Restructuring the Russian Electricity Sector: Re-Creating California?

Russell Pittman*

Abstract

The Russian Federation has begun restructuring its electricity sector, following the standard restructuring model of complete vertical separation of generation from transmission, with the aim of creating competition in regional generation markets. This paper examines the structure of the six principal regional generation markets that are in their early stages of development and argues that they are likely to be characterized by high levels of market power on the part of individual privatized generation companies, especially during the peak winter demand season. These levels – considerably higher than those that caused competitive problems in California – seem to create a serious risk of price spikes in deregulated wholesale electricity markets, and thus of significant price increases to consumers of electricity.

JEL categories: L13, L22, L94, L98, P28

Keywords: Russia, electricity, generation, restructuring, vertical separation, competition, market power.

---

* Director of Economic Research, Economic Analysis Group, Antitrust Division, U.S. Department of Justice, and Visiting Professor, New Economic School, Moscow. Outstanding research assistance from Egor Matveyev is gratefully acknowledged; likewise the support for his work from the Centre for Financial and Economic Research, Moscow. In addition, the author is grateful for helpful comments from Robin Allen, Lev Belyaev, Tim Brennan, James Wilson, and Ksenia Yudaeva, as well as from Christian Growitsch and other participants in the International Industrial Organization Conference (Boston, April 2006). None of these can be blamed for errors that remain. The views expressed are not those of the U.S. Department of Justice or of any other organization.

Restructuring the Russian Electricity Sector: Re-Creating California?

1. Introduction

The Russian electricity sector is in the relatively early stages of a mammoth restructuring process. The plan calls for complete ownership separation of electricity generation from long-distance transmission, with thermal generation plants privatized, nuclear and most hydro plants constituting separate state-owned generation companies, and the high voltage grid owned and controlled by a separate, state-owned National Grid Company. A small free market in wholesale electricity has been created that is to constitute a gradually increasing share of total electricity supply annually.

The goal of the restructuring strategy is the same as that behind the application of this now-standard reform model in other infrastructure sectors in other countries: to replace, where feasible, the old regulated, state-owned monopoly enterprises with deregulated, privately owned enterprises, competing among themselves to operate and invest efficiently and provide outputs at the lowest efficient prices.

As has been noted regarding the electricity sector as well as others, however, the degree to which this reform model performs well depends in no small part on the degree to which effective competition is actually created.[1] In fact this may be a special problem in the electricity sector because of certain characteristics of the product and the markets in which it is traded. One pertinent example is the conclusion of some analysts that a significant portion of the price increases in the disastrous California electricity sector restructuring experience were the result of anticompetitive behavior – more specifically, the unilateral withholding of output by marginal producers –by generators (Borenstein, *et al*., 2002; Joskow and Kahn, 2002).

A recent study has raised the question of whether the Russian electricity system, as restructured according to current plan, may exhibit market power in several regional generation markets (IEA, 2004). As noted in that study, although Russian policy seeks to come as close as possible to creating a wholesale electricity market of national scope, the poor condition and small capacities of inter-regional high transmission linkages mean that for the foreseeable future there are likely to be six mostly distinct regional wholesale electricity markets, in regions labeled by the incumbent monopolist RAO UES as the Northwest (including St. Petersburg), Central (including Moscow), South, Volga, Urals, and Siberia.[2]

[1] Newbery (1999); Pittman (2003a). See also Hogan (2002): "Substantial market power would call into question any proposal to rely on markets for generation", and Thomas (2004): "it is far from clear that a weakly regulated [generation] oligopoly is preferable to a properly regulated monopoly."
[2] A potential seventh regional market, the Far East, is apparently so fragmented that it is likely to be composed of multiple smaller regional geographic markets. This raises different issues from those of the present paper, and we do not consider the Far East further.

The IEA study warns that under current plans for the future ownership of particular generation plants by particular newly created regional and national generation companies, the wholesale electricity markets in several of these regions will be structured oligopolistically rather than competitively, with the top four generation companies controlling 92 percent of capacity in the Volga region, 85 percent of capacity in the Northwest region, and no less than 60 percent in the others.[3]

This paper argues that the important IEA warning of market power in future regional wholesale electricity markets in Russia in fact likely understates the risk. Though the IEA notes that "technological or seasonal problems affecting one of the two large[st] companies [in a region] could sharply increase the other's ability to control the available capacity to meet residual demand," that study does not systematically consider the degree to which such problems may occur in each region, exacerbating the problems that are suggested by the raw concentration data.

In this paper, I examine more closely the degree to which particular generation plants may act as baseload plants in particular seasons – especially, combined heat and power generating plants in the winter season that is the peak season for demand in Russia – and the degree to which the reduced set of plants with production flexibility may enjoy market power during particular seasons. The level of market power possessed by particular peakload plants is further highlighted by two additional factors not included in the IEA and most other analyses: the fact that regional generation capacity varies across different seasons when hydro generation is an important component of the mix, and the fact that when a particular generation company owns both baseload and non-baseload plants it may have increased incentives to restrict production at times of peak demand, as the baseload plant may earn the resulting inframarginal rents. Generation markets that appear relatively less concentrated with annual data may show higher concentration levels in particular seasons and with these additional factors included.

Overall, the more detailed data demonstrate that the current plan for restructuring the Russian electricity system is likely to create significant levels of market power and even monopoly power under peak load conditions in particular regions – market and monopoly power that could be exercised with great harm to Russian economic welfare.

[3] It is important to acknowledge – as the IEA report does – that these regional markets are merely rough forecasts: it is impossible to know exactly what will be the boundaries of regional electricity markets in Russia until the markets begin to operate. Further, the boundaries of the markets will doubtless vary according to the state of demand and production. Nevertheless there is widespread acceptance that wholesale electricity markets in Russia will be regional rather than national. See, *e.g.*, CMS Cameron McKenna (2004): "Interregional integration is generally quite weak, as the system was developed primarily to connect large power stations to closed centres of industrial load, although some capacity providing not much more than interregional emergency support does exist."

2. The Policy Setting[4]

Since 1992, RAO UES has owned, in addition to the nationwide high-voltage transmission grid, all of the large thermal generation plants, all the hydro plants, and the Central Dispatch Unit. Nuclear powered generation plants are owned by the Ministry of Atomic Energy and operated by the state-owned company RosEnergoAtom. Smaller thermal plants – many of them cogeneration (*i.e.*, combined heat and power) facilities – have been controlled by regional power companies called AO-*energos*, which are in turn owned and controlled to differing degrees by RAO UES and by regional authorities.

Under the restructuring plan, the national transmission system would be turned over to a new company called the Federal Grid Company in which the federal government will own a majority share. Vertical separation would be complete; the Federal Grid Company would not own or control generation assets. The state would continue to own and control all nuclear and most hydro powered generation facilities.[5] The thermal generation facilities now owned by RAO UES would be sold off to six new private companies of roughly equal size that would be expected to compete among each other in regional markets throughout the Russian Federation; in addition, there will be fourteen smaller, territorial generation companies owning and operating the smaller generation plants. The stated rationale behind the number of new generation companies chosen is to create competitive generation markets while at the same time constructing companies that are large enough to achieve management efficiencies and for their shares to enjoy market liquidity.[6] In order to create and preserve competitive generation conditions, no single company will be permitted to own more than 35 percent of the generation capacity in any wholesale price zone. As competitive generation markets are created in various regions, wholesale price regulation will be gradually eliminated.

