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CAPACITY MARKET IN RUSSIA: ADDRESSING THE ENERGY TRILEMMA

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Abstract

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This doctoral dissertation examines the contribution of the capacity market and capacity remuneration mechanisms (CRMs) introduced in the liberalized electricity market of Russia to achieving the objectives of the energy trilemma: energy security, sustainability, and energy affordability. CRMs are chosen to provide the security of electricity supply by ensuring investments in new conventional power plants. The investors receive guarantee of return on their investments within 10 to 20 years, while agreeing on building contracted capacity on time. Similar CRMs were introduced for renewable energy power plants in 2013 in order to achieve the sustainability goals. Being non-market-based investment incentives, the implementation of CRMs, together with overestimation of the demand growth, has resulted in a capacity oversupply, increasing the amount of the capacity that is not selected in the capacity auction and receives capacity payments to stay in the market for the system reliability reasons. Therefore, CRMs and capacity payments question the design of the capacity market and impact on the final consumer capacity price, and thus, result in an energy affordability issue. The objective of this doctoral dissertation is to analyse the outcomes of having a capacity market and CRMs in Russia and their effectiveness in the context of the energy trilemma. The results suggest that implemented CRMs can guarantee energy security in the short term. However, the current capacity market design cannot provide market-based incentives to invest in new power plants, thereby undermining the provision of energy security in the future. CRMs for renewable energy alone will not suffice to achieve the sustainability goals set by the policy makers, at least in the short term. At the same time, CRMs, capacity payments, and challenges faced in the wholesale electricity and capacity market contribute to the increase in the final consumer electricity cost, producing incentives for demand response.

Keywords: Russia, electricity market, capacity market, capacity remuneration mechanism, energy trilemma, energy security, affordability, sustainability

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Evgenia Vanadzina
December 2016
Lappeenranta, Finland

Dedicated

to my Grandfather Nikolai A. Grigoriev

Contents

List of publications

This doctoral dissertation contains material from the following papers. The rights have been granted by the publishers to include the material in the dissertation.

I. Vasileva[1], E. and Viljainen, S. (2014). Capacity market as an incentive for demand response in Russia. In *Proceedings of the European Energy Market Conference*. 28–30 May 2014, Krakow, Poland.

II. Vanadzina, E., Gore, O., Viljainen, S., and Tynkkynen, V-P. (2015). Electricity production as an effective solution for associated petroleum gas utilization in the reformed Russian electricity market. In *Proceedings of the European Energy Market Conference.* 19–22 May 2015, Lisbon, Portugal.

III. Vasileva, E., Viljainen, S., Sulamaa, P., and Kuleshov, D. (2015). RES support in Russia: Impact on capacity and electricity market prices. *Renewable Energy*, 76, pp. 82–90.

IV. Gore, O., Vanadzina, E., and Viljainen, S. (2016). Linking the energy-only market and the energy-plus-capacity market. *Utilities Policy*, 38, pp. 52–61.

V. Vanadzina, E. and Gore, O. (2016). Capacity Market in Russia: possibilities for new generation entry and cost of CRMs. In *Proceedings of the European Energy Market Conference.* 6–9 June 2016, Porto, Portugal.

[1] The maiden name of the author of this doctoral dissertation

Nomenclature

APG	Associated Petroleum Gas
ATS	Administrator of the Trading System
BM	Balancing Market
CBA	Cost-Benefit Analysis
CCA	Competitive Capacity Auction
CDA	Capacity Delivery Agreement
CFC	Center of Financial Calculations
CHP	Combined Heat and Power
CRM	Capacity Remuneration Mechanism
DAM	Day-Ahead Market
DG	Distributed Generation
DR	Demand Response
FAS	Federal Antimonopoly Service
FBC	Free Bilateral Contract
GDP	Gross Domestic Product
GHG	Greenhouse gas
IDGC	Interregional Distribution Grid Company
LP	Linear Programming
LTA	Long-Term Agreement
MC	Market Council
RC	Regulated Contract

RES	Renewable Energy Source
SO	System Operator
WEC	World Energy Council

1 Introduction

The Russian electricity industry is one of the largest in the world. At the current stage, a total installed generating capacity amount of 235 GW (SO, 2016a) and 95 % of the produced electricity is traded in the wholesale electricity market (ATS, 2016a). After the liberalization of the industry in 2011, the electricity price is formed in the competitive day-ahead market (DAM), while the capacity price is determined in the long-term competitive capacity auction (CCA). Nevertheless, some challenges still remain on the regulative side and in the market design, resulting in non-transparent and high electricity costs for final consumers.

In liberalized markets, the electricity price should be formed in a competitive way, and at the same time, it should provide market-based signals for the energy efficiency improvement and investments in new power plants. The role of market design in liberalized markets is a very important and sensitive matter as a regulatory failure can cause an overall market failure. Therefore, apart from the “textbook” structure (Joskow, 2008), each country liberalizing its market has a specific regulatory approach of its own. For Russia, the main driver for liberalization was the lack of investments in the electricity industry in general, which was the reason behind the introduction of a capacity market and capacity remuneration mechanisms (CRMs), viz. capacity delivery agreements (CDAs). These CRMs, initially designed as a temporary solution to overcome the capacity deficit situation, guarantee return on investments to the investors. However, CDAs are still the only way of attracting investments in new power plants within the electricity and capacity market in Russia. Moreover, a renewable energy support scheme is implemented using a CRM, similar to CDAs, as previous attempts of renewable support mechanisms did not provide sufficient investments. The introduction of the long-term CCA was supposed to solve the problem of oversupply and attract new efficient investments. Furthermore, new rules of the CCA, adopted in 2015, should provide market-based signals for the power plants to enter and leave the market.

The cost of the restructuring of the market has been placed on the consumers. However, in Russia, the residential customers pay a lower regulated tariff owing to a government subsidy as part of the social protection program. Therefore, the burden of paying for the capacity remuneration lies on the industry, resulting in cross-subsidization of the residential consumers. Similar rules apply to the natural gas trade, with the difference that the domestic market is subsidized by export sales. In the case of gas, this cross-subsidization creates a favourable environment for the industry to develop on site-generation technologies based on natural gas because of low domestic gas prices. Furthermore, for the main industry of Russia, oil production, the high electricity prices together with the recent flaring ban make investing in own power plants more beneficial than buying electricity from the wholesale market. Yet another issue is connected to the cross-border trade arrangements; Russia has neighbours that employ energy-only markets, and thus, having markets of different design can cause losses in welfare or under-usage of transmission capacities. Therefore, the rules for cross-border trade play a key role when countries have different market designs.

The objective of this doctoral dissertation is to investigate the outcomes of introducing a capacity market and CRMs in the wholesale electricity market using the framework of energy trilemma. Five original articles included in this dissertation address the three dimensions of the trilemma and elaborate on the ability of the capacity market to provide the balance. The experiences from Russia are unique, but can provide valuable lessons for other countries implementing CRMs.

The main contributions of the work are an analysis of the capacity market and CRMs implemented in Russia, the factors affecting the total consumer electricity cost resulting from their implementation, and the outcomes that could emerge in the case of adoption of a certain policy change. The results of the publications are obtained by solving different linear optimization tasks, including a model of the CCA of Russia, which, to the author's knowledge, has not been done before.

1.1 Energy trilemma

The concept of energy trilemma is defined by the World Energy Council (WEC) as the concept that addresses the triple energy challenge of supporting secure, sustainable, and affordable energy (energy equity) (WEC, 2013), Figure 1. The balance of energy trilemma is targeted to deliver energy transformation towards a sustainable energy system.

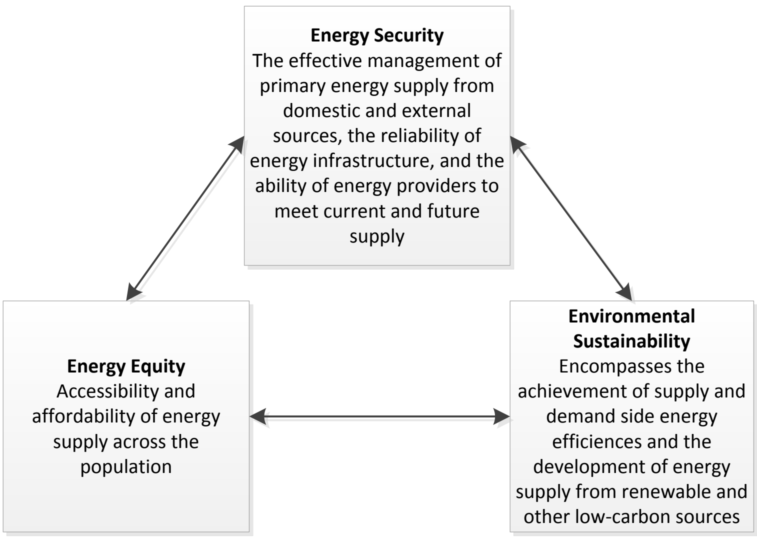


Figure 1. Energy trilemma definition (WEC, 2015a).

The WEC (2016) has developed an energy trilemma index based on the countries' overall performance in achieving a sustainable mix of policies and a balance between the three dimensions of the trilemma. The index is based on metrics such as concentration of total primary energy supply (%), change in energy consumption in relation to gross domestic product (GDP) growth, import dependence (%), concentration of electricity generation (%), access to electricity (%), industry electricity price (US cents per kWh), CO_2 intensity (kCO_2 per US$), and greenhouse gas (GHG) emissions from the energy sector ($MtCO_2e$).

1.2 Outline of the work

The doctoral dissertation consists of two parts. The first part provides the background and rationale of the research, the research objectives and questions, and a summary of the results and publications. Chapter 2 discusses the background of the Russian electricity and capacity market design and its changes, and outlines the main challenges faced by the market players, both on the generation and consumer sides. Chapter 3 describes the research design and delineates the main research questions and objectives. Chapter 4 summarizes the papers included in this dissertation and presents the key findings. Finally, Chapter 5 draws conclusions and reflects on the work done in the dissertation.

The second part of the dissertation consists of five original refereed articles. Three of the articles were presented in international conferences on the European energy markets. Two articles have been published in scientific journals. The articles and the author's contribution to them are summarized below.

Publication I *Capacity market as an incentive for demand response in Russia*

Publication I examines the profitability of the installation of on-site distributed generation (DG) for industrial consumers in order to reduce their total electricity cost. According to the wholesale electricity and capacity market rules, the consumer pays for the capacity according to its highest peak consumption during the peak hours. At the same time, the implementation of CRMs has a tendency to lead to a further increase in capacity prices. These two arguments resulted in a hypothesis that large consumers with a high peak consumption could cut their peak demand by employing on-side DG. The hypothesis has been tested by applying a linear optimization approach with an objective to minimize the total electricity cost. The results indicate that at the current fuel and electricity prices there are strong incentives for the industry to invest in on-site DG, which result in unintended incentives for demand response (DR). The present author carried out the model formulation and analysis of the results. The author of the dissertation was the principal author in the publication.

Publication II *Electricity production as an effective solution for associated petroleum gas utilization in the reformed Russian electricity and capacity market*

Publication II continues the discussion on the impact of the capacity remuneration on the final consumer capacity cost and provides a cost-benefit analysis of implementing own distributed generation for oil and gas production sites. The government of Russia introduced a policy on reducing associated petroleum gas (APG) flaring in 2009 and increased fines for flaring in 2012. Therefore, gas and oil producers were forced to exploit APG, which was previously considered a waste product of the oil industry. Our findings suggest that by investing in a small-scale power plant, oil producers can benefit not only from avoiding high fines for flaring but also from avoiding paying for electricity and capacity. The calculation takes into account the oil field depletion rate and considers an option for excess electricity sales into the market, thereby decreasing the payback period of the power plant. The author of the dissertation was the principal author in the publication and was responsible for the analysis of the option for APG utilization and the cost-benefit analysis presented in the publication.

Publication III *RES support in Russia: Impact on capacity and electricity market prices RES in Russia*

Publication III assesses the impact of the renewable energy policy of Russia on the electricity and capacity prices. Being one of the largest fossil fuel producers and suppliers, Russia had a weak renewable energy policy compared with other countries. The Government introduced a new capacity-based renewable energy support in 2013 (CRM for renewable power plants), which targeted mainly at the promotion of renewable energy sources (RES) technologies in the country. Therefore, the scheme had a limited amount of capacity and technology that could be supported, and introduced a local content requirement. The paper reviews Russia’s renewable energy policy and provides an electricity and capacity price forecast in the case of implementation of a capacity-based renewable support. The findings suggest that the impact of the new support scheme is less significant than that of the capacity support for conventional energy. The author of the dissertation was the principal author in the publication, carried out data collection, and conducted discussion on the numerical results from the capacity market price calculation and the results of the simplified equivalent circuit model.

Publication IV Linking the energy-only market and the energy-plus-capacity market

Publication IV analyses the implications of capacity markets and allocation mechanisms for cross-border trade and market welfare by applying an analytical model for two markets with distinct market designs: energy-only and energy-plus-capacity market. The publication considers a case where two markets are interconnected and operated under explicit or implicit transmission capacity allocation schemes. The findings suggest that having an energy-only market on one side of the border and an energy-plus-capacity market on the other side may interfere cross-border trade and result in under-usage or misusage of transmission in the case of explicit allocation of the transmission capacity. Nevertheless, an implicit allocation scheme (market coupling) would increase the efficiency of the cross-border trade, but could result in distributional effects, involving a free-riding effect. The author was responsible for the data gathered for the Finnish case and contributed to the discussion and formulation of the scenarios. The author of the dissertation acted as a co-author of Publication IV.

Publication V *Capacity Market in Russia: possibilities for new generation entry and cost of CRMs*

Publication V analyses the impacts of a capacity remuneration mechanism on the final consumer electricity price from the long-term perspective. The Russian electricity industry faces the consequences of the capacity market with CRMs, namely capacity oversupply. Before 2013 there were no proper signals for power plants to exit from the market and for new to enter. Therefore, introduction of a new sloping demand curve in the long-term competitive capacity auction was supposed to provide right market-based signals. The paper examines the effectiveness of the sloping demand curve as a solution for providing market-based exit end entry signals and considers the development of the consumer capacity price based on a two-step linear model. The first part of the model determines the profitability gap in the electricity market, while the second part estimates capacity auction prices. The model results are used to estimate the consumer capacity price peak caused by CRMs and to elaborate on the low effectiveness of implementing a sloping capacity demand curve in the capacity auctions with the current price floor. The present author carried out the model formulation and analysis of the results. The author of the dissertation was the principal author in the publication.

2 Russia's wholesale electricity and capacity market

Russia has a market of two commodities: electricity and capacity. This market design evolved as a result of long reforms and restructuring of the electricity supply industry, which took place between 2003 and 2011. The rationale behind the liberalization of the industry and the step-by-step evolution of the regulatory basis is described in Section 2.1. Next, in Section 2.2, the current design of the electricity and capacity market is presented. Finally, Section 2.3 elaborates on the remaining issues and challenges faced by the market as an outcome of having a capacity market and capacity remuneration mechanisms.

2.1 Russia's electricity industry liberalization

Russia's electricity industry of the 1990s can be characterized as stagnant because of the economic situation in general in the country. The financial crisis in Russia resulted in low electricity consumption and massive non-payments of electricity bills. Consequently, the lack of investments in generating capacities and renovation of existing assets became an urgent problem of the industry, forcing to reconsider the organization of the industry and electricity trade arrangements. At the time, the whole industry was controlled by the state-owned vertically integrated company RAO UES, which owned 78 % of the generation capacities and 100 % of high-voltage transmission lines, and had a monopoly on electricity export (Chernenko, 2013). Further, the RAO UES was responsible for the dispatch and acted as a system operator. The company was founded to centralize the decision making process in the electricity industry during the privatization period in order to ensure the reliable heat and power supply and to increase the effectiveness of the industry. The latter could not be achieved without further restructuring and liberalization of the industry as it required enormous investments. The drivers for the liberalization of Russia's electricity industry are quite different from the experience in developed countries. According to (Nepal & Jamasb, 2015), liberalization in developing and transition countries is driven by a burden of energy subsidies, a deficit of production capacity, a low service quality, and energy sector investment constraints. Hence, the liberalization of the electricity sector in Russia can be considered an example of a liberalization process in a transition country. The history of the Russian reforms has been covered by (Chernenko, 2013), (Boute, 2013), (Melnik & Mustafina, 2014), and (Solanko, 2011), and an assessment of the early stage market performance has been provided by (Kennedy, 2002) and (IEA, 2005).

The electricity industry reform in Russia followed the world's experience and had features similar to the "textbook" architecture, as shown in Figure 2. According to (Joskow, 2008), the standard liberalization reform of an electricity sector usually consists of several main components such as privatization of state-owned electricity monopolies, separation of potentially competitive and natural monopoly segments, introduction of voluntary wholesale energy spot markets, and setting up of independent regulatory agencies and transitional mechanisms to transform the sector from a monopoly into a competitive market. Even through the key components of the liberalization were similar in many countries, every country had to adjust its regulatory measures based on the needs and constraints of the local electricity industry.

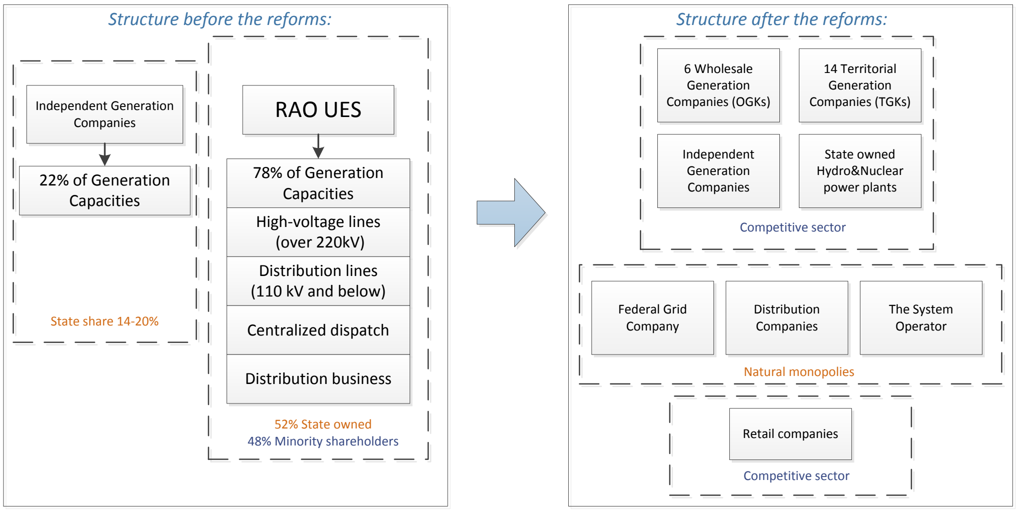


Figure 2. Structure before and after the reforms. Based on (Chubais, 2008).

The major issue for the electricity sector in Russia was the lack of investments, and consequently, the resource inadequacy in the near future. Resource adequacy is an ability to provide adequate supply during peak load and in generation outage conditions (Pfeifenberger, 2014). Initial legislative moves such as introduction of the wholesale electricity market with "cost-plus" tariffs were not sufficient to provide the required resource adequacy (Boute, 2013). Therefore, restructuring and privatization of the RAO UES seemed the only option to produce investments in the generation sector in a cost-effective way. The transition period and the liberalization principle were first determined in 2001, followed by the adoption of the Federal Law on Electricity in 2003; the key regulatory steps are listed in Table 1.

As a result, the generation sector was unbundled into large competitive wholesale and territorial companies (OGKs and TGKs), which were then opened for private investments (Gore, et al., 2012). The nuclear and hydropower production companies remained state owned. The transmission and distribution businesses stayed state-owned natural monopolies, but the distribution was split into Interregional Distribution Grid Companies (IDGCs). The System Operator (SO), responsible for the dispatch, was separated from the production and supply companies, and the Administrator of Trading System (ATS) was established to deal with commercial operations. These measures strictly followed the "textbook" structure.

The things changed when Russia introduced capacity auctions. Short-term CCAs were held in 2008 to guarantee capacity availability for 2009. The aim of the capacity auction was to promote additional competition apart from the electricity market for selecting efficient capacity to ensure the short-term resource adequacy in the system. The capacity market design for 2011 and the following years was defined in the Government Decree No. 89 "On organization of long-term capacity market" on 24 February 2010 (Government of the Russian Federation, 2010a). Furthermore, a capacity remuneration mechanism was introduced for the new power plants in 2010, called Capacity Delivery Agreements (CDA), in order to induce investments in the generation sector, targeting to provide resource adequacy in the long term. Such agreements guaranteed return on investment for investors in ten years for conventional power plants. Similar agreements were introduced for hydro and nuclear power plants, called Long-Term Agreements (LTAs), which guaranteed return in 15 to 20 years. In return, investors were obliged to build and deliver the capacity by an agreed deadline, otherwise they would have to pay fines for not delivering on time. The return on investments was in the form of a monthly capacity payment, which was calculated based on the required return rate and collected from the capacity market. The operating and capital costs used to calculate the price of capacity under CDAs are set in the Government Decree No. 238 of 13 April 2010. Therefore, capacity remuneration payments were an addition to the CCA price, and the total cost of capacity was split equally among the consumers.

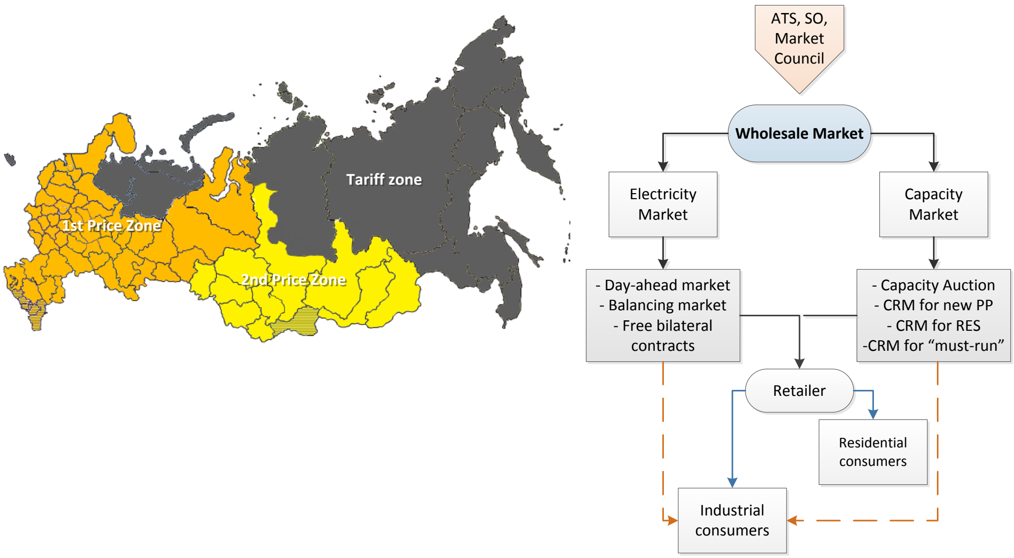
Table 1. Key regulatory steps in the electricity industry reforms in Russia.

Year	**Document**	**Definition**
1992	Decree No. 923 of 15 August	Foundation of the RAO UES (The President of RF, 1992)
1996	Decree No. 793 of 12 July	Introduction of the wholesale market (Government of the Russian Federation, 1996)
2001	Decree No. 526 of 11 July	Start of the restructuring and liberalization of the electricity sector (Government of the Russian Federation, 2001)
2003	Federal Law N - 35 FZ of 26 March; Decree No. 623 of 24 October	The law defines the legislative basis for energy trade and parties responsible for its organization. Start of the transition period (Russian Federation, 2003)
2010	Decree No. 89 of 24 February	Introduction of the Competitive Capacity Auction (CCA)
2010	Decree No. 238 of 13 April	Introduction of Capacity Delivery Agreements (CDAs)
2010	Decree No. 1172 of 27 December	Rules of the wholesale electricity and capacity market operation (Government of the Russian Federation, 2010b)

2.2 Electricity and capacity market design: post-liberalization

In the current wholesale market design, electricity and capacity are traded on auction-based platforms as separate commodities. The market covers the western part of Russia and Siberia, constituting two price zones. There are still isolated territories with a high concentration[2] of power plant ownership and limited transmission capacities, where prices are regulated and set by the Federal Antimonopoly Service (FAS), the grey area in Figure 3 (a). The total installed capacity of power plants in Russia was 235 GW in 2015, and 91.6 % of the electricity production was traded in the wholesale electricity and capacity market (SO, 2016a) (ATS, 2016a).

Decree No. 1172 "On adoption of the wholesale electricity and capacity market rules" provides the regulatory basis for the wholesale trade. The financial part of electricity and capacity trade is organized and carried out by the ATS, together with the Center of Financial Calculations (CFC). A non-profit organization, the Market Council (MC), is responsible for the control, monitoring the market participants' compliance with the obligations, and regulation of the wholesale market. The physical balancing and dispatch of the system is entrusted to the independent SO, Figure 3(b).



(a) (b)

Figure 3. Competitive price and tariff zones (a) and the structure of the wholesale market (b).

[2] Competition is not possible

2.2.1 Electricity market

Electricity market is divided into two segments: regulated and competitive. The regulated segment consists of regulated contracts (RCs), which are intended for power supply to residential consumers and consumers, equated with the residential ones according to (Government of the Russian Federation , 2013a). Each RC defines the tariff for electricity and capacity, depending on the forecasted demand and supply balance. The tariffs and volumes are subject to the FAS regulation and are usually set below the electricity market prices. Regulated electricity tariffs are considered part of social protection in Russia, and thus, residential consumers pay about 50 % less than industrial consumers (Ryapin, 2012). About 9 % of the whole electricity produced in the market is sold through regulated contacts (ATS, 2016b).

The competitive segment includes free-bilateral contracts (FBC), where the price and supply periods for electricity and capacity are defined as a result of negotiation between the supplier and the consumer, the Day-Ahead Market (DAM), and the balancing market (BM). The SO organizes the unit commitment procedure before the DAM, where it forecasts demand for each hour of the day and a set of generating units that can supply power. Then, the ATS organizes the DAM a day before the physical power supply. The DAM applies a bid-based model with nodal pricing, where the price is defined for each of more than 8700 nodes of the system in both price zones for every hour by balancing demand and supply, based on the suppliers’ and consumers’ bids. As the forecasted demand usually deviates from the supply in reality, the SO coordinates the BM, where market participants can sell or buy electricity to meet their demand or supply. The DAM price indices and supply volumes are published daily on the ATS website together with the forecasted demand and the set of technologies for power production (Market Council, 2016a).

The electricity price is highly dependent on fuel prices, as the market often clears at the last bid equal to the thermal power plant bid running on gas or coal. The correlation of electricity price dynamics and fuel prices is shown in Figure 4. The majority of the power plants in the first price zone run on natural gas because of the gas transmission infrastructure available, while in the second price zone coal is the major source of energy owing to the limited gas transmission capacities and the proximity of the coal mining sites in Eastern Siberia.

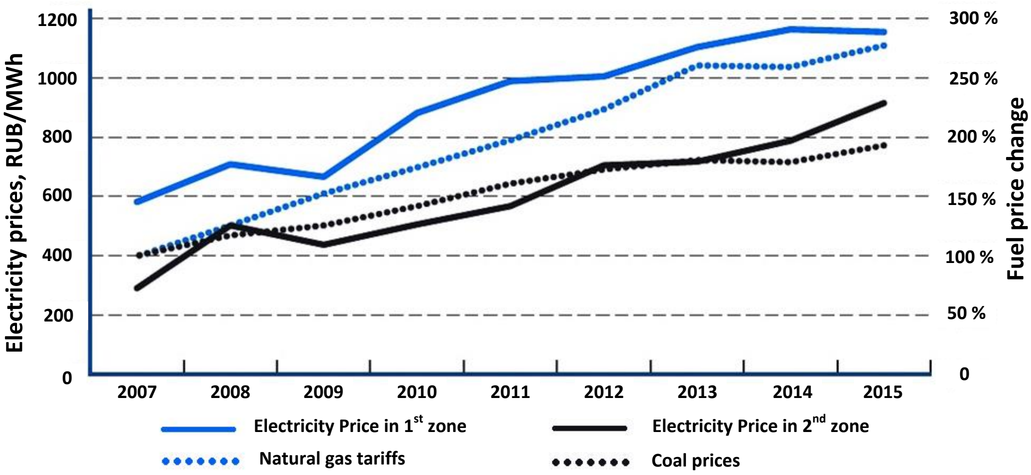


Figure 4. Electricity price dynamics (ATS, 2016a).

