Date: September 3rd, 2012

Smart Metering in Romania

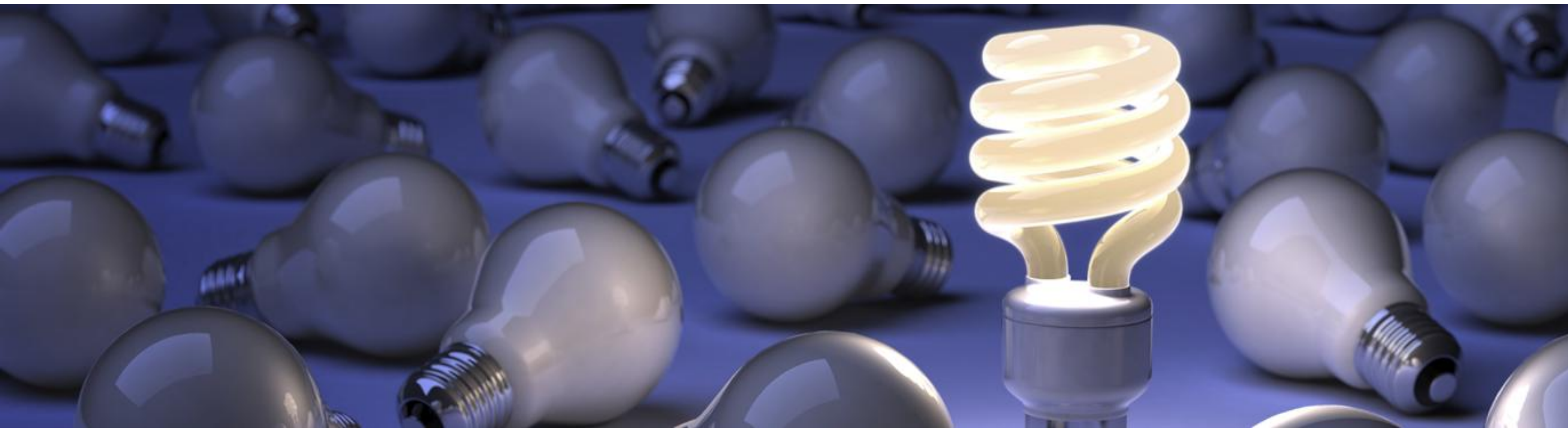


Table of Contents

List of figures

List of tables

Executive summary

With regards to European Union's 3rd Energy package, European Bank for Reconstruction and Development (EBRD) has commissioned the preparation of a smart metering market feasibility study, including a cost-benefit analysis, to assess the possibilities of introducing smart meters in the electricity, gas and heat markets in Romania.

A.T. Kearney has been selected to perform this market study, as it has a comprehensive and relevant experience in similar assignments in the area of smart metering around Europe.

The study performed by A.T. Kearney with involvement of several market stakeholders indicates that implementation of smart metering in the electricity sector has a potential to be a profitable investment thanks to benefits coming from reduction of grid losses and reduction in the operational cost at utilities. The net present value of the investment in smart metering, in the recommended model and over the analyzed period of time (from 2013 to 2032) rises to almost 1.170 million RON, indicating a return on investment of about 44 percent.

In the gas sector, there is a risk that benefits will not cover all costs related to the implementation of smart gas meters. Benefits from reduction of losses in gas are much smaller than such benefits in the electricity sector and operational cost reduction is not justifying significant investments. If we assume a slow pace of installation of gas meters then the business case for the gas sector may be slightly positive. Additionally, for some specific utilities the investment in smart gas meters can be more profitable if they explore internal synergies in purchasing and installation processes.

At this stage major benefits in the heat sector can be achieved by installation of submeters and additional benefits coming from smart meters in heat are minor. Additional, benefits in the heat sector could be brought by installation of Home Area Network (HAN) technologies and energy management systems disregarding if smart meters are installed or not.

The additional arguments for implementation of smart metering in the electricity sector are benefits for the whole Romanian society, which can be achieved by installation of smart grid solutions based on smart metering infrastructure. Significant reduction in the electricity consumption level and reduction in CO_2 emissions can be achieved by providing information about consumption either by central internet portals, which consumers can access over the internet or directly to devices present in consumption places (dedicated in-home displays, tablets, TV screens and others). Additionally, demand response solutions can support reduction of the peak load consumption leveraging data from smart meters and using the communication channel provided by smart metering infrastructure. Such benefits, although very significant for the whole society, were not included in the business case because realization of such benefits requires additional significant investments and such benefits are hardly transferable to companies investing in smart metering. The document is presenting them in a separate chapter.

We recommend implementation of smart metering in the electricity sector in Romania whereas installation of gas smart meters should be optional for utilities willing to do so. We believe that several investors may have a significant purchasing power therefore can achieve better prices of smart metering components and more favorable business cases than the ones included in our assumptions. We do not recommend a mandatory installation of smart meters in the heat sector. We believe that most benefits in the heat sector in Romania can be realized by installation of simple submeters.

The beginning of this document describes the status of smart meter implementation in Romania and other countries. Further on, it proposes a set of minimum requirements that need to be met to realize the assumed benefits. Additionally, this document presents all relevant elements of the cost-benefit analysis, and proposes an efficient approach to installing smart meters. A number of recommendations are also presented that illustrate how to improve the profitability of the investments and mitigate risks related to the implementation of smart metering. Finally, we have included a proposed implementation schedule.

In terms of smart metering deployment, an overview of what is happening at the international and level is included. With companies taking different approaches to roll-out timing and implementation, enforced by either regulatory frameworks and set national targets or driven by the economic benefits they foresee from implementation, we can draw a few conclusions about the risks that Romania may be facing in its effort to deploy smart meters:

- **Technological risk** — here the key will be to ensure interoperability of the systems between different vendors given the uncertainty of future technologies,
- **Regulatory risk** — regulations impacting the smart metering projects should be defined and transparent so that investors know what they can expect in the future in terms of obligations and return from investments,
- **Social acceptance risk**—consumers may be resistant towards smart meters fearing that smart metering can have a negative health impact and their privacy can be disturbed.

Romania is still in the early stages of smart metering implementation. Initially, a few pilot projects are being undertaken that focus on deploying automatic meter readings (AMR), with only about 15,000 consumers having an advanced meter management system implemented. This leaves room for vast opportunities yet to be explored.

With regards to the start up in the electricity, gas, and heat markets, based on our project team's experience and our learning from other markets, we have analyzed four models of deployment:

Model 1—independent communication infrastructures without middleware,
Model 2—independent communication infrastructures with middleware,
Model 3—common communication infrastructure without middleware,
Model 4—common communication infrastructure with middleware.

Within these four identified models, we have analyzed an exhaustive list of costs and benefits, and have taken into consideration, from a qualitative standpoint, some other benefits and costs. When quantified and included in the cost benefit analysis, they would lead to biased results.

Therefore, the cost-benefit analysis has been based on two major pillars:

1. **Analysis made from a country perspective**—we have measured and identified the value created by the investment in smart metering not from the distribution system operator's (DSO's) point of view, but from the market's perspective. In other words, we have not taken into consideration any cost recovery method for the DSOs (for example, inclusion of costs in the tariff) since it depends on final regulations,

2. **Analysis of the target customers includes all low-voltage clients** (households and small economic agents) for electricity and all households for gas. We did not include in the analysis medium or high voltage customers and big industrial consumers since these clients already have advanced metering devices or it is planned to install them.

In addition to the detailed description of all costs and benefits, this report contains the preliminary findings and conclusions of the cost-benefit analysis. These conclusions can be briefly summarized as follows:

- For the electricity market in Romania, smart metering can indeed bring added value, if the model has a middleware layer (data concentrators and balancing meters) and communication of data is made through PLC wiring from the meters to the concentrators and through various communication ways from concentrators to the central application.
- Other technology architectures can be considered if they bring additional value.
- Biggest benefits from smart metering for the electricity sector come from the reduction of commercial losses and meter-reading costs.
- The business case for electricity is positive, but with certain risks: We considered, based on other market data, that smart metering will bring a reduction of 60 percent in commercial losses by the end of the implementation period. We believe this is a realistic scenario, however, it's highly sensitive to the following: A reduction of commercial losses of only 30 percent (pessimistic scenario) makes the business case is only slightly positive. Next to the roll-out, companies will have to ensure that state-of-the-art processes are put in place, and that additional efforts are made regarding necessary transformations in current organizational models.
- For the gas market, current findings given current assumptions show negative results, regardless of whether the implementation model uses a common infrastructure with the electricity. Opting for the common communication infrastructure, thereby connecting the gas smart meters to the electrical ones seems to bring the best overall results.
- Although the economic feasibility for the gas market is negative, it does not necessarily mean that DSOs should halt smart metering deployment. For while the

case is negative from the market point of view, each DSO result would depend on its own capabilities, such as its meter purchasing power determined by the economies of scale it can leverage at the group level (for DSOs that are international players), the level of commercial and technical losses, its own distribution operation expense structure, and more.

- For the electricity market, we have chosen an implementation period of 20 years (2013-2032), and schedule that would allow for achieving 80 percent of implementation by 2020 and 100 percent by 2022.
- The rate of implementation, however, can significantly impact the present net values of the investments, depending on whether the company opted for faster installation in the case of electricity, and even a slower, much smoother implantation in the gas market (thereby resulting in a slightly positive case).
- For the heat market, we believe that smart metering does not bring sufficient added value to offset the high costs of the investment. Current market conditions in the Romanian central district heating market make the modernization of grids a top priority for companies, followed by the investment in the submetering system.
- Although smart metering for heat is not a viable option, we believe that submetering would bring significant benefits at a very low cost, and suggest it as the potential alternative solution.

After the presentation of these findings, the final chapters of this report discuss the recommended implementation model, approach, and schedule for smart metering, and discuss briefly the necessary changes in regulations to allow for a smooth deployment.

1. Introduction

1.1 Background

In 2009, the European Parliament approved the EU's third energy package, a legislative initiative that seeks to improve competition in the gas and electricity markets, provide ownership unbundling with regards to production, transmission, and the supply of energy, and reduce of carbon emissions across the entire energy value chain.

One of the key aspects of this legislative package is the implementation of smart meters in the electricity and gas markets. It states that until 2020, 80 percent of electricity consumers in each EU member country should have smart meters installed, if an economic assessment (cost-benefit analysis) proves the implementation as feasible. In regards to the gas markets, the package does not impose any targets, but instead recommends that a timetable be prepared for the implementation of intelligent metering systems, with no recommendation regarding a scale or a deadline.

A majority of the countries in Western Europe have adopted a policy of regulation-driven introduction of smart meters. Large implementation projects have already started in several countries in Western Europe (Spain, Italy, France, and others), and also in Eastern Europe (Poland, for example).

In the Romanian market, European Bank for Reconstruction and Development (EBRD) commissioned the preparation of a smart metering market feasibility study, including a cost-benefit analysis, to assess possibilities of introducing smart meters in the electricity, gas and heat markets. The EBRD's main objective was to assess the investment opportunities, possibilities and conditions as they relate to the introduction of smart meters in Romania. To this end, the study provided a detailed cost-benefit analysis illustrating the likely economic impact of a smart metering system introduction in the Romanian electricity, gas and heat markets.

This report also includes a review of analyses that have been made during the project, including:

- A review of international and European smart metering implementation status and regulatory frameworks,
- An analysis of the status of Romanian smart metering electricity, gas, and heat markets, current metering systems and tariff methodologies, and views of DSOs regarding the expected benefits and perceived barriers of smart metering introduction,
- An analysis of main benefits and costs associated with the implementation,
- A review of cost-benefit analysis findings and the likely economic impact of smart metering introduction,
- A review of the minimum functional requirements for smart meters,
- A review of which client segments would be recommended for smart meter introduction, with an implementation approach and schedule.

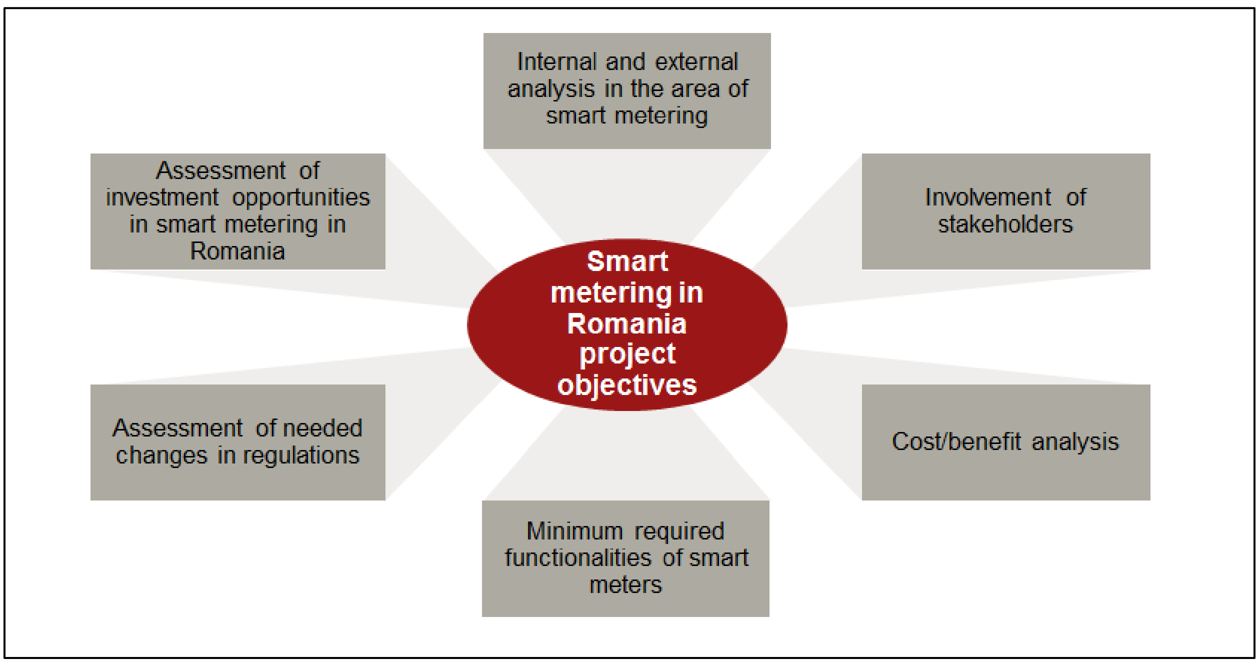
The purpose of this report is to present our findings of the analyses with the EBRD and the Romanian Authority for Energy Regulation (ANRE). The report will also provide final conclusions regarding the likely impact of the introduction of smart meters for heat, gas, and electricity markets, along with recommendations for implementation and a proposed schedule.

In preparation of this report and development of the cost-benefit analysis, A.T. Kearney performed several meetings and workshops with various market stakeholders and developed a model for cost and benefit analysis. All the work has been done in close cooperation with ANRE – Romanian Authority for Energy Regulation, the regulator of electricity, gas and heat (produced in co-generation) markets.

1.2 Project objectives

The purpose of the project was to determine what kind of economic impact introduction of smart metering would hold for key stakeholders of the electricity, gas and heat markets. This report presents the final findings of the cost benefit analysis undertaken with regards to the smart metering implementation for these markets. Several detailed objectives have been defined for the project (Figure 1):

Figure 1: Project objectives



Internal and external analysis in the area of smart metering

The market assessment covers two specific topics:

1. A review of the European smart metering literature and an overview of the smart metering status in mature markets in Europe, together with theoretical and practical lessons for Romania from these markets,

2. An analysis of the Romanian heat, gas and electricity markets in terms of regulations with regards to metering and tariff methodology and an assessment of the currently domestic metering systems.

Involvement of stakeholders

Here, we seek to understand the current metering systems by looking at the views, expectations, and perceived barriers of the distribution companies and the changes needed to implement smart metering in Romania. In addition, an assessment of current smart metering initiatives of utilities was undertaken, together with best practice scenarios for the cost-benefit analysis.

Cost-Benefit Analysis

The purpose of this analysis is to provide a holistic overview of both the costs and benefits associated with the introduction of smart meters, and assess its likely economic impact, together with expected consequences and results. It will also provide an overview of the roll-out benefits for consumers and the retail market operation. Among the expected benefits we found are the following: improved retail competition; energy efficiency and energy savings; lower bills due to better customer feedback; new services for consumers, including the vulnerable consumer; improved tariff innovation with use of time tariffs; accurate billing; reduced costs and increased convenience for pre-pay; less environmental pollution due to reduced carbon emissions; and the facilitation of micro-generation, including renewable generation.

Minimum required functionalities of smart meters

In addition to the cost-benefit analysis, the market study provides recommendations on the minimum functional requirements for smart meters in Romania (including those for later development and future metering integration), and on which categories of customers could be supplied with these smart meters.

Assessment of needed changes in regulations

This assessment addresses the link between all recommendations and results of the analysis and the regulatory framework needed to ensure a proper and effective implementation of smart meters. The purpose of the market study is to make recommendations on changes in primary legislation regarding communication standards, changes in legislation regarding the ownership of meters (including installation, calibration, and maintenance), the collection, calculation, forwarding and security of data, and the flexibility of metering and communications standards to allow for more smart demand side management (DSM) or metering applications and grid operation in the future. The purpose of the market study is also to propose a schedule for the introduction of smart meters.

Assessment of investments opportunities in smart metering in Romania

The market study also assesses the investment opportunities for key stakeholders in the electricity, gas, and heat markets in Romania for smart metering.

1.3 Involvement of market stakeholders

Involvement of ANRE

ANRE, the national energy regulator in Romania, was a key stakeholder in the project. During the project, we had several workshops with ANRE, including the kick-off meeting and workshop, which took place on May 25, 2012, and a second workshop on June 26 of this year. A third workshop was held on August 2, with the primary purpose of aligning the preliminary findings of the cost-benefit analysis with the hypotheses and assumptions used to drive the draft results. A final workshop with ANRE was held at the end of August to discuss the final conclusions from the analysis.

In preparation for the status meetings and teleconferences, ANRE was continually updated with the status of all work performed. In addition, a formal request for information was sent to ANRE, aimed at gathering aggregated data about the electricity, gas, and heat markets, similar to the information collected from distributors and suppliers.

Involvement of utilities

Utilities in Romania were involved in this project in order to better understand the expectations and perceived barriers regarding the introduction of smart metering, and to identify current smart metering pilot projects that are under way. Therefore, we organized meetings with selected distributors and suppliers in the gas, electricity, and heat markets. Before each meeting, a formal data request was sent to utilities, and the majority responded in a timely manner. In addition, joint workshops were organized after the individual meetings.

Involvement of other stakeholders

We worked closely with other stakeholders, such as technology providers, to ensure all costs and benefits for the introduction of smart metering in the gas, electricity, and heat markets in Romania were taken into account.

A request for information was sent to about 40 suppliers of smart metering equipment in order to collect information on prices and to assess the readiness of technology suppliers to offer their solutions on the Romanian market. Request sent to technology providers focused on collecting data regarding:

- General information of the suppliers,
- Production capabilities and deployment of products,

- Projects undertaken in the area of advanced metering infrastructure (AMI) and the major clients served,
- Pricing of smart metering and adjacent products,
- General technical specifications of products and functions.

2. Status of smart metering implementation at the international level

2.1 Energy challenges

In the recent years, the energy world has been challenged in various ways. These challenges continue to fall into a few basic categories that need to be tackled:

- Pressure to achieve or **improve energy efficiency**: optimizing the use of energy and reducing waste and losses on the value chain, together with a regulatory push for enhancement of grids to achieve efficiency gains,
- Regulatory **pressure on costs**: optimizing operating expenses and capital expenditure, reducing grid losses and increasing the need for new investments in desired direction,
- **Growing demand**: demand for energy increased in the last two years with ~5 percent compound annual growth rate, and by 2030, it will further increase, as population increases,
- **Electricity prices:** also expected to increase by 40-70 percent by 2020, as a result of growing demand,
- **Environmental issues**: increased pressure by climate change and global warming to reduce pollution from energy production and shift towards greener sources of energy, pressure to reduce carbon dioxide and nitrogen oxide emissions,
- **Security of supplies**: reliance on foreign sources and “stability” of nations that provide them (for example, imported gas in the EU is forecasted to increase by more than 70 percent),
- **Mix of energy sources – renewables’ role:** share of renewables is expected to reach between 18 percent and 35 percent by 2035 in total energy consumption; fossil fuel to reduce from the level of 81 percent (2010) to the level of 75 percent (2030), following significant pressures after the Fukushima disaster in 2011 to reduce reliance on nuclear energy.