As I have argued in previous papers (Pittman, 2003a and 2003b), there are likely to be a number of potential problems with vertical separation as a restructuring plan. Complete separation of the grid company from the generation companies removes any economies of vertical operations across these two activities and correspondingly imposes new transactions costs – using this term very much in the sense of the "transactions cost economics" of Williamson (2000). One aspect of these costs that has been a special concern in electricity sectors around the world has been the difficulty of creating

[4] For more information see, *e.g.,* Hubert (2002), Kennedy (2002), Tompson (2004), International Energy Agency (2004), and Yi-Chong (2004).

[5] In this sense one could argue that vertical separation would not really be "complete", since the state would continue to own the separate grid, nuclear, and hydro companies. This raises the interesting question of the incentives facing state-owned companies – and in this case, multiple, interacting state-owned companies. However, to the extent that nuclear and (sometimes) hydro are baseload technologies, the question of discriminatory access to the grid – generally the primary argument for complete vertical separation – becomes a less important factor.

[6] See, *e.g.*, Galkin and Zsiga (2004).

appropriate incentives for expenditures on maintenance and improvements on the part of the grid company.[7]

A second potential problem is the complicated institutional structure that is under discussion and construction to manage the operation of the markets to be created. Regarding the generation/transmission interface there has been discussion of a transmission system operator, a separate national systems operator, and a regulator to keep an eye on both. Regarding efficient price signals for generation (especially investment in new generation), there has been discussion of locational marginal pricing that would reflect transmission constraints. Further regarding incentives for investment in generation, there have been calls for some form of "capacity payment" schemes. (On all three of these points, see World Bank [2004a].)

All of these imply a level of experience and sophistication of the Russian governance and regulatory mechanisms that may be quite optimistic.[8] Whether the Federal Antimonopoly Service will have the resources – and the Federal Tariff Service, the expertise – to deal with issues of this magnitude and complexity in the electricity sector remains very much an open question.

Perhaps most important, however, it is not at all clear that the plan will succeed in creating competition in generation markets.

First of all, these six large generation companies will be encountering each other in multiple geographic markets in repeated interactions over time (and perhaps indeed in other product markets as well, depending on the identity of the purchasers of the six large companies). It seems quite possible that they will be able to learn from their experiences and coordinate their interactions in such a way as to maximize prices and profits rather than competition and efficiency in particular regional markets.[9] The fourteen smaller regional generation companies will play the same intertemporal game without its interregional dimension.

Second, a good deal of generation in any particular geographic market is likely to be baseload rather than peak-load – that is, capacity that operates constantly and regardless of (most) fluctuations in wholesale electricity prices, similar to what is sometimes termed "must run" generation capacity. Most supply responses to wholesale price fluctuations

---

[7] See OECD (2005): "Under-investment in transmission networks and inter-connectors has been a thorny issue in the US, and it now appears to be emerging in Europe, particularly in the wake of the power failures of 2003." See Buehler, *et al*. (2004) for a theoretical discussion.

[8] See Bayliss (2001): "Even now – ten years since privatization – Ofgem, the UK regulator – is struggling to prevent market abuses by private firms. This is in a wealthy country where the regulator has substantial resources. How much more difficult then is the job of the regulator in developing countries where organizations are staffed by poorly paid public sector workers with little exposure to international corporate activities and where the 'opposition' consists of highly paid internationally trained corporate executives. What is more, the regulator has little at hand in the way of sanctions, should the firm refuse to adhere to the rules of the regulator." Yi-Chong (2005) discusses the problems inherent in pushing a policy reform agenda for the electricity sector that requires more sophistication governance and regulatory mechanisms than are likely to be available. See also World Bank (2004b).

[9] See, *e.g*., the discussion in Pogrebniak (2005) and as the empirical results of Fabra and Toro (2005).

will take place in the smaller set of capacity represented by peak-load plants, and among these plants the upward slope in the supply curve may become quite dramatic. In combination with the extremely inelastic short-term demand for electricity – because of the general absence of real-time pricing – this creates strong incentives for the exercise of market power by owners of marginal generation plants, a problem that has vexed even experienced regulators in places like California and the UK.

As noted earlier, for the foreseeable future Russian wholesale electricity generation markets will be regional, not national. However, even for the Russian Federation as a whole, note that 16.3 percent of generation capacity is nuclear, 19 percent is coal, and 17.1 percent is hydro; the first two are almost always baseload and the third is flexible only to some degree and under some circumstances. In addition, about a third of capacity is co-generation (combined heat and power), which is generally baseload during the long Russian winter.[10] Finally, recall that both nuclear and most hydro capacity will remain under government ownership.

In this context, six does not seem a large number of nationwide generating companies, nor 35 percent a prophylactic limit on the share of total generation capacity controlled by a single firm in a particular geographic market. In the electricity restructuring in California, the 54 percent of generation capacity that was represented by thermal production was divided primarily among five new generation companies that individually controlled 16 to 22 percent *of this 54 percent of total capacity*.[11] These firms then individually controlled only 8.6 to 11.9 percent of total generation capacity; yet analysts later estimated that "market power [in generation] could be blamed for 59 percent of the increase in wholesale electricity prices from summer 1999 to the crisis in summer 2000."[12] Similarly, one of the architects of British electricity restructuring, Stephen Littlechild, admitted in 1999 that there was "still scope to exercise substantial market power" in the UK generation sector – and this at a time when the largest participant had only 21 percent of national generation.[13]

3. The Structure of Regional Generation Markets in Russia

Table 1 shows the regional generation market shares of companies according to the announced allocation of particular generation plants to the newly created regional and national generation companies, as well as to the government-owned nuclear (RosEnergoAtom) and hydro (Hydro OGK) companies. The shares are similar to those presented in Table 7 of the IEA study, with differences owing to different reports of ultimate plant ownership, different estimates of plant capacity from different sources, and a few plants allocated to different regions. Under the generally accepted wisdom that a particular level of market concentration suggests more market power in electricity

---

[10] All of these share estimates are taken from Tompson (2004).

[11] Blumstein, *et al*., 2002; Puller, 2002. For valuable broad discussions of the California experience, see Brennan (2001) and Joskow (2001).

[12] Sherman, 2003, citing Borenstein, *et al*., 2002; see also Joskow and Kahn, 2002.

[13] See also Green and Newbery (1997), Wolfram (1999), and Day and Bunn (2001) on market power in the restructured UK generation sector.

generation markets than in the average commodity market,[14] these markets all appear at least moderately concentrated, raising concerns about the presence of market power. The four-firm concentration ratios in the seven regional markets range from 60 to 92 (59 to 93 in the IEA study), while the Herfindahl-Hirschman indexes (HHIs) range from 1205 to 2249 (1196 to 2293 in the IEA study).[15] (Note that the data for California in Table 1 of Blumstein, *et al.* [2002] yield a four-firm concentration ratio of 53 and an HHI of 930.)

However, the data in this Table should arguably be adjusted in several ways if they are to give an accurate picture of market concentration and behavior in the future. The adjustments proposed in this paper take four forms: a) the separation of baseload plants from the more flexible peak-load plants, which includes both b) a closer analysis of the production flexibility of hydro plants, and c) the inclusion of combined heat and electricity plants in the baseload category during the winter; and d) the adjustment of capacity shares to reflect differing hydro capacities during different seasons. Let us consider these four in turn.

