**IPM Research Center**

**German Economic Team**

Policy Paper Series [PP/04/2008]

# The case for tariff differentiation in the Belarusian electricity sector

Georg Zachmann and Alexander Zaborovskiy

Berlin/Minsk, October 2008

IPM RESEARCH CENTER
Research · Forecasting · Monitoring

## About the IPM Research Center

The IPM Research Center was established in 1999 within the mutual project of the Institute for Privatization and Management (Minsk, Belarus) and CASE – Center for Social and Economic Research Foundation (Warsaw, Poland). It is a member of the CASE research network, William Davidson Institute NGO Alliance, and Economic Policy Institutes Network (project of the UNDP's Regional Bureau for Europe and the CIS). The main activities of the IPM Research Center are monitoring, analysis and forecasting of Belarusian economy development, economic research and elaboration economic policy recommendations, promotion of dialogue on the issues of economic development through conferences and seminars, publication of the results of research conducted by Belarusian and foreign economists in ECOWEST journal, and training of specialists in the field of modern methods of economic analysis. Within its cooperation with the German Economic Team in Belarus, the IPM Research Center provides independent policy advice on economic issues to the different official agencies, namely to the Council of Ministers, National Bank, Ministry of Economy, Ministry of Finance and other organizations involved in the process of formation and implementation of economic policy.

The Mission of the IPM Research Center is to enhance national competitiveness through elaboration of the research-based economic policy recommendation and the promotion of professional dialogue on the urgent issues related to economic performance.

**IPM Research Center**
50Б Zaharova Street, 220088, Minsk, Belarus
Tel: +375 (17) 2 100 105
Fax: +375 (17) 2 100 105
E-Mail: research@research.by
http://www.research.by/

## About the German Economic Team in Belarus (GET Belarus)

The main purpose of GET Belarus is to conduct a dialogue on economic policy issues with the government, civil society, and international organizations. Experts of German Economic Team have experience in policy advice in several transition economies, including Ukraine, Russia, and Kazakhstan. In Belarus the IPM Research Center and the German Economic Team provide information and analytical support to the Council of Ministers, the National Bank, the Ministry of Foreign Affairs, the Ministry of Economy and other institutions involved in the process of formation and implementation of economic policy.

**German Economic Team**
c/o Berlin Economics
Schillerstr. 59
D-10627 Berlin
Tel: +49 30 / 20 61 34 64 0
Fax: +49 30 / 20 61 34 64 9
E-Mail: info@get-belarus.com
http://www.get-belarus.com/

# The case for tariff differentiation in the Belarusian electricity sector


## Executive Summary

This study analyzes the current state of the art and potentials for tariff differentiation in the Belarusian electricity sector. Attempts to implement intertemporal tariff differentiation in Belarus have not been successful but the benefit expected from an efficient scheme might be significant. By reducing peak demand by 5% an efficient tariff differentiation scheme could reduce the annual cost of the Belarusian electricity system by USD 25-30 m. Because time-of-use demand measuring is costly, we argue that targeted demand shifting incentives for a small number of big consumers (industry) would be more efficient than a general scheme in Belarus.

The paper is organized in four parts: The concept, advantages and international experiences of tariff differentiation are presented in the next section. In the second section the Belarusian electricity sector is introduced. The third section studies the case for tariff differentiation in Belarus, and the fourth section concludes.


## Authors


Georg Zachmann zachmann@berlin-economics.com +49 30 / 20 61 34 64 0
Alexander Zaborovskiy


## Acknowledgement


The authors would like to express their gratitude to Stephan von Cramon-Taubadel for lectoring the paper.


## Contents

## 1. Tariff differentiation in electricity markets

Electricity demand is characterized by high volatility and strong daily, weekly and annual seasonalities. Therefore, in general the electricity consumption at the hour of highest annual electricity demand (peak load) exceeds the average load significantly. As the power plant fleet of an electricity system must be able to meet the peak demand plus some security margin, the fixed cost of an electricity system are to a large extent determined by this peak load.[1]

By reducing the peak load of the system either the fixed cost of serving a given demand can be lowered, or demand increases can be accommodated without additional investments in new capacities, or security of supply can be increased without additional cost.[2] Additionally, smoothing the load curve often allows lowering fuel and emission cost as peak power plants are usually characterized by below-average fuel and emission efficiency. Therefore, the aim of intertemporal tariff differentiation[3] is to provide electricity consumers with incentives to shift demand from high-load to lower-load hours. In the energy economic literature, a number of potential contracts that provide incentives for load-shifting are discussed:

### 1.1. Two-Part Tariffs

The general idea of two-part tariffs is to charge the customer a fee for the electricity consumed and another fee for the maximum load they incur. The later component might depend on the actual maximum capacity usage, the allowed maximum capacity usage, the capacity usage during peak-load, or more sophisticated measures. In some cases even a third component that penalizes low power factors (phase between voltage and amperage) is introduced.

### 1.2. Time-of-Use Pricing

Generally electricity demand is higher on weekdays during day-time than on week-ends, holidays and at night. Thus, an obvious approach is to introduce separate tariffs for working and non-working hours. Corresponding contracts are offered even in the residential sector. Billing is mainly performed using two separate meters, and sometimes by obliging users to install separate circuits. Contracts might specify minimum and maximum capacities for both types of electricity. In Germany such schemes are often used for powering storage-heating devices. An experiment with 30% higher peak than off-peak prices resulted in a 5% reduction in peak consumption in the US.[4]

### 1.3. Critical Peak Pricing

Critical peak pricing involves billing especially high prices during the 60-100 highest load hours. It does require the installation of additional equipment. This scheme, which has, inter alia, been implemented in the French residential sector (on an experimental base), also requires that customers *ex ante* know when these "red hours" occur, so that they can adjust their behavior correspondingly.