In order to respond to the challenges, the EU has set **three goals** under the catch phrase of 20-20-20 by 2020. They are to:

- Reduce greenhouse gas emissions by at least 20 percent by 2020 in comparison to 1990 levels,
- Increase the share of renewable energy sources in energy consumption to level of 20 percent,

- Reduce primary energy use by 20 percent compared with projected levels, to be achieved by improving energy efficiency.

2.2 Smart metering will support the realization of EU objectives

Before delving deeper into the analysis, at a high level it is generally acknowledged that smart metering can contribute to answering the above mentioned challenges. Smart meters can have a direct impact on:

- The need to increase energy efficiency, by a **better transparency in data measurement** and **incentivizing consumers to modify their consumption habits** accordingly,
- Regulatory pressures to decrease costs, by **reducing losses and costs of meter reading**, together with **better identification of needed investments,**
- Replying to growing demand, by **educating consumers to reduce peak load consumption,**
- Environmental concerns, as **reduced peak load power will lead to lower production and usage of power plants with high carbon dioxide emissions,**
- Security of supplies, by enabling flexible industry infrastructures and minimization of energy inventory, and by increasing the share of base load production.

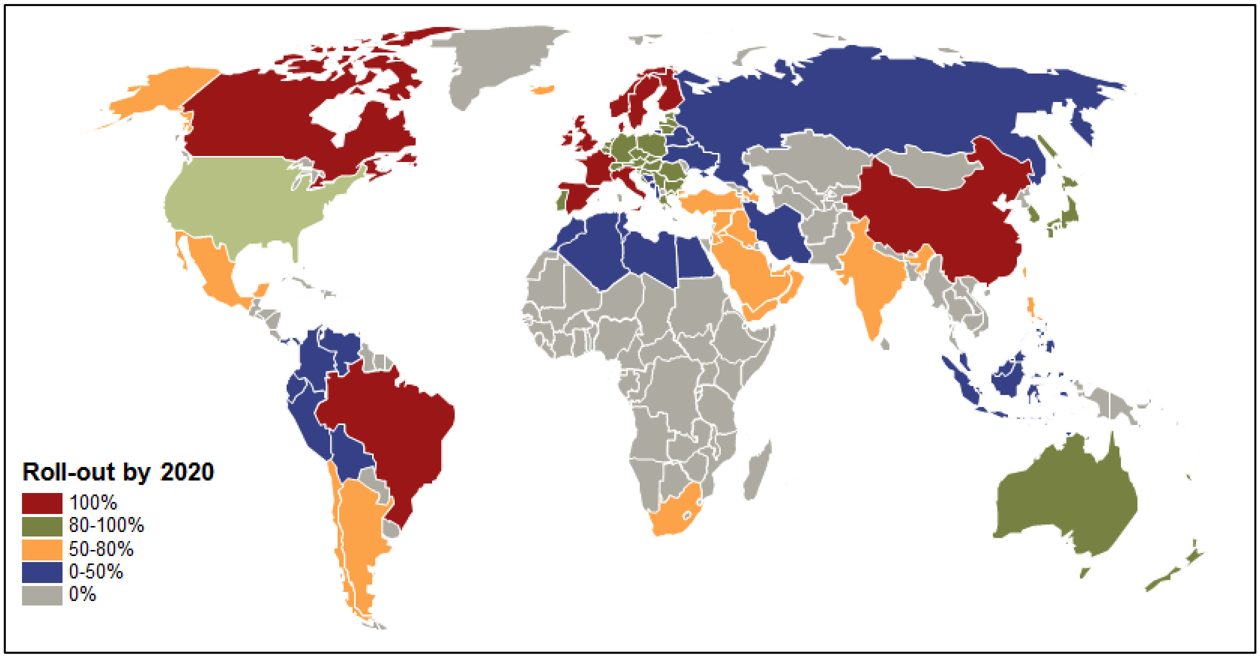
With the expected regulatory changes in Europe, smart meters will also play an important role in: recording usage time, supporting consumption-based billing, providing detailed energy usage information, and enabling commercial management systems to audit energy. It will, ultimately, encourage consumers to conserve energy and optimize consumption. For all these reasons and more, the installation of smart meters is the right choice for all types of facilities.

2.3 Regulatory support for smart metering

At a global level, several countries have developed regulatory framework and set target deadlines for the installation of smart metering and in some cases, smart grids. The United States, Canada, China, Japan, Brazil and South Korea are among the countries outside Europe with the most ambitious targets in terms of smart metering introduction, especially for the electricity market (see figure 2).

In Canada for example some states introduced smart meters to customers as early as 2011. Leading Asian countries, such as Japan and China, set target dates in the next five years. In the case of Japan, rapid developments are planned, triggered by last year's disaster at Fukushima. Japanese regulators are keenly aware of the benefits that smart metering and the smart grid can bring to network safety and monitoring. India is also moving forward with plans to install 200 million smart electricity meters.

Figure 2: Smart metering targets set for 2020



Source: DRSG, A.T. Kearney

Figure 3: Regulatory status in selected countries around the globe

	Europe	US & Canada	Australia	China & Japan	S.Korea & Brazil
Level of enforcement/ progress					
Legal and Regulatory status	• **By 2020, 80% smart meters in electricity** (no target for gas and heat, only recomm.) • **Major roll-out in Italy and Nordic** finalized (Denmark - advanced multiutility market structure) • SM introduced on **massive scale in Spain, France and the UK** • **Plans also in CEE.** Czech Rep. and Poland: large scale pilots. Most advanced plan (Poland) - 3 million electricity SM by 2017 • Forecasts: **half of Europe's households wil get SM by 2016**	• No federal mandate - however, 25 states (USA) and several provinces (Canada) have smart metering policies/regulations • **Ontario finalized in 2011 full roll-out**, with British Columbia **target 100% smart meters in 2012** • **Large projects in California and other states**	• 2009-Council of Australian Governments committed to **roll out of smart meters nationally** • Victoria is the only state to have **imposed a mandatory rollout** so far. • Extensive pilots undertaken in other states or territories	• Chinese governmental plan to build nationwide **smart grid by 2020** • **Smart metering** deployment – **five-years plan** (2011-2015) • Smart grid infrastructure to be **deployed by the stateowned companies** • After Fukishima disaster, Japan revised its **smart meter distribution target to 80% of total power demand within the next 5 years**	• South Korean government is targeting the rollout of smart meters to **half of the country's households by 2016** • Brazilian regulator targeted installation of **63 million smart meters by 2021**

Source: BERG, ICER, ESMA, A.T. Kearney

In the United States, California is the smart metering leader. Currently, they are on course to finalize the installation of more than five million smart meters this year, with efforts under way in other states as well.

Europe had an early start following the turn of the century, when Italy became the first nation to roll-out automated meter reading for more than 30 million customers. This has rapidly led to the installation of more advanced smart meters. Here, in one of Europe's frontrunner countries (next to Sweden), the regulator not only set targets for smart metering deployment (especially for gas, with 80 percent of residential customers set to be on line by 2016, and electricity customers already benefitting from these meters), but also imposed annual penalties on suppliers that fail to reach the defined targets (including interim targets).

Nordic countries also rapidly deployed these technologies. Sweden, for example, mandated installation of more than five million smart meters by 2009. In Denmark, while there is no legal provision of smart meters, a number of large-scale deployments have still taken place. Denmark is also providing their customers with an advanced market model and a structure that includes multi-utilities. Finland is calling for 80 percent of households to have electricity smart meters by 2014, and Norway is targeting a full roll out by 2017. Norway's regulator recently mandated that all 130 Norwegian utilities deploy smart metering systems with specific criteria, including 15-minute interval readings, remote connect and disconnect option, encrypted communication, and integrated gas and water meters.

Spain, France and the United Kingdom are, at the moment, the most active markets for both electricity and gas. Spain mandated an operational smart metering system by 2014 and 100 percent deployment by 2018. In France, Commission de Regulation de l'Energie (CRE), the energy regulator, wants to see mandatory smart metering implementation for all electricity consumers by 2016 (at least 95 percent coverage) and GrDF prepares to introduce gas smart meters to all customers. In fact, in 2010, it has undertook the largest gas pilot project to more than 28.000 customers.

In the United Kingdom, the British government has announced plans to install 53 million electric and gas smart meters in households and businesses by 2019.

Not all countries, though, have been eager to impose strict targets for smart metering deployment. In Germany, for example, devices for electricity and gas must be installed in new buildings, while owners of existing buildings can choose to use this technology on a voluntary basis.

The regulatory call for smart metering implementation and development has not been seen for heat sector. Therefore, no target dates or strong regulatory framework have been set up for these sectors. However, with water infrastructure in Europe needing updating, researchers show that the smart metering market in both the heat and water sectors will be worth several billions of Euro by 2020. In the United Kingdom, the roll out for electricity and gas has taken into account that the infrastructure should be able to support future smart meters for other utilities.

2.4 Regulatory strategies for smart metering implementation

Smart meters are being rolled out for different reasons in different regions. In most countries the implementation decisions are based on complex cost-benefit analysis for investors or for the society as a whole. In most cases significant benefits are identified for societies however not in all cases investments are profitable for investors.

In the United States, an analysis performed by the Electric Power Research Institute showed that smart grid technologies with smart metering as a starting point could reduce electricity usage by 4 percent a year by 2030. A different study by the Pacific Northwest National Laboratory estimates a 6 percent reduction in power usage due to consumers choosing to use energy during times that are both more affordable and less impactful on the environment. The United States, however, lacks a nationwide policy to set smart metering targets because of high consumer resistance with respect to data privacy and security, and the fear of increased energy bill costs. Here, however, unlike in Europe, curbing peak power is critical, as Americans use far more electricity than Europeans.

In Ontario, Canada, the positive impact of smart metering was officially recognized after a 2005 study showed peak-load usage was reduced by 2 percent. A pilot project, one year later, saw a reduction of 6 percent in energy consumption and, as a result, the state has now finalized the roll out.

In the United Kingdom, a study taken by the Energy Saving Trust showed that households could save up to 10 percent a year on their energy bills by deploying smart meters. This would reduce costs by more than 100 pounds. These results have been tested with pilot projects undertaken by Scottish and Southern Energy and supported by the Department of Energy and Climate Change (DECC) and the regulator Ofgem. As a result, the government has acknowledged that the deployment of smart meters is the most effective way to help customers cut energy use as part of this country's target to reduce CO_2 emissions by 2020. In addition, the British business case for smart meter installation showed a 2,8 percent reduction in electricity consumption.

Ireland's Commission for Energy Regulation (CER) published the following results of a smart metering pilot project performed using more than 10.000 customers: a 2,5 percent drop in electricity consumption for residential customers (though other studies have shown a 9,4 percent average reduction), with a peak demand reduction of 8,8 percent. Eighty-two percent of all customers made a change in their energy consumption behavior, and it was noted that in-house displays played an important role in enabling them to reduce peak consumption. Both results in Ireland and in the United States showed that smart meters also brought benefits to consumers with limited incomes, or households that usually receive state allowances or subsidies, enabling them to reduce their electricity bills and consumption behavior.

In Italy, after the successful roll out of smart meters for the electricity sector, the regulator performed a cost-benefit analysis before announcing in 2008 the mandatory installation of 21 million gas smart meters, with 19 million of them occurring before 2016. The analysis showed positive results for DSOs with more than 50.000 customers.

In Sweden on the other hand, the installation of smart meters was not made mandatory. However, there was an implicit obligation since, starting in July 2009, legislation required hourly reading of all electricity meters, which resulted in the large scale implementation of smart meters. The decision to do hourly readings was made as a result of a positive cost-benefit analysis undertaken in 2010, which showed significant gains in energy efficiency for households with more than 8000 kWh of consumption.

The Dutch government announced its requirement that all seven million households in the country have a smart metering system by the year 2013, as a cost-benefit analysis showed positive results for the country. The roll out of smart metering was postponed in 2009, however, due to potential privacy concerns among consumers. But the government reached out to the people, finding a middle ground between achieving energy efficiency benefits (proved through analyses and studies) and protecting the consumers' privacy. This was accomplished by setting different target deadlines for the implementation of electricity and gas smart meters, and making the transition optional for customers.

Tables 1 and 2 present a summary of cost-benefit analyses (CBA) undertaken in EU countries in the electricity and gas sectors.

Table 1: Status of CBA development in the EU - Electricity

Country	CBA already undertaken	Positive impact from CBA	Intention to conduct CBA	Countries with no CBA but no longer relevant
Austria	✓	✓		
Belgium			✓	
Czech Republic			✓	
Denmark	✓			
Finland				✓
France	✓	✓	✓	
Germany			✓	
Greece			✓	
Hungary	✓			
Ireland	✓			
Italy				✓
Latvia			✓	
Lithuania				

Luxemburg			✓	
Norway	✓	✓		
Poland	✓	✓	✓	
Portugal	✓	✓	✓	
Slovak Republic				
Slovenia	✓			
Spain				✓
Sweden	✓			
Netherlands	✓	✓		
United Kingdom	✓	✓		

Source: energy-regulators.eu

Table 2: Status of CBA development in the EU - Gas

Country	CBA already undertaken	Positive impact from CBA	Intention to conduct CBA
Austria	✓	✓	
Belgium			✓
Czech Republic			✓
Denmark			
Finland			✓
France	✓	✓	
Germany			✓
Greece			✓
Hungary	✓		✓
Ireland	✓		✓
Italy	✓	✓	
Latvia			✓
Lithuania			✓

Luxemburg			✓
Norway			
Poland			
Portugal			✓
Slovak Republic			
Slovenia			✓
Spain			✓
Sweden			✓
Netherlands	✓	✓	
United Kingdom	✓	✓	

Source: energy-regulators.eu

In Germany for instance, smart metering policy is mainly driven by customer demand and the country has hesitated to impose strict targets due to large public reluctance towards privacy of consumption metering data.

One of major benefits realized by investors is the **reduction of the technical and commercial losses.** This was one of the key reasons for implementation in for both Italy and Poland, where studies have indicated a potential reduction of commercial losses even by as much as 60 percent (in some cases even 90 percent). Evidence has also shown an increasing focus on reduction of grid losses in South American countries.

There are other reasons too, for setting ambitious targets, such as those in Japan, where the target to roll-out smart meters for 80 percent of households in the next five years was encouraged because of the **governmental concerns and pressure** to increase energy efficiency and network safety and monitoring after the Fukushima disaster last year. China, on the other hand, is an example of a country where all such reasons are combined with a purely political ambition to build a smart grid industry. The Chinese government is making phenomenal investments in the energy sector and planning to build a nationwide smart grid by 2020, with smart metering being only one part of the plan.

2.5 Barriers to the implementation of smart metering

Although in many cases there is strong motivation to install smart meters, a number of barriers can hinder both the speed and effectiveness of the implementation. The following should be considered when putting smart metering into operation:

- **Consumer resistance is one of the key barriers** to implementation. It is driven by data security and privacy issues, as collected data allow for very detailed conclusions to be made regarding a household's behavior. The impact of this barrier can be observed in some key markets, where the potential for smart metering is high, but the installation process has not progressed because of high customer resistance.

- **Cost is another key barrier**. In most countries, the cost of smart meter roll out can be recovered either through regulated network tariffs or through customers' bills. The United States, Canada, Sweden, the United Kingdom, and France are examples of where grid operators (DSOs or, in the case of the United Kingdom, suppliers) have the right to recovery costs for relevant and cost-efficient investments, such as smart metering, by adding those costs into the taxes. Cost recovery systems can be thought of in different ways. In Italy, for instance, the laws allow cost recovery through taxes based on revenues from the different types and quantities of meters installed (including the decreased allowed revenues for DSOs that fail to meet interim targets for deployment), whereas in other countries (Victoria state in Australia is a good example) everyone gets charged, regardless of when the smart meter is installed. A further example comes from First Utility in the United Kingdom, which charged a one-off installation fee.

- Cost issues are even more problematic as tangible benefits, especially for customers, are expected after a certain period of time from the start of the implementation, whereas investment expenditures are incurred at the beginning. In other words, **consumer benefits are delayed** compared to costs.

- **Economic constraints also pose a problem** when it comes to the speed of a roll out, as there is the risk **of a biased distribution of benefits**. Costs can be easily assessed, while benefits remain uncertain. Benefits can also be distributed among market participants, so that investors are not accurately awarded. With high investment costs, market parties become hesitant. The United Kingdom has seen a great deal of debate around the topic of just how accurate many of the studies are that prove the benefits of smart meters. For example, an important benefit for consumers, such as the decrease or modification of energy consumption, is only possible with installation of in-house displays, which in some studies have not been taken into account, while in others, they were considered.

- **There are also technical restrictions**, resulting mainly from the **lack of standardization** and the rapid development and advancement of technologies. Together, they often result in the technologies not interacting when trying to integrate products from different suppliers. This is due, in part, to proprietary solutions. In Spain, for example, two open standards of communication protocol have been put in place to ensure that multiple vendors can access the market. Setting such standards through the regulatory framework, however, needs to be done carefully. In Canada, for instance, technology vendors failed to meet the stated specifications, which resulted in DSOs teaming up in a joint request for proposal.

- **Stranded costs** may be an important implementation aspect also when considering the business case from the DSO's point of view. If speed of implementation is not accurately accounted for and the pace is too fast, replacing assets that are not fully depreciated, negatively impact accounting results of the companies replacing meters.

Figure 4: Barriers of implementation and mitigation measures in different countries

	Europe				Rest of world		
	UK	France	Spain	Italy	Australia	Canada	US
Barriers	• Significant issues regarding **data transfers** between the multitude of parties involved in the market	• Though cost of meters is less than EU average, **total cost of installing the meters is double than other countries**	• High costs of roll-out due to ageing stock of primarily electricity meters • Market **didn't offer all required functionalities**	• **Consumer's** perception **resistive towards the introduction of smart meters**	• **Inefficient market processes** for changing the meters, resulting in errors, **corrupt supplier database and issues in settlement**	• **Technical barriers, providers failing to meet stated specifications** • Risk of adverse consumer reaction to new ToU tarrifs	• Costs proved prohibitive for an end-to-end configuration of smart metering introduction (pilot test)
Mitigation measures found and applied	• Decision of creating a **central data depository is** being analysed	• Costs are to be recovered through **regulated network tariffs paid by customers**	• Extensive reforms, support **for tariffs, regulatory flexibility** • **Major R&D projects for** creating open tech specs and interoperable smart meters from multiple vendors	• Strong **regulations regarding data protection** on entire end-to-end chain • Introduction of tariffs to increase transparency	• Re-engineered industry processes which cut down the number of transactions from six to only one	• **Utilities communicated early with consumers** • DNOs clubbed together in a single RFP and chose interoperable technologies	• Colorado pilot offers different retail pricing options: standard ToU, critical peak price rate, peak time rebate rate

Source: BERG, Datamonitor, A.T. Kearney

- **Regulatory environment** can, ultimately, be both a driver and a barrier. In liberalized markets, role of regulators in promoting smart metering may be limited. In addition, the regulator's responsibility may stretch further, protecting consumers against undue price increases and protecting consumers' privacy.

2.6 Development of smart metering in different markets

Throughout the world, countries differ in terms of smart meter penetration. Figure 5 briefly describes the implementation status for a few select countries in Europe in both the electricity and gas sectors.

In Italy, Enel, the nation's largest power company, has installed 32 million residential smart electricity meters, which offer customers several benefits. Italy is also taking steps towards the installation of gas smart meters, setting minimum standards for smart gas metering implementation. The goal is that by 2016 they will be deploying gas smart meters to 100 percent of industrial customers and 80 percent of residential customers. Italy's regulator also set interim targets: 5 percent replacement by 2012, 20 percent by 2013, and 60 percent by 2015.