2.2.2 Capacity market

The capacity market in Russia was introduced in order to ensure resource adequacy in the period of peak demand and provide signals for investments in new capacity in the long term. The market employs capacity auction, where generation companies bid their capacity and its cost, and the capacity price is cleared at the least expensive capacity that would cover the capacity demand. Thus, as a result of the selection, the most cost-effective capacities would be selected to provide resource adequacy in the price zone. Prior to the auction, the SO forecasts the peak capacity demand for each price zone for every month of the selection period, and the information of the required amount of capacity is published on the CCA web page (SO, 2016b). It should be noted that extra 17–20 % of capacity is added to the forecasted capacity demand for reliability and import reasons, determined by the federal executive body with recommendations from the SO and the MC, according to (Government of the Russian Federation, 2010b). The capacity selected in the CCA must guarantee its availability during the period of getting capacity payments, meaning that it should be ready to produce power anytime by the request from the SO.

The capacity market was held one year ahead for the transition period. Starting from 2016, capacity is selected annually four years ahead of the delivery (Government of the Russian Federation, 2015). New rules of the long-term capacity market, adopted in 2015, intend to improve the efficiency of the capacity market in providing market-based signals for power producers to enter and exit the wholesale market. The first long-term capacity selection took place in 2015 for the capacity that should be available between 2016 and 2019. An upward sloping demand curve introduced in the CCA should increase the efficiency of capacity selection as it simulates elastic demand. The concept of using a sloping demand curve for capacity selection was adopted from the capacity auction rules in the UK (BEIS, 2014). The new rules define a price cap and a price floor for the capacity demand within an acceptable interval of the demand curve, see Figure 5. The demand function is a linear function passing through two points of the maximum capacity demand (D_{max}) at a price floor ($P_{\min}$) value and the minimum capacity demand (D_{min}) at a price cap (P_{max}) value. These parameters are determined separately for each price zone and CCA period, according to the procedure of the Ministry of Energy based on the forecast of peak demand in the price zone and the planned reserve ratio. The price cap was set at 150 000 RUB/MW for the CCA 2016 for the first price zone and 210 000 RUB/MW for the second price zone at the point of required minimum demand. The value of the maximum demand is calculated using a ratio of 1.12, and the price floors were set at 110 000 RUB/MW for the first price zone and 150 000 RUB/MW for the second price zone. Capacity price is cleared at the interception of the supply curve, which is based on power generators' bids, and the demand curve, defined by the SO for each year. The new rules of the CCA provide a choice for the power producers: they could sell more capacity at a lower price or sell less capacity for a higher price.

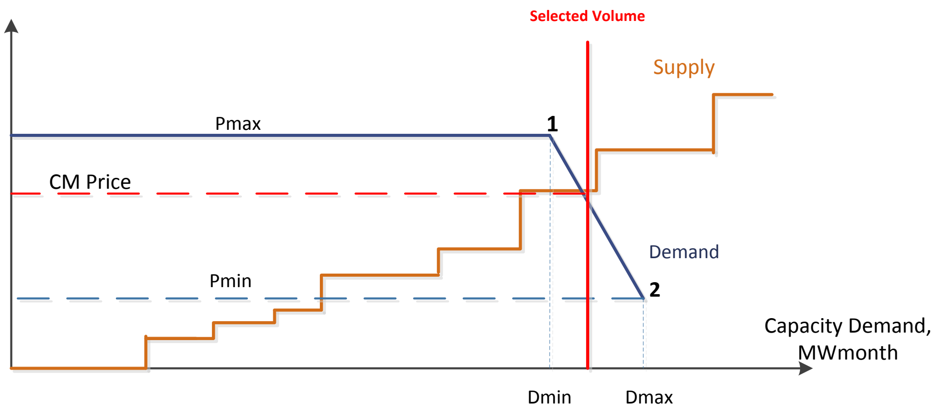


Figure 5. Competitive Capacity Auction with a sloping demand curve.

The capacity under different capacity mechanisms is selected in the CCA by default, meaning that the capacity can be considered a price-accepting bid (zero bid). New conventional power plants receive capacity payments according to signed CDAs or LTAs. Those payments are usually considerably higher than the capacity price of the CCAs. For instance, capacity payments for a conventional power plant can reach more than 1 million RUB/MW/month, depending on their location, technical features, and installed capacity (Ponomarev, 2010).

Furthermore, the renewable energy support scheme in Russia is based on the CRM. Therefore, renewable power plants' bids under the CRM-RES are also selected in the CCA by default. CRMs for the construction of renewable power plants were adopted in

2013 (IFC, 2013). The Government Resolution No. 449 defines the amount of supported capacity, its allowed capital cost, and the technologies that can take part in the competitive RES project selection (Government of the Russian Federation, 2013b). Despite the limitation of the capacities under the CRM-RES, the capacity payments for renewable power plants can be significant because of their high capital costs.

Some of the generators that cannot be selected in the auction because of their high capacity cost can request from the MC a status of the "must-run" generator (MRG) prior to the CCA and sometimes after its completion. This status can be given to generators whose work is necessary for the power system operation and reliability, or to combined heat and power plants (CHPs) for thermal energy supply during winter months. Usually, MRGs are old and inefficient power plants close to populated territories, which are mainly supplied by those old power plants. In the case of CHP plants, again, the unprofitability of the plants is associated with weak heat power regulation in Russia. MRGs receive a regulated capacity tariff defined for every year by the FAS, which is higher than the capacity market clearing price.

Together, the capacity under support and the MRGs add to the capacity price formed in the CCA. The actual price of the capacity can be defined by transferring capacity payments for new power plants under CDAs and LTAs, renewable capacity under the CRM-RES, and tariffs for MRGs on top of the cleared CCA price; see the schematic representation in Figure 6. The total cost of the capacity market can be calculated as an actual capacity multiplied by the CCA demand (D_{CCA}). The impact of the supported capacity has a high dependence on the volume.

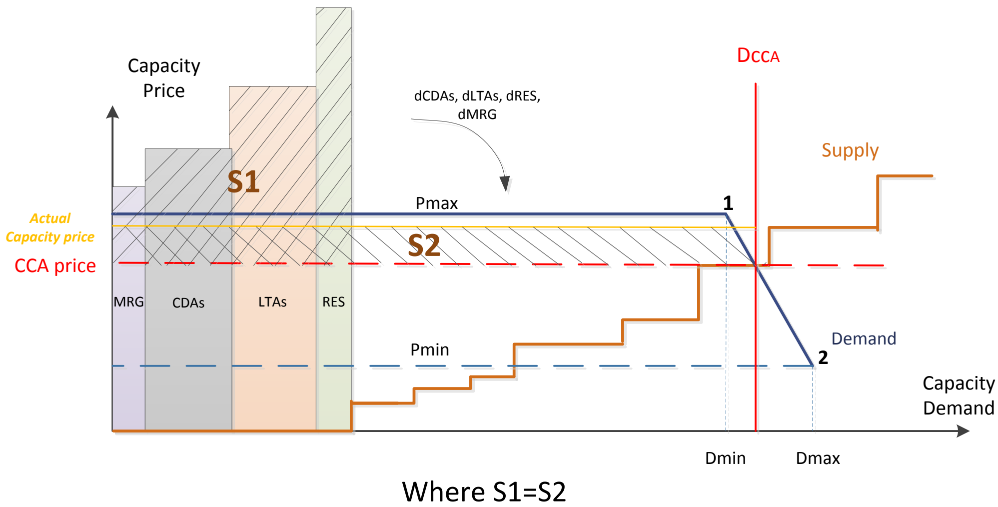


Figure 6. Formation of capacity cost.

2.3 Challenges faced in the current organization

After the liberalization of the electricity industry in Russia, currently, 95 % of the produced electricity is sold in the wholesale market and according to the studies, the competition level is high (Erdogdu, 2013), (Chernenko, 2015). Nevertheless, the market is facing new and old (postponed) challenges. As the focus of this doctoral dissertation is on the capacity market, the section concentrates primarily on issues related to or caused by the capacity market and CRMs, implemented during the transition period.

All the issues faced by the Russian market are not unique and can be considered parts of the energy trilemma, which is found in any energy market. Nevertheless, from the perspective of the Russian electricity and capacity market, those issues can be interpreted in a different way, see Figure 7. Energy security can be interpreted as an ability of the market to ensure resource adequacy both in the short and long term and independence of imported power production technologies. The latter is a sensitive matter when it comes to renewable energy technology. Energy cost refers to the affordability of the electricity and capacity costs as the purchasing power of the Russian economy is not strong enough to afford high energy costs because of the consequences of the economic crises in 2008 and 2014 (Milov, 2015). Sustainability is associated with efficiency improvement and the environmental policy of Russia.

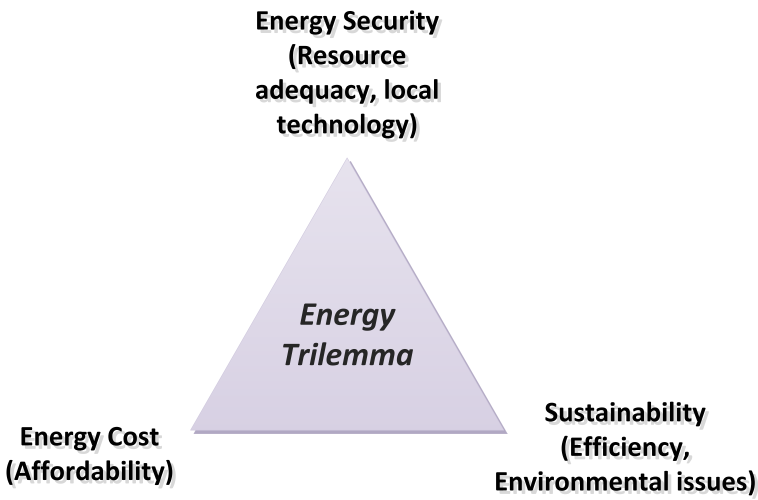


Figure 7. Energy trilemma in the context of the electricity and capacity market in Russia.

According to (WEC, 2015b), Russia maintains a good level of overall energy security, an average performance on energy equity, and a poor environmental sustainability ranking. The high level of energy security in Russia is not surprising, given the fact that it is a large oil and gas producer. Still, the issue of energy security is put into a different light when considering the electricity and capacity market, for instance because of uncertainty of future investments in new generating capacity and the development of local renewable energy source technology (Sections 2.3.1 and 2.3.2). Environmental sustainability and renewable energy policy are always mentioned on the Government’s agenda (Government of the Russian Federation, 2009a); however, they are usually postponed until good times. Because of the reliance of the industry on abundant fossil fuel resources, the concept of sustainability is often addressed as measures towards energy efficiency improvement, and emission reduction as a means to reach this improvement (Section 2.3.2). Energy cost or affordability is a complex issue, consisting of a mixture of efficient market-based prices on the one hand and regulated subsidies on the other hand. Subsidization is a common and non-transparent feature, which takes place at all levels of the energy supply chain. For instance, residential power consumers are subsidized in the electricity market by industrial consumers, while industrial consumers are subsidized in the gas market by the gas export market. At the electricity and capacity market level, traditionally, the subsidies and CRMs are transferred to the final consumer, resulting in a high total cost of electricity discussed (Sections 2.3.3–2.3.5.).

2.3.1 Investments in the generating capacity

In theory, capacity markets should ensure resource adequacy for the power system and provide price signals for investments in generating capacities in the future (Harbord & Pagnozzi, 2014). Therefore, the capacity price should be high enough so that revenues from the electricity trade and the capacity market would be sufficient to cover all the costs of the investor and ensure profit in the future. The need for a capacity market occurs as result of the insufficiency of energy-only markets in ensuring resource adequacy in developed countries because of the merit-order effect caused by penetration of renewable energy sources or because of the lack of economic incentives to develop new capacity in developing or transition countries with a capacity deficit (Nepal & Jamasb, 2015). In both cases, the main reason for the introduction of a capacity market is underinvestment in the generation sector.

Russia was clearly a transition country facing risks of shortages at the beginning of 2000s. Therefore, in order to speed up investments, it introduced CRMs for the base load in addition to the CCA. Up to date, investments in new generating capacities have mainly been attracted through CRMs. More than 20 GW of new capacity was built between 2011 and 2016, and another 5 GW will be constructed until 2020 (Market Council, 2016b). Therefore, investment decisions will continue to be based on CRMs (see Figure 8), and investors are not willing to invest without any guarantees on returns.

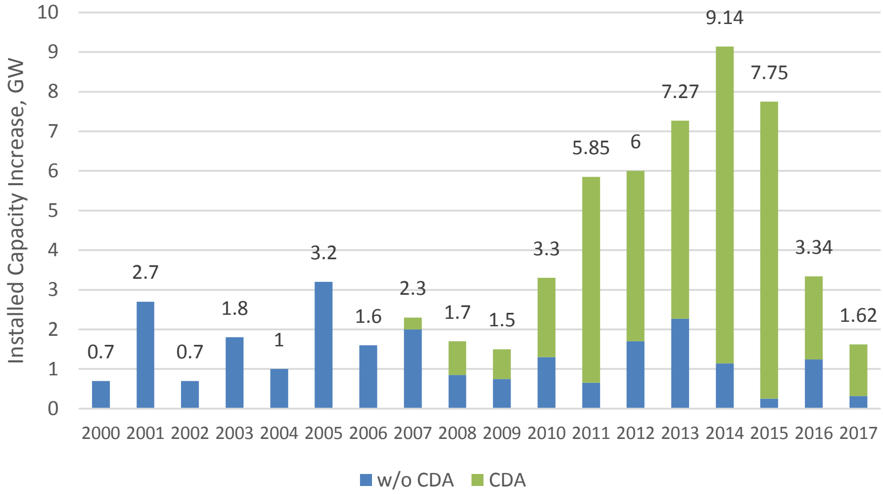


Figure 8. New capacity development dynamics with and without CDA, GW (Kuchaev, 2013).

The results of the CCA of the last two years indicated an oversupply of capacity in the system, and thus, 7.5 GW in 2014 and 5.8 GW in 2015 requested a status of MRGs. The reasons behind such overcapacity are complex and partially connected to demand overestimations, which resulted in a large number of CDAs contracted. Moreover, overcapacity indicates an inability of the capacity market design to provide signals to leave the market. The changes made in the capacity market rules in 2015 were intended to solve this problem. However, the number of MRGs increased to 12 GW in 2017. Such dynamics convert the missing money problem into a missing market problem (Newbery, 2016), as all the investments were not market based, and the increasing amount of not selected capacity reveals an over-procurement issue. At the same time, old and ineffective generators still manage to get capacity payments.

Nevertheless, the question is: Does Russia need more capacity investments? According to (Milina & Karaulov, 2016), 52 % of the CHPs in Russia are older than 30 years, and the need to replace old generation will remain in the near future. The main challenge for the capacity market is to ensure that the replacement takes place in a cost-effective way, because CRMs, in their current design, are effective in increasing the amount of installed capacity, but their cost effectiveness is doubtful.

2.3.2 Renewable and environmental policy

Russia is one of the largest oil, gas, and coal producers and exporters. More than 65 % of the electricity was produced using fossil fuel in 2015, while the proportion of renewable power plants was less than 1 % (SO, 2016a). Such numbers are a consequence of the country’s long history of reliance on fossil fuel, the resources of which are estimated to last for another hundred years. Currently, the gas transmission network covers all the western part of Russia, and the coal mining fields situated in Southern Siberia make coal transport easier and cheaper to the 2nd price zone. In addition, because of the high concentration of the gas market, gas prices for the main gas producer, Gazprom, are regulated, and are considerably low compared with export prices. Therefore, reliance on fossil fuel resources and possibly strong lobbying from the oil and gas producers have adverse effects on renewable energy development and the environmental policy in general.

The renewable energy and environmental policy is a very political topic in Russia. According to (National Energy Security Fund, 2015), the peak of interest on renewable energy and sustainability in Russia was between 2008 and 2013 during the rule of president Medvedev. Indeed, this period was very fruitful in presenting policies intended to promote renewable energy and efficiency improvements. Consequently, the target of reaching 4.5 % renewable energy production in 2020 was set in 2009 (Government of the Russian Federation, 2009a) and the principles of the State policy in the area of environmental development up to 2030 were adopted in 2012 (President of the Russian Federation, 2012). The document states required actions such as increasing fines for the air contamination and introduction of market-based instruments to reduce environmental impacts, but does not elaborate on methods for the implementation of those actions. In the same year, the Government increased fines for flaring APG (Government of the Russian Federation, 2012) in oil fields and prioritized the purchase of electricity produced by using APG in the wholesale electricity and capacity market. In the following year, a support mechanism for the renewable energy sources was finalized (Government of the Russian Federation, 2013b).

The renewable energy support in Russia applies a capacity-based scheme similar to the CDA for conventional power plants and guarantees return on investments in 15 years. The choice of the support scheme is unique and was based on the success of the CDA in attracting investments into the generation sector. Nevertheless, it has certain specifics such as a local content requirement[3] and limitation of the capital cost by technologies, which makes it more challenging for the investors. The intention of the local content requirement is to promote development of renewable technologies in Russia. However, the time frame for the development of those technologies is also limited. Yet another interesting feature of the support mechanism is that renewable power plants do not have to guarantee their availability in the market, unlike conventional power plants under CDAs and LTAs. Instead, they are obliged to shut down the power plant by the request of the SO. Nevertheless, a mandatory minimum electricity production is considered in the CRM. Other rules of the CRM-RES are similar to CRMs for conventional power plants, such as fines for not delivering capacity on time or participation in the CCA.

[3] Local content requirements are provisions (usually under a specific law or regulation) that commit foreign investors and companies to a minimum threshold of goods and services that must be purchased or procured locally (UNCTAD, 2014)

The introduction of the CRM-RES was considered as a game-changer and the first step towards sustainable development. Nonetheless, the results of the past competitive bidding demonstrate that more than half of the supported capacity is not demanded, Figure 9. Still, the CRM-RES is currently the only support scheme for renewable energy in Russia.

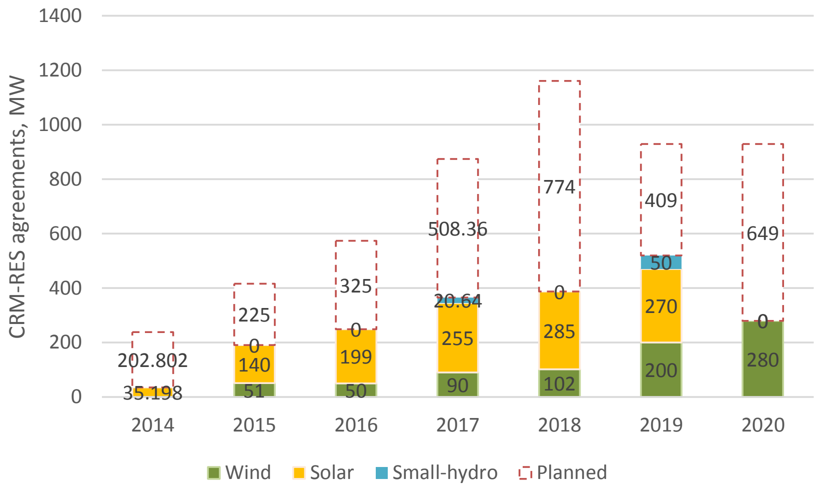


Figure 9. CRM-RES agreements: planned and signed, MW (based on (ATS , 2016b)).

2.3.3 Cross-subsidization in the electricity market

Cross-subsidization in the electricity sector is defined as a mechanism where some consumer groups are charged a higher price when compared with the cost of supplying power to them, and the additional revenue generated from them is redirected to cover the revenue shortfall from other consumer groups (PwC, 2015). Cross-subsidization in Russia appeared during the economic reforms as an element of social protection (Hubert, 2002). At the electricity and capacity market level, residential customers, paying low tariffs according to their RCs, are subsidized by the industrial consumers, paying full cost of capacity and electricity with the addition of a subsidy. According to Skolkovo Energy Center (Ryapin, 2012), the volume of cross-subsidization in the power sector in Russia reached 323 billion RUB in 2011, 20 % of which is covered by the electricity and capacity market. The majority of the cross-subsidization, more than 60 %, was associated with transmission and distribution businesses.

The issue of cross-subsidization is complex and non-transparent. Further, the real impact of cross-subsidies on the electricity prices is hard to define. However, this issue remains a challenge in the market and should be mentioned as a possible constraint for the market development and an additional cost to the industrial consumers.

2.3.4 Cross-border trade issues

Having a capacity market in addition to the electricity market poses extra challenges in the cross-border trade arrangement. Russia is neighbouring with Post-Soviet states in the West and South and with Finland in the North-West. The Post-Soviet states are synchronized with the Russian system. The trade is organized in such a way that the importing countries do not pay for the capacity in Russia, producing a “free-riding” effect. When defining the capacity demand for the CCA, the SO reserves capacity for the import demand, but the cross-border trade is based on price spreads in the electricity market. Therefore, the neighbouring countries could have double benefits: buying cheaper electricity and enjoying reliability improvement at the expense of consumers in the other country.

One way how the issue can be resolved is the adoption of explicit cross-border transmission allocation. In such a case, an independent cross-border trader could reserve capacity in the country with a capacity market and take into account the capacity cost in the cross-border trade. Another option under explicit transmission allocation is the case where a country with an energy-only market could participate in the capacity market of the other country in order to receive capacity payments for increasing reliability in that country.

2.3.5 Final consumer electricity cost

The total consumer electricity cost consists of four main components, see Figure 10, excluding the value added tax (VAT), which adds 18 % to the electricity and transmission service costs (Russian Federation, 2000). The proportion of the wholesale market in the cost structure accounts for about 46 %, while the power transmission and distribution costs are significant and can contribute by more than 50 % to the final consumer electricity cost.

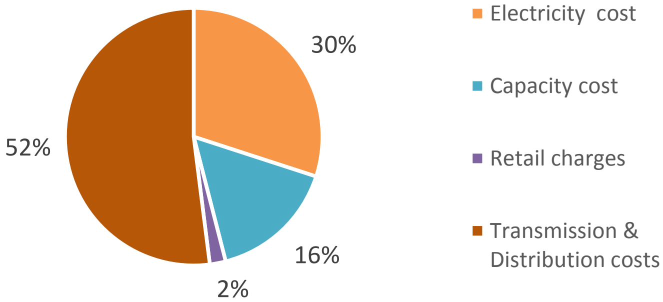


Figure 10. Electricity cost structure of a final consumer.

From the issues discussed in Section 2.3, it can be concluded that industrial consumers pay for the majority of the CRMs, externalities of the cross-subsidy, and the "free-riding" effect of the neighbour countries, which undoubtedly has an impact on the electricity and capacity prices for industrial consumers. The average electricity and capacity price dynamics for industrial consumers are depicted in Figure 11. The cost of electricity is based on the power consumed, while the cost of the capacity is defined according to the consumer peak demand in a month. The SO defines the peak demand hours for every region depending on the season. In addition, the transmission tariffs include a capacity component, the cost of which is also defined by the peak consumption similarly to the capacity cost. The increasing capacity costs and the high cost of transmission produce incentives for industrial consumers to reduce their consumption by implementing generation of their own. As the gas prices in the domestic market are low and close to the regulated prices, the marginal cost of producing power would be similar to the electricity market price. In the case of oil producers, incentives are higher, because they also benefit from using free fuel and avoiding recently introduced high fines for flaring APG.

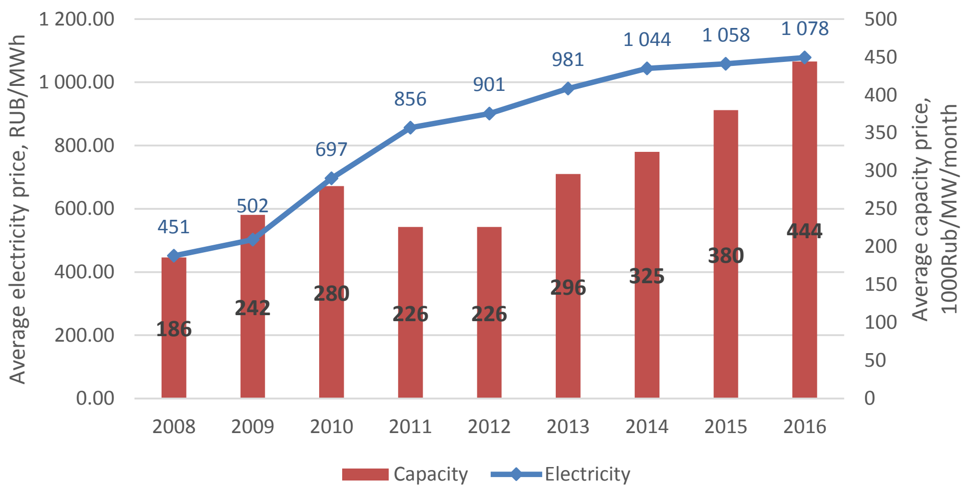


Figure 11. Average electricity and capacity prices for industrial consumers in Russia (based on the data provided by the Market Council).

3 Research design

This doctoral dissertation considers the Russian capacity market and CRMs in the post-liberalization period, where electricity and capacity prices are defined in a competitive way by the market. The research addresses the outcomes of having a capacity market and CRMs in Russia in the context of the energy trilemma (see Figure 12), where the balance should be the best option. On the one hand, CRMs in Russia are intended to provide energy security by ensuring capacity adequacy in the future. Furthermore, CRMs are chosen to be a support tool for renewable energy to achieve the sustainability goals and diversification of electricity generation. On the other hand, the question remains: is having a capacity market and CRMs an affordable choice? Thus, the trilemma framework is a viable way to define the questions and approaches taken in this research, as it examines the capacity market from different dimensions.

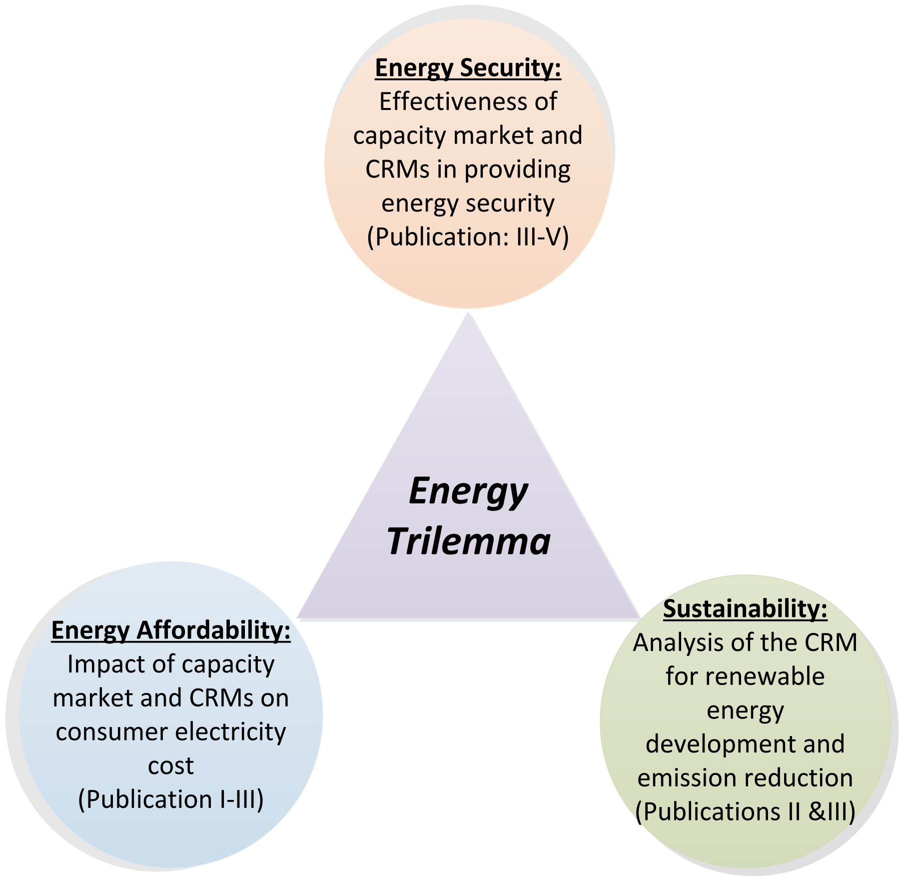


Figure 12. Research design in the context of the energy trilemma.

