Carbon pricing on the Russian electricity market

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Abstract

The paper examines the impact of pricing carbon emissions in the Russian electricity supply industry. We find that emissions are reduced at any level of the carbon price. Most active fuel switching takes place at the carbon tax of 200...500 Roubles per tonne of CO_2, but the effect is uneven by zones. The social surplus turns out to be positive. A special case of a new interconnector "Ural - Siberia" is also examined. Since gas prices in Russia are regulated by the government, the results of the models are tested against different levels of the gas tariffs.

1 Introduction

Carbon emission trading has become a significant instrument of the European environmental policy and as such has influenced the development of the European electricity markets. In Russia, carbon pricing remains a prospective plan to implement. Russia's Strategy 2020, a broad policy document that defines the objectives of, and the instruments for, the national development until the year 2020, makes provisions for carbon taxation in mid-term (e.g. around or after 2016). Therefore we deem it useful to estimate the possible impact of carbon taxation on the electricity supply industry.

In Russia, as in many other countries, the energy sector, both electricity and heat production, is a major source of CO_2, accounting for 56 % of the national emissions (year 2010). Several studies that considered Russia's policy on carbon emission and/or the role of the electricity sector did so only as part of computable equilibrium models (Webster et al 2006, Bernard et al 2008).The focus has been primarily on Russia's positions in international carbon trade, and the welfare benefits for the trading parties. An input-output balance model by Malakhov (2010) examined the Russian economy as whole, where the electricity industry was only one of several important carbon sources (others were fuel mining, transport and agriculture).

The only study of the Russian electricity industry (ESI) with carbon pricing was conducted by Veselov et al. (2010). The paper compares the long-term industry development (until year 2050) under two scenarios: 'business as usual' and the innovative model. Both scenarios impose a specific technology mix and the CO_2 payment to produce figures on fuel consumption and carbon emission. From our point of view, setting a generation mix is excessive. Carbon pricing per se can provide incentives for choosing cleaner technologies and can have a significant effect on the fuel mix.

The Russian electricity industry went through a series of reforms in 2003-2008 where a vertically integrated monopoly company called RAO EES was dismantled to create a competitive industry and a liberalised wholesale energy market. Competitive electricity pricing highlighted the importance of upstream fuel markets. While the Russian coal market is oligopolistic and is based on private long-term contracts, the Russian gas market is dominated by the state-owned monopoly company called Gazprom and the domestic gas prices are regulated by the federal government. There is systematic evidence that the gas tariffs are too low compared to the European prices, net of transportation cost (e.g. Tarr and Thompson 2003, Tsygankova 2008). Under-priced gas fuel creates distortion in electricity pricing, and as part of this study we estimate the 'correct' gas price and the impact of the carbon taxation in the presence of 'true' gas prices.

To simulate the Russian electricity market and its response to carbon pricing we built a linear programming model that minimises total cost of meeting the demand given plants' installed capacity and inter-zone transmission constraints. We find that most active fuel switching takes place at the the carbon tax of 200...500 Roubles per tonne of CO_2, albeit the substitution effect is geographically uneven. At the highest tax rate in our model, 1000 Rub/tonne, carbon emissions are reduced by 13% and coal-fired generation is reduced by almost 50%. As for the social surplus, it appears to be positive, reaching 20 bln Roubles at the highest tax rate. Given the plans to connect the now separated areas of Ural and Siberia, we include the future interconnector in our model as a separate parameter. We find that new transmission line would avdersly affect carbon emission levels, because Siberian coal-fired generaiton, being cheap and at the same time carbon-intesive, would substitute production in the neighbouring areas. As for gas pricing, we believe that the domestic gas tariffs might constitute only 54% of the competitive price paid by the European customers. If gas fuel is priced correctly, carbon emissions would surge and social surplus would reduce, albeit remain positive.

Our study is novel in several aspects. Firstly, it examines the consequences of the carbon pricing within the liberalised Russian electricity market. Secondly, from a more general perspective, it highlights the role of market zoning and the transmission network in fuel switching. Finally, we test our conclusions against different gas tariffs and show that the social surplus would stay positive, even when gas fuel is competitively priced.

The paper is organised as follows. The next section outlines the main features of the Russian ESI, with the focus on the zoning and the generation mix. The third section presents the model and the input data and the fourth section discusses the results. Section 5 deals with a prospective interconnector between Ural and Siberia and its impact of the carbon trade. Section 6 examines the robustness of the model outcome to different gas tariffs. Final section concludes.

2 Russian electricity supply industry - overview

The Russian electricity supply industry has 230 GW of installed capacity and more than 2.6 million km of transmission and distribution network. The territory served stretches through 11 time zones, with a population of 143 million people. The annual demand in the year 2011 was c.1000 TWh and the peak demand was 147.7 GW. According to the UN FCCC database, the carbon emissions in Russia in the year 2010 amounted to 1,593 bln tonnes, or 16% of the Annex I parties.

As already mentioned in the introduction, the Russian energy sector was responsible for 889 million tonnes, or 56%, of the national emissions. A comprehensive study by McKinsey (2009) states that the electricity production and heat production have roughly equal shares. The heat production comes from co-generation (combined heat and power, CHP) and district boiler houses in the residential areas, the co-generation having the 45% share. The heat production developed historically as centralised systems (natural monopolies), therefore the potential for plant substitution is quite limited if not absent. The heat supply is strictly regulated (both the norms on heat consumption and the tariffs), so the incentives for reducing emission are either administrative measures or via indirect links to the electricity market.

In the 1990s the industry experienced a severe decline of demand in light of the general economic downturn, the annual consumption dropped by 23% from 1068 TWh in 1990 to 826 TWh in 1998. In 1992-94 the industry had been transformed from a Soviet-planned enterprise into a state-owned monopoly called RAO EES. The corporatisation of the generation assets was marked by the conflicts between the federal government and the regional authorities over ownership and control of the power stations, and the final property structure of the RAO EES reflected the trade-off between the conflicting parties. A few regions managed to defend the independent status of the local producers; these are known as *energo* companies. The RAO EES monopoly controlled 172 GW and the four *energo* producers had 26 GW in total. Among the main problems in the industry at the time were low electricity tariffs (completely regulated by the federal authorities) that did not cover full cost of production, the non-payment problem and the resulting financial deficit, and a number of inefficiencies in the wholesale market design.

The economic revival of the late 1990s - early 2000s stimulated the growth of the ESI and provided the background for structural changes in the industry. The most recent reform of the Russian ESI dates back to 2003-2008[1]. The monopoly company RAO EES was unbundled into generation companies, a dispatch operator, a network company and distribution companies. The hydropower assets of the RAO EES were separated out. Nuclear generation remained under the

[1] For a review of the reforming process see reports by the International Energy Agency (2002, 2005) and a book by Yi-chong (2004); for a review of the outcome see Solanko (2011).

control of the federal government but it changed its status from a government agency into a state-owned company. The energo producers were also required to unbundle generation and distribution. The wholesale market was re-designed in 2007 and liberalised from January 2011, so that government tariff regulation was restricted to the prices for households.

Currently, there are two main types of generation company: wholesale and territorial. A wholesale generation company, WGC, has thermal power plants only, sufficiently large is size that are dispersed across the country. There are six WGCs, with installed capacity around 8,300 – 9,200 MW each. The hydropower company (25 GW) and the nuclear generation company (23 GW) are also treated as wholesale. A territorial generation company, TGC, has smaller stations that are located in the same administrative regions (or within a few neighbouring regions). The territorial company typically has small thermal power plants, combined heat and power plants, and sometimes small hydropower stations. There are 14 TGCs, with installed capacity varying form 600 MW up to 11,000 MW. The energo companies are also treated as TGCs (26 GW in total as before).

