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Dynamic transmission tariff on the EU (Finnish) border – Russian border

SKM Market Predictor AS

6/3/2015

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List of Abbreviations

ATS	Administrator of Trading System
CCA	Competitive Capacity Auction
CDA	Capacity Delivery Agreements
CPM	Capacity Payment Mechanism
FAS	Federal Antimonopoly Service
FFZ	Free Flow Zone
LMP	Local Marginal Pricing
LTA	Long-Term Agreements
SO	Russian System Operator
TGK	Territorial Generating Company
TSO	Transmission System Operator
UPS NW	Unified Power System Northwest Russia
UPS Center	Unified Power System Central Russia
WGK	Wholesale Generating Company

1. Summary

This study investigates the effects of a dynamic cross-border tariff structure on the power exchange between Finland and Russia. Unlike the current fixed tariffs, the dynamic tariff structure would be adjusted according to the price difference between the two markets. The main purpose of the dynamic structure is to better facilitate power exchange, especially during the hours of low price differences. During 2013 and 2014 there were 2260 hours when the price difference between Finland and North West Russia was below the sum of cross-border fees on both Finnish and Russian sides (7.2 EUR/MWh). The Dynamic tariff structure would also enable the exchange during these hours. The TSOs also have a cost associated with the cross-border exchange, which needs to be covered. Therefore, one of the main purposes of the study was to suggest a new structure that would provide the income necessary to cover the costs associated with the Finnish-Russian cross-border trade and at the same time increase the power flows and social economic benefits for the entire system. In this study, three different scenarios have been simulated to investigate the effects of the dynamic structure. Our Base Case scenario represents the most likely development of the Nordic and Russian power markets with the current fixed tariff structure for the exchange between Finland and Russia. The two other scenarios have been simulated with the dynamic tariff structure. In the first dynamic tariff scenario we assumed the dynamic tariff structure for Fingrid and in the second dynamic tariff scenario for Federal Grid Company, as well; other than changes in tariff structure, the three cases are identical. According to the results, the dynamic tariffs would increase the power exchange between Finland and North West Russia in both of these scenarios compared to the Base Case scenario. The highest increase of power exchange is in the scenario where both Fingrid and Russian Federal Grid Company have a dynamic tariff structure. We have also investigated the effects of the currency exchange rate in two additional scenarios.

The use of a dynamic tariff structure would increase the power exchange between the countries. However, after 2018, the price difference between the Finnish and North West Russian spot prices is expected to decrease due to the change of the general market situation. Due to this covering of costs from the cross-border exchange will face difficulties after 2018. Anyway, even in these circumstances the dynamic tariff structure would increase trade more than the current fixed tariff structure.

The use of a dynamic tariff structure would increase the overall welfare on the both sides of the border. According to our analysis, the total social economic surplus would grow by 74 MEUR during 2015-2021 if only Fingrid applied the dynamic structure. The overall welfare would further increase in case Federal Grid Company also applied a dynamic tariff structure, totalling about 128 MEUR during 2015-2021.

Based on the results of this study,[1] we suggest the use of the dynamic tariff structure for the power exchange between Finland and Russia. More precise tariff structures for both non-capacity and capacity hours are presented in Chapter 7 of this report.

[1] Assuming that the market structure of the Finnish and North West Russian power markets will remain similar to the structure described in this study.

2. Introduction

This study is the result of the research and analysis implemented by SKM Market Predictor on behalf of Fingrid Oyj. The project was carried out between December 2014 and February 2015. The purpose of this study is to investigate the introduction of a dynamic tariff mechanism for the cross-border exchange between Finland and Russia. The report includes the overview of the current power market structure, legislation, tariffs, recent and future development of the Russian power market.

The analytical part of the report is focusing on the analysis of the tariff structure and its impact on the cross-border exchange. The proposal of a new dynamic structure is suggested, and the effect of its introduction is simulated and analysed.

2.1. General

The exchange pattern between Finland and Russia has changed remarkably since 2010. During the recent years the price for electricity in Russia has been increasing quite steadily up to the current price level around 20-25 EUR/MWh, while the introduction of the capacity market led to much higher costs for peak consumption. In the Nordic area, the development has been a bit different, the price level as well as future price expectations have deteriorated quite strongly. As a result, the Nordic and Russian price levels have converged closer and sooner than anticipated. The low price difference between Finland and Russia, in addition to the effect of the capacity price mechanism, has become apparent as the nearly constant flow of 1 300 MW from Russia to Finland has dropped significantly after 2011.

Looking into the future, the expected low price difference between the Nordic area and Russia will lead to decreasing flows. The cross-border fees both on Russian and Finnish sides represent an additional cost for the exchange of electricity between the countries.

The introduction of dynamic tariffs will allow closer relationship between the exchange flows and price signals that will improve social welfare both on the Russian and Finnish side.

The assumptions regarding consumption, development of production capacity and both fuel and EUA prices have been estimated by SKM Market Predictor.

2.2. Description of the Simulation Model

The simulations have been performed using our in-house version of the commercial modelling system called EFI's Multi-area Power Scheduling model (EMPS model), also known as Samkjøringsmodellen or

Powel Market Analyzer[2]. EMPS is a stochastic, market-oriented simulation model for power systems where hydropower plays a significant role. The model allows simulation of large power systems with a relatively high degree of detail, so it is well suited for comprehensive studies on a multi-national level. The EMPS model is used by major Nordic Transmission System Operators and many of the largest power producers in the Nordic market.

The Nordic power production portfolio is a mix of several different technologies. The characteristics of the different technologies are represented in the simulation model, giving a good representation of the actual power system. The main production technologies are hydropower, nuclear power, wind power, thermal condensing power and combined heat and power production (CHP).

Weather plays a significant role in the Nordic power market. Previously the power market was focusing mainly on precipitation and temperature as the former determines the availability of hydropower and the latter determines the level of winter consumption. Over the last years, both wind and solar have quickly become new important weather parameters for the power market. The influence of weather can be best seen as large variations in power prices. As far as precipitation and hydropower are concerned, these variations usually take place in one or two-year perspective. Wind and temperature cause variations in a shorter perspective, usually from one or two days to a month. Even if the effect of weather can be observed over a relatively short period of time, it is important to notice that the influence of weather is well represented in long-term simulation. This is because the market's ability to function in different hydrological situations is modified by the future changes in consumption and capacities in various production categories. In the long-term simulation, the changing electricity production system has to be tested against various weather scenarios.

Perhaps the main reason why EMPS model has become so well established in the Nordic power market is its capability to simulate hydropower production in collaboration with thermal capacity. Later EMPS allowed including other effects of weather as well. Our model uses 75 historical inflow and temperature series in order to simulate the effects of varying availability for hydropower and fluctuating consumption. As a result, each scenario run includes 75 alternative weather developments for inflow and temperature and, therefore, the prices we present in this study for each scenario are actually the average prices simulated with all the 75 weather developments. All of the 75 individual price series for the Nordic and Baltic price areas are included in the numerical data provided in this report.

As mentioned above, the modelling of conventional thermal production can be divided in two groups: condensing power production and combined heat and power production (CHP). Regarding power price simulation, these two categories differ from each other in a very essential way. Condensing capacity can be regulated in a rather dynamic manner and therefore this capacity produces electricity only when the price is high enough. This means that the electricity price has to be equal or higher than the variable production cost and a plant owner's profit margin. The variable production cost is basically determined by fuel, efficiency and carbon costs. On the other hand, the CHP power production is usually quite indynamic. Power

[2] http://www.powel.no/Global/DOCUMENTS/Norwegian/Products/Powel 20Market 20Analyzer_29062011.pdf

production of a CHP unit is determined by local heat load rather than the price of electricity. As these two thermal production categories behave in a completely different way in the market, it is important that they are modelled separately.

In Finland most thermal power plants belong purely either to the condensing or the CHP category. However, many thermal units in Denmark as well as some units in Finland and Sweden, are practically a combination of these two categories: they produce a certain amount of CHP electricity, but some share of the capacity is available for dynamic condensing production. In such units, the amount of dynamic production varies during the year. In summer, when the heat load is low, there is more dynamic capacity available than in winter when the heat load is high.

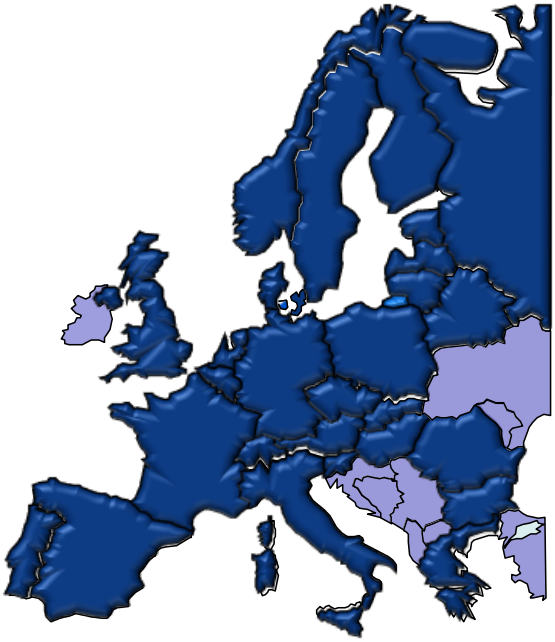


Figure 1: *Regional Subsystems in the Simulation Model.*

In the EMPS model, the interconnected power system is divided into several regional subsystems. Our model consists of 47 individual subsystems including most of the European countries. Modelled countries are shown in dark colour in Figure 1. Due to the dominance of hydro production, Norway is divided into 12 subsystems and Sweden is represented by 6 subsystems. Denmark is divided in two subsystems and Finland is represented by one subsystem. From this year, the European part of Russia is included in the model with five subsystems while the rest of the countries are modelled as one subsystem each. The model calculates area prices for each subsystem. The Nordic system price is calculated from area prices using weight factors that are based on historical observations.