### 1.4. Real Time Pricing

The idea of real time pricing (RTP) is that the tariff for electricity depends on an exogenous time-varying index. For example the tariffs might be allowed to change from hour-to-hour according to the corresponding spot price at the power exchange. Therefore, RTP requires the existence of a transparent index (e.g., system-load or electricity price). Furthermore, costly infrastructure (real time metering, two-way communication, software, etc.) is needed for the roll-out of RTP. Therefore, this system is usually applied for big customers that are able to adjust their electricity consumption to tariff changes in real time. Nevertheless, combined with

[1] The margin should take the stochasticity of demand and the potential of supply-sided failures into account (N-1 criterion – i.e., the system could accommodate the failure of at least one unit without breaking down).

[2] Spees and Lave (2008), for example, estimate for PJM (the US East Coast electricity system) that 15% of the power plants run less than 96 hours per year (i.e., 1.1%).

[3] In this study we focus on intertemporal tariff differentiation. Other types of tariff differentiation (e.g. according to different location or different consumer segments like industry vs. households) are not explicitly addressed.

[4] The experiment was carried out in 2001-2003 involving 300,000 residential customers and 20,000 small commercial customers in Washington state [energypriorities.com/entries/2006/02/pse_tou_amr_case.php].

certain electricity consuming devices (e.g. air conditioning, electric heating) RTP is also applied in the residential sector in some countries (Italy).

1.5. Interruptible contracts

Implementing real time pricing involves considerable investment costs. An alternative that costs less are interruptible contracts. In return for lower average prices, big consumers agree (under certain conditions) either to reduce their consumption when requested to do so by their supplier, or to pay a penalty. There are many such contracts, all of which try to solve the associated moral hazard problems.[5]

All competitive wholesale electricity markets (e.g. all EU and US power exchanges) feature either hourly or half-hourly prices. Furthermore, the transmission and distribution tariffs are also differentiated in many countries.[6] As suppliers typically purchase the electricity that they sell to end-consumer on these wholesale markets and pay the potentially differentiated transmission/distribution tariffs, their costs vary from hour to hour. In addition, the exact hour-by-hour demand of the end-consumers is usually uncertain for suppliers, although some general estimates of the demand profile exist. Therefore, it is quite likely that a flat tariff for a big end-consumer will either be too high (the consumer will choose another supplier) or too low (the supplier will lose money). This is especially true if one considers that an end-consumer who knows his flat tariff might have incentives to deviate *ex post* from his estimated load profile. Hence, if transaction costs (e.g., for metering) are sufficiently low, offering differentiated contracts will provide suppliers with a competitive advantage. Therefore, in a perfect electricity market,[7] each contract between suppliers and end-consumers should optimally balance tariff differentiation and the related transaction costs. Thus, in general one can observe that the bigger the end-consumer, the more sophisticated is the price differentiation scheme he negotiates with his supplier.

In practice, the existence of contractual freedom between suppliers and end-consumers in open electricity markets has led to a coexistence of all of the tariff schemes presented above. Due to increasing market liberalization, decreasing costs of sophisticated electronic metering and billing technology, and increasing experience, some suppliers are even considering introducing real-time pricing at the household level.

## 2. The Belarusian electricity sector

The Belarusian electricity sector is characterized by:

*A vertically integrated monopoly*: Belarus is the only country in Europe that maintains the monopolistic structure of its electricity market without attempting to unbundled, liberalize or privatize. The vertically-integrated state-owned monopolist "BELENERGO" is under control of the Ministry of Energy and consolidates the six regional vertically-integrated utilities (one for each oblast). These regional utilities (RUE-oblenergo) operate all power plants as well as transmission and distribution networks in the corresponding region (see Figure 1).

*Tightening capacity*: While today's capacity is still sufficient (in 2007 the maximum load was 6,200 MW and the generation capacity was 7,882 MW), the load forecasts (8,000-13,000 MW in 2020) as well as the fact that around 60% of the power plant fleet are worn out point towards a severely tightening capacity situation (see Table 1).[8]

---

[5] E.g., a utility may be tempted to provoke punishment payments by its customer by declaring unnecessary interruptions at times the customer is unable to react.

[6] Time differentiation (hourly-seasonal) of transmission tariffs is practised by many countries. Although, time differentiation is implemented differently across countries and it does not apply to the same elements of the tariff. In England, for example, the capacity term is computed from the three annual higher values (the "triad"). Spain distinguishes between six periods, each with a different value for capacity and energy. In Norway, we find that each two month period has two distinct schedules (high load, low load) for the energy component, based on recovery of the marginal cost of losses and used to calculate losses, while Sweden divides each year into four periods for purposes of computing loss coefficients and charges. Italy distinguishes between four hourly periods, applicable to the energy component (see Glachant (2002)).

[7] In other words, abstracting from market imperfections such as market power and search costs.

[8] On the capital depletion see for example: Hirschhausen and Rumiantseva (2006).

**Figure 1: Power system of the Republic of Belarus**


**Table 1: Peak Load Demand Forecast, MW**

| Year | World Bank | London Economics | Belarus Thermal and Power Institute | IAEA |
|---|---|---|---|---|
| 2010 | 9,600-10,390 | 6,610-8,300 | 9,480 | 8,530 |
| 2015 | 10,970-11,760 | 7,450-9,360 | 10,720 | 9,670 |
| 2020 | 12,410-13,310 | 8,400-10,560 | 12,130 | 10,950 |

*Source*: IAEA (2003).

*An unbalanced power plant portfolio*: Roughly 90% of Belarusian electricity generation capacities are fueled with natural gas.

*A high share of combined heat and power plants (CHP)*: With around 57% of total capacity, Belarus has one of the highest shares of CHPs in the world. While CHPs are remarkably efficient in cogeneration mode, their advantage quickly vanishes outside the heating period.

*High baseload generation cost*: As the efficiency of most Belarusian generation units is below Western standards, and prices for natural gas have increased significantly,[9] average generation cost in Belarus are significantly above the regional average. At a natural gas price of USD 200, the pure fuel cost of producing one MWh of electricity at the Beresovskaya Power plant amounts to 65 USD/MWh. Under the same gas price assumptions, the pure fuel cost for producing one MWh at the Lokomlskaya power plant[10] are 58 USD/MWh. Since the Beresovskaya (1,000 MW) and the Lokomlskaya (2,400 MW) power plants are the only big non-CHP facilities in the country, and together represent 46% of the Belarus generation capacity, it is most likely that they very often act as marginal suppliers.