First, it is a well known feature of electricity generation that different technologies exhibit great differences in both fixed and variable costs. Plants with high fixed costs but low variable costs generally run at full capacity and are termed baseload plants; plants with lower fixed costs but higher variable costs run when the level of demand justifies their addition to the mix and are termed flexible or peak-load plants. Nuclear plants are always baseload plants, and coal-fired plants nearly always so. Natural gas plants, especially the modern combined-cycle generating technology (CCGT) plants, are generally not baseload; nor are the older oil-fired plants, most of which have been replaced in Russia and elsewhere by gas-fired plants.

Hydro plants occupy more of a middle ground here. In the Russian situation, as in many transition countries, hydro plants will be mostly state-owned – in this case, part of the large, state-owned Hydro OGK generation company – and there is no clear indication yet how much their production levels may be varied in response to wholesale electricity prices.[16] In general, even hydro plants that have large reservoirs and can be operated according to economic signals are not fully flexible as electricity generators, since they are also operated in response to demands related to irrigation, drinking water supply, and the preservation of environmental amenities. Moreover, hydro plants operate subject to the constraints of river flows. Many hydro plants have large reservoirs in which they can

[14] The reasons include non-storability of product, inelasticity of supply and demand at peak periods, and transmission bottlenecks that may preclude supply increases at almost any price. See, for example, Newbery (2003) and Bushnell (2005).

[15] These are the two most commonly used measures of market concentration in the industrial economics literature. The four-firm concentration ratio is the percentage of market sales accounted for by the four firms with the largest individual shares. The HHI is the sum of the squared percentages accounted for by all firms in the market.

[16] For example, IEA (2005) expresses the concern that the state may use hydro generation strategically to keep prices down, which would protect the population from price spikes but also create uncertainty for private investors in generation facilities. This would suggest the allocation of hydro plants where such flexibility is possible to the flexible, peak-load category. Bushnell (2003) emphasizes both the importance of and the difficulty of predicting the behavior of a publicly owned hydro generation firm in analyzing the likely competitive outcomes in particular wholesale generation markets.

store water and then release it for power generation at a later time, but others, called "run of river" plants, lack such reservoirs and so operate passively, generating electricity as the river flows.[17] Even hydro plants that have reservoirs may find their storage capacities overwhelmed by water flows in the spring and so have no effective ability to vary generation load. Finally, many analysts believe that when the rules and regulations for generation markets are finalized, Russian hydro plants will be paid regulated prices based upon average costs rather than free prices based upon market marginal costs. Thus in many situations it may be appropriate to consider hydro plants as baseload rather than flexible generation plants.

Furthermore, as noted earlier, fully one-third of Russia generation capacity consists of plants that are combined heat and electricity generation facilities. Like hydro plants that must consider other demands for water, combined heat and power (CHP) plants cannot be fully responsive to price signals in wholesale electricity markets: during the Russian winter these plants will be run under almost any regime of electricity prices, given the inelasticity of demand for district heating. (In fact many of these plants cannot be operated economically with the heat generation function turned off – in what is called "condensing mode" – and so are not operated during the warm weather.) Considering the length of the Russian winter in many regions, it is probably a conservative adjustment to allocate these plants to the baseload category only during the three months of the official winter season.

It is then when these CHP plants are moved from the flexible to the base-load category that we encounter the further problem discussed earlier: the fact that a generation company owning both baseload and non-baseload plant may enjoy enhanced incentives to restrict peak production, so that its baseload plants (under some pricing circumstances) earn inframarginal rents (Wolfram, 1998).

Finally, it is a common feature of countries with variable weather conditions that the generation capacity of hydro plants varies a good deal across different seasons. This means that a single aggregate "capacity" figure for a given region – as used in Table 1, in the IEA's Table 7, and presumably in the 35 percent ceiling for individual firm market share in the Russian legislation – may mask seasonal variation. In this paper we use the variation exhibited in hydro production in each region over the past four years to adjust seasonally the listed capacities of the hydro plants in each region.[18]

Let us consider the structure of the individual Russian regional wholesale electricity markets taking account of these additional factors.

---

[17] See, for example, Arellano (2004) and Atkinson and Halabí (2005).

[18] The data used are available upon request. Bushnell (2003) performs similar adjustments for seasonal water flows in his simulation of strategic behavior by a hydro generation firm.

3.1 The Volga Region

I begin with the Volga region because it offers perhaps the most striking example of the high level of market power in a regional market as demonstrated by the inclusion of these factors in the analysis.

Tables 2, 3, and 4 list the individual generation plants in the Volga region, grouped according to their announced post-privatization ownership and separated into base-load and non-base-load technologies, for the spring, summer/fall, and winter seasons, respectively. Higher water flows yield greater hydro plant capacities in the spring and overwhelm production flexibility for some of the hydro plants in the spring as well. More crucially, the very large number of CHP plants lose their flexibility and become baseload plants in the winter.

Even in the spring, summer, and fall, market structure appears to be of more serious concern than is indicated by the unadjusted figures in Table 1 (and the IEA's Table 7). In the spring, 43 percent of capacity is baseload. The top four non-baseload generation companies control the remainder of capacity, so the generation market in the spring is indeed a four-firm oligopoly, with a four-firm concentration ratio for non-baseload generation of fully 100 percent. It should be a matter of serious concern for electricity customers in the Volga region that in the spring season, the firms TGK-7, Tatenergo, TGK-5, and TGK-6 will likely have abilities significantly greater than those enjoyed by generation companies during the California crisis to manipulate prices, either by coordinating their production levels or by withholding output unilaterally.

The situation is better in the summer and fall than in the spring, but only marginally so, and only if we assume that the Zhigulevskaya and Cheboksarskaya hydro plants belonging to the Hydro OGK will be operated according to price signals from the wholesale electricity market. Even in that optimistic situation, with baseload generation accounting for 23 percent of capacity, non-baseload generation is now a five-firm oligopoly, with a four-firm concentration ratio of 96 percent. The same four generation firms listed in the previous paragraph now have only the state-owned generation company Hydro OGK added to their numbers as a tight oligopoly – though if the two hydro plants are in fact operated independently of the oligopoly and according to market signals, the market power of the other four non-base-load generation companies will be correspondingly reduced.[19]

It is in the winter, however, that the situation becomes most serious, as we assume that the CHP plants become baseload ("must run") in order to supply heat to the population. That factor, combined with the reduction in hydro capacity during the winter season, renders 72 percent of capacity as baseload, leaving only the same two hydro plants, a single gas plant owned by TGK-7, and three plants owned by Tatenergo as flexible, peak-load capacity. At best the result is a two-firm oligopoly with a non-participating hydro

[19] Of course one cannot eliminate the possibility that a regional generation cartel – explicit or tacit – will find a way to include the managers of the regional hydro plants in the spoils of the exercise of market power, and so exercise this market power without the unwelcome interference of the fringe plants.

fringe; at worst it is virtually a Tatenergo monopoly, with miniscule TGK-7 capacity and two plants owned by Hydro OGK that may or may not act to limit the power of Tatenergo to manipulate prices. Of course, it is in precisely the winter season of peak demand that surplus electricity from neighboring regions is least likely to be available in response to wholesale price increases. All in all, the competitive situation regarding Volga generation in the winter could be a very troublesome one for Russian regulators.