In our model, a week is divided into four time segments representing different load levels: working day peak, working day off-peak, working day night and weekend. We have modelled years 2015-2021.

We are continuously testing and maintaining our model against the changes in the power market fundamentals. We perform weekly power market simulations as a part of our normal analysis procedure and check the actual market development against our previous predictions. This procedure allows us to quickly notice any unforeseen changes in the market fundamentals and update them in our simulation model. Our model is the product of several years' continuous development with both medium (up to 10 year) and long-term (up to 35 year) simulations.

3. Description of power markets

3.1. Production capacity

3.1.1. Russia

The Russian power market is divided into three main power systems with constrained or non-existing capacity between them – European, Siberian and the Far East. The Far East is not a part of the Russian Day-Ahead power market in addition to Kaliningrad, Komi and Arkhangelsk oblast. Russian electricity grid is divided into seven practically self-balanced Unified Power Systems (UPS). The last one is located in the Far East of Russia. The grid is characterized by low exchange capacities compared to generation capacity. This also means that cheap hydropower from Siberia plays an insignificant role in the price areas closest to Europe. Despite the lack of the exchange capacity more or less stabile power export to former Soviet countries, China, Poland, Turkey, Iran, Afghanistan and Pakistan still exists. The Baltic power systems operate in a parallel synchronous mode with the Russian power system. Currently, there are plans to synchronize the Baltic power system with the European system; however, the potential effect of these plans is beyond the scope of this study.

The Russian System Operator (SO) further divides the UPSs into the Free Flow Zones (FFZ). Currently, 21[3] Free Flow Zones are defined for European and Siberian part of Russia. The FFZ's definition relies on the assumption that no significant transmission constraints exist inside the FFZs. The number of FFZ is expected to decrease due to introduction of new transmission capacity.

The total installed capacity in Russia (including Far East) was 232.5 GW by the end of 2014. Roughly 67 per cent of Russia's generation capacity comes from thermal power plants, 21 per cent from hydro power, 11 per cent from nuclear, and 1 per cent comes from renewables such as wind, geothermal energy and waste heat (Figure 2). About 16 per cent of actual generation is from hydro and 16 per cent is from nuclear. The majority of the thermal generation in the European part of Russia comes from gas.

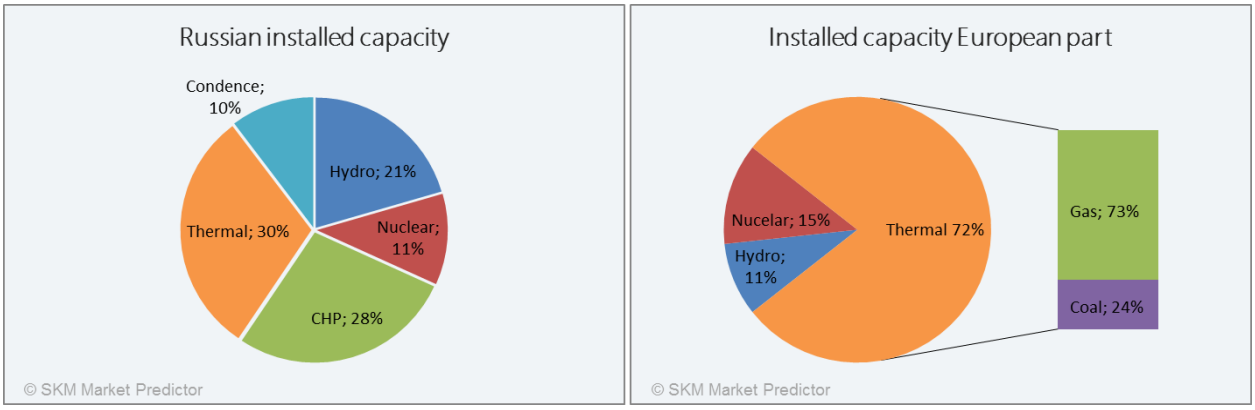


Figure 2: *Share of different production modes in Russia and European part of Russia, %.*

[3] Number of Free Flow Zones in Russia was 29 in 2011 but since that has been decreased to current 21.

In the North West Russia region (UPS NW), which consists of Lenigrad, Murmansk, Novgorod and Pskov regions, the total production capacity was 23.3 GW in 2014. Peak demand in the region was much lower being 15.2 GW.

In the Leningrad region, production capacity in 2014 totalled to 12.6 GW, peak demand being 7.5 GW. Respectively, Murmansk region had a production capacity of 3.7 GW, peak demand being 1.8 GW in 2014. More than 60 per cent of the capacity in Leningrad region is gas based thermal capacity (Figure3).

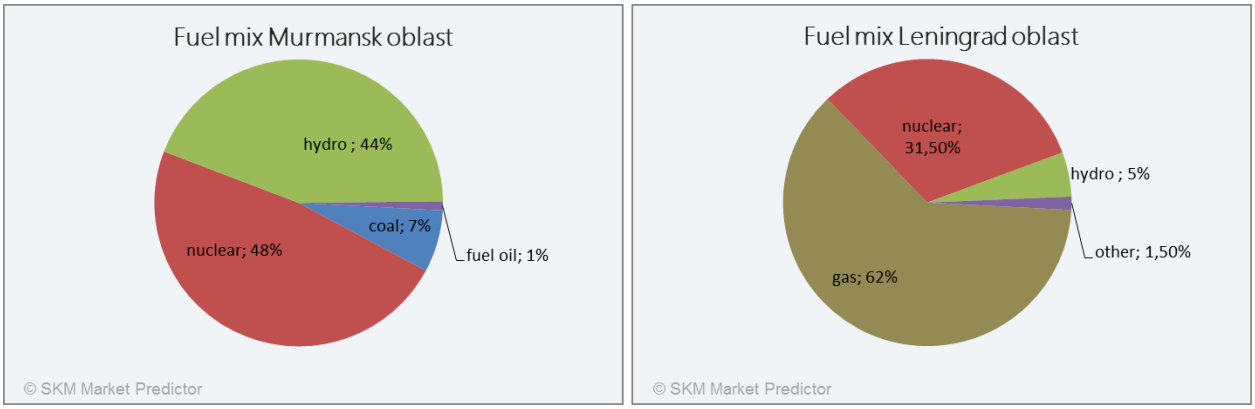


Figure 3: *Fuel mix in Leningrad and Murmansk regions, %.*

The Federal Tariff Services (FTS) regulates natural gas prices on a district level, based on the access to pipelines. Due to historically low domestic prices, the Russian government aims at increasing the price of gas in the longer-term perspective. The target for the domestic price level was the so-called European netback level (European border gas price minus transmission costs and taxes). This was also one of the main assumptions for allowing Russia to enter the WTO.

According to the Governments's plans, the initial target should have been reached by 2011, however, increasing oil prices made it impossible to reach the netback level. In 2014, the Russian government approved freezing the domestic price for gas tariffs at a 2014 level and adjusting them according to inflation in 2015 and 2016. Given the fact fact that Russian inflation is expected to remain around 12-15 per cent, domestric gas prices will continue to increase. Even though Gazprom is constantly pushing towards increased domestic prices, reaching the netback level seems to be impossible in the medium-term. The current official Russian position is that the gas prices will gradually increase and the prices are regulated by the government on a quarterly basis. However, based on long-term crude oil level of around 100 USD/bbl we expect netback level to be reached only by 2022. We expect the changes of the domestic prices for natural gas still being the main driver for the development of Russian electricity prices.

During 2014, the Russian System Operator (SO) implemented several steps to increase the transmission capacity between UPS NW and UPS Center. According to the Russian scheme for development of power sector, this work will continue until 2020 by building a 750kV line between UPS Center and UPS NW and reinforcement of the power grid due to construction of new nuclear units at Leningrad NPP-2. This leads to increased exchange between UPS NW and UPS Center, so, in the long-term perspective the impact of the

extended exchange capacities needs to be incorporated. The development of the UPS Center should be analysed as well.

Historically, the official demand forecast of the Russian general scheme for the development of power sector has been too optimistic. The fundamental for the planning of new generation and the assumptions for the introduction of the capacity market are based on this scheme. The forecasts assumed the average annual growth of 2.2% in the Base scenario and 3.1% in the Maximum scenario. The decommissioning of the old capacity was estimated to be 67.7 GW, leading to the necessity to build additional 173.4 GW in the official Base scenario and 228.5 GW in the Maximum scenario during the period 2010-2030. The comparison of the official forecasts and SKM forecasts based on the current GDP prospects is presented in Figure 4.

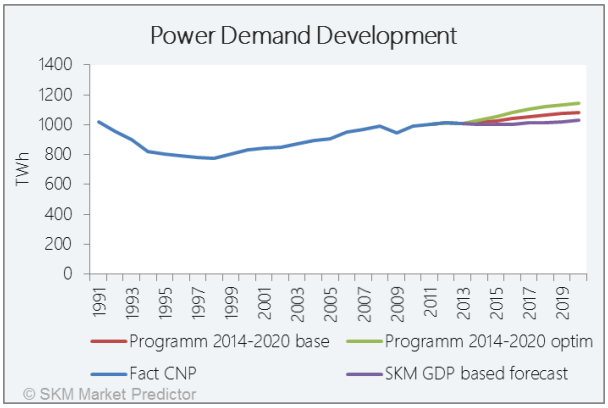


Figure 4: *Power demand scenarios in Russia, TWh.*

The most recent official forecast for the demand development until 2020 is found in the annual scheme published during 2014. This indicated an annual increase of +0.64% in the UPS NW and +0.95% in the UPS Center. However, the increase of the demand over the next few years seems be lower than assumed in those forecasts. The estimate for power consumption in North West Russia used in this study is based on our assessment and is somewhat in line with the latest official estimate.

