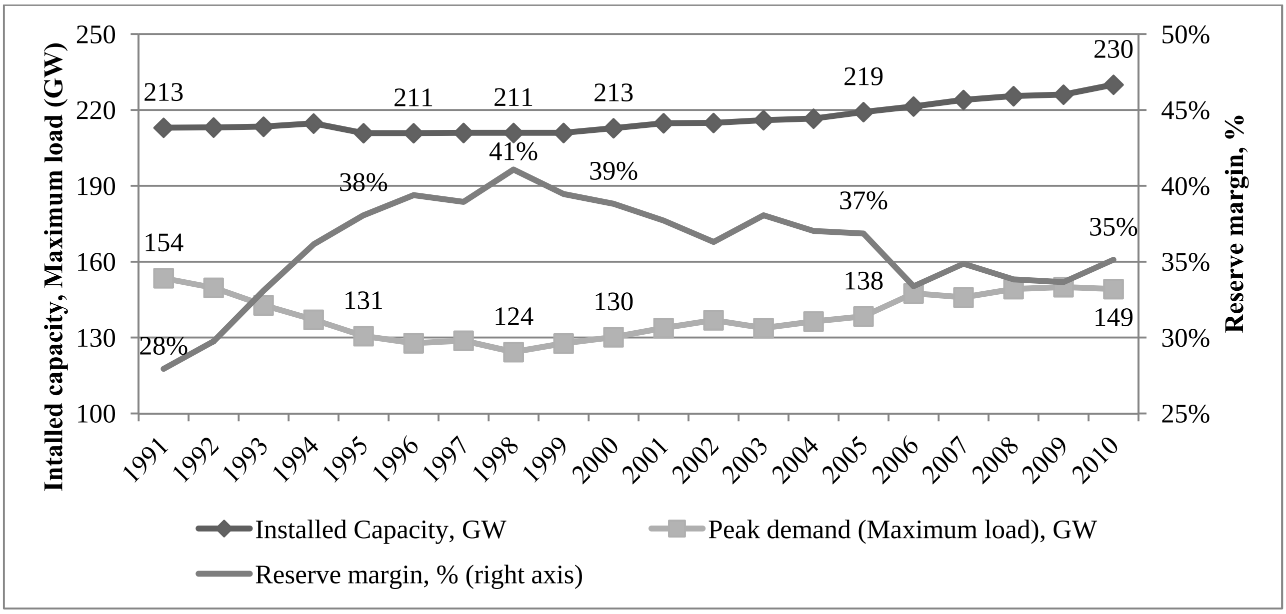

Figure 3.Installed capacity, maximum load and reserve margin.

Source: Installed capacity – UN data (1991-99) and Russian Federal Statistics Service (2000-10); Maximum load – System Operator of the Russian ESI; reserve margin – author's calculation.

As for the age of the generation equipment, estimates are contradictory. According to the Russian-based agency APBE, in 1990 the bulk of the installed capacity, namely 63%, was twenty years old or less[8]. However, the International Energy Agency claims that the proportion of such plants was only 1/3[9]. As noted in the report by the Russian State Council (2001)[10], the different estimates of the age structure might be based on the nominal lifetime or the actual lifetime (e.g. after plant refurbishment). The same report further remarks that much of the generation capacity could be renovated and have its lifetime extended. The question of aging equipment became quite important during the reform of the 2000s, as the claims about old machinery were used to highlight the industry crisis and hence support the reform.

[8]Agency for Forecasting the Energy Balance (2006), page 45, table 2.2.1.8
[9] International Energy Agency (1995), page 213, table 7.
[10] State Council of the Russian Federation, Working group on the electricity industry reform (2001)

3.3. Dispatch zones and transmission system

Historically, the expansion of the electricity system in the soviet era moved from the west of the country to the east. This dictated the development of the seven dispatch zones: North-West, Centre, Volga, South, Siberia and Far East (figure 4). The first six zones are synchronised, and the Far East dispatch zone operates nearly autonomously. The links between the zones are quite weak, which has several implications for system stability and market operations. First, there has been no major blackout that would affect the whole country, although regional blackouts took place throughout the history of the ESI. Second, the presence of interconnectors that stretch through eleven time zones helps stabilise to a certain extent the system by using time difference and intra-day fluctuations. When it is morning in Siberia, it is still night-time in the European part of the country, so it is possible to start up some plants in the European part and serve the growing morning load in Siberia. Finally, in terms of market design, the constrained interconnection means that there is limited potential for trading between remotely located players and for levelling the prices across different regions.

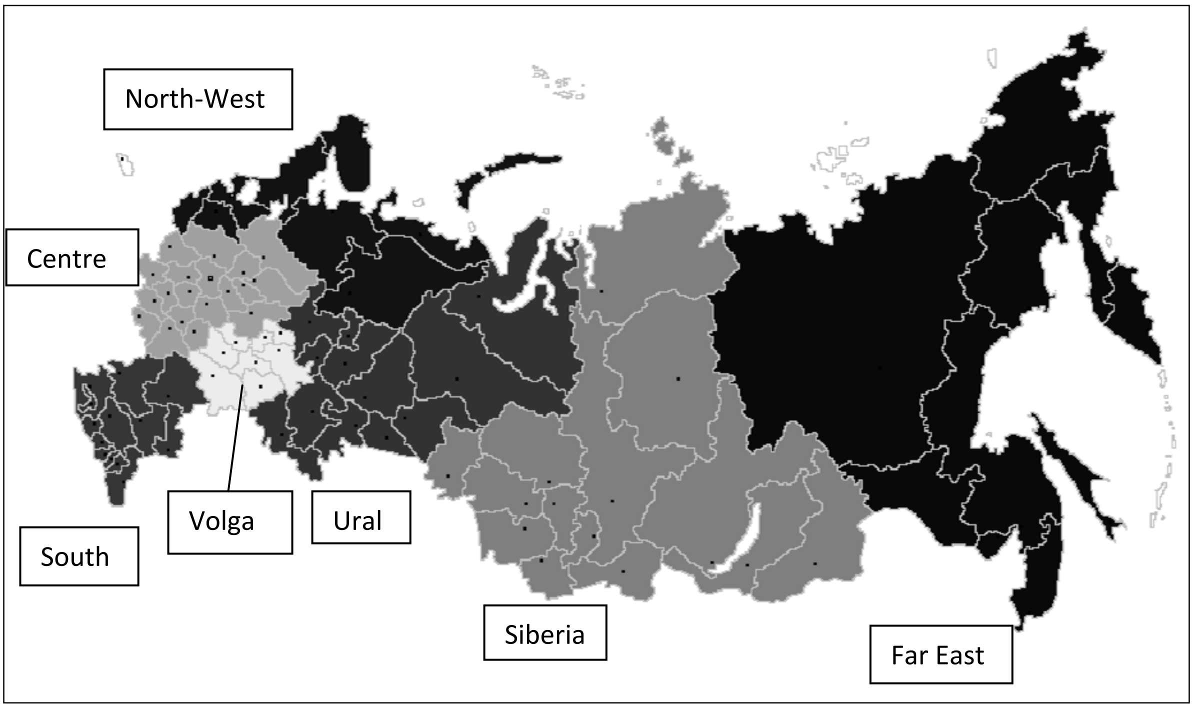

Figure 4. Russian electricity supply industry. Dispatch zones.

The transmission system of the Soviet ESI was conventionally divided between the high-voltage grid (330kV and above, to connect the dispatch zones) and the distribution network (220kV and below). There seem to be no detailed statistics for the 1990s on the length and distribution of lines by voltage. The Russian State Council (2001) provides the data for the year 2000 (see tables 1 and 2). The high-voltage lines includedapprox.42,000 km, of which the 500kV lines comprised 73% and 330kV lines comprised 17%. The distribution network was much more extensive: 2.6 million km. There were a few DC lines built in the Soviet time, but currently only one line remains in operation. The line ensures cross-border trade with Finland; the capacity is 1400 MW.

For comparison, the US Department of Energy reports in 2002 that the US transmission system was252 thousand km[11]. The grid was essentially divided between three types of lines: 230 kV (49%), 345 kV (31%) and 500 kV (16%). The very high voltage network (765 kV) and direct current network constitute together the remaining 4%. Given the relative size of the installed capacity (213 GW in Russia versus 812 GW in the US), the Russian grid appears reasonably scaled, albeit, as discussed below, not without bottlenecks.

Table 1. Length of high-voltage lines, year 2000.

Voltage, kV	Length, thousand km	Share
1150	1.0	2.4%
800	0.4	1.0%
750	2.8	6.7%
500	30.5	72.8%
400	0.01	0.02%
330	7.2	17.2%
Total	**41.91**	**100.0%**

Source: State Council of the Russian Federation (2001).

Table 2. Length of distribution network lines, year 2000.

Voltage, kV	Length, thousand km	Share
220	100	3.8%
110-150	293	11.2%
35	200	7.6%
15-20	6	0.2%
10	1,085	41.3%
0.38-10	93	3.5%

[11] US Department of Energy (2002) “National Transmission Grid Study”, page 3. The figure reported is 157.8 circuit miles.

0.38	849	32.3%
Total	**2,626**	**100%**

Source: State Council of the Russian Federation (2001).

Within the regional distribution network there are a number of bottlenecks, meaning that some regions are in constant deficit or surplus of supply. During the market reform in 2003-08, this meant that some (small) areas of the country were completely excluded from the wholesale market. Many other areas with transmission constraints were included in the market, but limited line capacity still meant supply deficits and hence higher electricity prices.

4. Reform in the 1990s – the lost decade[12]

In the very early 1990s, the aim of creating a competitive industry faced strong opposition from professional bodies and some politicians[13]. The industry structure and market design that emerged was a result of compromise and did not fully achieve economic efficiency. The following section discusses various aspects of the restructuring – ownership, regulation, markets, prices and investment – in order to point out some problems and issues necessary for understanding the later reform of the 2000s.

4.1. Ownership

The general reforms in the Russian post-Soviet economy were vast in terms of scale and depth. The privatisation process was unrolling throughout the economy, often involving the chaotic transferral of state-owned plants and enterprises into private hands. By 1994, most core industries were privatised, including the coal mining industry, however the gas industry remained under full government control and formed the basis of the state monopoly company, Gazprom.

The post-Soviet development of the electricity supply industry might look contradictory in the light of economic liberalisation reforms, but it reflects the government's concern for social stability and secure supply. The Soviet industry structure was represented by 72 regional divisions that were subsequently privatised by the federal government, regional administrations or various interest groups. Thus, the first *energos* were formed as vertically integrated regional companies that combined generation, transmission and local distribution.

[12] In the exposition of the history of the Russian ESI I shall rely partly on the surveys and statistics by the International Energy Agency. See further Yi-chong (2004) for the detailed discussion of the early reform in the Russian ESI.
[13] Yi-chong (2004), page 115.

The federal government regarded the formation of *energos* as a threat to the overall security of supply (or rather it feared losing control over the strategic assets). As a result, a counter-process of corporatisation was launched. In 1992, the federal government formed the holding company "Russian Joint-Stock Company United Energy Systems", abbreviated to RAO EES in Russian. The new company became the owner of large power plants, in particular thermal plants with capacity above 100 MW and hydropower plants with capacity above 300 MW. It also received 49% of the capital of almost every *energo* company, and quickly managed to gain control of 50% or more of the capital in 51 *energos*[14]. The complex property and operational structure that emerged as a result of the corporatisation process reflected, to a large extent, the compromise between central and regional authorities[15].

The very few *energos* (in Irkutsk, Novosibirsk, Tatarstan and Bashkiria) that maintained independence from RAO EES were privatised as early as 1991 by the regional governments. RAO subsequently tried to reverse the privatisation decisions at the High Court of Russia, but was unsuccessful.

The total installed capacity directly belonging to RAO EES amounted to 57.5 GW; the monopoly controlled twice that amount through its dependent *energos*. In total, RAO EES ran nearly 78% of the industry generation of 212 GW. The company also owned the high-voltage transmission lines (330 kV and above)[16], while the low-voltage distribution network was in the hands of *energo* companies.

As for nuclear generation, the federal government maintained direct ownership and control of the sector, which consists of ten power stations, varying in size from 600 to 4,000 MW[17], totalling 23,000 GW. All the stations are located in the European part of the country.

The early stage of the Russian reform resembles to a certain extent the nationalisation of the electricity industry in Brazil in the 1970s,where the "power system was never completely centralized"[18]. RAO EES did not have full control over the installed capacity and distribution, but was responsible for dispatch operations.

[14]RAO EES company (1997). Annual report.
[15] International Energy Agency (1995), page 200.For a detailed review of privatisation in the very early 1990s, see Xu, Yi-chong (2004) pages 167-169.
[16] International Energy Agency (1995), page 201.
[17]The smallest nuclear station is only 50MW but it is located in the Far East of the country in the Chukotka region and has been considered as an isolated producer.
[18]João Lizardo R. Hermes de Araújo "The Case of Brazil: Reform by Trial And Error?" Ch. 16 in Sioshansi and Pfaffenberger, ed. (2007), p.570.

4.2. Government regulation of the industry

The regulation of the electricity industry was assigned to the Federal Energy Commission that was formed in 1992 as a part of the Price Committee of the Ministry for the Economy. The FEC moved under direct governmental control in 1995. The regional level of regulatory authorities was represented by the Regional Energy Commissions (REC). The very first commissions emerged as public committees formed of professional and political representatives, however very soon the commissions became part of regional administrations. The status of the RECs was formalised by the federal government in 1995, alongside that of the FEC.

The Federal Energy Commission was responsible for setting the following[19]:

- guidelines for tariff setting on electricity and heat;
- the minimum and maximum price level for energy sold on the wholesale market;
- charges for transmission and distribution;
- service charges on the wholesale market;
- investment plans of the industry (and controlling the implementation of the investment programmes by the *energos*).

The Commission was also responsible for defining the minimum and maximum level of residential prices, as well as monitoring the decisions of the Regional Energy Commissions and resolving disputes between RECs and third parties. In practice, "many RECs faced local political pressure to keep tariffs below those recommended by the FEC"[20], in particular residential tariffs, hence the need to maintain higher tariffs for industry customers and the resulting problem of cross-subsidies.

The methodology for defining tariffs in the very early 1990s was rather obscure. There seems to be no publicly available document, either legislation or research, that describes rules or guidelines for setting tariffs at the time. Some features of the methodology can be deduced from later documents issued by the regulatory authorities in 1997 and beyond.