Figure 5: Smart metering status in selected countries

Italy	France	Spain	Netherlands	Nordic
Electricity • First country to finalize roll-out as Enel replaced 30 million meters in ca. 5 years • Own meter design in cooperation with IBM **Gas** • CBA showed economic benefit for DSOs with >50k customers • 80% penetration until 2016	**Electricity** • From 2012, every new installed meter must be smart • By 2014, 50% coverage • By 2016, 95% coverage **Gas** • GrDF is preparing introduction for all customers • Largest pilot project in gas sector in 2010: 28k customers	**Electricity** • All DSOs required operational SM system by 2014 • 100% coverage by 2018 • Investment cost at around 5.5 billion EUR • By 2016, 95% coverage **Gas** • First pilot project in 2009 • End-of-life replacement to be 100% from 2016 • Target of 100% by 2020	**Electricity** • Initial deployment of 500k smart meters (2012-2013) • Full roll-out from 2014 to 2018 **Gas** • From 2011, smart metering is mandatory for all new build and end-of-life replacement • Trials in 2011-2012, full roll-out between 2013 and 2018	**Electricity** • SE: first to achieve 100% penetration (70% installed in first 18 mo., 100% in 2009). No required functionalities • FI: 80% by 2013. In 2011, contract in place for 98% of meter points • NO: 80% by 2016 and full roll-out by 2018 • DK: introduction started in 2004. All major 10 have plans for full deployment – some DSOs replace gradually the old meters with SM **Gas** • Some utilities offer both electricity and gas

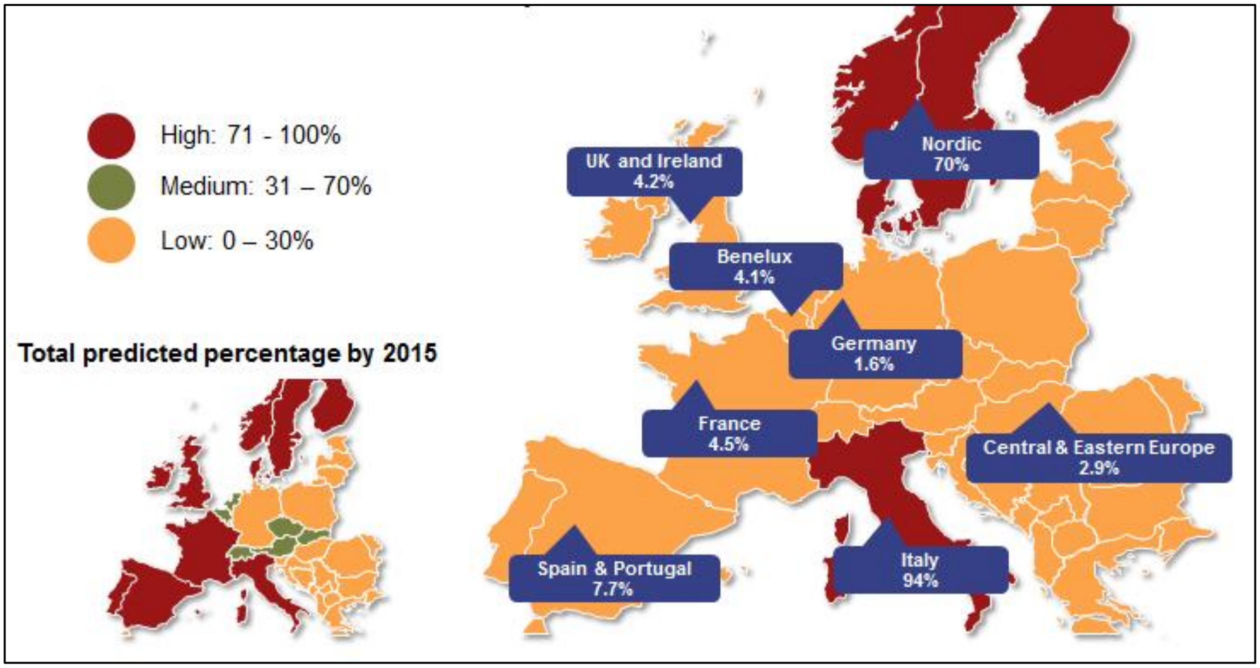
Source: BERG, Datamonitor, A.T. Kearney

Apart from these, other markets have also achieved significant progress in introducing smart metering. The United Kingdom and Ireland are making great strides and have ambitious plans regarding smart metering roll out for both the electricity and gas sectors. Smart meters here are forecasted to reach a 65 percent penetration by 2015.

Spain and Portugal will reach approximately 73 percent penetration by 2015, with Nordic countries taking the lead with a 92 percent penetration, according to IP Multimedia Subsystem (IMS) research. Central and Eastern European countries are still behind Western European countries, with the official user forecast for this region not going beyond 15 percent by 2015.

Germany is one Western European country that is lagging behind. Figure 6 shows the status of smart metering implementation in Europe, depending on degree of penetration and the forecasted situation in 2015.

Figure 6: Smart meters penetration rate in 2011 and forecast for 2015



Source: IMS Research, A.T. Kearney

As you can see, Central and Eastern European countries show slower progress, with Poland and the Czech Republic being the region's frontrunners. Poland's ambitious plan to install three million smart meters for electricity before 2017 represents the highest target currently set in the region. Other countries here have not made significant progress towards deployment of smart metering, with the exception of few pilot projects (the majority of which are related to automated meter reading).

2.7 Utility approaches to smart metering implementation

Several utilities have already taken important steps towards implementing smart meters, registering significant achievements in quality, results, or the number of smart meters installed. These **actions of corporate players are triggered mainly:**

- **By the regulatory push** to achieve the national targets,
- **From within the companies, as the economic benefits** to their clients become apparent.

Enel's deployment of electricity smart metering in Italy, between 2002 and 2008, proved the economic viability of this investment. It also led to interesting results, such as **decreased operational expenditure** per network customer from 80 euro to less than 48 euro or **reduced average interruption time** from 128 to only 46 minutes. Nine hundred thousand meters are read daily, with close to a 100 percent success rate. In addition, as this solution proved viable and efficient, Enel started commercialization of its smart metering technology platform into other countries. A good example for this is Endesa of Spain, which plans to install approximately 13 million smart meters by 2015. In fact, last year alone close to 1.5 million meters were already installed.

In just two years (2010-2011), ERDF in France deployed about 250,000 smart meters and 7,000 concentrators, with very good results in terms of communication reliability: **92 percent of the meters were able to communicate instantly**, with 98 percent of the data collected in the first 48 hours. ERDF expects a full deployment of up to 35 million meters to begin in 2013, with the first seven million delivered by 2014.

British Gas has installed a base of nearly two million smart meters, replacing worn-out ones at a rate of 850.000 meters per year. They have not only piloted several smart meter installation projects for thousands of households, but have also **discovered important benefits with customers who have installed PV solar panels and other micro-generation technologies**. In fact, the utility giant launched the United Kingdom's first micro-combined heat (micro-CHP) boiler in the consumer market, which can generate electricity and heat, helping bring savings in energy bills and cut CO_2 emissions by 20 percent. First Utility, Npower, EDF, Scottish and Southern Energy, Scottish Power, and E.ON are other companies in the United Kingdom that have started installation of smart meters.

Their deregulated market structure (the meter market has been opened up to competition, as in Germany, where customers are free to choose the meter operator) leaves room for a **more competitive, economics-driven implementation**. Many companies are seeing additional advantages in the market from having smart meters, such as the **ability to offer new and more customized services to customers**. The advantages derived from these new offerings could also be interpreted as a stranded asset cost risk for suppliers, as they install meters (having the ownership), then face the possibility that customers will move to another supplier.

One of the largest deployments in North America is operated by Hydro-Quebec in Canada, which plans to replace 80 percent of its 3,8 million meters. This will allow customers to **monitor their energy consumption in real time**, along with data management systems, service, and support. The deployment was started with two pilot projects of 30.000 meters that were to test implementation assumptions.

Pilot projects are key when it comes to testing hypotheses related to benefits, costs, and implementation approaches. Fortum, Norway's seventh largest utility company, for example, started a pilot project in 2011, deploying the smart meters to 100,000 domestic electricity customers and its 550.000 customers in Finland. In Netherlands, Oxxio installed more than 100.000 meters in pilot projects, while in Germany, numerous trials involving RWE, Yello Strom, EnBW, EWE, TWK, and other utility leaders led to the installation of almost 250.000 smart meters.

In terms of **heat and water smart technologies**, Germany's E.ON Bayern conducted a pilot project, where more than 10.000 households were equipped with state-of-the-art smart metering technologies. Moreover, the public works department of the town of Erding is currently installing smart metering technologies for electricity, gas, heat, and water usage in 33.000 households.

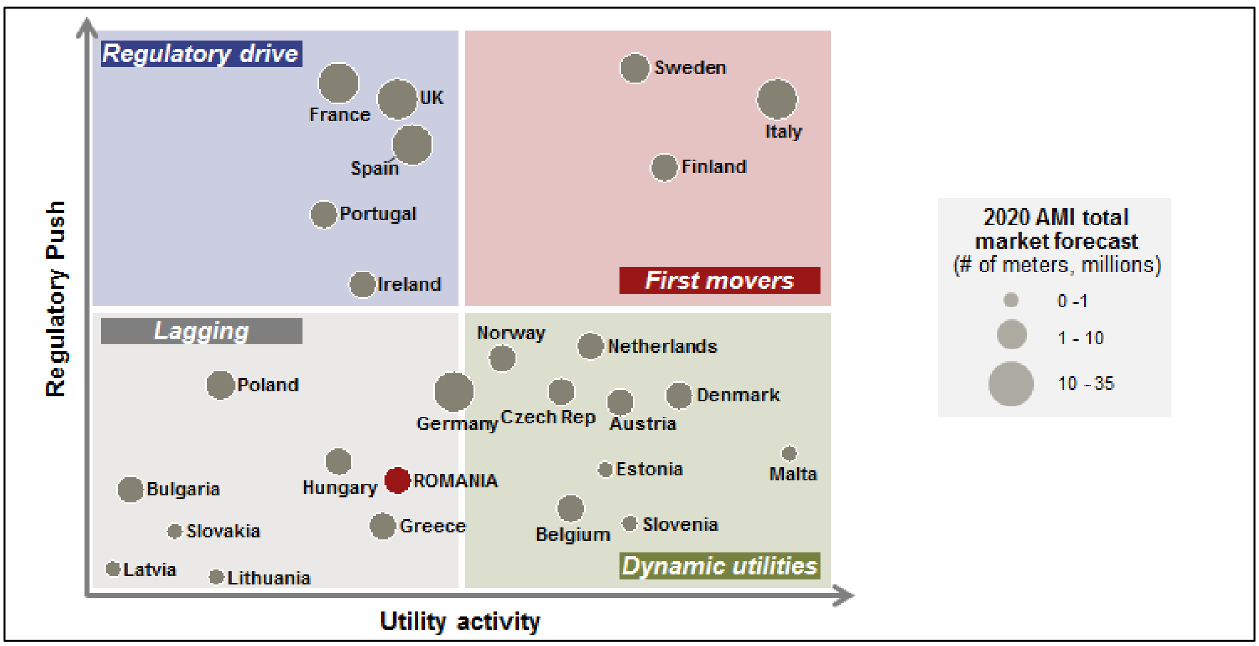
This test will lead to a better understanding of the underlying benefits of efficient utility consumption.

In Finland, another heat smart metering pilot project is being undertaken by the Tampere District Heating company. This project supplied 5.000 customers with automatic meter management (AMM) solutions, and offered clients hourly consumption data, such as heat energy, water flow, and flow and return temperatures. The project resulted in an **exceptionally positive outcome**, giving customers the chance to **optimize consumption and reduce the amount of inaccurate billing**, while helping improve management, operation, and maintenance activities for the company (optimization of network dynamics and pumping).

In Scandinavia and Poland, several heat utilities installed remotely read meters at commercial customers, facilitating a reduction in operational costs.

Regulatory push, however, is not the only thing that drives the implementation of smart metering systems. In many cases, utilities initiate the installation of smart metering without the urging of the government. Utilities in Denmark are good examples of this. There, companies initiate investments in smart metering systems, realizing the long-term economic benefits these deployments can bring. In Sweden, the regulator has not imposed any rules or guidelines regarding the minimum functions of smart meters. But due to high labor costs, energy companies are extremely proactive in terms of smart metering implementation.

Figure 7: Drivers for implementation of smart metering by countries – 2020 AMI total market forecast



Source: GTM research

Figure 7 illustrates the driving forces behind the smart metering topics in European countries. By 2016, more than 100 million smart meters are expected to be deployed.

In Spain, companies have taken up where the government dropped off, taking significant steps towards smart metering and even the implementation of so-called **“smart cities”**, with utilities like Endesa and Iberdrola investing large amounts of money in cities such as Malaga and Castellon respectively. The latter is the first electric smart grid city in the country, with more than 100.000 meters installed and 600 transformer stations upgraded, offering real-time power consumption monitoring.

2.8 Different market structures

Countries that embrace smart metering differ also in terms of market structure. These differences occur in the areas of ownership of meters and management of data exchange between different market participants.

In **most countries ownership of meters and their maintenance lies with the DSOs**. There are, however, **exceptions** to this rule: In France, electricity meters are owned by municipalities, but maintenance is the responsibility of the DSOs (for gas meters, both ownership and maintenance are under DSOs). In the United Kingdom, meters are owned by suppliers, and in Germany, although the DSO is the default metering operator, customers can choose their service provider, making ownership of meters unclear. In the case of small utilities, meters are owned by the customers. In Nordic countries other situations appear. In Denmark, for example, DSOs own not only electricity, but also gas and, in some cases, heat meters. Other structures can be seen in the United States, where in Colorado, meters are owned and maintained by vertical integrated utilities.

Using a **common communication infrastructure for electricity and gas is believed to be more cost effective** for smart meter installers, rather than each having its own communication infrastructure. In Europe, we see a few examples of utilities sharing the same infrastructure. For example, the Italian gas metering industry looked at the opportunity to link their meters to the existing electricity metering infrastructure, but as this uses proprietary protocols, the approach was not seen as a valid solution. The industry is still seeking an independent solution, with the regulator guaranteeing cost neutrality.

In the United Kingdom, the government has mandated dual gas and electric smart meters for every home and business by 2020, and in the Netherlands, the Dutch utility, Oxxio, put electric and gas smart metering systems into action using wireless data communication instead of the electricity grid (PLC). Oxxio created a self-service platform for customers called “myOxxio,” where they can monitor both their electricity and gas consumption. This example also shows how outsourcing the management of metering operations and the underlying IT infrastructure can work, as they work in partnership with IBM.

In California, Pacific Gas & Electric deployed a smart metering system for collection of electricity and natural gas data from households and businesses. The data is collected from electricity meters once every 15 minutes and from gas meters daily, and then transmitted through a secure wireless communications network. The roll out of this system is expected to reach to about 10 million meters by the end of this year. According to the company, the program will encourage growth in renewable energy sources, reduce CO_2 emissions, and empower consumers to understand and reduce their energy consumption and, hence, monthly energy costs.

2.9 Key lessons for Romania

As a newcomer to the smart metering arena, Romania has the distinct advantage of being able to learn from the experiences of others, and can quickly leverage these lessons to ensure a smooth introduction into the marketplace.

For them, the following three, key risk areas must be considered when implementing this new technology:

Regulatory risk:

- The experiences of other countries indicate that regulatory framework has to clearly state whether or not **implementation of smart metering is mandatory**. Regulatory rules should be clear before investments are made.

- The rules must also be clear when it comes to **cost recovery**. In most countries, the cost of meter roll out can be recovered through regulated, network tariffs. In other countries, regulators must create incentives to invest in smart metering.

- It is also important to set the **minimum functional requirements** for the smart meters. In Italy or France, functional requirements are defined by the regulators. However, in a country such as Sweden or the state of Colorado (United States), no minimum function requirements are legislated. Here, also companies have realized, independently, the economic benefits of smart metering.

Technology risk:

- **Interoperability** of smart metering systems, and architecture as a whole, will be a key challenge. Spain and Canada are examples where regulatory bodies worked closely with utilities in defining open standard communication protocols to allow equipment from multiple vendors to be interoperable. This ability to interface is the standard in nearly all countries considering the introduction of smart meters.

- **Rapid technological advancements** require a forward-thinking approach to smart metering, as smart meters will need to be interconnected in the future with the home area network. This will allow them to capture additional benefits from the more advanced future technologies. In fact, smart metering is the basic requirement for further development of the smart grid.

Social acceptance risk:

- **Consumers' resistance** has proven to be an important barrier in smart meters roll-out in some countries. Consumer reluctance results from worries regarding:
    - **Personal data protection**, as smart meters will allow access to much more detailed data about households' consumption. This cultural resistance to any form of data registration was one of the reasons behind Germany's strong regulations regarding roll out.
    - **Fear that the electricity and gas prices will increase** as a result of smart metering implementation. The state of Colorado in the United States, for example, used several types of tariff systems as tools for decreasing customers' resistance (standard ToU, real time, critical peak pricing, peak time rebate rate). In Ontario, Canada, the regulator undertook a pilot project as early as 2006 to understand consumer reactions, which eventually resulted in the use of tariffs.
    - **Fear the communication technology in smart metering will cause health problems**

In order to mitigate social acceptance risks, it is recommended that tailored educational programs be designed to engage consumers in the implementation process as early as possible. Such programs are used in France, where the regulator has organized working groups with all electricity stakeholders, including consumer organizations, since 2007. Italy also conducted numerous studies and customer surveys to help identify customers' needs.

Smart metering provides numerous **benefits**, the most important of which is **greater energy awareness for customers**. This leads to them adjusting their consumption of energy, thereby **reducing peak loads**, **reducing CO_2 emissions, and reducing losses**, **both technical and commercial** (as was experience by countries such as Poland, Italy, and some countries in Latin America). This last one results in lower operational costs for DSOs, and numerous other consumer and supplier benefits.

Doubts have risen, however, regarding whether or not costs and benefits are appropriately distributed among stakeholders. This leads to reticence on the investor's part (usually the DSOs). There is evidence, though, that shows that even DSOs will enjoy economic advantages as a result of smart metering implementation (a CBA in Italy, for example, showed economic benefits for DSOs, with the onboarding of more than 50.000 customers). Of course, results differ between countries and are subject to many factors that can drive the speed and cost effectiveness of implementation.

Finally, the implementation approach will have a great impact on the process:

- **Resource availability** is critical, influenced by the **implementation pace and schedule**. Operators especially need to provide enough human and financial resources, in the short term, for the installations of meters, concentrators, balancing meters, and all other elements of the smart metering infrastructure. There is no best answer that outlines what the quantity of human resources should be for projects of this type.

- **Stranded costs** of replacing meters, which are not fully depreciated, is closely connected to the regulatory framework provided and implementation pace taken. Some European countries have chosen to replace old meters with new ones when they reach the end of their life cycle. This gives these operators an advantage over those who have a specific installation number set for them by regulators. The majority of installation goals, especially in lagging countries, are set to reach EC targets as quickly as possible. This puts added pressure on operators to replace meters, which are not fully depreciated. For the purpose of this study, which is made from a single country's perspective, stranded costs do not impact the results. Since the investment occurred in the past, these costs can play a significant role when considering the business case for each distribution company, since it will have an impact on the bottom line.

- **Cooperation of utilities** is especially important when it comes to working together on electricity, gas, and heat metering infrastructure. It is true that a common communication infrastructure can reduce the implementation cost. However, it requires the trust and cooperation of utilities. A number of DSOs have ventured into TV, cable, Internet, and other telecom services by relying on the common infrastructure. All of the above topics are treated in the upcoming chapters of this study, building on the benefits and costs of the implementation and ending with the recommended model and regulatory changes needed for a successful deployment.

3. Status of smart metering in Romania

3.1 Key challenges on the Romanian energy market

The Romanian energy market will face a series of challenges in years to come that need to be addressed today. These can be summarized in the following areas:

- **Increase of energy efficiency**. In 2005 compared to 1996, the energy efficiency index (ODEX) decreased by 26 percent at the level of the entire economy. Although progress has been made in both industrial and household segments (e.g.: measures for improving the performances of existing buildings), these need to do better as pressures are increasing. Romania's target for energy efficiency is for the achievement of savings at the level of 9 percent by 2016, contributing thus to the overall target of the European Union.

- **Increase of share of renewable sources**. As part of the EU target, Romania has to ensure an achievement of 24 percent of renewable sources in total energy consumption by 2020. Through the National Energy Efficiency Action Plan however there is an even more ambitious target of 38 percent of all electricity production in renewable sources. This target is set high also because this year the regulator estimates 30 percent of internal consumption came from renewable sources (in 2010 the share was even higher, 35 percent, as it was a rainy year). The target for heating and cooling from renewable sources of 22 percent also poses a major challenge.