The total power demand in 2014 was 43.8 TWh in Leningrad region and 12.2 TWh in Murmansk region respectively. The industrial demand covers almost half of the annual consumption in Leningrad region. In the Murmansk region the industrial demand is well over half of the annual consumption (Figure 5).

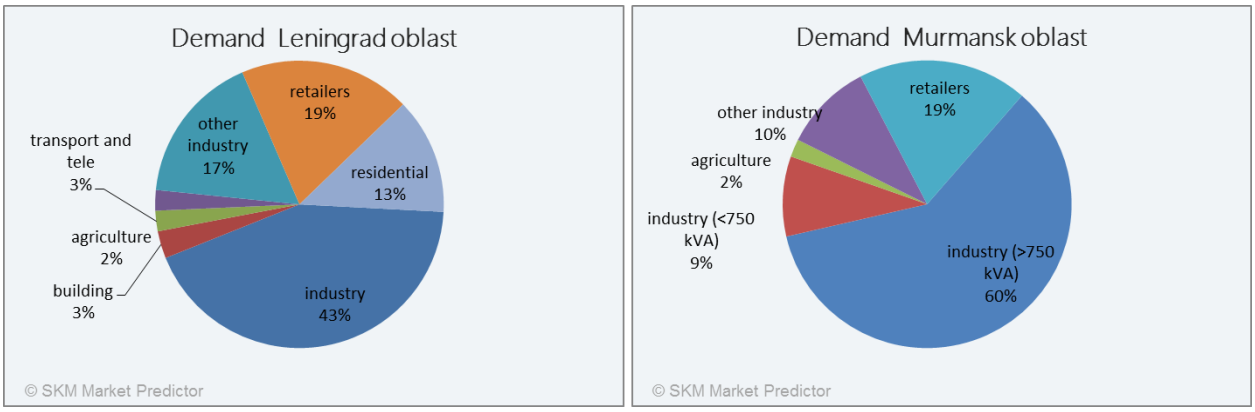


Figure 5: *Power demand by sectors in Leningrad and Murmansk regions, %.*

The decline in the demand was not expected in the planned increase of the generation capacity, which mainly constructed through the capacity market mechanism, where Russian System Operator sets the level

of expected peak demand to settle the market price. Similar situation in the next years will lead to the increase of the available capacity reserve in the system, particularly during 2015 and 2016.

The average age of thermal power stations in Russia is 30 years, hydro power stations 35 years and nuclear 24 years. The major part of the thermal generation is from the Soviet Union time with low efficiency rate around 33-36%. However, the new units are based on the modern technologies and fully comparable with similar ones in Europe.

In the North West Russia some 700 MW new nuclear capacity is expected to be commissioned by 2020. The two first units of both Leningrad-1 and Kolskaya nuclear power plants are expected to be decommissioned and replaced by three first units of Leningrad-2 nuclear power plant. According to the official plans, these are expected to be commissioned between 2015 and 2019, but it seems that all of these units will be delayed. We have assumed them online 2 years after the official timetable (Leningrad2 unit 1 in 2017, Leningrad2 unit 2 in 2019 and Leningrad2 unit 3 in 2021).

There are additional plans to construct the forth unit of Leningrad 2 nuclear plant of 1 170 MW, but no decision has been taken yet. However, North West Russia can be considered as an oversupply area with 30% higher available capacity than the capacity needed to meet forecasted peak demand. Part of the excess capacity (around 17%) is due to reliability considerations.

Slow growth of demand and increase of new generation leads to the situation where capacity reserves in the Russian system are expected to continue increasing until 2018.

3.1.2. Nordic and Baltics

Power demand in Finland has been decreasing during the last years. The annual power consumption decreased to 83.1 TWh in 2014. We expect that Finnish power consumption will pick up in 2015 and grow moderately during the period considered.

In the Baltic countries the demand for electricity was 24.7 TWh in 2014, peak consumption being close to 4 500 MW. Consumption is divided equally between the countries with Lithuanian consumption being at a bit higher level than the other Baltic countries. We expect that the Baltic consumption of electricity will increase moderately in line with the GDP growth by the end of the period considered. Expected power demand in Finland and in the Baltic countries is presented in Table 1.

Table 1: *Power demand Finland and the Baltic countries, GWh.*

	2015	2016	2017	2018	2019	2020	2021
Finland	85.7	86.7	87.2	88.0	88.6	89.4	90.3
Estonia	8.3	8.3	8.4	8.4	8.5	8.5	8.6
Latvia	7.7	7.7	7.8	7.8	7.8	7.8	7.9
Lithuania	11.4	11.6	11.6	11.6	11.7	11.8	11.9

Commissioning of the 5th Finnish nuclear unit, Olkiluoto3, will increase Finnish nuclear capacity from current 2 750 MW to 4 350 MW. The unit is currently running well behind the schedule and we assume that the power plant will become online at the second half of 2018.

Aging and tightening of technical requirements due to the Industrial Emission directive is expected to result in significant decommissioning of fossil-fuelled condensing power capacity in Nordics. This has been taken into account in the simulation.

The Baltic power production system is going through a phase of significant changes. Massive production overcapacity, the heritage from the Soviet era, has been erased due to decommissioning of both Ignalina nuclear units and various old and inefficient condensing units. In addition, the changes in the neighbouring regions, especially in Russia, will increasingly influence the Baltic power market in the coming years. On one hand, this is caused by the strong transmission capacity between the regions and, on the other hand, by a large share of the Baltic production capacity being dependent on Russian natural gas. In addition, the Baltic power market is shaped by the gradual deregulation of the power market and the introduction of power exchanges.

The current total generation capacity in the Baltic countries is approximately 9.5 GW and in 2013 the annual net production was 20.0 TWh. After the closure of Ignalina nuclear power plant, thermal production has contributed to some 50 percent of the Baltic production of electricity. Main fuels for thermal production have been oil shale and gas. In addition to thermal production, hydropower plays an important role in the Baltic energy balance, contributing with 20 percent of the total power generation in the region.

Estonia has abundant oil shale reserves and it has been a natural choice for fuelling the region's power production. Over 90 percent of the country's power generation originates from oil shale fuelled generation units, mainly two power plants (Eesti and Balti) having originally the production capacity of about 2 400 MW. The Narva power plants were constructed during the 1960's and 1970's and some units have already been taken out of active use. In addition to oil shale fired capacity, there are two natural gas fired CHP units in Estonia with the overall capacity of 190 MW. Including the closures due to the IE directive, we estimate that the active production capacity would drop down to 1 100 MW by 2016. Thus, the total capacity will be cut by more than 50 per cent in comparison with the original level. To cover some of the lost capacity Eesti Energia is constructing a new oil shale fuelled power plant (Eesti 9) with the capacity of 300 MW. The

company is also considering another unit with the same capacity. The first unit is expected to be in use by 2015 and the second unit is abandoned according to the information from Eesti Energia.

3.2. Transmission capacities

The transmission capacity between Russia and Finland totals to 1 400 MW. Fingrid has reserved 100 MW of this for system reserve, commercial capacity being thus 1 300 MW. From the December 2014 exports from Finland have been possible with the capacity of 320 MW, until that only imports from Russia to Finland have been possible.

Transmission capacity between Finland and Estonia consists of Estlink 1 and Estlink 2 interconnectors, with the total capacity of 1 000 MW. Currently, there is no commercial power exchange between Estonia and Russia. The power exchange between the countries is based on co-operation under the BRELL association between the Baltic countries, Belarus and Russia. The transmission capacity from Russia to Estonia is 950 MW and from Estonia to Russia is 800 MW.

By the end of 2015, the Baltic power system will also be connected to the Nordic countries through the NordBalt-interconnector between Sweden and Lithuania. Swedish Svenska Kraftnät and Lithuanian LitGrid are building a 700 MW submarine power cable between Klaipeda in Lithuania and Nybro in Sweden.

The Baltic power system is also expected to be connected to Continental Europe with the LitPol interconnector between Lithuania and Poland. The interconnector has a total capacity of 1000 MW and it will be constructed in two phases, which are assumed to be completed at the end of 2015 and 2020. These, as well as other assumptions regarding the development of external transmission capacities are presented in Table 2.

Table 2: *Interconnector Capacity Outlook.*

NordBalt (SwedLit)	**2016**	NordBalt is a power link between Nybro in Sweden and Klaipeda in Lithuania. Work at Nybro station was commenced in February 2013. The interconnection will have a capacity of 700 MW in both directions and will be based on a new VSC-technology. We have assumed that the cable will be operational from the beginning of 2016.
EE-LV	**2020**	In 2020 the capacity between Estonia and Latvia is assumed to increase from 750 to 1 200 MW.
NO4-RU	**2017, 2020**	We have assumed NO4-RU capacity to be upgraded to 100 MW (two ways) by 2017 and to 250 MW by 2020.
LitPol	**2015, 2020**	The power systems of the Baltic States and Continental Europe are assumed to be linked with the LitPol interconnector between Lithuania and Poland. The interconnector has a total capacity of 1 000 MW and it will be constructed in two phases that are assumed to be completed in 2015 and 2020. This interconnector requires a series of internal reinforcements to the Polish grid that are now implemented.