The five publications included in the dissertation provide an analysis of the three dimensions of the trilemma. Publications I–III focus on the final consumer cost, which includes the capacity and CRMs costs, answering the energy affordability question. Publications II and III discuss Russia's environmental and renewable policies and the contribution of the CRMs to achieving the set sustainability goals. Publications I–V assess the capacity market from the perspective of ensuring capacity adequacy in the short term and long term.

3.1 Research questions and objectives

Capacity markets have been established to resolve the market failures connected to the resource adequacy. According to (Briggs & Kleit, 2013), the need for a capacity market results mainly from the inelasticity of demand and the presence of price caps in the energy-only market, set by the regulators. When the capacity market alone cannot provide the required resource adequacy, capacity subsidies (CRMs) are introduced in order to ensure it, as it has happened in Russia, the PJM market, and the UK (Gore, et al., 2012) (Briggs & Kleit, 2013) (Harbord & Pagnozzi, 2014). Capacity subsidies are usually organized at the expense of power consumers; however, the extent of their expenses has not been analysed for the electricity and capacity market in Russia. Moreover, there are other consequences associated with the implementation of a particular capacity market and CRMs, such as cross-border trade issues, capacity oversupply, and the use of capacity subsidies for the renewable energy support.

The main objective of this dissertation is to analyse the capacity market and CRMs in Russia to draw conclusions on its outcomes from different angles, such as ensuring resource adequacy, final consumer electricity cost, renewable energy development, and impacts on cross-border trade. The main research question is: What are the outcomes of the Russian capacity market and introduction of CRMs, where each outcome requires individual consideration? The question is complex and could be addressed from the perspective of the dimensions of the energy trilemma.

Each publication included in this doctoral dissertation answers a research question of its own, supplementing the main research question:

- **Publication I and II:** Does a high capacity cost provide incentives for large industries to leave the capacity market?
- **Publication III:** What are the contributions of a renewable support scheme to achieving a sustainability goal and to the electricity cost paid by a final consumer?
- **Publication IV:** From the perspective of cross-border trade, what are the consequences of having an energy-plus-capacity market?
- **Publication V:** Is there an opportunity for a new power plant to enter the market without subsidies?

This topic became relevant to academic and political discussions in the last decade. This is explained by the fact that many developed and developing countries are forced to consider a capacity market in order to ensure resource adequacy in the future. Regardless of the reasons behind implementation, the capacity market has similar challenges and issues as discussed above. An analysis of the Russian case could provide general lessons for other countries, as it is one of the first cases in the history of introducing a capacity market.

3.2 Research approach and methods

Four publications included in this dissertation apply a linear optimization approach, while Publication II employs a cost-benefit analysis (CBA). The analysis tool is commonly used for investment decision-making in energy management and planning (Meeus, et al., 2013). Publication II analyses the costs and benefits of the power production from APG in two cases, based on the access to the network, and defines the profitability of investing in a power plant for oil producers.

The linear optimization approach or linear programming (LP) is widely used for energy system modelling and for solving a variety of problems related to energy system operation (Zeng, et al., 2011). There are well known input-output dynamic market models based on linear programming for the system analysis such as MARKAL, EFOM, and TIMES (Bhattacharyya, 2011). They simulate system operation and identify the optimal configuration of the system that would ensure a minimum cost supply to meet the demand. The LP method is also often used to solve some specific problems addressing energy efficiency issues, such as renewable energy sources and storage integration, and emission reduction. Zhou and Ang use LP models to measure economy-wide energy efficiency performance (Zhou & Ang, 2008). The methodology is used to solve the dispatch problem, especially in the case of integration of intermitted renewable power sources (Wang, et al., 2015). The primary fuel cost plays a crucial role in the formation of the total system cost, and it should be taken into account in electricity market models.

Application of LP models for the electricity market dispatch and pricing has evolved over the past few decades. For instance, (Vespucci, et al., 2013) and (Chernenko, 2012) apply LP models to estimate hourly market prices in Italy and Russia, respectively. They define an optimum market price by minimizing the total cost of the electricity in a price zone, assuming perfect competition. The main constraints in a modelling approach of this kind are the equality of supply and demand in one price zone and transmission constraints between price zones.

Usually, LP models have an objective to minimize the costs or maximize the profit or welfare of the market participants, which are subject to satisfying the constraints. In the general form, the model can be written as:

$$\max: F(X), \tag{3.1}$$

$$S.t. AX \leq 0 \tag{3.2}$$

$$X \geq 0 \tag{3.3}$$

where X is a vector of decision variables of the linear objective function F, and the matrix A indicates the economic, operational, or regulative constraints.

Publication I applies a single objective function to minimize the total electricity cost of an industrial power consumer. The decision variable in the case is the power production of an on-site distributed generator, which is constrained by the regulative requirement to be less than 25 MW. In Publication IV, the total welfare from cross-border trade is maximized for both interconnected markets for various transmission allocation schemes and capacity market arrangements.

Publications III and V use linear optimization to model DAM electricity prices with an assumption of perfect competition, that is, assuming perfect information for all market participants and no strategic behaviour. A two-step linear optimization model is developed in Publication V, where two markets (electricity and capacity) are modelled separately. Step one, the electricity market model, defines market-clearing prices for a point of the load duration curve in order to estimate the profit of the power producers from the electricity market. Then, in step two, a capacity auction price is estimated to decide upon the opportunity of a new generation entry.

3.3 Research data

The data used in the research are gathered from the official websites and open access reports of companies or organizations. A detailed list of the sources is given in Table 2. The currency exchange rates and capital costs for power plants were taken for the year when the research was conducted. Therefore, some price references may deviate considerably as result of weakening of the Russian rouble in 2014 (Milov, 2015).

Data on power producers in Russia were collected for Publication V from various sources such as the official web site of the generation companies and databases such as the Energy Base (Energy Base, 2016) for the year 2015.

Table 2. Main sources of research data.

N	Source	Description	Data
1	http://www.atsenergo.ru/	Administrator of Trading System of Russia	Electricity prices, electricity demand
2	http://monitor.so-ups.ru/	Competitive Capacity Auction	Results of the CCA, capacity demand
3	http://so-ups.ru/	System Operator of Russia	Installed capacities, types of power technologies
4	http://www.np-sr.ru/	Market Council	Regulatory documents, installed capacities under CRMs
5	http://www.consultant.ru/	Legal document source	Government Decrees, Resolutions, and Federal Laws
6	http://www.fstrf.ru/tariffs	Federal Tariff Service[4]	Electricity and transmission tariffs
7	http://www.gazprom.com/	JSK Gazprom	Natural gas tariffs for the domestic market
8	http://www.nordpoolspot.com/	Nord Pool	Electricity price in the Nordic countries
9	http://www.stat.fi/	Finnish statistic	Energy and fuel prices in Finland
10	http://energia.fi/	Finnish Energy	Finnish electricity sector technology mix and demand

3.4 Limitations of the research

The major limitation of conducting research on the Russian electricity and capacity market is associated with data accuracy and sources. For instance, not all the power production companies provide detailed data on each power plant efficiency and installed capacity. Instead, companies tend to give aggregated data on their production assets. The official reports of market participants are sometimes not consistent, or the data provided in one year may be absent in the next. Such behaviour is connected to the constant amendments to the Decree No. 24 on information disclosure by the electricity and capacity market participants (Government of the Russian Federation, 2004).

Publications I and II consider hypothetical cases of distributed generation implementation by large power consumers and refer to average electricity and capacity prices. However, electricity price is volatile and highly dependent on fuel prices. The oil field depletion rate in Publication II was assumed based on the literature review on oil production technology, yet the depletion rate can vary significantly for different oil fields. Therefore, the results can vary considerably depending on the case, and a separate CBA should be made for each case.

[4] The Federal Antimonopoly Service took over the responsibilities of the Federal Tariff Service in 2015

The analysis in Publication III considers a case where all the capacity under the CRM-RES is constructed. However, the results of competitive bidding for RES show that not all of the supported capacity is going to be constructed, and therefore, the impact of the support scheme will be lower than the results shown in the publication. The locations of the renewable power plants under capacity support were assumed based on the renewable power source map, because at the time of the research competitive bidding had not been implemented.

The welfare calculations in Publication IV were based on supply curves calibrated by the authors; these curves, again, are subject to data collected from different sources. Thus, more accurate data would provide more accurate numerical results. However, the same conclusion would most likely be drawn.

An assumption of perfect competition in the electricity and capacity market is made in Publication V; it is a rather theoretic approach, yet widely used in the literature. Such an assumption is possible in cases where market participants have no market power. According to Chernenko (2015), despite the high market concentration there was no sign of market power abuse in the Russian electricity and capacity market.

The impact of cross-subsidization on the electricity and capacity market prices, mentioned as a challenge of the current market organization in Russia, is not taken into account in this doctoral dissertation. Because of the difficulties associated with the non-transparency of cross-subsidization allocation to the final consumer cost, it is not addressed in more detail in this research.

4 Summary of the results and publications

This chapter summarizes the publications of this dissertation and draws the main conclusions. An overview of the objectives, methods, and findings is given in Table 3.

Table 3. Summary of the publications.

	Title	Objective	Method	Findings
Publication I	Capacity market as an incentive for demand response in Russia	Investigate the potential for the on-site generation to reduce the total electricity cost to industrial consumers	Linear optimization	High industrial electricity prices in Russia can be a strong driver for the development of distributed generation in Russia
Publication II	Electricity production as an effective solution for associated petroleum gas utilization in the reformed Russian electricity and capacity market	Analyse the profitability of producing electricity from associated petroleum gas for an oil production site	Cost-benefit analysis	By producing power from associated petroleum gas, oil companies could benefit from avoiding high fines for flaring, high capacity cost and also from selling excess power in the retail or wholesale market.
Publication III	RES support in Russia: Impact on capacity and electricity market prices of RES in Russia	Assess the impact of introduced renewable capacity-based energy support scheme on the merit order and consumer capacity price formation	Linear optimization	Renewable energy support scheme has no significant impact on the prices mainly due to the limitation of the capacity and technology under support.
Publication IV	Linking the energy-only market and the energy-plus-capacity market	Analyse the implications of the capacity market and allocation mechanisms for cross-border trade in the case of different electricity market designs	Linear optimization	Explicit allocations of transmission capacity can result in low capacity utilization, while implicit allocation can cause a “free-riding” effect.
Publication V	Capacity Market in Russia: possibilities for new generation entry and cost of CRMs	Test the effectiveness of the sloping demand curve in providing correct market-based entry and exit signals	Linear optimization	At the current level of price cap and price floor, CCAs do not provide efficient signals to enter or exit the market. New regulatory mechanisms should be presented in order to solve the oversupply issue.

4.1 Publication I: Capacity market as an incentive for demand response in Russia

Publication I considers implementation of on-site DG for large industrial consumers in order to reduce their total electricity cost by cutting peak hour consumption. In Russia, the consumer pays for the capacity according its peak consumption during the peak hours defined by the SO. Capacity cost, in turn, has a strong tendency for a considerable increase because of the implementation of CRMs for new power plants in Russia. Therefore, the paper tests whether having an on-site power generator to produce energy only during the peak hours is more beneficial than paying for the capacity.

The liberalization of the electricity industry targets to attract new investments in a cost-effective and competitive way. However, during the transition period towards liberalization in Russia, CDAs for new capacity construction were introduced in order to promote fast investments in the generating sector. The Ministry of Energy forecasted a substantial electricity demand deficit for 2020 and more than 40 GW of new production capacity was planned to be built under the CDA. At the same time, no actions from the demand-side management were considered in the Energy Strategy (Government of the Russian Federation, 2009b). In addition, the cost of transmission and the cost of connection to the transmission network include capacity payments apart from the actual energy consumption. Both the capacity and the transmission capacity are paid according to the highest peak demand during the month. Therefore, for the consumer with a high peak demand, it could be more beneficial to cut the peak demand and pay less for the capacity.

The paper examines the on-site generator option for a large industrial consumer using a linear model with the objective to minimize the cost of electricity including transmission charges for different tariff options. The main constraint of the on-site generator is the limitation of installed capacity, because according to the wholesale market rules, power plants with installed capacity of more than 25 MW must sell their capacity and electricity in the wholesale market. The results of the optimization model suggest that on-site distributed generation is profitable for cutting the peak demand as far as the cost of running it does not exceed 3100 RUB/MWh and the payback period is about 11 years, depending on the gas prices and the initial capital costs. Consequently, there are strong incentives for the development of on-site distributed generation installation in the electricity and capacity market in Russia, which may generate unintended but economically justified demand response. Capacity cost and transmission could cause considerable expenses for industrial consumers, who actually pay for the CRMs in the market, where the cost of CRMs is distributed equally between consumers. On the other hand, if the large industries went for massive installations of distributed generation, it would decrease the proportion of consumers in the capacity market resulting in higher capacity costs for the rest of the consumers. Therefore, there is a risk of even higher capacity cost in the wholesale capacity market.

4.2 Publication II: Electricity production as an effective solution for associated petroleum gas utilization in the reformed Russian electricity and capacity market

Publication II examines power production from APG for the needs of oil production. APG had been considered a waste product of oil extraction, and there have been burn off flares all over the West Siberian oil fields. From 2012, the Ministry of Energy has increased fines for flaring up to 120 times if the company burns more than 5 % of the produced APG. Thus, flaring ceased to be a solution to getting rid of the waste gas for the oil producers, and a feasible solution for the utilization of APG had to be found.

The publication discusses options for the monetization of APG, such as re-injection back to the well, processing it in a gas processing plant, refining the APG and selling it as natural gas and, lastly, power production for own use. Considering all the discussed options, only the solution of power production can meet the two requirements: gas monetization and independency from the other companies. In order to process gas, oil companies would have to negotiate terms and processing capacities with Sibur, which is the de facto monopoly for gas processing, whereas for selling natural gas, they would have to reach an agreement with Gazprom to use its gas transport capacities. Therefore, the publication analyses the power production option by a cost-benefit analysis. It is assumed that the oil producer invests in an on-site generator in order to supply the power needed for oil production. Thus, the costs consist of the capital cost of the power plant and the operational costs of running it. The cost of fuel is neglected, and it is assumed that the power plant runs fully on the produced APG. The benefits obtained are the avoidance of high fines for flaring, the avoidance of electricity and capacity costs, and selling the excess electricity to the market. The analysis takes into account the oil field depletion rate, which is not correlated with the APG production at the beginning. The volumes of the APG production are highest at the beginning of oil extraction. The publication considers two cases: Case 1 is power production from all APG produced in the field and selling the excess electricity and capacity to the market, and Case 2 is production of power only for own needs (in the case of limited accessibility to the network).

The results of the analysis show that investing in an on-site power plant is highly profitable for the oil production industry. The payback period in Case 1 is around five years and four years in Case 2. However, in Case 2, not all the produced APG is utilized, and additional measures are required to reach the 95 % utilization rate.

4.3 Publication III: RES support in Russia: Impact on capacity and electricity market prices

Publication III discusses the renewable energy policy of Russia and assesses the impact of a capacity-based renewable support scheme on the electricity and capacity prices. With its significant fossil fuel resources and regulated (low) natural gas tariffs, Russia has historically not been keen to develop renewable energy power plants significantly at the country level. The renewable policy and the environmental policy were often neglected in the Government’s energy policy agenda with an exception of large hydro power. Furthermore, after the liberalization of the industry, the lack of investments in conventional power plants led to the introduction of a capacity-based support (CDA) for building and renovating thermal, nuclear, and large hydro power plants. Consequently, a similar support scheme was also introduced for renewable energy-based power plants in 2013, which potentially could contribute to a further consumer capacity cost increase and a merit-order effect in the DAM as it is widely happening in the European markets.

The paper analyses the development of capacity cost and electricity market price separately by calculating the capacity price based on the data from the regulator and by estimating the DAM prices using a simplified equivalent circuit model of the Russian power system. The contribution of the RES capacity support to the final consumer capacity cost could be considerable because of the higher capital costs; the capacity payment in the case of an RES-based plant could be two to four times as high as for the conventional plants. At the same time, certain measures were taken to limit the undesired outcomes of the capacity costs. The Government defined the specific RES technology and amount of installed capacity for each technology, and capped the capital cost of power plants and introduced a local content requirement. The local content requirement was intended to incentivize the development of local RES technology, as most of the renewable power plant components were imported from other countries.

The results suggest that the RES support would produce an about 2 % increase in the consumer capacity cost and a 2 % decrease in the electricity market price during off-peak hours. These impacts can be considered minor; however, as the RES-based power plants do not guarantee availability (in contrast to conventional power plants), this increase in the capacity cost, only arising from the ambition to have an RES agenda in place, would be at the power consumers’ cost.

4.4 Publication IV: Linking the energy-only market and the energy-plus-capacity market

Publication IV provides an analysis of the cross-border trade between two markets with distinct designs, where one country has an energy-only market and the other an energy-plus-capacity market. The paper evaluates the short-term impact of capacity markets on the cross-border trade under explicit and implicit cross-border allocation mechanisms. The case study was made for Russia and Finland, which is one of the cases where Russia has an energy-plus-capacity market and Finland an energy-only market. This study contributes to the discussion on the integration of markets with distinct designs as many countries are considering introduction of CRMs (including a capacity market) in addition to the energy-only trade (Linklaters, 2014). At the same time, many countries are keen to keep an energy-only market design. This dynamics raise a question of how to organize efficient cross-border trade and a power transmission allocation mechanism in the future.

The paper analyses three cases of cross-border trade and transmission capacity allocation. The first case assumes an explicit allocation of transmission capacity and cross-border trade where foreign capacity cannot participate in the national capacity market. The second case considers explicit allocation of transmission capacity and a design where foreign capacity can participate in the national capacity market. Finally, the third case examines the implicit allocation of transmission (i.e. market coupling), and the power flow is determined based on the day-ahead market price difference between the markets; thus, there is no foreign participation in the capacity auction. The analysis is made by comparing the social welfare in both markets applying a short-term simulation model, where the objective is to maximize the social welfare in both markets and the trader's profit.

The findings suggest that the cross-border trade between markets with different designs has certain unpleasant externalities affecting the social welfare. In the case of explicit transmission allocation with no foreign capacity participation, the cross-border trade faces "dead bands" during peak hours even when the price difference between the countries justifies the cross-border flow. When the foreign capacity is allowed to participate in the capacity auction, the direction of the cross-border flow can be reversed. If the capacity from the energy-only market is selected in the capacity auction in the foreign capacity market, it has to guarantee its availability in order to receive capacity payments. Therefore, the cross-border flow can be from a low-price market to a higher-price market, resulting in inefficient cross-border trade. Both cases result in considerable misusage of the cross-border transmission capacity, leading to low cross-border flows, thereby producing considerable welfare losses on both sides of the border. Implicit allocation of the transmission capacity can solve the problem of transmission capacity misusage. However, this arrangement also has certain negative externalities such as the "free-rider" effect. Because the market participants in the energy-only market do not pay for the capacity in the energy-plus-capacity market and the cross-border flow is only based on the day-ahead price difference, they benefit from the increase in reliability at the expense of the neighbouring market and the lower electricity price. From the perspective of social welfare analysis, implicit allocation of cross-border capacity results in the highest social welfare in both markets compared with explicit allocation. At the same time, it cannot be considered the best solution as it raises a new dilemma connected to the capacity market coupling or designing foreign capacity participation in national capacity auctions under implicit cross-border transmission capacity allocation.

4.5 Publication V: Capacity Market in Russia: possibilities for new generation entry and cost of CRMs

Publication II tests the option of new power plants entering the market without any CRM. As the capacity support mechanism in Russia was considered an urgent solution for the transitional period of the reforms, the long-term capacity auctions were planned in order to attract investments in a competitive-market-based manner. Together with the required capacity overestimation and the lack of incentives for old and outdated capacity to exit the market, the capacity market of Russia faces two main problems: overcapacity of inefficient power plants and a lack of incentives for investing in new efficient ones. The introduction of an upward sloping demand curve for the CCA in 2015 is supposed to solve these problems in a market-based manner.

The paper presents a two-step linear optimization model to estimate capacity prices in the first price zone in a medium-term period (2015–2027). The first step calculates the profit of the power producers in the electricity market by simulating a day-ahead market. The second step estimates the capacity auction clearing price that is based on the bids of the power producers and the slope of the demand curve defined by the SO. Perfect competition is assumed in both steps, and thus, it is assumed that power producers bid their marginal cost in the day-ahead market and their profitability gap in the capacity auction, which is defined as a difference between the total costs of a power producer and the profit from the electricity sales. New power plants can also participate in the CCA, and they are assumed to bid their profitability gap in order to reach a zero NPV in 30 years.

The model considers two scenarios: only market-based incentives and forced (by regulation) replacement of must-run capacities. The results show no market-based incentive to invest in new power plants during the modelling period. Such outcomes can be explained partially by the not high enough price cap and the not low enough price floor in the CCA. The model shows that at the current price floor, the power producer covers its fixed costs even without running a power plant, indicating that the choice of the right price floor is very essential for capacity auction implementation. The higher spread between the price cap and the price floor could be more efficient in providing an incentive for the old capacity to leave the market. In addition, there are still a considerable number of must-run generators and capacity under the CCA in the market, which has an impact on the final consumer capacity cost. Under the second scenario, must-run generators are replaced by new efficient power plants, and they also get a capacity compensation similar to CDAs. Therefore, new investments are made but the support cost also has an effect on the final consumer's capacity cost. Nevertheless, the final consumer capacity cost has a tendency to decrease in any case because some of capacity agreements will start to expire, facilitating the burden on the consumers. The paper concludes that in order to incentivize market-based investments, the rules of the CCAs should be reconsidered (pro-market solution) or a new capacity support should be made in a way that would replace the most inefficient capacity (pro-regulation solution).

5 Discussion and concluding remarks

This doctoral dissertation analysed the outcomes of the Russian capacity market and capacity remuneration mechanisms (CRMs) in the context of energy trilemma and defined their role in achieving the objectives of the trilemma dimensions.

5.1 Energy Security

In Russia, the CRMs have provided the required energy security level in power generation in the short term. An overestimation of the demand growth in the Energy Strategy up to 2030 resulted in the commissioning of more than 20 GW of new power generation under the capacity support. Furthermore, the majority of the investments in capacity were made using capacity delivery agreements (CDAs) or long-term agreements (LTAs), indicating that the capacity market does not provide market-based incentives to invest in construction of power plants. Furthermore, the market does not provide incentives for old generation to leave the market, which can be concluded from the increasing number of must-run generators (MRGs). New amendments to the competitive capacity auction (CCA) rules, made in 2015, were supposed to provide the signals required for entering and exiting the market by applying a sloping demand curve. However, the results of the capacity market model show that the set of power plants remains unchanged. The modelling results suggest that the price floor chosen for the CCA is too high, and thus, inefficient power plants can get a capacity payment even if they do not produce any power, and their marginal cost is too high to be accepted in the electricity market. Usually, those power plants have already recouped the investments and cover only the fixed costs. At the same time, the capacity market price cap limits the opportunities for new power plants to enter the market, and the capacity price bids of new power plants cannot be accepted in the CCA. Therefore, a suggestion would be to lower the price floor and to raise the price caps in order to increase the efficiency of the CCA. Another action to tackle the problem could be forced replacement of MRGs, which could result in a 20 GW increase in the installed capacity by 2027. However, in such a case, new investments would be made in a similar non-market-based manner as CRMs, but the benefit would be the avoidance of high capacity tariffs for the MRGs.

Diversification of the power production technology by integrating renewable energy sources is not likely to take place in Russia. There are two main reasons for that; first, the CRM-RES, the only support mechanism for renewable energy, limits the installed capacities of renewable power plants and introduces a local content requirement. Consequently, of the planned 5 GW of RES power plants, contracts are signed only for more than 2 GW. Secondly, the abundance of fossil fuel resources and the related production and transportation infrastructure, together with the low domestic prices of natural gas and coal, contribute to the further postponement of the diversification goals. Therefore, the energy security relies on conventional technologies using mainly fossil fuel resources, leaving the concentration of electricity generation almost unchanged.

The development of demand response programs for large-scale industrial companies could be one of the options to enhance the energy security in Russia. By reducing their peak demand, industrial consumers could cut their monthly capacity cost and reduce the need for new capacity to cover the peak demand in the future. The results of this study show that with the current electricity and capacity market prices and transmission tariffs, application of distributed generation for peak demand cutting can be beneficial for the industrial consumers in Russia, and it could be promoted by the implementation of a market-based demand response mechanism. However, no demand response programs have been developed in the country.

For the time being, Russia may enjoy a high level of energy security in terms of availability of power production capacities, but in the long run, more than 52 % of the power plants in the country should be replaced as their age exceeds 30 years. Therefore, when it comes to the generation sector, the energy policy has still two goals to achieve in terms of energy security: resource adequacy in the long term and diversification of the production mix by integrating renewable power plants. The first objective can be achieved by adjusting the price cap and floor in the CCA, or by interfering in the market, and boosting the replacement of inefficient capacities by new ones. Implementation of demand response programs for peak demand reduction could also enhance the long-term energy security. However, achieving the second objective requires more efforts from the policy makers than only the provision of a capacity support.

5.2 Energy Sustainability

For Russia, the energy sustainability issue bears theoretical meaning rather than physical actions. Therefore, different policy documents were published on renewable energy objectives and the principles on improving the environmental situation in the country. Only limited economic incentives followed these documents. This dissertation includes two publications discussing incentives for sustainability development, which were provided through the wholesale electricity and capacity market, namely a renewable energy support scheme through the capacity market and prioritization of electricity produced from APG in the wholesale market.

The CRM-RES, as discussed in Section 5.1, could not guarantee energy diversification to enhance the energy security. Nevertheless, the ability of the support scheme to increase energy sustainability[5] remains unclear. Currently, the selection of the RES project has been carried out until 2020. The effectiveness of the CRM-RES has not been as expected compared with the CRMs for conventional power plants. However, the amount of applications has been increasing lately, despite the increase in the local content requirement. Therefore, some improvements in local technology development could have

[5] In this context, by 'energy sustainability' the author means development of renewable technologies rather than an increase in the production capacity.

taken place. If such a tendency continues, the support scheme would contribute to the sustainability goal in the long run.

The APG utilization by producing power could be a highly beneficial option for the oil producers. This option could enable the utilization of all APG produced in the oil field and avoid fines for flaring, which were increased in 2012. Without sales to the wholesale market, the oil producers have to consider other options because APG production volumes are not correlated with oil production volumes, meaning that there will be more petroleum gas in power equivalent than it is required for oil production purposes. By reaching the 95 % APG utilization target, Russia could avoid production of 113.4 $MtCO_2$, which would significantly contribute to the sustainability goal.

In Russia, the energy sustainability is very vulnerable to fossil fuel market distortions, similarly as the whole economic situation in the country. The oil and gas export revenues account for almost half of the national budget. Therefore, the topic of energy sustainability was at the top of the energy policy agenda when the oil prices were high enough to support actions for its development between 2009 and 2013. Thus, as contradictory as it may seem, Russia would need to increase its fossil fuel production and exports in order to continue the policy of enhancing energy sustainability of the country.

5.3 Energy Affordability

Affordable energy was one of main concerns of the policy makers in Russia at the time of the reform. They protected residential consumers by implementing regulated contracts (RCs). In the current market design, residential consumers are still protected by tariffs in RCs, while industrial consumers buy electricity from the market. The total cost of industrial consumers includes the bulk of CRMs implemented in the wholesale market and the cost of inefficient power plants with the MRG status. In addition, their electricity cost includes the import capacity cost. The proportion of CRMs in the consumer's electricity cost will decrease as the agreement period for new capacity will expire, which would take approximately seven years to considerably reduce the impact of now implemented CDAs and LTAs if no other CRMs are implemented. The peak of the consumer capacity cost is expected to occur in 2020, accounting for 218 000 RUB/MW/month, if no more CRMs are implemented. In the case of forced replacement of MRGs by a power plant, the capacity cost decrease can be delayed even by ten years. Nevertheless, the capacity cost is estimated to reach 165 000 RUB/MW/month in 2027, easing the burden of industrial consumers when new capacity is introduced instead of MRGs. The CRM-RES would lead to a 2 % consumer capacity price increase, and at the same time, it would contribute to the electricity price decrease by 2%. Therefore, the impact of the renewable support scheme on the consumer cost is minor compared with CRMs for the conventional power plants.