- **Improvement of technical infrastructure**. The capacity of country's power grid poses a challenge, as well as increasing age of the current network. This poses a serious challenge to achieving the targets for energy efficiency and increased share of renewables.

- **Liberalization of the electricity and gas markets and increasing prices**. The national regulator, ANRE, has set up calendars for full-market liberalization for both electricity and gas, which next to the additional needed investments to modernize the grids, are expected to lead to increasing prices for energy.

- **Growing demand**. As purchasing power of Romanians is expected to grow in the next years and as the economic crisis flushes away, so the energy consumption is expected to grow. This has to be seen in parallel with the increasing energy prices, as a trade-off between the two might also be possible. The key challenge for Romania will be actually to optimize the consumption as a result of implementing energy efficiency measures such as smart metering and demand response solutions.

- **High grid losses**. It is generally acknowledged that in Romania, as it is the situation in many Central and Eastern European countries, energy theft is on increased levels, as well as technical losses primarily due to aging network and poor monitoring of assets. Again, separately from needed investments to upgrade the grid infrastructure, the challenge consists in adopting measures that can help in identification of places of commercial and technical losses.

Smart metering is expected to help address these challenges for Romania. Additionally It is expected that smart metering will help distribution system operators as well as other players along the chain in facing these increasing challenges by leveraging their operational capabilities and **enhancing efficiency of day to day operations.**

3.2 Current tariff methodologies

Electricity

For both electricity and gas markets in Romania, the regulator (ANRE - Romanian Authority for Energy Regulation) is approving tariffs for electricity and gas utilities.

The tariff methodology for electric energy contains indications on electricity price composition for various consumer categories, composition covering entire value chain from production to final supply.

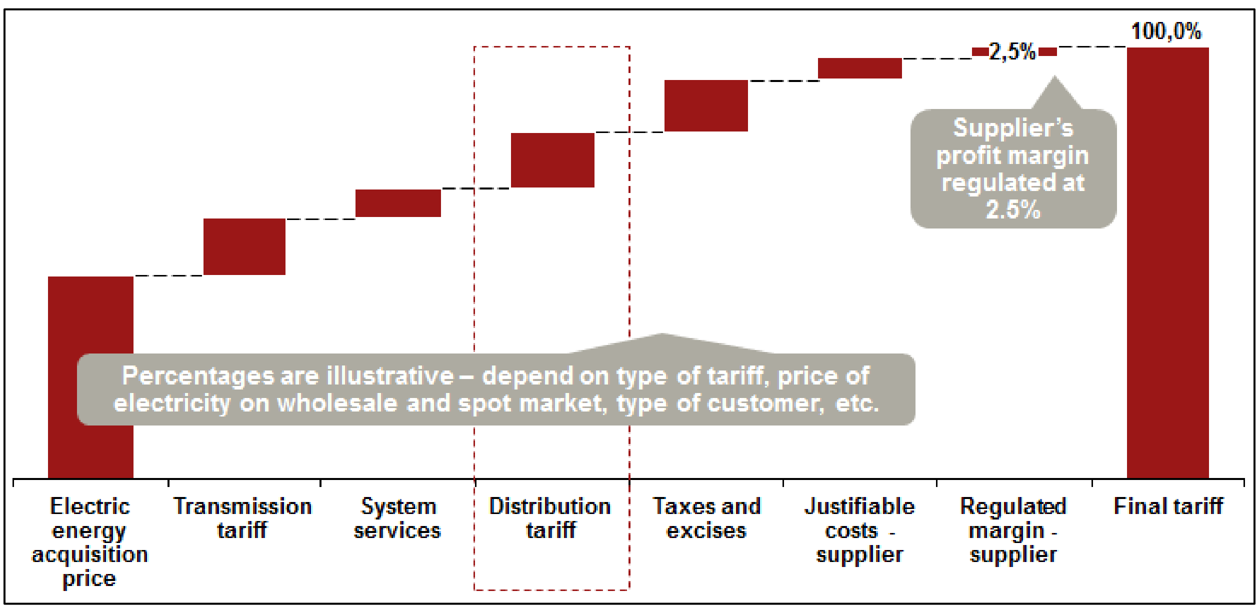
The tariffs **methodology is designed to set pricing guidelines for captive consumers**, while for the non-captive ones the price is set based on the competitive market. Captive consumers have the possibility to change their supplier and thus become non-regulated consumers, if they request so, without having the possibility to change back to the captive (regulated) status.

The general architecture for the electric energy supplied and final electricity price/supply tariff (for captive customers) is similar to that of most EU countries. The regulator states that **all costs of the supplier associated with acquisition of electric energy for supplying captive customers, transport services (transmission tariff), system services, market settlement, distribution services (distribution tariff), taxes and excises are to be transferred to the final customer, including any other justified costs for supplying energy**. Each of these components is regulated, including the profit margin of the supplier, set at 2.5% of the cost of acquiring the energy to be supplied (see figure 8).

Electric energy can be acquired by the supplier from three main sources:

- On the wholesale market, based on bilateral regulated contracts (electric energy quantities are established annually and can be adjusted each semester to cover the necessities, based on consumption forecasts – these quantities can be revised if customers migrate and become non-captive or forecast errors decrease),
- On the spot market (called also "next day market"),
- On the balancing market (as a result of a registered energy unbalance, so that in the end the acquired energy is equal to the supplied energy).

Figure 8: Final electricity tariff composition



Source: ANRE documentation, Romanian legislation

For the **household consumers' tariffs several, criteria are considered**: type of meter installed (prepaid or post-consumption), voltage level of the network, where the meter is placed (low or medium voltage), whether or not a certain amount of consumption is reserved, whether a subscription for a certain daily quantity of energy is set or not, differentiation on time of use (either day/night or season – winter/summer) and whether there is a social tariff or not. The latter is set by the regulator for the households with a monthly average income per household member less than the legal minimum salary, and varies progressively according to three ranges of consumption (less than 2 kWh per day, between 2 and 3, and above 3 kWh per day).

For captive non-household customers the regulator sets different tariff levels for each supplier. Several types of tariffs, for which customers can choose (depending on already defined factors and rules) are based on several criteria, among which: differentiation on time of use (peak time, normal or low-consumption, defined also by month, time of day, and type of day (working or week-end), or day/night split) or non-differentiation, duration of utilization, voltage level on the points of installations' delimitation (high, medium or low voltage), tariffs separated for power (price/kWh/year) or for energy (price/kWh). The regulator also sets tariffs in the case of each supplier for reactive energy; reactive energy tariffs also apply to customers that become non-captive

Regarding **market liberalization in terms of tariffs**, ANRE set out a **timetable regarding the introduction of a free-price of energy acquisition component (percentage)** for electricity tariffs, for households and commercial customers alike. This component is to be applied in the current supply tariff calculation, on an increasing basis, according to a specific calendar that aims to achieve a **completely liberalized market until end of 2017 for households and until end of 2013 for commercial customers**. The timetable is presented in table 3 below:

Table 3: Timetable for liberalization of electricity acquisition price

Implementation date	Percentage of acquisition from competitive market (commercial) [%]	Percentage of acquisition from competitive market (households)[%]
01.09.2012	15	
01.01.2013	30	
01.04.2013	45	
01.07.2013	65	10
01.09.2013	85	10
01.01.2014	100	20
01.07.2014		30
01.01.2015		40
01.07.2015		50
01.01.2016		60
01.07.2016		70
01.01.2017		80
01.07.2017		90
31.12.2017		100

Source: ANRE

A detailed methodology addressing DSOs with more than 100.000 customers sets rules for establishing and application of **distribution tariffs, which are unique for each DSO**. Each DSO has the obligation of providing a transparent accounting evidence for each regulated and non-regulated activity and allocating costs for the regulated activities to determine a distribution tariff to be approved by ANRE. For calculation of distribution tariffs, the regulator states that **any justified cost associated with the distribution activity can be included in the tariff**, however sets a **ceiling limit for each year's tariff compared to the previous one**, **according to a formula** based on inflation rate, a distribution-network quality factor (which is also regulated to be a maximum 2 percent of the revenues per year until 2012 or 4 percent after 2012) and the percentage of variation of the tariff.

Generally, **six major cost clusters are recognized in the distribution tariff**:

a) **Controllable network operation and maintenance costs**
These include: costs with materials and consumables, water, electric energy and other utilities, other materials (**including metering devices registered as inventory**), maintenance and repairs done by third parties, rents, insurances, studies and research, other services performed by third parties (including personnel training, publicity, protocols, telecommunication costs, etc.), personnel costs (salaries), and more.

b) **Uncontrollable network operation and maintenance costs**
These include: costs as a results of paid taxes, royalties, contributions to health and other salary funds, distribution costs as a results of utilizing the distribution network of other operators, compensatory salaries, costs generated by the inability to disconnect from a special commercial entity (based on legislator act – only part of the costs which is not covered by bank guarantees), costs with bad debts and costs with compensatory payments (imposed after lawsuits) for third parties for maintenance work.

c) **Cost of acquisition of electric energy for own technological consumption**
This cost includes both technical and commercial own technological consumption or losses (as otherwise known in the utilities terminology). For 2012, the average value per operator for this cost was set by the regulator at the level of 9,5 percent. The regulator also set out a program of own technological consumption reduction, to be implemented by DSOs, which is to be included in the tariff in the upcoming years, however regulator is flexible on setting yearly the target for this depending on investments for increased efficiency and other factors.

d) **Depreciation of existing assets and of new efficient investments**
This is composed of **depreciation of initial existing asset base** (on inventory until 2005 – privatization date), **depreciation of current assets** (on inventory after 2005, until t-1 year) and **depreciation forecasted for investments/assets put in place in year t**. For the initial existing asset base (on inventory until 2005 – privatization date) a normal depreciation duration of 25 years was set. For the other assets, the depreciation duration is set according to accounting rules. For **those with a duration of less than 10 years, the yearly depreciation cannot be more than 30 percent of all depreciation for fixed assets in that respective yea**r. The initial existing asset base is calculated each year based on specific formulas imposed by the regulator.

e) Return on assets and cost of equity for existing assets and new efficient investments

The regulator sets rules (formulas) for calculating the return on assets, but also for determining the types of investments that can be recognized in the distribution tariff. Each DSO transmits to ANRE every year in November a two-year investment plan, with main scope of reducing the losses (own technological consumption) and improve the quality of the distribution system. Three types of investments are defined by the regulator:

- **Essential investments**: made for maintaining the safety of the network and continuity of supply, replacement of old equipment, modernization of overloaded parts of the network,
- **Necessary investments**: made for modernization of the network to achieve high quality standards according to the legislation (replacements of depreciated assets, extension of the network, new connections),
- **Justifiable investments**: proved based on a cost-benefit analysis, including for example quality improvements of the distribution system or **replacement of equipment for reduction of losses (own technological consumption)**.

The regulator also sets rules for calculation of the **cost of equity**. Currently, this is **set at the level of 10 percent (2008 – 2012)** but starting next year it **will be calculated based on CAPM** – capital asset pricing model **and will be included in the WACC** – weighted average cost of capital **to be approved by ANRE**.

The distribution tariff for each DSO is approved based on the above cost clusters, after **applying a reduction percentage set with the goal of reducing operation and maintenance controllable costs and increase the efficiency of electricity distribution system**. This percentage and its application are also set by the regulator.

The distribution tariff is finally split for voltage levels: low, medium and high.

Gas

As with the electricity market, for the gas market the regulator defines clear principles and detailed methodologies for setting-up tariffs for supply, transportation, transit, storage and distribution of natural gas.

Starting with 2008, a megawatt hour (MWh) became the measurement unit used for calculating tariffs in the gas market. Regulator has set conditions and rules for transformation of a cubic meter of gas into MWh depending on gas measurement conditions (pressure, temperature and combustion temperature, caloric power, and so on).

Final **gas supply tariffs or prices are split** customer segments: **households** (including non-households that produce thermic energy (heat) in cogeneration plants and in plants that serve the general population) and **non-households** (other than those described before), and based on the weights in the final consumption basket of internal or imported gas.

For both households, **fixed unitary gas acquisition costs** for the period January – June 2012 are set based on several sources of information: forecasts regarding gas consumption demand, based on statistical data for the years 2010 and 2011, forecasts of quantities to be supplied for the target period, evolution of import gas prices and internal production gas prices, and transportation tariffs (latter is included thus in the fixed unitary gas acquisition costs).

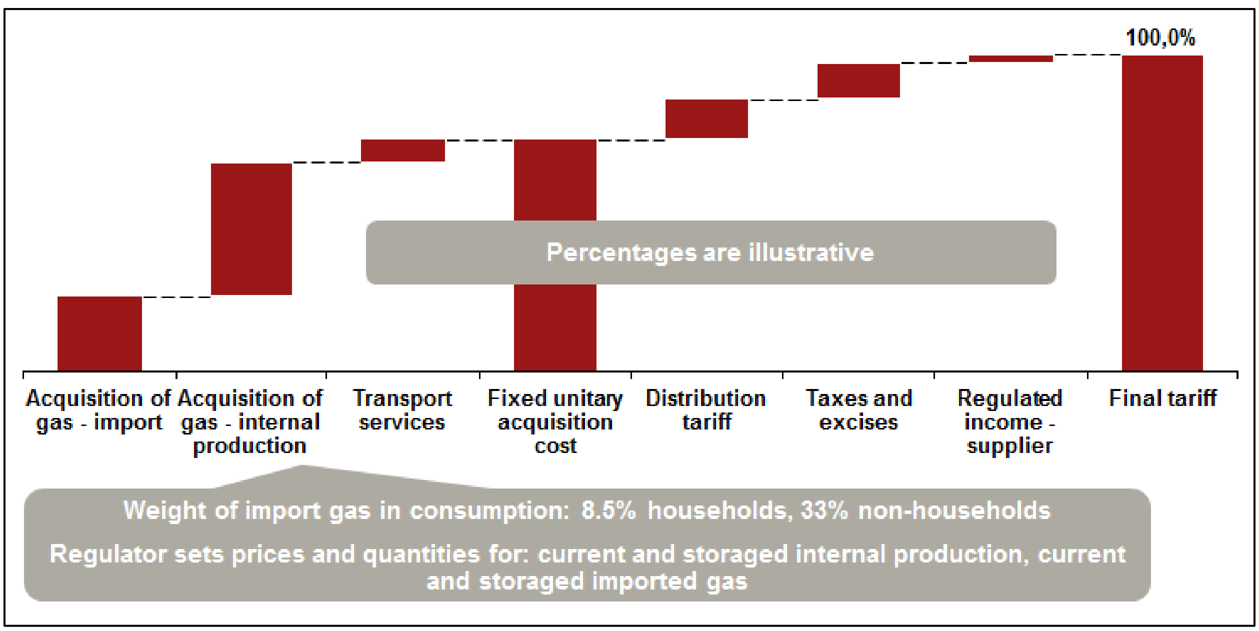
The evolution of imported and internal production gas prices is set according to: gas acquisition price, average storage tariff and distribution and supply tariffs.

The regulator also sets target for the **cost of capital/equity** afferent to the calculation of costs of financing stock and storage of gas. This level is currently set at the level of **8,63 percent for distribution and supply activities**. For the transportation and storage activities is set at the level of 7,72 percent for the third regulatory time-frame (2012-2016).

The weight of imported gas in determining the fixed unitary gas acquisition costs (at the entrance in the distribution system) for households is currently set at the level of 8,5%, while for the non-households at the level of 33%. This factor makes the differentiation of price level between the two groups of customers, other variables being equal.

Final regulated gas prices paid by customers (differentiated between type of customers, as mentioned before) are thus composed of: the fixed unitary acquisition cost, the regulated income afferent to the supply activities and the distribution tariff, plus a correction factor accounting for the difference between fixed unitary acquisition cost regulated for the past year and the actual cost realized and recognized (see figure 9).

Figure 9: Final gas tariff composition



Source: ANRE documentation, Romanian legislation

As for the electricity market, the **regulator proposed a calendar of gas prices liberalization**, starting with December 1st, 2012 for non-household customers and with 1st of July 2013 for households. The market for **non-households** will be fully **liberalized by the end of 2014**, while for **households,** this will happen by **October 1st, 2018**.

With respect to the purpose of this study, the **distribution tariff methodology** is of utmost importance as DSOs will typically bear costs of smart metering implementation.

Generally, the regulator allows DSOs including **all justified costs in the tariff**. Generally, this will include as a first step **operational expenditure (OPEX)**, the **value of regulated existing asset base multiplied by the cost of equity** (regulated as well), the **depreciation of assets recognized by ANRE** and an **economic efficiency gain or increment**. The latter is calculated as a positive difference between OPEX approved by regulator during that respective year and the actual costs incurred and recognized (economic efficiency gain or increment does not include own technological consumption – technical and commercial losses). The **sum of these cost elements** is divided by the total quantity of gas estimated to be distributed (estimation, which is again subjected to approval of ANRE). **Other costs are added** to the result, such as: **unitary unforeseen costs, in year t-1** (appeared due to unpredictable external factors), **other unitary costs incurred in year t-1** and **various correction factors** (for costs with penalties, compensation costs, unitary unpredictable costs, invested capital correction – all of them being regulated through the tariff methodology).

These distribution tariffs (differentiated by customer type and homogenous distribution systems, depending on technical and maintenance regime of each system) quantify the fixed and variable costs incurred for the activity of gas distribution. Split between fixed costs (costs that are independent of the quantity of gas distributed) and variables costs are also regulated.

As for the electricity tariffs, **generally recognized costs for gas distribution will be**:

- **OPEX**: costs with materials and raw materials, energy, fuel and water, personnel costs (salaries, compensations, etc.), costs incurred with operation and maintenance of the network, replacements of parts or components of assets (which are not to be included as depreciation and that do not lead to modernization of gas grid), marketing and publicity costs, general administrative costs, penalties and compensation costs and own technological consumption. The latter includes (in limits acceptable by ANRE) all consumption registered by the DSO (except gas and water utilized for own administrative purposes), including technical and commercial losses. The difference between own technological consumption approved and actually realized in a year is to be adjusted for the upcoming year
- **CAPEX**: expenditures connected to acquisition/production of fixed or non-fixed assets, modernization of network, increased capacity and safety in the asset functioning, increased life duration (technical and economic) of assets, replacements of assets fully depreciated (or if not fully depreciated, the difference between the value of new assets and value un-depreciated of old assets) and costs incurred with connection to the transportation system. **The regulator states that all metering devices and equipment are considered as capital expenditures**.

As with electricity tariffs, **gas distribution tariffs can be annually adjusted** with the inflation rate and the **regulated rate of economic efficiency increase** (rates which are also regulated).

Heat

Unlike the electricity and gas markets, the heat market in Romania has two main regulators: ANRE, for the heat energy produced in cogeneration, and ANRSC (Romanian Authority for Public Utilities Community Services), for heat energy produced from other sources than cogeneration.

Generally, the **heat energy tariffs will include justifiable costs** for production, transportation, distribution and supply of heat, **inclusive of costs associated with development and modernization of overall centralized heat supply system**, technical losses, environmental protection expenditures and a profit margin (of maximum 5%).

The methodology for establishing the tariff resembles those of the electricity or gas markets. But, heat energy tariffs are established for local levels (cities or counties), with average local tariffs being approved by regulators. Next to these local reference prices, local municipalities can offer different levels of subsidies, depending on several factors (winter season, economic power of households, etc.) thus resulting in very different price levels across the country.

From the standpoint of this market study, the regulators require that **installation, operation and maintenance costs of metering devices for the heat energy should be in the responsibility of heat service operators, and this would be included in the price of heat energy.**

3.3 Current metering systems

Energy Law (Law 13/2007) states the obligation of existence of one meter for each electricity consumption point in order to measure its consumption. Meters are in the ownership of distribution system operators and operation and maintenance of meters are their responsibility, even if this activity is sometimes outsourced. Reading is to be done at least once a year (as required by the Regulator; however DSOs usually read meters once every three months). In between, customers are offered the possibility of own reading, case in which invoice is based either on self-read consumption or estimated consumption.

A similar setup is valid for the gas market, where each consumption point is required to have own meter. In case of condominium or blocks of flats, it can be one meter for the entire building, with distribution of costs or consumption between individual customers and apartments being the responsibility of condominium's association of inhabitants.