The first tariffs were one-tier and based on reported costs, including variable and fixed components, as well as investment charges. The charge seemed to be designed to cover the

[19]As defined by the article 5, the Federal Law No. 41-FZ issued on 14.04.1995"On the State Regulation of the Tariffs for Electricity and Heat Energy".
[20] International Energy Agency (2002), page 207.

cost of constructing new capacity. It is not clear whether there was any norm on capital return, and whether it could be used to pay for construction. Since the early 1990s were marked by vast transformation, cost reporting was often inaccurate. Moreover, hyperinflation invalidated price and cost estimates, so pre-set tariffs could not, in general, reflect the actual cost of running a power plant.

Formal rules on price regulation seem to have been adopted only in 1997. The rules introduced the two-tier tariff[21], as well as a specific investment charge.

The tariff consisted of prices for electricity and for capacity. The electricity tariff was to cover the fuel cost, any other types of expenditure that vary with the output (some taxes, in particular) and the normal rate of return. The rate of return was set as equal for any thermal station, but seems to have never been published. The capacity tariff was to cover all the other operational costs of the power plant not included in the electricity tariff. The general perception (well documented in various international and domestic studies) is that the tariffs were low and did not reflect the true cost of generating and transmitting electricity.

The investment charge (discussed below in greater detail) was part of a more general service fee that covered the expenses of the RAO EES as the dispatch and market operator. The service fee was added to the retail price and thus was paid for by any retail customer (including large industrial consumers at the time).

Tariff regulations did not specify separately any transmission charges or payments, as the cost of transmitting the electricity was included in the service fee.

4.3. Wholesale market

The Federal Wholesale Electricity and Capacity Market (FOREM) was established as early as 1993[22], but its legal framework was finalised only by 1996[23].Although called a market, FOREM was rather a mechanism for balancing electricity flows between the federal power plants and regional *energos*. The *energo* supplied energy to local customers from its own

[21]Federal Energy Commission Decree No. 76 issued on 06.05.1997. “Temporary methodology for defining the wholesale two-tier tariffs”.
[22]Xu, Yi-chong (2004), page 216.
[23] Federal Law No. 41-FZissued on 14.04.1995 and Government Decree No. 793 on 12.07.1996 .

power stations and entered the FOREM only to sell surplus energy or buy deficit. The amount of electricity supplied to the market was around 1/3 of industry production[24].

The Federal Energy Commission regulated the price (or tariff, in Roubles per MWh), both for the energy supplied to and purchased on the FOREM[25]. In other words, the *energos* would sell surplus at the nominated price or would buy extra energy also at the nominated price.

The Commission set the tariffs for electricity and capacity individually for every power plant. The planned generation mix (dispatch schedule) together with individual station tariffs determined the average production cost of the *energo* companies, which was the basis for the sell tariff[26]. The buy tariff was uniform for all *energos*: it was an average of the sell tariffs weighted by the amount of electricity sold. As for the supply to local customers, the *energos* were subject to tariffs set by the Regional Energy Commissions.

Apart from completely regulated pricing, the organisation of the FOREM had other major deficiencies[27]. First, RAO EES, the major electricity producer, acted simultaneously as the market operator. The conflict of interest was obvious, as RAO EES would order dispatches from its own thermal stations instead of hydropower plants belonging to independent *energos*. Second, direct bilateral contracts were not permitted: all transactions had to be completed via the wholesale market. Finally, large consumers could not purchase energy on the market at wholesale prices, and had to buy energy from local *energos* at higher prices (the reason being the desire of regional political forces to support local energy producers).

4.4. Prices and profitability

As described above, wholesale prices were completely regulated. It is worth noting that tariffs were low by international standards, especially tariffs for households, which seems to be a typical situation throughout the 1990s. The World Bank (1999) provides a summary of power tariffs in Russia in different dispatch zones in 1996 (table 3). The price for industrial customers varied between 2.05 and 9.66 US cents/kWh. The lowest tariff was observed in the Siberia dispatch zone, which is endowed with large hydro resources. The households paid

[24] RAO EES company (1998).Annual report.
[25]Federal Energy Commission, Resolution No. 123/1 issued on 24.11.1997 “On the tariff son electric and heat energy (capacity)”
[26] International Energy Agency (1995), page 208.
[27] International Energy Agency (2002), page 205. See also Opitz (2000).

2.63 US cents at most[28]. By contrast, in the OECD in the same year, industry customers paid 7.38 US cents/kWh on average, and residential customers paid 14.6 US cents/kWh.

Nominal tariffs in Russia were regularly increased to adjust for cost inflation, however by the end of the decade they still remain relatively low. In 2009, the price for industry in Russia was only 4.76 US cents per kWh, whereas the OECD average was 13.90 US cents.[29]

Table 3. Power tariffs prevailing in Russia in 1996 (US cents/kWh)

Dispatch zone	**Average Tariff**	**Industries > 750 kW**	**Industries < 750 kW**	**Households**
Centre	4.33	5.23	6.71	1.33
North West	3.78	4.51	5.79	1.33
Volga	3.67	4.96	5.17	0.71
Ural	3.75	4.37	5.07	1.21
Siberia	2.05	2.05	3.90	1.11
Far East	4.95	6.79	9.66	2.63
South	4.41	6.92	7.02	1.32

Source: World Bank (1999), p. 111, table 5.

Note: the World Bank report does not specify what exchange rate was used to convert the tariffs in Roubles to US cents. Presumably, it was the current rate at the time, either the end-of-year rate or the average annual rate.

The situation with low electricity prices was aggravated by the problem of non-payment. In the very early 1990s, companies collected as little as 6-8% of the bill. By 1998, the figure had risen to 84-90%; however cash payment constituted only 17% of the total bill. The rest was paid using barter, promissory notes and offset agreements. Non-cash methods implied inadequate valuation of the underlying assets used in the agreements, which prevented the normal recovery of costs. An important part of the non-payment problem was the relationship between the *energos* on one side and the regional government and its enterprises on the other. The *energos* did not receive enough cash and were unable to pay the taxes which were

[28] World Bank (1999), p. 111, table 5.

[29] Source: Figures for OECD 1996, 2009 and Russia 2009 - International Energy Agency (2011): Energy Prices and Taxes (Edition: 2011, Quarter 4). ESDS International, University of Manchester. DOI: http://dx.doi.org/10.5257/iea/ept/2011q4

necessary to finance the public and municipal entities, who were often the worst non-payers (the phenomenon labelled “vicious circle of non-payment” by the World Bank)[30].

Finally, the low tariffs were not supported by adequately low input prices. In contrast to regulated electricity industry and energy tariffs, the markets for equipment and coal fuel were liberalised, and hyperinflation pushed up the cost of inputs. As a result, the *energos* were in constant financial deficit. The IEA report (1993) estimated the aggregate accounting losses of the industry at the time at $1.5 million, with a caveat that this figure could be even worse due to the widespread non-payment of bills[31].

4.5. Investment

As the demand for energy was low in the early 1990s, so was the demand for new capacity. The main source of financing investment needs was the one-tier tariff that included the investment component together with other costs.

The federal government introduced an investment charge in 1997specifically to finance the investment needs of the RAO EES monopoly[32]. In addition, the Federal Energy Commission became responsible for approving the part of the monopoly’s investment plan that was financed with the charge. As an example, the monopoly reported its investment cost in 1999 at $1.21 billion (nominal terms), whereas the investment approved by the FEC and thus financed by the charge was $0.17 billion, or 14% of the total cost.

RAO EES stated that the monopoly financed its capital expenditures mainly from depreciation payments (63%) and from the profits of dependent *energo* companies (15%)[33]. The contribution of the investment charge is not reported, but given other sources of financing it could not constitute more than 10%.

The total investment cost of the RAO EES was constantly increasing in nominal terms during the ‘90s, but it dropped in real terms by nearly 2/3[34].As demand was in decline, the monopoly focused mainly on refurbishment and renovation of the existing capacity.

[30] World Bank (1999).
[31] IEA report (1993) “Russian Energy Prices, Taxes and Costs”, page 76.
[32] Government resolution No. 390 issued on 03.04.1997. “On the measure to improve the formation of the investment resources in the electricity industry and on the government control of the use of the resources”.
[33] RAO EES company (1998). Annual report. The use of different annual reports is due to inconsistent reporting by the monopoly where one type of cost might be reported in one year and not in the following one.
[34] RAO EES (1999) Annual report, Section on investment and innovation. See also International Energy Agency (2002), page 203

After the demand trend reverse in 1999, electricity consumption grew by 2% for several years. Since there was no lead-in for the 90s, concerns were growing about the reserve margin and adequacy of the installed capacity. Positive demand dynamics, together with the general economic revival, pushed RAO EES to adopt an extensive investment programme. The programme was based on rather optimistic scenarios of 6% growth p.a., which was met with strong criticism. Nonetheless, when RAO EES was restructured, the programme was not abandoned, but passed, in a reduced form, onto new generation companies, which complicated the design of the electricity markets in the following reform.

5. Preparation for the new reform

The structure of the industry that emerged in 1990s was complex and non-transparent. RAO EES was a holding company in the monopoly position, and the regulatory bodies lacked the power to curb RAO's ambitions. Numerous inefficiencies of the FOREM market and the poor economic performance of the *energo* companies contributed to overall dissatisfaction. The need for reform was clear, and the discussion was open as to what measures to take to improve the situation.

The presidential decree in 1997 on the reform of the natural monopolies offered quite sensible, although mostly general, solutions[35]. In the electricity industry, the decree prescribed the unbundling of the monopoly and the creation of independent generation companies, a grid company and an independent market/dispatch operator. Market liberalisation, i.e. competitive trading, free pricing and free entry for large customers, should have been completed by the year 2000, though the plans were only completed eleven years behind schedule, in 2011.

As for RAO EES, the monopoly began by employing consultants from Hagler Baily to develop a reform plan[36]. The project envisaged that RAO EES would consolidate its thermal generation (mostly old and inefficient), but keep control over the high-voltage grid and hydropower stations (more valuable assets in the industry). The US Agency for International Development (USAID) that supported the study (as part of more general support for reforming the natural monopolies in Russia) criticised the final report, saying that it should have explained how to reform the industry, not how to reform the monopoly.

[35] Decree of the President No. 426 issued on 28.04.1997. Natural monopolies were electricity, railways, telecommunication and gas production.
[36] Xu, Yi-chong (2004), page 217.

Appointing Anatoly Chubais as the head of RAO EES in 1998 was an important step towards the reform of the monopoly: Mr. Chubais was one of the prominent figures in the economic reforms of the early '90s, and 'the industry welcomed Chubais as the head [...] because it wanted somebody who had both management competence and political influence in the government'[37].

Discussions on the reform are summarised in the report by the Russian State Council (April 2001). The report outlines the main concepts proposed by the Ministry for Economic Development, by RAO EES and various institutions and think-tank groups, for a total of eleven concepts. Both the Ministry and RAO reform plans offered the following:

(i) to keep the holding company;

(ii) to create generation companies and endow them with hydropower and thermal stations and CHP, but keep these companies as subsidiary properties of RAO EES;

(iii) to keep the *energo* companies (the report is a summary and does not provide details what generation assets would be left to the *energos*).

RAO EES suggested that the transmission grid (both the high and low voltage networks) should be consolidated as a grid company-subsidiary of RAO EES, but the Ministry insisted that the grid company should become a separate entity, both in terms of ownership and management.

Most other reform concepts were similarly minded. The authors offered partial divestiture of RAO EES generation assets and *energo* companies, but kept the vertically integrated structure of either RAO or the *energos*. Only two plans recommended the full unbundling of RAO and the separation of power plants, the grid and distribution networks[38].

The State Council report also summarises international experience of reforms in the electricity industry, more specifically the cases of England, Nordpool, PJM, California and Argentina. The summaries are diverse, with a focus on different aspects of the reform in each case (industry structure in England, customer switching in PJM, regulatory issues in California, etc.) The report concludes that after divestiture and market liberalisation new generation

[37] Xu, Yi-chong (2004), page 171.
[38] Concepts 4 and 6 as numbered in the report of the State Council (2001). The first plan was presented by the National Investment Council, non-government non-for-profit organisation that aims to improve the investment climate in Russia. The second plan came from the RAO EES competitor, the nuclear generation company Ros*Energo*Atom.

companies generally seek to consolidate their assets (by mergers and acquisitions) and integrate their business (upstream, to gain control over fuel supply companies, and downstream, to gain control over retail suppliers).

Among the key elements of the reform, the report lists the financial separation of generation/transmission/retail, the independent status of the regulatory body, the system (dispatch) operator and commercial operator, and the creation of the proper markets. However, the same list of key elements stipulates that vertically integrated companies guarantee the stability of supply, that asset consolidation ensures competition, a lower cost of production and higher investment returns.

The time-lapse between the presidential decree of 1997 and the final report by the State Council of 2001 gives an idea of the lengthy discussions and the underlying difficulties in finding a suitable reform plan. The State Council report shows that most opinions were in favour of maintaining the status quo, possibly with slight modifications, rather than profoundly transforming the electricity industry and design of the markets.

In the light of strong opposition to the reform, the final list of measures as listed in the Government resolution (July 2001)[39] should be regarded, perhaps, not without surprise. The document mentions the following as the main components of the industry reform:

- Competition in energy production and supply (implying the separation of generation from distribution);
- State monopoly over the transmission and dispatch service;
- Equal access to market infrastructure for any producer or consumer;
- Unified technical standards and rules;
- Financial transparency in the markets and regulated sectors of the industry;
- Protection of investors' and shareholders' rights during the restructuring.

The first phase of the reform saw the adoption of two major laws in March 2003:no. 35-FZ "On the electricity industry" and no. 36-FZ "On the electricity industry in the transition period". The main law on electricity defined the principles of the network functions, dispatch service, regulatory framework and rules of the wholesale market. The law on the transition period stipulated the priority order of legal acts that could become contradictory during the divestiture of the monopoly. Other notable changes in the legislation included the

[39] Government resolution No. 526 issued on 11.07.2001. Also enlisted by Xu, Yi-chong (2004), page 222.

modification of the Civil Code and of the laws on natural monopolies, on state regulation of the tariffs and on energy conservation.

Subsequently, as the reform was unrolling, RAO EES announced its revised reform programme, dubbed “5 plus 5”. The plan divided the reform into two stages, each five years long (hence the title).The first block of measures planned for 1998-2003included finalising the new market structure and the adoption of necessary legislation, including acts on regulation, tariff setting and wholesale market rules. The second phase of the reform in 2003-08 envisaged the actual restructuring of the industry, with the dismantling of RAO EES, vertical disintegration of the *energos*, and the creation of independent generation companies.