3.3. Power exchange between Finland and Russia

Until 2011, the annual power exports from Russia to Finland were around 11 TWh. However, in 2012 good Nordic hydrological balance decreased the spread between Finnish and Russian spot prices to the level at which previously introduced capacity prices started to affect the optimization of power export. This led to considerable reductions in exports. This is shown in Figure 6.

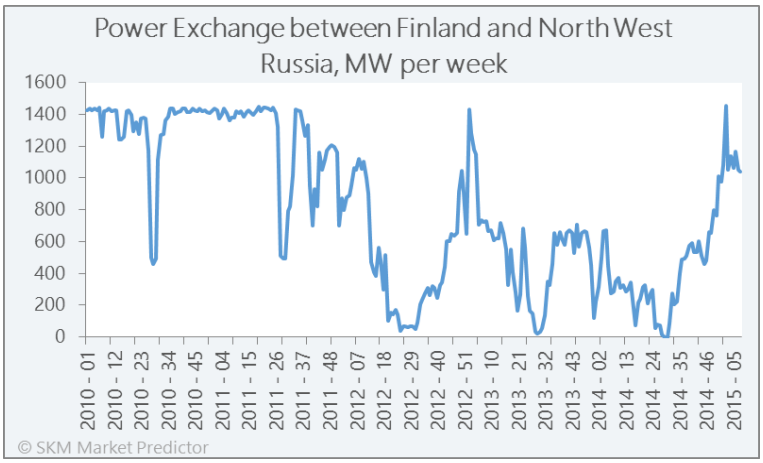


Figure 6: *Power exchange between Finland and Russia, MW per week.*

Russian exporter also started optimizing the flow due to increased cost of capacity in Russia. The highest periods of the highest flows from Russia were determined by the lowest Russian cost and not necessary by the highest Finnish price. The capacity payments were imposed during peak hours that reduced flow to Finland during that time. The impact of the capacity prices has already been very visible for the flow from Russia to Finland that has been significantly reduced during the last years, especially in the peak hours.

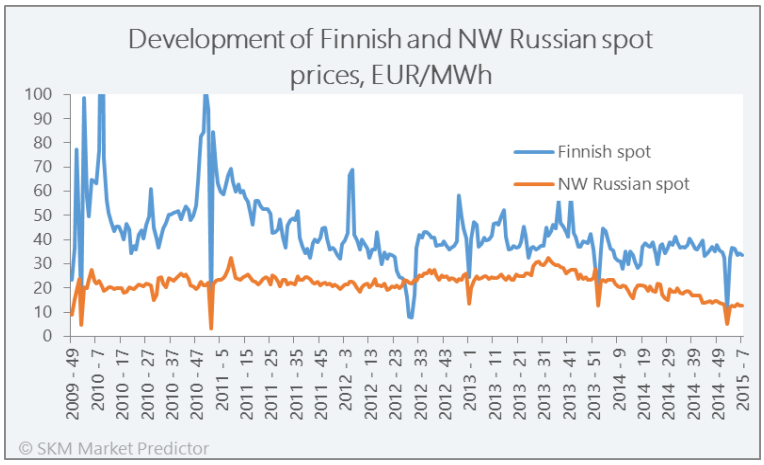


Figure 7: *Development of Finnish and NW Russia spot prices, EUR/MWh (with actual exchange rate).*

Due to the strong hydrological balance in the Nordic region in 2012, 12 per cent of the hourly prices (excluding capacity tariff) during the year were higher in Russia than in Finland. On the other hand, in 2013, there were some 90 hours when the price spread between Finland and Russia was above 50 EUR/MWh, but the available capacity was not utilized. This is illustrated in Figure 7.

Mainly due to the lower Nordic price level the spread between the Finnish and North West Russian spot prices has remained well below previous levels. In 2009 and 2010, the annual average price spread was 32 – 36 EUR/MWh, compared to 14 – 17 EUR/MWh in 2013 and 2014. A slight increase of spread after mid 2014 is due to the recent weakening of exchange rate between rouble and euro.

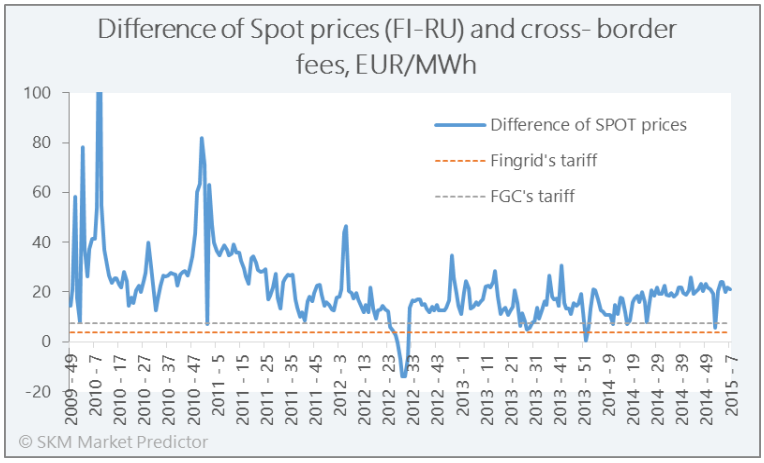


Figure 8: *Difference of spot prices and level of cross-border fees, EUR/MWh*[4].

Low price spread further reduces incentive for power exchange, after cross-border fees have been taken into account. Cross-border fees of Fingrid and Federal Grid Company total up to some 7 EUR/MWh (FGC's tariff has been set on top of Fingrid's), as shown in Figure 8.

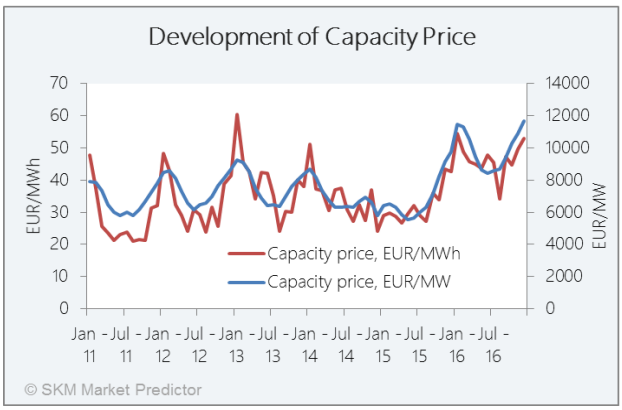
The capacity payments are imposed during the peak hours. Thus, the larger price spread between Finland and Russia did not necessary led to higher flows, due to the impact of capacity tariff during the peak hours since exporter is treated as a normal power consumer under the Russian legislation.

[4] Both cross-border fees have been changed several times, cross-border fees in the figure equal current ones.

Although the capacity payment has to be paid in peak hours in working days, increase of capacity cost in addition to decreased overall spread between spot prices has reduced power exports substantially, as seen in Figure 6.

The capacity cost for consumers and power exporters is defined per consumed MW and varies on a monthly level, being at the highest level during winter months. The capacity cost for consumers is shown in Figure 10. A power exporter as well as any consumer has to pay the daily capacity cost according to peak consumption during the peak hours of the day. The actual capacity cost is defined at the end of the month, by multiplying average peak demand of the capacity days over the month by the monthly capacity cost. Thus, for power exporter the capacity cost during one day is equal whether he would export 1 MW during one hour or 1 MW during all the capacity hours. When assessing the capacity cost per MWh this has to be taken into account. In the figure below, the capacity cost per MWh has been defined by dividing monthly capacity cost by monthly capacity hours.

The annual capacity price have been steadily increasing since 2011, measured in roubles. The monthly prices are the effect of the seasonal profile applied by Russian SO. The exchange rate between rouble and euro was stable until mid-2013, and increased to 75 RUB/EUR in January 2015 leading to a significant depreciation of Russian capacity price in terms of EUR. In 2016, the capacity cost is expected to increase due to both expected strengthening of exchange rate between rouble and euro as well as due to projected increase of rouble nominated capacity price, due to the increase of production capacity in the agreement. We have expected that the exchange rate between Rouble and Euro will strengthen to the level of 50 RUB/EUR by early 2016, as you can see from the right-hand graph in Figure 9.



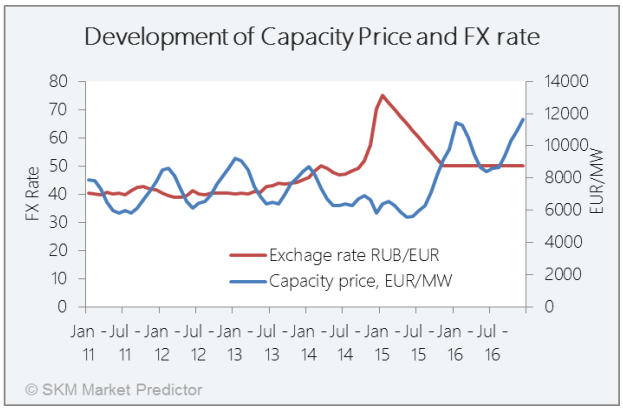


Figure 9: *Capacity cost for consumer, EUR/MW and EUR/MWh and effect of currency exchange rate.*

3.4. Current transmission fees

The total of the current cross-border transmission cost on the Finnish side consists of four different elements. The capacity reservation fee is fixed and paid for each MW reserved for possible exchange. The other components are based on energy exchanged and make up the main part of the total fee. ITC fee is based on the EU regulation and applies for electricity trade between the EU internal electricity market and the third countries. Regarding ITC fee, we have assumed the proposed fee level for 2015 that is marginally lower than the current fee level. The same fees apply for both imports to Finland and exports from Finland.