With the introduction of the wholesale market, the country was subdivided into price areas and non-price areas. The two price areas are called 'Europe' and 'Siberia', together they account for 80% of the industry installed capacity and for 95% of the generation. The two non-pricing areas are located in the Far East of the country and in the north of the European part, they do not enter the market and remain under government regulation.

The 'Europe' and 'Siberia' price areas in turn are sub-divided into free flow zones (numbered #1 to 6 in 'Siberia' and #7 to 28 in 'Europe'). The FFZs are defined by major transmission constraints. One FFZ might comprise one or several administrative regions, or in a few instances, only a part of the region. Electricity trading is unrestricted within a zone, but trading between the zones is limited. The wholesale electricity market is based on the nodal pricing mechanism. The data is readily available only for the free flow zones, but it is reasonable to expect that nodal prices within one zone would be strongly correlated.

The installed capacity on the market is divided between thermal (66%), hydro (22%) and nuclear (12%) power plants. The 'Siberia' price area houses only hydropower stations and thermal stations (mainly coal-fired CHP). The 'Europe' price area has all three types of the generation, albeit the thermal plants are predominantly gas-fired. Among the FFZ only a few zones have both coal-fired and gas-fired plants; these are #1, 7, 19, 24 and 26. The rest of the zones have thermal plants that are either coal-fired (zones #2 to 6) or gas-fired. There are a small number of plants that use both types of fuel, but usually one type of fuel clearly dominates, e.g. the share of coal is 4/5 and the share of gas is 1/5.

Coal-fired plants tend to have low fuel cost but also low thermal efficiency and hence a high carbon emission factor, ranging from 0.87 up to 1.33 tonne of CO_2 per MWh(e). By contrast, gas-fired stations have higher fuel cost, higher efficiency and consequently a lower emission factor, 0.38…0.78 tonne/MWh(e).

The discrepancy in fuel cost and carbon emission factors, together with the zoning, would have considerable impact on the switching values of the carbon price.

3 Model and input data

A linear programming model is used to simulate the Russian wholesale electricity market and to estimate the equilibrium prices, given the installed capacity and cost of production, the demand level and transmission constraints between the zones. The model is formulated as follows:

$$\min \sum_{k,i,j} (q_i^k c_i^k + x_{ij}^k c_i^k) \tag{1}$$

s.t.

$$\sum_k q_i^k + \sum_{k,j} x_{ji}^k = D_i, \forall i \tag{2}$$

$$q_i^k + x_{ij}^k \leq K_i^k, \forall k, i \tag{3}$$

$$\sum_k x_{ij}^k \leq T_{ij}, \forall \{ij\} \tag{4}$$

$$q_i^k \geq 0, x_{ij}^k \geq 0 \tag{5}$$

where

$i, j \in \{1...28\}$ − index of a free flow zone;

$k \in \{1...139\}$− index of a plant or a generation unit (continuous numbering);

c_i^k− marginal (variable-only) cost of plant k located in zone i, Roubles/MWh(e);

$$c_i^k(t) = f_i^k + e_i^k \cdot t \tag{6}$$

f_i^k− fuel cost, Roubles/MWh(e);

e_i^k− emission factor, tonnes of CO_2 per 1 MWh(e);

t− carbon price (tax), Roubles per 1 tonne of CO_2;

K_i^k− installed capacity of plant k, MW;

q_i^k − amount of production of unit k located in zone i, to meet the 'domestic' demand in zone i, MWh;

x_{ij}^k− amount of production of unit k located in zone i, for export to zone j, MWh;

D_i−demand in zone i, MWh;

T_{ij}− max allowed transmission from zone i to zone j, MWh. Note that $T_{ij} \neq -T_{ji}$.

The model is based on the cost and demand data for the year 2011. The time period is one hour. For every hour in the year the objective function (1) minimises the cost of meeting hourly demand (2), given installed capacity (3) and transmission constraints (4). The carbon price t is treated as a parameter that ranges from 0 to 1000 Rub/tonne (approx. 25 euro), with a step of 50 Rub/tonne.

The model does not consider start-up costs, planned or unplanned outages, restrictions on must-run generation or inter-hour adjustment by hydropower stations. It does not include the cross-border exports/imports between Russia and the neighbouring countries. The main reason is the absence of data on these parameters.

For the purpose of this study, the power stations of the wholesale companies are treated as independent generation units. The assets of the territorial companies and the energos (regional producers), that are of the same technology and are located in the same zone, are combined into a single unit. For example, if a TGC has thermal power plants and hydropower plants and is based in two free flow zones, then we would have 4 units.

The cost of production in the study is limited to fuel and carbon cost only[2]. Hence, in the benchmark model without the carbon tax, the equilibrium prices might be lower than the actual figures. Adding up the carbon cost provides not only qualitative results but also quantitative estimates that show the magnitude of changes in the volumes of production and transmission flows.

Companies' annual reports provide data on thermal efficiency (as the amount of fuel used per 1 kWh(e) produced). The price of gas and coal is estimated differently. As mentioned in the introduction, the Russian coal market is oligopolistic, where the sales are mainly done via privately negotiated contracts. Some generation companies reveal the type of coal used and the contract price and we therefore use this information as a proxy for coal prices where direct reports from the companies are not available. As for the gas market, since the gas prices are completely regulated, the tariff decisions are publicly available on the regulator's website.

Finally, the demand in the model is taken as a fixed value, i.e. not responding to price increase following the introduction of the carbon tax. Thus, the consequences ofthe carbon pricing are the change in amount of production, the technology mix of the generation (mainly coal-fired versus gas-fired) and the flows between the zones.The Administrator of the Trade System (commercial operator of the wholesale market) publishes hourly time series of the various indicators for each free flow zones, which provide data on consumption and transmission flows.

[2]The operation cost added to the fuel cost would change the merit order of the plant, however the zoning of the market suggest the merit order within the zones is largerly preserved.

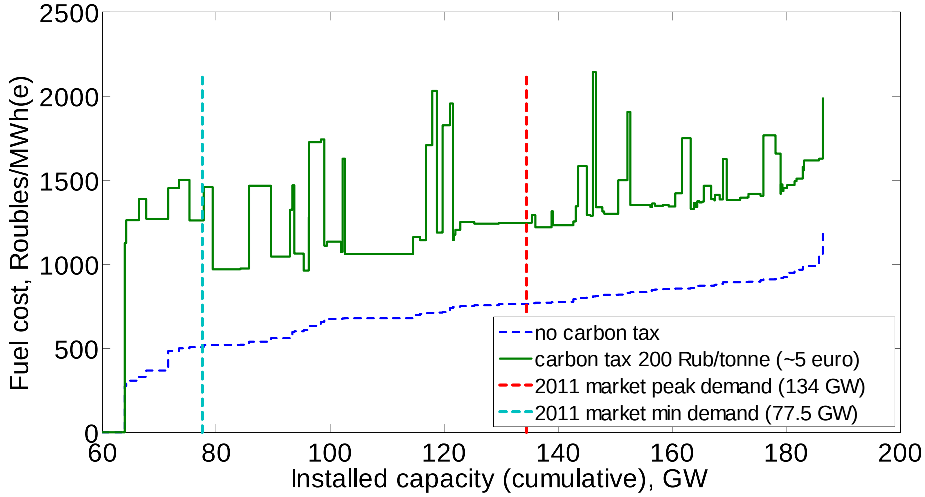

Figure 1: Supply curve (fuel and carbon cost, year 2011). Russian wholesale electricity market.

4 Results and discussion

4.1 Carbon price - switching values

Introducing a carbon tax leads to switching of plants with high emission per 1 MWh(e) by plants with lower emission. Increasing the tax pushes up the cost of a polluting plant and moves it further down in the dispatch ordering, possibly to the point where it is never dispatched. The effect can be easily seen on the supply curve where the coal-fired plants have low fuel cost but high carbon emission factor and consequently higher carbon cost (figure 1). The market installed capacity is.188 GW. The market demand variation is quite large druing the year, the peak demand is 134 GW whereas the minimum demand is 77.5 GW, i.e. only half of the peak.The demand variabilty suggests potential for carbon emission reduction and positive welfare gains.