In the programme, RAO EES emphasised the need for higher efficiency in power generation and stability in energy supply.[40] It was further declared that the unbundling of the vertically integrated companies and creation of the competitive markets was necessary to improve the situation and to attract private capital into the industry. RAO EES admitted that the government was an inefficient manager and proclaimed that only private investors would have incentives to lower the production cost.

The final programme published by RAO EES is in line with the general principles of the electricity market liberalisation and contrasts the initial plans and concepts of limited restructuring. However, the actual course of the reform, in particular the ownership structure that emerged, has demonstrated that opposition to liberal markets is quite strong and the whole process of industry liberalisation might be at risk of slowdown or even reversal.

6. *Liberalisation reform in 2003-08*

The reform of the electricity industry took several directions. The monopoly was dismantled to create private generation companies, whereas the dispatch and grid operators were transformed into two (separate) state monopolies. The regulatory framework was amended and clarified, and finally the wholesale and retail markets were introduced. An important part of the reform was the investment programme and the development of capacity mechanisms.

[40] RAO EES company. Reform Strategy Concept. http://www.rao-ees.ru/en/reforming/conc/show.cgi?con2003.htm#2 [accessed on July, 1st, 2012].

The unbundling of the monopoly is a typical step towards industry liberalisation. In Russia, the total number of generation companies created was above twenty, which contrasts with the case of other markets with just a few companies. The large number reflects the size of the Russian ESI, the geographical scope and the need to ensure competition not only at a national level but also in the regions. The functions of the grid operator and the system operator are separated (cf. the case of an Independent Transmission Operator who is also in charge of dispatch), which also reflects the size of the industry and the associated degree of responsibility.

The wholesale market for electricity was created almost from scratch (including a market-clearing mechanism to compute prices and quantities, bilateral contracts, financial markets etc.). The baseline model relies on locational marginal pricing rather than on unique national or zonal prices. The retail market has been partially de-regulated, with household tariffs still under stringent government control.

Finally, the RAO EES investment programme was ‘imposed’ on the newly-created generation companies with a special kind of guarantee of investment returns. The capacity market was introduced, though investment obligations complicated the design. Moreover, the new capacity market is subject to severe regulation, which means that market trading has been virtually replaced with government planning and control.

6.1. Price zones and generation mix

Before discussing the restructuring of the industry, it is useful to describe changes in market zoning (important when designing the composition of new generation companies). As a result of the reform, the zoning of the Russian electricity market has become more complex[41]. The dispatch zone formed the basis for the pricing areas of the wholesale market. The first five dispatch regions (North-West, Centre, South, Volga, and Urals) are united into the Europe price area. Two administrative regions in the North-West dispatch area are excluded from the market due to weak transmission links. They are combined into the non-pricing zone 1, which is regulated by the government. The Siberia dispatch region is left as a second single price area and the Far East remains under regulation (non-pricing zone 2). The map of the dispatch zones and the price areas is given as figure 5.

[41] Zones not mentioned here include those of the Federal Grid Company and those of the holding distribution company. Neither of these zoning schemes coincides entirely with the dispatch regions.

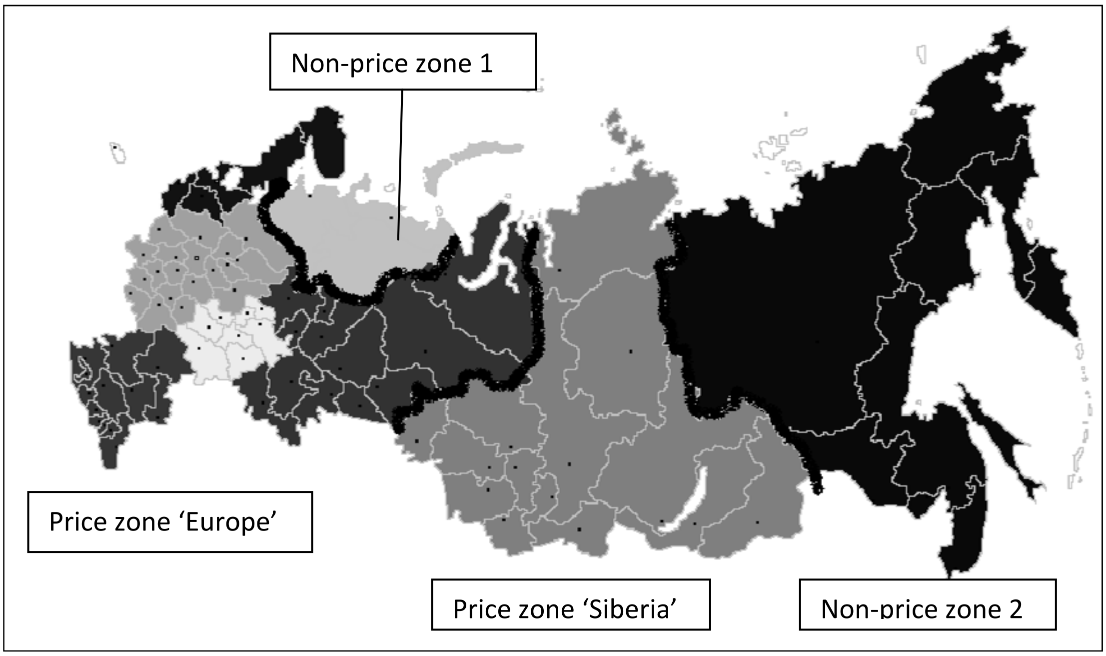

Figure 5.Russian wholesale market. Pricing and non-pricing zones.

The total installed capacity of the industry in 2010 reached 230 GW. The overall generation mix in the industry has largely remained unchanged. The European price area has 144 GW, and the Siberia price area 39.5 GW (the rest belongs to the non-pricing zones). The distribution of generation by type in each area is shown in figure 6. The 'European' zone houses all three main types of technology, with predominantly gas-fired thermal stations. The 'Siberian' zone does not have nuclear stations, yet it is rich with hydro resources and its thermal power plants are mostly coal-fired.

The two pricing zones are further subdivided into 28 free flow zones (FFZ), of which 6 belong to Siberia and 22 are located in Europe. The zones are defined on the basis of transmission constraints. Inside the FFZ, energy trading is not limited, but the flow between the zones inbounded by the capacity of major transmission lines. The transmission constraints for electricity flows and capacity flows are different. Given the geographical location of the FFZs, only 102 export-import lines can possibly exist. Data from the Commercial Operator shows that eighty-five lines are currently active (with positive flows on several days in the year).

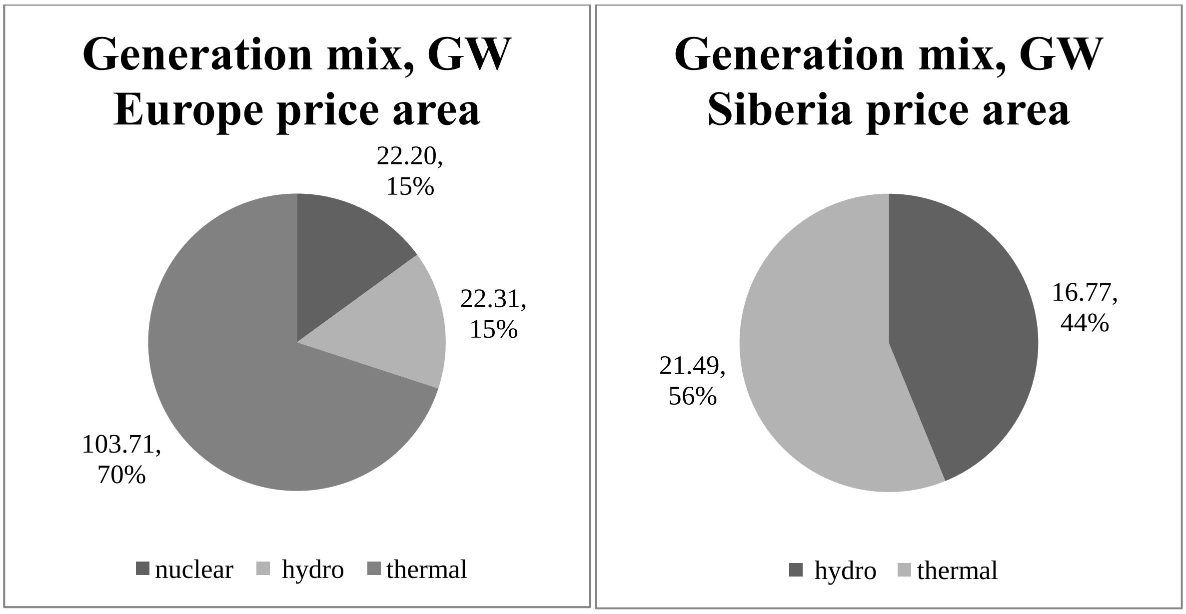

Figure 6. Generation mix in 2006 (a) Europe price area; (b) Siberia price area.
Source: Agency for Forecasting the Energy Balance (2006). «Functioning and development of the electricity industry in the Russian Federation" [in Russian].

Most FFZs span one or several administrative regions of Russia, but a few regions are split between two FFZs. Following national grid development, four of the zones will be integrated with their larger neighbours by late 2013, and another two zones will be integrated by the following year, so that the total number of FFZs will reduce to 22.

The size of the free flow zones varies greatly. The smallest FFZ (#22) in the south of Russia has only 75 MW. The largest are FFZs #1, #7 and #24, located in Siberia (26 GW), near the Ural mountains (22.4 GW) and in the European part of Russia (26.6 GW), respectively. The small size of many zones limits competition in the capacity market, and the Federal Anti-Monopoly Commission introduced a price cap in all but three of the aforementioned large FFZs.

6.2. Unbundling the monopoly

A cornerstone of any ESI reform is creating competition where possible, i.e. in generation and retail supply, while maintaining regulation where competition cannot be achieved, i.e. natural monopolies of transmission and distribution. Post-reform development of many electricity markets highlighted the need to design new generation companies in such a way as to avoid market power abuse on the market, either at the national or a local level. The England and Wales Pool was exposed to market power abuse by the two largest companies National Power and PowerGen until they were required to divest some of their generation assets (Newbery

2002). The Spanish ESI restructuring did not involve strict ownership separation in generation, distribution and upstream fuel production, but only the separation of accounts, so the market is highly concentrated, with the two major firms, Endesa and Iberdrola, controlling over 70% of generation assets.

Since the Russian electricity industry is on a larger scale than any other European market, having a few dominant companies would greatly exacerbate the market power problem. Consequently, the composition of new generation companies, or in other words the distribution of existing power plants among them, had to be carefully designed. Apart from geographical location, technology (in particular combined heat and power - CHP), fuel use and plant size must also be considered. The specificity of CHP means that local monopolies on energy production cannot be entirely avoided and some companies end up endowed with groups of local CHP stations.

The hydropower station represents a large fixed asset, with a significant fixed cost (as compared to thermal power plants). There was political fear that no private investor would be able to properly finance the maintenance expenditure, hence the idea to keep the sector under government control. The initial plan of the reform was to create four companies, one per hydro-station cluster, but eventually one state-owned company was formed. The company now manages the plants in Siberia, in the Volga region and in the south of Russia. The stations in Karelia were transferred to a private generation company (TGC-1).Nuclear generation remained under government control, albeit reorganised from a government agency into a state-owned company.

The restructuring of the industry was largely completed by 2008, when the new companies were legally singled out of the monopoly and RAO EES ceased to exist as a separate entity. The current structure of the wholesale market incorporates generation companies, large business customers and retail suppliers. The market is run by the Administrator of the Trading System (as Commercial Operator) and the System Operator. The ATS is broadly responsible for the electricity market and for commercial transactions between market players. The System Operator surveys the technical parameters of the system and organises the capacity market. Large business customers (with aloud above 750 kVA) are entitled to enter the wholesale market directly and buy electricity from the generation companies. The retail suppliers sell the energy to residential and small business customers.

After reforming RAO EES, the following companies were created:

- 6 wholesale generation companies. Each consists of large thermal stations only, which are dispersed across the country, i.e. in different free flow zones. The WGCs have between 8.3 and 9.2 GW.
- 14 territorial generation companies. Each company spans one or several administrative regions and is typically located within one free flow zone. Assets include small thermal stations, small hydro stations, combined heat and power plants, and district heating boilers. Installed capacity of the TGCs varies from 600 MW up to 11 GW.
- RusHydro - a state-owned generation company that controls the hydro stations of Russia (25.5 GW in total).
- RosEnergoAtom - a state-owned company that manages ten nuclear stations of 22.25 GW in total.
- InterRAO - a state-owned company that has monopoly over the export-import operations and owns a number of small plants near the state borders.

The independent *energo* companies continue to operate on the restructured wholesale market. To comply with the industry reform, the companies had to divest generation and network and form legally independent entities (ownership of capital has not been completely separated). The companies are NovosibirskEnergo, IrkutskEnergo, TatEnergo, and BashkirEnergo. Their total capacity is 26.7 GW.

Despite efforts to create ex ante competition, the new industry structure looks quite concentrated. The HHI based on installed capacity varies from 1,466 up to 10,000 across the free flow zones (these zones are critical for the capacity market; see below). The median value is 3,914. Out of 29 free flow zones, only six have an index below 2,500 - these zones are large in size and have a sufficient number of producers. Three FFZs have only one station each.

As for the owners of the new generation companies, the main stakeholder turns out to be the federal government. The WGC-1 did not attract private investment and remained a state property. The second and sixth WGCs were bought by Gazprom, the gas monopoly, and later merged into a single company. The major shareholders of the Third wholesale company became Norilsk Nickel (a Russian ore producer). The fourth and fifth WGCs were sold to

E.On (Germany) and Enel (Italy), respectively. Some of the territorial generation companies were acquired by Gazprom, including one of the largest – MosEnergo (or TGC-3). The private energy holding IES secured control of capital in four TGCs (numbered 5, 6, 7 and 9), as well as minor shares in other generation companies. Only one foreign company invested in TGC: Fortum (Finland) bought shares in TGC-1 and secured full control in TGC-10.

The merger and acquisition wave that followed initial restructuring narrowed the pool of investors. The lead part in the merger wave belongs to state-owned companies Gazprom and InterRAO. Gazprom merged its two subsidiaries (the Second and Sixth WGCs) into one company. InterRAO, initially a small producer, acquired controlling shares in the first and third WGCs, as well as in TGC-11 (with 19.6 GW in total). The company also has non-controlling but significant shares (20-40%) in five other companies, with a total capacity of 35.2 GW. All the merged or acquired companies are located in different market zones, so the post-merger HHI did not change much, with the lowest value now being 1,628 but the median value remaining the same 3,914. Yet, the situation might change if and when some zones are integrated with each other (as a result of grid development).