Table 3: *Finnish cross-border transmission service fees, EUR/MW and EUR/MWh.*

FINGRID	
Tariff structure	**Export and import**
Capacity reservation fee	102 EUR/MW per month
Cross-border fee	0.36 EUR/MWh
Main grid service fee	2.20 EUR/MWh
ITC/perimeter fee	0.60 EUR/MWh*

*to be decided in March 2015

The total transmission fee structure for electricity exchange operation on the Russian side is more complex compared to the Finnish one. The total transmission fees consist of several different elements that are charged by different entities. The fee structure is applied to all grid transmission operations including operation of the Vyborg link. The tariffs are changed on a quarterly basis and available in the public domain. The reported numbers for the fourth quarter of 2014 are presented in Table 4 and have been used for estimation of tariffs during the simulation period.

We have used exchange rate of 50 RUB/EUR for converting roubles to euros.

Table 4: *North West Russian cross border transmission fees, RUB/MWh, EUR/MWh (with exchange rate 50 RUB/EUR).*

FEDERAL GRID COMPANY				
Tariff structure		**Export**	**Import**	
Tariff ATS(Power exchange)	0.00011	RUB/KWh	0.00011	RUB/KWh
Tariff SFR (Clearing center)	0.00003	RUB/KWh	0.00003	RUB/KWh
Tariff TSO (System operator)	0.00153	RUB/KWh	9.0	RUB/KW/month
Tariff FSK (Grid owner)	135.0	RUB/KW/month		RUB/KW/month
Tariff structure		**Export**	**Import**	
Tariff ATS(Power exchange)	0.0022	EUR/MWh	0.0022	EUR/MWh
Tariff SFR (Clearing center)	0.0006	EUR/MWh	0.0006	EUR/MWh
Tariff TSO (System operator)	0.0306	EUR/MWh	180.2	
Tariff FSK (grid owner)	2699.3	EUR/MW/month		
Total fees EURO/MWh	**3.7**		**0.25**	

It is important to notice that the current tariff structure is different for export and import operations. The Russian System operator is having commodity-based fee for export operation while fixed capacity fees are applied for the import operation. As we know, no fees have been introduced from FSK for the import operation so far, that means that FSK tariffs will not be charged for the possible imports from Finland to Russia.

3.5. Capacity market

3.5.1. Current structure of capacity market

The distinct issue of the Russian electricity market is its dual nature with functioning power and capacity market. The share of the capacity payments in the final electricity bill excluding grid transmissions constitutes up to 40-60%.

The main reasons for the introduction of the capacity market are the following:

- Stimulation of demand reduction during the peak load
- Financial guarantee for the payback of the long-term investment in the construction of the new capacity
- Reduction of electricity prices volatility
- Additional payments for the old capacity to cover fixed costs and have capacity in reserve

Historically, the capacity payment (the ability of generators to have capacity in the reserve) was introduced in the nineties, to support the generators during the strong decline of the demand during the structural crisis in Russia. The main reason was to compensate existing generation for their fixed costs and still have them in the reserve.

During the liberalization of the Russian power market, the capacity market remained and got additional functions such as payment for the investment in new generation.

The assumption of the strong demand development in Russia and a large amount of the old capacity needed to be decommissioned implied construction of significant volumes of new efficient capacity. In 2010, the Russian government signed the agreements with generation companies to guarantee the construction of new capacities. These agreements called Capacity Delivery Agreements (CDA) for thermal generation and Long-Term Agreements (LTA) for nuclear and hydro capacities guaranteed Russian and foreign investors' reimbursement of a major share of their investment during next 15-20 years according to regulated rates. Adding CDA and LTA to the Competitive Capacity Auction mechanism further complicated it as price of those agreements has direct impact on the final capacity price settlement.

According to the conditions of these agreements, the generators have obligations to commission the new capacity at the certain date and location otherwise daily fees will be imposed. The fixed capacity price of the CDA is settled by the government to guarantee return of investment during the next fifteen years. For the nuclear and hydro generation the price of LTA is calculated for twenty years based on the thirty years payback.

Until recently, FTS has been calculating capacity tariffs taking into account the age and technology of generating units in the Free Flow Zones (FFZ). The liberalized capacity market was launched in 2010, where consumers were obliged to buy capacity that corresponds to the expected maximum load during the next year. Competitive capacity auctions for 2011-2014 were fully liberalized from the organizational point of view. Nevertheless, the Federal Antimonopoly Service decided that in 27 of the 29 FFZs[5] the competition level was not satisfactory enough and price-caps calculated by the FTS were introduced. Price-caps are calculated based on basic assumptions about technological and economical description of the system to optimize the recovery of the financial costs of building a new or maintaining an old power plant. Long-term projects qualified by the Ministry of Energy can be guaranteed a certain capacity price in order to stimulate investments.

Thus, the total income for the production of electricity of the Russian generators consists of following parts:

- Fixed costs for having the capacity where generator receives monthly payments for each MW of the available capacity during this month. The investment in the new generation is paid in the same way through the LTA capacity contracts for the nuclear and hydro generation and Capacity Delivery Agreement (CDA Agreements) for the thermal generation
- Variable cost (cost of fuel) is paid through the day ahead market (based on each MWh produced)

The principles of the long-term capacity market are regulated by two government decrees N89 from 24th of February 2010, and N238 from 13th of April 2010.

The total capacity demand is calculated by estimating peak demand for each consumer on a monthly level for the following year. The information is provided by Regional Energy Commissions (RECs) and aggregated by SO based on the notification from the customers on the new grid connections, peak demand and estimations for those customers that cannot plan their consumption. The sum of all peak demand for the FFZ is calculated and represents the demand side of the capacity market that is further used in the Competitive Capacity Auction mechanism to select the generation required to cover this demand.

Competitive capacity price in the Russian market is settled by the market clearing mechanism (CCM) through the annual auction of the capacity by the generators and planned demand for the capacity. The demand is estimated by SO based on the information from consumers. The actual capacity payments are based on the actual peak demand for the consumers and recalculated on a monthly basis during the following year. In reality, the capacity market is the payment from consumers to generators for the ability

[5]At that time there were 29 FFZ in Russia

to provide capacity for peak demand taking into consideration N-1 condition in the grid. In other words, capacity payments are the payments to the generators to have available peak capacity.

The supply curve in the Competitive Capacity Auction consists of two main categories. The price of the new capacity, launched after 2007 is covered by the CDA and LTA agreements. Those prices are regulated by separate agreements and are known before the auctions. This price is covering both investment and maintenance costs of those market participants. The generators built before 2007 only cover their maintenance costs, and have to provide their bids in the auction. The capacity settlement price is then calculated by the SO based on the lowest bids for each particular FFZ, demand for the capacities and transmission capacity between FFZ.

Therefore, the final bill for the consumers consists of the capacity and electricity payments.

- Capacity payment is based on the average of maximum consumption during peak hours of working days in a month (in MW). The capacity hours for each month are set by the Russian SO.
- The payment for the electricity is based on the electricity purchased according to the prices in the Day Ahead market (in MWh).

The capacity prices paid by the demand side reflect the total costs of capacity. The monthly capacity compensations for the generators under the CDAs and LTAs are collected from all electricity users in the whole market.

It is important to understand that generators receive payments for available capacity, while consumers pay for the actual peak demand and reserve. For balancing, the monthly financial balance is recalculated for each FFZ zone where data on actual peak consumption of capacity buyers during specific peak hours exists. Actual monthly capacity demand is defined as the average of daily peak demands over a month. The daily peak demand is the highest observed consumption during specific peak hours of the day defined by SO. The monthly capacity payment is obtained by multiplying the average peak demand (MW) by the monthly capacity price (RUB/MW), where Russian SO has included a reservation coefficient increasing the final price for the consumers.

Taking into consideration that export from Russia, according to the current regulations, is treated as demand, the factor of the capacity payments during peak hours need to be taken into the calculation of the total price of the electricity exported from Russia. InterRAO being a monopoly exporter participates in the annual Competitive Capacity Auction and provides notification about planned export capacity on a monthly level for next year two months ahead of the auction. The actual capacity payment is then determined during the year as the average of the daily peak exports over a month. The highest exports volume during the specific peak hours of the day then represents the daily peak export.

Due to general volatility of the Nordic market and low expected exports from Finland during the first years, it is natural to expect that no additional regulations will be created. This means that the Finnish exports to Russia will not be able to receive the additional payments from the capacity market. Kazakhstan is the only

country Russia is importing electricity from based on the OTC contracts and according to our knowledge no capacity payments are allocated from the export operations[6].

3.5.2. Expected price development

During the Competitive Capacity Auction for 2015, 15 GW of capacity are supposed to be phased-out of the market that indicates the current capacity oversupply in the Russian system. However, at the later stage 12 GW of this generation received status of the "forced generation" that brought it back to the market. The approval of the status for the "forced generation" is granted to each power unit separately. Mainly CHP units have received this status.

Oversupply of inefficient and expensive capacity is expected to increase up to 25 GW in 2016, according to official forecasts. There is still no decision taken whether the "forced generation" will be handled in a similar manner, as in this year's capacity allocation auctions. The Russian government is currently investigating the issue and results are expected during April 2015. Some kind of temporary solution for the "forced generation" can be expected and not the total amount of 25 GW will be excluded from the market.