Following Newbery (2006), we find it useful to estimate the lower and upper bounds of the carbon price that enable switching from coal-fired to gas-fired units and vice versa. The two values are computed as follows

$$t^{lb} = \frac{c^E_{gas,j} - c^I_{coal,i}}{e^I_{coal,i} - e^E_{gas,j}} \tag{7}$$

$$t^{ub} = \frac{c^I_{gas,j} - c^E_{coal,i}}{e^E_{coal,i} - e^I_{gas,j}} \tag{8}$$

Superscript E (I) denotes the most (in)efficient plant in the zone, subscript $coal$ (gas) - the type of fuel used. Hence, $c^I_{coal,i}$ means the marginal cost of the most inefficient coal-fired power plant in zone i, and $e^E_{gas,j}$ is the emission factor of the most efficient gas-fired power plant in zone j. At the lower bound of the tax t^{lb} or below even most inefficent coal-fired plant is preferred to any gas-fired unit; conversely, at the upper bound t^{ub} or above any gas-fired stations are dispatched first.

The upper and lower bounds are computed within each zone and between a pair of interconnected zones. Given the distribution of coal-fired and gas-fired power plants between the zones, the possibility for switching fuel is quite limited. The European price area is dominated by gas-fired units, whereas the Siberian price area houses the bulk of the coal-fired generation. Most of switching would occur not within a zone, but between two zones. For example, a coal-fired plant might be no longer dispatched in its own zone at a certain level of the carbon tax but it still might be competitive in, and hence produce and export electricity to, the neighbouring zone.

For coal to be preferred to gas, irrespective of thermal efficiency, the carbon price has to drop below 53 Rub/tonne (1.2 euro), and the median value across the zones is 248 Roubles (6.20 euro)[3] The carbon price above which any gas-fired unit is a cheaper option reaches 4,831 Rub/tonne (approx. 120 euro), but the median value is more sensible, 725 Roubles (18 euro). Increasing the gas tariffs, e.g. up to competitive European prices, would move up the tax range $[t^{lb}, t^{ub}]$, moreover the upper bound would increase faster than the lower bound and so the range would also expand. At the gas price which is twice high the exisitng tariff, the minimum lower bound of the tax would equal 300 Rub/tonne (7.50 euro) but the maxiumum upper bound would hit the value of 13,640 Rub/tonne (340 euros) [4]

4.2 Emission and fuel mix

Figure 2 displays total emission at different values of the carbon tax and the assoicate volume of coal-fired generation. The overall trend is declining: as the carbon tax increases from 0 to 1000 Rub/tonne, the emission reduces from 260 to 227 bln tonnes/year, or by 13%. The minimum emission the market can achieve is 226 bln tonnes, hence further increase of the tax would be meaningless. The production by coal-fired plants reduces more dramatically, by nearly one half. The model emission in the no-carbon-price case, 260 bln tonnes, appears to be half of the McKinsey estimate. The difference probably stems from model simplifications (no start-up cost or restrictions on must-run generation) as well

[3] For some zones, the lower bound would be negative, i.e. the inefficent coal-fired plant would require a subsidy to be preferred to the most efficient gas-fired plant. Considering all negaitve values, the minimum of the lower bound is -2,464 Rub/tonne and the median value is -63 Rub/tonne

[4] Similarly, at price equal to 2 tariffs, the lower bound would start from -1,900 Roubles, and the median would be 515 Roubles. Excluding the negative values would give 300 and 1,079 Roubles respectively.

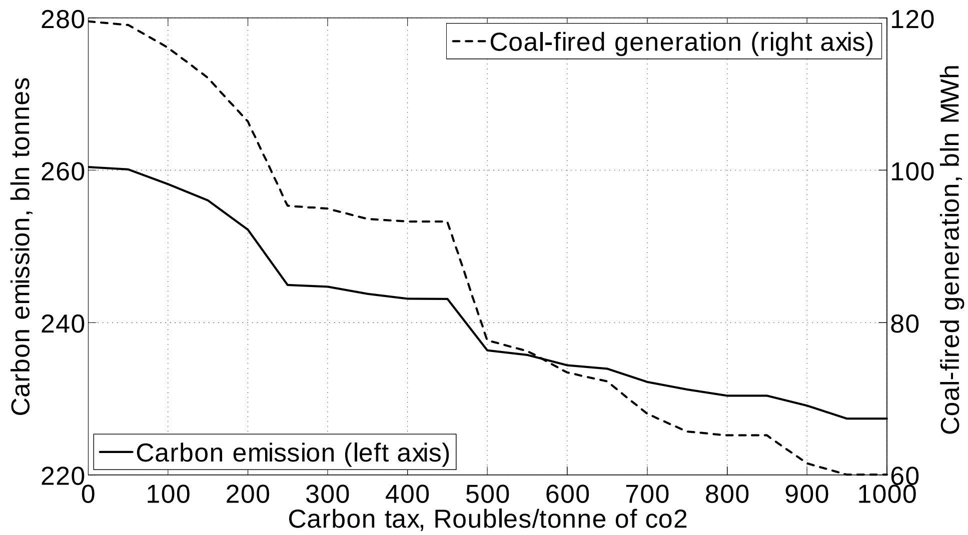

Figure 2: Total emission and coal-fired generation at different levels of the carbon tax

as no-heat production.

Aa for the generation mix, the change in the carbon tax affects only the proportion of gas-fired generation versus coal-fired one. The amount of electricity produced by hydropower and nuclear plants remains practically unchanged (a predictable result given the assumption of zero variable cost). As the carbon tax progressively increases, the share of coal-fired generaiton does not continuously decline. Rather, it remains unchanged for a certain range of the tax and then jumps down once the tax crosses some switching value. Figure 3 depicts the share of coal-fired generaiton for such switching levels of the carbon tax which are 250 and 500 Roubles/tonne of CO_2 (c. 6 and 12 Euro respectively). More specifically, imposing a carbon tax shifts the coal-fired plants along in the dispatch schedule, from the top priority to the middle or low priority. In the winter period when the demand is high, coal-fired stations are likely to be called into production irrespective of the carbon cost, whereas in the summer period they are more likely to remian idle, hence the downward jump in the share of production.

As an illustration of the substitution effect consider the zone #7 'Ural'. The zone has two larger coal-fired stations (2059 MW and 3800 MW), which accounts for 43% of the total electricity produced on the market by coal-fired generation and for 32% of the total emission (without tax, model estimates). As the carbon price does up, the total amount of coal-fired generation declines steadily. Moreover, at the carbon price 400 Rub/tonne or above, one of the

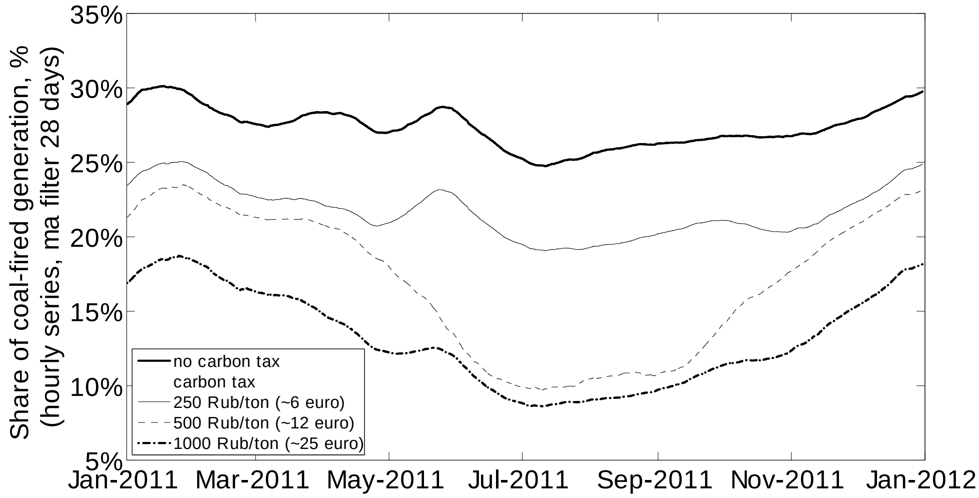

Figure 3: Share of coal-fired generation at the switching values of the carbon tax

coal-fired plants remains completely idle and the other changes its status from 'baseload' to 'peaking'. The change of status is clearly visible on figure 4.