To summarise, despite extensive privatisation the government controls directly or indirectly, via Gazprom and InterRAO, over 50% of the newly created companies. The remaining capacity is distributed between a few private shareholders. Given the high concentration of ownership, it is doubtful whether the declared goal of developing competition in the industry has been achieved.

6.3. Transmission and distribution. Last-mile contract.

The transmission network was subject to substantial restructuring during the reform. Two companies were singled out of the RAO EES monopoly and the former *energo* companies. The first, the Federal Grid Company (FSK, in the Russian abbreviation), became responsible for the high-voltage grid (330kV and above), but also for the 220kV lines that were transferred to it from the former *energos*. The second company, Holding MRSK, is in charge of the distributional network across the whole country (lines of 150kV and below). Holding MRSK is not an integrated company but consists of 11 regional distribution companies (labelled MRSK in Russian). Both companies belong to the federal government[42].

[42]FSK and Holding MRSK have recently been merged into one company "Russian Network", thus the entire network has been consolidated.

There was no special regulation of the transmission charges within the RAO EES monopoly. However, two network companies, being both natural monopolies, necessarily require explicit price regulation for the service they provide. The Federal Tariff Service (a new regulatory body in lieu of the FEC) now approves the relevant tariffs, which are the connection charge and the transmission charge.

The connection charge is paid only once by the consumer, depending on the amount of load added to the grid. The payment only covers the direct cost of linking a new customer to the nearest substation. The tariff for connection is pre-set for the low-voltage network and small load (i.e. small businesses and households). The charge for larger customers depends on the amount of load, the grid voltage and other technical parameters, which leads to almost individual pricing. There have been numerous complaints that the resulting connection cost is often too high, to such an extent that some industrial users find it more profitable to build their own generator and sell the residual energy to small local consumers[43].

The tariff for transmission was until recently set on a cost-plus basis. From 2010 the Federal Grid Company and some distribution companies moved to the RAB-based tariffs[44] that allow faster recovery of investment expenditures. Currently, the norm of the investment return for these companies is set at nominal11%. As a result of the RAB-methodology, transmission charges have increased significantly, which in turn translate into the upsurge of retail tariffs.

The pricing for connection and transmission, apart from being unclear and excessive, hides another problem, that of the cross-subsidy. Before the reform, higher wholesale tariffs for large customers were established, so as to subsidise residential energy consumption. With the wholesale de-regulation of the market, a price distortion could no longer be implemented, so the cross-subsidy scheme became more sophisticated. The scheme is now known as the last-mile contract and the practice is officially fixed by a Government resolution[45].

Most industrial users are directly connected to the high-voltage transmission grid, which belongs to the Federal Grid Company. Normally, the user would pay for the relevant transmission to the grid company at its tariff. Now, the last mile of the high voltage grid is rented out to the local distribution network. The user is forced to pay transmission charges to

[43]Business World Agency. 25th January 2010 “Rossiya: Proryv Tarifa” [in Russian; accessed via Factiva]

[44]The Federal Government and the Federal Tariff Service have already adopted the necessary legislation, and some regional distribution companies have tried using the new method. http://www.holding-mrsk.ru/clients/rab/ [in Russian]

[45] Government resolution No. 1173 issued on 27.12.2010 “On the lease of the objects of the national electricity grid to the territorial network companies”.

the distribution company at the appropriate tariff, which is generally higher than that of the grid company. Thus, extra revenue is generated simply from the difference in tariffs, and the revenue goes to the distribution company to keep the prices low for households. The amount of cross-subsidy in 2010 is quoted as varying from 60 to 200 billion Roubles ($2 to $6.7 billion)[46]. Some industrial consumers tried, successfully or not, to appeal in court against the obligation of the last-mile rule, hoping to enforce a direct contract with the Federal Grid Company[47].

6.4. Fuel supply

There are two main features of fuel supply in the Russian ESI. First, the gas industry is dominated by a monopoly under government regulation (for both prices and volumes of consumption), which obviously distorts the fuel markets. Second, vertical integration between fuel suppliers and some generation companies was not prevented at the privatisation phase and it appears to create favourable conditions for some generators (although the benefits of integration appear to be outweighed by other negative factors).

Roughly 70% of generation in Russia is thermal; two thirds of it is gas-fired while the rest is coal-fired (hard coal or brown coal). Coal mines are found predominantly in southern Siberia (Kuzbass area) and in north-eastern Kazakhstan (Ekibastuz mines), so most coal-fired stations are concentrated in the south of Siberia. Gas-fired power plants dominate the European part of Russia, supplied by a developed pipeline network from major gas fields found in the north areas of Siberia. The gas industry in Russia is monopolistic and the prices are regulated by the government, whereas the coal industry is oligopolistic and operates mostly under long-term privately negotiated contracts.

The gas industry is dominated by Gazprom, a state-owned monopoly, with the remaining supply being produced by smaller gas and oil companies (associated petroleum gas). The electricity supply industry consumes c. 43% of total gas production (Gas strategy 2030); Gazprom supplies c. 28% of its production to the ESI. Gazprom prices, or tariffs, are regulated by the government and are differentiated by region. According to various estimates, the tariffs are too low compared to their European counterparts (the so-called "netback value"

[46] Various estimates were quoted in the media but no formal calculation was ever presented.
[47] Successful publicised case of the legal battle against the last-mile contract is the Rusal aluminium company vs. MRSK (distribution company) of Siberia. Unsuccessful case is the SUAL coal company vs. MRSK of Ural.

comparison, see Tsygankova 2008, Stern et al. 2009)[48].Gas consumption is regulated by the government: any customer, including power stations, has a pre-set annual amount, which it prices at the tariff level. Any amount above the quota can be purchased from Gazprom at commercial (negotiated) prices or from independent suppliers. The proportion of quota (or limited) gas, commercial gas from Gazprom and gas from independent suppliers varies greatly from one generation company to another.

At the start of privatisation of RAO EES, the government signed five-year contracts between Gazprom and generation companies, which in the short-term secured the positions of the gas monopoly in the electricity industry. However, many generation companies complained about Gazprom's inflexible price policy: the gas monopolist insists on “take-or-pay” contracts and charges highly for above-quota gas. Not surprisingly, when the contracts expired some generation companies preferred to switch to alternative suppliers: WGC-1, WGC-5 and TGC-10 signed long-term agreements with independent gas producers, Novatek and Rosneft. Interestingly, MosEnergo (TGC-3), controlled by Gazprom, also switched part of its supply (roughly 1/3) from Gazprom to Novatek.

Whether low gas tariffs are problematic in the long-run is an open question and is related to issues of plant efficiency and carbon policy. Low tariffs influence investment decisions by stimulating construction of gas-fired power plants. However, existing thermal plants in Russia, whether coal-fired or gas-fired, typically have low to moderate thermal efficiency, up to 40-42%. New owners of generation companies invest in CCGT technology with high efficiency, which is more resilient against gas price increases or possible carbon taxes. Owners of coal-fired power plants also aim at improving efficiency, and may be more competitive should the gas market be liberalised (although not so competitive if carbon taxes were introduced in the industry).

Lower gas tariffs in Russia, as compared to domestic coal prices to European export gas prices, give the existing (relatively inefficient) thermal generation in Russia a great cost advantage. The entry of efficient and compact CCGT power plants which was observed in many port-reformed markets elsewhere is practically absent in Russia: the share of the CCGT-based capacity is c. 3-5% of the industry and would probably remain at this level for the next decade.

[48]Although there are objections to these estimates that in gas-abundant Russia gas tariffs may be lower than gas prices in gas-deficit Europe, there is no reason why gas should be cheap per se, e.g. in extremely cold winter the gas price might be very high.

In addition to gas market distortions, vertical integration between fuel suppliers and generation companies may act as yet another impediment to the development of the electricity industry. The integration process works both ways: fuel producers acquire control over generation companies, while some generation companies buy fuel sources (e.g. coal mines). Examples of the first type of integration have already been presented: Gazprom invested heavily in generation companies (WGC-2 and 6, TGC-1 and 3); the Russian coal company SUEK acquired shares in TGC-12 and TGC-13; the holding company IES controls both generation assets as well as the gas and oil producer company TNK-BP which facilitates fuel supplies from TNK-BP to generation companies. An example of the second type of integration is given by WGC-3, which bought a coal mine near one of its stations. The coal mine and the station were built in the Soviet period as two parts of one technological process, the coal mine and the station thus being in a monopoly-monopsony relationship.

Given the monopoly on the gas market, vertical integration between fuel producers and generation companies may put at risk competition in the long-run. Gazprom, as the owner of generation companies, secures its supply, but may prevent its subsidiaries from finding the most efficient solutions, and thus limit overall potential for improving market efficiency. Moreover, as the sole owner of the gas pipeline network, Gazprom may constrain the supply of independent producers if it feels that they threaten its own positions on the gas market.

6.5. Retail companies

The retail suppliers were formed from the remainders of the *energos* and kept the term '*energo*' in the title. Their primary role is electricity sales to residential and small commercial customers. Like the energy sold to large consumers, the energy sold on the wholesale market to a retail supplier *and* designated for smaller commercial customers, can be priced in a free manner. The energy sold to a retail supplier *and* designated for households is traded under regulated contracts. Consequently, the Federal Tariff Service continues to set wholesale tariffs for any power station as it might (and would eventually) supply residential demand. Note that the tariff is not a price cap, as it applies to the whole volume of such demand.

As for the price customers pay, households are charged an average tariff based on energy consumption and capacity needs. The tariff for households is set by regional energy commissions. Small commercial customers may choose one-tier (average) or two-tier (separate) pricing, as well as time-differentiated or time-uniform pricing, subject to installing necessary metering equipment. The prices vary depending on the amount of energy contracted (e.g. 4500 or 6500 MWh per year) and on the possibility of paying for deviations from the scheduled consumption.

Each administrative region of Russia has one or several guaranteed retail suppliers who cannot refuse to provide energy to any customer (as opposed to non-guaranteeing/private suppliers). Currently, any region has 2-4 guaranteeing suppliers, which provides a basis for competition among them (not only vis-à-vis private retail companies). The competition matter is quite important, as guaranteed suppliers currently buy up to 75% of electricity on the wholesale market on a winter day and 58% on a summer day.

As for ownership, the consolidation of assets anticipated in the early reform plans gradually took place. Direct ownership of retail companies by generators is not permitted, but the shareholders of generators may acquire the capital of retail companies.

The financial situation of the all-retail suppliers is under constant risk because of the cash gap. Payments to the wholesale market have to be cleared the next trading day, whereas retail customers have 45 days to pay their bill. Suppliers have to rely on credit lines, and include interest in the retail price.

The guaranteeing suppliers still suffer from the non-payment issue. Since they cannot refuse service to any customer, the latter might abuse their rights and delay bill payment as long as possible. Often, such problematic customers are local authorities and municipal enterprises who cannot be disconnected from the grid for the reason of social security.

6.6. Advances in regulation

To improve the regulatory mechanism, a new body, the Federal Tariff Service (FTS), was established in 2004[49]. In the electricity industry, the FTS replaced the Federal Energy Commission and became broadly responsible for the same amount of work: setting guidelines for tariff formation, as well as the tariffs themselves. The Federal Tariff Service preserved the two-tier structure of tariffs, so that the electricity tariff reflects the variable cost of production whereas the capacity charge (increased substantially in comparison with the fixed part of the tariff in ‘90s) covers the replacement cost of the equipment.

The Regional Energy Commissions (RECs) have been preserved, although their privileges have been greatly reduced. To avoid huge discrepancies in tariffs throughout the country and

[49] Government resolution No. 332 issued on 30.06.2004 “On the Federal Tariff Service”.

between neighbouring regions, FTS now sets maximum and minimum tariffs for each region, so that a REC can only adopt local tariffs within the prescribed limits. In this way, FTS, being the regulator of a single market, enjoys much broader authority over local regulators, unlike e.g. FERC in the United States, where FERC is responsible chiefly for the general oversight of multiple electricity markets and inter-market communication.

Although the FTS advanced tariff-setting procedures and regularly increased nominal tariffs, the issue of cost recovery was still critical. According to the author's estimates[50], electricity tariffs for power stations might constitute only 50-90% of actual operational expenses. It appears that wholesale tariffs were, in general, insufficient to cover the variable costs of the generating companies. The issue was not resolved, but rather 'disappeared' from the agenda, when the market was liberalised and moved to free pricing. However, initially low tariffs led to unavoidable price increases, which provoked dissatisfaction and criticism among public and political forces, albeit without much practical consequence.

6.7. New wholesale market: liberalisation and trading rules

An important part of the reform was the re-organisation of the wholesale market ***F***OREM (***federal*** wholesale electricity and capacity market) into ***N***OREM (***new*** [...]), under the supervision of the newly created non-profit partnership Market Council. The new market began its operation in September 2006 (initially with trading under tariffs only).

The market design had to be completely revised. The system created in the 1990s gave priority to dispatch rules that balanced the physical flows of electricity, whereas the energy exchange served only as a place for clearing payments at regulated prices. Although called a market, such a system did not allow for the free choice of a counterparty, prices or quantities to buy/sell, and hence was obviously inefficient. The aim of the reform was to introduce proper trading, where the players would have freedom both in making bids and/or signing bilateral contracts, and where the dispatch schedule follows their choice.

The Market Council, in conjunction with the Administrator of the Trade System (Commercial Operator) and the System Operator, elaborates the rules and procedures both for energy and capacity markets. Electricity trading now takes place on the one-day-ahead and balancing (or real-time) market. Capacity is traded separately in annual auctions with monthly prices. There

[50]Unpublished Master thesis. Estimates were made for the six power stations of the Third Wholesale Generation Company (WGC-3).

is a special market for ancillary services, where generators that satisfy technical requirements can sell spinning reserves and other similar services. Finally, the financial markets (futures trading) were launched in 2007, but these are not very liquid. The development of financial transmission rights is still an undecided matter.

The wholesale market for energy has been fully liberalised since January 2011. Before that, some fraction of the electricity traded had to be sold under tariffs. The liberalisation was launched in January 2007 with 5-15% of energy traded freely on the market[51]. The share of the regulated sector had to decrease every six months (see figure 7)[52], although the actual pace of liberalisation somewhat slowed down by the end of the transition period, so the final liberalisation of the electricity market is a success of the reform.