In the gas market, approximately 6 percent of meters serve such blocks of apartments, where individual consumers do not have their own meters. What usually drives the installation of individual gas meters is the level of consumption of individual apartments: some consumers, by installing gas boilers for heat purposes (disconnecting them from the central district heating scheme of the condominium) drive the consumption of gas up, leading thus to inequalities on how much each apartment has to contribute for the overall invoice and desire from others to have a transparent split of consumption between apartments.

The heat market provides a similar situation, with its own characteristics. Meters are to be installed at the entrance of the pipe in the condominium. Responsibility of costs or consumption sharing falls, again, under the association of inhabitants, however it is stated that individual customers or apartments should have submeters for water – devices that measure the water consumption and based on which costs are distributed based on an accurate consumption level. These are, however, mandatory only for water consumption, and not for heating. Consumers which do not have them for heat will typically bear the difference cost between condominium's invoice and consumption measured for customers with submeters.

In many other cases, the apartments do not have submeters for heat consumption, leading to lack of transparency regarding payments needed from individual consumers for the overall invoice of the association of the condominium. Apart from this, district heating companies do not have a transparency on the actual level of heat consumption.

The challenge for heat metering systems is that many blocks of flats usually have some apartments connected to the central district heating system, and some with their own boilers (usually gas, as described just above). The current legislation allows for this. But, it does lead to inequalities in sharing costs among the individual consumers. Some changes are expected in regulations to force all consumers in a building to choose one of two options: either use their own separate boiler for heating, or all units should be connected to the central district heating system. The latter option will create a need for increased transparency in the measurement of consumption, which, in turn, will drive the need for submetering systems.

Energy Law does not impose any requirements regarding metering systems or meters functionalities, **either for electricity or for gas or heat meters**, **the only requirement being measurement of consumption**.

3.4 Smart metering initiatives in Romania

With some utilities forging ahead in the area of smart metering, and others taking bold steps to conduct research and pilot projects, Romania is the ideal testing ground for pro-active initiatives.

Table 4 summarizes the information gathered during meetings with different market stakeholders in Romania (DSOs in this case). Several pilot projects have already started or are planned to start. The information presented below is shown at an aggregated level, as not all information was made public at the time this report was written.

Table 4: Estimation of the size of smart metering market

Sector	Customer group	Number of customers	Consumers which already have Remote Reading (Pilot Projects – AMR)	Consumers which already have AMI/AMM (Pilot Projects)
Electricity	**Total**	**9.000.000**	**~ 75.000**	**~ 15.300**
	Large public/ non-residential large customers	20.000	-	-
	Small and medium non-residential customers	600.000	-	-
	Residential customers (households)	8.380.000	-	-
Gas	**Total**	**3.032.000**	**~ 3.000**	-
	Non-residential customers	176.330	-	-
	Residential customers (households)	2.855.670	-	-
Heat	**Total**	**1.557.000**	**~ 1.705**	-

Source: ANRE reports, questionnaires to market stakeholders, meetings with market stakeholders

As the above figure indicates, most Romanian pilot projects have focused on the installation of automatic meter reading equipment, as opposed to the more complex AMM or AMI systems. Examples of such projects are:

- The installation of AMM system in approximately 1.300 households and small commercial agents (LV customers); meters communicate through power lines combined with fiber optics and GPRS
- The start-up of a converge remote reading system for around 8.000 households and small commercial customers using GPRS as communication infrastructure
- An AMM system installation in nearly 13.000 households and small commercial customers, with communication being made through PLC (from LV to MV), measuring consumption at 60 minutes intervals
- An automatic meter reading system installed in approximately 35.000 commercial customers, using GPRS as means of communication

The Romanian pilot projects that have been undertaken can also be characterized by the customer segments the metering system covers. That's because most of the MV commercial customers have installed an automatic meter reading system or even a more sophisticated option, thereby allowing remote consumption monitoring. In the gas sector, only about 3,000 customers are being served by automatic meter reading systems to-date.

Following tables 5 and 6 briefly summarize expectations and barriers perceived by market stakeholders.

Table 5: Main expectations perceived by market stakeholders

Expectations
Costs associated with investments should be recognized by the Regulator in tariffs
Decrease of commercial and technical losses
Certain aspects should not be decided by Regulator but by companies (e.g.: existence of balancing meters)
Accuracy of the meters lead to an increase in recorded consumption
Decreased number of field readings necessary
Monthly billing of customers based on accurate consumption
Load profiles preparation for different customers segments
Operational costs savings
Substantially reduce client reconnection time
Meters to be owned by distributors - no changes in market structure are expected; independent meter operator is not seen as a viable option
Better consumption monitoring and increased transparency on the demand curve
Signals with regards to outages
Better forecasts with regards to energy levels, leading to better balancing of losses and lower cost of energy acquisition
Monitoring or power quality
Possibility of creating new tariff systems

Source: meetings and workshops with distributors and suppliers

Table 6: Main barriers perceived by market stakeholders

Perceived barriers
High initial investments and lack of funds and budgets
High risk of error rates from the new systems due to incompatibilities
No standardized rules for basic functionalities
Alignment with future perspective of smart grids - avoid investing now in something that will become obsolete in the future
Supplier dependency needs to be avoided
Communication support: volumes, security levels, filters necessities
Managing the new higher volumes of data
Metrology legislation (legalization period) needs to be aligned with the new life-time of the smart meters
Technological issues: e.g.: current switchers positioned along the grid at almost all exchange points could hinder a good communication
Low levels of consumption (15% of the EU level); many customers with very low invoices (1-2 EUR per month)
Remote disconnections not allowed for electricity; remote reconnections not allowed for gas, by current regulatory framework
Dependency on technology providers and on the IT systems (especially with regards to errors in reading data)
Consumer resistance

Source: meetings and workshops with distributors and suppliers

4. Smart metering landscape

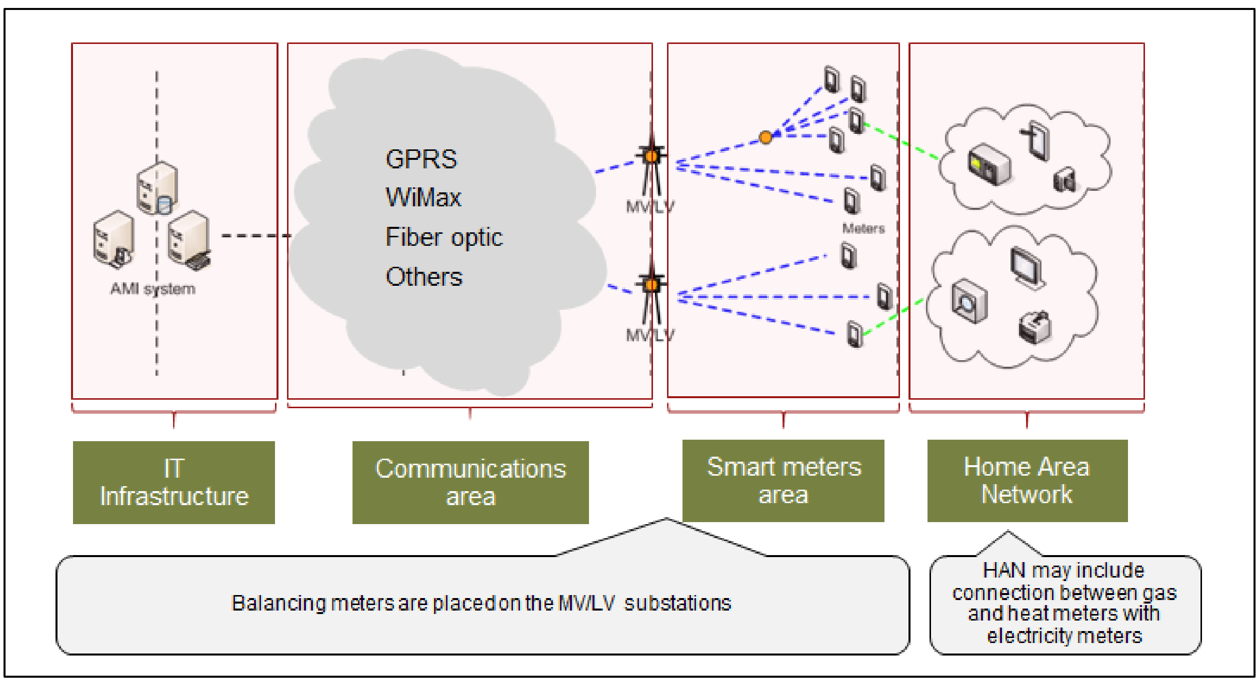
4.1 Smart metering architecture

The smart meter is defined as a utility meter with embedded computing and networking capabilities. It combines electronic metering with a programmable communication terminal that can interface with multiple networks and devices. Three different technologies are typically considered, each with different characteristics and functions:

- **AMR – Advanced Metering Reading**, that offers only "one-way" communication; it provides the opportunity to read meters automatically remotely, without the need to deploy employees in the field
- **AMM – Advanced Metering Management**
- **AMI – Advanced Metering Infrastructure**, that includes meters able to provide bi-directional ("two-way") communication between consumers and the suppliers and operators. AMI can facilitate remote control meter reading. This exchange of information with the consumer can improve consumption behavior and enable them to take energy-efficient measures.

The introduction of this technology in the electricity, gas, and heat markets, however, **takes more than just the actual smart meters**. The general architecture of smart metering systems consists of three main layers: a**n IT infrastructure layer, a communications layer, and a smart meters layer**, as depicted in figure 10. Smart meters can also be connected with devices from the home area network.

Figure 10: Smart metering high-level architecture



Source: A.T. Kearney

- **IT infrastructure** and systems represent the first layer—or foundation—of the smart metering system. Its main characteristic is its modularity, spread across the database, metering data management, and user interface. A well-documented abstract layer should be created by the IT application vendor between the system and the drivers of the particular meter types. Access to the application source codes creates a competitive environment for future development of the system.

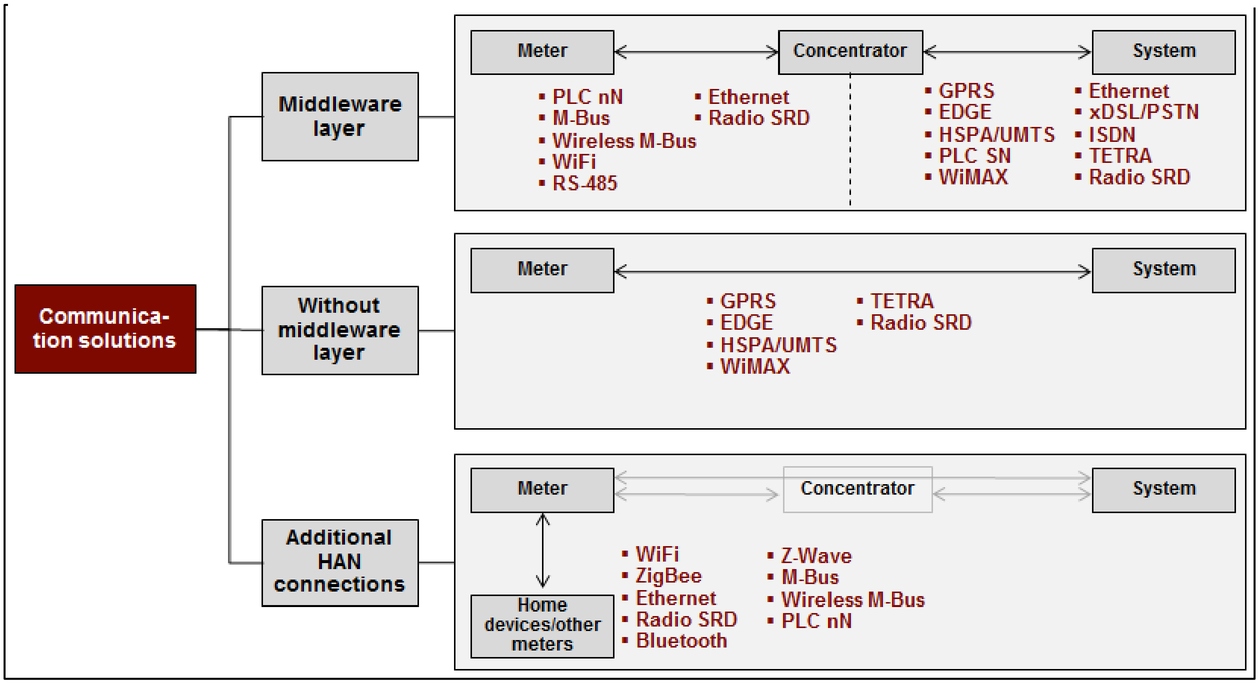
- **The communications area** ensures the interface between the IT infrastructure and the main smart meters area and through any network, whether it's an electricity, gas, or heat distributor. Various communications technologies do exist, depending on the existence of a middleware layer of data concentrators. With this middleware layer, a data concentrator makes the connection between the meters and the IT systems. In its absence, the connection is made directly (a communication solution without a middleware layer is more suitable for gas and heat markets, and less for electricity), or a combination of the two layers, in which a data concentrator only intervenes in certain connections depending on the characteristics of the network, and the additional connections between meters and home devices and other meters are ensured.

- **The smart meters area** is only part of the entire smart metering infrastructure, connecting the first two layers of the system with the home area network. In advanced cases, the home area network includes more than one device installed on a customer's premises. The home network area is part of the more advanced smart grid architecture, and a feasible **introduction of smart meters will have to account for an extension of the this infrastructure to the more advanced smart grid in the future (including HAN).**

The communication technologies or elements between the different layers can look very different, depending on decisions of investors, as seen in figure 11.

Particularly in the smart metering, technology advancements and network/architecture requirements will dictate different smart meter types: typically, the smart meters will be either single-phase or three-phase. **In addition to the usual smart meters**, which can be of various types (typically AMI – advanced metering infrastructure), the architecture will require (depending on necessities) a middleware infrastructure that contains **a balancing meter**, used as an interface of control between meters installed at customer premises and the central application. The **existence of balancing meters is especially important in countries where the level of commercial grid losses is high**. This helps accurately identify the area where such losses are occurring, by analyzing the difference between the power transmitted to household and the registered consumption.

Figure 11: Available communication solutions



Source: A.T. Kearney

But, smart meters form only the front-end system, performing the metering of energy consumption. In addition to this, the back-end system also provides several other important components, such as: data conversion and analysis modules for processing meter data, data acceptance, tests, and quality assurance; the integration layer for data integration and distribution, and the back-end layer of data assessment and processing, including billing, meter management, energy data management, customer portal, CRM, and so on.

The connection between the front-end and back-end systems are ensured through the above mentioned communication channels and modules, in charge with transfer and consolidation of data. Typically, there are **two structures of communication:**

- An **end-to-end structure**, where communication is done **directly between metering system and meters.** This can be based on both wireless and wire-based connections, depending on existing infrastructure. This solution is also called **"without middleware"**.
- A **hierarchal structure,** consisting of a **concentrator that is used between the smart meters and the central system**. This solution is called **"with middleware"**. Communication can be done both wirelessly and through wire-based connections, depending on infrastructure and cost. For example, in the case of electricity, the most commonly used connector is PLC—power line communication. It is typically selected for LV to transmit data from meters to the concentrator. From there, GPRS is used to send the data to the central application.

4.2 Smart metering models

Based on A.T. Kearney's experience with similar smart metering projects, and on the lessons taken from prior implementation projects, we identified the general installation models to be evaluated in the cost-benefit analysis. These models fall into two distinct types:

- **Independent or common communication infrastructures** to be used for each type of utility or distributor: electricity, gas or heat,
- **With or without middleware**, containing or not data concentrators and balancing meters.

Normally, one could argue that it is more beneficial for all market stakeholders if a common communication structure for electricity, gas, and heat is used, as:

- New infrastructure construction costs could be shared between utilities,
- Basic infrastructure already exists, consisting of the power lines used by electricity distributors, which can be also used by smart gas or heat meters.

Figure 12 below briefly summarizes the four general models identified above. The communication technologies presented in the figure show the many options that exist to transmit data between the central application and meters.

Figure 12: Infrastructure models and high-level evaluation

	Communication technologies used			Benefits	Cost attractiveness	Ease of implementation
	Gas, heat meters to electricity SM	SM to Concentrator	Concentrator to IT system			
1. Electricity, gas and heat smart meters with independent infrastructures and without middleware	N/A	GPRS, EDGE, HSPA/UMTS, WiMAX, Radio SRD, TETRA		◕	◔	◕
2. Electricity, gas and heat smart meters with independent infrastructures and with middleware	N/A	PLC (Electricity) M-Bus, Radio SRD, Ethernet, WiFi, Wireless M-Bus, RS-485	GPRS, PLC, EDGE, HSPA/UMTS, WiMAX, Radio SRD, TETRA	●	◑	◕
3. Electricity, gas and heat smart meters with common communication infrastructure and without middleware	M-Bus, Radio SRD, ZigBee, Ethernet, Z-Wave, Bluetooth, Wireless M-Bus	GPRS, EDGE, HSPA/UMTS, WiMAX, Radio SRD, TETRA		◕	◑	◕
4. Electricity, gas and heat smart meters with common communication infrastructure and with middleware	M-Bus, Radio SRD, ZigBee, Ethernet, Z-Wave, Bluetooth, Wireless M-Bus	PLC, M-Bus, Radio SRD, Ethernet, WiFi, Wireless M-Bus, RS-485	GPRS, PLC, EDGE, HSPA/UMTS, WiMAX, Radio SRD, TETRA	●	◕	◑

● High ○ Low

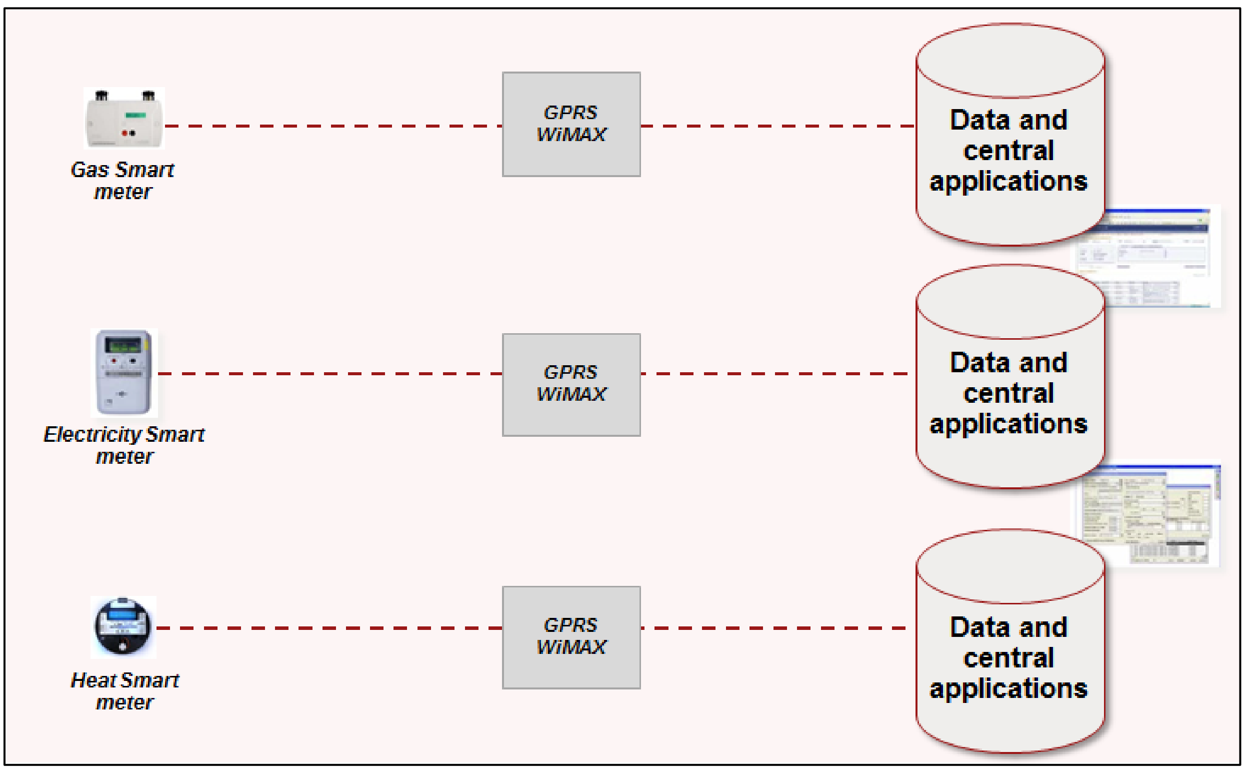
Source: A.T. Kearney

The benefits, affordability, and ease of implementation of the four options presented in figure 12 illustrate what could be the likely impact of each of these models. We tested, in our cost-benefit analysis, the following **general hypotheses about the models**:

- **Models without middleware are generally less cost attractive**, as the communication technologies used (for example, GPRS) are typically more costly than power line communication (although power line communication is more CAPEX intensive, and GPRS more OPEX intensive, the high cost of data transfer might not be a good trade-off),
- **Models with common infrastructure** between electricity and other utilities' meters **are generally more attractive from a cost perspective**, as synergies can be achieved between the different networks,
- **Models with middleware can be more beneficial**, as the existence of data concentrators and balancing meters can help in faster identification of theft, hence leading to lower commercial and technical losses.