Another example of fuel substitution is found in zone #1 located in the Siberia price area, albeit at a much smaller scale. The Siberia price area has a small share of gas-fired generation and no connection to the European price area. The transmission links between the main Siberian FFZ #1 and its neighbours, smaller zones ##2 to 6, are constrained. Fossil fuel generation in zone #1 is used primarily during the winter period, so the carbon pricing effect is limited. The annual coal-fired generation in FFZ #1 is reduced by 2 GWh at most (cf. consumption of 132 GWh).

Other mixed-fuel zones have different picture. In zone #19 'Rostov' the coal-fired power plants remain active at any carbon price, although they reduce output at clear switching values of the carbon tax 150 Rub/tonne and 550 Rub/tonne. The gas-fired generation in zone #19 responds modestly to the carbon price, the compensation for the reduced output of the coal-fired plants comes from another zone #16 'Caucusus'. In zone # 24 'Centre' coal-fired generation, however small, discontinues at the carbon tax 250 Rub/tonne and above. Zone #26 'Moscow' has a low level of coal-fired generation, the carbon pricing leads to a substantial increase of gas-fired generation mainly to be exported to the zone #24.

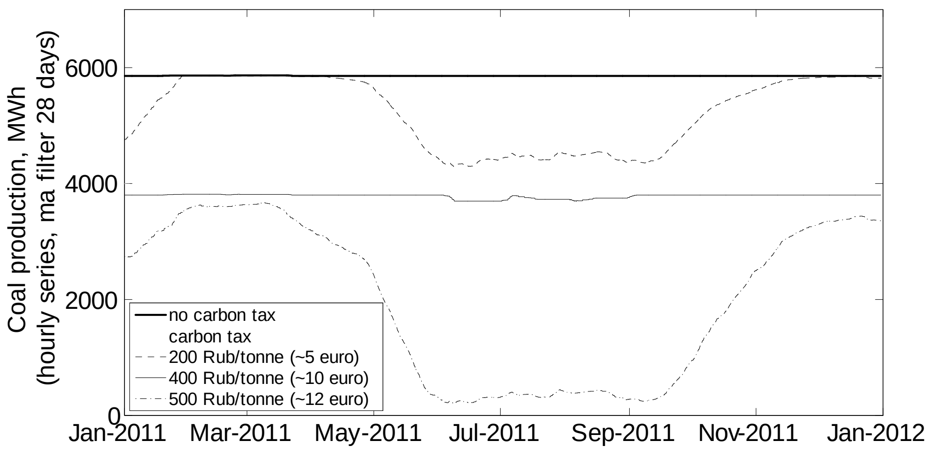

Figure 4: Gas-fired generation in free flow zone #7 'Ural' at the switching values of the carbon tax

4.3 Cost of electricity and emission

Introducing a tax creates distortions on a competitive market by shifting the supply or the demand curve, and the tax incidence and the size of the deadweight loss depend on the relative elasticity of supply and demand. In our model the demand for electricity is fixed, so the incidence falls 100% on consumers. A unit tax would simply shift a supply curve inwards. However on the electricity market the carbon tax not only shifts the supply curve, but also changes its "slope" since the carbon cost per 1 MWh(e) is specific for each power plant (because of different thermal efficiencies). The tax revenue would be no longer a simple product of output and the tax rate, but rather a sum of individual tax obligations.

To illustrate graphically the effect of the carbon tax, assume for simplicity that the tax does not affect the dispatch order, i.e. a more efficent plant has lower production cost. Adding up a carbon tax would make the supply curve steeper (see figure 5) so that the tax would be represented by the shaded area [c-d-e-f]. The conventional rectanglur area [b-d-e-f] would define the reduction of consumer surplus. Finally, the shift and twist of the supply curve implies change in the producer surplus which would be positive (figure 6, area [a-b-e]). In a more realistic setting, where the carbon tax does alter the dispatch schedule, the permutration of the plants could flatten the supply curve and lead to negative producer surplus.

While the gas-fired plants have lower dispatch priority compared to the coal-fired plant (absent carbon pricing), correcting domestic gas tariffs by setting them at a higher level would make the gas-fired generation even less competitive.

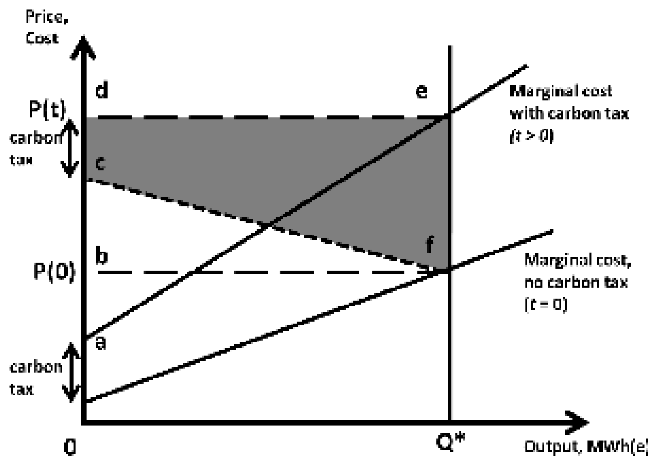

Figure 5: Carbon tax revenue [c-d-e-f] and reduction of consumer suprlus [b-d-e-f]

The intial supply curve would be steeper, and a higher carbon tax would be needed to induce fuel switching. With higher gas tariffs and a relatively small carbon tax the producer surplus might diminish or even become negative. The surplus would remain positive at a sufficiently large tax .

More formally, the overall social surplus from carbon pricing can be computed as follows:

$$S(t) = \Delta CS + \Delta PS + R(t) + EB(t) \tag{9}$$

where

$S-$ the socail surplus as a function of the carbon tax t;

$\Delta CS-$ change in consumer surplus;

$\Delta PS-$ change in producer surplus;

$R(t)-$ tax revenue at the carbon tax t.

$EB(t)-$ environmental benefit (of reduced emissions);

The change in consumer surplus is computed as:

$$\Delta CS = \alpha \cdot P(t) \cdot Q - \alpha \cdot P(0) \cdot Q \tag{10}$$

where

$\alpha-$ share of the thermal generation in the total electricity production (explained below);

$P(t)-$ electricity price as a function of the carbon price;

$Q-$ (fixed) demand for electricity.