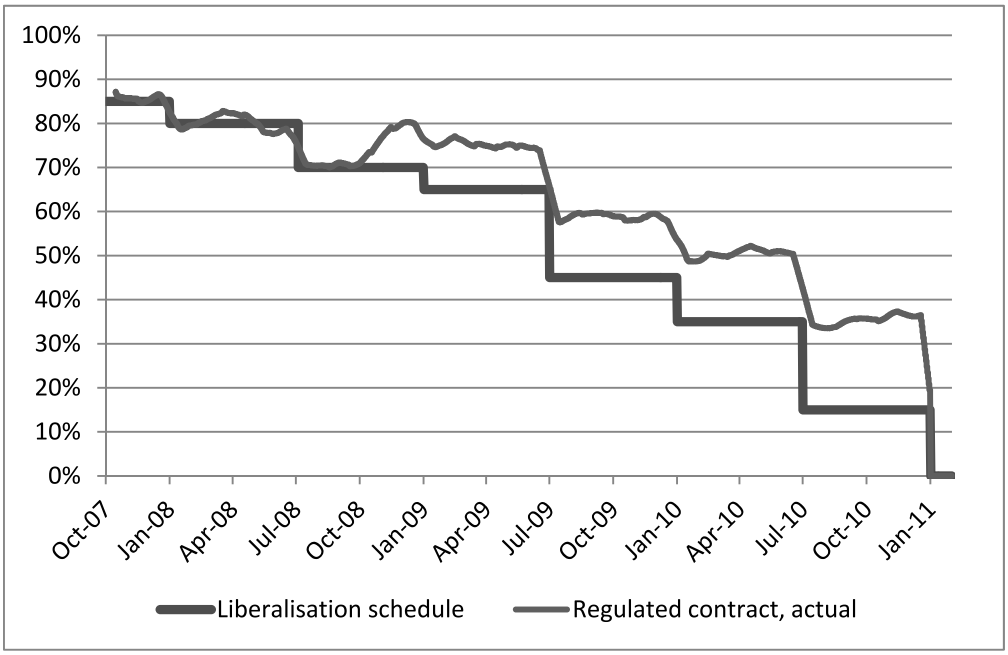

Figure 7. Liberalisation schedule and the actual pace of liberalisaiton of the wholesale market. Source: Russian government, ATS Energo (Commercial Operator).

The retail market that serves commercial customers has been deregulated in the sense that consumers can now freely choose their suppliers, and negotiate price and quantity. The guaranteed suppliers, however, continue to charge regulated prices that are set by the regional authorities. The electricity that retail suppliers buy on the wholesale market for households is still sold under regulated tariffs, and the total volume of such contracts constitutes around 15% of the market, which matches the share of the residential sector in terms of total

[51] The fraction of the free sector is taken with respect to the 2007 annual industry production. All new stations led in after 2007 sell energy to the free sector only.
[52] The liberalisation schedule was approved by the Government Decree No. 643 issues on 24.10.2003.

electricity consumption, namely 16% (cf. 26% in Europe). The liberalisation of the retail market that serves households was planned for the year 2011, but was postponed until 2014 (and there is a risk of further delay).

Market players can privately negotiate free contracts for energy, with a fixed or variable supply schedule. Free contracts can be used to cover regulated sales, and may include both energy and capacity. Standardised free contracts are traded on the Moscow Energy Exchange[53].

Non-contracted energy is offered on the day-ahead market[54]. Market participants must submit bids to the ATS by 13.00 Moscow time the preceding day, and the System Operator provides the relevant technical information. ATS then solves the computational model for the 24 hours of the following day to define equilibrium hourly prices and quantities. ATS returns the individual results to the market players by 16.00; the final aggregate data is published on the ATS web-site by 19.00. The balancing market operates on the day of actual energy production and consumption, and the financial settlement takes place the following day.

On the day-ahead market, generators are required to bid at variable cost (in particular for fuel expenses)[55], while the fixed cost is recovered on the capacity market. A specific variable generation cost (e.g. start-up time, minimal running time) is not incorporated into the price component of the bid, but comprises the third part of the bid. The Federal Anti-Monopoly Commission is entitled to monitor bidding and may (indeed, does) impose fines on those violating the rule[56].

Given the large scale of the industry and the territory, the computational model is based on nodal pricing, or equivalently locational marginal pricing, LMP. The total number of nodes is around 7000[57]. The model incorporates price-quantity bids, the forecast of consumption, transmission constraints and various technical requirements (minimum production, ramp-up speed etc.) Given the consumer bids $\mathbf{<b^{cons}, Q^{cons}>}$ and producer bids $\mathbf{<b^{prod}, Q^{prod}>}$, the objective function is formulated as $\mathbf{\Sigma_i (b_i^{cons} * P_i^{cons} – b_i^{prod} * P_i^{prod}) \rightarrow max \{P_i^{cons}, P_i^{prod}\}}$,

[53] http://www.arena-trade.ru/eng/
[54] Regulation No. 7 of the NOREM "Competitive selection of the price bids for the day ahead"
[55] Irish electricity market has a similar requirement, see Bidding Code of Practice (2007), Single Electricity Market Operator (Ireland), available at [www.allislandproject.org/GetAttachment.aspx?id=6ce5b381-927e-4e4f-8642-341d53985720]
[56] Successful cases against TGC-11 in 2008, MosEnergo in 2009 and BiyskEnergo (a small IPP) in 2010.
[57] The System Operator lists around 5700 nodes (by index), see, for example, http://monitor.so-ups.ru/Files/File.aspx?id=439. Approximately extra 2300 nodes are introduced in the model as 'dummies'.

where summation is over market participants and 24 hours and "P" is the optimal level of consumption and generation. The model therefore aims at satisfying as much demand as possible while producing as little as possible (conditional on the bids submitted)[58].

Each node is assigned a balance constraint that equals inflow to the node plus production to the consumption. The Lagrange multipliers to the balance constraints are interpreted as nodal prices since they reflect the cost of meeting the marginal MW of net demand. The Lagrange multipliers are also computed for the capacity transmission constraints. The multipliers are interpreted as congestion prices for each transmission link, and if the link is congested the price is positive.

6.8. Output and prices[59]

The total annual amount of energy produced in the industry in 2010 was 1025 TWh; the bulk of which, 949 TWh, was traded on the wholesale market. The Europe price zone accounted for 78% of market volume and Siberia price zone accounted for the remaining 22%. The peak season in Russia is winter; the highest hourly production is around 115,000 MW in 'Europe' and around 30,000 MW in 'Siberia' (figure 9). Thermal production accounts for roughly 70% on the peak hour (figure 10).

The nodal price variation accross both zones is quite significant (figure 11). Although nodal prices drop occasionannly to zero during nights and weekends, the maximum nodal price might be five times as large as the average zone price.

[58] The algorithm defines a unique price, unlike, for example, in the PJM market where LMP consists of the three components, system marginal price, transmission congestion cost and cost of marginal losses.

[59]All the figures in this section are sourced either from the web-sites of the ATS (commercial operator) or the System Operator.

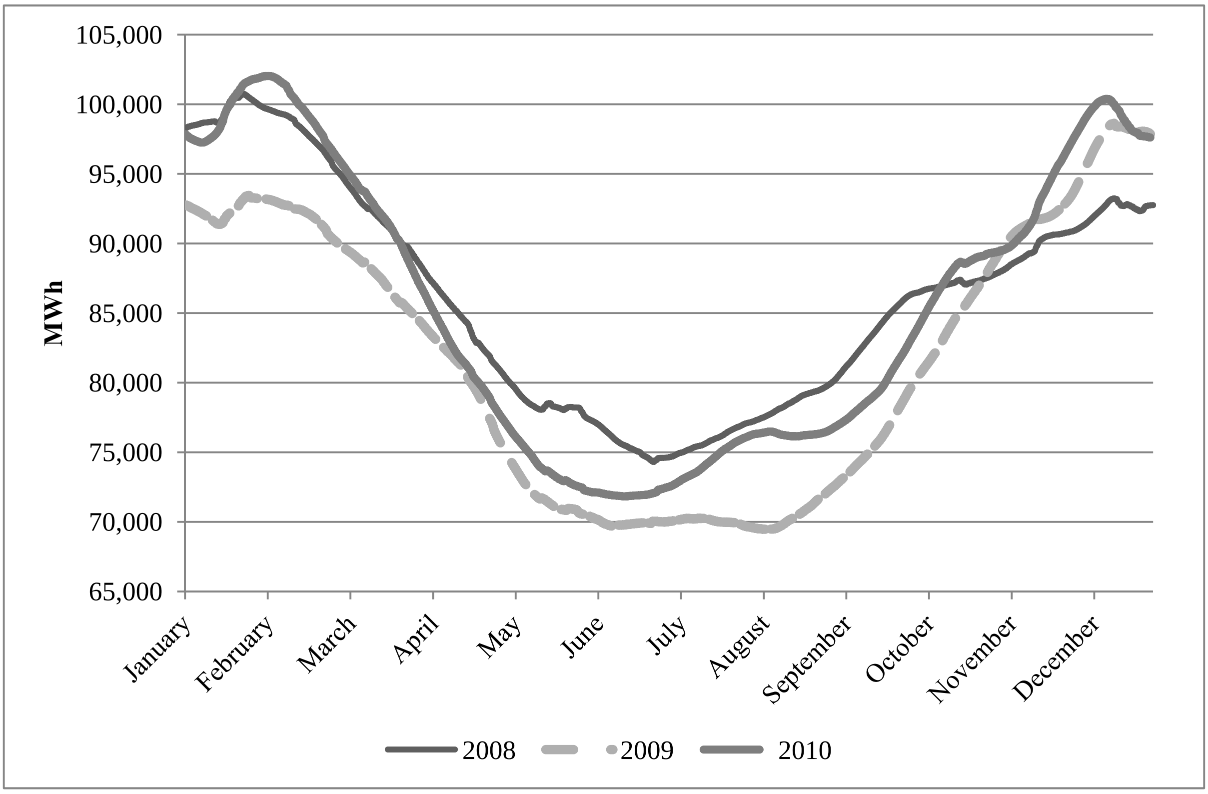

Figure 9a. Europe price zone. Trading sell volumes, MWh, moving average (28 days).

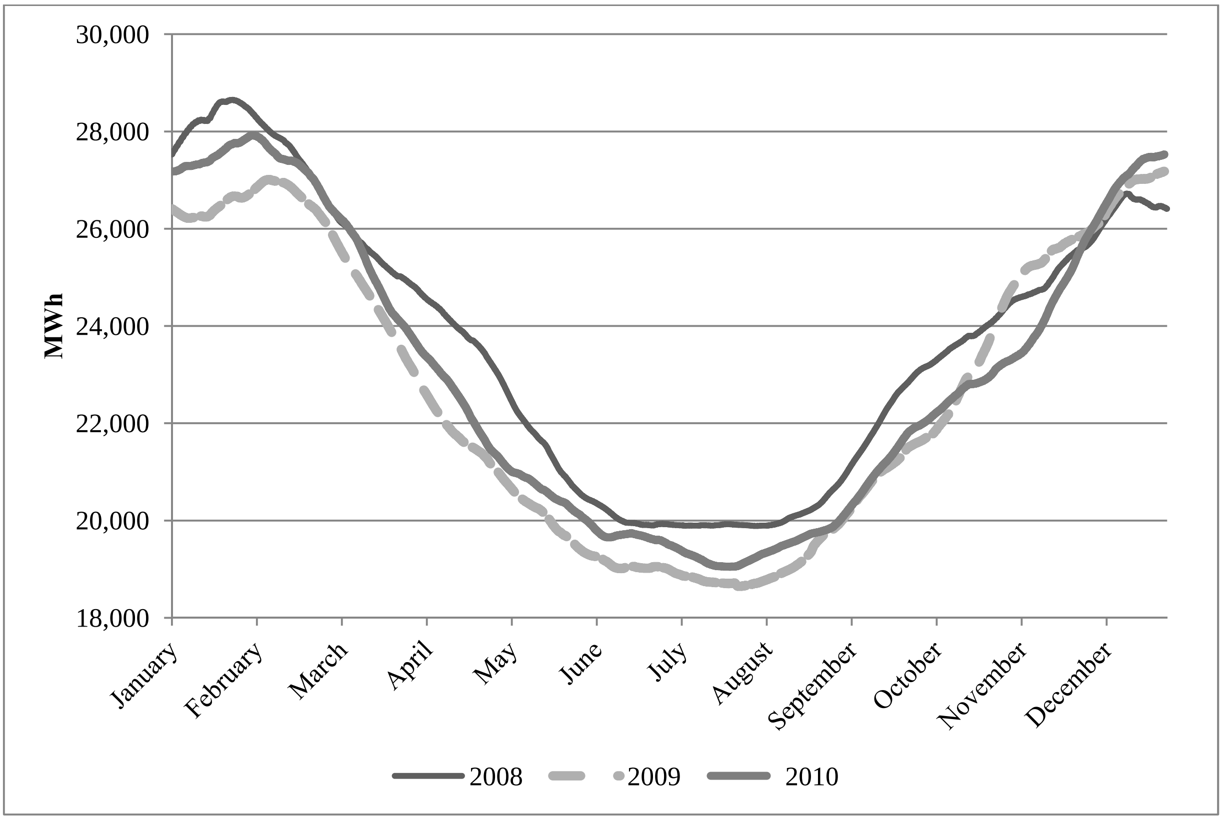

Figure 9b. Siberia price zone. Trading sell volumes, MWh, moving average (28 days).