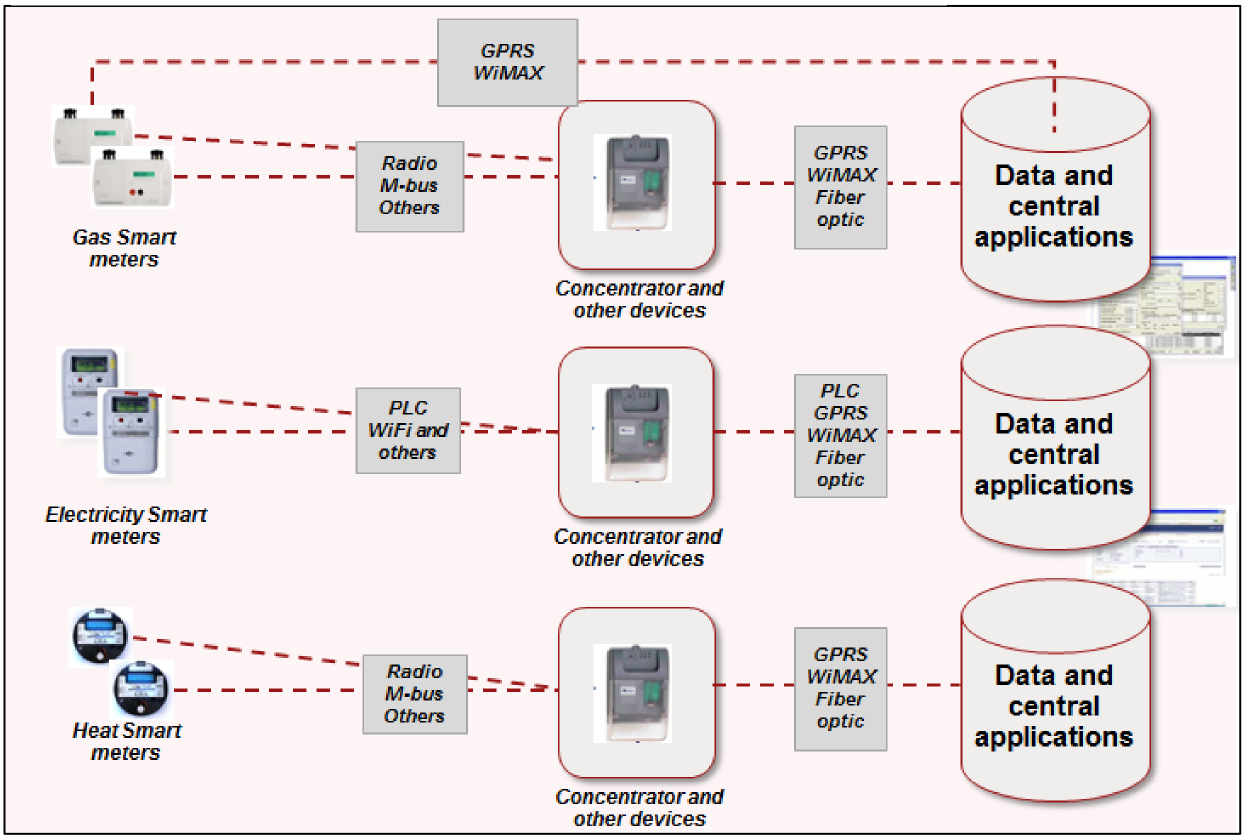
The first model considered in the cost benefit analysis assumes independent infrastructures for each type of energy distributed (electricity, gas or heat) and no middleware. Figure 13 gives on overview of this model.

Figure 13: Model 1 - independent infrastructures and without middleware



For the roll out in the electricity market, the most cost-effective and used method of implementation is still the one where communication between individual meters and the concentrator is done through the low-voltage power line. This is because, as a general rule, it is more affordable than running it through GPRS or installing WiFi or WiMAX communication systems. From the data concentrator to the central application, the mostly commonly used communication channel is the GPRS public infrastructure. Figure 14 gives an overview of this model.

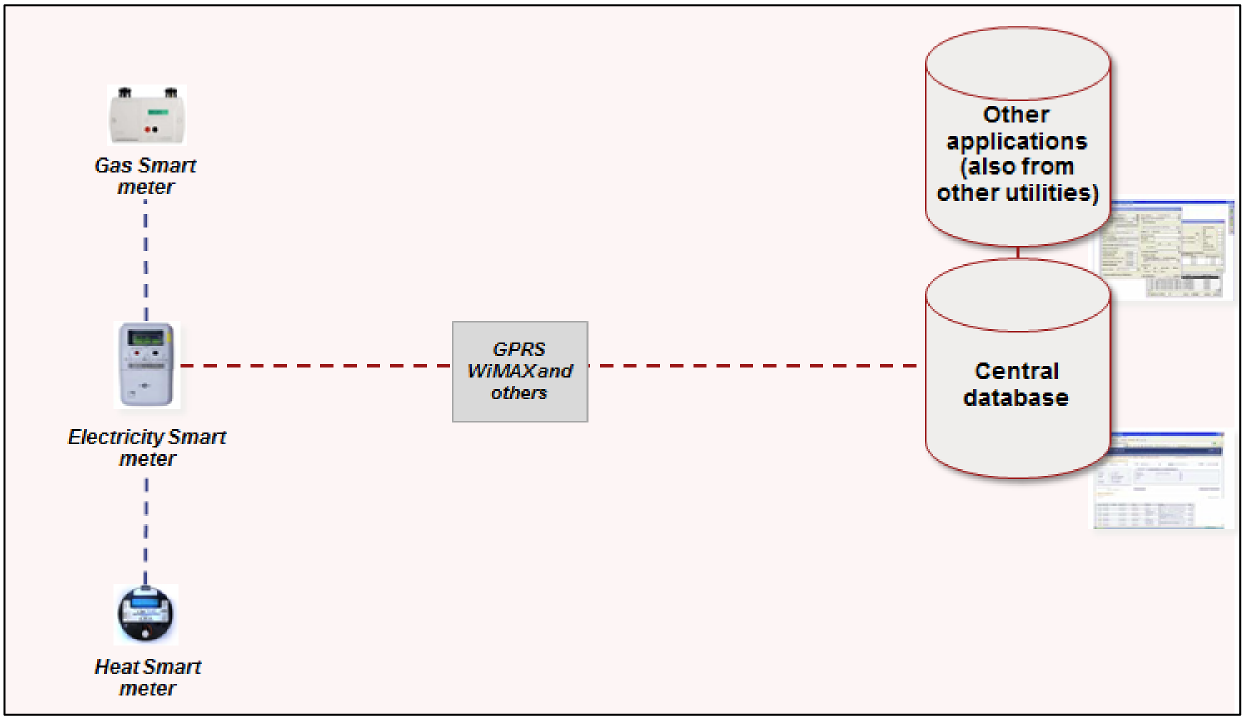
Figure 14: Model 2 - independent infrastructures and with middleware



For the connection between the concentrators and the central application, the architecture proposed for the Romanian electricity system contains balancing meters. These will serve to verify energy balances at local levels. For countries in Central and Eastern Europe, where the level of commercial losses is high, this tool will be of the utmost importance in order to realize major benefits.

The third model assessed in our analysis assumes a common infrastructure of communication shared between electricity, gas, or heat meters. However, without any middleware devices, meters transmit data directly to the central application (see figure 15)

Figure 15: Model 3 - common infrastructure without middleware

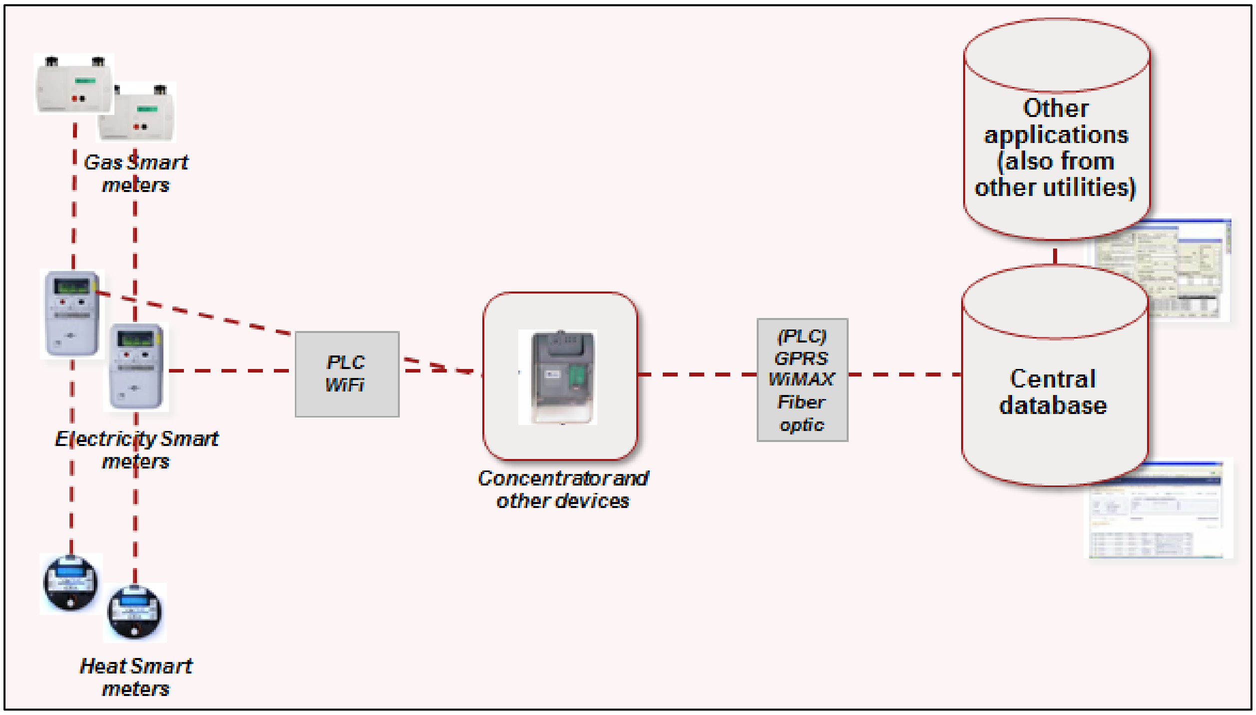


The common infrastructure architecture scenario assumes that gas and heat meters will connect directly to the electricity metering infrastructure (through various technologies like M-Bus or WiFi). From there, the data (assuming consumption of both electricity and gas or heat) is transmitted to the central application of the electricity distributor, which then sends the gas or heat consumption data to the central application of the appropriate distribution companies.

The final model analyzed is a combination of the previous two models, presuming a common infrastructure with the existence of middleware devices, such as data concentrators and, possibly, balancing meters (especially for electricity data verifications).

Communication between the meters is achieved as it is in the examples above. From the electricity meter, data is then transmitted to the concentrator through either PLC or WiFi, and then through GPRS, WiMAX, fiber optics, or even PLC to the central application of the electricity distribution company (see figure 16)..

Figure 16: Model 4 - common infrastructure with middleware



Something to keep in mind — and this holds true for any model, but especially for those with common infrastructure — is that when connecting individual meters with data concentrators, and then on to the central application, it's important to impose (by regulatory means) and use **open standard communication protocols**. This helps to avoid investing heavily in equipment that is not interoperable, cannot connect, or causes frequent errors in data transmission when acquired from various vendors

4.3 Overview of functional requirements

Smart meters are usually considered as "smart" because, compared to traditional meters they have more functions that enable system operators to use two-way communication with installed smart meters. Thus, with smart meters, data can be read remotely, but it can also be transferred back. Moreover, the meter can be operated without the need of a physical visit to the customer location. This capability is light-years ahead of the AMR devices that have been implemented in the last ten years on a large scale in several countries.

The EC also set, in addition to the target of an 80 percent roll out by 2020 for the electricity market (Directive 72/2009), ten agreed-upon, common-minimum functions for smart meters (in the case of electricity). Below, Table 7 describes these functions with respect to their scope and target.

Table 7: Ten minimum functionalities of smart smart metres recommended by EU

Target	Functionality	Description
For the customer	**A) Provide readings directly to the customer and any third party designated by the consumer**	Accurate, user-friendly and timely readings provided to customer and any third party designated by customer, through a standardized interface. Standardized interfaces would enable energy management solutions in 'real-time' (e.g.: home automation, demand response schemes and secure delivery of data directly to customers).
	B) Update the readings referred to in point a) frequently enough to allow the information to be used to achieve energy savings	The rate at which consumers can see the data has to be adapted to the response time of energy-consuming or energy-producing products - general consensus that update rate of 15 minutes is needed at least. Recommendation that meters should also be able to store consumption data for a reasonable time to allow consulting and retrieving data from past consumption, including a calculation of costs.
For the metering operator	**C) Allow remote reading of meters by the operator**	This functionality relates to the supply side
	D) Provide two-way communication between the smart metering system and external networks for maintenance and control of the metering system	This functionality relates to metering.
	E) Allow readings to be taken frequently enough for the information to be used for network planning	This functionality related to both demand and supply side.
For commercial aspects of energy supply	**F) Support advanced tariff systems**	Smart meters should include advance tariff structures, time-of-use registers and remote tariff control, for empowering consumers to improve energy efficiency. Information about advanced tariffs options is recommended to be automatically transferred to the final customers via standardized interface
	G) Allow remote on/off control of the supply and/or flow or power limitation	It provides additional protection for the consumer by allowing grading in the limitations. It speeds up the processes of connection and disconnection, according to needs of both supplier and customer and it is needed for handling technical grid emergencies.
For security and data protection	**H) Provide secure data communications**	High levels of security and privacy are essential for all communications between meter and operator, including messages passed via the meter to or from any appliances or controls on customer's premises.
	I) Fraud prevention and detection	Security and safety in case of access, necessity to protect the consumer, for example for hacking access.
For distributed generation	**J) Provide import/export and reactive metering**	Functionality necessary to allow renewable and local micro-generation, thus future-proofing meter installation. Function should be installed by default and activated/disabled in accordance with wishes and needs of customers.

Figure 17, below, illustrates the importance that select European countries have placed on each of these functions, including three initial ones, which were not included on the final list of common-minimum functions of smart meters recommended by the EC.

Figure 17: Minimum functionalities recommended by European Commission and level of consideration in selected countries

European Commission Recommendations for Requirements		Final ten	AT	BE	FR	NL	PL	SE	UK
			Level of considerations in each country						
For the customer	Provide readings directly to the customer and any third party designated by the consumer	✓	◑	◑	●	●	◑	◑	●
	Update the readings frequently enough to allow the information to be used to achieve energy savings	✓	●	●	●	●	●	●	●
	Provides these readings in a form easily understood by the untrained consumer with calculations enabling final customers to better control their energy consumption	✗	●	◑	○	●	◑	○	●
For the metering operator	Allow remote reading of meters by the operator	✓	●	●	●	●	●	●	●
	Provide two-way communication between the system and external networks for maintenance and control	✓	●	◑	●	●	●	●	●
	Provides for the monitoring of Power Quality	✗	○	○	●	◑	◑	○	●
	Allow readings to be taken frequently enough for information to be used for network planning	✓	●	●	●	●	●	●	●
For commercial aspects of energy supply	Support advanced tariff systems	✓	●	◑	●	●	●	●	●
	Supports energy supply by pre-payment/on credit	✗	◑	○	○	●	●	○	●
	Allow remote on/off control of the supply and/or flow or power limitation	✓	●	◑	◑	●	●	●	●
For security and data protection	Provide secure data communications	✓	●	●	●	●	●	●	●
	Fraud prevention and detection	✓	●	●	●	◑	●	●	●
For distributed generation	Provide import/export and reactive metering	✓	◑	●	●	●	●	○	●

● *Yes* ◑ *Partially* ○ *No*

Source: European Commission, A.T. Kearney

In addition to these minimum smart metering minimum functional requirements, the European Commission has also provided a recommendation of 33 other requirements that could be considered as optional. Appendix 1 presents these functions. This, however, is purely for informational purposes.

4.4 Minimum functional requirements for Romania

Based on the experience gleaned from other markets that have already started implementation of smart metering systems, and on specific characteristics of the Romanian market, several other functional requirements are being proposed for Romania, in addition to the ten required by the EC. Four additional functions have been identified for inclusion from the list of 33 recommended by the EC, with others proposed by the project team based on past experience.

Table 8 presents all functions that we considered for electricity, gas, and heat smart meters, including the minimum functions required by the EC and those identified by the project team. These functions are accounted for in the cost-benefit analysis. More information regarding them is included in Chapter 5.

Some of proposed functionalities have been considered as optional for gas and heat meters, because they can lead to higher purchasing price of meters, but without bringing benefits justifying the incremental cost (for the customer, operator or supplier):

- The functionality to **support advance tariff systems is indicated as optional for gas meters**, as gas tariffs are usually not as sophisticated as electricity tariffs. This functionality would be interesting, for example, in case of prepayment contracts,

- Same case stands for the functionality to **allow remote on/off control of the supply and/or flow or power limitation, optional in case of the heat meters**, since this functionality significantly increases the price of smart gas meters (more complex mechanical mechanisms to shut off water supply on the pipe due to high pressure).

Optional functionalities were not taken in consideration into the quantitative assessment of costs and benefits.

Table 8: Recommended functionalities of smart meters for Romania

Functionality	Electricity	Gas	Heat
Minimum functionalities recommended by EC			
A) Provide readings directly to the customer and any third party designated by the consumer	✓		
B) Update the readings referred to in point a) frequently enough to allow the information to be used to achieve energy savings	✓		
C) Allow remote reading of meters by the operator	✓	✓	✓
D) Provide two-way communication between the smart metering system and external networks for maintenance and control of the metering system	✓	✓	
E) Allow readings to be taken frequently enough for the information to be used for network planning	✓	✓	✓
F) Support advanced tariff systems	✓	Optional	
G) Allow remote on/off control of the supply and/or flow or power limitation	✓	✓	Optional

H) Provide secure data communications	✓	✓	
I) Fraud prevention and detection	✓	✓	
J) Provide import/export and reactive metering	✓		
Additional functionalities from the list of 33 recommended			
K) Automated fault identification/grid reconfiguration, reducing outages times *(functionality 5 from the list of 33)*	✓	✓	✓
L) Enhance monitoring and control of power flows and voltages *(functionality 6 from the list of 33)*	✓		
M) Improve monitoring of network assets *(functionality 8 from the list of 33)*	✓		
N) Identification of technical/non-technical losses by power flow analysis *(functionality 9 from the list of 33)*	✓		
Additional functionalities identified by project team			
O) Meter enables use of different technologies providing communication with the HAN network and other smart meters	✓	✓	✓
P) Meters should transmit to the Central Application info about the status of the device integrity breach sensor	✓	✓	✓
Q) AMI System central application should store meter data at least for the period relevant for billing, complaint, collection	✓	✓	
R) Communication infrastructure should enable expanding the AMI System with additional meters, without the need to replace existing elements	✓		
S) AMI system should allow integration of at least one balancing meter at every MV/LV station	✓		
T) Meters should have capability of storage of the data for a sufficient time period	✓	✓	
U) Time synchronization	✓		
V) Remote software update	✓	✓	

Definitions for additional functionalities:

- **Automated fault identification and grid reconfiguration, reducing outages times –** meters should have the functions to send information about the power outage (if connecting to the central application is physically possible) and about the end of power outage and the duration of it. IT systems should be able to identify the occurrence and the length of interruptions in the power supply.