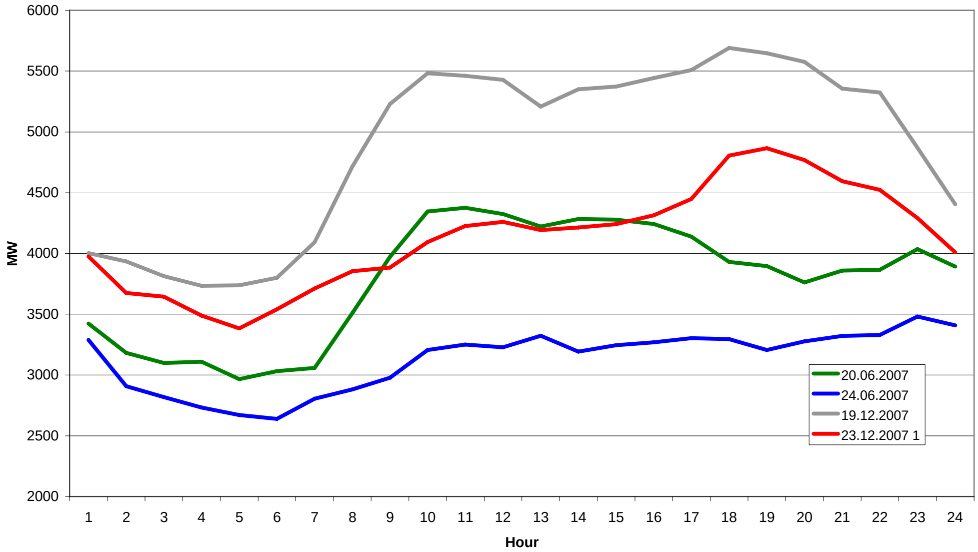
[9] According to a contract with Russia, natural gas prices for Belarus are expected to increase to "European level minus cost of transit" by 2011.

[10] The proposal for upgrading the existing gas turbines at the Beresovskaya Power plant lists an average (over all 6 blocks) specific natural gas consumption of 350-353 g of coal equivalents per kWh. For the Lokomlskaya power plant 316 g/kWh are assumed.

*Dependence on imports*: Due to the high generation cost of its power plant fleet, Belarus opts to import a significant share (>10%) of its electricity consumption from Russia (62%), Lithuania (21%) and Ukraine (16%). With the planned decommissioning of Lithuania's only nuclear power plant Ignalina, the import situation might, however, tighten as well.

*A pronounced peak load*: The Belarus peak load (6,200 MW) exceeded the average load (4,000 MW) by almost 50%. In comparison, the peak load in Germany (78,377 MW, 07.Nov.07 18:30) exceeded the average load (56,694 MW) by 38% (see Figure 2).

**Figure 2: Four Typical Belarus Load Curves**




*Regulated tariffs imply cross-subsidization*: Electricity tariffs for households are under regulation of the Council of Ministers; tariffs for other consumers are under regulation of the Ministry of Economy. Tariff rates are adopted for each group of consumers. The classification of consumers for grouping has not principally changed since Soviet times. The tariff system in the Republic of Belarus consists only of two tariff schemes: a two-part tariff (for used electricity and installed capacity) for industrial enterprises with an installed capacity ≥ 750 kVA and different one-part tariffs for all other consumers.[11] While residential consumers pay a strongly subsidized tariff of USD 0.0523 per kWh, industrial and commercial users usually pay approximately cost reflecting rates (USD 0.079–0.106).[12] Furthermore, experimental schemes apply for a small number of consumers.[13]

*An industrialized nation's consumption structure*: The electricity consumption structure in Belarus is comparable with that in Germany, with a slightly lower importance of households and a larger share of consumption going to the transportation industry (Table 2).

**Table 2: Consumption Structure**

| | Belarus 2003 | Belarus 2004 | Belarus 2005 | Germany 2005 |
|---|---|---|---|---|
| industry & construction | 46% | 48% | 48% | 45% |
| transportation industry | 8% | 8% | 8% | 3% |
| households | 23% | 22% | 22% | 27% |
| agriculture and others | 23% | 22% | 23% | 25% |

*Source*: http://data.un.org.

[11] There are ten groups of consumers: (1) Industrial and equated consumers with installed capacity 750 kVA and more; (2) Industrial and equated consumers with installed capacity less than 750 kVA; (3) Electrified railway transportation; (4) Electrified urban transportation; (5) Non-industrial consumers; (6) Electricity for heating and hot water supply; (7) Electricity for industrial needs of agricultural consumers; (8) Electricity for auxiliaries of the power engineering; (9) Urban households; (10) Rural households.

[12] The tariff policy and regulation system in the Belarusian energy sector is inefficient and outdated. The current state, main problems and prospects of the tariff policy are discussed in: Padalko and Zaborovskiy (2008).

[13] http://www.lawbelarus.com/repub/sub06/texb0241.htm. See also part 3 of the paper.

### 3. The case for price differentiation in Belarus

In the following we analyze whether tariff differentiation would be desirable for Belarus, given the characteristics of the Belarusian electricity sector discussed above. As laid out in Part 1, tariff differentiation schemes are set up to provide consumers with incentives to shift demand from high-load to low-load hours. The final aim of such a strategy is twofold: first, lowering fuel and emission cost; and second, reducing the fixed cost of the power generation and transmission system. In the following we provide an illustrative analysis of the potential benefits of a five percent peak load reduction with respect to both aims.

3.1. Lowering fuel and emission costs

In a system with a homogenous production structure, electricity by definition is always produced by the same technology.[14] As the current Belarusian electricity system comes close to such an 'idealized' situation, no significant gains from tariff differentiation would be expected. This is, however, only true if one ignores the considerable electricity imports as well as the intended extensions and modernizations of the Belarusian power plant fleet. To resolve tightening capacity, the Belarusian administration is planning to build a nuclear power plant, to extend the use of renewables, and to increase imports from Russia and Ukraine (at least in the interim). The marginal costs of these three options will be below the marginal cost of the current Belarusian power generation system (see Table 3).