The change in producer surplus is the change in profit before and after the tax:

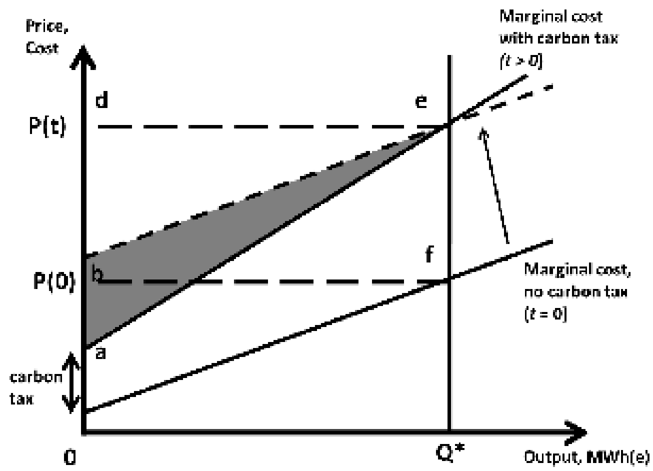

Figure 6: Producer surplus [a-b-e] with carbon taxation

$$\Delta PS = \Pi(t) - \Pi(0) \tag{11}$$

$$\Pi(t) = \alpha \cdot P(t) \cdot Q - c(t) \cdot Q \tag{12}$$

$\Pi(0)-$ producer profits (surplus) before introduction of the carbon pricing;
$\Pi(t)-$ producer profits after introduction of the carbon pricing
$c(t)-$ production cost that includes both fuel and carbon cost (see formula 6).

The tax revenue is given by

$$R(t) = E(t) \cdot t \tag{13}$$

where $E(t)-$ total emission at a given carbon tax;
and the environmental benefit is the monetary value of the emission reduction:

$$EB(t) = [E(t) - E(0)] \cdot t \tag{14}$$

Formula (9) compares the change in producer surplus (profits) to the tax revenue collected. The profit is computed as the revenue sales less the produciton cost. Since (9) is based both on the demand-side parameter (demand Q) and the production-side parameter (emission E), the total surplus is computed for the market as a whole, not at the zone level. In other words, the emission saving and moderate price increase in one zone might be at the cost of the larger emission and much higher price in the neighbouring zone.

Given the fixed (hourly) demand in the model, the hourly shares of the thermal, hydro and nuclear generation remain the same for any level of the carbon tax. The aggregate share of the thermal generation in the annual production in the base model is 48% (and the α parameter would represent the hourly share). Carbon pricing affects only the ratio of coal-fired generation versus the gas-fired generation. However, the hydropower and nuclear stations benefit from higher electricity prices that include the carbon tax. Therefore it is necessary to consider only thermal generation and the social surplus associated with cleaner production. The rent that the non-thermal power plants receive with the introduction of the carbon tax can be used, for example, to reduce their capacity prices or to finance their long-term investment projects (new construction or equipment refurbishment).

Plugging in (10)-(14) into (9) yields:

$S(t) = \Delta CS + \Delta PS + R(t) + EB(t) =$

$= [\alpha \cdot P(t) \cdot Q - \alpha \cdot P(0) \cdot Q] + [\alpha \cdot P(t) \cdot Q - c(t) \cdot Q - \alpha \cdot P(0) \cdot Q +$
$c(0) \cdot Q] + E(t) \cdot t - [E(t) - E(0)] \cdot t$

$= -c(t) \cdot Q + c(0) \cdot Q + E(0) \cdot t,$

so that we have the reduced formula:

$$S(t) = E(0) \cdot t - [c(t) - c(0)] \cdot Q \tag{15}$$

Hence, the total surplus compares the cost of initial emission to the fuel cost increase. Mechanical introduction of the tax, absent fuel swithcing, would generate the tax revenue $E(0) \cdot t$, which is equivalent to the income effect. However, replacing carbon-intensive coal plants with low-carbon gas plants is costly, and the increase in fuel cost $[c(t) - c(0)]$ measures the subsititution effect. From a different perspective, emissions represent an externality imposed on consumers. The value of initital emission $E(0) \cdot t$ is the cost to be internalised through carbon taxation, and the $[c(t) - c(0)]$ reflects the associated change in the production cost.

The aggregate surplus from carbon pricing turns out to be positive for any level of the carbon tax. (see figure). At the highest tax rate, 1000 Roubles/tonne, the overall surplus is 20 bln Roubles; as for the specific values, the cosumer suprlus CS is reduced by 277 bln Roubles, producer surplus PS increases by 37 bln, the tax revenue $R(t)$ amounts to 227 bln and the environmental benefit $EB(t)$ is equal to 33 bln.

Although the reduction in cosumer suprlus and tax revenues appear to be excessive relative to the producer surplus and environmental benefit, practical consequences of the carbon taxation might be not so severe.The relative impact of carbon taxation on fuel cost (as a result of plant switching) is moderate; the cumulative fuel cost rise from 278 to 291 bln Roubles, or by 4.6%. As the tax increases from zero to the 1000 Roubles/tonne the share of the tax payment in operational cost rises from 0% to 43%. Correspondingly, the average electricity price on the market almost doubles, jumping from 570 to 1,080 Rub/MWh(e). Yet in our study we consider only variable cost and the wholesale market. If we account for fixed production cost, transmission charges and retail profit margin,

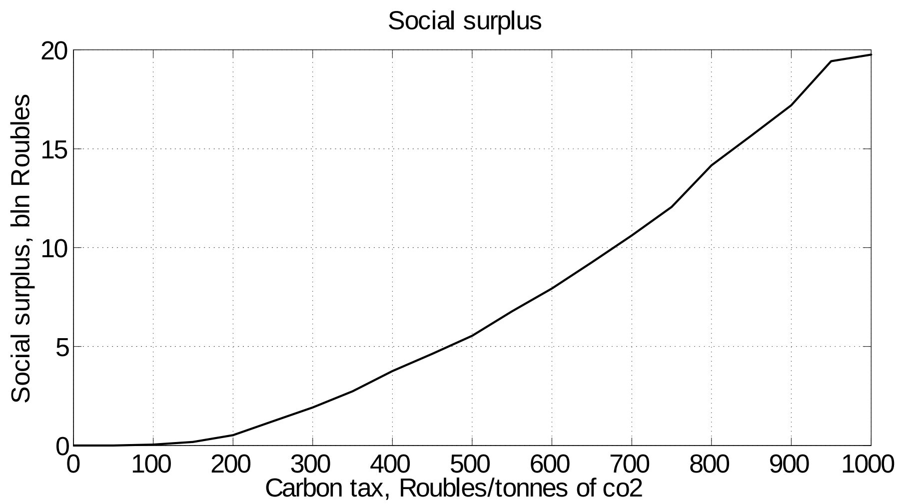

Figure 7: Social surplus at different levels of the carbon tax

then the carbon tax might constitute a relatively small fraction of the retail electricity price .

It is useful to compare the projected carbon emission and tax revenue with the existing environmental obligations borne by the generation sector. The total polluting emission into water and air from both electricity and heat production in 2010 amounted to 3.14 bln tonnes (carbon monoxide, nitrogen oxides and some other substances). The gross environmental payments in 2010 equals 1,590 bln Roubles, of which 558 bln correspond to water and air pollution charges [5]. The carbon tax which stimulates active fuel switching lies in the range 250-500 Roubles/tonne and the associated tax revenue is 61-118 bln Roubles. Assuming electricity and heat production contribute equally to the actual environmental charges, the carbon tax revenue would constitute 8-14% of the electricity sector's payments. Moreover, substituting away inefficent coal-fired generation would lead to reduction of other polluting emission and the associated charges so the total contribution of the carbon tax to improving the environmental situation would be even greater.

To summarise, the carbon pricing results in some producer surplus and much higher tax revenue. However, the share of the tax in the retail price might be small and for moderate levels of the carbon tax, the projected tax revenue would increase the existing environmental payments by 8-14%.

[5] All figures - Ministry of Natural Resources and Ecology (2012) "State Report on the Condition and Protection of the Environment in Russian Federation in 2010", part 4.1.

5 Interconnector "Ural - Siberia"

The two price areas 'Siberia' and 'Europe' are not currently connected to each other, which means there is no opportunity for energy trading and more specifically for carbon emission reduction. The General Scheme 2020 (a policy document that describes the development of the Russian ESI until the year 2020) envisages the construction of a 500 kV interconnector (310 km long) between the zones #7 'Ural' and #1 'Siberia' by the year 2013. According to the System Operator, the line would have a capacity of 2,128 MW. We therefore include this transmission link in the model to estimate its effect on carbon emissions.

