Energy Technology and Governance Program:

South East European Distribution System Operators Benchmarking Study

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LIST OF TABLES

LIST OF FIGURES

1. TERMS OF REFERENCE

Climate change induced and manmade outages occurring in the distribution system networks in Southeast Europe threaten the security of the electricity supply for end-use consumers and disrupt economic activity. To assist distribution system operators in Southeast Europe to reduce the breadth and scope of outages in their networks, USAID, together with the United States Energy Association, has establish a Southeast Europe Distribution System Operator (DSO) Security of Supply Working Group. Working Group members currently include representatives from the DSOs of:

Albania,
Bosnia and Herzegovina,
Croatia,
Macedonia
Serbia.

The DSOs from Kosovo and Montenegro are expected to join the Working Group and participate in this study. Representatives from the regulatory agencies (RAs) in these countries serve as observers to the Working Group.

Modelled after the Southeast Europe Cooperation Initiative (SECI) Transmission System Planning Project, the activities of the DSO Security of Supply Working Group will be demand driven to respond to the needs of the distribution companies in the region, with an emphasis on the following deliverables:

- **Business continuity plans** to help electric companies plan for all scenarios such as severe weather events that may impact their ability to provide reliable electric power to consumers;
- **Mutual assistance plans** to encourage distribution companies to share staff and materials necessary for fast restoration of service after a significant outage;
- **Maintaining and sharing critical inventory** to ensure adequate supply of spare parts necessary to respond to outage events;
- **Emergency procurement systems** to allow for rapid procurement of essential equipment in emergency situations;
- **Asset management programs** to optimize the life of distribution network infrastructure; and
- **Benchmarking of best practices**.

These deliverables will assist the SEE DSOs harden their distribution systems, thereby mitigating potential system outages induced by weather and climate related events. It will also assist them to adapt to climate induced outages by improving their ability to restore service in an efficient and timely manner as a result of weather related system disturbances.
Though it is widely accepted that distribution system outages continue to plague Southeast European electric power systems, the exact number, frequency, duration and the scope of outages in terms of the number of customers effected is not quantified.

Scope of Work

The Consultant will prepare a Benchmarking Study that estimates for each DSO the number, the cause, frequency, duration and scope of outages it has experienced during a time frame to be agreed upon by members of the Working Group at its initial meeting (generally presumed to be 1-3 years). This data will be compiled and used for a comparative analysis to benchmark the performance of the DSOs in the region against one another. A similar comparative analysis will be prepared to benchmark the performance of the DSOs in Southeast Europe against a utility(ies) in Western Europe or North America.

Results from the Benchmarking Study will provide the DSOs, regulators, donors, consumer groups and other interested parties a set of region-wide metrics on the extent to which distribution system outages threaten security of supply, an understanding of their route causes, and a comparison of the performance within the region and with other regions in their prevention and restoration of service. It is expected, that based on the results of the Benchmarking Study, the Consultant will assist the Working Group to develop a set of recommendations to improve system outage data acquisition and analysis as well as to provide preliminary indications of areas in which the Working Group should engage to improve outage mitigation and service restoration.

In preparing the Benchmarking Study, the Consultant will perform the following tasks:

TASK ONE: Select the Set of DSO Outage Benchmark Metrics to be Applied to the Benchmarking Study. In doing so, the Consultant will take into account the quality of data available from the DSOs by preparing a questionnaire to be distributed as a result of and following the initial Working Group meeting. Data returned in the questionnaire will be used to select the metrics used for the Benchmarking Study, based on the availability of data reported by the DSOs. A second questionnaire requesting data specific to those metrics selected by the Consultant for this Benchmarking Study will be issued to each DSO. With assistance from USEA, the Consultant will be responsible for collecting the responses to the first and second questionnaires.

A list of metrics are proposed by the Consultant and agreed to by the Working Group members during the July 16-17 meeting, 2013.

TASK TWO: **Compile and Benchmark System Outage Data within Southeast Europe and against a European or North American DSO.** The Consultant will prepare a profile report for each member of the Working Group that contains a physical and technical description of the network; information on commercial performance including losses, etc.; and other non-outage related information. This profile will provide a context in which outage data may be examined. The Consultant will then compile outage indices to report on the selected metrics for each Working Group member. The indices will provide the basis for two benchmarking studies enabling Working Group members and their regulators to: 1) assess an individual company's performance against another in the region and; 2) against a DSO in Europe or North America selected by the Consultant.

TASK THREE: **Develop Recommendations** on: 1) Improving Data Acquisition and 2) Areas in Which the Working Group Should Focus on Mitigating Outages and Improving Service Restoration. It is expected that data acquisition will be among the foremost difficulties in preparing the Benchmarking Study. The Consultant will provide recommendations on hardware, software, processes and procedures needed to improve DSO data acquisition and reporting on system outages. Based on the results of the Benchmarking Study, the Consultant will prepare a set of suggestions to the Working

Group for areas of future collaboration on mitigating outages and improving service restoration in line with the deliverables detailed on page one above.

TASK FOUR: Improve the capacity of distribution system operators to monitor and report system outages using harmonized definitions across the region. The consultant will conduct a two day training course to introduce counterpart DSOs to best practices of defining outage frequency and duration, restoration time, unserved load and other metrics by which the Working Group will benchmark their performance. The training will be considered the first in a series of training programs designed to promote common reliability definitions throughout Southeast Europe.

2. EXECUTIVE SUMMARY

Introductory remarks

Within this study central part of South East Europe is analyzed, including Croatia, Bosnia and Herzegovina, Serbia, Kosovo, Macedonia and Albania, as shown on the following Figure. In this region distribution system is operated by 9 DSOs:

1. HEP ODS (Croatia) - *HEP – Operator distribucijskog sustava d.o.o.*,
2. EPBiH (BiH) - *JP Elektroprivreda BiH*,
3. EPHZHB (BiH) - *JP Elektroprivreda Hrvatske Zajednice Herceg-Bosne*,
4. ERS (BiH) - *JP Elektroprivreda Republike Srpske*,
5. EDB (BiH) - *JP Komunalno Brcko*,
6. EPS (Serbia) - *Elektroprivreda Srbije*,
7. KEDS (Kosovo) - *Kosovo Electricity Distribution and Supply*,
8. EVNM (Macedonia) - *EVN Macedonia,*
9. OSHEE (Albania) - *OSHEE Operatori i Shpërndarjes së Energjisë Elektrike sh.a.*.

Figure 2.1 Geographical area analyzed in this study

Here it must be underlined that principally five distribution companies are operating in Serbia, all subsidiaries of EPS - “Elektrovojvodina” Novi Sad, “Elektrodistribucija Beograd”, “Elektrosrbija” Kraljevo, “Jugoistok” Nis, “Centar” Kragujevac, but within this report aggregated data have been evaluated.

At the beginning, it is important to note that this benchmarking study is the first common benchmarking analysis in this region for more than 25 years. Actually, from 1991 to 2004 the SEE power system was not connected in unified synchronous operation and there was no mutual cooperation. Prior to 1991 there were two separate power systems in the Balkans region: the Union for the Coordination and Transport of Electricity (UCTE), comprised of the western European and western Balkans power systems of Yugoslavia, Albania and Greece and the eastern system comprised of Hungary, Romania, Bulgaria and Soviet system. These asynchronous systems were connected through several direct current DC links.

Following the regional conflict, in October 2004 the systems were reconnected in synchronous operation under UCTE (now ENTSO-E). For the first time in history all of continental Europe (with the exception of Former Soviet countries and Turkey) operated as a single synchronous electricity area comprised of a population of 450 million and annual electricity consumption of 2 300 TWh. The synchronous power system of SEE was further enlarged in September 2010, when after 10 years of detailed preparations the Turkish power system connected to ENTSO-E via three 400 kV interconnections with Bulgaria and Greece. With its current 44 000 MW of installed generation capacity and 30 000 MW of peak load the Turkish power system effectively doubles the size of the SEE electrical area. SEE population is around 52 million. After the UCTE reconnection strong mutual cooperation of the regional TSOs was re-established again. But, due to its responsibility to operate and control local distribution networks, the DSOs did not have the strong need to re-established its regional cooperation yet.

Till 1991 all of analyzed DSOs, except Albanian one, were part of common ex-Yugoslavian power system. The organizational and ownership structure of the DSOs was different, but the coordination was strong. They were having common meetings on the regular basis within Yugoslavian CIGRE committee where different benchmarking indicators and experiences were developed and exchanged. Unfortunately, when the war conflict started in 1991 this cooperation was completely abandoned and this is the first action to re-establish regional DSO cooperation on the regular basis again.

Scope

This Benchmarking Study consists of 15 Chapters on 245 pages, including 97 tables and 218 figures. The Study is based on the large set of input data delivered by the DSOs through 1st benchmarking questionnaire developed and collected in the period July 2013 – February 2014 and 2nd benchmarking questionnaire developed and collected in the period May – August 2014. Even though there is a significant space for improvement of input data collection and benchmarking analysis, this is valuable input both internally for the SEE DSO working group to determine the most important topics of common interest to be addressed in the future work, as well as to all relevant decision makers in the region.

Terms of Reference is given in the Chapter 1 and Executive Summary in Chapter 2. In Chapter 3 basic information of 9 SEE DSOs are given, including total number of metering points, total number of customers, electricity delivered, supply area size, number of employees, length and age of the network, number of feeders, substations and transformers, distributed generation installed capacity and total network losses. After introductory part, in this Chapter all above mentioned values are compared among the DSOs. In Chapters 4, 5 and 6 relevant benchmarking indicators are analyzed, while in the Chapter 7 comparison to the US DSOs is given. Chapter 8 extensively covers the topic of metering, with a special emphasis on smart meters and advanced metering infrastructure (AMI), while the following Chapter 9 metering effectiveness is addressed. In Chapter 10 the basic legal, technical and economic issues of disconnection and reconnection / re-supply are given. Chapter 11 covers the billing process, and Chapter 12 revenue collection. Financial aspects, costs and competitiveness is given in Chapter 13 and the most important issues of customer services are addressed in Chapter 14. Finally, Chapter 15 gives recommendations for future work.

General characteristics of SEE DSOs

Total number of metering points in this region is 9,8 million. There is a large difference between the smallest one – EDB, BiH with just 36.000 metering points to the largest one EPS, Serbia and its 3,554 million metering points. EPS is holding 36 % of all metering points in this region. About the same relations will be found in the number of customers and supply area size. It is interesting that in the last five years (2008 – 2012) total number of metering points increased for 11 %, from 8,933 million to 9,878 million. Out of total 9,878 mil. metering points in the region in 2012, there are 8,814 mil. metering points on the low voltage – household level. Low voltage – commercial category is covered by 1,04 mil. metering points. Number of metering points on the medium voltage in the region is very low – just 23 721. Total number of customers in the region is 9,237 million and it was going up and down in the last five years (in the range 8,5 mil. to 9,2 mil.).

Total amount of electricity delivered to final customers in the region is about 64,1 TWh per year and there was no significant change on the regional level in the last five years. But, on the individual DSO level there were some more significant changes in total electricity delivered with respect to the referent year - 2008. For example, in Kosovo there was significant consumption growth since 2008 (up to 28 % compared to 2008), while at the same time in Croatia it felt down for about 6 % in 2009 and didn’t recovered yet. Dominant regional players are Serbian EPS (43,7 %) and Croatian HEP (23,1 %), delivering together more than 2/3 of total electricity delivered in the region. More than half of total electricity in the region (52 %) was delivered to the households, with these shares varying from 44 % in Croatian HEP to 62 % in Macedonian EVNM.

As expected, the largest share of the network length is at 0,4 kV voltage level (68 %), out of which 86 % aerial network. The distribution network is dominantly aerial (82 %), with the highest share in BiH (ERS) and Kosovo (KEDS) (more than 90 %), while in Macedonia (EVNM) and Croatia (HEP) there are largest shares of cable network (more than 30% of total distribution network length). On the other side, 54 % of all cables and 71 % of all overhead lines can be found in LV network.

Average distribution network age in SEE is 27 years. Looking per each DSO, the oldest distribution network can be found in Albania (OSHEE) with the average age of 37 years and Serbia (33 years). The lowest distribution network age is in Croatia (17 years).

Average distribution transformers age in SEE is 24. Looking per each DSO, the oldest distribution transformers can be found in Albania (OSHEE) with the average age of 34 years and Serbia (33 years). The lowest distribution network age is in Croatia (15 years) and Kosovo (17 years).

In SEE distribution network there are 119.125 substations, most of it in Serbia (29%), Croatia (21%) and Albania (20%). Total sum of all distribution transformers capacity in the region is 71.053 MVA or 0,6 MVA (600 kVA) per substation.

These 9 regional DSOs cover the area of 252.875 km^2, about the size of United Kingdom or Nevada (USA). The largest area portions are covered by Serbian EPS (31%) and Croatian HEP (22%).

In 9 regional DSOs there are 36.797 employees altogether. But, just 27.105 employees (74%) are dealing purely with network business. Remaining 4.943 employees (13%) are engaged in supply business, while 4.749 (13%) employees are shared between network and supply business.

In line with EU energy policy targets, as well as national energy strategies, there has been a lot of distributed generation projects in SEE under development in the last decade. At the end of 2012 there were 438,95 MW of distributed generation installed capacity. The largest part is installed in Albania (111,6 MW), BiH (total of 134 MW, with the largest contribution of EP BiH (94 MW)) and Macedonia (79,9 MW). Based on the number of DG projects under development, it is expected to have significant increase in DG integration in the near future.

General benchmarking indicators

One of the most important DSO benchmarking indicators is electricity delivered per each consumer. In SEE this range is between 3.654 kWh/consumer (OSHEE, Albania) and 8.125 kWh/consumer (EPS, Serbia). The average amount of electricity delivered to each consumer in SEE is 6.939 kWh/consumer. The average amount of electricity delivered to each metering point in SEE is slightly lower - 6.488 kWh/metering point.

Electricity delivered per employee slightly increased since 2008, i.e. from 1.633 MWh/employee in 2008 to 1.834 MWh/employee in 2012, or 12 %. Average of all DSOs in 2012 equaled 1.738 MWh/employee. The largest increase in 2012 comparing to 2008 is noticed in OSHEE (73,3 %) and EVNM (43,2 %). In two DSOs electricity delivered per employee in 2008 is higher than in 2012 – EPHZHB (-19,6 % since 2008) and HEP (-0,6 % since 2008).

Electricity delivered per km of distribution network (including all voltage levels) strongly depends on the distribution area shape and size, as well as geographical dispersion of consumers. That is why a large variety of values could be observed, i.e. between 0,07 GWh/km in ERS (BiH) and 0,29 GWh/km in EVNM (Macedonia). Average value was on the level of 0,148 GWh/km in 2012; it decreased around 12 % since 2008.

It has always been a question for power system planners how to optimize number of transformations and its loading in the system. In that sense it is interesting to measure the level of transformers loadings, in other words electricity delivered per transformer installed capacity or installed capacity usage (hours per year). For X/MV transformers this indicator varies significantly, between 1.541 h/year (EPHZHB, BiH) and 6.807 h/year (EPBiH, BiH). The average value is 3.405 h/year. For MV/LV transformers this indicator does not vary significantly. It is in between 1.066 h/year (ERS, BiH) and 1.686 h/year (EPS, Serbia). The average value is 1.473 h/year.

The average transformer capacity in X/MV substations in the region is 14 MVA. The average transformer capacity in MV/LV substations in the region is 334 kVA and it is in the range between 205 kVA (OSHEE, Albania) and 599 kVA (EVNM, Macedonia).

Average number of MV (20 kV, 10 kV and 6 kV) feeders per X/MV substation (i.e. 110/10 kV; 110/20 kV; 35/20 kV; 35/10 kV; 35/6 kV) is in the range form 6,9 in OSHEE (Albania) to 20,4 in HEP (Croatia), with an average of 10,6. Average number of LV (0,4 kV) feeders per MV/LV substation (i.e. 35/0,4 kV; 20/0,4 kV; 10/0,4 kV) is between 4,2 in HEP (Croatia) and 6,8 in ERS (BiH), with an average of 5,0.

Regional DSOs operate at the different supply area size and shape. Due to its very small size, EDB, BiH is having the largest electricity delivered per supply area size – 455 MWh/km^2. Regional average is almost twice lower, around 253 MWh/km^2, while the lowest level of electricity delivered per supply area size is in EPHZHB (BiH), around 107 MWh/km^2. Accordingly, the ratio between the lowest and the highest level of electricity delivered per supply area size is more than 4 times.

Continuity of supply

SAIDI for unplanned interruptions on all voltage levels, for all events in distribution network generally shows a smooth trend change, decreasing (EPBiH) or being constant in given timeframe (HEP, ERS, EPHZHB). It is important to keep in mind that all DSOs didn't provide the same set of input data (for example, some data for interruptions on LV are missing). There are no available input data on continuity of supply for EVNM, Macedonia. Based on available data it can be concluded that only in KEDS smooth increase of SAIDI value is found in the period 2008 – 2012. SAIDI range for unplanned interruptions in SEE is between 245 – 6.849 minutes. The largest level of SAIDI is found in OSHEE, Albania (up to 6.849 min) and it is significantly higher than in other DSOs (all up to 1.589 min). The lowest SAIDI is in HEP (Croatia). The level of SAIDI on medium voltage network is not significantly lower than on the system level and it is between 256 (HEP, Croatia) and 6.008 minutes (OSHEE, Albania).

Duration of planned interruptions relates to those minutes off supply experienced by network users after they receive prior notice of planned electricity interruption. SAIDI range is in between 25 minutes (KEDS, Kosovo in 2012) and 881 minutes (EPHZHB, BiH in 2010). Country data show (more or less) slightly decreasing trend (ERS, EPBiH, EPHZHB, KEDS, EPS). The only outlier in respect of planned SAIDI is Croatian HEP which has almost persistent values over observed period.

CAIDI indicator is given just for unplanned interruptions at all voltage levels. It is in the range between 47,3 minutes (EDB, BiH in 2012) and 236,7 minutes (KEDS, Kosovo in 2009). In 2012 all DSOs, except Albanian OSHEE, are having CAIDI values below 120 minutes (i.e. 2 hours). In most of the DSOs (except KEDS) CAIDI is at almost a constant value within a given timeframe.

The data for electricity not delivered to final consumers on all voltage levels due to unplanned interruption in the distribution network were available only for 3 DSOs (HEP, EPS and KEDS). Values range between 2 GWh/year (EPS, Serbia in 2011 and 2012) and 155 GWh/year (KEDS, Kosovo in 2011).

4 out of 8 DSO which provided data have less than 8.000 unplanned interruptions per year in the observed period. Of course, these values strongly depend on the network length. Higher values can be observed in Serbian EPS (the largest DSO based on distribution network length), but also in Albanian OSHEE (the third largest DSO in the region), BiH ERS (the fourth largest DSO in the region) and Kosovo KEDS (the sixth largest DSO in the region). Share of unplanned interruptions in total number of interruptions is in the range between 32,6 % (HEP, Croatia in 2011) and 98,2 % (KEDS,

Kosovo in 2012). Out of 8 DSOs 7 DSOs have over 50 % share of unplanned interruptions in total number of interruptions.

Electricity losses

the level of total losses in distribution network in SEE in the period 2008 – 2012 was in the range between 7,2 % (HEP, Croatia in 2008) and 43,5 % (OSHEE, Albania in 2012), but mainly in the range of 9 % and 17 %. Region average in 2012 equals 17 %. In Albanian OSHEE and Kosovo KEDS levels of losses are significantly higher than in the rest of the region. Besides, in given timeframe there is no significant losses reduction in any of analyzed DSOs.

Some of DSOs provided the estimations of shares of technical and commercial losses. In KEDS, EPHZHB and ERS the levels of technical losses are almost the same as the levels of commercial losses; in EPHZHB and KEDS commercial are slight higher, while in ERS technical losses are slightly higher than commercial. The outliers are EPS and OSHEE. In OSHEE the level of commercial losses almost doubled in 2012 in comparison to 2011 (from 18 % to 29 %). In EPS estimated technical losses are uncertainly low; i.e. 1 %. In ERS and EPHZHB commercial losses has been declining in the observed period. In EPHZHB in 2012 commercial losses were 40 % lower than in 2008, while in ERS in 2012 they were 18 % lower than in 2008.

In the case of OSHEE it can be seen that in the three years period 2008 – 2010 the level of approved losses was exactly the same as realized total losses (technical + commercial). The same applies to Serbian EPS in all years. In EDB in 2012 approved level of approved losses was slightly lower than realized total losses. In 2011 and 2012 total losses in OSHEE were slightly lower than losses approved by the regulator even though total level of losses was higher than in 2010. In other words OSHEE was acting more efficient with lower losses than the regulator expected. The same applies to EPBIH for the last two years in the observed period. On the contrary, in the case of Macedonian EVNM, ERS (BiH) and KEDS (Kosovo) in the whole period 2008 – 2012 level of total losses was higher than the level approved by the regulator. In Macedonia the regulator was slightly increasing the level of approved losses, while for ERS (BiH) and KEDS (Kosovo) approved losses (in %) in the last three years were almost constant.

Cost of total losses is defined as the unit cost of electricity losses paid annually for procurement of one MWh of energy losses. In some countries it is fully regulated, while in other it is linked to market price. It is expected that in the future all network losses will be procured using market based methods. In 2012, the range of unit cost of losses is 27 €/MWh (KEDS, Kosovo) – 83 €/MWh (EPHZHB, BiH). In most of the DSOs the unit costs of losses were quite stable in the period 2008 – 2012. The exception is ENVM, Macedonia where significant increase was present – from 35 €/MWh (2008) to 66 €/MWh (2012). Data for ERS, BiH are not available.

Comparison to the US DSOs indicators

One of the tasks to be realized in this study is to benchmark SEE DSOs with DSOs from the western countries. For this purpose American Electric Power with its 7 subsidiaries are chosen since American Electric Power (AEP) is a major investor-owned of electric utility in the United States. These 7 AEP companies and total of AEP are having similar level of electricity delivered per consumer (22 – 39 MWh/year). It is much higher than in DSOs in SEE where values range from 3.654 kWh/consumer (OSHEE, Albania) to 8.125 kWh/consumer (EPS, Serbia), with an average of

6.939 kWh/consumer. This clearly shows different level of economic development and/or small to medium industrial activity.

Similar to that, US companies are also having much higher level of electricity delivered per employee (22 – 35 GWh/employee). It is much higher than in SEE DSOs where average electricity delivered per employee equals 1,738 GWh/employee (on average 16 times lower). Without going into internal organizational structure of each DSO (whether DSO is bundled with supply business, and/or with other parts of vertically integrated company, outsources some of its tasks, etc.), it is clear that US companies are significantly more efficient. Accordingly, average number of customers per employee in SEE DSOs is 250, while in the US DSOs it is 927, (3,7 times higher).

US companies are having significantly higher values of electricity delivered per network length than those from the SEE even though it varies between 0,07 GWh/km in ERS (BiH) and 0,28 GWh/km in EVNM (Macedonia). In 2012 average value in SEE equalled 0,15 GWh/km, while in given US companies it was about 0,44 GWh/km. This suggests that the distribution network infrastructure in US AEP is about three times more efficiently used than in SEE.

SAIFI indicator for unplanned interruptions at all voltage levels shows large differences between SEE and US DSOs. In given US DSOs SAIFI for unplanned interruptions is up to 3, while in SEE DSOs it is in the range between 2 interruptions/year (KEDS, Kosovo in 2009) and 34 interruptions/year (OSHEE, Albania in 2012). On the other side, for planned interruptions at all voltage levels SAIDI indicators in the US companies are practically equal to zero. In other words, network maintenance and other planned activities in the US cause almost no supply interruptions, mostly due to "live working" (work without disconnection) or different maintenance practice. SAIDI range is in between 25 minutes (KEDS, Kosovo in 2012) and 881 minutes (EPHZHB, BiH in 2010).

Total number of long unplanned interruptions is significantly lower in SEE than in the US DSOs, as expected due to network size. With exception of AEP, the other US DSOs are all below 54.000 long unplanned interruptions. On the other side total numbers of long planned interruptions vary a lot between different DSOs, starting from KEDS and EPHZHB in SEE and SWEPCO in the US with small number of long planned interruptions (<1.000) up to HEP and EPS in SEE and AEP in the US with large number of long planned interruptions (>10.000). In general, it can be concluded that there are no regional specificities that would explain differences in number of long planned interruptions in SEE and the US.

In SEE DSOs shares of planned in total number of interruptions are predominately higher than 30%, with the exception of ERS (~15,4 %), OSHEE (~11 %) and KEDS (~1,8 %), while in US DSOs all values are below 20 % (only exception is AEP-OH with 28,3 % in 2010). These values prove that the maintenance and other planned interruptions are performed in different way in the US and SEE DSOs. Differences mainly refer to "live working" (i.e. work on the equipment without its disconnection). This could be one of the areas in which SEE DSOs could analyze and take over US practice and experience in order to reduce number and duration of planned interruptions.

Meters

In some countries worldwide there are specific customer classes that are allowed connections without meters. In the observed region the latter applies only to Albanian OSHEE.

On MV in 6 out of 9 DSOs (KEDS, HEP, EVNM, EPS, EPHZHB, EPBIH) share of smart meters exceeds 50 %. Remote reading of MV customers prevails in 5 out of 9 DSOs: KEDS, HEP, EVNM, EPHZHB and EPBIH. In EPS and OSHEE on MV prevails automatic reading using terminal, while in ERS and EDB manual reading.

On the LV level 73 % of meters are electromechanical ones, on average 26 years old, which is close to reported lifespan of analog meters of about 30-40 years. The share of smart meters is 2,8 %. In 3 DSOs (EDB, EVNM and OSHEE) there are no smart meters on LV level, while the largest share of smart meters in LV distribution network is in EPHZHB (19 %). The highest share of smart meters is present at LV commercial customers with peak power registration (31 %).

For LV commercial customers with peak power (demand) registration in 4 DSOs the most common type of electricity meter is smart meter (KEDS, HEP, EPHZHB, EPBIH). In other 4 DSOs it is the electronic meter: EVNM, ERS, EPS, EDB. The most of LV commercial customers with peak power (demand) registration are read remotely.

For LV commercial customers without peak power (demand) registration common types of electricity meters differ. The meter reading is mostly conducted manually (in 6 DSOs: KEDS, EPBIH, OSHEE, ERS, EDB, EPHZHB) or automatically using terminals (in 3 DSOs: HEP, EVNM, EPS). In EPHZHB smart meters (their share equals nearly 30%) are read remotely.

At LV households customers dominate electromechanical meters. Exception is EVNM where electronic meters prevail. With regard of meter readings, manual reading prevails at 6 DSOs: KEDS, ERS, EPHZHB, EPBIH, EDB and OSHEE. In HEP and EPS (two largest DSOs in the region) and EVNM automatic readings using terminal dominate.

Average age of all MV meters in SEE DSOs equals 5,7 years (this is due to the fact that 63% of MV meters are smart meters and 32% electronic). On average, LV electromechanical meters are 26,2 years old, LV electronic meters are 11,8 years old and LV smart meters 5,6 years old.

Remote meter reading is considered the most important reason for the roll out of smart meters. DSOs shall take a central role in the roll-out of smart meters. In line with the provision of the EU Third Energy Package this report suggest National Cost Benefit Analysis to be performed by the Regulatory Authority on electricity smart metering roll-out. The main reasons for the roll-out are:

- efficient remote meter reading,
- reducing electricity losses,
- reducing fraud,
- improving responses to delayed or lack of payment by consumers;
- many new services, including energy efficiency services, for customers (however, to realize potential feedback-induced savings, advanced meters (smart meters) must be used in conjunction with in-home (or on-line) displays and well-designed programs that successfully inform, engage, empower and motivate people.).

By examining countries cases (forerunners in the roll-out of the Smart Grid or countries that have applied a distinctive approach to the roll-out and/or to the management of the meter data, e.g. Sweden, Italy, Denmark, France, the UK, Texas in the USA), lessons can be learned on successful market models in support of a large scale roll-outs and on potential pitfalls and challenges.

Metering effectiveness

In the observed region unauthorized connection points (connections without metering) and also unauthorized use of meters (e.g. tempered meters, tempered time switch, broken seal) are present, however they are not prevalent. Although their shares (given as a portion of total number of connection points) are not higher than 1,7%, in some years detected irregularities exceeded 20 % of conducted inspections (either planned inspections or inspections due to reported finding of irregularity/fraud). Therefore, to detect unauthorized connections and lower losses caused by them in the system, customer connections and meters should be frequently inspected.

In the observed region monthly readings of almost all electricity meters are required which is very valuable initial position for market activities and management of distribution system (exception are households in Croatia). Croatia is the only country with self-reading for households envisaged by the law. Self-reading shall be strongly encouraged for customers that are not read monthly.

Because of ordinary monthly readings all DSOs are exhibiting relatively low shares of meters without any reading during a year. Exception is Albanian OSHEE (with 13 % average for 2008-2012 period) in households category and HEP in households and LV commercial customers without peak power registration (5 % and 4 % in 2012 respectively).

Percentages of meters not read according to prescribed schedule in the observed period are all lower than 7 %, with the highest values in households category. Performance of DSOs in this regards shall be subject to quality of service standards established by regulatory authority.

Disconnection and reconnection / re-supply

In almost all DSOs Supply Rules and Distribution Grid Code propose unauthorized connection and use of electricity, legal conditions for disconnection, fines and penalties envisaged and also methodology for estimating unauthorized electricity consumption. Failure to pay a bill owed to the supplier/DSO results in electricity supply suspension until payment of overdue amounts or agreement on payment schedule.

General prohibition to disconnect customers does not exists in SEE DSO (the same applies to Europe DSOs). A majority of SEE DSOs have protective measures in place in order to prevent or at least have a process in place to delay disconnection from electricity supply. Groups that benefit from a general prohibition of disconnection are people with life threatening illnesses, hospitals or other specific population groups that are deemed particularly vulnerable.

In 2012 there were 1.182.235 disconnections and supply suspensions due to theft and non-payment of bills in SEE DSOs; 12% of all connection points. On average, there were 3.239 disconnections/supply suspensions every day. This number is rather high. Kosovo KEDS, Albanian OSHEE and Macedonian EVNM obviously have to struggle with electricity theft and payment of bills in timely manner.

Examination of data provided by DSOs on reconnection/resupply aspects (prescribed period of time to provide service, realized time of service, averages fees charged to customers for service) and observed differences, reveal need of precise definitions and data acquisition harmonization in future work on benchmarking of SEE DSO.

Billing

Besides the primary function of charging the customers for the network and other power system services, usually including energy supply, the bill is also important as a comprehensive information to customers on energy consumption, prices, opportunities for savings and efficiency. Therefore billing the customers for the service of electricity distribution should be based on accurate periodical meter readings and bills issued on a monthly bases.

In Bosnia and Herzegovina and Serbia provisional billing is used only exceptionally. Other DSOs have shares of provisional billing up to 17%, depending on customer categories. Provisional billing should be avoided as much as possible and bills should be based on accurate and timely conducted periodical meter readings. For households self-reading should be promoted as an effective alternative to meter reading conducted by DSO staff.

For MV customers and LV customers with peak power registration bill processing time is between 2 and 5 days, with exception of OSHEE where it halved from 16 days in 2008 to 8 days in 2012 for MV customers. For households and LV customers without peak power registration in 2012 it is between 3 and 10 days, while for public lighting it is between 3 and 12 days.

Frequency of billing errors corrected before sending the bills to households, LV commercial customers with peak power registration and LV commercial customers without peak power registration is below 0,5 %.

Frequency of billing errors corrected after sending the bills to households is relatively high in KEDS (4 % to 5 %) and HEP where it is between 3,5 % and 4 %, due to half-yearly meter readings and high share of provisional billing. For the rest of DSOs it is between 0,02 % (OSHEE in 2008) and 1,43 % (OSHEE in 2011). Frequency of billing errors corrected after sending the bills for LV commercial customers with peak power registration, LV commercial customers without peak power registration and public lighting is between 0 % and 0,5 %, with exception of HEP where it is between 1,3% and 2,3 % (data for all non-household customers).

Majority of billing errors should be detected and corrected before sending the bill to customer, which is still not the case in the SEE DSOs. Therefore more accurate and strict procedures for control and auditing of the entire metering and billing procedures and correction of errors in timely manner should be developed.

Revenue collection

ERS has the highest average days of bill payment (in 2012 166 days i.e. 5,5 months). All others DSOs in 2012 have values lower than 35 days for households, and 60 days for LV non-households.

Albanian OSHEE has the highest values of bill payment overdue. In 2012 average for all MV and LV customers equals 175 day which is around 6 months overdue. All other DSOs have averages below 45 days. The best performing LV category in the region are households (the exception is only EPBIH).

With regard of ratio of bills collected in due time only 5 DSO provided data. It could be observed that in EPS, EVNM and OSHEE for around 50 % of customers (in all observed MV and LV categories) bills are collected in due time; the exception is the worst performing category public lighting in OSHEE with 12 %. In EDB and EPBIH ratios of bills collected in due time are over 92 % in 2012 (exception is EDB in households category with 85 %).

With regard of ratio of bills collected in fiscal year all DSOs provided data. In MV category 90 % of bills are collected. In LV consumption categories in almost all DSOs 92 % of bills are collected in fiscal year. Exception is OSHEE with 71 % in households category, 66 % in public lighting, 85 % in LV commercial without peak power registration and 64 % in LV commercial with peak power registration. Besides, there is also KEDS with 83 % in households category.

It could be concluded that the collection performance is complicated in the region by DSOs restricted resource for non-payment or delayed payment: limited legal recourse to recover unpaid bills, inability to write-down bad customer debts or negotiate payments, effective inability to disconnect non-paying customers (e.g. for political or social reasons).

Competitiveness analysis

Distribution and retail business is relatively labor intensive, implying companies should strive for efficient level of staffing and staffing cost. The lowest average labor cost per MWh of distributed energy are observed in OSHEE, EPS and EVNM respectively with costs below 5 €/MWh. The rest of the DSOs exhibit costs in the range of 10-15 €/MWh, with the exception of EDB which records 20,1 €/MWh.

With regard to labor cost per metering point, the similar pattern is observed. The lowest values are observed at OSHEE, EVNM and EPS respectively with average values below 45 €/MWh, whilst the reaming DSOs had values in the range of 69 €/MWh (EPBIH) to 147 €/MWh (EDB).

When taking into account employment level per number of metering points, DSOs seem to exhibit more similar results.

It is important to indicate potential limitations of this analysis. In particular we were not able to identify to what degree did the DSOs outsource services. Thus, to get the complete picture of employment efficiency this issue deserves further investigation.

Most of the DSOs exhibit values of ratio of depreciation to book value of property plant and equipment below 8 % whilst OSHEE and EDB exhibit significantly higher values. Values of around 8 % are to be expected as this value is commensurate with average distribution asset life.

In order to more easily compare the values of investment and depreciation to book value, their difference was observed. Positive values imply the ratio of investment to book value is greater than depreciation to book value, hence the DSO is investing more that it is depreciating. Taking the average value for the five year period, four DSOs have on average invested more than what has been written off, whilst four DSOs (OSHEE, EDB, ERS and EPS) have invested less than what was written off in the period 2008 – 2012.

The ratio of maintenance cost to book value of distribution assets for all of the DSOs are below 3 %, where EDB stands out as an exceptionally high level of maintenance costs. It can be stated that EPBIH, HEP, OSHEE, ERS spend proportionate amounts on maintenance. EPHZHB, EVN spend slightly more whilst EPS and EDB spend significantly more than the rest of DSOs.

The lack of standardization and harmonization of the reported data is particularly observed with regard to financial data and operating expenses. Having identified some of the issues, a more detailed data collection exercise is proposed with the following emphasis:

- revenues from distribution and / or retail services should be clearly identified. It is important to distinguish revenue from sale of electricity and revenue from use of distribution network,
- pass through costs should be clearly identified and not taken into account (e.g. transmission costs),
- all data should then be adjusted to reflect purchasing power differences among countries.

Additionally, in order to determine the efficiency of observed DSOs, a more complex analysis should be used such as Stochastic Frontier Analysis of Corrected Ordinary Least Squares which would give additional valuable insights. Such advanced analysis would allow each DSO to observe how far away it is from efficient operations.

Customer service

Customer rights in SEE DSOs are definitely lagging behind in comparison to customer rights in the EU DSOs. On the other hand, DSOs customer service may be a DSO's principal means to establish/improve public image (especially when increasing tariffs).

Although it seemed the indicators in this group are instantly recognizable, the actual standards and ranges used by different DSOs show that customer services in future reports should be developed in terms of definitions needed for precise benchmarking of DSOs.

As observed in 5th CEER Benchmarking Report on the Quality of Electricity Supply, no adequate statistical data exists for most commercial quality indicators. In observed DSOs commercial quality is largely enforced by standards that in essence are not guaranteed to customers because there is no compensation for individual customers and often there is no penalty defined. Therefore, further development of the legislation and practice to accommodate even basic service quality regulation is needed.

For customer complaints only average times can be calculated (or more often estimated). All DSOs lack call centers standards and do not record visits/appointments. It could be concluded that there is a need for developing technical systems designed for customer care.

Most of the observed DSOs are only in a very early stages of developing service quality regulation. This report suggests DSOs to follow with:

- the establishment of legal framework,

- usage of standards and guidelines of good practice (e.g. definitions should be developed in order to allow monitoring and acquisition of data, standards should be based on specific and precise definitions),
- the implementation of the monitoring system,
- quality standards and incentive schemes.

Recommendations

Based on all provided data and derived indicators, taking into account best practices and relevant case studies, the final chapter presents the recommendations for improvement of DSOs performance divided in three groups:

- organizational recommendations,
- data harmonization and
- share of best practices in distribution business.

3. GENERAL CHARACTERISTICS OF SEE DSO

As an introduction for the benchmark analysis, in this Chapter basic information of nine Southeast European distribution system operators (SEE DSO) are given. All basic information in Subchapter 2.1 are referring to 2012. After set of basic information, 13 benchmarks are given (number of metering points, number of customers, electricity delivered, distribution network length, distribution network age, number of substations, number of transformers, supply area size, transformer capacity, number of feeders, distribution network not operated and owned by the DSO, number of employees and distributed generation data).

3.1. BASIC INFORMATION ABOUT SEE DSO

OSHEE - ALBANIA

In Albania there is one DSO that has been privatized in 2009. when Czech energy holding CEZ entered Albanian market and bought 76% in CEZ Shperndarje. However, since July 2014 Albanian state got back CEZ shares on OSHEE *Shpërndarje*.
Information on Albanian DSO *OSHEE* for 2012 are given in the following Table.

Table 3.1 Basic data on Albanian distribution system operator - OSHEE

OSHEE - Albania	
	2012
Total number of metering points	1.181.950
Total number of customers	1.181.950
Electricity delivered to final customers [MWh]	4.318.583
Supply area size [km²]	28.748
Total length of distribution network owned by DSO [km]	45.270
Length of 110 kV distribution network owned and operated by DSO [km]	0
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	15.382
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	29.888
Total length of distribution network operated but not owned by DSO [km]	0
Distribution network average age [yrs]	37
Number of 110/35 kV substations	25
Number of 110/x kV and 35/x kV substations*	147
Number of x/0,4 kV substations	23.719
Total number of transformers	24.430
Sum of installed capacities of all transformers [MVA]	7.746
Average age of transformers [yrs]	34
Total number of feeders	1.192
Number of 6 – 20 kV feeders	1.192
Number of 0,4 kV feeders**	n.a.
Number of employees	4.123
Distributed generation installed capacity [MW]	111,655
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	43,51

* x denotes 20 kV, 10 kV, 6 kV or 3 kV
** data not available

EDB - BOSNIA AND HERZEGOVINA

Bosnia and Herzegovina is organized in two entities (Federation BiH and Republika Srpska) and one district (Brčko). In Federation BiH there are two DSOs (EPBiH and EPHZHB), in Republika Srpska one DSO (ERS) and in Brčko Distric there is also one DSO. *JP Komunalno Brcko (EDB)* in Brčko District in Bosnia and Herzegovina operates the local distribution network and provides electricity supply to all customers in the District. Utility is 100% owned by Brčko District.

Information on Brčko District's distribution system operator in Bosnia and Herzegovina (*EDB)* are given in the following Table.

Table 3.2 Basic data on BiH distribution system operator - EDB

EDB - Bosnia and Herzegovina	
	2012
Total number of metering points	35.970
Total number of customers	35.970
Electricity delivered to final customers [MWh]*	224.456
Supply area size [km²]	493
Total length of distribution network owned by DSO [km]	2.072
Length of 110 kV distribution network owned and operated by DSO [km]	0
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	509
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	1.563
Total length of distribution network operated but not owned by DSO [km]	0
Distribution network average age [yrs]	20
Number of 110/35 kV substations	2
Number of 110/x kV and 35/x kV substations*	8
Number of x/0,4 kV substations	488
Total number of transformers	513
Sum of installed capacities of all transformers [MVA]	428
Average age of transformers [yrs]	20
Total number of feeders	2.795
Number of 6 – 20 kV feeders	55
Number of 0,4 kV feeders	2.740
Number of employees	180
Distributed generation installed capacity [MW]	0
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	14,20

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

EPBIH - BOSNIA AND HERZEGOVINA

Elektroprivreda Bosne i Hercegovine (EPBIH) is 90% owned by the Federation BiH. The remaining shares are privately owned. On its territory EPBiH is distribution system operator, having factual monopoly for electricity generation and electricity supply to all customers. The company operates as public enterprise.

Information on EPBiH are given in the following Table.

Table 3.3 Basic data on BiH distribution system operator - EPBIH

EPBIH - Bosnia and Herzegovina	
	2012
Total number of metering points	715.411
Total number of customers	715.411
Electricity delivered to final customers [MWh]	3.933.902
Supply area size [km²]	17.657
Total length of distribution network owned by DSO [km]	33.842
Length of 110 kV distribution network owned and operated by DSO [km]	0
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	9.054
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	24.787
Total length of distribution network operated but not owned by DSO [km]	452
Distribution network average age [yrs]	24
Number of 110/35 kV substations	23
Number of 110/x kV and 35/x kV substations*	111
Number of x/0,4 kV substations	7.317
Total number of transformers	7.578
Sum of installed capacities of all transformers [MVA]	2.784
Average age of transformers [yrs]	24
Total number of feeders	34.967
Number of 6 – 20 kV feeders	1.029
Number of 0,4 kV feeders	33.938
Number of employees	2.756
Distributed generation installed capacity [MW]	94,038
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	9,36

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

EPHZHB - BOSNIA AND HERZEGOVINA

Similarly as EPBiH, *Elektroprivreda Hrvatske Zajednice Herceg-Bosne (EPHZHB) is* also 90% owned by the Federation BiH. The remaining shares are privately owned. On its territory EPHZHB is distribution system operator, having monopoly for electricity generation and electricity supply to all customers. This company also operates as public enterprise.

Information on EPHZHB are given in the following Table.

Table 3.4 Basic data on BiH distribution system operator – EPHZHB

EPHZHB - Bosnia and Herzegovina	
	2012
Total number of metering points	188.918
Total number of customers	188.918
Electricity delivered to final customers [MWh]	1.181.143
Supply area size [km²]	11.000
Total length of distribution network owned by DSO [km]	12.013
Length of 110 kV distribution network owned and operated by DSO [km]	0
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	4.310
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	7.703
Total length of distribution network operated but not owned by DSO [km]	257
Distribution network average age [yrs]	21
Number of 110/35 kV substations	
Number of 110/x kV and 35/x kV substations*	15
Number of x/0,4 kV substations	3.563
Total number of transformers	3.642
Sum of installed capacities of all transformers [MVA]	1.151
Average age of transformers [yrs]	20
Total number of feeders	18.302
Number of 6 – 20 kV feeders	86
Number of 0,4 kV feeders	18.216
Number of employees	914
Distributed generation installed capacity [MW]	4,225
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	14,01

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

ERS - BOSNIA AND HERZEGOVINA

In the other BiH entity - Republika Srpska there is one DSO. The holding company *Elektroprivreda Republike Srpske (ERS)* is 100% owned by the entity. At the same time the holding ERS is the owner of 65% of the shares in all of its subsidiaries (5 for electricity generation and 5 for distribution and supply). Company also operated as public enterprise.

Information on ERS DSO are given in the following Table.

Table 3.5 Basic data on BiH distribution system operator – ERS

ERS - Bosnia and Herzegovina	
	2012
Total number of metering points	540.615
Total number of customers	535.469
Electricity delivered to final customers [MWh]	3.124.475
Supply area size [km²]	24.067
Total length of distribution network owned by DSO [km]	45.130
Length of 110 kV distribution network owned and operated by DSO [km]	0
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	11.719
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	33.411
Total length of distribution network operated but not owned by DSO [km]	1.189
Distribution network average age [yrs]	23
Number of 110/35 kV substations	26
Number of 110/x kV and 35/x kV substations*	101
Number of x/0,4 kV substations	9.658
Total number of transformers	9.838
Sum of installed capacities of all transformers [MVA]	4.753
Average age of transformers [yrs]	24
Total number of feeders	66.225
Number of 6 – 20 kV feeders	717
Number of 0,4 kV feeders	65.508
Number of employees	3.789
Distributed generation installed capacity [MW]	35,682
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	14,87

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

EPS - SERBIA

The main electricity undertaking in Serbia is fully state owned. The public enterprise *Elektroprivreda Srbije (EPS)* is a vertically integrated holding encompassing a total of thirteen legal entities. Five undertakings within *EPS* perform activities in electricity distribution and distribution system operation.

Information on Serbian distribution system operator *EPS* are given in the following Table.

Table 3.6 Basic data on Serbian distribution system operator – EPS

EPS - Serbia	
	2012
Total number of metering points	3.554.417
Total number of customers	3.426.447
Electricity delivered to final customers [MWh]	27.839.979
Supply area size [km²]	77.696
Total length of distribution network owned by DSO [km]	150.829
Length of 110 kV distribution network owned and operated by DSO [km]	342
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	46.195
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	104.292
Total length of distribution network operated but not owned by DSO [km]	3.134
Distribution network average age [yrs]	33
Number of 110/35 kV substations	62
Number of 110/x kV and 35/x kV substations*	682
Number of x/0,4 kV substations	33.354
Total number of transformers	38.196
Sum of installed capacities of all transformers [MVA]	28.256
Average age of transformers [yrs]	33
Total number of feeders	170.921
Number of 5,25 – 35 kV feeders	5.201
Number of 0,4 kV feeders	165.720
Number of employees	10.692
Distributed generation installed capacity [MW]	40,807
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	14,14

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

EVN - MACEDONIA

Macedonian distribution system operator is *EVN Makedonija*. Austrian utility *EVN* holds 90% of shares in *EVN Makedonija*, the owner of most of the distribution assets and supplier of 98% of all sales to “tariff customers”.

Information on Macedonian distribution system operator *EVNM* are given in the following Table.

Table 3.7 Basic data on Macedonian distribution system operator – EVNM

EVNM - Macedonia	
	2012
Total number of metering points	827.366
Total number of customers	827.366
Electricity delivered to final customers [MWh]	5.252.288
Supply area size [km²]	25.713
Total length of distribution network owned by DSO [km]	18.453
Length of 110 kV distribution network owned and operated by DSO [km]	188
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	3.316
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	14.949
Total length of distribution network operated but not owned by DSO [km]	1.009
Distribution network average age [yrs]	n.a.
Number of 110/35 kV substations	53
Number of 110/x kV and 35/x kV substations*	75
Number of x/0,4 kV substations	6.859
Total number of transformers	10.911
Sum of installed capacities of all transformers [MVA]	8.017
Average age of transformers [yrs]	n.a.
Total number of feeders	n.a.
Number of 6 – 20 kV feeders	n.a.
Number of 0,4 kV feeders	n.a.
Number of employees	2.215
Distributed generation installed capacity [MW]	79,909
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	17,41

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

HEP ODS - CROATIA

Electricity distribution in Croatia and public supply is performed by the distribution system operator *HEP-Operator distribucijskog sustava d.o.o. (HEP ODS)*. HEP ODS is 100% state owned and it is part of HEP Group.

Information on Croatian distribution system operator *HEP ODS* are given in the following Table.

Table 3.8 Basic data on Croatian distribution system operator – HEP ODS

HEP ODS - Croatia	
	2012
Total number of metering points	2.350.885
Total number of customers	1.848.851
Electricity delivered to final customers [MWh]	14.753.134
Supply area size [km²]	56.594
Total length of distribution network owned by DSO [km]	105.094
Length of 110 kV distribution network owned and operated by DSO [km]	89
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	41.233
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	63.772
Total length of distribution network operated but not owned by DSO [km]	0
Distribution network average age [yrs]	17
Number of 110/35 kV substations	7
Number of 110/x kV and 35/x kV substations*	323
Number of x/0,4 kV substations	25.073
Total number of transformers	26.954
Sum of installed capacities of all transformers [MVA]	14.769
Average age of transformers [yrs]	15
Total number of feeders	112.880
Number of 6 – 20 kV feeders	6.592
Number of 0,4 kV feeders	106.288
Number of employees	9.052
Distributed generation installed capacity [MW]	57,317
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	8,68

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

KEDS - KOSOVO

On 8 May 2013, the licenses and assets for distribution system operation and public supply in Kosovo were transferred from *KEK* to the joint-stock company *Kosovo Electricity Distribution and Supply (KEDS)*. Since then, following the signature of the share-purchase agreement between the Government of Kosovo and Turkish companies *Çalik Holding and Limak*, the latter own and control *KEDS*.

Information on Kosovo's distribution system operator *KEDS* are given in the following Table.

Table 3.9 Basic data on Kosovo distribution system operator – KEDS

KEDS - Kosovo	
	2012
Total number of metering points	483.251
Total number of customers	476.840
Electricity delivered to final customers [MWh]*	3.468.238
Supply area size [km²]	10.907
Total length of distribution network owned by DSO [km]	19.453
Length of 110 kV distribution network owned and operated by DSO [km]	0
Length of medium voltage (6-35 kV) distribution network owned and operated by DSO [km]	7.549
Length of low voltage (0,4 kV) distribution network owned and operated by DSO [km]	11.905
Total length of distribution network operated but not owned by DSO [km]	0
Distribution network average age [yrs]	18
Number of 110/35 kV substations	0
Number of 110/x kV and 35/x kV substations*	62
Number of x/0,4 kV substations	7.372
Total number of transformers	7.657
Sum of installed capacities of all transformers [MVA]	3.151
Average age of transformers [yrs]	17
Total number of feeders	38.301
Number of 3 – 20 kV feeders	686
Number of 0,4 kV feeders	37.615
Number of employees	3.161
Distributed generation installed capacity [MW]	15,324
Total losses (technical & non-technical) compared to electricity delivered to final customers [%]	33,52

* x denotes 20 kV, 10 kV, 6 kV or 3 kV

3.2. NUMBER OF METERING POINTS

Total number of metering points in SEE is 9,8 million. Number of metering points in each SEE DSO in 2012 is shown in the following Figure.

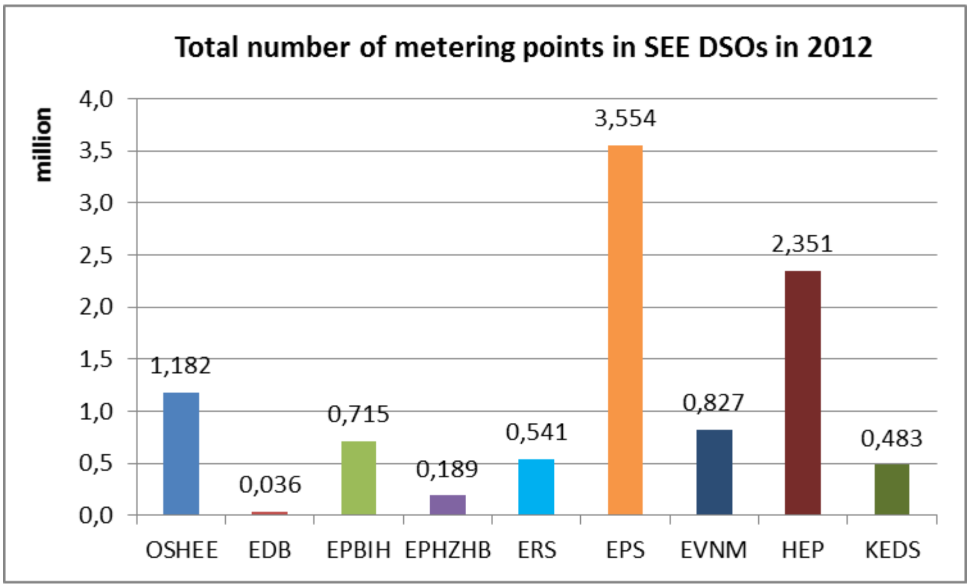


Figure 3.1 Total number of metering points in SEE DSOs in 2012

There is a large difference between the smallest one EDB with just 36.000 metering points to the largest one EPS and its 3,554 million metering points. EPS is holding 36% of all metering points in the region, as shown on the following Figure. About the same relations will be found in the number of customers and supply area size.

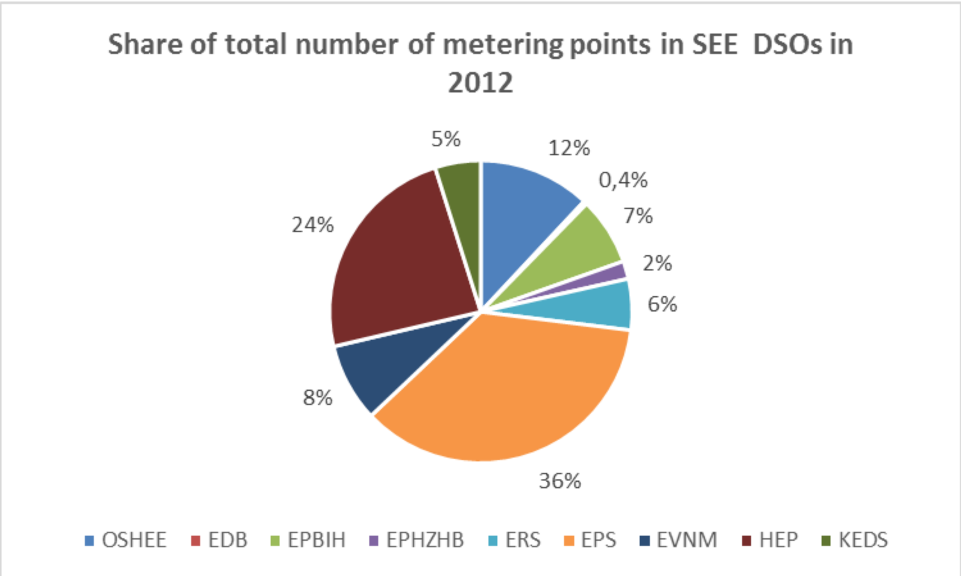


Figure 3.2 Share of total number of metering points in SEE DSOs in 2012

As expected, the number of low voltage (LV) - households metering points is far the largest for every SEE DSO regarding division by consumer categories. Out of total 9,878 mil. metering points in the region in 2012, there are 7,790 mil. metering points on the low voltage – household level. Low voltage – commercial category is covered by 1,891 mil. metering points. Number of metering points on the medium voltage in the region is very low – just 23.715.

In the last five years (2008 – 2012) total number of metering points increased 11 %; from 8,933 million to 9,878 million.

Number of metering points for each SEE DSO in period 2008-2012 per consumer category are given in the next five Tables.

Table 3.10 Number of metering points in SEE DSOs in 2008 per different consumer categories

2008	Number of metering points						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**SUM**
OSHEE	2	4647	878.313	798	306	120.507	1.004.573
EDB	0	19	31.193	379	63	4.470	36.124
EPBIH	0	641	621.830	4.704	1.215	49.934	678.324
EPHZHB	0	121	167.101	1.474	1.427	13.460	183.583
ERS	9	678	474.541	2.515	1.960	37.568	517.271
EPS	29	4.003	3.060.900	23.013	83.446	256.458	3.427.849
EVNM	0	1.261	689.056	5.707	1.282	105.778	803.084
HEP	5	2.056	2.069.016	20.401	15.109	176.411	2.282.998
KEDS							
SUM	45	13.426	7.113.637	58.193	104.808	1.643.697	8.933.806

Table 3.11 Number of metering points for SEE DSO in 2009 per different consumer categories

2009	Number of metering points						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**SUM**
OSHEE	2	5.465	977.584	1.396	335	139.603	1.124.385
EDB	0	19	31.338	392	65	4.346	36.160
EPBIH	0	604	630.503	5.031	1.320	51.056	688.514
EPHZHB	0	125	168.736	1.484	1.406	13.441	185.192
ERS	9	725	482.570	2.728	1.831	37.198	525.061
EPS	32	4.103	3.091.990	24.233	83.384	262.020	3.465.762
EVNM	0	1.244	704.394	5.910	1.495	115.009	828.052
HEP	4	2.081	2.099.133	20.818	15.810	172.965	2.310.811
KEDS							
SUM	47	14.552	7.208.664	60.596	105.649	1.804.418	9.193.926

Table 3.12 Number of metering points in SEE DSOs in 2010 per different consumer categories

2010	Number of metering points						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**SUM**
OSHEE	2	5651	1.001.021	1.463	338	145.899	1.154.374
EDB	0	20	31.449	398	62	4.153	36.082
EPBIH	0	660	637.086	5.225	1.738	51.119	695.828
EPHZHB	0	143	169.851	1.611	1.382	13.307	186.294
ERS	9	788	487.964	2.985	1.720	36.523	529.989
EPS	33	3.997	3.124.354	24.469	83.476	262.228	3.498.557
EVNM	0	1.250	708.647	5.152	1.854	92.347	809.250
HEP	4	2.112	2.116.379	21.126	16.636	174.075	2.330.332
KEDS							
SUM	48	14.621	8.276.751	62.429	107.206	779.651	9.240.706

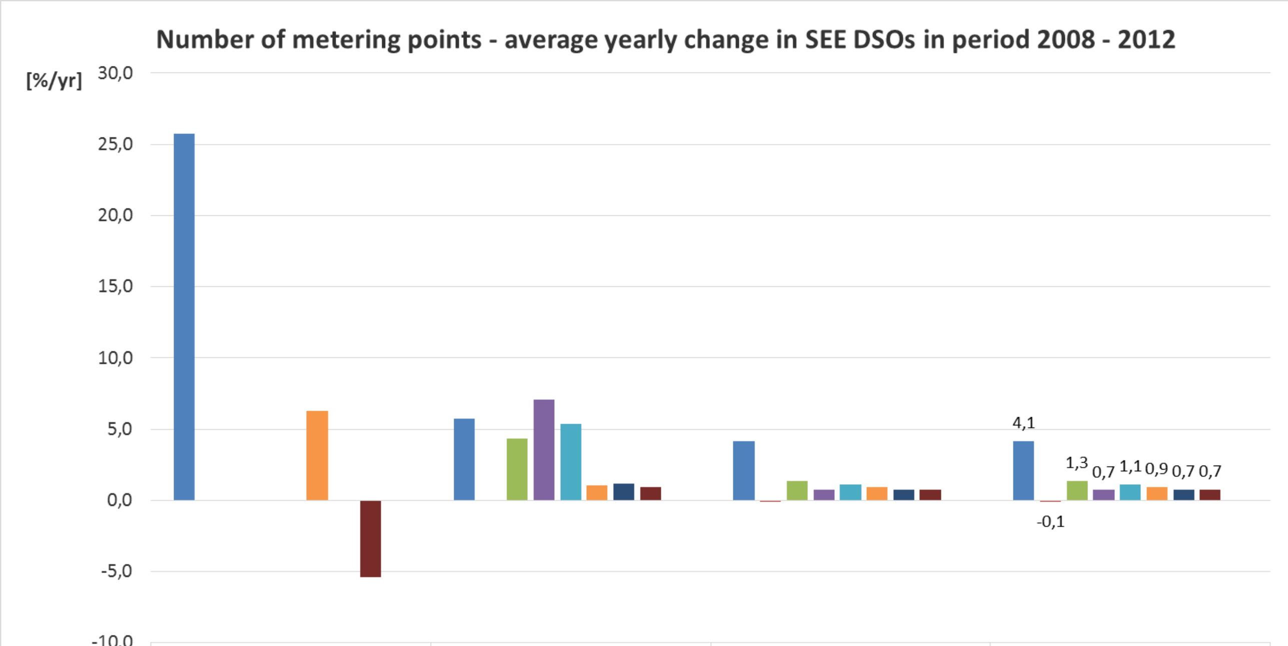
Table 3.13 Number of metering points in SEE DSOs in 2011 per different consumer categories

2011	Number of metering points						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**SUM**
OSHEE	5	6012	1.035.149	2.244	341	155.514	1.199.265
EDB	0	20	31.492	399	63	3.882	35.856
EPBIH	0	701	645.244	3.395	2.983	54.978	707.301
EPHZHB	0	154	171.156	1.649	1.361	13.322	187.642
ERS	9	828	493.599	3.219	1.796	35.714	535.165
EPS	33	4.099	3.145.909	24.764	83.189	268.912	3.526.906
EVNM	0	1.284	714.688	5.378	2.139	92.834	816.323
HEP	4	2.124	2.130.247	21.351	17.386	173.796	2.344.908
KEDS							
SUM	51	15.222	8.367.484	62.399	109.258	798.952	9.353.366

Table 3.14 Number of metering points in SEE DSOs in 2012 of different tariff users and their sum

2012	Number of metering points						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**SUM**
OSHEE	5	5813	1.024.497	2.251	343	149.041	1.181.950
EDB	0	19	31.733	399	59	3.760	35.970
EPBIH	0	760	652.102	3.546	3.275	55.728	715.411
EPHZHB	0	159	172.416	1.659	1.316	13.368	188.918
ERS	9	836	498.891	3.380	1.893	35.606	540.615
EPS	37	4.176	3.171.804	24.095	83.183	271.122	3.554.417
EVNM	0	1.321	725.958	5.444	2.487	92.156	827.366
HEP	4	2.135	2.137.283	21.537	17.741	172.185	2.350.885
KEDS	90	8.502	400.170	1.018	1.731	71.740	483.251
SUM	145	23.721	8.814.854	63.329	112.028	864.706	9.878.783

Average yearly changes of number of metering points in each SEE DSO per consumer categories are given in the following Figure.



	HV	MV	LV	All voltage levels
OSHEE	25,7	5,8	4,1	4,1
EDB		0,0	-0,1	-0,1
EPBIH		4,3	1,3	1,3
EPHZHB		7,1	0,7	0,7
ERS		5,4	1,1	1,1
EPS	6,3	1,1	0,9	0,9
EVNM		1,2	0,7	0,7
HEP	-5,4	0,9	0,7	0,7
KEDS				

Figure 3.3 Number of metering points -average yearly change in SEE DSOs in period 2008 - 2012

3.3. NUMBER OF CUSTOMERS

Total number of customers in the region is 9,237 million and it was going up and down in the last five years (in the range 8,5 mil. to 9,2 mil.). Total number of customers in 2012 in SEE DSOs and their shares are given in the following Figures.

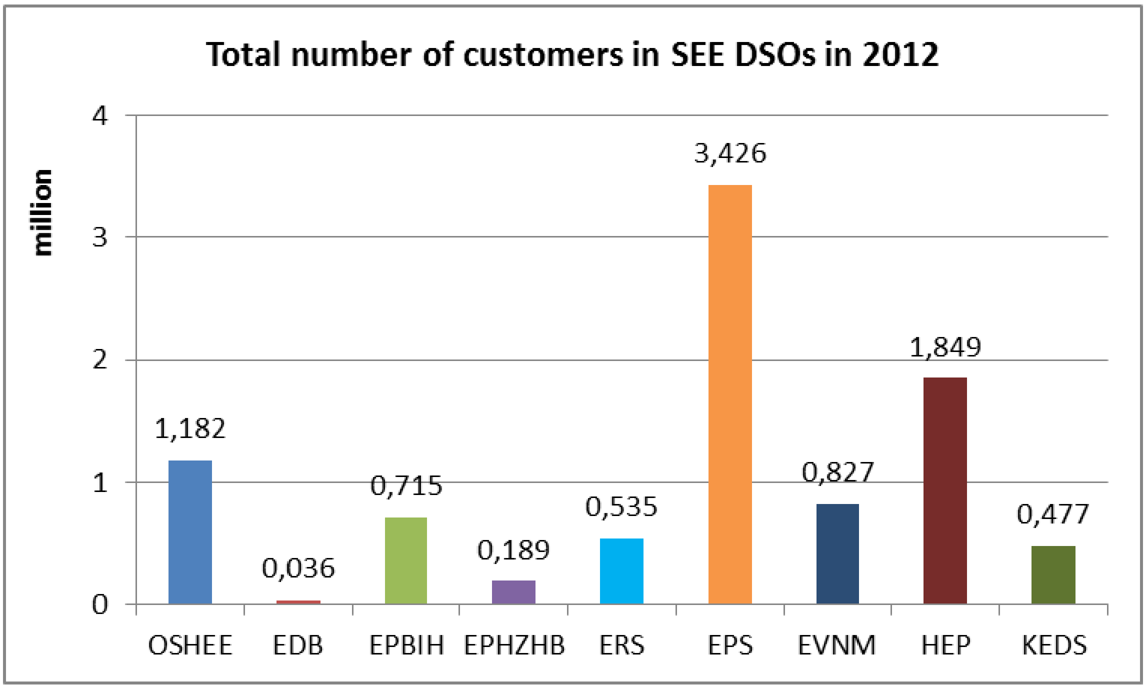


Figure 3.4 Total number of customers for SEE DSOs in 2012

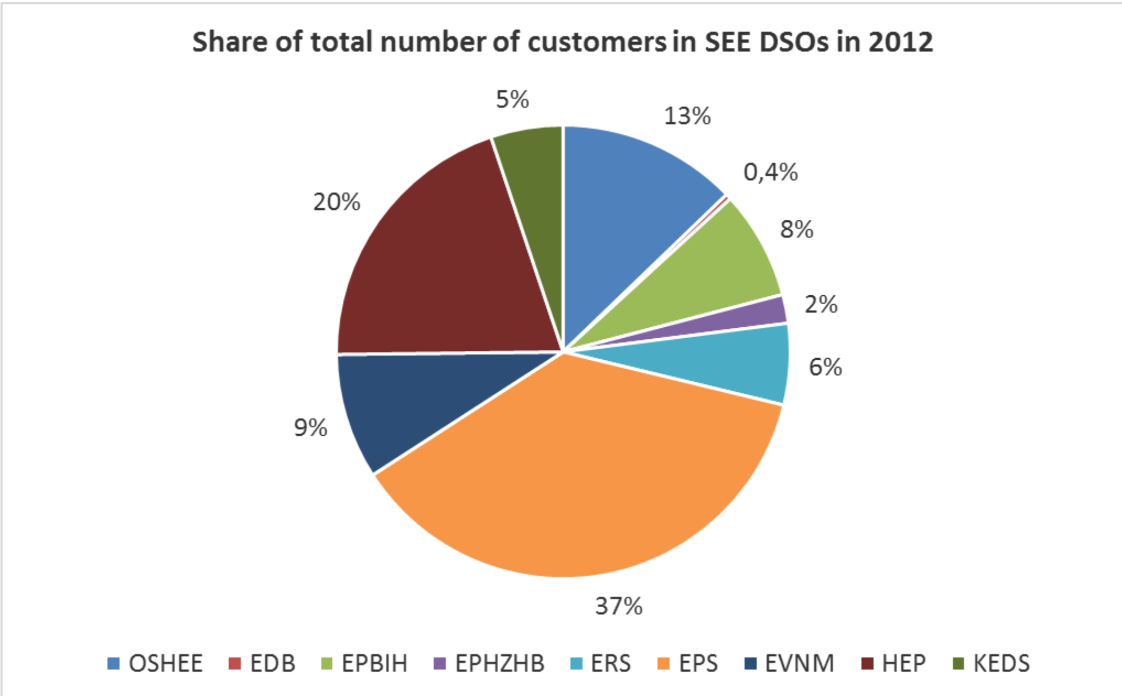


Figure 3.5 Share of total number of customers in SEE DSOs in 2012

Number of customers per each SEE DSO in period 2008-2012 per different consumer categories are given in the next Tables.

Table 3.15 Number of customers in SEE DSOs in 2008 per different consumer categories

2008	Number of customers			
DSO	HV	MV	LV - households	**SUM**
OSHEE	2	4.647	999.924	1.004.573
EDB	0	19	36.124	36.143
EPBIH	0	641	677.683	678.324
EPHZHB	0	121	183.462	183.583
ERS	4	623	512.274	512.901
EPS	20	2.825	3.316.026	3.318.871
EVNM	0	1.261	801.823	803.084
HEP	3	1.081	1.794.382	1.795.466
KEDS	3	264	388816	389.083
SUM	32	11.482	8.710.514	8.722.028

Table 3.16 Number of customers in SEE DSOs in 2009 per different consumer categories

2009	Number of customers			
DSO	HV	MV	LV - households	**SUM**
OSHEE	2	5.465	1.118.918	1.124.385
EDB	0	19	36.141	36.160
EPBIH	0	604	687.910	688.514
EPHZHB	0	126	185.067	185.193
ERS	4	675	519.718	520.397
EPS	23	2.876	3.347.512	3.350.411
EVNM	0	1.244	826.808	828.052
HEP	2	1.094	1.816.243	1.817.339
KEDS	3	266	435773	436.042
SUM	34	12.103	8.538.317	8.550.451

Table 3.17 Number of customers in SEE DSOs in 2010 per different consumer categories

2010	Number of customers			
DSO	HV	MV	LV - households	**SUM**
OSHEE	2	5651	1.148.721	1.154.374
EDB	0	20	36.062	36.082
EPBIH	0	660	695.168	695.828
EPHZHB	0	143	186.151	186.294
ERS	4	728	524.354	525.086
EPS	24	2.887	3.370.664	3.373.575
EVNM	0	1.250	808.000	809.250
HEP	2	1.111	1.831.575	1.832.688
KEDS	3	259	432702	432.964
SUM	35	12.709	9.033.397	9.046.141

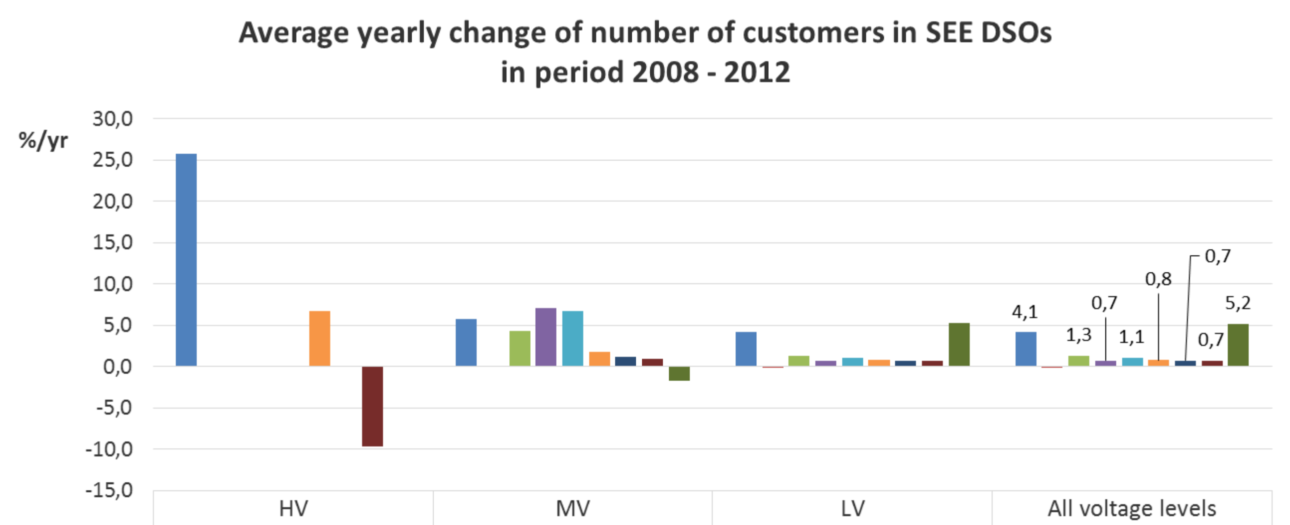
Table 3.18 Number of customers in SEE DSOs in 2011 per different consumer categories

2011	Number of customers			
DSO	HV	MV	LV - households	**SUM**
OSHEE	5	6.012	1.193.248	1.199.265
EDB	0	20	35.836	35.856
EPBIH	0	701	706.600	707.301
EPHZHB	0	154	187.488	187.642
ERS	4	768	529.385	530.157
EPS	24	2.932	3.435.162	3.438.118
EVNM	0	1.284	815.039	816.323
HEP	2	1.117	1.843.033	1.844.152
KEDS	3	247	455.535	455.785
SUM	31	5.859	5.709.510	8.758.814

Table 3.19 Number of customers in SEE DSOs in 2012 per different consumer categories

2012	Number of customers			
DSO	HV	MV	LV	**SUM**
OSHEE	5	5.813	1.176.132	1.181.950
EDB	0	19	35.951	35.970
EPBIH	0	760	714.651	715.411
EPHZHB	0	159	188.759	188.918
ERS	4	809	534.656	535.469
EPS	26	3.036	3.423.385	3.426.447
EVNM	0	1.321	826.045	827.366
HEP	2	1.123	1.847.726	1.848.851
KEDS	3	246	476.591	476.840
SUM	40	13.286	9.223.896	9.237.222

Average yearly change of number of customers is given on the following Figure.



	HV	MV	LV	All voltage levels
OSHEE	25,7	5,8	4,1	4,1
EDB		0,0	-0,1	-0,1
EPBIH		4,3	1,3	1,3
EPHZHB		7,1	0,7	0,7
ERS	0,0	6,7	1,1	1,1
EPS	6,8	1,8	0,8	0,8
EVNM		1,2	0,7	0,7
HEP	-9,6	1,0	0,7	0,7
KEDS	0,0	-1,7	5,2	5,2

Figure 3.6 Average yearly change of total number of customers in SEE DSOs in period 2008 - 2012

3.4. ELECTRICITY DELIVERED TO FINAL CONSUMERS

Total amount of electricity delivered to final customers in the region is about 64 TWh per year. Electricity delivered by each DSO in 2012 and its shares are shown on the following two Figures.

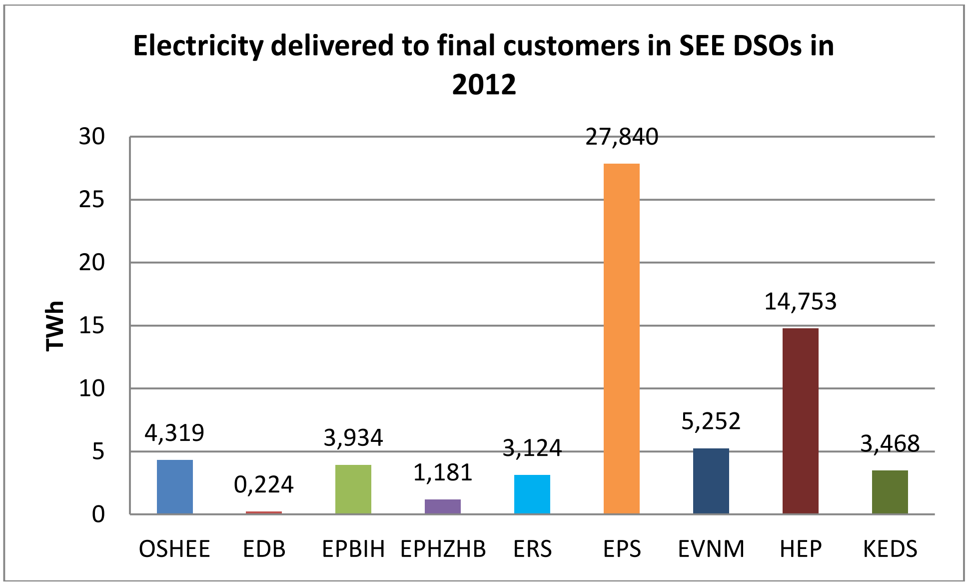


Figure 3.7 Electricity delivered to final customers in SEE DSOs in 2012

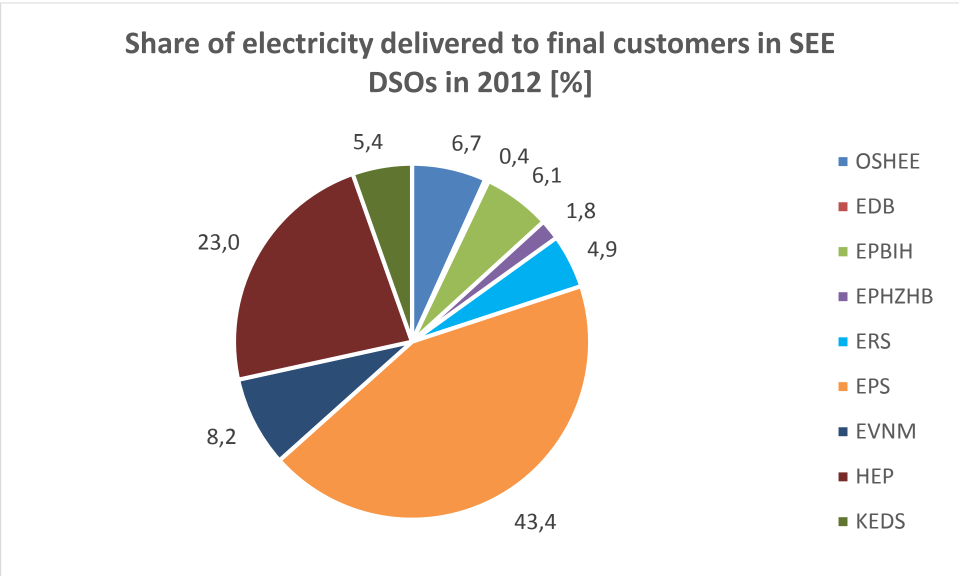


Figure 3.8 Share of electricity delivered to final customers in different SEE DSOs in 2012

Clearly, dominant regional players are Serbian EPS (43,4%) and Croatian HEP (23%), delivering more than 2/3 of total electricity delivered in the region.

Electricity delivered to different consumer categories by SEE DSOs in the period 2008-2012 is given on the following Figure. More than half of total electricity (52%) was delivered to the households.

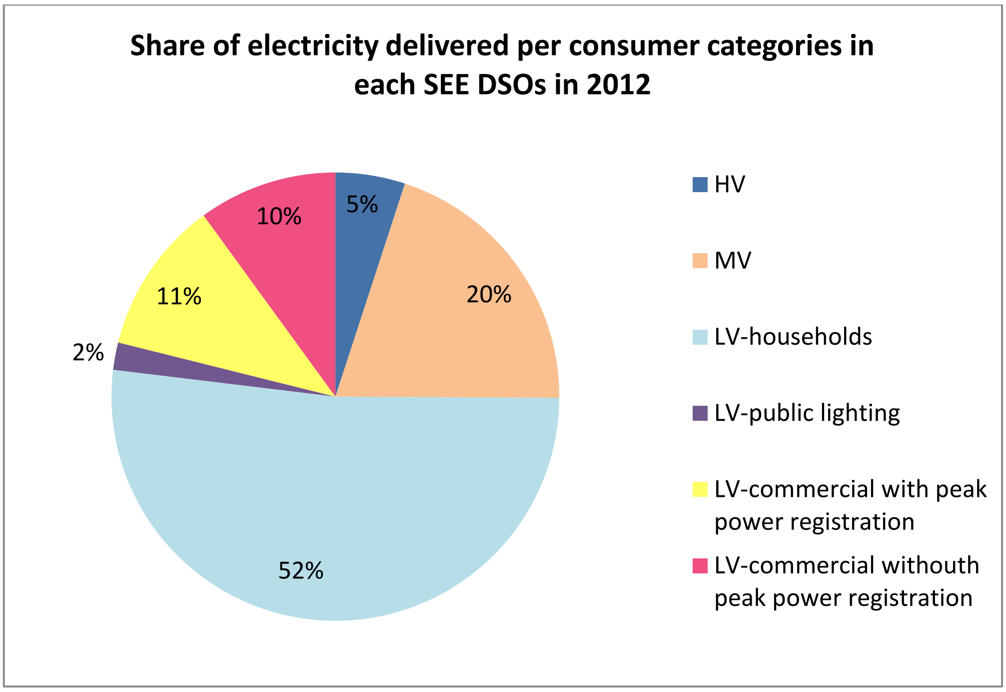


Figure 3.9 Share of electricity delivered per consumer categories in each SEE DSOs in 2012

Electricity delivered to different consumer categories in each SEE DSO in the period 2012-2008 is given in the following five Tables.

Table 3.20 Electricity delivered to different consumer categories in SEE DSOs in 2008

2008	Electricity delivered to final customers [MWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**SUM**
OSHEE	199.076	744.712	2.179.611	26.726	-	739.036	3.889.161
EDB	0	26.972	126.581	8.493	20.034	32.205	214.284
EPBIH	0	955.905	1.807.727	73.175	194.594	541.155	3.572.556
EPHZHB	0	144.986	673.429	21.862	112.114	143.383	1.095.773
ERS	148.233	549.756	1.598.367	55.822	201.292	331.417	2.884.887
EPS	2.366.895	5.344.592	14.312.833	461.217	3216415	1936972	27.638.924
EVNM	0	877.686	3.134.206	104.612	215.378	703.886	5.035.768
HEP	806.428	3.492.679	6.711.928	444.277	2.529.296	1.750.850	15.735.459
KEDS	473.447	215.839	1.575.403	7.927	140.984	292.355	2.705.955
SUM	3.994.079	12.353.127	32.120.085	1.204.111	6.630.107	6.471.260	62.772.768

Table 3.21 Electricity delivered to different consumer categories in SEE DSOs in 2009

2009	Electricity delivered to final customers [MWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	SUM
OSHEE	206.841	776.442	2.389.620	34.992	-	800.207	4.208.101
EDB	0	28.706	132.346	10.908	21.451	33.448	226.858
EPBIH	0	957.867	1.956.826	77.739	197.221	538.562	3.728.215
EPHZHB	0	143.699	689.650	21.682	111.234	141.482	1.107.747
ERS	120.904	600.360	1.662.563	60.326	202.215	331.279	2.977.646
EPS	2.052.318	5.126.509	14412374	479.090	3144350	1943847	27.158.488
EVNM	0	841.024	3.299.687	107.346	234.770	799.256	5.282.084
HEP	180.326	3.362.145	6.471.768	446.329	2.554.865	1.685.489	14.700.922
KEDS	544.041	227.478	1.743.114	8.515	177.877	336.559	3.037.584
SUM	3.104.430	12.064.231	32.757.948	1.246.926	6.643.982	6.610.129	62.427.646

Table 3.22 Electricity delivered to different consumer categories in SEE DSOs in 2010

2010	Electricity delivered to final customers [MWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	SUM
OSHEE	281.844	775.214	2.245.920	30.527	150	773.759	4.107.415
EDB	0	33.576	135.820	9.057	23.458	33.478	235.390
EPBIH	0	994.629	2.017.678	77.742	207.028	525.482	3.822.559
EPHZHB	0	150.117	707.445	21.299	121.587	137.222	1.137.670
ERS	110.263	654.562	1.685.379	59.060	208.936	331.762	3.049.961
EPS	2.378.155	5.317.137	14.645.163	490.892	3.099.700	1.943.615	27.874.662
EVNM	0	840.986	3.233.037	119.038	257.600	714.722	5.165.382
HEP	147.958	3.399.354	6.664.707	440.314	2.583.646	1.626.898	14.862.878
KEDS	700.618	226.600	1.855.984	9.949	200.572	362.159	3.355.882
SUM	3.618.838	12.392.176	33.191.133	1.257.877	6.702.677	6.449.098	63.611.799

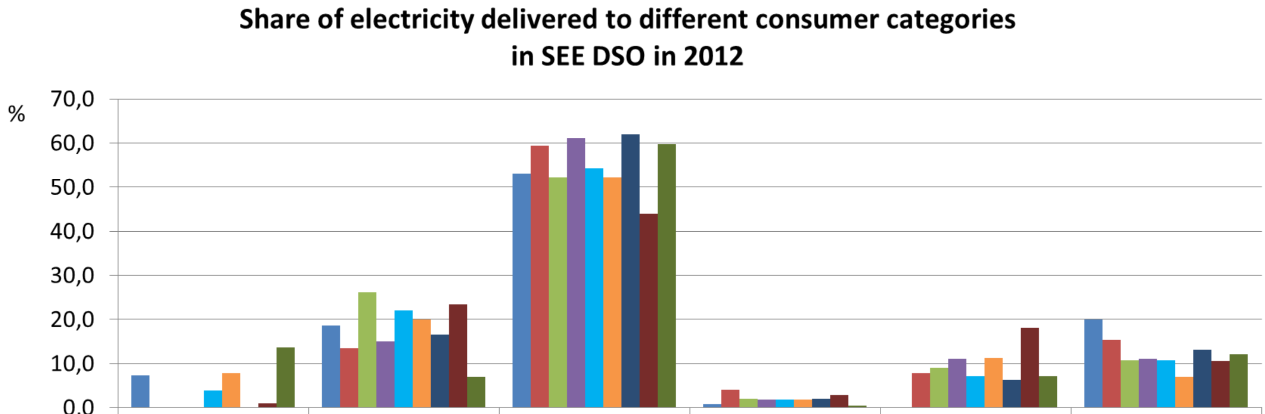
Table 3.23 Electricity delivered to different consumer categories in SEE DSOs in 2011

2011	Electricity delivered to final customers [MWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	SUM
OSHEE	577.554	769.671	2.162.768	31.730	29	799.548	4.341.301
EDB	0	32.828	134.366	8.714	22.089	33.936	231.933
EPBIH	0	1.018.518	2.029.373	81.017	279.528	469.211	3.877.647
EPHZHB	0	166.472	710.923	22.334	130.608	130.287	1.160.624
ERS	124.082	692.999	1.677.098	59.803	218.822	331.311	3.104.114
EPS	2.580.347	5.552.532	14.665.630	500.541	3.165.307	1.973.397	28.437.754
EVNM	0	871.257	3.345.160	110.254	297.376	733.996	5.358.043
HEP	99.760	3.541.173	6.540.376	432.872	2.644.409	1.592.245	14.850.835
KEDS	679.488	244.433	1.988.095	12.834	224.381	400.094	3.549.325
SUM	4.061.231	12.889.882	33.253.789	1.260.100	6.982.549	6.464.026	64.911.577

Table 3.24 Electricity delivered to different consumer categories in SEE DSOs in 2012

2012	Electricity delivered to final customers [MWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**SUM**
OSHEE	318.900	801.682	2.288.795	36.655	6.733	865.818	4.318.583
EDB	0	30.177	133.171	8.959	17.597	34.551	224.456
EPBIH	0	1.030.975	2.050.311	76.460	354.362	421.794	3.933.902
EPHZHB	0	176.531	721.877	21.703	130.808	130.222	1.181.143
ERS	119.185	690.044	1.695.205	59.560	223.913	336.569	3.124.475
EPS	2.168.191	5.569.773	14.516.977	507.238	3.120.220	1.957.580	27.839.979
EVNM	0	867.262	3.257.489	105.790	328.354	693.392	5.252.288
HEP	142.967	3.450.572	6.486.495	432.203	2.676.854	1.564.043	14.753.134
KEDS	473.070	240.949	2.069.376	16.954	249.129	418.759	3.468.238
SUM	2.903.732	12.857.966	33.219.697	1.265.523	7.107.970	6.422.729	64.096.198

In the most of SEE DSOs the share of LV – households in total delivered electricity is between 50 – 60%, while electricity delivered on the mid voltage is usually between 10 – 25% of total delivery. All other consumer categories are supplied with lower amount of electricity, as shown on the following Figure.

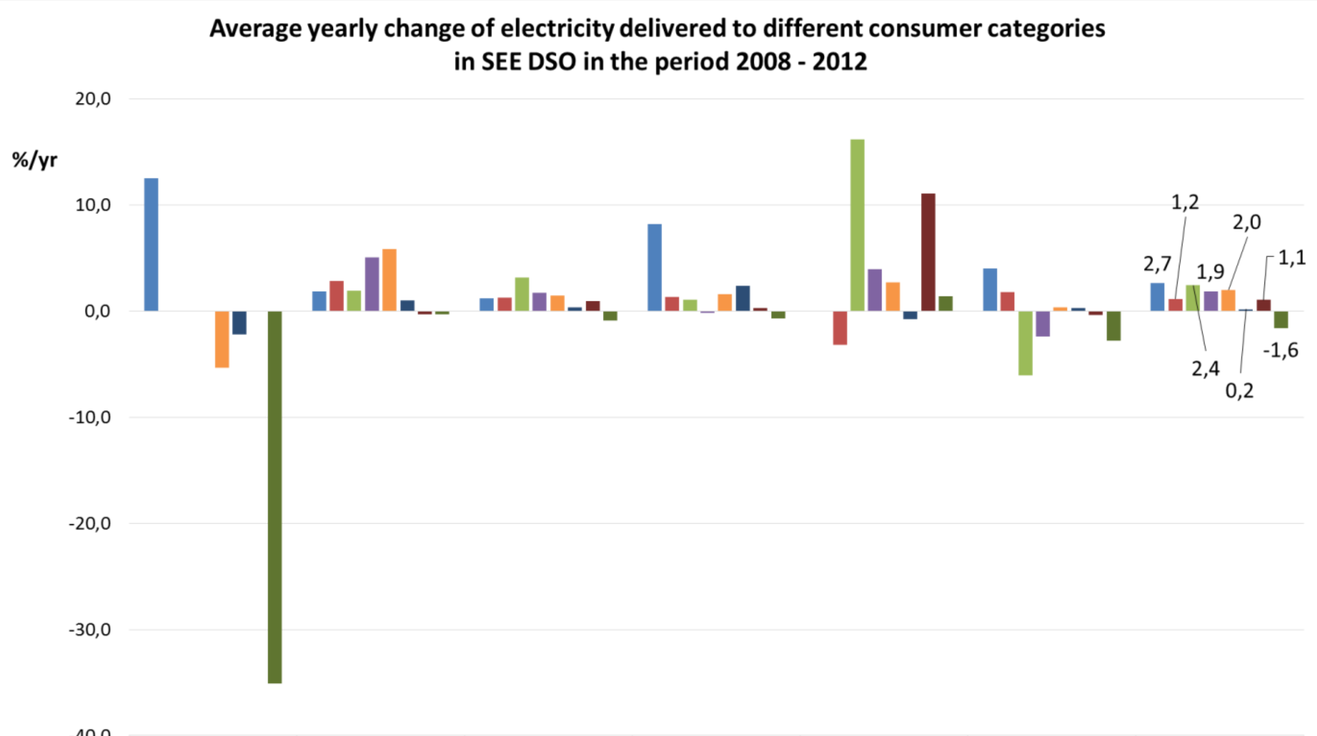


	HV	MV	LV-households	LV-public lighting	LV-commercial with peak power registration	LV-commercial withouth peak power registration
OSHEE	7,4	18,6	53,0	0,8	0,2	20,0
EDB	0,0	13,4	59,3	4,0	7,8	15,4
EPBIH	0,0	26,2	52,1	1,9	9,0	10,7
EPHZHB	0,0	14,9	61,1	1,8	11,1	11,0
ERS	3,8	22,1	54,3	1,9	7,2	10,8
EPS	7,8	20,0	52,1	1,8	11,2	7,0
EVNM	0,0	16,5	62,0	2,0	6,3	13,2
HEP	1,0	23,4	44,0	2,9	18,1	10,6
KEDS	13,6	6,9	59,7	0,5	7,2	12,1

Figure 3.10 Share of electricity delivered to different consumer categories in each SEE DSO in 2012

Average annual change of electricity delivered per each consumer category is given on the following Figure. It is interesting to note that electricity delivered on the high voltage dropped in all DSOs, while electricity delivered on the mid voltage and to the households increased in the given timeframe.

In total electricity delivered to consumers increased by around 0,5 %/yrs since 2008.



	HV	MV	LV household	LV public lighting	LV commercial - with peak power registration	LV commercial - no peak power registration	All categories
OSHEE	12,5	1,9	1,2	8,2		4,0	2,7
EDB		2,8	1,3	1,3	-3,2	1,8	1,2
EPBIH		1,9	3,2	1,1	16,2	-6,0	2,4
ERS		5,0	1,8	-0,2	3,9	-2,4	1,9
EPS	-5,3	5,8	1,5	1,6	2,7	0,4	2,0
EVNM	-2,2	1,0	0,4	2,4	-0,8	0,3	0,2
HEP		-0,3	1,0	0,3	11,1	-0,4	1,1
KEDS	-35,1	-0,3	-0,9	-0,7	1,4	-2,8	-1,6

Figure 3.11 Average yearly change of electricity delivered to different consumer categories in each SEE DSO in the period 2008 - 2012

Total electricity delivered in the region per each consumer category is shown on the following Figure. It proves that there was no significant change on the regional level in the last five years.

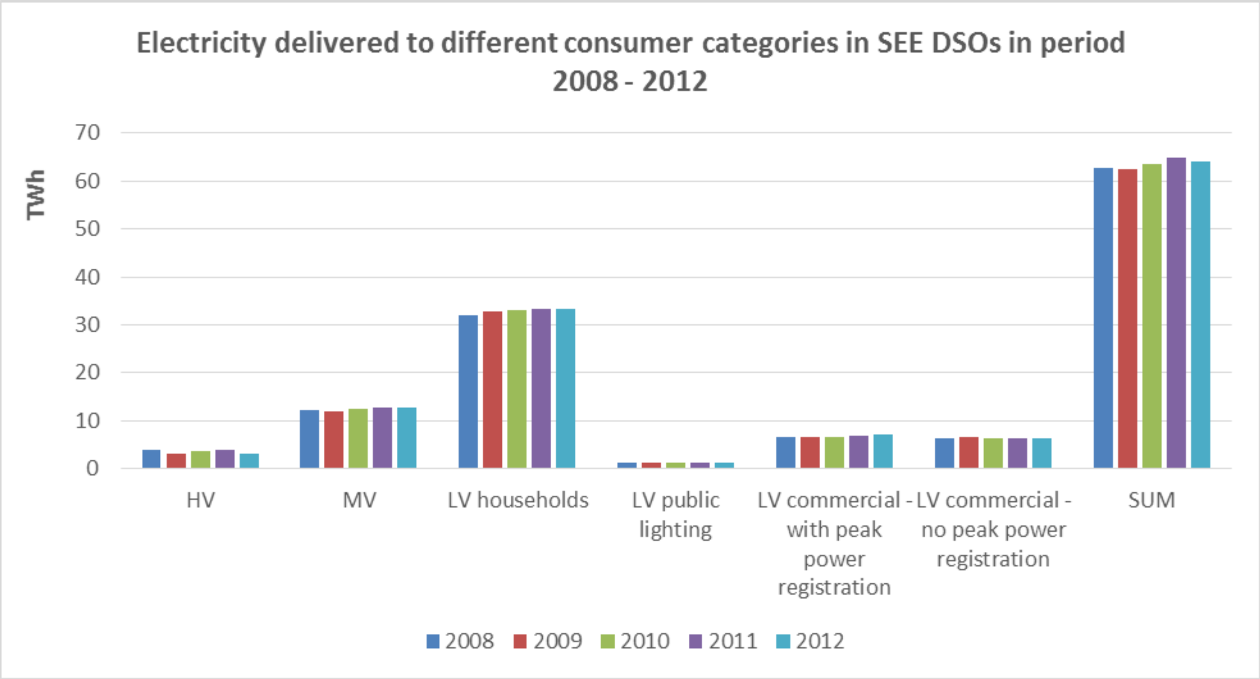


Figure 3.12 Electricity delivered to different consumer categories in SEE DSOs in period 2008 -2012

But, on the individual DSO level there were more significant changes in total electricity delivered with respect to the referent year - 2008. For example, in Kosovo there was significant consumption growth since 2008 (up to 28 % compared to 2008), while at the same time in Croatia it felt down for about 6 % in 2009 and didn't recovered yet.

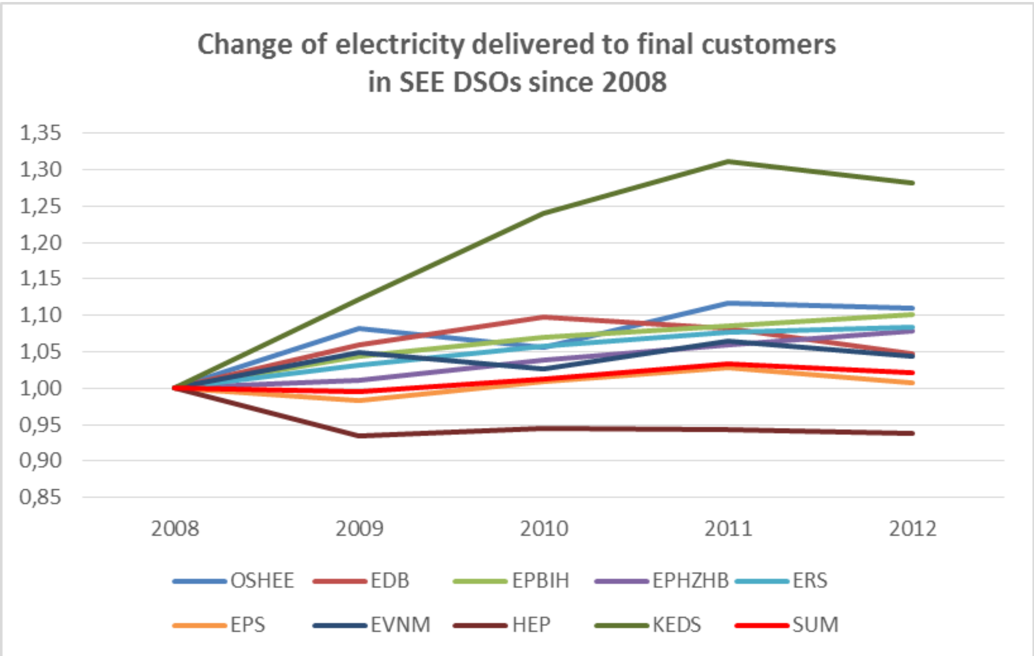


Figure 3.13 Change of electricity delivered to final customers in SEE DSOs since 2008

Similar values are valid for the most dominant consumer category – households, as shown on the following Figure.