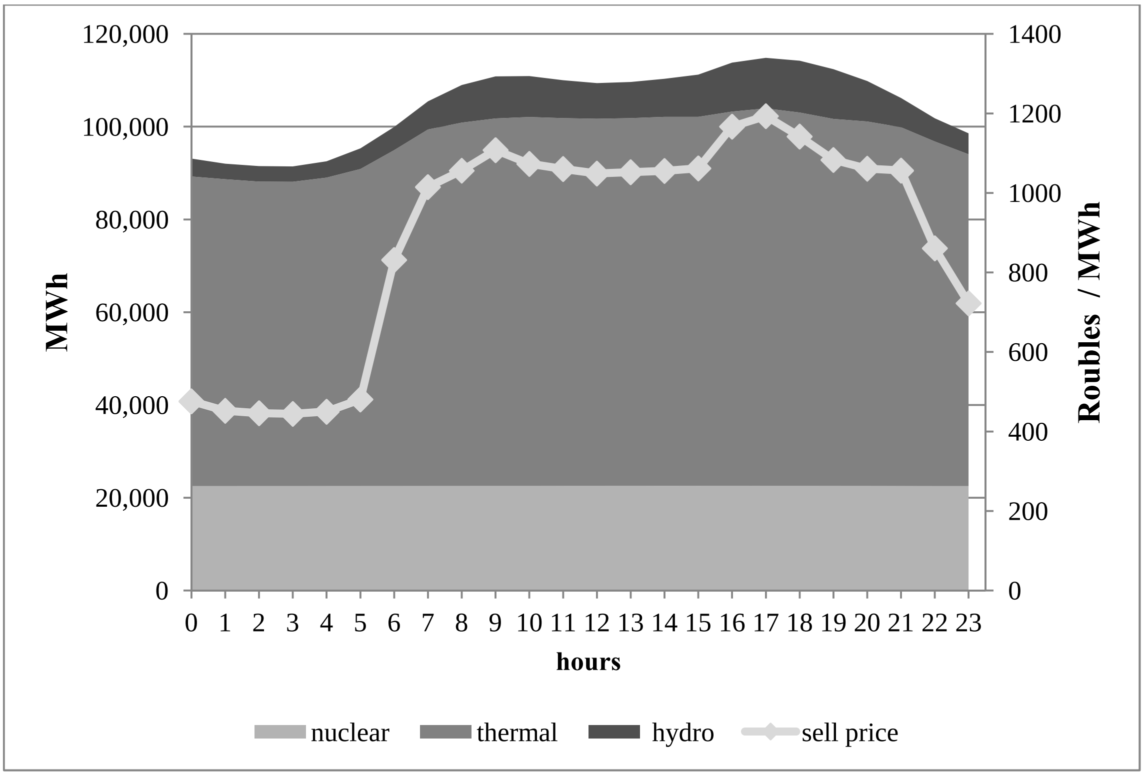

Figure 10a. Europe price zone, generation mix (MWh) and the sell price(right axis, Roubles/MWh) on the peak day 18th December 2009.

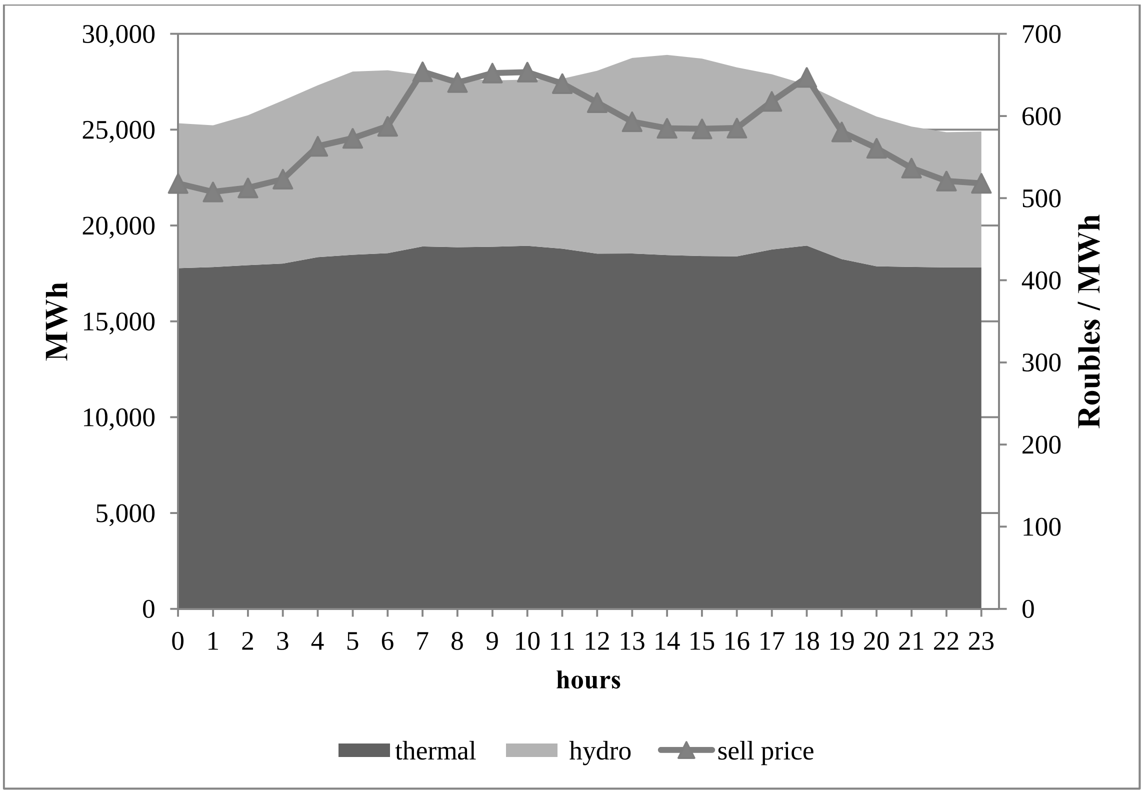

Figure 10b. Siberia price zone, generation mix (MWh) and the sell price(right axis, Roubles/MWh) on the peak day 24th December 2009. Note: Horizontal axis – Moscow (system) time, which lags 4 hours Siberian time.

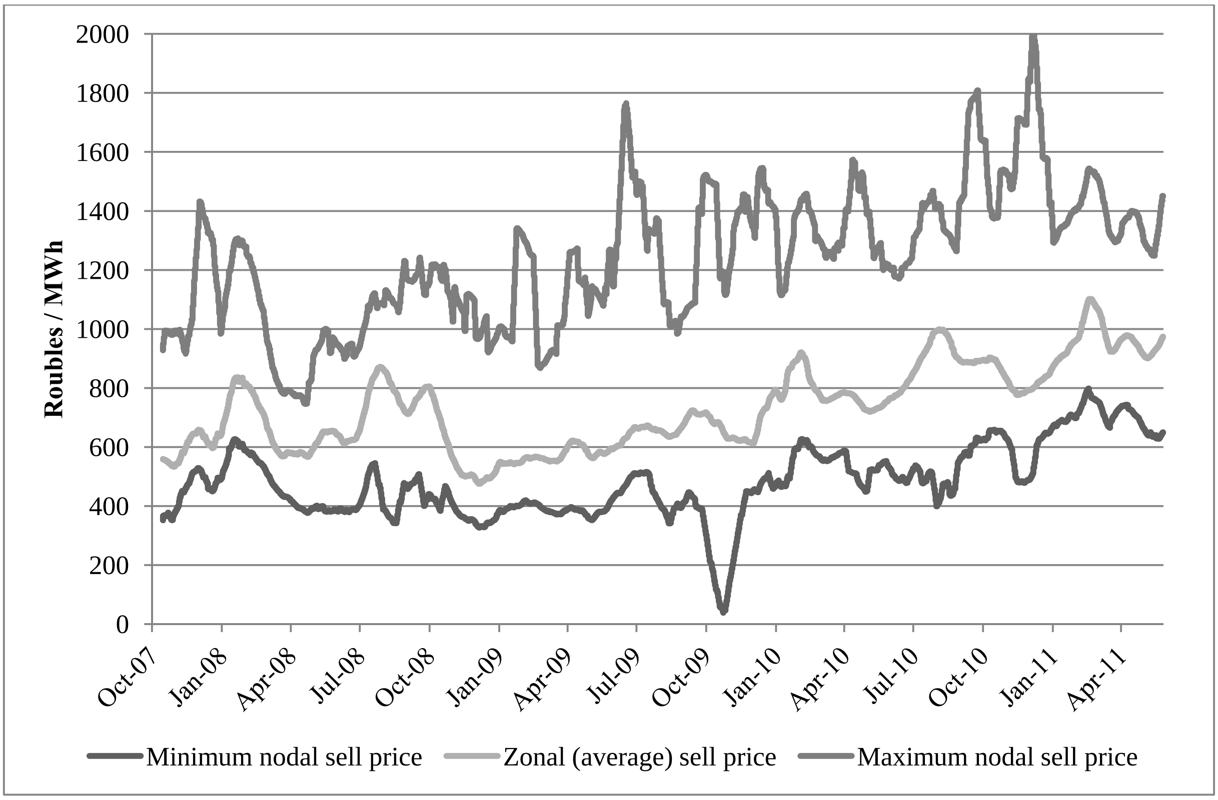

Figure 11a.Europe price zone. Minimum nodal, zonal average and maximum nodal prices. All series – MA filtered (28 days).

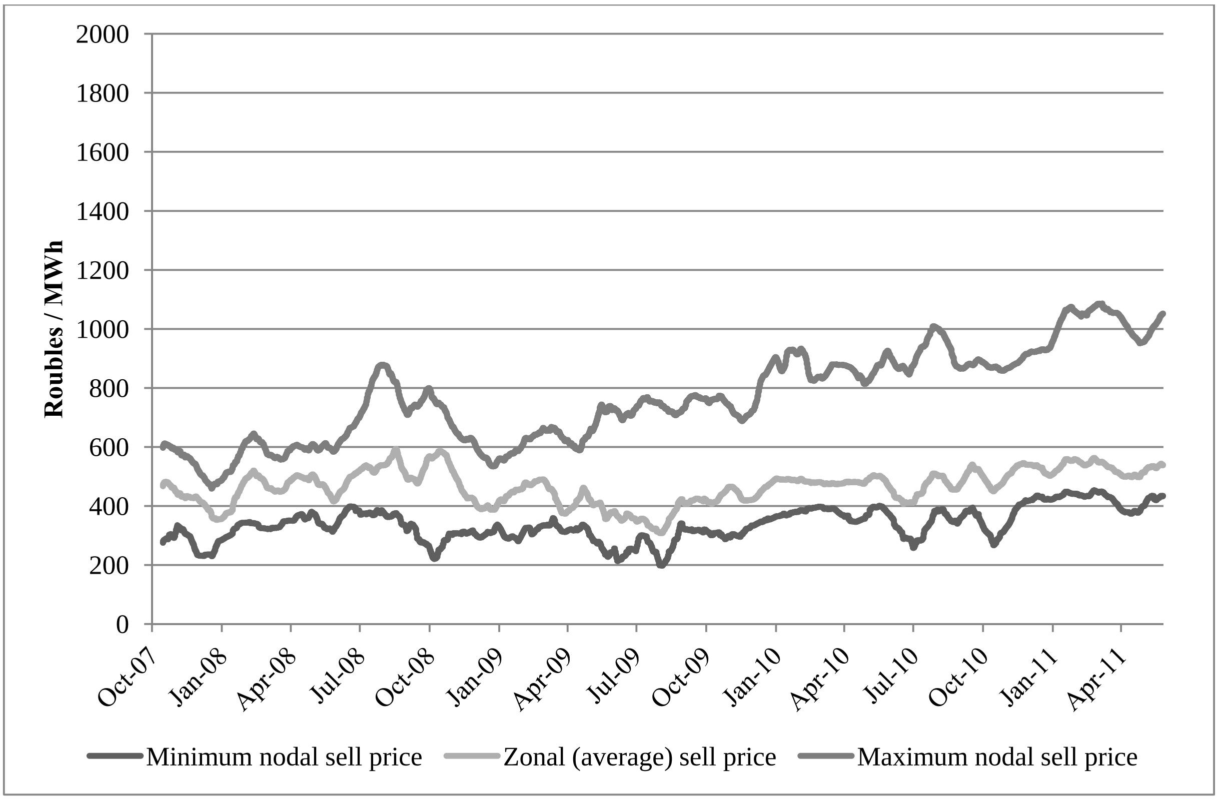

Figure 11b.Siberia price zone. Minimum nodal, zonal average and maximum nodal prices. All series – MA filtered (28 days).

6.9. Thermal efficiency and fuel cost

The issue of thermal efficiency remains important on the policy agenda. Currently, efficiency varies from 23% (old coal-fired CHP) up to 52% (recently built CCGT), with an average value of 36%. Given the calorific values of fuel, the gas price must be1.5 times less than the coal price to opt in favour of the gas-fired turbine. Currently, gas tariffs are 2+ times higher than the coal price. Gazprom gas tariff incorporates transportation costs (via pipeline), so that a station located in the European part of Russia away from gas fields might pay twice as much as a station in Siberia near the field.

Let us consider two examples to demonstrate the difference in fuel costs. The first example involves two thermal stations, one is gas-fired, and the other coal-fired. Both stations are located close to the fuel source (see table 4). The gas-fired plant appears to have variable cost nearly twice as high as the coal-fired plant.

The comparison offers a different perspective on the intentions of Gazprom to increase domestic gas tariffs up to the level of its foreign gas prices. The tariff increase, if implemented, would inevitably lead to the increase of the marginal cost and hence the wholesale electricity price. The strategic switching of some gas-fired generation to coal plants might create an ambiguous effect in the long-term on gas sales and Gazprom's profitability.

The second example shows the role of the distance to the gas deposits. Compare the gas plant from the first example to a CHP plant in Saint-Petersburg. The approximate pipeline length between the two plants is 4,000 km. The first plant is based on the conventional open-cycle turbine, whereas the Saint-Petersburg plant is CCGT-based (see table 2). The lower gas tariff for the Siberian CHP plant is counter-balanced by the plant's lower efficiency, so that both stations have almost equal fuel costs.

Table 4. Variable cost comparison, gas-fired and coal-fired stations, year 2010.

	Urengoy GRES (thermal station)	**Krasnoyarsk GRES (thermal station)**
Capacity	24 MW	1,250 MW
Location	north of Siberia	south of Siberia
Fuel	Gas	Coal
Fuel price, year 2010	1,457 Roubles / 1000m^3	570 Roubles / ton
Thermal efficiency	28%	31.5%

Fuel cost	548 Roubles/MWh(e)	287 Roubles/MWh(e)
Variable cost	794 Roubles/MWh(e)	435 Roubles/MWh(e)

Source: Gas price – regulated tariff, thermal efficiency – producers' annual reports. Coal price, fuel and variable cost – author's estimate.

Table 5.Variable cost comparison, gas-fired stations, different distance to gas fields (year 2010)

	Urengoy GRES (thermal station)	**Severo-Zapadnaya CHP (combined heat and power)**
Capacity	24 MW	1,250 MW
Location	north of Siberia	Saint-Petersburg
Technology	Gas-fired	CCGT
Thermal efficiency	28%	52%
Gas tariff, year 2010	1.457 Roubles/1000m3	2,730 Roubles/1000m3
Fuel cost	548 Roubles/MWh(e)	528 Roubles/MWh(e)

Source: Gas price – regulated tariff, thermal efficiency – producers' annual reports. Fuel cost – author's estimate.

The difference in fuel prices translates into the difference in electricity prices. The power plants in the European price zone operate on gas and are obviously further away from the fuel source. The coal stations (mainly CHP) are located predominantly in the south of Siberia and are nearer to the fuel deposits. Consequently, the average hourly price of electricity on the wholesale market in the year 2010 was 877 Roubles/MWh in the Europe price zone and 508 Roubles/MWh in the Siberia price zone[60].