The above-mentioned factors, together with transmission charges, provide an incentive for industrial consumers to implement distributed generation for their power needs. However, the massive switching of industry to distributed generation would have a controversial impact on prices. On the one hand, demand response through the implementation of own power plants would enhance energy security and contribute to the limiting of a further increase in the capacity cost, as it would curb the need for new capacity, and consequently, a need for new CRMs. On the other hand, the consumers, who would still buy the capacity in the market, would have to pay more, because the burden of CRMs and MRGs would be equally distributed among the remaining consumers.

Energy affordability in the electricity and capacity market without market disturbances can be achieved by maintaining the balance between the demand response program and provision of market-based incentives for investments. Further implementation of CRMs would have an adverse effect on the situation with the final consumer capacity cost; as a result, the consumers might leave the market, or their electricity costs might be directed to end products, which would have a negative effect on the development of the country in general.

5.4 Future Research

Capacity market is a broad topic that cannot be treated exhaustively within the scope of a single doctoral dissertation; therefore, further research is needed to determine the implications of the capacity markets and various CRMs for providing resource adequacy to the electricity industry, and to analyse their cost to the final consumer. Introduction of CRMs is always associated with the interference of regulation with the market design, resulting in non-market-based decisions by market participants. The question of the extent of such interference remains open in the case of Russia. Which path would be beneficial for the market development: a set of regulatory incentives or new adjustments to the current design favouring market-based incentives? Moreover, in the latter case, what specific adjustments to the design would be needed to provide these incentives in a cost-effective way?

According to the discussion presented in the dissertation, the CRM-RES is not able to provide incentives to the development of electricity production in Russia. However, the RES potential of the country is enormous, and with the RES technology development, there might be an opportunity for feasible and economically viable application of RES within the market using other support mechanisms or subsidies.

From the consumer perspective, the development of distributed generation (DG) in Russia should be investigated in more detail, and using more detailed data on the cost structure of the consumers in different regions to define the advantages and disadvantages of them leaving the market. Furthermore, such a proposition would require an analysis of the impact of DG on the electricity and capacity prices, raising the question of a need for a demand response (DR) mechanism in the market.

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Publication I

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Capacity market as an incentive for demand response in Russia.

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[6] The maiden name of the author of this doctoral dissertation

Capacity market as an incentive for demand response in Russia

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***Abstract*—Russian electricity market reform was accompanied with an implementation of a capacity market in 2008. The capacity market was designed to oblige and incentivize mainly the existing generators to invest in new generation. However, the current capacity market rules and the high capacity prices create an unintended incentive for industrial response in Russia. At present, especially the industrial consumers in Russia are facing rapidly increasing costs of electricity due to high network charges and capacity prices, while the electricity price for household consumers is regulated and subsidized. This paper discusses how industrial consumers can reduce their total electricity costs by investing in their own generation. However, if a large amount of this kind of unintended industrial demand response took place, the cost base of the current capacity market would break while the going forward costs of capacity (i.e. the payments to the generators) are locked for several years ahead with the Capacity Delivery Agreements between the generators and the Russian state.**

Keywords—capacity market, price formation, Russian electricity market

I. Introduction

Implementation of capacity market in Russia was announced as a solution to solve a lack of investment in new generation and to ensure the reliability of supply. According to the Russian Ministry of Energy, the deficit of installed capacity was forecasted to reach 275 GW in 2020 according to base scenario [1]. In 2010, the concern about the future energy balance led to the introduction of Capacity Delivery Agreements (CDA) to give incentives for new investments to reduce the threat of capacity deficit.

The CDAs by nature are classified as regulated contracts that guarantee a predictable return on investments to investors. At present, part of the long-run forecasted capacity deficit is yet to be covered through some mechanism, and so far the CDAs are still the only regulatory mechanism that promotes investments in new generation. Meanwhile, the CDAs have already contributed to the rapid increase of industrial consumers' capacity prices. The burden of the high investment cost of new power plants is spread between industrial consumers, because total electricity prices for the population are regulated and fixed by the Federal Tariff Service (FTS). The volumes of introducing new capacities under the CDAs have a crucial impact on capacity price formation, thus eventually leading to high costs of electricity to the industrial consumers. In addition, notable increases in transmission tariffs have also taken place, with their share reaching about 50% of the industrial consumers' total electricity bill in 2013 [2].

High total costs of electricity create an economic incentive for the industry to develop own generating facilities, distributed generation (DG), in order to cut their peak demand or even become independent from the market. Our findings indicate that industrial electricity users can effectively cut their peak load using on-side DG and thereby decrease total electricity costs, demonstrating an accidental and unintended result of the capacity market that can have significant consequences to the long-term sustainability of the Russian capacity market. On the one hand, the DR activities can notably decrease the electricity cost for industrial electricity users and may contribute to the system reliability as well. On the other hand, the price of building new generation under the CDAs has to be paid anyway and the industrial electricity users may face a risk of further increases in capacity prices due to ignorance of central planning to entrepreneurial actions.

This paper is structured as follows: Section II describes price formation in Russian electricity market; Section III gives an understanding about electricity and capacity price levels for industrial consumers; Section IV discuss incentives for unintentional demand response and possible consequences for the market efficiency. Finally, Section V offers concluding remarks.

II. Features of Electricity Price Formation for Industrial Consumers in Russia

Russian power sector encompasses the electricity market and the capacity market. Rules of the electricity and capacity market are defined in the Decree N1172 [3]. Electricity prices are formed in the day-ahead market for every hour of the following day depending on bids from suppliers and buyers. Capacity market price is determined for one year at a time in Competitive Capacity Auction (CCA). Currently Russia is divided into two price zones, where electricity prices are determined by the market, and a tariff zone, where prices are regulated by the FTS. For an industrial consumer, the electricity purchasing costs amount to about 50 % of the total costs, and the other half is transmission and distribution charges.

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A. *Electricity market*

In terms of traded volume, the largest part of the electricity market is the day-ahead market. Other two markets where electricity is traded in Russia include the balancing market, which is the intraday market, and the bilateral contracts. The electricity wholesale prices in Russia are currently about 20-25 €/MWh [4]. Power production in Russia is mainly carried out by using natural gas in the first price zone whereas coal and hydro power are dominant in the second price zone [5]. The average annual day-ahead market prices are lower in the second price zone but due to transmission capacity limitation power cannot be transmitted to higher priced first zone.

Electricity prices in Russia are highly dependent on the domestic gas price. For example, a 15% increase in gas tariff leads to 21% increase in electricity cost [6]. Russia was aiming to reach a netback gas price by 2017, by annually increasing domestic gas prices by 15%. However, after the Ministry of Economic Development forecast [7], this policy was reconsidered and the gas prices were "frozen" until 2016 as an experiment to decelerate inflation growth, and, as a consequence decelerate electricity price growth.

B. *Capacity market*

Capacity market was introduced in 2008 to ensure the reliability and resource adequacy of electricity supply. Initially, annual Competitive Capacity Auctions (CCA) were planned to be held until the end of the transition period in 2011. However, the annual CCAs still continue, although the Russian Government is currently reconsidering the capacity market model. In its present form, the CCA is organized as illustrated in fig.1: the new capacities under CDA are selected by default, as well as hydro and nuclear generation under Long-Term Agreements (LTA) and the renewable energy capacity under the specific RES CDAs (capacity remuneration mechanism for renewable energy). In addition, the so-called "must-run" generation that is needed for reliability reason and for the heat production requirements during winter time is also selected by default. The CCA prices for the year 2014 for two price zones are about 2660-2880 €/MW • month for 2014. The CCA prices only take into account the costs of old capacity. The end-users' capacity prices, calculated as the weighted average of the costs of new capacity under the CDAs, LTAs and RES-CDAs, and the CCA prices, in 2014 are about 4500 €/MW • month.

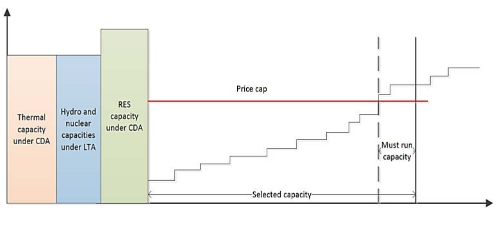

Fig. 1. Capacity price formation in the capacity market

The industrial consumers' capacity costs depend on their peak power consumption during specific hours defined by the system operator (SO). Peak hours are defined and published annually and there are approximately 8 peak hours during every working day. The industrial consumers can reduce their capacity charges by reducing the power withdrawal from the system during peak hours. This can be done, for example, through own generation, or by improving energy efficiency, or by shifting the peak demand to some other time, or by peak shaving. However, most industries seem to prefer to transmit cost of the electricity to the goods that they are producing [7].

C. *Transmission cost*

Transmission and distribution businesses are natural monopolies regulated by the FTS of Russia. Maximum and minimum limits for the tariffs are provided every year for every regional network company to form unified tariffs depending on voltage level.

Customer chooses the type of the tariff in the transmission agreement [8]:

- Two-part tariff, which includes payment for the maintenance of electrical network (average is 17636 €/MW • month in 2014) and payment for the losses in electric network (8.27 €/MWh in 2014).
- Single tariff per 1 MWh consumed electricity with taking into account cost of the losses (average is 39.81 €/MWh).

In two-part tariff maintenance payment is calculated according to the peak consumption of consumer. Industry can chose its tariff according to its the load profile, thereby industry with uniform pays two-part tariff and industry with daily peak consumption pays single tariff. Tariffs are defined as necessary gross revenue for transmission and distribution companies. However, tariffs for the industry are higher than for population due to the cross-subsidization of the electricity transmission and distribution business that is discussed in the next sub-chapter.

D. *Cross-subsidization*

Cross-subsidization has appeared in Russia during economic reforms as an instrument for social security. Cost burden for the electricity production and transmission is redistributed between industrial consumers to decrease burden on population. According to [9], about 80% of cross-subsidization is spread within transmission and distribution tariffs, amounting to 6.28 billion €[1]. The remaining 20% of subsidization is a result of regulated agreement for the electricity for population. Russia has struggled with the problem of cross-subsidization for 15 years already but the industry will have to continue subsidizing the population until changes in the current regulation are made.

E. *Retail charges*

The guaranteed suppliers have the right to sell the electricity bought from the markets to retail consumers with

[1] 1 euro was equal to 42 rubles according to the exchange rate in 2011

markup. Currently, this markup amounts about 5% of electricity price purchased in the wholesale market (without transmission cost). Thereby, retail charge counts little more than 2% in end consumer electricity price for the industry.

III. Problem Description

High end-consumer prices serve as an indication for long run demand response (such as self-generation) in the Russian electricity market. For example, an industrial consumer can save about 22136 €/MW monthly on the transmission and capacity costs alone. However, power plants with installed capacity equal or more than 25 MW (even if owned by an industrial company) must sell electricity in the wholesale market according to Federal Law on Electricity [3]. There are two exemptions from this rule:

- Power plant is technologically associated with the industrial production and uses its waste product as fuel (APG, petrochemical industry, etc.);
- Power plant is technologically associated with the industrial production and less than 40% of electricity demand is covered by other electricity supplier.

Industrial consumers can use the second exemption for implementing their own generation with installed capacity more than 25 MW. Assume that consumer's peak consumption is N MW, thereby consumer have to pay for capacity according to its peak consumption during the peak hours defined by the SO. The value N can be also used for calculation of transmission cost if there is two-part tariff provided in transmission agreement. Total electricity costs depend on the day-ahead market prices and the consumer's real consumption during calculation period. Thus, the daily costs of electricity for the industrial consumer are defined as (1).

$$C_{el1}^{day} = 1,05 \cdot \left(\frac{N \cdot C_{cap}}{30} + \sum_{i=1}^{24} E_i \cdot C_i^{el}\right) + \sum_{i=1}^{24} E_i \cdot T_{loss} + \frac{N \cdot T_{grid}}{30} \tag{1}$$

Where N is peak capacity value (MW), C_{cap} is a capacity price for the month (€/MW • month), T_{grid} is transmission tariff (€/MW • month), E_i is electricity consumed during the hour i (MWh), C_i^{el} is electricity price for hour i (€/MWh), T_{loss} is tariff for transmission losses (€/MWh) and 1.05 is coefficient which takes into account retail charges.

Capacity price is defined for every month of year and stays fixed for whole year. Electricity price is defined every hour in the day-ahead market. Retail charge and transmission tariff are defined in the respective agreements signed by two parties, industrial company and the retail company.

When considering the implementation of self-generation, the industrial consumer can cut its peak capacity demand, decrease total monthly energy consumption from the grid, and thereby decrease monthly cost of electricity. The running costs of the self-generation plant depend on fuel cost, and they are a function of efficiency:

$$C_{DGi} = \frac{c_{fuel}}{H \cdot \eta_i\left(E_{DGi}\right)} \tag{2}$$

Where c_{fuel} is cost of fuel (in our example calculations natural gas from Gazprom, [$€/1000m^3$]), H is the heat rate of natural gas (kWh/m^3), and $\eta_i\left(P_i\right)$ is the efficiency of gas turbine that depends on the output power. Efficiency of a gas turbine reaches its nominal value when the power output is also nominal.

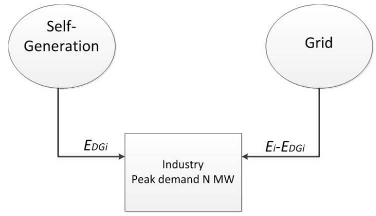

Fig. 2. Structure of industrial load consumption after the implementation of self-generation.

The task of industrial consumer is to minimize its electricity costs by running its own power plant (fig.2) so the costs of self-generation should be included in function:

$$\begin{aligned} C_{el1}^{day} = 1,05 \cdot \Big(& \frac{\max_{peak}\left(N - N_{DG1}\right) \cdot C_{cap}}{30} \\ & + \sum_{i=1}^{24}\left(\left(E_i - E_i^{DG}\right) \cdot C_i^{el}\right) \\ & + \sum_{i=1}^{24}\left(E_i - E_i^{DG}\right) \cdot T_{loss} \\ & + \frac{\max\left(N - N_{DG}\right) \cdot T_{grid}}{30} \\ & + \sum_{i}^{24} C_{DGi} \cdot E_i^{DG} \end{aligned} \tag{3}$$

Where N_{DG1} is output of industrial consumers own power plant during the peak hours determined by the SO, when $\left(N - N_{DG1}\right)$ is maximal during peak hours, however transmission capacity should be paid according to maximum consumption during day (can be different from peak consumption), E_{DGi} is the power produced by self-generation during hour *i*.

During off-peak hours industrial consumer can buy electricity from the market so long as the market prices are lower than the costs of self-generation (4) and the electricity bought form the markets does not exceed 40% of the total electricity consumption (5).

$$C_{DGi} > C_i^{el} \tag{4}$$

$$\sum_{i=1}^{24}\left(E_i - E_i^{DG}\right) < 0,4 \sum_{i=1}^{24} E_i \tag{5}$$

Obvious solution for function (3) minimization is the industrial consumer's full supply from its own power plant when the costs of self-generation is about 23.89 €/MWh, taking into account domestic gas prices. Implementation of DG becomes irrelevant in case when cost of running DG exceeds 62 €/MWh.

IV. Discussion

In Russia, the industrial consumers' self-generation became a topic of heated discussions in 2010 with establishment of the technological platform "Small-scale distributed generation", which suggested to increase the target value of installed distributed generation capacities in Russia from 3.1 GW to 50 GW until 2030 [3] as a grid connected generation. The main reason to implement distributed generation, from power system point of view, is to increase the reliability of the system. For example, in the US the power outages of 2003 became a critical point for the implementation of distributed generation [10]. Indeed, distributed generation can sometimes be developed by consumers and municipalities to guarantee their power supply. In Russia, however, the main drivers of distributed generation are the industrial consumers' high total electricity costs due to the high capacity and transmission costs, and the costs of cross-subsidization.

Distributed generation in Russia is characterized by the availability of relatively cheap fossil power sources. As [11] estimated, the payback period of industrial distributed generation is about 11 years.

A. *Barriers*

Despite the economic attractiveness, there are certain risks and barriers to the implementation of on-site industrial self-generation power plants:

- Construction of a power plant requires technical regulation and licensing. The project of power installation must pass inspection and obtain permission from the numerous instances, which can cause delays up to 2 years [12];
- Connection to the distribution network will require technical documentation and approval of the network company as well as payment for the connection which is often fairly close to the capital cost of the power plant;
- If the power plant has the installed capacity more than 25 MW, and the output is used mainly to cover the industrial consumers own consumption, the Market Council requires every year a documentation that confirms use of the power plant for self-generation;
- Changes in regulation may affect the profitability of distributed generation. For instance, a new electricity market model and the deregulation of the heating sector are currently under consideration in the Ministry of Energy of Russia;
- Risk of excessive gas price increases for the industry (e.g. following the failure to introduce more cost-reflective gas prices for the household consumers).

In addition to the above barriers, wholesale market participants may also aim to hinder the emergence of distributed generation. First, the industrial self-generation directly competes with large generators in supplying the industrial demand. Furthermore, the industrial consumers are mainly responsible for covering the capacity costs and their exit from the markets puts the whole capacity market under stress. Similarly, the exit of the industrial consumers would affect the income of the network companies.

B. *Impacts of industrial self-generation on the price of electricity and capacity*

The reduction of industrial demand as a result of self-generation would put downward pressure on electricity prices [13]. However, for the capacity prices the opposite would be true: while the lower industrial demand could actually lead to lower capacity auction prices for old generators, the entry of new expensive generation would undermine any such price reduction, leading to the increase of the total capacity costs payable by the demand side.

The purpose of the capacity market is to give incentives for new investments through CDAs. For example, the central plans indicate an increase of 18.85 GW of installed capacity under CDA by 2017, and a 5 GW increase of renewables under similar capacity remuneration mechanism [14]. However, the increase of the new generation capacity is independent of the development of demand, and the exit of industrial consumers would reduce the number of players sharing the total costs of capacity. Fig.3 shows an estimation for the all included capacity price development in case of demand reduction of 2GW annually (low demand) in comparison to the case where demand stays the same.

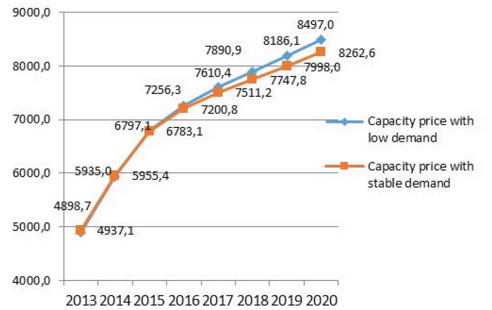

Fig. 3. Capacity price development (€/MW • month).

C. *Impact of industrial self-generation on the network sector*

In principle, the development of distributed generation can delay transmission equipment reinforcement and reduce need for transmission capacity additions [15]. The limited transmission capacity and obsolescence of current transmission network require immediate actions, and the grid companies are strongly dependent on their existing industrial customer base. At present, the grid companies and the generation companies are lobbying for a new support program similar to the CDAs but for the reinforcement of transmission lines and the existing power plants.

V. Conclusion

Despite of the many reforms over the past decade, the Russian electricity sector is still characterized by numerous non-market-based mechanisms. For example, the capacity price formation is influenced by the existence of the CDAs and the capacity remunerations for the renewable energy, both of which constitute as regulatory instruments. In addition, the high transmission charges of the industrial consumers that amount to about half of their total electricity costs are partly explained by the cross-subsidization to keep the residential customers happy. Our findings suggest that the high industrial electricity prices in Russia can be a strong driver for the development of distributed generation in Russia. Under the current market rules, the industrial electricity consumers in Russia have an incentive to invest in their own generation to reduce their peak demand, therefore, creating unintentional demand response. However, the consequences of such industry behavior can increase burden for the rest of industry without on-site generation.

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Publication II

Vanadzina, E., Gore, O., Viljainen, S. and Tynkkynen, V-P.
Electricity production as an effective solution for associated petroleum gas utilization in the reformed Russian electricity market.

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Electricity production as an effective solution for associated petroleum gas utilization in the reformed Russian electricity market

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***Abstract*—Russia leads the list of countries in which most flaring occurs, with an estimated 15-37 BMC of associated petroleum gas (APG) being burned in Siberian oil fields annually. In view of the environmental impact of flaring and ineffective use of energy resource, fees for flaring are being increased from 2012. Significantly increased fines pose a challenge for oil producers, which have focused only on oil production. A number of solutions for utilizing APG are currently used in Russia: processing of APG in gas processing plants, re-injection of gas back into the oil field, and production of heat and power for the needs of the oil industry. These commonly used options for APG utilization are analyzed and discussed in this paper, taking into account the specific features of the Russian oil and gas market and barriers presented by monopolies in the gas export and gas processing industry. Analysis of the utilization options indicates the appropriateness of APG as a fuel for effective power production within Russia's reformed electricity market.**

***Index Terms*—Associated Petroleum Gas, Electricity Market, Russia, Oil, Gas.**

I. Introduction

Associated petroleum gas (APG) is a hydrocarbon that is not often considered as a valuable natural resource. Consequently, this gas is released as a waste product from the petroleum extraction industry and frequently flared instead of being utilized. Russia led the list of Top 20 Flaring Countries with 37 BCM of APG burned in Siberian fields in 2011, while other oil producing giants, Saudi Arabia and USA, flared 3,7 and 7,1 BCM respectively [1]. Flaring of APG is considered a global environmental problem, CO2 emissions from flaring amounted 400 million tons in 2012 [2]. At the same time, it is a national problem for Russia since APG flaring is, in effect, a huge waste of energy, which could potentially generate additional revenue from its use and sales. Annual APG production in Russia (around 70 BCM) has the potential to meet 15% of total annual domestic need for natural gas [3]. Since 2007, the Russian government has highlighted the importance of flaring reduction in the country, which led to the introduction of the Government Decree N7 [4]. This Decree set a 95% APG utilization target for oil companies from 2012. Further, the Decree N1148 introduced higher fines for non-utilization of APG from January 2013 [5]. However, the target of 95% APG utilization has not yet been met.

Many technologies are available for efficient APG utilization. APG can be used in three main areas: delivery to consumers through existing gas pipelines, delivery to gas processing plants, and electricity generation in oil fields [6]. Despite the availability of sophisticated technologies and the introduction of a system of penalties, insufficient flaring reduction has occurred during the last 5 years. Previous studies have focused on reasons why flaring reduction has progressed slowly [7] and the main barriers faced by oil producers in utilization of APG [8]. It has been found that lack of access to monopoly-owned gas processing and transport facilities create high institutional barriers toward efficient APG utilization. Furthermore, the marginal costs for processing APG for sale are higher than the actual regulated domestic gas prices, which make it more profitable to burn the gas than utilize it.

In the current business environment of institutional barriers created by the monopolistic gas sector, oil companies are confronted with the challenge of finding an economically viable solution of meeting APG utilization targets and thus avoiding large fines. In the prevailing legislative framework, the only option for APG utilization that obviates the need to deal with monopolistic processing and transport institutions is use of APG for oil companies' own needs in the oil field, for example, for the production of electricity. Producing electricity using fuel generated on-site allows the energy intensive oil industry to avoid fines and mitigates the increasingly high energy costs resulting from the reformed electricity market. This paper shows that Russia's reformed electricity market creates new incentives for oil companies to utilize APG for producing electricity for their own needs. Despite some technical barriers,

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such as non-constant availability of APG, this option is shown to be commercially and technologically viable.

This paper has following parts. “APG status in Russia” and “APG utilization methods” describe current situation in solving gas flaring problem. “Electricity market: potential for APG use” offers a solution for effective APG utilization in the scope of liberalized electricity market. Section “Discussion and Conclusions” analyses all findings.

II. APG Status in Russia

The problem of flaring involves environmental issues. Toxic compounds from APG can be accumulated in sources of drinking water, soils, plants and animals, and harm people’s health getting into supply chain. As a result of flaring, about 8 kg of emissions are produced with 1 ton of oil extracted from the well [9]. The intensity and harmfulness of emissions have high dependence on APG content, height of flares, territory characteristics etc. Oil and gas industry (including APG flaring/venting) contribute up to 70% to Russia’s overall emissions [10]. Thereby, the attention to the APG problem that occurred recently in Russia is completely justified.

The official government position regarding the APG problem is very clear; flaring must be reduced dramatically and the APG utilization rate must increase substantially according to the Russian Energy Strategy document [11]. The government set the target APG utilization level for oil companies [4]. High fees for flaring and venting were supposed to force oil companies to invest in APG utilization projects. Thereby, oil fields which APG utilization level was lower than the targeted 95% must have paid the fee increased by coefficient K=12, from 2014 this coefficient is K=25. In addition, the coefficient K=120 is used in case of absence of metering system for APG production in the oil field [5]. The coefficient is not used in fee calculation if annual APG production is lower than 5 million cubic meters and/or carbon content of produced APG is lower than 50%. These additions were made in order to prevent shutdown of the oil fields with high production costs [12].

Despite all the effort, the target of 95% APG utilization has not yet met. Only “Surgutneftegas”, second largest APG producer, has reached the required level of APG utilization. While state owned and the largest producer of APG, “Rosneft”, has utilization level of only 68.7% [3]. The dynamics of associated gas utilization level indicates only slight growth by the end of 2013 (Fig.1). According to the official Russian statistics 74.4 BCM of APG was produced in Russia in 2013, of which 15.8 BCM (21% of total production) were burned in flares [3].

Reasons for non-utilization are due to a range of factors. Oil deposits are often situated in a long distance from gas collection infrastructure, transportation and processing systems, which makes utilization task more expensive. Historically formed concentration of the oil industry on plans for oil production also impacts significantly on deceleration of APG utilization process.

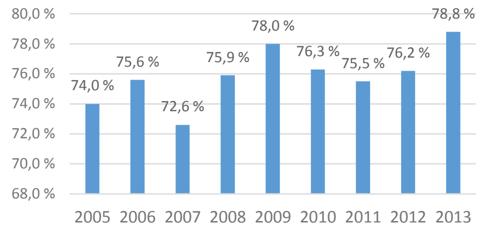

Figure 1. Dynamics of APG utilization level in Russia

III. APG Utilization Methods

Although there are numerous ways to utilize APG, only a few methods are used in practice (Fig.2). The choice of suitable method is based on economic analysis that takes into account oil field location, associated gas composition and availability. One of the important factors is gas-to-oil ratio (GOR) which is variable, and oil and gas production from the same oil well does not have the same ratio throughout its lifetime. The largest GOR in Russia is recorded in the Yamal-Nenets Autonomous Regions fields, with over 130 cubic meters/ton of oil. In other regions, GOR is lower and generally around 100-110 cubic meters/ton [13]. Although, high GOR promotes effective utilization of APG, since the gas is a valuable fuel and wasting it is unreasonable for the company.

In addition to technical considerations, financial implications are of significance and oil companies are challenged by increased fees for flaring and the need to find a suitable solution for the APG problem. This paper proposes a systematization of options available for APG utilization (Fig.2), giving the benefits and drawbacks for each option and describing main barriers. The approaches will be discussed further in the following sections.

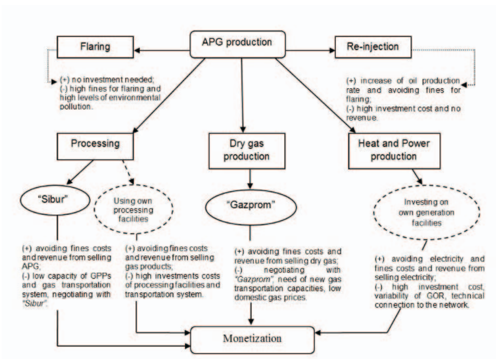

Figure 2. Solutions for APG monetization

A. *Re-injection*

Re-injection (or cycling process) of APG and water back into the field allows an increase in crude oil production by 10-35%. From the technological point of view, this approach has several advantages, such as uploading APG back to the reservoir without separation and independence from GOR. On the other hand, gas pumped in the field should be extracted later anyway, which leads to additional expenses. With a few exceptions, this method is not widely used in Russia due to the high costs involved. The first cycling process was implemented in the Yarakta field by the "Irkutsk Oil Company" in 2009 [14]. Booster compression plant had a capacity 1.5 million cubic meter/ day in the end of 2012 and another two facilities are under implementation. However, company's plan also includes construction of gas processing plant.