**Table 3: Marginal cost of electricity in USD / MWh**

| Domestic generation | Nuclear | Wind / Hydro | Imports from Russia | Imports from Ukraine |
|---|---|---|---|---|
| 55-65 [1] | 10-20 [2] | 0 | 40-48 [3] | <50 [3] |

*Notes*. This are estimates of the pure marginal cost of producing one MWh of electricity. Consequently, investment, maintenance or labor costs are not included.
[1] see Footnote 10. In the cases, where CHPs are marginal in condensing mode, marginal cost might be substantially higher and reach 70 USD/MWh, in cogeneration mode marginal costs of CHPs are about 26 USD/MWh.
[2] Energywatchgroup (2007).
[3] according to IPM Research Center.

Under these conditions, shifting each MWh away from peak hours (where the existing expensive generation units will continue to run) to off-peak hours (where imports, nuclear power and renewables represent the marginal units) could save approximately USD 10-30 per MWh. Nevertheless, the potential fuel cost savings are rather unimpressive: shifting 5% of the load at the three highest load hours would provide savings of around USD 16,000 per day[15] or USD 5.8 m per year. However, in addition to the pure fuel cost, $CO_2$ emissions could also be reduced. If the 5% peak demand reduction would result in shifting the entire corresponding generation from natural gas (emission intensity of 0.4 t/MWh) to quasi emission free baseload generation (nuclear, renewables) the emission reductions could reach 116,000 tonnes of $CO_2$ per year.[16] In this rather overoptimistic case,[17] and at an emission certificate price of USD 20 the savings would amount to around USD 2 m per year. Furthermore, assuring constant load for the nuclear power plant and the non-controllable renewables in off-peak periods is an additional argument for load smoothing. Finally, Belarus might want to establish itself as a peak electricity producer in the region, exporting its peakload production at the corresponding high price[18] to its baseload dominated neighbors.

3.2. Reducing the fixed cost of the power generation and transmission system

Providing consumers with incentives to shift demand is a cornerstone of a least cost approach to the challenges faced by the Belarusian electricity sector. If projected demand growth (Table 1) materializes, Belarus will have to construct significant generation capacities. Most of the

[14] In a system consisting of only one type of power plant, marginal costs will only depend on load if individual power plants are characterized by increasing or decreasing efficiencies of scale (usually, a power plant has an optimal load factor).
[15] 3 h/day x 5,300 MWh/h x 5% x 20 USD/MWh = 15,900 USD/day.
[16] 365 d/a x 3 h/day x 5,300 MWh/h x 5% x 0.4 t/MWh = 116,070 t/a.
[17] Some of the shifted generation will still be produced in Belarusian natural gas power plants, others might even be imported from the more emission intensive Ukrainian coal power plants.
[18] To our knowledge, load-period differentiated prices for exports and imports do not exist currently.

new generation will have to be baseload producers (i.e., high investment and low fuel cost) but also the existing worn out peak-load generation will have to be modernized or replaced. When evaluating the cost of peak units, in addition to investment costs, labor, maintenance and other fixed costs have to be considered as well. According to the assumed annualized capacity costs in Table 4, natural gas power plants will be selected as peak units. Consequently, the effects of reducing the peak load can roughly estimated based on the annualized capacity cost of natural gas power plants. A reduction of peak load by 5 % (5% x 5300 MW = 265 MW) would reduce the annual cost of power plant capacity by USD 21 m. In addition, costs of ancillary services as well as the cost of potentially necessary transmission system extensions would also be reduced. Finally, the introduction of tariff differentiation often induces customers to carefully review their electricity consumption behavior resulting in the detection of additional saving possibilities[19].

**Table 4: Assumed annualized capacity cost of one kW**

| Nuclear | Natural Gas | Hard Coal |
|---|---|---|
| USD 270 | USD 80 | USD 150 |

*Note*. This table gives a rough approximation of annualized investment (interest=10%), maintenance and labor cost deduced from the collection of cost-figures in Öko Institut (1998).[20]

### 3.3. The cost of metering

Currently, most meters used for smaller consumers in Belarus do not have time-of-use metering capabilities. Time-of-use metering is, however, needed for price differentiation. The cost of improving metering equipment is relatively high. Table 5 shows some estimates of meter costs as a function of the meter's capabilities and the scale of its use. Due to its high cost as well as the limited price response capabilities of households, the installation of two-rate meters cannot at present be justified for the residents of urban apartment buildings with central heating, hot water and a standard set of household electric appliances.[21]

**Table 5: Cost of metering equipment**

| Meter Type | Functions | Unit Cost for 100 Consumers | Unit Cost for 50,000 Consumers |
|---|---|---|---|
| Meter Modifications | Limited AMR* | 175-300 | 75-300 |
| Existing Electronic Meters | AMR* Load Profiling | 250 | 100 |
| Advanced 'Smart' Meters | AMR* Load Profiling Time-of-use Control | 600 | 500 |

*Note*. AMR* = Automated Meter Reading.
*Source*: IEA (2001).

## 4. Implementation of intertemporal tariff differentiation in Belarus: lessons learned

In recent years Belarus implemented experimental tariff differentiation schemes for a small number of customers. But these experiments did not produce the expected results. Less electricity consumption than anticipated was shifted away from peak hours while the associated cost for the electricity utilities was higher than predicted. Although the system is still running, only a small number of consumers participate and consequently the impact on overall electricity consumption is very limited. The schemes of intertemporal tariff differentiation tested in Belarus and results obtained during the experiments are described in this section of the paper.