The interconnector between Ural and Siberia enables switching not only within these two areas, but also between them. Competition now takes place between Siberian hydropower plants and coal-fired power plants (very cheap), Ural coal-fired stations (medium cost) and Ural gas-fired stations (most expensive). A fraction of thermal generation is replaced by hydropower production, the all-market annual share of the thermal generation decreases from 48% to 44%. As such, it is natural to expect that the electricity price would increase in Siberia and decrease in Ural. Indeed, according to the model estimates, the average annual price in the free flow zone 'Siberia' jumps from 300 to 359 Roubles/MWh(e), or by almost 20%. The electricity price in the free flow zone 'Ural' goes down from 748 to 728 Roubles/MWh(e), or only by 2.6%.

Since the Siberian coal-fired generation has lower cost, a higher carbon tax is needed to reduce total carbon emissions. The theoretical upper bound is 1680 Rub/ton (420 euro) above which gas-fired stations from zone #7 are absolutely preferred to any coal-fired power plant from zone #1.

At the given cost structure and without the carbon tax, the Siberian power plants appear more competitive so the electricity flows solely in one direction from Siberia to Ural. The line is congested for 99% of the time, and the all-year congestion remains in place for the carbon tax up to 950 Roubles/tonne. The situation changes only at the highest level of the carbon tax in the model, i.e. at 1000 Roubles/tonne, when the line is used at full capacity only in the winter months.

In the presence of the interconnector, introducing carbon taxation has similar effect on the overall emission, the generation mix and the socail surplus as in the base model. The emission declines as the tax increases, however with the interconnector the emission volume is, in fact, higher for any level of the tax than in the baseline case (see figure 8). As for the overall surplus, it is the same at small levels of the carbon tax, i.e. below 500 rub/tonne and is lower at higher levels of the tax (figure 9). Finally, the Ural coal-fired generation is reduced in greater proportion for any tax rate as it now competes with its Siberian counterpart.

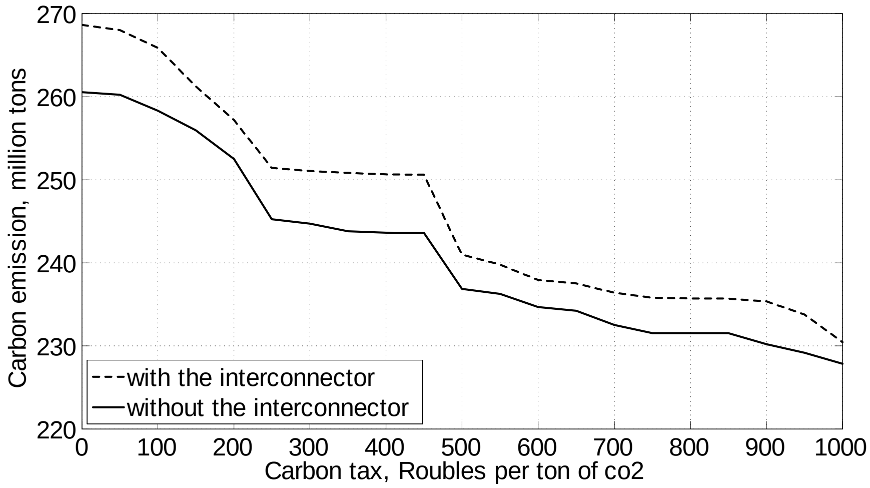

Figure 8: Total emissions, with and without the interconnector

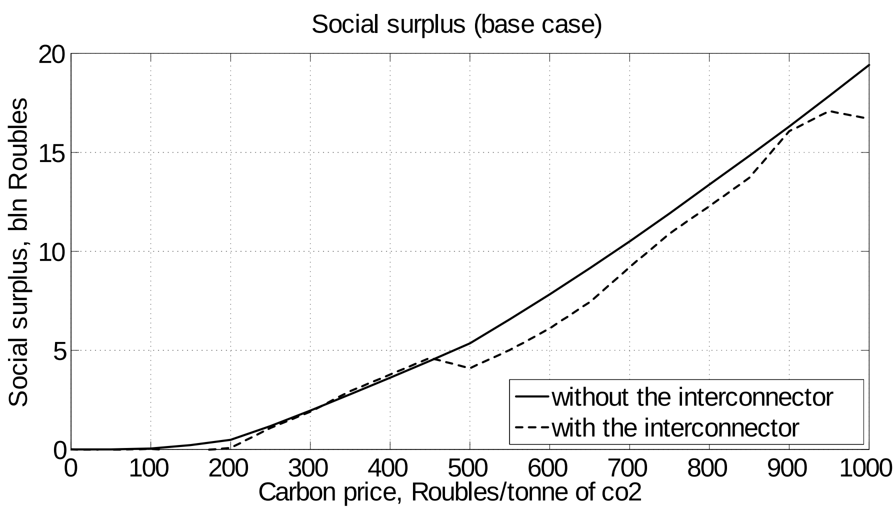

Figure 9: Social surplus, with and without the interconnector

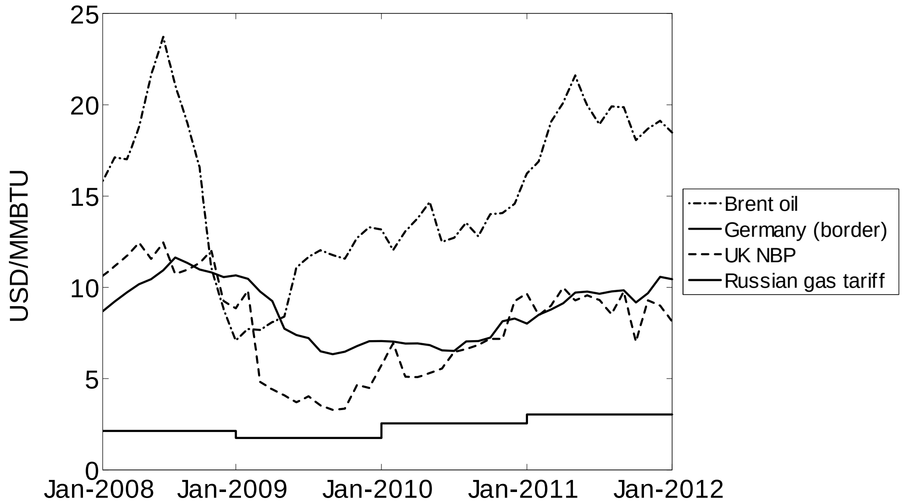

Figure 10: Gas prices in Germany and in the UK vs Russian gas tariffs

6 Robustness to gas tariffs

As mentioned above, the Russian gas market is represented by the monopoly company Gazprom. The gas prices are regulated by the government and are set annually as fixed tariffs that incorporate both the production and transportation cost and so vary across regions[6]. In the years 2008-2011 the tariffs have been increasing uniformly across regions, but the nominal rate of increase changed from year to year. The federal government is committed to further raising the gas tariff to ensure the equal return on domestic and foreign gas sales. As a result of 'euql-returns' tariff policy, the domestic gas tariff has been linked (indirectly) to the world oil price which proved to be volatile[7]. Figure 10 illustrates the low level of Russian gas tariffs, and the volatility of the UK and German gas prices and the Brent oil price. The predictability of further gas tariff increase, together with the volatility of the world fuel prices, requires us to test the model against possible changes in the gas prices.

Estimating the competitive price of gas for Russian customers is conventionally based on some European border gas price net of transportation cost.