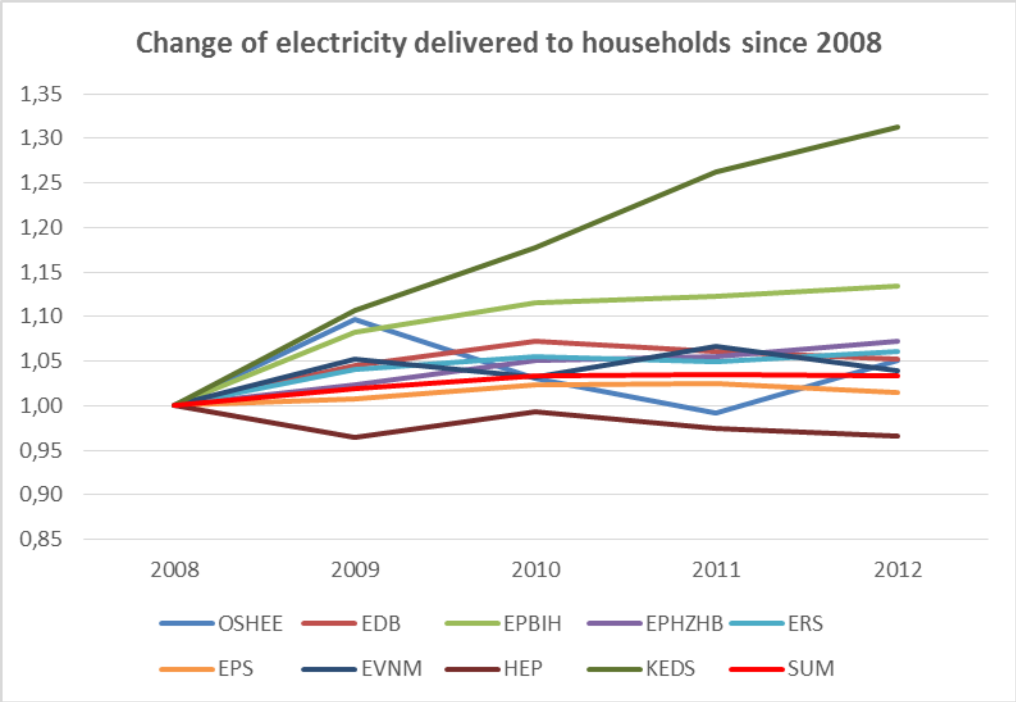


Figure 3.14 Change of electricity delivered to households since 2008

3.5. DISTRIBUTION NETWORK LENGTH

Distribution network length in the region equals 432.155 km. Distribution network length in each SEE DSO is given in the following Figure.

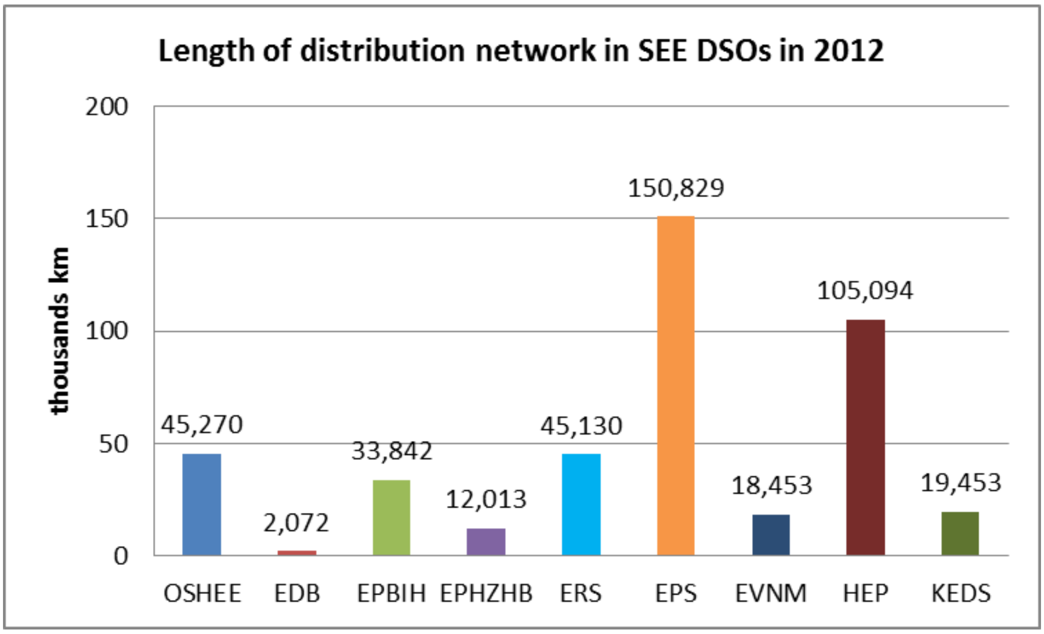


Figure 3.15 Length of distribution network owned by SEE DSOs in 2012

Table 3.25 Length of distribution network for different voltage levels in 2012

2012 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV - aerial						311	188	72		571
110 kV - cable						31	0	17		48
35 kV - aerial	1.112	302	742	285	805	5.886	788	3.326	596	13.841
35 kV - cable	11	108	133	4	21	987	72	1.447	29	2.768
20 kV - aerial	76	0	487		3.402	6.297	8	3.244	665	14.179
20 kV - cable	1.237	0	208		329	2.590	2.449	3.127	293	10.233
16 kV - aerial	10	-	-	-	-	-	-	-	-	10
16 kV- cable	0,2	-	-	-	-	-	-	-	-	0
10 kV - aerial	7.404	65	5.368	3.176	6.233	23.620		18.852	5.141	69.859
10 kV - cable	168	35	2.117	845	900	6.816		11.237	774	23.114
6 kV - aerial	5.072				20	-	-	-	44	5.136
6 kV - cable	292				8	-	-	-	5	305
0,4 kV - aerial	25.554	1.386	22.816	7.026	32.069	91.717	11.498	46.637	11.294	249.997
0,4 kV - cable	4.334	176	1.972	677	1.342	12.576	3.451	17.135	610	42.274
SUM	45.270	2.072	33.842	12.013	45.130	150.829	18.453	105.094	19.453	432.156

The following figure show share of total network length at different voltage levels. As expected, 0,4 kV aerial network accounts for the largest share in the total distribution network length (58 %).

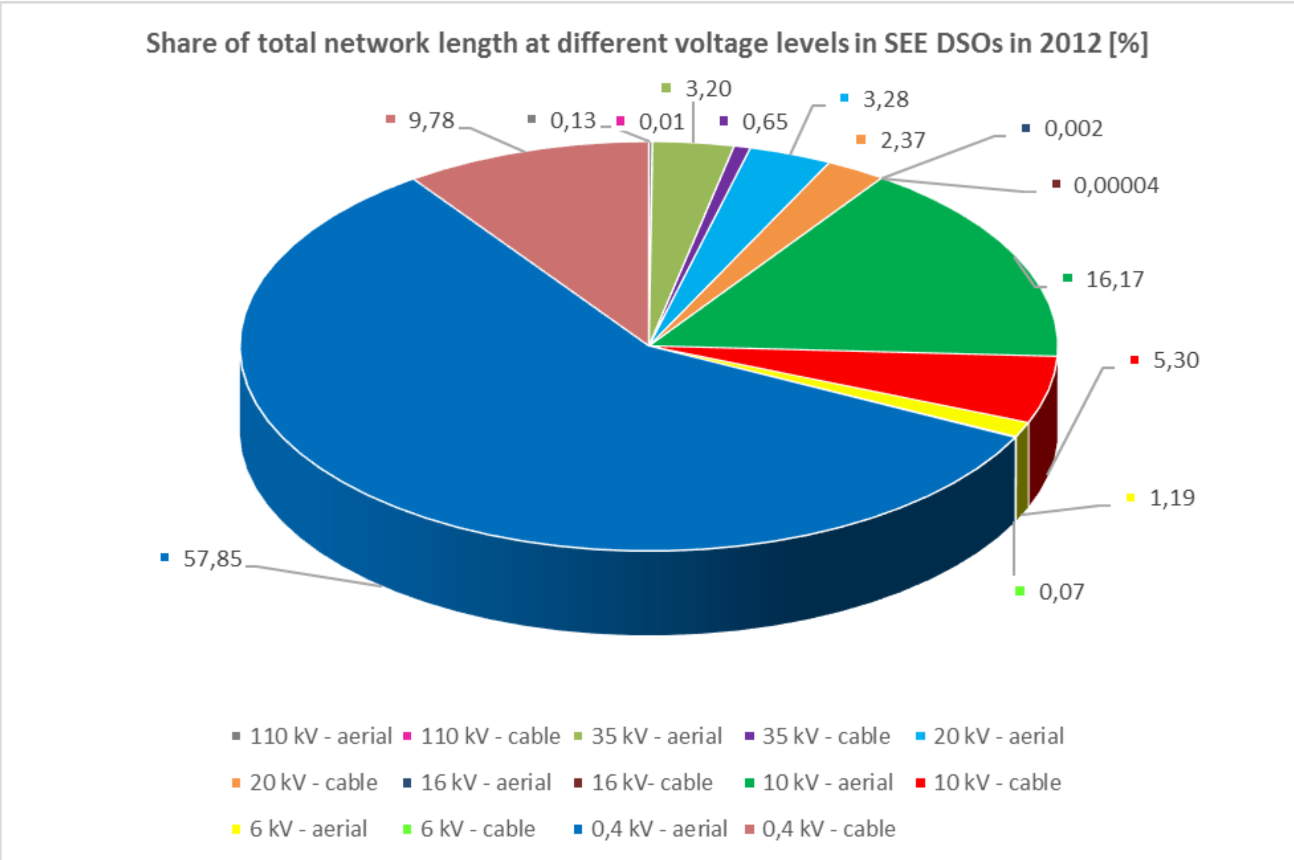


Figure 3.16 Share of total network length at different voltage levels in SEE DSO in 2012

Again, the largest distribution network can be found in Serbia (35 % of total regional distribution network length) and Croatia (24 %).

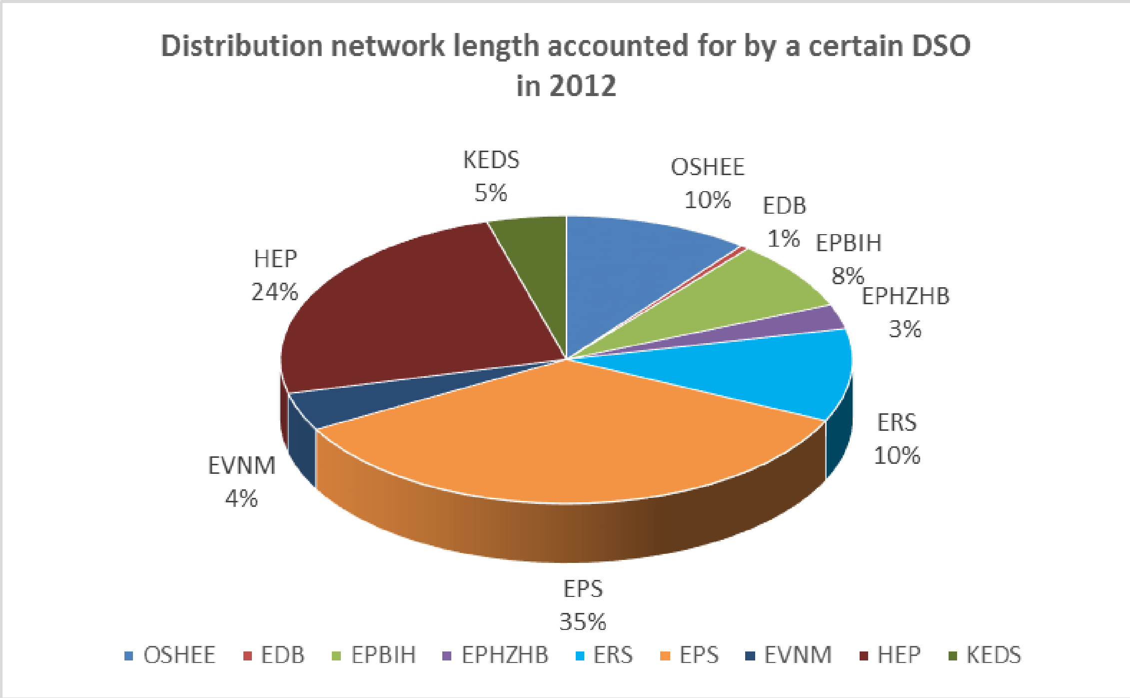


Figure 3.17 Share of distribution network length in SEE DSOs in 2012

The following four Tables show distribution network length per each voltage level in the period 2008 – 2011 (not all data are available).

Table 3.26 Distribution network length per different voltage levels in 2008

2008 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV - aerial				-	-	463	184	72	-	719
110 kV - cable				-	-	31	0	17	-	48
35 kV - aerial	1.111	302		280,5	78	5.874	833	3.341	648	13.171
35 kV - cable	11	108		3	13,2	940		1.373	26	2.474
20 kV - aerial	31	0		-	3.094	5.950	9.674	2.761	265	21.775
20 kV - cable	843	0		-	313,9	2.141		1.926	145	5.370
16 kV - aerial	10	-		-	-	-	-	-	-	10
16 kV- cable	0,2	-		-	-	-	-	-	-	0
10 kV - aerial	6.909	63		2945	6.450	24.207	-	19.668	4.171	64.413
10 kV - cable	123	30		642	846	6.501	-	10.385	789	19.316
6 kV - aerial	4.699			-	21	-	-	-	44	4.764
6 kV - cable	307			-	6	-	-	-	2	314
0,4 kV - aerial	23.398	1.368		6.854	25.482	85.230	14.372	45.641	9.337	211.683
0,4 kV - cable	3.584	176		650	1.120	10.145		14.832	474	30.981
SUM	41.029	2.048		11.375	38.127	141.482	25.063	100.016	15.901	375.039

Table 3.27 Distribution network length per different voltage levels in 2009

2009 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV - aerial				-	-	465	184	72	-	721
110 kV - cable				-	-	31	0	17	-	48
35 kV - aerial	1.111	302		280,5	851	5.901	841	3.309	648	13.245
35 kV - cable	11	108		4	14	954		1.416	26	2.533
20 kV - aerial	20	0			3.169	6.029	9.766	2.748	274	22.006
20 kV - cable	1.031	0			321	2.206		2.283	165	6.006
16 kV - aerial	10	-		-	-	-	-	-	-	10
16 kV- cable	0,2	-		-	-	-	-	-	-	0
10 kV - aerial	6.901	63		2.999	6.421	24.086	-	-	5.071	45.541
10 kV - cable	131	33		651	850	6.480	-	-	795	8.940
6 kV - aerial	4.854			-	21	-	-	19.614	44	24.533
6 kV - cable	160			-	8	-	-	10.513	2	10.683
0,4 kV - aerial	23.574	1.376		6.857	27.087	85.512	14.524	46.857	11.386	217.173
0,4 kV - cable	3.939	176		651	1.172	10.531		15.703	483	32.655
SUM	41.744	2.059		11.443	39.913	142.195	25.315	102.532	18.894	342.350

Table 3.28 Distribution network length per different voltage levels in 2010

2010 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV - aerial			-	-	-	506	184	72	-	761
110 kV - cable			-	-	-	31	0	17	-	48
35 kV - aerial	1.111	302	757	291,1	886	6.032	770	3.317	648	14.115
35 kV - cable	11	108	104	4	17	994	71	1.429	26	2.765
20 kV - aerial		0	469		3.245	6.117	8	2.935	297	13.070
20 kV - cable		0	184		329	2.324	2.297	2.377	184	7.696
16 kV - aerial		-	-	-	-	-	-	-	-	0
16 kV- cable		-	-	-	-	-	-	-	-	0
10 kV - aerial		64	5.388	3.036	6.380	24.334		19.297	5.159	63.658
10 kV - cable		34	1.915	669	864	6.769		10.960	801	22.012
6 kV - aerial			-	-	21	-	-	-	44	65
6 kV - cable			-	-	8	-	-	-	2	10
0,4 kV - aerial		1.381	22.577	6.877	28.720	92.131	11355	46.621	11.503	221.167
0,4 kV - cable		176	1.891	667	1.226	11.824	3282	16.375	485	35.927
SUM	1.123	2.066	33.285	11.544	41.697	151.062	17.968	103.400	19.149	381.293

Table 3.29 Distribution network length per different voltage levels in 2011

2011 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV - aerial				-	-	434	186	72	-	692
110 kV - cable				-	-	31	0	17	-	48
35 kV - aerial	1.111	302	744	284,8	795	5.869	779	3.319	648	13.853
35 kV - cable	11	108	115	4,2	23	980	72	1.429	26	2.768
20 kV - aerial	48	0	468		3.323	6.243	8	3.263	441	13.793
20 kV - cable	1.213	0	198		321	2.467	2.379	3.060	167	9.806
16 kV - aerial	10	-	-	-	-	-	-	-	-	10
16 kV- cable	0,2	-	-	-	-	-	-	-	-	0
10 kV - aerial	7.211	64	5.300	3145	6.326	23.374		18.930	5.046	69.396
10 kV - cable	161	35	2.052	811	888	6.652		10.902	709	22.210
6 kV - aerial	4.993		-	-	20	-	-	-	44	5.058
6 kV - cable	309		-	-	8	-	-	-	2	318
0,4 kV - aerial	24.629	1.384	22.596	6.942	30.098	89.604	11.440	46.589	10.724	244.008
0,4 kV - cable	4.054	176	2.008	670	1.283	11.833	3.378	16.820	546	40.768
SUM	43.754	2.070	33.481	11.857	43.086	147.488	18.242	104.401	18.353	422.730

The following Table and Figure show shares of aerial and cable network. As expected, in total distribution network is dominantly aerial (82 %).

Table 3.30 Distribution network length per type (in km and %)

2012 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
Aerial	39.228	1.753	29.413	10.487	42.529	127.830	12.481	72.131	17.741	353.594
Cable	6.041	319	4.429	1.526	2.601	22.999	5.972	32.963	1.712	78.562
%										
Aerial	87	85	87	87	94	85	68	69	91	82
Cable	13	15	13	13	6	15	32	31	9	18

This ratio of aerial to cable distribution network length is the largest in BiH (ERS) and Kosovo (KEDS) (more than 90 % to 10%), while in Macedonia (EVNM) and Croatia (HEP) shares of cable network are considerably higher (over 30 % of DSO total distribution network length).

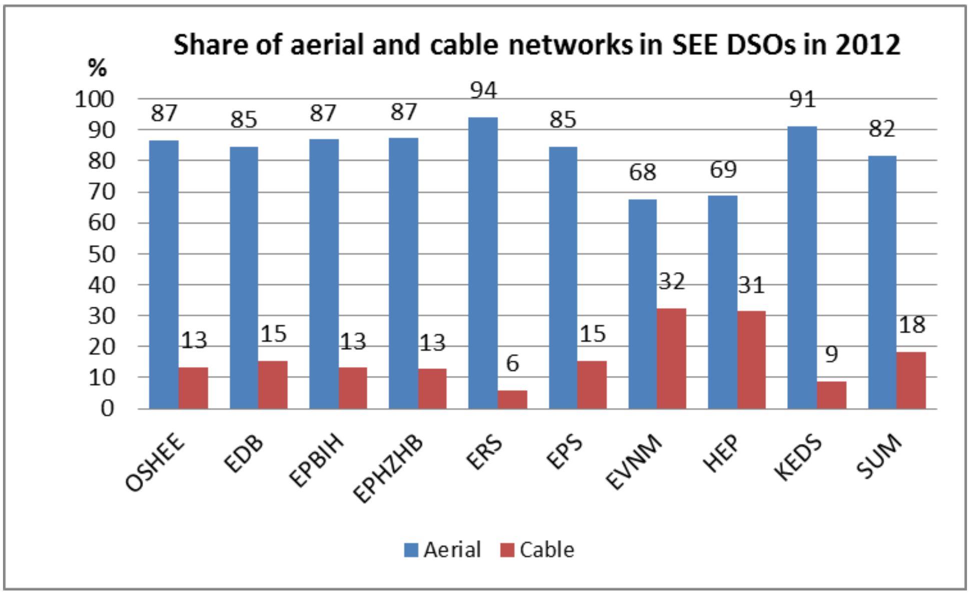


Figure 3.18 Share of aerial and cable network in SEE DSOs in 2012

The following Figure and Table show share of aerial and cable lines in HV, MV and LV network comparing to total network length. MV cables share in total length of cables is 46 %, while LV network cable line share is 54 %.

Table 3.31 Length (in km and %) of aerial and cable distribution HV, MV and LV network for each SEE DSOs in 2012

2012 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
HV - aerial	0	0	0	0	0	311	188	72	0	571
HV - cable	0	0	0	0	0	31	0	17	0	48
% HV to total	0	0	0	0	0	0,2	1,0	0,1	0	0,1
MV - aerial	13.674	367	6597	3.461	10.461	35.802	795	25.422	6.447	103.026
MV - cable	1.707	143	2458	849	1.258	10.392	2.521	15.811	1.102	36.241
% MV to total	34,0	24,6	26,8	35,9	26,0	30,6	18,0	39,2	38,8	32,2
LV - aerial	25.554	1.386	22.816	7.026	32.069	91.717	11.498	46.637	11.294	249.997
LV - cable	4.334	176	1.972	677	1.342	12.576	3.451	17.135	610	42.274
% LV to total	66,0	75,4	73,2	64,1	74,0	69,1	81,0	60,7	61,2	67,6

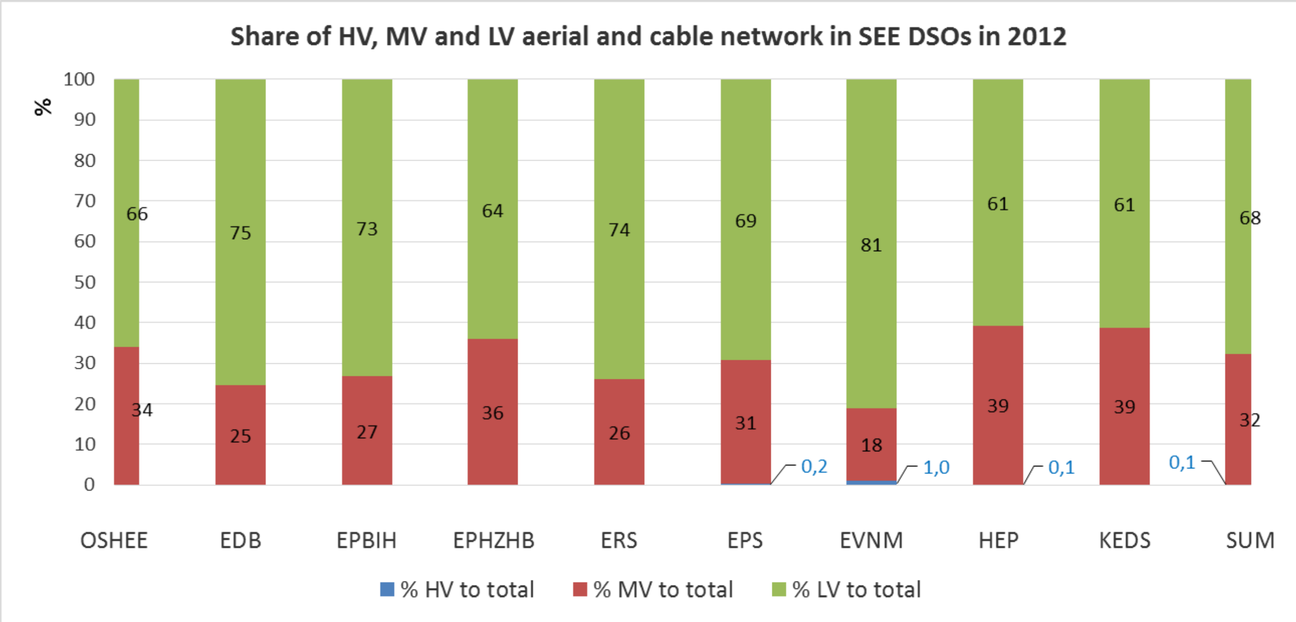


Figure 3.19 Share of HV, MV and LV in total cable network in SEE DSOs in 2012

3.6. DISTRIBUTION NETWORK AGE

One of the most important data for estimation of distribution network reliability is distribution network age. As shown on the following Figure and Table, average distribution network age in SEE is 27 years.

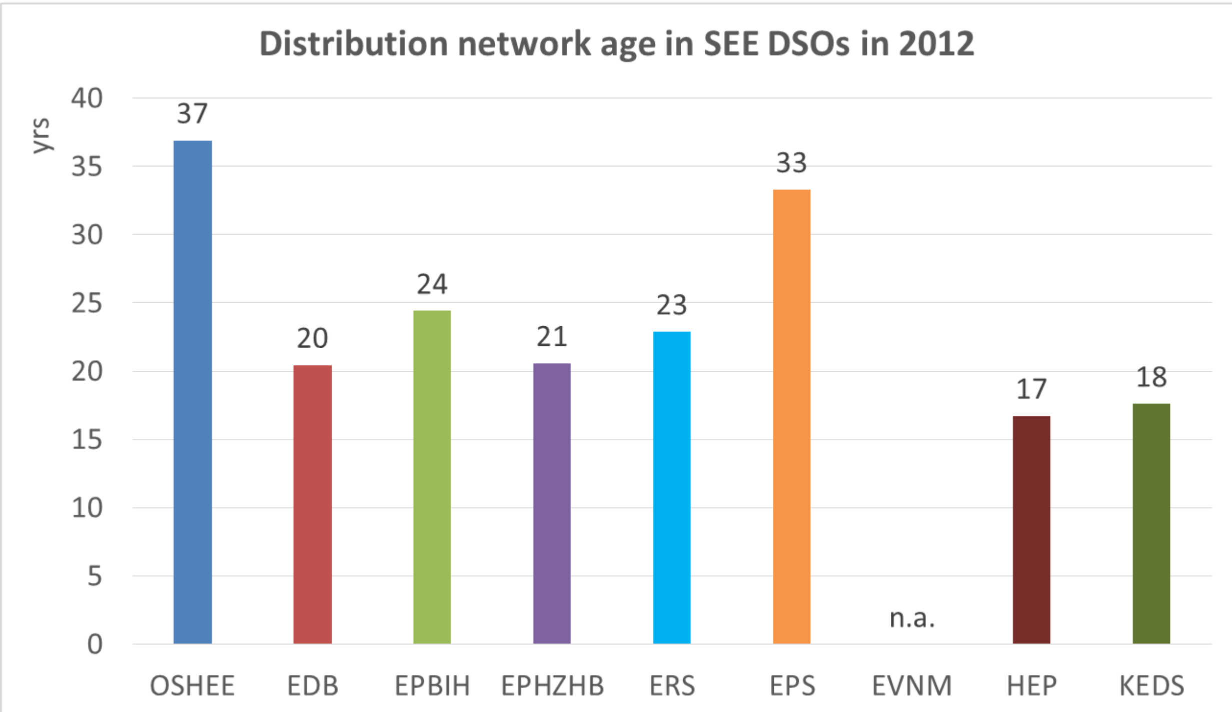


Figure 3.20 Calculated average distribution network age in SEE DSOs in 2012

Looking at individual DSOs, the oldest distribution network can be found in Albania (OSHEE) with the average age of 37 years and Serbia 33 years. The lowest distribution network age is in Croatia (17 years). The following Table and Figure provide distribution network age per type (cable/aerial) and voltage level.

Table 3.32 Distribution network age in SEE DSOs in 2012

2012 [years]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS
110 kV - aerial	-	-	-	-	-	31		32	
110 kV - cable	-	-	-	-	-	30		21	
35 kV - aerial	38	15	37	30	26	33		30	
35 kV - cable	38	20	17	30	10	32		22	
20 kV - aerial	12		16	-	23	28		19	
20 kV - cable	12		14	-	21	24		15	
16 kV - aerial	-	-	-	-	-	-		-	
16 kV- cable	-	-	-	-	-	-		-	
10 kV - aerial	36	25	25	25	28	32		19	
10 kV - cable	36	30	21	10	23	30		15	
6 kV - aerial	38	-	-	-	20	-		-	
6 kV - cable	38	-	-	-	23	-		-	
0,4 kV - aerial	38	20	24	20	22	35		16	
0,4 kV - cable	38	30	28	15	25	30		14	
AVERAGE (calculated by EIHP)	***37***	***20***	***24***	***21***	***23***	***33***		***17***	
AVERAGE (as provided by DSOs)		23	23		22				18

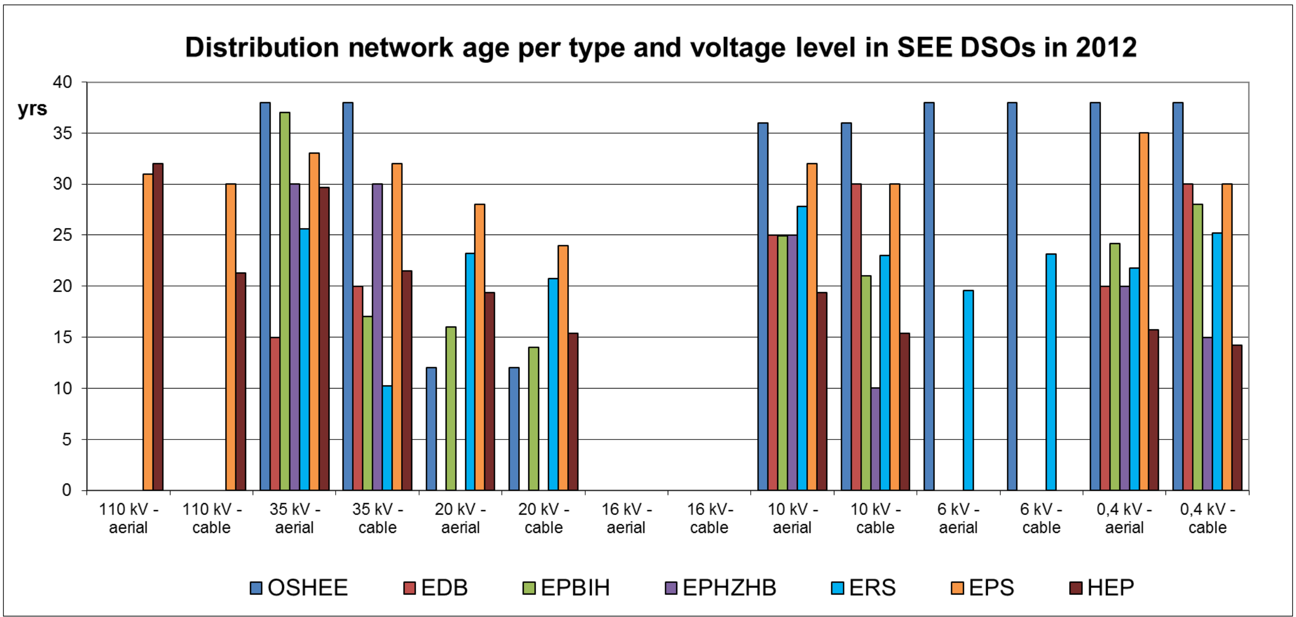
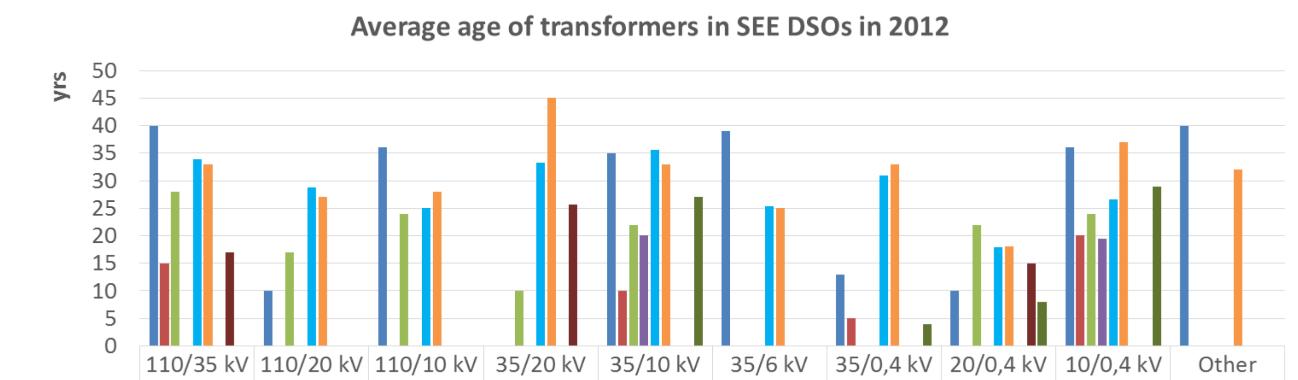


Figure 3.21 Distribution network age per type and voltage level in SEE DSOs in 2012

3.7. DISTRIBUTION TRANSFORMERS AGE

In what follows are given data on average age of transformers per type in SEE DSOs in 2012. Figure 3.23 gives calculated average age of all transformers in individual DSO. KEDS, EPBiH and EPHZHB values are calculated based on 35/20 kV; 35/10 kV; 35/6 kV and lower transformation ratios data, reason being that KEDS, EPBiH and EPHZHB transformers data do not comprise 110/10 kV and 110/20 kV substations and transformers (EPBiH provided data for 110/X substations, but not for 110/X transformers).



	110/35 kV	110/20 kV	110/10 kV	35/20 kV	35/10 kV	35/6 kV	35/0,4 kV	20/0,4 kV	10/0,4 kV	Other
OSHEE	40	10	36		35	39	13	10	36	40
EDB	15				10		5		20	
EPBIH	28	17	24	10	22			22	24	
EPHZHB					20				20	
ERS	34	29	25	33	36	25	31	18	27	
EPS	33	27	28	45	33	25	33	18	37	32
EVNM										
HEP	17			26				15		
KEDS					27		4	8	29	

Figure 3.22 Average distribution transformers age per type in SEE DSOs in 2012

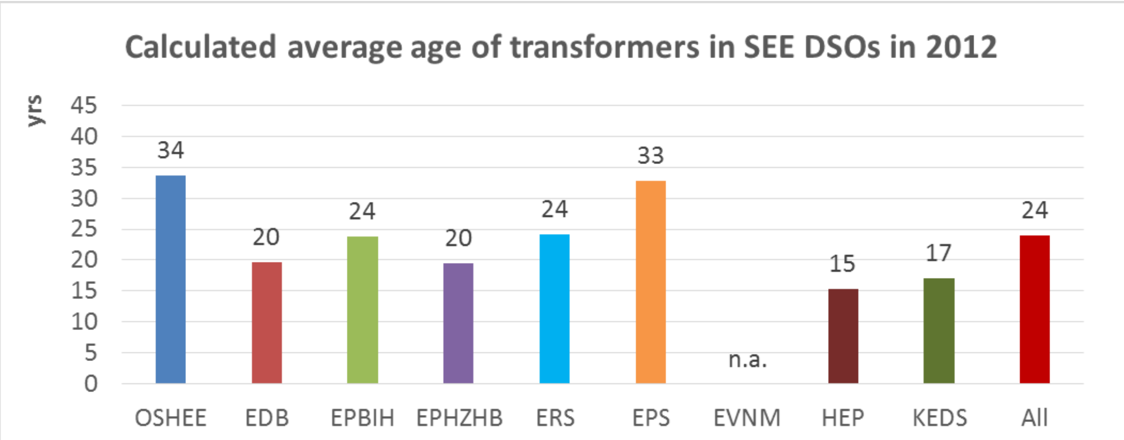


Figure 3.23 Calculated average distribution transformers age per type in SEE DSOs in 2012

3.8. NUMBER OF SUBSTATIONS

In SEE distribution network there are 119.125 substations, most of it in Serbia (29%), Croatia (21%) and Albania (20%). Here it must be observed that, unlike other DSOs substations data, EPHZHB and KEDS substations data do not include 110/x substations.

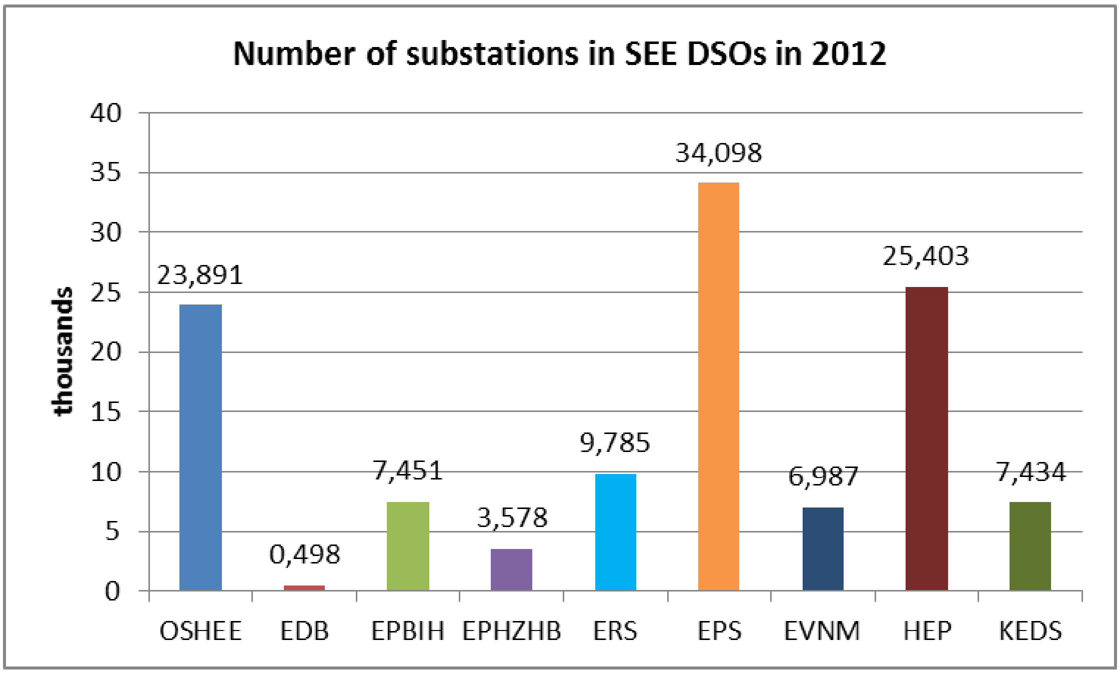


Figure 3.24 Number of substations in SEE DSOs in 2012

The following Tables show the growth of total number of substations in the last 5 years (missing data are given as green empty cells). By "Other" this report means all other substations with transformation ratios not listed in tables, i.e. 110/6 kV, 110/5,25 kV, 35/3 kV, 6/0,4 kV.

Table 3.33 Number of substations in SEE DSOs in 2008

2008	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	25	2			26	56	52	7		168
110/20 kV	12	0			20	47				79
110/10 kV	16	0			2	27				45
35/20 kV		0			3	13		327		343
35/10 kV	51	8		15	84	593	75			826
35/6 kV	46	0			2					48
35/0,4 kV	67	1			25	58				151
20/0,4 kV	2.716	0			2.584	7.106	6.475			18.881
10/0,4 kV	7.536	467			6.100	25.528		23.970		63.601
Other	9.749	-		3.389	-					13.138
SUM	20.218	478	0	3.404	8.846	33.428	6.602	24.304		97.280

Table 3.34 Number of substations in SEE DSOs in 2009

2009	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	25	2			26	60	53	7		173
110/20 kV	14	0			20	45				79
110/10 kV	16	0			2	27				45
35/20 kV		0			3	13		325		341
35/10 kV	51	8		15	79	586	75			814
35/6 kV	46	0			2	-				48
35/0,4 kV	72	1			25	58				156
20/0,4 kV		0			2.635	7.309	6.541			16.485
10/0,4 kV		476			6.222	24.273		24.337		55.308
Other	15	-		3.444	-					3.459
SUM	239	487	0	3.459	9.014	32.371	6.669	24.669		76.908

Table 3.35 Number of substations in SEE DSOs in 2010

2010	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV		2	23		26	59	53	7		170
110/20 kV		0	10		20	47				77
110/10 kV		0	19		2	28				49
35/20 kV		0	2		3	13				342
35/10 kV		8	79	15	79	586	75	324		842
35/6 kV		0	1		2	-				3
35/0,4 kV		1	0		25	58				84
20/0,4 kV		0	544		2.688	7.117	6.645			16.994
10/0,4 kV		482	6.625		6.346	25.047		24.588		63.088
Other		-		3.472	-					3.472
SUM		493	7.303	3.487	9.191	32.955	6.773	24.919		85.121

Table 3.36 Number of substations in SEE DSOs in 2011

2011	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	25	2	23		26	58	53	7		194
110/20 kV	15	0	10		20	48				93
110/10 kV	16	0	19		2	28				65
35/20 kV	-	0	2		3	13				344
35/10 kV	53	8	79	15	79	586	75	326		895
35/6 kV	47	0	1		2	-				50
35/0,4 kV	72	1	0		25	59				157
20/0,4 kV	3.207	0	548		2.742	7.638	6.758	24.806		45.699
10/0,4 kV	8.586	486	6.683		6.473	24.935				47.163
Other	10.488	-		3.517	-					14.005
SUM	12.021	497	7.365	3.532	9.372	33.365	6.886	25.139		108.665

Table 3.37 Number of substations in SEE DSOs in 2012

2012	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	25	2	23		26	62	53			198
110/20 kV	15	0	10		20	48		7		93
110/10 kV	16	0	19		2	28				65
35/20 kV		0	2		3	13				341
35/10 kV	54	8	79	15	74	590	75	323	49	944
35/6 kV	47	0	1		2	1			9	60
35/0,4 kV	65	1	0		25	62			12	165
20/0,4 kV	3.458	0	562		2.866	7.861	6.859	25.073	2.074	48.753
10/0,4 kV	9.111	487	6.755		6.767	25.431			5.286	53.837
Other	11.100	-		3.563	-	2			4	14.669
SUM	23.891	498	7.451	3.578	9.785	34.098	6.987	25.403	7.434	119.125

In addition to total number of substations given above, the following two Figures give number of X/MV substations (i.e. 110/10 kV; 110/20 kV; 35/20 kV; 35/10 kV; 35/6 kV; 35/3 kV) and MV/LV substations (i.e. 35/0,4 kV; 20/0,4 kV; 10/0,4 kV).

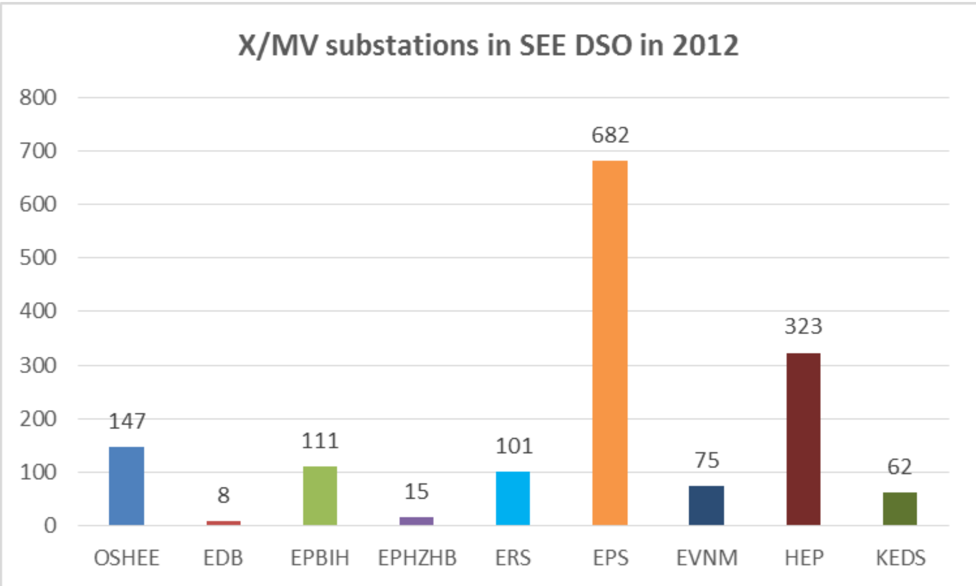


Figure 3.25 Number of X/MV substations in SEE DSOs in 2012

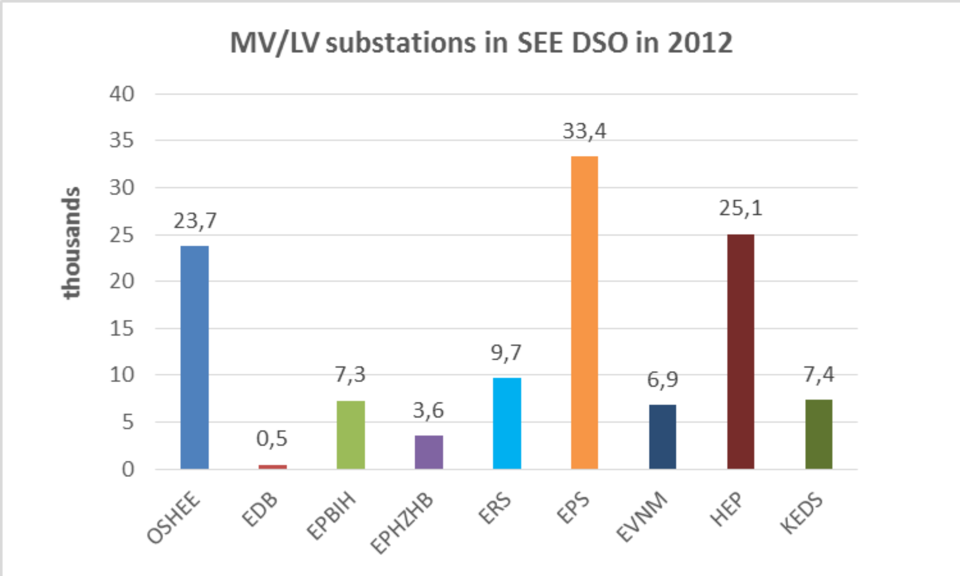


Figure 3.26 Number of MV/LV substations in SEE DSOs in 2012

3.9. NUMBER OF TRANSFORMERS

In addition to substations, in this chapter there is a benchmark of transformers in the region. Altogether there was 129.759 transformers in the region in 2012, compared to 119.125 substations. The shares of each DSO is about the same as in the case of substations.

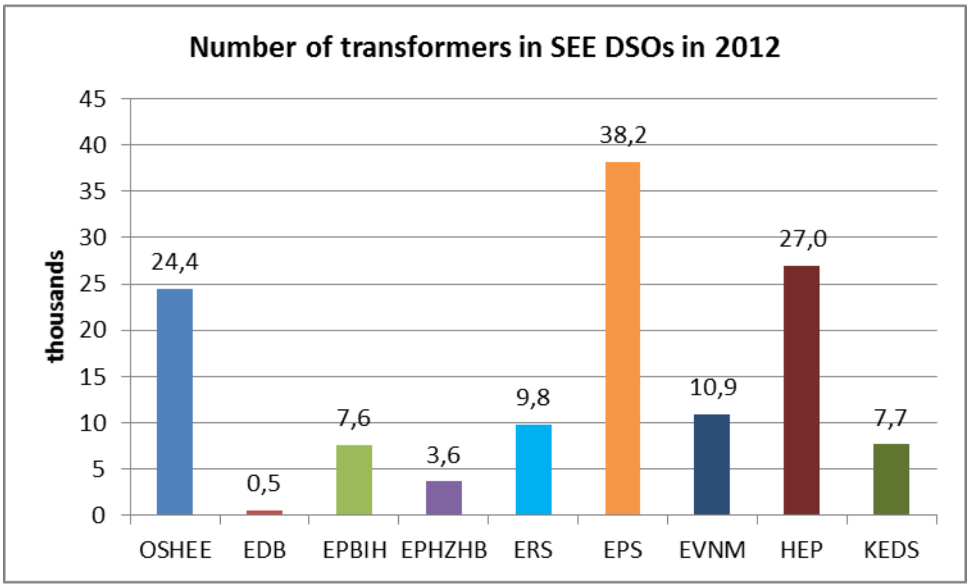


Figure 3.27 Number of transformers in SEE DSOs in 2012

The following Tables show the growth of total number of transformers in the last 5 years (missing data are given as green cells). By “Other” this report means all other substations with transformation ratios not listed in tables, i.e. 110/6 kV, 110/5,25 kV, 35/3 kV, 6/0,4 kV.

Table 3.38 Number of transformers in SEE DSOs in 2008

2008	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	74	4			54	112		76		320
110/20 kV	24	0			32					56
110/10 kV	23	0			3					26
35/20 kV		0			6	28		693		727
35/10 kV	90	12		20	117					239
35/6 kV	88	0			3					91
35/0,4 kV	74	2				109				185
20/0,4 kV	2804	0			2.584			3.070		8.458
10/0,4 kV	7427	475		3.420	6.100			21.751		39.173
Other	9.846	-								9.846
SUM	20.450	493		3.440	8.899	249		25.590		59.121

Table 3.39 Number of transformers in SEE DSOs in 2009

2009	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	76	4			54	120		70		324
110/20 kV	27	0			32					59
110/10 kV	24	0			3					27
35/20 kV		0			6	28		691		725
35/10 kV	89	12		20	112					233
35/6 kV	86	0			3					89
35/0,4 kV	82	2				109				193
20/0,4 kV		0			2.635			3.709		6.344
10/0,4 kV		484		3.503	6.222			21.987		32.196
Other	22	-								22
SUM	406	502		3.523	9.067	257		26.457		40.212

Table 3.40 Number of transformers in SEE DSOs in 2010

2010	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV		4			54	120		74		252
110/20 kV		0			32					32
110/10 kV		0			3					3
35/20 kV		0	3		6	28		686		723
35/10 kV		12	136	20	112					280
35/6 kV		0	2		3					5
35/0,4 kV		2				109				111
20/0,4 kV		0	548		2.688	7.641		3.797		14.674
10/0,4 kV		490	6.639	3.531	6.346			22.017		39.023
Other		-								0
SUM		508	7.328	3.551	9.244	7.898		26.574		55.103

Table 3.41 Number of transformers in SEE DSOs in 2011

2011	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	71	4			54	119				327
110/20 kV	28	0			32			79		60
110/10 kV	24	0			3					27
35/20 kV		0	3		6	28		684		721
35/10 kV	87	12	136	20	112					367
35/6 kV	80	0	2		3					85
35/0,4 kV	82	2				110				194
20/0,4 kV	3446	0	552		2.742	7.854		4.505		19.099
10/0,4 kV	8649	494	6.755	3.576	6.473			21.445		47.392
Other	10.555	-								10.555
SUM	23.022	512	7.448	3.596	9.425	8.111		26.713		78.827

Table 3.42 Number of transformers in SEE DSOs in 2012

2012	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	70	4			54	122	100			428
110/20 kV	28	0			32	76		78		136
110/10 kV	24	0			3	52				79
35/20 kV		0	3		6	28		680		717
35/10 kV	86	12	136	20	107	1.100	196		97	1.754
35/6 kV	81	0	2		3	2			21	109
35/0,4 kV	74	2				114			15	205
20/0,4 kV	3765	0	566		2.866	8.161	10.615	4.628	2.119	32.720
10/0,4 kV	9180	495	6.871	3.622	6.767	28.536		21.568	5.401	82.440
Other	11.122					5			4	11.131
SUM	24.430	513	7.578	3.642	9.838	38.196	10.911	26.954	7.657	129.719

In addition to total number of transformers given above, the following two Figures give number of X/MV transformers (i.e. 110/10 kV; 110/20 kV; 35/20 kV; 35/10 kV; 35/6 kV; 35/3 kV) and MV/LV transformers (i.e. 35/0,4 kV; 20/0,4 kV; 10/0,4 kV).

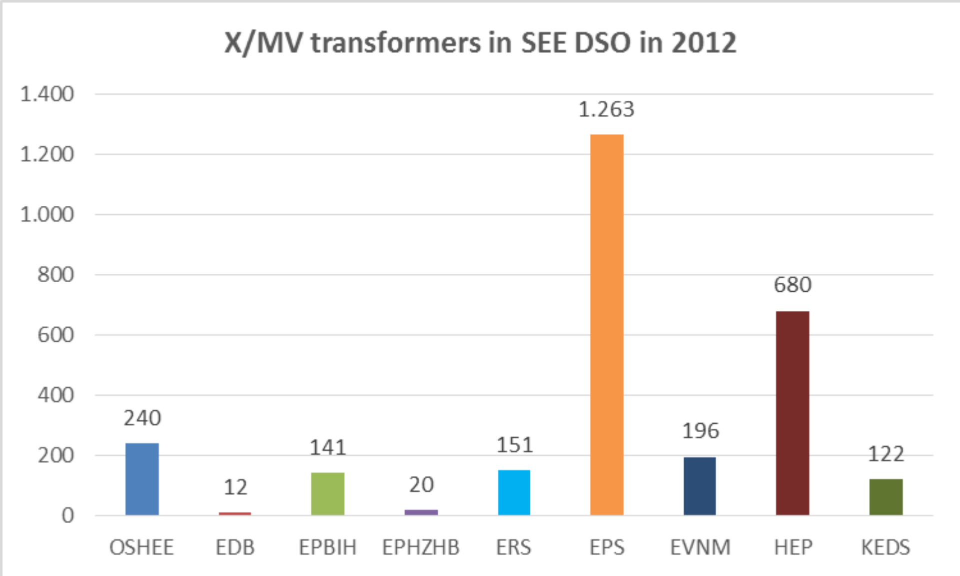


Figure 3.28 Number of X/MV transformers in SEE DSOs in 2012

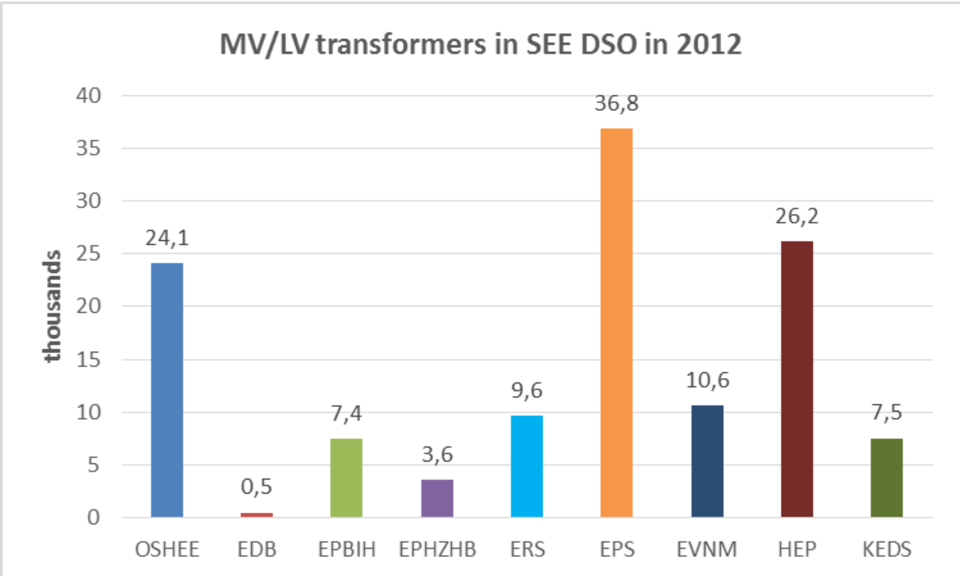


Figure 3.29 Number of MV/LV transformers in SEE DSOs in 2012

3.10. SUPPLY AREA SIZE

These 9 DSOs cover the area of 252.875 km^2, about the size of United Kingdom or Nevada (USA). The largest area portions are covered by Serbian EPS (31 %) and Croatian HEP (22 %).

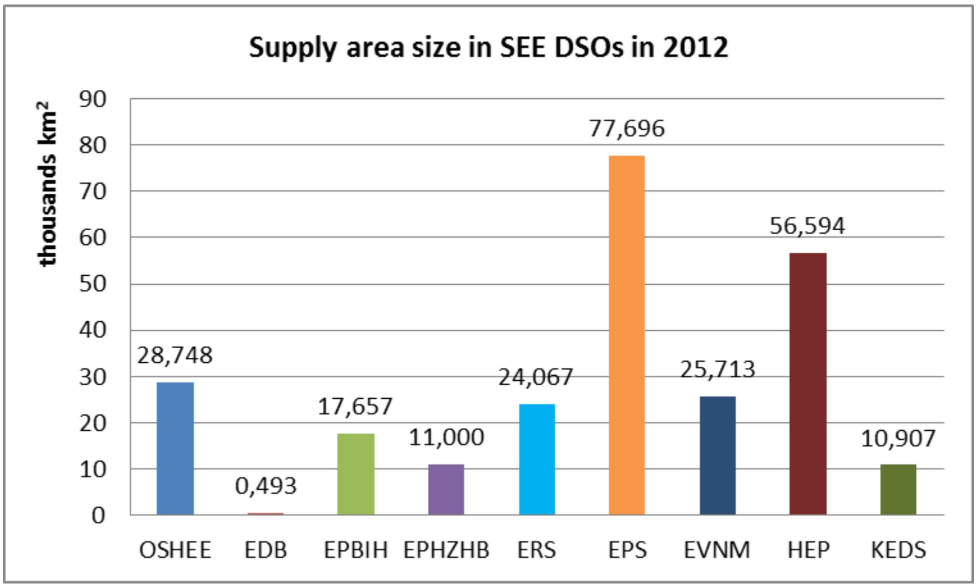


Figure 3.30 Supply area size in SEE DSOs in 2012

Table 3.43 Supply area size in SEE DSOs in 2012

DSO	Supply area size in 2012 [km^2]
OSHEE	28.748
EDB	493
EPBIH	17.657
EPHZHB	11.000
ERS	24.067
EPS	77.696
EVNM	25.713
HEP	56.594
KEDS	10.907
SUM	**252.875**

3.11. SUM CAPACITY OF TRANSFORMERS

As given above, there are 119.125 substations (119.073 without 110/MV substations in EPBiH) in this region (see Table 3.37) and it is interesting to analyze the sum capacity of transformers. Total sum of all distribution transformers capacity in the region is 71.053 MVA (value does not include data on capacity of 110/MV transformers in EPBiH, EPHZHB and KEDS (see Table 3.48)) or 71.053 MVA/119.073 = 0,6 MVA (600 kVA) per substation.

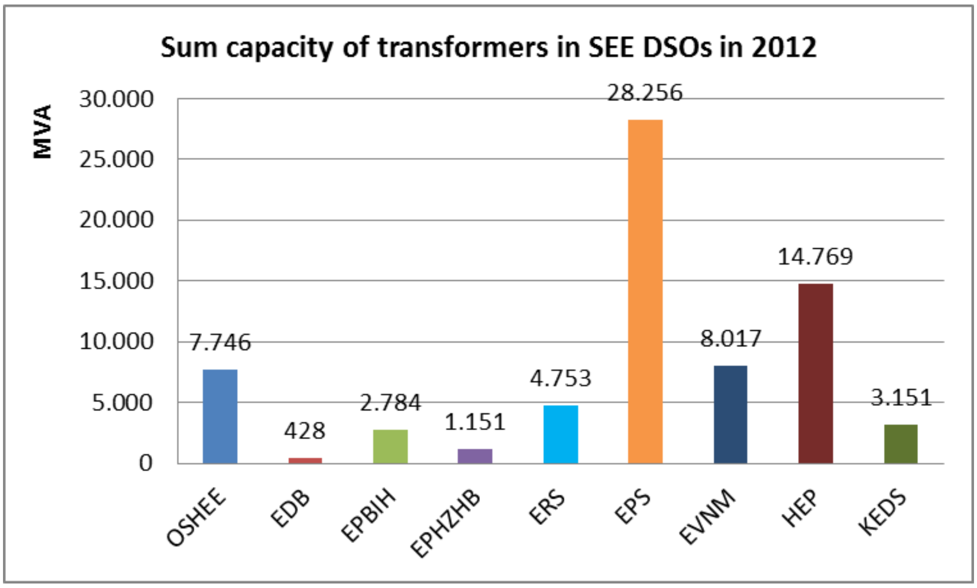


Figure 3.31 Sum capacity of transformers in SEE DSOs in 2012

Table 3.44 Sum capacity of transformers in SEE DSOs in 2008 [MVA]

2008	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	1141,5	140			986	3.103				7.657
110/20 kV	616,6				655	2.483		2.286		3.755
110/10 kV	201,1				72	1.434				1.707
35/20 kV					24	285		4.414		4.723
35/10 kV	311,8	96		86	609	6.193				7.295
35/6 kV	460,2				10	-				470
35/0,4 kV	51,5	5			99	577				733
20/0,4 kV	1128				501	2.697		860		5.186
10/0,4 kV	1171	178,82		965	1.184	10.152		6.325		19.976
Other	1.830,2					-				1.830
SUM	6.912	420		1.051	4.139	26.924		13.885		53.331

Table 3.45 Sum capacity of transformers in SEE DSOs in 2009 [MVA]

2009	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	1167,1	140			986	3.219				7.704
110/20 kV	721,6				655	2.431		2.192		3.808
110/10 kV	204,8				72	1.546				1.822
35/20 kV					24	285		4.417		4.726
35/10 kV	298,85	96		86	465	6.160				7.105
35/6 kV	444,5				10	-				454
35/0,4 kV	66	5			99	577				747
20/0,4 kV					551	2.794		1.029		4.374
10/0,4 kV		183,96		999	1.301	8.985		6.532		18.001
Other	191,5					-				192
SUM	3.094	425		1.085	4.162	25.997		14.170		48.933

Table 3.46 Sum capacity of transformers in SEE DSOs in 2010 [MVA]

2010	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV		140			986	3.229				6.627
110/20 kV					655	2.494		2.272		3.149
110/10 kV					72	1.578				1.650
35/20 kV			12		24	285		4.409		4.730
35/10 kV		96	618	86	465	6.133				7.397
35/6 kV			8		10	-				18
35/0,4 kV		5			99	577				681
20/0,4 kV			157		605	2.744		1.079		4.584
10/0,4 kV		185,33	1.941	1.017	1.429	9.208		6.586		20.366
Other						-				0
SUM		426	2.735	1.103	4.344	26.248		14.346		49.202

Table 3.47 Sum capacity of transformers in SEE DSOs in 2011 [MVA]

2011	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	1121	140			986	3.221				7.900
110/20 kV	717,8				655	2.566		2.432		3.939
110/10 kV	195,3				72	1.598				1.865
35/20 kV			12		24	285		4.434		4.755
35/10 kV	294,8	96	618	86	465	6.226				7.785
35/6 kV	412,55		8		10	-				430
35/0,4 kV	66	5			99	581				751
20/0,4 kV	1462		157		665	2.868		1.397		6.549
10/0,4 kV	1431	186,33	1.957	1.037	1.571	9.171		6.377		21.730
Other	1.906,5					-				1.907
SUM	7.607	427	2.752	1.123	4.546	26.515		14.640		57.611

Table 3.48 Sum capacity of transformers in SEE DSOs in 2012 [MVA]

2012	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110/35 kV	1111	140			986	3.284	2.942			10.875
110/20 kV	703,3				655	2.586		2.412		3.944
110/10 kV	195,3				72	1.678				1.944
35/20 kV			12		24	285		4.417		4.738
35/10 kV	271,4	96	618	86	450	6.284	968		660	9.433
35/6 kV	411,75		8		10	3			69	501
35/0,4 kV	60	5			99	586			38	789
20/0,4 kV	1.554		160		731	2.986	4.107	1.431	732	11.701
10/0,4 kV	1.486	186,96	1.986	1.065	1.726	10.395		6.509	1.650	25.004
Other	1.952,9					170			2	2.125
SUM	7.746	428	2.784	1.151	4.753	28.256	8.017	14.769	3.151	71.053

As given above, total sum of all distribution transformers capacity in 2012 in the region is 71.053 MVA. But, to get clear picture these values should be given separately for X/MV kV (i.e. 110/10 kV; 110/20 kV; 35/20 kV; 35/10 kV; 35/6 kV; 35/3 kV) and MV/LV transformers (i.e. 35/0,4 kV; 20/0,4 kV; 10/0,4 kV).

As given on the following Figure, Serbian EPS has the highest total installed capacity of X/MV transformer in the region is in – 11.005 MVA.
Data on sum capacity of X/MV transformers provided by EPHZHB, as given in Table 3.48*Table 3.53* (i.e. 86 MVA), relates to 35/10 kV transformers only. On Figure 3.32 (based on NOS BiH data) value presents total sum capacity of X/MV transformers (892 MVA); i.e. regardless of ownership.

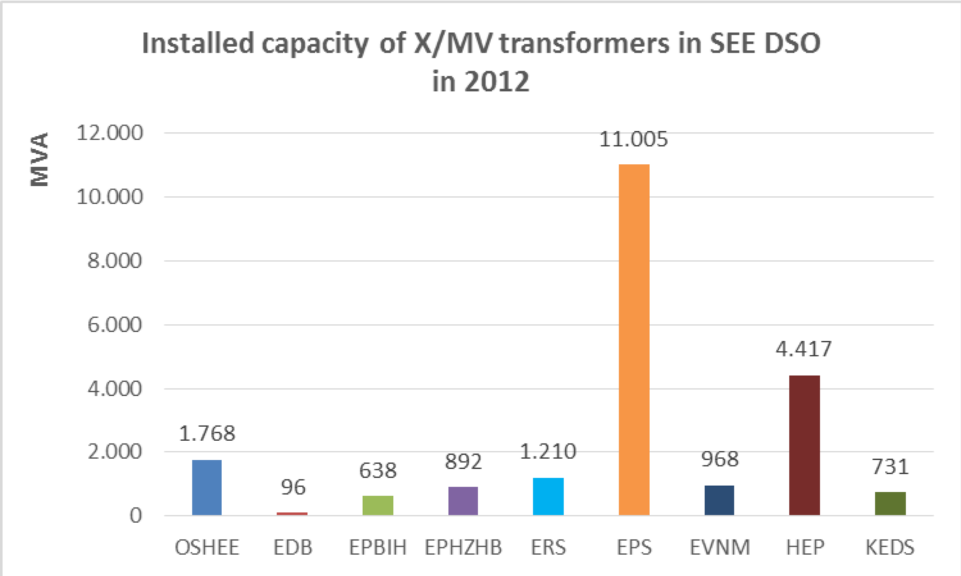


Figure 3.32 Installed capacity of X/MV transformers in SEE DSO in 2012

Total installed capacity of MV/LV transformers is given on the following Figure. As expected, the largest MV/LV transformers capacity is again in EPS, Serbia – 13.967 MVA.

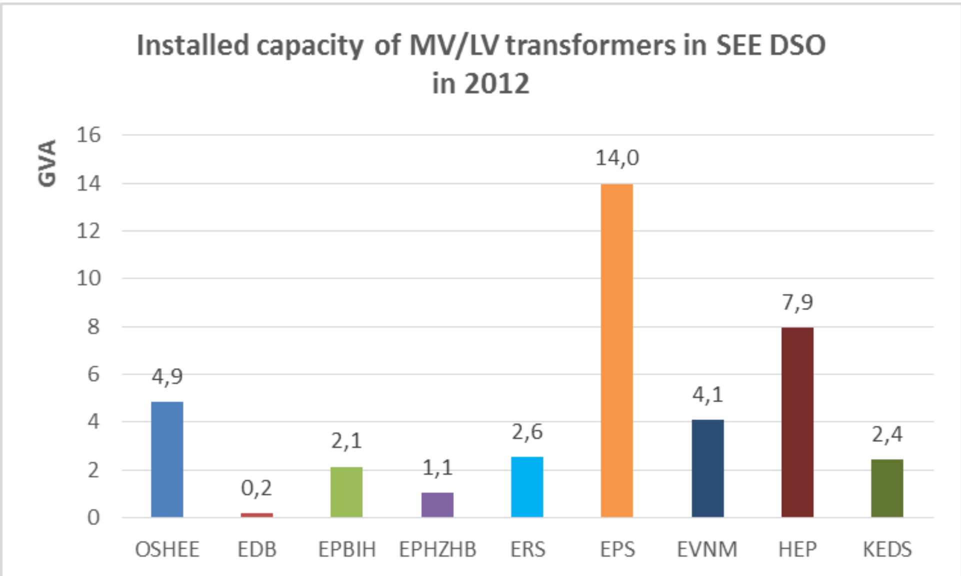


Figure 3.33 Installed capacity of MV/LV transformers in SEE DSO in 2012

3.12. NUMBER OF FEEDERS

One of the usual benchmarking indicators is number of feeders. In the region in 2012 in total there were 445.583 feeders, without EVNM (data not available).

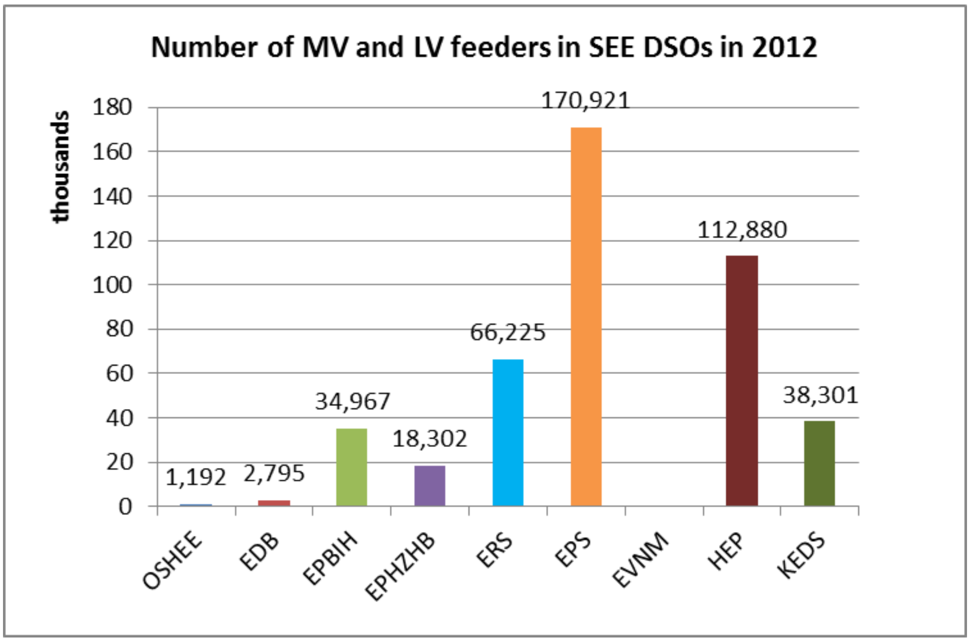


Figure 3.34 Number of feeders in SEE DSOs in 2012

In the following Tables number of feeders in the period 2008 – 2012 are given, clearly indicating significant growth in the observed period (for example in EPS 7,7%, ERS 6%, HEP 5,6% etc.). Only Serbian EPS provided data for 35 kV feeders.

Table 3.49 Number of feeders in SEE DSOs in 2008

2008	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
35 kV						12				12
20 kV	167	-		-	178	50		774		1.169
10 kV	408	55		86	528			5102		6.179
6 kV	600	-		-	11			0		611
3 kV										0
0,4 kV		2.580		17564	60.073	339		100.788		181.344
SUM	1.175	2.635		17.650	60.790	401		106.664		189.315

Table 3.50 Number of feeders in SEE DSOs in 2009

2009	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
35 kV						12				12
20 kV	167	-		-	178	50		834		1.229
10 kV	408	55		86	528			5133		6.210
6 kV	600	-		-	11			0		611
3 kV										0
0,4 kV		2.652		17.804	61.273	339		104.265		186.333
SUM	1.175	2.707		17.890	61.990	401		110.232		194.395

Table 3.51 Number of feeders in SEE DSOs in 2010

2010	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
35 kV						12				12
20 kV		-	83	-	178	50		856		1.167
10 kV		55	940	86	528			5253		6.862
6 kV		-	6	-	11			0		17
3 kV			-							0
0,4 kV		2.700	32.936	17.936	62.496	31803		104.995		252.866
SUM		2.755	33.965	18.022	63.213	31.865		111.104		260.924

Table 3.52 Number of feeders in SEE DSOs in 2011

2011	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
35 kV						12				12
20 kV	173	-	83	-	178	50		937		1.421
10 kV	414	55	940	86	528			5318		7.341
6 kV	604	-	6	-	11			0		621
3 kV			-							0
0,4 kV		2.732	33.425	18.128	63.744	33.462		105.685		257.176
SUM	1.191	2.787	34.454	18.214	64.461	33.524		111.940		266.571

Table 3.53 Number of feeders in SEE DSOs in 2012

2012	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
35 kV						154				154
20 kV	173	-	83	-	178	751		957		2.142
10 kV	415	55	940	86	528	4.275		5.635	655	12.589
6 kV (5,25 kV)	604	-	6	-	11	5 (16)		0	25	651
3 kV		-	-	-	-			-	6	6
0,4 kV	-	2.740	33.938	18.216	65.508	165.720		106.288	37.615	430.025
SUM	1.192	2.795	34.967	18.302	66.225	170.921		112.880	38.301	445.583

Besides total number of feeders it is interesting to analyze number of MV and LV feeders, as given on the following Figures. In the region in 2012 the largest number of MV feeders was in Croatia - 6.592 feeders. Number of MV feeders provided by EPHZHB as given in Table 3.53 (i.e. 86) is for feeders in the property of DSO. On Figure 3.35 (based on NOS BiH data) this value presents total number of MV feeders (i.e. 310 MV feeders), regardless of ownership.

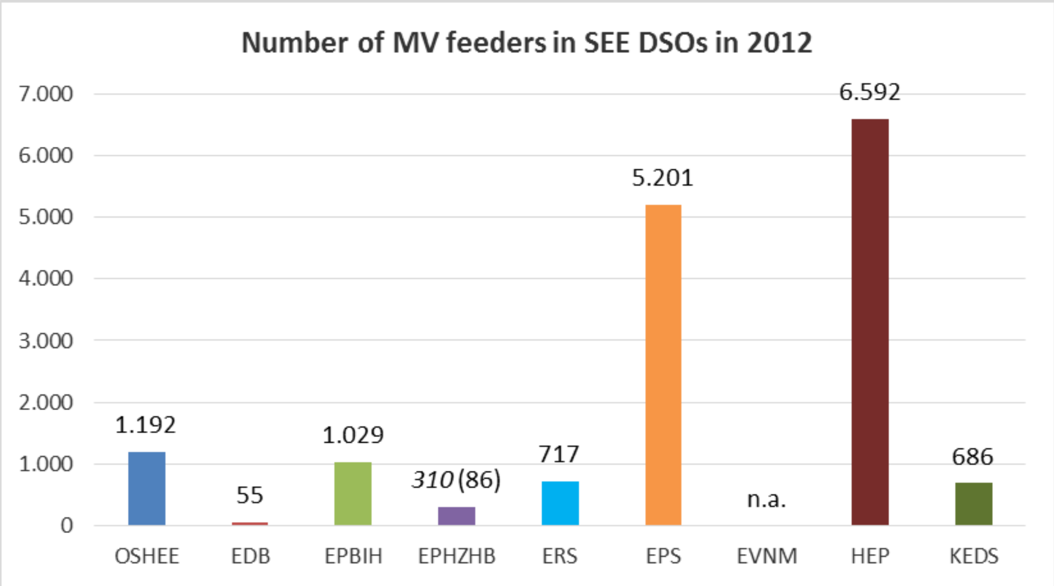


Figure 3.35 Number of MV feeders in SEE DSOs in 2012

The largest number of LV feeders in 2012 was in EPS, Serbia - 165.720 feeders.

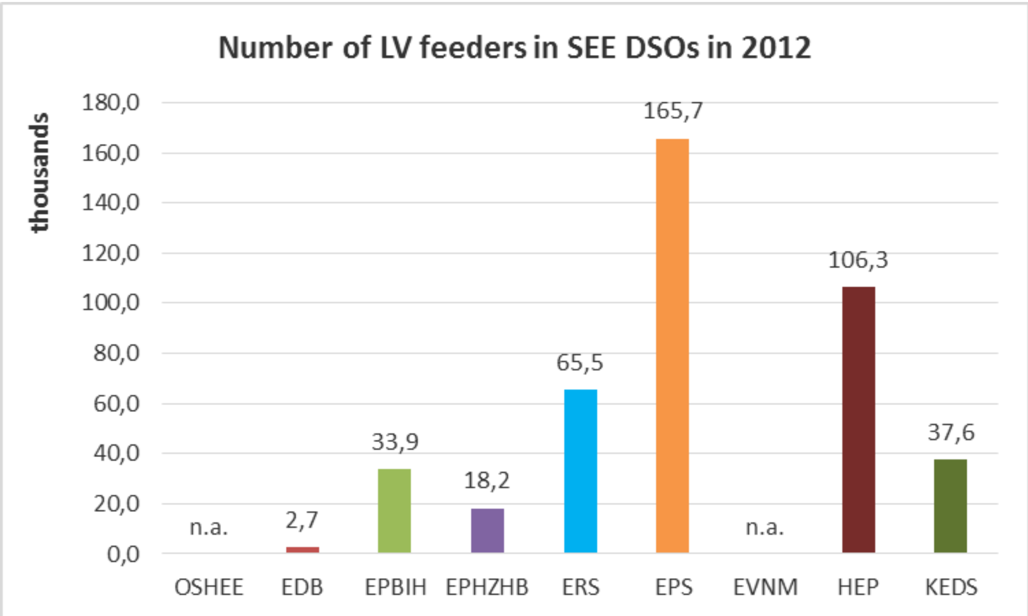


Figure 3.36 Number of LV feeders in SEE DSOs in 2012

3.13. DISTRIBUTION NETWORK OPERATED AND NOT OWNED BY DSO

In some cases part of distribution network is not owned by the DSO, but some other entities (industrial, municipal, TSO, etc.). In these cases DSO is obliged to operate and control (sometimes to maintain) this part of distribution network in order to keep it reliable and harmonized with the remaining part of the system. In these cases regulatory framework has to be very comprehensive.

In the region in 2012 there were 6.041 km of distribution lines operated and not owned by the DSOs. Most of them are in Serbian EPS (52%), ERS (20%) and EVNM (17%), as shown on the following Figure and Tables for the period 2008 - 2012.

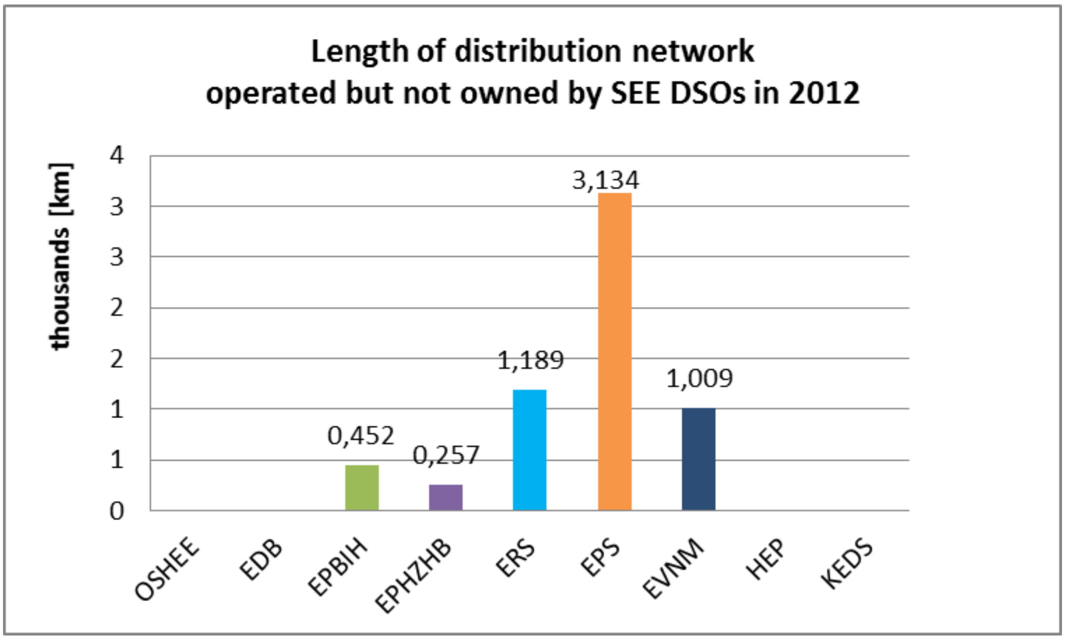


Figure 3.37 Distribution network length operated but not owned by SEE DSOs in 2012

Table 3.54 Distribution network length operated but not owned by SEE DSOs in 2008

2008 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV										0
35 kV				75						272
20 kV					197	1.787				1.787
10 kV				176						176
6 kV										0
0,4 kV					992	674				1.666
SUM	0	0	0	251	1.189	2.461	0	0	0	3.901

Table 3.55 Distribution network length operated but not owned by SEE DSOs in 2009

2009 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV										0
35 kV				75						272
20 kV					197	1.784				1.784
10 kV				176						176
6 kV										0
0,4 kV					992	675				1.667
SUM	0	0	0	251	1.189	2.459	0	0	0	3.899

Table 3.56 Distribution network length operated but not owned by SEE DSOs in 2010

2010 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV										0
35 kV			76	75						348
20 kV			47		197	1.767				1.814
10 kV			323	181						504
6 kV										0
0,4 kV					992	677				1.669
SUM	0	0	446	256	1.189	2.444	0	0	0	4.335

Table 3.57 Distribution network length operated but not owned by SEE DSOs in 2011

2011 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV										0
35 kV			77	75						349
20 kV			47		197	1.686				1.733
10 kV			323	182						505
6 kV										0
0,4 kV					992	675				1.667
SUM	0	0	447	257	1.189	2.361	0	0	0	4.254

Table 3.58 Distribution network length operated but not owned by SEE DSOs in 2012

2012 [km]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
110 kV										0
35 kV			78	75		347				697
20 kV			47		197	1.691				1.738
10 kV			327	182		422	657			1.587
6 kV										0
0,4 kV					992	675	351,8			2.019
SUM	0	0	452	257	1.189	3.134	1.009	0	0	6.041

3.14. NUMBER OF EMPLOYEES

One of the most usual benchmarking indicators for the company efficiency is number of employees per given service. In DSO activity it is quite specific, especially in SEE, since part of staff is shared with supply business (in all regional DSOs but EPHZHB) or eventually with other parts of vertically integrated company. In most of the cases in SEE supply business is not fully unbundled from network business, company restructuring is still underway with lot of shared staff, so these indicators should be analyzed carefully.

In nine regional DSOs there are 36.797 employees altogether. But, 27.105 employees (74%) are dealing purely with network business. Remaining 4.943 employees (13%) are engaged in supply business, while 4.749 (13%) employees are shared between network and supply business.

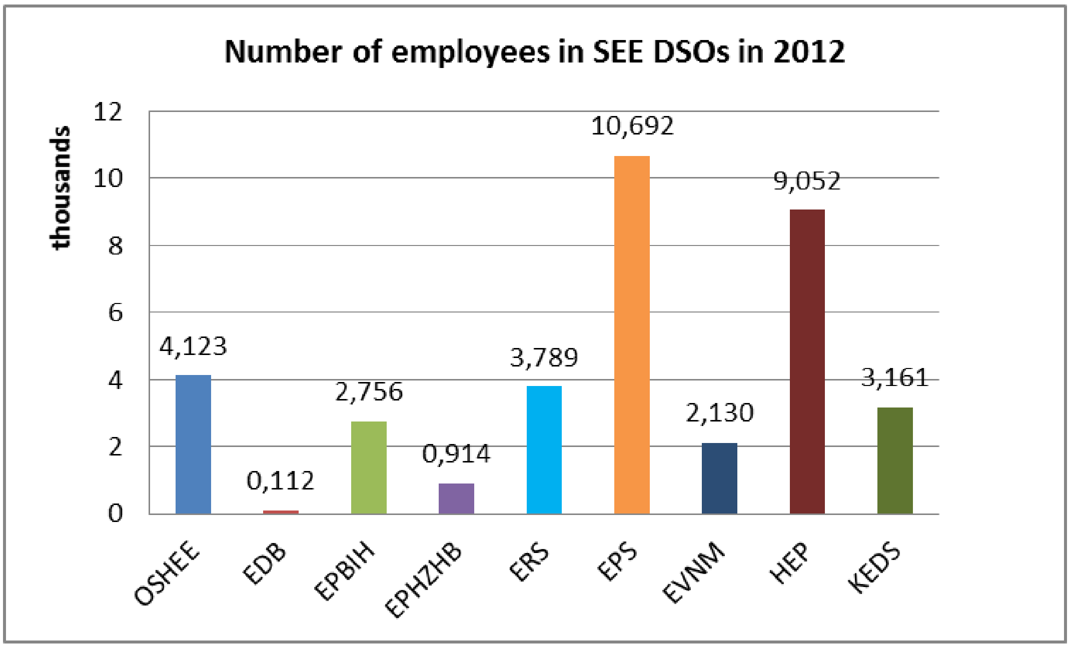


Figure 3.38 Number of employees in SEE DSOs in 2012

Table 3.59 Number of employees in SEE DSOs in 2012

	Employees									
2012	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM*	HEP	KEDS	SUM
Supply and network business integrated	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	
Network (distribution) business – NB	3.310	112	2.374	914	3.789	6.680	1.658	5.641	2.627	27.105
Supply business (i.e. energy procurement, marketing and sales, billing, customer care,..) – SB	736	68	382			2.973	18	766		4.943
Shared staff (i.e. working in supply and network business) – SS	77					1.039	454	2.645	534	4.749
Sum of Employees	4.123	180	2.756	914	3.789	10.692	2.130	9.052	3.161	36.797
Data availability in the last 5 years	Yes	No	No	Yes	Yes	Yes	Yes	Yes	No	

**in 2013*

3.15. DISTRIBUTED GENERATION DATA

In line with EU energy policy targets, as well as national energy strategies, there has been a lot of distributed generation projects in SEE in the last decade. At the end of 2012 there were 438,957 MW of distributed generation installed capacity. The largest part is installed in Albania (111,6 MW), BiH (total of 134 MW, with the largest contribution of EP BiH (94 MW)) and Macedonia (79,9 MW).

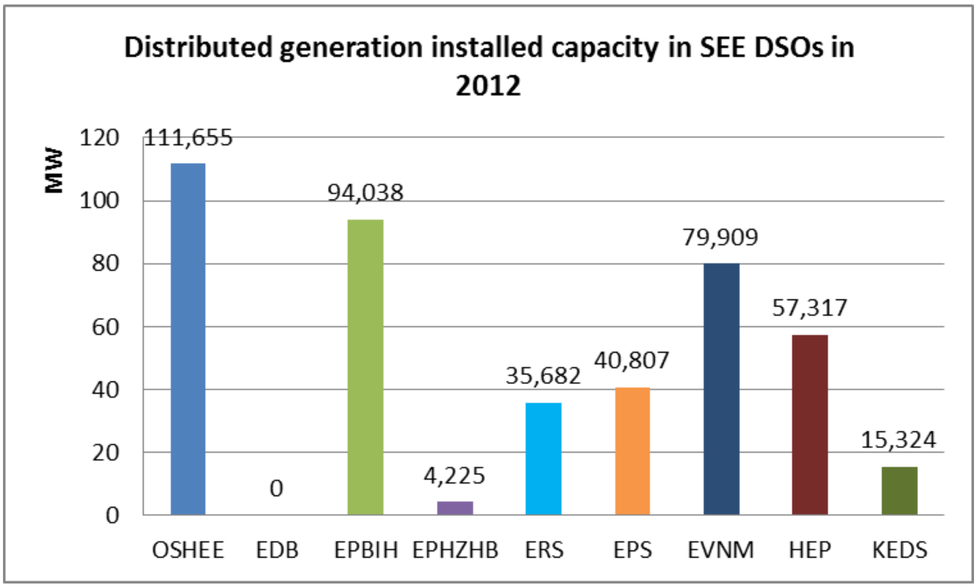


Figure 3.39 Distributed generation installed capacity in SEE DSOs in 2012

The largest portion in distributed generation capacity is installed in hydro power plants (68%). Wind farms are covering 8,2% of total installed distribution generation capacity in the region, as shown on the following Figure.

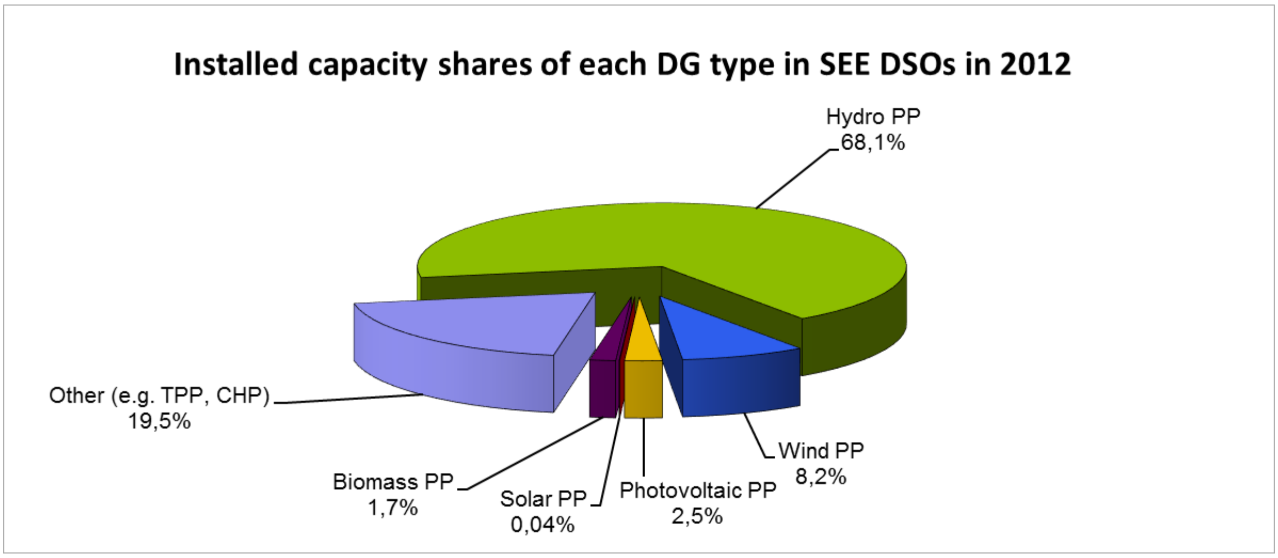


Figure 3.40 Installed capacity shares of each DG type in SEE DSOs in 2012

The following Tables show distributed generation installed capacities per each DG type per each SEE DSO in 2012.

Table 3.60 Distributed generation installed capacity in SEE DSOs in 2012

Distributed generation (2012)			
SUM of installed capacity	[kW]		
ALL DSOs	MV	LV	**SUM**
Hydro PP	298.477	311	298.788
Wind PP	36.052	0	36.052
Photovoltaic PP	6.461	4.380	10.841
Solar PP	0	172	172
Biomass PP	7.480	0	7.480
Fuel cells	0	0	0
Geothermal PP	0	0	0
Tidal PP	0	0	0
Stirling motor	0	0	0
Energy storage	0	0	0
Other (e.g. TPP, CHP)	85.456	168	85.624
SUM	433.926	5.031	438.957

Table 3.61 Distributed generation installed capacity in each SEE DSO in 2012

Distributed generation (2012)	[kW]	
OSHEE	MV	LV
Hydro PP	111.655	0
Wind PP	0	0
Photovoltaic PP	0	0
Solar PP	0	0
Biomass PP	0	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other	0	0
SUM	111.655	0

Distributed generation (2012)	[kW]	
EDB	MV	LV
Hydro PP	0	0
Wind PP	0	0
Photovoltaic PP	0	0
Solar PP	0	0
Biomass PP	0	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other	0	0
SUM	0	0

Distributed generation (2012)	[kW]	
EPBiH	MV	LV
Hydro PP	26.643	0
Wind PP	0	0
Photovoltaic PP	0	0
Solar PP	0	172
Biomass PP	0	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other (small TPP)	67.223	0
SUM	93.866	172

Distributed generation (2012)	[kW]	
EPHZHB	MV	LV
Hydro PP	3.925	0
Wind PP	0	0
Photovoltaic PP	0	300
Solar PP	0	0
Biomass PP	0	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other (small TPP)	0	0
SUM	3.925	300

Distributed generation (2012)	[kW]	
ERS	MV	LV
Hydro PP	35.607	75
Wind PP	0	0
Photovoltaic PP	0	0
Solar PP	0	0
Biomass PP	0	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other (small TPP)	0	0
SUM	35.607	75

Distributed generation (2012)	[kW]	
EPS	MV	LV
Hydro PP	31.781	206
Wind PP	152	0
Photovoltaic PP	124	175
Solar PP	0	0
Biomass PP	635	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other (Cogeneration PP)	3.500	0
Other (Gas PP)	1.020	
Other (CHP PP)	3.215	
SUM	40.427	381

Distributed generation (2012)	[kW]	
EVNM	MV	LV
Hydro PP	73.572	0
Wind PP	0	0
Photovoltaic PP	6.337	0
Solar PP	0	0
Biomass PP	0	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other (small TPP)	0	0
SUM	79.909	0

Distributed generation (2012)	[kW]	
HEP	MV	LV
Hydro PP	1.320	30
Wind PP	34.550	0
Photovoltaic PP	0	3.906
Solar PP	0	0
Biomass PP	6.845	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other	10.498	168
SUM	53.213	4.104

Distributed generation (2012)	[kW]	
KEDS	MV	LV
Hydro PP	13.974	0
Wind PP	1.350	0
Photovoltaic PP	0	0
Solar PP	0	0
Biomass PP	0	0
Fuel cells	0	0
Geothermal PP	0	0
Tidal PP	0	0
Stirling motor	0	0
Energy storage	0	0
Other	0	0
SUM	15.324	0

As shown in the previous Tables, most of the DG capacity is connected to the medium voltage network (98,9 %). There is only one DSO with significant DG capacity connected to the low voltage network and that is Croatian HEP – 4,104 MW. That is 82 % of all DG capacity connected to the low voltage network in the region.

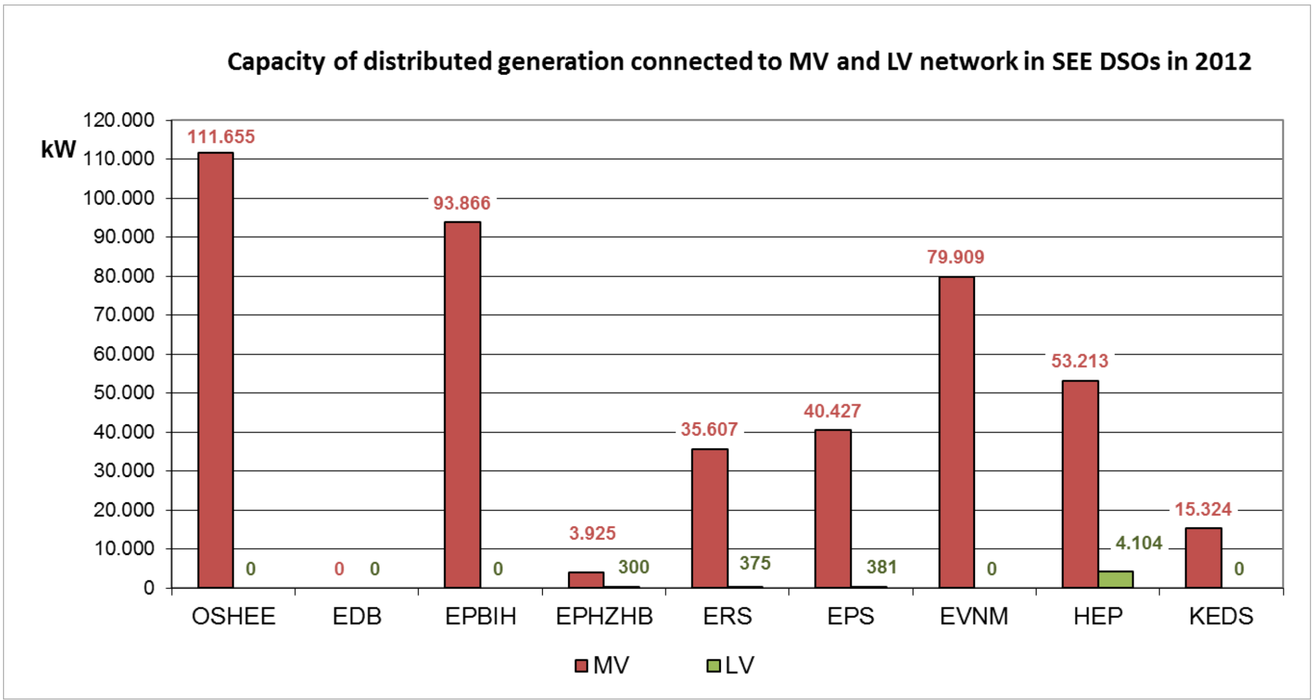


Figure 3.41 Capacity of distributed generation connected to MV and LV network in SEE DSOs in 2012

Table 3.62 Capacity of distributed generation connected to MV and LV network in SEE DSOs in 2012

[kW]	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	SUM
MV	111.655	0	93.866	3.925	35.607	40.427	79.909	53.213	15.324	433.926
LV	0	0	172	300	75	381	0	4.104	0	5.031
SUM	111.655	0	94.038	4.225	35.682	40.807	79.909	57.317	15.324	438.957

4. GENERAL BENCHMARKING INDICATORS

4.1. ELECTRICITY DELIVERED PER CONSUMER

One of the most important DSO benchmarking indicators is electricity delivered per each consumer Please note that the number of consumers is not the same as the number of metering points. Electricity delivered per metering point will be discussed in the following Subchapter.

The following Figure shows that in SEE electricity delivered per consumer in 2012 is between 3.654 kWh/consumer (OSHEE, Albania) and 8.125 kWh/consumer (EPS, Serbia). The average amount of electricity delivered to each consumer in SEE is 6.939 kWh/consumer. In most of the countries this indicator is, on average, increasing in the period 2008 – 2012; for all DSOs electricity delivered per consumer has, on average, decreased for 0,9 %/year (or 3,6 %) since 2008.