3.2 The Central Region

The situation during times of peak demand is not much better in the Central region. From here on we conserve space by not including the tables with the raw generation sector data in the paper; they are available from the author.

During the spring, baseload plants constitute 31 percent of capacity, as multiple hydro plants are unable to operate with significant flexibility. Non-baseload capacity is divided among ten regional and national generation companies, with the top four accounting for about two-thirds of non-base-load capacity. The summer/fall seasons are basically the same if one assumes non-flexibility on the part of hydro plants, and somewhat less concentrated if the hydro plants are assumed to respond to wholesale market price signals.

Again, however, the likelihood that CHP plants become "must run" in the Russian winter has a serious impact on the competitiveness of generation markets (and again this effect is exacerbated by a reduction in hydro capacity as compared with the spring). Now baseload capacity accounts for 58 percent of generation capacity. There remain ten generation companies with non-base-load capacity, but they are dividing a much smaller pie. The four-firm concentration ratio for non-base-load capacity in the winter is 74 percent. Furthermore, the top four all have significant baseload capacity, raising the possibility that anticompetitive output restriction by these companies would yield monopoly rents for these inframarginal plants – depending, of course, on the price system chosen for inframarginal plants generally. As with the Volga region, it appears that in the peak demand periods of winter there may be serious problems with competition in the Central region generation market, and so a real danger of significant price spikes during periods of peak demand.

3.3 The Northwest Region

There may be significant problems with concentration in the Northwest region as well. In the spring/fall and summer seasons, base-load generation accounts for not quite 40 percent of generation capacity. In all three of these seasons, the top four non-base-load generation companies control over three-fourths of the remaining capacity, raising the possibility of coordinated behavior in such a concentrated market. In addition, the top non-base-load generation company, TGK-1, owns a large number of baseload hydro plants, which raises additional concerns about the withholding of peak-load production in order to earn inframarginal rents on base-load capacity. In both cases there are two small additional non-base-load generation companies that may provide some small challenges to anticompetitive output reductions by the big four.

In the winter, when the many CHP plants move into the base-load category, baseload generation accounts for a very high 72 percent of all generation capacity. In that case, as in some other regions, especially during periods of peak demand, virtually all non-base-load capacity is controlled by only four generation companies, and again one of these, TGK-1, controls significant amounts of baseload capacity as well. One must conclude that anticompetitive behavior by a small number of oligopolists playing a repeat game is a significant worry in the Northwest region as well.

3.4 The Siberia Region

In Siberia there appear to be no generation plants that meet the usual qualifications for base-load capacity in the spring and fall, so the competitive situation in those seasons is essentially the same moderately concentrated level as in Table 1: the top four privately owned firms own 56 percent of capacity, with seven firms with significant additional capacity. Combined with the 21 percent of capacity controlled by Hydro OGK, this may be the least worrisome situation of all six regions and all four seasons.

Things are not quite as bright in the summer and winter, however, with the reallocation of some generation plants into the base-load category removing some of the flexibility in the market. In the summer it is the loss of hydro flexibility that moves almost 53 percent of capacity into the base-load category. In that case the top four non-base-load companies come to control almost two-thirds of non-baseload capacity, with the additional problematic incentive feature that one of these, Irkutskenergo, controls significant baseload hydro capacity as well.

In the winter it is the loss of flexibility in the CHP plants that moves 29 percent of generation capacity into the base-load category. Now the top four privately owned non-base-load generation companies account for 30 percent of non-base-load generation capacity, and the behavior to be expected from the almost 20 percent of capacity accounted for by Hydro OGK (once the Boguchanskaya GES plant is completed) takes on great importance. A likely exacerbating factor here is that three of these four top non-base-load generation companies control significant amounts of baseload CHP capacity as well, which may encourage them to restrict production in their non-baseload plants.

3.5 The South Region

The Southern region – sometimes referred to as the "Northern Caucasus" region – is unusual because the peak of hydro production – when many hydro plants become baseload – is in the summer rather than the spring, and because it has only a small number of CHP plants that become baseload in the winter. Of course the winter weather is less fierce in this region, so the winter peak in demand is less pronounced as well, but we do not deal with that factor here.

In the spring and fall, base-load power is only 14 percent of generation capacity, while in the summer it is 37 percent. However, in either season there are only four significant privately owned non-baseload generating companies, one of which (TGK-8) owns a small baseload plant as well. Such a small number of competitors playing this repeat game may well be able to coordinate production decisions in such a way as to raise wholesale prices, although in the spring and fall the government-owned Hydro OGK could use its considerable capacity to mitigate anticompetitive reductions in output.

The situation becomes slightly worse in the winter, because so many of the TGK-8 generation plants are CHP plants that move into the baseload category. Otherwise the situation is the same as the fall: four firms with almost all the privately owned non-base-load generation capacity, but subject to procompetitive output increases by Hydro OGK plants should they decide to act as load-shavers.

Thus in the South the situation appears worst in the winter if one fears incentives by baseload plant owners to restrict peak-load output in order to seek inframarginal rents, but worst in the summer if one forecasts that the government-owned Hydro OGK can be counted on in the other seasons to use its production flexibility to defeat anticompetitive price increases. In all four seasons there appears to be a real potential for anticompetitive behavior among this group of only four privately owned non-baseload generation companies.

3.6 The Urals Region

The Urals region appears on the unconcentrated end of the spectrum in Table 1, but becomes perhaps a bit more problematic when we look more closely at seasonal and flexibility factors.

In the spring and summer/fall seasons, only a very small share of generation is baseload, so non-baseload generation concentration is not appreciably greater than annual overall generation concentration. However, fully 27 percent of Urals generation capacity is made up of CHP plants, and thus in the winter, baseload generation increases to the 29 to 31 percent range, depending on how one treats the Votkinskaya and Kamskaya hydro plants. There remain nine companies with non-base-load generation, but the top four account for around two-thirds of non-base-load generation capacity. On the other hand, none of these four owns any CHP plants, so there is no additional incentive to withhold output for inframarginal gains at base-load plants.

3.7 Cross-Regional Issues

As the preceding analysis suggests, when all the relevant seasonal factors are taken into account, there appear to be real reasons for concern regarding anticompetitive structure and behavior in the majority of these post-restructuring regional generation markets in Russia.

Two additional, related findings are suggested by the previous analysis. First, in terms of repeat games across regions rather than over time, there will be what we might characterize as a moderate amount of intermarket interaction among the announced privatized generation companies. Among those in the top four owners of flexible generation plant in each region, OGK-3 appears in both the Central and Northwest regions; OGK-7 appears in the Central, South, and Northwest regions; OGK-2 appears in the Urals, South, and Northwest regions; and OGK-5 appears in the Urals and South regions. There are of course more cross-regional interactions if we move beyond the top four generation companies in each region, as Table 1 demonstrates. Regardless of who ultimately comes to own these national generation companies, it seems unlikely that they will ignore their frequent interactions across geographic markets when they make their production decisions.