[6] In the year 2011 the tariffs ranged from 1,679 to 3,200 Roubles/1000m^3. The lowest tariff was set for the Yamal region in North Siberia which is the closest to the gas field (hence low transportation cost). The highest tariff was in the Krasnodar region in the south of Russia.

[7] See Government Resolutions N156-e issued on May 5th, 2007 and N 165-e/2 issued on July 14th, 2011. For economic analysis of the price formula see, e.g. the already mentioned Tsygankova (2008).

Usually it is the German border gas price less the transportation and storage charges via the Czech Republic, Slovakia and Ukraine, i.e. the price netted back to the Russian border, hence the name "netback value". Perhaps, the most problematic issue is to obtain information on the transit cost via Ukraine as these cost are privately negotiated between Gazprom and Naftogaz (Ukrainian gas producer and major pipeline operator). We circumvent partly the lack on information by using the Ukrainian domestic tariffs for gas transportation, albeit we cannot obtain similar figures for storage cost. Our calculations (see the appendix for details) suggest that in 2011 the competitive gas price in Kursk region that borders Ukraine would be 1.8 times higher the regional gas tariff; equivalently, the tariff represents only 54% of the competitve price The difference is probably upward biased since the storage cost is unknown although the bias might be relatively small. Pirani, Stern and Yafimava (2009) estimated the Ukrainian netback value for the years 2004-8 and found that their estimates is twice higher the actual import prices.

Given the current monopoly structure of the Russian gas market, it is not possible to simulate the gas price dynamics at frequent time intervals or in specific geographic areas. Consequently, we change the gas tariff uniformly across all producers, by setting the tariff as a percentage of the 2011 values: below the level at 50% and 75% and above the level at 125%, 150%, 175% and 200%. The lower values are used for information reference and the upper values are used as a proxy for competitve pricing. Note that we do not change the coal prices and keep them constant for any level of the gas tariff. Combination of higher (lower) gas tariffs and unchanged coal prices means that the switching values of the carbon tax would increase (decrease).

When the gas tariff goes up, the carbon-intensive coal becomes a cheaper option to use in generation, hence the surge in the carbon emission (see figure 11). The gas- and coal-fired generation adjust accordingly to the different gas tariffs. When the tariffs are below the 2011 level the coal generation is reduced substantially, and when the tariff is set above the default values, coal-fired generation dominates the market. Thus at competitive gas prices, a higher carbon tax is needed to induce fuel switching

As shown in section 5, the interconnector induces electricity sales from Siberia to Urals, but it also leads to higher carbon emission. At the normal level of the gas tariff, the electricity flow from Siberia is reduced only at very high carbon tax. To stimulate active switching from coal-fired plants in Siberia to gas-fired plant in Ural, at small values of the carbon tax, the gas tariffs have to be lowered. At the 50% or 75% gas tariff the electricity begins to flow from Ural to Siberia, mostly in the winter months, albeit the line in this direction is never congested. Increasing the gas tariffs above the 100% level does nothing but strengthens the positions of the Siberian coal-fired plants so that the electricity flows from Siberia to Ural at any carbon tax and the line is congested all the year round.

As for the welfare implications of varying the gas tariffs, they are ambigous. Since the domestic gas tariffs appear to be lower than the competitive international prices, increasing the tariff reduces the distortion on the fuel market. On

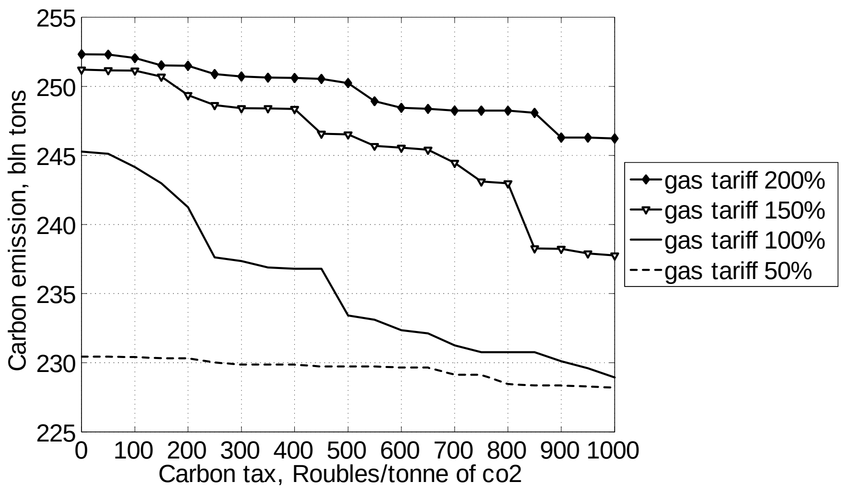

Figure 11: Total emission at selected levels of the gas tariff

the other hand, gas-fired generation becomes more expensive and is less likely to be dispatched, so the negative externality of carbon-intesive coal-fired plants is amplified. To induce swithcing, we need a higher carbon tax which leads to higher tax revenue, lower consumer surplus and higher environmental benefit.

Figure 12 presents the socail surplus at the selected levels of the gas tariffs. The gains are above zero at any level of the carbon tax which indicates the positive effect of internalising the carbon emission. The aggregate surplus is the highest for the actual 2011 tariffs, it is lower for higher gas tariffs. If we were to extend the carbon tax range beyond 1000 Rub/tonne,where fuel swithcing is more likely with competitive gas prices, we would probably obtain similar total surplus as with the distorted gas tariffs. What is, perhaps, surprising is that the total surplus is the lowest for the lowest gas tariff (50% of the orignial value). The reason is that the gas fuel turns out to be both cheap and not carbon intensive, so.the carbon emissions are relatively small (c. 230 bln tonnes which is close to the absolute minimum of 226 bln tonnes). Introducing a carbon tax does not alter much the dispatch schedule and hence brings little benefit.to the market.

The case of the interconnector adds further details to the gas tariff discussion. While the carbon emissions curves shift upward for any level of the gas tariff (cf. figure 8), the welfare implications are somewhat different (see figure 13). The surplus curves shift downwards for any level of the gas tariff, so that at the lowest gas tariff of 50% the surplus, in fact, becomes negative in the given tax range.

In the case of 50% gas tariff, when we look at the specific components of the socail surplus formula (9), it turns out that the reduction in the consumer

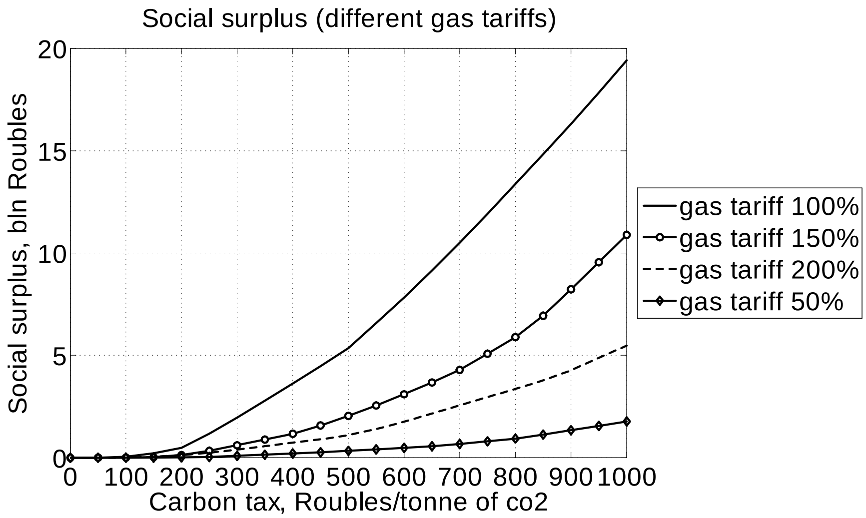

Figure 12: Welfare benefit, at selected levels of the gas tariffs

surplus dominates the total sum of the tax revenue, producer surplus and environmental benefit. As we showed above, the interconnector leads to a substantial price increase in Siberia, and the effect is preserved even when we lower the gas price. In the reduced formula (15) the fuel cost increase would outweight the initial cost of emission. With the interconnector and low gas tariffs, Ural gas-fired plants are dispatched first, so the choice of margianl plant is between Ural and SIberian coal-fired power stations. Siberian coal-fired plants have lower fuel cost but are more carbon intensive than the Ural couterparts A moderate carbon tax replaces the Siberian plants with the Ural plants, so we have higher fuel cost that outweight emission.saving.