B. Processing

Processing of APG requires significant investments in own processing plant or a negotiation with the "SIBUR" company, which has a monopoly in gas processing and has limited capacity of processing plants and transmission system [15]. The "SIBUR" company processed 23.1 BCM of APG in its Gas Processing Plants (GPPs) in 2013 [16], which is about 40% of total utilized APG, excluding flaring and direct utilization in oil fields. "SIBUR" has a stable leading position in the Russian gas processing industry. Liberalization of APG prices in 2008 permitted oil companies and "SIBUR" to negotiate prices, taking into account transportation of APG to the GPP, such that the deal can be profitable for both parties. The company has increased the volume of APG processed in its GPPs by 2.25 times compared to 2003 [15].

Industry-wide processing of APG is complicated by the fact that the necessary industrial and technological infrastructure does not exist. Long distances between GPPs and oil fields lead to additional expenses. Construction of a pipeline to transport APG is highly capital-intensive; 1 km of such pipeline will cost 1-1.2 million euro [6]. Transportation of APG to a GPP increases the cost of APG to 23 euro for each 1000 cubic meter, while the cost of production of natural gas by "Gazprom" is 3-5.4 euro per 1000 cubic meter.

C. Dry Gas Production

Dry gas selling is limited by the "Gazprom" monopoly [8]. "Gazprom" itself determines the presence of spare capacity in the transmission system and checking the objectivity and accuracy of this information is rather difficult, despite the fact that officially access to the national gas pipeline should be possible for all producers. Other solutions exist for oil companies to utilize associated gas and enter gas markets without using "Gazprom" pipelines, such as compressed natural gas (CNG), gas to liquids (GTL), gas to chemicals (GTC), gas to solids (GTS) and gas to wire (GTW). From an economical point of view, GTL is the best option for remote and large reservoirs [17]. Commissioning and operation of GTL plants is challenged by the volatility of oil and gas prices; capital investments based on the current market situation may become economically unfavorable due to changes in the oil and gas markets [18]. In spite of its potential, GTL technology is not well studied compared to the widely used LNG technology.

D. Electricity and Heat Production

Electricity and heat production primarily serves as electricity cost avoidance, since oil extraction is an energy intensive process. Depending on the operating conditions, electricity makes up 30-35% of oil production costs [19]. Electricity costs will continue to increase due to the high water content in depleting existing oil wells and may reach 40% by 2020 in Russia. In the balance of energy consumption of the oil industry, more than two thirds of all costs are associated with the work of well pumping units [19]. Therefore, own site power generation using APG as a fuel can be solution to reduce the cost of electricity. Especially it becomes attractive in case of remote oil fields, which are located far from electricity network. For oil fields close to the electricity network, power generation fueled by APG can become a source of additional revenue. According to the Wholesale Electricity and Capacity Market rules, electricity produced using APG as fuel should be selected in a priority order in the day-ahead market and producer has a right to operate only in retail market, while other producers with installed capacity over 25MW must operate in wholesale market [20].

The principal benefit of the energy production solution, undoubtedly, is independence from "Gazprom" or "SIBUR". However, the approach require investment of the power generating facility. This approach is discussed and analyzed in details below.

IV. Electricity Market: Potential For APG Use

Russia liberalized its electricity market in 2011. Deregulation of the electricity industry was focused on attracting private investment to the industry and establishing competition between power generators [21]. Reformed market has two different components: electricity market and capacity market. The electricity market is designed to cover the variable costs of generators, while the capacity market is designed to cover fixed costs, including investments cost in the generation sector. Over 37 GW of new generation capacity is to be added in 2010-2015. The capacity price is strongly driven by new investment projects, realization of which will be repaid through the capacity market. Capacity prices are expected to increase due to commissioning of new generation and replacement of old generation [22]. In addition, transmission and maintenance services constitute about 50% of electricity cost. The average structure of Russian consumer payments is illustrated in Fig.3.

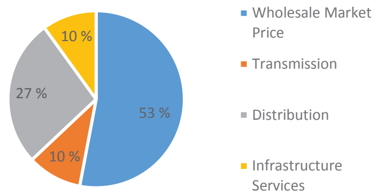

Figure 3. Structure of electricity cost for the end-consumers in Russia

Growing electricity prices and transmission costs are a strong motivation to implement own generation for most of large industrial companies. Currently, such option is economically justified even in the scenario if industrial producer would need to buy natural gas from the gas network [23]. While, from oil producer prospective, associated gas can be considered as almost a free fuel.

We developed a model, which shows that avoidance of electricity cost from the grid has a significant impact on cost-benefit analysis. Power plant with the installed capacity 25MW is taken as an example for our calculation, which is enough to utilized all APG in the oil field with annual production 330 thousand tons. Assuming that, based on current equipment costs, investments for construction of a 25 MW plant are 700 EUR/kW, GOR decreases linearly during the lifetime of the oil well, it is possible to construct a cost-benefit graph. The first year is considered as the year of construction, the lifetime of the deposit is 15 years [24] and during this period, oil and APG resources become exhausted. The benefits of such a project become evident from comparing costs and returns during the lifetime of the oil well, including renovation costs in the tenth year of exploitation (based on the requirements of the generating equipment).

$$Cost = Investments_t + Operational\ cost_t \tag{1}$$

$$\begin{gathered} Benefit = Income\ from\ electricity\ selling \\ +Savings\ from\ avoiding\ electricity\ purchasing + \\ Saving\ from\ avoiding\ fines\ payment \end{gathered} \tag{2}$$

The benefit includes the avoidance of electricity costs and income from the sale of electricity in the wholesale market, taking into account the rise in electricity prices in the wholesale market (Fig. 4). In other words, by producing electricity for the needs of oil production and selling excess electricity in the market the company can have double benefit. The share of the capacity market in the total income is about 30%.

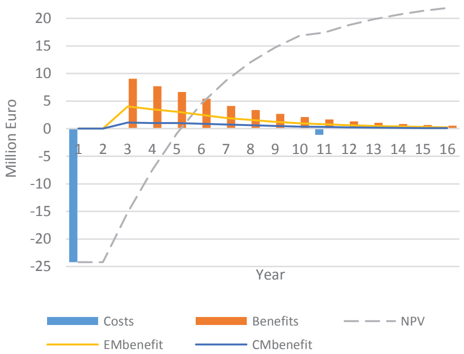

Figure 4. Cost-Benefit illustration of a 25MW example AGP-based power plant and share of incomes from the wholesale market

In case of long distance from electricity grid to oil production field, electricity can be produced only for own needs of oil production. Thus, *Benefits* formula (2) will not include *Income from electricity selling* component. Oil producer would invest in power plant with less capacity only to cover production demand. Results (Fig.5) shows that this solution is more beneficial compared to previous solution. However, in this case 40% of produced APG is used for power production. Another, 55% should be further utilized, therefore, additional investment would be needed in order to reach 95% utilization target.

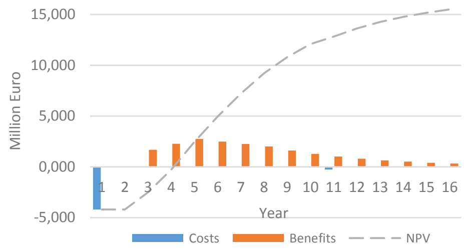

Figure 5. Cost-Benefit illustration of off-grid electricity production solution for oil industry's own need

When evaluating APG utilization approaches, the most beneficial solution is determined by the conditions and geo-economic context of the oil production. If the oil field is located in territory that is far from a gas pipeline system and power grid, power generation can be organized as distributed generation and operate in retail market, where prices are agreed in bilateral contracts. The development of distributed generation is a growing trend worldwide. In Russia, import of generators has doubled in recent years, which means that distributed generation has increased considerably [25].

V. Discussion and Conclusions

Russia has great APG resource potential from its oil resources, proved oil reserves of the country are 12.7 thousand million tons [26]. Based on this value, APG resources can be estimated at more than 1000 BCM, which is a significant amount, considering that around 50% of state budget revenue comes from hydrocarbons. Currently more than 20% of produced APG is flared directly on the oil fields involving harm to the environment. Oil production always has the highest priority in the strategy of oil companies, which is why the APG utilization issue is difficult to solve in a short time. The most problematic region is Western Siberia, which is the largest oil-producing region, where APG transportation and processing facilities are not developed. Existing regulation establishes high fees for flaring and venting APG. The coefficient K=25 from 2014 in fee calculation for flaring more than 5% of produced APG [5] would put oil producers into position where the option of simply paying for emissions is no longer attractive.

Generally, oil companies have four economically and technologically feasible ways of utilizing APG in their deposits, but existing barriers caused by monopolies prevent rapid achievement of the target. Despite the fact that APG has priority of access to the gas transportation system, decision to allocate transmission capacity or not is made by "Gazprom". The company may, at its discretion, fully load its transport system and refer to the fact that it has no opportunity to accept APG from other companies. In addition, in the light of projected increase in oil production [11], APG production would increase respectively, as APG production is inseparable process of oil production. Russia would face a situation where gas production may be more significant in future. At the same time, competition in European markets will remain high [25], which can affect gas prices. In such conditions, APG delivery as a dry gas looks irrelevant, and Russia risks having a reduced state budget income, since half of Russian state revenue comes from the sale of hydrocarbons. As for domestic market, gas prices for domestic customers are regulated and fixed by the Federal Tariff Service [8]. Thus, there is no possibility for APG to be competitive in the domestic market without government support.

Similar situation with “SIBUR”, limited capacity of GPPs and lack of transmission capacities would serve as serious obstacle. Such a situation creates serious obstacles for oil companies; they have to reach an agreement with at least two large enterprises, such as “SIBUR” and “Gazprom”. On the other hand, developing own GPP require large investments not only on processing facilities but also transportation and product sales management, while investing in power generation can be decentralized.

Oil production is a very energy intensive industry and the use of APG for power production can be an effective and affordable way to utilize APG directly in the oil field. This solution can provide double benefit: avoid annually increasing electricity costs and avoid high fines for flaring. Nonetheless, implementation would require considerable investments in power plant.

There is no versatile solution for APG utilization. Each solution should be evaluated and analyzed for each case. In this paper, we analyzed power production solution to utilize APG. There are two options: electricity production only for own needs and electricity production from all available APG. The first option has higher outcome, but not all the APG would be utilized, which would require another solution for the rest APG. However, this option does not require connection to the power transmission grid and suitable in case of long distance to transmission grid. In the second option, all available APG is used to produce electricity, from which part is used for own need and part for selling in the wholesale market, providing additional benefit. In addition, utilization target can be fully achieved, no other solutions are needed. Results show that electricity production from APG is economically justified and can be implemented independently from existing gas processing and transport monopolies. Current prices for electricity for industrial customers in reformed Russian electricity market and high fees for flaring are strong incentive for APG use as fuel for power production.

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Publication III

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RES support in Russia: Impact on capacity and electricity market prices

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RES support in Russia: Impact on capacity and electricity market prices

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ABSTRACT

Russian renewable energy policy has undergone changes following an establishment of targets for installed capacity and power production using renewable energy sources and the introduction of new capacity based support scheme for renewable energy. The forecasted amount of future renewable power will not provide enough power production to meet growing demand for renewable energy; although, it will help with modernization of the energy sector and development of renewable technology and innovation. At the same time, the capacity support scheme for renewable energy may adversely affect capacity prices and become an additional burden for industrial consumers, who are already paying the cost of capacity support for conventional power plants, so-called Capacity Delivery Agreements (CDAs). This work assesses the impact of the new capacity based support scheme on capacity and electricity price formation. Modeling results show that the impact of capacity support for renewable energy is small compared to that of capacity support for conventional energy, suggesting that the Russian energy production mix will continue to be dominated by fossil fuel based generation.

1. Introduction

Abundance in fossil resources, low domestic gas prices and a lack of political willingness to support renewable energy sources (RES) have been the main obstacles to renewable energy development in Russia [1]. However, Russia undoubtedly has great potential in (RES) due to its large land area, significant climate variation, and the low population density in most parts of the country. The economic potential of RES in Russia is estimated to be 189–224 Mtoe per year [2,3]. Currently, the Russian power sector is dominated by gas, coal and oil based generation, and Russia is one of the world's leaders in fossil fuel based energy production and export. Russian natural resources account for 19% of the world's coal resources and 23% of the world's natural gas reserves, and Russia accounts for 8% of global natural uranium production [4].

The position of the Russian government regarding RES is reflected in the policy document of 2009, “The Energy Strategy up to 2030” [4], which recognized the importance of RES technology development. Recently, the issue of promoting renewable energy sources has become more visible in Russian political and industrial discourse. Following on from the establishment of an overall target of reaching 4.5% renewable energy production in 2020 [5] and the approval of incentives for renewable energy production [6], renewable policy has been supplemented with targets on installed capacity, production and local content requirement within the wholesale market [7]. Consequently, 11,586 GWh of energy should be produced using renewble energy sources by 2020, which would represent 0.9% of total forecast production in 2020 [7].

Without support and subsidies, renewable energy is uncompetitive in Russian power markets [5], due to high capital costs and the existence of comparatively low domestic gas prices. A key document in Russian RES development is the Federal Law on Electricity № 35 with its current amendments. Based on these amendments, the cost of technical connection to the grid can be refunded by a subsidy for qualified renewable power producers and producers can sell their electricity at a premium price (the premium scheme) or receive a capacity payment (the capacity-based scheme). It has to be borne in mind, however, that investments in traditional power also receive support, namely via a capacity remuneration mechanism consisting of Capacity Delivery Agreement (CDAs) for thermal power plants and Long-Term Agreements (LTAs) for hydro and nuclear power plants, which

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0960-1481/

guarantee investment returns [8]. In a recent development, RES based power plants have become eligible to receive similar capacity support.

The inclusion of RES projects in the capacity-based support scheme and changes to wholesale electricity and capacity market rules may provide a much-needed stimulus to RES development in Russia [9]. As of autumn 2013, renewable energy producers can participate in a RES project selection process for a scheme similar to the CDA mechanism that guarantees payback for 15 years. The requirements for selection are known, and all deadlines and limits have been announced [10].

Many reports have been published that assess Russian RES potential and analyze renewable policy development in Russia, starting from Martinot [11], who suggested that Russia could benefit from renewable support in remote areas. The same conclusion was reached by the International Energy Agency (IEA) [12]. However, renewable projects are considered within the wholesale electricity market in current support schemes. In Ref. [1] it is argued that capacity-based support should be implemented in Russia in order to attract investment; and [13] and [9] offer detailed analysis of current support schemes in Russia from a policy and regulation perspective, concluding that capacity support could promote investment in RES projects. However, production incentives are also needed in order to avoid "steel in the ground" syndrome [13].

Much of the literature, including the above-mentioned works, is policy oriented. This paper, however, aims to address a more practical and concrete issue, namely the impact of support schemes on wholesale market prices. The main focus of the paper is on possible capacity price increases resulting from commissioning of RES power plants and from subsidies for conventional power plants. However, the low electricity production costs of RES power may reduce the electricity market price in the Russian wholesale market, thereby reducing the burden on consumers. This paper proposes two separate approaches, one based on consumer capacity price formation and the other on electricity price modeling, to assess the contribution of the capacity-based renewable support scheme to changes in the consumer capacity price and electricity market price.

2. Renewable energy in Russia: needed or imposed

2.1. Russian power production and demand growth

Total installed capacity of power generation units in Russia was 226.47 GW at the end of 2013 and energy production amounted to 1023.5 TWh. Russian electricity is mainly generated by burning fossil fuel, usually natural gas (see Fig. 1). Russian gas reserves are believed to be the largest in the world, and according to the Ministry of Energy document, "General Scheme of the Gas Industry Development up to 2030", gas production will satisfy all internal and external needs until 2030 [14]. Domestic gas prices in Russia remain low, despite the government strategy of reaching netback price parity with export gas prices by 2015. In a possible change in policy, the Ministry of Economic Development has suggested reducing the envisioned 15% annual increase in order to avoid a slowdown in economic growth [15]. Such a policy change would maintain natural gas as the main fuel for power production while meeting demand growth.

Demand growth in the revised version of the policy document "General Layout of Power Units from 2010" is forecasted to be 3.1% annually in the maximum scenario and 2.2% annually in the base scenario until 2030 [17]. According to the document, the volume of installed capacity in Russia is forecasted to reach 311.55 GW by 2030 if demand increases according to the base scenario. Commissioning of new generation capacities should be 173 GW by 2030, of which 6.1 GW is expected to be based on RES. Meeting this need for new generation requires appropriate incentives in order to attract the required investment. The large amount of required new generation reflects the old age of existing power generating facilities, with about 1–1.5 GW of power generation units being decommissioned annually, as well as the expected demand growth. Concern about security of supply in anticipation of forecasted demand growth led to the introduction of a capacity remuneration mechanism for new traditional power plants, CDAs and LTAs [18], which could guarantee investors a predictable return on investments. This mechanism seemed a necessary measure at the time of its introduction and has had some success in its objective of increasing the amount of new power generating capacity.

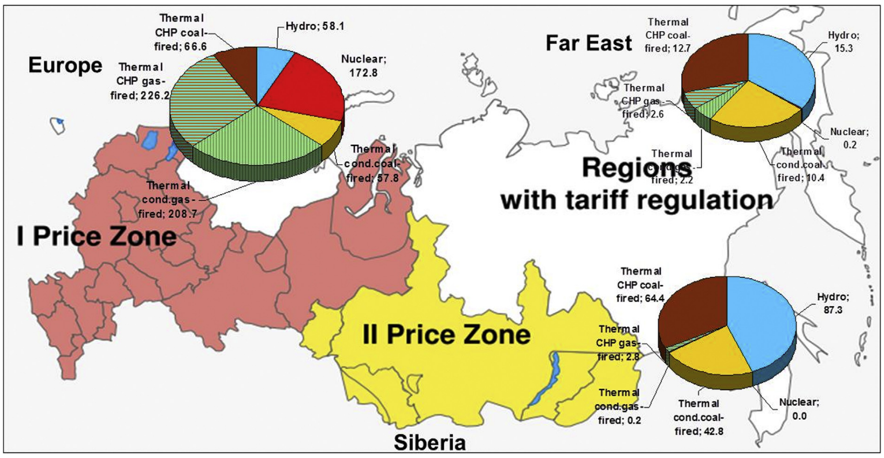

Fig. 1. Power production in Russia [16].

In recent years, however, annual demand growth has been less than forecast, below 2%, and even negative in 2013 (see Table 1). Maximum demand reached 147 GW in 2013, which is about 65% of installed capacity. The overestimated demand forecast has contributed to current oversupply and the increasing number of new power plants expected to be installed in the next years will only exacerbate this situation. Nevertheless, commitment to the planned changes in Russian power production remains strong, and the Russian Ministry of Energy is providing support for the introduction of further new capacity. In total, 30 GW of new capacity under CDAs should be commissioned in 2007–2017 [19].

2.2. Renewable energy support and its contribution to future power production

Strategic development of renewable energy is not a new issue in Russia. Attempts to introduce legislation and regulations on renewable energy started in the early 2000s [2]. Suggestions for legislation on RES, along with other recommendations on promoting renewable energy, were highlighted in the government documents, “Energy Strategy of Russia for the Period up to 2020” and “Energy Strategy of Russia for the Period up to 2030” [26,4]. Russia adopted a premium support scheme, a price-based mechanism, in 2007. The only legal description of this support scheme was decree 32 of the Federal Law on Electricity. The premium was needed to ensure the achievement of the strategic goal at the time of 4.5% RES production share in 2020 [1]. Currently, the support scheme is not in use due to the absence of regulations on premium calculation. Moreover, according to [27], the premium would be calculated on a yearly basis by the Federal Tariff Service (FTS). However, the changing premium tariff would lead to uncertainty of RES project payback and mask long-term signals to the investors. A RES based power producer could gain extra income from selling electricity (at a premium) but it is difficult to estimate whether it would cover also the investment costs. Despite government efforts, Russia's renewable energy policy had previously been evaluated as likely to have had the effect of reducing renewable energy production and consumption growth in the long-term in 2011 [28]. The targeted 4.5% share of renewable production in 2020 would require 14.7–25 GW of new capacity based on renewable sources of energy, excluding large hydro power with installed capacities more than 25 MW, and RES production has not been accompanied by sufficient renewable support regulation to realistically reach this target.

Russian support for RES power generating facilities includes grid connection cost compensation. Connection to the network forms a significant part of the cost of new power plant commissioning in Russia. This cost can reach 150–300 euro/kW [29]. Rules of subsidies from the Federal budget to compensate the cost of grid connection of generation facilities were approved in 2013. The main requirement is that the generation facility is qualified as RES based and has capacity no more than 25 MW. The subsidy is limited such that it is possible to compensate 50% of total connection cost but no more than 30 million rubles (~685.000 euro) [30]. The decision to grant a subsidy is made by the Ministry of Energy.

At present, the CDAs and LTAs form the primary incentive for investments in power generation in Russia. Following the existing practice for traditional power plants, the government introduced a capacity based support mechanism for renewable power plants in 2013 [31]. The RES policy target document was supplemented with targets on installed capacity, which should be entered into the wholesale market through new capacity support [7]. The government Program on Energy Efficiency established another target until 2020, 2.5% share of renewable power production [32]. However, the program does not negate the previous target, 4.5% share of renewable energy production, announced in 2009. Despite the discrepancy of the production share targets in the two government documents, targets for RES installed capacity, supported through capacity remuneration mechanism remain the same (see Table 2).

Currently, low domestic natural gas prices in Russia have led to low competitiveness of renewable energy in the power production mix. Nevertheless, the Russian Ministry of Energy intends to promote renewable energy to achieve also the RES production target of 11,589 GWh. This would amount to only 0.9% of the forecasted demand in 2020. Thus, to achieve national production share target (2.5% or 4.5%) the government needs to promote renewable energy in the retail market and in the isolated zones, which currently receive little attention.

For the isolated zones of Russia, RES development may be an efficient solution for utilizing local energy sources and avoiding high fuel transportation costs. Currently, many power plants in the Far East of Russia use diesel and oil as fuel. Due to the lack of a suitable transport system, fuel often needs to be transported by air, which dramatically increases power production costs, which can reach 1440 euro/MWh for instance in North East Russia [33]. The RES potential of decentralized territories has been assessed as about 1 GW, which is lower than the evaluated potential of the centralized territory (6 GW) [34]. In the retail market, the government has obliged network companies to buy electricity produced in qualified renewable power plants for regulated tariffs to compensate for transmission losses [34]. The efficiency of current support in the retail market is under question, as with the premium support scheme due to uncertainty about the regulated tariff, since there is no clear methodology for tariff calculation [35].

Despite the need for promotion of RES in isolated zones and retail market for the target achievement, the current capacity-based support works only within the wholesale market. Since 2013 the main renewable support scheme has been through capacity-based support. This support scheme and its possible impact on wholesale market prices are described in the following chapters.

2.3. Price formation in the wholesale electricity and capacity market

The Russian power sector encompasses the electricity market and the capacity market. Rules of the electricity and capacity markets are defined in the Decree N1172 [8]. Russia is divided into two price zones, where electricity prices are determined by the market, and a tariff zone, where prices are regulated by the Federal Tariff Service (FTS). Electricity prices are formed in the day-ahead market for every hour of the following day on the basis of bids

Table 1
Demand development in Russia [20–25].

	2008	2009	2010	2011	2012	2013
Demand, TWh growth,%	990 2.0	943 −4.8	989 4.9	1000 1.1	1017 1.6	1001 −0.6
Installed capacity, GW	211	212	215	218	223	227

Table 2
State target on renewable energy power plants installation until 2020 [7], MW.

Type of power plant	2014	2015	2016	2017	2018	2019	2020	Total
Wind	100	250	250	500	750	750	1000	3600
Solar	120	140	200	250	270	270	270	1520
Small hydro	18	26	124	124	141	159	159	751
Other	–	–	–	–	–	–	–	–
Total	238	416	574	874	1161	1179	1429	5871

from suppliers and buyers. In terms of traded volume, the largest part of the electricity market is the day-ahead market. Usually, more than 80% of electricity in the market is traded on the day-ahead and balancing markets; the rest is sold through regulated contracts. The electricity wholesale prices in Russia are currently about 25 €/MWh [36]. The average annual day-ahead market prices are lower in the second price zone but due to transmission capacity limitation power cannot be transmitted to the higher priced first zone.

The capacity price is determined for one year at a time in a Competitive Capacity Auction (CCA). Initially CCAs were planned to be held only until the end of the transition period in 2011, however, the annual CCAs still continue. Before the CCA, the System Operator (SO) defines demand for each price zone, with a 17% reserve to ensure emergency power supply. Generators participating in the CCA make their bids with monthly volumes of their available capacity (MW/month) and monthly payments (Rub/MWmonth). Then, the capacities of generators that can cover the planned capacity demand are selected in the price up order. In cases of high market concentration (HHI > 0.25) price caps are applied in the capacity market. Generation whose capacity price bid is more than the price cap but which has to be accepted to ensure system reliability is given a regulated tariff and called "must-run" capacity. "Must-run" capacity is often old generation with low efficiency and high operational and maintenance costs. In addition to reliability requirements, required heat production of CHPs is a further reason for "must-run" capacity. Capacity under CDAs and LTAs participates in the CCA with zero prices and has to be selected. The CCA price is defined as illustrated in Fig. 2: the new capacities under CDAs and LTAs are selected by default. The capacity auction price is formed by the old capacity (without support) and if there is still demand it is covered by more expensive "must-run" capacity.

The consumer capacity price is calculated as the weighted average of the costs of new capacity under the CDAs, LTAs, the CCA prices and regulated tariff for "must-run" generation for one price zone. In other words, the burden of costly capacity support for new generators and expensive "must-run" generation is distributed among consumers in one price zone. While electricity and capacity for the population is traded through regulated contracts, industrial consumers have to bear the additional burden of cross-subsidizing the population. Strong regulation resulted in 50% of the capacity demand in 2013 being met in a competitive way [37].

Capacity based renewable support implementation will be similar to the CDA and LTA mechanisms and will contribute to further increase of the regulated component in the consumer capacity price. According to [38] an increase in the consumer capacity price due to capacity based renewable support could reach 3–3.5%, resulting in additional cost of 1.5 billion euro per year [37]. This could be politically not feasible development as any price increase is not seen favorably among the policymakers.

3. Capacity-based support in Russia

RES power producers are able to enter into a CDA for renewable power plants. This agreement guarantees RES power plants investment payback through the capacity market with 14% return for 15 years. The main aim of adopting CDA for renewable energy producers is to attract investors. The scheme does however impose limits on capital cost, total installed capacity of power plants and degree of localization (i.e. the share of Russian renewable technologies and solutions in the project).

Regulation of the capacity based support scheme is based on amendments made to the Russian Federation resolution "Rules of the Wholesale Electricity and Capacity Markets" (clauses 194–214) adopted on 28.05.13 [8]. According to the new rules, renewable energy producers will have a possibility to participate in a projects competition in the form of a competitive auction to be held every year. The main condition for selection is the planned investment cost of 1 kW of installed capacity, taking into account the cost of the technological connection to the network. The Government of the Russian Federation has defined limits for the investment cost [10] (see Table 3). The application for entry to the project competition must contain [8]:

- Guarantee of fulfillment of the obligations by participants (financial insurance);
- Information on the applicant, who must be a participant of a wholesale market;
- Name of the project;
- Name of the generating facility;
- Reference to a notional group of supply points;
- Expected month of commissioning of the generating facility;
- Planned volume of installed capacity of the power plant;
- Type of power plant (only 3 types of power plant can participate in the project competition);
- Planned location of the power plant;
- Planned investment cost per 1 kW of installed capacity taking into account technological connection of 1 kW of installed capacity to the electricity network.
- Planned degree of localization (local content requirement).

The volume of installed capacity that can be commissioned in one year is also limited, see Table 4.

Selection of projects to receive capacity-based support is carried out by the Commercial Operator and is done in two steps. The first step selects all the projects which meet the requirements. The second step selects projects based on capital cost value and with

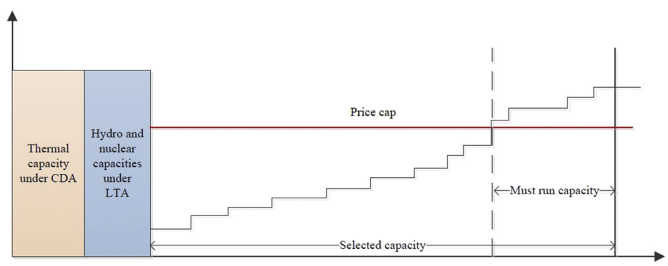

Fig. 2. Capacity auction for the concentrated zone.