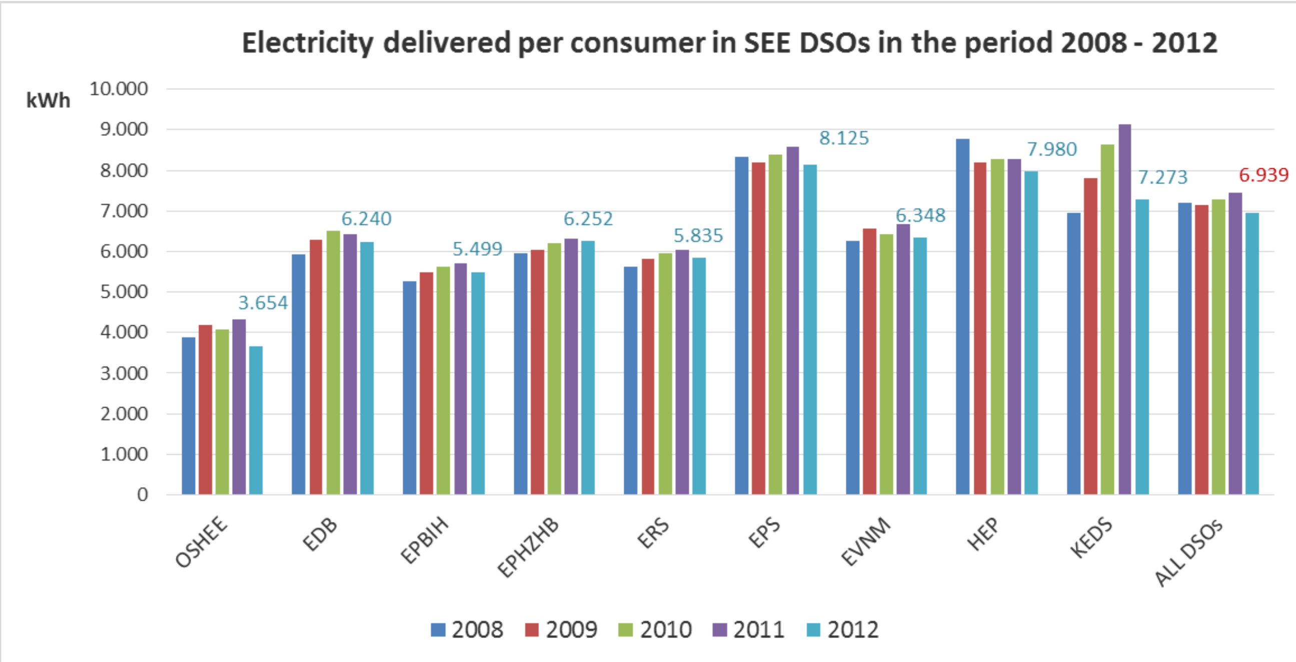


Figure 4.1 Electricity delivered per consumer in SEE DSOs in the period 2008 - 2012

All DSO consumers are usually divided in two main categories: consumer on the medium voltage level and on the low voltage level. Electricity delivered per MV consumer is shown on the following Figure and it shows that in SEE electricity delivered per MV consumer in 2012 is between 138 MWh/consumer (OSHEE, Albania) and 3.073 MWh/consumer (HEP, Croatia). The average amount of electricity delivered to each MV consumer in SEE is 968 MWh/consumer. Only in KEDS and EDB this indicator slightly increased in the period 2008 – 2012; for all DSOs electricity delivered per MV consumer has, on average, decreased for 2,6 %/year (or 10 %) since 2008.

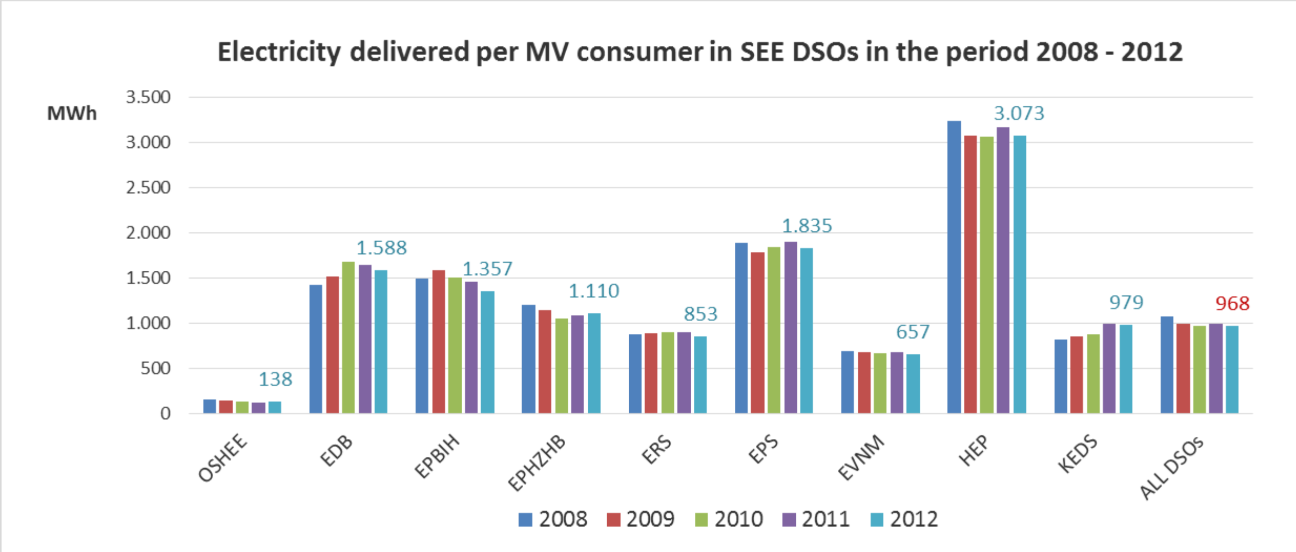


Figure 4.2 Electricity delivered per MV consumer in SEE DSOs in the period 2008 - 2012

Electricity delivered per LV consumer (mainly households) is shown on the following Figure and it shows that in SEE electricity delivered per LV consumer in 2012 is between 2.719 kWh/consumer (OSHEE, Albania) and 6.040 kWh/consumer (HEP, Croatia). The average amount of electricity delivered to each LV consumer in SEE is 5.206 kWh/consumer. In 6 out of 9 DSOs this indicator increased in the period 2008 – 2012; for all DSOs electricity delivered per LV consumer has, on average, decreased for 0,6 %/year (or 2,3 %) since 2008.

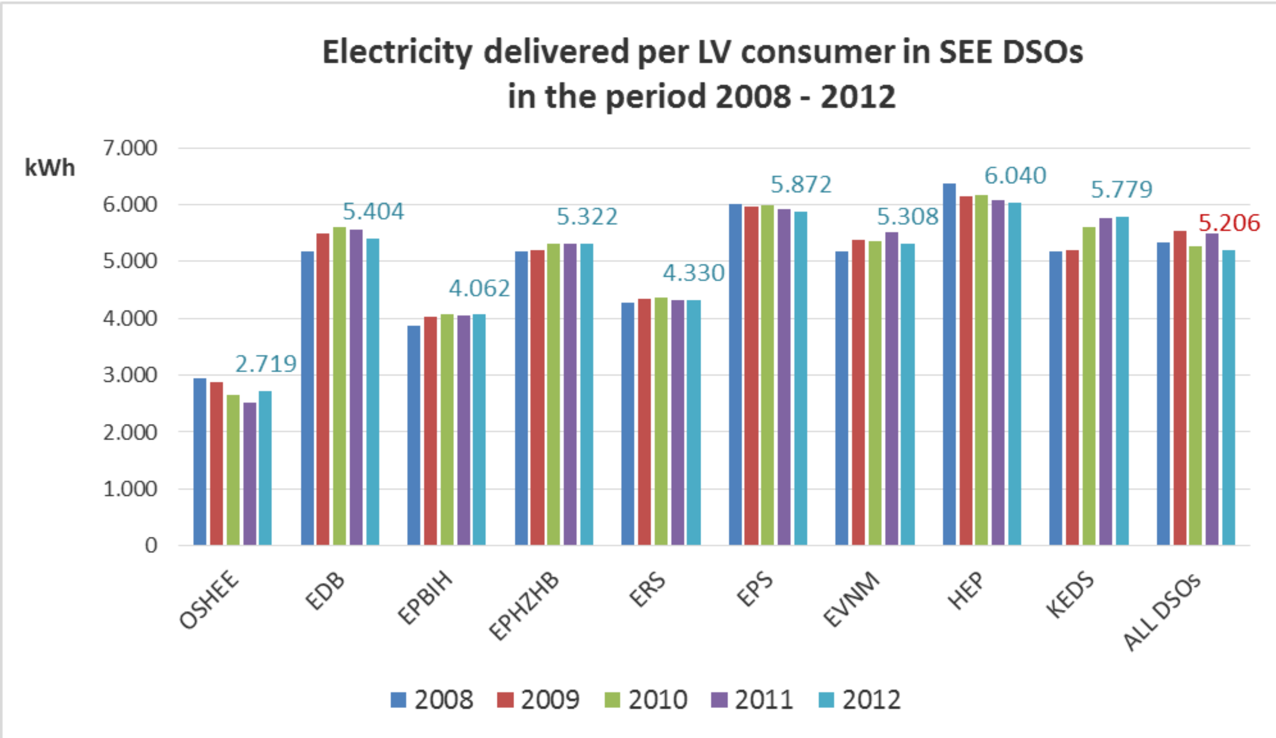


Figure 4.3 Electricity delivered per LV consumer in SEE DSOs in the period 2008 - 2012

4.2. ELECTRICITY DELIVERED PER METERING POINT

One of the DSO benchmarking indicators is electricity delivered per each metering point. The following Figure shows that in SEE it is between 3.645 kWh/metering point (OSHEE, Albania) and 7.833 kWh/metering point (EPS, Serbia). The average electricity delivered to each metering point in SEE amounts 6.488 kWh/ metering point.

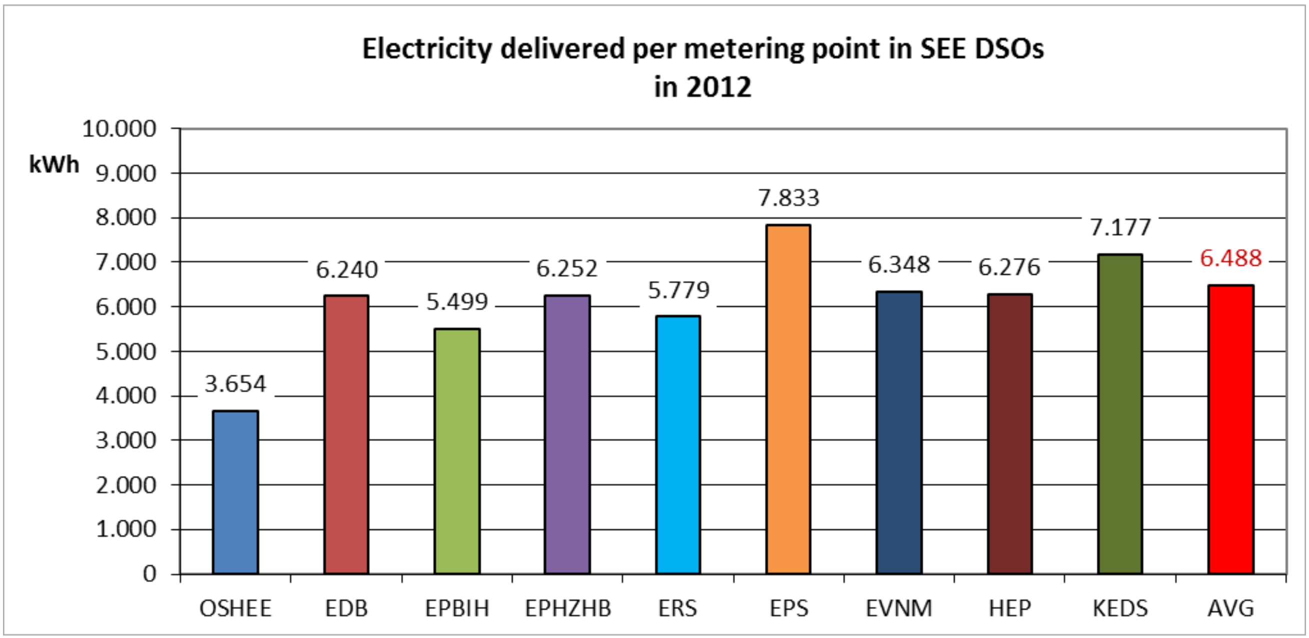


Figure 4.4 Electricity delivered per metering point in SEE DSOs in 2012

Industrial consumption category is mostly connected to the medium voltage. The following Figure shows that the average electricity delivered to the metering point at the MV level in SEE is 542.050 kWh, while DSOs values are in the range from 28.340 kWh (KEDS, Kosovo) to 1.616.193 kWh (HEP, Croatia).

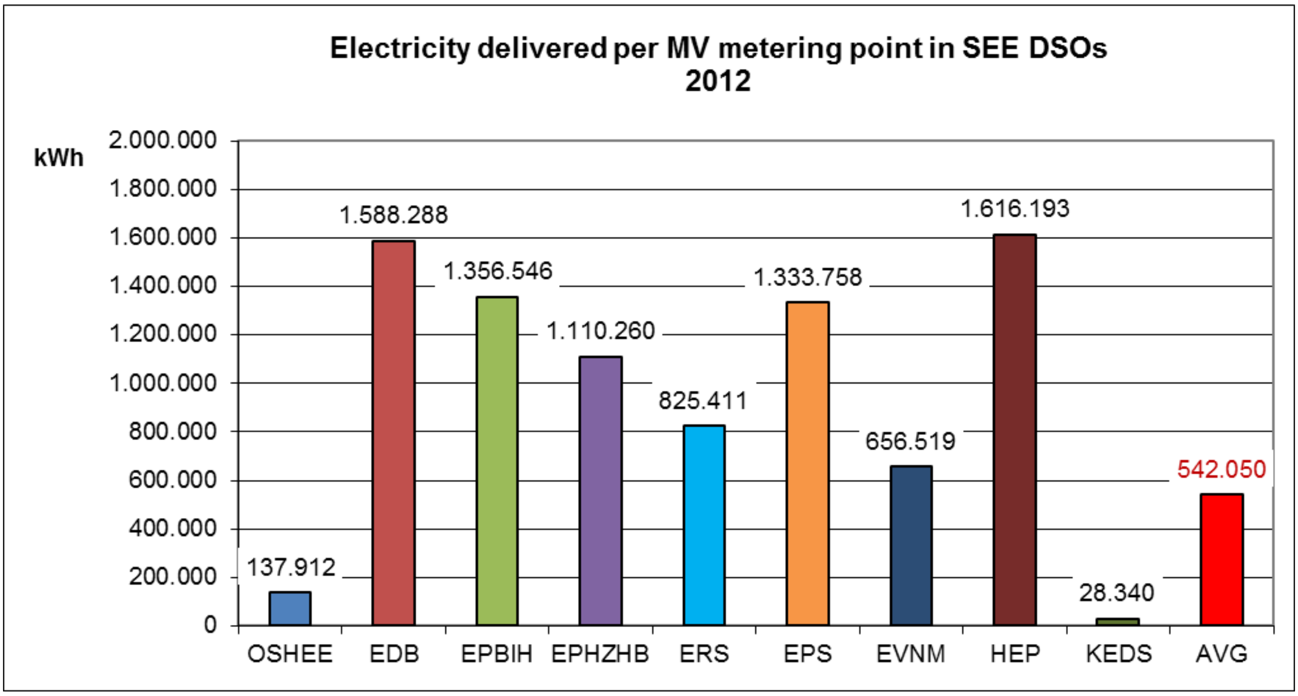


Figure 4.5 Electricity delivered per metering point at the medium voltage level in SEE DSOs in 2012

Dominant consumption category in all DSOs is household. The following Figure shows that the average electricity delivered to the household in SEE is 3.769 kWh, while DSOs values are in the range from 2.234 kWh (OSHEE, Albania) to 5.171 kWh (KEDS, Kosovo).

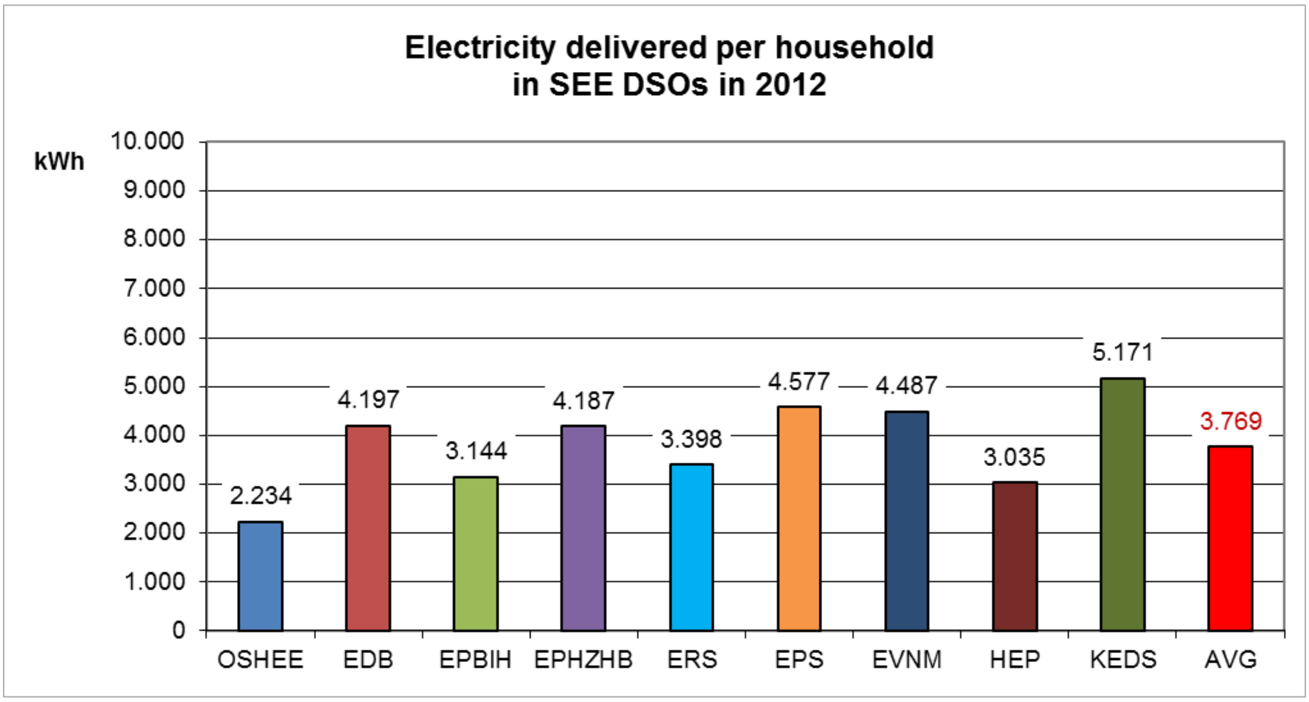


Figure 4.6 Electricity delivered per household in SEE DSOs in 2012

Average electricity delivered per metering point in each consumption category in the period 2008 – 2012 is given in the following Tables. Average electricity delivered per metering point has declined from 7.026 kWh (2008) to 6.488 kWh (2012), which is a clear evidence of economic crises in the region.

Table 4.1 Electricity delivered per metering point for different consumer categories in SEE DSOs in 2008 [kWh]

2008	Electricity delivered per metering point [kWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**AVG**
OSHEE	99.538.170	160.256	2.482	33.491	-	6.133	3.871
EDB	-	1.419.555	4.058	22.410	317.994	7.205	5.932
EPBIH	-	1.491.271	2.907	15.556	160.160	10.837	5.267
EPHZHB	-	1.198.228	4.030	14.831	78.566	10.653	5.969
ERS	16.470.291	810.849	3.368	22.196	102.700	8.822	5.577
EPS	81.617.069	1.335.147	4.676	20.042	38.545	7.553	8.063
EVNM	-	696.024	4.549	18.331	168.002	6.654	6.271
HEP	161.285.668	1.698.774	3.244	21.777	167.403	9.925	6.892
KEDS							
SUM	88.757.313	920.090	4.019	20.412	63.260	8.464	7.026

Table 4.2 Electricity delivered per metering point for different consumer categories in SEE DSOs in 2009 [kWh]

2009	Electricity delivered per metering point [kWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	AVG
OSHEE	103.420.319	142.075	2.444	25.066	-	5.732	3.743
EDB	-	1.510.838	4.223	27.826	330.010	7.696	6.274
EPBIH	-	1.585.873	3.104	15.452	149.410	10.548	5.415
EPHZHB	-	1.149.593	4.087	14.611	79.114	10.526	5.982
ERS	13.433.767	828.082	3.445	22.114	110.439	8.906	5.671
EPS	64.134.938	1.249.454	4.661	19.770	37.709	7.419	7.836
EVNM	-	676.065	4.684	18.163	157.037	6.950	6.379
HEP	45.081.501	1.615.639	3.083	21.440	161.598	9.745	6.362
KEDS							
SUM	66.051.700	839.777	4.002	20.114	62.889	8.308	6.812

Table 4.3 Electricity delivered per metering point for different consumer categories in SEE DSOs in 2010 [kWh]

2010	Electricity delivered per metering point [kWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	AVG
OSHEE	140.922.127	137.182	2.244	20.866	443	5.303	3.558
EDB	-	1.678.810	4.319	22.757	378.360	8.061	6.524
EPBIH	-	1.507.014	3.167	14.879	119.119	10.280	5.494
EPHZHB	-	1.049.771	4.165	13.221	87.979	10.312	6.107
ERS	12.251.399	830.663	3.454	19.785	121.474	9.084	5.755
EPS	72.065.303	1.330.282	4.687	20.062	37.133	7.412	7.967
EVNM	-	672.788	4.562	23.105	138.943	7.740	6.383
HEP	36.989.458	1.609.543	3.149	20.842	155.305	9.346	6.378
KEDS							
SUM	75.392.455	847.560	4.010	20.149	62.521	8.272	6.884

Table 4.4 Electricity delivered per metering point for different consumer categories in SEE DSOs in 2011 [kWh]

2011	Electricity delivered per metering point [kWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	AVG
OSHEE	115.510.830	128.022	2.089	14.140	86	5.141	3.620
EDB	-	1.641.384	4.267	21.839	350.618	8.742	6.468
EPBIH	-	1.452.950	3.145	23.864	93.707	8.535	5.482
EPHZHB	-	1.080.988	4.154	13.544	95.965	9.780	6.185
ERS	13.786.834	836.955	3.398	18.576	121.839	9.277	5.800
EPS	78.192.333	1.354.606	4.662	20.212	38.050	7.338	8.063
EVNM	-	678.549	4.681	20.501	139.026	7.907	6.564
HEP	24.940.011	1.667.219	3.070	20.274	152.100	9.162	6.333
KEDS							
AVG	79.631.976	846.793	3.974	20.194	63.909	8.091	6.940

Table 4.5 Electricity delivered per metering point for different consumer categories in SEE DSOs in 2012 [kWh]

2012	Electricity delivered per metering point [kWh]						
DSO	HV	MV	LV - households	LV Public lighting	LV-commercial with peak power registration	LV-commercial without peak power registration	**AVG**
OSHEE	63.780.000	137.912	2.234	16.284	19.629	5.809	3.654
EDB	-	1.588.288	4.197	22.454	298.254	9.189	6.240
EPBIH	-	1.356.546	3.144	21.562	108.202	7.569	5.499
EPHZHB	-	1.110.260	4.187	13.082	99.398	9.741	6.252
ERS	13.242.768	825.411	3.398	17.621	118.285	9.453	5.779
EPS	58.599.757	1.333.758	4.577	21.052	37.510	7.220	7.833
EVNM	-	656.519	4.487	19.432	132.028	7.524	6.348
HEP	35.741.668	1.616.193	3.035	20.068	150.885	9.084	6.276
KEDS	5.256.334	28.340	5.171	16.654	143.922	5.837	7.177
AVRG	22.222.846	542.050	3.769	19.983	63.448	7.428	6.488

4.3. ELECTRICITY DELIVERED PER EMPLOYEE

The following Table and Figure give an overview of electricity delivered per each employee in SEE DSO in the period 2008 – 2012. For 6 DSOs that provided data on number of employees for all observed years, this indicator slightly increased since 2008, i.e. from 1.633 MWh/employee in 2008 to 1.834 MWh/employee in 2012, or 12 %. Average of all DSOs in 2012 equaled 1.738 MWh/employee. The largest increase in 2012 comparing to 2008 is noticed in OSHEE (73,3 %) and EVNM (43,2 %). Slight increases are present in EPS (4,5 %) and ERS (3,2 %).

In two DSOs electricity delivered per employee in 2008 is higher than in 2012 – EPHZHB (-19,6 % since 2008) and HEP (-0,6 % since 2008).

Table 4.6 Electricity delivered per employee in SEE DSOs in period 2012 - 2008

[MWh]	2008	2009	2010	2011	2012
OSHEE	605	700	843	1.015	1.047
EDB*					1.247
EPBIH*					1.427
EPHZHB	1.607	1.322	1.280	1.274	1.292
ERS	799	820	819	838	825
EPS	2.492	2.480	2.581	2.655	2.604
EVNM	1.656	1.861	1.960	2.279	2.371
HEP	1.639	1.543	1.586	1.610	1.630
KEDS*					1.097
AVERAGE of all DSOs	1.633	1.640	1.740	1.836	1.834
					1.738

**number of employees only available for 2012*

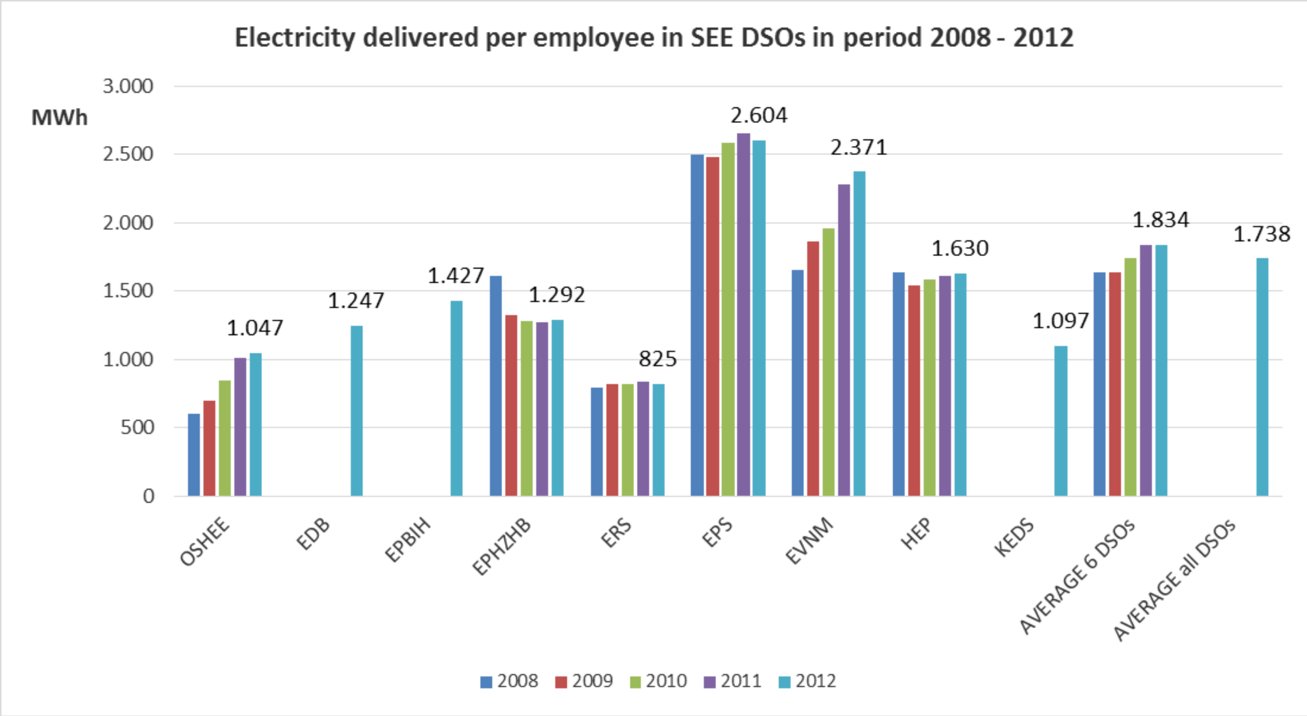


Figure 4.7 Electricity delivered per employee in SEE DSOs in period 2008 - 2012

4.4. ELECTRICITY DELIVERED PER NETWORK LENGTH

Electricity delivered per km of distribution network (including all voltage levels) is given on the following Figure and Table. This indicator strongly depends on the distribution area shape and size as well as geographical disperse of the consumers. That's why there is a large variety of values, between 0,07 GWh/km in ERS (BiH) and 0,29 GWh/km in EVNM (Macedonia). Average value in the observed region is 0,148 GWh/km. It can be concluded that the average value decreased 12 % since 2008.

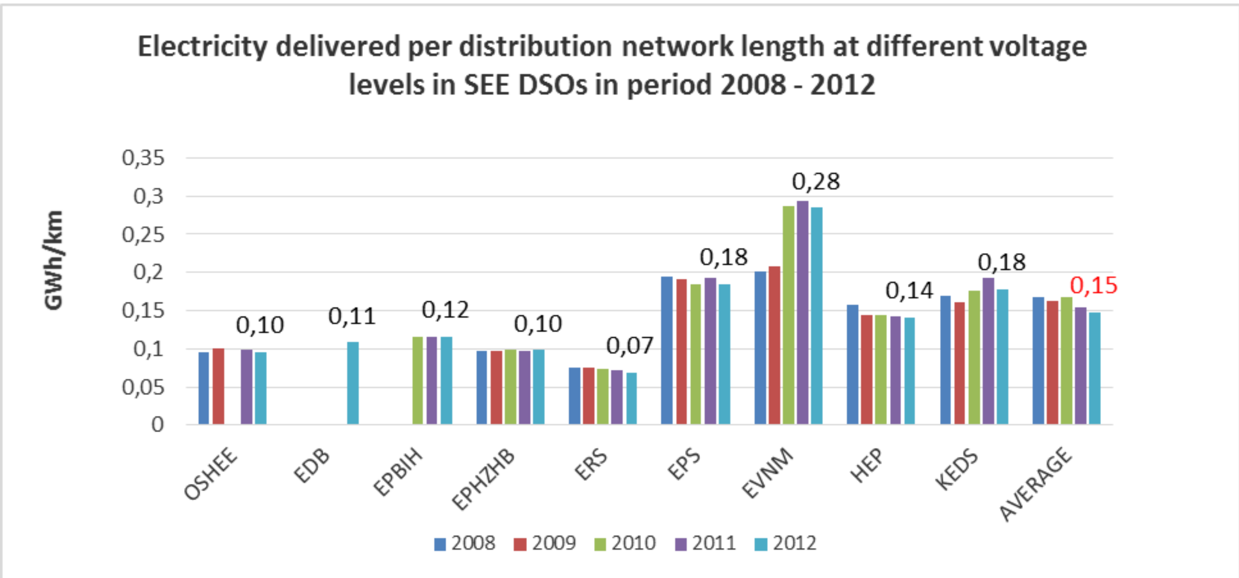


Figure 4.8 Electricity delivered per distribution network length at different voltage levels in SEE DSOs

Table 4.7 Electricity delivered per distribution network length in SEE DSOs in period 2008 - 2012 [GWh/km]

[GWh/km]	2008	2009	2010	2011	2012
OSHEE	0,095	0,101		0,099	0,095
EDB					0,108
EPBIH			0,115	0,116	0,117
EPHZHB	0,096	0,097	0,099	0,098	0,098
ERS	0,076	0,075	0,073	0,072	0,069
EPS	0,195	0,191	0,185	0,193	0,185
EVNM	0,201	0,209	0,287	0,294	0,285
HEP	0,157	0,143	0,144	0,142	0,140
KEDS	0,170	0,161	0,175	0,193	0,178
AVERAGE	0,168	0,163	0,168	0,154	0,148

Above mentioned indicator can be divided in two groups: 1) electricity delivered per MV network length and 2) electricity delivered per LV network length, as given in the following two tables.

Table 4.8 Electricity delivered per MV distribution network length in SEE DSOs in period 2008 - 2012 [GWh/km]

[GWh/km]	2008	2009	2010	2011	2012
OSHEE	0,263	0,281		0,250	0,260
EDB					0,441
EPBIH			0,434	0,437	0,434
EPHZHB	0,283	0,282	0,284	0,273	0,274
ERS	0,237	0,245	0,250	0,255	0,256
EPS	0,554	0,550	0,547	0,567	0,556
EVNM	0,479	0,498	1,642	1,655	1,584
HEP	0,378	0,364	0,365	0,361	0,354
KEDS	0,367	0,355	0,371	0,405	0,397
AVERAGE	0,447	0,444	0,486	0,443	0,437

Table 4.9 Electricity delivered per LV network length in SEE DSOs in period 2008 - 2012 [GWh/km]

[GWh/km]	2008	2009	2010	2011	2012
OSHEE	0,109	0,117		0,104	0,107
EDB					0,124
EPBIH			0,116	0,116	0,117
EPHZHB	0,127	0,128	0,131	0,131	0,130
ERS	0,082	0,080	0,076	0,073	0,069
EPS	0,209	0,208	0,194	0,200	0,193
EVNM	0,289	0,306	0,295	0,303	0,293
HEP	0,189	0,178	0,180	0,177	0,175
KEDS	0,206	0,191	0,203	0,233	0,231
AVERAGE	0,191	0,189	0,185	0,168	0,164

It is interesting that electricity delivered per MV and per LV network length is different across the DSOs. Macedonian EVNM exhibits higher values than other DSOs. On average, electricity delivered per MV network length is 2,7 higher than electricity delivered per LV network length.

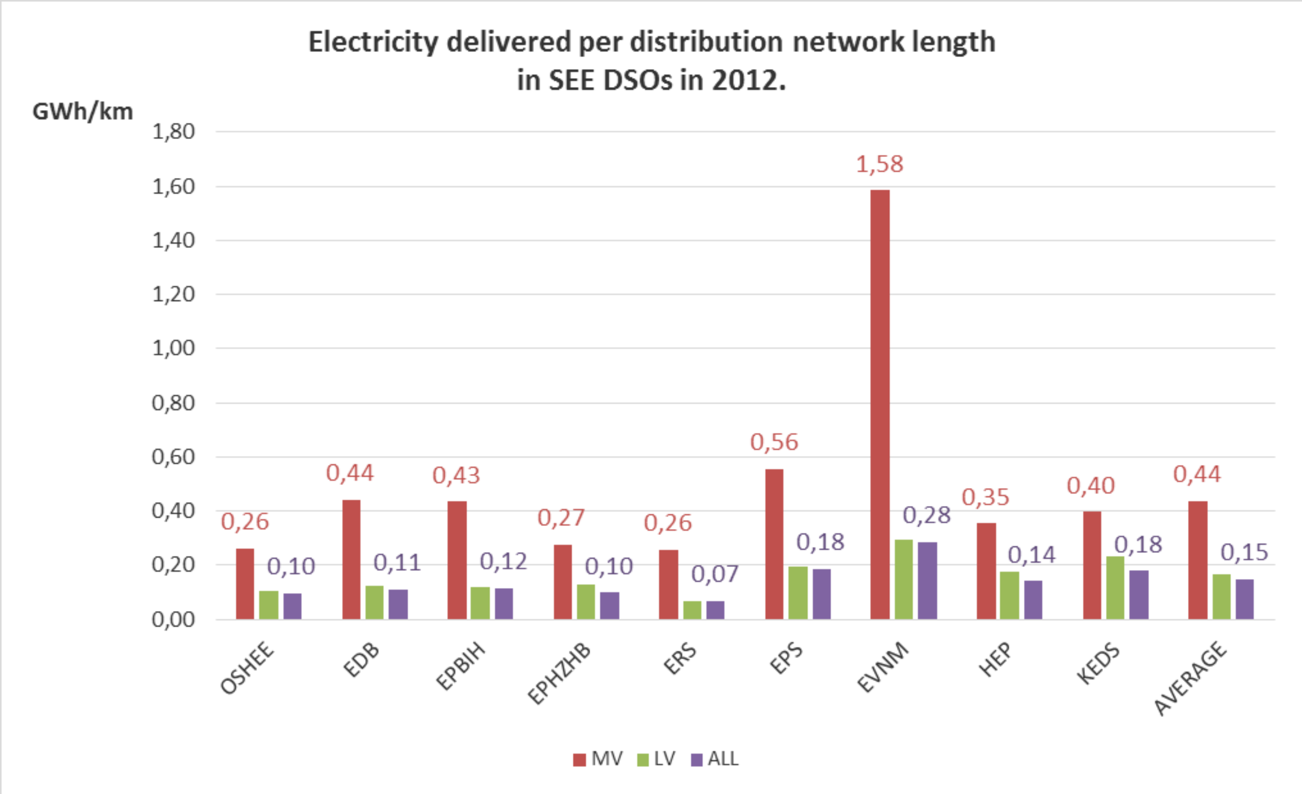


Figure 4.9 Electricity delivered per distribution network length in SEE DSOs in 2012

4.5. TRANSFORMER CAPACITY PER SUBSTATION

Total number of substations and also transformers have been divided in two groups: X/MV substations and transformers (i.e. 110/10 kV; 110/20 kV; 35/20 kV; 35/10 kV; 35/6 kV) and MV/LV substations and transformers (i.e. 35/0,4 kV; 20/0,4 kV; 10/0,4 kV).

The following Figure show average capacity of X/MV substations and transformers in the region. KEDS, EPBiH and EPHZHB values for X/MV substations and transformers are calculated based on 35/20 kV; 35/10 kV; 35/6 kV data, reason being that KEDS, EPBiH and EPHZHB data do not comprise 110/10 kV and 110/20 kV substations and transformers (EPBiH provided data for 110/X substations, but not for 110/X transformers).

It could be observed that EPBiH and EPHZHB values are considerably lower than others values. If those data are estimated (based on EIHP previous studies), than EPHZHB average capacity of X/MV substations would be approximately 22.

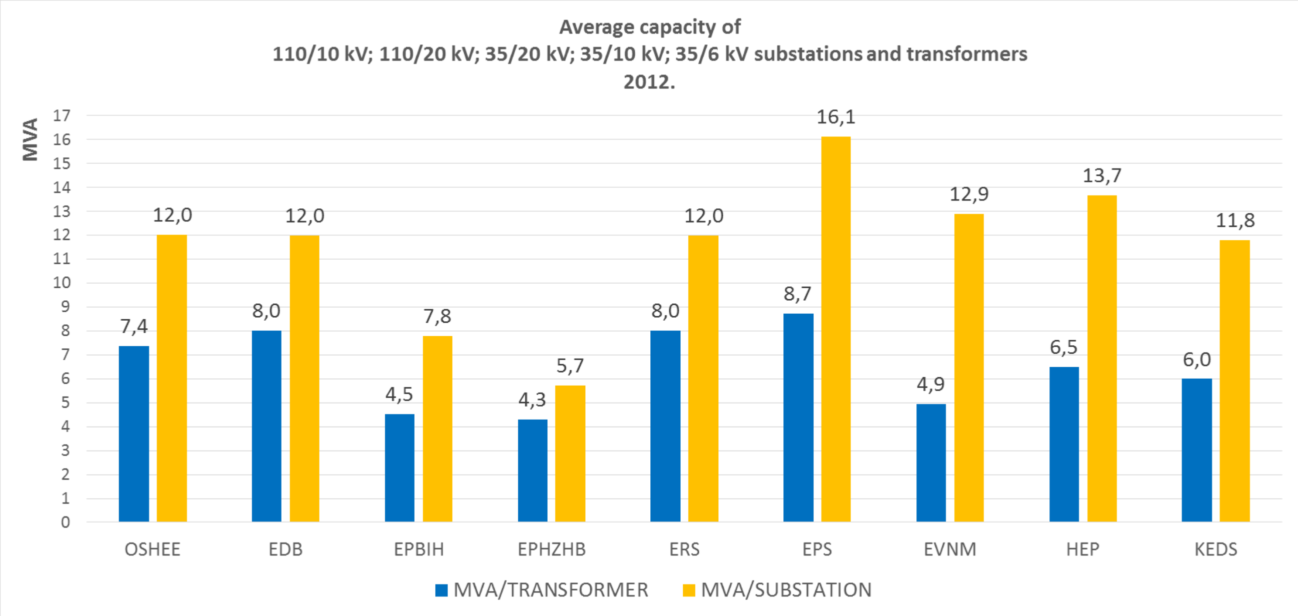


Figure 4.10 Average capacity of 110/10 kV; 110/20 kV; 35/20 kV; 35/10 kV; 35/6 kV substations and transformers in 2012

Average capacity of MV/LV substations in the region is 334 kVA and it is in the range between 205 kVA (OSHEE, Albania) and 559 kVA (EVNM, Macedonia).

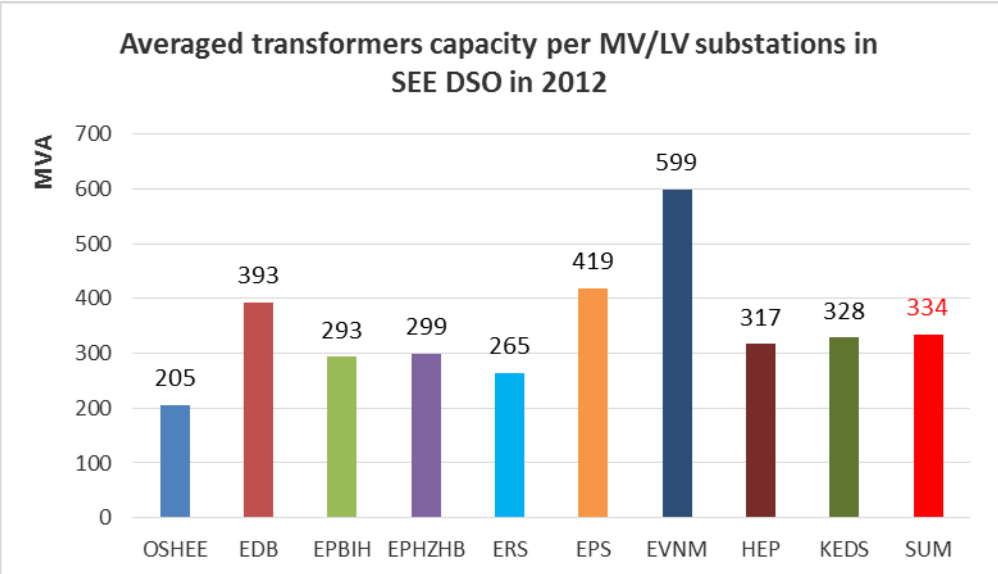


Figure 4.11 Average transformer capacity per MV/LV substation

4.6. USAGE OF SUBSTATION INSTALLED CAPACITY

It has always been a question for power system planners how to optimize number of transformations and its loading in the system. In that sense it is interesting to measure the level of transformers loadings (usage), in other words ratio between electricity delivered per transformer and its installed capacity.

In this report the value of electricity delivered per X/MV transformer comprises electricity delivered to consumers at 35 kV. This is because 35 kV consumption has not been reckoned separately, instead this value is included in value of electricity delivered to MV consumers (Table 4.5).
In calculation of indicator, it was assumed that all losses (see Chapter 6.1) are passing through X/MVs substations, and also that technical and non-technical losses on HV and MV network (i.e. without MV/LV substations and LV network) equal 25% of total losses.
For X/MV substations this indicator varies significantly, between 1.541 h/year (EPHZHB, BiH) and 6.807 h/year (EPBiH, BiH). The average value is 3.405 h/year.
For MV/LV substations this indicator does not vary significantly. It is between 1.066 h/year (ERS, BiH) and 1.686 h/year (EPS, Serbia). The average value is 1.473 h/year.

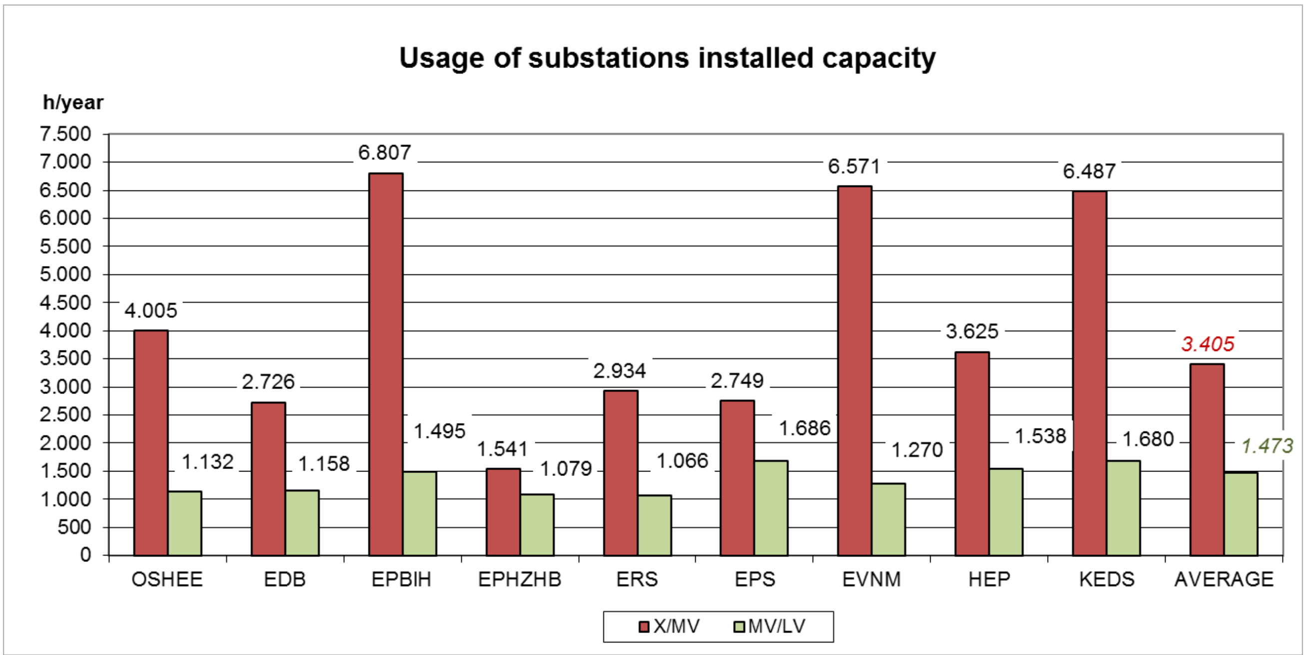


Figure 4.12 Usage of transformer installed capacity

4.7. ELECTRICITY DELIVERED PER SUPPLY AREA SIZE

As given in Chapter 3, regional DSOs operate in different supply area sizes and shapes.
Due to its very small size, EBD (BiH) is having the largest electricity delivered per supply area size – 455 MWh/km^2. Regional average is almost twice lower, around 253 MWh/km^2, while the lowest level of electricity delivered per supply area size is in EPHZHB (BiH), around 107 MWh/km^2. Accordingly, the ratio between the lowest and the highest level of electricity delivered per supply area size is more than 4 times.

Table 4.10 Electricity delivered per supply area in SEE DSOs in the period 2008 - 2012

[MWh/km²]	2008	2009	2010	2011	2012
OSHEE	135	146	143	151	150
EDB	435	460	477	470	455
EPBIH	202	211	216	220	223
EPHZHB	99,6	101	103	106	107
ERS	120	124	127	129	130
EPS	356	350	359	366	358
EVNM*					204
HEP	278	260	263	262	261
KEDS*					318
AVERAGE for all DSOs	254**	250**	255**	259**	253

**supply area size only available for 2012*
*** average for 6 DSOs*

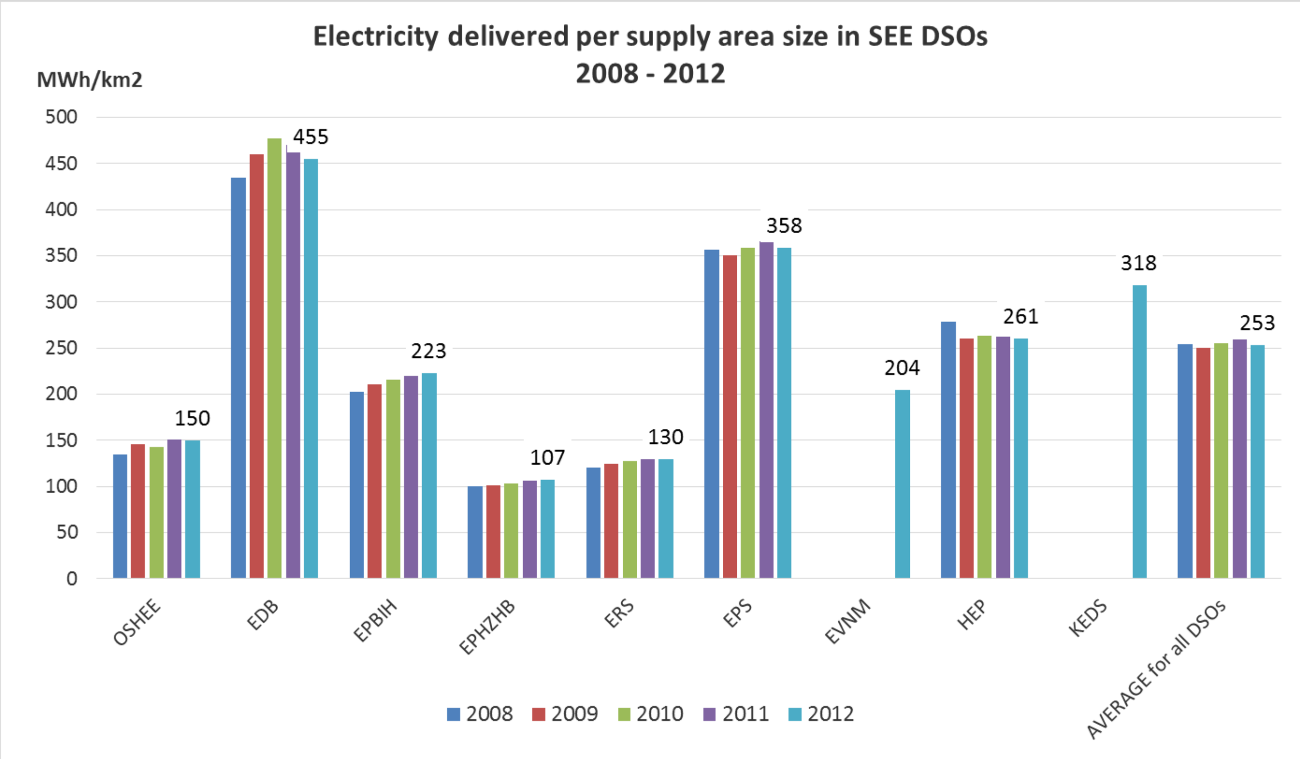


Figure 4.13 Electricity delivered per supply area size in SEE DSOs in the period 2008 - 2012

4.8. NETWORK LENGTH PER SUPPLY AREA SIZE

In addition to the previous indicator, it is interesting to measure the ratio between network length (owned by DSO) and supply area size. In SEE the average network length per supply area size is 1,7 km/km². Network length per supply are size ranges from 0,7 km/km² in EVNM (Macedonia) to 1,9 km/km² in EPBiH (BiH), ERS (BiH), EPS (Serbia), HEP (Croatia) and 4,2 km/km² in EDB (BiH). Relatively low value in Macedonia is a consequence of low network length.

Table 4.11 Network length per supply area size in SEE DSOs in 2012

[km/km²]	2012
OSHEE	1,6
EDB	4,2
EPBIH	1,9
EPHZHB	1,1
ERS	1,9
EPS	1,9
EVNM	0,7
HEP	1,9
KEDS	1,8
AVERAGE	1,7

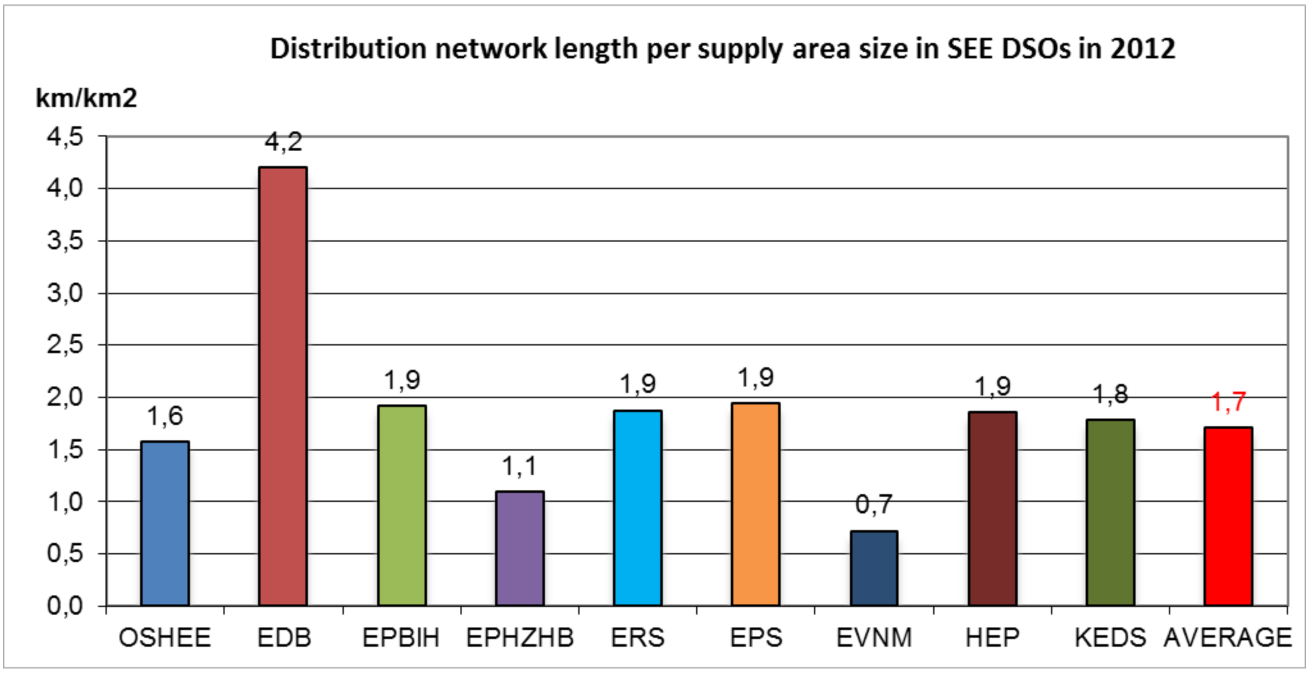


Figure 4.14 Distribution network length (owned by DSO) per supply area size in SEE DSOs in 2012

This indicator can also be divided in to groups: MV and LV network, as given in the following Table.

Table 4.12 MV and LV network length per supply area size in SEE DSOs in 2012

2012		
[km/km²]	MV	LV
OSHEE	0,5	1,0
EDB	1,0	3,2
EPBIH	0,5	1,4
EPHZHB	0,4	0,7
ERS	0,5	1,4
EPS	0,6	1,3
EVNM	0,1	0,6
HEP	0,7	1,1
KEDS	0,7	1,1
AVERAGE	0,6	1,2

As expected, LV network length per supply area size is (twice) larger than MV network length per supply area size.

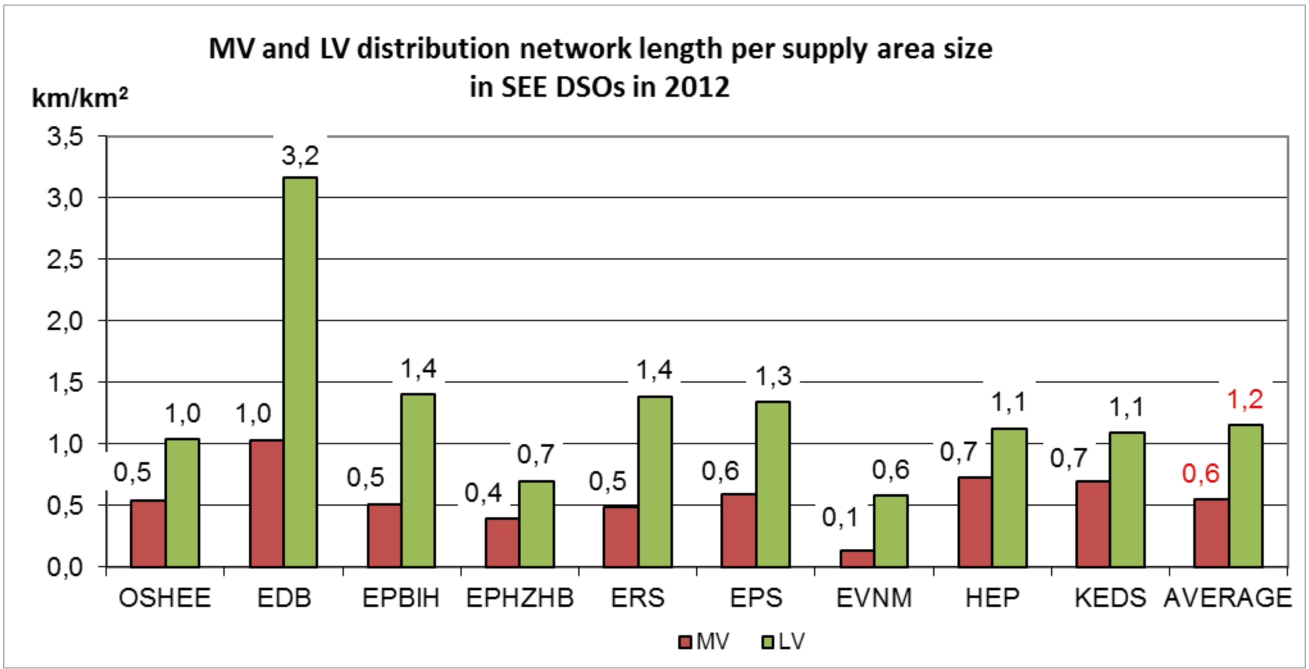
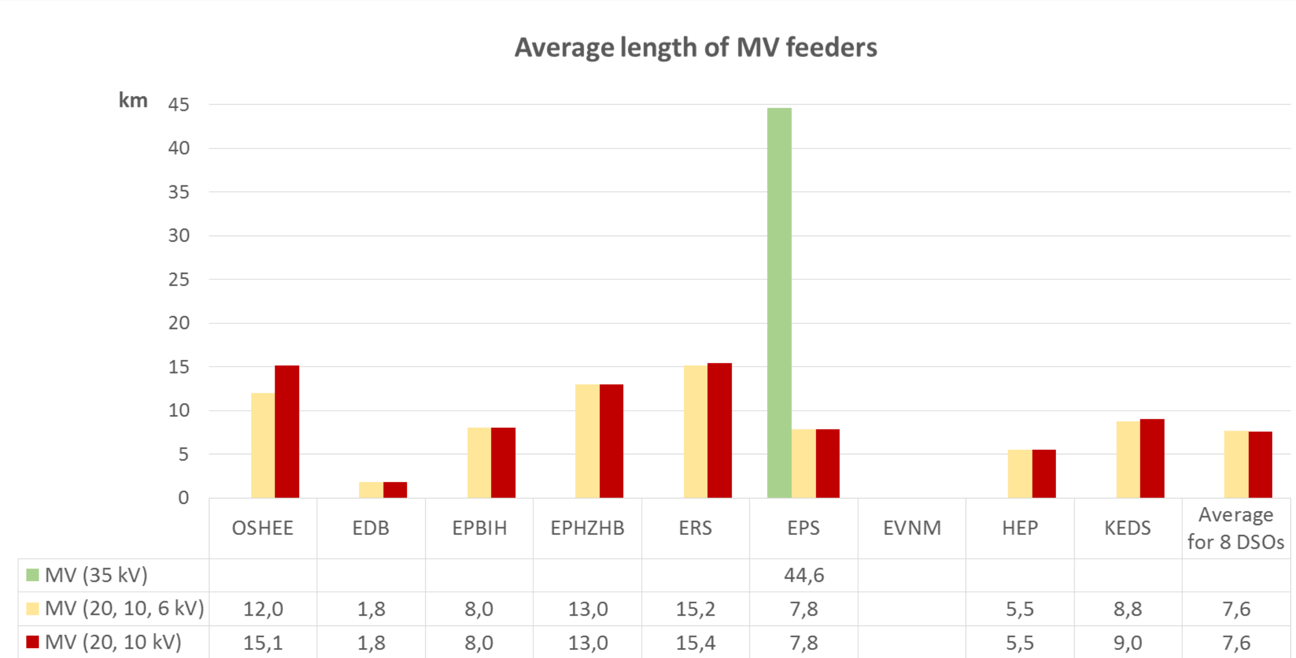


Figure 4.15 MV and LV network length per supply area size in SEE DSOs in 2012

4.9. AVERAGE FEEDER LENGTH

Average length of 35 kV feeders in EPS (Serbia) equals 44,6 km – other DSOs have not provided data on number of 35 kV feeders (see Table 3.53).

Average MV (20 kV, 10 kV and 6 kV) feeder length in SEE is 7,6 km. The following Figure provides data on average MV feeders length in all DSOs except EVNM for (20 kV, 10 kV and 6 kV) and (20 kV, 10 kV) feeders respectively. EDB and EPHZHB values relate to 10 kV feeders only. OSHEE, ERS and KEDS values are different for (20 kV, 10 kV and 6 kV) and (20 kV, 10 kV) due to presence of 6 kV feeders in their networks. On average, the longest (20 kV, 10 kV and 6 kV) feeders are in ERS (BiH); i.e. 15,2 km.



	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	Average for 8 DSOs
MV (35 kV)						44,6				
MV (20, 10, 6 kV)	12,0	1,8	8,0	13,0	15,2	7,8		5,5	8,8	7,6
MV (20, 10 kV)	15,1	1,8	8,0	13,0	15,4	7,8		5,5	9,0	7,6

Figure 4.16 Average MV feeder length in SEE DSOs in 2012

Average LV feeder length in 7 DSOs equals 0,58 km with the longest LV feeders in EPBiH – 0,73 km on average.

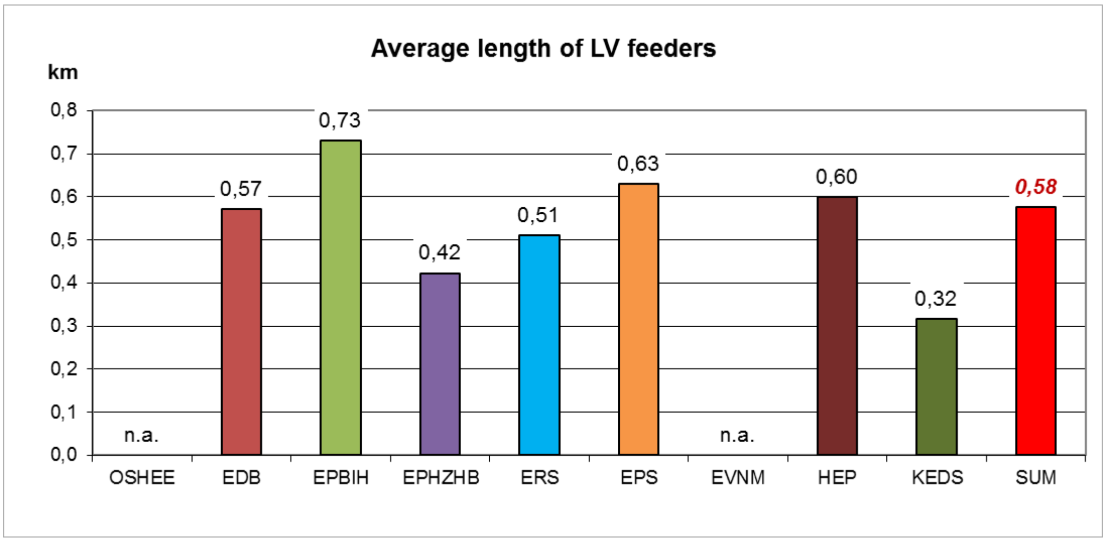
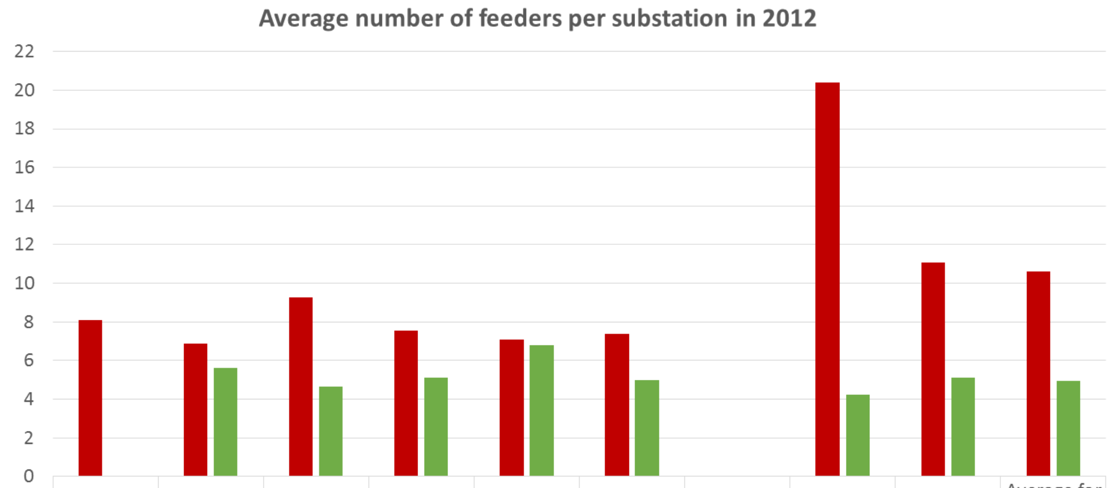


Figure 4.17 Average LV feeder length in SEE DSOs in 2012

4.10. NUMBER OF FEEDERS PER SUBSTATIONS

Average number of MV (20 kV, 10 kV and 6 kV) feeders per X/MV substation (i.e. 110/10 kV; 110/20 kV; 35/20 kV; 35/10 kV; 35/6 kV) is in the range form 6,9 in OSHEE (Albania) to 20,4 in HEP (Croatia), with an average of 10,6 for 8 DSOs.

Average number of LV (0,4 kV) feeders per MV/LV substation (i.e. 35/0,4 kV; 20/0,4 kV; 10/0,4 kV) is between 4,2 in HEP (Croatia) and 6,8 in ERS (BiH), with an average of 5,0 for 7 DSOs.



	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	Average for 8 (7) DSOs
20 kV, 10 kV and 6 kV	8,1	6,9	9,3	7,6	7,1	7,4		20,4	11,1	10,6
0,4 kV		5,6	4,6	5,1	6,8	5,0		4,2	5,1	5,0

Figure 4.18 Average number of MV (20 kV, 10 kV and 6 kV) and LV (0,4 kV) feeders per X/MV and MV/LV substations respectively

5. CONTINUITY OF SUPPLY

Continuity of supply concerns interruptions in electricity supply. In other words, it focuses on the events during which the voltage at the supply terminals of a network user drops to zero or nearly (practically) zero. Continuity of supply can be described by various quality dimensions. The ones most commonly used are number of interruptions per year, unavailability (interrupted minutes per year) and energy not supplied per year.

Continuity of supply indices are traditionally one of the important tools for making decisions on the management of distribution networks. According to the quality dimensions, regulatory instruments now mostly focus on accurately defined continuity of supply indices of frequency of interruptions, duration of interruptions and energy not supplied due to interruptions. These instruments normally complement incentive regulation, which (either in the form of price or revenue-cap mechanisms) is commonly used across Europe at present. Incentive regulation provides a motivation to increase economic efficiency over time. However, it also carries a risk that network operators could refrain from carrying out investments and proper operational arrangements for better continuity, in order to lower their costs and increase their efficiency. To account for this drawback in incentive regulation, a large number of European regulators adopt regulatory instruments to maintain or improve the continuity of supply (CEER - 5th Quality of Supply Benchmarking Report, 2011).

5.1. SAIDI, SAIFI, CAIDI, ENS

Within this subchapter four indicators are analyzed:

- SAIDI - System Average Interruption Duration Index - the average outage duration for each customer served. SAIDI is measured in units of time, often minutes or hours. The values given here are divided in two groups: planned and unplanned interruptions. Also, SAIDI can be calculated per voltage level or at all voltage levels (the system as a whole). Here, SAIDI is calculated for unplanned and planned interruptions, both for all voltage levels and MV voltage level. The definition of a planned interruption assumes the requirement for advance notice that varies strongly between European countries (between 24 hours and 50 days). The definition of unplanned interruptions assume all other interruptions.

- SAIFI - System Average Interruption Frequency Index - the average number of interruptions per customer (the ratio between total number of interruptions and total number of customers). Similarly to SAIDI indicator, in this report SAIFI is given for unplanned and planned interruptions at all voltage levels and at MV voltage level.

- CAIDI - Customer Average Interruption Duration Index. CAIDI gives the average outage duration that any given customer would experience. It is the ratio between SAIFI and SAIDI. CAIDI can also be viewed as the average restoration time. CAIDI is measured in units of time, often minutes or hours. For this benchmarking report CAIDI is calculated for unplanned interruptions at all voltage levels.

- ENS – Electricity not supplied is calculated for both unplanned and planned interruptions at all voltage levels, as well as for TSO and DSO network. ENS TSO assumes electricity not supplied to final consumers due to interruptions in transmission network.

The following Figure shows SAIDI for unplanned interruptions at all voltage levels, for all events in distribution network. At the beginning of this kind of analysis it is important to clarify which voltage levels are included in input data. It is given in the following Table. Continuity of supply input data for EVNM are not available. One of the recommendations for the next benchmarking analyses would be to expand and harmonize data collection for continuity of supply indicators.

Table 5.1 Voltage levels included in the data on SAIDI, SAIFI and ENS

2012	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS
HV - TSO	Yes	No	No	Yes	Yes	Yes	n.a.	Yes	Yes
HV - DSO	Yes	No	No	No	No	Yes	n.a.	No	Yes
MV	Yes	Yes	Yes	Yes	Yes	Yes	n.a.	Yes	Yes
LV	No	Yes	Yes	No	Yes	No	n.a.	Yes	No

The curves per country generally show a smooth trend change, decreasing (EPBIH) or being constant in given timeframe (HEP, ERS, EPHZHB). Only in KEDS smooth increase of SAIDI value is found in the period 2008 – 2012.

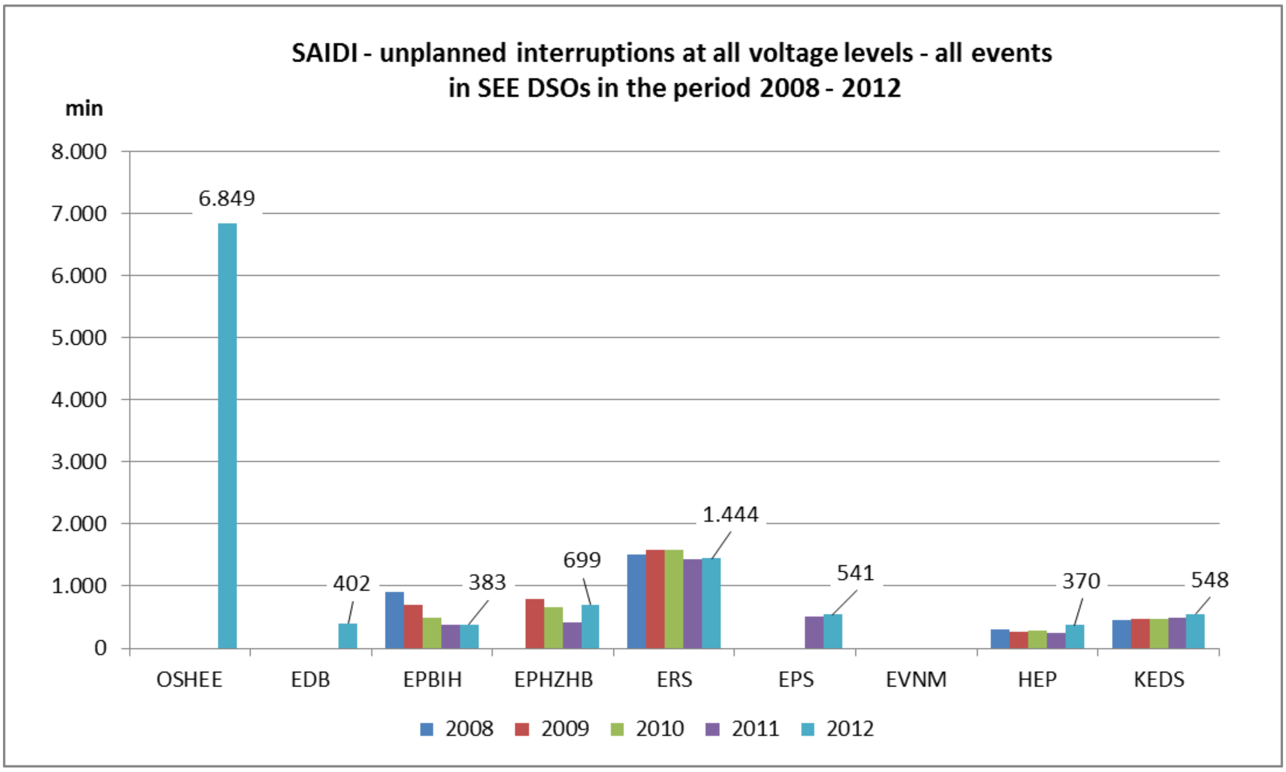


Figure 5.1 SAIDI - unplanned interruptions at all voltage levels - all events in SEE DSOs in the period 2008 - 2012

Over the period 2008-2012, SAIDI in SEE DSOs ranges between 245 and 6.849 minutes. The highest level of SAIDI is found in OSHEE (Albania) (up to 6.849 min) and it is significantly higher than in other DSOs (all up to 1.589 min). The lowest SAIDI is in HEP (Croatia) in 2011.

The following Figure shows SAIDI for unplanned interruptions at medium voltage (MV) levels, for all events in distribution network. The complete data were available just for 3 DSOs (ERS, EPHZHB and

EPBiH), and just for 2012 are given for HEP and OSHEE. It is clear that the level of SAIDI at MV voltage network is not significantly lower than at the system level; it is between 256 (HEP, Croatia in 2012) and 6.008 minutes (OSHEE, Albania in 2012).

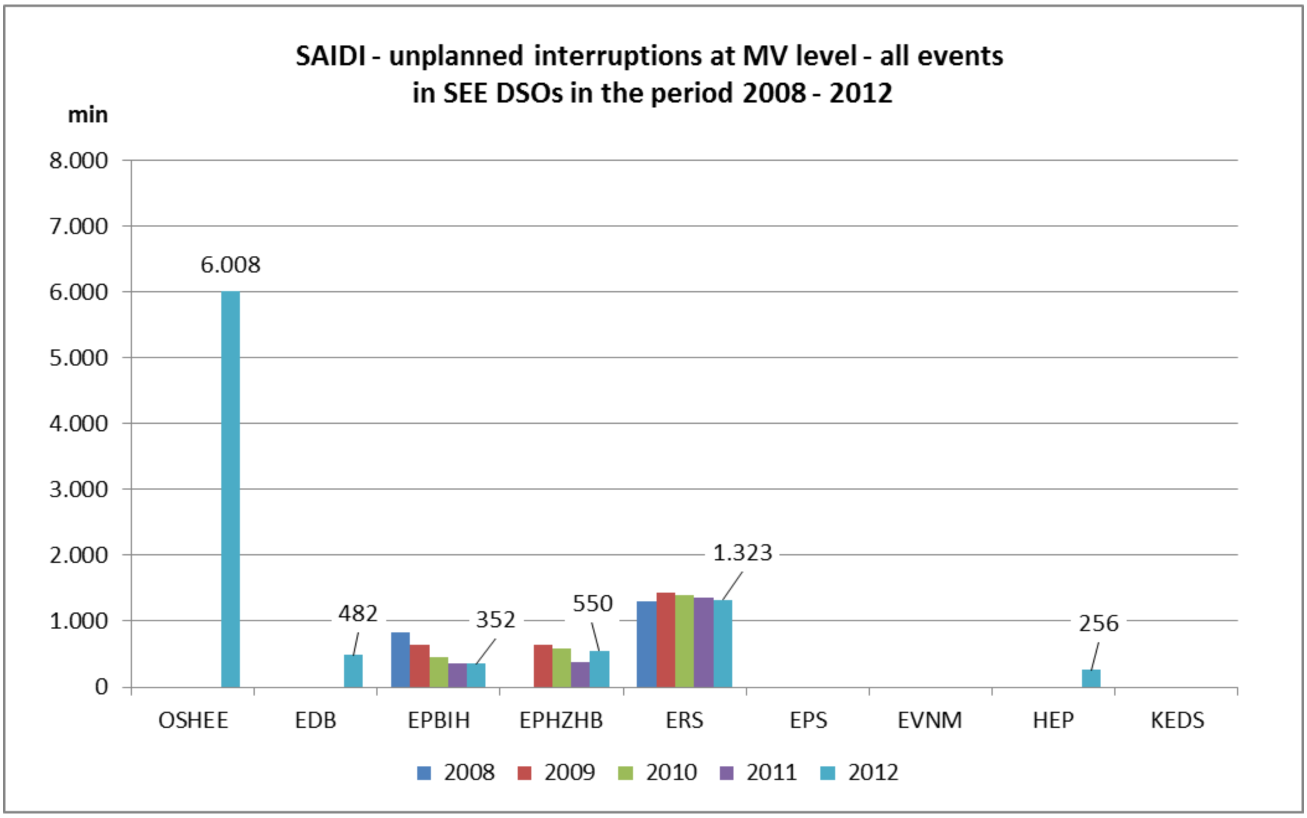


Figure 5.2 SAIDI - unplanned interruptions at MV level - all events in SEE DSOs in period 2008 - 2012

EPHZHB delivered data for all events and data without exceptional events separately. Which occurrences are considered an exceptional event can be done in different ways. In general, some countries have a more statistical approach and others focus their definition on the causes of exceptional events. Excluding exceptional events from unplanned performance figures highlighted the significant improvements being made by many countries in terms of both the duration and the number of interruptions.

For example, exceptional weather conditions, natural disasters (earthquake, flood, lightning strike, storm, icing, etc.), epidemics, explosions, other than those caused by improper or careless handling, which are not foreseeable and are not due to wear and tear of materials or equipment, war, riot or sabotage and other exceptional circumstances can significantly affect the continuity of supply. Interruptions, due to exceptional events, are usually very long and/or affect a substantial number of customers, even if quite rare. The concept of exceptional events reflects the unique characteristics of each electricity sector and the impact of severe weather conditions.

The following Figure shows SAIDI for unplanned interruptions with and without exceptional events in EPHZHB, BiH. By definition in BiH exceptional events (i.e. force majeure) are defined as all events which cause interruption of supply and are out of control of a distributor such as: natural disasters (earthquake, fire, flooding), extreme weather conditions (lightning, storm wind, excessive ice etc.), interruptions at the transmission voltage level, load shedding due to shortage of supply, under-frequency relief of load and orders of the respective authorities. It can be clearly seen that in 2012 without exceptional events SAIDI is significantly lower (~ 20 %) than the value corresponding to all events. For other SEE DSOs there are no data available.

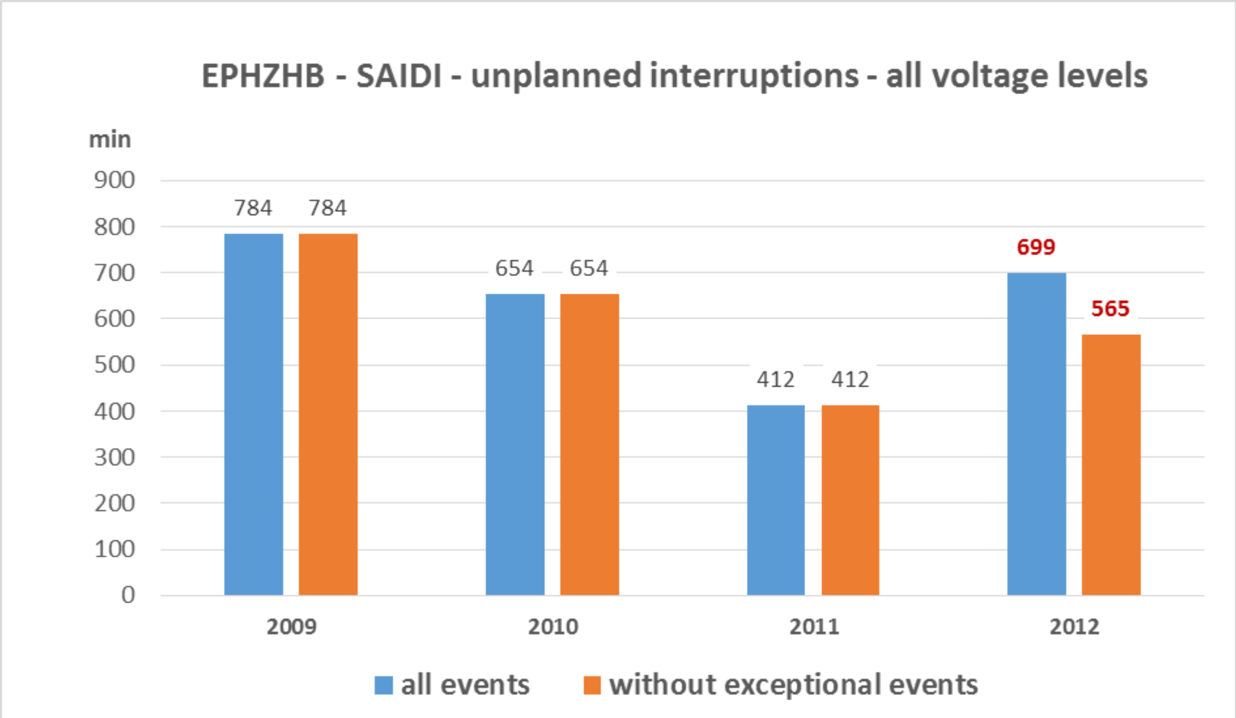


Figure 5.3 EPHZHB - SAIDI - unplanned interruptions at all voltage levels with and without exceptional events in the period 2008 - 2012

Duration of planned interruptions relates to those minutes off supply experienced by network users after they receive prior notice of planned electricity interruption. SAIDI range is in between 25 minutes (KEDS, Kosovo in 2012) and 881 minutes (EPHZHB, BiH in 2010). Country data show (more or less) slightly decreasing trend (ERS, EPBiH, EPHZHB, KEDS, EPS). The only outlier in respect of planned SAIDI is Croatian HEP which has almost persistent values over observed period.

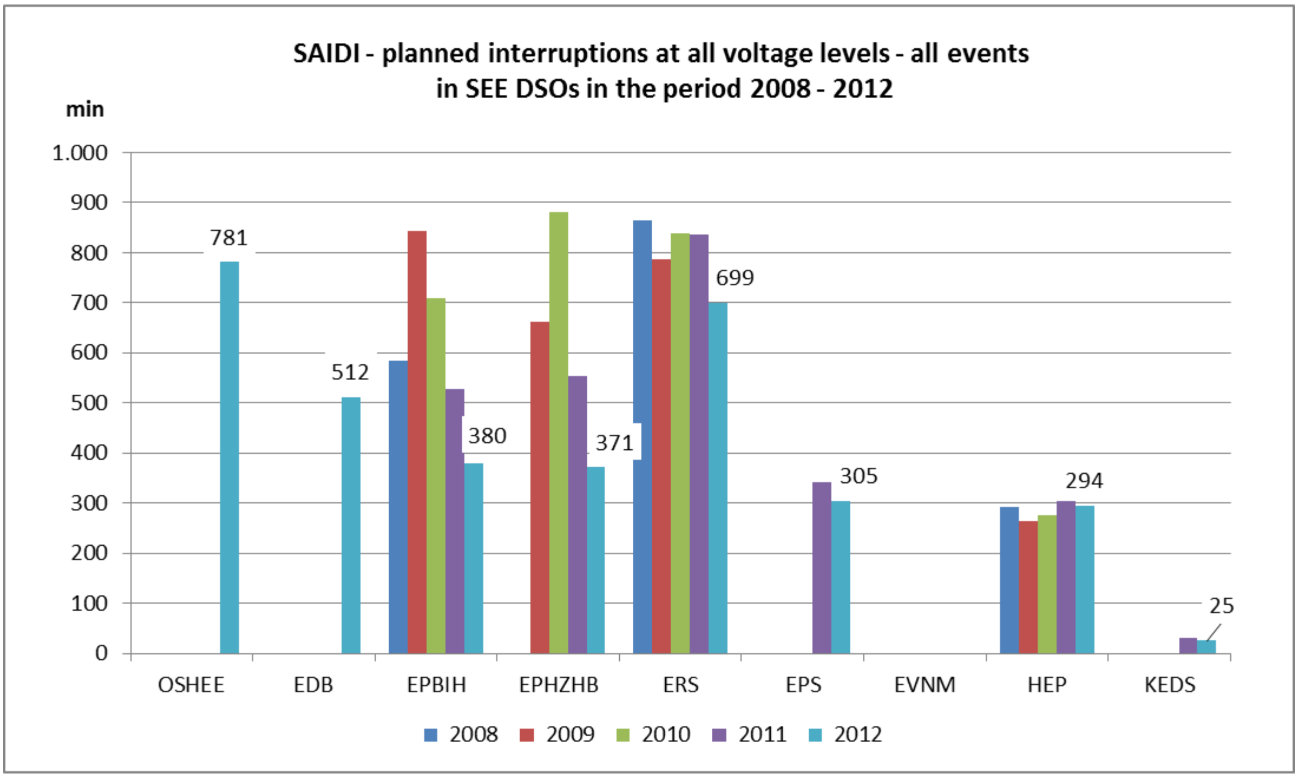


Figure 5.4 SAIDI - planned interruptions at all voltage levels - all events in SEE DSOs in period 2008 - 2012

Similar conclusion can be drawn for MV network, as shown on the following Figure based on the data available for five DSOs.

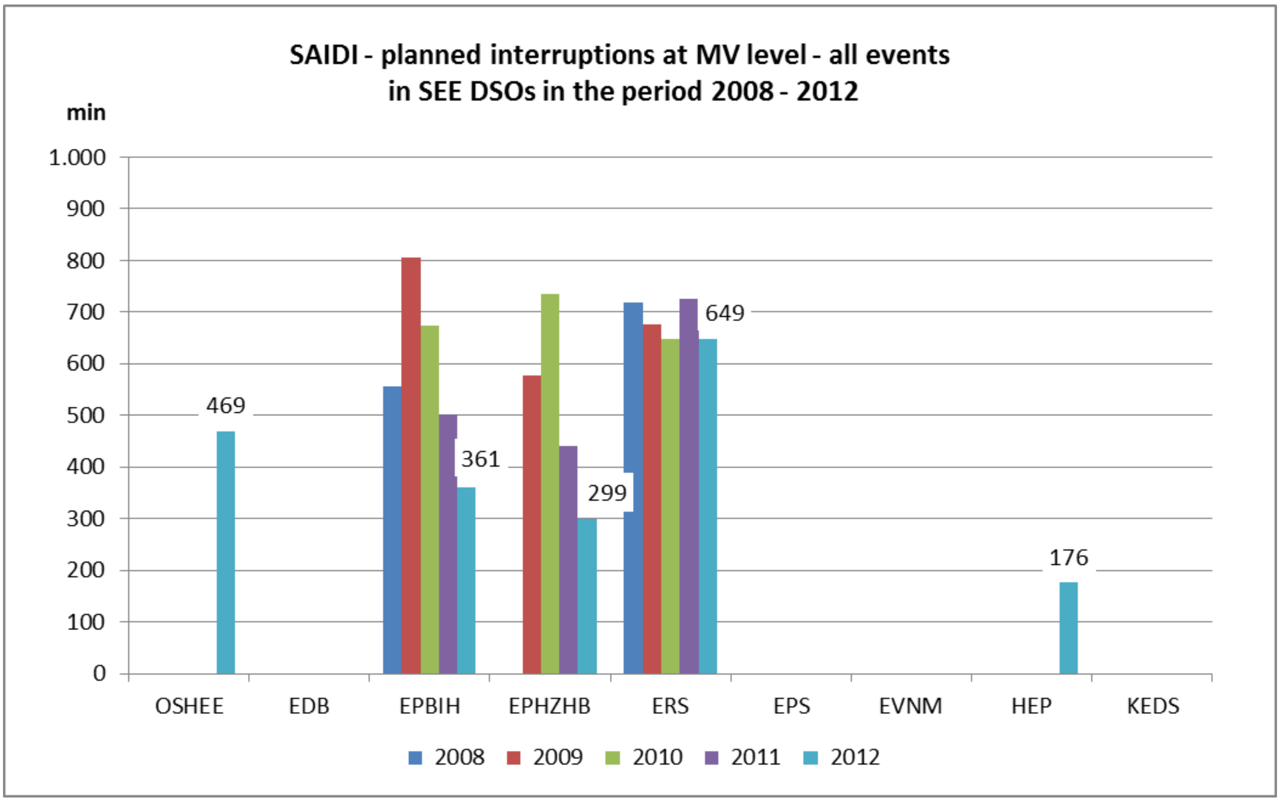


Figure 5.5 SAIDI - planned interruptions at MV level - all events in SEE DSOs in period 2008 – 2012

Similarly to SAIDI indicator, in this subchapter SAIFI is given for unplanned and planned interruptions for all voltage levels and for MV level. For unplanned interruptions SAIFI is in the range between 2 interruptions/year (KEDS, Kosovo in 2009) and 34 interruptions/year (OSHEE, Albania in 2012).
In HEP (Croatia) SAIFI for unplanned interruptions is being at almost a constant value within a given timeframe, in EPBiH (BiH) it is continuously decreasing, while in other DSOs there are certain ups and downs.

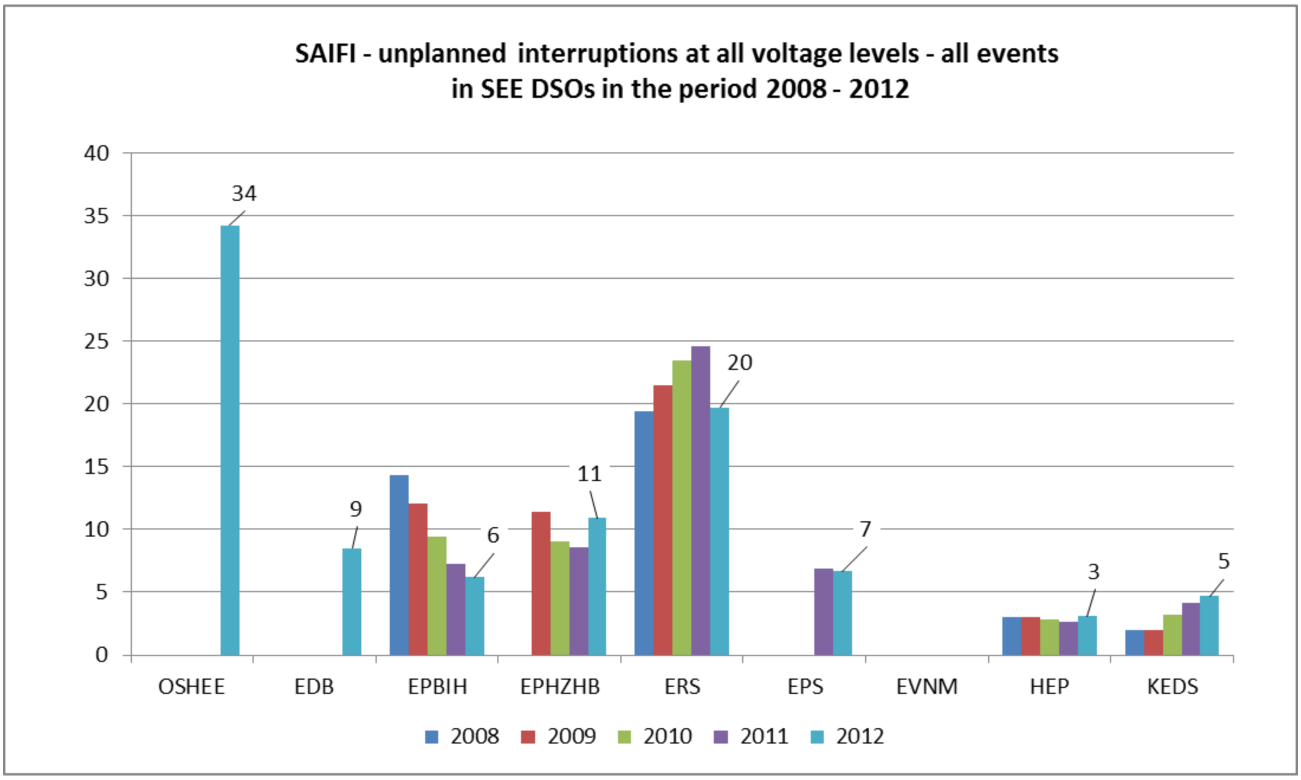


Figure 5.6 SAIFI - unplanned interruptions at all voltage levels - all events in SEE DSOs in period 2008 - 2012

For planned interruptions SAIFI is in the range between 0,2 interruptions/year (KEDS, Kosovo in 2012) and 9,7 interruptions/year (ERS, BiH in 2009).

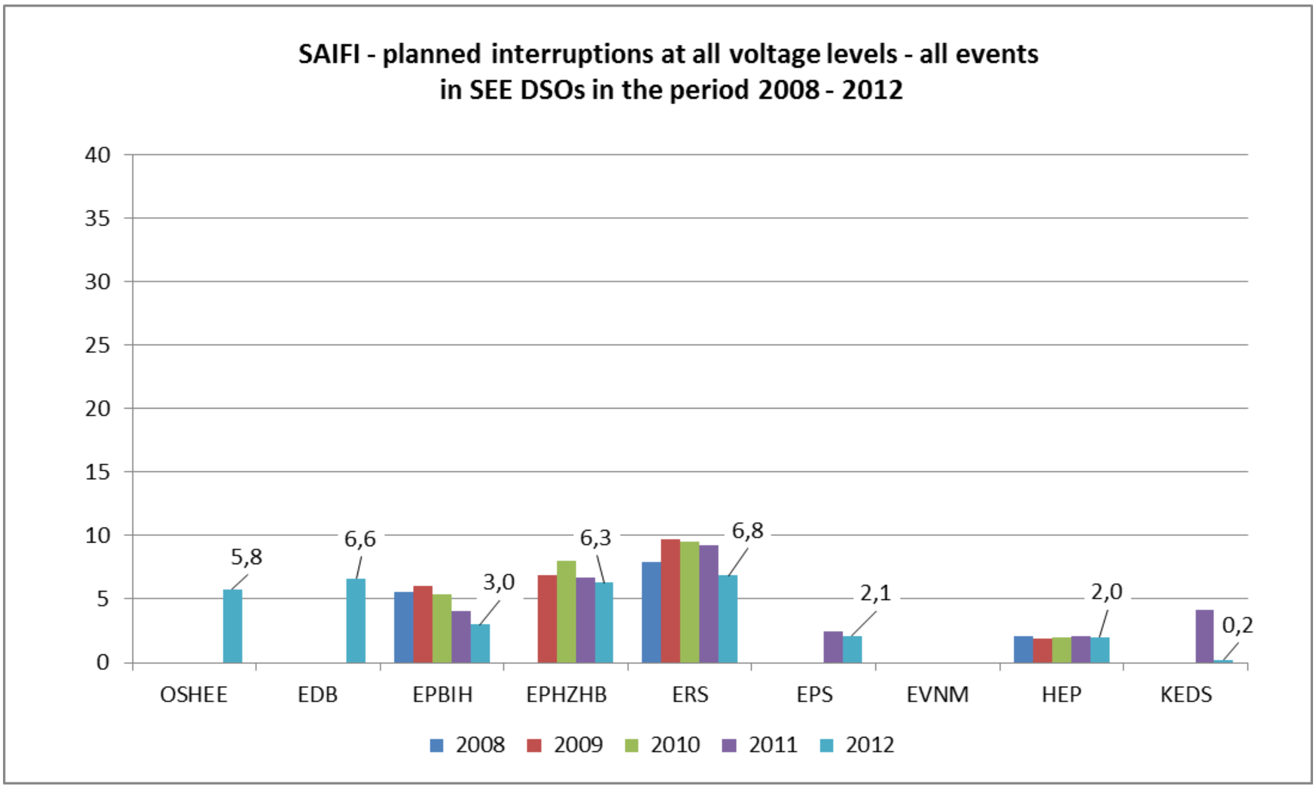


Figure 5.7 SAIFI - planned interruptions at all voltage levels - all events in SEE DSOs in period 2008 – 2012

CAIDI indicator is given just for unplanned interruptions at all voltage levels. It is in the range between 47,3 minutes (EDB, BiH in 2012) and 236,7 minutes (KEDS, Kosovo in 2009). In 2012 all DSOs, except Albanian OSHEE, are having CAIDI values below 120 minutes (i.e. 2 hours). In most of the DSOs (except KEDS) CAIDI is at almost a constant value within a given timeframe.

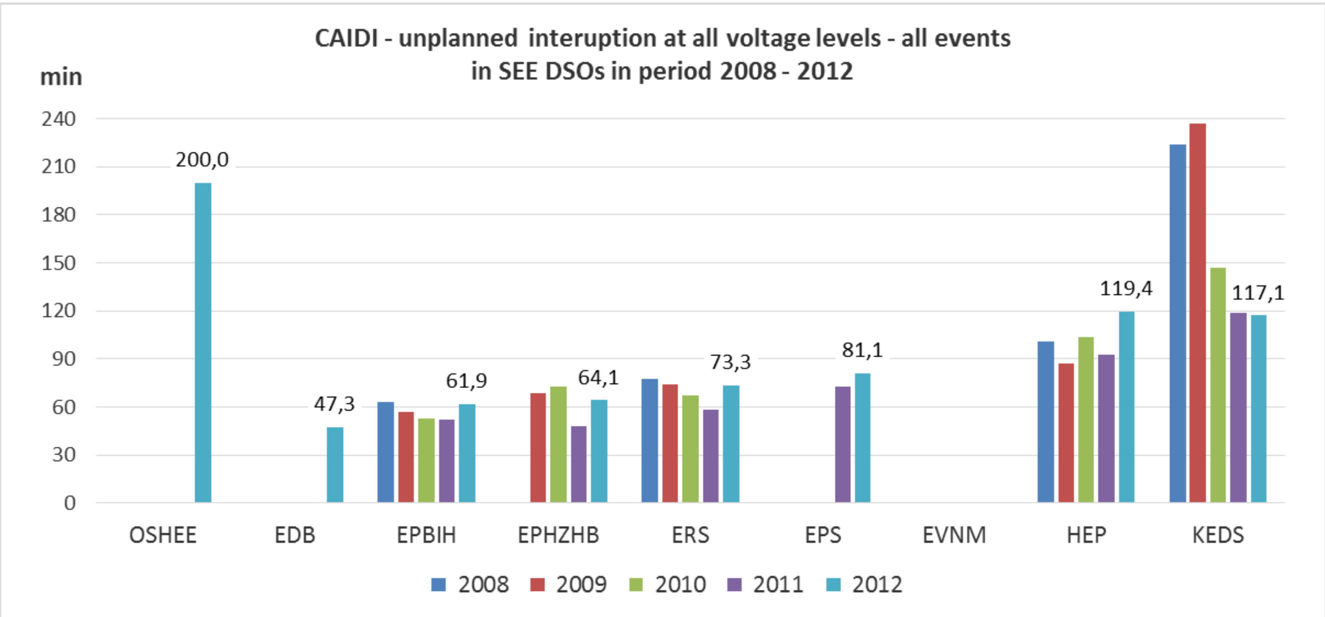


Figure 5.8 CAIDI - unplanned interruptions at all voltage levels - all events in SEE DSOs in period 2008 - 2012

The following Figure refers to electricity not supplied (ENS) to final consumers due to unplanned interruptions in distribution network. The data were available only for 3 DSOs (HEP, EPS and KEDS). Values range between 2 GWh/year (EPS, Serbia in 2011 and 2012) and 155 GWh/year (KEDS, Kosovo in 2011).