While gas-fired stations can (technically) contract any gas fuel supplier, the relationship between a coal-fired station and a coal mine can be either monopoly-monopsony or free market. The first type occurs when the station was built close to amine and the furnace is adjusted to the given type of coal. The mine is exploited primarily to satisfy the station's demand for fuel and there is substantial difficulty in exporting the coal from the area to other customers. The natural decision for the station would be to buy the coal mine, as happened to the Gusinoozerskaya power station, which belongs to the Third Wholesale Generation Company (discussed above).

[60] The large hydro resource in Siberia contribute to lower prices by "shaving" peak prices down to the price set by thermal power plants with low fuel cost.

7. *Capacity market after the reform*

The capacity market in the Russian ESI was introduced (or developed) in order to: (i) cover the fixed cost of the existing power plants (in this way it superseded the capacity tariff of the two-tier system); and (ii) induce new construction and guarantee investment returns.

There are several factors that complicated the design of the capacity market. First, the RAO EES investment programme was passed onto the new generation companies. Related to this problem is the preferential treatment of the nuclear and hydro generation capacity, which is owned by the government. Second, it is the transmission-constrained FFZ where the capacity price is to be regulated or capped. Since the number of such FFZs is 26 out of 29, regulatory intervention creates a strong bias in the pricing of capacity.

The section opens with a discussion of the investment programme and the industry development as seen by the government. Then the three main components of capacity trading are presented: the capacity delivery agreement, auctions for existing capacity and auctions for future capacity reserves.

7.1. RAO EES investment programme and the General Scheme-2020

In March 2008, shortly before disappearing into history, RAO EES adopted an extensive investment programme for 2008-12. The total amount of capacity to be built (thermal and hydro) was nearly 42 GW, which meant expanding the existing 210 GW of installed capacity by 20%. When the new generation companies were singled out, roughly half of the projects were passed onto them, together with the existing generation assets (the other half was abandoned or postponed at this point).

A month previously, in February 2008, the federal government presented a general plan for industrial development until 2020, entitled General Scheme-2020[61]. Both documents are linked to the reform and the capacity market, as they describe long-term capacity planning. Obviously, the General Scheme has a longer planning horizon, and includes in its first part (for 2006-10) the bulk of the investment projects of the former monopoly. The General Scheme focuses on the following major aspects: (i) construction of new capacity and transmission lines, and (ii) renovation of the old power block and transmission equipment.

[61] Government Decree No. 215-r issued on 22.02.2008 “General Scheme for location of the energy facilities up to the year 2020”.

To justify the needs for new generation, the Scheme assumed the 4.1% growth in electricity demand in the basic scenario and the 5.2% growth in the optimistic scenario. In fact, the 5% rate was observed only in 2006, one year prior to the elaboration and adoption of the programme[62]. The average growth of electricity consumption in Russia in 2000-07 was 2.1% p.a. The programme for new construction was obviously inflated and, not surprisingly, was widely criticised. The economic crisis in 2009-10 reduced energy demand and hence the demand for new capacity, and also made it difficult to finance the excessive construction projects.

To strengthen the network, the Scheme envisages construction of high-voltage lines that would run through several dispatch zones. Shorter high-voltage links would help remove the "bottlenecks" or connect new power stations to the network. The network development aims at doubling the overall length of the high-voltage grid (48,000 km as of 2010)[63].It is anticipated that the new lines would enable the integration of some of the free flow zones and hence remove price caps.

Another aspect of the Scheme is the refurbishment of older stations and network equipment. The Scheme claims that in 2006 nearly 40% of generation capacity was outdated and needed replacement, and that by 2020 the proportion of obsolete stations would increase to 57%. However, as discussed in the overview section, the estimates of the age structure might be misleading if they use the lead-in date rather than expected lifetime of the (refurbished) plants.

The capital expenditure associated with the modernisation of the industry seemed too high to be borne solely by the government (as the main asset holder), hence the idea of privatising companies in order to attract private investment and improve production efficiency (cf. the above-mentioned reform goals as declared in the "5 plus 5" programme).Indeed, most power stations were privatised on the condition of implementing deep refurbishment or capacity enlargement. To guarantee investment returns to new shareholders, the government introduced capacity delivery agreements.

[62]Russian Federal Statistics Service. http://www.gks.ru/free_doc/new_site/business/prom/natura/natura4g.htm
[63]Federal Grid Company (2010) Annual report.

7.2. Types of capacity contracts and auction

Capacity sales were completely regulated before the reform; both the price (tariff) and volume to be sold were determined by the regulatory authorities. The liberalisation of the capacity market started in July 2008, with the share of the free sector at 30%. Further expansion of the free sector was in line with the electricity market liberalisation, so that liberal pricing started in January 2011. The proportion of the free market was determined with respect to the 2007 installed capacity (in both price zones); any new lead-in would automatically enter the free sector.

The total volume of capacity that is located in the price zones, and hence could be sold on the market, is roughly 180GW. For the purposes of trading, the period of delivery is one month, i.e. the capacity price is specified as Roubles per MW per month. Monthly frequency means that there are only 12 price figures for one year for any free flow zones (unlike, say, some of the US markets with hourly capacity trading).

The capacity, both existing and under construction, could be traded under:

- A capacity delivery agreement;
- Regulated contracts (RC), in particular special regulated contracts for hydro and nuclear generation;
- Free bilateral contracts for the supply of energy and capacity, both on and outside the energy exchange;
- Auctions (entitled “competitive selection of capacity”, abbreviated in Russian as KOM).

To plan future development of the industry and new construction, the government introduced auctions for capacity reserves. The auction rules are already available for analysis and discussion but no auction has yet taken place.

As will be shown later, the government heavily regulates the capacity price, save in the case of free bilateral contracts. Such intervention creates an obvious discrepancy between the actual fixed cost and revenue received. The main reasons for excessive regulation are deemed to be political, as the government fears that uncontrolled prices would soar and thus threaten social stability.

7.3. Capacity delivery agreement (DPM scheme)

The capacity delivery agreement (abbreviated in Russian as DPM) was created as part of the RAO EES reform to guarantee future capacity sales, and thus investment returns, to new generation companies. The scheme was subject to many public discussions, as well as negotiations between companies and regulatory authorities, and the final details of the DPM were only published during the summer of 2010.

From a legal point of view, the DPM contract is an agency agreement between a generator and the Commercial Operator[64], which is complemented by a contract for capacity sales between the CO and customers. The DPM contract stipulates the obligation to construct a new station or to modernise existing equipment by a given date. The maximum possible delay to the lead-in is one year; further delay is subject to heavy penalties.

The total volume of new thermal generation to be built during 2010-17 is around 22.5 GW[65]. Around ¾ is based on the CCGT technology, which has higher thermal efficiency, i.e. above 50% (cf. 36-38% of the existing stations). The nuclear company RosEnergoAtom plans to build 9,800 MW. The investment programme of RusHydro is for three years only (2011-13) and envisages construction of 4,700 MW. The amount of new capacity construction under the DPM scheme totals 37 GW and the breakdown by lead-in year is shown on figure 12. Given the existing capacity of 226 GW, the overall expansion looks quite significant (at 14.3%), yet the increase per year is quite modest: 1.5-2.0% of the existing volume.

[64] Contract form D-15 of the NOREM "Standard form of the agency contract that ensure the implementation of the investment program by the wholesale and Territorial Generation Companies".
[65] Government Decree No. 1334-r issued on 11.08.2010 "The List of Generation Facilities Covered by the DPM".

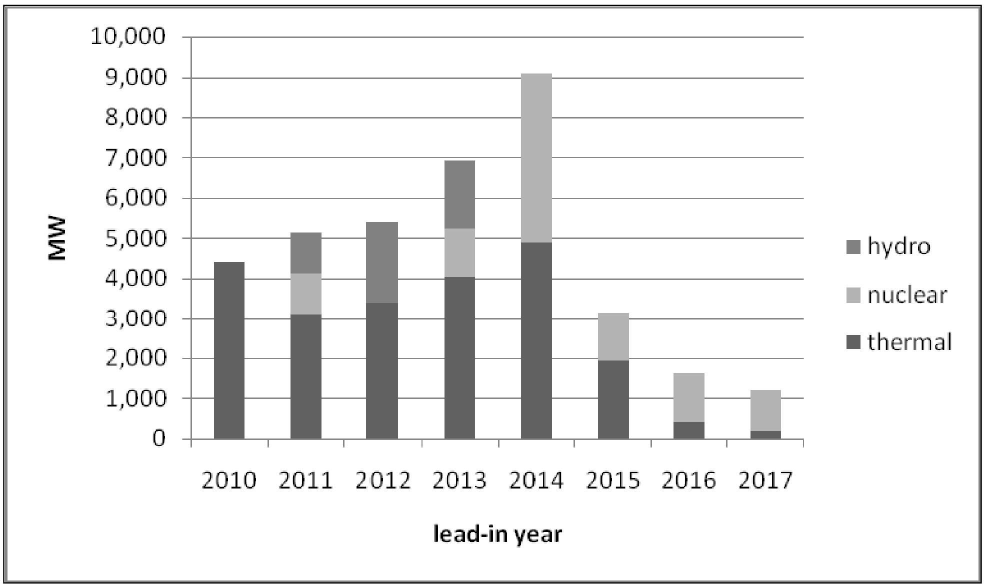

Figure 12. Lead-in of new capacity under the capacity delivery agreement (DPM scheme). Soucre: Author's calculation.

The government resolution[66] specifies the sum of capital expenditure, non-fuel operational costs, property taxes and connection charges that are included in the DPM price. The latter is then adjusted for climate and seismic conditions, the type of fuel and the option of reserve fuel. According to the estimates of the Market Council, the price should vary between 0.5 and 1.8million Roubles/month (roughly £10,000 and £35,580) for one MW of new capacity. A minimum charge applies to a big gas-fired power block in the Europe price zone, and the highest charge applies to a small coal-fired plant in the Siberia price zone[67].

This final price for capacity is guaranteed for 15 years of station lifetime (not including the construction phase). It is indexed every year to reflect inflation. The price could be lowered to account for any excessive revenue that the company might earn on the electricity market.

Some generation companies report the cost of construction, which allows for the comparison of different technologies. Thus, 1 kW of CCGT costs around 21 thousand Roubles (approximately $1245 or £745). For other types of turbines, the price varies from 34 to 137 thousand Roubles per 1kW (approx. £680 and £2,740).

Special regulated contracts for hydro and nuclear power plants ensure that any capacity not sold by these stations under standard regulated contracts, free contracts or at auction is

[66] Ibid.
[67] Ponomarev D. (2012).

forcibly sold to consumers in proportion with their peak demand[68]. Since all nuclear generation and the bulk of hydro generation belong to the federal government, such contracts create an unjustified advantage over private thermal plants. The price of hydro/nuclear capacity sold is often quoted to be excessive, but no formal regulation is published that outlines the price formation for this type of contracts.

6.4. Capacity auction

The auction for the competitive selection of capacity (KOM) is designed as a mechanism to determine capacity market prices. The System Operator is responsible for running the auction; it verifies the technical parameters of the generation equipment and collects price-quantity offers from the generators. The SO calculates the 'actual' demand for capacity based on the historic peak load. The customers, either large-scale consumers or retail companies, cannot bid directly in the market and have to pay for all capacity selected by the SO at the auctions.

From the theoretical point of view, the KOM auction is:

- simultaneous – all the capacity is sold during one procedure;
- one-stage – the equilibrium price and quantities are determined once only;
- multi-unit – multiple power stations sell their capacity;
- identical-good – there are no substitutes/complements for a MW of capacity (in a given month);
- sealed-bid – generators do not know each other's bids;
- uniform-price – one equilibrium price is calculated for the whole of the free flow zone;

There are two periods in the development of the auctions, which differ drastically in terms of pricing and the state of the capacity market. The liberalisation phase, when the market was still partially regulated, appears to be more market-oriented, whereas the liberalised stage looks more like a planning system.

The first KOM auction took place in June 2008, for the delivery of capacity in the second half of the year. Three transitory auctions for the delivery of the following year were held in December 2008-10 for 2009-11, respectively. These were used partly to test the auction mechanism and help the market players learn the rules of the game. Capacity trading during

[68] Regulation No. 6.5 of the NOREM

the transitory period followed the liberalisation schedule of the electricity market. The share of the free sector on both markets was the same and was increased at the same pace.

The equilibrium auction price is a uniform auction price (the price of the last supplying unit); it is the same for producers and consumers. In the case of forced generation ('must run'), it might be the initial bid offer or the regulated price. During the transitory period, the price was computed for each month of the year and for the price zones 'Europe' and 'Siberia', yielding 24 annual values. The dynamics of the actual buying price (the auction price corrected for the actual supply and arrears) in July 2008-December 2010 are shown on figure 13.The capacity buying price was uniformly higher in the Europe price area.

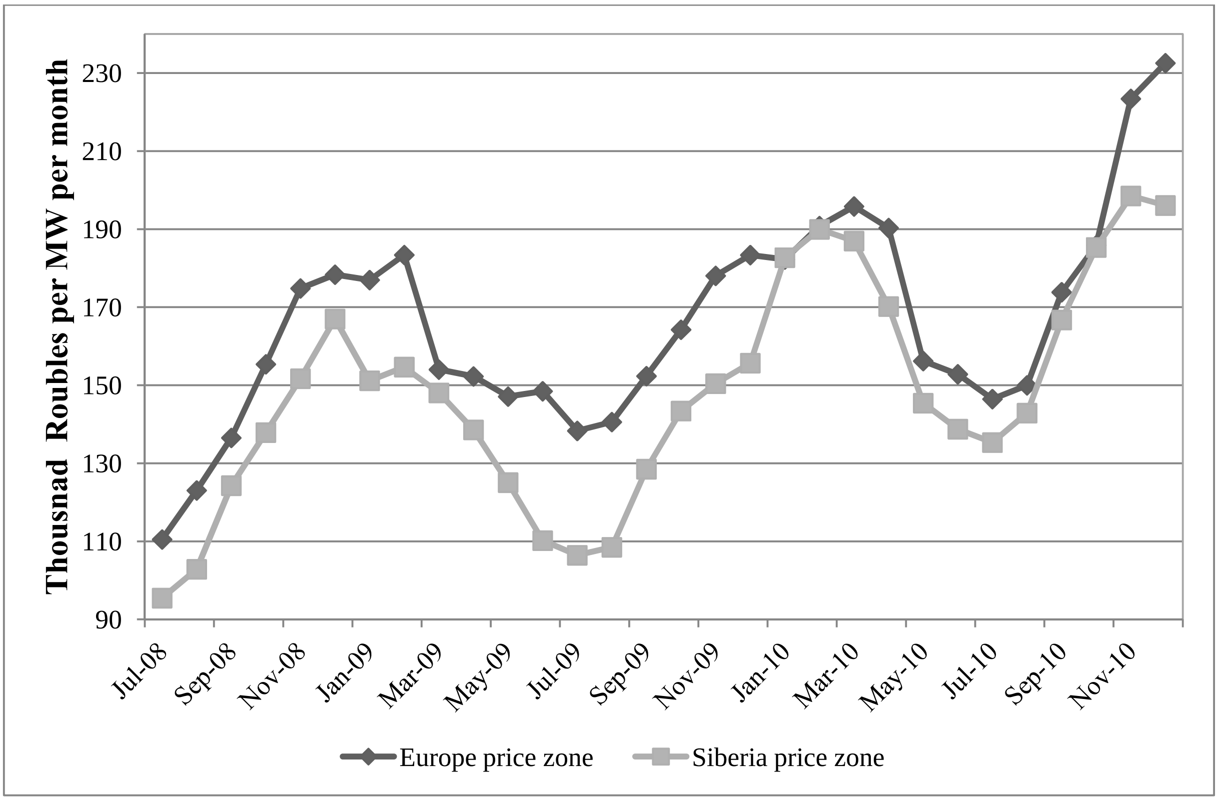

Figure 13. Average actual capacity prices(thousand Roubles/MW/month).
Transitory period July 2008 – December 2010.