### 4.1. Two-part differentiated tariff

Introduced in 2002 this tariff scheme has been applied on a limited number of electricity consumers. In contrast to the simple two-part tariff the differentiated tariff contains a reducing coefficient ($k_a$) to the load component and differentiated coefficients to the electricity component.[22] The differentiated coefficients for the electricity component are defined for three time

[19] Studies (e.g., US DOE (2006)) also show that customers who are provided with more timely and/or more granular (e.g., hourly) information about their energy use will conserve energy.
[20] For detailed cost estimates of a Belarusian nuclear power plant, see Hirschhausen and Rumiantseva (2006).
[21] See Varnavskii (1994).
[22] This tariff scheme was developed by Boris V. Pekelis and approved by the Ministry of Energy. To our best knowledge no corresponding publication exists.

zones: night ($k_n$), semi-peak ($k_{sp}$) and peak ($k_p$). Consequently, the total fee according to the two-part differentiated tariff ($TF_d$) can be written as:

$$TF_d = a \cdot k_a \cdot P_f^{\max} + b \cdot (k_n \cdot W^n + k_{sp} \cdot W^{sp} + k_p \cdot W^p),$$

with $a$ being the load component of the two-part tariff, $P_f^{\max}$ the actual capacity usage during peak-load hours, $b$ the electricity component of the two-part tariff and $W^n$, $W^{sp}$, $W^p$ the electricity consumed during the night (11 p.m. – 6 a.m.), semi-peak (6 a.m. – 8 a.m. and 11 a.m. – 11 p.m.) and peak time (8 a.m. – 11 a.m.). The coefficients were laid down by Minenergo (see Table 6). The motivation behind this set of coefficients is unknown to the authors as corresponding explanations are unavailable.

The implementation of the presented tariff differentiation scheme took place on a voluntary basis.[23] The self-selection of the participants caused economic losses for the energy companies as almost only customers with load profiles that assured lower tariffs under the experimental scheme switched to those contracts. Customers with strong on-peak consumption by contrast did mostly not switch as most of them were unable/unwilling to offset the higher peak prices by shifting demand. The situation can be illustrated at a real-world example with two consumers with different load profiles. The first consumer has a relatively smooth electricity consumption while the second customer faces a pronounced on-peak electricity consumption.

**Table 6: Tariff Coefficients as set by Minenergo**

| | |
|---|---|
| $k_a$ | 0.5 |
| $k_{sp}$ | 1.0 |
| $k_n$ * | ~ 0.78 |
| $k_p$ * | ~ 2.09 |

*Note*. * see FN [24]

As illustrated in Table 7 the first consumer profits from switching the tariff scheme without any changes in his mode of consumption. As he could easily save BYR 33 bn or almost 5% of his monthly bill he will certainly switch. By contrast, the second customer would increase its monthly electricity bill by BYR 13.75 bn or almost 10.6% if he would switch the tariff scheme without changing its consumption behavior. Consequently he would only participate in the experimental scheme if he could inexpensively shift his consumption.

**Table 7: Example - Monthly Tariffs for two Customers with Different Load Profiles**

| | Customer 1 | Customer 2 |
|---|---|---|
| $W^n$ | 3.604 m kWh (35%) | 0.074 m kWh (5%) |
| $W^{sp}$ | 6.292 m kWh (60%) | 0.89 m kWh (60%) |
| $W^p$ | 0.52 m kWh (5%) | 0.52 m kWh (35%) |
| $P_f^{max}$ | 6000 kW | 6000 kW |
| Old two-part tariff | BYR 674.8 m | BYR 130.0 m |
| Experimental differentiated two-part tariff | BYR 641.8 m | BYR 143.7 m |

But the observed losses for the electricity companies associated with the experimental scheme were not only caused by the self-selection of the participants. Other main problems were:

– *Weak methodological base of tariff coefficient selection*: Both, the reduction coefficient for the capacity component and the differentiated coefficients for the electricity component were set without obvious economic reasoning.

– *All customers treated homogenously*: As the load profile of the customers prior to the experiment played no role in the tariff setting significant windfall profits for certain customers (with low peak consumption) arose.

[23] In fact, the Ministry of Energy required that participation in the scheme was on a purely voluntary basis.

[24] The values for $k_n$ and $k_p$ were set according to $k_n = 1 - \frac{a \cdot k_a \cdot (4 \cdot t_p - t_n)}{b \cdot d \cdot ((t_n)^2 - (t_p)^2)}$ and $k_p = 1 + \frac{a \cdot k_a \cdot (4 \cdot t_n - t_p)}{b \cdot d \cdot ((t_n)^2 - (t_p)^2)}$ with d being number of days in the settlement period. The presented coefficients correspond to the values at the beginning of the experiment (December 2002).

– *Annual seasonality of the Belarusian load curve is ignored*: The duration and time of the night, semi-peak and peak zones do not take into account annual seasonality of the Belarusian load curve. In winter and in summer time of the peak load differs significantly.

As a result the proposed tariff differentiation scheme has not created incentives to switch demand from high-load to lower-load hours. Some changes introduced in the proposed scheme after 2006 restricted its implementation and actually stopped the experiment.

4.2. Two-part interval differentiated tariff

This scheme was introduced in 2005 and intended to implement a new approach to intertemporal tariff differentiation taking into account the problems revealed during the experiment with the two-part differentiated tariff. [25] The interval differentiated tariff implements real-time pricing by linking the electricity component of the two-part tariff to the individual deviation from the system load curve. The total fee paid by the consumer using the two-part interval differentiated tariff is calculated according to $TF_{id} = a \cdot P_f^{\max} + \left[T_b + (b - T_b) \cdot (1 - \delta)\right] \cdot W$, where $T_b$ is a uniform base-load tariff for all consumers and δ an individual deviation index. For each day δ measures the deviations of the individual customers load profile from the system load profile.26 The value of δ lies between -1 (optimal, i.e. individual consumption mirrors the system load curve) and 1 (worst, i.e. individual consumption parallel to the system load curve).

Despite the half-hourly time resolution and the sophisticated deviation index the results of this experiment were not impressive with respect to contracts switched and electricity consumption shifted. Several reasons for this setback could be identified:

– *Relatively low shifting incentives*: According to the values for the deviation index (δ) the differentiated part of the tariff scheme ranges between a minimum value of $T_b$ (if δ = 1) and a maximum of 2b - $T_b$ (if δ = -1). Therefore, the max to min ratio (2·(b/ $T_b$) – 1) is not very high. Consumers have not changed the mode of consumption significantly because the difference between the electricity component of the two-part tariff and the differentiated rate of the two-part interval differentiated tariff was insignificant in case of typical industrial mode of electricity consumption.