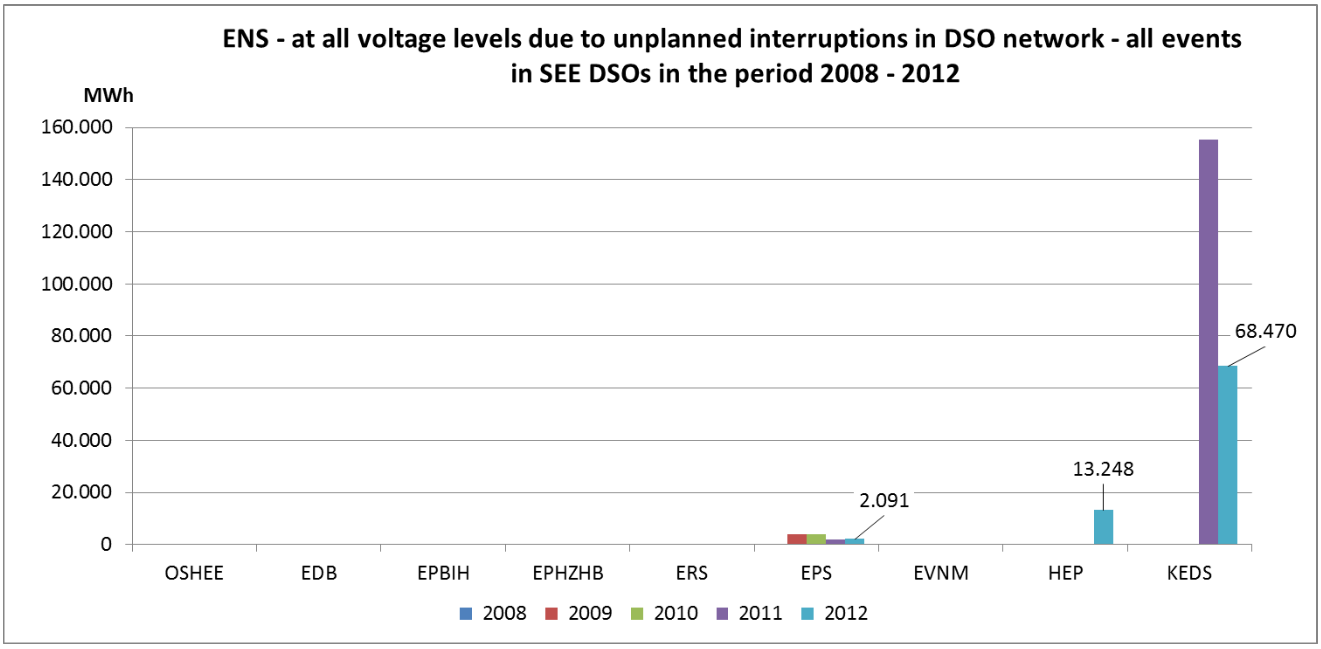


Figure 5.9 ENS – at all voltage levels due to unplanned interruptions in DSO network- all events in SEE DSOs in period 2008 - 2012

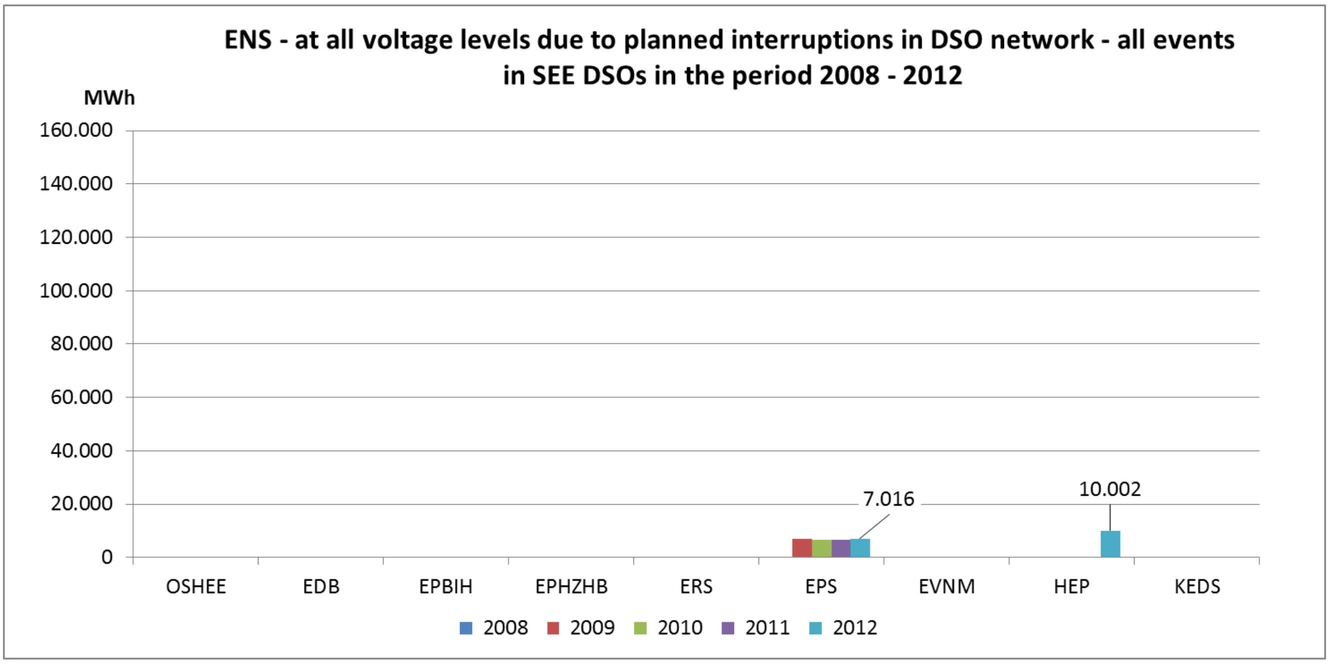


Figure 5.10 ENS - at all voltage levels due to planned interruptions in DSO network - all events in SEE DSOs in the period 2008 - 2012

For the planned interruptions in distribution network there are two data sources – Serbian EPS and Croatian HEP. Clearly, one of the recommendations is to establish and integrate adequate system for ENS calculation.

5.2. SHARE OF UNPLANNED INTERRUPTIONS IN TOTAL NUMBER OF INTERRUPTIONS

In the following Figure the total number of unplanned interruptions is given for each DSO. 4 out of 8 DSO which provided data have less than 8.000 unplanned interruptions per year in the observed period. Of course, these values strongly depend on the network length. Higher values can be observed in Serbian EPS (the largest DSO based on distribution network length), but also in Albanian OSHEE (the third largest DSO in the region), BiH ERS (the fourth largest DSO in the region) and Kosovo KEDS (the sixth largest DSO in the region).

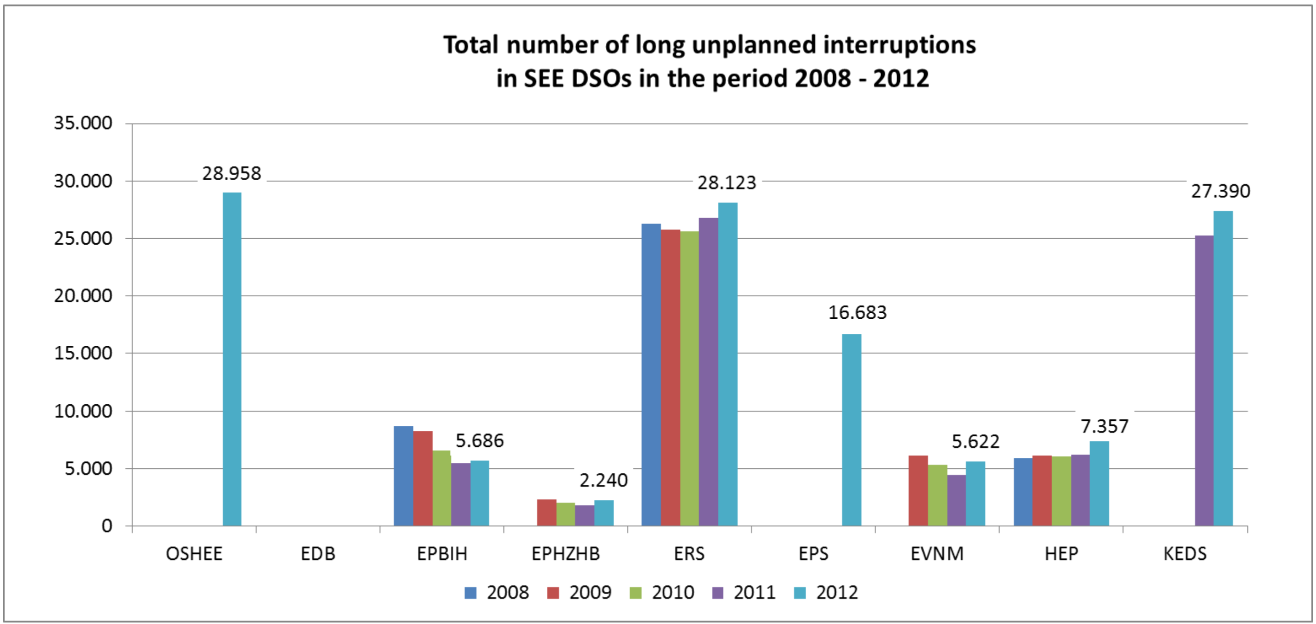


Figure 5.11 Total number of long unplanned interruption in SEE DSOs in the period 2008 - 2012

In the following Figure the total number of planned interruptions is given for each DSO. In 8 DSOs which provided data values are below 13.000 interruptions/year. Most of the DSOs have less than 5.200 planned interruptions per year. Expectedly, Serbian EPS and Croatian HEP, being the two largest DOS in the region, have significantly high number of planned interruptions.

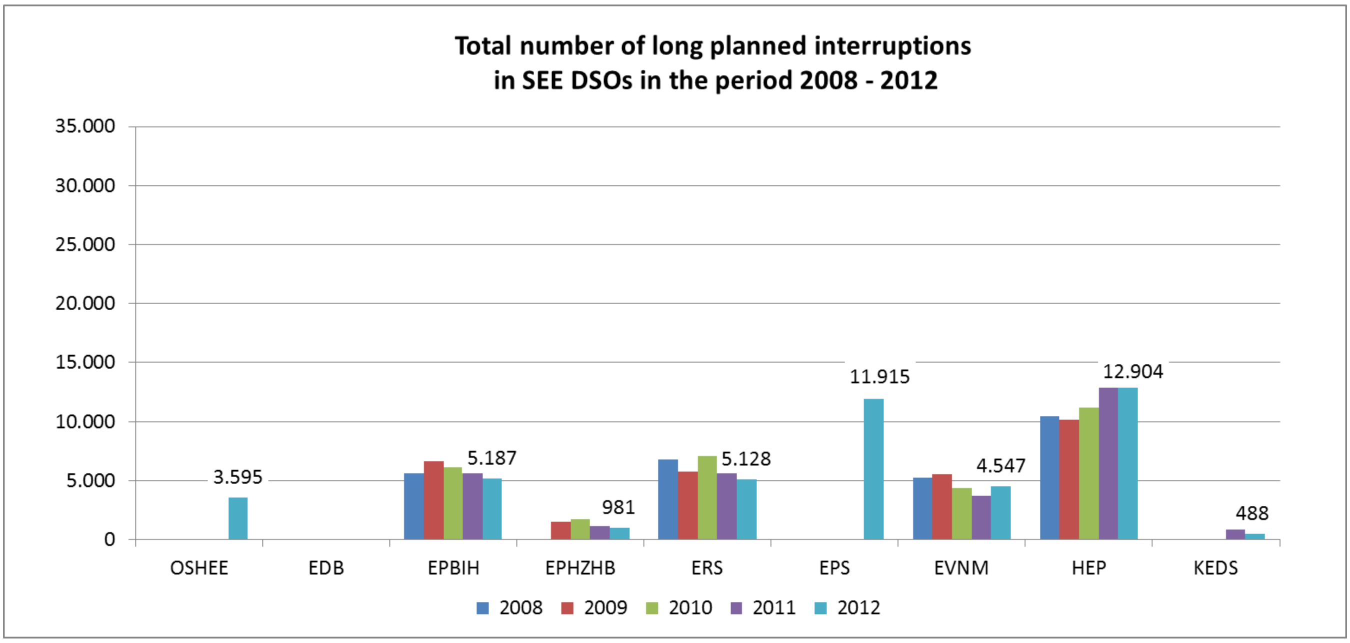


Figure 5.12 Total number of planned long interruptions in SEE DSOs in the period 2008 - 2012

Based on the previous two values (provided by DSOs) share of unplanned interruptions in total number of interruptions has been calculated and given in the following Figure. This share is in the range between 32,6 % (HEP, Croatia in 2011) and 98,2 % (KEDS, Kosovo in 2012). Out of 8 DSOs 7 DSOs have over 50 % share of unplanned interruptions in total number of interruptions.

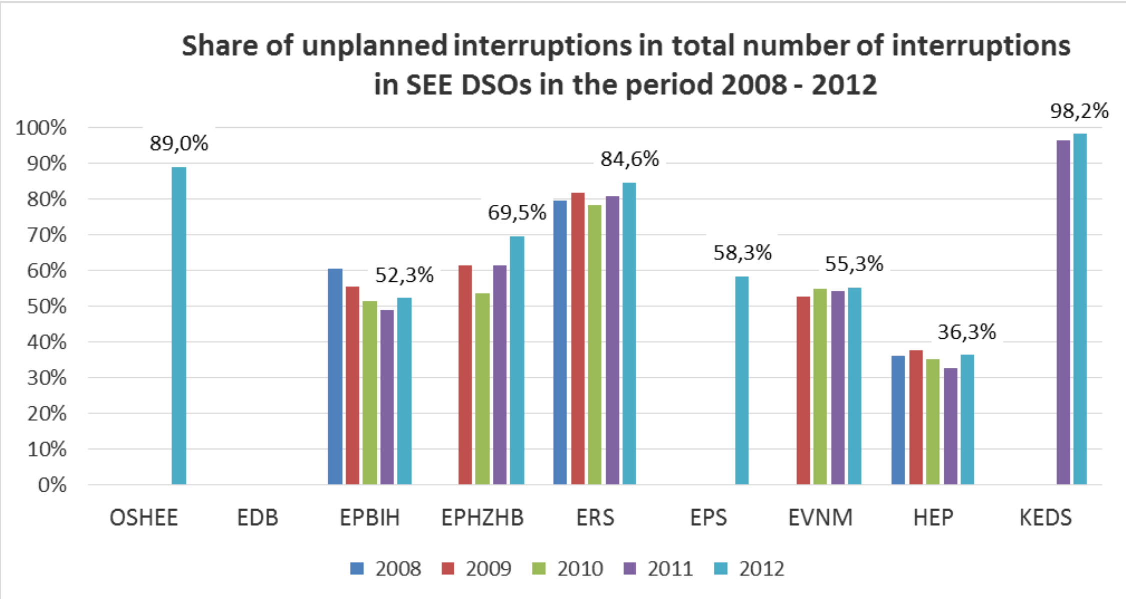


Figure 5.13 Share of unplanned interruptions in total number of interruptions in SEE DSOs in the period 2008 - 2012

6. ELECTRICITY LOSSES

One of the most interesting indicators of the DSO operational performance relates to electricity losses. It is crucial to clearly set common definition of power losses. Total losses are calculated as the difference between electricity received in the distribution network (from the transmission network and distributed generation) and electricity delivered to the final customers. In percentage, total losses are calculated as the ratio between total losses and sum of total sale and total losses. It is important to note that total losses include technical losses (caused by the physical properties of the components of the power system; i.e. power dissipated in distribution lines and transformers due to internal electrical resistance) and commercial losses (theft, non-payment by customers, unmetered supply, errors in meter reading, etc.).

6.1. VOLUME AND COST OF AGGREGATED TECHNICAL AND COMMERCIAL LOSSES

The following Figure shows that the level of total losses in distribution network in SEE in the period 2008 – 2012 was in the range between 7,2 % (HEP, Croatia in 2008) and 43,5 % (OSHEE, Albania in 2012), but mainly in the range of 9 % and 17 %. Region average in 2012 equals 17 %. In Albanian OSHEE and Kosovo KEDS levels of losses are significantly higher than in the rest of the region. Besides, in given timeframe there is no significant losses reduction in any of analyzed DSOs.

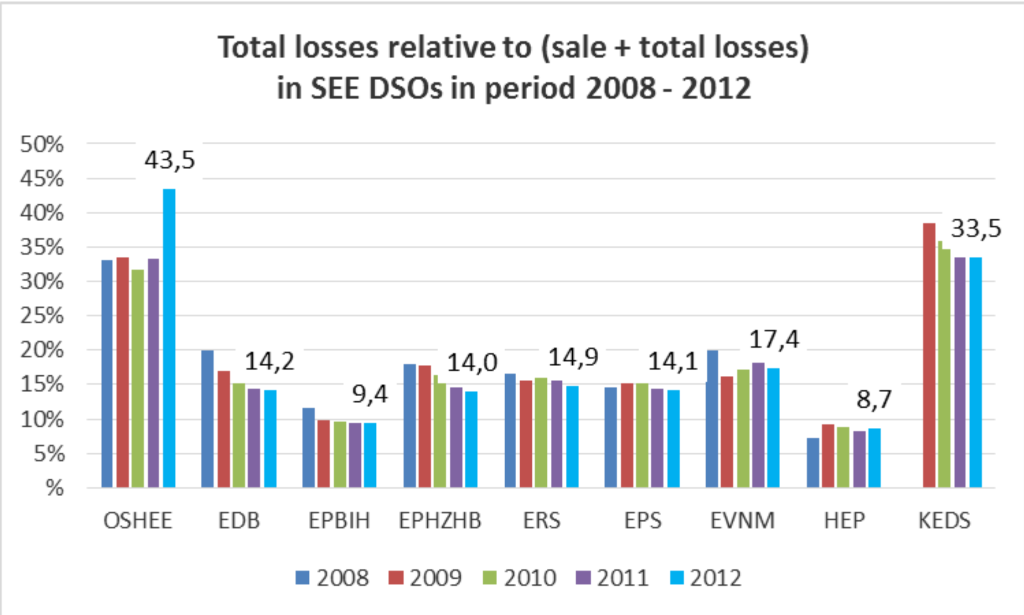


Figure 6.1 Total losses relative to sale + total losses in SEE DSOs in the period 2008 - 2012

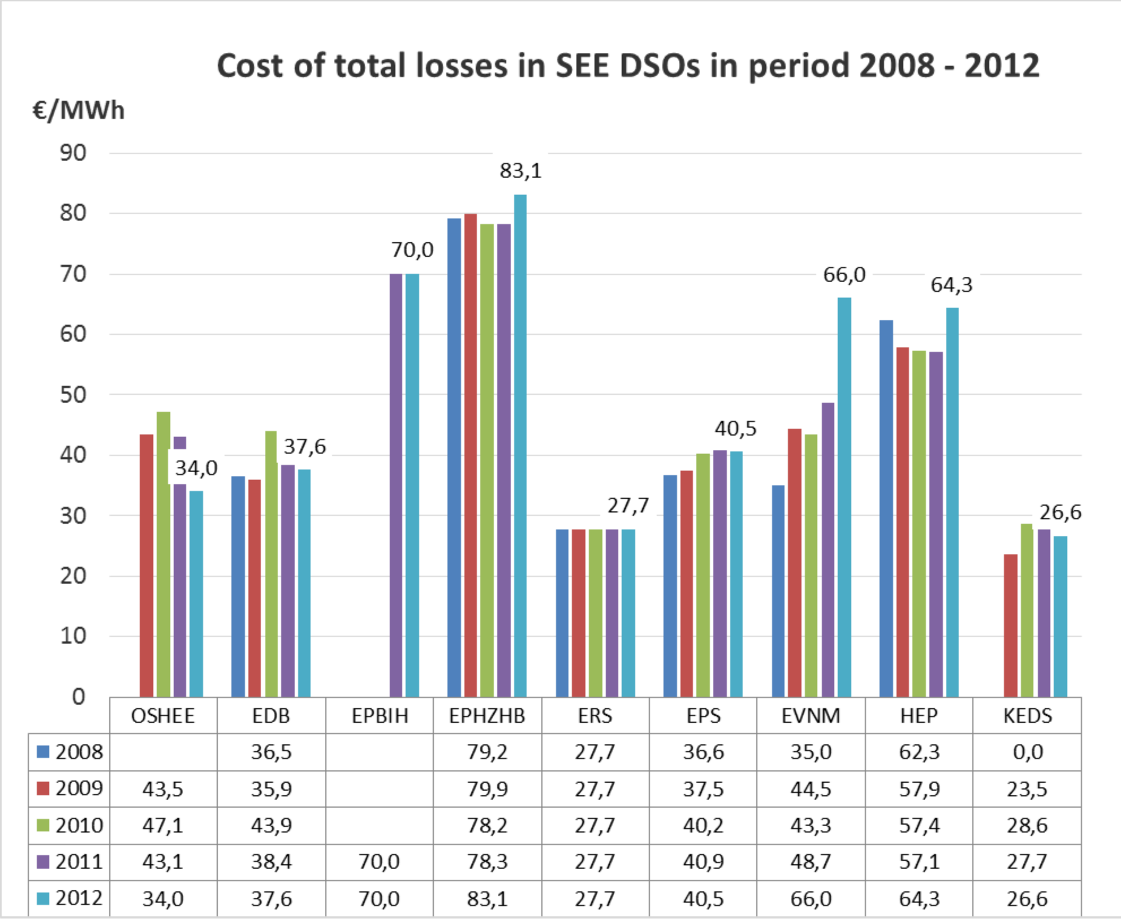
Table 6.1 Total losses relative to (sale + total losses) in SEE DSOs in 2008-2012 period

%	2008	2009	2010	2011	2012
OSHEE	33,14	33,47	31,75	33,25	43,51
EDB	19,87	16,99	15,12	14,39	14,20
EPBIH	11,65	9,78	9,69	9,49	9,36
EPHZHB	17,95	17,67	16,36	14,49	14,01
ERS	16,56	15,51	16,04	15,65	14,87
EPS	14,48	15,19	15,10	14,31	14,14
EVNM	20,02	16,11	17,22	18,13	17,41
HEP	7,21	9,30	8,74	8,19	8,68
KEDS	-	38,42	35,90	33,42	33,52
All DSOs	14,24	16,83	16,43	16,06	17,05

The following Figure shows only the relative losses data for 2012.

Figure 6.2 Total losses relative to sale + total losses in SEE DSOs in 2012

Cost of total losses is given on the following Figure. It is defined as the unit cost of electricity losses paid annually for procurement of one MWh of energy losses. In some countries it is fully regulated, while in other it is linked to market price. It is expected that in the future all network losses will be procured using market based methods. In 2012, the range of unit cost of losses is 27 €/MWh (KEDS, Kosovo) – 83 €/MWh (EPHZHB, BiH). In most of the DSOs the unit costs of losses were quite stable in the period 2008 – 2012. The exception is ENVM, Macedonia where significant increase was present – from 35 €/MWh (2008) to 66 €/MWh (2012). Data for ERS, BiH are not available.



	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS
2008		36,5		79,2	27,7	36,6	35,0	62,3	0,0
2009	43,5	35,9		79,9	27,7	37,5	44,5	57,9	23,5
2010	47,1	43,9		78,2	27,7	40,2	43,3	57,4	28,6
2011	43,1	38,4	70,0	78,3	27,7	40,9	48,7	57,1	27,7
2012	34,0	37,6	70,0	83,1	27,7	40,5	66,0	64,3	26,6

Figure 6.3 Unit cost of total losses in SEE DSOs in the period 2008 - 2012

Even though distribution systems in the region are of different sizes, and therefore hardly comparable, the following Figure shows volume of total losses in the period 2008 – 2012. As expected, the highest amount of distribution network losses is in the largest DSO EPS, Serbia; up to 4,6 TWh/year.

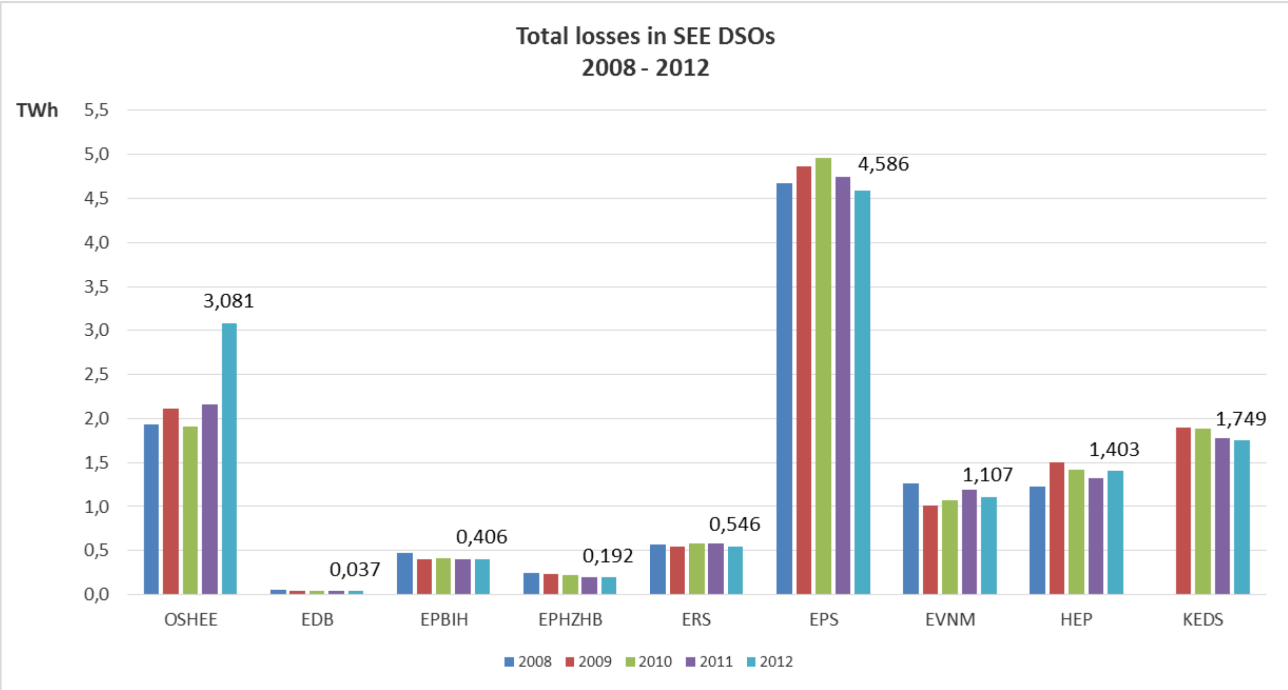


Figure 6.4 Volume of total losses in SEE DSOs in the period 2008 - 2012

Table 6.2 Volume of total losses in SEE DSOs in the period 2008 - 2012

MWh	2008	2009	2010	2011	2012
OSHEE	1.927.365	2.117.142	1.910.953	2.162.484	3.080.674
EDB	53.434	46.241	41.939	39.103	37.280
EPBIH	470.901	404.244	410.362	406.521	406.380
EPHZHB	239.752	237.741	222.481	196.713	192.441
ERS	572.412	546.718	582.495	576.124	545.843
EPS	4.678.895	4.865.178	4.959.272	4.747.720	4.586.363
EVNM	1.260.636	1.014.060	1.074.828	1.186.414	1.107.271
HEP	1.222.910	1.507.778	1.424.082	1.325.405	1.402.635
KEDS		1.895.427	1.879.324	1.781.934	1.749.037
All DSOs	10.426.305	12.634.529	12.505.735	12.422.417	13.107.925

6.2. ESTIMATED TECHNICAL LOSSES

As stated above, total losses could be divided in technical and commercial losses. Data on estimated technical losses are available just for 5 DSOs: OSHEE, KEDS, ERS, EPHZHB and EPS, as given on the following Figure. Data for EDB, EPBIH, EVNM and HEP are not available.

It could be observed that the level of estimated technical losses in Serbian EPS is very low; i.e. ~ 1 % of (sale + total losses). EPS indicated that the method of technical losses estimation is based on the following – in 2 distribution areas out of 5 DMS software is used, which includes power flow calculation, modeling of characteristic network elements, data on procurement and sales of electricity, while in other areas estimation is based on sample measurements and analyses of typical network regimes.

In other DSOs estimated technical losses range between 8 % (EPHZHB, BiH) and 17,4 % (OSHEE, Albania in 2008).

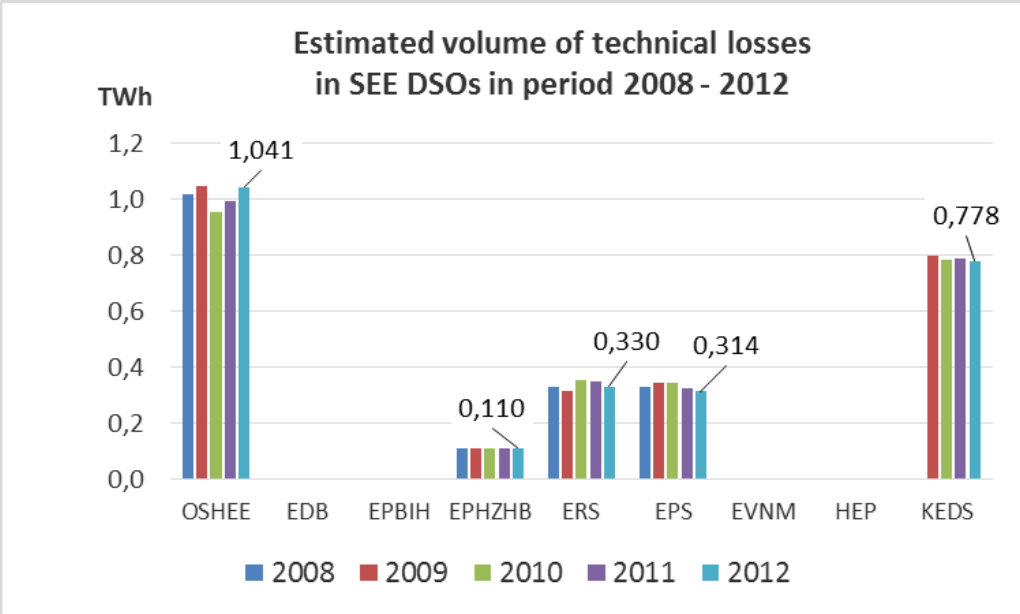


Figure 6.5 Estimated volume of technical losses in SEE DSOs in the period 2008 - 2012

6.3. LEVEL OF LOSSES APPROVED BY THE REGULATOR

In the process of network tariff system adoption, national energy regulatory agencies are approving certain level of network losses that will be covered by the network charge. It is usually defined for regulation period of several years in a descending order as incentive to system operators to decrease system losses. The losses higher than approved by regulator are not supposed to be covered by the network charge. They are paid from other sources, such as DSOs' regulated profit.

Total amount of the network losses approved by the regulator are given on the following Figure. Data for EDB, EPHZHB and HEP were not available.

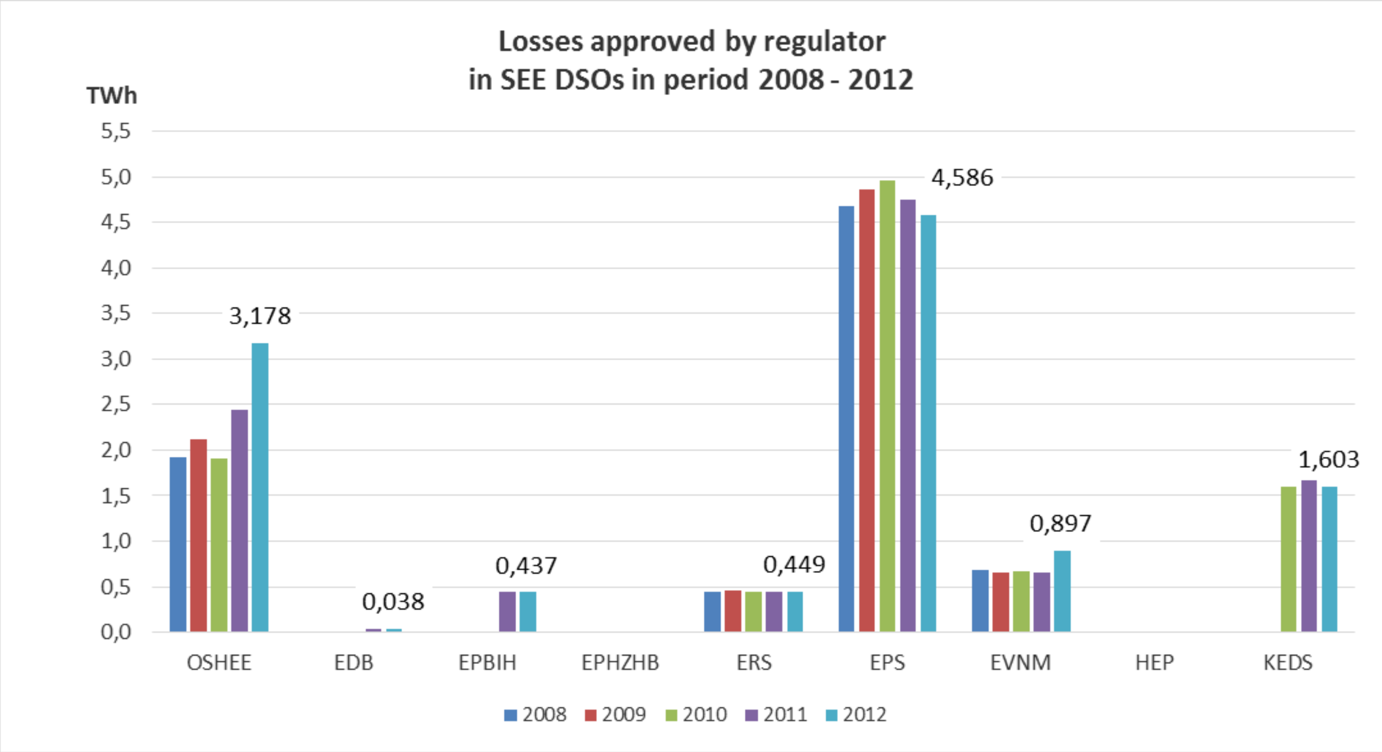


Figure 6.6 Level of losses approved by regulator in SEE DSOs in the period 2008 - 2012

All the above analyzed categories of losses are given on the following Figure: where available total losses are divided into estimated technical and estimated commercial losses. Besides, for 6 DSOs these realized losses can be compared to losses approved by national regulatory authority (NRA).

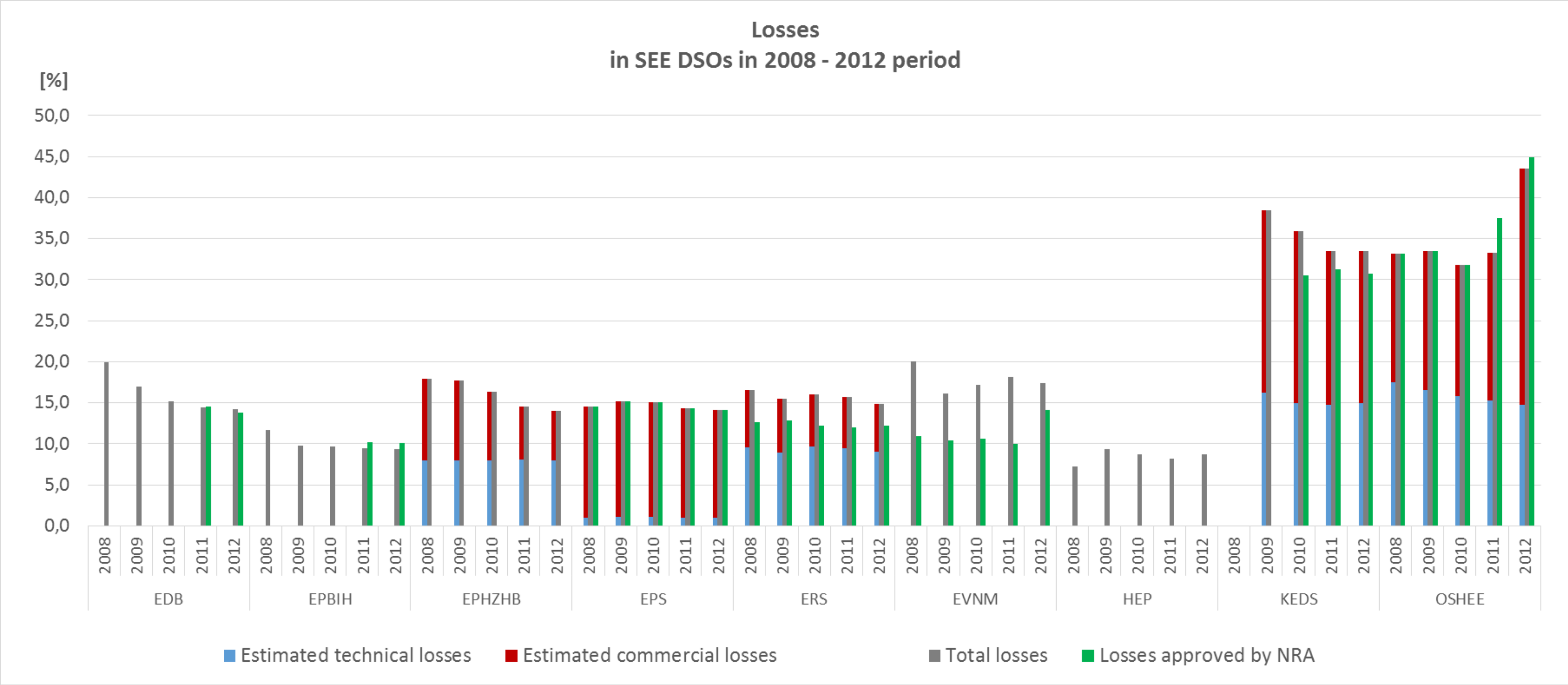


Figure 6.7 Technical, commercial (or total) and approved losses relative to (sale + total losses) in SEE DSOs in 2008 - 2012

Some of DSOs provided the estimations of shares of technical and commercial losses. In KEDS, EPHZHB and ERS the levels of technical losses are almost the same as the levels of commercial losses; in EPHZHB and KEDS commercial are slight higher, while in ERS technical are slightly higher. The outliers are EPS and OSHEE. In OSHEE the level of commercial losses almost doubled in 2012 in comparison to 2011 (from 18 % to 29 %). In EPS estimated technical losses are uncertainly low; i.e. 1 %.

In ERS and EPHZHB commercial losses has been declining in the observed period. In EPHZHB in 2012 commercial losses were 40 % lower than in 2008, while in ERS in 2012 they were 18 % lower than in 2008.

In the case of OSHEE it can be seen that in the three years period 2008 – 2010 the level of approved losses was exactly the same as realized total losses (technical + commercial). The same applies to Serbian EPS in all years. In EDB in 2012 approved level of approved losses was slightly lower than realized total losses.

In 2011 and 2012 total losses in OSHEE were slightly lower than losses approved by the regulator even though total level of losses was higher than in 2010. In other words OSHEE was acting more efficient with lower losses than the regulator expected. The same applies to EPBIH for the last two years in the observed period.

On the contrary, in the case of Macedonian EVNM, ERS (BiH) and KEDS (Kosovo) in the whole period 2008 – 2012 level of total losses was higher than the level approved by the regulator. In Macedonia the regulator was slightly increasing the level of approved losses, while for ERS (BiH) and KEDS (Kosovo) approved losses (in %) in the last three years were almost constant.

7. COMPARISON TO THE US DSOs INDICATORS

One of the tasks to be realized in this study is to benchmark SEE DSOs with DSOs from the western countries. For this purpose American Electric Power with its 7 subsidiaries have been chosen since American Electric Power (AEP) is a major investor-owned electric utility in the United States, delivering electricity to more than 5,3 million customers in 11 states. AEP ranks among the nation's largest electricity generators, owning nearly 38.000 MW of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 63.000 km of the network that includes 765 kV ultra-high voltage transmission lines; i.e. more than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 % of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 % of the electricity demand in Electric Reliability Council of Texas, the transmission system that covers a large part of Texas.

AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia, West Virginia, and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

The main AEP characteristics are shown on the following Figure.

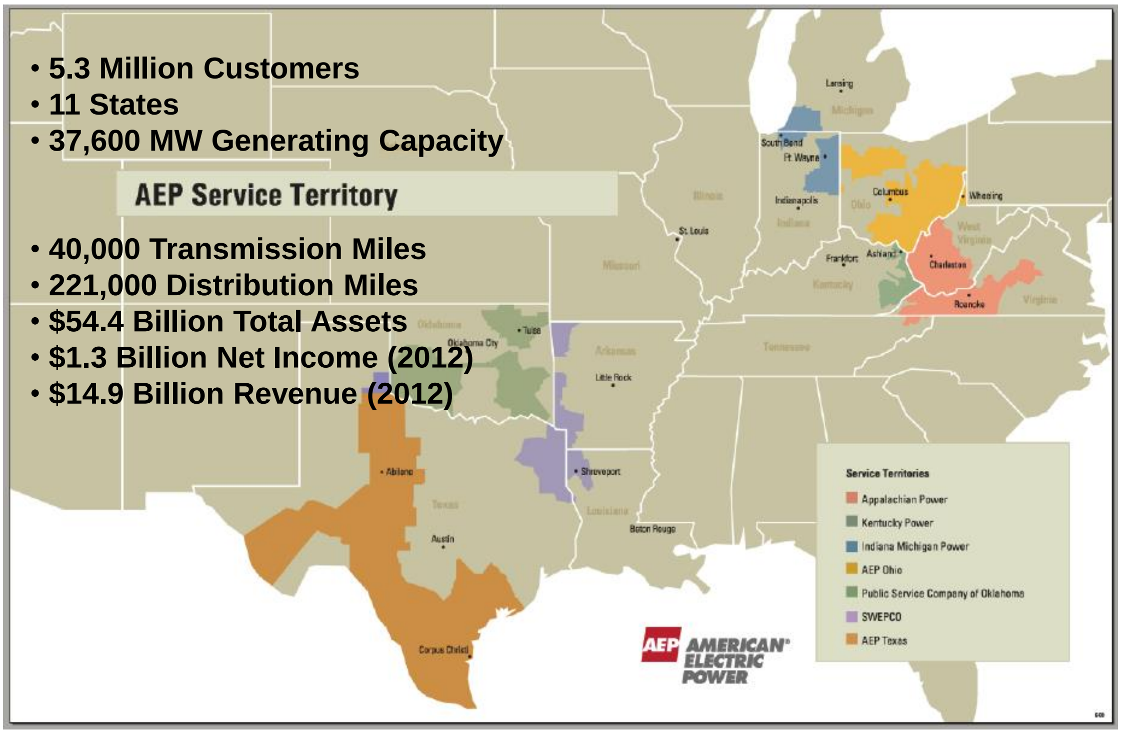


Figure 7.1 Main characteristics of AEP

7.1. DELIVERED ELECTRICITY

These 7 AEP companies and total of AEP are having similar level of electricity delivered per consumer (22 – 39 MWh/year). It is much higher than in DSOs in SEE where values range from 3.654 kWh/consumer (OSHEE, Albania) to 8.125 kWh/consumer (EPS, Serbia), with an average of 6.939 kWh/consumer. This clearly shows different level of economic development and/or small to medium industrial activity.

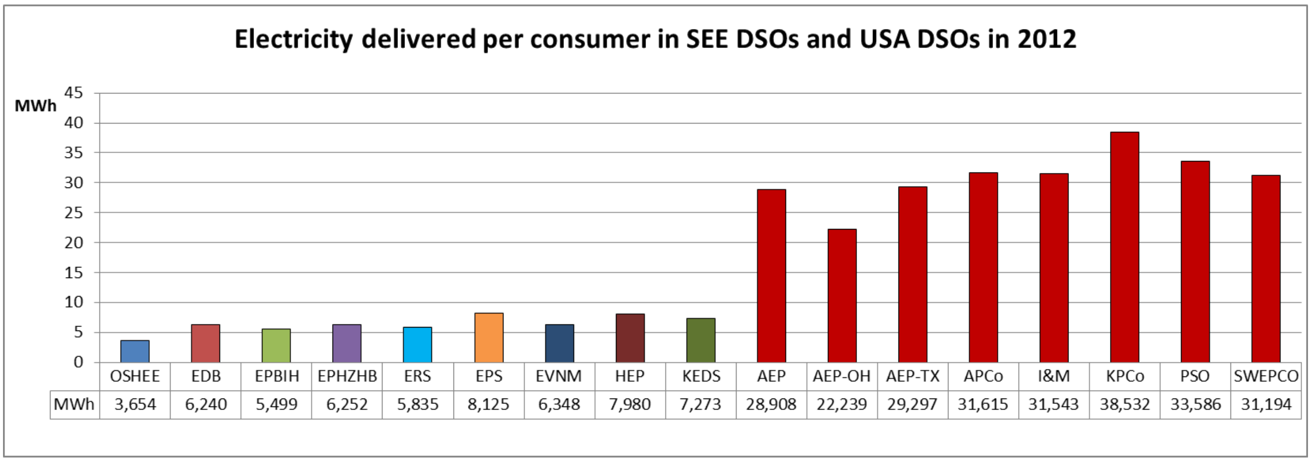


Figure 7.2 Electricity delivered per consumer in SEE and US DSOs in 2012

Similar to that, US companies are also having much higher level of electricity delivered per employee (22 – 35 GWh/employee). It is much higher than in SEE DSOs where average electricity delivered per employee equals 1,738 GWh/employee (on average 16 times lower). Without going into internal organizational structure of each DSO (whether DSO is bundled with supply business, and/or with other parts of vertically integrated company, outsources some of its tasks, etc.), it is clear that US companies are significantly more efficient.

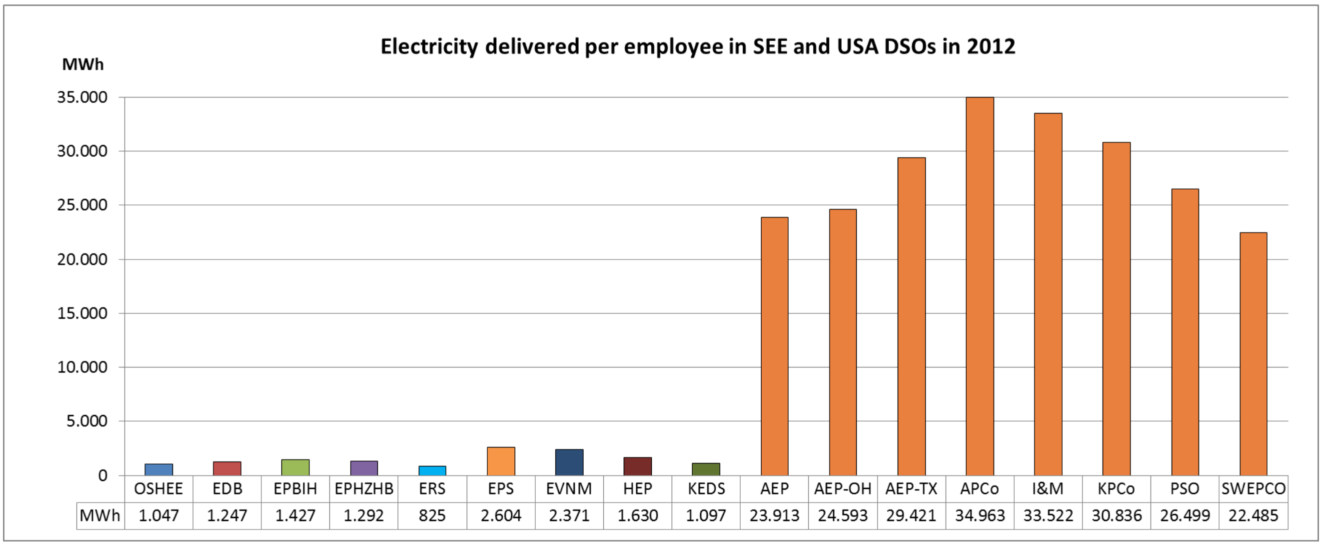


Figure 7.3 Electricity delivered per employee in SEE and US DSOs in 2012

The number of customers per employee is calculated and shown on the following Figure. It shows that average number of customers per employee in SEE DSOs is 250, while in the US DSOs it is 927, (3,7 times higher).

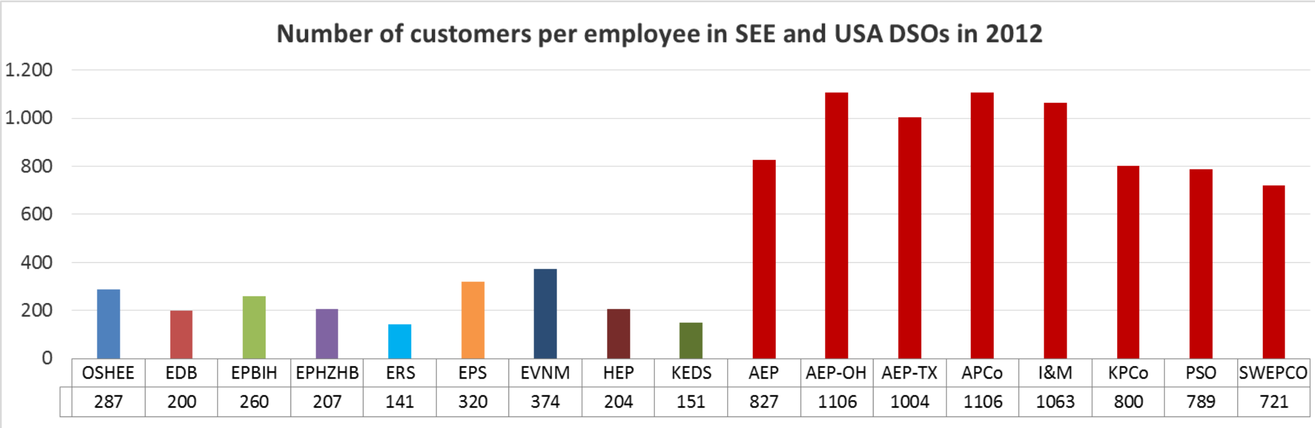


Figure 7.4 Number of customers per employee in SEE and US DSOs in the period 2008 - 2012

The following Figure shows the level of electricity delivered per network length. Again, US companies are having significantly higher values than those from the SEE even though it varies between 0,07 GWh/km in ERS (BiH) and 0,28 GWh/km in EVNM (Macedonia). In 2012 average value in SEE equalled 0,15 GWh/km, while in given US companies it was about 0,44 GWh/km. This suggests that the distribution network infrastructure in US AEP is about three times more efficiently used than in SEE.

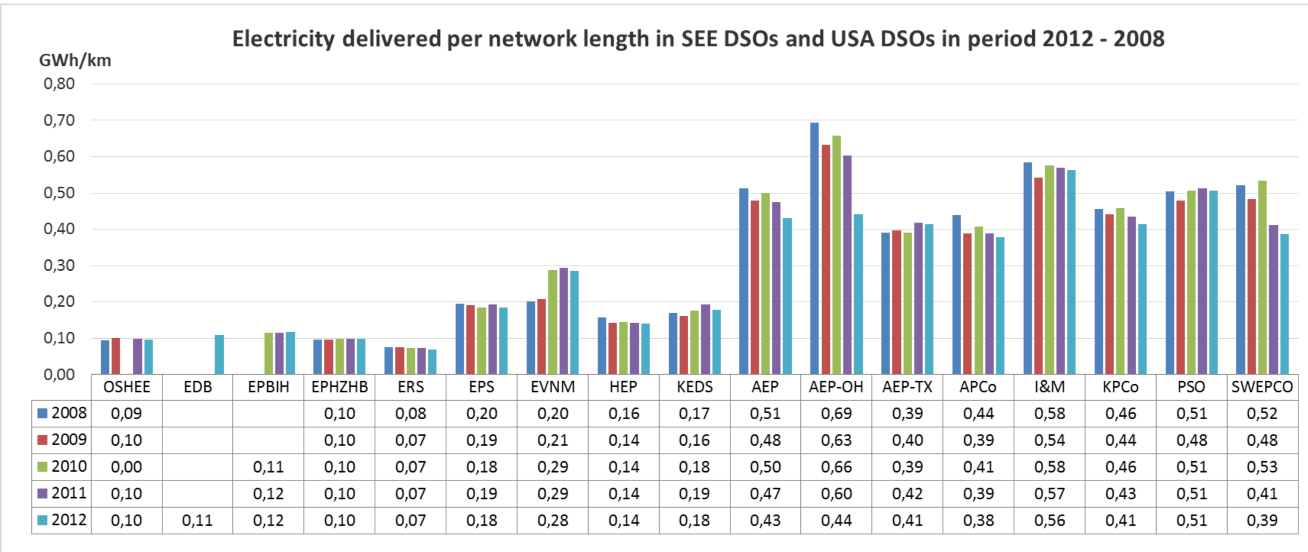


Figure 7.5 Electricity delivered per network length in SEE and US DSOs in the period 2008 - 2012

7.2. CONTINUITY OF SUPPLY

SAIDI indicator for unplanned interruptions at all voltage levels shows that in the US there were larger peak values than in SEE. That's the reason why total average values in the US are a bit higher than in all SEE DSOs except OSHEE (Albania).

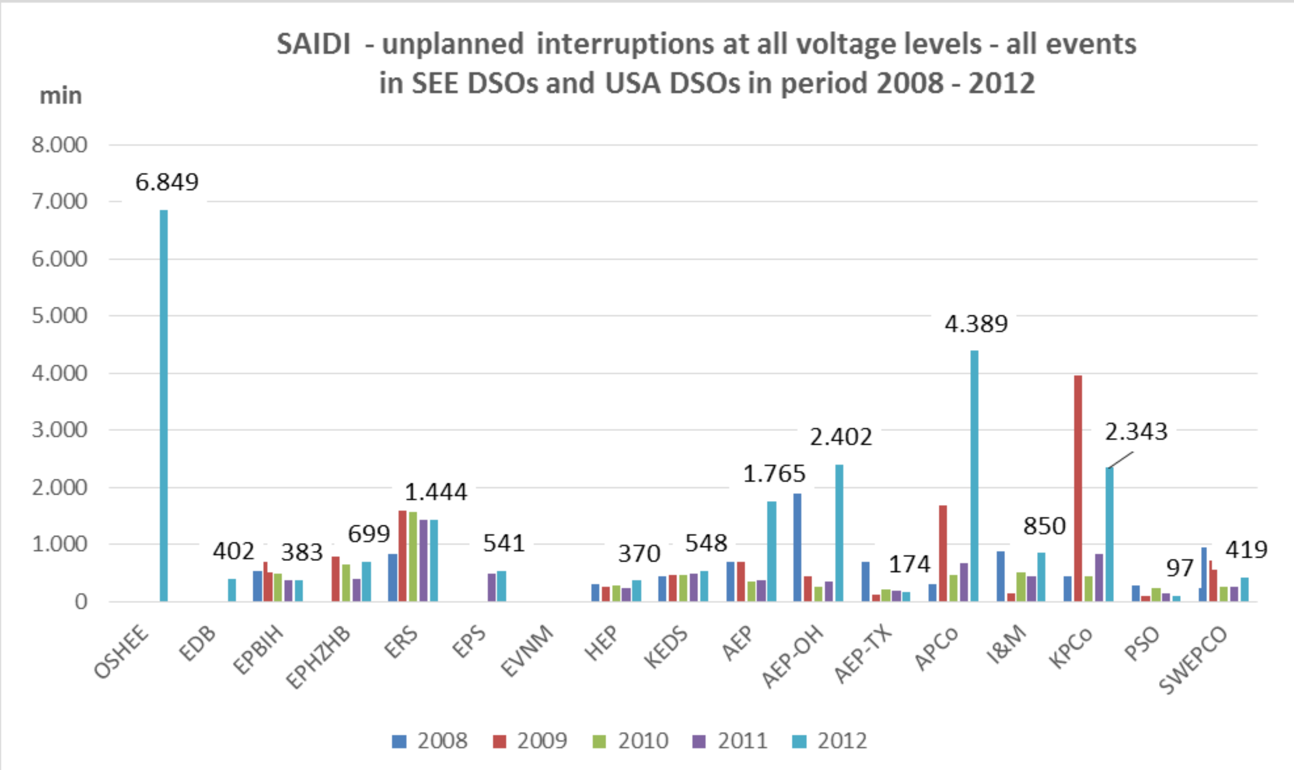


Figure 7.6 SAIDI - unplanned interruptions at all voltage levels - all events in SEE and US DSOs in the period 2008 - 2012

Similarly, SAIFI indicator for unplanned interruptions at all voltage levels shows large differences between SEE and US DSOs. In given US DSOs SAIFI for unplanned interruptions is up to 3, while in SEE DSOs it is in the range between 2 interruptions/year (KEDS, Kosovo in 2009) and 34 interruptions/year (OSHEE, Albania in 2012).

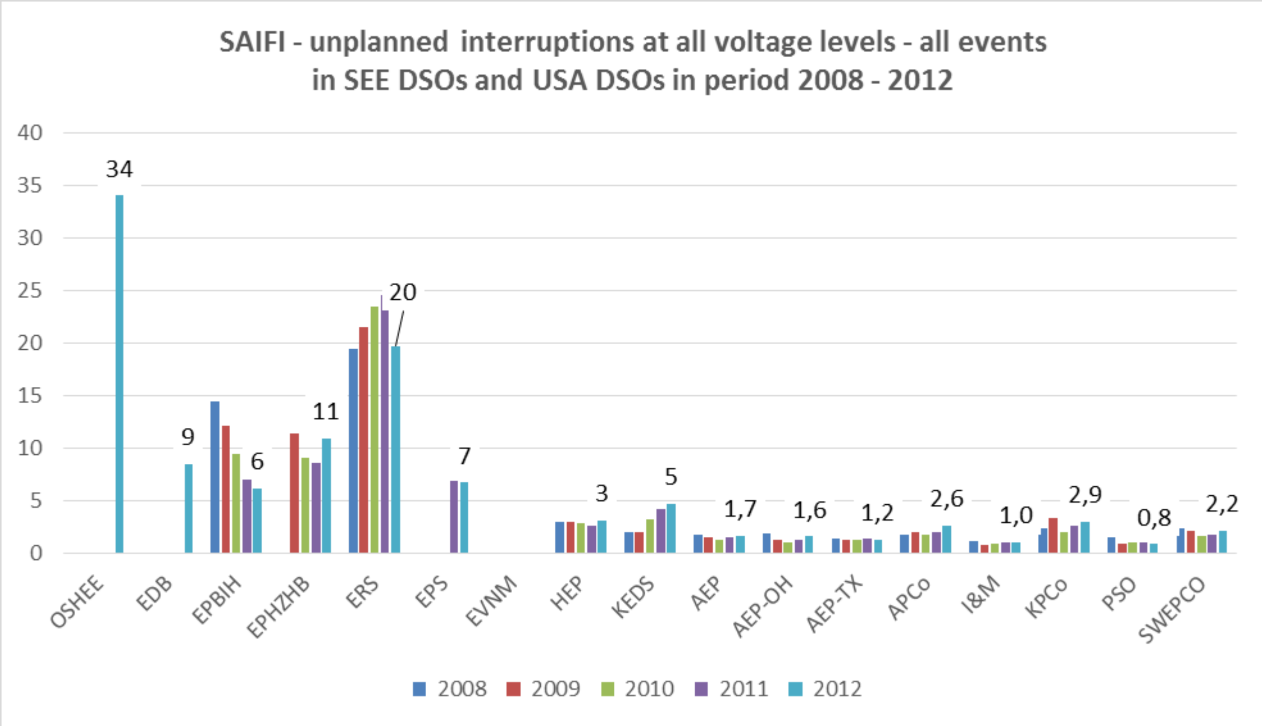


Figure 7.7 SAIFI - unplanned interruptions at all voltage levels - all events in SEE DSOs and USA DSOs in period 2008 - 2012

On the other side, for planned interruptions at all voltage levels SAIDI indicators in the US companies are practically equal to zero. In other words, network maintenance and other planned activities in the US cause almost no supply interruptions, mostly due to “live working” (work without disconnection) or different maintenance practice. SAIDI range is in between 25 minutes (KEDS, Kosovo in 2012) and 881 minutes (EPHZHB, BiH in 2010).

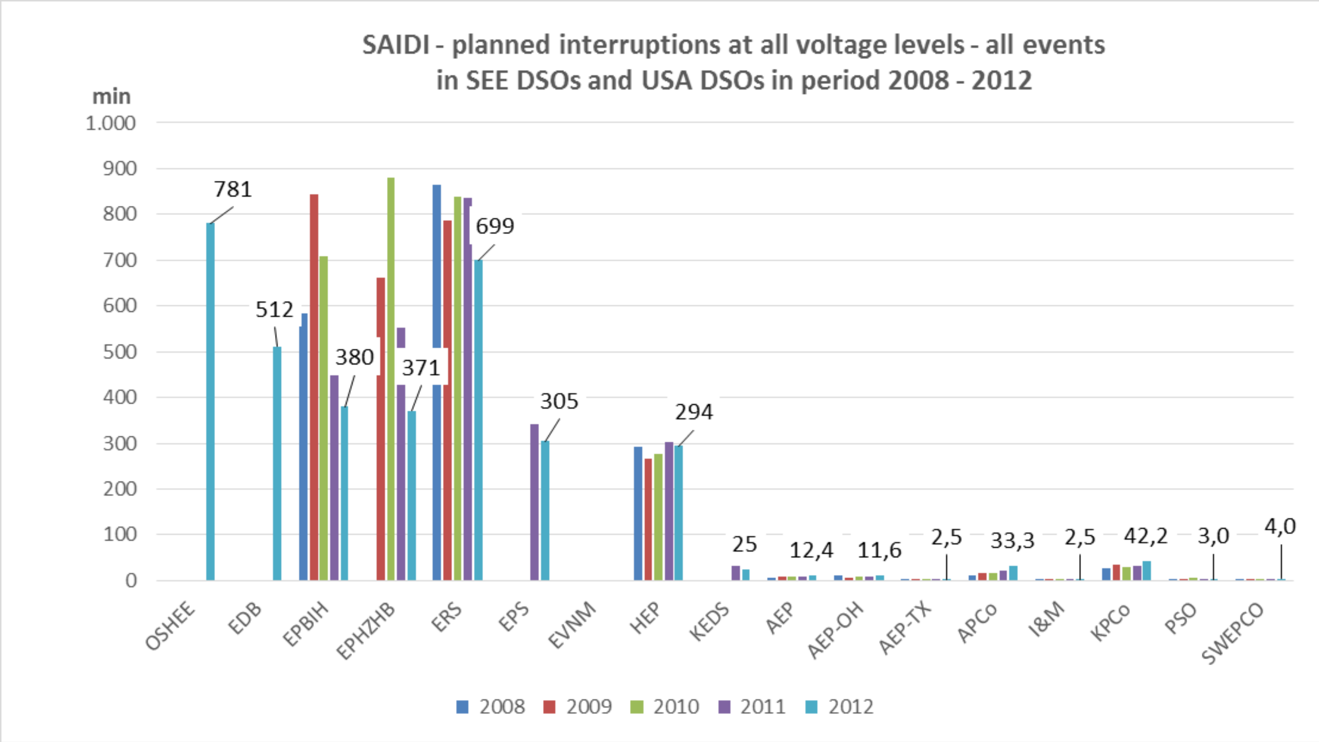


Figure 7.8 SAIDI - planned interruptions at all voltage levels - all events in SEE and US DSOs in the period 2008 - 2012

Similarly, SAIFI indicator for planned interruptions at all voltage levels follows the shape of above mentioned SAIDI indicators for planned interruptions, with US DSOs values close to zero.

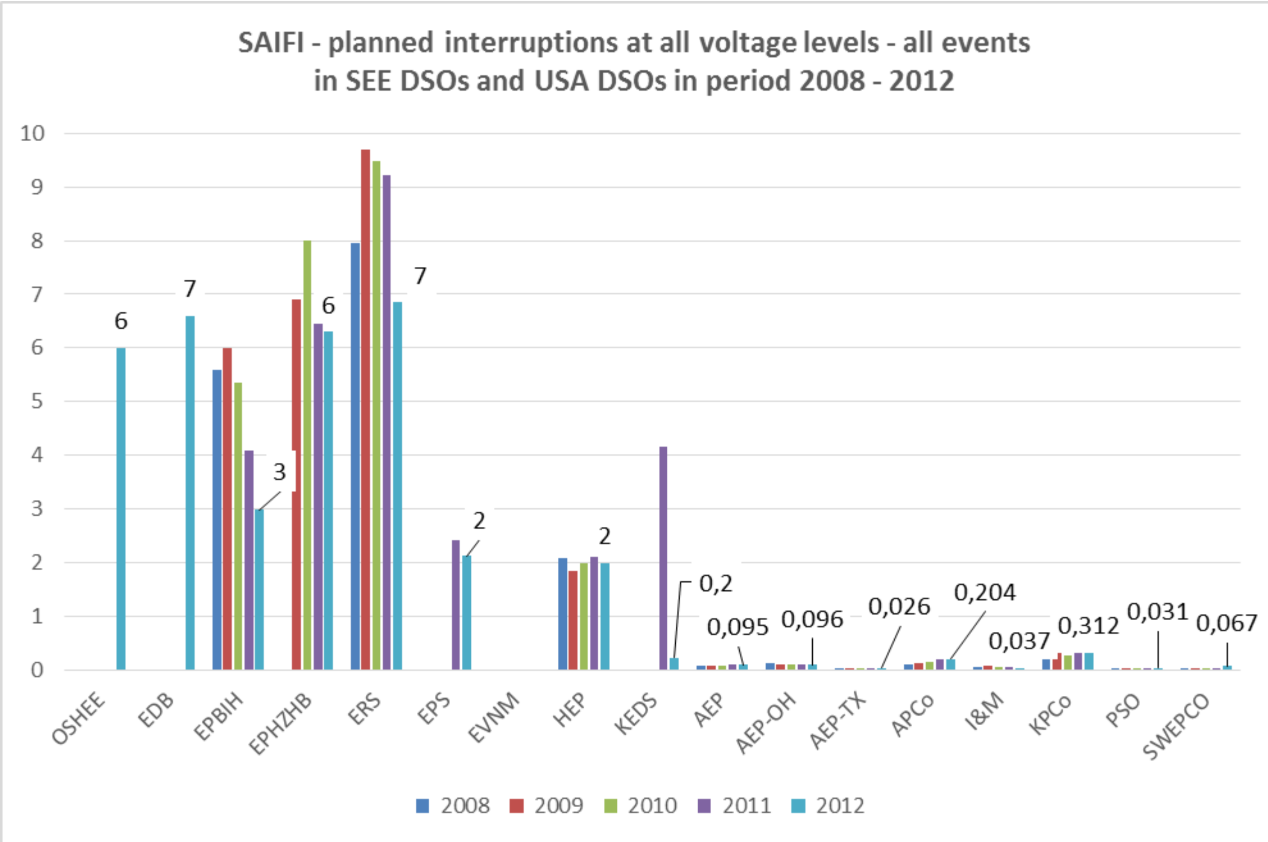


Figure 7.9 SAIFI - planned interruptions at all voltage levels - all events in SEE and US DSOs in the period 2008 - 2012

7.3. NUMBER OF INTERRUPTIONS

A distinction is often made between the types of interruptions, based on their duration (source: CEER - 4th Benchmarking Report on Quality of Electricity Supply, 2008). In most European countries, an interruption is referred to as a “short interruption” if it lasts 3 minutes or less. A long interruption is an interruption that lasts more than 3 minutes. These definitions are in accordance with the European standard EN 501601. The reason for this distinction has to do with the way in which continuity data has traditionally been collected. The event that has traditionally been recorded by the system operator was the manual reconnection of the supply. The start of the interruption, when due to the automatic opening of a piece of switchgear (typically a circuit breaker triggered by a protection relay), was not recorded in some cases, or was recorded only by the data-acquisition system and not included in continuity statistics. Also, the end of the interruption was not recorded if the interrupting device was closed automatically (in practice referred to as “auto-reclosing”). The collection of data for these interruptions requires automatic registration, either of voltages at the customer connection or of switching actions in the network. As the duration of interruptions terminated by auto-reclosing is much shorter than interruptions terminated manually, the former are referred to as “short interruptions”. Apart from the difficulties in recording automatically-terminated interruptions, there are other reasons for treating these interruptions differently. The aim of the auto-reclosing scheme is to prevent customers from experiencing long interruptions with durations of several hours or more. Instead, the customers experience short interruptions, with durations between a few seconds and a few minutes. In many cases, the auto-reclosing scheme is such that the customer experiences more short interruptions with the scheme than long interruptions without the scheme. Traditionally, for many customers, the impact of a 1-minute interruption is negligible or at least, much less than the impact of a 1-hour interruption. The result of the auto-reclosing scheme has therefore traditionally been a reduction of the total inconvenience for customers. Due to a number of developments, beyond the scope of this report, the situation has changed.

However, the impact is strongly dependent on the type of customer, with industrial and commercial customers typically being impacted more than household customers. For a growing number of customers, especially industrial customers, even 1-minute interruptions are of similar concern as a longer interruption. Therefore, the need has arisen for information on the number and duration of short interruptions. In some more developed systems, a further distinction between short interruptions and transient interruptions is made, where the transient interruptions are interruptions of up to a few seconds. The reason for this distinction is partially due to the difference in origin between short and transient interruptions and partly due to the difference of the impact of the interruptions on customers. The impact of transient interruptions is typically less, but in cases of large motor loads a transient interruption may lead to equipment damage when there is insufficient coordination between the motor protection and the auto-reclose scheme. Also, damage to electronic equipment due to transient interruptions has been reported.

For the purpose of this study the data on long unplanned and long planned interruptions were collected both for SEE and US DSOs. The following Figure shows total number of long unplanned interruptions in SEE and US DSOs. Besides already mentioned exceptions (OSHEE, ERS and KEDS), total number of long unplanned interruptions is significantly lower in SEE than in the US DSOs, as expected due to network size. With exception of AEP, the other US DSOs are all below 54.000 long unplanned interruptions.

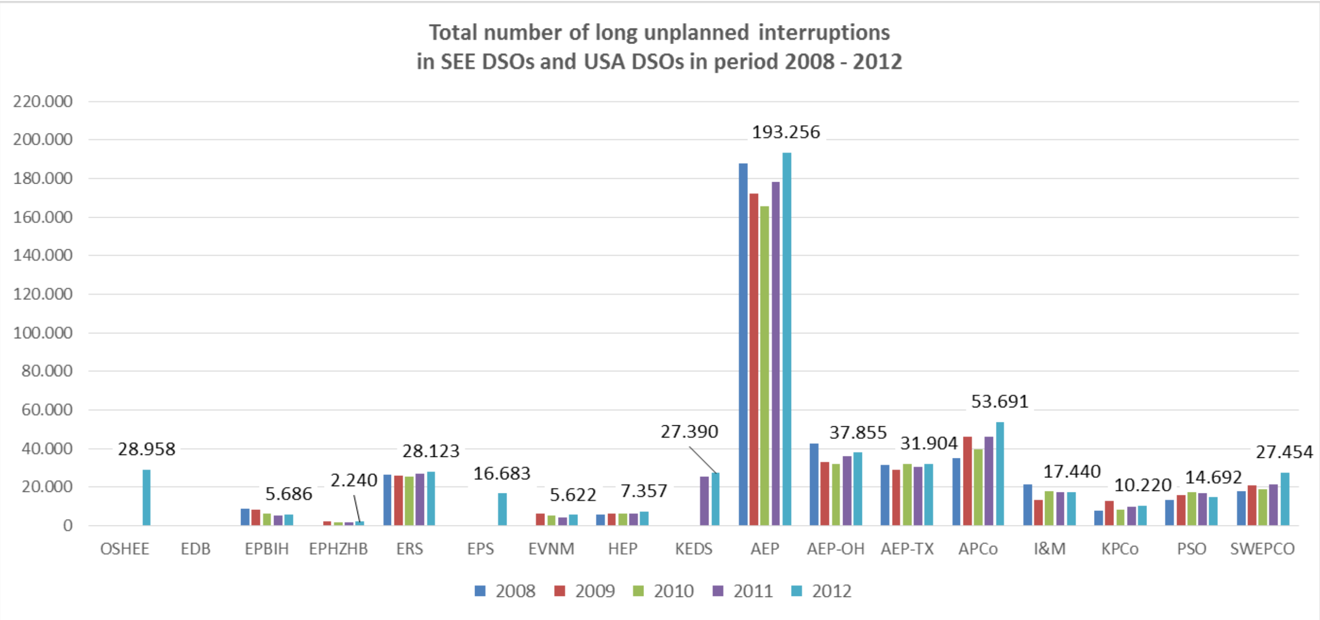


Figure 7.10 Total number of long unplanned interruptions in SEE and US DSOs in the period 2008 - 2012

On the following Figure total number of long planned interruptions are shown. These data are showing large variations between different DSOs, starting from KEDS and EPHZHB in SEE and SWEPCO in the US with small number of long planned interruptions (<1.000) up to HEP and EPS in SEE and AEP in the US with large number of long planned interruptions (>10.000). In general, it can be concluded that there are no regional specificities that would explain differences in number of long planned interruptions in SEE and the US.

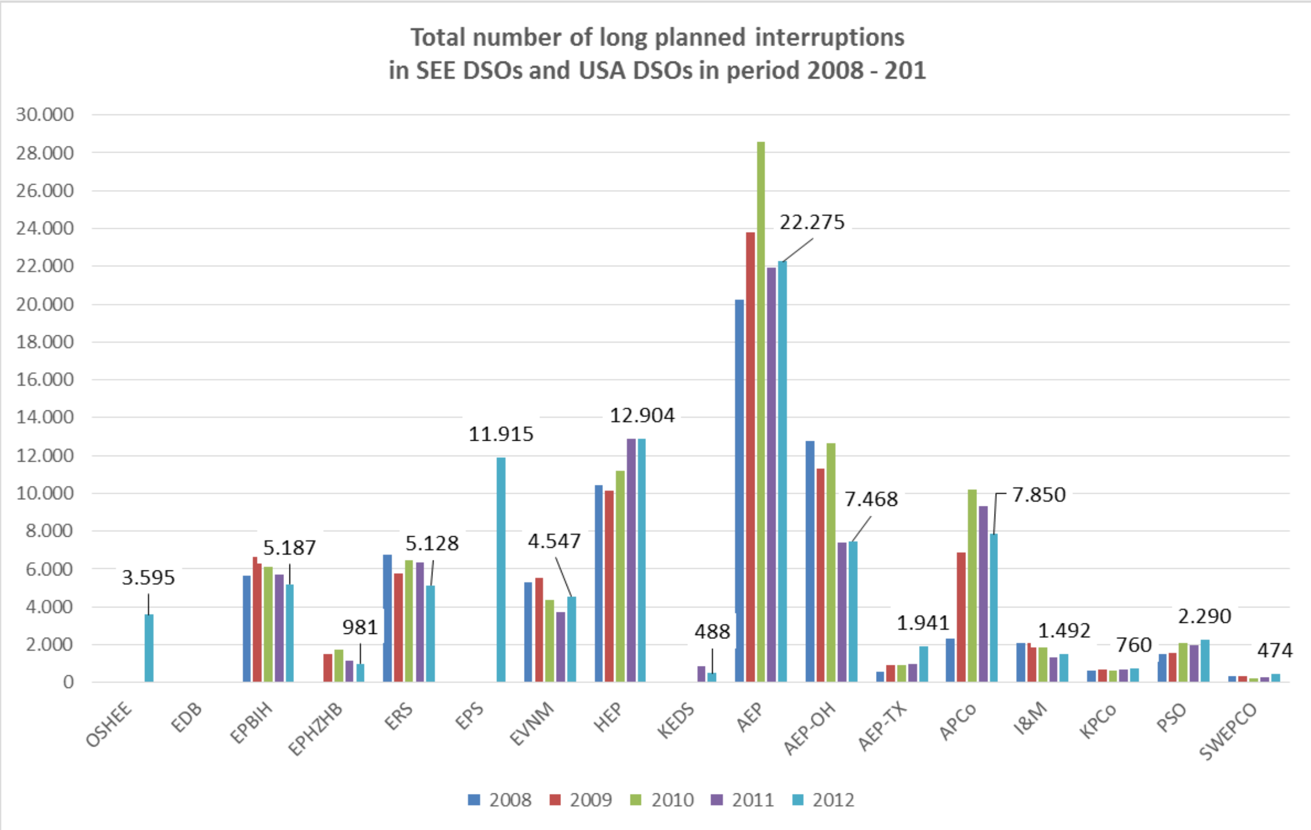


Figure 7.11 Total number of long planned interruptions in SEE and US DSOs in the period 2008 - 2012

7.4. SHARE OF PLANNED TO TOTAL INTERRUPTIONS

Finally, it is interesting to analyze the share of planned in total number of interruptions. The following Figure show some kind of structural difference between SEE and the US DSOs. In SEE DSOs share of planned in total number of interruptions is predominately higher than 30%, with the exception of ERS (~15,4 %), OSHEE (~11 %) and KEDS (~1,8 %), while in US DSOs all values are below 20 % (only exception is AEP-OH with 28,3 % in 2010).

These values again prove that the maintenance and other planned interruptions are performed in different way in the US and SEE DSOs. Differences mainly refer to “live working” (i.e. work on the equipment without its disconnection). This could be one of the areas in which SEE DSOs could analyze and take over US practice and experience in order to reduce number and duration of planned interruptions.

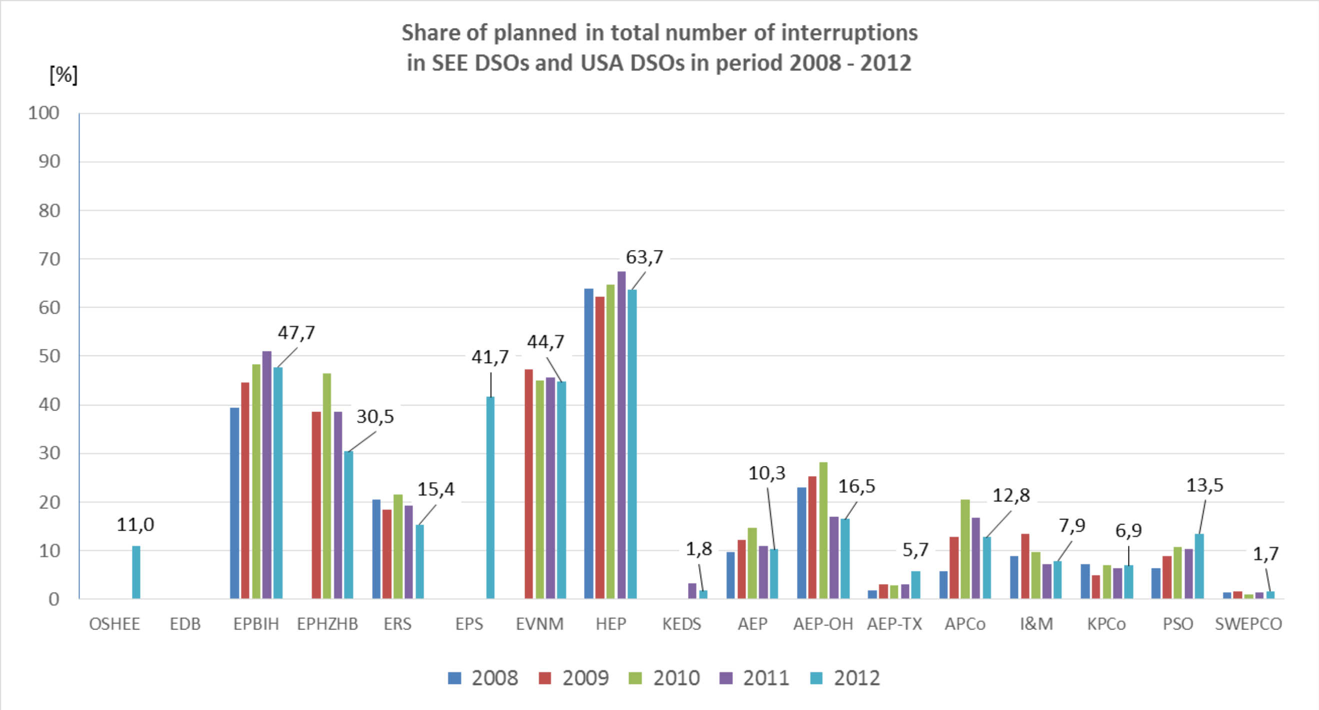


Figure 7.12 Share of planned in total number of interruptions in SEE and US DSOs in the period 2008 – 2012

8. METERS

The customer meter is a critical resource for DSO as it enables both internal accounting of losses on the distribution system and proper accounting of sales to customers. Installation of meters at all customer sites is basic prerequisite for effective tariff development and progress toward financial sustainability for DSOs. Malfunctioning and tempered meters are also common problems that cause inaccurate sales recognition and insufficient revenue collection.

The proposed benchmarking measures in this report are intended to evaluate issues of metering accuracy, precision, extent that different types of meters and reading tools are used to measure electricity consumption (i.e. smart meters, electronic/digital meters, electromechanical meters), meters age, etc.

8.1. METERING COVERAGE

In some countries worldwide there are specific customer classes that are allowed connections without meters. In the observed region the latter applies only to Albanian OSHEE. Figure 8.1 depicts number of connection points with metering intentionally omitted for different LV consumption categories in the 2008-2012 period. In OSHEE connection points with metering intentionally omitted are present in 3 LV consumption categories: households, commercial customers without peak power registration and public lighting. Their shares in the total number of customers are almost negligible: 0,16 % for households, 0,22 % for commercial customers without peak power registration and 0,53 % for public lighting. Besides, continuous declining trend in number of connection points with metering intentionally omitted could be observed over 2008-2012 period.

The metering coverage is expresses as the number of connection points equipped with meters per customer (Figure 8.2). It is separately analyzed for MV and LV level customers. It could be observed that only for KEDS on MV there is a considerable number of metering points per customer (on average 34,6 metering points per MV customer). On LV level in almost all DSOs customers have one metering point (there is a slight difference in case of HEP where average number of metering points per LV customer equals 1,27).

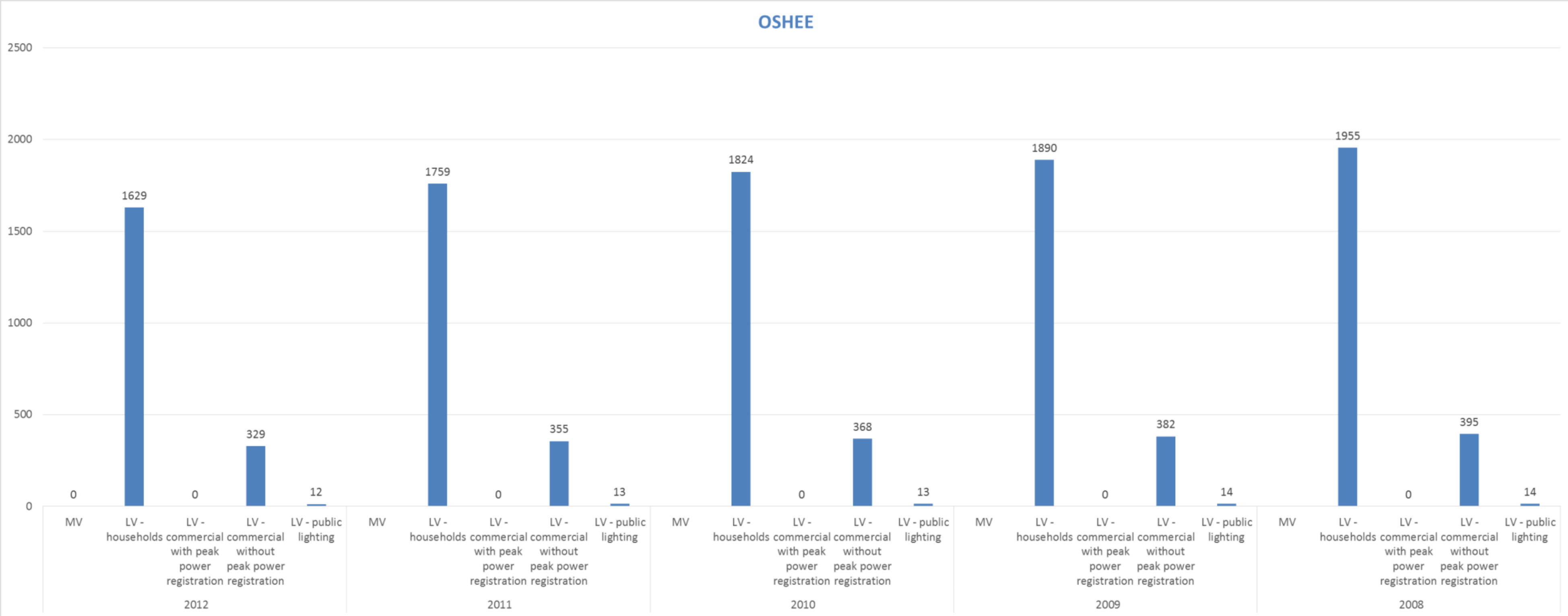


Figure 8.1 Number of connection points with metering intentionally omitted - Albanian OSHEE

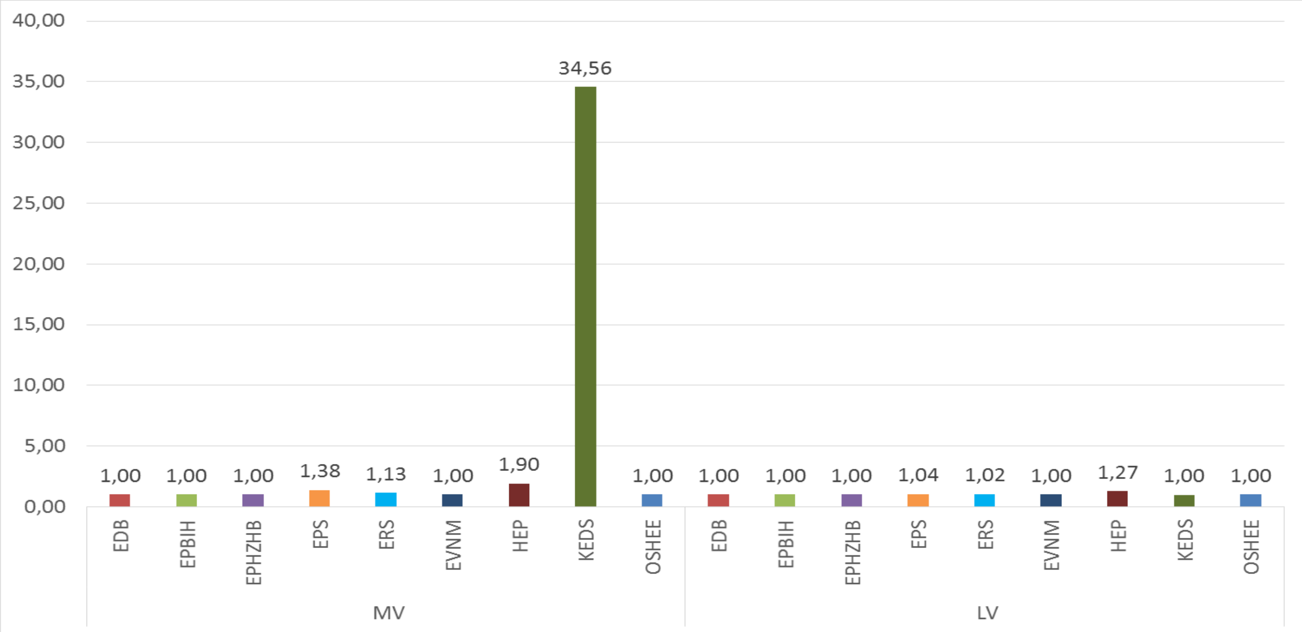


Figure 8.2 Number of metering points per customer on MV and LV level in 2012

8.2. METER TYPES AND METER READING

This section grasps meter types (electromechanical, electronic and smart meter) and meter reading approaches (manual, automatic meter reading, remotely) applied in the observed DSOs. It is necessary to point out that data on the number of meters provided in this section are related to the current situation (presumably second half of 2013). In this sense it does not necessarily match number of meters from the metering set of data. This difference is noticeable for Albanian OSHEE and Kosovo KEDS DSOs; DSOs with high level of electricity losses.

A smart meter is an electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information back to the utility for monitoring and billing purposes. Smart meters enable two-way communication between the meter and the central system. Such an advanced metering infrastructure (AMI) differs from traditional automatic meter reading (AMR) in that it enables two-way communications with the meter.

On MV (Figure 8.3) in 6 out of 9 DSOs (KEDS, HEP, EVNM, EPS, EPHZHB, EPBIH) share of smart meters exceeds 50 %. In Albanian OSHEE on MV prevail electronic meters with automatic reading using terminals (87,3 %), while in ERS and EDB on MV prevail electronic meters with manual reading (Figure 8.4). Electromechanical meters on MV are present in 4 DSOs: KEDS, EPS, EDB and OSHEE (Figure 8.3). Remote reading of MV customers prevails in 5 out of 9 DSOs: KEDS, HEP, EVNM, EPHZHB and EPBIH. In EPS and OSHEE on MV prevails automatic reading using terminal, while in ERS and EDB manual reading.

At LV households (Figure 8.5) dominate electromechanical meters. Exception is EVNM where prevail electronic meters. With regard of meter readings (Figure 8.6), manual reading prevails at 6 DSOs:

KEDS, ERS, EPHZHB, EPBIH, EDB and OSHEE. In HEP and EPS (two largest DSOs in the region) and EVNM dominate automatic readings using terminal.
For LV public lighting (Figure 8.7) in 6 out of 9 DSOs the most common type of electricity meter is the electromechanical: KEDS, HEP, ERS, EPS, EPHZHB and EPBIH. In EVNM and EDB prevail electronic meters. Figure 8.8 depicts meter reading approaches used for LV public lighting. In most of DSOs (5 out of 9) prevail manual readings. In HEP, EVNM and EPS prevail automatic readings using terminal.

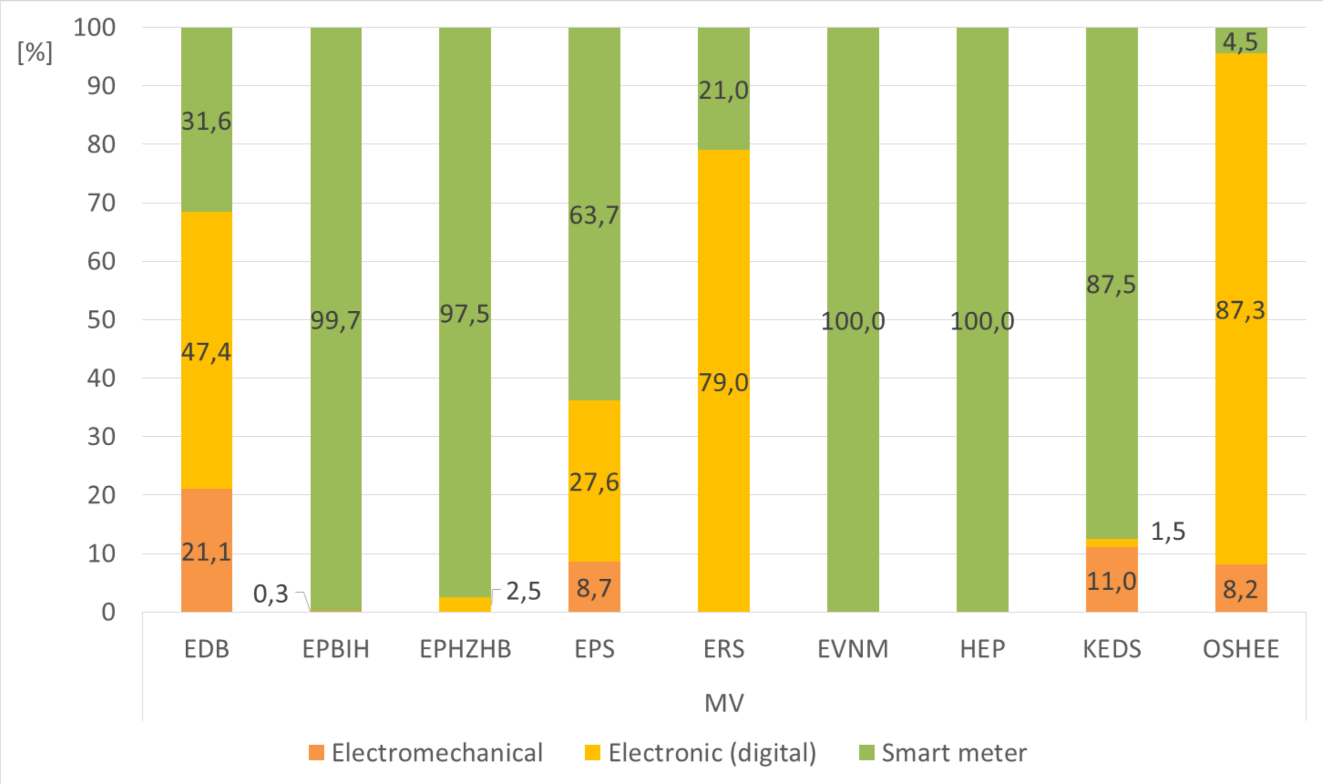


Figure 8.3 Share of different meter types - MV customers (2012.)

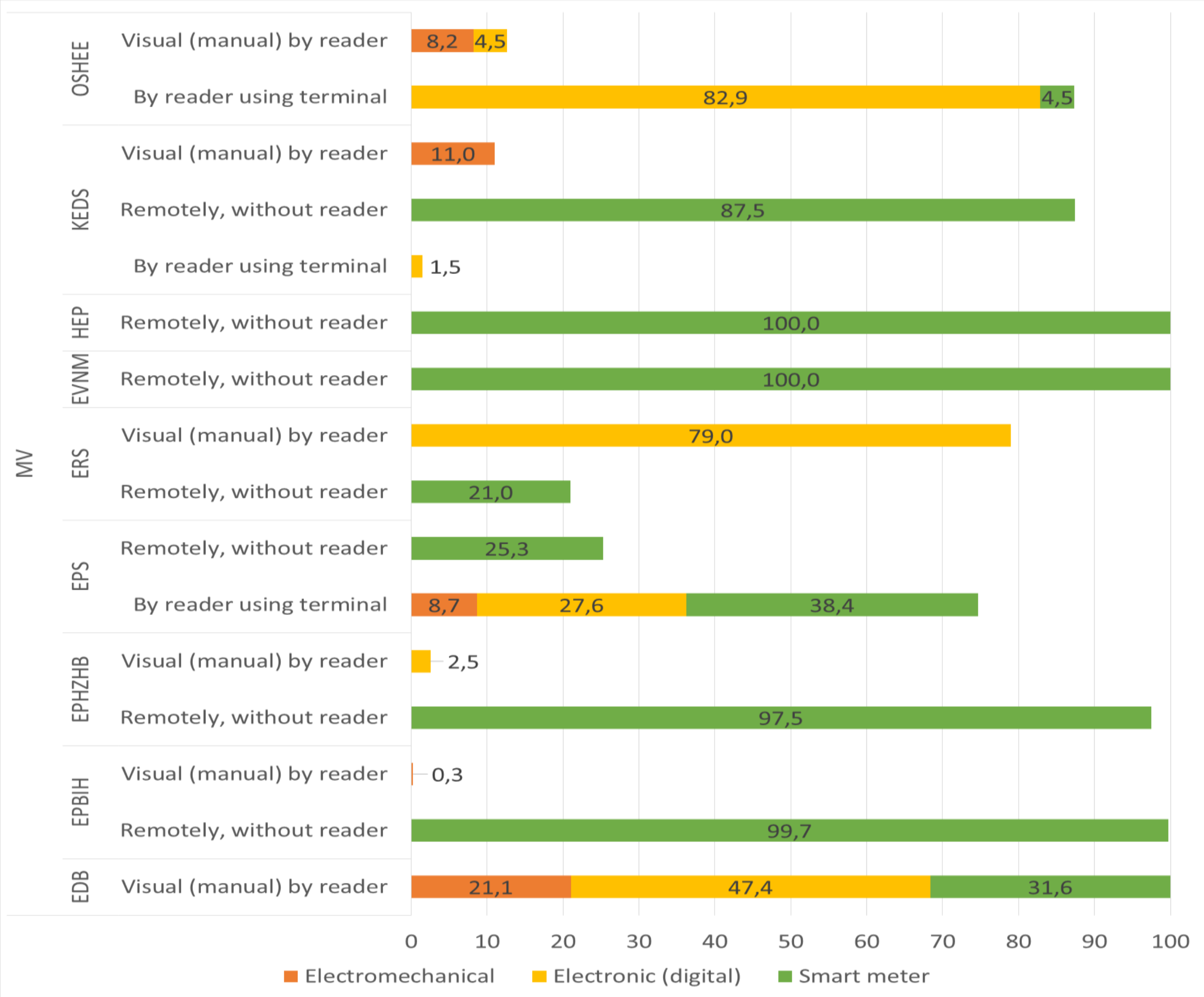


Figure 8.4 Share of different meter types and readings [%] - MV customers (2012.)