Table 3
Investment cost limits for 1 kW of installed capacity [10], rub/kW (euro/kW).

Type of generation	2014	2015	2016	2017
Wind power	65,762 (1529)	65,696 (1527)	65,630 (1526)	65,565 (1524)
Solar power	116,451 (2708)	114,122 (2654)	111,839 (2600)	109,602 (2548)
Small hydro (less than 25 MW)	146,000 (3395)	146,000 (3395)	146,000 (3395)	146,000 (3395)

respect to the limit of capacity to be installed that year. Information on the progress of the selection procedure is published by the Commercial Operator on the official web page [8].

The requirements of the project competition are challenging for new participants in the wholesale market as they need to sign a contract of accession to the Wholesale Market Trading System, which imposes stringent conditions, and they need to have an agreement with a notional group of supply points. The renewable energy producer should also be accredited by the Market Council, which creates additional challenges and extends the time from project acceptance to start of operations [13].

4. Impact on the wholesale market of the capacity based support scheme

The main issue surrounding capacity-based support for RES is possible capacity price increases due to the high investment costs of RES projects to be implemented. Representatives of Russian consumers have argued that the capacity price change will be significant [39]. Although the magnitude of price changes is unclear, it is evident that RES projects and the associated support schemes will potentially have a noticeable impact on electricity market prices. Having low short-term marginal cost, RES electricity reduces the wholesale electricity price at times of high RES generation and the impact becomes more significant with large RES power share. On the other hand, for markets with low RES penetration the impact on the electricity market price is small, considering also the volatility of renewable energy [40]. A certain dynamic discrepancy exists between the high investment cost of renewable power installations and the resulting low market prices (at times of high RES generation) and this mismatch affects incentives for investments. For example, most renewable power plants in the EU have been constructed under different support mechanisms, which have led to higher final cost for customers. However, market price reductions should compensate some of the costs of RES support. For example in the EU, 1% RES electricity increase in the market could equate to a 0.018% final electricity cost increase for households [41].

The short-term impact of renewable capacity support in Russia on the consumer capacity price and electricity price is assessed in following subsections.

4.1. Impact on the capacity market

At present, approximately 16 GW of new power generation has entered the market under CDAs or LTAs, and another 20 GW of new capacity should be installed by 2017, see Fig. 3 [42]. The capacity

Table 4
Limits of capacity selection [10], MW.

Type of generation	2014	2015	2016	2017
Wind power	100	250	250	500
Solar power	120	140	200	250
Small hydro (less than 25 MW)	18	26	124	124

price of new generation under CDA amounts to 13 488–30 088 euro/MW per month [43], depending on location and type of fuel.

Capacity price results of the CCA for 2013 were [44]:

- 200 000 rubles/MW (4651 euro/MW) per month in the 1st price zone;
- 164 012 rubles/MW (3814 euro/MW) per month in the 2nd price zone.

The capacity cost after CCA is expected to increase in the next few years due to the commissioning of new power plants under CDAs and LTAs. Renewables capacity support will be an addition to the final consumer capacity price and this addition can be estimated using a simplified formula. To calculate the customer capacity price increase, a function (Eq. (1)) can be developed that represents consumer capacity price formation according to the market regulations. Knowing the volume of installed capacity that should be commissioned every year under the capacity remuneration mechanism (Fig. 3) and knowing its cost, and taking demand growth according to data from central planning, the consumer capacity price can be determined for the next years. Eq. (1) estimates the consumer capacity price without taking into account renewable support.

$$\mathrm{CP}_j^k = \frac{\sum P_i^{\mathrm{LTA}} \cdot V_i^{\mathrm{LTA}}}{\sum V^{\mathrm{total}}} + \frac{\sum P_i^{\mathrm{CDA}} \cdot V_i^{\mathrm{CDA}}}{\sum V^{\mathrm{total}}} + \frac{P^{\text{price cap}} \cdot \sum V_i^{\text{price cap}} + \sum P_i^{\mathrm{RT}} \cdot V_i^{\mathrm{RT}}}{\sum \left(V_i^{\text{price cap}} + V_i^{\mathrm{RT}} \right)} \tag{1}$$

where,

P_i^{CDA} – Capacity price of the generator *i* under CDA
V_i^{CDA} – Installed capacity of the generator *i* under CDA
V^{total} – Total need for capacity in the market
P_i^{LTA} – Capacity price of the generator *i* under LTA
V_i^{LTA} – Installed capacity of the nuclear or hydro generators *i* under LTA
$P^{\text{price cap}}$ – Price cap applied in the zone *k*
$V_i^{\text{price cap}}$ – Installed capacity of generator *i* in the zone *k* under price cap
P_i^{RT} – Regulated tariff applied for the “must-run” generator *i*
V_i^{RT} – Installed capacity of “must-run” generator *i*

When RES under CDA appears in the concentrated zone, the picture will change, see Fig. 4. It is assumed that the impact of renewable electricity generation capacity under CDAs will have a negligible effect on the amount of “must-run” capacity in the CCA because conventional power plants in critical locations will be needed for reliability reasons regardless of the amount of RES in the system (or because of the intermittent nature of RES). The effect of the addition of new expensive renewable generation in the concentrated zone can be calculated using Equation (2).

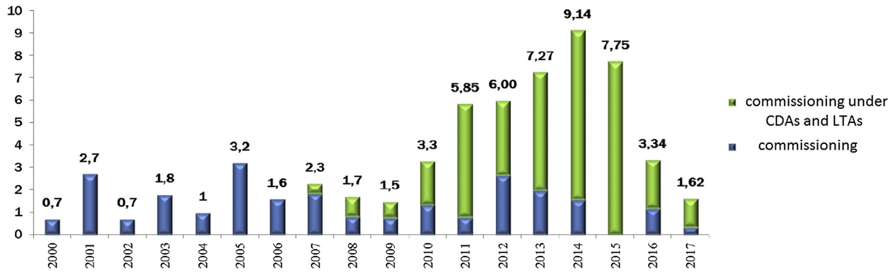

Fig. 3. Power commissioning in Russia [42].

$$\mathrm{CP}_j^k = \frac{\sum P_i^{\mathrm{LTA}} \cdot V_i^{\mathrm{LTA}}}{\sum V^{\mathrm{total}}} + \frac{\sum P_i^{\mathrm{CDA}} \cdot V_i^{\mathrm{CDA}}}{\sum V^{\mathrm{total}}} + \frac{\sum P_i^{\mathrm{RES}} \cdot V_i^{\mathrm{RES}}}{\sum V^{\mathrm{total}}} + \frac{P^{\text{price cap}} \cdot \sum V_i^{\text{price cap}} + \sum P_i^{\mathrm{RT}} \cdot V_i^{\mathrm{RT}}}{\sum \left(V_i^{\text{price cap}} + V_i^{\mathrm{RT}} \right)} \tag{2}$$

In the calculation of the consumer capacity price (with or without RES support) below, certain assumptions have been used:

- The prices of the CDAs and LTAs agreements are equal and amount to 18 000 euro/MW month;
- The price cap increases according to the inflation rate k_{ir}, $k_{\mathrm{ir}} = 6\%$;
- The tariff for "must-run" generation also takes account of inflation;
- Planned RES capacity is distributed into two zones according to zone demand;
- Capacity payment is calculated with return = 14%;

Calculations are made for the two different price zones, results are shown in Figs. 5 and 6.

The planned commissioning volumes for RES based generation are significantly lower than those for traditional generation. Consequently, the contribution of RES to the consumer capacity price is also relatively small, that is, only about 2% in 2017. As seen in Figs. 6 and 7, the significant increase in the capacity prices in both price zones arises due to commissioning of new thermal power plants under CDAs, and new hydro and nuclear power plants under LTAs. This new capacity is prioritized in the CCA, thus decreasing the amount of capacity that is selected on the basis of the competitive capacity price. At the same time, capacity that is not selected in the CCA may be considered as ineffective and could be decommissioned. However, renewable (intermittent) energy cannot guarantee availability and theoretically cannot be selected in the capacity auction as firm capacity. Therefore, the selected capacity in CCA is likely to include predominantly conventional capacity according to the forecast of the SO and renewables as an addition, thus leading to overcapacity.

4.2. Impact on the electricity market

The electricity price development in the day-ahead market is modeled using a simplified equivalent circuit model of the Russian power system (for detailed description of the modeling methodology, see Ref. [45]). In the modeling, it is assumed that the price bids in the market correspond to the marginal production costs of the thermal generators, which are calculated on the basis of their average fuel rates and expected fuel costs. In addition, it is assumed that commissioning of new power plants and decommissioning of old generation is in accordance with the central plans of the Russian power system development, and that demand is expected to develop as forecasted by the SO of Russia.

RES power plants are allocated according to the renewable resources map [46], due to uncertainty about their location. Power outputs are taken with a reduction coefficient equal to 0.35 for wind power plants and 0–0.7, depending on the hour, for solar power plants. Price bids from renewable power plants are assumed to be zero (price-accepting bids).

Modeling of the electricity market price including RES installations shows different price decreasing effects during peak and off-peak hours (Fig. 7). Renewable power production usually lowers price in the merit-order. Nevertheless the price difference caused by the RES power production is fairly low, reaching 2.2% during off-peak hours and 1.4% in peak hours in 2016. The existence of a capacity market in Russia prevents the problem that occurs in Europe, where due to high renewable energy penetration, conventional power plants are unable to cover their fixed costs in the market.

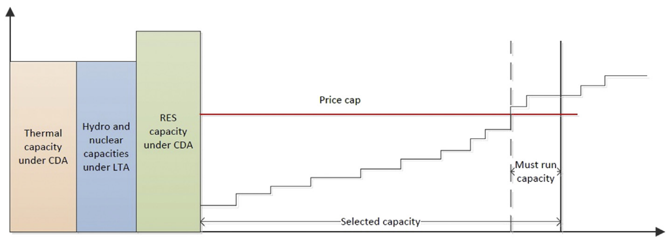

Fig. 4. Capacity auction for the concentrated zone in the presence of RES capacity.

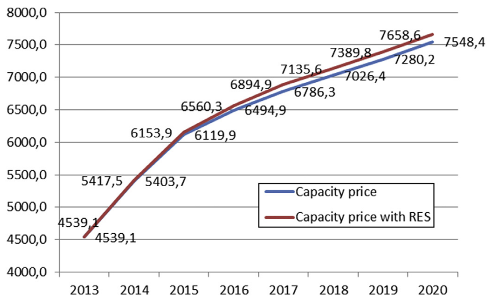

Fig. 5. Impact of RES capacity cost on the capacity price in the 1st price zone.

Conventional power plants in Russia will continue to receive capacity payments, thus, cover their fixed costs in capacity market. The level of renewables penetration will remain low due to the capacity limits in the support scheme. Thus, the market price will be driven by conventional power plant production, allowing conventional power producers to cover their variable cost in the energy market.

The results of the above analysis indicate a 20–25% decrease in market price for the next few years even without the introduction of RES power plants. This finding can be explained by the commissioning of power plants with higher efficiency and the commissioning of new hydro and nuclear generation, which often make price-accepting bids in the market. Theoretically, annual commissioning of 5 GW of new capacity can reduce electricity prices by 3–6% [47]. The modeling does not take into account gas price increases due to the decision of the government to "freeze" gas tariffs [48]. In the case of continuing equal profitability from domestic and export gas markets, an annual domestic gas price increase of 15% would lead to a 21% increase in electricity cost [49]. Nonetheless, electricity market prices will decrease in the short-term as new power plants enter the market.

5. Discussion

5.1. The first step to achieve the target

The forecasted increase in demand, assuming that it occurs, can be easily satisfied by capacity from gas power plants. The comparatively low installed capacity target for renewable generation of 5.8 GW (2% of forecasted capacity) by 2020 will obviously not provide a strategic source of energy but its appearance in the market gives an important signal. The CDA for RES can be seen as an effective solution to meet these aims as it gives investors incentives

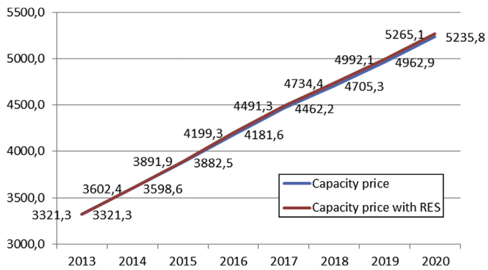

Fig. 6. Impact of RES capacity cost on the capacity price in the 2nd price zone.

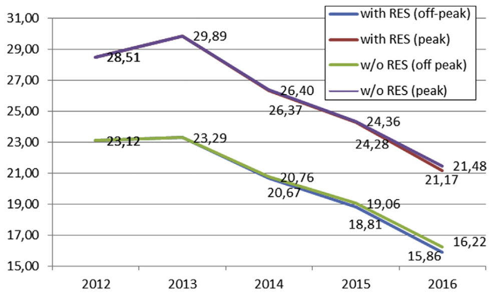

Fig. 7. Results of electricity market prices modeling (euro/MWh).

to invest in the energy business, providing they meet all the requirements of the scheme. The CDA for conventional power plants has already proven to be an effective way to attract investment to the field. However, complying with the requirements of the RES CDA mechanism can be challenging for new producers, because it takes time to become a participant in the wholesale market and bureaucracy related to the progress of RES projects can pose difficulties. The demanded local content requirement is increasing [10], which makes the conditions for acceptance to the RES CDA scheme even more stringent and burdensome.

When all the requirements of the selection part of the scheme have been completed, the operational requirements should be met, such as the ability to halt power generation if there is a command from the System Operator [31]. If the power producer cannot halt power production, it will receive a decreased capacity payment. Decreased capacity payments will also be paid to the producer if its capacity factor is less than the required amount (0.14 for solar power; 0.27 for wind power; 0.38 for hydro) [13]. Wind and solar energy have high dependence on the weather and season, which is a risk that needs to be taken into consideration. Although the requirements are strict, the reward is a guaranteed return on investment for 15 years.

Successful implementation of the capacity support would mean only 0.9% of the forecasted demand in 2020 is met by RES. The current support alone cannot provide achievement even of the 2.5% renewable production share mentioned in the Energy Efficiency program [32]. However, according to [5], it is the government's intention is to incentivize development of renewable energy equipment production. On the one hand, renewable capacity support in combination with local content requirement may encourage achievement of such a goal. On the other, capacity support will create an additional burden for consumers, who bear also the burden of support for conventional power plants.

5.2. Cost of support for consumers

Results of the capacity price modeling show that the main contribution to the capacity price increase occurs due to the CDAs for conventional power plants. As can be seen from Figs. 6 and 7, the capacity price trend is a significant increase in both price zones, reaching 160–170% of the current capacity price already in 2017. The impact of CDA for RES implementation on the total capacity price is relatively low compared to the traditional CDA cost and will amount to about 2% of the capacity price in 2020. The limited effect of RES is due to limitations on the total installed capacity of RES based power plants (about 2 GW until 2017). Despite the lower capacity price for traditional power plants in CDA, their total installed capacity is significant (about 30 GW till 2017).

Unlike for the capacity price, RES electricity has the effect of reducing electricity prices Electricity production prices for RES power plants are regulated and can be considered as a price-accepting bid in the day-ahead market. Due to the limited amount of capacity of planned power plant construction, the effect of RES electricity on the electricity price is low, reaching 2.2% during off-peak hours and 1.4% during peak hours in 2016. Conventional power plant commissioning also decreases the market electricity price, as new and more efficient power plants should produce electricity at low marginal cost.

The entire burden of high capacity payments will be on industrial customers, since electricity for retail consumers is sold under tariffs set by the FTS. However, it is difficult to ascertain exactly the amount of cross-subsidization of population by industrial consumers. High end user electricity prices appear to be forcing large industrial consumers to develop their own generating facilities; according to recent data the import of generating equipment grew twofold in 2010 and 2011 [50]. This trend can be interpreted as demonstrating the intention of large industries to cut their peak demand, which forms the basis for their purchases in the capacity market. By reducing peak demand, industry can partly avoid high capacity costs and by commissioning their own generation companies can minimize risks resulting from decisions imposed by market authorities.

Despite the fact that CDA can attract investment in new power plants, the efficiency of this mechanism is doubtful. On the one hand, CDAs for conventional power plants together with forecast shortcomings creates capacity deficit in some parts of the system. In such cases, “must-run” power plants should be kept in the market to avoid capacity scarcity. On the other hand, excessive commissioning of new power plants under CDAs results in oversupply in other parts [51]. Accordingly, RES power plant commissioned in the region with low demand or with oversupply will contribute to the ineffective arrangement of generating units and further increase the consumer capacity price.

5.3. Local content requirement

A local content requirement was introduced to facilitate the Russian government's intention to develop renewable energy technology production. The required local content is quite challenging for investors as it directly affects the CDA capacity price. If the target level is not met, investors can lose 55–65% of the capacity price under the CDA [50]. RES projects should have a considerable share of Russian technology and equipment, reaching 70% in 2016 for solar power plants [10]. However, such technology could be less efficient and more expensive than equivalent foreign technology [13]. The problem of high local renewable technology cost is solved by limiting the capital costs of RES power plants at the selection stage. As for technology efficiency, the effect of the localization requirement can be known only during implementation of the support mechanism.

In addition to promoting renewable technology, the Russian government's intention is that RES technology will encourage a desired diversification of the Russian economy and over time permit export of the technology, while simultaneously closing the market for imports of renewable technology. Such aims coupled with the structure of the support mechanism may open the Russian government to accusations of protectionism by the World Trade Organization (WTO). A precedent has already occurred in Ontario, where Ontario's provincial government was accused of subsidizing renewable energy equipment produced locally [52]. Despite the fact that a number of countries currently have local content requirement in their renewable policy, renewable support schemes with local content requirement, in general, violate the WTO law [53].

5.4. Future of RES capacity support

The power production sector in Russia needs structural change and the construction of new generating facilities to meet forecasted future demand and to replace current outdated generating facilities. In current market conditions, the CDA mechanism provides an important and, as yet, the only investment incentive within the wholesale market for the required development of the sector. This mechanism was developed to ensure adequate investment during the transition following liberalization of the electricity market; however, data for future investment in new generating facilities indicate that the mechanism will remain in place until 2017. The Ministry of Energy should present a new model of electricity market after 2017 [54], which will continue using the CDA mechanism to attract investment in modernization of existing power plants or introduce free bilateral contracts. The option of implementing a new CDA bears with it a threat of further increasing the consumer capacity price since all costs of CDAs are allocated to the consumers. The second option of free bilateral contracts implies the rejection of a capacity market, and that capacity costs should be included in the contracts signed by the two parties. In the case of adoption of bilateral contracts, the market risks failing in the task of attracting investment for modernization [54]. ATS has published information for the CDA RES competition for 2018 [55], which indicates that CDA for renewables will remain in force until the end of the target period. CDAs contracted before 2017 will continue to receive capacity payment according to their agreements, but how the cost of CDAs will be distributed between consumers remains unclear.

6. Conclusions

With its significant fossil fuel resources, Russia is not yet ready to develop renewable energy significantly at a Federal level. Furthermore, overestimated demand growth has led to a situation where only about 65% of available installed capacity in the country is used to produce power. Despite the oversupply, Russia is seeking to develop renewable technology and is making efforts to promote renewable power through support schemes. In 2013, the Russian government issued legislation that provides reliable support for RES development. The RES support is in the form of capacity-based subsidies resembling the Capacity Delivery Agreements (CDAs) available for conventional power producers in the Russian electricity market. However, the new legislation also brings about challenges to both RES power producers and power consumers.

In order to enter into CDAs RES power producers have to tender for RES project support in a process that has strict requirements and limited capacity for every year until 2018. The capacity price for the CDA is also partly dependent on the local content, which imposes limits on power producers' freedom of action, since failure to meet localization requirements means that the guaranteed capacity price will be 55–65% lower. This addendum aims to stimulate development of RES technologies and RES research in Russia; currently equipment for RES power plants is often imported.

Consumers associations have petitioned against the capacity price increase purportedly resulting from introduction of CDA for RES. The analysis presented in this paper concludes that while capacity prices will certainly be higher in 2020, the price increase will predominantly be caused by the CDA cost for conventional power generation. RES power plants will add about 2% to the total capacity price. The impact is relatively low due to the limit in planned installed capacity. The increase in capacity price will reach 5000–7000 euro/MWmonth in 2017, which is a capacity price increase of about 60% over 4 years. This price increase is forcing large industrial companies to consider construction of their own power plants, which might lead to a risk of oversupply becoming an issue.

The results of the electricity market price modeling show a future market price decrease due to the installation of new power units with higher efficiency and new nuclear and hydro power plants. Commissioning of RES power also decreases electricity prices but the effect is insignificant in view of the limited volume of capacity to be installed.

Coming changes will provide a minor increase in RES production level. The results of price analyses indicate an insignificant impact on both capacity and electricity markets; our findings suggest that the capacity-based support scheme for RES will provide about 2% capacity price increase and 2% decrease in electricity market price during off-peak hours.

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Publication IV

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Linking the energy-only market and the energy-plus-capacity market

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Linking the energy-only market and the energy-plus-capacity market

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ABSTRACT

This article analyzes the implications of capacity markets and allocation mechanisms for cross-border trade and market welfare by applying an analytical model where two markets with different market designs, the energy-only market and the energy-plus-capacity market, are interconnected and operate under different transmission capacity allocation schemes. The findings suggest that having an energy-only market at one side of the border and an energy-plus-capacity market at the other side may impede cross-border trade and result in underusage or misusage of transmission in the case of an explicit allocation of transmission capacity. Implicit allocation or market coupling, in principle, would increase the efficiency of cross-border trade, but may result in distributional effects, involving for instance a free-riding effect.

1. Introduction

An internal market for electricity is a key part of the EU 2020 strategy (European Commission, 2010). Efficient cross-border trade facilitates efficient use of resources and an increase in social welfare. The sharing of resources enables consumers in high-cost regions to have access to low-cost electricity generation in other regions, resulting in more efficient use of resources and increasing the probability that the demand will be met by the least-cost means of production. Moreover, opening the national markets to foreign participants should enhance market competition and strengthen the security of supply (Booz&Co, 2013; Creti, 2010; Jasamb and Pollit, 2005; Pellini, 2012). However, in order to facilitate efficient cross-border trade, transmission capacity allocation methods should be market based. In Europe, explicit and implicit transmission auctions are used to allocate transmission capacity. Under explicit allocation of transmission capacity, the available transfer capacity of the interconnector is sold separately for each direction to market participants through a uniform-pricing auction of transmission capacity on a yearly, monthly, or daily basis. After obtaining transmission capacity rights, traders are allowed to trade energy through the interconnector. However, as a result of trading costs resulting from separate markets for transmission and energy, together with the asymmetry of information on electricity prices in the trading markets, explicit allocation brings about inefficiencies in the form of underusage (flows lower than the available capacity when there is a price difference) or misusage (flow against price differential) of transmission capacity (Bunn and Zachmann, 2010; Kristiansen, 2007; Newbery and Mc Daniel, 2002). Under implicit allocation of transmission capacity (or market coupling) no separate auctions exist for transmission capacity, and the flows on the interconnectors are determined by the clearing of the energy markets. Market coupling ensures that the use of transmission capacity is welfare maximized. Efficiency gains from the introduction of market coupling are examined in detail in various studies (Hobbs et al., 2005; Creti et al., 2010; Pellini, 2012). Market coupling is the target model for cross-border transmission capacity allocation in the EU member states.

Numerous EU member states are currently considering moving from energy-only markets to energy-plus-capacity markets (CREG, 2012). The discussion about the need for capacity markets in Europe centers on how to ensure that there is enough capacity to meet the future demand and back up increasing proportions of renewable energy sources (RES) in the long term (Brunekreft, 2011; Nicolosi, 2012; Cepeda and Finon, 2013). However, as more European markets become increasingly interconnected, uncoordinated capacity remunerative mechanisms (CRMs) may create negative cross-border effects and hinder the achievement of the Internal Electricity Market in Europe. A concern is that market design changes at the level of EU member countries might conflict with the European target of a single market. However, the degree to which individual CRMs could impact cross-border trade depends on the degree of interconnectivity among markets and the correlation of

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prices and scarcity conditions (ACER, 2013; Meyer et al., 2014; Sweco, 2014; Thema, 2013). A few real-life examples of the interaction of energy-only and CRM markets are available, including the PJM and the Midwest ISO control areas in the US, Ireland and Great Britain, and Russia and the Nordic market. Inefficient cross-border trade has been observed in all these cases because of the CRM (Gore et al., 2014; Lawlor, 2012; McInerney and Bunn, 2013; Viljainen et al., 2013). Experiences in these markets demonstrate how challenging the integration of energy-only and energy-plus-capacity markets can be.

This article analyzes the implication of capacity markets and cross-border allocation mechanisms on cross-border trade and market welfare by applying an analytical model where two markets with different market designs, namely the Nordic energy-only market and the Russian energy-plus-capacity market, are interconnected and operate under different transmission capacity allocation schemes. The article is structured as follows. The second section provides an overview on the Russian energy-plus-capacity market and the Nordic energy-only market and describes the main differences in the operation of the markets. The third section presents the simulation that we developed to analyze the implications of capacity markets and cross-border allocation mechanisms for the cross-border trade and market welfare. The fourth section reports the results of the simulation and welfare analysis consisting of welfare indicators such as the TSO income, the producers' and consumers' surpluses from the energy market, and the capacity payments, and discusses the limitations of the analysis. The fifth section discusses the policy implications for the European energy markets that are considering to implement capacity remuneration mechanisms. The sixth section concludes the main findings of the article.

2. Main differences in the operation of the Finnish energy-only market and the Russian energy-plus-capacity market

2.1. Energy-only market compared with energy-plus-capacity market

In energy-only markets, generators are paid for the volume of electricity (kWh, MWh, or GWh) produced, but are not compensated for keeping capacity available. In a competitive energy-only market, generators bid their short-run marginal costs, and the hourly market-clearing price equals the marginal cost of the last generating capacity or the demand-response resource that clears the supply and the demand given that the demand does not exceed the available capacity. The fixed costs of the dispatched generators are recovered through inframarginal rents and scarcity rents. Inframarginal rents are reflected in the difference between market clearing prices and marginal costs of generation. Scarcity rents, again, are reflected in the difference between scarcity prices that are charged when demand exceeds the generation available in the market and the marginal costs of the last available unit in the system. In theory, in the absence of market failures, energy-only markets should generate sufficient revenues to cover the full costs of power plants over their whole lifetime and attract new investments, thereby ensuring generation adequacy in the market. However, a threat of market-power abuse during scarcity conditions may force regulators to set a price cap in the energy-only market. Capped scarcity prices may cause a missing money problem, that is, a situation where the electricity prices are not high enough at times of peak demand to recover the fixed costs of power plants and incentivize new investments (Joskow, 2006). Because of the concern that energy-only markets alone may not be able to ensure resource adequacy, different forms of capacity remuneration mechanisms have been introduced in addition to the energy markets. The objective of capacity remuneration mechanisms (capacity markets and capacity payments) is to ensure the profitability of the existing power plants and to support investments in new power plants by restoring the missing money of the energy-only market. Providing stable revenues for power producers, capacity mechanisms aim to increase both the short-run reliability and the long-run adequacy of power supply (Cramton and Ockenfels, 2012; De Vries, 2007; Joskow, 2008). The focus of this article is on capacity markets.

2.2. Finnish energy-only market

Finland represents one price zone of the Nordic energy-only market, which has the zonal pricing model. Geographically, the Nordic electricity market covers Denmark, Finland, Sweden, Norway, Estonia, Lithuania, and Latvia (Nord Pool, 2014). In the absence of inter-zonal transmission congestion, a uniform market clearance price is formed for the entire market. In the case of transmission congestion, the Nordic electricity market is divided into fourteen price zones, and separate prices are calculated for each zone. In 2010–2012, the market uniformity (the same price in all price zones) was achieved about 20% of the time, which is well below the targeted 65% market uniformity. Owing to the rapid congestion of the line between Finland and Sweden, Finland decouples from the Nordic market 80% of the time and forms a price zone of its own with zonal electricity prices significantly higher than the system price in the Nord Pool market. Finland is considered a net importer of electricity; imports accounted for 18.8% of the annual Finnish consumption in 2013. The maximum transmission capacity between Nord Pool and Finland is 2850 MW, and between Russia to Finland, the capacity is 1400 MW (Viljainen et al., 2012). The total generation capacity in Finland is about 13,000 MW while the peak demand is 15,000 MW.