To summarise, the gas tariffs appear too low compared to the European prices net of trasport cost. At competitive prices carbon emissions would surge as coal fuel becomes a cheaper option. Nonetheless, the total surplus remain positive with the competitive gas prices and a positive carbon tax. Perhaps, the general caveat when estimating the gas prices is that the domestic demand and supply are unknown functions of the price. There is an assertion that the true gas price would lie between the current tariffs and the netback value because of the abundant supply hence the twofold increase is less likely to occur should the gas market be reformed and liberalised.

7 Conclusion

The paper examines the effect of carbon pricing in the Russian electricity industry. The environmental benefit, as measured by the reduction in emission,

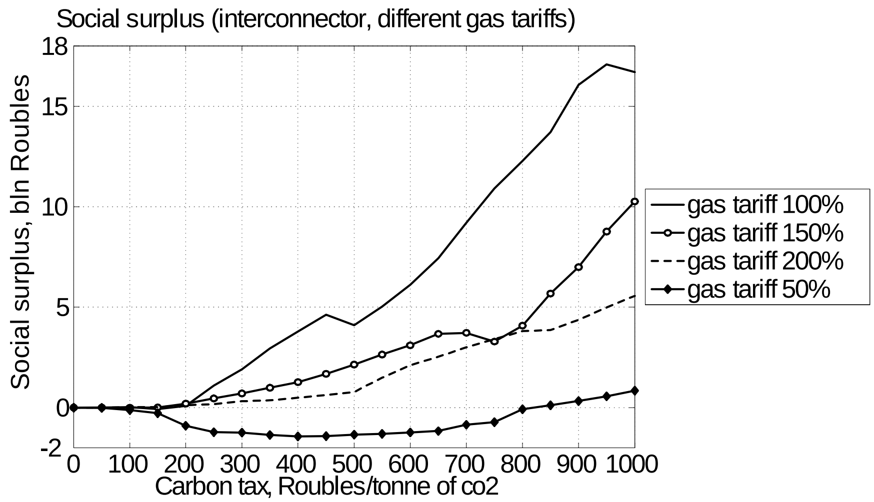

Figure 13: Welfare benefit, case of interconnector, at selected levels of the gas tariff

is positive at any level of the tax. The consequences for fuel consumption are uneven by zones. Zones with both coal-fired and gas-fired generation have clear potential for switching between different types of fuel. Zones with a single type of fuel, even if connected to mix-fuel zones, demonstrate limited response to a positive carbon price. Switching fuel creates additional producer surplus and environmental benefit which, togehter with the tax revenue, help outweight the reduction in consumer surplus. From apractical point of view, carbon cost is likely to be a small fraction of the retail electricity price and the exisitng environmental charges paid by producers.

The construction of an interconnector between zone #7 'Urals' and zone #1 'Siberia' would lead almost surely to higher carbon emission. Siberia coal-fired generation is quite cheap, consequently higher carbon tax is needed to induce fuel switching, at least 1000 Rub/tonne of CO_2 or above (approx. 25 euro). However, coal-fired generation is also carbon-intensive hence the increase in the emission. Substitution of the Siberian coal-fired power plants by the Ural between gas-fired stations, in the presence of the carbon tax, is possible only at very low gas prices.

The model results, both the baseline case and the interconnector case, appears quite robust to varying gas prices. The carbon emission is increased once the low-carbon gas is priced competitvely and hence higher carbon tax is needed to induce fuel switching. The social surplus however remain largerly positive, albeit at reduced magnitude compare to the base case of actual gas tariffs.

The results of the modelling have several economic and policy implications. Firstly, the results indicate the need for more efficient power plants. Secondly, they highlight the role of transmission system, both existing lines and potential interconnectors, in the fuel generation mix. Finally, the robustness checks emphasize the role of the gas tariff policy in carbon reduction mechanisms.

The model used in the paper has short-term horizon, therefore it does not consider demand response, options for improving plants thermal efficiency or introducing new technologies . These options could provide useful extensions in understanding the reaction of the Russian electricity market to carbon tax policy.

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9 Appendix. Estimating competitve gas price for Russia

As mentioned in the main part, estimating a competitive price of gas for Russian customers, or the netback value, is conventionally based on the German border gas price less the transportation and storage charges via the Czech Republic, Slovakia and Ukraine.

While the German gas price and the transportation tariffs in the Czech Republic and Slovakia are readily available from the relevant regulatory authorities, the transportation cost of gas via Ukraine is privately negotiated between Gazprom and Naftogaz (Ukrainian gas producer and major pipeline operator). Note that the European customers buy gas from Gazprom at the Ukrainian-Slovak border, not the Russian-Ukrainian border hence the importance of the price that Gazprom pays to Naftogaz for using the pipelines. The absence of reliable information on transportation cost via Ukraine (as paid by Gazprom) often leads to the use of semi-official sources, such as news or media reports, which makes any estimate of the Russian netback value highly subjective.

In an attempt to estimate the Ukrainian tariffs for gas pipeline transport, one can refer to the national regulator's decisions on tariffs for the regional pipeline operators, in particular the tariffs for using large pipelines that are under the regional operators' control. These tariffs are defined for domestic Ukrainian customers and might not fully reflect the true cost of transportation, yet they can give an indication of how much German customers would pay if they could buy gas at the Russian-Ukrainian border, not the Ukrainian-Slovak border.

The Russian gas export is subject to an export duty which is levied at the Ukrainian-Russian border (according to the joint customs law). Consequently, the gas price netted back to Ukraine has to be adjusted for the export duty and only then netted back to the Russian border.

From 2008, the Russian domestic gas tariffs are computed by the Federal Tariff Service of Russia (FTS) using the netback value, yet our estimate suggest that the tariffs are still downward biased. We use the following formula for the Russian netback value which is based on the FTS guidelines (where TC stands for 'transportation cost'):

Russian netback value = (German border price – TC via the Czech Republic – TC via Slovakia) * (1 – export duty) – TC cost via Ukraine

The input figures and the netback value are given in the table below (prices and TC are in Euro per 1000 m^3)

German border gas price	271.52
– TC via the Czech Republic (Net4gas)	6.28
– TC via Slovakia (EuStream)	6.36
Ukrainian netback value	258.87
– Export duty, nominal rate	30%
Ukrainian netback value corrected for the export duty	181.21
– TC cost via Ukraine	41.56
Russian netback value	**139.65**
Gas tariff, Kursk region at Russian-Ukrainian border	75.09
Discrepancy , Russian netback value / Gas tariff	**1.87 times**
Gas tariff as a **percentage** of the netback value	**54%**

Notes:

1. The TC cost is computed using the online calculators of Net4gas and EuStream and the relevant entry/exit points at the national borders. Both TC represent the total transportation cost of 1000 m^3 via the country.

2. TC via Ukrain is the sum of tariffs for the regional pipeline companies that operate major pipelines. Each tariff is the total transportation cost of 1000 m^3 via a given region.

2. The TC cost and tariffs are set in local currency (except for Slovakia). The exchange rates of Czech Krona, Ukrainian Hryvnia and Russian Roubles versus Euro are 2011 annual average values. The actual time series are available from the European Central Bank and the Central National Banks of Ukraine and Russia.