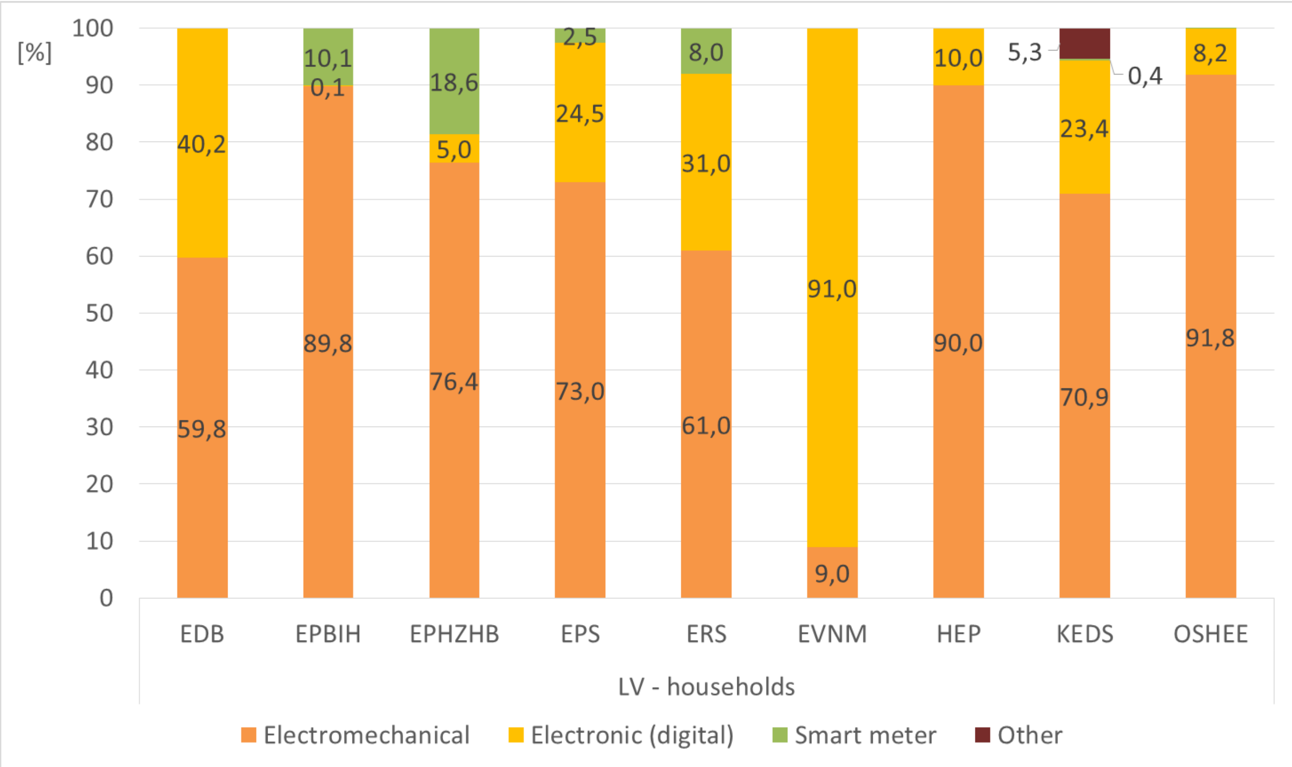


Figure 8.5 Share of different meter types - LV households (2012.)

Figure 8.6 Share of different meter types and meter readings [%] - LV households (2012.)

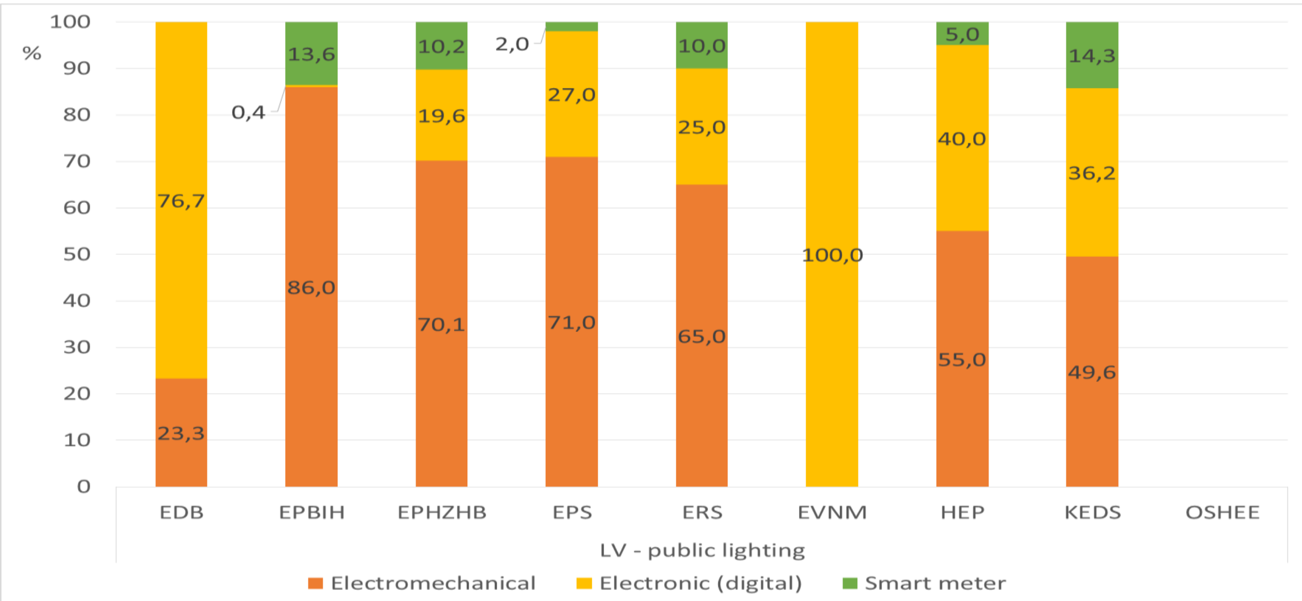


Figure 8.7 Share of different meter types - LV public lighting (2012.)

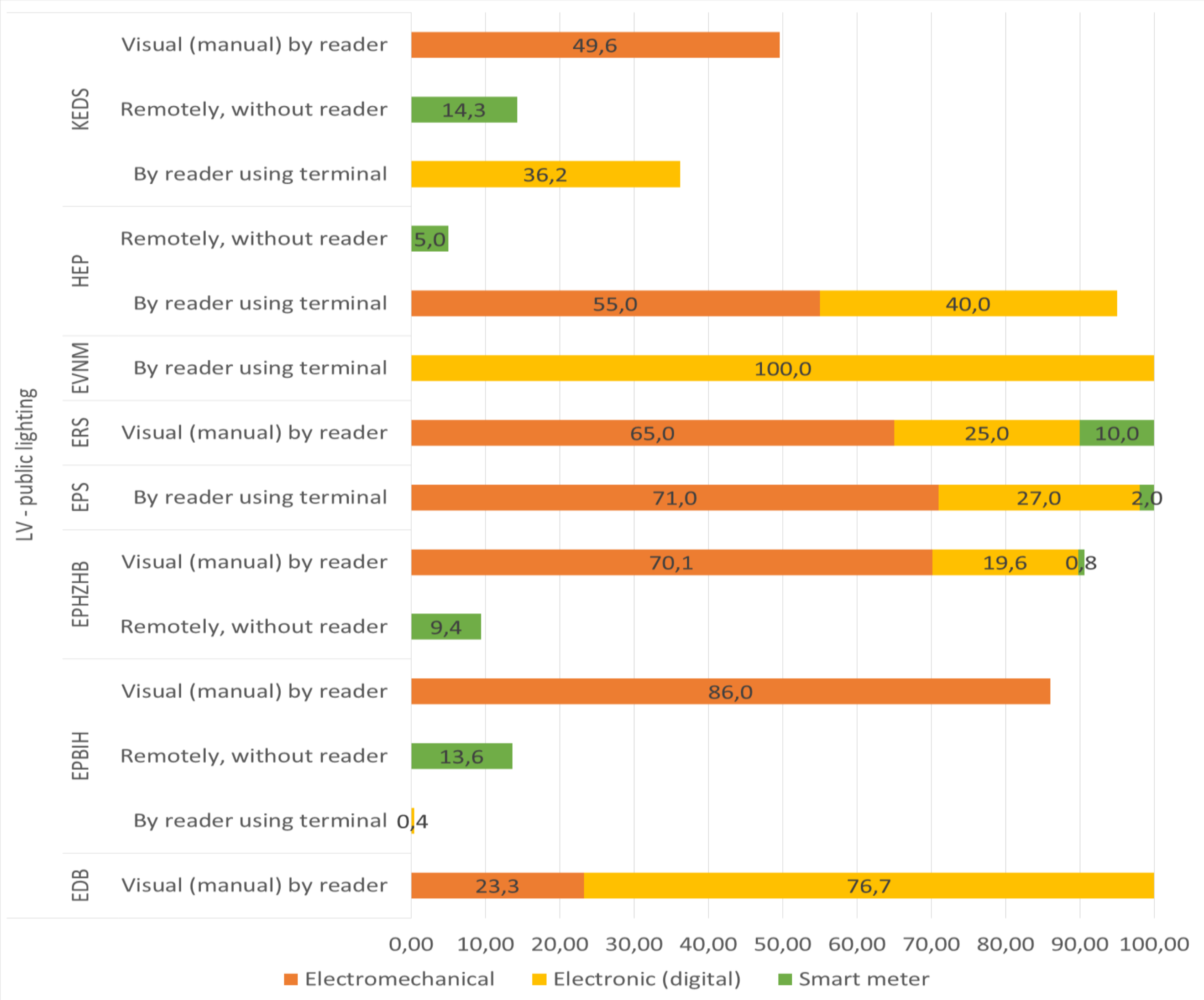


Figure 8.8 Share of different meter types and meter readings [%] - LV public lighting (2012.)

For LV commercial customers with peak power (demand) registration common types of electricity meters differ. In 4 DSOs the most common type of electricity meter is smart meter (KEDS, HEP, EPHZHB, EPBIH). In other 4 DSOs it is the electronic meter: EVNM, ERS, EPS, EDB. While in Albanian OSHEE electromechanical meter is exclusively used.

The most of LV commercial customers with peak power (demand) registration are read remotely (in 5 DSOs: KEDS, HEP, EPHZHB, EPBIH, EVNM). In 2 DSOs (ERS and EDB) prevail visual (manual) readings, while in other 2 DSOs (EPS, OSHEE) prevail automatic readings using terminals.

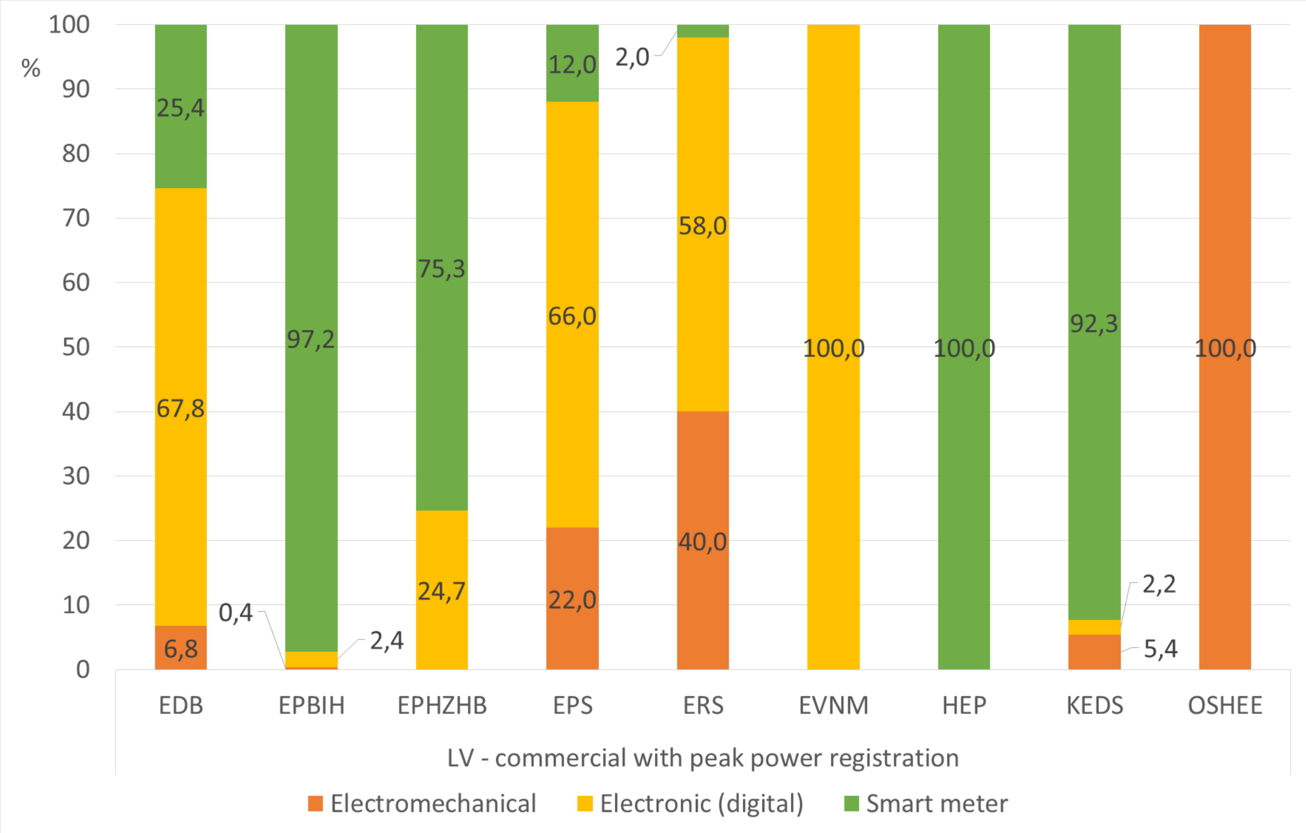


Figure 8.9 Share of different meter types - LV commercial customers with peak power registration (2012.)

Figure 8.10 Share of different meter types and meter readings [%] -
LV commercial customers with peak power registration (2012.)

For LV commercial customers without peak power (demand) registration common types of electricity meters differ. Electronic and electromechanical meters are nearly equally present in 4 DSOs: HEP, ERS, EPS, EDB. While smart and electromechanical meters are almost equally present in EPHZHB. In 3 DSOs prevail electromechanical meters: KEDS, EPBIH and OSHEE. In EVNM prevail electronic meters.

The most LV commercial customers without peak power (demand) registration are read manually (in 6 DSOs: KEDS, EPBIH, OSHEE, ERS, EDB, EPHZHB). In 3 DSOs (HEP, EVNM, EPS) prevail automatic readings using terminals. In EPHZHB smart meters (their share equals nearly 30%) are read remotely.

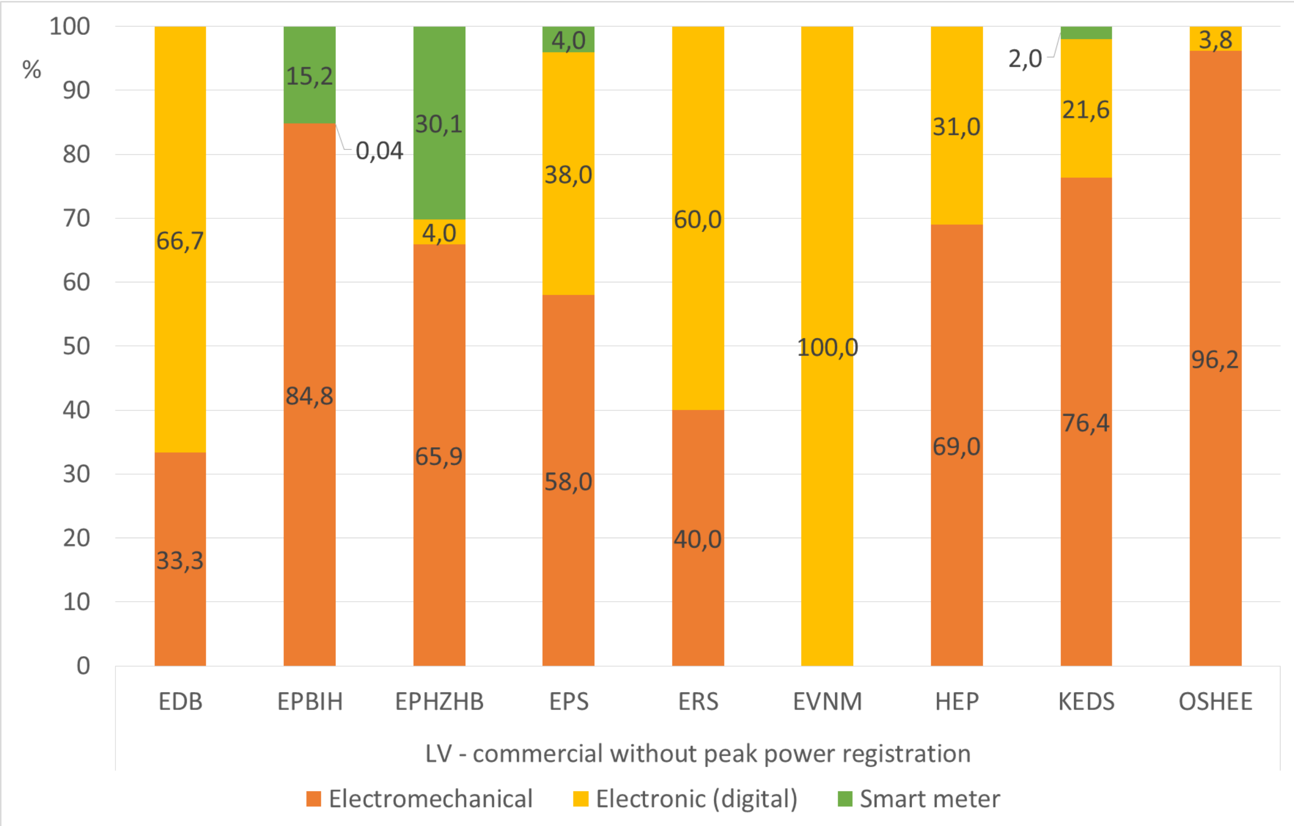


Figure 8.11 Share of different meter types - LV commercial customers without peak power registration (2012.)

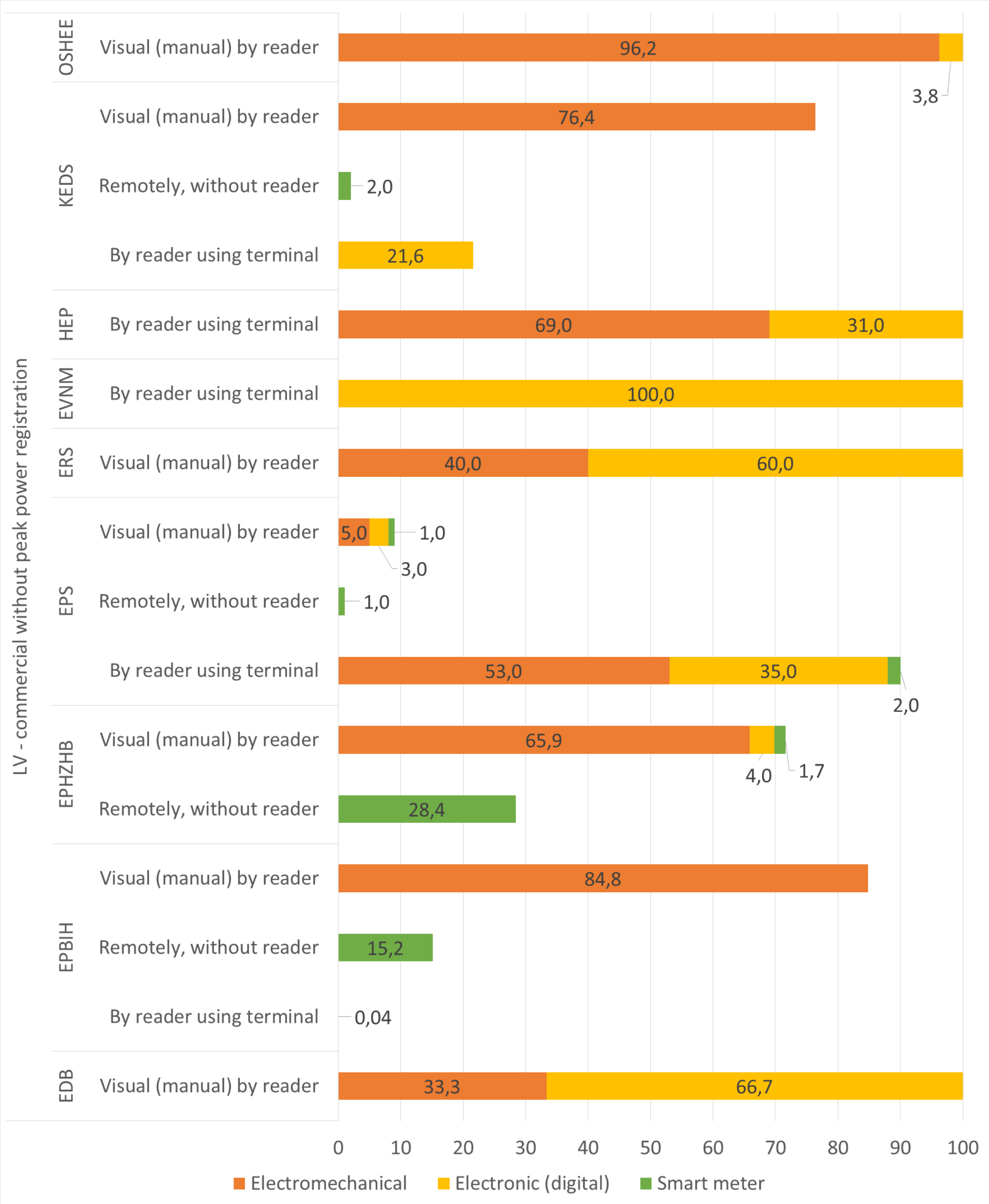


Figure 8.12 Share of different meter types and meter readings [%] - LV commercial customers without peak power registration (2012.)

8.3. AVERAGE AGE OF METERS

Average age of meters is intended as an approximate indicator of meter accuracy.

It must be stated that the report lacks the data from ERS (for all meters). Besides, the report lacks the data on HEP electromechanical meters average age (i.e. 2,04 mil. meters or 87% of all LV meters in HEP). This should be taken into account when evaluating data on average ages of LV meters for households (21,6 yrs, Figure 8.20), commercial LV customers without peak power registration (18,9 yrs, Figure 8.20), and also average age of all LV meters (21,1 yrs, Figure 8.18).

Figure 8.13 depicts average age of meters for MV customers. As might be expected, in all DSOs electromechanical meters are the oldest (10-25 years old). Electronic meters are aged between 5 to 12 years. Smart meters are the youngest; aged between 3 and 5 years. Average age of all MV meters in SEE DSOs equals 5,7 years (this is due to the fact that 63% of MV meters are smart meters and 32% electronic).

Figure 8.15, Figure 8.16 and Figure 8.17 contain average age of meters for different LV consumption categories and meter types. In all DSOs electromechanical meters are the oldest (5-30 years old), followed by electronic (1-20 years old) and the youngest smart meters (3-10 years old). On average, LV electromechanical meters are 26,2 years old, LV electronic meters are 11,8 years old and LV smart meters 5,6 years old (Figure 8.14). Figure 8.21 gives average age of LV meters by type and consumption category.

Average age of all LV meters in SEE DSOs equals 21,1 years (Figure 8.18). At LV level Macedonian EVNM has the youngest meters and Serbian EPS has the oldest (Figure 8.18). In Serbian EPS in all LV consumption categories electromechanical meters are older than 27 years (Figure 8.15), electronic over 14 years (Figure 8.16) and smart meters over 8 years (Figure 8.17); on average 30 years, 19,4 years and 8 years respectively (Figure 8.19).

On average, meters in households category are 21,6 years old, in public lighting category 17,2 years old, and in commercial with and without peak power registration 13,6 and 18,9 years old respectively (Figure 8.20).

Here it must be mentioned that KEDS have indicated in theirs reports that LV electromechanical meters are over 10 years old, therefore “10” given in figures (e.g. Figure 8.15) should be regarded as lower age limit.

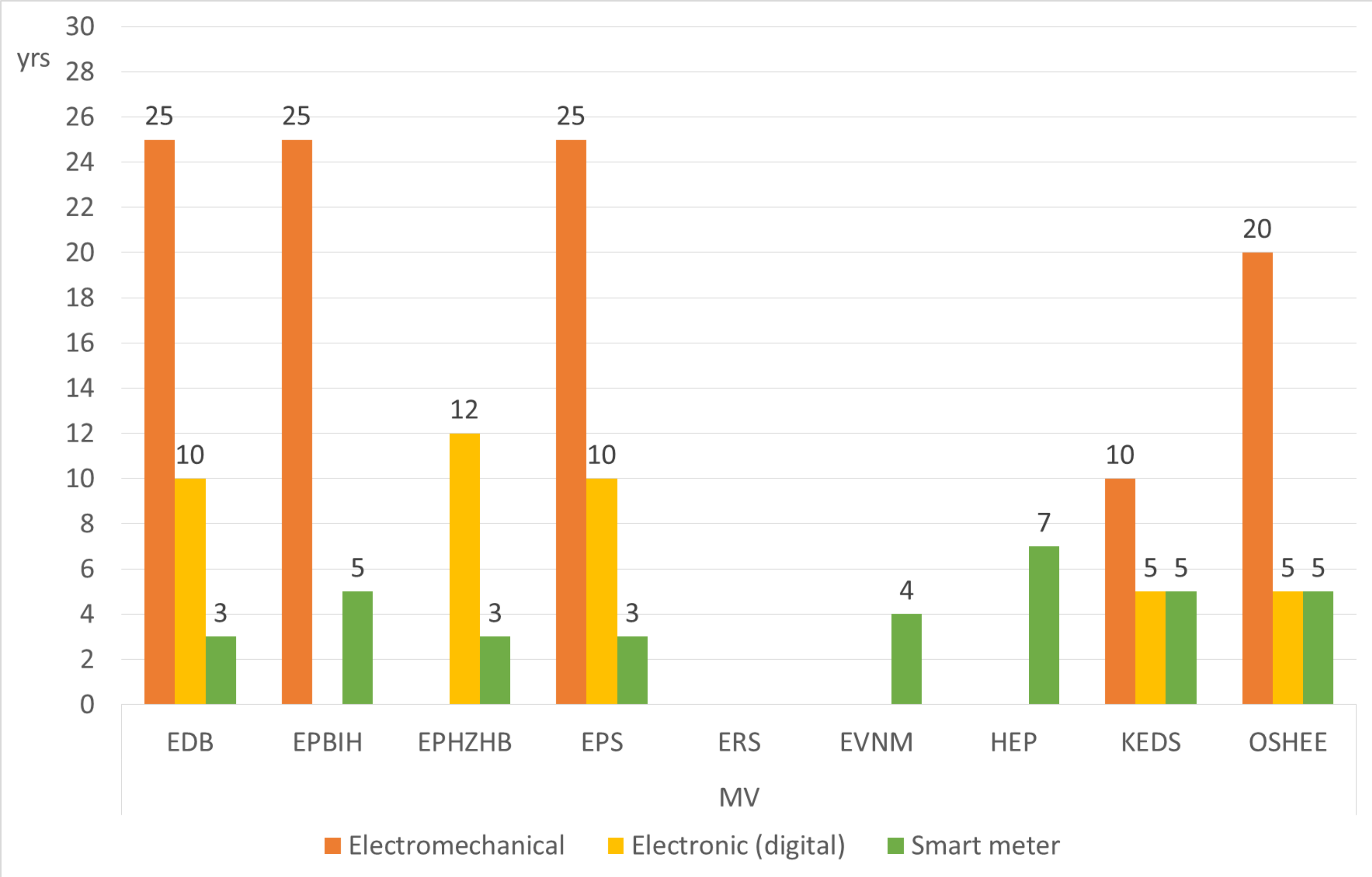


Figure 8.13 Average age by type of meter for MV customers in SEE DSOs

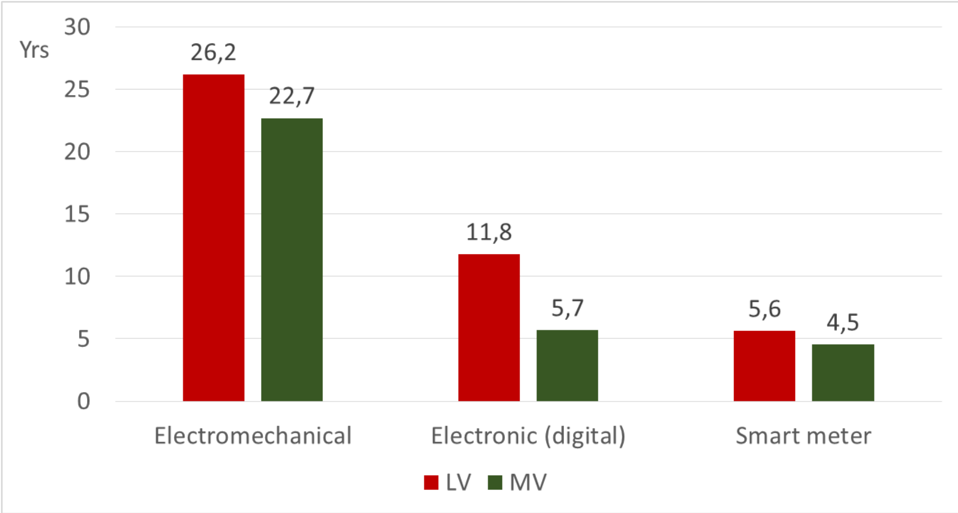


Figure 8.14 Average age of MV and LV meters by type – for all DSOs

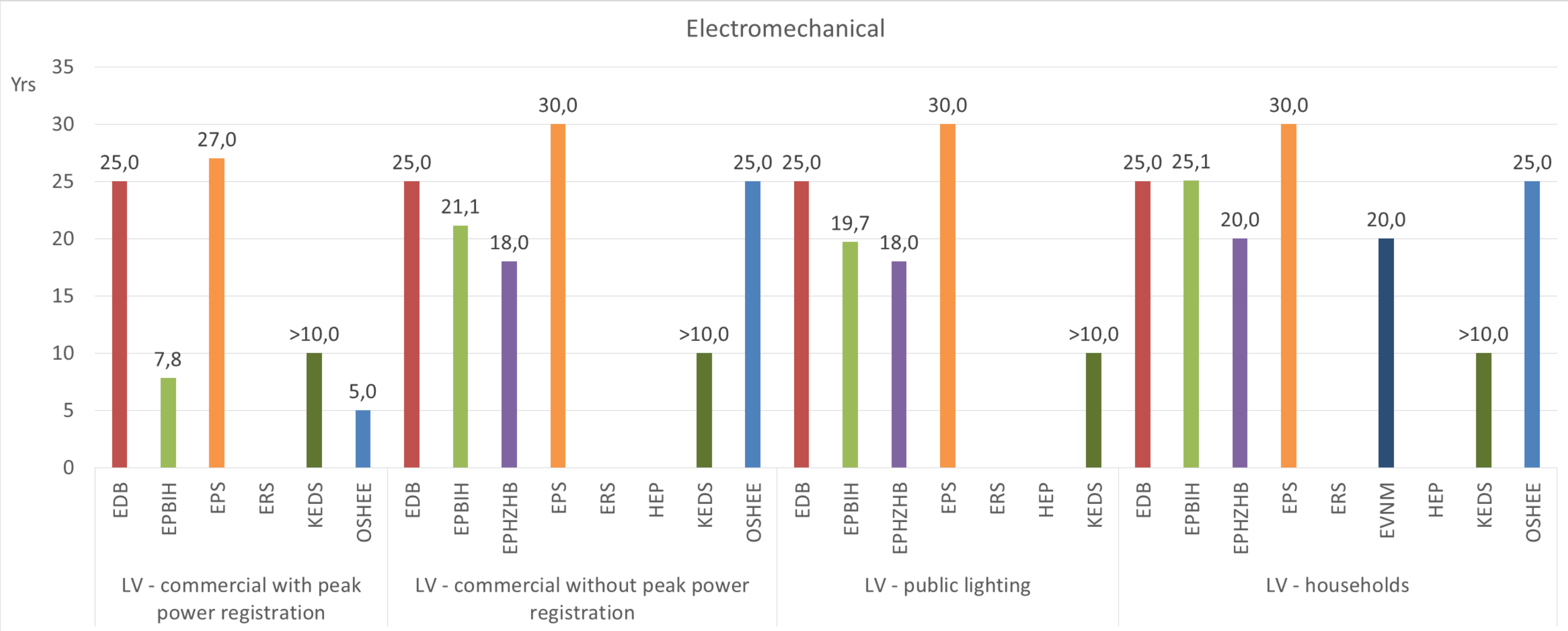


Figure 8.15 Average age of electromechanical meters at LV customers

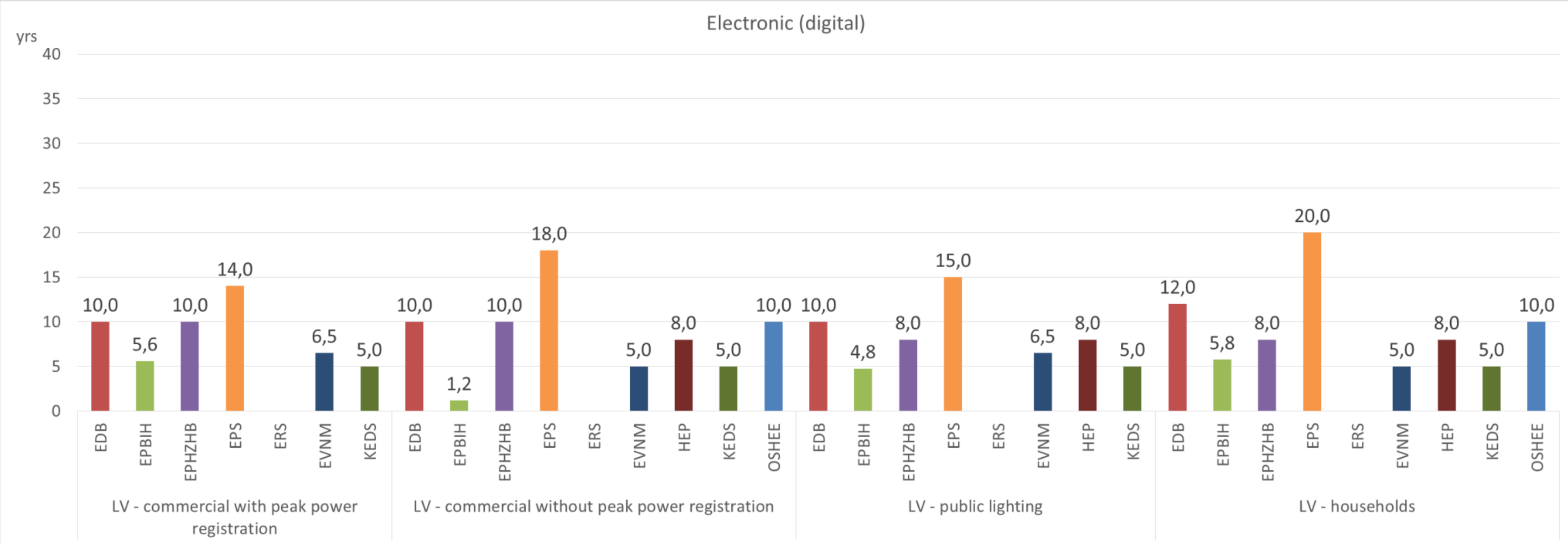


Figure 8.16 Average age of electronic meters at LV customers

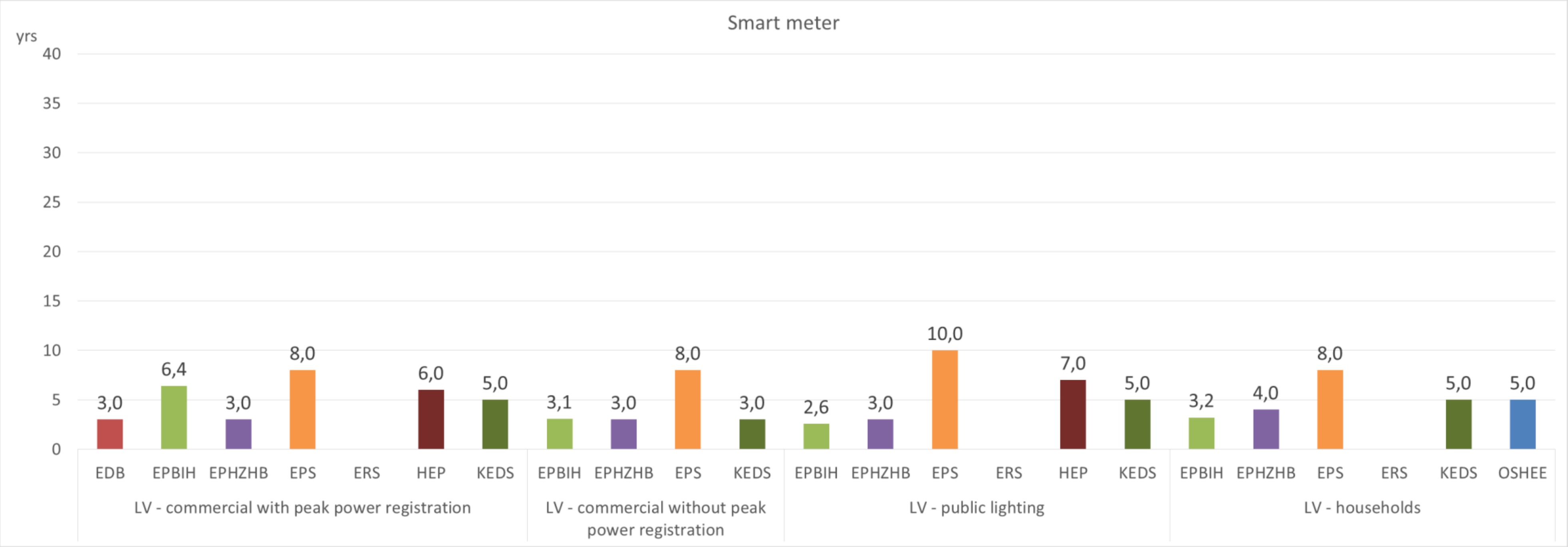


Figure 8.17 Average age of smart meters for LV customers

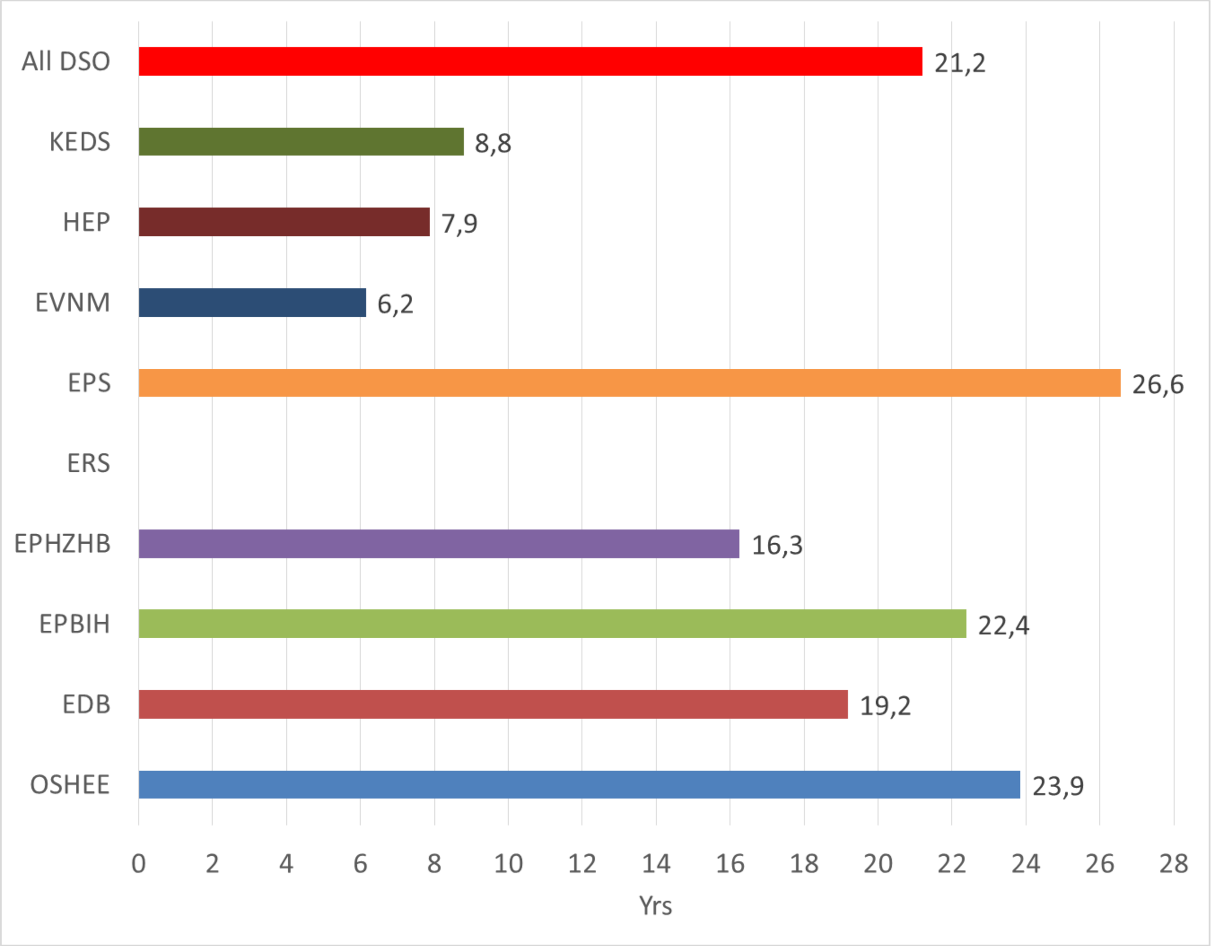


Figure 8.18 Average age of meters for LV customers in SEE DSOs

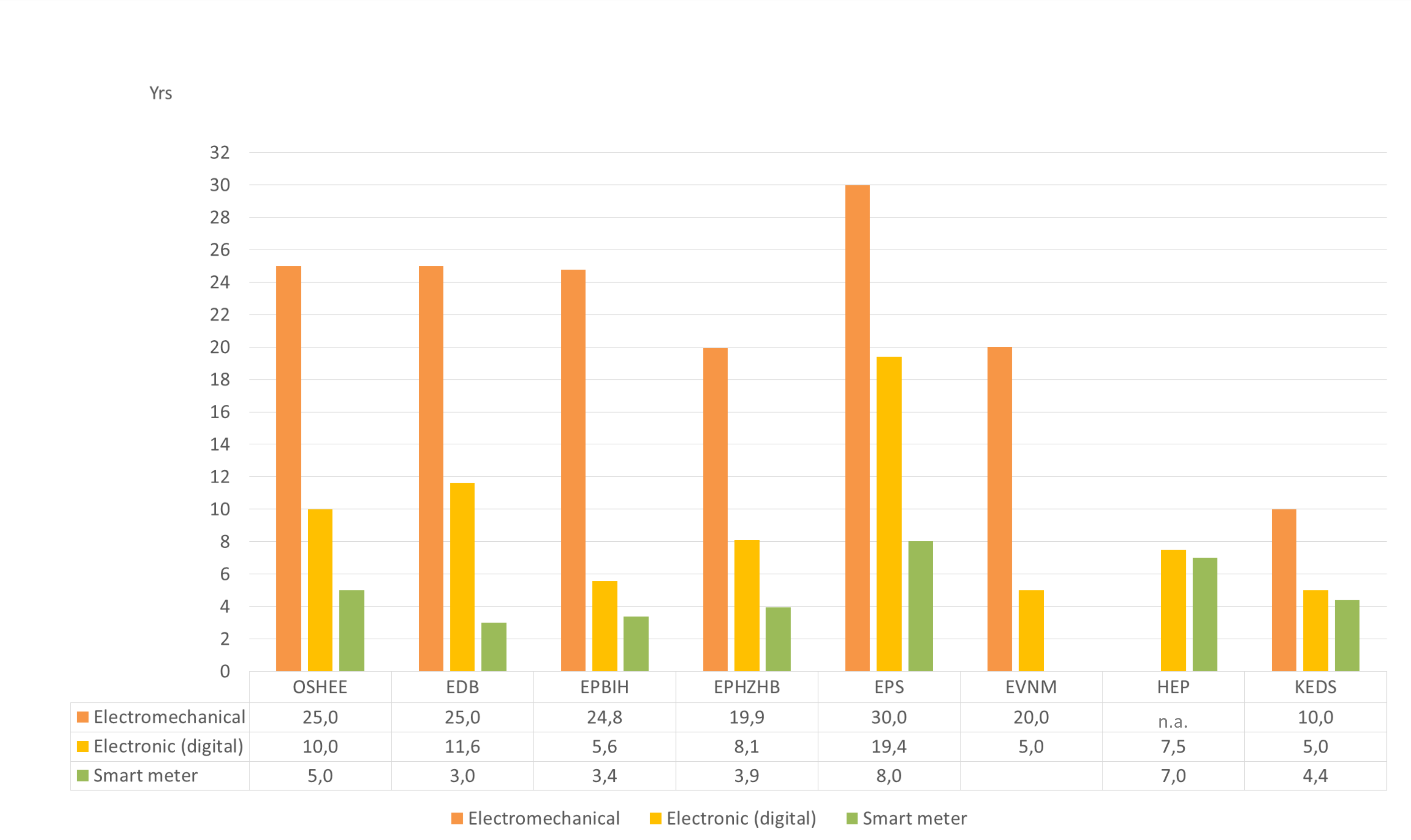


Figure 8.19 Average age of meters at LV customers by type in SEE DSOs

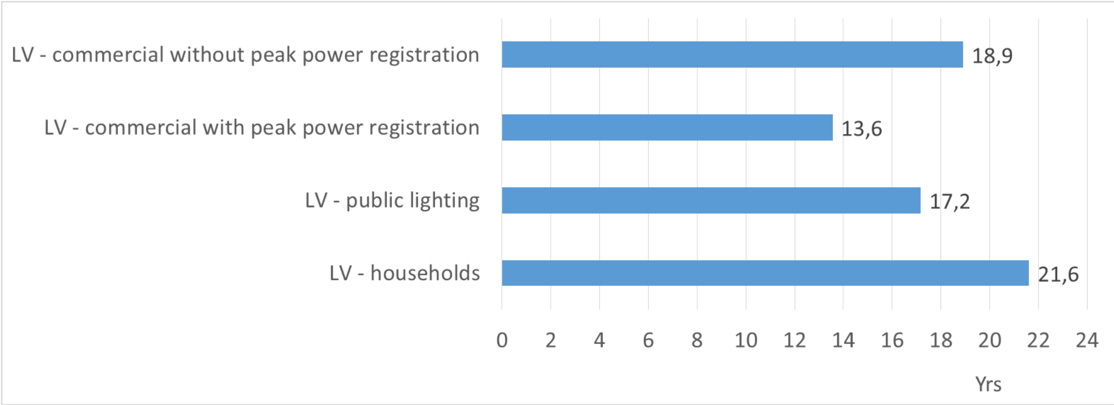


Figure 8.20 Average age of meters by LV consumption category

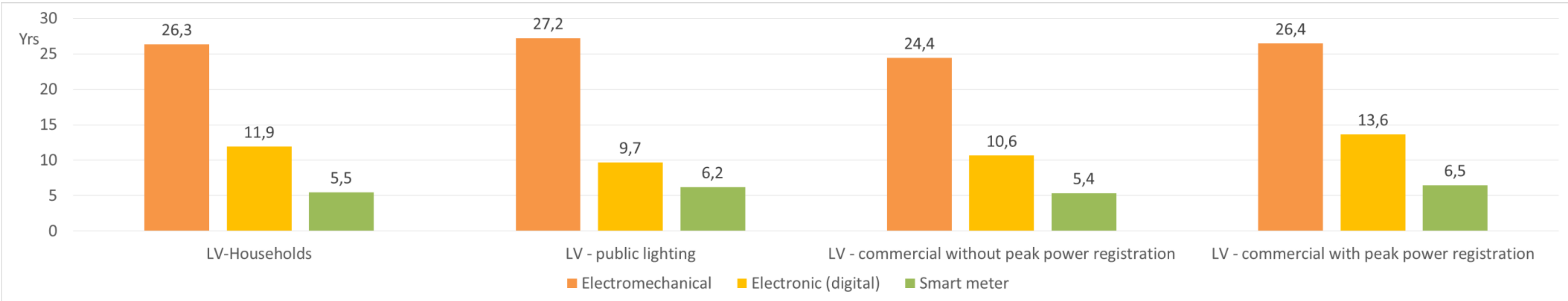


Figure 8.21 Average age of LV meters by consumption category and type

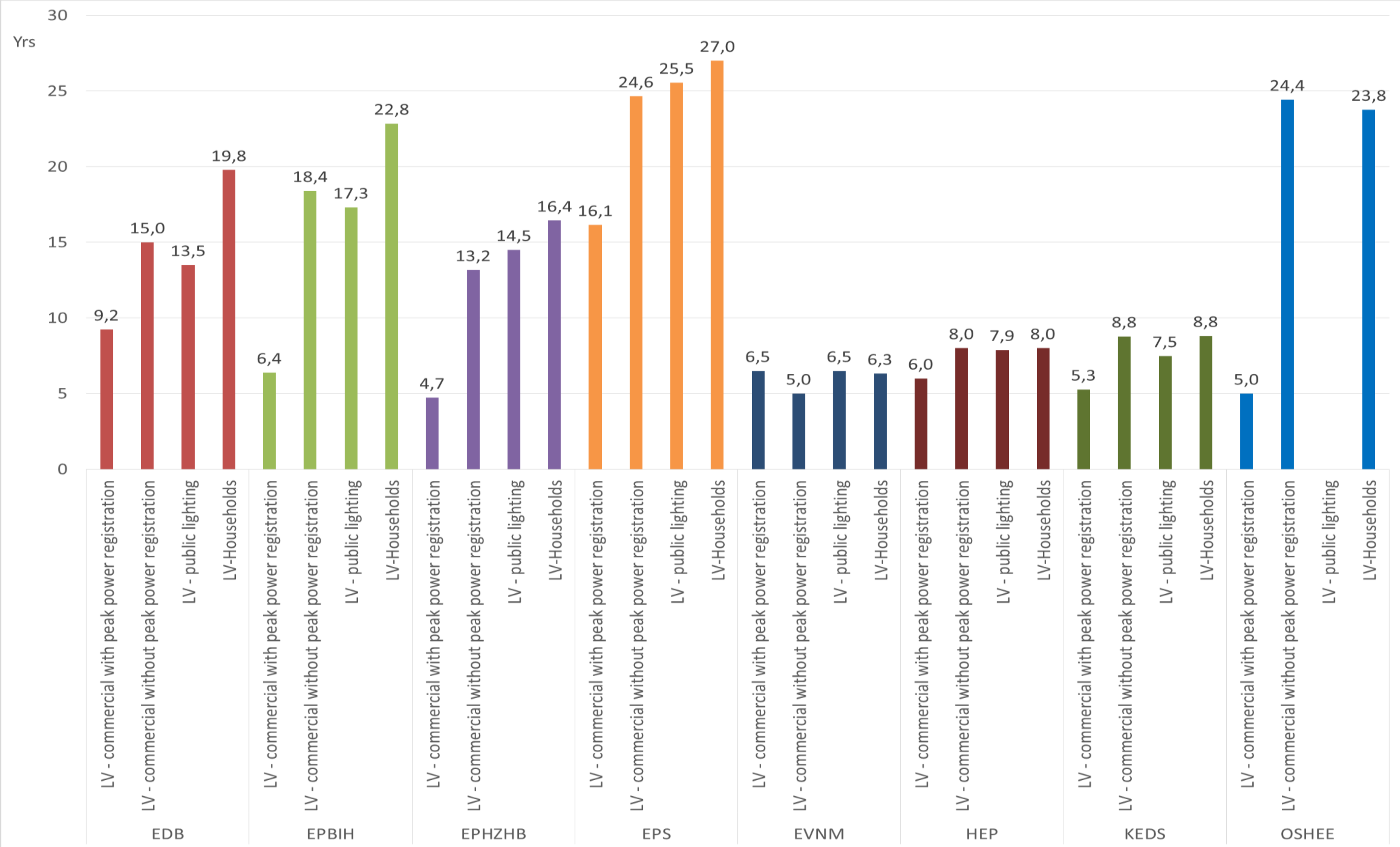


Figure 8.22 Average age of meters for LV customers – per category and DSO

8.4. METER REPLACEMENT RATE

This measure is expressed as the number of meters replaced by a specific type of meters in a year as a portion of the total meters in service in some consumption category.

When analyzing meter replacement data it should be taken into account that:

- OSHEE did not provide data,
- ERS provided lump sum data for all meters on MV and LV voltage level respectively (i.e. 3 % meter replacement rate on MV for all meter types and 1 % meter replacement rate on LV for all meter types and consumption categories),
- ERS also indicated that DSO planned to replace 3,3 % of existing meters in 2012 (which is considerably higher than indicated 1 % realized meter replacement rate on LV),
- EPHZHB provided lump sum replacement rate data for all meters (on MV and LV level) being 3,3%,
- EDB provided lump sum replacement rate data for MV meters 16%,
- this year EPBIH planned to replace all electromechanical meters on MV level (their share on MV equals 0,3%) by smart meters.

Figure 8.23 depicts yearly replacement rate of smart meters in MV and LV network, Figure 8.24 depicts yearly replacement rate of electronic meters in MV and LV network and Figure 8.25 depicts yearly replacement rate of electromechanical meters in MV and LV network.

It could be observed that the largest replacement rate of smart meters on MV level is inherent in EVNM (11%). Here it must be observed that the latter conclusion does not take into account EDB since it provided lump sum data for all meters (meter types) on MV level.

On LV level the largest replacement rate of smart meters is inherent in in the smallest DSO EDB (13,3 %).

For electronic meters the largest replacement rate is present in EDB (for MV customers) and in EVNM (for LV customers).

For electromechanical meters the largest replacement rate is present in EDB (for MV and LV commercial customers) and in KEDS (for LV households and public lighting).

It must be observed that although EDB has high replacement rates in MV and LV commercial categories, number of respective customers in EDB is very low; i.e. 19 MV and 3.819 LV commercial customers (0,4 % of number of MV and LV commercial metering points in the region).

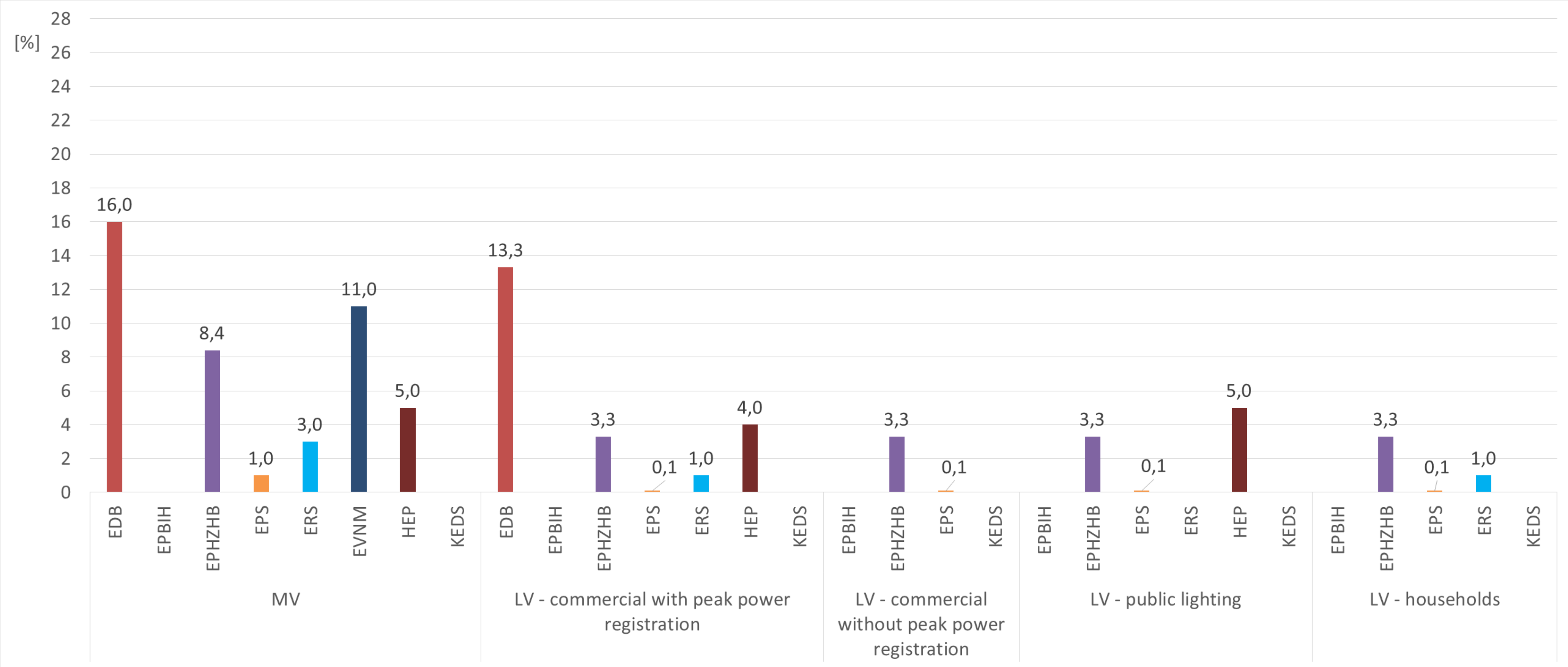


Figure 8.23 Smart meter replacement rate (MV and LV customers)

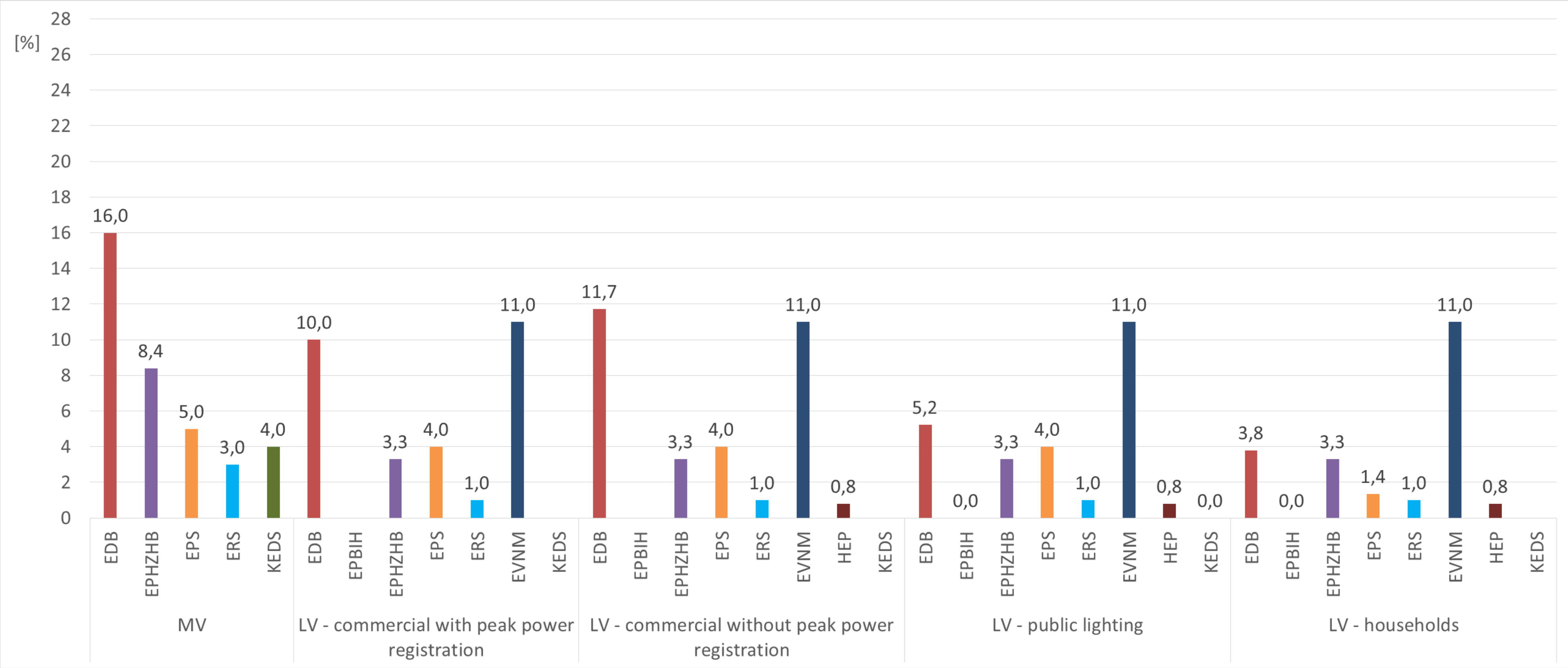


Figure 8.24 Electronic meter replacement rate (MV and LV customers)

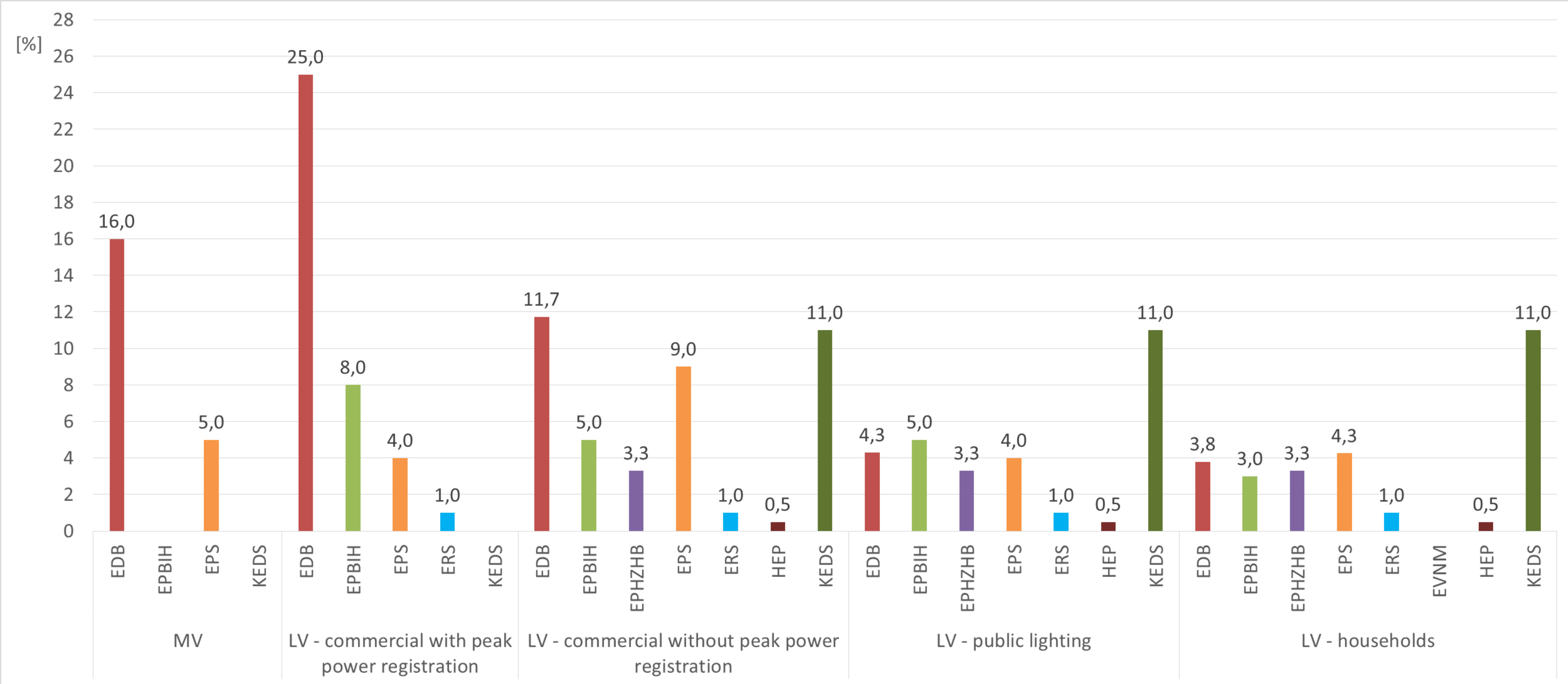


Figure 8.25 Electromechanical meter replacement rate (MV and LV customers)

8.5. INSTALLATION OF NEW METERS

Table 8-1 provides number of new meters installed in 2012, either at new customers premises or by replacing meter at existing customers premises. It could be observed that DSOs are installing either electronic (digital) or smart meters. Electronic meters are used for LV customers with lower electricity consumption (e.g. households, commercial customers without peak power registration), whereas smart meters for MV and LV customers with higher yearly electricity consumption (e.g. commercial customers with peak power registration). Kosovo KEDS exhibited the highest installation of new meters in 2012; 24 % of the total meters in service. All other DSOs' installed less than 5 % of new meters (EVNM has not provided data).

Table 8-1 New meters installed in the distribution system (MV and LV) - meters installed at new customers and old meters replaced at existing customers premises

DSO	Number of new meters in 2012	[%] of existing customers	Type
EDB	1.674	4,7	Electronic (digital)
EPBIH	9.816	1,35	Smart meter
EPHZHB	2.600 new customers (6.153 existing customers)	1,4 (3,3)	Smart meter
EPS	108.498	3,05	Electronic (digital) Smart meter
ERS	5.939	1,1	Electronic (digital) Smart meter
EVNM	n/a	n/a	n/a
HEP	85.847	3,65	Electronic (digital) – households, public lighting, LV commercial customers without peak power registration Smart meter – MV customers, LV commercial customers without peak power registration
KEDS	120.835	24,1	Electronic (digital) (95,4 %) Smart meter (4,6 %)

8.6. FREQUENCY OF METER CALIBRATION

The calibration assures that the measurement errors can be kept within the desired limits. In this report measure is developed as the number of calibrations performed in a year divided by the number of meters in service.

- In this report:
- data on meters calibration frequency are missing for KEDS on LV level (only data on electromechanical meters of LV households have been provided),
- EDB provided lump sum data for all meters on MV level (i.e. 11 % is frequency of meter calibration on MV level for all meter types),

- EPBIH indicated that electronic and smart meters have not been calibrated in the observed year because these meters are relatively new (recently installed); so, EPBIH provided only data on electromechanical meters,
- EPHZHB has not provided data for different meter types (i.e. electromechanical, electronic and smart meters) nor for two voltage levels (i.e. MV and LV); EPHZHB provided data for different connection types (i.e. direct, semi direct and indirect) – 9.206 (5 % of all meters in service) directly connected meters and 525 (0,3 % of all meters in service) semi directly and indirectly connected meters were calibrated in 2012,
- ERS has provided lump sum data for all meters on MV and LV voltage level; i.e. 27 % is the frequency of meter calibration on MV level for all meter types and 6 % is the frequency of meter calibration on LV for all meter types and consumption categories; ERS provided exact data for different connection types (i.e. direct, semi direct and indirect) – 30.331 (5,6 % of all meters in service) directly connected meters and 719 (0,1 % of all meters in service) indirectly and semi directly connected meters were calibrated in 2012,
- KEDS has provided only data for LV households electromechanical meters, i.e. 1,8 %,
- OSHEE provided lump sum data for all meters on MV and LV level, i.e. 10 %.

Figure 8.26 depicts frequencies of smart meters calibration in SEE DSOs. ERS has the highest frequency of MV meters calibration. EDB has the highest frequency of LV smart meters with peak power registration calibration. The highest frequencies of LV smart meters calibration have EPHZHB, HEP and OSHEE in commercial without peak power registration, public lighting and households consumption categories respectively.

Figure 8.27 depicts frequencies of electronic meters calibration. ERS has the highest frequency of MV meters calibration. EVNM has the highest frequencies of LV electronic meters calibration in two consumption categories (i.e. commercial with peak power registration and public lighting), while OSHEE in other two consumption categories (i.e. commercial without peak power registration and households).

Figure 8.28 depicts frequencies of electromechanical meters calibration. The highest frequency of MV electromechanical meters calibration has EDB. The highest frequency of LV electromechanical meters calibration has OSHEE, although here it must be observed that OSHEE provided lump sum data for all consumption categories.

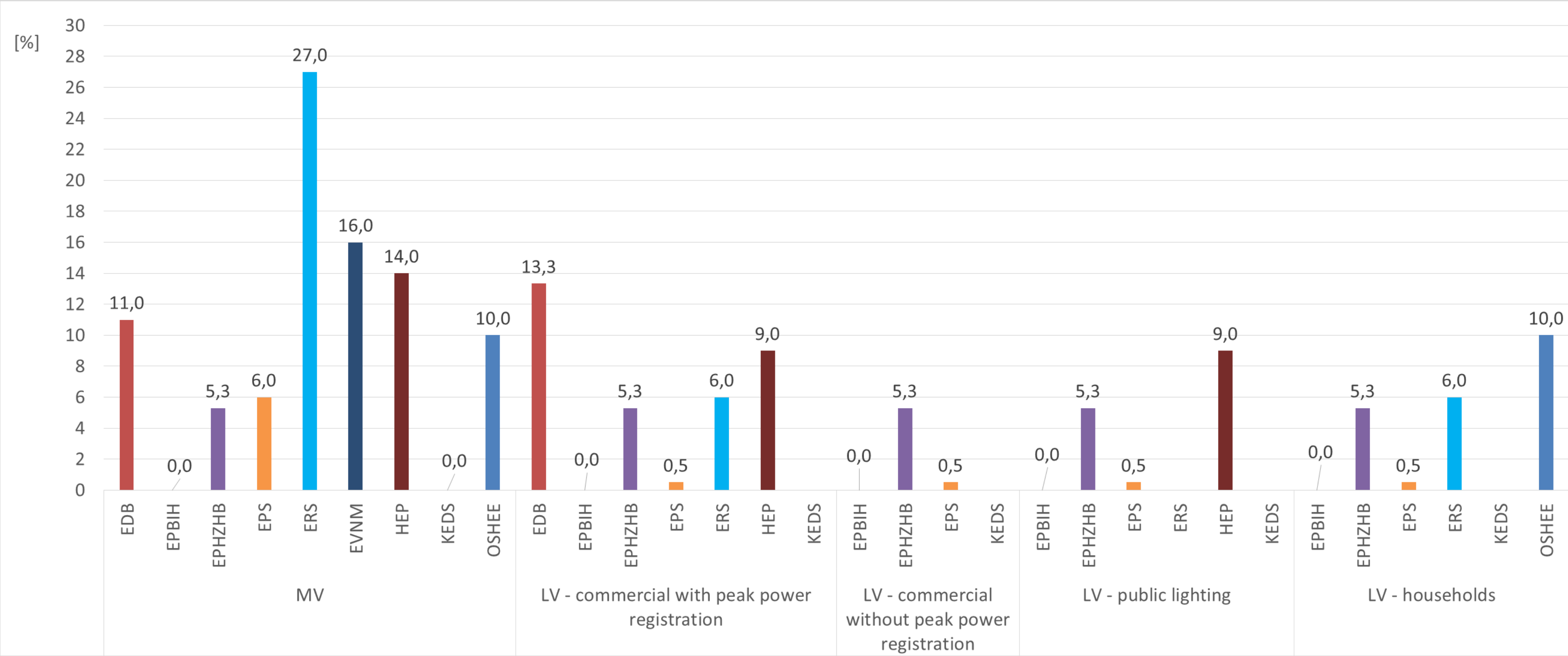


Figure 8.26 Frequency of smart meter calibration

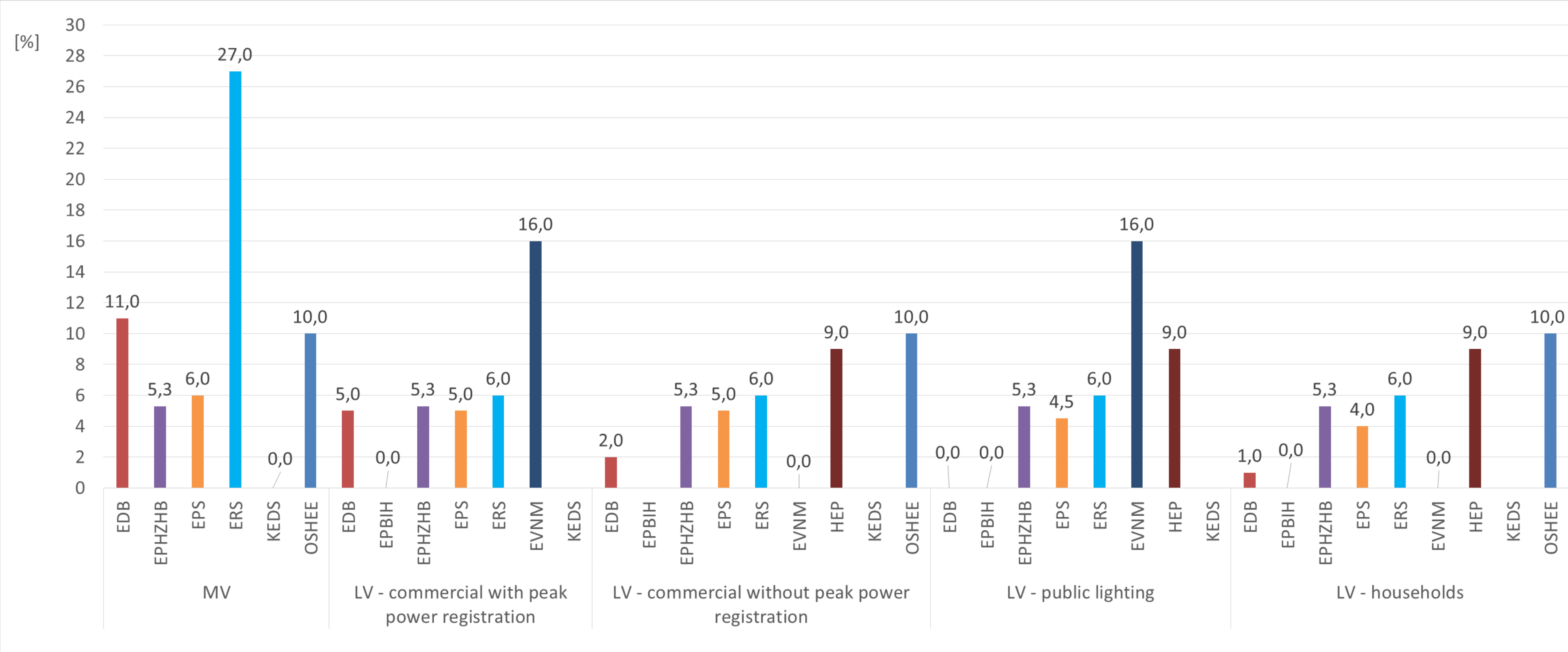


Figure 8.27 Frequency of electronic meter calibration

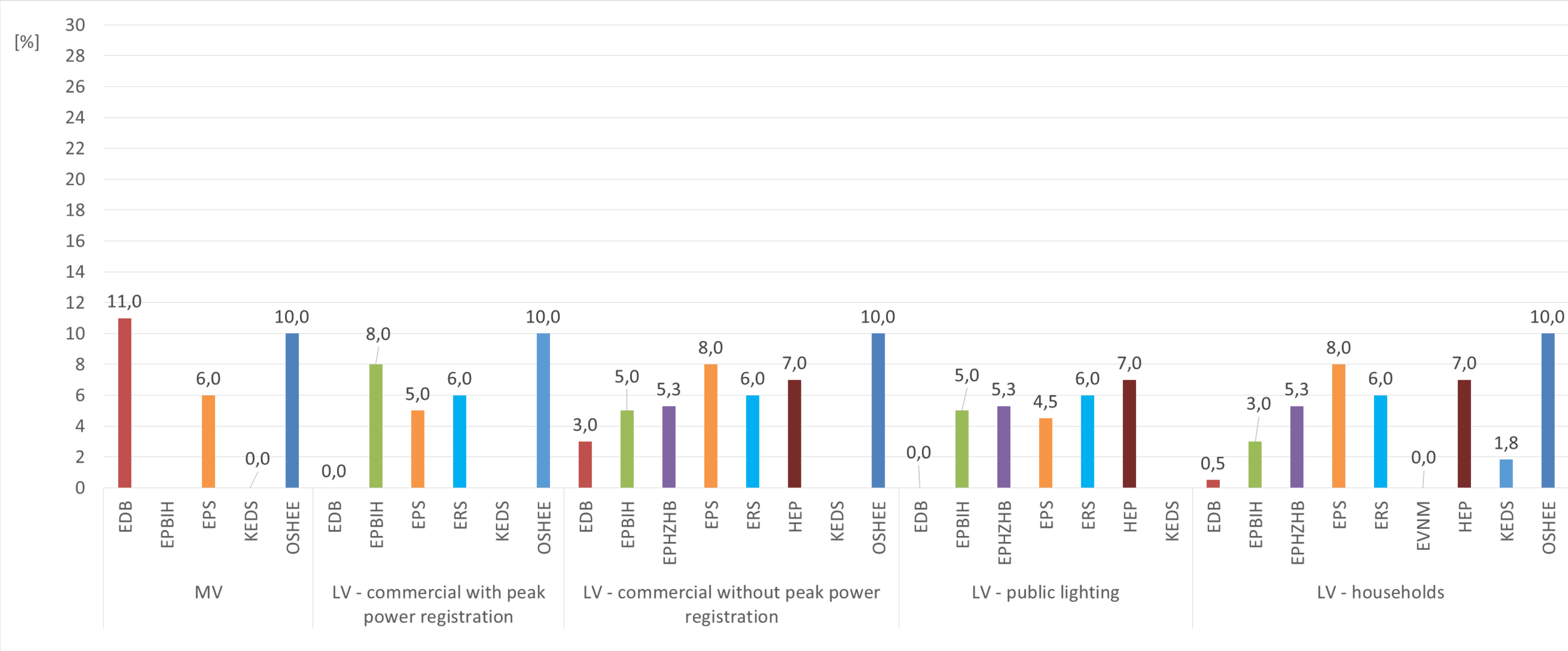


Figure 8.28 Frequency of electromechanical meter calibration

In addition to previous indicator (frequency of meter calibration) DSOs have delivered data on prescribed meter calibration intervals (subject to the laws of the country). Figure 8.29, Figure 8.30 and Figure 8.31 give data on prescribed calibration intervals of electromechanical, electronic and smart meters respectively.

For electromechanical meters prescribed calibration interval ranges from 5 to 16 years on MV and 3 to 16 years on LV level. In accordance with the regulations, the latter implies that frequency of electromechanical meters calibration per year must be greater than 6,3 % to 20 % on MV and 6,3 % to 33,3 % on LV.

For electronic meters prescribed calibration interval ranges from 3 to 8 years on MV and 3 to 12 years on LV level. The latter implies that frequency of electronic meters calibration per year must be greater than 12,5 % to 33,3 % on MV and 8,3 % to 33,3 % on LV.

For smart meters prescribed calibration interval ranges from 3 to 12 years on MV and 3 to 12 years on LV level. The latter implies that frequency of smart meters calibration must be greater than 8,3 % to 33,3 % per year.

On average, on MV, digital (electronic and smart) meters shall be calibrated every 5,7 years and electromechanical meters every 8,3 years.

On LV, digital (electronic and smart) meters for commercial customers with peak power registration shall be calibrated every 7,2 years and for all other customers every 11,6 years. On LV electromechanical meters for commercial customers with peak power registration shall be calibrated every 7,4 years and for all other customers every 12,3 years.

By dividing 100 % and prescribed calibration interval it is possible to determine share of meters that shall be calibrated every year. Compliance of realized with prescribed shares (of meters calibrated in DSOs) is present only in Croatian HEP.

With regard of allowed number of calibrations per meter almost all DSOs responded with “not legally prescribed”. Only EPBIH responded by concrete limit of 3 calibrations per meter.

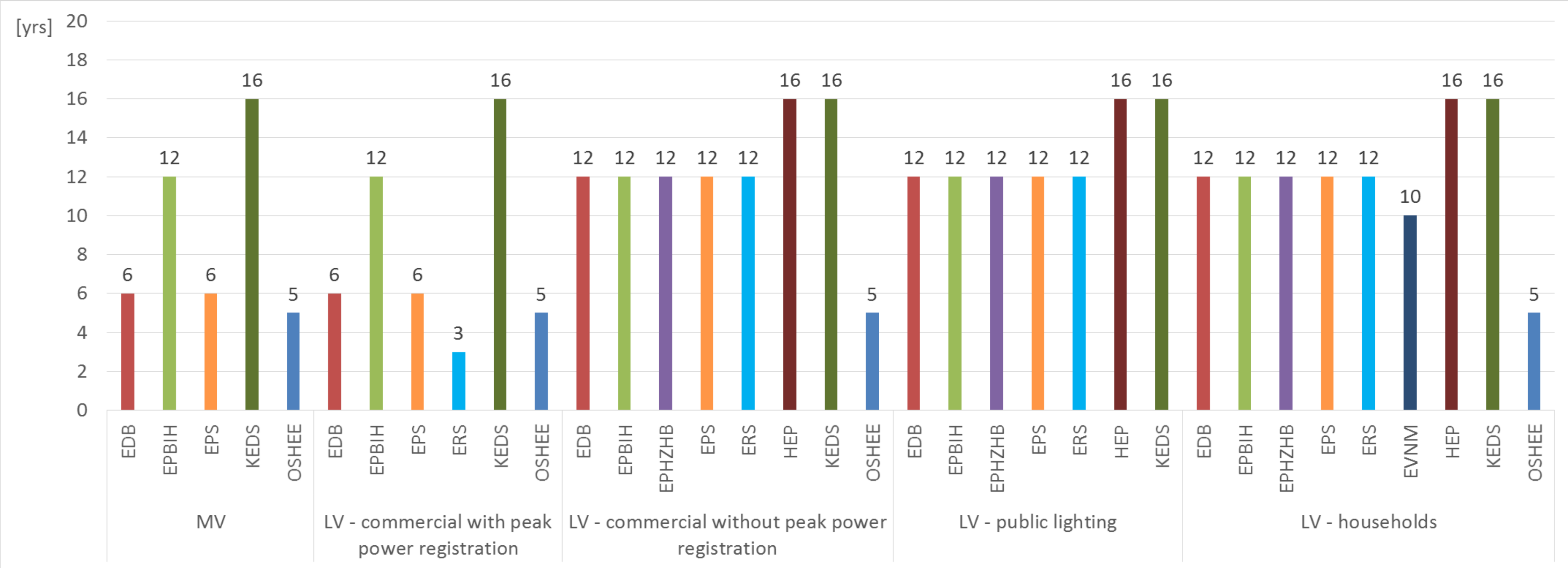


Figure 8.29 Prescribed calibration interval of electromechanical meters

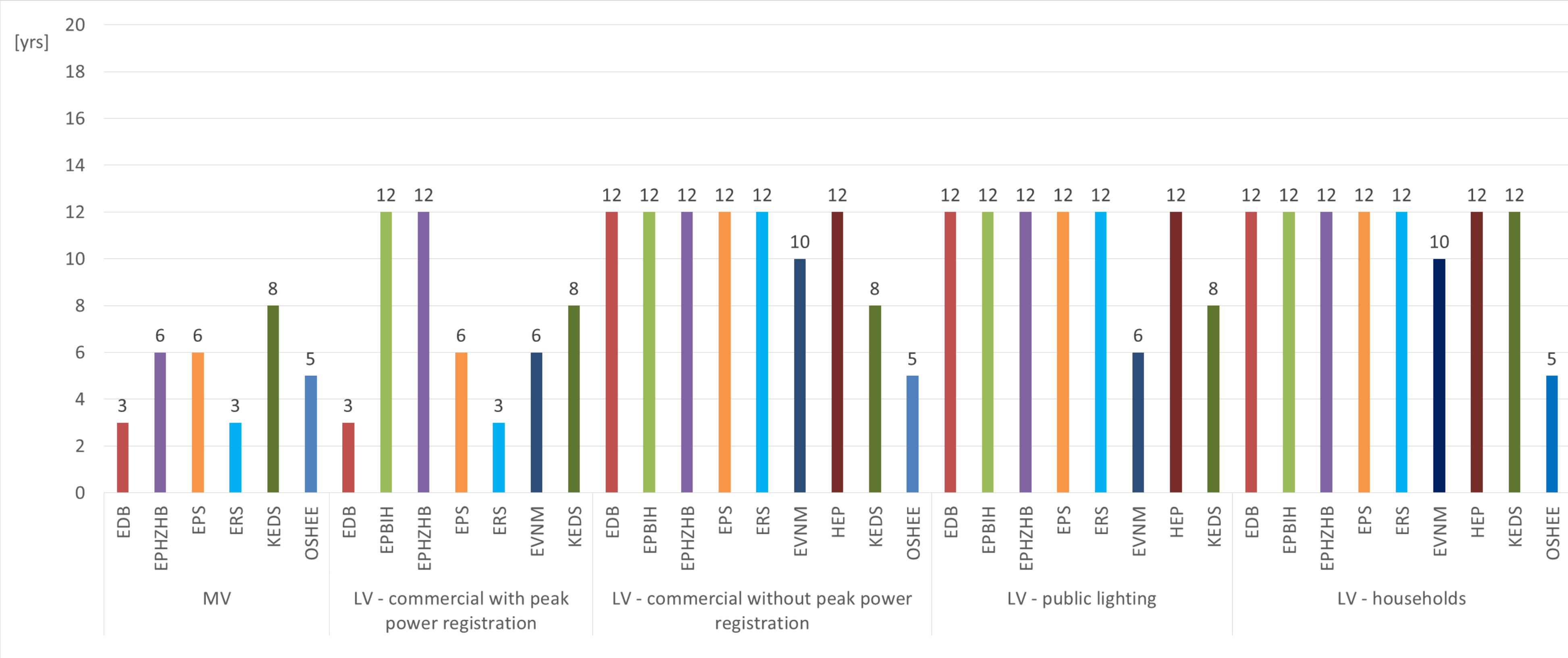


Figure 8.30 Prescribed calibration interval of electronic meters

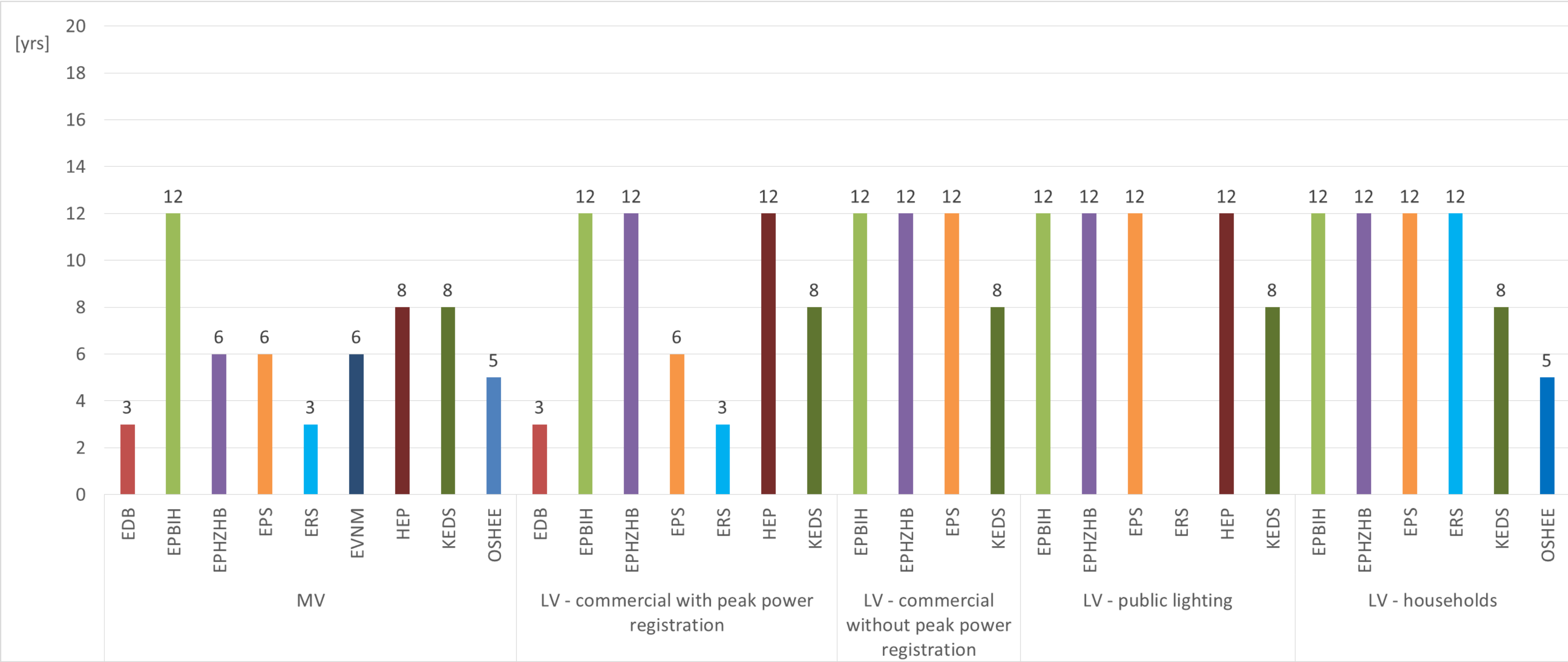


Figure 8.31 Prescribed calibration interval of smart meters

8.7. FREQUENCY OF METER AND SEAL INSPECTION

Inspections are an important mean to assure meter accuracy and detect theft. Some DSOs assign this task to meter readers and they may claim that inspections of meters and seals thus occur on every site visit. In many cases this belies the prevalence of broken seals and tampered meters. However, measures should focus on inspections by personnel independent of meter reading.

For this report the measure is developed from the number of yearly inspections as portion of the total meters in service.

Here it must be indicated that:

- OSHEE and EVNM have not delivered any data on frequency of meter and seal inspections,
- for KEDS part of data are missing (e.g. for electromechanical and electronic meters on MV level, smart meters on LV),
- ERS provided lump sum data for all MV (99 %) and LV meters (20 %) respectively,
- the same applies to MV meters in EDB (42 %),
- EPHZHB provided lump sum data for different consumption categories.

Figure 8.32 depicts frequency of smart meter and seal inspection. It could be observed that in most of DSOs smart meters and seals are inspected at least once a year. Exceptions are EPBIH and EDB on LV level. DSOs like EPHZHB and ERS provided lump sum data and therefore cannot be judged.

Figure 8.33 depicts frequency of electronic meter and seal inspection. It could be observed that only in EPS all electronic meters and seals are inspected at least once a year. Except in EPS and EDB for LV customers with peak power registration (i.e. larger LV customers), in other DSOs frequency of LV electronic meter inspections does not exceed 22%.

Figure 8.34 depicts frequency of electromechanical meter and seal inspection. It could be observed that only in EPS all electromechanical meters and seals are inspected at least once a year. In all other DSOs this value does not exceed 25% at LV level.

In general, MV meter and seal inspections are done at least once a year in almost all DSOs (exception is EDB with 42%). On LV 100% values could be observed for smart meters in HEP, KEDS and EPHZHB and for all meters in EPS.