2.3. Russian energy-plus-capacity market

In the Russian energy-plus-capacity market, generators earn revenues by selling their volumetric production into the wholesale electricity market and selling their production capacity into the capacity market (Gore and Viljainen, 2012).

2.3.1. Market of electric energy

The day-ahead market is the central exchange for electricity trade in Russia. The day-ahead market model in Russia employs the concept of bid-based centralized dispatch with nodal prices. Trading in the day-ahead market is organized as a closed auction with one trading cycle per day. Electricity prices are defined for each location of the grid, and include the marginal cost of produced electricity, the cost of transmission, and the cost of power losses. The commercial operator ATS (or power exchange) operates the day-ahead market by collecting supply and demand bids of the market participants and computing electricity market prices in 8100 nodes for each hour of the following day. The Russian electricity market is natural gas dominated, with 65% of electricity production based on gas generation. Domestic gas prices in Russia are regulated by the government and are at levels that are one-fourth of the gas prices in Finland, making the price of electricity imported from Russia cheaper than the gas- and even coal-produced electricity in Finland.

Fig. 1 presents the historical development of the electricity prices in Finland and Russia as well as the interconnector flow.

[1] All series are moving average filtered (28 days). The Russian price is converted into euros by using daily exchange rates as quoted by the Central Bank of Russia.

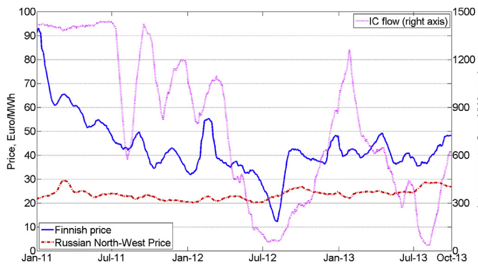

Fig. 1. Finnish and Russian electricity prices (left-hand axis) and the IC flow from Russia to Finland (right-hand axis).[1]

2.3.2. Capacity market

The capacity market in Russia was designed to ensure resource adequacy during periods of peak demand. The capacity market in Russia is comprised of two different mechanisms: capacity payments designed to incentivize the development of new generation and Competitive Capacity Auctions (CCA) for the existing generators. The performance and price parameters of the capacity market are presented in two government decrees (Russian Government, 2010a,b). As Russia has recently reformed its electricity sector and faces substantial investment needs for generation capacity, the Government decided that in the first period of 2010–2015, the development of new generation capacity will be ensured through regulated capacity payments (Russian Government, 2013). According to this mechanism, called a Capacity Delivery Agreement (CDA), the investor in new generation has obligations with regard to punctual commissioning of the power plant while the government guarantees capacity payments for ten years to owners of thermal power plants and for twenty years to owners of nuclear and hydro power plants. The capacity payment depends on the type of generation and location, and is calculated based on typical investment costs of new power plants (Gore and Viljainen, 2012). This mechanism is temporary and designed to address the immediate need for new investment in the generation sector. About 40 GW of nuclear, hydro, and thermal generation will be launched by CDAs in 2010–2015 (Russian Government, 2010c).

The existing generators participate in the Competitive Capacity Auction (CCA). The procedure of Competitive Capacity Auctions is as follows. The System Operator (SO) defines the zones of free-power flow that emerge during peak hours because of an inadequacy of the transmission capacity between the zones. In 2012, the market was divided into 27 free-power flow zones (System Operator of Russia (2011)). Fig. 2 illustrates the North-West zone of free-power flow (the one linked to the Finnish market) and its interconnections with other zones. For each zone, the SO estimates the generation capacity need for each month of the following year. The generation capacity need of one zone of free-power flow is a sum of the capacity demands of different end-users located in that zone. The capacity demand for small end-users is forecast by the SO as the peak demand multiplied by the reserve ratio (17%). Large end-users plan and notify the SO about their capacity demand in a particular month, which is equal to their planned peak demand multiplied by the reserve ratio (17%). Once the generation capacity demand is defined for every zone of free flow, the SO selects the capacity of generators that can cover the demand. New generators under CDAs are selected by default, while existing generators participate in the CCA. The generators participating in the CCA submit bids of monthly offered capacity (MW/month) and price (ruble/MW/month). The capacity bids of generators are selected in the price-up order. The last accepted capacity bid forms the capacity price for the CCA. This guiding principle is illustrated in Fig. 2.

The final capacity price paid by the consumers takes into account the remunerations paid to both existing and new power plants. Therefore, the capacity cost of the generators under CDAs and generators selected in the CCA in the one zone of free-power flow are allocated equally among all customers located in the same zones of free-power flow in proportion to their capacity demand. Fig. 3 illustrates the monthly volume of capacity accepted as a result of the CCA, the volume of capacity under the CDAs, the

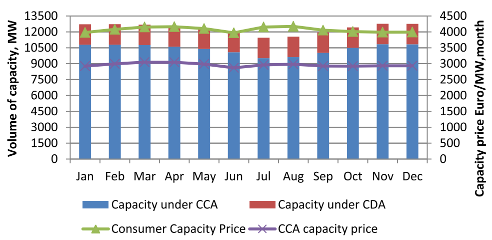

Fig. 3. Results of the Capacity Market for the North-West zone of the Russian market.

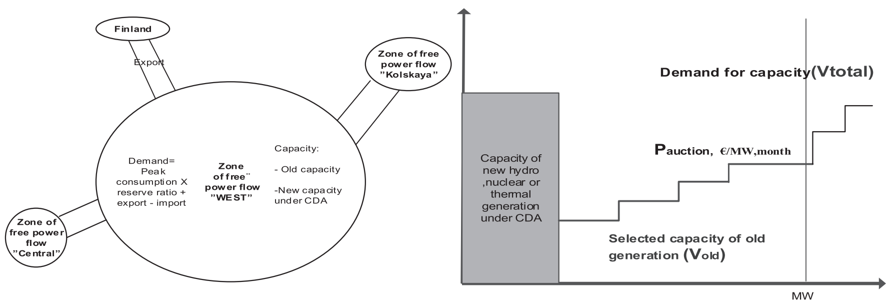

Fig. 2. North-West zone of free-power flow and the Competitive Capacity Auction in Russia.

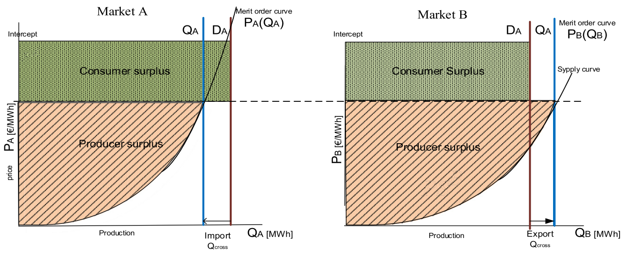

Fig. 4. Social welfare of two interconnected markets.

capacity price of the CCA, and the consumer capacity prices in the North-West[2] zone of free-power flow (System Operator of Russia (2011)).

3. Methodology and basic assumptions

3.1. Methodology

To analyze the implications of capacity markets and cross-border allocation mechanisms for cross-border trade and market welfare, we set up a two-country simulation model. Market A is an energy-only market and represents the Finnish price area of the Nordic market while market B is an energy-plus-capacity market and represents the North-West zone of the free-power flow of Russia. We assume that this zone represents one node of the Russian market. The markets are interconnected by a transmission link. Both markets are represented by their merit orders (or supply curves), described by an exponential function (see e.g. Takashima et al., 2007), as specified below:

$$P_A(Q_A) = a1\cdot e^{b1\cdot(Q_A)} \tag{1}$$

$$P_B(Q_B) = a2\cdot e^{b2\cdot(Q_B)} \tag{2}$$

P_A, P_B are the marginal costs of electricity production and Q_A,Q_B are the electricity production volumes in markets A and B, respectively.

The short-run simulation model of two interconnected competitive day-ahead energy markets generates market clearing prices, production, and cross-border trade for varying demand levels. All parameters of the power markets (merit orders and demands) and constraints (maximum available generation and maximum transmission capacity of the interconnector) are taken as inputs to the social welfare maximization problem represented by the sum of consumer and producer surpluses, as illustrated in Fig. 4. The social welfare maximization problem is solved either individually for each market or jointly for both markets depending on the transmission capacity allocation mechanisms, as discussed in the next section.

Producer surplus (PS) and consumer surplus (CS) are given by Eqs. (3)–(6):

$$PS_A = P_A(Q_A)\cdot Q_A - \int_0^{Q_A} P_A(Q_A)\cdot dQ_A \tag{3}$$

$$PS_B = P_B(Q_B)\cdot Q_B - \int_0^{Q_B} P_B(Q_B)\cdot dQ_B \tag{4}$$

$$CS_A = (Intercept - P_A(Q_A))\cdot D_A \tag{5}$$

$$CS_B = (Intercept - P_A(Q_A))\cdot D_B \tag{6}$$

As noted, the producer surplus reflects the benefit (or surplus) that producers gain from selling their product at a market price that is higher than the price at which they would be willing to sell. Consumer surpluses indicate the benefit (or surplus) that consumers gain by buying electricity at a price that is lower than the price that they would be willing to pay (*Intercept*[3]).

3.2. Cases

Depending on the treatment of capacity market in the cross-border trade and the transmission capacity allocation mechanisms, we examine three different cases, as follows.

Case 1. Explicit allocation of transmission capacity; *foreign capacity cannot participate in the national capacity market*. In explicit allocation of transmission capacity, we assume that there is a single trader who buys electricity in one market and sells it in another market. The trader reserves the amount of interconnection capacity and pays a fixed cross-border reservation fee for each MW reserved for possible exchange. In addition, it pays the cross-border fee based on hourly energy exchanged, which makes up the main part of the total fee. We disregard the fixed cross-border reservation fee in the analysis, as it is considerably small compared with the cross-border fee based on energy exchanged. Moreover, the trader has to reserve capacity in capacity market B if it plans to export from B to A (and is not allowed to receive capacity payments if it imports from A to B), and the hourly energy export from market B to market A in peak hours[3] should not exceed the capacity reserved in capacity market B. We assume that the trader operates under perfect information regarding the demand and supply curves in both markets; that is, the trader can estimate the impact of cross-border trade on electricity prices and thereby maximize the profits by deciding upon the cross-border flows.[4] Thus, the optimal cross-border flows in off-peak and peak hours can be defined by maximizing the profit function of the trader in off-peak hours given in Eq. (7) and in peak hours given in Eq. (8), both subject to constraints

[2] The Russian price is converted into euros by using monthly exchange rates as quoted by the Central Bank of Russia.

[3] Typically, there are 8–9 peak hours a day. The peak hours are assigned and published by the System Operator. Available online: <http://www.so-ups.ru/fileadmin/files/company/markets/pik_chas2012.pdf>.

[4] In reality, the trader has incomplete information; however, we consider this simplification acceptable.

in Eq. (11). Further, the social welfare maximization problem is solved separately for markets A and B by their corresponding power exchanges, where the cross-border flows of the trader are taken as an exogenous variable in the optimization problem given in Eq. (9) subject to constraints in Eq. (11).

Case 2. Explicit allocation of transmission capacity; *foreign capacity can participate in the national capacity market*. Here, we assume that the import capacity is allowed to participate in capacity market B while submitting the volume of the import capacity to the competitive capacity auction (CCA). According to the capacity market rules, in order to receive a capacity payment, the availability of imports has to be ensured, meaning that in peak hours the trader should bid to the day-ahead market B the energy in the volume no less than the capacity accepted by the results of the CCA. We solve the same optimization problems given in Eqs. (7)–(9) as for Case 1 in order to obtain cross-border flows, market clearing prices, and productions in markets A and B.

Case 3. Implicit allocation of transmission capacity; *no cross-border participation in the capacity market*. In the case of implicit allocation of transmission capacity, transmission capacity is made available to both power exchanges, and the flows on the interconnectors are determined by simultaneous clearing of two energy markets; that is, the power exchanges combine the supply- and demand-side bids of both markets and maximize the total welfare according to Eq. (10) and subject to constraints in Eq. (11). The capacity market does not concern the cross-border trade but the flow is determined based on the day-ahead electricity price differences in markets A and B only.

$$Max\{(P_A(Q_A) - P_B(Q_B) - |T|) \cdot Q_{cross}\} \tag{7}$$

$$Max\{(P_A(Q_A) - P_B(Q_B) - |T| - CP) \cdot Q_{cross}\} \tag{8}$$

$$Max\{PS_A + CS_A\}; \;\; Max\ \{PS_B + CS_B\} \tag{9}$$

$$Max\{PS_A + CS_A + PS_B + CS_B\} \tag{10}$$

$$s.t. \quad Q_A = D_A - Q_{cross};\ Q_B = D_B + Q_{cross} \quad \text{(power balance)} \tag{11}$$

$$Q_A \geq 0;\ Q_B \geq 0 \quad \text{(non − negative outputs)}$$

$$Q_A \leq K_A;\ Q_2 \leq K_B \quad \text{(generation constraints)}$$

$$-IC \leq Q_{cross} \leq IC \quad \text{(interconnection constraint)}$$

where Q_A, Q_B are the generation outputs in markets A and B, Q_{cross} is the cross-border flow, K_A, K_B are the generation capacity constraints (maximum outputs) in markets A and B, D_A, D_B are the demand levels in markets A and B, *IC* is the interconnection constraint, *T* is the cross-border fee regulated by the Transmission System Operators in both markets ($T = 5$ EUR/MWh). *CP* is the capacity price in market B, where for Case 1: $CP = 20$ EUR/MW/h, h if $Q_{cross} \geq 0$ (flow from B to A), $CP = 0$ EUR/MW/h if $Q_{cross} \leq 0$ (flow from A to B); Case2: $CP = 20$ EUR/MW/h for any Q_{cross}.

3.3. Data

3.3.1. Merit-order curves

The merit-order (or supply) curves of markets A and B are illustrated in Fig. 5. The parameters *a1*, *a2*, *b1*, and *b2* of the merit orders given in Eqs. (1) and (2) and presented in Table 1 were obtained when calibrating the merit orders based on the data on average electricity production and the marginal costs of each particular technology in 2012 (hydro, nuclear, CHP, gas, coal, and oil-fired generation) in markets A and B (Finnish Energy Industries, 2012; System Operator of Russia (2012)). The marginal costs of electricity production were estimated based on the information on fuel rates and fuel prices of each technology (Statistics Finland, 2012; Russian Government, 2012).

3.4. Load and load duration

We assume price-inelastic demand in both markets. We disregard differences in stochastic variations between the two markets; that is, the demands in markets A and B are assumed to be perfectly correlated.[5] Thus, the demand in market B is a linear transformation of the demand in market A. Fig. 6 illustrates the load-duration curves for markets A and B, showing the proportion of hours for which the demand exceeded a certain value. The load-duration curve L(D) for both markets is given by Eq. (12), and the parameters of the load-duration curves are presented in Table 2. The parameters *p*, *q*, *and r* of the load-duration curves given in Eq. (12) were obtained when approximating the load-duration curves calibrated using the statistical data on hourly demands (D) in both markets for the year 2012 (Nord Pool, 2012; System Operator, 2012). The Finnish market is an importing price area of the Nord Pool. In our analysis, we isolate the Finnish area from the Nordic market, and the hourly imports from the Nordic market are subtracted from the hourly demands in Finland to calibrate a load-duration curve for market A. Thus, the load-duration curve in market A represents a residual load-duration curve of the Finnish market. The North-West zone of free-power flow is an area with excess capacity, and thus, it mainly exports electricity to the rest of the Russian market. We isolate the North-West zone from the Russian market while its hourly exports to the Russian market are added to the hourly demands in the North-West zone to calibrate a load-duration curve for market B.

$$L(D) = p \cdot exp(q \cdot D) + r \tag{12}$$

where parameter *q* determines the curvature of the function, while *p* and *r* are calculated as a residual such as *L(D)* matches the given values of maximum D_{max} and minimum demandD_{min}:

$$p = 1/(exp(q \cdot D_{max}) - exp(q \cdot D_{min})) \tag{13}$$

$$r = (exp(q \cdot D_{max}) \cdot p \tag{14}$$

4. Results

4.1. Cross-border flows

The simulation of market results is performed by repeatedly solving the optimization problems (Eqs. (7)–(9)) for Case 1 and Case 2 and the optimization problem (Eq. (10)) for Case 3 for the full range of demand levels from minimum to maximum. Fig. 7 illustrates the cross-border flows against the electricity price differences between markets A and B for Cases 1–3, and Fig. 8 depicts the total energy transmitted through the interconnector over a year.

In Case 1, as seen in Fig. 7, the cross-border fee in off-peak hours and the cross-border fee together with the capacity price in peak hours create a barrier to the cross-border trade. This results in

[5] The assumption is reasonable as the correlation coefficient R is 0.924.

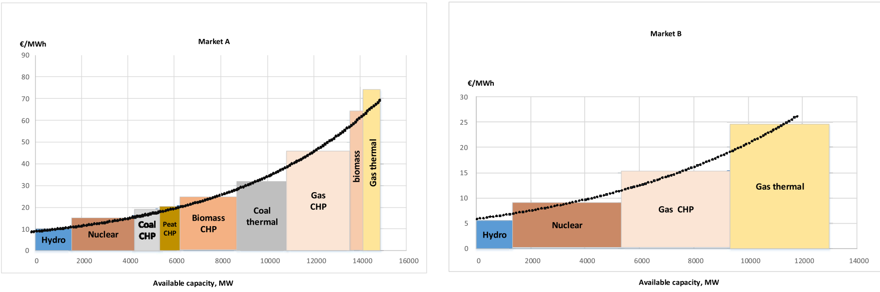

Fig. 5. Cost-based merit orders in markets A and B.

Table 1
Merit order parameters.

Market A	Market B
$a1 = 9.3$	$a2 = 6$
$b1 = 1.5 \cdot 10^{-4}$	$b2 = 1.8 \cdot 10^{-4}$

Table 2
Load-duration curve parameters.

	Market A	Market B
p	−0.47	−0.47
q	0.0001	0.0001
r	1.8	1.8

underutilization of the transmission link. In peak hours, even if the electricity price spread (the difference between the day-ahead electricity prices in two markets) justifies cross-border trade, the capacity payment could prevent it, thereby producing “dead bands” or price intervals when it is not rational to export at any level.

In Case 2, providing the opportunity for a cross-border trader to receive capacity payments in the case of importing to energy-plus capacity market B poses a problem of inverse cross-border flows. The capacity payments produce incentives to export from the high-cost market A to the low-cost market B against the price difference, which can be considered an inefficiency of the cross-border trade with a negative welfare impact on the market participants in both markets. It is assumed that the foreign capacity provider can receive capacity payments only if it ensures full availability, which can be provided through reservation of transmission capacity.

In Case 3, market coupling maximizes the use of the interconnection capacity between two countries, eliminating inefficient arbitrage under Case 1 and Case 2 and allowing more energy to flow from market B to market A. Under market coupling, the cross-border flow is not determined by a cross-border trader, but rather by the power exchanges aimed at maximizing social welfare in both markets. Since the capacity mechanism does not concern the cross-border trade, the flow is determined based on the day-ahead electricity price differences in markets A and B only. This leads to a higher utilization rate of the transmission link (e.g. the volume of trade in Case 3 is 12,264 GWh/year against 4733 GWh/year in Case 1). The transmission capacity is fully utilized (or congested), justifying the small price difference as presented in Fig. 7.

4.2. Welfare analysis

By repeatedly solving the optimization problem given in Eqs. (7)–(10) for the full range of demand levels from minimum to maximum, we obtained the results for the cross-border trade, the volume of cleared generation, and the market clearing electricity prices required to estimate the welfare indicators in both markets for Cases 1–3. The welfare indicators consist of the TSO income, the producers' and consumers' surpluses from the energy market, the capacity payments, and the cross-border trader profit for the whole study period (one year). In Cases 1 and 2, the TSOs' income is the cross-border fee multiplied by the cross-border flows. In Case 3, the TSOs' income is the price difference between two markets multiplied by the cross-border flow (that is, congestion rent). We assume that the TSOs' income is redistributed equally between the consumers in markets A and B. Consumer surplus is the difference between the price consumers are willing to pay and the price they actually pay. If demand is inelastic, the consumer surplus is infinite as the demand does not respond to any change in price. However, in our analysis, in order to provide a quantitative measure of consumer surplus, the value of intercept (or the price that the consumers are willing to pay) is assumed to be 300 €/MWh (see e.g.

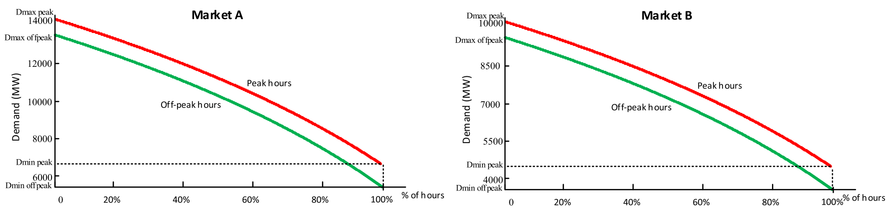

Fig. 6. Load-duration curves.

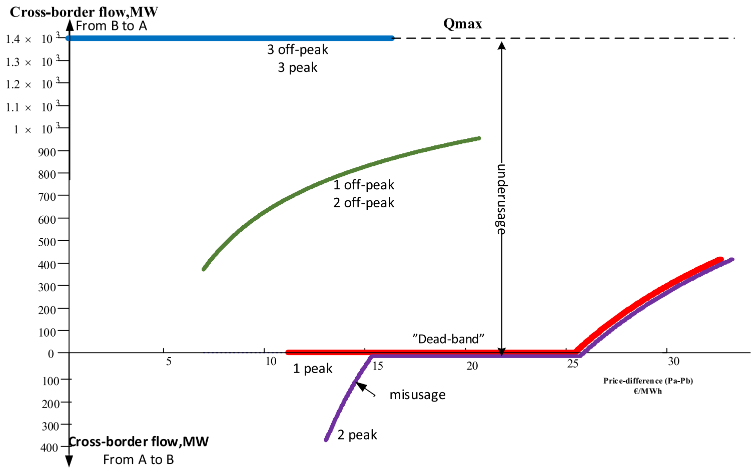

Fig. 7. Cross-border flows depending on the price spread for Cases 1–3.

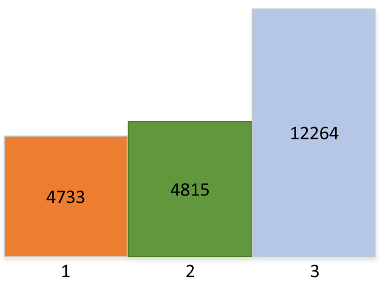

Fig. 8. Total energy transmitted through the interconnector (GWh/year).

Pellini, 2012). Thus, the consumers' surplus is calculated by summing the differences between the intercept and market clearing prices over a year (that is, weighted by the respective number of hours given by load durations). The producers' surplus is calculated by summing the differences between the market clearing prices and the costs of electricity production over a year. Regarding capacity market B, the total capacity payment paid by the domestic consumers is calculated by summing over the number of peak hours in a year a multiplication of the domestic capacity demand (which is the reserve ratio multiplied by the peak demand) by the capacity price.

The total capacity paid/received by the cross-border trader is calculated by summing over the number of peak hours in a year a multiplication of exports/imports from/to market B in peak hours by the capacity price. In Case 1, the total capacity payments received by the generators in market B is the sum of the capacity payments paid by the domestic consumers and the capacity payments paid by the cross-border trader. In Case 2, where we assume that the import capacity can participate in capacity market B, the import capacity reduces the total need for generation capacity in market B required to cover the total demand for capacity. Thus, capacity payments received by the generators in market B are the total capacity payments paid by the domestic consumers and the exporters minus the capacity payments paid to the importers. The import capacity reduces the total need for generation capacity in market B required to cover the total capacity demand. In Case 3, where market coupling is introduced, we assume no cross-border participation in capacity market B, and the total capacity payments received by the generators in market B equal the capacity payments paid by the domestic consumers in market B. The results of the welfare analysis are presented in Fig. 9. Table 3 presents the result of the total welfare in markets A and B, that is, the sum of the consumers' and producers' surpluses as presented in Fig. 9.

As shown in Table 3, we observe a small decrease in overall welfare in Case 2 compared with Case 1, caused by the inverse cross-border flows (that is, the electricity flow is from the higher-price market to the lower-price market). Because of the capacity remuneration available in market B, the trader has incentives to trade against the price difference in the day-ahead market (when the expected price difference is below 15 EUR/MWh) as the benefits gained from selling capacity in the capacity market B are higher than the loss incurred from buying energy at a higher price in market A and selling at a lower price in market B. This increases the inefficiency of the short-term dispatch because generators with high marginal costs in market A substitute the low marginal costs of generators in market B. The negative welfare effect is rather small, because most of the time the price difference is above 15 EUR/MWh and the flow is still toward the higher-price market A. However, more frequent small price differences or higher capacity prices in market B may increase the probability of inverse cross-border flows and thus result in a higher negative welfare effect.

In Case 3, we can see that both markets benefit from the introduction of market coupling. With the present supply-cost structure in the two markets, the welfare benefit (difference between the total welfare in Cases 3 and 1) is around 80 MEUR/year (around 2% of the total market welfare). The welfare benefit can be explained by the high diversity in the supply-cost structures and the fuel price differences resulting in a considerable electricity

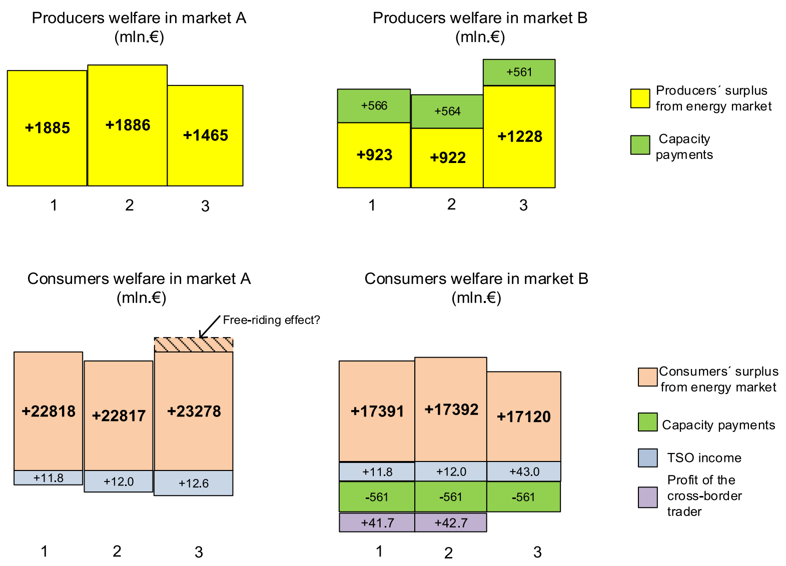

Fig. 9. Producers' and consumer's welfare (in MEUR/year).

Table 3
Total welfare (in MEUR/year).

	Total welfare market A	Total welfare market B	Total welfare market A + market B
Case 1	24714.8	18372.5	43087.3
Case 2	24715.0	18371.7	43086.7
Case 3	24775.6	18391.0	43166.6

price difference between the markets. The electricity prices in market B are mainly driven by domestic gas prices, since almost 65% of the installed capacity relies on gas generation. Future domestic gas prices are subject to political decision-making, and thus, very unpredictable.