The development of the capacity prices in the future depends on a number of issues. On one hand, Competitive Capacity Auctions have decreased capacity payments during the last years due to competition between the generators. On the other hand, the final capacity payments are supported by the necessity to pay under the LTA and CDM agreements and permission to allow "forced generation" to remain in the market. The situation with "forced generation" might change from next year; however, some type of consensus solution will be mostly introduced as well. It seems that the final price for the capacity payments in the coming years will not change significantly unless structural changes are introduced to the market model.

3.5.3. Future outlook

The current dual structure of the Russian power market possesses significant challenges. While observed demand decline in Russia directly lowers power prices, the investment in the new capacity through LTA and CDM mechanism is regulated and needs to be fulfilled leading to increased capacity prices for end-users.

The signed capacity agreements were based on significantly higher expectations of demand development, leading to excess capacity in the market. The Russian government is attempting to partly regulate this unbalance through the annual Competitive Capacity Auctioning mechanism, phasing out inefficient thermal generation. However, the problem, as seen through the results of the CCA for 2015, with the major part of

[6] This can be explained by the fact that the power from Siberia goes through Kazakhstan to reach the European part of Russia. Thus, by charging capacity payment from Siberian "exporters" one has to cover the capacity costs on the European part of the transit link through Kazakhstan.

the inefficient generation returning to the market as "forced generation" is remaining. This excess of the capacity caused by the "forced generation" is contributing to significant cost for end users. In addition, the cost of the new capacity is also passed over to consumers, who are obliged to pay through the capacity market.

The existing model of the capacity market is under constant critics both from generators and consumers, especially the industry. One of the main issues is a too strong interference from the government into the mechanism, which originally supposed to be fully market-based. This was clearly visible after the Capacity Auctions where the government abandoned 15 GW of the inefficient generation, but later was forced to give 12 GW status of the "forced generation" leading to the situation where those remained in the market. The excess capacity will remain in the market in the coming years that will continue to give higher capacity prices and lifting the prices for the final consumers.

Other issues with capacity market are linked to the retail and financial market establishment. The capacity market constitutes a significant part of the final energy bill for the consumers and in the current model, consumers do not have any possibility to hedge the volatility of power prices due to linkage with capacity prices. Establishment of the financial market for the electricity is also an issue due to complex nodal pricing and interference of the capacity mechanism into the final energy prices.

During the 2013-2014, the amendment of the market structure has been actively discussed in Russia. Tree alternative models for the current capacity market have been introduced.

1. "CDA touch". The model assumes the introduction of new CDA for building generation, where price for the capacity delivery agreements was regulated by the government and guarantees investors return on the investments similar to the current CDA structure. The model was strongly supported by the major generators since the final costs and risk would be transferred to energy consumers.

2. "Long-Term Capacity Auctions". In this model the capacity auctions and payment for the capacity are supposed to be done through the market clearing mechanism, and the price for the capacity payments to be fixed for the next four years. This should guarantee investors a certain income during the first years of power plant operation.

3. "Udaltsov model". This model introduced a more market-based capacity allocation mechanism. While the main structure with power and capacity market supposed to remain, the price for the capacity was planned to be set by the OTC capacity agreements to be traded in the free market. In this model, the consumers supposed to cover the capacity needs through purchasing monthly capacity contracts for base and peak load on the exchange from generators. The payment for the capacity for consumer will be based on the real peak demand for this consumer and generators will compete offering the capacity contracts.

Based on the public discussions in the media and indication from the Russian government, the "Udaltsov model" was assumed to be a consensus between consumers and generators and the introduction of this model was supposed to find place in 2014. However, the process is consistently delayed.

One of the main reasons for the delay is the ongoing introduction of the heat market in Russia. The heat market is supposed to guarantee the thermal generators clarity regarding the payment for the heat produced in the CHP units. The heat market, based on the principles of the "Alternative CHP", is supposed to be introduced in 2015, but the process is also delayed. Another reason for postponing the amendments of the new capacity mechanism is the non-payment problems due to financial crisis across the Russian power sector, which has the main priority of the Government of Russia now.

Looking forward, we do not expect any major amendment of the existing capacity mechanism in the Russian market until 2018 at least because there are several other issues on the agenda for the Russian Energy Ministry that have higher priority. During May 2015, the Russian Ministry of Energy is supposed to provide guidelines for the next capacity auctioning mechanism for 2016. The main changes, which expected to be announced, are how the "forced generation" will be treated as well as potential modification of long-term capacity auction.

4. Dynamic tariff structure

The current fixed tariff structure on both Russian and Finnish side reduces incentives for power exchange during hours when price differences are small. During 2013 and 2014 there were 2 260 hours when the price difference between Finnish and North West Russia was below the sum of cross-border fees on both Finnish and Russian sides (7.2 EUR/MWh). The introduction of the dynamic tariff structure will adjust tariff level according to the price difference, thus enabling more efficient use of transmission capacity and increased power flows. The general structure of dynamic tariff can be presented in a form:

Equation 1:

$$Tariff_{t,\,dynamic} = k * (P_{t,\,Country\,A} - P_{t,\,Country\,B}),$$

where

$$k = income\ coefficient$$
$$P_{t\ Country\,A} = hourly\ spot\ price\ of\ country\ A(t)$$
$$P_{t,\,Country\,B} = hourly\ spot\ price\ of\ country\ B(t)$$

Compared to the fixed tariff structure, dynamic tariff will decrease during hours with small price difference, thus increasing power exchange during these hours. In the case of bigger price difference, dynamic tariff level might be higher than the fixed structure, depending on coefficient *k*. When coefficient *k* is well below 1, the power exchange would be still profitable from the power exporter's point of view during hours of high price difference.

While using dynamic tariff structure, all the costs of power exchange for transmission operators might not be covered during hours of small price differences. Thus, coverage of both variable and fixed costs has to be set as the main criteria when determining coefficient *k*.

For the dynamic tariff structure being efficient, the price difference between the countries should be measured on an hourly level.

For the capacity hour's dynamic tariff should be set separately. The difference of spot prices may be remarkable during peak hours, but the capacity cost must be also covered during these hours. By taking out too high share of price difference during these hours, exchange might be suppressed. Thus, coefficient *k* in tariff equation for capacity hours should be much lower in order to reduce the total cost of exports including capacity and electricity price on the Russian side.

5. Methodology and scenarios

To investigate the effects of a dynamic tariff structure we have simulated 3 different scenarios. Our *Base Case scenario* describes the most likely outcome of the Nordic, Russian and Baltic power markets. In Base Case scenario, we have assumed the current cross-border fees structure.

To find out the effect of a dynamic tariff structure we have simulated 2 different scenarios. The first one, *Study Case 1* scenario, assumes a dynamic tariff structure implemented by Fingrid, and the present fixed tariff structure remaining at Russian Federal Grid Company. In the second dynamic tariff scenario, we have assumed a dynamic tariff structure for both Fingrid and Federal Grid Company. This scenario is called *Study Case 2*. Other than changes in the tariff structure, all both study cases are identical to the base case. In all scenarios, we have assumed that the current situation between Estonia and Russia with no cross-border trade will remain during the period. All these scenarios have been simulated with the exchange rate of 50 RUB/EUR.

The dynamic tariff structure, as it has been defined in this study, is based on the difference of power prices in neighbouring countries. To find out the effect of RUB/EUR rate we have simulated *Base Case scenario* and the first dynamic tariff scenario also with the exchange rate of 75 RUB/EUR. These scenarios are called *Base Case RUB75* and *Study Case 1 RUB75* scenarios respectively.

The scenarios are summarised in Table 5.

Table 5: Different scenarios and expected tariff structure.

	Fingrid	Federal Grid Company
Base Case	Present	Present
Base Case RUB75	Present	Present
Study Case 1	Dynamic	Present
Study Case 1 RUB75	Dynamic	Present
Study Case 2	Dynamic	Dynamic

To identify the effect of a dynamic tariff structure both the scenarios have been implemented without cross-border fees in the first step. In the next step, we have defined the dynamic tariff level needed to cover the costs form the cross-border exchange. Finally, we have compared this tariff level to the simulated price difference between Finland and Russia.

6. Results

6.1. Base Case scenario

Table 6 presents the Finnish power balance in Base Case scenario until 2021. We expect the Finnish power consumption to increase to 89 TWh by 2020. Regarding power production, we have assumed that the Finnish wind power production will reach the 6 TWh target by 2020 and will be the main source of additional capacity before Olkiluoto 3 that is expected to be operational late 2018. The share of power imports until commission of Olkiluoto 3 unit would make up some 20 per cent of demand. After that, the share of imports reduces to half of that. In Base Case scenario we have used an exchange rate of 50 RUB/EUR.