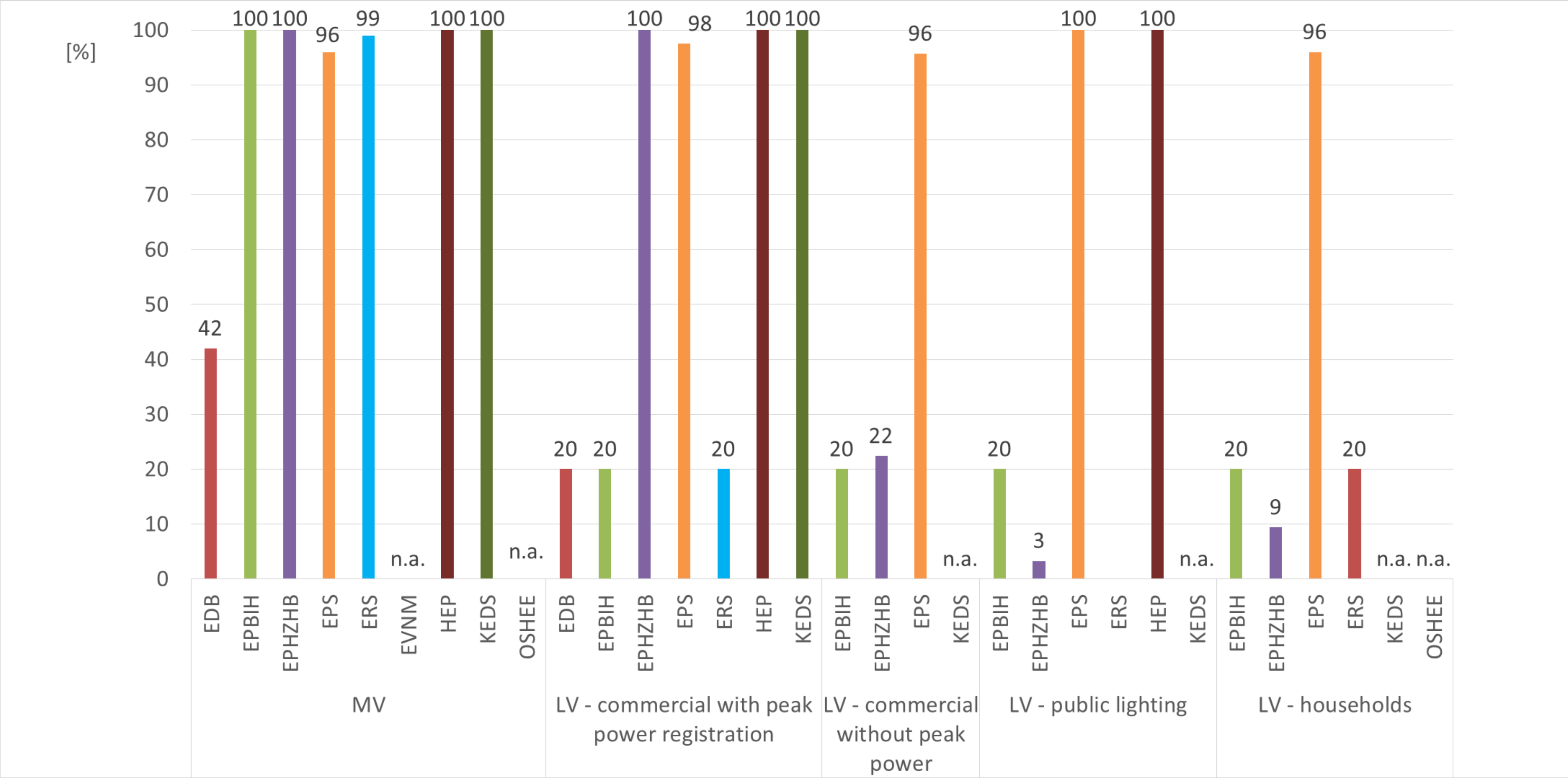


Figure 8.32 Frequency of smart meter and seal inspection

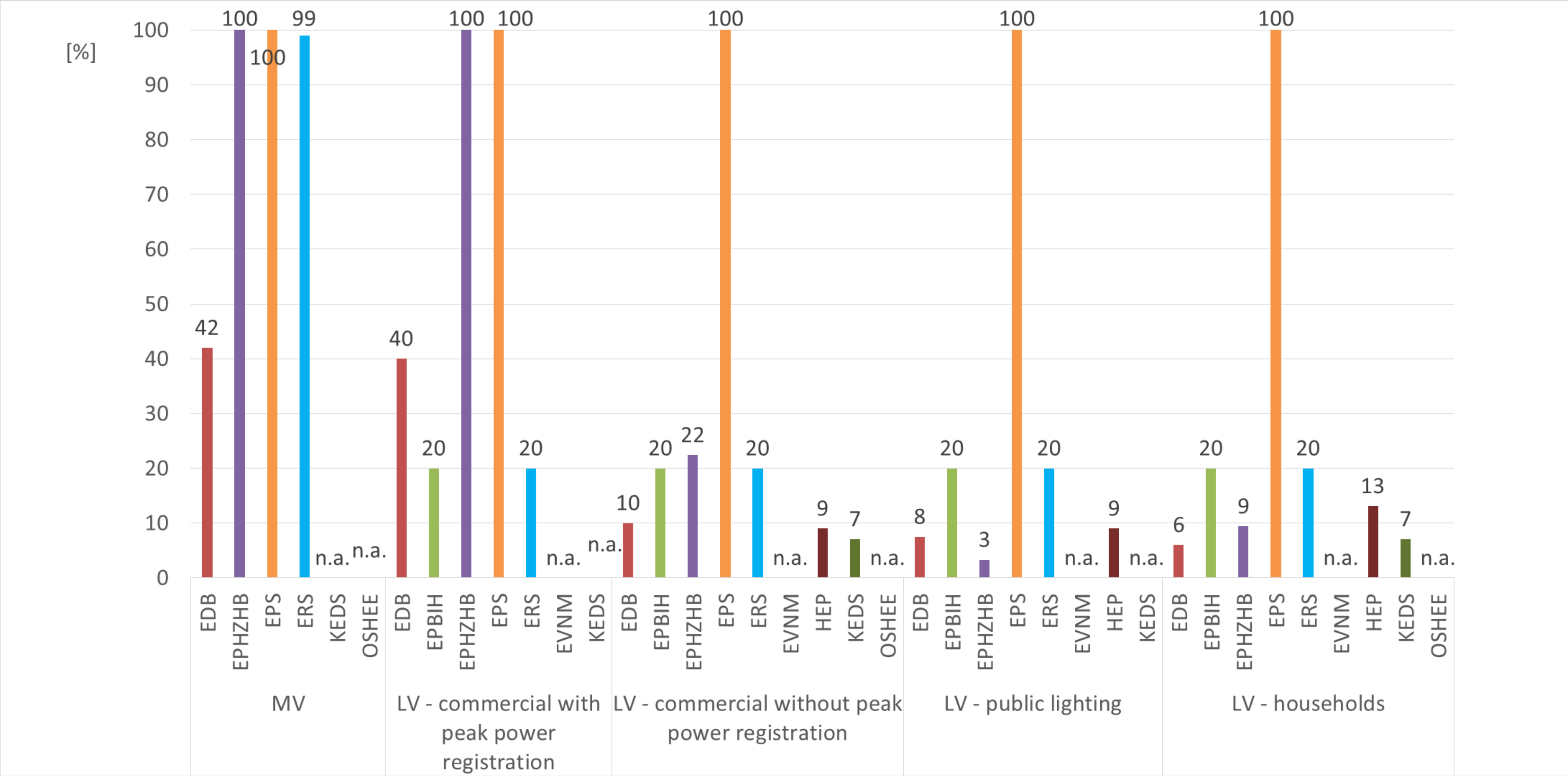


Figure 8.33 Frequency of electronic meter and seal inspection

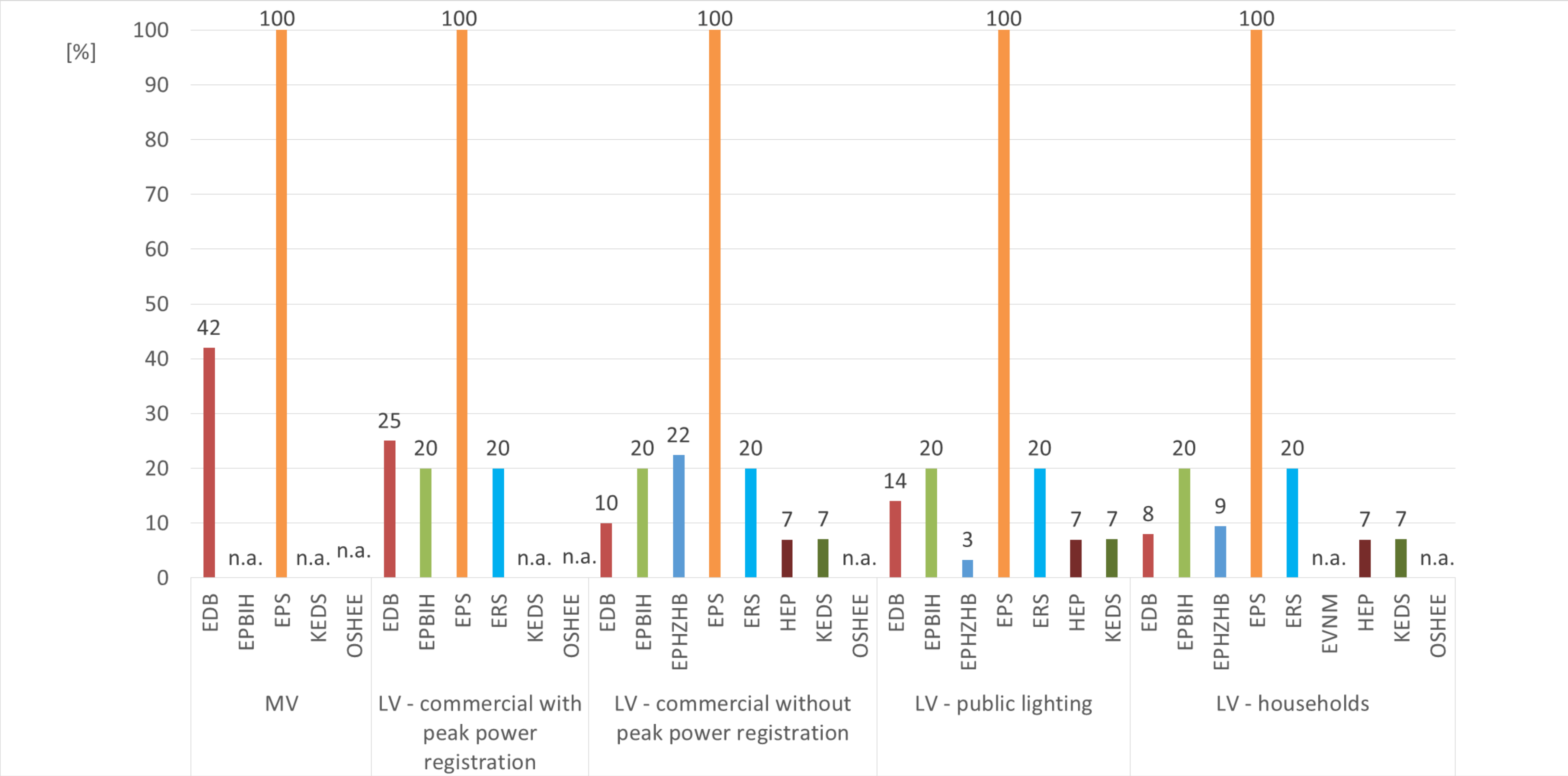


Figure 8.34 Frequency of electromechanical meter and seal inspection

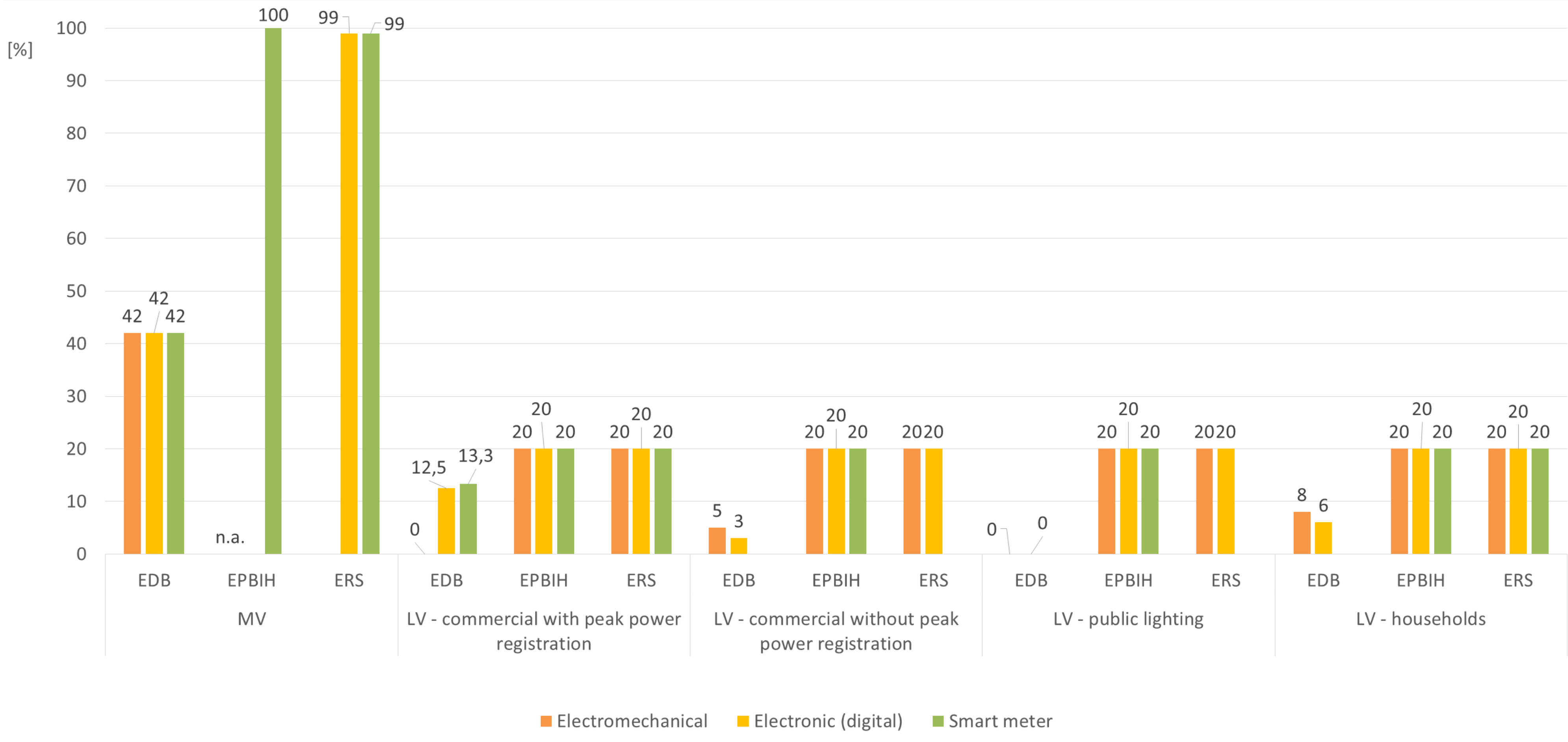


Figure 8.35 Frequency of connection and installation inspections

8.8. FREQUENCY OF CONNECTION AND INSTALLATION INSPECTIONS (SERVICE INSPECTIONS)

To detect unauthorized connections, customer connections should be inspected periodically. For this report the measure is developed from the number of yearly service inspections as portion of the total meters in service.

Here it must be observed that:

- OSHEE, EPHZHB, HEP and EPS have not provided data on service inspections,
- EVNM provided only data for households electronic meters with remote reading (i.e. 21,5 %),
- KEDS provided partial data; from these data it is possible to conclude that smart meter connections are inspected every year and also 7,05 % of other connections,
- EPBIH and ERS provided the same data for connection and meter inspections (Figure 8.35),
- in EDB there are some differences between frequencies of meters/seal and connection/installation inspections (Figure 8.35).

8.9. OBSERVATIONS/RECOMMENDATIONS

It is important to stress that none of the proposed metrics in this section measures meter accuracy directly. They infer the quality of metering practice on the basis of indicators, and provide benchmarks for good meter maintenance practice. Direct measurement of metering accuracy would be beyond the scope of benchmarks, though would be valuable study for individual DSOs to undertake.

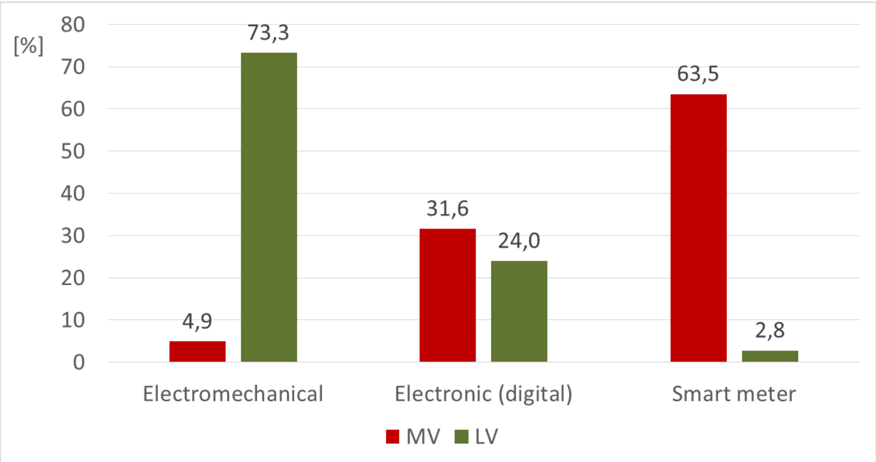


Figure 8.36 Share of different meter types in the observed region

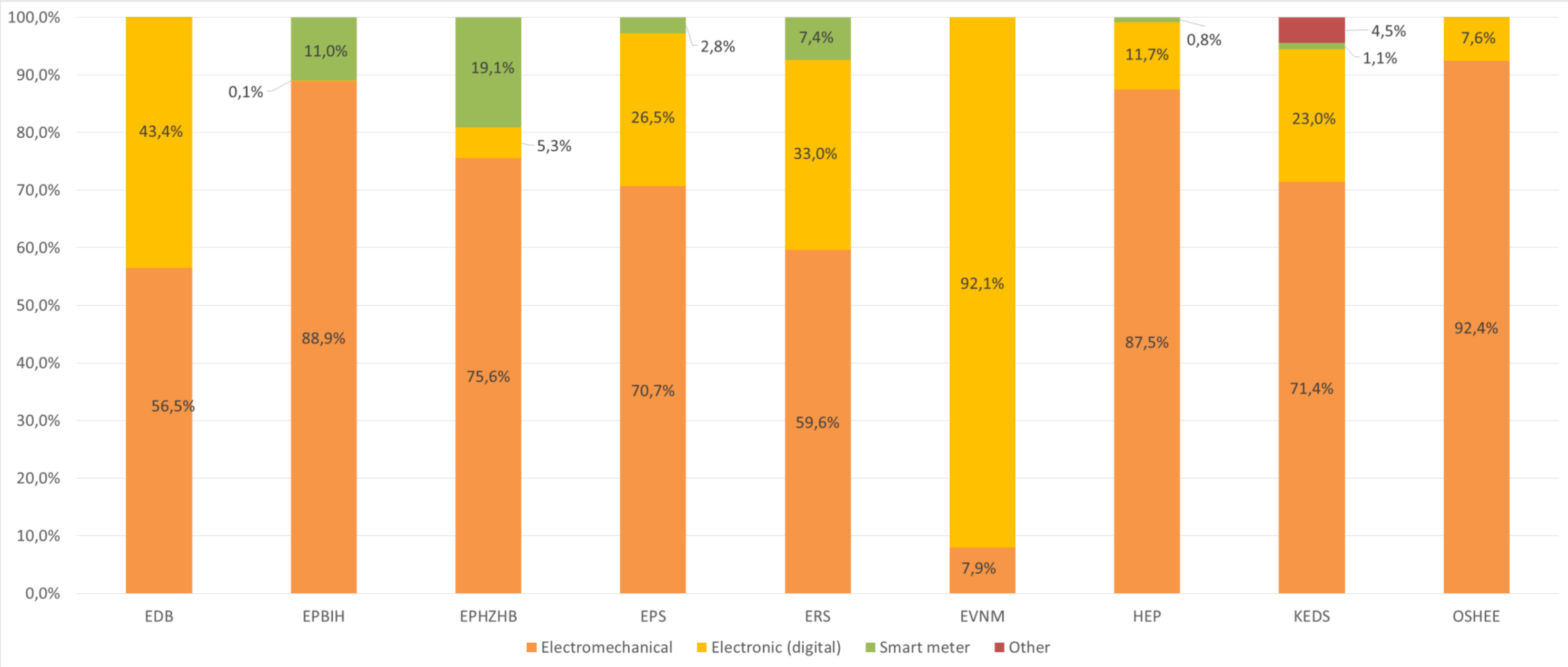


Figure 8.37 Share of different meter types in DSOs - LV customers (2012)

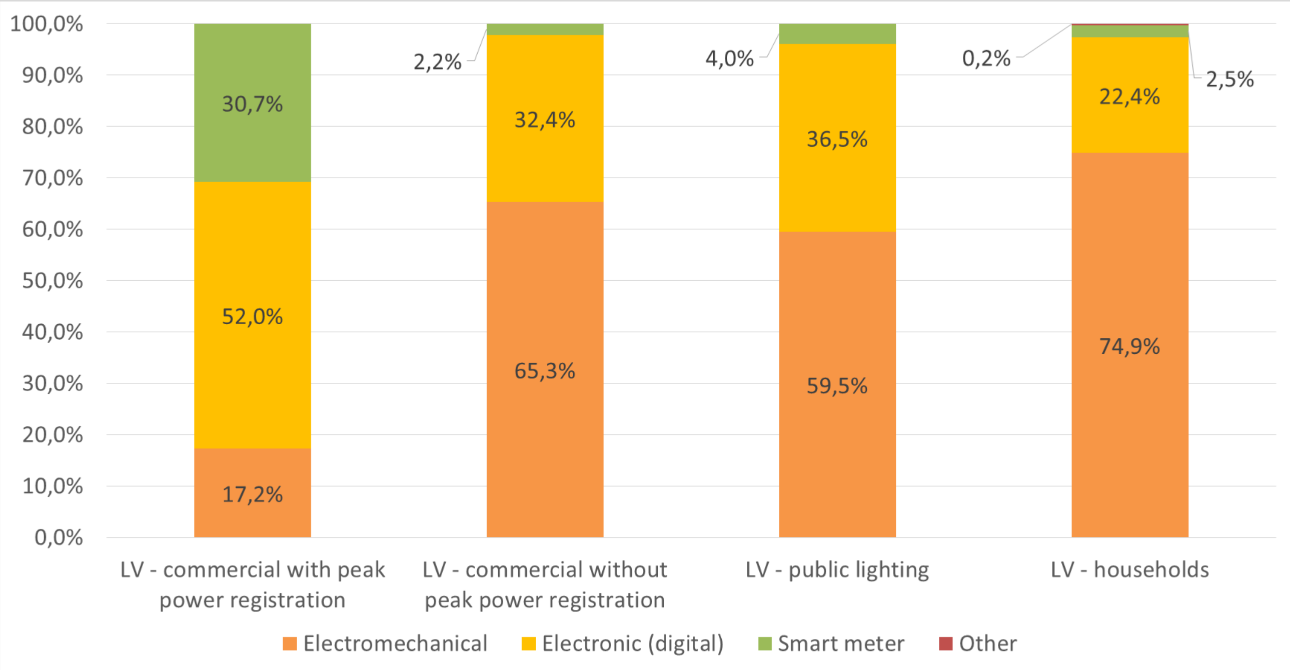


Figure 8.38 Share of different meter types in LV consumption categories (2012)

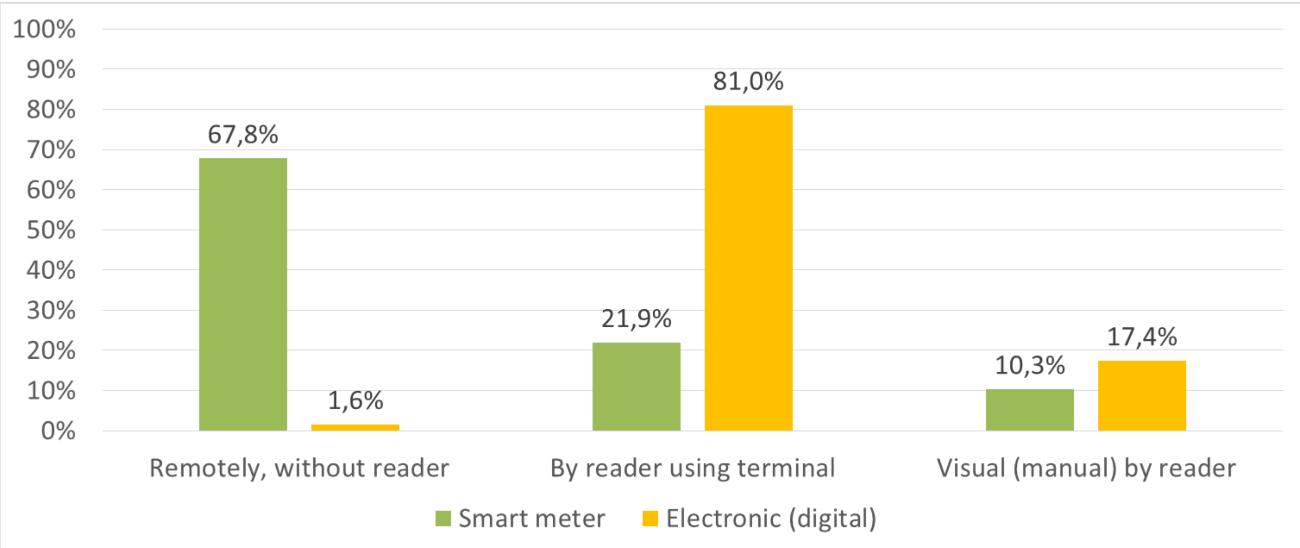


Figure 8.39 Share of different types of LV smart and electronic meter readings in the region (2012.)

With regard of smart metering presence in the region, the following are the main findings:

- on the LV level there are 2,8 % of smart meters (Figure 8.36),
- on the LV level 73,3 % are electromechanical meters; on average these meters are 26,2 years old which is high (the reported lifespan of analog meters is 30-40 years),
- in 3 DSOs (EDB, EVNM and OSHEE) there are no smart meters on LV level,
- the largest share of smart meters in LV distribution network is in EPHZHB, i.e. 19,1 %,

- except in EVNM, in all other DSOs on LV level dominate electromechanical meters (Figure 8.37),
- on LV level the largest share of smart meters is present at commercial customers with peak power registration, i.e. 30,7 %,
- remote meter reading is considered the most important reason for the roll out of smart meters; in the observed region only 67,8 % of smart meters are read remotely; besides, there are 1,6 % electronic meters that are read remotely (Figure 8.39).

DSO shall take a central role in the roll-out of smart meters. In line with the provision of the EU Third Energy Package this report suggest National Cost Benefit Analysis to be performed by the Regulatory Authority on electricity smart metering roll-out. The main reasons for the roll-out are:

- efficient remote meter reading,
- reducing electricity losses,
- reducing fraud,
- improving responses to delayed or lack of payment by consumers,
- many new services, including energy efficiency services, for customers (however, to realize potential feedback-induced savings, advanced meters (smart meters) must be used in conjunction with in-home (or on-line) displays and well-designed programs that successfully inform, engage, empower and motivate people).

By examining countries cases (forerunners in the roll-out of the Smart Grid or countries that have applied a distinctive approach to the roll-out and/or to the management of the meter data, e.g. Sweden, Italy, Denmark, France, the UK, Texas in the USA), lessons can be learned on successful market models in support of a large scale roll-outs and on potential pitfalls and challenges.

Compliance of realized with prescribed shares of meters calibrated in DSOs is present only in Croatian HEP. However, all meters shall be regularly calibrated.

9. METERING EFFECTIVENESS

With regard of metering, billing and collection objectives are to measure consumption accurately, transmit meter data to the DSO billing department and improve bill processing and dispatch, revenue collection and payment processing. In most DSOs there is a scope for improvement both through investment in facilities and changes to work processes. The benchmarks clearly must establish both targets for improvements and expectations for reasonable performance.

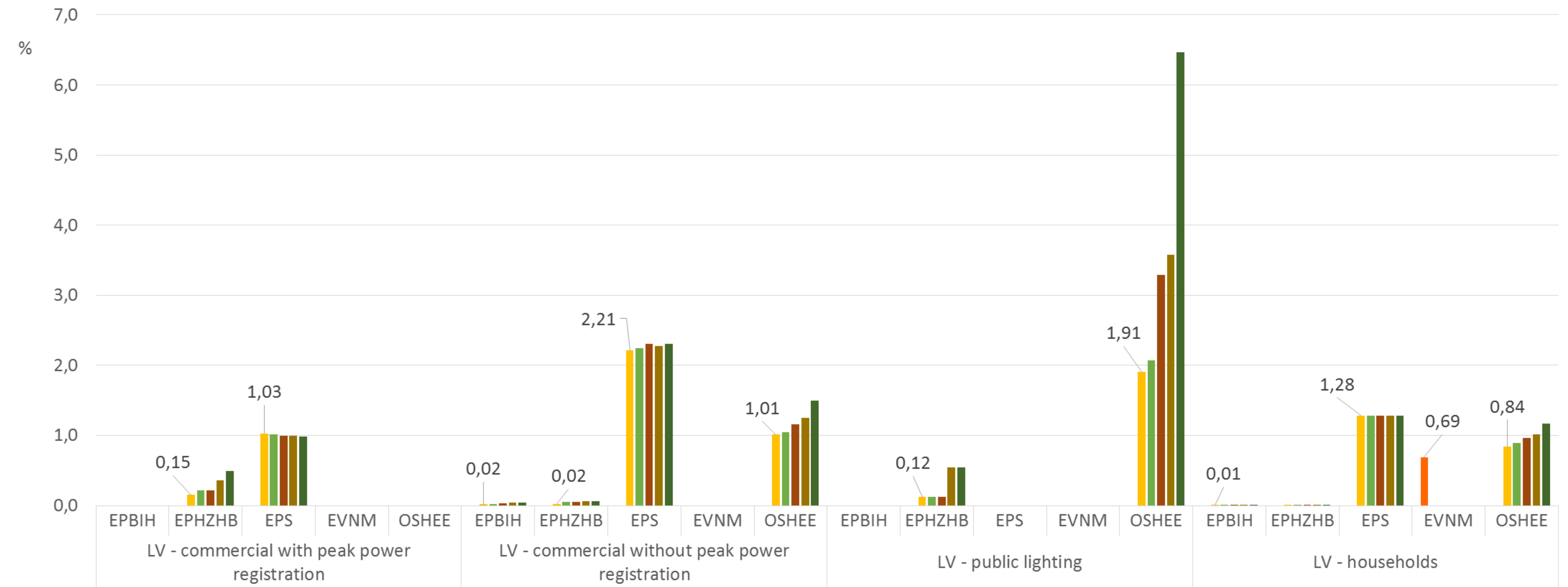
9.1. ESTIMATED NUMBER OF UNAUTHORIZED CONNECTION POINTS

Regarding estimated number of unauthorized connection points (without metering), 5 DSOs provided data: OSHEE, EPBIH, EPHZHB, EPS and EVNM. EVNM provided data only for 2013. (households), while other DSOs for 2008.-2012. period (Figure 9.1).

In EVNM in 2013, in households category, estimated share of unauthorized connection points equaled 0,69 %. It could be observed that in 2012 only in EPS estimated number of unauthorized connection points in households category exceeds 1 %. In other DSOs shares of unauthorized connection points in the total number of metering points in households category are less than 1 %.

The good thing about number of unauthorized connection points is that it is steadily declining in the observed time period (noticeable decline could be observed in Albanian OSHEE).

The largest share of unauthorized connection points in category of commercial customers is present in Serbian EPS, i.e. 2,21 % and 1,03 %.



	LV - commercial with peak power registration					LV - commercial without peak power registration					LV - public lighting					LV - households				
	EPBIH	EPHZHB	EPS	EVNM	OSHEE	EPBIH	EPHZHB	EPS	EVNM	OSHEE	EPBIH	EPHZHB	EPS	EVNM	OSHEE	EPBIH	EPHZHB	EPS	EVNM	OSHEE
2013																			0,69	
2012		0,15	1,03			0,02	0,02	2,21		1,01		0,12			1,91	0,01	0,00	1,28		0,84
2011		0,22	1,01			0,02	0,05	2,25		1,05		0,12			2,07	0,01	0,00	1,28		0,89
2010		0,22	0,99			0,04	0,05	2,31		1,16		0,12			3,29	0,01	0,01	1,28		0,96
2009		0,36	0,99			0,04	0,06	2,28		1,25		0,54			3,57	0,01	0,01	1,28		1,02
2008		0,49	0,98			0,04	0,07	2,31		1,50		0,54			6,47	0,01	0,01	1,28		1,17

2013 2012 2011 2010 2009 2008

Figure 9.1 Estimated share of unauthorized connection points in 2008-2012 period

9.2. NUMBER OF YEARLY DETECTED UNAUTHORIZED CONNECTION POINTS (WITHOUT METERING)

Besides, estimated number of unauthorized connection points (without metering) in DSOs supply areas (Figure 9.1), this section provides data on number of yearly detected unauthorized connection points (without metering). In Figure 9.2 these are given as a portion of total number of connection points.

Usually unauthorized connections are related to:

- electricity meter deliberately omitted or bypassed,
- direct tapping from distribution line,
- reconnection without authority after disconnection for nonpayment or use of distribution network not in line with the network code.

In this report:

- 1 DSO did not provide data: OSHEE,
- in EDB was no unauthorized connections,
- EPHZHB, ERS, EVNM and KEDS provided lump sum data.

It could be observed that unauthorized connection points are detected only in LV network (exception is the case of EPS on MV in 2011).

The largest share of unauthorized connections in 2012 was in EVNM, i.e. 0,3 % of all connection points in MV and LV distribution network. In other observed years (2008-2011) largest shares of unauthorized connections were in Serbian EPS, predominately in households consumption category.

Here it must be highlighted that in all years shares of unauthorized connection have been lower than 0,35 %.

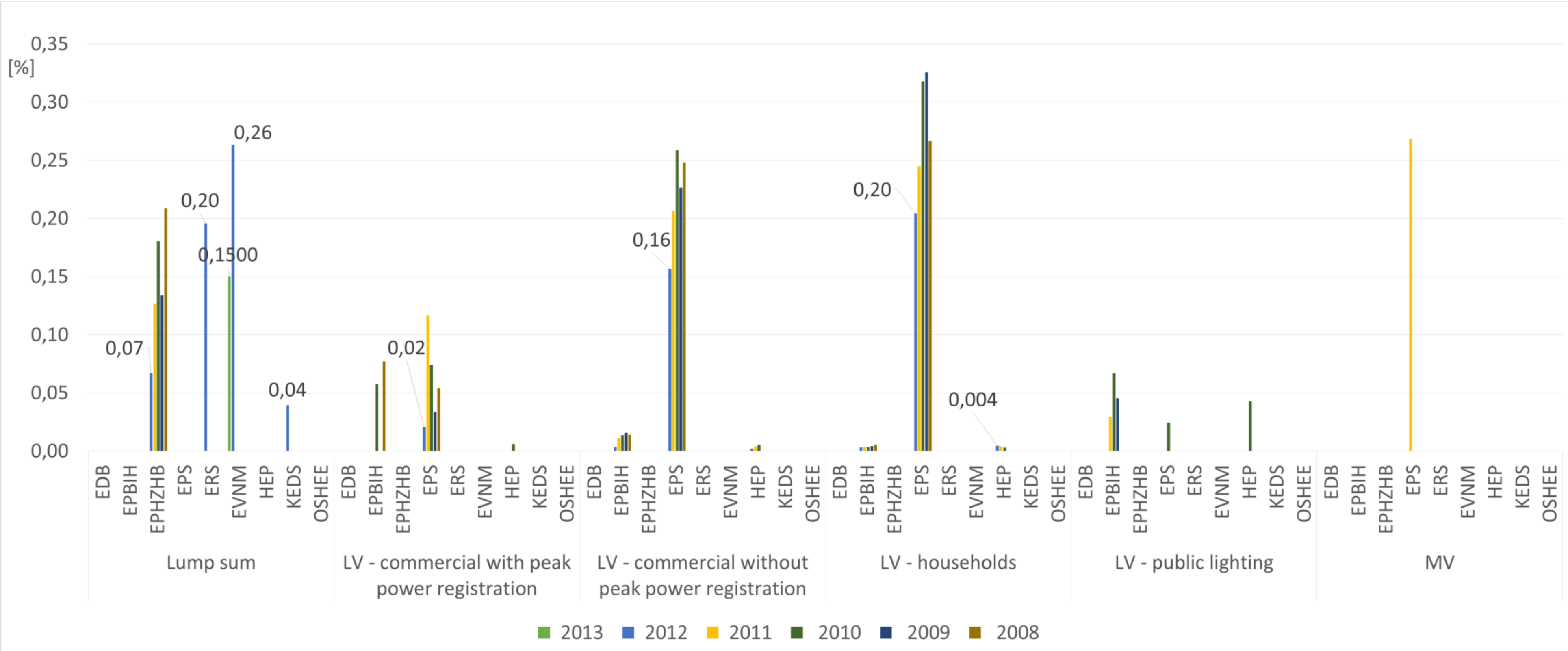


Figure 9.2 Share of yearly detected unauthorized connection points (connections without metering)

9.3. NUMBER OF YEARLY DETECTED CONNECTION POINTS WITH TAMPERED METERS

This section provides data on number of yearly detected connections with tampered meters. In Figure 9.3 these are given as a portion of total number of connection points.

Usually connections with unauthorized use of meters are related to:

- tempered meter,
- broken seal,
- tempered time switch,
- unauthorized meter relocation/displacement,
- usage of electricity for unauthorized purposes (e.g. misrepresentation of consumption category to DSO).

Here DSOs should report all connections with unauthorized use of meters detected by means of either planned inspections or inspections due to reported finding of irregularity/fraud.

In this report:

- two DSOs did not provide data: OSHEE and ERS,
- EPHZHB, EVNM and KEDS provided lump sum data.

It could be observed:

- connections with unauthorized use of meters were detected only in LV network,
- the largest share of unauthorized use of meters in 2012 was in Serbian EPS, in LV category of commercial customers without peak power registration, i.e. 1,45 %,
- there was a considerable rise in number of yearly detected tempered meters in households category in Serbian EPS in the last two years (i.e. 2011 and 2012),
- the same applies to LV category of commercial customers without peak power registration in Serbian EPS,
- in public lighting category connections with unauthorized use of meters have been detected only in Croatian HEP.

9.4. RATIO OF DETECTED IRREGULARITIES

Numbers of detected unauthorized connection points and detected connections with tampered meters have been added together and then divided by the number of conducted inspections.

Figure 9.4 depicts ratio of detected irregularities (unauthorized connection, tempered meter) to the number of conducted inspections. Results are given as a lump sum for all consumption categories on MV and LV level. It could be observed that in 2012 EPS had the highest ratio (9,5 %). In 2011 and 2010 the highest ratio was in KEDS (9 % and 13 % respectively), and in 2009 and 2008 was in EDB (10 % and 18 % respectively).

Figure 9.5 depicts ratio of detected irregularities (unauthorized connection, tempered meter) to the number of conducted inspections in different consumption categories for 4 DSO (namely, EDB, EPBIH, EPS and HEP provided data for different consumption categories). It could be observed that in 2012 Serbian EPS had the highest ratio in three categories: households (10,2 %), LV commercial customers without peak power registration (10,6 %) and in LV commercial customers with peak power registration (0,8 %). Besides, in the observed time period this ratio for EPS is increasing in two categories – households and LV commercial customers without peak power registration.

In comparison to other DSO, somewhat higher values are also inherent to EDB in two categories: households and LV commercial customers without peak power registration.

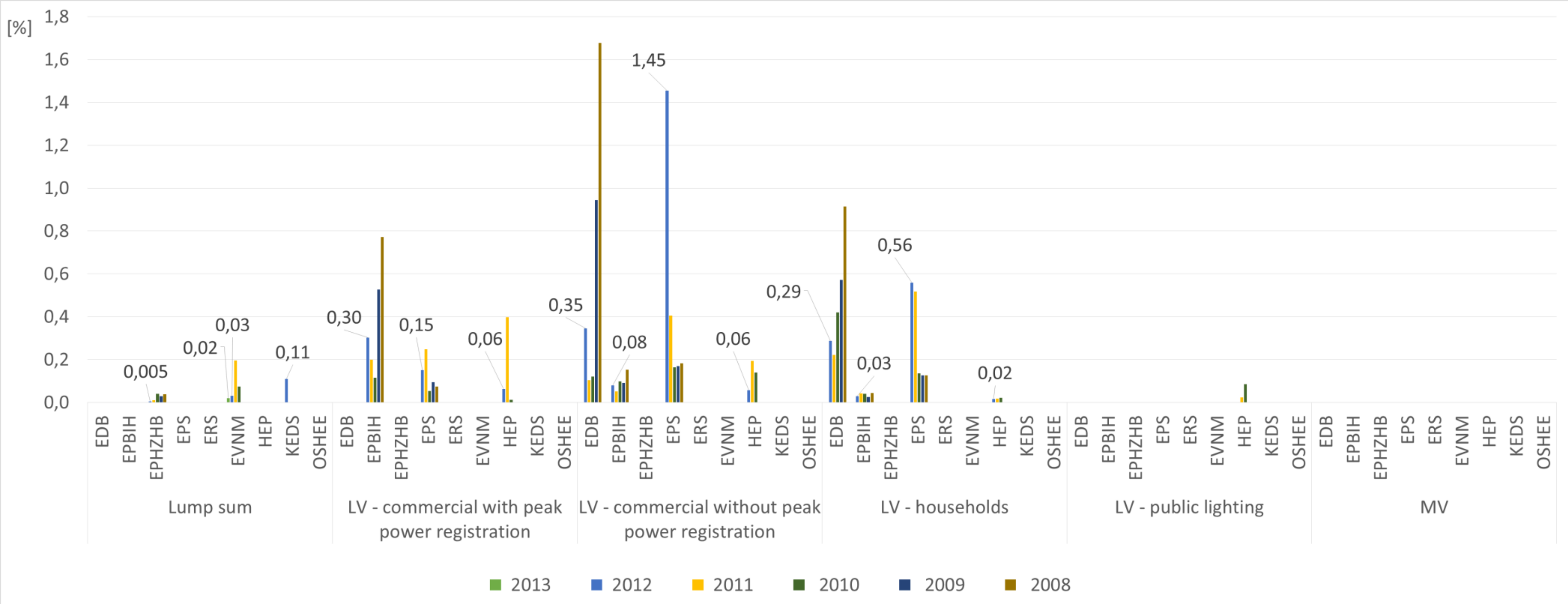


Figure 9.3 Share of yearly detected connections with tempered meters

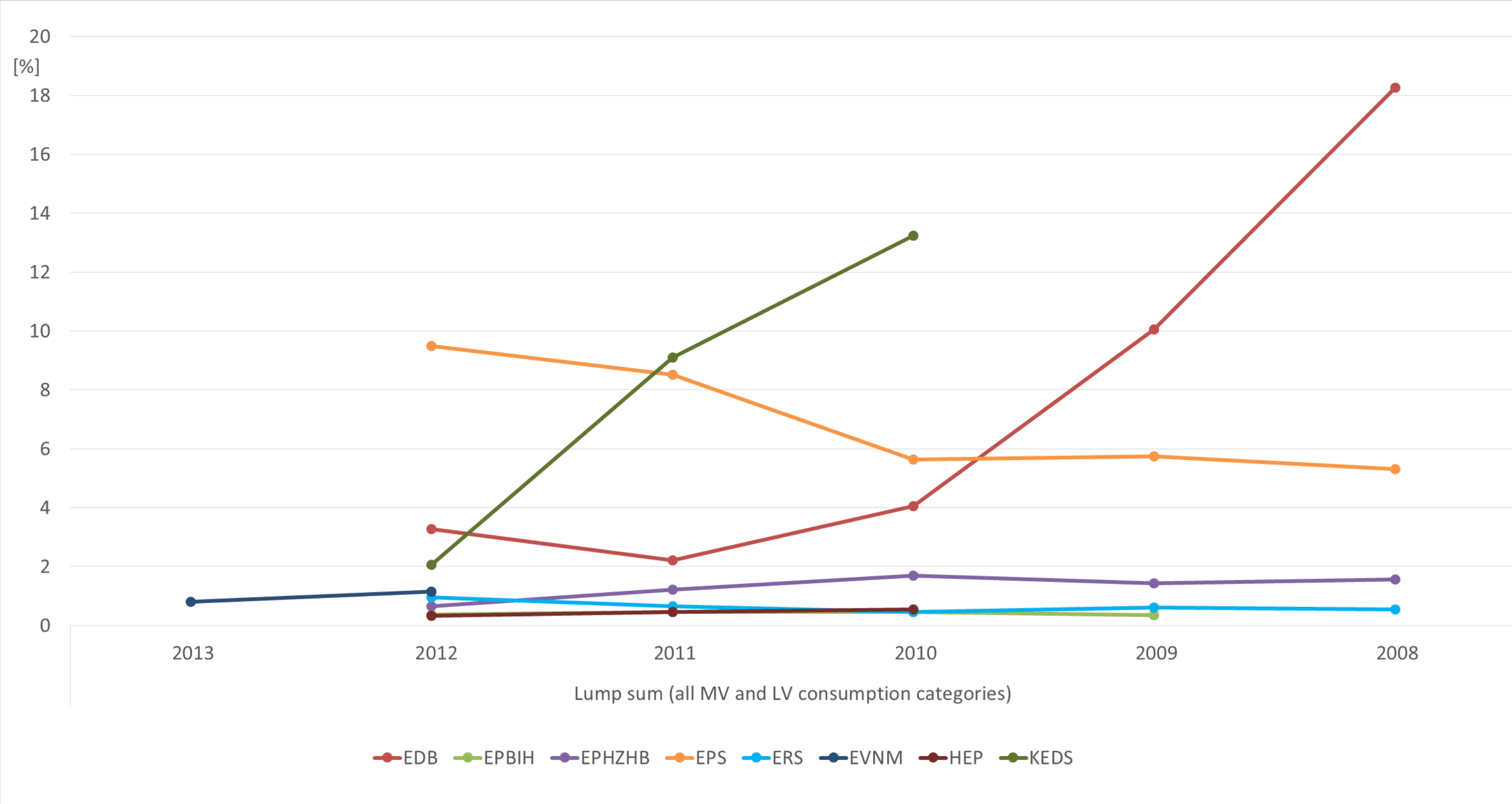


Figure 9.4 Ratio of detected irregularities (unauthorized connection, tempered meter) and number of conducted inspections

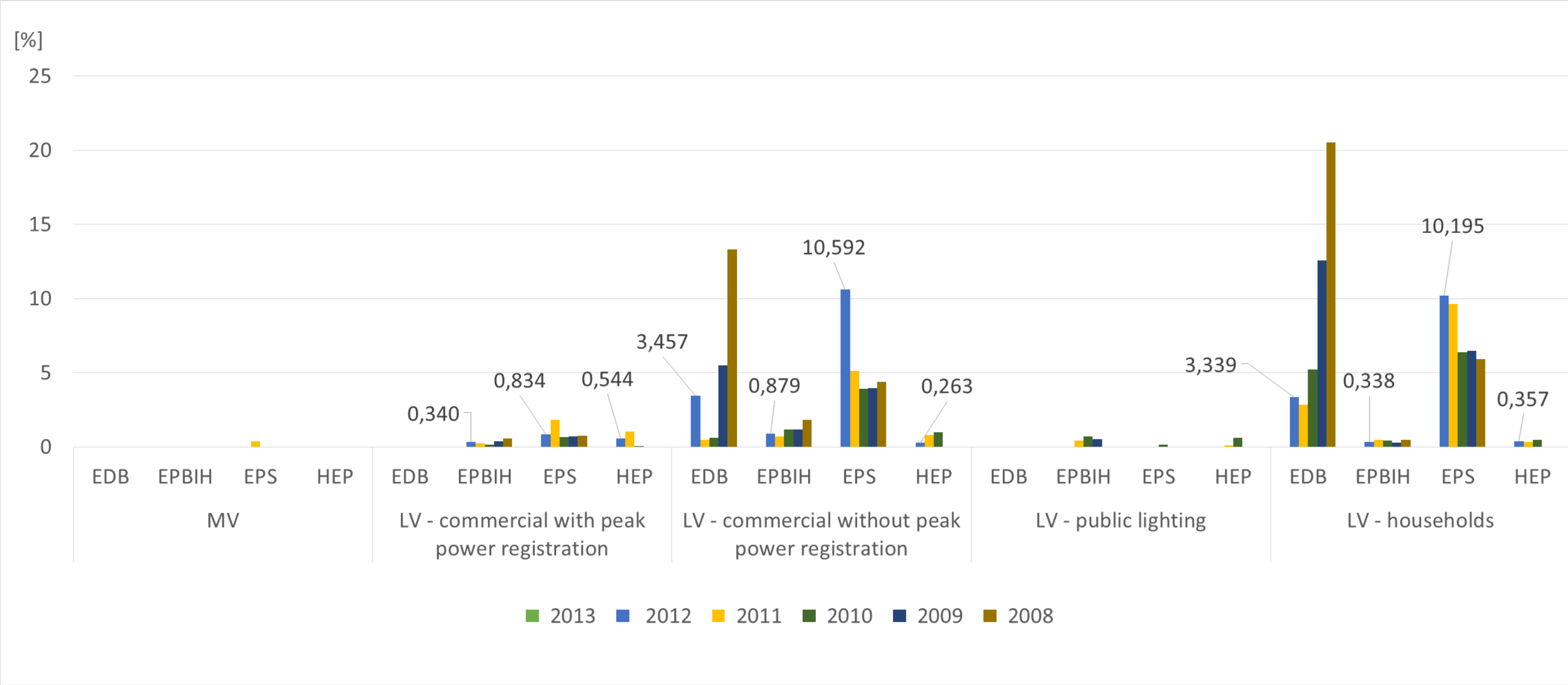


Figure 9.5 Ratio of detected irregularities (unauthorized connection, tempered meter) and number of conducted inspections per consumption category in 4 DSOs

9.5. METERING CYCLES (METER READING REGIME)

The standard business model of electricity retailing involves the electricity company billing the customer for the amount of energy used in the previous month. In some countries (e.g. households in KEDS), if the retailer believes that the customer may not pay the bill, a prepayment meter may be installed (it requires the customer to make advance payment before electricity can be used). Billing the customer for the amount of energy used presumes "scheduled meter readings". Scheduled means an actual meter reading on a cycle that equates to the end–use customer's billing cycle, usually monthly.

In the observed DSOs all electricity meters should be read 12 times a year (monthly), except households in Croatia that should be read 2 times a year, Table 9-1. Due to the monthly billing periods and six-month readings, monthly bills for households in Croatia are estimated until scheduled meter reading.

Table 9-1 Meter reading regime

DSO	Prescribed meter reading cycle	Allowed deviations from the scheduled readings (in days)	Self-reading envisaged by regulation
EDB	monthly	-6 days prior to end of month (households) -2 days prior to end of month (all other customers)	no
EPBIH	monthly	30	no
EPHZHB	monthly	-3 days prior to end of month (households, public lighting, LV commercial with peak power registration) 0 days prior to end of month (other customers, i.e. remotely read)	no
EPS	monthly	5	no
ERS	monthly	±3 days form the end of the month	no
EVNM	monthly	28 days (households) 3 days (all other customers)	no
HEP	twice (exceptionally at least once) a year (households) monthly (all other customers)	±15 days form the scheduled meter reading (households) ±3 days form the scheduled meter reading (all other customers)	yes for households
KEDS	monthly	4	no
OSHEE	n.a.	n.a.	no

Once DSO does scheduled meter read, if DSO:

- overestimated what customer owe it receives a credit to its account,
- underestimated what customer owe it will have to make up the difference in the next billing period.

However, contrary to other DSOs practices, Croatian metering regulation envisages self-reading for households (up to 10 time a year; if household supplies the readings, the utility has the responsibility to take an actual reading every 6 months.). This way, if households would like all bills to be based on actual meter readings instead of estimates, they may supply the utility with readings during estimated billing periods.

9.6. REGULARITY OF METER READINGS

This section of the report evaluates the regularity of meter readings, according to provisions in metering regulation. The performance have been evaluated based on:

- number of readings conducted during a year and
- number of readings conducted in a timely manner (within a prescribed schedule).

In what follows labels have the following meaning:

- “Percentage of meters read according to schedule and in a timely manner” is given as a percentage of all meters that are read (at least once) during a year.
- “Percentage of meters read according to schedule” gives a share of meters (out of all meters in service in observed consumption category) that are read in line with the prescribed number of readings per one year (some of these readings might not be conducted in a timely manner, i.e. standard given in Table 9-2 3rd column is breached).
- “Percentage of breach” gives a share of meters (out of all meters in service in observed consumption category) that are read but not in line with the prescribed number of readings per one year.
- “No meter reading during a year” gives a share of meters (out of all meters in service in observed consumption category) that are not read during a year.

For some consumption category sum of percentage of meters read according to schedule, percentage of breach and percentage of meters without any reading during a year added up must give 100 %.

In this report:

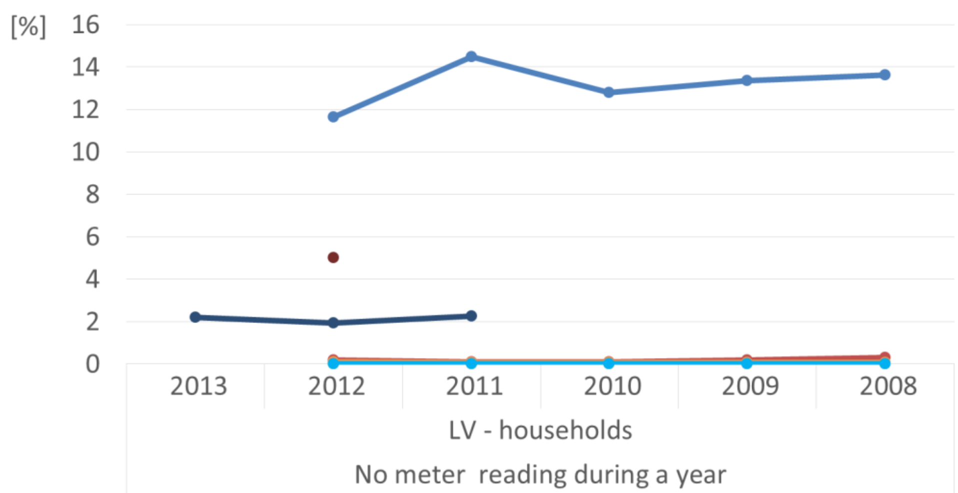
- two DSOs did not provide data: EPHZHB and KEDS,
- EVNM provided yearly lump sum data for all consumption categories,
- HEP provided data only for 2012.

With regard of meters without any reading within a year in households category, the highest share can be observed in Albanian OSHEE. It is followed by Croatian HEP and Macedonian EVNM, while the rest of the DSOs (except EPHZHB and KEDS which have not provided data) exhibit much lower levels.

Croatia exhibited such share because, contrary to other DSO with monthly readings, households are as a rule read twice a year (i.e. there is a higher possibility of not being read during a year).

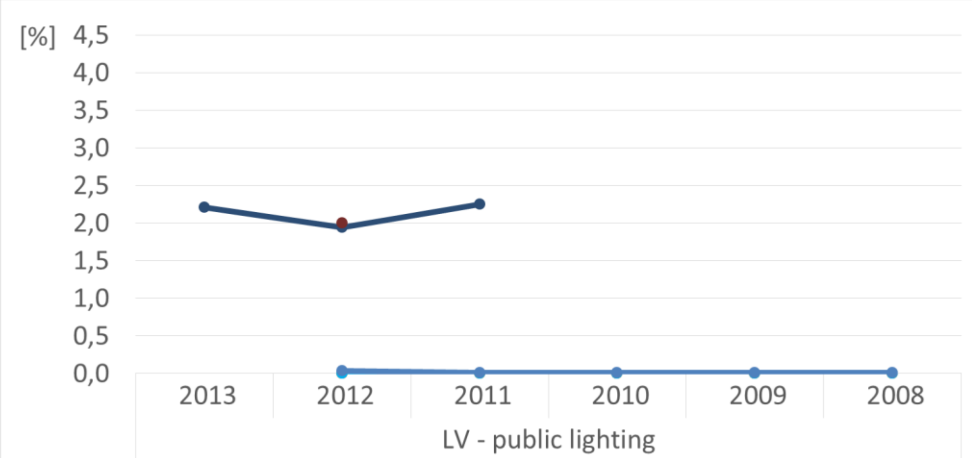
Primarily because of ordinary monthly readings in all other consumption categories DSOs are exhibiting relatively low shares of meters without any reading during a year:

- less than 2,3 % of meters in LV public lighting category,
- less than 4 % of meters in LV commercial without peak power registration category,
- less than 2,3 % of meters in LV commercial with peak power registration category.



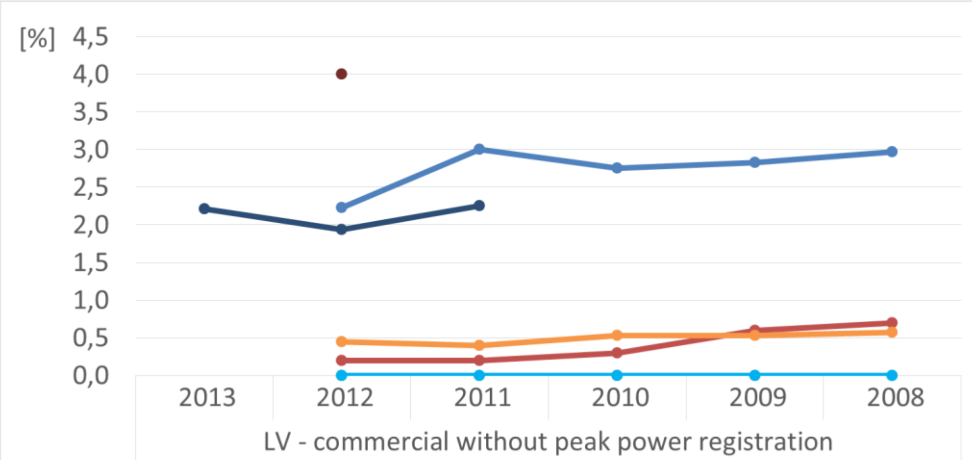
	2013	2012	2011	2010	2009	2008
EDB		0,20	0,10	0,10	0,20	0,30
EPBIH		0,00	0,00	0,00	0,00	0,00
EPS		0,10	0,08	0,08	0,06	0,07
ERS		0,00	0,00	0,00	0,00	0,00
EVNM	2,21	1,94	2,25			
HEP		5,00				
OSHEE		11,64	14,50	12,79	13,35	13,63

Figure 9.6 Share of LV households connection points without meter reading during a year



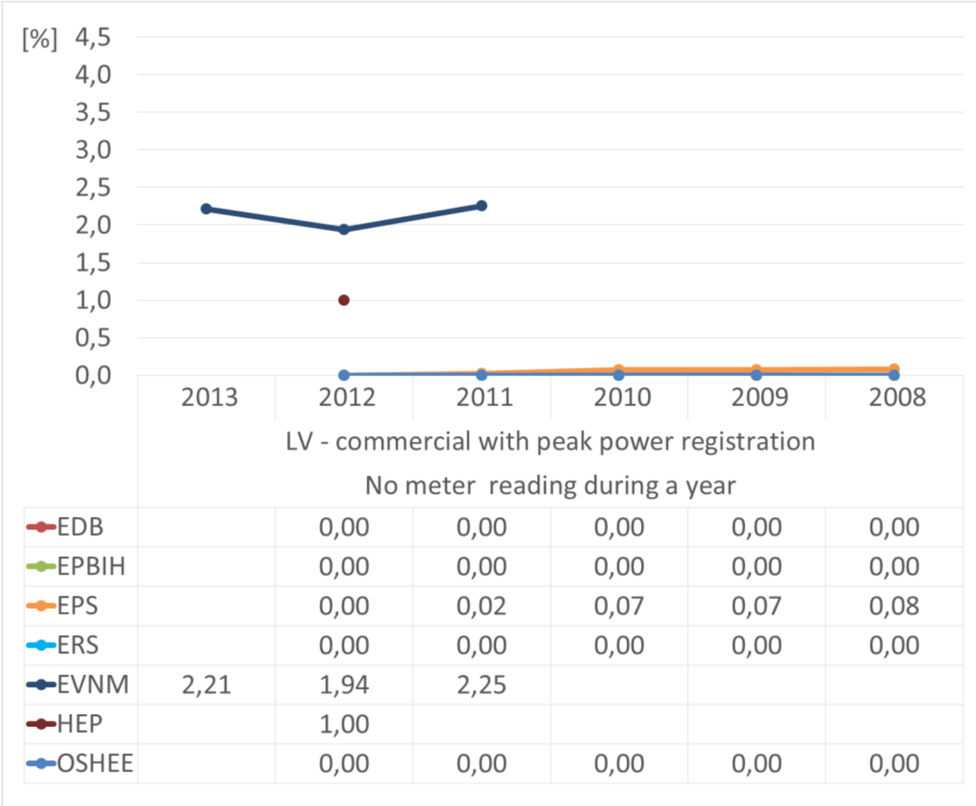
	2013	2012	2011	2010	2009	2008
EDB		0,00	0,00	0,00	0,00	0,00
EPBIH		0,00	0,00	0,00	0,00	0,00
EPS		0,00	0,00	0,00	0,00	0,00
ERS		0,00	0,00	0,00	0,00	0,00
EVNM	2,21	1,94	2,25			
HEP		2,00				
OSHEE		0,04	0,01	0,01	0,01	0,01

Figure 9.7 Share of LV public lighting connection points without meter reading during a year



	2013	2012	2011	2010	2009	2008
EDB		0,20	0,20	0,30	0,60	0,70
EPBIH		0,00	0,00	0,00	0,00	0,00
EPS		0,45	0,40	0,53	0,53	0,57
ERS		0,00	0,00	0,00	0,00	0,00
EVNM	2,21	1,94	2,25			
HEP		4,00				
OSHEE		2,23	3,01	2,75	2,83	2,97

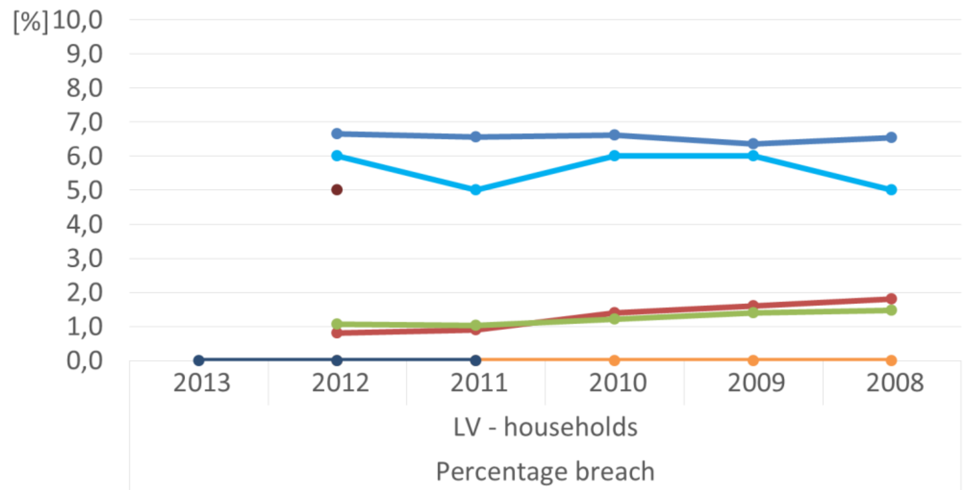
Figure 9.8 Share of LV commercial connection points without peak power registration without meter reading during a year



	2013	2012	2011	2010	2009	2008
EDB		0,00	0,00	0,00	0,00	0,00
EPBIH		0,00	0,00	0,00	0,00	0,00
EPS		0,00	0,02	0,07	0,07	0,08
ERS		0,00	0,00	0,00	0,00	0,00
EVNM	2,21	1,94	2,25			
HEP		1,00				
OSHEE		0,00	0,00	0,00	0,00	0,00

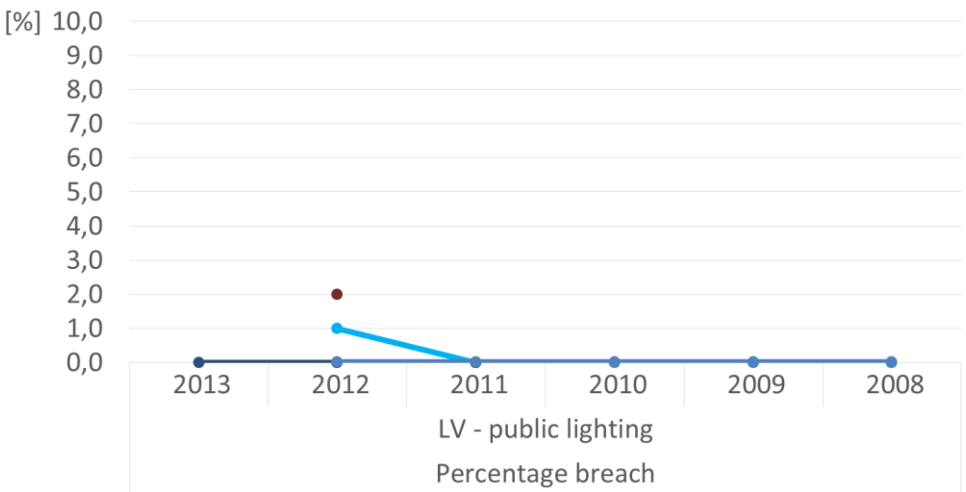
Figure 9.9 Share of LV commercial connection points with peak power registration without meter reading during a year

Figure 9.10, Figure 9.11, Figure 9.12 and Figure 9.13 give percentages of meters not read according to prescribed schedule in the observed period. It could be observed that most breaches occurred in households category; e.g. Albanian OSHEE has 6,55 % average for 2008-2012 period, ERS has 5,6 % average for 2008-2012 and HEP 5 % in 2012.



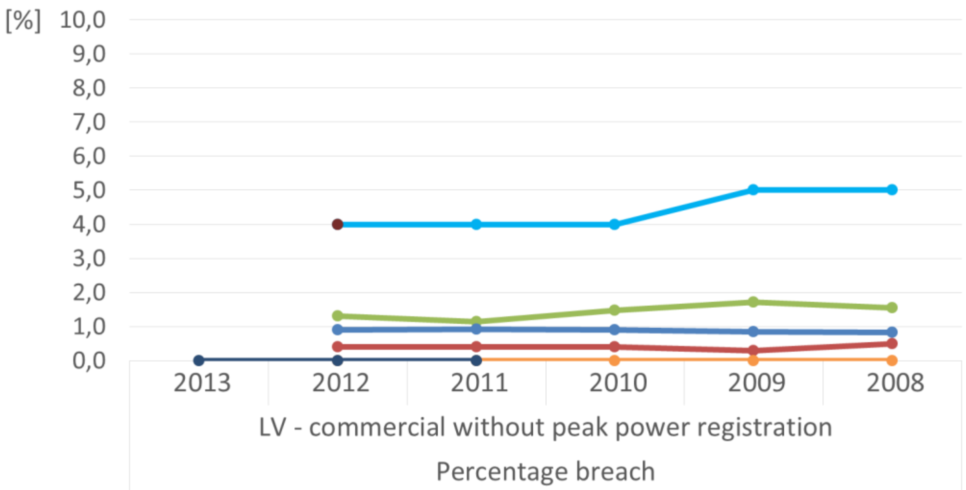
	2013	2012	2011	2010	2009	2008
EDB		0,80	0,90	1,40	1,60	1,80
EPBIH		1,06	1,03	1,21	1,40	1,47
EPS		0,00	0,00	0,00	0,00	0,00
ERS		6,00	5,00	6,00	6,00	5,00
EVNM	0,00	0,00	0,00			
HEP		5,00				
OSHEE		6,65	6,56	6,62	6,37	6,55

Figure 9.10 Share of households with readings not in line with the prescribed number of readings per one year



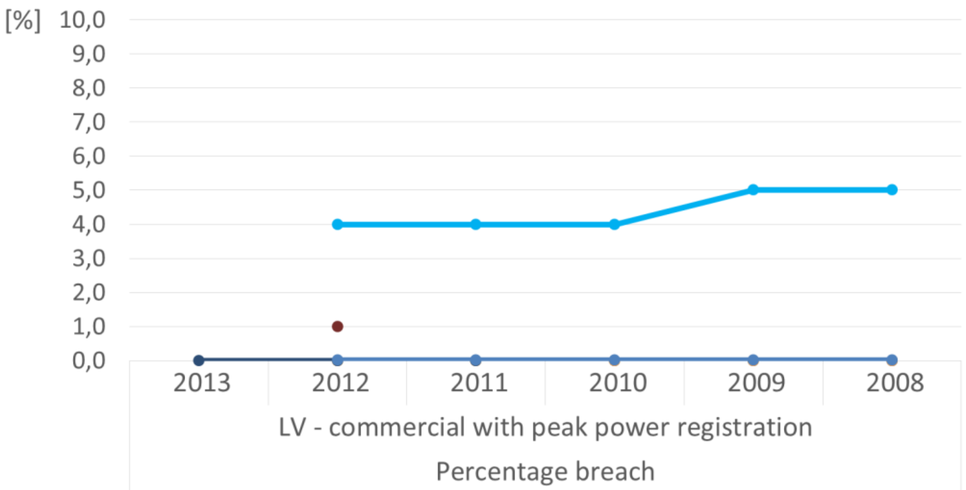
	2013	2012	2011	2010	2009	2008
EDB		0,00	0,00	0,00	0,00	0,00
EPBIH		0,00	0,00	0,00	0,00	0,00
EPS		0,00	0,00	0,00	0,00	0,00
ERS		1,00	0,00	0,00	0,00	0,00
EVNM	0,00	0,00	0,00			
HEP		2,00				
OSHEE		0,01	0,01	0,01	0,01	0,01

Figure 9.11 Share of public lighting with readings not in line with the prescribed number of readings per one year



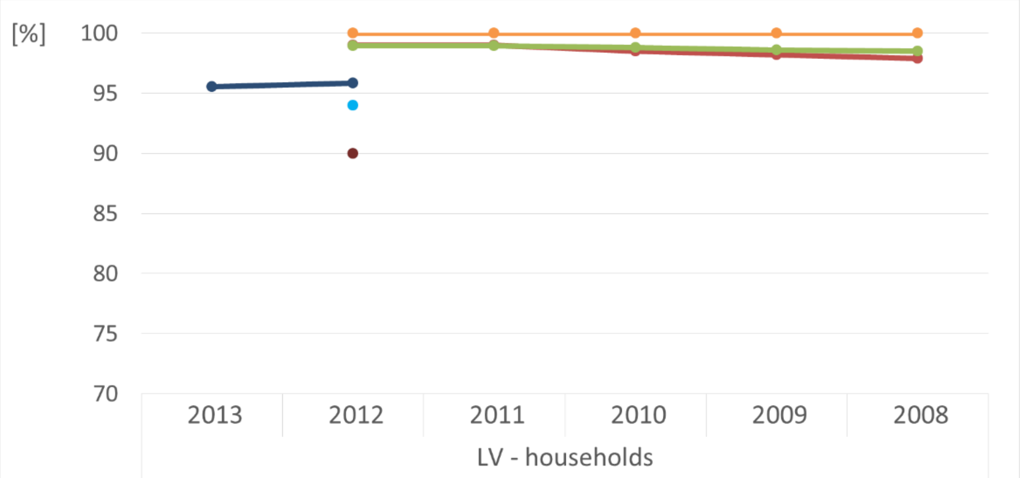
	2013	2012	2011	2010	2009	2008
EDB		0,40	0,40	0,40	0,30	0,50
EPBIH		1,31	1,15	1,47	1,72	1,54
EPS		0,00	0,00	0,00	0,00	0,00
ERS		4,00	4,00	4,00	5,00	5,00
EVNM	0,00	0,00	0,00			
HEP		4,00				
OSHEE		0,91	0,92	0,91	0,84	0,83

Figure 9.12 Share of commercial customers without peak power registration with readings not in line with the prescribed number of readings per one year



	2013	2012	2011	2010	2009	2008
EDB		0,00	0,00	0,00	0,00	0,00
EPBIH		0,00	0,00	0,00	0,00	0,00
EPS		0,00	0,00	0,00	0,00	0,00
ERS		4,00	4,00	4,00	5,00	5,00
EVNM	0,00	0,00	0,00			
HEP		1,00				
OSHEE		0,01	0,01	0,01	0,01	0,01

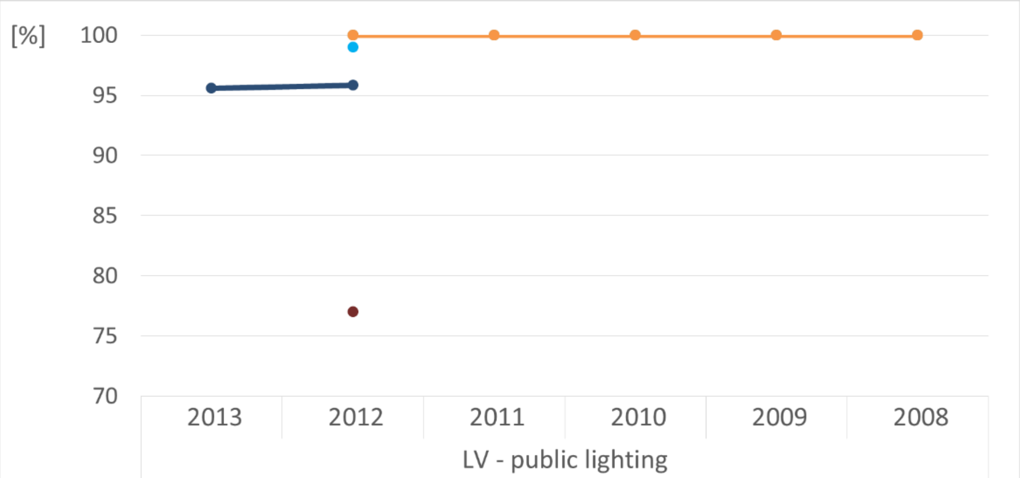
Figure 9.13 Share of commercial customers with peak power registration with readings not in line with the prescribed number of readings per one year



Percentage of meters read according to schedule and in a timely manner

	2013	2012	2011	2010	2009	2008
EDB		99,00	99,00	98,50	98,20	97,90
EPBIH		98,94	98,97	98,79	98,60	98,53
EPS		100,00	100,00	100,00	100,00	100,00
ERS		94,00				
EVNM	95,57	95,85				
HEP		90,00				

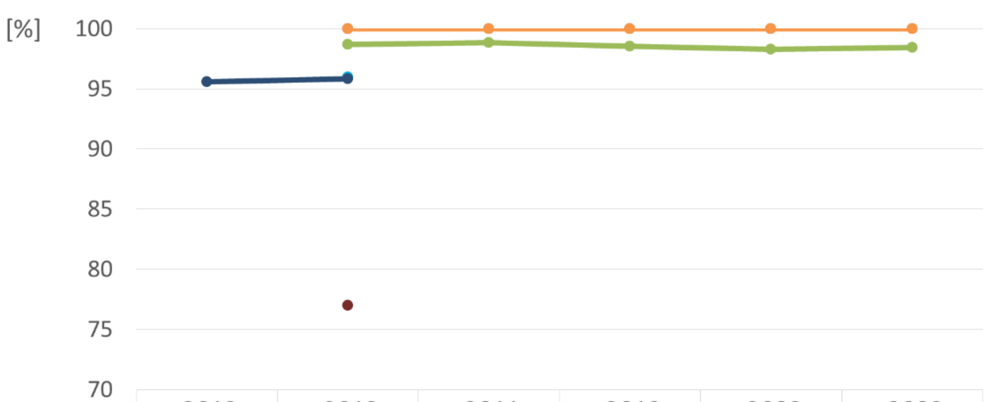
Figure 9.14 Share of households with meter reading according to schedule and in a timely manner



Percentage of meters read according to schedule and in a timely manner

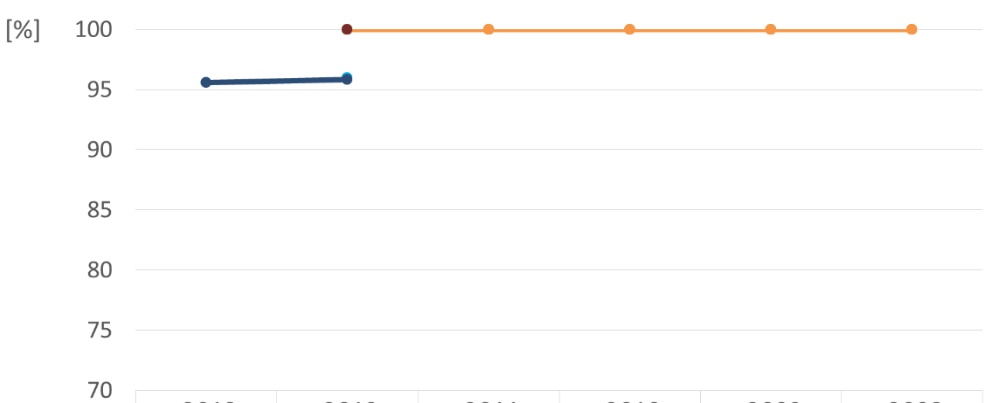
	2013	2012	2011	2010	2009	2008
EDB		100,00	100,00	100,00	100,00	100,00
EPBIH		100,00	100,00	100,00	100,00	100,00
EPS		100,00	100,00	100,00	100,00	100,00
ERS		99,00				
EVNM	95,57	95,85				
HEP		77,00				

Figure 9.15 Share of LV public lighting with meter reading according to schedule and in a timely manner



	2013	2012	2011	2010	2009	2008
	LV - commercial without peak power registration					
	Percentage of meters read according to schedule and in a timely manner					
EDB		100,00	100,00	100,00	100,00	100,00
EPBIH		98,69	98,85	98,53	98,28	98,46
EPS		100,00	100,00	100,00	100,00	100,00
ERS		96,00				
EVNM	95,57	95,85				
HEP		77,00				

Figure 9.16 Share of LV commercial customers without peak power registration with meter reading according to schedule and in a timely manner



	2013	2012	2011	2010	2009	2008
	LV - commercial with peak power registration					
	Percentage of meters read according to schedule and in a timely manner					
EDB		100,00	100,00	100,00	100,00	100,00
EPBIH		100,00	100,00	100,00	100,00	100,00
EPS		100,00	100,00	100,00	100,00	100,00
ERS		96,00				
EVNM	95,57	95,85				
HEP		100,00				

Figure 9.17 Share of LV commercial customers with peak power registration with meter reading according to schedule and in a timely manner

9.7. OBSERVATIONS/RECOMMENDATIONS

In the observed region unauthorized connection points (connections without metering) and also unauthorized use of meters (e.g. tempered meters, tempered time switch, broken seal) are present, however they are not prevalent. Although their shares (given as a portion of total number of connection points) are not higher than 1,7%, in some years detected irregularities exceeded 20 % of conducted inspections (either planned inspections or inspections due to reported finding of irregularity/fraud). Therefore, to detect unauthorized connections and lower losses caused by them in the system, customer connections and meters should be frequently inspected. Besides, expansion of meter coverage is an important means to allow improved internal energy auditing by which the DSO is able to track energy flows from substations to customers and detect theft (e.g. such practice has been efficiently implemented in EPHZHB). On this point it should be mentioned that while this report focuses on meter coverage of customer accounts, meter coverage at substation and feeder levels is also important.

In the observed region monthly readings of almost all electricity meters are required which is very valuable initial position for market activities and management of distribution system (exception are households in Croatia). Croatia is the only country with self-reading for households envisaged by the law. Self-reading shall be strongly encouraged for customers that are not read monthly.

Because of ordinary monthly readings all DSOs are exhibiting relatively low shares of meters without any reading during a year. Exception is Albanian OSHEE (with 13 % average for 2008-2012 period) in households category and HEP in households and LV commercial customers without peak power registration (5 % and 4 % in 2012 respectively). If there is no access to the meter a DSO estimates the account. It is very important to have at least one reading per year. So, where access is an ongoing problem, the regulator shall require a customer to make an appointment to provide access for a special meter read (special reading means reading performed outside of the usual reading cycle for the customer/meter). Ultimately DSO shall have the authority to discontinue supplying premises where there is failure to provide this access.

Percentages of meters not read according to prescribed schedule in the observed period are all lower than 7 %, with the highest values in households category. Performance of DSOs in this regards shall be subject to quality of service standards established by regulatory authority (e.g. standard aimed to have all meters read when scheduled). Remote reading of meters and smart metering programs facilitate easier meter reading and billing based on the electricity consumer actually consumed (i.e. DSO will not have to estimate its electricity consumption).

10. DISCONNECTION AND RECONNECTION / RE-SUPPLY

This section deals with disconnections of customers due to non-payment of bills and/or theft (illegal connection).

Table 10-1 Data provided by DSOs on legal conditions for disconnection and penalties

DSO	Legal conditions for disconnection	Penalties for illegal connections
EDB	Prescribed by the Electricity Law and the General terms and conditions for the supply of electricity	Customer is obliged to pay charge for illegal consumption for the period of illegal consumption. The quantity of electricity (kWh) depends on voltage level, nominal current of connection fuses or nominal current of conductors for the connection and tariff level (household, industry, etc). DSO has right to disconnect the customer and initiate criminal proceedings.
EPBIH	Prescribed by the Electricity Law and the General terms and conditions for the supply of electricity	Prescribed by the Electricity Law.
EPHZHB	Prescribed by the Electricity Law and the General terms and conditions for the supply of electricity	General terms and conditions for the supply of electricity prescribe methodology for illegal electricity consumption estimation.
ERS	Prescribed by general terms and conditions for the supply of electricity, electricity supply suspension and/or limitation to customer and customer disconnection are due to: • customer connected to the distribution system without approval, • there is evidence of theft of service, • there has been tampering with the equipment of the DSO, • non-payment in a timely manner, • using service in a manner that interferes with the service of others or the operation of nonstandard equipment, • customer allowed another person to connect to their installations or use electricity supplied through their meter, • customer does not allow access to his/her property or to the property under his/her tenure for the purpose of preventing DSO to perform metering, reading, control, calibration, replacement of meters, • customer breached provisions of the supply contract.	General terms and conditions for the supply of electricity prescribe methodology for illegal electricity consumption estimation. Unauthorized consumption shall be documented by competent authority of the Ministry of Internal Affairs. The relevant police station, following completion of documenting, submits to the competent criminal prosecutor application for investigation based on suspicion of the commission of acts of theft of electricity. Based on evidence of illegal electricity consumption, the competent criminal prosecutor press charges in front of the competent court. According to the Electricity Law illegal connection to the electrical network is sentenced by a imprisonment up to 1 year.

DSO	Legal conditions for disconnection	Penalties for illegal connections
EPS	Legal framework differs customer electricity supply suspension and customer disconnection. Customer electricity supply suspension is due to: • failure to comply with the connection contract/authorization, • failure to reduce peak power exceeding **contracted** connection power required by the DSO, • customer allowed another person to connect to their installations or use electricity supplied through their meter, • replacement of main fuses or power/current limiting devices by fuses or limiting devices whose nominal current is higher than contracted or approved, not affecting accuracy of electricity metering, • failure to comply with the terms of supply contract (on supplier request), • on customer request. Customer disconnection is due to: • electricity supply suspension lasting longer than a year, • using service in a manner that interferes with the service of others or the operation of nonstandard equipment, • unauthorized electric service usage: 1. customer connected to the distribution system without approval, 2. unauthorized reconnection, 3. electric energy consumption without a metering device or with bypassing the metering device, 4. electric energy consumption using a metering device that the customer has disabled from recording consumption accurately, 5. electric energy consumption using a metering device on which the seal of the DSO or an authorized organization has been damaged by the customer, 6. replacement of main fuses or power/current limiting devices by fuses or limiting devices whose nominal current is higher than contracted or approved, thus affecting accuracy of electricity metering.	By detection of illegal electric service usage, customer electric service is disconnected and parallel proceeding (criminal and civil) are initiated. In accordance with a criminal law illegal electric service usage is sentenced by a fine or imprisonment up to 3 years (most common judge issues a suspended sentence). In the civil proceeding illegal electric service usage is sentenced by a fine (compensation to DSO for damage caused by illegal electric service usage). For estimation of illegal electricity consumption, period of illegal consumption cannot be longer than 12 months (usually period form the last connection inspection). Illegal consumption is estimated based on based on voltage level and nominal current of connection fuses or nominal current of conductors for the connection.
EVNM	Prescribed by Supply Rules and Distribution Grid Code. • DSO, on Supplier request, has right to disconnect the customer because of one unpaid bill in prescribed time period.	Customer is obliged to pay charge for illegal consumption for the period of illegal consumption, but not longer than 12 months. The quantity of electricity (kWh) depends on voltage

DSO	Legal conditions for disconnection	Penalties for illegal connections
EVNM	• DSO has right to disconnect the customer in case of: 1. customer connected to the distribution system without approval, 2. customer does not allow access to his/her property or to the property under his/her tenure for the purpose of preventing DSO to perform metering, reading, control, calibration, replacement of meters, 3. the existing consumer has denied or has not signed the Electricity Supply Contract with the Supplier, 4. it has been ordered by a competent court or other competent authority, 5. the use of distribution system users' facilities, devices and installations causes immediate hazard for the life and health of people and the property, 6. the approval decision's validity for connecting to the distribution system has expired.	level, nominal fuses and tariff level (household, industry, etc). DSO has right to initiate judicial procedure for theft of electricity in accordance with a Criminal Law.
HEP	Unauthorized (illegal) use of electricity is prescribed by General terms and conditions for the supply of electricity as: • failure to pay a bill owed to the supplier/DSO or to make a deferred payment arrangement by the date of disconnection (prior to disconnecting service DSO is obliged to send termination notice with scheduled turn-off date), • failure to comply with the terms of a deferred payment arrangement or other payment agreement made with the supplier/DSO (e.g. prepayment, payment guarantees, installation of prepayment meter), • service is connected or reconnected without authority, or there has been tampering with the equipment of the DSO or customer does not allow access to its property or to the property under its tenure for the purpose of preventing DSO to perform metering, reading, control, calibration, replacement of meters.	Unauthorized (illegal) electricity consumption is estimated in line with the methodology prescribed by General terms and conditions for the supply of electricity. DSO disconnects the customer and calculates illegal consumption based on voltage level and nominal current of conductors for the connection. By failure to pay a bill for unauthorized (illegal) electricity consumption owed to the DSO, DSO shall initiate action for damages.
KEDS	Prescribed by Rules on disconnection and reconnection of customers in Energy Sector.	Utility is entitled to charge fees for issuance of the disconnection and reconnection notice, and for disconnection and reconnection of customer. Penalties for the illegal connection are defined in the Law on Electricity. Any person who connects or reconnects illegally shall be punished by fine. (natural persons: € 500-€ 5.000, legal persons: € 5.000 - € 50.000.

DSO	Legal conditions for disconnection	Penalties for illegal connections
OSHEE	According to the energy supply contract the legal conditions for disconnections are: • the client does not pay the invoice within 30 days after the defined deadline, which is no later than the last calendar day of the previous month of the invoiced one, • in order to proceed with the disconnection of the electrical energy supply, the supplier has to notify the client in writing 48 hours in advance.	Penalties for illegal connections are: • disconnection of the electrical energy supply, • criminal charges. According to the Criminal Code illegal connection to the electrical network constitutes a penal contravention and is sentenced by a fine or imprisonment up to 2 years. Stealing electrical power is punishable by a fine or up to three years of imprisonment.

This report focuses on two issues (data have been provided for 2008-2012 period):

- number of supply suspensions (disconnections) due to non-payment of bills to DSO/supplier,
- number of disconnections due to theft.

Regarding reconnection of service or resupply of electricity (after it has been disconnected or electricity supply suspended), data have been segmented into:

- reconnection or resupply without charge:
  - service has been suspended (disconnected) due to non-payment:
    - prescribed (required) time for resupply (time which elapses from the date on which all conditions for resupply of customer are fulfilled),
    - actual average time for reconnection/resupply,
  - service has been disconnected due to unauthorized use of electricity (theft):
    - prescribed (required) time for reconnection (time which elapses from the date on which all conditions for reconnection of customer are fulfilled),
    - actual average time for reconnection/resupply,
- reconnection or resupply with charge:
  - service has been suspended (disconnected) for non-payment:
    - prescribed (required) time for resupply (time which elapses from the date on which all conditions for resupply of customer are fulfilled),
    - actual average time for reconnection/resupply,
    - average fee charged for resupply (reconnection),
  - service has been disconnected for unauthorized use of electricity (theft):
    - prescribed (required) time for reconnection (time which elapses from the date on which all conditions for reconnection of customer are fulfilled),
    - actual average time for reconnection/resupply,
    - average fee charged for reconnection.

In this report:

- OSHEE has not provided data on reconnection or resupply with charge since OSHEE does not apply re-connection charge for disconnections due to non-payment,
- OSHEE, EPHZHB and KEDS provided lump sum data on number of judicial proceedings for non-payment and theft for all consumption categories,
- ERS and EVNM provided lump sum data on number of disconnections and juridical proceedings for non-payment and theft for all consumption categories,
- ERS did not provide data on actuals for reconnection/resupply,
- KEDS did not provide data on actuals for reconnection after unauthorized use of electricity,
- EDB, EPBIH, EPHZHB, ERS, EPS and EVNM have not provided data on reconnection or resupply without charge since reconnection is always charged,
- since 2007 KEDS has not applied re-connection charge for disconnections; besides, remark has been given by KEDS in 2nd questionnaire that data it has provided on re-connection are hardly reliable.

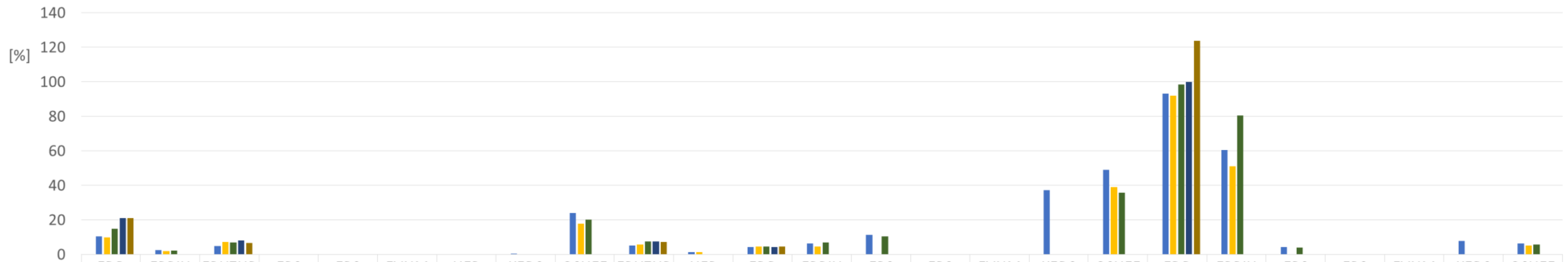
10.1. NUMBER OF SUPPLY SUSPENSIONS AND DISCONNECTIONS DUE TO NON-PAYMENT AND THEFT

Figure 10.1 and Figure 10.2 give ratios of disconnection/supply suspensions and number of connection points in different consumption categories in five consecutive years (2008-2012; only EVNM provided data for 2013). Besides, in Figure 10.3 “total” represents ratio of all disconnection/supply suspensions and total number of connection points in the observed year (i.e. average of all consumption categories).

It could be observed that:

- in LV commercial category higher values are in EDB (with 100 % average for customers with peak power registration in 2008-2012 period), EPBIH (with 64 % average for customers with peak power registration in 2010-2012 period) and OSHEE (with 41% average for customers without peak power registration in 2010-2012 period),
- in households category higher values are in KEDS (with 57,4 % in 2012) and OSHEE (with 25,4 % average for 2010-2012 period),
- in LV public lighting higher values are in OSHEE (with 15,5 % average for 2010-2012 period), KEDS (with 14,1 % in 2012) and EPHZHB (with 10,9 % average for 2008-2012 period),
- on average (for all consumption categories), higher values are in KEDS (with 53,2 % in 2012) OSHEE (with 27,3 % average for 2010-2012 period) and EVNM (with 21,7 % average for 2012-2013 period).

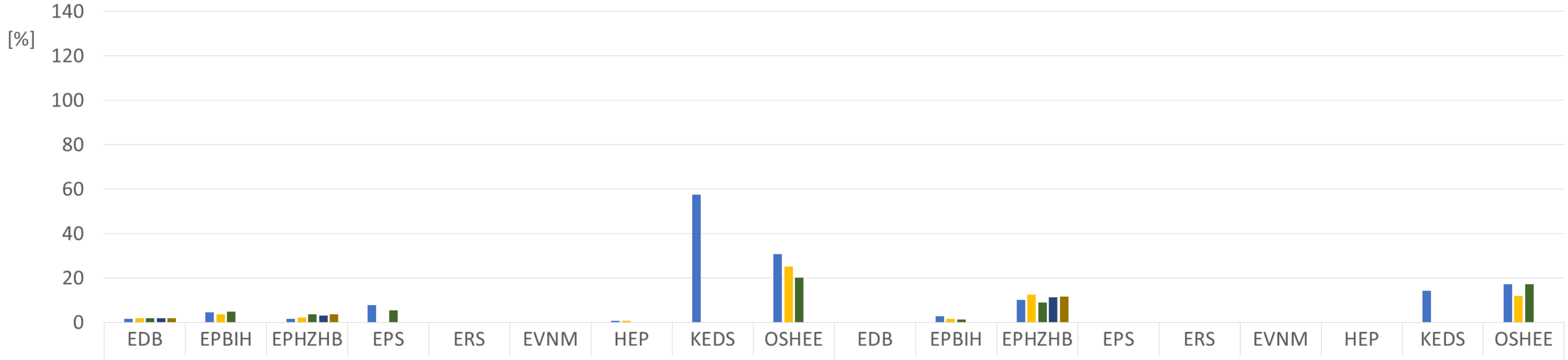
In 2012 there were 1.182.235 disconnections and supply suspensions due to theft and non-payment of bills in SEE DSOs (12 % of all connection points). On average, there were 3.239 disconnections/supply suspensions every day.



	MV									LV - commercial		LV - commercial without peak power registration							LV - commercial with peak power registration						
	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE	EPHZHB	HEP	EDB	EPBIH	EPS	ERS	EVNM	KEDS	OSHEE	EDB	EPBIH	EPS	ERS	EVNM	KEDS	OSHEE
2013																									
2012	10,5	2,6	5,0	0,0				0,6	23,9	5,2	1,3	4,4	6,3	11,3			37,3	49,0	93,2	60,5	4,2			7,9	6,4
2011	10,0	1,8	7,1						17,7	5,8	1,2	4,5	4,6					39,1	92,1	51,1					5,3
2010	15,0	2,3	7,0	0,0					20,2	7,6		4,5	7,1	10,6				35,9	98,4	80,5	3,9				5,9
2009	21,1		8,0							7,6		4,4							100,0						
2008	21,1		6,6							7,3		4,5							123,8						

2013 2012 2011 2010 2009 2008

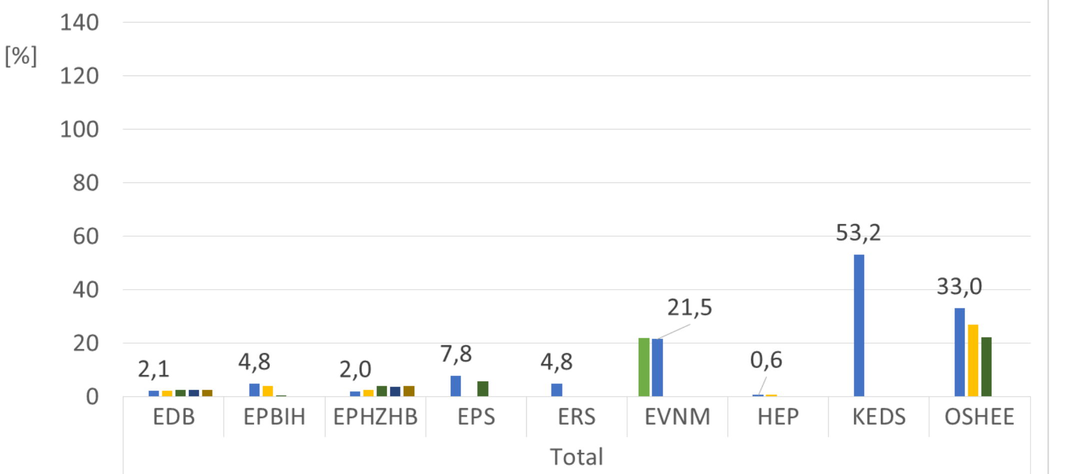
Figure 10.1 Ratio of disconnection/supply suspensions and connection points in MV and LV commercial consumption categories



	LV - households									LV - public lighting								
	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
2013																		
2012	1,7	4,4	1,7	7,7			0,6	57,4	30,8	0,0	2,8	10,2	0,0				14,1	17,3
2011	1,9	3,7	2,1				0,6		25,2	0,0	1,5	12,4						12,0
2010	1,9	4,9	3,5	5,3					20,1	0,0	1,3	9,0	0,0					17,1
2009	1,9		3,1							0,0		11,3						
2008	1,9		3,6							0,0		11,5						

2013 2012 2011 2010 2009 2008

Figure 10.2 Ratio of disconnection/supply suspensions and connection points in LV households, public lighting consumption categories

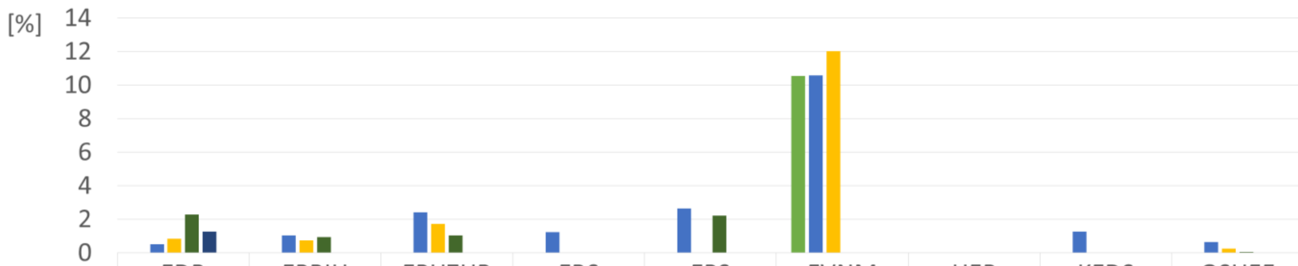


	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
2013						21,9			
2012	2,1	4,8	2,0	7,8	4,8	21,5	0,6	53,2	33,0
2011	2,3	3,9	2,5				0,6		26,9
2010	2,3	0,1	3,9	5,7					22,1
2009	2,4		3,5						
2008	2,5		3,9						

Figure 10.3 Ratio of disconnection/supply suspensions and total number of MV and LV connection points

10.2. NUMBER OF JURIDICAL PROCEEDINGS DUE TO NON-PAYMENT AND THEFT

Figure 10.4 gives ratio of judicial proceedings due to non-payments and electricity theft and total number of MV and LV connection points in some DSO. It could be observed that values are the highest in Macedonian EVNM (with 11 % average for 2011-2013 period), primarily due to non-payments of bills (98,4 %).



	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	KEDS	OSHEE
2013						10,5			
2012	0,5	1,0	2,4	1,2	2,6	10,6		1,3	0,6
2011	0,8	0,7	1,7			12,0			0,2
2010	2,3	0,9	1,0		2,2				0,03
2009	1,3								
2008									

Figure 10.4 Ratio of judicial proceedings due to non-payments and theft and total number of MV and LV connections

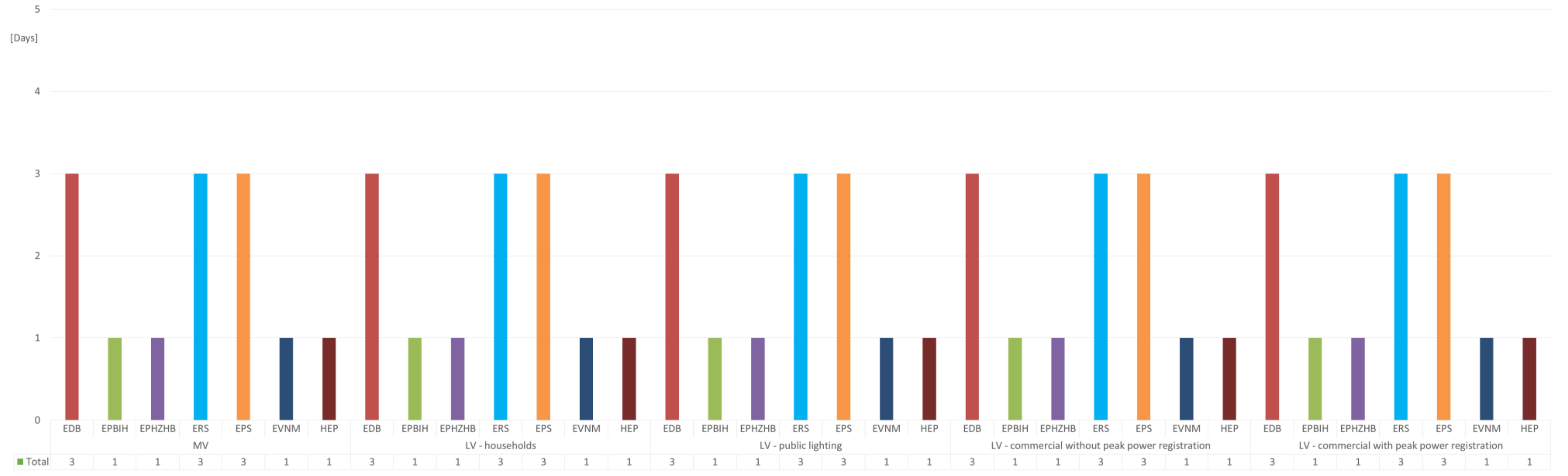
10.3. RECONNECTION/RESUPPLY

Figure 10.5 and Figure 10.6 give prescribed time period for reconnection/resupply upon disconnection due to non-payment and upon disconnection due to electricity theft respectively. It could be observed that in all DSOs prescribed time period for reconnection/resupply upon disconnection due to non-payment is lower than 3 days. In EPS and OSHEE prescribed time periods for reconnection/resupply upon disconnection due to electricity theft are higher than in other DSOs; i.e. 15 days and 10 days respectively, while in other DSOs lower than 3 days.

Figure 10.7 and Figure 10.8 give average of realised time periods for reconnections/resupplies upon disconnections due to non-payment and upon electricity thefts (unauthorised connections) respectively. It could be observed that only in EDB there were certain changes in the observed years (i.e. decline). Beside, comparing actuals with prescribed time period for reconnection/resupply (Figure 10.5, Figure 10.6), it could be observed that actuals in all DSOs are in line with prescribed limits.

Figure 10.9 and Figure 10.10 give average reconnection charges for disconnections due to non-payment. It could be observed that in all DSOs, except in EDB and EPS, charges are lower than 50 €. In EDB, in comparison to other DSOs, charges are very high; they exceed 100 €. In EPS on LV are around 60 €, except for households (30 €), while on MV are 175 €.

Figure 10.11 gives average reconnection charges for disconnections due to electricity theft (unauthorised connection). In comparison to other DSOs, charges in EPS are very high (i.e. 800-1000 €). This is because upon detection of theft, customer in EPS have to borne not only costs of estimated unauthorised electricity consumption but also charges for a connection to the distribution network. Higher values could be observed also in EBD.