Second, it has gone largely unremarked (to my knowledge) in the discussions of Russian electricity restructuring, but it is clear from the Tables that there is virtually no Russian generation capacity that remains to be purchased by a buyer who is unsuccessful in bidding for one of the national or regional generation companies (or not interested in doing so). Furthermore, though it is quite possible that new generation capacity will be constructed – for example, by industrial firms with access to inexpensive gas supplies – this procompetitive action is discouraged by the provisions of the reform laws barring any single company from owning both generation and transmission assets (Branan, 2004). Absent changes in the allocation of generation plants to generation companies, then, the structure of Russian regional electricity generation markets has already been determined – and the likelihood of anticompetitive behavior, with the resulting increases in consumer prices, is real.

4. Conclusion

It is difficult to tell in advance how competitive each regional wholesale electricity market in Russia will be. Russia is only now beginning its experience with dispatching electricity flows in response to market signals, and the precise locations where there may be congestion or where electricity may flow from one "region" into another in response to demand/supply imbalances remains to be seen (and will, of course, depend in part on the regulation and pricing of transmission).

Still there is enough information available that one may make at least educated guesses about the likely outcomes of particular policy decisions that have already been made. Until very large additional amounts of resources are devoted over long periods of time to upgrading the long-distance transmission system, something like the six regions that (along with the Far East) are the basis of RAO UES operations will likely act as regional wholesale electricity markets under most circumstances, and especially under peak-load circumstances – those very times when the balance of inelastic supply and inelastic demand is most likely to yield significant wholesale price increases.

Likewise, and building on the work of previous researchers, we may make certain assumptions about the behavior of particular generation plants under particular conditions

– that CHP plants will not be particularly flexible during peak-demand winter months, that some hydro plants have more production flexibility than others, and that some lose their flexibility at times of peak water flow – that allow us to predict in more detail what the competitive structure of the flexible portion of particular regional generation markets may look like.

Using these simple tools, this paper reaches findings that suggest that the warnings of the recent IEA study of Russian electricity restructuring concerning the likelihood that some regional markets may not be competitively structured are, if anything, understated. It appears that several regional generation markets may be characterized by tight four-firm oligopolies or even worse during periods of peak demand, and that in many cases the firms in those tight oligopolies may face further incentives to restrict output because of their ownership of baseload as well as non-baseload plants. After the experiences of California, the UK, and other locales with sizable price increases from generation companies able to restrict output anticompetitively in oligopolistic markets, Russian policy makers may want to consider carefully whether their current electricity market restructuring plans risk creating similar problems at home.

What are the policy alternatives available? A thorough discussion is beyond the scope of this paper, but several candidates should be mentioned. First of all, many of the problems that have appeared in restructured electricity markets in other countries have been due at least in part to the very inelastic supply and demand curves that are characteristic of this sector, especially during times of peak demand. Thus policies that seek to render supply and/or demand more elastic have an obvious appeal (Borenstein and Bushnell, 1999; Borenstein, Bushnell, and Knittel (1999).

For example, as noted earlier, improved interregional transmission capabilities would enlarge wholesale geographic markets and tend to reduce market power, especially to the degree that peak times in adjacent regions are not simultaneous. Similarly, one could argue for a demonopolization scheme that resulted in an increased number of smaller companies, each with correspondingly less market power and thus reduced incentives to restrict output. (This is an option urged by World Bank [2004a].) Third, some kind of system of "capacity payments" may encourage the construction of new generation plants in the future, thus similarly reducing the market power of existing plants. Fourth, the more that large users are made subject to real-time pricing, the greater will be the ability of the system to avoid the largest price spikes. Finally, long-term contracts between generation companies and large customers may reduce the returns to generation companies from withholding output in order to increase spot prices.

None of these potential "fixes" is easy, or without potential drawbacks. There is a small but growing group of electricity market skeptics around the world who argue that, even with ameliorative policies like these, the creation and operation of "free" markets in electricity has turned out to be sufficiently expensive, complex, and difficult as to call into question the entire reform strategy of vertical separation here. These skeptics argue that the old electricity sector model of regulated vertically integrated monopolists may not have performed so badly after all in retrospect. Perhaps it is too late in the day for

Russia to reconsider its overall electricity reform strategy, and ameliorative measures such as those listed in the previous paragraph are the best we can do. Still, Brennan (2001) and others urge us to face the very real possibility that "electricity will be the sector in which markets meet their match."

References

Arellano, M. Soledad (2004), "Market Power in Mixed Hydro-Thermal Electric Systems," working paper, Universidad de Chile, April.

Atkinson, Scott E., and Claudia Elizabeth Halabí (2005), "Economic Efficiency and Productivity Growth in the Post-Privatization Chilean Hydroelectric Industry," *Journal of Productivity Analysis*, 23, 245-273.

Bayliss, Kate (2001), "Privatisation of electricity distribution: some economics, social and political perspectives," working paper, Public Services International Research Unit, School of Computing and Mathematical Sciences, University of Greenwich, April.

Blumstein, Carl, Lee S. Friedman, and Richard Green (2002), "The History of Electricity Restructuring in California," *Journal of Industry Competition and Trade*, 2, 9-38.

Borenstein, Severin, and James B. Bushnell (1999), "An Empirical Analysis of the Potential for Market Power in California's Electricity Industry," *Journal of Industrial Economics*, 47, 285-323.

_____, _____, and Christopher R. Knittel (1999), "Market Power in Electricity Market: Beyond Concentration Measures," working paper PWP-059r, Program on Workable Energy Regulation (POWER), University of California Energy Institute, February.

_____, _____, and Frank A. Wolak (2002), "Measuring Market Inefficiency in California's Wholesale Electricity Market," *American Economic Review,* 92, 1376-1405.

Branan (2004), "Restructuring of Regional Electricity Companies," in Terterov (2004).

Brennan, Timothy J. (2001), "The California Electricity Experience, 2000-01: Education or Diversion?", Washington, DC: Resources for the Future, RFF Report, October.

Buehler, S., A. Schmutzler, and M.-A. Benz (2004), "Infrastructure quality in deregulated industries: is there an underinvestment problem?" *International Journal of Industrial Organization,* 22, 253-268.

Bushnell, James (2003), "A Mixed Complementarity Model of Hydrothermal Electricity Competition in the Western United States," *Operations Research*, 51, 80-93.

_____ (2005), "Looking for Trouble: Competition Policy in the U.S. Electricity Industry," in Griffin, James M. and Steven L. Puller, eds., *Electricity Deregulation: Choices and Challenges,* Chicago: University of Chicago Press.

CMS Cameron McKenna (2004), "Practical and Institutional Barriers to Reform Implementation," in Terterov (2004).

Day, Christopher J., and Derek W. Bunn (2001), "Divestiture of Generation Assets in the Electricity Pool of England and Wales: A Computational Approach to Analyzing Market Power," *Journal of Regulatory Economics*, 19, 123-141.

Fabra, Natalia, and Juan Toro (2005), "Price Wars and Collusion in the Spanish Electricity Market," *International Journal of Industrial Organization*, 23, 155-181.

Galkin, Mikhail, and Andreas Zsiga (2004), "Mosenergo," in Terterov (2004).

Green, Richard, and David M. Newbery (1997), "Competition in the Electricity Industry in England and Wales," *Oxford Review of Economic Policy*, 13, 27-46.

Hogan, William W. (2002), "Electricity Market Restructuring: Reform of Reforms," *Journal of Regulatory Economics*, 21, 103-132.

Hubert, Franz (2002), "Reform of Russian Power Industry: Which Lessons from Abroad?", working paper, Humboldt Universität zu Berlin, March.