Table 6: *Finnish power balance in Base Case scenario*

FINLAND	2015	2016	2017	2018	2019	2020	2021
Hydro Production	12 867	12 804	12 897	13 000	12 740	12 950	13 000
Nuclear	23 109	22 146	22 470	23 470	35 910	35 910	35 910
Condensing	11 519	10 632	7 113	6 929	4 849	5 066	5 474
CHP	22 299	22 200	22 131	22 101	22 037	22 038	22 044
CHP DH	13 469	13 370	13 301	13 271	13 207	13 208	13 214
CHP Ind	8 830	8 830	8 830	8 830	8 830	8 830	8 830
Wind	1 050	1 560	2 645	3 830	5 015	5 900	6 035
Solar	20	40	55	70	85	100	115
Import (net)	14 872	17 319	19 913	18 634	7 968	7 449	7 692
Sweden	11 023	11 352	12 383	12 448	6 960	7 497	7 566
Norway	186	216	248	315	250	214	247
Russia	4 731	4 572	5 190	4 650	2 082	1 219	951
Estonia	-1 068	1 179	2 092	1 221	-1 323	-1 481	-1 072
Total Consumption	**85 737**	**86 701**	**87 224**	**88 034**	**88 604**	**89 412**	**90 269**

The planned increase of nuclear and hydro capacity dominates the picture for the North West Russian power balance. Expected commissions of units 1 and 2 of Leningrad 2 nuclear power plant will considerably increase nuclear power production during the period. However, the planned decommissions of two oldest units of Leningrad 1 nuclear power plant and expected decrease of usage hours of two other Leningrad 1 units will somewhat balance the effect of new capacity by early 2020's. Increase of hydropower is based on Russian plans to construct new 1 540 MW hydro pump storage in North West Russian region.

Table 7: *North West Russian power balance in Base scenario*

NW RUSSIA (FFZ27)	2015	2016	2017	2018	2019	2020	2021
Nuclear	28 761	29 581	36 961	36 960	31 152	31 150	27 343
Gas	40 159	36 376	32 190	28 038	32 089	31 522	33 227
Coal	1 267	1 286	1 230	1 336	1 510	1 608	1 717
Hydro	6 065	9 048	9 100	12 066	12 111	12 127	12 135
Other	341	482	618	762	903	1 044	1 184
Import	-3 034	-2 344	-5 179	-3 719	-1 806	-974	1 416
Total Consumption	**73 841**	**74 385**	**74 931**	**75 459**	**76 001**	**76 546**	**77 073**

During the next four years, almost similar weekly profile of exchange between Finland and North West Russia can be observed. The export levels during winter are remaining high, while substantially decreasing during summer. The main reason for this is the difference in weekly profiles between Nordics and Russia with Russia having relatively high prices during summer due to low CHP production and maintenance period while lower consumption and high inflows in Nordics depress the Nordic and Finnish power prices.

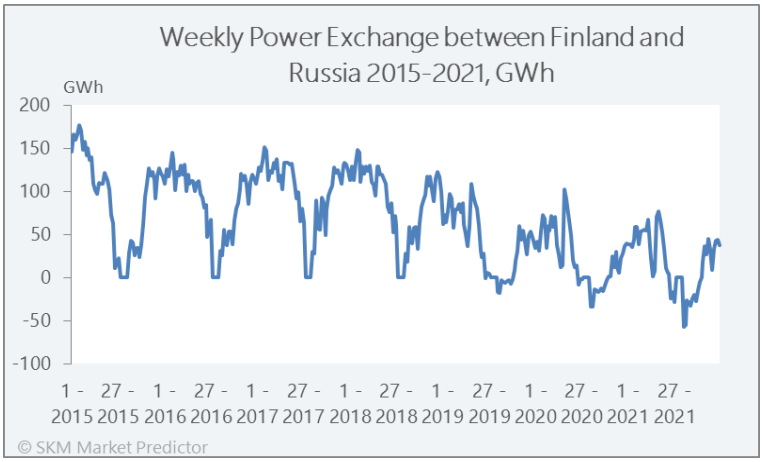


Figure 10: *Weekly power exchange between Finland and North West Russia in Base scenario, GWh.*

Years 2016 and 2019 are of special interest in this study due to expected commissioning of NordBalt interconnector and Olkiluoto3 unit respectively. Nordbalt interconnector between Lithuania and Sweden will strengthen the Lithuanian and Baltic power system remarkably. As well, expected commission of Olkiluoto 3 unit late 2018 will enhance the Finnish power balance considerably decreasing the Finnish spot price.

In 2016, the Finnish power price remains on a weekly level above the North West Russian power price, the average price difference being some 10 EUR/MWh, but after commissioning of Olkiluoto 3 unit the average price difference will decrease by half. During summer weeks, the Finnish power price is expected to decrease below the North West Russian price especially in years of strong hydrological balance. This is shown in Figure 11 and Figure 12.

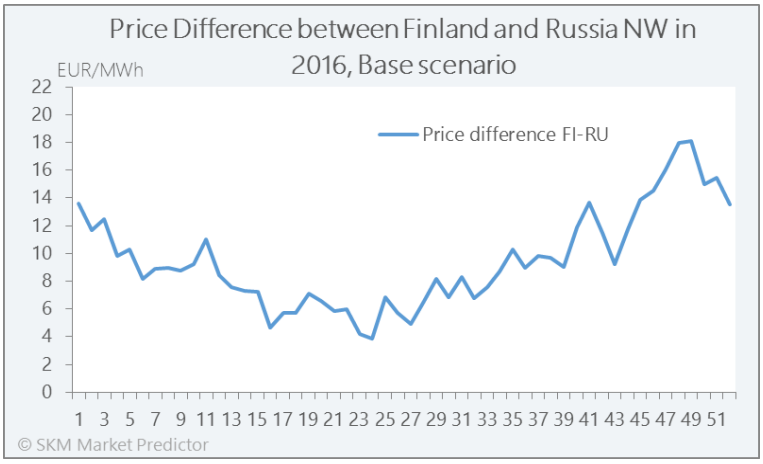


Figure 11: *Weekly price difference between Finnish and North West Russian power prices in 2016, EUR/MWh.*

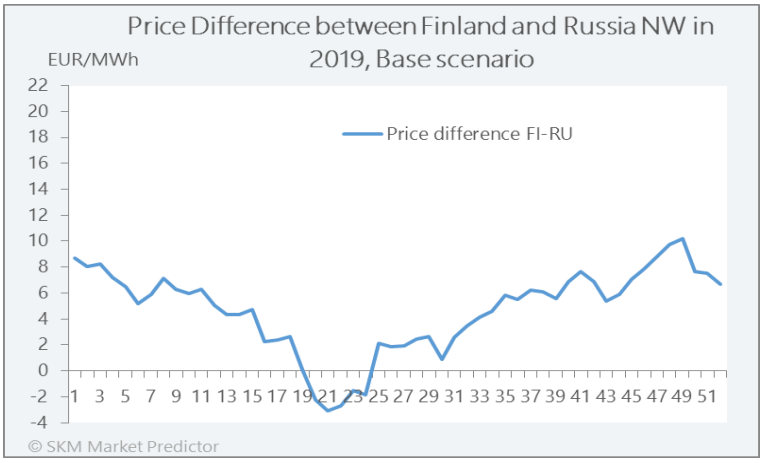


Figure 12: *Weekly price difference between Finnish and North West Russian power prices in 2019, EUR/MWh.*

In the Base RUB75 scenario, in which we assumed exchange rate between rouble and euro being 75, both the North West Russian power price and capacity cost are lower than in Base scenario when euro nominated. Due to this power imports to Finland are in this scenario on essentially higher level than in Base scenario (Table 7).

6.2. Dynamic tariff structure scenarios

The results of the dynamic tariff structure scenarios are summarized in Table 8. Compared to Base Case scenario, the power exchange between Finland and Russia will increase in all the scenarios with the introduction of the dynamic tariff structure. If only Fingrid implements a dynamic tariff structure (Study Case 1), the annual gross power exchange will increase by 0.9 – 1.8 TWh. In Study Case 2, in which also Federal Grid Company is expected to implement a dynamic tariff structure, the power exchange would further grow.

Scenario Study Case 1 RUB75 that assumes RUB/EUR rate of 75 RUB/EUR and only Fingrid having a dynamic tariff structure provides the highest level of gross exchange. In this scenario higher RUB/EUR rate decreases both North West Russian spot price and capacity cost for exports when euro nominated. Thus, the price difference between the Finnish and North West Russian power prices is higher and the capacity cost is lower than in other scenarios.

Table 8: *Exchange in different scenarios, GWh,*

Exchange between Finland and North West Russia, GWh							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Base Case[7]	**4 731**	**4 572**	**5 190**	**4 650**	**2 082**	**1 219**	**951**
import to Finland	4 731	4 572	5 190	4 650	2 150	1 399	1 315
export from Finland	0	0	0	0	68	179	364
Base RUB75	**6 820**	**7 120**	**7 267**	**6 989**	**5 864**	**5 241**	**4 659**
import to Finland	6 820	7 120	7 267	6 989	5 866	5 247	4 669
export from Finland	0	0	0	0	2	6	10
Study Case 1[8]	**5 634**	**5 979**	**6 519**	**6 378**	**3 864**	**2 445**	**1 732**
import to Finland	5 634	5 979	6 519	6 378	3 931	2 812	2 469
export from Finland	0	0	0	0	67	367	737
Study Case 1 RUB75	**7 082**	**7 545**	**7 581**	**7 247**	**6 470**	**6 043**	**5 683**
import to Finland	7 082	7 545	7 581	7 247	6 470	6 054	5 707
export from Finland	0	0	0	0	0	11	24
Study Case 2[9]	**6 333**	**6 895**	**7 045**	**6 948**	**5 412**	**3 851**	**2 513**
import to Finland	6 333	6 895	7 045	6 948	5 412	4 006	3 141
export from Finland	0	0	0	0	0	155	628

[7,8,9] In the Base Case, Study Case 1 and Study Case 2 scenarios we have assumed exchange rate of 50 RUB/EUR

7. Proposal for the dynamic tariff structure

In this chapter we present our proposal for the dynamic tariff structure. We propose separate dynamic tariff structures for non-capacity hours and for capacity hours. For non-capacity hours, we propose a tariff structure, in which the difference between the Finnish and North West Russian spot prices is multiplied by a dynamic tariff coefficient. Thus the tariff is calculated on hourly level unit of it being EUR/MWh. This is shown in equation 2.