	MV							LV - households							LV - public lighting							LV - commercial without peak power registration							LV - commercial with peak power registration						
	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
Total	3	1	1	3	3	1	1	3	1	1	3	3	1	1	3	1	1	3	3	1	1	3	1	1	3	3	1	1	3	1	1	3	3	1	1

Figure 10.5 Data provided by DSOs on prescribed time period for reconnection/resupply upon disconnection due to non-payment

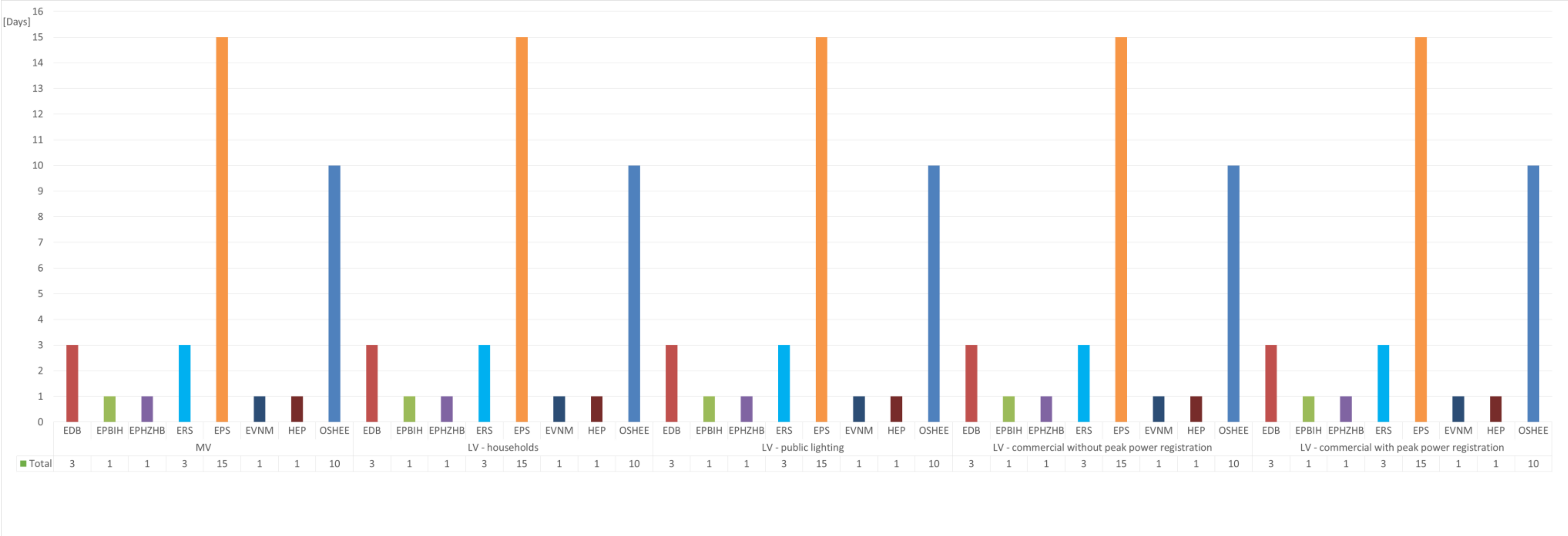
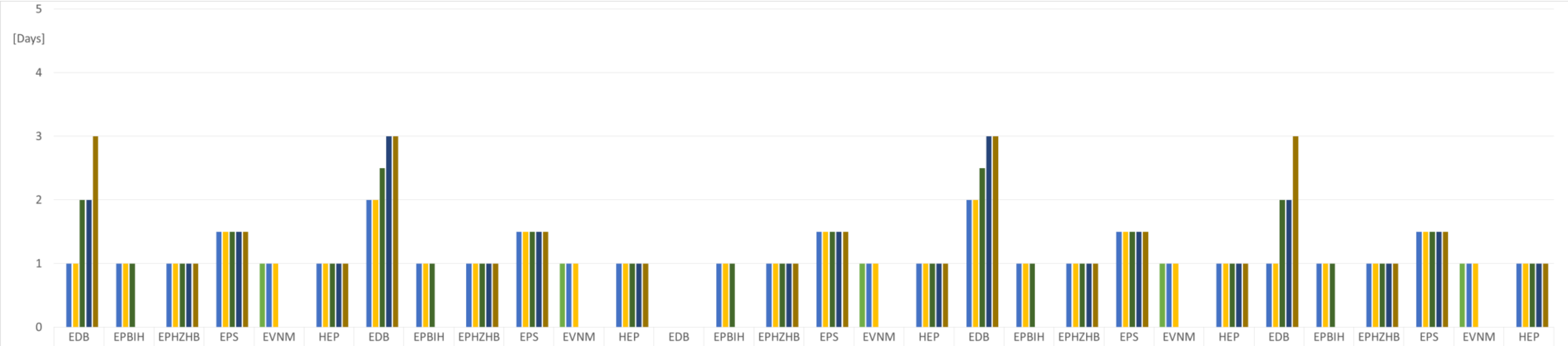


Figure 10.6 Data provided by DSOs on prescribed time period for reconnection upon disconnection due to electricity theft (unauthorized connection)



	MV					
	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	1	1	1	1,5	1	1
2011	1	1	1	1,5	1	1
2010	2	1	1	1,5		1
2009	2		1	1,5		1
2008	3		1	1,5		1

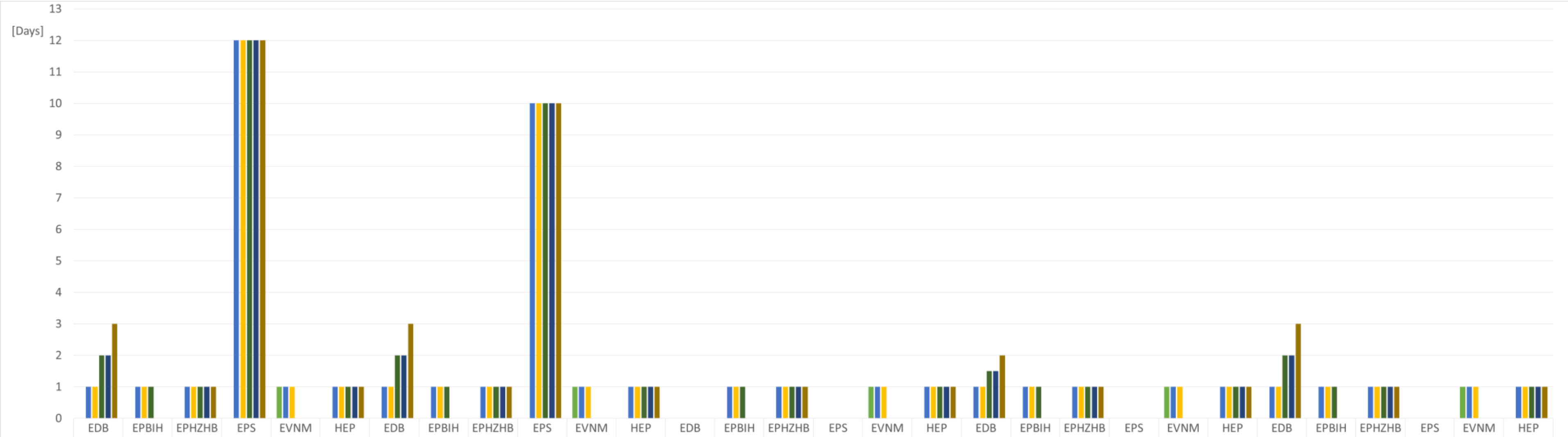
	LV - households					
	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	2	1	1	1,5	1	1
2011	2	1	1	1,5	1	1
2010	2,5	1	1	1,5		1
2009	3		1	1,5		1
2008	3		1	1,5		1

	LV - public lighting					
	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	0	1	1	1,5	1	1
2011	0	1	1	1,5	1	1
2010	0	1	1	1,5		1
2009	0		1	1,5		1
2008	0		1	1,5		1

	LV - commercial without peak power registration					
	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	2	1	1	1,5	1	1
2011	2	1	1	1,5	1	1
2010	2,5	1	1	1,5		1
2009	3		1	1,5		1
2008	3		1	1,5		1

	LV - commercial with peak power registration					
	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	1	1	1	1,5	1	1
2011	1	1	1	1,5	1	1
2010	2	1	1	1,5		1
2009	2		1	1,5		1
2008	3		1	1,5		1

Figure 10.7 Data provided by DSOs on realized (actual) time period for reconnection/resupply upon disconnection due to non-payment



MV	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	1	1	1	12	1	1
2011	1	1	1	12	1	1
2010	2	1	1	12		1
2009	2		1	12		1
2008	3		1	12		1

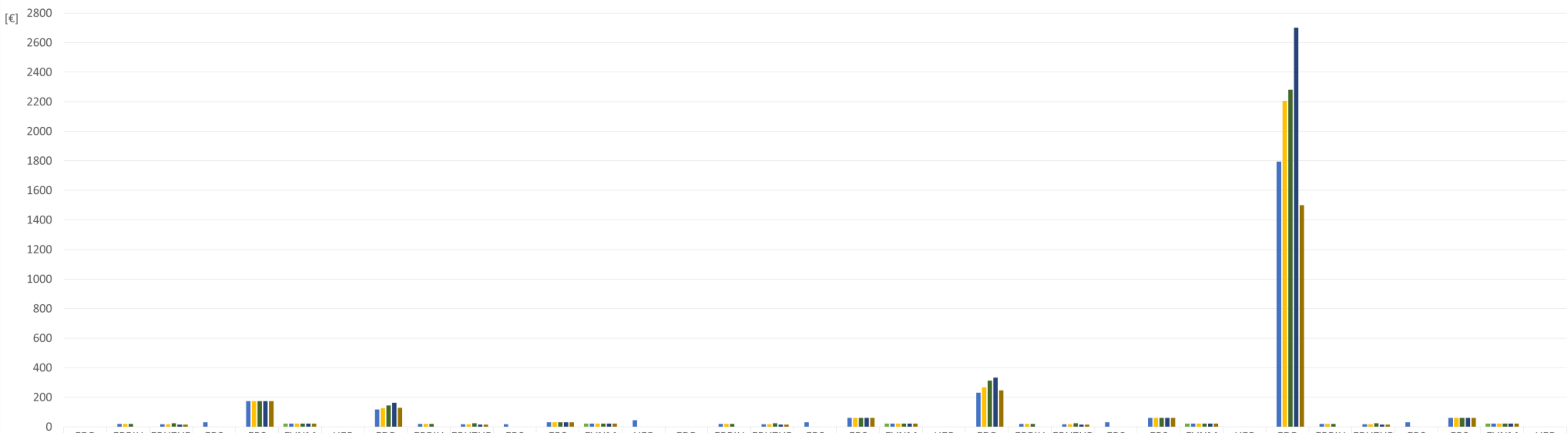
LV - households	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	1	1	1	10	1	1
2011	1	1	1	10	1	1
2010	2	1	1	10		1
2009	2		1	10		1
2008	3		1	10		1

LV - public lighting	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	0	1	1		1	1
2011	0	1	1		1	1
2010	0	1	1			1
2009	0		1			1
2008	0		1			1

LV - commercial without peak power registration	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	1	1	1		1	1
2011	1	1	1		1	1
2010	1,5	1	1			1
2009	1,5		1			1
2008	2		1			1

LV - commercial with peak power registration	EDB	EPBIH	EPHZHB	EPS	EVNM	HEP
2013					1	
2012	1	1	1		1	1
2011	1	1	1		1	1
2010	2	1	1			1
2009	2		1			1
2008	3		1			1

Figure 10.8 Data provided by DSOs on realized (actual) time period for reconnection/resupply upon disconnection due to electricity theft (unauthorized connection)



MV

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013						22	
2012	0	20,42	17	30,28	175	22	
2011	0	20,42	17		175	22	
2010	0	20,68	25		175	22	
2009	0		15		175	22	
2008	0		15		175	22	

LV - households

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013						22	
2012	118	20,42	17	17,66	30	22	45
2011	126	20,42	17		30	22	
2010	144	20,68	25		30	22	
2009	162		15		30	22	
2008	128		15		30	22	

LV - public lighting

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013						22	
2012	0	20,42	17	30,28	60	22	
2011	0	20,42	17		60	22	
2010	0	20,68	25		60	22	
2009	0		15		60	22	
2008	0		15		60	22	

LV - commercial without peak power registration

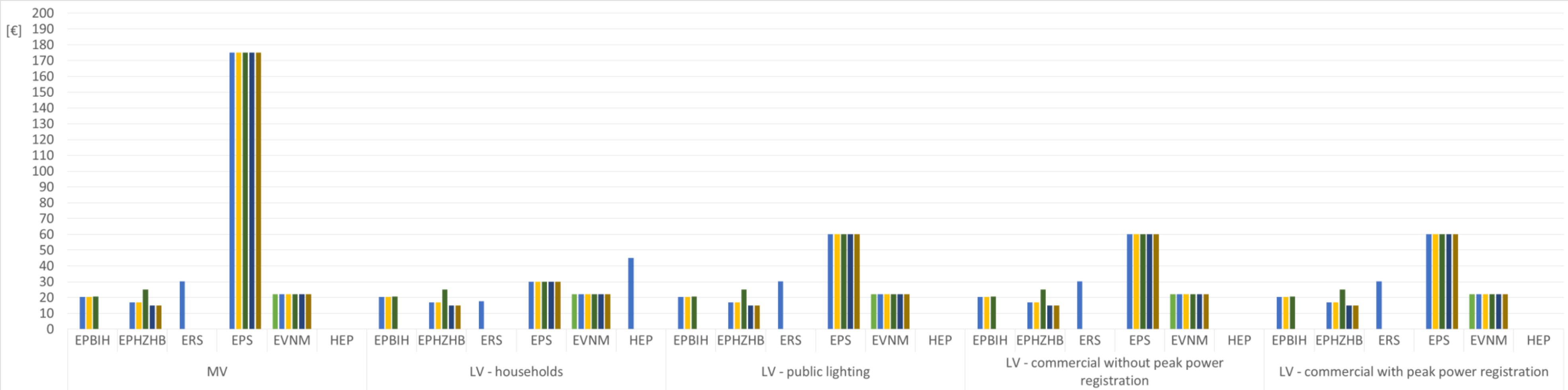
	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013						22	
2012	231	20,42	17	30,28	60	22	
2011	267	20,42	17		60	22	
2010	313	20,68	25		60	22	
2009	333		15		60	22	
2008	246		15		60	22	

LV - commercial with peak power registration

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013						22	
2012	1795	20,42	17	30,28	60	22	
2011	2205	20,42	17		60	22	
2010	2281	20,68	25		60	22	
2009	2700		15		60	22	
2008	1500		15		60	22	

■ 2013 ■ 2012 ■ 2011 ■ 2010 ■ 2009 ■ 2008

Figure 10.9 Data provided by DSOs on average reconnection charges for disconnections due to non-payment



MV	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013					22	
2012	20,42	17	30,28	175	22	
2011	20,42	17		175	22	
2010	20,68	25		175	22	
2009		15		175	22	
2008		15		175	22	

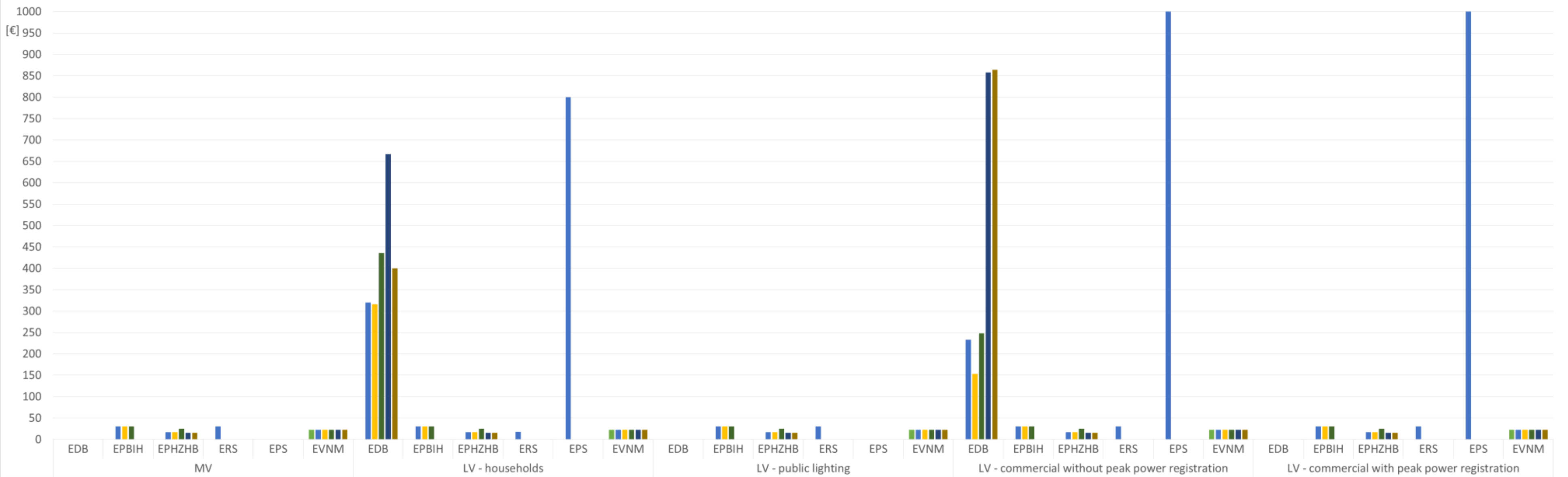
LV - households	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013					22	
2012	20,42	17	17,66	30	22	45
2011	20,42	17		30	22	
2010	20,68	25		30	22	
2009		15		30	22	
2008		15		30	22	

LV - public lighting	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013					22	
2012	20,42	17	30,28	60	22	
2011	20,42	17		60	22	
2010	20,68	25		60	22	
2009		15		60	22	
2008		15		60	22	

LV - commercial without peak power registration	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013					22	
2012	20,42	17	30,28	60	22	
2011	20,42	17		60	22	
2010	20,68	25		60	22	
2009		15		60	22	
2008		15		60	22	

LV - commercial with peak power registration	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
2013					22	
2012	20,42	17	30,28	60	22	
2011	20,42	17		60	22	
2010	20,68	25		60	22	
2009		15		60	22	
2008		15		60	22	

Figure 10.10 Data provided by DSOs on average reconnection charges for disconnections due to non-payment (for better clarity high EDB values intentionally omitted)



MV

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM
2013						22
2012	0	29,91	17	30,28	0	22
2011	0	29,91	17			22
2010	0	29,91	25			22
2009	0		15			22
2008	0		15			22

LV - households

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM
2013						22
2012	320	29,91	17	17,66	800	22
2011	316	29,91	17			22
2010	436	29,91	25			22
2009	667		15			22
2008	400		15			22

LV - public lighting

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM
2013						22
2012	0	29,91	17	30,28	0	22
2011	0	29,91	17			22
2010	0	29,91	25			22
2009	0		15			22
2008	0		15			22

LV - commercial without peak power registration

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM
2013						22
2012	233	29,91	17	30,28	1000	22
2011	153	29,91	17			22
2010	248	29,91	25			22
2009	858		15			22
2008	864		15			22

LV - commercial with peak power registration

	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM
2013						22
2012	0	29,91	17	30,28	1000	22
2011	0	29,91	17			22
2010	0	29,91	25			22
2009	0		15			22
2008	0		15			22

Figure 10.11 Data provided by DSOs on average reconnection charges for disconnections due to electricity theft (unauthorized connection)

10.4. OBSERVATIONS/RECOMMENDATIONS

In almost all DSOs Supply Rules and Distribution Grid Code propose unauthorized connection and use of electricity, legal conditions for disconnection, fines and penalties envisaged and also methodology for estimating unauthorized electricity consumption. Failure to pay a bill owed to the supplier/DSO results in electricity supply suspension until payment of overdue amounts or agreement on payment schedule. However, illegal connection in all DSOs results in service disconnection, juridical proceeding and is sentenced by a fine and/or imprisonment.

General prohibition to disconnect customers does not exists in SEE DSO (the same applies to Europe DSOs). A majority of SEE DSOs have protective measures in place in order to prevent or at least have a process in place to delay disconnection from electricity supply. Groups that benefit from a general prohibition of disconnection are people with life threatening illnesses, hospitals or other specific population groups that are deemed particularly vulnerable in a given state (e.g. mostly elderly persons, households with children, cases in which there is a danger of severe property damage or residential customers dropped by their supplier). Besides protecting vulnerable customers, this report recommends all DSOs to have warning mechanisms in place in order to allow for sufficient time and notification before potential disconnections can take place and also prohibiting disconnection of electricity at critical times (e.g. cold winter months).

In 2012 there were 1.182.235 disconnections and supply suspensions due to theft and non-payment of bills in SEE DSOs; 12% of all connection points. On average, there were 3.239 disconnections/supply suspensions every day. This number is rather high. Kosovo KEDS, Albanian OSHEE and Macedonian EVNM obviously have to struggle with electricity theft and payment of bills in timely manner.

Examination of data provided by DSOs on reconnection/resupply aspects (prescribed period of time to provide service, realised time of service, averages fees charged to customers for service) and observed differences, reveal need of precise definitions and data acquisition harmonisation in future work on benchmarking of SEE DSO.

11. BILLING

Besides the primary function of charging the customers for the network and other power system services, usually including energy supply, the bill is also important as a comprehensive information to customers on energy consumption, prices, opportunities for savings and efficiency. Therefore billing the customers for the service of electricity distribution should be based on accurate periodical meter readings.

The indicators of billing effectiveness provided within this chapter include frequency of provisional billing, bill processing time and frequency of billing errors.

11.1. FREQUENCY OF PROVISIONAL BILLING

Frequency of provisional billing corresponds to the share of bills issued on the bases of estimated consumption instead of a conducted meter reading.

The data were provided by all DSOs, although by some of them not for all five observed years due to transition to new billing software (KEDS) or other issues with older data.

In Bosnia and Herzegovina and Serbia provisional billing is used only exceptionally, due to regular meter readings conducted on monthly bases. Other DSOs have shares of provisional billing up to 17 %, depending on customer categories. For MV customers provisional billing is not an issue in any DSO, and for LV commercial customers with peak power registration (Figure 11.1) it is between 0,7 % and 0,8 % in HEP and between 0,2 % and 0,6 % in KEDS.

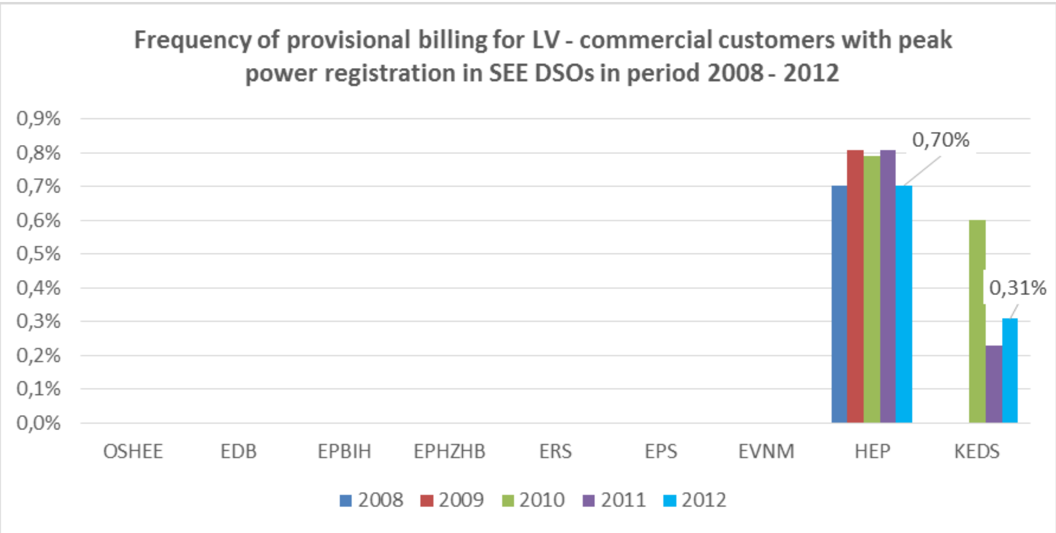


Figure 11.1 Frequency of provisional billing for LV – commercial customers with peak power registration in SEE DSOs in the period 2008 - 2012

Provisional billing is more frequent for customer with low consumption, such as households (Figure 11.2) and LV commercial customers without peak power registration. Due to half-yearly meter readings, with allowed estimation once a year, frequency of provisional billing for households in HEP is about 7 % throughout the whole observed period. The recent data for KEDS show about 3 % and for EVNM about 2 %, while OSHEE showed a significant reduction from 7 % to below 0,2 % since 2008.

Similar to households is the status of LV commercial customers without peak power registration (Figure 11.3), with values for HEP of about 6 %, KEDS up to 5 %, OSHEE down from 0,8 % to below 0,1 %, and EVNM having no issue on provisional billing for non-household customers.

With regard to public lighting (Figure 11.4), frequency of provisional billing in HEP is similar to LV commercial customers without peak power registration (between 6 % and 9 %), while in KEDS it amounts to relatively high 17 %.

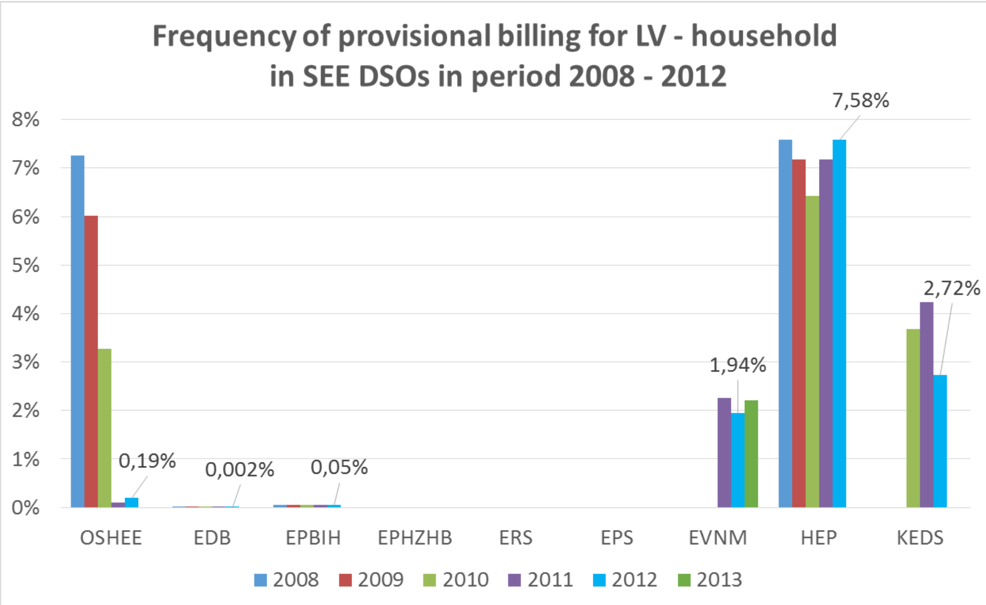


Figure 11.2 Frequency of provisional billing for LV – household in SEE DSOs in the period 2008 - 2012

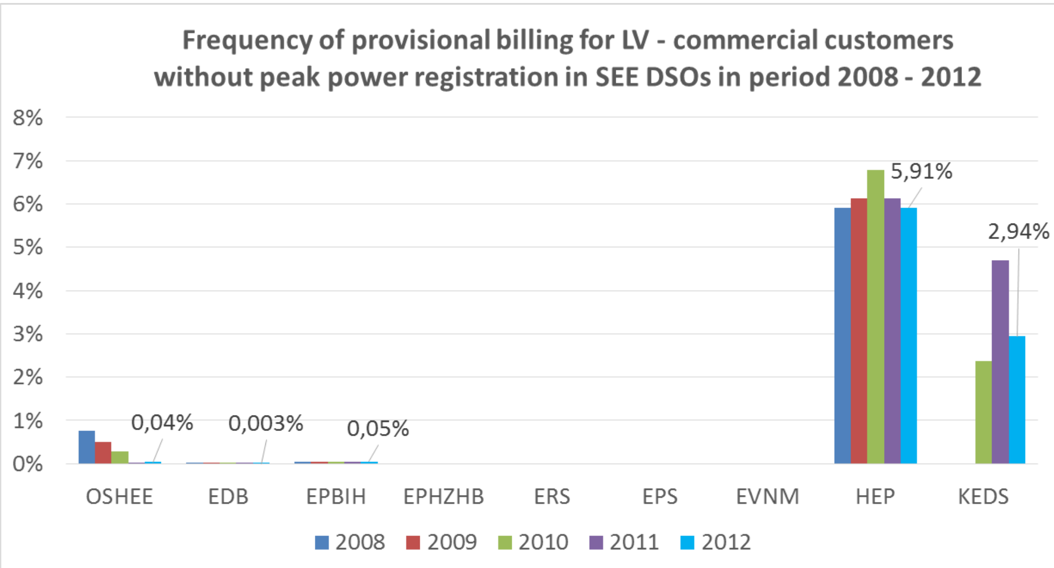


Figure 11.3 Frequency of provisional billing for LV – commercial customers without peak power registration in SEE DSOs in the period 2008 - 2012

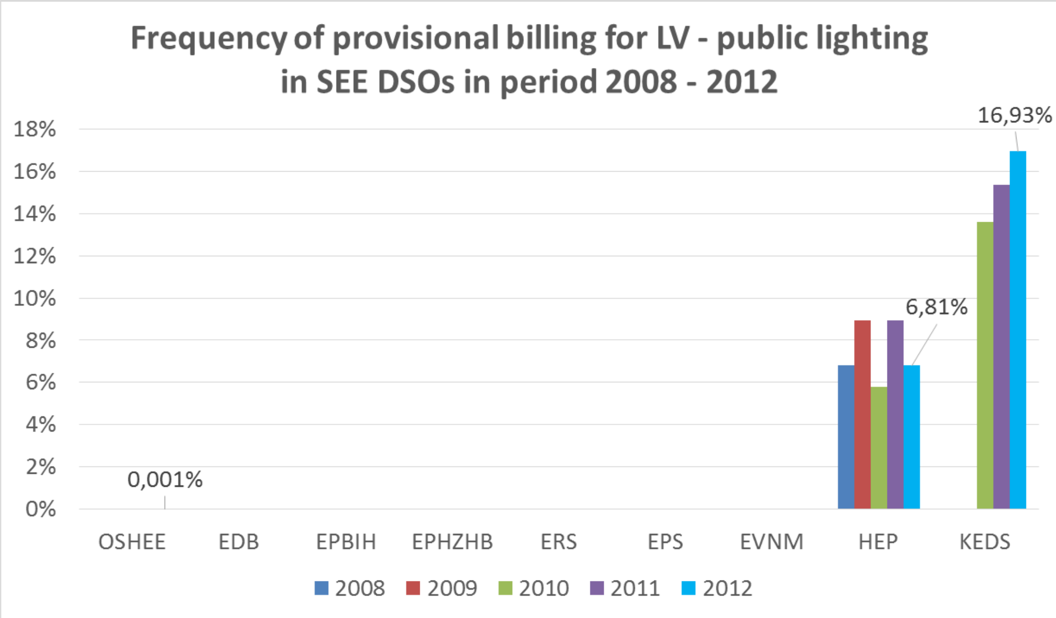
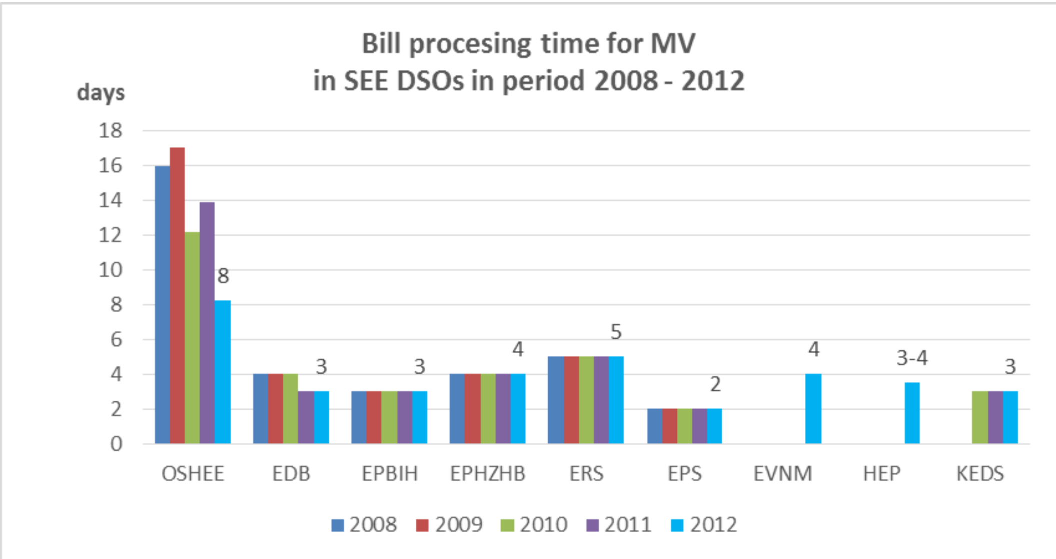


Figure 11.4 Frequency of provisional billing for LV – public lighting in SEE DSOs in the period 2008 - 2012

11.2. BILL PROCESSING TIME

Bill processing time is equal to time interval between meter reading and bill dispatch.

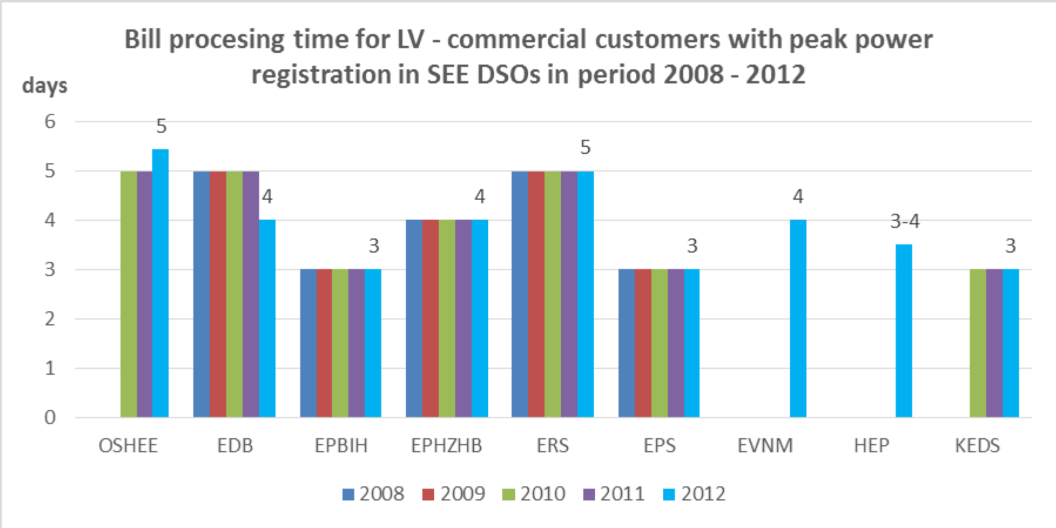
The data were provided by all DSOs. For MV customers (Figure 11.5) and LV customers with peak power registration (Figure 11.6) it is between 2 and 5 days, with exception of OSHEE where it halved from 16 days in 2008 to 8 days in 2012 for MV customers.



Note: HEP estimated at 3-4 days.
EVNM data for 2013.

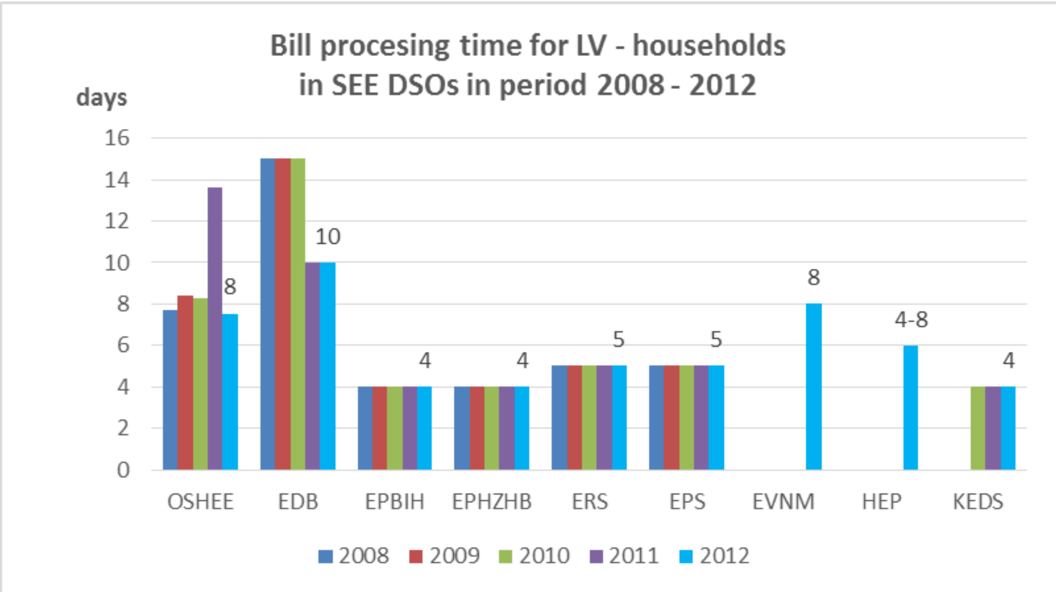
Figure 11.5 Bill processing time for MV in SEE DSOs in the period 2008 - 2012

For households (Figure 11.7) and LV customers without peak power registration (Figure 11.8) in 2012 it is between 3 and 10 days, while for public lighting (Figure 11.9) it is between 3 and 12 days.



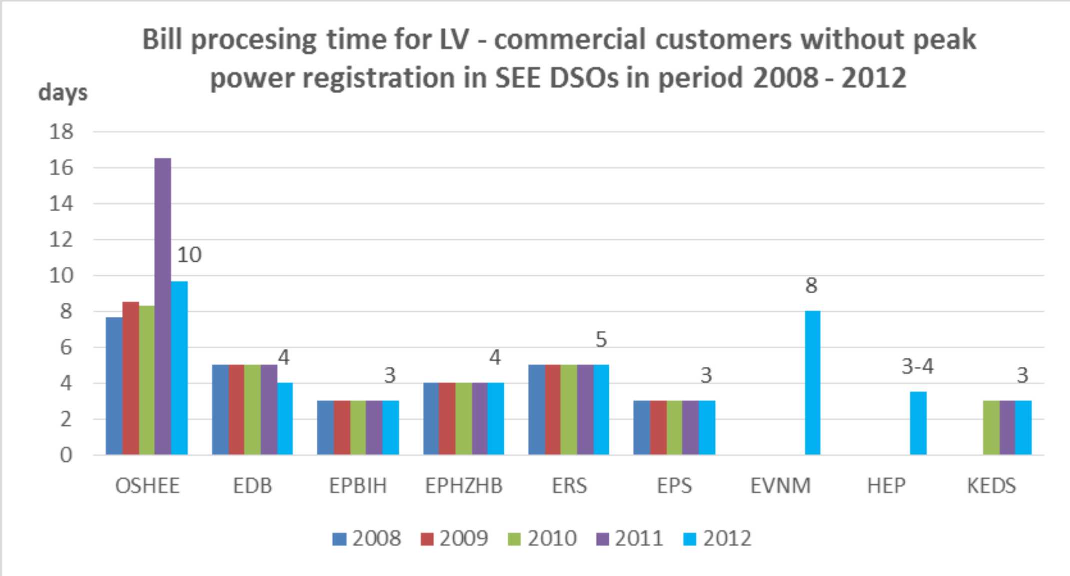
Note: HEP estimated at 3-4 days
EVNM data for 2013

Figure 11.6 Bill processing time for LV – commercial customers with peak power registration in SEE DSOs in the period 2008 - 2012



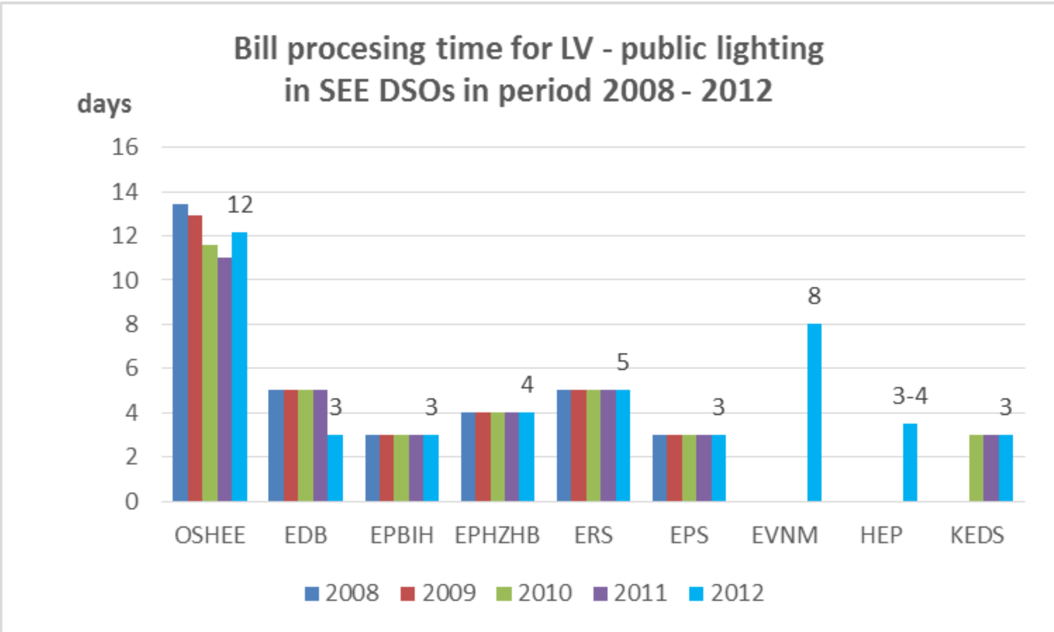
Note: HEP estimated at 4-8 days
EVNM data for 2013

Figure 11.7 Bill processing time for LV - households in SEE DSOs in the period 2008 - 2012



Note: HEP estimated at 3-4 days
EVNM data for 2013

Figure 11.8 Bill processing time for LV – commercial customers without peak power registration in SEE DSOs in the period 2008 - 2012



Note: HEP estimated at 3-4 days
EVNM data for 2013

Figure 11.9 Bill processing time for LV – public lighting in SEE DSOs in the period 2008 - 2012

11.3. FREQUENCY OF BILLING ERRORS

With regard to their impact on customers, within this report billing errors are divided in two main types:

- billing errors corrected before sending the bill to customers and
- billing errors corrected after the bill was sent (regardless whether the error was reported by customer or not).

The first type errors are registered only by OSHEE, EDB, EPBIH and EPS, while all DSOs except ERS reported on the billing errors corrected after sending the bills to customers.

Frequency of billing errors for HV and MV customers is negligible.

Frequency of billing errors corrected before sending the bills to households (Figure 11.10), LV commercial customers with peak power registration (Figure 11.11) and LV commercial customers without peak power registration (Figure 11.12) is below 0,5 %. The internal DSO procedures for billing control contribute to trend of reduction of billing errors.

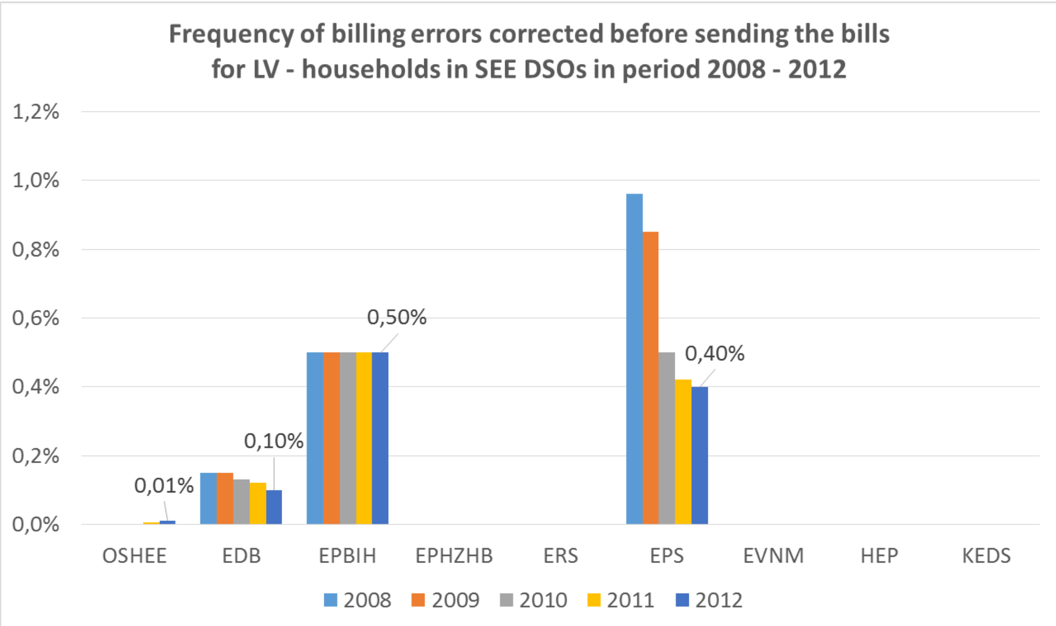


Figure 11.10 Frequency of billing errors corrected before sending the bills for LV - households in SEE DSOs in period 2008 - 2012

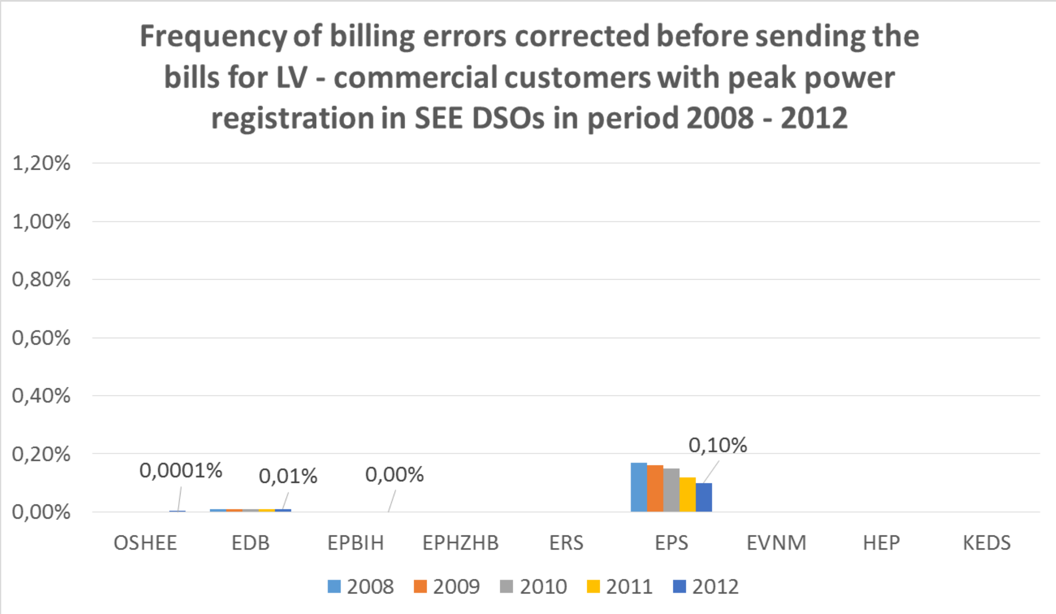


Figure 11.11 Frequency of billing errors corrected before sending the bills for LV - commercial customers with peak power registration in SEE DSOs in period 2008 - 2012

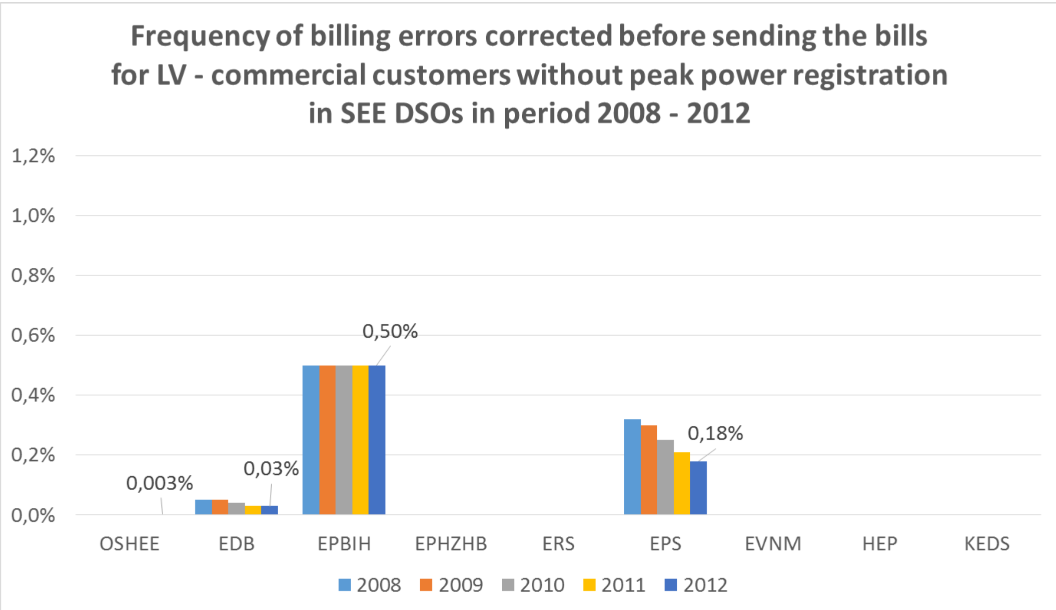


Figure 11.12 Frequency of billing errors corrected before sending the bills for LV - commercial customers without peak power registration in SEE DSOs in period 2008 - 2012

Frequency of billing errors corrected after sending the bills to households (Figure 11.13) is relatively high in KEDS (4 % to 5 %) and HEP where it is between 3,5 % and 4 %, due to half-yearly meter readings and high share of provisional billing. For the rest of DSOs it is between 0,02 % (OSHEE in 2008) and 1,43 % (OSHEE in 2011).

Frequency of billing errors corrected after sending the bills for LV commercial customers with peak power registration (Figure 11.14), LV commercial customers without peak power registration (Figure

11.15) and public lighting (Figure 11.16) is between 0 % and 0,5 %, with exception of HEP where it is between 1,3% and 2,3 % (data for all non-household customers).

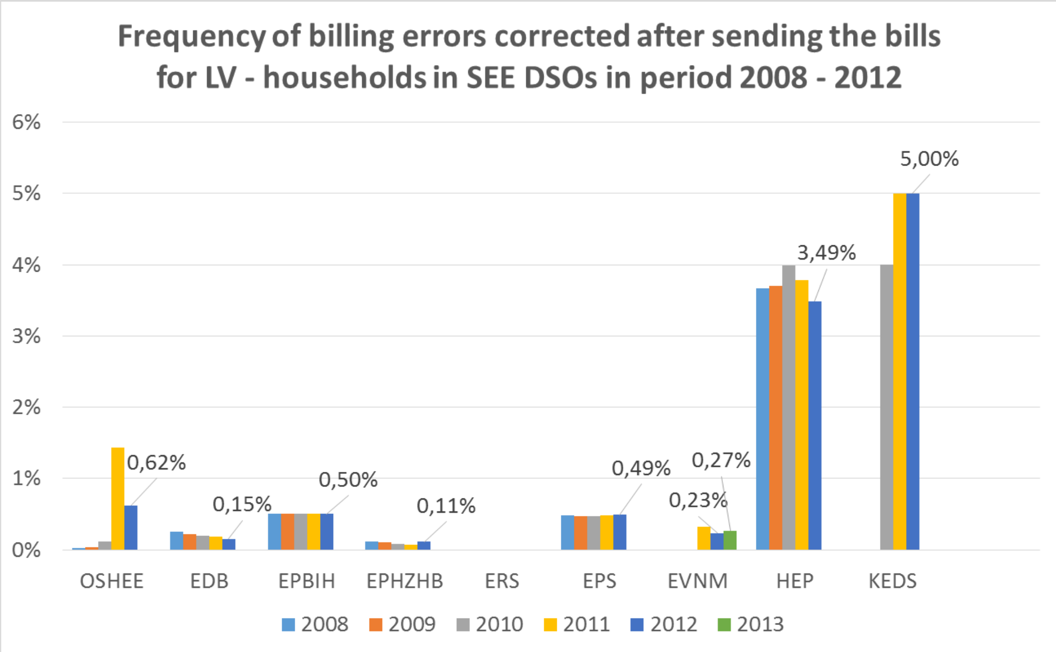
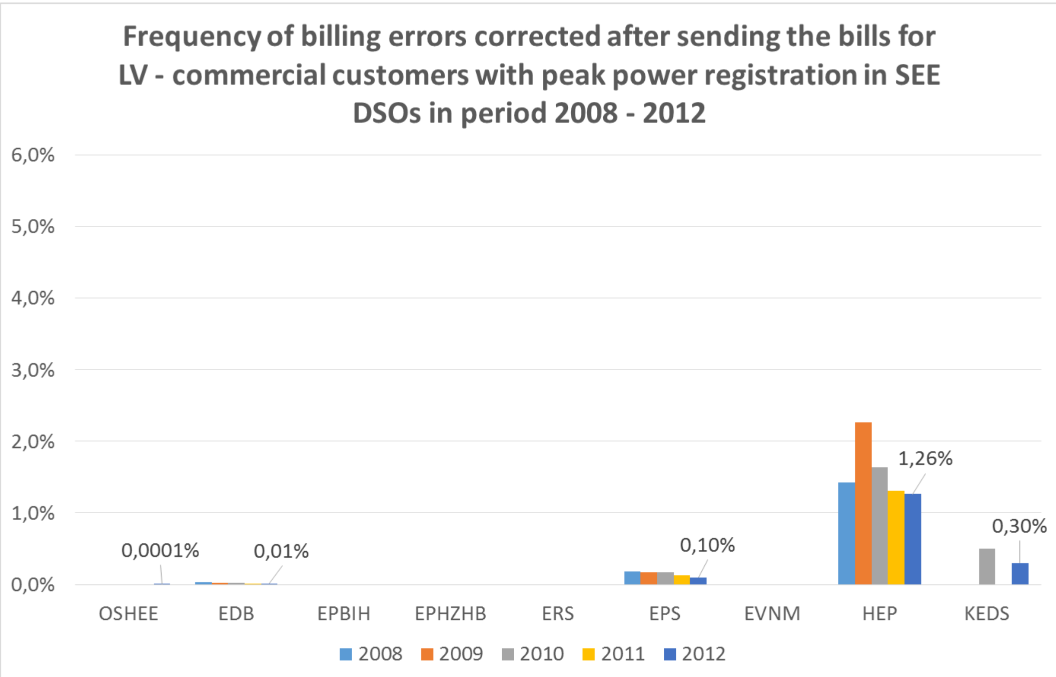
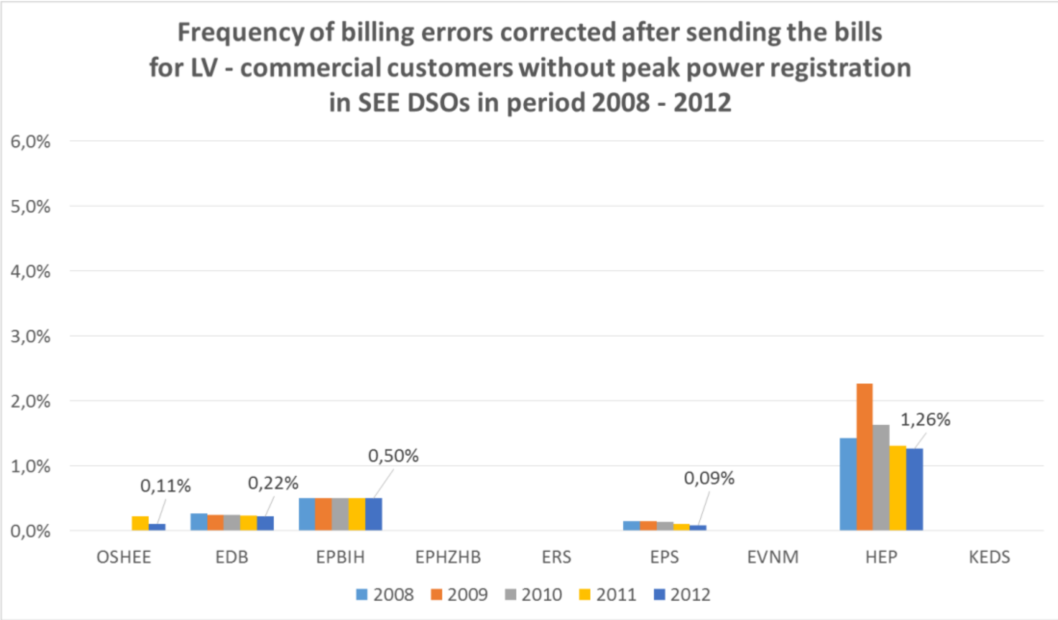


Figure 11.13 Frequency of billing errors corrected after sending the bills for LV - households in SEE DSOs in period 2008 - 2012



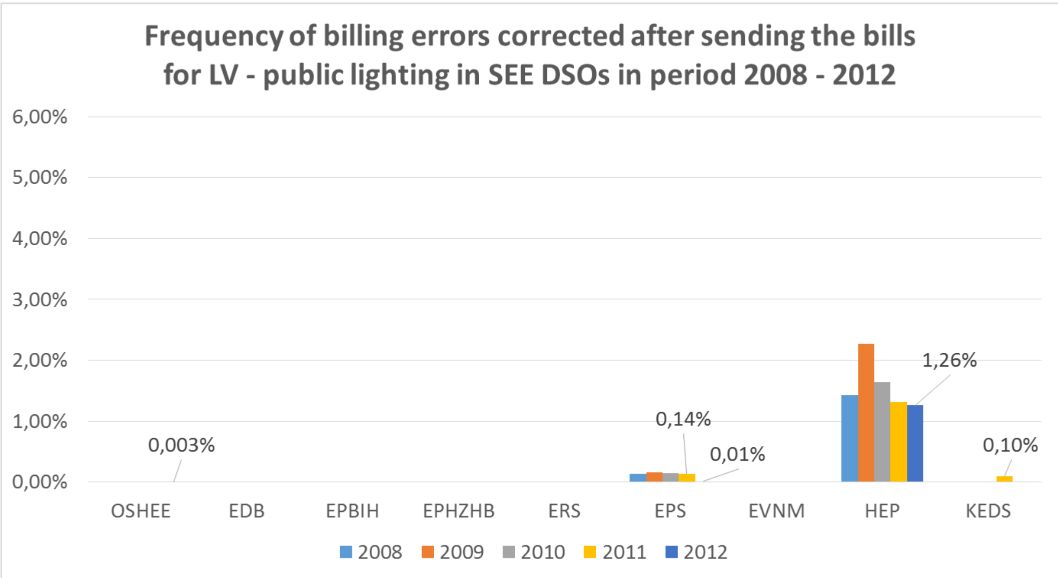
Notes: HEP data corresponds to all non-household customers

Figure 11.14 Frequency of billing errors corrected after sending the bills for LV - commercial customers with peak power registration in SEE DSOs in period 2008 - 2012



Notes: HEP data corresponds to all non-household customers

Figure 11.15 Frequency of billing errors corrected after sending the bills for LV - commercial customers without peak power registration in SEE DSOs in period 2008 - 2012



Notes: HEP data corresponds to all non-household customers

Figure 11.16 Frequency of billing errors corrected after sending the bills for LV – public lighting in SEE DSOs in period 2008 - 2012

11.4. OBSERVATIONS/RECOMMENDATIONS

To fulfil the role of being a comprehensive source of information to customers on energy consumption, prices, opportunities for savings and efficiency, bills should be issued on the monthly bases.

Provisional billing should be avoided as much as possible and bills should be based on accurate and timely conducted periodical meter readings. For households self-reading should be promoted as an effective alternative to meter reading conducted by DSO staff.

Majority of billing errors should be detected and corrected before sending the bill to customer, which is still not the case in the SEE DSOs. Therefore more accurate and strict procedures for control and auditing of the entire metering and billing process and correction of errors in timely manner should be developed.

12. REVENUE COLLECTION

Collection effectiveness refers to the DSO's ability to collect payment in a timely manner against the bills it issues. Due to possible existence of 'problematic' customer classes (in contrast to collections from most customers) performance has been segmented among customer types, so that it focuses on processes that the DSO management can control or influence.

Apart from these challenges, the measures should also reflect best practices toward streamlining the collections process. For example, the traditional approach to revenue collection was that the DSO issues a bill and waits for the customer to pay in person at the nearest district office. Many DSOs have made bill payment much easier for customers in an effort to reduce the collection period, such as by accepting payment at other locations such as bank branches, at ATMs, at selected merchants, by credit card over the internet or telephone, and by pre-pay card.

The proposed measures in this report are grouped as follows:

- average days of bill payment overdue,
- average days of bill payment,
- share of bills collected in bill due time,
- share of bills collected in fiscal year,
- amount of overdue payments (arrears),
- payment processing points (measure aims to express the DSO's efforts or resources employed to facilitate payment and reduce the collection time).

In this report all DSOs provided certain data, some segmented as requested by questionnaire and some lump sum data (e.g. for households and non-households consumption categories):

- EDB, EPBIH and OSHEE provided data segmented by 6 categories (as requested in questionnaire),
- EPHZHB did not provide data on "average days of bill payment" and "share of bills collected in bill due time"; for "share of bills collected in fiscal year" and "amount of overdue payments" it provided lump sum data for LV commercial customers; for "average days of bill payment overdue" data are estimated for 2012,
- EPS provided lump sum data for two categories: households and non-households customers,
- ERS did not provide data on "average days of bill payment overdue",
- EVNM did not provide data on "average days of bill payment" and for other measures provided lump sum data for all consumption categories,
- HEP did not provide data on "average days of bill payment overdue" and "share of bills collected in bill due time"; for other measures data are segmented in households and non-households category,

- KEDS did not provide data on “share of bills collected in bill due time”.

12.1. AVERAGE DAYS OF BILL PAYMENT OVERDUE

Figure 12.1 - Figure 12.7 provide data on average days of bill payment overdue for one MV and four LV consumption categories. HEP and ERS did not provide data, EPS provided lump sum data segmented in households and non-households category.

It could be observed that Albanian OSHEE has the highest values; in all consumption categories average days of bill payment overdue are over 92 days in the observed period (2008-2012). In 2012 average for all MV and LV customers equals 175 day which is around 6 months overdue. The favorable thing is that after increase in 2010 and 2011, in 2012 decline can be observed.

EVNM provided lump sum data for all customers; it could be observed that in 2012 average days of bill payment overdue equaled 70 days (which is the highest after OSHEE). All other DSOs have averages below 45 days. The best performing LV category in the region is households (the exception is only EPBIH).

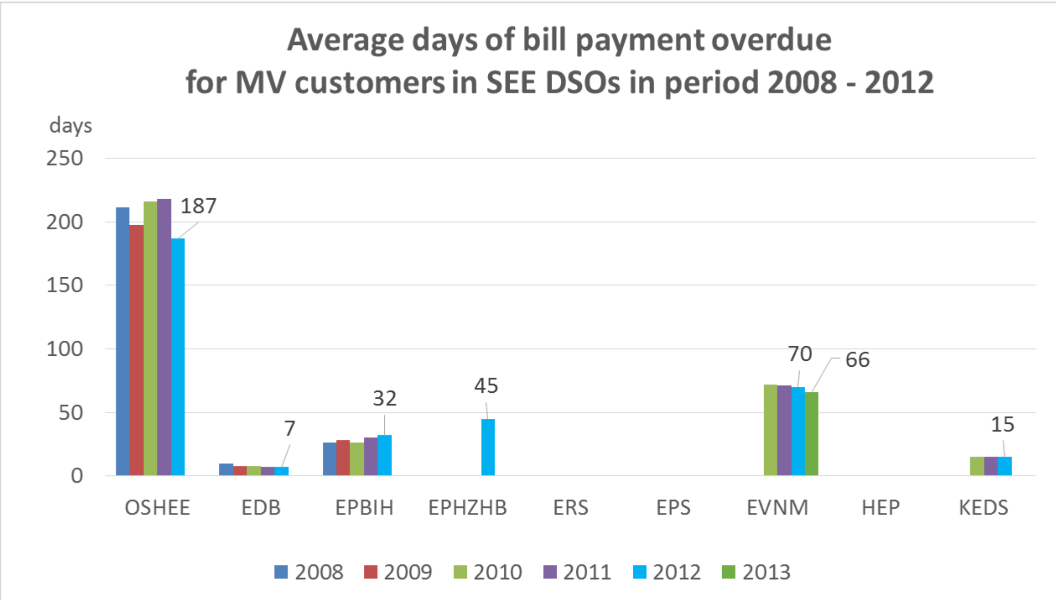


Figure 12.1 Average days of bill payment overdue for MV customers in SEE DSOs in the period 2008 - 2012

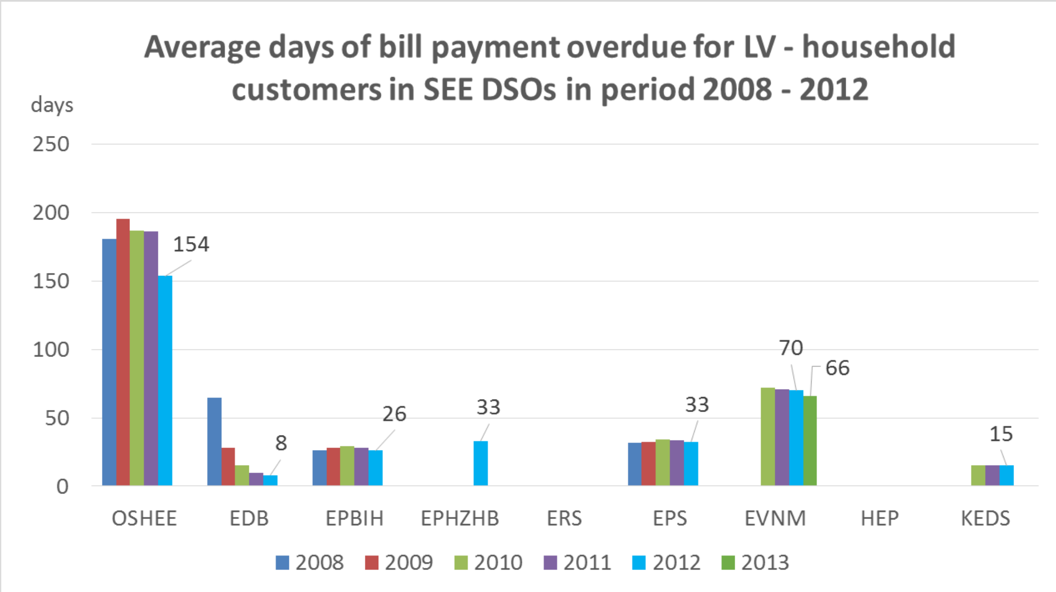


Figure 12.2 Average days of bill payment overdue for LV - household customers in SEE DSOs in the period 2008 - 2012

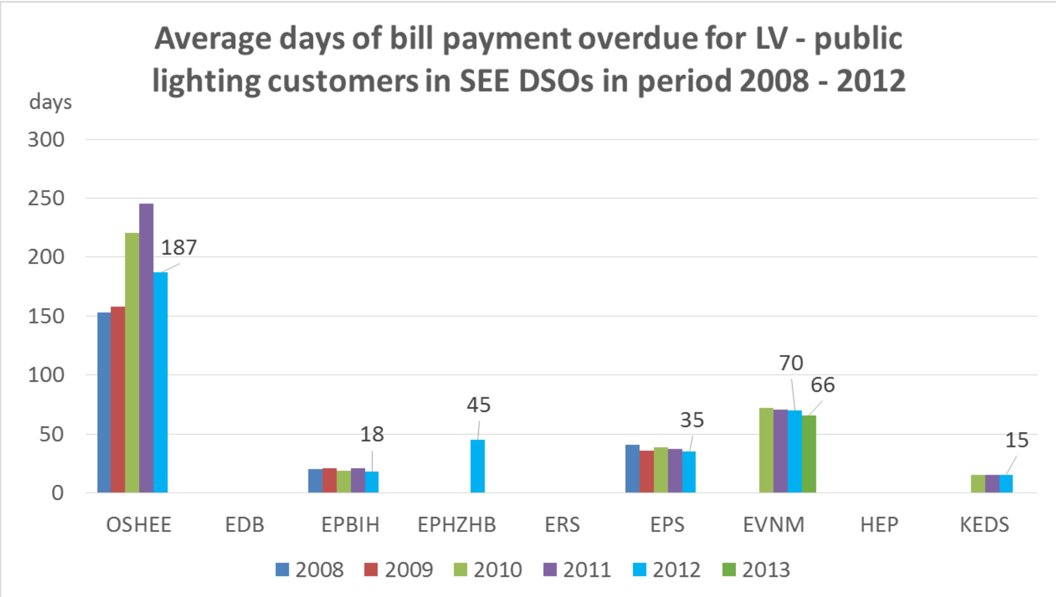


Figure 12.3 Average days of bill payment overdue for LV – public lighting customers in SEE DSOs in the period 2008 - 2012

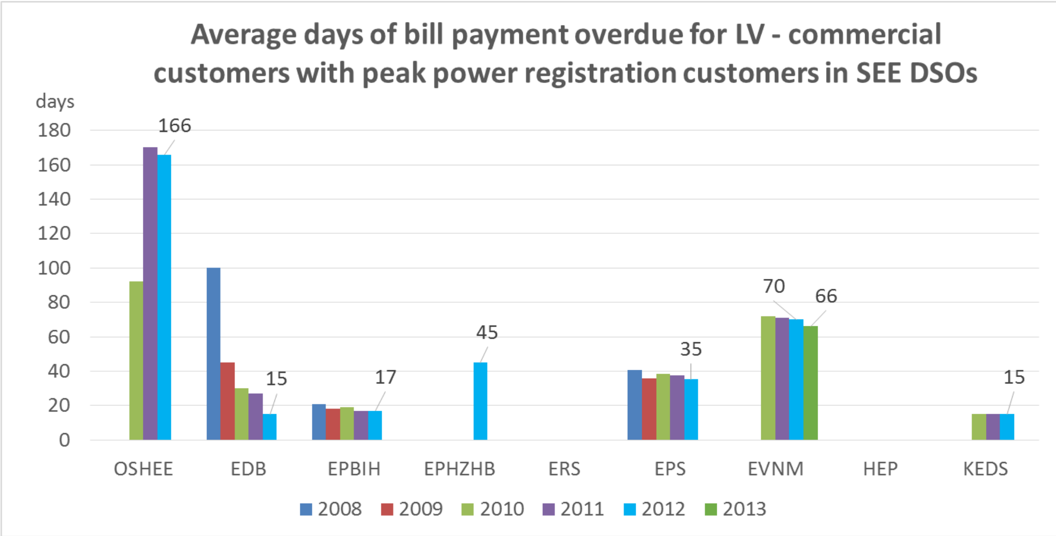


Figure 12.4 Average days of bill payment overdue for LV – commercial with peak power registration customers in SEE DSOs in the period 2008 - 2012

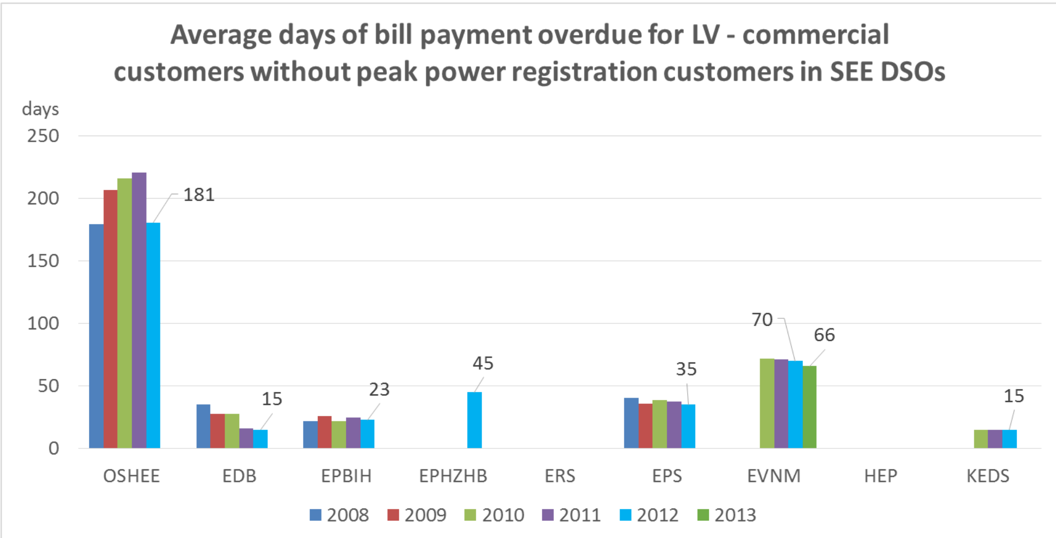


Figure 12.5 Average days of bill payment overdue for LV – commercial without peak power registration customers in SEE DSOs in the period 2008 - 2012

12.2. AVERAGE DAYS OF BILL PAYMENT

Figure 12.6 and Figure 12.7 provide data on average days of bill payment for LV households and LV non-households category (since most of DSOs segmented data in these two categories). EPHZHB and EVNM did not provide data, and ERS provided lump sum data for all customers.

It could be observed that ERS has the highest average days of bill payment (in 2012 166 days i.e. 5,5 months). All other DSOs in 2012 have values lower than 35 days for households, and 60 days for LV non-households. Although, ERS data cannot be easily compared to other DSOs data since ERS provided lump sum data, 166 days (i.e. 5,5 months) is still very high value.

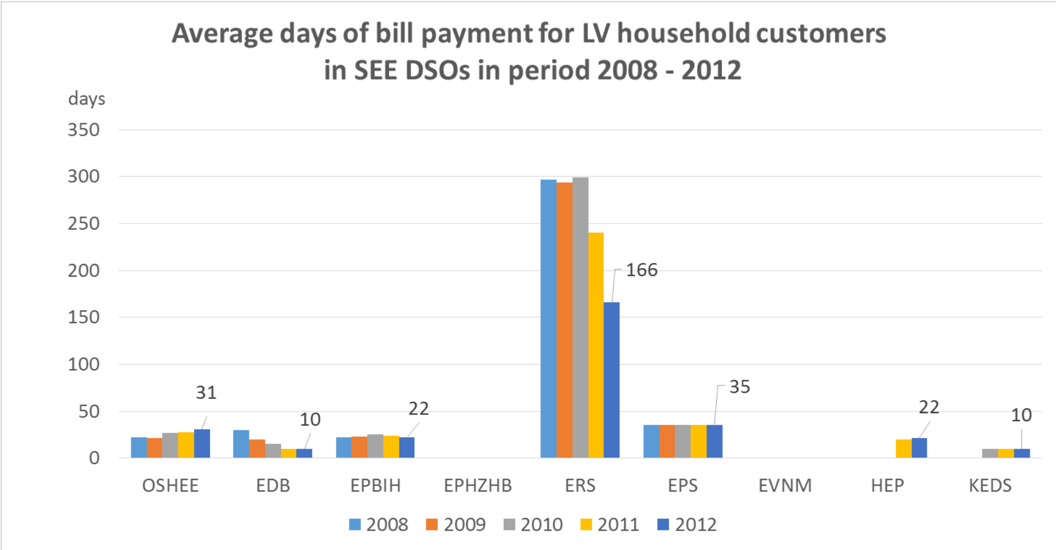


Figure 12.6 Average days of bill payment for LV household customers in SEE DSOs in the period 2008 - 2012

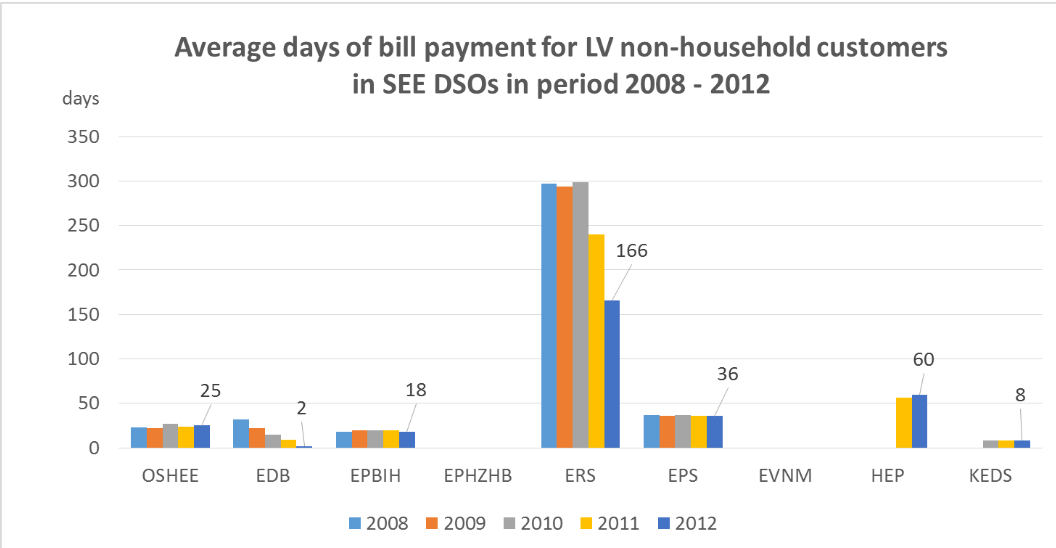


Figure 12.7 Average days of bill payment for LV non-household customers in SEE DSOs in the period 2008 - 2012

12.3. SHARE OF BILLS COLLECTED IN BILL DUE TIME

For this measure the following 4 DSOs did not provide data: EPHZHB, ERS, HEP and KEDS. EPS provided lump sum data for households and non-households. Figure 12.8 - Figure 12.12 depict ratio between collected bills in due time and issued bills for MV and 4 LV consumption categories respectively.

In MV category in OSHEE and EVNM approximately 50 % customers' bills are not collected in due time.

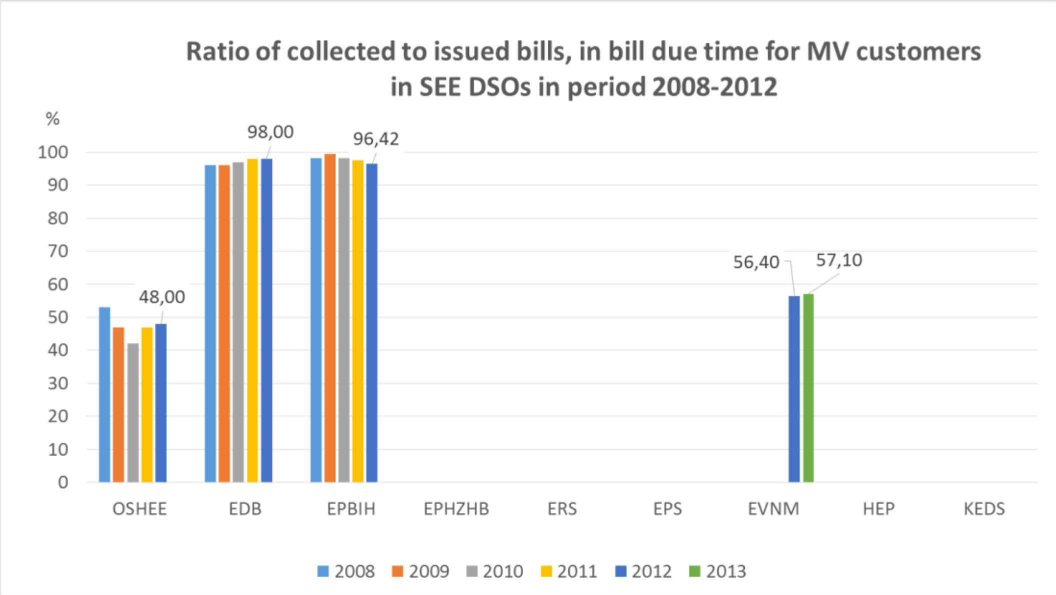


Figure 12.8 Ratio of collected to issued bills, in bill due time for MV customers in SEE DSOs in the period 2008 – 2012

In households category in 2012 in OSHEE, EVNM and EPS approximately 50 % customers' bills are not collected in due time. In EDB in 2012 bills were not collected in due time for around 15 % of households.

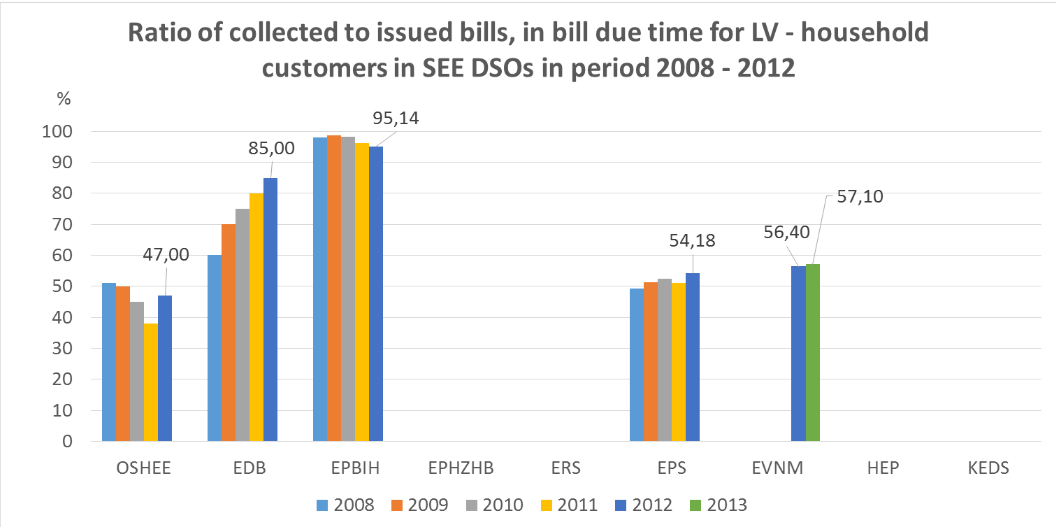


Figure 12.9 Ratio of collected to issued bills, in bill due time for LV household customers in SEE DSOs in the period 2008 – 2012

The worst performing category is public lighting in OSHEE with 12 %. In EVNM and EPS approximately 50 % customers' bills are not collected in due time. In EDB and EPBIH collection of issued bills is conducted in timely manner.

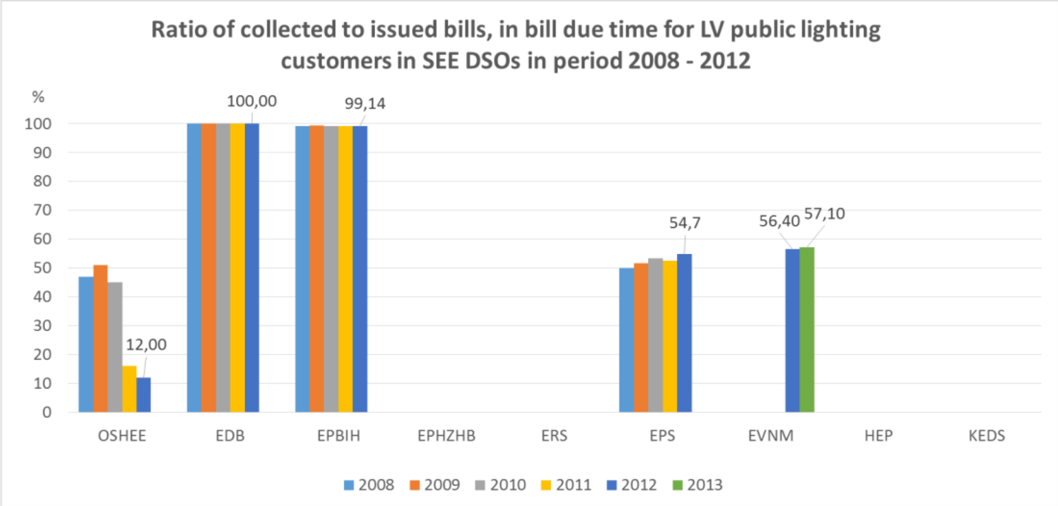


Figure 12.10 Ratio of collected to issued bills, in bill due time for LV public lighting customers in SEE DSOs in the period 2008 – 2012

In LV commercial customers without peak power registration in OSHEE, EVNM and EPS approximately 50 % of customers' bills are not collected in due time. The same applies to LV commercial customers with peak power registration.

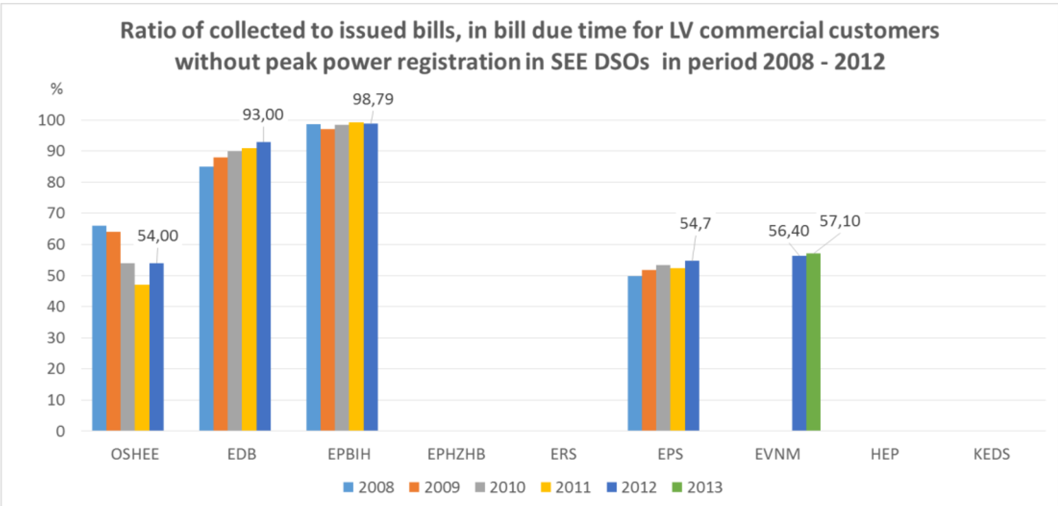


Figure 12.11 Ratio of collected to issued bills, in bill due time for LV commercial customers without peak power registration in SEE DSOs in the period 2008 – 2012

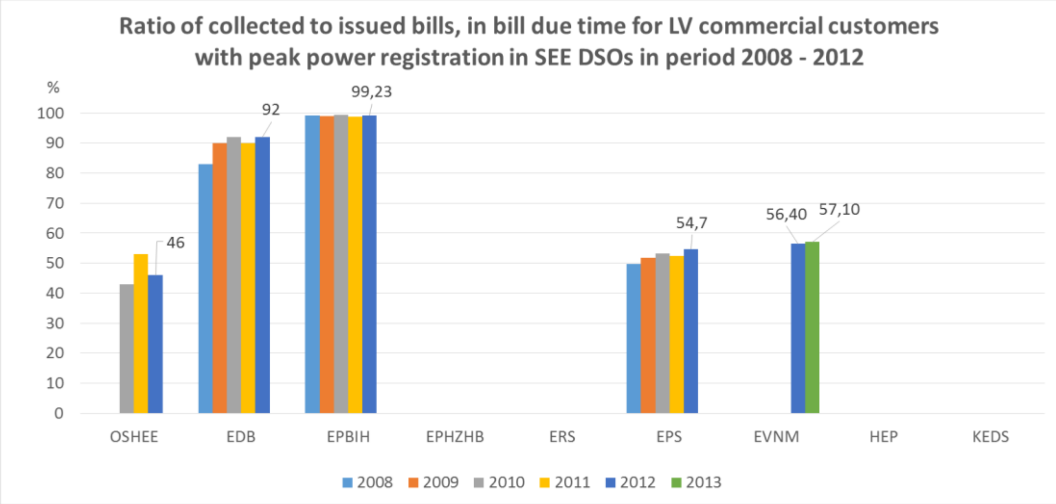


Figure 12.12 Ratio of collected to issued bills, in bill due time for LV commercial customers with peak power registration in SEE DSOs in the period 2008 - 2012

12.4. SHARE OF BILLS COLLECTED IN FISCAL YEAR

For this measure all DSOs provides certain data. Figure 12.13 - Figure 12.17 depict ratio between collected to issued bills in fiscal year for MV and 4 LV consumption categories respectively. Obviously this measure comprises both due and overdue bills collected in a fiscal year.

In 2012 in MV category over 90 % of bills were collected within a fiscal year.

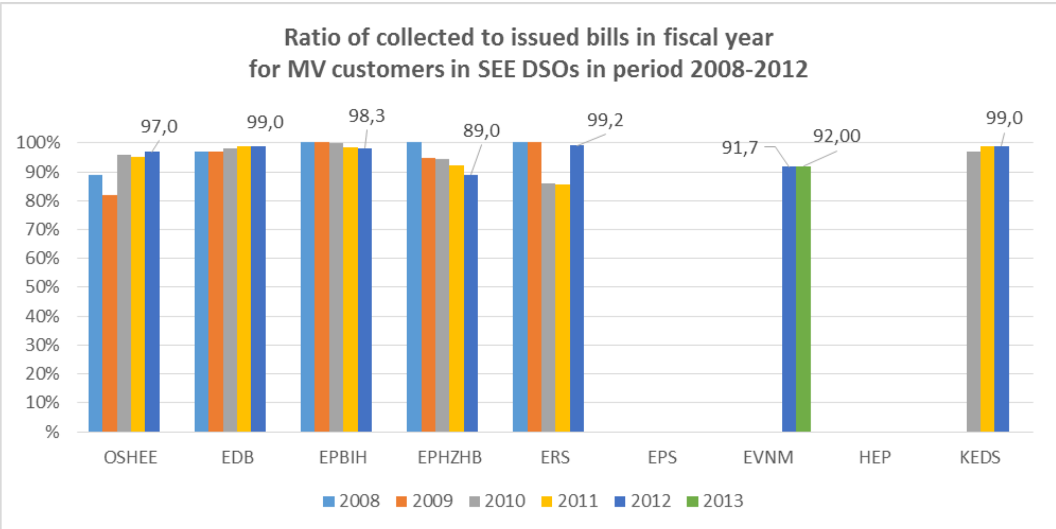


Figure 12.13 Ratio of collected to issued bills, in fiscal year for MV customers in SEE DSOs in the period 2008 - 2012

In 2012 in households category in almost all DSOs collection rate in fiscal year is over 92 %. Exceptions are OSHEE with 71 % and KEDS with 83 %.

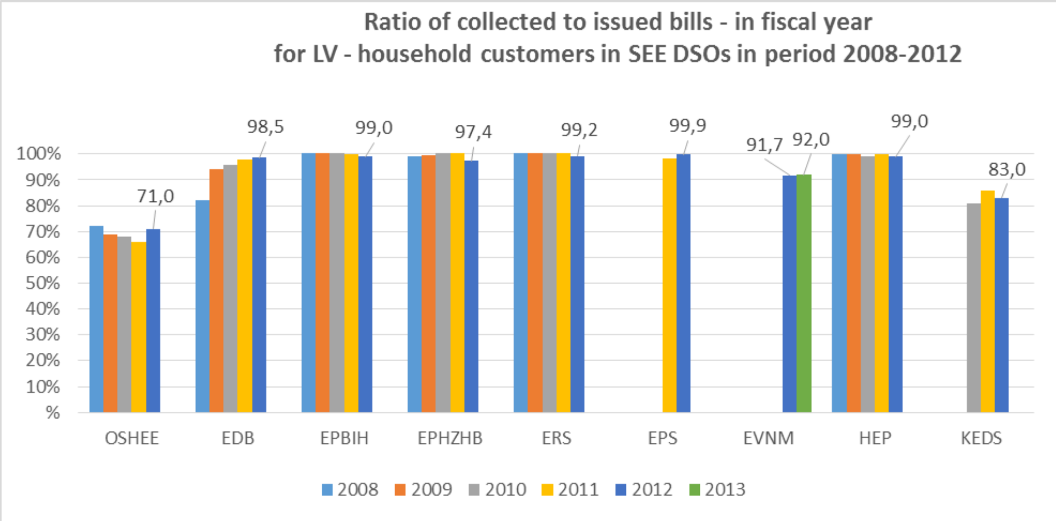


Figure 12.14 Ratio of collected to issued bills, in fiscal year for LV household customers in SEE DSOs in the period 2008 - 2012

In public lighting category in almost all DSOs collection rate in fiscal year is over 92 %. Exception is OSHEE with 66 %.

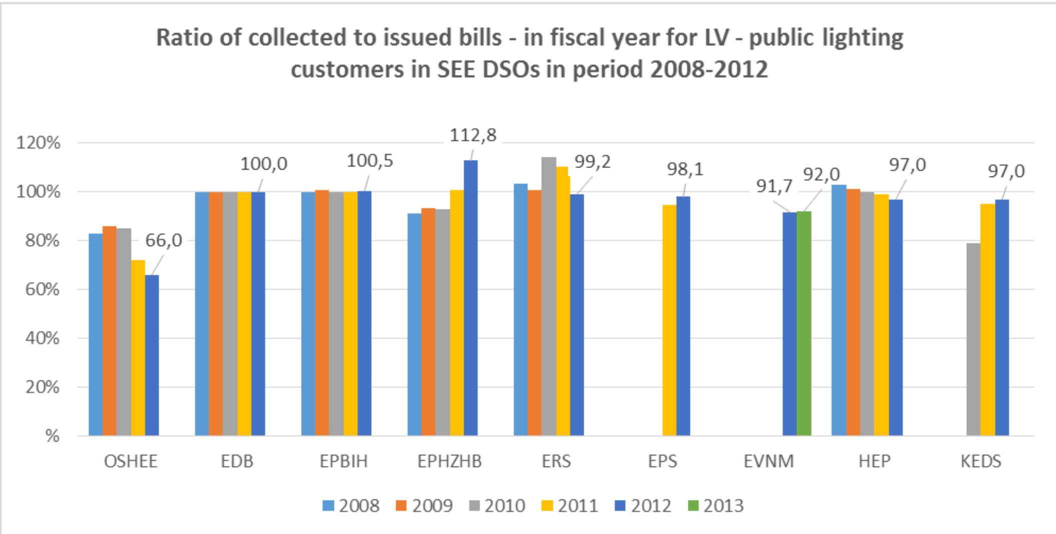


Figure 12.15 Ratio of collected to issued bills, in fiscal year for LV public lighting customers in SEE DSOs in the period 2008 - 2012

In 2012 in LV commercial category with peak power registration in almost all DSOs collection rate in fiscal year is over 92 %. Exception is OSHEE with 64 %.

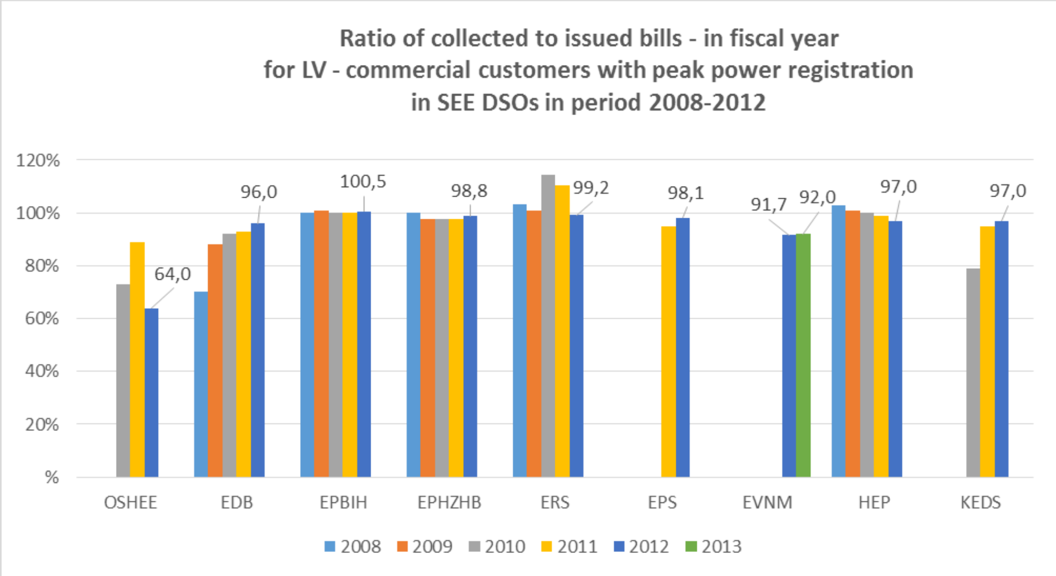


Figure 12.16 Ratio of collected to issued bills, in fiscal year for LV commercial customers with peak power registration in SEE DSOs in the period 2008 - 2012

In 2012 in LV commercial category without peak power registration in almost all DSOs collection rate in fiscal year is over 92 %. Exception is OSHEE with 85 %.

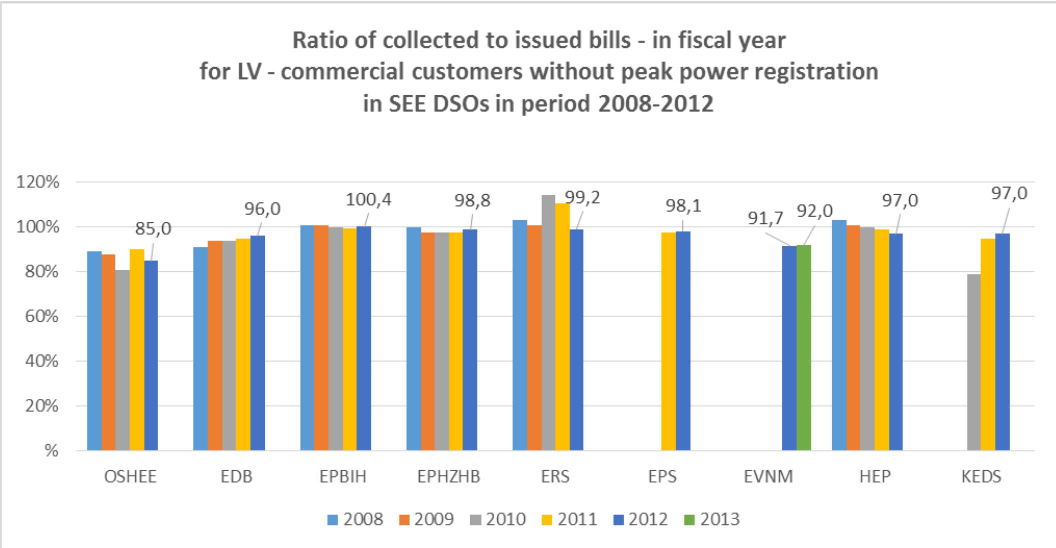


Figure 12.17 Ratio of collected to issued bills, in fiscal year for LV commercial customers without peak power registration in SEE DSOs in the period 2008 - 2012

12.5. THE AMOUNT OF OVERDUE PAYMENTS

For this measure all DSOs except KEDS provided data. For EDB and OSHEE data are segmented in 5 categories (MV and 4 LV as requested in questionnaire). For EPBIH and EVNM lump sum data are provided for all consumption categories. For ERS, EPS and HEP data are segmented in households and non-households. EPHZHB provided lump sum data for LV commercial category.

Figure 12.18 depicts MV customers arrears in SEE DSOs. EPBIH and EVNM data are not presented since these DSOs provided lump sum data for all consumption categories. Besides, EPS provided lump sum data for HV and MV customers, while OSHEE, EDB and EPHZHB for MV customers only.