Joskow, Paul L. (2001), "California's Electricity Crisis," *Oxford Review of Economic Policy,* 17.

_____ and Edward Kahn (2002), "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," *Energy Journal* (December 2002), 1-35.

Kennedy, David (2002), "Liberalisation of the Russian Power Sector," working paper #69, European Bank for Reconstruction and Development, January.

Littlechild, Stephen C. (1999), "Privatisation, Competition and Regulation," speech before the Wincott Foundation, December.

Newbery, David M. (1999), *Privatization, Restructuring, and Regulation of Network Utilities*, Cambridge, MA: MIT Press.

_____ (2003), "Regulatory Challenges to European Electricity Liberalisation," *Swedish Economic Policy Review*, 9, 9-44.

Pittman, Russell (2003a), "Vertical Restructuring (Or Not) of the Infrastructure Sectors of Transition Economies," *Journal of Industry, Competition and Trade,* 3, 5-26.

_____ (2003b), "Reform in the Rail and Electricity Sectors in Russia: Restructuring, Competition and the Ministry for Antimonopoly Policy," *Acta Oeconomica,* 53, 339-362.

Pogrebniak, Evgeniy (2005), "Simulation Model of a Competitive Wholesale Power Market in Russia and Measures for its Development, Institute for Complex Strategic Studies, Moscow, presented at the VI International Scientific Conference, "Modernisation of Economy and Nurturing of Institutions," State University – Higher School of Economics, Moscow, April.

Puller, Steven L. (2002), "Pricing and Firm Conduct in California's Deregulated Electricity Market," working paper, Program on Workable Energy Regulation (POWER), University of California Energy Institute, August.

Terterov, Marat, ed. (2004), *Doing Business with Russia's Electrical Energy Sector*, London: Kogan Page.

Thomas, Steve (2004), "Evaluating the British Model of Electricity Deregulation," *Annals of Public and Cooperative Economics*, 75, 367-398.

_____ (2005), "Electricity Privatisation and Restructuring in Russia and Ukraine," working paper, Public Service International Research Unit, School of Computing and Mathematical Sciences, University of Greenwich, January.

Tompson, William (2004), "Restructuring Russia's Electricity Sector: Towards Effective Competition or Faux Liberalisation?" Economics Department Working Paper No. 403, Paris: Organization for Economic Cooperation and Development, September.

Wolfram, Catherine D. (1998), "Strategic bidding in a multiunit auction: an empirical analysis of bids to supply electricity in England and Wales," *RAND Journal of Economics*, v. 29, 703-725.

_____ (1999), "Measuring Duopoly Power in the British Electricity Spot Market," *American Economic Review*, 89, 805-826.

Williamson, Oliver E. (2000), "The New Institutional Economics: Taking Stock, Looking Ahead," *Journal of Economic Literature*, v. 38, 595-613.

World Bank (2004a), "Structural and Design Issues in the Russian Electricity Reforms: A Policy Note," Infrastructure and Energy Services Department, Europe and Central Asia Region, June.

_____ (2004b), "Policy Perspective and Analysis of the Regulatory Regime in the Restructured Russian Power Sector: A Policy Note," Infrastructure and Energy Services Department, Europe and Central Asia Region, June.

Yi-Chong, Xu (2004), *Electricity Reform in China, India and Russia: The World Bank Template and the Politics of Power*, Northampton, MA: Edward Elgar.

Table 1 – Structure of regional markets

Company	Technology	Capacity	Capacity share	Cumulative capacity share	HHI
The Volga Region					
Tatenergo	CHP/GRES/hydro	6,986.00	29.61%	29.61%	876.65
TGK-7	CHP/GRES	5,800.70	24.58%	54.19%	604.41
Hydro OGK	hydro	5,007.00	21.22%	75.41%	450.33
RosAtom	nuclear	4,000.00	16.95%	92.37%	287.40
TGK-5	CHP	1,047.00	4.44%	96.80%	19.69
TGK-6	CHP	754.00	3.20%	100.00%	10.21
Total		23,594.70	100.00%		2,248.70
The Central Region					
RosAtom	nuclear	10,800.00	21.85%	21.85%	477.22
TGK-3	GRES/CHP	10,588.80	21.42%	43.26%	458.74
OGK-3	GRES	5,025.00	10.16%	53.43%	103.31
Hydro OGK	hydro	4,701.00	9.51%	62.94%	90.42
OGK-6	GRES	3,580.00	7.24%	70.18%	52.44
TGK-4	GRES/CHP	3,185.40	6.44%	76.62%	41.51
OGK-5	GRES	2,400.00	4.85%	81.48%	23.57
TGK-6	GRES/CHP	2,361.00	4.78%	86.25%	22.81
TGK-8	GRES/CHP	1,981.00	4.01%	90.26%	16.06
OGK-1	GRES	1,885.00	3.81%	94.07%	14.54
OGK-4	GRES	1,730.00	3.50%	97.57%	12.25
TGK-2	CHP	1,201.00	2.43%	100.00%	5.90
Total		49,438.20	100.00%		1,318.76
The Northwest Region					
TGK-1	GRES/CHP/hydro	6,065.05	34.09%	34.09%	1,161.83
RosAtom	nuclear	5,760.00	32.37%	66.46%	1,047.90
OGK-6	GRES	2,100.00	11.80%	78.26%	139.29
TGK-2	CHP	1,238.50	6.96%	85.22%	48.45
OGK-3	GRES	1,060.00	5.96%	91.18%	35.49
TGK-9	CHP	690.00	3.88%	95.05%	15.04
North-West CHP	CHP	450.00	2.53%	97.58%	6.40
OGK-2	GRES	430.00	2.42%	100.00%	5.84
Total		17,793.55	100.00%		2,460.23
The Siberia Region					
Irkutskenergo	hydro/CHP	12,975.90	27.14%	27.14%	736.78
Hydro OGK	hydro	10,176.00	21.29%	48.43%	453.12
Krasnoyarskaya GES	hydro	6,000.00	12.55%	60.98%	157.53
TGK-11	GRES/CHP	4,526.00	9.47%	70.45%	89.64
Novosibirskenergo	CHP	3,112.00	6.51%	76.96%	42.38
TGK-12	GRES/CHP	3,101.20	6.49%	83.45%	42.08
TGK-13	GRES/CHP	2,362.00	4.94%	88.39%	24.41
OGK-3	GRES	1,690.00	3.54%	91.92%	12.50
OGK-4	GRES	1,440.00	3.01%	94.93%	9.07
OGK-6	GRES	1,250.00	2.61%	97.55%	6.84
TGK-14	CHP	1,071.40	2.24%	99.79%	5.02
Mamakanskaya GES	hydro	100.00	0.21%	100.00%	0.04
Total		47,804.50	100.00%		1,579.42
The South Region					
Hydro OG K	hydro	3,067.72	25.83%	25.83%	667.22
OGK-2	GRES	2,400.00	20.21%	46.04%	408.37
OGK-6	GRES	2,245.00	18.90%	64.94%	357.33
TGK-8	CHP/hydro/GRES	1,823.60	15.35%	80.30%	235.77
OGK-5	GRES	1,340.00	11.28%	91.58%	127.31
RosAtom	nuclear	1,000.00	8.42%	100.00%	70.90
Total		11,876.32	100.00%		1,866.90
The Urals Region					
OGK-1	GRES	7,175.00	18.17%	18.17%	330.08
OGK-2	GRES	5,865.00	14.85%	33.02%	220.55
OGK-4	GRES	5,400.00	13.67%	46.69%	186.96
Bashkirenergo	CHP/GRES/hydro	5,113.79	12.95%	59.64%	167.67
OGK-5	GRES	5,005.00	12.67%	72.31%	160.61
TGK-10	CHP/GRES	2,947.00	7.46%	79.78%	55.68