- **Enhance monitoring and control of power flows and voltages** – meters should transmit to the central application all information about exceeding the thresholds of acceptable deviations of voltage (time flags for occurrence of the event and for return to value below threshold).

- **Improve monitoring of network assets** – data from meters should be sufficient enough to optimize the operation of distribution assets and improve the efficiency of the network.

- **Identification of technical and non-technical losses by power flow analysis** – data from meters should allow for better understanding and management of technical and non-technical losses.

- **Meter enables use of different technologies providing communication with the HAN network** – meters (consisting of measurement module, executive module and communication sections) should enable communication with household appliances which offer this possibility, including other meters. The module's connection should be based on generally used standards and protocols and the meter should ensure possibility of customization of internal software without intervention into the measurement module and meter data memory.

- **Meters should transmit to the Central Application info about the status of the device integrity breach sensor** – meters should be able to detect events such as opening of the meter cabinet or applying external magnetic field.

- **AMI System central application should store meter data at least for the period relevant for billing, complaint, collection** – this functionality refers more to the central system, rather than the meters. But it implies that meters should also have the capability of storage of data, in an internal memory, for as long as it is necessaary.

- **Communication infrastructure should enable expanding the AMI System with additional meters, without the need to replace existing elements** – smart metering implementation should be forward thinking, allowing infrastructure to be flexible enough to build on future technology advancements and increasing network (including additional meters) with minimum new investments in communication infrastructure upgrade and without replacing existing elements.

- **AMI system should allow integration of at least one balancing meter at every MV/LV station** – this functionality is required for the Romanian market as one of the key benefits from smart metering introduction in Romania (similar to most Eastern Europe countries) is the reduction of technical and especially non-technical losses. Therefore the existence of balancing meters for measurement and monitoring purposes is necessary. Poland is a good example of this, where Energa operator planned the roll-out of electricity smart meters taking into consideration balancing meters through-out the network for the exact same purposes.

- **Meters should have the capability of storage of the data for a sufficient time period** – this functionality allows the customer or any other third party with enough relevant information from past to analyze consumption and draw the adequate conclusions.

- **Time synchronization** – meters and software respectively should have the capability of synchronizing data with the central application frequently enough, so the benefits that result from the other functionalities can be achieved.

- **Remote software update –** meters should offer remote updating of internal software through a two-way communication, without sending out a technical team to the client site.

5. Benefits

5.1 List of benefits and descriptions

Implementing smart metering offers a wide-range of various benefits that span the entire energy industry value chain—from producers, TSO, and DSOs to energy suppliers and customers.

The benefits considered in this study fall into two groups:

- **Benefits directly related to smart metering that can be monetized**. These have been included in the cost-benefit analysis
- Benefits that can be **assessed from a qualitative point of view**. For these, monetization is based on variables with a high degree of variance, thus we decided to treat them outside of quantitative analysis.

Table 9 summarizes main benefits, which can be transferred to investors and which were included in the cost benefit analysis for electricity and gas secotrs.

Table 9: List of benefits quantitatively assessed in the CBA

Benefits	Electricity	Gas
1. Reduced meter reading cost	✓	✓
2. Reduced (electricity/gas) commercial losses	✓	✓
3. Reduced energy (electricity/gas) technical losses	✓	✓
4. Reduced distribution operations cost	✓	✓
5. Reduced outages	✓	
6. Deferred distribution investments	✓	✓
7. Reduced energy (electricity/gas) cost	✓	✓
8. Reduced restoration costs	✓	

1. Reduced meter reading cost – the cost incurred for the labor force to read meters (typically once every three months for households) will be reduced. All costs associated with this activity (such as transportation) have been included by considering an average cost of single reading per meter, which was collected from market stakeholders (distributors) separately for electricity and gas.

2. Reduced (electricity/gas) commercial losses – this refers to decreasing commercial losses or volume of energy that is delivered, but not invoiced. Smart metering can help accurately identify consumers involved experiencing commercial losses

3. Reduced energy (electricity/gas) technical losses – the benefit of reduced technical losses comes from three main areas:

- Reduction of commercial losses leads to less energy distributed through the system. As technical losses are a percentage of this energy, reducing commercial losses leads to a reduction of technical losses (in absolute value) as well
- Increase in the amount of energy registered by meters as a consequence of lowering the threshold of the meter's initiation
- Reduction of the energy consumed by the measurement system – this is treated as an avoided cost, as it has been calculated based on estimated energy consumed by traditional meters. The energy consumed by smart meters is treated, on the other hand, as an element of the implementation cost.

4. Reduced distribution operational cost – the benefits that smart metering brings in distribution OPEX have been considered in the following way:

- Avoided legalization costs of traditional meters (referring to the legalization fees per meter),
- Optimization of the asset maintenance process – connection and disconnection costs eliminated due to personnel no longer visiting client locations.

These benefits have been treated as avoided costs with performing the above operations with the traditional meters, in case smart meters hadn't been installed. All new expenses with legalization and connections or disconnections associated with smart meters have been considered as costs in the Chapter 7.

5. Reduced outages – reduction of time spent locating where failures have occurred has a direct impact on sales and losses.

6. Deferred distribution investments – this benefit comes from two main drivers:

- An avoided cost with replacement of traditional meters (we have considered as a baseline the business as usual, without any smart meters installed, where traditional meters are replaced based on their life duration, based on damages, based on not passing legalization procedures and meters installed for new customers),
- An avoided cost with the installation of the traditional meters, based on FTE capacity to make the installations.

8. Reduced energy (electricity/ gas) costs – decrease in energy purchase costs:

- For suppliers as a result of increased accuracy of forecasts regarding consumption, benefit reflected in supplier's profit,
- For distributors as a result of increased accuracy of forecasts regarding losses, as a certain amount of these losses will be covered at a better price.

9. Reduced restoration costs - reduction of time needed to identify location of a failure, with an impact on resources.

In addition, smart meters can bring other benefits to market stakeholders. But, they require significant added investment or it is difficult for investors to realize them. Therefore, they were not considered in the cost-benefit analysis. Such benefits are described and calculated separately.

5.2 Mapping of benefits to functionalities

All required smart metering functionalities for Romania have been mapped to benefits, in order to show which functionalities are needed for realization of specific benefits. Mapping of functionalities to benefits also helps in the following areas:

- Ensures all applicable functionalities are considered, as each benefit should require at least one functionality to make it worthwhile,
- Helps in associating each functionality to a benefit and ensures that unneeded functionalities are not included in the list of minimum required for Romania,
- Provides the basis for future scenario and sensitivity analysis: price of meters is influenced by functionalities they can offer, thus mapping will allow for fast and easy analysis of potential influence on price and on cost-benefit result.

Table 10 presents the mapping of functionalities considered for Romania to benefits, which are assessed in the cost-benefit analysis. Mappings have been made separately for electricity, gas and heat.

Table 10: Mapping of functionalities to benefits for electricity

Functionalities / Benefits (legend below tables)			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Agreed common minimum smart metering functionalities *	A	Provides readings to the customer and any third party designated by the consumer;				■						■	■	■					
	B	Updates these readings frequently enough to allow the information to be used to achieve energy savings;				■	■	■		■		■	■	■	■		■	■	
	C	Allows remote reading of meter registers by the Meter Operator;	■	■	■	■	■		■		■	■						■	■
	D	Provides two-way communication between the meter and external networks for maintenance and control of the meter;	■	■	■	■	■		■		■	■	■			■		■	
	E	Allows readings to be taken frequently enough to allow the information to be used for network planning.	■	■	■	■		■		■	■		■		■	■	■	■	
	F	Supports advanced tariff systems;					■			■			■	■	■				
	G	Allows remote ON/OFF control of the supply and/or flow or power limitation.		■	■	■	■			■			■	■	■			■	
	H	Provides Secure Data Communications;	■									■	■	■					■
	I	Fraud prevention and detection.		■				■					■		■				■
	J	Provides Import / Export & Reactive Metering.	■		■	■		■		■			■	■	■	■	■	■	
Selection from smart grid functionalities **	K	Automated fault identification/grid reconfiguration, reducing outages times				■	■				■			■	■	■		■	
	L	Enhance monitoring and control of power flows and voltages	■		■	■	■	■	■	■	■			■	■	■	■	■	
	M	Improve monitoring of network assets			■	■	■	■	■		■				■	■		■	■
	N	Identification of technical and non-technical losses by power flow analysis		■	■										■			■	
Other proposed functionalities	O	Meter enables use of different technologies providing communication with the HAN/LAN network and other smart meters	■									■	■	■				■	■
	P	Meters should transmit to the Central Application info about the status of the device integrity breach sensor	■	■		■													■
	Q	AMI System central application should store meter data at least for the period relevant for billing, complaint, collection	■	■		■							■	■					
	R	Communication infrastructure should enable expanding the AMI System with additional meters, without the need to replace existing elements	■									■							
	S	AMI system should allow integration of at least one balancing meter at every MV/LV station		■	■											■			
	T	Meters should have capability of storage of the data for a sufficient time period	■	■		■			■				■	■			■		
	U	Time synchronization		■	■		■		■		■		■			■	■	■	
	V	Remote software update	■			■						■	■	■					

Table 11: Mapping of functionalities to benefits for gas

Functionalities / Benefits (legend below tables)		1	2	3	4	5	6	7	8	9	11	12	13	14	16	17
C	Allows remote reading of meter registers by the Meter Operator;	■		■				■			■	■	■		■	■
D	Provides two-way communication between the meter and external networks for maintenance and control of the meter;		■		■						■					
E	Allows readings to be taken frequently enough to allow the information to be used for network planning.	■				■	■	■			■			■	■	
F	Supports advanced tariff systems;	■			■							■	■			
G	Allows remote ON/OFF control of the supply and/or flow or power limitation.		■		■	■						■				
H	Provides Secure Data Communications;	■									■	■				■
I	Fraud prevention and detection		■				■				■		■			
K	Automated fault identification/pipelines reconfiguration, reducing outages times					■	■	■				■		■		
O	Meter enables use of different technologies providing communication with the HAN/LAN network, incl. other meters	■									■	■			■	■
P	Meters should transmit to the Central Application info about the status of the device integrity breach sensor		■			■						■				
Q	AMI System central application should store meter data at least for the period relevant for billing, complaint, collection	■	■		■						■	■				
T	Meters should have capability of storage of the data for a sufficient time period	■	■		■			■			■	■				
V	Remote software update	■			■						■	■				■

Table 12: Mapping of functionalities to benefits for heating

Functionalities / Benefits (legend below table)		1	3	4	5	7	13	16	18
C	Allows remote reading of meter registers by the Meter Operator;	■				■	■	■	
E	Allows readings to be taken frequently enough to allow the information to be used for network planning.	■	■	■	■		■	■	
K	Automated fault identification/grid reconfiguration, reducing outages times	■		■	■	■	■		
O	Meter enables use of different technologies providing communication with the HAN/LAN network, incl. other meters						■		■
P	Meters should transmit to the Central Application info about the status of the device integrity breach sensor		■		■		■		

Benefit	***Assessment methodology***
1. Reduced meter reading cost	Quantitative
2. Reduced commercial losses	Quantitative
3. Reduced technical losses	Quantitative
4. Reduced distribution operations cost	Quantitative
5. Reduced outages	Quantitative
6. Deferred distribution investments	Quantitative
7. Reduced equipment failures	Quantitative
8. Reduced electricity cost	Quantitative
9. Reduced restoration cost	Quantitative
10. New product sales opportunities	Qualitative
11. Supplier benefit	Qualitative
12. Consumer benefit	Qualitative
13. Reduced CO2 emissions	Qualitative
14. Deferred transmission capacity investments	Qualitative
15. Detection of anomalies on contracted power	Qualitative
16. Improvement of network quality parameters	Qualitative
17. Reduced implementation costs from smart metering implementation bundled with other investment plans	Qualitative

5.3 Split of benefits to stakeholders

The results from the smart metering roll out cost-benefit analyses for EU member states other than Romania proved that the benefits of this new technology are likely to vary across different stakeholder groups along the entire value chain of the industry.

As the analysis undertaken by the A.T. Kearney project team aims at assessing benefits and costs from a market perspective, it is hard to decide at this stage which market stakeholders will profit from the benefits. One could predict that the DSOs will profit the most, with such benefits as reduced meter reading costs or distribution operation costs, deferred distribution capacity investments, or reduced electricity and restoration costs. However, the final distribution of benefits depends on regulations. Even if most benefits happen at the grid level, the final distribution will depend how much DSOs will be able to keep benefits in tariffs, and how capital expenditures for smart metering will be included in those tariffs.

Other market stakeholders will also see several benefits come their way, such as:

- Reduced meter reading costs could impact customers, since a reduced cost can easily be transferred into reduced tariffs,

- Reduced commercial and technical losses can benefit customers for the same reason, but they will also lead to less energy produced and therefore lower CO_2 emissions,
- Reduced outages and restorations costs are not only beneficial for distributors, but also for customers because they get a better service and for suppliers because they can increase sales,
- Reduced electricity cost is a benefit to both suppliers and distributors, due to access to more accurate forecasts of consumption, but it can ultimately translate in lower energy cost for consumers as well.

Not all the benefits, however, can be directly assigned to distributors: for example, disconnection and reconnection costs are not paid by DSOs. Instead it is invoiced to suppliers and, finally, paid by customers, who pay the fee for that specific service. Avoiding such costs could be a benefit for customers, depending on regulatory framework.

So far, we have seen the calculated benefits as an advantage for the whole market, instead of specific stakeholders. The final distribution of benefits will depend on regulatory tools. However, it should be emphasized that investors will receive a justified return on investment; otherwise, they will be hesitant to invest despite the significant benefits for the overall market.

Below is a summary of smart metering benefits that we considered from a qualitative point of view only.

Benefits for consumers

One of the biggest benefits for customers can be the increase of energy awareness and decrease of energy consumption, resulting in a decrease in energy cost. To take advantage of this benefit, however, requires other significant investments (screens, visualization systems, and more) and customer education. In the end, these benefits will not trickle down to investors.

Final customers may benefit also from:

- More accurate meter reading and billing as well as fewer complaints,
- Innovative tariff systems,
- Improved customer service quality,
- Reduction of cost and delay of interventions,
- Easiness to change suppliers (leading towards a more competitive market place and a more fierce price-battle and high quality services),
- Increased competition among suppliers as they are able to offer customized contracts and value-added services,
- Ability to manage consumption as smart metering can allow consumers to remotely control home devices. This latter benefit requires additional investments in smart grid functionalities like provision of a home display or internet platform to provide consumption information.

Supplier benefits

Suppliers can take advantage of many benefits from smart metering implementation, including:

- Additional revenue from new customized customer services,
- Reduced call center costs,
- Customized prices to reduce churn (better knowledge of consumption pattern of each household giving them opportunity to target different prices options for different customers),
- Acceleration of the process to change suppliers through automation of meter readings (from reading to invoicing),
- Better quality and frequency of billing data,
- Fewer billing complaints as they are based on real rather than estimated consumption and can be resolved online,
- Fewer unpaid debts as smart metering allows to remotely cut-off and reconnect customers when needed,
- Additional revenue from various energy management services.

Benefits for the society

Reduced electricity losses, reduced consumption, reduced number of necessary vehicles and transports to physically reach the consumption points (for various operations), and reduction of peak load consumption will lead ultimately to reduced carbon dioxide, sulfur and nitrogen oxide emissions.

Additional benefits for network operators

- Deferred Transmission Capacity Investments – reduction of the load and stress on transmission elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring, rerouting of power flow and reduction of fault current could enable utilities to optimize upgrades of lines and transformers.
- Detection of anomalies on contracted power – various anomaly detection methods can be employed based on statistical signal processing. This is feasible due to the high accuracy and granularity of data provided by smart meters; it requires however capabilities of IT system software to process the necessary amount of data.
- Improvement of network quality parameters – easiness in tracking network quality parameters and key performance indicators will lead to lower variance in network quality parameters.
- Reduced implementation costs from smart metering implementation bundled with other investment plans – this benefit acts double-folded: on one side, by bundling various investments with smart metering implementation economies of scale and efficiency can be achieved, while on the other hand smart metering can decrease the

need of future investments to replace old parts of the network by helping in a better prioritization
- Costs reduction on the balance market and with system technology services, as better knowledge of the consumption curves means improvement of forecast models.

Generation companies or (small) producers (and even storage facility companies for gas) could benefit from:

- Continuous high or linear utilization of generation capacity. This benefit is subjected also to consumers modifying their consumption behavior appropriately, so that peak periods are smoothed and the total consumption curve is more adjusted to the production curve. This leads to lower costs of altering generation capacity (shutting off, keeping in stand-by and powering on production facilities), which can ultimately lead to lower transmission tariffs.
- Better integration of distributed generation. Smart metering and other smart grid solutions will also enable development of distributed generation plants including micro generation at final consumers' premises.

6. Smart metering costs

6.1 List of costs and description

The costs for smart metering implementation are always easier to quantify and assign to stakeholders than benefits. The costs considered in the cost-benefit analysis have been split according to assumptions made based on the smart metering architecture presented in Chapter 4. We took into consideration three groups of costs incurred for smart metering:

- Implementation and investments costs (mostly, but not exclusively, CAPEX),
- Costs for system operations and maintenance,
- Financing costs.

Here are the areas we considered when calculating **implementation and investment costs**:

Cost of meter layer

The following costs were considered in this group:

- Procurement of modular meters and procurement of communication modules and/or costs of meters integrated with communication modules (depending on type of meter – single phase of three phase and on communication module used – GPRS/UMTS, PLC, WiFi, WiMAX),
- Legalization of meters and procurement cost of meters not undergoing re-legalization),
- Costs of installation of new meters,
- Depreciation (of meters and other assets) – for calculation of the residual value.

Cost of middleware layer

The following costs incurred for the middleware (depending on the analyzed model – whether or not middleware was used) were considered:

- Cost of concentrators and balancing meters,
- Costs of modems and couplers,
- Costs with installation of concentrators, balancing meters and other assets,
- Costs of construction of fiber optic, WiMAX or WiFi infrastructures,
- Depreciation of assets – to calculate the residual value.

Cost of application layer

Costs incurred for the application layer include:

- Cost of development, testing and implementation of the AMI central application,
- Integration with external systems (interfaces),
- Procurement and installation of computer equipment (servers, disk spaces, cost of data back-up, etc.) and licenses,
- Depreciation of assets – for the residual value calculation.

In addition, several cost clusters were identified for **system operation and maintenance**:

- **Project costs –** mainly costs for training relevant personnel, costs for the management and provision of resources (both FTEs engaged in project and additional costs such as travel), costs for professional services,

- **Communication/connectivity costs** – costs of connectivity generated by each type of meter and concentrator,

- **Consumed energy costs –** the cost of energy consumed by the measuring system (by meter layer, by intermediate or concentrator layer),

- **Costs of service, maintenance and development** – costs for replacing damaged meters, servicing and repairing meters, legalization services for smart meters, replacing damaged communication modules, servicing and repairing communication modules, manual meter reading (manual reading will still be required by the regulator; some readings will still require manual verification due to possible errors or customer complaints), servicing and repairs of concentrators and communication lines, maintenance of telecommunication infrastructure, AMI application maintenance and maintaining licenses,

- **Employment costs –** labor costs associated with maintenance of intermediate layer, application, verification of event alerts, and so on.

The cost of financing – interest rates paid for the contracted capital – are dependent on the financing structure.

Stranded costs will also impact financial results. Therefore, companies will have to consider them separately from the quantitative analysis. Depending on the pace of implementation, a certain amount of traditional meters will be replaced before the end of their depreciation period. Such assets would have to be scrapped, with the cost included in the profit and loss statement. From the country's perspective, as shown in our analysis, this will have no impact on profitability, since the cash has already been expended. From a corporate perspective, stranded costs can seriously impact financial results. Therefore, the pace of implementation should be adjusted. In addition, companies should attempt to find disposal solutions that will lessen the impact of these scrap meters.

Generally, **variance of costs** will depend on many factors that have to be accounted for. Some examples of these are:

- **Guaranteeing the interoperability of systems** (open protocols, possibility to acquire assets from multiple vendors, etc.) so as not to squander investments in technological solutions,
- **Choosing communication technologies** (for example, PLC or GPRS) and the number of meters communicating through different technologies. This can impact the final cost significantly (both as total sum and roll-out overtime, as GPRS is more OPEX intensive, while PLC is more CAPEX intensive. Depending on the age and condition of the power lines, PLC might also require significant operational expenditures over time for maintenance and verifications),
- **Financing structure**, in other words, what percentage of the investment is supported by the operator and what percentage will be financed from external sources (implying interest rate payments),
- **Determining pace of implementation** and coordination between electricity, gas, and heat operators in terms of the quantity of smart meters installed**,**
- **Taking advantage of discount rates** used for discounting cash flows in the investment.