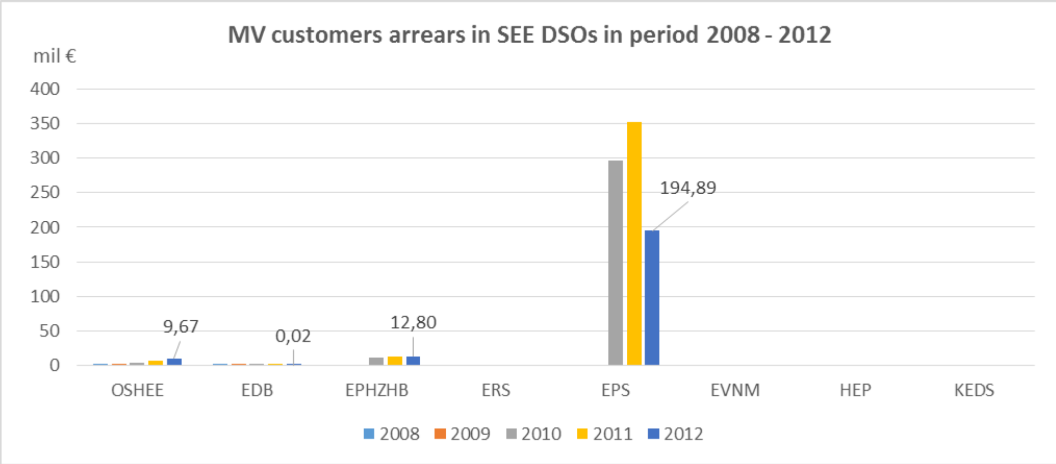


Figure 12.18 MV customers arrears in SEE DSOs in the period 2008 - 2012

Figure 12.19 depicts lump sum customer arrears in EVNM and EPBIH.

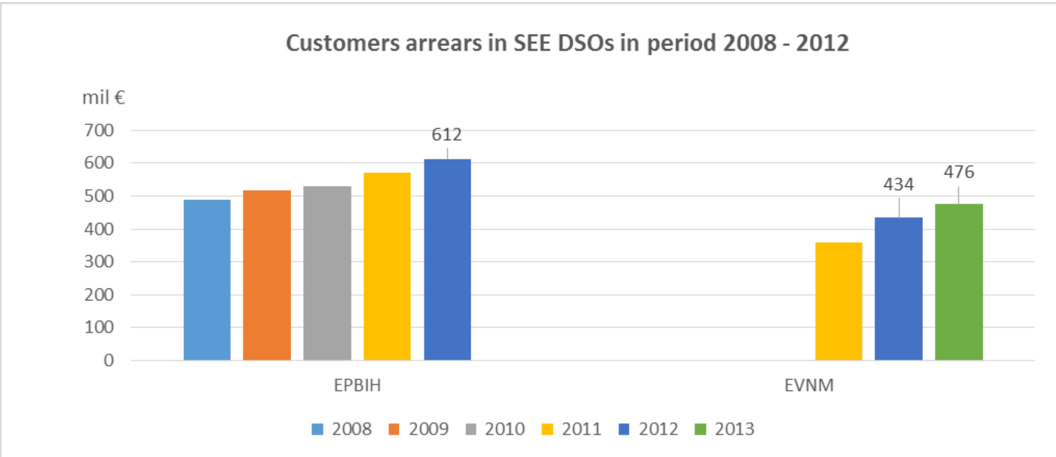


Figure 12.19 Customers arrears in EPBIH and EVNM in the period 2008 - 2012

Figure 12.20 and Figure 12.21 provide households and non-households arrears in 6 DSOs.

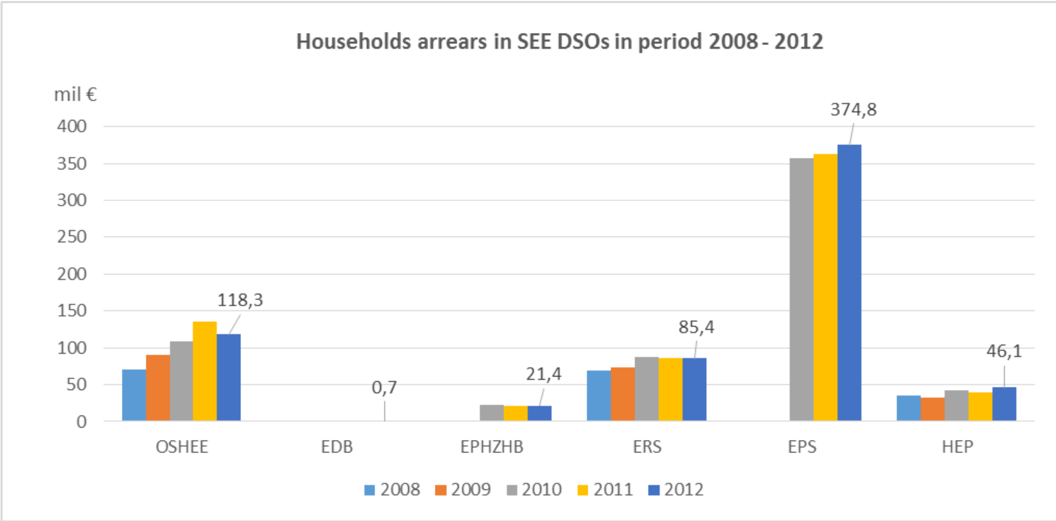


Figure 12.20 Households arrears in SEE DSOs in the period 2008 - 2012

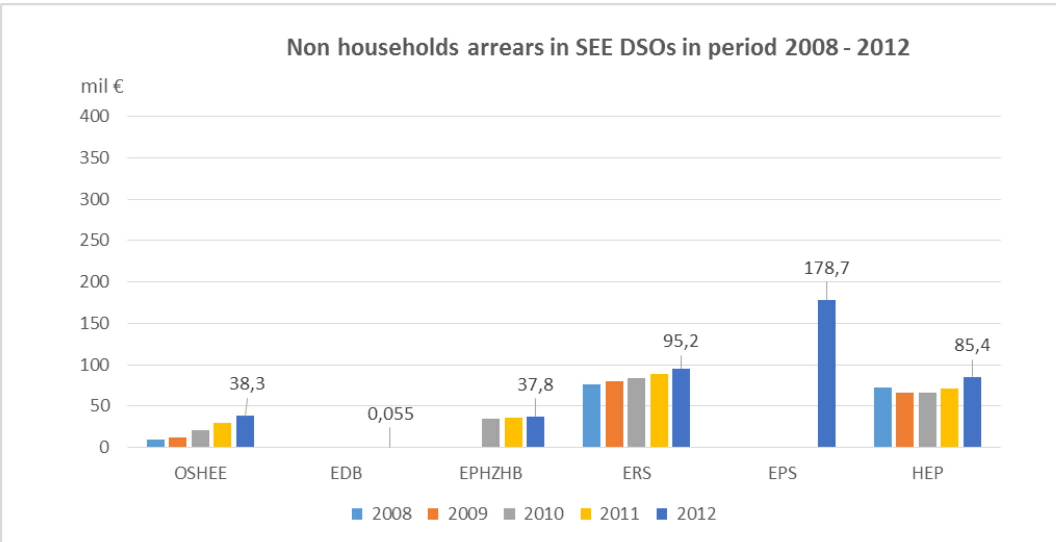


Figure 12.21 Non households arrears in SEE DSOs in the period 2008 – 2012

12.6. OBSERVATIONS/RECOMMENDATIONS

ERS has the highest average days of bill payment (in 2012 166 days i.e. 5,5 months). All others DSOs in 2012 have values lower than 35 days for households, and 60 days for LV non-households.

Albanian OSHEE has the highest values of bill payment overdue. In 2012 average for all MV and LV customers equals 175 day which is around 6 months overdue. All other DSOs have averages below 45 days. The best performing LV category in the region are households (the exception is only EPBIH).

With regard of ratio of bills collected in due time only 5 DSO provided data. It could be observed that in EPS, EVNM and OSHEE for around 50 % of customers (in all observed MV and LV categories) bills are collected in due time; the exception is the worst performing category public lighting in OSHEE with 12 %. In EDB and EPBIH ratios of bills collected in due time are over 92 % in 2012 (exception is EDB in households category with 85 %).

With regard of ratio of bills collected in fiscal year all DSOs provided data. In MV category 90 % of bills are collected. In LV consumption categories in almost all DSOs 92 % of bills are collected in fiscal year. Exception is OSHEE with 71 % in households category, 66 % in public lighting, 85 % in LV commercial without peak power registration and 64 % in LV commercial with peak power registration. Besides, there is also KEDS with 83 % in households category.

It could be concluded that the collection performance is complicated in the region by DSOs restricted resource for non-payment or delayed payment: limited legal recourse to recover unpaid bills, inability to write-down bad customer debts or negotiate payments, effective inability to disconnect non-paying customers (e.g. for political or social reasons).

13. COMPETITIVNESS ANALYSIS

In the following we show financial and performance indicators for observed DSOs. Note that data for KEDS are not shown as it did not provide any information. Furthermore, all costs are converted from local currency to € by the participating DSOs. No adjustment was made for purchasing power difference.

13.1. STAFFING BENCHMARK

Distribution and retail business is relatively labor intensive, implying companies should strive for efficient level of staffing and staffing cost. The following section tries to determine to what degree staffing levels and costs among participating DSOs are similar. For this purpose we use the following benchmarks:

- labor cost per MWh distributed energy,
- labor cost per MWh delivered energy,
- labor cost per metering point,
- level of employment per metering point.

Figure 13.1 shows labor cost per MWh of distributed energy. The graph shows that lowest average costs are observed in OSHEE, EPS and EVNM respectively with costs below 5 €/MWh. The rest of the DSOs exhibit costs in the range of 10-15 €/MWh, with the exception of EDB which records 20,1 €/MWh.

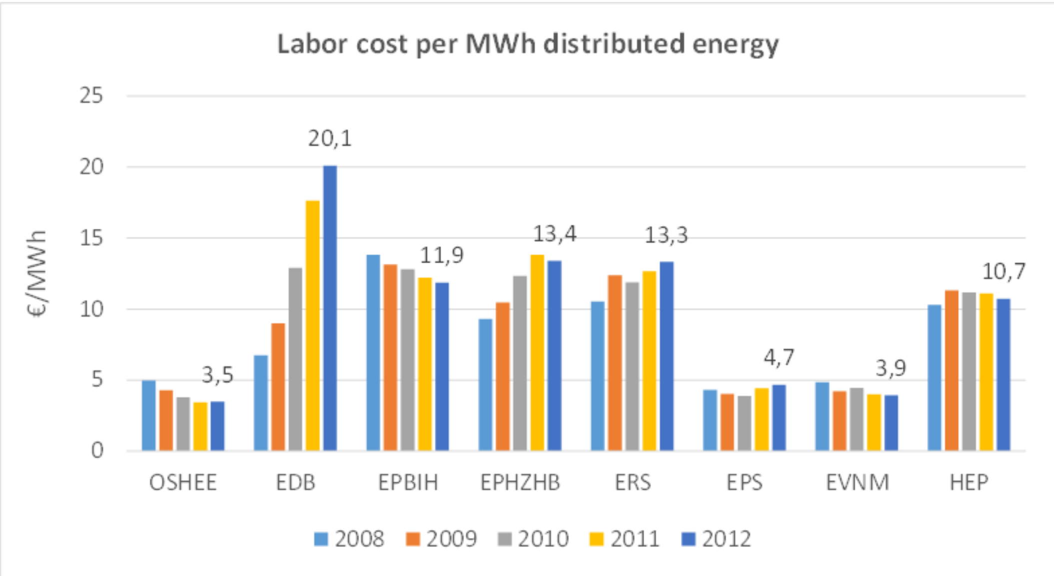


Figure 13.1 Labor cost per MWh distributed energy

Slightly different results are obtained when delivered energy is analyzed. Reason for this is different level of losses among participating DSOs. The lowest costs are observed again in EPS, EVNM and

OSHEE respectively with labor costs below 6,5 €/MWh, whilst other DSOs exhibit costs in the range of 12 €/MWh (HEP) to 16 €/MWh, with the exception of EDB which recorded costs of 24 €/MWh.

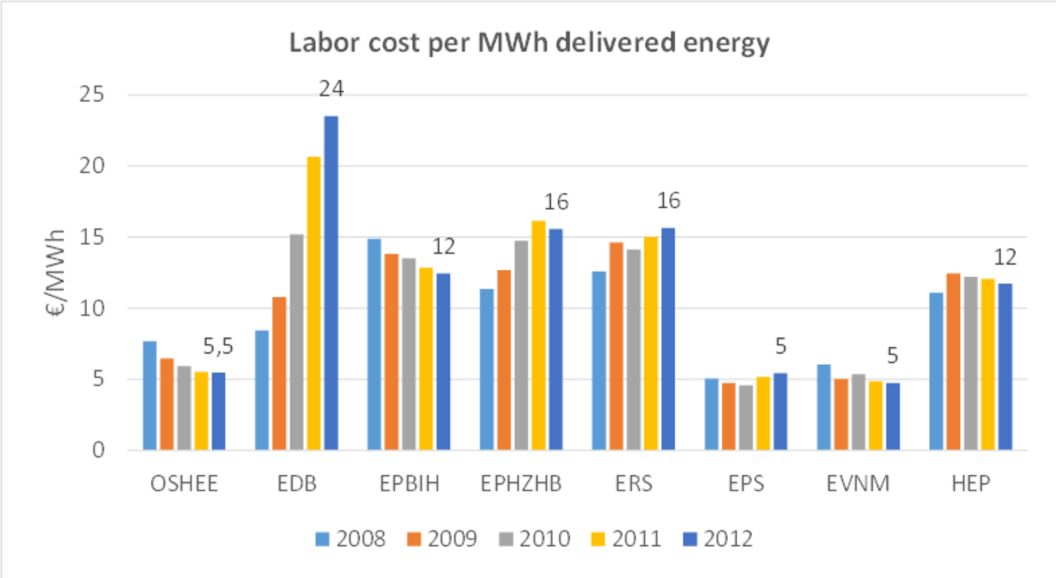


Figure 13.2: Labor cost per MWh delivered energy

In the following figure labor costs per metering point are shown. Here again the similar pattern is present. The lowest values are observed at OSHEE, EVNM and EPS respectively with average values below 45 €/MWh, whilst the reaming DSOs had values in the range of 69 €/MWh (EPBIH) to 147 €/MWh (EDB).

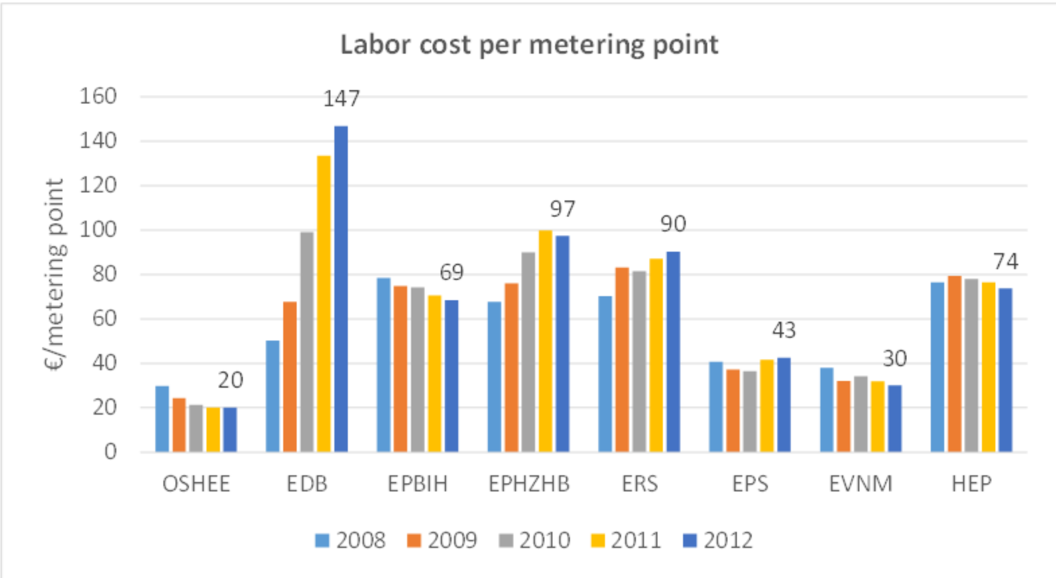


Figure 13.3: Labor cost per metering point

What can be observed in the preceding three figures is the rising trend in labor cost for EDB. Whilst all DSOs exhibited relatively stable labor costs, EDB experienced a rise in all three benchmark values from 2010.

Whilst three previous benchmarks were based on monetary values, the following graph shows employment level per 1000 metering points. The figure shows a bit different picture. Whilst in the previous threes graphs EDB exhibited the highest level of labor expenditures, in terms of total employment per number of metering points it sits in the middle. This is difficult to reconcile with the previous graphs. The only explanation could be that wage levels at EDB are much lower compared to other DSOs, which seems unlikely.

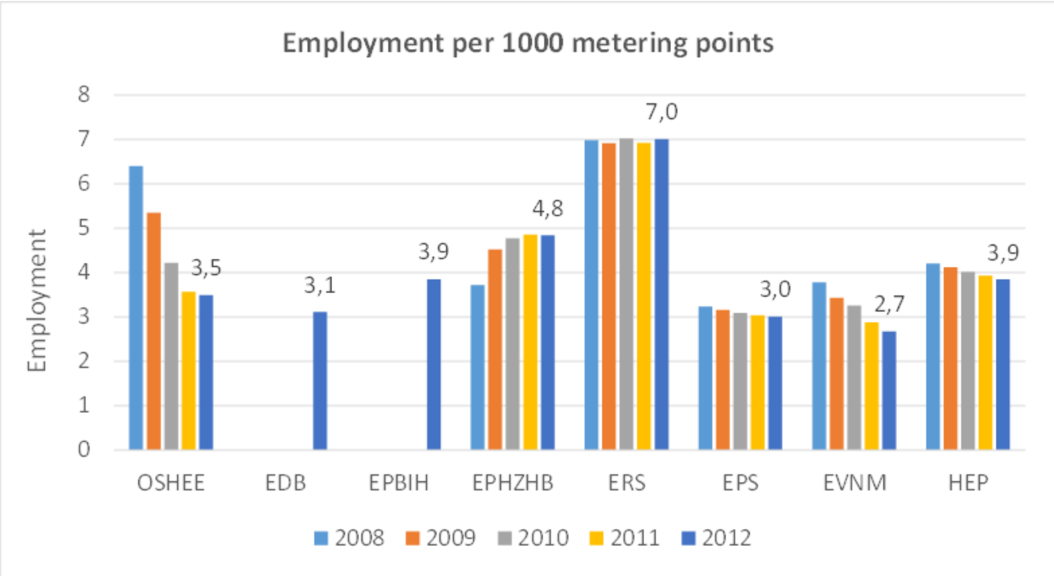


Figure 13.4: Employment per 1000 metering points

The following table gives average values for five year period for the above benchmarks.

Table 13.1: Five year average values for observed indicators

Indicator / DSO		OSHEE	EDB	EPBIH	EPHZHB	ERS	EVNM	HEP	KEDS
Labor cost per MWh distributed	€/MWh	3,98	13,27	12,76	11,86	12,15	4,26	4,29	10,92
Labor cost per MWh delivered	€/MWh	6,24	15,72	13,51	14,10	14,41	5,00	5,22	11,92
Labor cost per metering point	€/MWh	23,09	99,46	73,32	86,20	82,44	39,72	33,32	76,79
Employment per 1000 metering point	#	4,6	3,1	3,9	4,5	7,0	3,1	3,2	4,0

Based on the above values ranking for each DSO has been calculated as shown in the following table. The table shows that EPS and EVNM are the best performing, i.e. most efficient DSOs in terms of employment cost and level of employment. ***One should bear in mind this is only a qualitative table where each indicator is given equal weight.*** Furthermore, as stated before, no adjustment is made for purchasing power parity.

Table 13.2: Ranking of DSOs based on average values of observed indicators

Indicator / DSO	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
Labor cost per MWh distributed	1	8	7	5	6	2	3	4
Labor cost per MWh delivered	3	8	5	6	7	1	2	4
Labor cost per metering point	1	8	4	7	6	3	2	5
Employment per 1000 metering point	7	1	4	6	8	2	3	5
Overall rank	***3***	***7***	***5***	***6***	***8***	***1***	***2***	***4***

It is important to indicate potential *limitations* of this analysis. In particular we were not able to identify to what degree did the DSOs outsource services. It is possible that some DSOs rely completely on their own staff whilst other outsource some services: to what degree this happens could not be determined. Thus, to get the complete picture of employment efficiency this issue deserves further investigation.

13.2. CAPITAL EXPENDITURE BENCHMARK

The next question we address is to what degree do DSOs renew their assets. To this end we use the following benchmarks:

- depreciation to book value,
- investment to book value,
- difference between investment to book value and depreciation to book value.

In essence DSOs should investment in the amount which is sufficient to replace depreciated assets.

The following figure shows a ratio of depreciation to book value of property plant and equipment (PPE). Most of the DSOs exhibit values below 8 % whilst OSHEE and EDB exhibit significantly higher values. Values of around 8 % are to be expected as this value is commensurate with average distribution asset life. ***We cannot provide explanation for high depreciation rates observed at EDB and OSHEE.***

Note: EDB is in a particular situation compared to other DSOs. Unlike other DSOs who own and operate the network, EDB owns part of the network, while other part (approximated to 61,2 million of KM is owned by the government). The government also makes investments in the network.

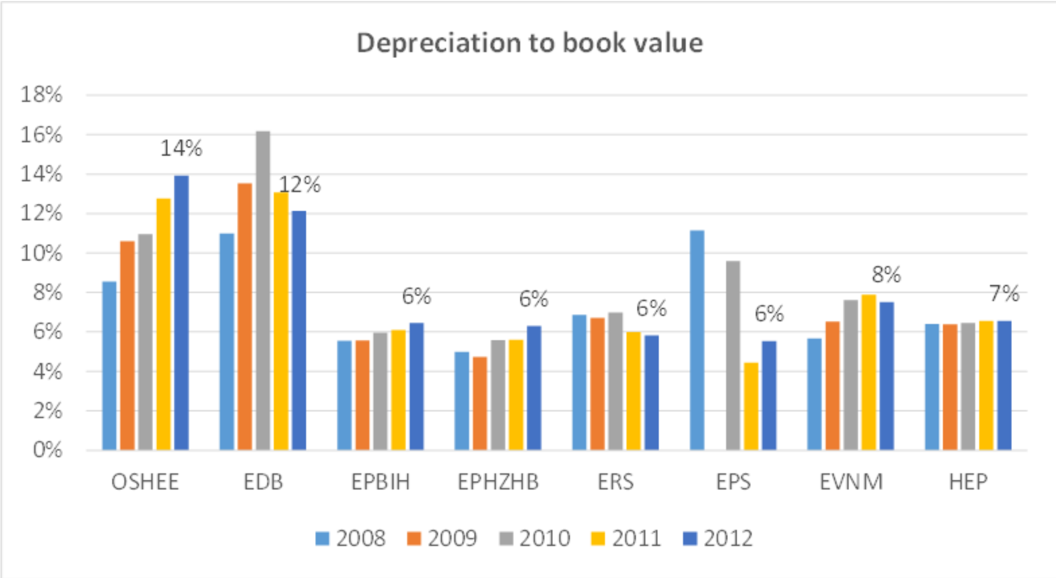


Figure 13.5: Depreciation to book value

Whilst the previous figure showed the pace of asset depreciation, the following figure shows the pace of investment in capital equipment. The figure shows that the highest level of investment to book value is observed at EPBIH.

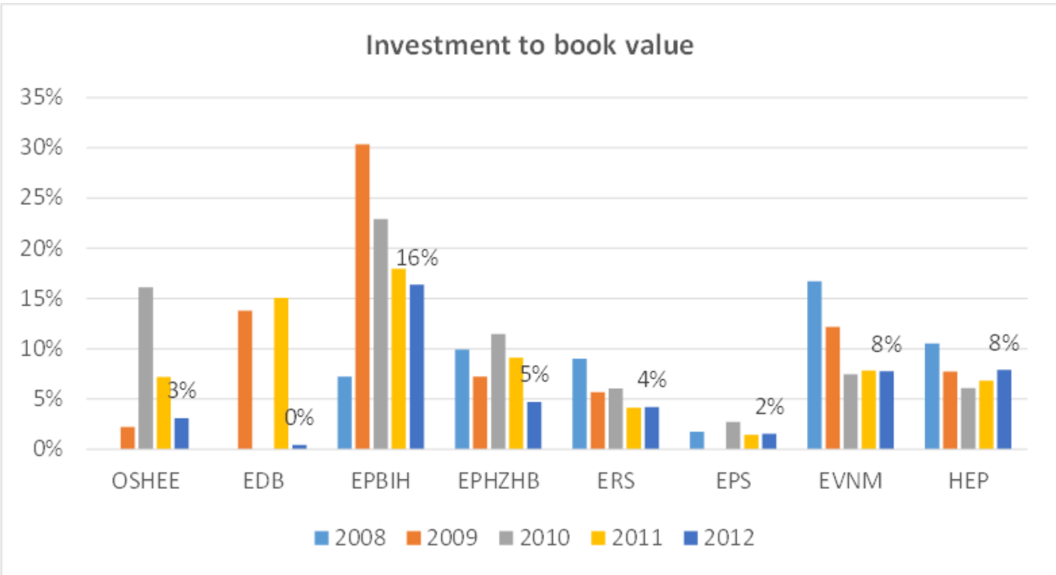


Figure 13.6: Investment to book value

In order to more easily compare the values of investment and depreciation to book value, the following table gives their difference. Positive values imply the ratio of investment to book value is greater than depreciation to book value, hence the DSO is investing more that it is depreciating. Taking the average value for the five year period, four DSOs have on average invested more than what has been written off, whilst four DSOs (OSHEE, EDB, ERS and EPS) have invested less than what was written off in the period 2008 – 2012.

Table 13.3: Difference between investment to book value and depreciation to book value

DSO	2008	2009	2010	2011	2012	Average
OSHEE		-8%	5%	-6%	-11%	-5%
EDB	0%	0%	-16%	2%	-12%	-5%
EPBIH	2%	25%	17%	12%	10%	13%
EPHZHB	5%	2%	6%	4%	-2%	3%
ERS	2%	-1%	-1%	-2%	-2%	-1%
EPS	-9%		-7%	-3%	-4%	-6%
EVNM	11%	6%	0%	0%	0%	3%
HEP	4%	1%	0%	0%	1%	1%

13.3. MAINTENANCE COST

The following table shows ratio of maintenance cost to book value of distribution assets. Most of the DSOs are below 3 %, where EDB stands out as an exceptionally high level of maintenance costs. This can be explained by aging equipment, but additional information is needed to confirm this assumption.

Table 13.4: Maintenance cost to book value of assets

DSO	2008	2009	2010	2011	2012	Average
OSHEE	3%	3%	3%	4%	3%	3%
EDB*	4%	9%	8%	11%	7%	8%
EPBIH	2%	2%	2%	2%	2%	2%
EPHZHB	3%	2%	3%	2%	2%	3%
ERS	3%	2%	2%	2%	2%	2%
EPS	4%		5%	2%	1%	3%
EVNM	3%	3%	3%	4%	4%	3%
HEP	1%	2%	2%	2%	1%	1%
KEDS	3%	3%	3%	4%	3%	3%

** Even though EDB owns only part of the network, it is responsible for maintenance of the entire network. This might explain higher share of maintenance cost to book value of assets.*

Ratio of maintenance cost to book value of assets is supplemented with ratio of maintenance cost to network length and number of metering points. The following figure shows ratio of maintenance cost per kilometer of network. From the figure it can be seen that most of the DSOs have rather similar levels of maintenance expenditure per kilometer of network except for EPS and EVNM.

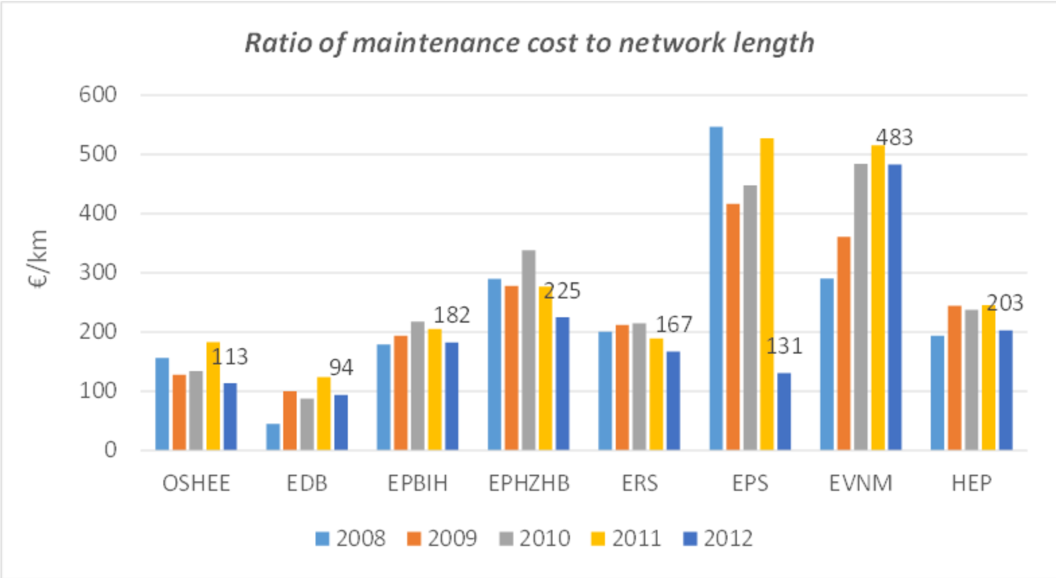


Figure 13.7: Ratio of maintenance cost to network length

As an additional indicator of maintenance expenses we show ratio of maintenance expenditure to number of metering points. As expected EDB exhibits the highest level of expenditure.

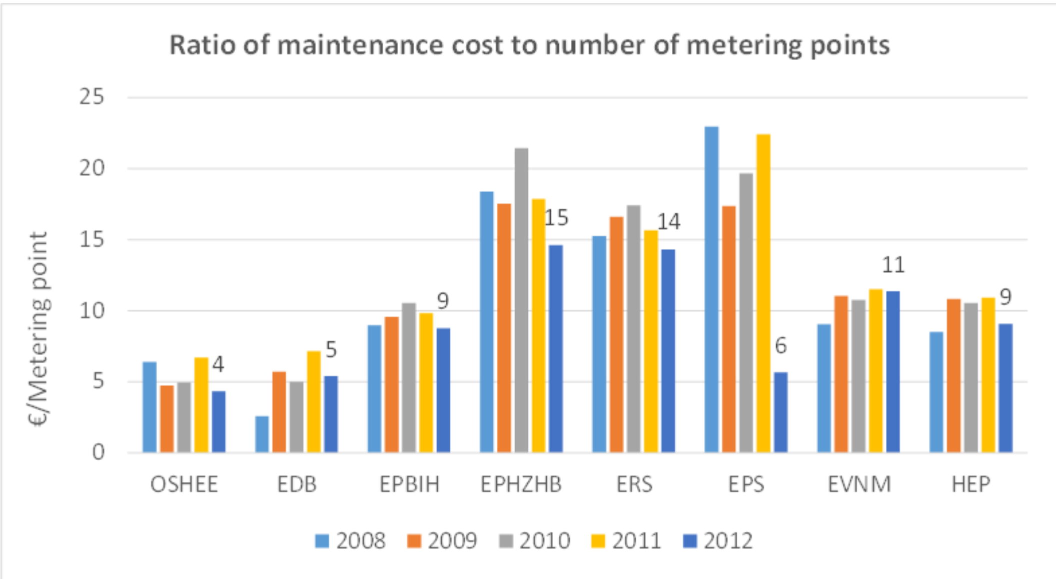


Figure 13.8: Ratio of maintenance cost to number of metering points

The following table gives summary for average values during five years.

Table 13.5: Average values for five year period

Indicator / DSO		OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
Maintenance to book value	%	3%	8%	2%	3%	2%	3%	3%	1%
Maintenance per km network	€/km	143	90	196	281	197	414	427	225
Maintenance per # metering points	€/met.pt.	5	0	10	18	16	18	11	10

The following table ranks DSOs according to maintenance: the lower value imply less maintenance expenditure. The difference between best performing DOSs is not significant thus it can be stated that EPBIH, HEP, OSHEE, ERS spend proportionate amounts on maintenance. EPHZHB, EVNM spend slightly more whilst EPS and EDB spend significantly more than the rest of DSOs.

Table 13.6: Rank of DSOs according to how much they spend on maintenance

Indicator / DSO	OSHEE	EDB	EPBIH	EPHZHB	ERS	EPS	EVNM	HEP
Maintenance to book value	5	8	2	4	3	6	7	1
Maintenance per km network	2	1	3	6	4	7	8	5
Maintenance per # metering points	2	1	3	8	6	7	5	4
Total	9	10	8	18	13	20	20	10
Rank	**2**	**3**	**1**	**6**	**5**	**7**	**7**	**3**

The following table shows correlation coefficient between investment to book value indicator and three maintenance indicators. The table shows that maintenance costs are rather negatively correlated to investment. The matrix indicates lower maintenance cost are observed at those DSOs that have investment more in capital equipment.

Table 13.7: Correlation matrix

	Capital expenditure to book	Maintenance to book	Maintenance to metering	Maintenance to length
Capital expenditure to book	1,00	-0,40	-0,44	-0,31
Maintenance to book	-0,40	1,00	-0,45	-0,32
Maintenance to metering	-0,44	-0,45	1,00	0,61
Maintenance to length	-0,31	-0,32	0,61	1,00

13.4. COMPETITIVENESS

The following six graphs show average tariffs for participating DSOs for various voltage levels. We have excluded ERS as it has not provided total revenue per voltage level but only revenue related to distribution network fee, i.e. its values were not comparable to values of other DSOs.

From the following graphs it can be seen that not all DSOs distribute electricity at all voltage levels.

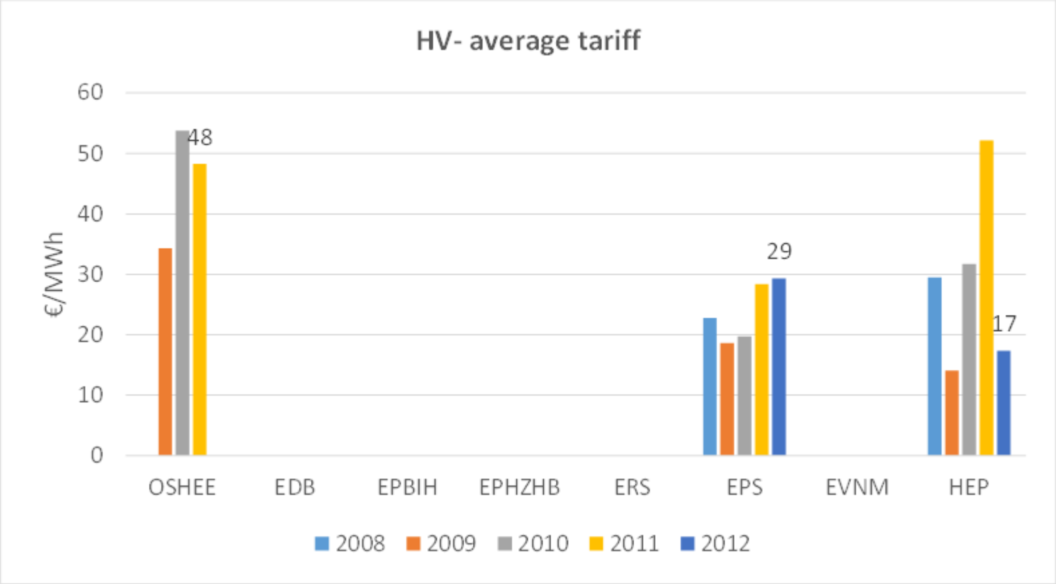


Figure 13.9: Average high voltage tariff in the period 2008 – 2012

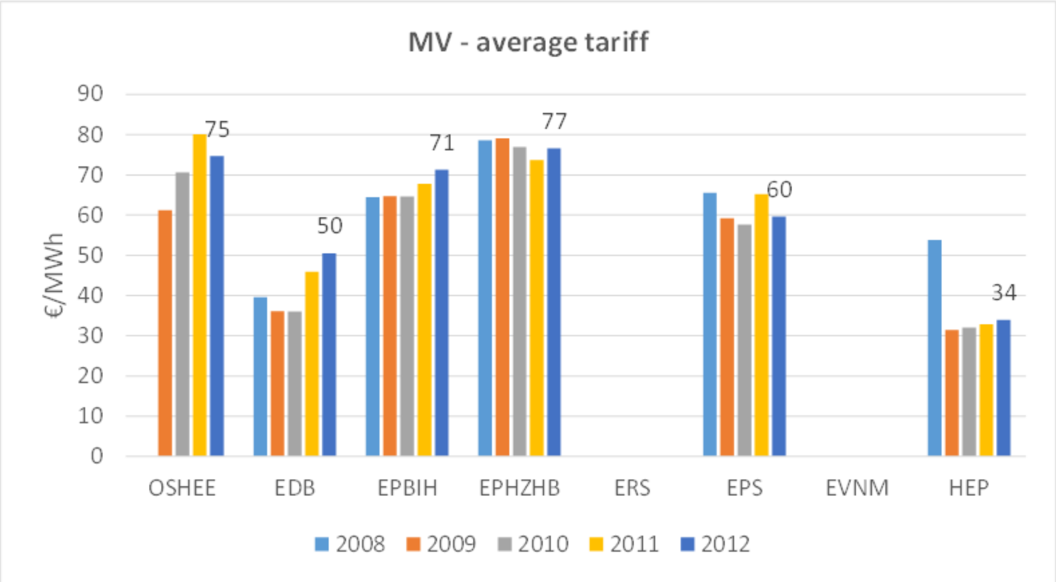


Figure 13.10: Average medium voltage tariff in the period 2008 – 2012

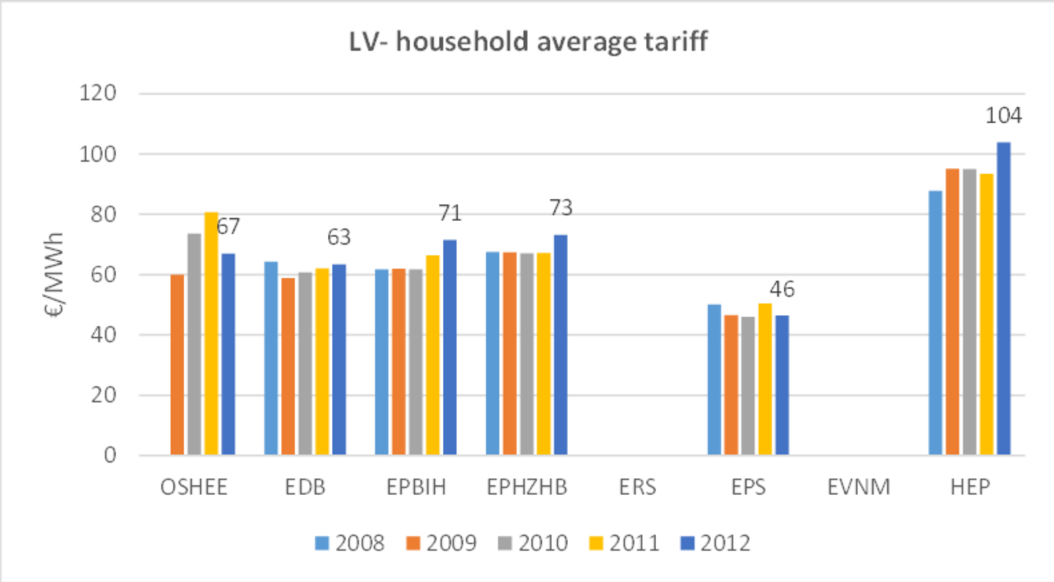


Figure 13.11: Average low voltage tariff for households in the period 2008 - 2012

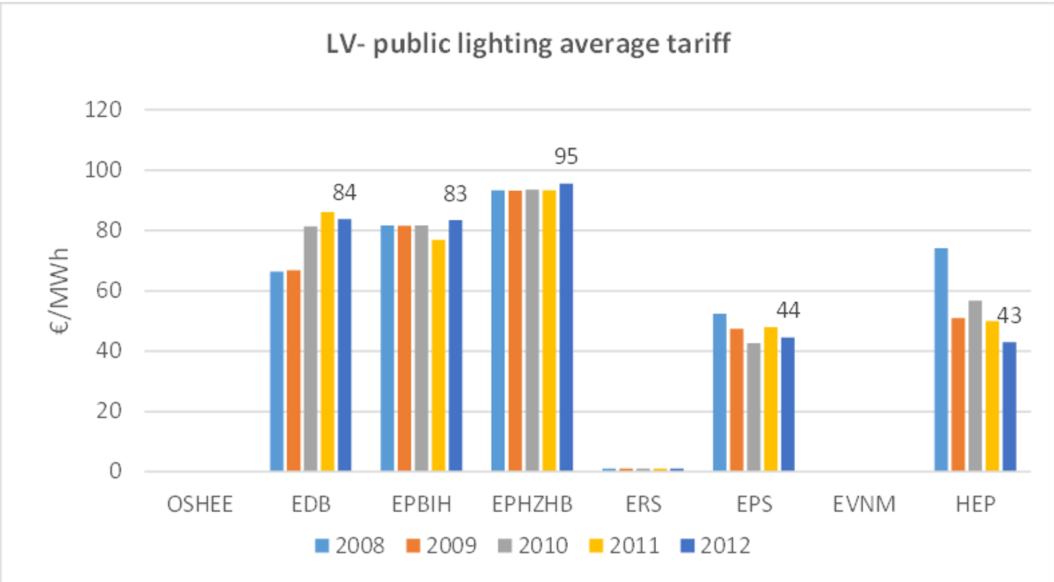


Figure 13.12: Average low voltage tariff for public lightning in the period 2008 - 2012

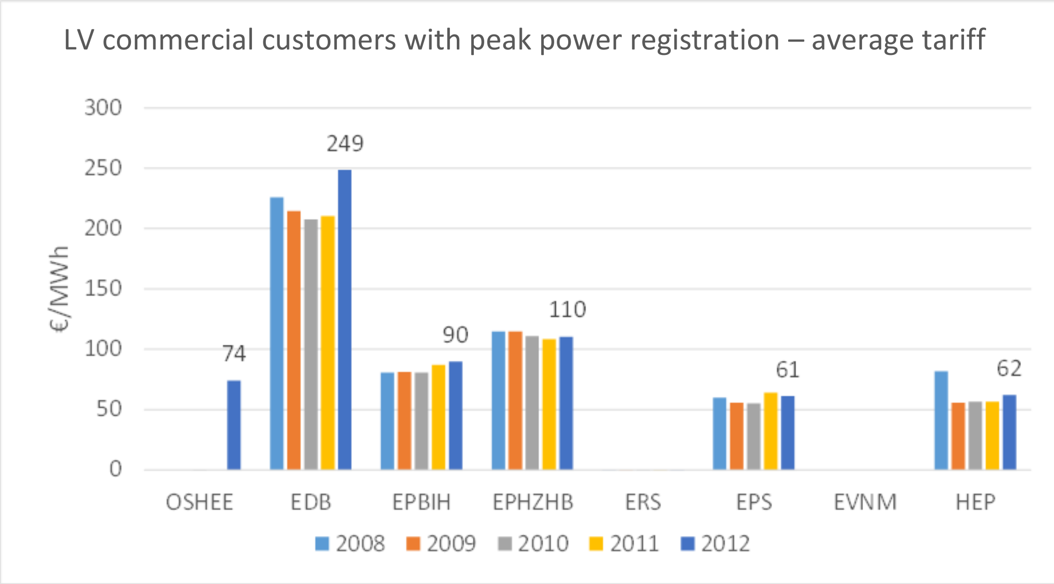


Figure 13.13: Average low voltage tariff for LV commercial customers with peak power registration in the period 2008 – 2012

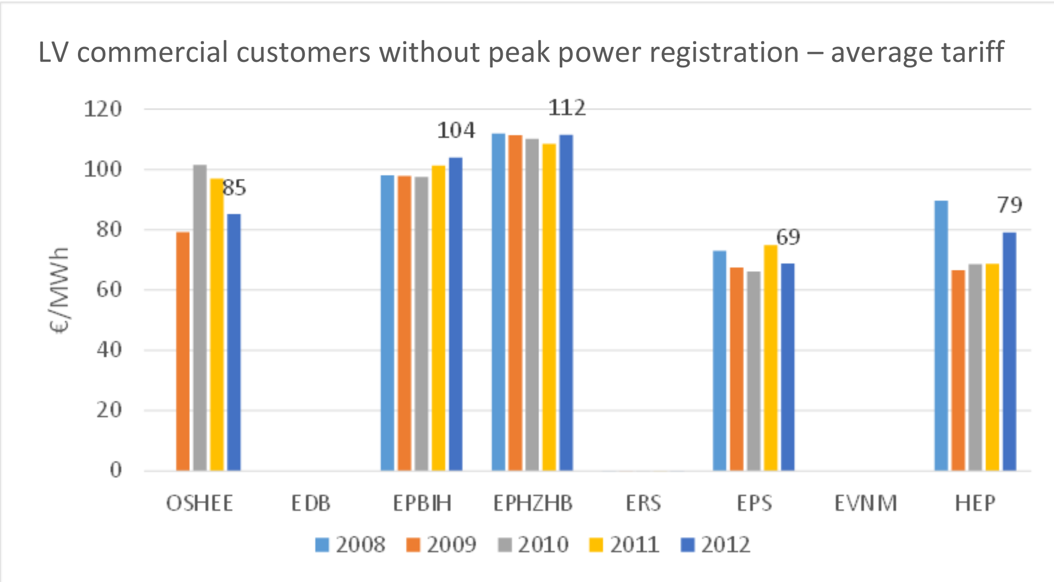


Figure 13.14: Average low voltage tariff for commercial customers without peak power registration in the period 2008 - 2012

At the end we show average tariff calculated as a sum of revenues at each voltage level divided by electricity delivered.

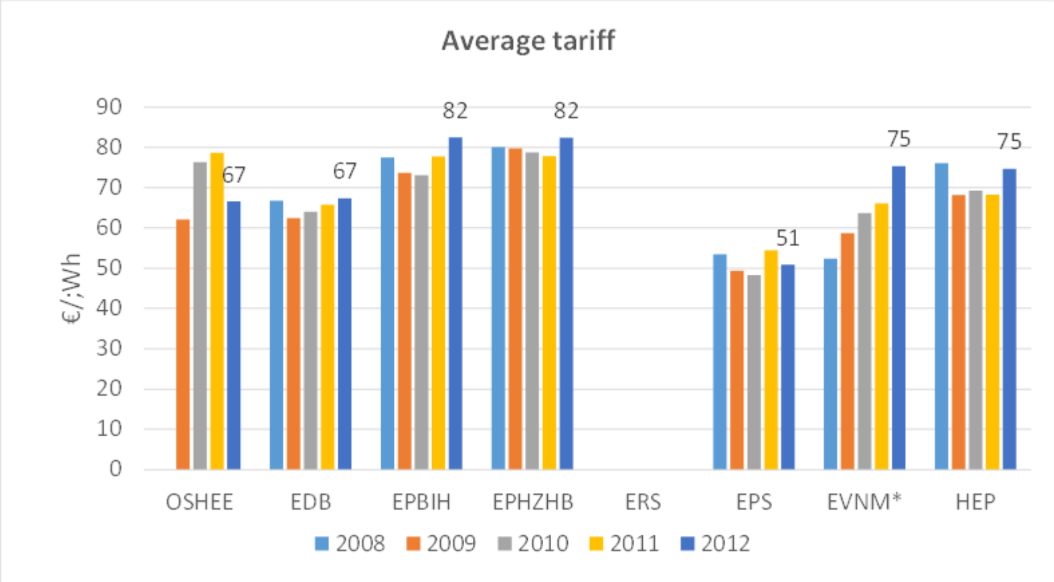


Figure 13.15: Average tariff in SEE DSOs in period 2008 - 2012

13.5. OBSERVATIONS/RECOMMENDATIONS

The goal of preceding analysis was to determine to what degree do financial and operating benchmarks diverge among the participating DSOs. In analyzing the received data we observed the lack of standardization regarding the reported data. Having identified some of the issues we propose more detailed data collection exercise is carried out with the following emphasis:

- revenues from distribution and / or retail services should be clearly identified. It is important to distinguish revenue from sale of electricity and revenue from use of distribution network,
- pass through costs should be clearly identified and not taken into account (e.g. transmission costs),
- all data should then be adjusted to reflect purchasing power differences among countries.

Using benchmark indicators to compare the DSOs can only be used to compare the DSOs on a benchmark by benchmark basis. This has several drawbacks as:

- some benchmarks are rather correlated implying double counting,
- all benchmarks are given equal weight.

Therefore, such an analysis does not allow for determination of efficiency ranks (scores) of DSOs. In order to determine the efficiency of observed DSOs more complex analysis should be used such as Stochastic Frontier Analysis of Corrected Ordinary Least Squares which we believe would give additional valuable insights. Such advanced analysis would allow each DSO to observe how far away it is from efficient operations.

14. CUSTOMER SERVICE

Customer service benchmarks measure the quality and effectiveness of the DSOs interaction with customers.

Commercial quality is directly associated with transactions between electricity companies (either DSOs or suppliers, or both) and customers, and covers not only the supply and sale of electricity, but also various forms of contacts established between electricity companies and customers. Former (regulated) traditional supply companies have been replaced by traders/suppliers acting under competitive conditions (theoretically, in an efficient retail market). Meanwhile, the DSO still performs a monopoly activity which is regulated in detail; in most countries, the distribution activity is supposed to be separated from the supply activity. At the same time, DSOs may perform other activities (like grid maintenance, repairs, restoration of supply, etc.) that involve commercial aspects to a high degree. The term “commercial quality” cannot strictly be linked to the term “trade”, and thus other activities must also be included in the commercial quality assessment.

The principal points of interaction occur when a customer applies for new connection or a change of service, receives his monthly bill and provides payment, or other communication related to billing, contacts the DSO to obtain information, review his bill, requests that his meter be checked, or make a complaint, participates in a special service provided by DSO (e.g. energy audit, demand side management, on-site testing, etc).

The quality of customer service is difficult to measure quantitatively, although this area has become one of the most important functional area and highest priority in developed DSOs. Increasing tariffs put a great strain on public relations; now in many DSOs customer service may be a DSO’s principal means to establish competitive advantage. Yet it remains difficult to measure, a few standard benchmarks have been established.

In the regulatory environment, many DSOs and regulatory bodies rely on a combination of customer satisfaction surveys and registered customer complaints as aggregated indicators of DSOs effectiveness in customer service. That is, there are means used by regulators to assess whether a DSO expenditures on customers service are adequate, excessive or too little. This performance measurement approach works in comparing a DSO’s progress in customer service form one year to the next, but is not effective means to compare different DSOs.

Another approach is comprehensive analysis. Comprehensive analysis of the commercial quality aspects in EU and nine contracting parties to the Energy Community is given in 5th CEER Benchmarking Report on the Quality of Electricity Supply (*available online: https://www.energy-community.org/pls/portal/docs/1522177.PDF*). On this point it should be mentioned that CEER report recognizes six countries (Albania, Bosnia and Herzegovina, Croatia, FYR of Macedonia, Serbia and UNMIK) instead of nine DSOs in this report. Furthermore, it focuses on standards (requirements imposed to SEE DSOs) while this report on actual DSO performance.

Developed DSOs have strong, performance oriented incentives to induce improvements in customer service, which also suggests a basis for benchmarking. The regulatory agencies have established penalties for missing customer service targets. The penalties are provided directly to the affected consumer as a credit against his bill (example of this targets include: advance notice of planned outages, time to resolve complaints, etc).

In the region observed in this report there is no compensation for individual customers and often there is no penalty defined. Most DSOs in the region are state owned - their business culture is supply oriented. It could be said that they are inexperienced with demand-oriented, customer care orientation common among firms operating uncompetitive markets. Hence, many DSO have no data or internal reporting procedures required to develop performance targets.

In what follows the report focuses on several measures that DSOs are expected to track in some form. It proposes performance indicators in three areas:

- measures of performance in connection services,
- measures of performance in complaint handling and
- (so called) other measures of customer service.

With regard of commercial quality this report should be regarded as one of efforts to investigate commercial quality in 9 DSOs in the observed region. The questionnaire used for this report stressed the complexity of commercial quality with multiple suppliers and regulated entities (DSO, universal supplier, supplier of tariff customers). More thorough analysis and benchmarking would require deep examination of business processes, market design and legal framework in all countries involved. This should be taken into account when analyzing results contained in this report.

14.1. CONNECTION SERVICES

Performance measures for connection services generally focus on the amount of time required for a customer to obtain a new connection or other type of service related to his connection. From a customer's perspective this is a vital aspect of DSO service. Alongside billing and repair issues, connection services are a significant source of customer complaints and hence a focus area for DSOs' efforts at performance improvement.

The proposed performance measures in this report focus on service response times. As described in the 5th CEER Benchmarking Report on the Quality of Electricity Supply, performance benchmarks in developed country markets go a step beyond service response time and track other measures. However, this level of detail is not expected in the observed DSOs records (i.e. no adequate statistical data exists for most commercial quality indicators). Therefore this report focuses on measures that DSOs are expected to track in some form:

a) lead time to provide new connection:
   The time required to obtain power supply from the time that the customer submits application to the DSO. From the DSO perspective this should not include time lost if the customer's application is not complete according to the DSOs published requirements. Hence, the starting point is when the application is recognized as complete until the time when an inspection results in approval.

b) lead time to provide service upgrades or other changes to service:
Changes to service include changes from single to three phase, voltage supply upgrades, change in allowed peak demand, and the like, all of which require applications to the DSO.

c) lead time to test/replace meters in case of request/complaint:
This measure is related to customers complaint that the meter readings are faulty and the meter in fact may require recalibration or replacement. The DSO performance on this measure reflects on its commitment to accurate metering and ability to improve collections. This is the time which is needed to inspect the meter in case of meter failures, and counted in days from the date of receipt of the customer’s notice on the meter problem until the date of inspection of the meter.

Connection-related activities have a complex structure. It could be observed that DSOs use different approaches (criteria) in grouping data related to lead time for new connection. Some DSOs differentiated connection procedures based on:

- the type of customer; in addition to the obvious household type, categorizations used in different DSOs distinguish between industry, commercial customers on different voltage levels, etc,
- voltage level,
- allowed peak demand,
- connection line length and entity responsible for connection construction (DSO or customer).

Besides, DSOs data could not be easily compared (benchmarked) since all DSO did not comply with the request to provide data on *realized time* required to obtain power supply from the time that the customer submits application to the DSO (e.g. HEP and KEDS provided legal obligations).

We suppose that some DSOs included time for construction works (EPHZHB, EPBIH) while others provided data for certain connection process phases only (in most cases approval and commissioning). In this sense there is a doubt that the times indicated by some DSOs (e.g. ERS, EDB, EPS) are longer, if the whole lead time to provide new connection is addressed.

Beside averages, ERS provided data on best and worst performing distribution area lead time for connection after connection agreement signed.

To summarize, data from the second questionnaire related to the commercial quality are hardly comparable. Main reasons are:

- DSOs have used different approaches in grouping data,
- some DSOs provided real data while other standards (upper/lower limits that must be meet),
- DSO have not followed the same structure while preparing data – some provided data for the whole process (all phases) while others only for certain phases.

Therefore only some remarks are given in sections analyzing particular groups of data.

Diversity of regulation and data provided by DSOs is clearly shown in Table 14-1.

Table 14-1 Lead time for new connection - data structure as provided by DSOs

DSO		Days
EDB		
Lead time to provide new connection - LV households		11
Lead time to provide new connection - other LV customers		12
EPBIH		
Lead time to provide new connection - LV customers		45
Lead time to provide new connection - MV customers		150
EPHZHB		
Lead time to provide new connection - LV customers		60
Lead time to provide new connection - MV customers		180
ERS *(after connection contract signed)*		
Lead time to provide new connection - other LV customers		3-14 (8,03 on average)
Lead time to provide new connection - LV households		4-16 (8,6 on average)
Lead time to provide new connection - MV customers		5
EPS *(two steps recognized)*		
Approval	HV	29
	MV	27
	LV	20
Commissioning *(all conditions satisfied)*	HV	n.a.
	MV	12
	LV	10
EVNM *(two steps recognized)*		
Approval	Lead time to provide new connection - up 40 kW	15
	Lead time to provide new connection - between 40 and 400 kW	15
	Lead time to provide new connection - above 40 kW	40
Realization	Lead time to provide new connection - up 40 kW	30
	Lead time to provide new connection - between 40 and 400 kW	50
	Lead time to provide new connection - above 40 kW	50
HEP *(provisions of energy-related laws on approval and commissioning lead times only)*		
Lead time to provide new connection - LV customers		45
Lead time to provide new connection - MV customers		45
KEDS *(provisions of energy-related laws)*		
Approval	Lead time to provide new connection – industry all voltage levels	40
	Lead time to provide new connection – LV customers, connection line up to 250 m in length	20
	Lead time to provide new connection - LV customers, connection line up to 35 m in length	15
Commissioning *(customer constructs connection)*		5
Connection construction (DSO)		5
OSHEE		
Lead time to provide new connection - up until 20 kW		78,8
Lead time to provide new connection - above to 20 kW		79,6

Table 14-2 gives data provided by Serbian EPS on the level of performance with regard of time for new connection. For example, if there are some "overall standards" (OS) related to the minimum level of performance (commonly in % of cases) that has to be met in a given period (e.g. in a 90 % of new customers connection approval provided within 30 days), then these data can be used to evaluate DSO performance.

Table 14-2 Level of performance (compliance percentage) with regard of time for new connection - EPS

Service	Voltage level		
	HV	MV	LV
	[%]		
Connection approval provided within 30 days	100	51	72
Commissioning provided within 15 days	100	71	66

Table 14-3 contains interesting data provided by Kosovo KEDS on the overall and guaranteed standards with regard of connection related services. KEDS have not provided its actual values on achieved performance.

Table 14-3 Overall (OS) standards and requirements (R) related to new connection – KEDS

Service	Standard (expected level of quality)
New connections for level 35 kV, 10 kV, and for 0,4 kV industrial consumers consent shall be given	(OS) within 40 days in 80 % of the cases
New connections for level 0,4 kV commercial and household consumers with distances up to 250 m consent shall be given	(OS) within 20 days in 80 % of the cases
New connections for level 0,4 kV commercial and household consumers with distance up to 35 m consent shall be given	(OS) within 15 days in 90 % of the cases
Commissioning where consumer responsible for connection construction shall be provided	(OS) within 5 days in 90 % of the cases
Where DSO responsible for new connection construction at 35 kV, 10 kV, and 0.4 kV levels action shall be carried out	(R) within 5 days

Since all except one DSO (Croatia following the EU accession changed its legal status from a Contracting Party to that of a Participant) are Contracting Parties to Energy Community, this report suggests to start with the adoption of CEER guidelines in future reports. To be able to compare data on lead time for new connection it is very important to follow guidelines on input data monitoring for calculation of the 4 indicators used in CEER report for setting standards related to connection:

- time for response to customer claim for network connection,
- time for cost estimation for simple works,
- time for connecting new LV customers to the network,
- time between signing contract and the start of supply.

This list of four indicators represents the whole process for connection (first there is the request for connection, to which there are two possible responses (feasibility response and estimation of costs);

then, when the estimated cost is accepted by the customer, there is the work for realizing the connection; last, there is the activation of the supply (only in this last step can the supplier be involved)).

It is worth mentioning that, based on 5th CEER benchmarking report, median value of standard for lead time to provide new LV connection in EU countries equals 47 working days (16 days for response to customer claim, 14 days for cost estimation for simple works, 11 days for connecting LV customer to the network and 6 days for commissioning after signing contract). These are only indicative values, since countries standards for connection-related activities often have a complex structure depending upon the complexity of the work to be done.

Table 14-4 provides analysis, prepared by regulators in SEE for the Energy Community, published as an Annex in 5th CEER Benchmarking Report on the Quality of Electricity Supply regarding Commercial quality, related to *standards* for connection related activities in 6 SEE countries: Bosnia and Herzegovina, Croatia, FYR of Macedonia, Croatia, Serbia and UNMIK. These standards can be compared to the EU countries standards provided in 4th column (*source: 5th CEER Benchmarking Report*).

Table 14-4 Commercial quality standards for connection related activities in observed countries (source: 5th CEER benchmarking report)

Quality indicator	Countries *grouped by type of standard*	Standard *median value and range*	Standard EU *median value and range*	Company involved
Time to response to customer claim for network connection	OS: Albania OAR: Bosnia and Herzegovina, Croatia, FYR of Macedonia, Serbia, UNMIK	25 days 15-30 days	*16 days* *8-30 days*	DSO
Time for cost estimation for simple works	OS: Albania OAR: Bosnia and Herzegovina, FYR of Macedonia, UNMIK None: Croatia, Serbia	21 days 8-30 days	*14 days* *5-35 days*	DSO
Time for connecting new customers to the network	OS: Albania, UNMIK OAR: FYR of Macedonia, Croatia, Serbia None: FYR of Macedonia	20 days 4-45 days	*11 days* *2-90 days*	DSO
Time to disconnection upon customers request (de-activation of supply)	OAR: FYR of Macedonia, Serbia, UNMIK O/M: Bosnia and Herzegovina None: Albania, Croatia	12 days 3-30 days	*5 days* *5-8 days*	DSO

OS – Overall standard; OAR – Other available requirement; O/M – only monitoring

Regarding the duration of an inspection of a meter failure (lead time to test/replace meters in case of request/complaint), almost all DSOs provided data (EVNM and HEP did not provide data). Three DSO provided historical data (OSHEE, EDB, KEDS), showing that in OSHEE and EDB lead time to test/replace meters in case of request/complaint declines steadily. ERS differentiated data by voltage level of customer connection and consumption category (MV customers 1 day; households 3,4 day; other LV customers 2,1 day; calculated average based on number of existing customers equals 3,3 days).

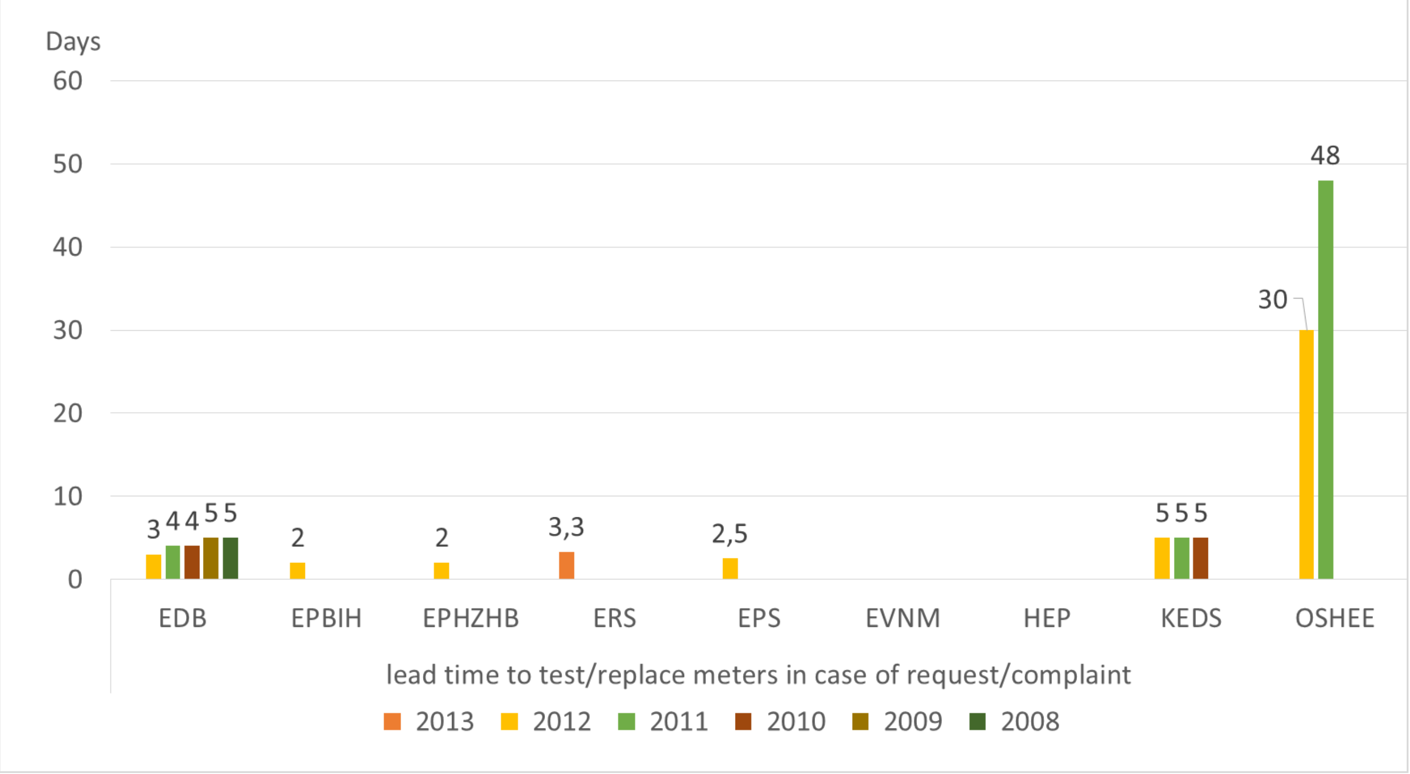


Figure 14.1 DSOs data provided on lead time to test/replace meters in case of request/complaint

It is worth mentioning that, as given in 5th CEER benchmarking report, median value of standard for lead time to test/replace meters in case of request/complaint in EU countries equals 10,5 working days (standards range 3-30 days). In general, only a few regulators have set standards relating to metering. Regarding the duration of an inspection of a meter failure, the typical standards in use are relatively heterogeneous. Compensation in case of non-performance is applied in a small number of EU countries.

Regarding the lead time to provide service upgrades or other changes to service, 3 DSOs (HEP, KEDS, ERS) did not provide data (neither standards or historic/realized data). Other 6 DSOs provided data on 5 indicators as given in Figure 14.2. These data are hardly comparable since some indicators are expressed as actual DSO performance data and others as prescribed DSO requirements. Besides it is reasonable doubt as to whether the DSOs have taken into account all phases/steps of the service provided.

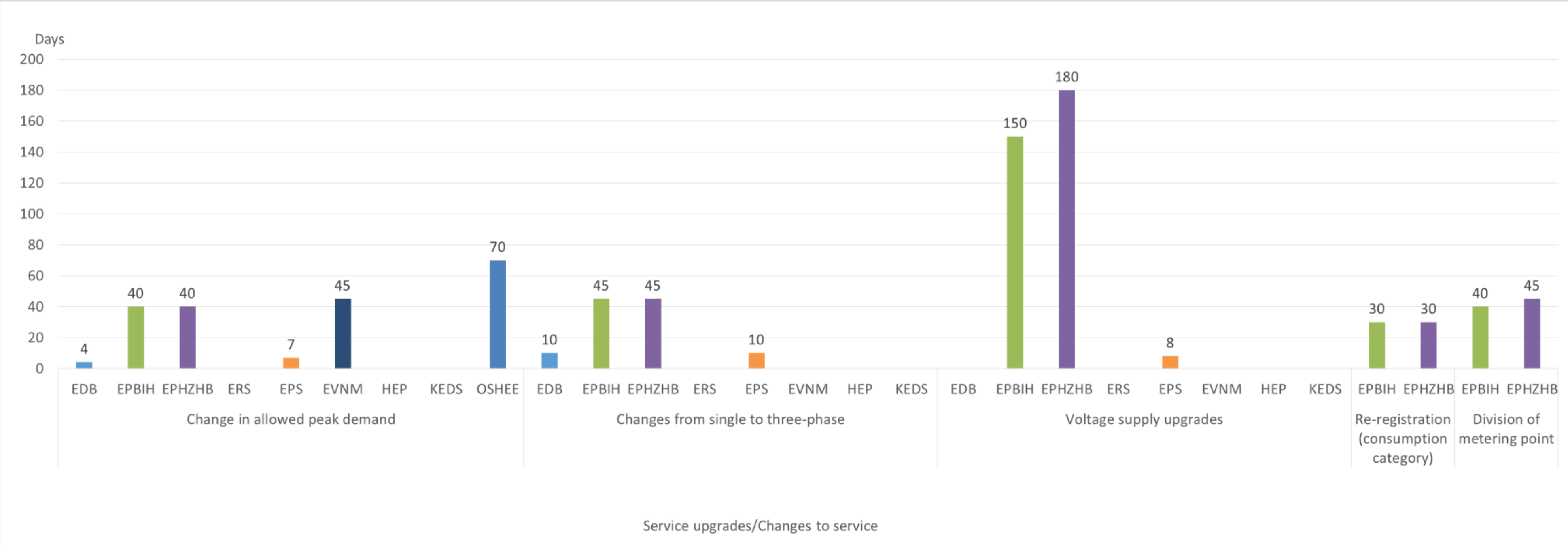


Figure 14.2 DSOs data provided on lead time to provide service upgrades or other changes to service

14.2. COMPLAINTS HANDLING

Complaint handling is an important function of customer service and is a key indicator of service quality for many regulatory commissions. This report focuses on:

a) Complaint response time:
Taking the customer's perspective, this is the time from submission of the complaint to an activation by the DSO toward resolving the complaint (such as arrival of the service personnel to address the issue, rescheduling of a service call and satisfactory clarification of a payment dispute). In this report this is the time needed to respond to customer's written complaint or enquiry, and shall be counted in days from the date of registration of the customer written complaint or enquiry (the date of receipt of the letter) until the date of dispatch of the written response to the intervention.

b) Complaints handled annually/100 customers:
This measure provides the volume of customer complaints, normalized by the number of customers. The measure is better characterized as an indicator of customers satisfaction rather than effectiveness of handling complaints.

c) Customers care staffing level/100 customer:
This is an indicator of the effort and resources devoted by DSO to customer service (omits services such as maintenance and repair).

Complaint response time is indicator related to time period between the registration of a customer complaint or enquiry and the date of the response to it. Figure 14.3 gives data delivered by DSOs (3 DSOs did not provide data). In this report ERS data relate to voltage quality complaints only. Response times do not exceed 5 days which is surprisingly low. Namely, based on 5th CEER benchmarking report, median value of standard for response time to customer complaints and enquiries in EU countries equals 15 working days (standards range 5-40 days), and in Energy Community contracting parties 26 days (standards range 15-30 days). Therefore, it is ordinary to expect for actuals, if not higher, to be close to this standard values.

On this point we could conclude that DSOs do not record complaints data in a manner this report (questionnaire) envisaged (e.g. this was evident from remark given by EPS in 2nd questionnaire) and, what is equally important, scope of complaints observed by DSO differs considerably (some DSOs focused on several technical and nontechnical services while others only to one or two technical). Therefore data provided are not good starting point for mutually comparison. In future reports more efforts shall be devoted to development of clear definitions and understanding of indicators meaning and also to harmonization of data collection procedures in DSOs.

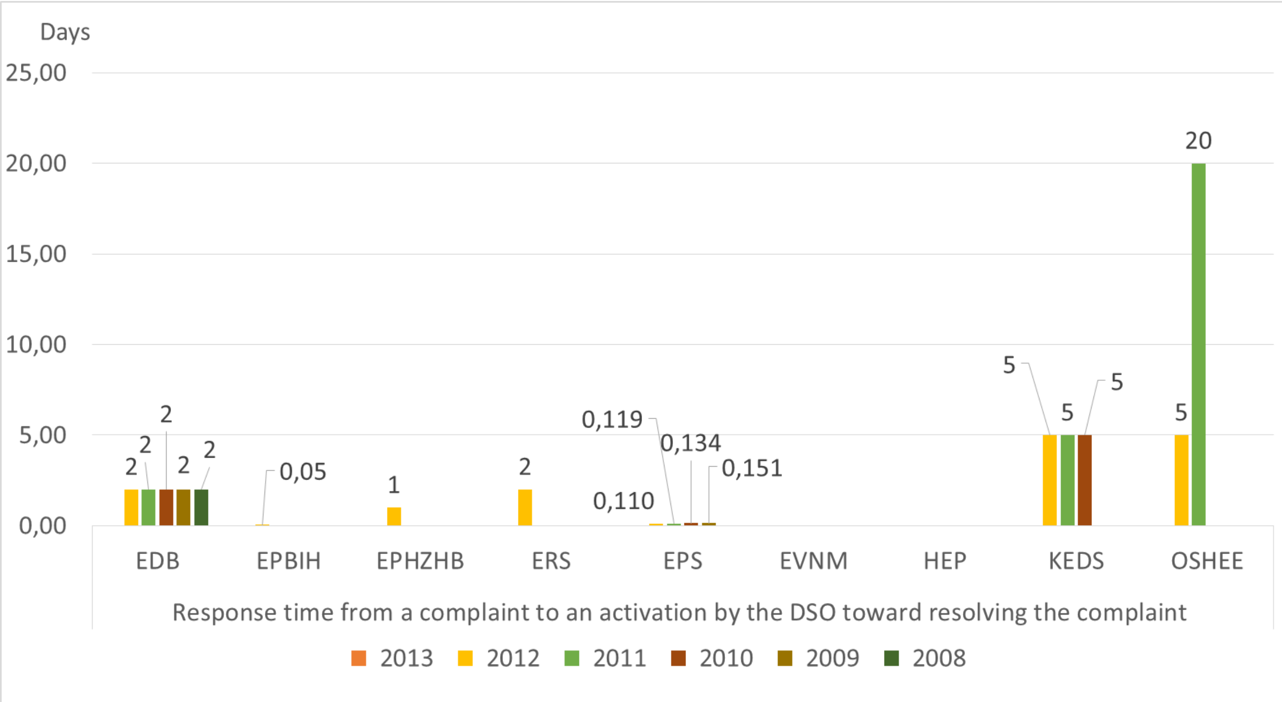


Figure 14.3 Data provided by DSOs on complaint/enquiry response time

2 out of 9 DSOs did not provide data on complaints handled annually/100 customers by DSO (Figure 14.4). Some DSOs (OSHEE, EDB, EVNM) provided even historical data which in two DSOs indicate steady decline in number of complaints handled by DSOs.

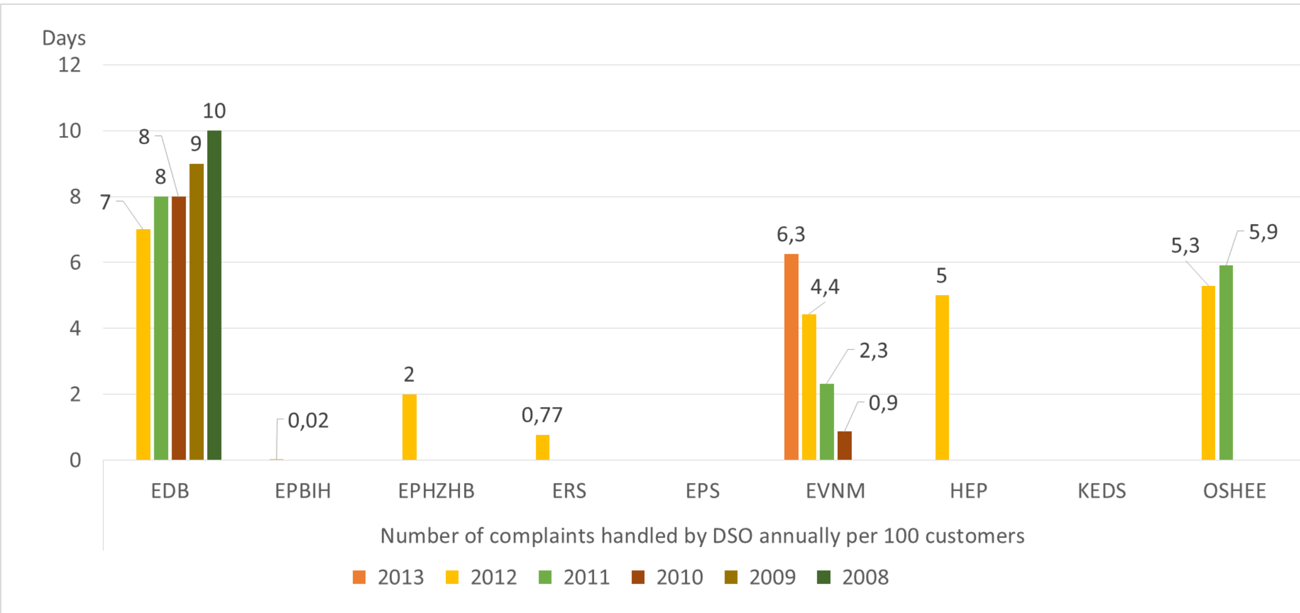


Figure 14.4 Data provided by DSOs on complaints handled annually/100 customers

4 out of 9 DSOs did not provide data on customers care staffing level/100 customer (Figure 14.5). Some DSOs (OSHEE, EDB, EPS, EVNM) provided even historical data which indicate steady decline in customers care staffing level in OSHEE and EPS, steady increase in EDB and unchanging conditions in EVNM.

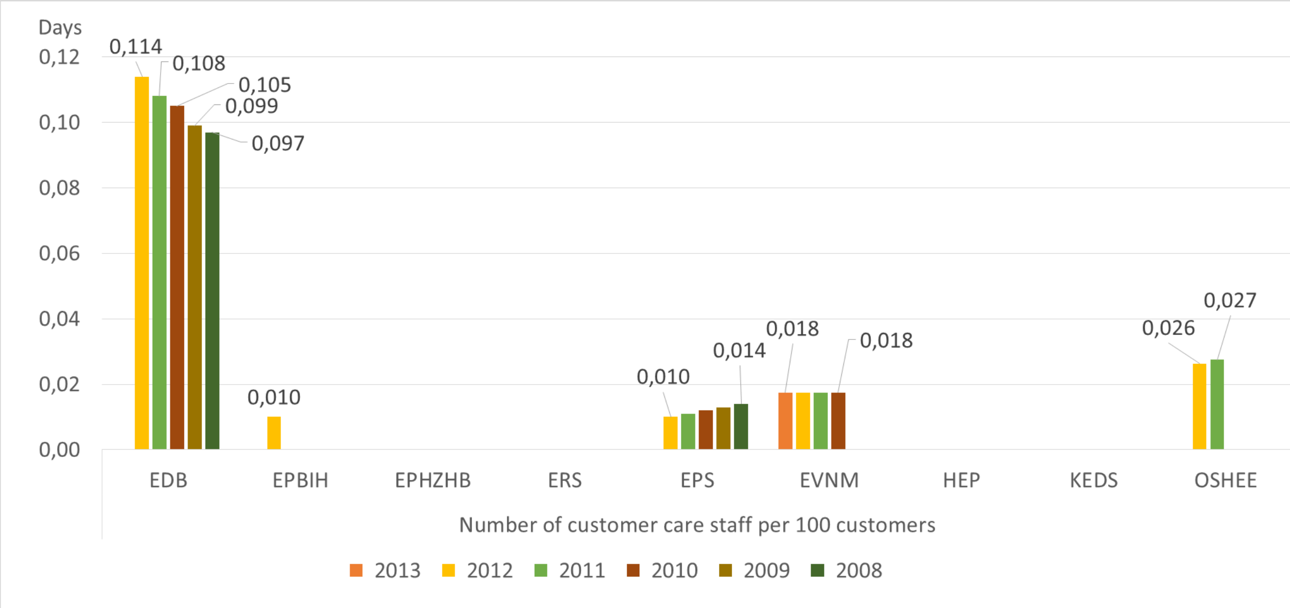


Figure 14.5 Data provided by DSOs on customers care staffing level/100 customer

In Table 14-5 are given OSHEE data on registered customer complaints as aggregated indicators of DSOs effectiveness in customer service. This data, although not effective mean to compare with other DSOs, are useful for performance measurement in comparing OSHEE progress in customer service form one year to the next (e.g. 2011 and 2012). For example, it could be observed that in 4 categories number of complaints rose up and in other 9 declined.

Table 14-5 Data structure on customer complaints - OSHEE

Description	**2012**	**2011**
Invoices	15.546	27.834
Wrong tariff	328	560
Economic damage	5.476	4.031
Unmatched payments	10.025	5.639
More than one contract	566	680
Measurement scheme problems	25.379	26.985
Cross metering	1.420	428
Defects in the company's distribution network and infrastructure	2.002	2.073
Appeal for power theft	696	411
Voltage quality	398	475
Blackouts	108	603
Services delays	526	1.243
To company employees	19	57
Total	**62.489**	**71.019**

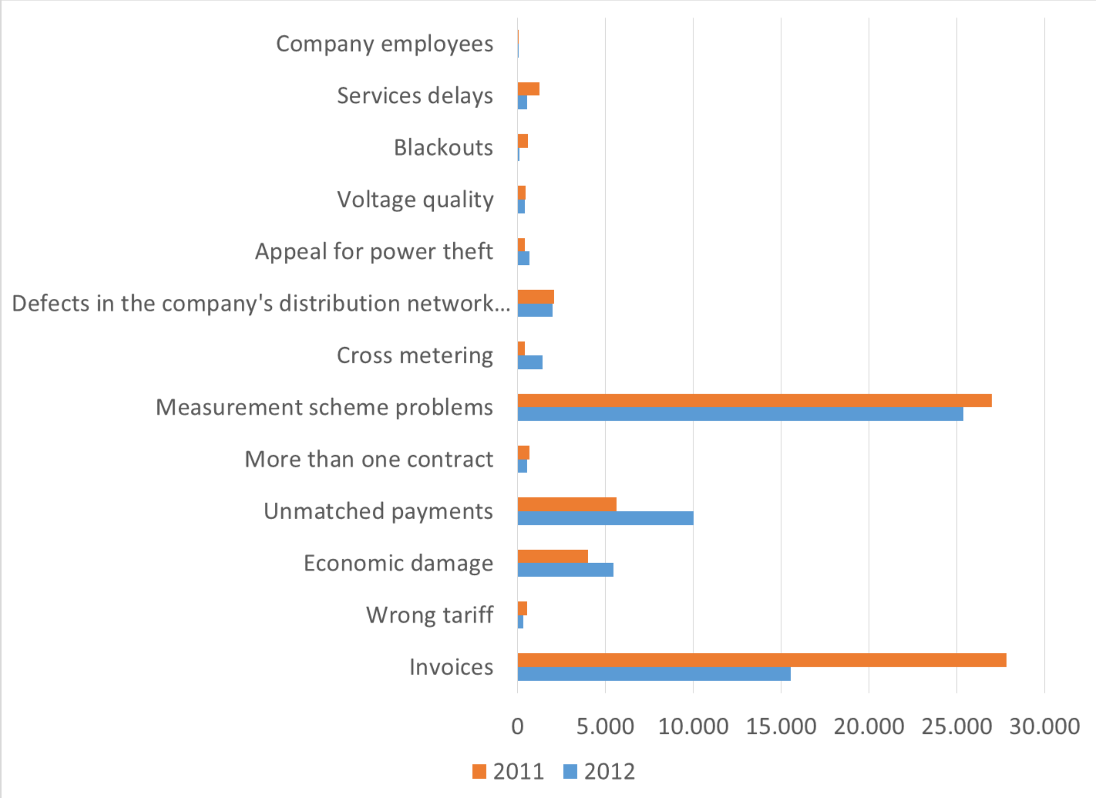


Figure 14.6 Number of customers complaints - OSHEE progress from 2011 to 2012

Table 14-6 Commercial quality standards for customer care activities (source: 5th CEER benchmarking report)

Quality indicator	**Countries** *grouped by type of standard*	**Standard** *median value and range*	**Standard EU** *median value and range*	**Company involved**
Response time to customer complaints and enquiries (total, including voltage complaints and interruption complaint)	OAR: Bosnia and Herzegovina, Croatia, FYR of Macedonia, UNMIK O/M: Serbia None: Albania	26 days 15-30 days	*15 days* *5-40 days*	DSO
Time for answering the voltage complaints (part of response time to customer complaints and enquiries)	OAR: Bosnia and Herzegovina, Croatia, FYR of Macedonia, UNMIK O/M: Serbia None: Albania	16 days 2-30 days	*18 days* *5-60 days*	DSO
Time for answering the interruption complaint as part of response time to customer complaints and enquiries	OAR: FYR of Macedonia, UNMIK O/M: Serbia None: Albania, Bosnia and Herzegovina, Croatia	20 days 15-30 days	*15 days* *7-21 days*	DSO
Response time to questions in relation with costs and payments (excluding connection)	OAR: Bosnia and Herzegovina, Croatia, UNMIK None: Albania, FYR of Macedonia, Serbia	8 days 1h-8 days	*13 days* *5-40 days*	DSO

OS – Overall standard; OAR – Other available requirement; O/M – only monitoring

Table 14-6 and Table 14-7 provide analysis, prepared by regulators in SEE for the Energy Community, published as an Annex in 5th CEER Benchmarking Report on the Quality of Electricity Supply regarding Commercial quality, related to *standards* for customer care activities and technical service in 6 SEE countries: Bosnia and Herzegovina, Croatia, FYR of Macedonia, Croatia, Serbia and UNMIK. These standards can be compared to the EU countries standards provided in 4th column (source: 5th CEER Benchmarking Report).

Table 14-7 Commercial quality standards for technical activities (require and include time for elimination of the problem by DSO) (source: 5th CEER benchmarking report)

Quality indicator	**Countries** *grouped by type of standard*	**Standard** *median value and range*	**Standard EU** *median value and range*	**Company involved**
Time between the date of the answer to the VQ complaint and the elimination of the problem	OS: UNMIK OAR: Bosnia and Herzegovina, Serbia None: Albania, Croatia, FYR of Macedonia	25 days 1-60 days	*6 months* *1-24*	DSO
Time until the start of the restoration of supply following failure of fuse of DSO	OS: UNMIK OAR: FYR of Macedonia O/M: Bosnia and Herzegovina None: Albania, Croatia, Serbia	12 hours 1-24 days	*4 hours* *3-24*	DSO
Time for giving information in advance of a planned interruption	OS: UNMIK OAR: Bosnia and Herzegovina, Croatia, FYR of Macedonia, Serbia None: Albania	3 days 1-10 days	*2 days* *1-15*	DSO
Time until the restoration of supply in case of unplanned interruption	O/M: Bosnia and Herzegovina OAR: FYR of Macedonia, Serbia None: Albania, Croatia, UNMIK	18 hours 2-24 hours	*12 hours* *1-24*	DSO

OS – Overall standard; OAR – Other available requirement; O/M – only monitoring

Obviously many DSO have no formal tracking mechanisms for complaints or response. Having such a system, in it-self, is an indication of customers service commitment. Since all observed countries are contracting parties to the Energy Community we recommend to start with monitoring data on commercial quality in line with recommendations outlined in CEERs benchmarking reports (in CEER report indicators relating to the commercial quality have been grouped into four main groups: connection, customer care, technical service, metering and billing).

The service providers shall in their customer centers introduce and keep the book of complaints, preferably in electronic form, so those customers who are dissatisfied with a particular service (waiting time, personal attention, etc) are enabled to complain.

Besides, service provides shall established and implement a complaints procedure which shall be:

- effective (aimed at solving problem),

- readily assessable (with clearly set steps, procedures and responsibilities),
- speedy (with time limits for dealing with complaints)
- confidential (the privacy of the individual customers should be protected)
- integrated (with the organization's operation and practices).

Staff in the customer center and local management shall be empowered to resolve complaints promptly. The complaints facilitator shall produce a monthly management report to monitor both the volume of complaints received and the response performance in relation to these complaints.

14.3. OTHER CUSTOMER SERVICE

The proposed measures for connection services and complaint handling do not cover all important facets of DSO customer service performance. For this report following measures have been analysed:

a) customers access to services
This measure considers ease of access to the DSO as an indicator of customers service. In the report focus has been to indicate the range of types of access points. For most DSOs, customer access points are principally the district offices, district payment centers, call in centers, some DSOs also provide web based services.

b) DSO staff resources providing special services
Personnel staffing levels devoted to activities other than connections and complaint handling (i.e. product promotions, training or consumer education programs, energy audits and DSM programs, power factor correction services, diagnostic fault testing service, technical system in lighting system design and so on). These services have been increasingly important for DSO public image.

Table 14-8 provides data provided by DSOs on range of types of access points (point of contacts with the DSO). In all DSOs there are customer care centers and call centers where customers can make a complaint, ask a question, claim something (e.g. enquiry for new connection), participate in some activity. Vital information related to the operation of distribution system such as planned maintenance, are published on company website and/or in the media (radio, press). HEP and EPS have introduced online account access web application ("My account") which serves customers for consumption tracking, notification/review of meter readings, to get information about invoices and their consumption.

Table 14-9 summarizes the data provided by DSOs on types of customer access points.

Table 14-8 Customer access to services (types of access points) – DSO data

DSO	Types of access points
OSHEE	44 ***customer care centers***. Each of them includes customer care service and cash point desk. There are 7 additional payment desk which operate separately from customer care centers. One ***call center*** located in the headquarters manages the ***email services***. Company ***web page***.
EDB	Communication with customers takes place most often through the media (e.g. radio, TV announcements) and company ***web page***. ***Customer care center, 3 payment centers, free phone communication, email service.***
EPBIH	52 ***customer care centers***, ***6 call centers,*** company ***web page***.
EPHZHB	35 ***customer care centers***, 1 ***call centers,*** company ***web page***.
ERS	In all local offices there are ***customer care center*** (e.g. information access points). Vital information are published on the **website** of DSO. Besides, customers can send their queries in written, by email or by phone call to call centers.
EPS	There are 5 large ***call centers*** (customers can get information about the state of the distribution system, planned maintenance, etc). Besides, such information can be obtained by phone calls to the DSO local offices. Planned outages are published on the **website** of distribution areas, as well as in the **local press**. Progress is present in terms of application of ***modern internet and mobile technologies*** to improve customer service: to ***provide information*** about planned interruptions, bills (current status, print invoices), consumption calculator, tariffs, payment options and personal invoice, about distribution services, customer notification of supply interruption, unauthorized consumption, meter reading value; surveys on customer satisfaction with DSO services.
EVNM	Customers can send their queries, enquires and complaint in written, by email, fax or by phone call to call centers. ***Customer care centers*** in all branches. Payment centers (payment of bills, complaints regarding bills). Company web page.
HEP	75 ***customer care centers*** 10 ***call centers*** ***free phone communication*** in all (21) branches Vital information are published on the **website** of DSO. Customers can send their queries, enquires and complaint in written, by email, web application. Web based application "My account" for consumption tracking, notification of meter reading value, information about invoices, consumption, etc.
KEDS	7 ***customer care centers*** 1 ***call center*** located in the headquarters Customers can send their queries, enquires and complaint by email, phone, web application.

Table 14-9 Summary of range of types of access points

Type/DSO	OSHEE	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS
Customer care centers/Payment centers	44/7	1/3	52	32	5	yes*	yes*	75	7
Call centers	1	yes	6	1	yes	yes	yes	10	1
Internet (company web page)	yes	yes	yes	yes	yes	yes	yes	yes	yes
Web services (personal account)					yes			yes	

**in all local offices*

Except EDB (0,028 employees providing special service per 1000 customers in 2012), other DSOs did not provide data related to so called special services (in this report these are all service other than services related to connections and complaint handling).

14.4. OBSERVATIONS/RECOMMENDATIONS

Customer rights in SEE DSOs are definitely lagging behind in comparison to customer rights in the EU DSOs. On the other hand, DSOs customer service may be a DSO's principal means to establish/improve public image (especially when increasing tariffs).

Although it seemed the indicators in this group are instantly recognizable, the actual standards and ranges used by different DSOs show that customer services in future reports should be developed in terms of definitions needed for precise benchmarking of DSOs.

As observed in 5th CEER Benchmarking Report on the Quality of Electricity Supply, no adequate statistical data exists for most commercial quality indicators. In observed DSOs commercial quality is largely enforced by standards that in essence are not guaranteed to customers because there is no compensation for individual customers and often there is no penalty defined. For most of these standards, penalties are based either on vague and imprecise general penal provisions or simply do not exists (even if required by primary legislation).

Therefore, further development of the legislation and practice to accommodate even basic service quality regulation is needed. Standards for technical services (and the legal framework governing the supplier business) must be developed to accommodate scenarios where customers contact the DSO directly or their supplier for technical services. In complaint procedures and afterwards benchmarking, precise definitions of triggers and time intervals are crucial, as well as defining the entity on which a certain trigger/event/process applies to, since it is really different if the customer calls his supplier in comparison to the scenario where the customer calls to DSO directly.

For customer complaints only average times can be calculated (or more often estimated). All DSOs lack call centers standards and do not record visits/appointments. It could be concluded that there is a need for developing technical systems designed for customer care.

Most of the observed DSOs are only in a very early stages of developing service quality regulation. This report suggests DSOs to follow with:

- the establishment of legal framework,
- usage of standards and guidelines of good practice (e.g. definitions should be developed in order to allow monitoring and acquisition of data, standards should be based on specific and precise definitions),
- the implementation of the monitoring system,
- quality standards and incentive schemes.

With regard to quality standards, the challenge is in identifying a set of performance targets that are appropriate for DSO in the region today, which may be just a brief list that can be broadened as the capability and standards of customer service improve over time (e.g. start with certain aspect related to connection services such as: time for response to customer claim for network connection, time for connecting new customers to the network, and certain aspects related to complaint handling: response time to customer complaints and enquiries, time for answering the interruption complaint, etc).

Additionally, to improve customer satisfaction, DSOs should consider to offer services other than connection and complaint handling (e.g. DSM, technical assistance, diagnostic, power factor corrections, etc).

It may be useful for DSOs to employ formal surveys related to customer satisfaction with services they provide.

15. RECOMMENDATIONS

Based on all collected data, calculations and other countries' experience, the main study recommendations are divided in three groups:

- organizational recommendations,
- data harmonization and
- share best practices in distribution business,

and are given in the following Table.

Table 15.1 Table of recommendations for SEE DSOs

Organizational recommendations	
Continuous monitoring of selected data and indicators	Based on data collection, study analyses and other countries' experience it is clear that the WG needs harmonization of definitions and data and establishment of a system for continuous monitoring rather than occasional ad-hoc analysis. The following steps are recommended: ▪ Determination of set of data and indicators included in continuous monitoring. ▪ Establishment of a secure web-site designed for specific benchmarking data entry. ▪ Data collection should generally complete by the end of May for the previous year. ▪ Benchmarking team should meet annually (January) to discuss any changes in the strategic direction of the group and consider any new members. ▪ Two-day benchmarking conference to be held in late June to review and discuss the previous year's data: • Day One – Review of data comparisons and regression analysis, • Day Two – Presentations from leading companies on key drivers of 1st quartile performance, • Attenders are combination of performance management leaders and distribution subject matter experts.
Periodical reporting	▪ Decide on the form and content of common benchmarking reporting. ▪ Prepare the benchmarking report on annual or bi-annual basis.

<table>
<tr><th colspan="2">Data harmonization</th></tr>
<tr><td>Distinction between network and supply service</td><td>Most of DSOs still provide supply service to at least part of the customers. Therefore it is necessary to:
▪ Determine obligations for legal and functional unbundling as defined in national legislative.
▪ Determine common understanding on supply services.
▪ Estimate share of staff and infrastructure (offices) functionally related to supply service.</td></tr>
<tr><td>Common rules for registering of DSO network energy balance</td><td>There are significant differences in structure of energy consumptions, possible other deliveries from distribution network as well as energy inflows to the distribution network. Since the energy losses are one of the most significant issues for most of DSOs, it is necessary to establish common way of balancing the energy flows and common rule for calculation of the losses:
▪ Determination of possible energy inflows to the distribution network (from transmission network or other DSO, from power plants connected to DSO network).
▪ Determination of possible energy deliveries from DSO network (to final customers, for DSO own consumption, for power plants own consumption, to other DSOs, to transmission network, …).
▪ Treatment of HV consumption in calculation of losses.</td></tr>
<tr><td>Estimation of technical and non-technical losses</td><td>Non-technical losses can be estimated only indirectly, as a difference between the total losses and technical ones. However, technical losses are also subject of an estimation based on very complex balancing and load/energy flow calculations.
In mid-term, the WG should aim to try to develop an approximate methodology for estimation of technical losses.</td></tr>
<tr><td>Registering power supply interruptions as a measure of security of supply</td><td>Power supply interruptions can be used as a direct measure of security of supply. However, to use common continuity of supply indicators in such a way, the following prerequisites should be met:
▪ Common rules in registering power supply interruptions, with special emphasis on those originating from MV network.
▪ Common rules for definition of exceptional events with regard to power supply interruptions.</td></tr>
</table>

Share best practices in distribution business	
US experience in reduction of planned interruptions and level of network usage	Generally, in regional DSOs number of planned interruptions is comparable to number of unplanned interruptions. The US DSOs provided significantly different data, with shares of planned interruptions of only a few percent of total number of interruptions. This indicates that a lot can be learned from US experience in: ▪ network maintenance and ▪ network operation. It is recommended to continue with deeper insight in relevant US experience and regulatory framework.
Use of remote control or automation in MV networks	Reduction of durations of power supply interruptions can most effectively be achieved by extensive installation and use of remote control or even automation in MV network. Therefore it is necessary to compare the DSOs with regard to: ▪ current status of SCADA and control centers, ▪ current status of remote control and automation along MV network, ▪ experience in reduction of time needed for location of faults in the MV network, ▪ best practices in optimal allocation of remote control switches along MV network.
Use of AMI for reduction of non-technical losses and registering of power supply interruptions	AMI can, among the usual functions of electricity meters, be used for: ▪ locating losses, to a certain extent, ▪ registering power supply interruptions, ▪ control of the connection point, ▪ measurement of voltage quality. Within the scope of activities, the WG is primarily interested in best practices with regard to first three aspects.
Reduction of commercial losses	Although potential reductions vary from only a few percent up to about 30 %, all DSOs should increase their efforts in reduction of commercial losses. Among other, the following measures are proven to be effective: ▪ detection of unauthorized connections or meter tampering, ▪ meter coverage at MV/LV substation and MV feeder levels.
Protection of vulnerable customers which cannot cover their energy bills	In order to improve their revenue collection, DSOs should take active role in deriving adequate measures, compliant to the 3rd EU energy directive package, for protection of vulnerable customers which cannot cover their energy bills.
Development of procedures for control and auditing of metering and billing process	Majority of billing errors should be detected and corrected before sending the bill to customer. Therefore more accurate and strict procedures for control and auditing of the entire metering and billing process and correction of errors in timely manner should be developed.
DSO unbundling (legal and functional)	The obligation for legal and functional unbundling and rebranding of DSO for EU member states was set by the 2nd EU energy directive package (2003). The WG DSOs are bound to it by signature of the Energy Community Treaty and a number of them is currently in the process of complying to those obligations. DSOs should share experience and solutions to possible obstacles that they had to overcome along the way.