TGK-9	CHP/GRES/hydro	2,556.40	6.47%	86.25%	41.90
Hydro OGK	hydro	1,482.00	3.75%	90.00%	14.08
TGK-5	CHP	1,426.30	3.61%	93.61%	13.04
TGK-7	CHP/hydro	1,040.00	2.63%	96.25%	6.93
OGK 3	GRES	882.00	2.23%	98.48%	4.99
RosAtom	nuclear	600.00	1.52%	100.00%	2.31
	Total	39,492.49	100.00%		1,204.82

Note: OGK – Wholesale Generation Company; TGK – Territrial Generation Company; CHP – Combined Heat and Power Plant; GRES – State Regional Power Plant; CCGT – Combined Cycle Gas Turbine; DES – Diesel Power Station; GTS – Geothermal Power Station; GES – Hydro Power Plant.

Table 2 – Market structure of the Volga region during the spring season

Plant	Energo	Proposed Parent	Technology	Capacity	Capacity share	Cumulative capacity share
		Base-load group				
Zhigulevskaya GES (F)		Hydro OGK	hydro	2,300.0	9.75%	9.75%
Saratovskaya GES (NF)		Hydro OGK	hydro	1,337.0	5.67%	15.41%
Cheboksarskaya GES (F)		Hydro OGK	hydro	1,370.0	5.81%	21. 22%
Balakovskaya NPP		RosAtom	nuclear	4,000.0	16.95%	38.17%
Nizhnekamskaya GES (F)	Tatenergo	Tatenergo	hydro	1,205.0	5.11%	43.28%
		Non-base-load group				
CHP Volzhskogo Avtozavoda	Samaraenergo	TGK-7	CHP	1,172.0	4.97%	48.25%
Tolyattinskaya CHP	Samaraenergo	TGK-7	CHP	710.0	3.01%	51.26%
Novokuybyshevskaya CHP-2	Samaraenergo	TGK-7	CHP	470.0	1.99%	53.25%
Balakovskaya CHP-4	Saratovenergo	TGK-7	CHP	465.0	1.97%	55.22%
Saratovskaya CHP-5	Saratovenergo	TGK-7	CHP	440.0	1.86%	57.08%
Ulyanovskaya CHP-1	Ulyanovskenergo	TGK-7	CHP	435.0	1.84%	58.93%
Ulyanovskaya CHP-2	Ulyanovskenergo	TGK-7	CHP	417.0	1.77%	60.70%
Samarskaya CHP	Samaraenergo	TGK-7	CHP	390.0	1.65%	62.35%
Saratovskaya CHP-2	Saratovenergo	TGK-7	CHP	315.0	1.34%	63.68%
Syzranskaya CHP	Samaraenergo	TGK-7	CHP	255.0	1.08%	64.76%
Novokuybyshevskaya CHP-1	Samaraenergo	TGK-7	CHP	236.0	1.00%	65.76%
Engelsskaya CHP-3	Saratovenergo	TGK-7	CHP	202.0	0.86%	66.62%
Bezymyanskaya CHP	Samaraenergo	TGK-7	CHP	183.7	0.78%	67.40%
Saratovskaya GRES-CHP-1	Saratovenergo	TGK-7	CHP	57.0	0.24%	67.64%
Samarskaya GRES	Samaraenergo	TGK-7	GRES	53.0	0.22%	67.87%
Zainskaya GRES	Tatenergo	Tatenergo	GRES	2,400.0	10.17%	78.04%
Naberezhno-Chelninskaya CHP	Tatenergo	Tatenergo	CHP	1,180.0	5.00%	83.04%
Nizhnekamskaya CHP-1	Tatenergo	Tatenergo	CHP	850.0	3.60%	86.64%
Nizhnekamskaya CHP-2	Tatenergo	Tatenergo	CHP	420.0	1.78%	88.42%
Kazanskaya CHP-3	Tatenergo	Tatenergo	CHP	405.0	1.72%	90.14%
Kazanskaya CHP-1	Tatenergo	Tatenergo	CHP	190.0	0.81%	90.94%
Kazanskaya CHP-2	Tatenergo	Tatenergo	CHP	175.0	0.74%	91.68%
Urussinskaya GRES	Tatenergo	Tatenergo	GRES	161.0	0.68%	92.37%
Cheboksarskaya CHP-2	Chuvashenergo	TGK-5	CHP	460.0	1.95%	94.32%
Novocheboksarskaya CHP-3	Chuvashenergo	TGK-5	CHP	380.0	1.61%	95.93%
Yoshkar-Olinskaya CHP	Marienergo	TGK-5	CHP	195.0	0.83%	96.75%
Cheboksarskaya CHP-1	Chuvashenergo	TGK-5	CHP	12.0	0.05%	96.80%
CHP-1	Penzaenergo	TGK-6	CHP	385.0	1.63%	98.44%
Saranskaya CHP-2	Mordovenergo	TGK-6	CHP	340.0	1.44%	99.88%
CHP-2	Penzaenergo	TGK-6	CHP	16.0	0.07%	99.94%
Alekseevskaya CHP-3	Mordovenergo	TGK-6	CHP	9.0	0.04%	99.98%
CHP-3	Penzaenergo	TGK-6	CHP	4.0	0.02%	100.00%

Source: Annual reports of AO-energos and Federal power plants.
Note: All hydro power plants marked either F or NF. F stands for flexible plant while NF – for non-flexible. Flexibility is defined in terms of plant's constant ability to cover peaks of demand for electric power.