During the transitory period, the System Operator published data on the total available capacity and aggregate demand estimates for the two price zones (see figure 14). The ratio of demand to capacity varied between 58% and 80% in the 'Europe' price zone and between 51% and 89% in the 'Siberia' price zone. The significant decrease of available capacity in the Siberian zone in 2010 (from 40 to 34 GW) is due to a major technical accident at the hydropower station Sayano-Shushenskaya that took place on August 17th, 2009, and completely destroyed the station's turbine equipment of 6,400 MW.

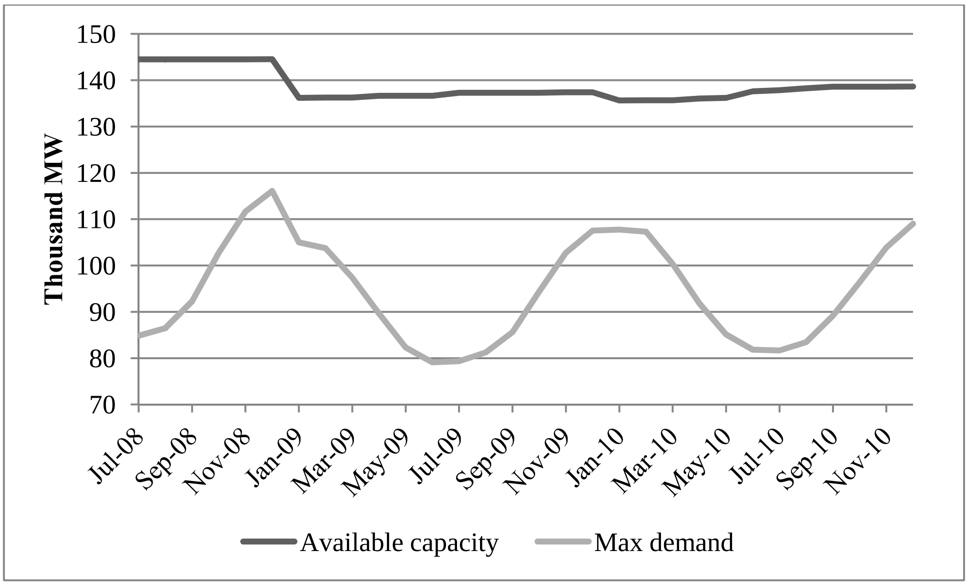

Figure 14a. Available capacity and maximum demand in the 'Europe' price zone. Transitory period July 2008 – December 2010. Source: System Operator.

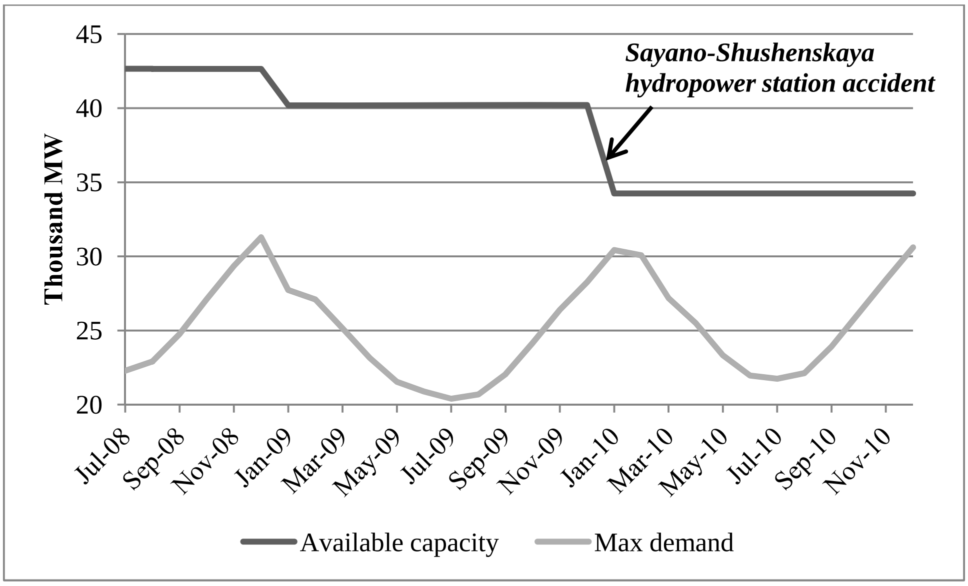

Figure 14b.Available capacity and maximum demand in the 'Siberia' price zone. Transitory period July 2008 – December 2010. Source: System Operator.

As the market was liberalised in 2011, the long-run auctions for the subsequent four years (2012-16) were scheduled for June 2011.However, these were delayed and trading for 2012 only took place in November 2011. The dates for the other auctions (2013-16) have been moved several times, and the auction finally took place in September 2012.All future long-run auctions should be held in August in year X for the delivery in year X+5. Now, the price zones are sub-divided into 29 free flow zones, hence the vector of equilibrium prices, instead of just two values. Ideally, this should lead to greater price variability across the regions and give relevant price signals about the deficit/surplus of capacity. However, because of the cap on auction bids (i.e. the upper limit on a price bid), price variation is effectively absent on the market, which undermines the information benefit from the price signals and zone price differentials.

The Federal Antimonopoly Service imposes a price cap in the free flow zones where the competition is deemed to be limited (typically, a small FFZ with just a few power stations). The algorithm that the System Operator employs to compute the equilibrium prices and quantities implements the cap only at the last stage, after the unconstrained prices are identified. However, generation companies cannot submit bids above the given limit; hence the System Operator itself cannot rely on price bids as a signal of deficit in demand or inadequacy of transmission capacity. Currently, the cap is introduced in 26 out of 29 zones, which affects 54% of the total installed capacity in the market. The upper limit for price bids is 118,000 Roubles/MW/month (£2,632) in the ‘Europe’ zone, and 125,000 Roubles/MW/month (£2,527) in the ‘Siberia’ zone.

To summarise, in the liberalised capacity auction the System Operator defines the amount of demand and the Federal Antimonopoly Service caps the prices. Generators and consumers can affect neither quantity nor price, hence the question arises whether such an auction can be called a proper market mechanism.

7.4. Auction for capacity reserves

To ensure further development and the construction of new capacity, the Government adopted rules for capacity reserves auctions in April 2010[69]. According to the rules, it is the System Operator that is broadly responsible for capacity adequacy. The SO must determine (i) the amount of capacity in MW needed, given the forecast for energy demand; (ii) a detailed technical requirement for a new generation block – installed capacity, fuel type, lead-in date, thermal efficiency, ramp speed, etc.; and (iii) the maximum cost of the project (which involves price estimates by regulatory authorities).

The System Operator will organise the auction for investment projects, to which any generation company is entitled to submit a sealed proposal. The document should include technical and financial offers. The technical part must obviously satisfy the requirement announced by the SO. The financial part must comprise construction costs, monthly capacity

[69] Government Resolution No. 269 issued on 21.04.2010 “On organising the auctions to form long-term capacity reserves for electricity production”.

payments and the forecast of fuel prices, or a contract for future fuel supply. The auctioneer then estimates the price for electricity and total cost of the investment project. The latter can be understood as a one-tier tariff that incorporates the forecast energy price and the offered capacity payment. The proposal that has the lowest investment cost (i.e. lowest one-tier tariff) wins the auction.

In short, the development of new capacity remains a highly regulated system. There is no room for a company to act on its own incentive to build a power plant. Not only is the size of the plant pre-determined, but also the technical parameters, such as fuel type. It is not clear how sustainable the auction is regarding moral hazards from the company that wins the auction, e.g. when a company offers a low bid, but then overstates construction costs, and lobbies for higher electricity and capacity tariffs.

8. Conclusions

The reform of the Russian ESI in 2003-2011 was induced by the unsuccessful transformations of the early 1990s. The Soviet industry relied on low prices, had excessive capacity and was quite inefficient. In the ‘90s it was transformed into a vertically integrated monopoly with heavy government regulation. The industry inherited the centrally-planned spirit and many of the existing problems (technical inefficiency, excess reserve margin). Low tariffs and overall economic decline contributed negatively to industry financial performance.

The last reform aimed at restructuring the monopoly and creating a competitive wholesale market for energy and capacity. These goals seem to be half-achieved. The monopoly was unbundled, and the new generation companies appeared to have sensible composition of the assets. However, the merger wave soon followed the restructuring. It was led by the state-owned companies Gazprom and InterRAO, and ss a result of the mergers the government now controls half of the industry installed capacity.

The wholesale markets are in full operation, yet the market players are subject to the bidding code of practice and suffer from retail tariff regulation. The bid-at-cost rule induced the introduction of the capacity market but the market turned out to be regulated and resembles a planned system. On the capacity market, once the DPM scheme expires, that is once the bulk of compulsory capacity is built, more attention should be devoted to design of a competitive market which gives more freedom to generation companies in planning their investment.

Demand-side bidding, and more broadly demand-side response and management (which is now barely discussed), can contribute significantly to development of the capacity markets.

Development of the distribution network is under full swing, however pricing and financing of the network raised much concern. The new RAB methodology fixes prices for longer periods which should add stability to the sector. Perhaps, questions about prices would be less relevant when the network expansion will contributes significantly to lowering prices in the currently locked areas and widening access to, and interaction between, more generators and customers.

Reforming the gas fuel market in Russia seems a more distant perspective, although not an improbable. In the present conditions the regulators can focus on improving the tariff methodology to better reflect the production cost (and possibly prepare Gazprom restructuring) and ensuring fair access to the pipeline network for IPPs.

Finally, complete retail competition, in particular, household access to the market, is still a sensitive and tough matter. Smart metering project which has been recently launched in Russia should collect relevant statistics on household consumption and provide basis for further policy development.

To summarise, the Russian ESI reform borrowed a lot from international experience and at first glance appears to be sensibly designed. However, further development showed that the government still tries to hold the grip, so this needs to be realised for better industry performance and completeness of the reform.

Appendix. Timeline of the reform in the Russian ESI

1991	Privatisation of *energos* by regional governments (Irkutsk, Novosibirsk, Tatarstan, Bashkiria)
1992	Creation of the RAO EES monopoly. Transferral of *energo* capital (from 100% to just 25%) to RAO EES.
1993	Wholesale market FOREM starts its operation. One-tier tariff is replaced by two-tier tariff for electricity and capacity
1994	Regulatory body Federal Energy Commission created. Regional Energy Commissions emerge and then are formalised as part of the regional authorities (regional government)
July 1996	Legal framework of FOREM is formalised
April 1997	President decree on reforming the natural monopolies (first attempt to reform the industry)
April 1998	Anatoly Chubais appointed head of RAO
	RAO commissioned a study to the Hagler Baley Consultancy how to reform the monopoly. The US AID that supported the study criticised the final report saying it should explain how to reform the industry, not how to reform the monopoly.
April 2001	Russian State Council report, summary of the reform concepts (11 in total)
July 2001	Government Decree for the reform
March 2003	Federal law on the electricity industry N 35-FZ (beforehand it was a more general law on natural monopolies)
May 2003	RAO EES announced its reform concept “5+5”, where first five is the preparation of the reform in the years 1998-2003, second five is the reform implementation in the years 2003-08.
2004-08	Unbundling of RAO EES, the following companies to be created: • Generation companies: OGKs and TGKs, HydroOGK (later RusHydro) and RosEnergoAtom; • Transmission and distribution (natural monopolies): FSK and MRSK; • Retail companies, including guaranteeing suppliers. Independent *energos* are required to separate generation, distribution and retail supply (create independent legal entities, but the question of common ownership is not discussed); to transfer network lines to FSK and MRSK.
June 2004	Federal Tariff Service established as a new regulatory body in lieu of

	several others. In electricity industry it replaced FEC. REC remain, their scope is constrained (i) to set tariffs of the guaranteeing suppliers and (ii) to set tariffs on energy sold to households within the limits prescribed by the FTS.
September 2006	New wholesale market NOREM and retail market start operation, with regulated contracts only.
January 2007	Partial liberalisation of the NOREM market, where 5-15% of electricity can be bought/sold freely on the market, with free choice of contractual parties and free pricing. “Bough/sold” means financial obligation with respect to trading operations, not physical requirement with respect to energy produced or consumed.
January 2008	Retail markets have free pricing for small commercial customers (free pricing for households in postponed until 2014)
February 2008	Government adopted the General Scheme-2020
March 2008	RAO EES presented its investment programme
June 2008	RAB methodology adopted for transmission and distribution companies (replaced the “cost plus” method). Gradual move of regional distribution companies to the RAB tariff setting should be completed by 2012.
July 2008	First (trial) capacity auction (KOM) for monthly delivery of capacity for July-December 2008
July 2008	RAO EES stopped its operation from 1st July 2008 and stopped to exist as a legal entity
End of 2008	Restructuring of the former monopoly and of the industry is largely completed
December 2008… December 2011	Capacity auction KOM for the next-year delivery
January 2011	Full liberalisation (free pricing) of the wholesale markets for electricity and capacity
April 2011	The framework for the capacity delivery agreement (DPM contract) is finalised
September 2012	Four capacity auctions for delivery in the years 2013-2016 (then August 2013 for delivery in 2017)

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