– *Voluntary participation*: Again, participation in this scheme has been on a voluntary basis. Due to the voluntary approach the problem of self selection described for the two-part differentiated tariff might have also been present for the two part interval differentiated tariff. But, as the scheme failed to attract any participants a small number of state-owned enterprises was finally forced to take part in this tariff scheme experiment.

– *Weak economic foundation of tariff coefficient selection*: Like in the case of the two-part differentiated tariff developed scheme does not give the basics for the correct tariff rates selection. It concerns, first of all, the setting of the base-load tariff ($T_b$) formation. Due to the political control over this variable $T_b$ does neither reflect variable nor marginal costs of base-load power generation.

4.3. Time-zones differentiated tariff

In response to unsuccessful attempts to implement an efficient tariff differentiation scheme and taking into account the difficulties observed during the previous experiments a new

[25] This tariff scheme was worked out in Zabello (1985) and adapted by E. P. Zabello for the Ministry of Energy of Belarus that approved it in 2005.

[26] The deviation index δ is calculated according to $\delta = \sum_{t=1}^{48} \lambda_t$ with $\lambda_t = \begin{cases} I_t^{es} - I_t^{cs} & if \;\; I_t^{es} > 1/48 \\ I_t^{cs} - I_t^{es} & if \;\; I_t^{es} < 1/48 \end{cases}, \forall t = \overline{1,\dots,48}$,

where $I_t^{es} = \frac{P_t^{es}}{\sum_{t=1}^{48} P_t^{es}}$; $I_t^{cs} = \frac{P_t^{cs}}{\sum_{t=1}^{48} P_t^{cs}}$ with $P_t^{es}$ the load of the energy system in time t and $P_t^{cs}$ the load of the consumer in time t.

scheme of intertemporal tariff differentiation was submitted to the Ministry of Energy – the time-zones differentiated tariff.[27] The basics of this tariff are:

- An individual approach to tariff formation for every consumer;
- A balance condition for tariff rates to guarantee the equality of payment before and after a consumer switched to the new tariff (given no consumption behavior changes take place);
- The introduction of three floating (in accordance with seasonal factors) time zones for night, semi-peak and peak;
- A tariff formation based on economic fundamentals. That is, tariff rates take into account marginal costs of electricity generation of base-load, semi-peak-load and peak-load capacities and long-run marginal costs of power plant construction.

The total fee paid by the consumer using the time-zone differentiated tariff is calculated according to: $TF_z = \tau_n \cdot W^n + \tau_{sp} \cdot W^{sp} + \tau_p \cdot W^p$, with $\tau_n, \tau_{sp}, \tau_p$ *the* tariff rates for the night, semi-peak and peak time zones as well as $W^n$, $W^{sp}$, $W^p$ the corresponding electricity consumption. The tariff rates for the night, semi-peak and peak time zones are set to represent the corresponding generation cost.[28] A balance equation guarantees that the total payment before and after time-zones tariff implementation is identical if the consumer does not change its consumption behavior. The implementation of the described approach leads to different tariff rates for each month of the year because of difference in the marginal costs of electricity production and duration of the peak time zone. Tariff rates for each time-zone are calculated by the energy supplier and results are specified in the contract with the consumer for the settlement period. Duration, beginning and finishing time of night, semi-peak and peak zones are specified in the contract as well.

The tariff rates of the time-zones differentiated tariff for a typical industrial consumer for different months of the year are presented in Figure 3. The max to min tariff ratio is substantial for the proposed tariff scheme and gives good incentives for demand shifting. In June for example the peak tariff rate is 5.5 times higher than the night rate and 2.3 times higher than the semi-peak rate.

The most sticking shortcomings of the described scheme are:

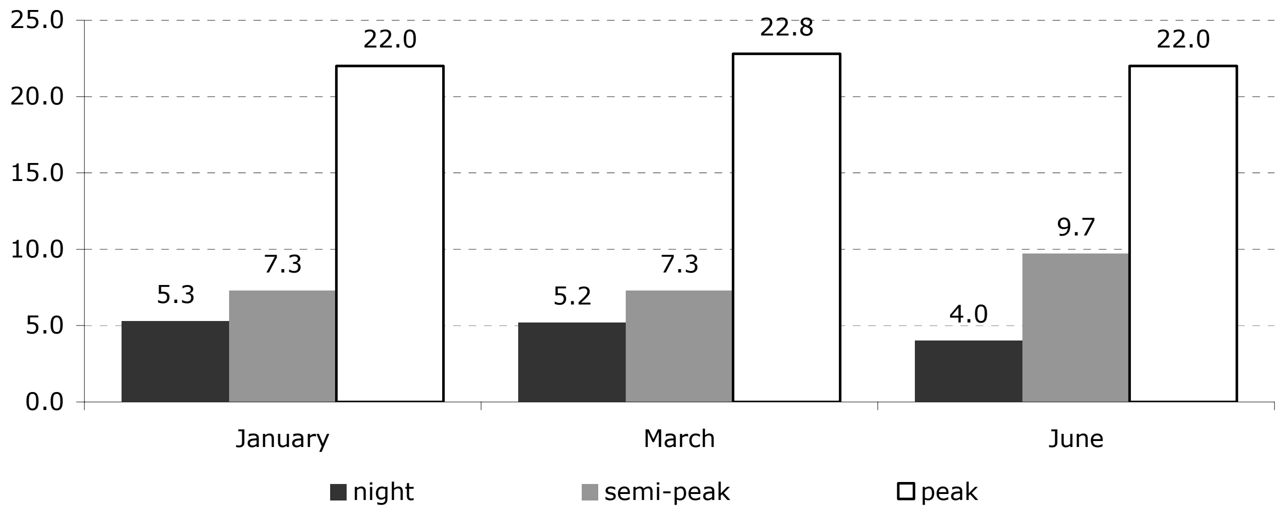
- *Comparatively high transaction cost for both the consumer and supplier*. The time-zones differentiated tariff has to be calculated and specified for each consumer based on its electricity consumption. Because of fuel prices adjustments the tariff has to be regularly updated. This procedure is not very complicated but requires recalculation of the tariff rates for each consumer.