The validity of theses results may be limited by several assumptions that were necessary to keep the model tractable. Firstly, we assumed that the trader operates under perfect information regarding the demand and supply curves in both markets; that is, the trader can maximize profits by deciding upon the optimal cross-border flows. We also accept the fact that in reality the rational behavior of the trader can be bound by the imperfect foresight of the future demand and supply. The modeling assumption on the rational trader behavior may lead to overestimation of the welfare benefit. A second limitation involves assumptions related to the modeling of supplies. Supply curves are expressed by an exponential function, while in reality, their shape is a step function. However, as a whole, the supply curve fits well with the exponential function. Although the supply curves used in this study are a time-independent fixed function, the supply function in an actual market changes on hourly basis as a result of power producer strategies, and seasonally based on availabilities of power plants and other factors. As the welfare benefits between the different cases are strongly driven by the assumed parameters of the supply curves presented in Table 1, we conducted a sensitivity analysis that shows the dependence of the parameters of the supply curves on welfare gains of market coupling (differences in overall welfares between Cases 3 and 1). Fig. 10 shows the dependence of the welfare gain on the parameter $a1$ of the supply curve in market A for the values of the parameters of market B $a2 = 4$, $a2 = 6$ and $a2 = 8$. We see that the welfare gain is very sensitive to the ratio a1:a2, which shows the magnitude of the price difference between markets A and B. Thus, the higher the price difference, the higher the welfare benefits obtained by the improved utilization of the transmission capacity resulting from the introduction of market coupling. This means that underestimated marginal costs of power technologies in market A in the reference case lead to an underestimation of the welfare benefits of market coupling, and vice versa. The third limitation relates to our disregard of the difference in the pricing models applied in the markets (where one applies nodal pricing and the other applies zonal pricing), where we assumed that both operate under the zonal pricing mechanism. In reality, it would be feasible to apply a hybrid congestion management model proposed by Bjørndal et al. (2014). In this case, social welfare optimization, aside from power balance and capacity constraints, includes physical flow constraints in the nodal pricing areas (that is, the loop flow law), which determines the power flow by the admittances of the line and the difference of the load angles of its two points. In this case, market B would comprise several nodes with different nodal prices, and cross-border flows to the

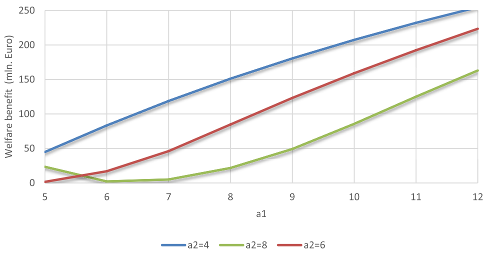

Fig. 10. Welfare benefit as a function of parameter a1 of the supply curve in market A for $a2 = 4$, $a2 = 6$ and $a2 = 8$.

zonal pricing market A would be affected by the price in the node connecting markets A and B. However, due to lacking data on the transmission network in market B, we aggregated all nodes within one zone of free-power flow into one node and coupled the markets as two markets with zonal pricing.

In sum, our modeling assumptions with regard to trader behavior and supply curves and the limits of our data in terms of detailed representation of all parameters of the power systems may lead to under- or over-estimation of cross-border and welfare effects. However, general findings on the impact of capacity markets that can be drawn based on this analytical model are noncontroversial despite these limitations and can be generalized and addressed to the integration of any energy-only and energy-based capacity markets, as we discuss below.

5. Discussion and policy implications

This article presented an analytical model of two interconnected markets with different market designs, namely the Nordic energy-only market and the Russian energy-plus-capacity market, and the cross-border trade between them in order to evaluate the short-term cross-border impacts and distributional effects of capacity markets under different cross-border allocation mechanisms (explicit and implicit). This is one of the few cases that allows for an empirical analysis of the interaction between an energy-only market and a capacity-based market. The case study contributes to the consideration of possible outcomes associated with the integration of markets with different designs, as the internal market for electricity is a key part of the EU 2020 strategy, and numerous Member States are currently contemplating moving from energy-only markets to capacity-based markets (European Commission, 2010).

The main findings here are that unilateral implementation of capacity markets may have several cross-border effects, depending on the treatment of capacity markets in the cross-border trade and the cross-border transmission capacity allocation principles under which the interconnectors operate. Under the explicit access to the use of the transmission capacity, the prospects for cross-border trading can be undermined by the treatment of the capacity payments imposed on cross-border traders, resulting in considerable underusage or misusage of transmission capacity. This hinders efficient sharing of resources, which is the rationale for the interaction or integration of the markets in the first place. Inefficient use of transmission capacity produces considerable welfare losses among market participants. This issue may be relevant to many European markets considering implementation of CRMs and explicit auctions. For example, the capacity market that is under consideration in France may bring cross-border trade distortions to interconnectors with Germany or Italy.

Short-term inefficiencies in cross-border trade brought by capacity markets can be eliminated by shifting from the explicit cross-border allocation mechanism to market coupling. However, introduction of market coupling between energy-only and energy-plus-capacity markets may introduce negative externalities. Capacity markets typically tend to reduce electricity prices by replacing energy-only remuneration of generators with two-part payments consisting of an energy-based payment and a capacity-based payment. Consumers in a country with a capacity market may pay for an increase in generation capacity that partly leaks to a neighboring country with an energy-only market. Thus, given the integration of markets by market coupling, consumers in the energy-only market A may act as “free-riders,” since they benefit from an increase in reliability and lower energy prices without having to pay for the additional capacity. On the other hand, price reductions may decrease revenues and thus the investment prospects of producers in the neighboring energy-only market, which in the long-run may result in lower market capacity in the energy-only market and put further pressure on this market to also introduce a CRM (Meyer et al., 2014). Hence, there are strong reasons for the coordination of market-design policies to help avoid these negative effects on the internal market.

In order to estimate the outcomes of the integration of markets with different designs in the long run, projections of welfare with respect to changing supply-cost structures and possible market design changes in both markets should be estimated, but this is outside the scope of our analysis. Moreover, a long-term welfare analysis should take into account the opportunities for cross-border participation in capacity markets, which may decrease the risk of inefficient allocation of investments and contribute to the achievement of generation adequacy in integrated markets in a cost-minimizing way. In the new guidelines on the EU State Aid Environmental Protection and Energy, the Commission puts forward a requirement for capacity remuneration mechanisms to be open to all capacity that can effectively contribute to meeting the required generation adequacy. The Commission emphasizes that coordination of Member States in the development of regional rather than individual criteria for generation adequacy may result in lower capacity requirements and lower total system costs in integrated markets (European Commission, 2013).

Several studies focus on the development of different options for cross-border participation in capacity markets (Frontier Economics, 2014; Tennbakk and Noreng, 2014). However, no common set of regulations has been proposed. The Commission recognizes the practical difficulties of considering cross-border capacity in national CRMs but does not provide guidance along these lines. One of the concerns is how to ensure fulfillment of the commitments of external generators in national capacity markets because the availability of domestic and foreign capacity is not easily comparable in reliability terms. Without direct reservation of the transmission capacity for the purpose of cross-border participation in CRMs, the availability of the foreign capacity could be difficult to ensure.

Thus, there remains a concern that the implicit cross-border allocation principle, which is shown to be the best mechanism to allocate transmission capacities and is the target model for cross-border allocation in the Internal Electricity Market in Europe, limits the opportunities of foreign capacities to participate in national CRMs as it completely excludes opportunities to reserve the cross-border transmission capacity by market participants for the purposes of ensuring availability in CRMs. This means that explicit auctions could be the only option that would enable the cross-border capacity participation. Furthermore, even though implicit auctions ensure the most efficient use of resources in the short run, explicit auctions may be economically more justified than implicit auctions to allocate cross-border capacity between an energy-only market and a capacity-based market (or two capacity-based markets) if in the long run the overall benefits of cross-border participation of foreign generators in national capacity markets through direct reservation of transmission capacity in explicit auctions are higher than the benefits of market coupling.

6. Conclusion

In this article, we have presented the implications of capacity markets, cross-border allocation mechanisms, and opportunities for cross-border capacity market participation in terms of cross-border trade and market welfare by applying an analytical model where an energy-only market and a capacity-based market are interconnected and operate under different transmission capacity allocation mechanisms (explicit and implicit). Our findings suggest that under explicit allocation of transmission capacity, a capacity market may impede cross-border trade and result in underusage of transmission capacity. Providing a possibility for import capacity to receive capacity payments, while ensuring availability through physical reservation of transmission capacity, could lead to misusage of transmission capacity.

To increase the short-term efficiency of cross-border trade, the optimal cross-border flow could be defined on the basis of the price difference in the day-ahead markets (that is, through market coupling), in which case the capacity payments would not create a barrier to trade. The result would be more efficient utilization of the interconnector. However, problematic distributional effects could arise if the consumers in the energy-only market were considered to benefit from lower costs and higher security of supply at the expense of the consumers in the capacity-based market. Moreover, the difficulty is to couple the capacity market to cross-border trading; since there is no straightforward way to identify the export capacity under implicit auctioning, opportunities of foreign generators to participate in national capacity markets and ensure availability are limited. Thus, explicit auctions could be more justified in economic terms as they allow cross-border capacity participation and contribute to the achievement of generation adequacy in integrated energy-only and energy-plus-capacity markets in a cost-minimizing way if the overall benefits of cross-border capacity trading are higher than the benefits of market coupling.

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Publication V

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Capacity Market in Russia: possibilities for new generation entry and cost of CRMs.

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Capacity Market in Russia: possibilities for new generation entry and cost of CRMs

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***Abstract*— While many European countries are implementing different capacity remuneration mechanisms (CRMs) or capacity markets, the Russian electricity industry faces the consequences of the capacity market with CRMs, i.e. capacity oversupply. Russia introduced the capacity market and CRMs for new capacity construction in 2011. Ideally, old inefficient generation should have exited the market leaving new and efficient ones. However, high number of "must-run" power plants that cannot be excluded in the capacity auction and overestimated capacity demand have led to an oversupply of capacity. In this paper we estimate the capacity market clearing price based on sloping demand and supply functions as well as test the possibility of new efficient generation entry. The outcomes of the model are used to predict the consumer capacity price peak due to CRMs and to conclude on efficiency of implementing sloping capacity demand curve in capacity auctions.**

***Index Terms*-- Capacity Market, Capacity Auction, CRM, Electricity Market.**

I. Introduction

Capacity markets are highly discussed topic in the literature [1] [2]. The main objective of capacity markets or capacity remuneration mechanisms (CRMs) is to provide resource adequacy to the power generation system at reasonable cost. It is the market which is created in order to deal with electricity market failures, such as missing money problem or an absence of long-run contracts [2]. These failures could result in underinvestment in new capacity construction or even prevent adequate remuneration for existing power producers. The last can be the case when a high renewable energy penetration causes merit-order effect and conventional power plants may not be economically viable while they are still needed in the system to back up an intermittent renewable power production. Capacity market can ensure the revenue to cover the missing money problem, so power plants can remain available if they are needed in the system and provide investment signal to introduce new generation capacities.

Although, there are continuous debates on the optimal capacity market design and discussions if the capacity market is a solution to the market failure problem. According to [3], an optimal capacity market should induce right investments on new generating capacity at the right location and in addition to that it should reduce risks and market power in the system. There are different approaches to reach that goal, such as capacity payments, capacity auctions, strategic reserves etc. One of the first implemented capacity mechanisms, PJM in the US, was assessed as effective in terms of providing reliable supply, flexibility and competitiveness. However, there are issues related to the total cost of capacity to the consumer [4]. When dealing with CRMs, the final cost is always important aspect to consider. A capacity market should also provide incentives for old generation to exit the market.

In this paper, we analyze the Russian capacity market from different perspectives: investment in new generation capacity, competitiveness, signals to exit the market and final consumer capacity cost taking into account CRM. Capacity market in Russia was created with the aim to attract investments which were highly needed after restructuring the market in 2000s. About 50% of generation assets required renovation or replacement. In order to incentivize construction of new power plants, long-term agreements were introduced in addition to the annual capacity auction. These agreements, a form of CRM, that guarantees return on investments, while the investor takes an obligation to deliver capacity at the agreed time. They called Capacity Delivery Agreements (CDAs) for thermal power plants and Long-term Agreements (LTAs) for nuclear and hydro power plants. Currently more than 28 GW of new capacity were constructed under such agreements. At the same time, old power plants have no incentives to exit the market, resulting in oversupply of capacity. This paper provides a forecast of capacity market clearing price in Russia for the next 10 years in order to investigate possibilities for competitive new generation entry. In addition, the final consumer capacity price is calculated to assess the total cost of CRMs.

The paper is organized as follows. Chapter II describes electricity and capacity market design in Russia, chapter III

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explains the methodology and assumptions used to forecast capacity market prices in Russia. Then, chapter IV provides results and sensitivity analysis. Finally, chapter V concludes.

II. Background

The power production industry of Russia was fully liberalized in 2011. State-owned vertically integrated generation companies were restructured and then privatized. At that time, generation assets were in a poor condition and companies could not raise enough money to provide sufficient reliability of supply. That led to the creation of a capacity market in addition to the existing electricity market. Therefore, Russia has two-commodity wholesale power markets: electricity and capacity. Rules of the market are determined by the Government Decree N1172 [5]. The wholesale market area covers the European part of Russia, Ural and Siberia - the most populated and industrial areas, see figure 1. The wholesale market is divided into two price zones. The European price zone (1st price zone) is dominated by gas fueled thermal power plants, while the Siberian price zone (2nd price zone) is dominated by coal and hydro power plants. In the rest of the country's territory, electricity prices are regulated and sold at tariffs.

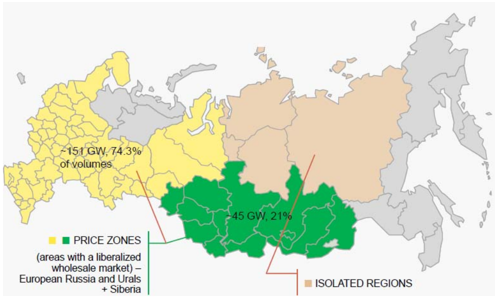

Figure 1. Competitive electricity and capacity price zones [6]

The wholesale electricity market includes the day-ahead market, balancing market and bilateral contracts. The day-ahead market model employs the concept of bid-based economic dispatch. The market price is defined by the bid of the last generator to cover the forecasted demand. The System Operator (SO) forecasts demand for every hour prior the market. The Administrator of Trading System (ATS) organizes the day-ahead market for zones of free power flow, where power can flow without any constraints. The electricity market in Russia can be characterized as a highly concentrated market. However, despite the high market concentration, generation companies do not exert market power according to [7].

The capacity market has two components: competitive capacity auction (CCA) for existing capacities and CRMs for new generation entry. CRMs for new generation capacities, CDAs and LTAs, were an immediate measure for attracting investment at the time. The mechanism guarantees return on investment for the investor within 10-20 years depending on the power plant type [8]. The investor is obliged to deliver contracted capacity at agreed time; otherwise he has to face a fine for delay. The amount of capacity payment for the investor is fixed and paid during agreed time. Current CDA prices are 560000 Rub/MW per month (~6600€/MW per month) for thermal power plants and 700000 Rub/MW per month (~8300€/MW per month) for hydro and nuclear power plants.

The SO defines capacity volumes to procure in CCA for each zone based on peak demand and required reserve amount. Existing power plants bid volume and price at which they can guarantee their availability to produce power. Capacity under CRM is selected in CCA by default with a price accepting bid (zero). The capacity market has undergone changes during 2015. Currently, the capacity auction is held for 3 year-ahead time-period from 2017 and it employs a sloping demand curve, see figure 2. Where point 1 is a minimal required capacity demand (D_{min}) which has a high price and it is capped at the price cap level (P_{max}) and point 2 is maximum capacity (D_{max}) which can be procured at a minimal price (P_{min}). These changes should give generation companies an incentive to reduce their output by decommissioning old generation assets and investing in efficiency for higher profit. The decision to use the sloping demand curve was motivated by capacity oversupply in 2015 CCA, when about 15 GW of capacity were not selected in auction [9]. After the auction, 7.5 GW of not selected in CCA power plants got status of "must-run" generations (MRG).

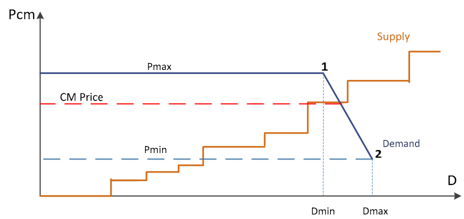

Figure 2. Capacity auction principle in Russia

MRG is a power plant which is expensive to run and perhaps outdated, but required to be in the system and run for system reliability reasons. They are also can be needed in order to produce heat during wintertime. The amount of such generation increased dramatically up to 14GW in 2016 CCA [10], indicating the need for replacement. If the power plant gets the MRG status, it can receive capacity tariff, which is usually higher than the capacity market price. The MRG tariff depends on the type of the power plant and its location. In 2016, the MRG tariff was about 200000 Rub/MW per month (~2400€/MW per month) on average [11]. Payments for capacity together with the revenue from the electricity market should cover fixed and variable costs of power plants, see Figure 3. Thus, in order to assess the profitability of power plants, both components have to be taken into account in power markets with two commodities.

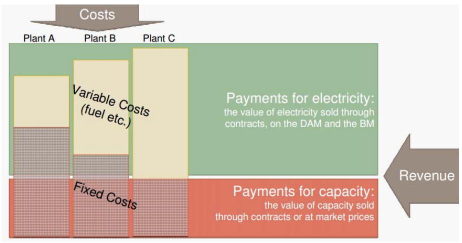

Figure 3. Principle of capacity and electricity market [11]

III. Methodology

We consider the capacity market held in the 1st price zone as the most competitive and with more capacity under the CRM. We distinguish 66 different power producers in the 1st price zone with the total capacity of 156315 MW. Some of the capacities are aggregated to a company level as there is no data available on specific power plants. A perfect competition is assumed in both electricity and capacity markets. Thus, the electricity price is cleared at a marginal cost of the most expensive power plant. Simulation of the capacity auction is made in such a way, that every generator bids according to its "capacity cost" (B_{it}) for every year, similar to [12], see (1). Existing power plants bid a non-capital fixed cost ($C_{it,Fixed}$) reduced by profit from electricity market ($\pi_{it,EM}$) or zero, if their revenue is enough to cover all fixed and variable costs. New power plants bid a profitability gap ($-\pi_t^{NEW,gap}$), which is needed to reach NPV=0 condition during power plant's life time. Capacity under the CRM and must-run generation bid is also zero. Their capacity bid is deducted from the total capacity demand.

$$B_{it} = \begin{cases} \max\left(0; C_{it,Fixed} - \pi_{it,EM}\right) \\ \max\left(0; -\pi_t^{NEW,gap}\right) \end{cases} \tag{1}$$

The capacity market-clearing price is defined as the interception of demand and supply curves. The clearing price can be defined using inverse demand function (F) and inverse supply function (S) based on the bids of power plants (2-3):

$$\begin{gathered} P_{CMt} = S^{-1}{}_t(B_i) \\ P_{CMt} = F^{-1}{}_t(D) \end{gathered} \tag{2}$$

$$S^{-1}{}_t(B_i) = F^{-1}{}_t(D) \tag{3}$$

Where:

$$\begin{gathered} S^{-1}{}_t(B_i) = a_{1t} + b_{1t}(B) \\ F^{-1}{}_t(D) = a_{2t} + b_{2t}(D) \end{gathered} \tag{4}$$

Inverse demand function is constrained by price cap (P_{max}) and price floor (P_{min}). Taking into account volumes of capacity under CRMs and MRG, the final consumer capacity cost can be calculated as:

$$\begin{aligned} C^{total}{}_t = \left(D_t - \sum\left(V_{CDA,t} + V_{MRG,t}\right)\right) \cdot P_{CM,t} \\ + \sum V_{CDA,t} \cdot P_{CDA,t} + \\ + \sum V_{MRG,t} \cdot P_{MRG,t} \end{aligned} \tag{5}$$

$$C_t^{consumer} = \frac{C_t^{total}}{D_t}$$

Where:
i – Index of power generator;
t – Time index, year;
$C^{total}{}_t$ - Total cost of capacity, Rub;
D_t – Capacity demand, MW;
$V_{CDA,t}$ – Volume of capacity under capacity agreement, MW;
$V_{MRG,t}$ – Volume of capacity considered as must-run capacity, MW;
$P_{CM,t}$ – Capacity market price, Rub/MWyear;
$P_{CDA,t}$ – Price of the capacity under CDA, Rub/MWyear;
$P_{MRG,t}$ – Price of the must-run capacity, Rub/MWyear;
$C_t^{consumer}$ – Final consumer capacity cost, Rub/MWyear.

A. Profit from the electricity market

To estimate the profit from the electricity market for every generation company in the 1st price zone, the difference between its marginal price and the market-clearing price during one year is calculated. For such purpose load duration curve (LDC) and consequently a price duration curve (PDC) were constructed based on demand data from the ATS on 2015 [13]. Data on power plants were collected from the generation companies' annual reports (capacities, efficiencies and fuel prices). As market price is usually cleared at fossil fuel based power technology (f), output of nuclear and hydro power plants were deducted from the demand. We use linear model to find market prices (P_{EMT}) at certain demand points of LDC (D_T):

$$\begin{gathered} min \sum_f Q_{fT} C_f \\ \text{S.t. } \textstyle\sum_f Q_{fT} = D_T, \quad \forall T \end{gathered} \tag{6}$$

Where:
Q_{fT} – output of the fossil fuel based generator f at the time T, MWh;
C_f – marginal cost of the generator, Rub/MWh;
D_T – demand and time T, MWh.

Profit from the electricity market for every fossil fuel based generation can be found as (7) and is graphically shown in fig.4.

$$\pi_{fT} = \sum_T (P_{EMT} - C_f) Q_{fT}, \quad P_{EMT} > C_f \tag{7}$$

Profit for nuclear and hydro power plants estimated as power plant capacity factor multiplied by average market price:

$$\pi_{h(n)} = CF_{h(n)} \cdot P_{EMT}^{av} \tag{8}$$

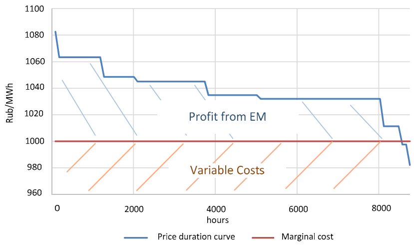

Figure 4. Profit from electricity market for thermal power plants

B. Power plants' fixed costs

Power plants' fixed costs are differentiated by the technologies they are using. Fixed costs of hydro and nuclear plant are taken as operational costs of Rushydro and Rosatom divided by their installed capacities. All the data are taken from companies' annual reports [14] [15]. Fixed costs of nuclear and hydro power plants are 4-6 times higher than the current capacity price. However, they have considerably lower marginal production cost which is assumed to be zero in this paper case. Fixed costs of power plants are taken as 105000 Rub/MW per month (~1000€/MW per month), according to [16]. It is assumed that fixed costs of power plants increases by 1% every year.

C. New power plant bid

As stated before, new power plants bid the profitability gap ($\pi_t^{NEW,gap}$) which is required in order to reach the positive NPV during the lifetime of power plant, see (9-10). The capital costs of a new power generator is calculated as 80000 Rub/kW (~1000€/kW), discount rate 10% and the life time of the power plant - 30 years.

$$\pi_t^{NEW,gap} = \pi_t^{NEW} - \pi_{EMt}{}^{NEW} + C_{Fixed,t}^{NEW} \tag{9}$$

Which comes from the function:

$$NPV^{NEW} = -C_{new} + \sum_{t=1}^{30} \frac{\pi_t^{NEW}}{(1+r)^t} = 0 \tag{10}$$

D. Market with capacity support for new generation

As an alternative scenario, in case of low competitiveness of new generation without CRM, profitability gap compensation scenario was analyzed. According to the new amendments to wholesale power market rules, the government announced competition for new power plants entry after 2019 [16]. We assume that new power plants are introduced to replace must-run generation. Therefore, capacity volume of new power plants is equal to must-run capacity volume decommissioning. Their volume is selected also by default in the CCA and they get a capacity remuneration which is equal to profitability gap.

IV. RESULTS

The model is used to forecast capacity prices for the following 10 years and to investigate the possibility for new capacity implementation without CRM. The results of capacity market simulation are shown in the figure 5, starting from 2016 to 2027. Price cap and price-floor are taken from CCA data and equal to 150000 Rub/MW per month (~1800€/MW per month) in the point of minimal capacity demand and 110 000 Rub/MW per month (~1300€/MW per month) in the point of maximum procured capacity demand. Capacity demand points are increased every year by 6.5% according to the CCA 2017-2018 methodology [17]. Modeled capacity prices are quite close to the real prices, indicating that power plants behave as in perfectly competitive market. The clearing market price is close to the fixed cost of thermal power plants, meaning that the power plants can be competitive in CCA even if they do not produce electricity at all. Current price-floor does not provide effective market exiting signals. Therefore, lowering the price floor in CCA should be considered in order to provide proper signals for exiting the market.

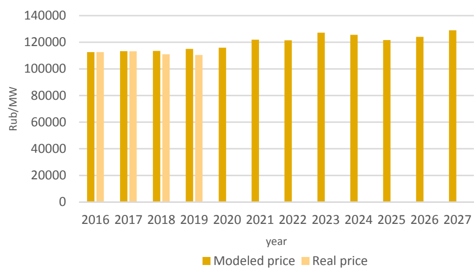

Figure 5. Capacity clearing price forecast

CCA prices slightly increase over years due to fixed cost increases and commissioning of new power plants. Commissioning of new efficient power plants result in lower profit from the electricity market. The marginal cost of new power plants is lower, thus, they shift the merit-order to the right and decrease day-ahead market prices. Consequently, it effects the profit for all power plants in the market, increasing bids in the capacity market.

As the capacity auction is capped by price cap which is higher than profitability gap for new generation entry, capacity market cannot provide signals for new capacity entry. Prices in the electricity market are not high enough to decrease profitability gap to price cap level. For instance, at capital investments of 80000-90000 Rub/kW (959-1079 €/kW), the profitability gap would be 587356-732683,6 Rub/MW per month (7040-8780 €/MW per month), which is comparable to current CDAs and LTAs prices. Therefore, different incentives for new capacity entry should be suggested. A tested alternative scenario "Market with capacity support for new generation" provides the most effective solution as it decreases the amount MRG which is getting high MRG tariff. In this case the contribution to the total consumer cost would be minimal, see figure 6. However, the suggested option consider only replacement of existing must-run generation with high must-run tariffs. New instruments or incentives are needed in order to attract investments in new generating capacity.

The total consumer capacity cost reaches its peak in 2020, accounting for 217898 Rub/MW per month (2600 €/MW per month) which is almost twice as high as the modeled CCA clearing price. After 2021 and onwards, capacity that was commissioned under CDA from 2011 becomes a participant of the CCA and does no longer receive the CDA price. Therefore, after 2021 the total consumer capacity cost is decreasing by up to 165291 Rub/MW per month (1981 €/MW per month).

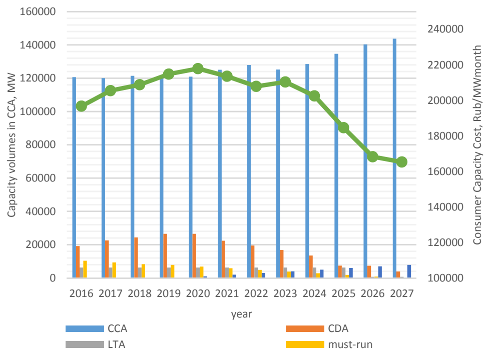

Figure 6. Total consumer capacity cost and volumes of capacity in CCA and CRMs

V. Conclusion

The capacity auction simulation which was made in order to predict the capacity market clearing price in Russia's capacity market has shown no investment signals for new capacity entry without any capacity investment support. Moreover, at the current capital cost of power plants profitability gap calculated for 30 years is much higher than the CDAs and LTAs capacity payments. The current capacity price is enough to cover the fixed costs of power plants, but not enough to cover profitability gaps for new power plants.

Findings suggest that there are no effective signals for decommissioning old power plants, as a price floor is set at level higher than fixed costs of power plants,. Therefore, additional regulative incentives are required. For instance, incentives for implementing competition to replace the old and outdated power plants or to decrease the price floor in CCA. The replacement of the must-run generation could potentially decrease the consumer capacity cost.

The capacity payment period for the most of CDA and LTA will end by 2027, resulting in total consumer capacity cost decrease. The highest capacity cost is expected in 2020, then the consumers' CRMs burden starts to decrease.

Proposed scenario of replacement of old generation (must-run) shows the possibility to ensure new generation entry. However, this scenario would require regulative mechanisms. As old power plants tend to stay in the capacity market and receive must-run tariff or the CCA price, which is in some cases is enough to cover all fixed costs.

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