Table 3 – Market structure of the Volga region during summer and fall seasons

Plant	Energo	Proposed Parent	Technology	Capacity	Capacity share	Cumulative capacity share
		Base-load group				
Balakovskaya NPP		RosAtom	nuclear	4,000.0	17.94%	17.94%
Saratovskaya GES (NF)		Hydro OGK	hydro	1,058.0	4.74%	22.68%
		Non-baseload group				
Zhigulevskaya GES (F)		Hydro OGK	hydro	1,820.0	8.16%	30.85%
Cheboksarskaya GES (F)		Hydro OGK	hydro	1,084.1	4.86%	35.71%
Zainskaya GRES	Tatenergo	Tatenergo	GRES	2,400.0	10.76%	46.47%
Naberezhno-Chelninskaya CHP	Tatenergo	Tatenergo	CHP	1,180.0	5.29%	51.76%
Nizhnekamskaya GES (F)	Tatenergo	Tatenergo	hydro	953.5	4.28%	56.04%
Nizhnekamskaya CHP-1	Tatenergo	Tatenergo	CHP	850.0	3.81%	59.85%
Nizhnekamskaya CHP-2	Tatenergo	Tatenergo	CHP	420.0	1.88%	61.73%
Kazanskaya CHP-3	Tatenergo	Tatenergo	CHP	405.0	1.82%	63.55%
Kazanskaya CHP-1	Tatenergo	Tatenergo	CHP	190.0	0.85%	64.40%
Kazanskaya CHP-2	Tatenergo	Tatenergo	CHP	175.0	0.78%	65.19%
Urussinskaya GRES	Tatenergo	Tatenergo	GRES	161.0	0.72%	65.91%
CHP Volzhskogo Avtozavoda	Samaraenergo	TGK-7	CHP	1,172.0	5.26%	71.17%
Tolyattinskaya CHP	Samaraenergo	TGK-7	CHP	710.0	3.18%	74.35%
Novokuybyshevskaya CHP-2	Samaraenergo	TGK-7	CHP	470.0	2.11%	76.46%
Balakovskaya CHP-4	Saratovenergo	TGK-7	CHP	465.0	2.09%	78.54%
Saratovskaya CHP-5	Saratovenergo	TGK-7	CHP	440.0	1.97%	80.52%
Ulyanovskaya CHP-1	Ulyanovskenergo	TGK-7	CHP	435.0	1.95%	82.47%
Ulyanovskaya CHP-2	Ulyanovskenergo	TGK-7	CHP	417.0	1.87%	84.34%
Samarskaya CHP	Samaraenergo	TGK-7	CHP	390.0	1.75%	86.09%
Saratovskaya CHP-2	Saratovenergo	TGK-7	CHP	315.0	1.41%	87.50%
Syzranskaya CHP	Samaraenergo	TGK-7	CHP	255.0	1.14%	88.64%
Novokuybyshevskaya CHP-1	Samaraenergo	TGK-7	CHP	236.0	1.06%	89.70%
Engelsskaya CHP-3	Saratovenergo	TGK-7	CHP	202.0	0.91%	90.61%
Bezymyanskaya CHP	Samaraenergo	TGK-7	CHP	183.7	0.82%	91.43%
Saratovskaya GRES-CHP-1	Saratovenergo	TGK-7	CHP	57.0	0.26%	91.69%
Samarskaya GRES	Samaraenergo	TGK-7	GRES	53.0	0.24%	91.92%
Cheboksarskaya CHP-2	Chuvashenergo	TGK-5	CHP	460.0	2.06%	93.99%
Novocheboksarskaya CHP-3	Chuvashenergo	TGK-5	CHP	380.0	1.70%	95.69%
Yoshkar-Olinskaya CHP	Marienergo	TGK-5	CHP	195.0	0.87%	96.56%
Cheboksarskaya CHP-1	Chuvashenergo	TGK-5	CHP	12.0	0.05%	96.62%
CHP-1	Penzaenergo	TGK-6	CHP	385.0	1.73%	98.35%
Saranskaya CHP-2	Mordovenergo	TGK-6	CHP	340.0	1.52%	99.87%
CHP-2	Penzaenergo	TGK-6	CHP	16.0	0.07%	99.94%
Alekseevskaya CHP-3	Mordovenergo	TGK-6	CHP	9.0	0.04%	99.98%
CHP-3	Penzaenergo	TGK-6	CHP	4.0	0.02%	100.00%

Table 4 – Market structure of the Volga region during the winter season

Plant	Energo	Proposed Parent	Technology	Capacity	Capacity share	Cumulative capacity share
		Base-load group				
CHP Volzhskogo Avtozavoda	SamaraEnergo	TGK-7	CHP	1,172.0	5.36%	5.36%
Tolyattinskaya CHP	SamaraEnergo	TGK-7	CHP	710.0	3.25%	8.61%
Novokuybyshevskaya CHP-2	SamaraEnergo	TGK-7	CHP	470.0	2.15%	10.75%
Balakovskaya CHP-4	SaratovEnergo	TGK-7	CHP	465.0	2.13%	12.88%
Saratovskaya CHP-5	SaratovEnergo	TGK-7	CHP	440.0	2.01%	14.89%
Ulyanovskaya CHP-1	UlyanovskEnergo	TGK-7	CHP	435.0	1.99%	16.88%
Ulyanovskaya CHP-2	UlyanovskEnergo	TGK-7	CHP	417.0	1.91%	18.79%
Samarskaya CHP	SamaraEnergo	TGK-7	CHP	390.0	1.78%	20.57%
Saratovskaya CHP-2	SaratovEnergo	TGK-7	CHP	315.0	1.44%	22.01%
Syzranskaya CHP	SamaraEnergo	TGK-7	CHP	255.0	1.17%	23.18%
Novokuybyshevskaya CHP-1	SamaraEnergo	TGK-7	CHP	236.0	1.08%	24.26%
Engelsskaya CHP-3	SaratovEnergo	TGK-7	CHP	202.0	0.92%	25.18%
Bezymyanskaya CHP	SamaraEnergo	TGK-7	CHP	183.7	0.84%	26.02%
Saratovskaya GRES-CHP-1	SaratovEnergo	TGK-7	CHP	57.0	0.26%	26.28%
Balakovskaya NPP		RosAtom	nuclear	4,000.0	18.29%	44.57%
Naberezhno-Chelninskaya CHP	Tatenergo	Tatenergo	CHP	1,180.0	5.40%	49.97%
Nizhnekamskaya CHP-1	Tatenergo	Tatenergo	CHP	850.0	3.89%	53.86%
Nizhnekamskaya CHP-2	Tatenergo	Tatenergo	CHP	420.0	1.92%	55.78%
Kazanskaya CHP-3	Tatenergo	Tatenergo	CHP	405.0	1.85%	57.63%

Kazanskaya CHP-1	Tatenergo	Tatenergo	CHP	190.0	0.87%	58.50%
Kazanskaya CHP-2	Tatenergo	Tatenergo	CHP	175.0	0.80%	59.30%
Saratovskaya GES (NF)		Hydro OGK	hydro	965.6	4.42%	63.71%
Cheboksarskaya CHP-2	ChuvashEnergo	TGK-5	CHP	460.0	2.10%	65.82%
Novocheboksarskaya CHP-3	ChuvashEnergo	TGK-5	CHP	380.0	1.74%	67.55%
Yoshkar-Olinskaya CHP	MariEnergo	TGK-5	CHP	195.0	0.89%	68.45%
Cheboksarskaya CHP-1	ChuvashEnergo	TGK-5	CHP	12.0	0.05%	68.50%
CHP-1	PenzaEnergo	TGK-6	CHP	385.0	1.76%	70.26%
Saranskaya CHP-2	MordovEnergo	TGK-6	CHP	340.0	1.55%	71.82%
CHP-2	PenzaEnergo	TGK-6	CHP	16.0	0.07%	71.89%
Alekseevskaya CHP-3	MordovEnergo	TGK-6	CHP	9.0	0.04%	71.93%
CHP-3	PenzaEnergo	TGK-6	CHP	4.0	0.02%	71.95%
Non-base-load group						
Zhigulevskaya GES (F)		Hydro OGK	hydro	1,661.1	7.60%	79.54%
Cheboksarskaya GES (F)		Hydro OGK	hydro	989.4	4.52%	84.07%
Zainskaya GRES	Tatenergo	Tatenergo	GRES	2,400.0	10.97%	95.04%
Nizhnekamskaya GES (F)	Tatenergo	Tatenergo	hydro	870.3	3.98%	99.02%
Urussinskaya GRES	Tatenergo	Tatenergo	GRES	161.0	0.74%	99.76%
Samarskaya GRES	SamaraEnergo	TGK-7	GRES	53.0	0.24%	100.00%