Equation 2:

$$Tariff_{dynnoncaphour} = k_{noncap} * abs(P_{fi,\ noncaphour} - (P_{ru,\ noncaphour} * ExcRate))$$

where

k_{noncap} = dynamic tariff coeffient for non-capacity hours
$P_{fi,\ noncaphour}$ = Finnish spot price, EUR/MWh
$P_{ru,\ noncaphour}$ = Free Flow Zone 27 region spot price, RUB/MWh[10]
$ExcRate$ = Daily exchange rate between euro and rouble[11]

To cover the ITC payment the minimum level for the tariff should set to the level of 0.6 EUR/MWh. Respectively, if the spread between the power prices would be negative during hours of exports it should be considered whether only the ITC payment should be charged.

The Russian spot price is defined here as the Free Flow Zone 27 spot price during non-capacity hors.

However, the use of the same tariff structure would decrease exchange flow incentives for the periods with capacity prices, because of the average price difference being higher during the capacity hours than during non-capacity hours.

Daily capacity cost for power export is calculated based on peak export of the day. In theory, for maximizing income a power exporter should export with maximum capacity during all capacity hours of the day, if the cumulative sum of spot price differences during the capacity hours was higher than capacity cost for exports. However, in practice this has not been the case during the last years. Power exchange during the first couple of capacity hours of the day has been on a higher level than during the afternoon hours. However, we base our assumption on the theoretical model of optimization. Since the capacity price is charged according to

[10] https://www.atsenergo.ru/nreport?rname=trade_zsp
[11] https://www.ecb.europa.eu/stats/exchange/eurofxref/html/index.en.html

the average daily peak exports, we propose a tariff structure for capacity hours, which is calculated on a monthly level.

Tariff equation during the hours of power exports from Russia to Finland can be presented as follows:

Equation 3:

$$Tariff_{dyncaphour} = k_{cap} * \sum_{t}^{caphours} abs\left(flow(t) * \left(p_{t,fi} - p_{t,ru} * ExcRate\right) - \left(P_{dailypeak} * \frac{p_{cap,year}}{h_{cap}} * MDCap * ExcRate\right)\right)$$

where

k_{cap} = Dynamic tariff coeffient for capacity hours
$P_{t,fi}$ = Finnish spot price, EUR/MWh
$P_{t,ru}$ = Free Flow Zone 27 region spot power price RUB/MWh[12]
$P_{cap,year}$ = Annual capacity cost in Free Flow Zone 27, RUB/MW[13]
$P_{dailypeak}$ = Expected daily peak export volumes
h_{cap} = Monthly number of capacity hours in Free Flow Zone 27[14]
$caphours$ = All the planned peak hours during the month
$ExcRate$ = Exchange rate between euro and rouble[15]
$MDCap$ =Monthly distribution of annual capacity price, index[16]

Since capacity payment does not affect the costs of power exports from Finland to Russia, the variables $P_{dailypeak}$, $P_{cap,year}$, h_{cap} and MDCap should equal zero for hours of power flows from Finland to Russia during the capacity hours.

Variable $P_{t,ru}$ is defined here as the hourly spot price for Free Flow Zone 27 during capacity hours. Variable $P_{t,fi}$ is the Finnish price during respective hours. Monthly capacity cost, $P_{cap,year}$ is the capacity cost for Free Flow Zone 27 published in December each year. The real capacity cost is calculated afterwards, but the

[12] https://www.atsenergo.ru/nreport?rname=trade_zsp
[13] https://www.atsenergo.ru/results/statistic/fcast/fcorem/index.htm
[14] http://so-ups.ru/index.php?id=newonsite_view&tx_ttnews[tt_news]=6572
[15] https://www.ecb.europa.eu/stats/exchange/eurofxref/html/index.en.html
[16] https://www.atsenergo.ru/nreport?access=public&region=eur&rname=season_koeff&rdate=20150116

estimate given by the Russia ATS is a good approximation of the final price. Variable h_{cap} is the number of capacity hours in each month and is published by Russian System Operator.

Due to additional capacity cost we propose a lower *k* coefficient to be applied during capacity hours when power flows from North West Russia to Finland. If power flow during capacity hours is towards NorthWest Russia the same value for k coefficient can be applied as for non-capacity hours. However, we propose to apply a constant tariff level if the term in the brackets $\left(\left(p_{t,fi} - p_{t,ru*} * ExcRate\right) - k(P_{dailypeak(t)} * \frac{p_{cap}}{h_{cap}} * MDCap * ExcRate\,)\right)$ for a given peak hour, or if the term $\left(p_{t,fi} - p_{t,ru*} * ExcRate\right)$ for a given non-peak hour has a negative value. This constant tariff level could equal to the variable cost of cross-border exchange or to ITC payment.

8. Welfare analysis

In this section, we assess welfare effects of the introduction of a dynamic cross-border tariff structure. We assess welfare effects as a total social economic welfare, which includes producer and consumer surpluses as well as capacity income and other minor welfare componets. We assess welfare effects separately for Finland and for North West Russia. Our analysis is based on the EMPS model and its functionality to provide welfare analysis for different outcomes of power markets and we calculate welfare effects for the whole period covering years 2015-2021.

At the first step we calculate social economic welfare in Base Case scenario. Base Case scenario represents the most likely outcome of Finnish and Russian power markets with fixed cross-border tariff structure. After that, we define social welfare in the dynamic tariff structure scenarios Study Case 1 and Study Case 2. At the third step we compare social welfare of the Study Case 1 and Study Case 2 scenarios to the Base Case scenario.

Results of the welfare analysis are presented in table 9.

Table 9: Main welfare components in different scenarios during the simulation period, MEUR.

	Total Social Economic Welfare	
	Finland	**North West Russia**
Change compared to Base Case scenario		
Study Case 1	47	27
Study Case 2	84	44

The use of a dynamic tariff structure would increase the welfare both on the Finnish and North West Russian markets. In the case that only Fingrid would apply dynamic tariff structure, the total social welfare in Finland would grow by 47 MEUR and in North West Russia by 27 MEUR during 2015 and 2021.

If also Federal Grid Company would alpply dynamic structure, welfare benefits would grow further. In this case Finnish social economic welfare would grow by 84 MEUR where as in North West Russia growth of welfare would be 44 MEUR during 2015-2021.

9. Conclusions

This report investigates the effects of a dynamic tariff structure between the Finnish and Russian power markets. A dynamic tariff structure, as defined in this study, adjusts absolute tariff level according to price difference between these two markets. The dynamic tariff structure would increase incentive for power exchange especially during the periods of low price differences.

For this study, we have simulated Base scenario and four different dynamic tariff scenarios. According to the results, the dynamic tariff structure would increase the power exchange in all the simulated scenarios until the end of 2021 when compared to Base Case scenario. However, due to expected decrease of spread between the Finnish and North West Russian power prices, the incentive for the power exchange will be essentially reduced from the beginning of 2019. Consequently, due to the change of the general market situation, covering of costs from the cross-border exchange will face difficulties after 2018. Anyway, the dynamic tariff structure would increase trade even in these circumstances compared to the current fixed tariff structure.

Both Finnish and North West Russian markets would face welfare benefits if the dynamic tariff structure were introduced. In case the dynamic tariff structure were applied on both sides of the border, the net annual welfare benefits would be some 84 million Euro's for the Finnish market and some 44 million Euro's for North West Russian market by 2021.

In theory, maximization of income from power exchange during capacity and non-capacity hours differs due to capacity cost. Thus, we propose that separate dynamic tariff structures should be used for non-capacity and capacity hours. However, only Russian power exporter faces the capacity cost. Our proposal takes this into account.

Our proposal for the dynamic tariff structure is presented in chapter 7.

10. Uncertainties

We have assumed somewhat lower power demand for both Finland and Russia than is expected in the latest official demand projections in both countries. However, due to the current instability of economic outlook, the power demand in the period considered might be lower in both countries. That might lead to smaller change of the pattern of power exchange between the countries.

Fuel prices are another source of uncertainty. In North West Russia, the main part of the thermal production capacity is gas fuelled. Russia aims to increase domestic gas price to the so-called European netback level, which equals European gas price minus transportation costs and taxes. In our modelling, we have assumed that the current oil and gas prices will rebound from recent drop in a couple of years and that Russian gas prices will reach the netback level by early 2020. However, in case oil price remains at the current level for a longer time, the need for a strong increase of gas prices will not be that profound that might lead to slower than anticipated increase of gas and electricity prices. In this case, also North West Russian power price would remain at a lower level than we have assumed, thus, incentivizing higher power exports to Finland. However, the Russian government has agreed to inflation-indexed increases in gas prices. So, even in case the exchange rate between rouble and euro remained at the current level, and there were no major needs to increase gas prices, the Government's agreement would increase gas prices during a couple of next years.

The third source of uncertainty is the development of production capacity. Although we have assumed that some new Russian production units will be delayed (especially Leningrad 1 and 2 units) compared to the original timetable, they might be further postponed due to the current weak political atmosphere. This might reduce the overcapacity situation in North West Russia, increase local power price, thus reducing the incentive for power exports to Finland.

All these uncertainties, if materialized, would affect the price spread and the power exchange between Finland and North West Russia in the medium-term perspective. Considering these main components when determining the structure of the dynamic tariff, we emphasize the need to reserve the right for adjusting coefficient *k* in the structural equations for dynamic tariffs.

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