---

[27] The foundations of this scheme were worked out in Verzhbickiy and Padalko (1983). The scheme was adapted for the Ministry of Energy of Belarus by Leonid P. Padalko and Alexander M. Zaborovskiy. The latest variant is represented here.

[28] Tariff rate for the peak time zone exceeds the night tariff rate by the marginal costs difference plus long-run marginal costs of generating capacity construction. It is calculated according to: $\tau_p = \tau_n + \Delta MC^{p-n} + \frac{k \cdot E}{h_p}$, with $\Delta MC^{p-n}$ the difference between marginal costs of peak and base electricity generation, *k* the generation capacity investment costs, *E* the accepted rate of return (daily updated) on investing capital and $h_p$ the duration of the peak time zone (*h*). The tariff rate for the semi-peak time zone exceeds the night tariff rate by the marginal costs difference. It is calculated according to $\tau_p = \tau_n + \Delta MC^{sp-n}$, with $\Delta MC^{sp-n}$ the difference between marginal costs of semi-peak and base electricity generation. Finally, the tariff rate for the night time zone is derived from $\tau_n \cdot W^n + (\tau_n + \Delta MC^{sp-n}) \cdot W^{sp} + (\tau_n + \Delta MC^{p-n} + \frac{k \cdot E}{h_p}) \cdot W^p = TF^{cs}$ where $TF^{cs}$ is the total fee paid by the consumer before the time-zones tariff implementation.

**Figure 3: Tariff rates of the time-zones differentiated tariff for a typical industrial consumer (USct/kWh)**




– *Different prices for same consumption*. From a fairness point of view it is bewildering that for the same consumption a consumer with high on-peak consumption in the last period has to pay a substantially lower price than another consumer with a lower historic consumption. This translates into a continued cross-subsidy for consumer with high on-peak demand in the first period.

– *Distortion of Competition*. Due to the described tariff scheme, newly entrant electricity consuming enterprises might face significantly higher electricity prices than existing ones in the same sector. This "protection" of old companies distorts competition and might be inefficient from an economic point of view.

– *Susceptible to strategic behavior*. The calculation of tariffs based on the initial consumption gives incentives to inflate the initial peak consumption to profit from lower electricity prices in all subsequent periods.

But it has to be noted, that it is exactly due to the highlighted cross-subsidies that described scheme gives incentives to existing peak-load consumer to switch contracts and shift consumption on a voluntary basis. Therefore, if the Belarusian government hesitates to introduce intertemporal price differentiation measures that might hurt some (peak load) consumer; the time-zones differentiated tariff might represent a feasible second best alternative.

### 4.4. Lessons Learned

Almost 7 years of experiments in Belarus have shown that effectively implementing intertemporal tariff differentiation is rather difficult in a vertically integrated state-owned electricity industry. The absence of a competitive wholesale market that provides reliable and timely price signals (on marginal generation cost) prevents the introduction of most of the schemes successfully implemented in Western countries (e.g. real time pricing or critical peak pricing). If in addition policy seeks to protect existing peak-load consumer from higher cost by opposing increasing flat rate prices and demanding a voluntary approach all known tariff differentiation approaches are bound to fail.

### 4.5. Selection of a tariff differentiation scheme

The introduction of a feasible tariff differentiation scheme entails three main methodological challenges:

– *Select a scheme suitable for the Belarusian electricity sector*;

– *Calculating the differentiated tariffs*. Taking into account that unbundling is absent in vertically-integrated energy utilities, capacities are unevenly distributed among regions and timely information on long-run marginal cost is unavailable it is quite difficult to calculate the economically sound tariffs;

- *Evaluate the peak-load reductions*. Because of the significant number of driving factors for electricity demand it is very difficult to asses quantitatively the peak load reductions due to an intertemporal tariff differentiation scheme. Such an evaluation, however, is necessary to obtain the described benefits because such information is needed for adjusting long term generation investments.

In open electricity markets, efficient tariff differentiation schemes are found through the contest of competing approaches. Because in Belarus a competitive electricity market is currently not in sight, it is hard to predict which tariff differentiation scheme would produce the optimal balance between peak-load reduction and increased transaction costs. Furthermore, the price responsiveness of Belarusian consumers, an important input for designing a tariff differentiation scheme, cannot be estimated as no transparent market exists.

In general, there is no one-size-fits-all solution because the relative impact of transaction costs (that increase with the complexity of the individual contract) decreases with the volume of the deal. For example, real-time-metering for one big customer is cheaper than installing thousands of time-of-use meters for residential consumer. Moreover, studies from other countries indicate that the price responsiveness of industrial consumer is higher than that of households. This is most likely to be the case in Belarus as well, because Belarusian households have only limited possibilities to shift load.[29] Furthermore, industrial customers represent a high share of peak electricity consumption and could certainly be provided with incentives to shift their consumption away from the early (9:00-10:00) and the late (17:00-18:00) peaks. Finally, for political reasons the Belarusian administration currently seems unwilling to confront residential electricity customers with market-near (or even time-varying) prices.

Consequently, we propose that introducing a well-designed and transparent tariff differentiation scheme especially targeted for medium and large customers is the most viable option. In this context, special attention should be paid to the long-term commitment to such a scheme. Otherwise customers would not commit to invest in long-term peak-load saving technologies that account for a substantial part of the overall load shifting.[30]

One important question for the introduction of a tariff differentiation scheme is the mode of implementation with respect to existing contracts. Different options exist:

- *Implementation of intertemporal differentiated tariffs on a voluntary basis*: To avoid that the self-selection of participants leads to high windfall profits for typical baseload customers without significant change in their consumption pattern this option requires the implementation of a sophisticated tariff scheme. The scheme should assure that for each consumer in the differentiated scheme the total payments before and after the switching are identical.
- *Implementation of intertemporal differentiated tariffs on a mandatory basis*: This option has not been tested in Belarus because of lacking political acceptance as well as difficulties with the ex ante evaluation of the expected outcomes.
- *Implementation of intertemporal differentiated tariffs on an economic basis*: The present cross subsidization of peak load customers (at the cost of off-peak load customers) could be avoided by significantly increasing the price for the undifferentiated tariff (it should be close to the marginal cost of peak-load generation). Then, most customers would switch to the differentiated scheme (with lower off-peak prices). Political acceptance for such a scheme however is uncertain, as it will produce winners (base load consumer) and losers (peak load consumer).
- *"Phase-in" approach*: This approach intends to make transition for peak-load consumer smooth and allow them to adapt to the higher cost. The tariff differentiation is introduced in predefined steps sequentially increasing the difference between off-peak and peak prices.

[29] Small customers have only few possibilities to shape peaks (e.g. low penetration of dish washers and air conditioning). Thus, strong incentives for shaping would require enormous mark-ups. Furthermore, too low night-electricity prices might promote the spreading of electricity storage-heating as a substitute for central heating. This would represent a threat to the CHP-system.

[30] The corresponding process optimization is characterized by significant initial investments in hardware and software (e.g., the corresponding SAP modul).

We suggest that the phase-in of the selected tariff differentiation scheme might be the best option to combine a smooth transition (without significant political resistance) and a sustainable long-term solution. If, however, existing consumer should be protected against rising prices at all cost, the implementation of tariff differentiation on a voluntary basis (as proposed by Padalko and Zaborovskiy; see Time Zone Differentiated Tariff) is an efficiency increasing second best solution.[31]

A final evaluation of tariff differentiation schemes goes beyond the scope of this paper. Such an evaluation would require a detailed analysis of electricity sector data that can only be carried out in close cooperation with the major electricity utilities and industry representatives. Despite the caveat that the selection of a tariff differentiation scheme requires careful comparison of all available options, we want to provide one example, how such a scheme for Belarus might look like:

Due to good international experiences, relatively low cost and political feasibility, critical peak pricing might represent a promising approach. To account for differences between medium and big customers a graduated scheme might for example consist of two groups:

– *Mandatory two-part tariff with time-of-use pricing for all consumers above a certain threshold (e.g., 10 MWh/a)*. The time-of-use difference should be successively increased from zero up to values representing the marginal cost difference.
– *Voluntary critical-peak pricing* with slightly lower electricity rates for all consumer willing to pay for the corresponding equipment.

## 5. Conclusion

Tariff differentiation could be a cornerstone of a least cost approach to the challenges faced by the Belarusian electricity sector. Assuming a 5% reduction of the peak-load through tariff differentiation, Belarus could annually save USD 25-30 m in capacity and fuel costs. Furthermore, a number of additional benefits that are difficult to quantify would arise: (1) reduction of ancillary services costs, (2) reduction of spending on transmission system extensions, (3) rising electricity consumption awareness that induces additional electricity savings, (4) reduction of $CO_2$ emissions, (5) assuring constant load for the nuclear power plant and renewables in off-peak periods, and finally, (6) price differentiation might serve as a political tool to implement important reforms such as reducing cross-subsidisation and direct subsidies, as well as increasing collection rates.

This paper does not intend to provide an optimal differentiation scheme for Belarus. Nevertheless certain issues related to the implementation of tariff-differentiation schemes should be kept in mind: (1) a long term commitment to the selected scheme is essential, (2) tariff differentiation for Belarusian households should not be prioritized and (3) maintaining the flat tariff implies subsidizing peak-load consumer at the expense of all other customers and distorts competition.

## References

Energywatchgroup (2007). *Hintergrundinfo Uranpreise - Einfluss der Urankosten auf die Stromerzeugungskosten in Atomkraftwerken.* (by Jörg Schindler und Dr. Werner Zittel). Ludwig-Bölkow-Systemtechnik Ottobrunn, April/Mai 2007.

Glachant, J.-M. (2002). "*Tariff Guidelines : Chapter 7: Tariff Features*". GRJM Working Paper 2002-11.

Hartman R.S., Doane M.J. and Woo C.K. (1991). *Consumer rationality and the status quo.* Quarterly Journal of Economics 141-62.

Hirschhausen, Ch. V. and Rumiantseva, I. (2006). *Economics of Nuclear Power Development in Belarus*. GET Policy Paper 03/06.

IEA (2001). *Competition in Electricity Market*. International Energy Agency, Paris.

[31] It should be noted, that all voluntary approaches face the problem that consumer prefer to stay in the default option (constraint rationality). So if the flat-tariff is the default option, consumer will hesitate to opt-out even it would save them money. Consequently, making tariff-differentiation the default option is good for both, the consumer and the utility (Hartman et al. (1991)).

IAEA (2003). Case studies to assess and compare different energy sources in sustainable energy and electricity supply strategies. International Atomic Energy Agency, Vienna.

Öko Institut (1998). Stromgestehungskosten von Großkraftwerken - Entwicklungen im Spannungsfeld von Liberalisierung und Ökosteuern. Freiburg.

Padalko, L. and Zaborovskiy, A. (2008). *Modern tariff policy on electricity and heat formation in the Republic of Belarus*. The economic bulletin of the Institute of economy of the Ministry of economy of the Republic of Belarus, No. 4, p. 41-53 (in Russian).

Spees, K. and Lave, L. (2008). Impacts of responsive load in PJM: load shifting and real time pricing. The Energy Journal, Vol, 29, No. 2.

US DOE (2006). Benefits of Demand Response and Recommendations. U.S. Department of Energy.

Varnavskii, T. (1994). Problems of large-scale Introduction of Electronic Electric Meters in Russia. Measurement Techniques, Vol. 37, No. 12.

Verzhbickiy, V. A. and Padalko, L. P. (1983). *About foundations of a three-part electricity tariff formation.* Power stations, No. 10 (in Russian).

Zabello, E.P. (1985). *About improvement of electricity tariffs*. Industrial power engineering, No. 5 (in Russian).