These costs are incurred for the roll-out phase of smart meters in the electricity market. For the gas market, costs are calculated in a similar way, based on several hypotheses

In addition to direct costs assessed in this cost-benefit analysis, other indirect costs might occur during implementation, such as:

- Recurring charges for telecommunication technologies and evolution of such charges,
- Potential costs for upgrading various system components towards smart grid,
- Various legal, institutional and planning costs,
- Compensatory packages for redundant personnel,

- Costs for suppliers and transmission system operators and other stakeholders on the value chain to upgrade their IT systems, for handling and processing the new amount of data,
- Costs associated with scrapping/disposal/recycling of old meters replaced.

6.2 Split of costs to stakeholders

Typically, **DSOs** will bear the lion's share of the costs, as they acquire, install, operate, and maintain the meters (according to current legislation in Romania and in many other European countries).

Due to the complexity of smart metering roll out, changing over ownership of the meters and the current market structure might not be a top priority for Romania at the moment. There are, however, different ways to optimize investment costs and improve the overall business case by challenging the current operating model in different ways. These are described in upcoming chapters.

Nevertheless, it is important to understand that other costs might be incurred by different market stakeholders, not specifically for installation of smart metering, but for additional costs to leverage smart metering investments. The purpose of this study is not to identify and calculate all investments, which could be done based on the smart metering infrastructure.

7. Impact of smart metering implementation

The detailed cost-benefit analysis used to determine the feasibility of smart metering implementation in Romania was performed for low-voltage electricity customers and for all gas-using households. Customers on medium- and high-voltage lines currently have smart meters, or they are in the process of having them installed. Smart meters for heat were not included in the model, since in this sector the biggest benefits can be realized through the installation of simple submeters. Installation of smart meters for heat consumers brings minor benefits in comparison to simple submeters, and the cost is significant.

Different options have been considered for assessing the implementation of smart metering initiatives in Romania, since there is obvious interconnection among the various utility companies.

The analysis was based on a series of assumptions and hypotheses related not only to market, but also to expected regulatory changes. It ends with a scenario analysis and a sensitivity analysis to identity major elements that could potentially drive the change in results.

The overall market perspective has been considered through quantification of benefits and costs associated with smart metering along the entire value chain.

The outcome of the analysis depends on which implementation model is chosen for electricity and gas, as described in detail in Chapter 4.2 above:

- Model 1 - independent infrastructures and without middleware,
- Model 2 - independent infrastructures and with middleware,
- Model 3 - common infrastructure without middleware,
- Model 4 - common infrastructure with middleware.

For the heat sector, smart metering does not bring sufficient incremental benefits compared to installation of submeters, which should be the first priority in the metering part of this sector. Hence we have not made any quantitative assessment of smart metering for the heat sector.

7.1 Main assumptions

We made two major underlying assumptions that we considered in our cost-benefit analysis, presented in figure 18.

Figure 18: Two major assumptions taken into consideration for the cost benefit analysis

Built from country perspective	• CBA was made from country point of view – No impact calculated from inclusion of costs in distribution tariffs – Value added measured from country perspective, not from a cost recovery potential for DSOs – Cost with middleware in case of common infrastructure considered only for electricity
Target customers	• CBA considered roll-out of smart meters for all low voltage customers in electricity and all households in gas, based on discussions with key stakeholders assuming that implementation of smart meters at MV customers has already been implemented • For some specific utilities, the CBA results can different because of **specific characteristics** (different purchasing power, experience from other markets, etc.) • In order to realize full benefits we assume that **all customers on LV** should have smart meters implemented, even if the cost of the investment in smart meters might be higher than the return of that client through the consumed energy

For the purpose of analysis, we used Discounted Cash Flow (DCF) method, with final results presented as a **net present value (NPV)** of cash-flows for the period of 2013 through 2032. Since the recently introduced legalization period for electricity meters (starting November 2012) will be 10 years, we used a 20-year average life duration for the meters (meters passing 1 legalization). For comparison reasons, despite having a legalization period of eight years, we considered the impact for gas meters over the same time period.

Discount rates of 7,5 percent for electricity and 8,63 percent for gas were used to calculate the NPV in the standard senarios. To help simplify this cost-benefit analysis, these values have been used as the cost of capital that's recognized by the regulator in the distribution tariffs. **Sensitivity analyses were** run to understand the impact of different discount rates, as final net present value is sensitive to this.

The proposed **implementation plan** assesses the likely impact of Directive 72 implementation plan of **80 percent of the smart meters by 2020** and assumes full roll-out by 2022. The assumption is that the implementation rate will be lower at the beginning due to the necessary learning curve, and then increase gradually thereafter.

Table 13: Implementation pace considered as a starting scenario in the cost benefit analysis

% of meters replaced	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electricity	6%	10%	10%	10%	11%	11%	11%	11%	10%	10%
Gas	6%	10%	10%	10%	11%	11%	11%	11%	10%	10%

To obtain costs associated with the smart metering implementation, a request for information (RFI) was sent to several technology companies within Romania and to several other countries. Potential providers of smart metering equipment were asked to provide average prices for their products. Based on this process, we set costs for major infrastructure elements in the following way:

Component	Value	Unit
Price of single phase smart meter – GPRS module	0,54	['000 RON]
Price of single phase smart meter – PLC module	0,33	['000 RON]
Price of single phase smart meter – WiFi module	0,32	['000 RON]
Price of single phase smart meter – WiMAX module	0,73	['000 RON]
Price of three phase smart meter – GPRS module	0,66	['000 RON]
Price of three phase smart meter – PLC module	0,46	['000 RON]
Price of three phase smart meter – WiFi module	0,69	['000 RON]
Price of three phase smart meter – WiMAX module	1,07	['000 RON]
Average price of a concentrator	2,26	['000 RON]
Average price of a balancing meter	0,64	['000 RON]

Furthermore, we assumed also that prices for the infrastructure elements will slowly decrease as the smart metering technology matures. We found that **average prices of smart metering components will decrease** in first year by -3 percent, by -2 percent in the following three years, and then -1 percent for the next four years. After that, prices will stabilize.

For each of the markets where a monetary quantification of the effects has been made, individual assumptions have been considered:

Electricity sector assumptions:

The following assumptions have been made for the electricity sector:

- **Discount rate** – defined at the level of 7,5%, level regulated by the National Authority for the electricity distributors for the third regulatory period, starting in 2013,

- **Reduction in commercial losses** – an achievable decrease in the level of non-technical losses for low-voltage lines, used for the purpose of the analysis, was set at the level of 60 percent at the end of the implementation period, following different market estimates (pessimistic scenario – 30 percent, realistic scenario – 60 percent and optimistic scenario – 80 percent),

- **Consumption evolution,** as a combination of two elements
    - **Natural evolution of consumption** (as a baseline, without considering any smart meters installed) of 1,6 percent growth per year (only until 2022; after 2023 we considered a stable evolution); information for this assumption was gathered from the questionnaire sent to major market stakeholders,
    - **Changes in consumption as a result of smart metering implementation –** smart meters are expected to support reduction in commercial losses. However, not all discovered commercial losses will affect consumption. We assumed that 50 percent of the discovered losses will be billed; the other 50 percent will come from reduced consumption, since most electricity of this kind is consumed in a very inefficient way,

- **Commercial losses –** were assumed at the level of 7 percent for the low-voltage customers, based on the data gathered from key market players and confirmed with the National Regulator. The level of commercial losses for distributors in Romania is above the average level of commercial losses in EU other countries,

- **Technical losses –** Romania is challenged by a high level of technical losses on the low voltage lines - on average12 percent. Levels of both commercial and technical losses have been confirmed with the National Regulator.

With regards to commercial losses, we have assumed that reduction that comes from the installation of a smart meter will occur in the year after the respective smart meter was installed, by half of the full potential considered (in the normal scenario that is 60%), and in the following year reaching maximum potential. This is because for detecting the possible theft, certain historical data would need to be analyzed, and this is highly unlikely to be possible in the period right after the meter was installed.

In addition to the above assumptions, a few others have been made to account for the major benefits and quantified costs in the analysis. Appendix 2 and 3 describe the deductions used in calculating benefits and costs for the deployment of electricity smart meters.

Gas sector assumptions:

The following assumptions have been made for the gas sector:

- **Discount rate** – defined at current regulated level by the National Authority for the electricity distributors at the level of 8,63% (no figure was made public regarding the level for the next regulatory period),

- **Reduction in commercial losses –** gas market has a lower level of commercial losses relative to the electricity market, but still along the reading cost the reduction in commercial losses could be one of main benefits from implementation of smart metering in gas. In this respect we considered as a realistic drop in the level of non-technical losses for gas to be 60%,

- **Consumption evolution -** is a combination of two elements:
    - **Natural evolution of consumption** (as a baseline, without considering any smart meters installed) 3.3 percent decrease per year (only until 2022; after 2023, we calculated stable progression); information for this assumption was gathered in the questionnaire sent to major market stakeholders,
    - **Changes in consumption resulting from smart metering implementation –** as in the case of electricity, not all discovered commercial losses will affect consumption. We assumed that 50 of discovered losses will be billed, and the other 50 percent will represent reduced consumption, since most gas of this kind is consumed in a very inefficient way,

- **Commercial losses** – estimated at an average market level of 2.5 percent—still higher than the European average value,

- **Technical losses –** for Romania, the gas technical losses were estimated at a level of 1 percent. Levels for both commercial and technical losses have been confirmed as well with the National Regulator.

When it comes to reducing commercial losses, the same assumption was made as in the case of electricity: the reduction will occur and will be observed one year after the respective smart meters were installed, by half of the potential, while in the following year it will reach the full potential considered (in the normal scenario this potential is 60 percent reduction of commercial losses).

Other assumptions are described in the Appendix 4 for benefits and in the Appendix 5 for costs.

Reduction of commercial losses stands as one of the major benefits from smart metering implementation in Romania. Realistically, we have calculated a reduction of 60 percent for the following reasons:

- For electricity, since the level of commercial losses is high (7 percent, which may be even a little bit underestimated in comparison to technical losses), a reduction of 60 percent seems to be realistic. This is especially true since after the installation of the analytical tools, it will be much easier to identify places where commercial losses occur,
- For gas, most commercial losses result from tempering of meters, and such cases are easy to discover with the use of available analytical tools.

The aforementioned potential models considered for this implementation cost-benefit analysis are:

• Model 1—independent infrastructures without middleware,
• Model 2—independent infrastructures with middleware,
• Model 3—common infrastructure without middleware,
• Model 4—common infrastructure with middleware.

From these four models, three main hypotheses were tested:

- **Models without middleware are generally more expensive –** models like 1 or 3 are already seen as more expensive because the communication has to be made directly from each meter directly to the central application,
- **Models with common infrastructure are generally less expensive** – this hypothesis is based on the idea that if different utilities (for example electricity and gas) would use the same communication infrastructure then the overall costs of smart metering deployment, seen from the country perspective, would be lower,
- **Models with middleware can bring more benefits –** the existence of data concentrators and balancing meters is important for the reduction of commercial and technical losses.

Another important assumption that can have a significant impact on the final results of the cost-benefit analysis is the method of calculating **residual value**. We estimated the life span of installed smart metering equipment at 20 years, and after that the investment would need to be renewed. However, given the fact that we install meters gradually until 2022 and that after 2022 we install new meters for replacement, we will still have not depreciated assets from the first investments in years 2033 – 2052. The residual value was therefore calculated as the total value of not fully depreciated assets in year 2033. This method of calculation was confirmed with the national regulator.

7.2 Main assumptions regarding changes in regulations

In performing the analysis, several regulatory aspects were considered for the implementation, and we found that changing the proposed parameters could have a significant impact on the business case results. We considered the following parameters:

- **Discount rate** was considered at the current level of 7,5% for electricity and 8,63% for gas. The current level of discount rates (for electricity and gas sectors) considered for our analysis is regulated, which is however expected to change starting 2013, with a cost of equity being calculated based on a CAPM model. We also think that, given the significant benefits smart metering can bring, an increased WACC could be considered for investments in smart metering,

- **Number of mandatory physical readings** and consumption location check (after smart meters are installed) is currently set at one check per year. However, should smart metering be implemented, the frequency and therefore the cost of manual readings could be reduced,

- **Number of actual readings is on average 4 per year** – however, the regulatory framework can designate more readings per year to acquire the information needed about actual consumption. In that case, the four avoided readings per year could be increased to 12, following full market liberalization of electricity starting in 2018, and of gas starting in 2019. This would severely impact the results of the cost-benefit analysis; therefore, we did not include such an assumption in our calculations. Moreover, there are no reasons to believe that the national regulator would allow for such thing to happen, since it will put a significant amount of pressure on the final customer, who will have to support the increased costs of meter readings.

7.3 Main findings

The cost-benefit analysis indicates that implementation of smart metering in the electricity sector has the potential to be a profitable investment. In the gas sector, however, there is a risk that benefits will not cover all related implementation costs.

The business case for electricity is positive, if the communication infrastructure with middleware layer (data concentrators and balancing meters) is selected. This is confirmed by the hypotheses that states that models without middleware bring less benefits and are actually more expensive. The business case for gas, on the other hand, does not show positive results on average, from the country perspective, regardless of the selected model. Table 14 shows the NPV resulting from the cost-benefit analysis.

Table 14: Net present values from the cost benefit analysis for the analyzed models

		Model 1 Independent communication infrastructure without middleware	Model 2 Independent communication infrastructure with middleware	Model 3 Common communication infrastructure without middleware	Model 4 Common communication infrastructure with middleware
NPV Electricity	['000 RON]	(2.777.525)	1.168.796	(2.777.525)	1.168.796
NPV Gas	['000 RON]	(904.163)	(739.800)	(812.563)	(71.767)

Regarding costs per metering point of the investment (CAPEX), we discovered the results to be in line with those of similar cost-benefit analyses undertaken in other countries with values under 100 euros.

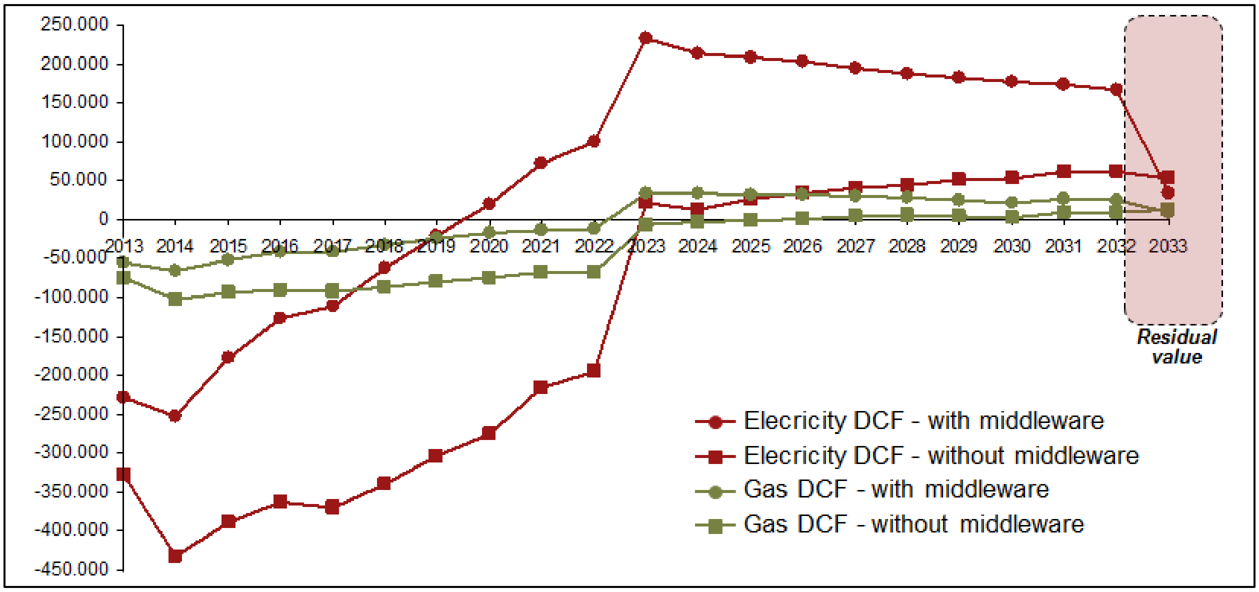
Table 15: Expenditures per metering point for the analyzed models

		Model 1 Independent communication infrastructure without middleware	Model 2 Independent communication infrastructure with middleware	Model 3 Common communication infrastructure without middleware	Model 4 Common communication infrastructure with middleware
Electricity	['000 RON]	0,60	0,43	0,60	0,43
Gas	['000 RON]	0,54	0,54	0,57	0,46

As the above tables depict, business case yields best results in case of model 4 – common communication infrastructure and with the middleware layer (including balancing meters and concentrators).

Figure 19 shows level cash flows over the analyzed time period, presenting an overview on when the incurred benefits repay capital expenditures and operational costs for smart metering implementation.

Figure 19: Evolution of discounted cash-flows for electricity and gas ['000 RON]

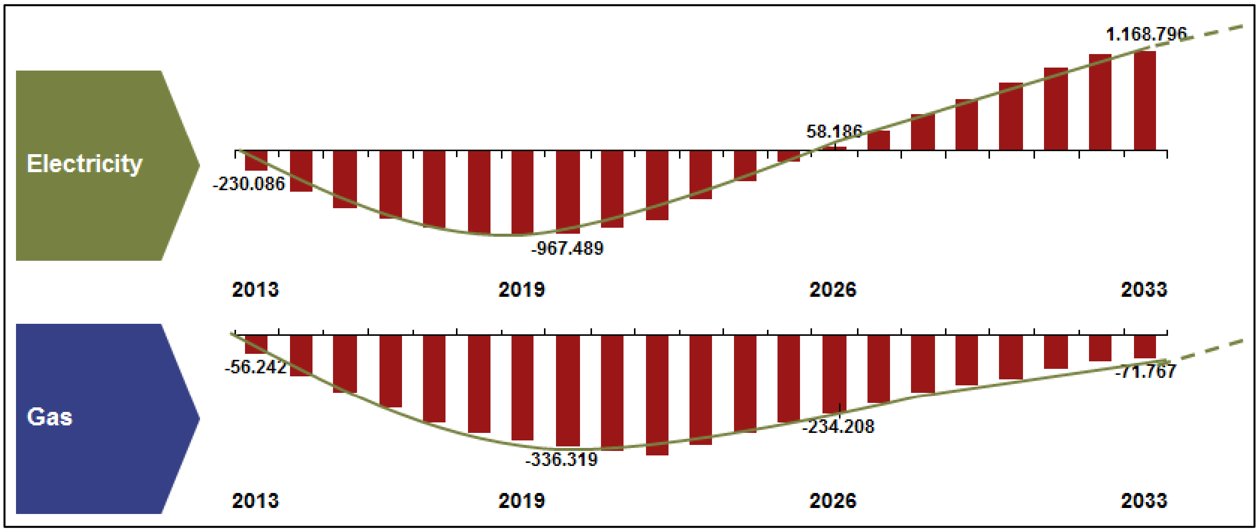


As the figure 19 illustrates, 2020 is when positive cash flow begins for the electricity case. Benefits grow consistently from the first years of implementation, as cash flow constantly increases. After 2023, it decreases slightly. This is due in large part to the fact that, after 2023, the first smart meters installed will need to be legalized, and some of these meters will not pass this legalization, but will need to be replaced instead.

Figure 20 can offer another interpretation of the net present value for electricity and gas business cases, by looking at the cumulated cash-flows over the analyzed period of time.

In case of electricity, we see that the business case turns positive in 2026, while for the gas sector it still remains negative at the end of period. The curve of the cumulated cash-flows in this case can give, however, a sense that the gas business case might return a positive NPV in the years to come after the analyzed period. Moreover, there is an indication that it might be positive if implementation takes a longer time and at a slower pace.

Figure 20: Cumulated cash-flows (incl. residual value), for model 4 [‘000 RON]



7.4 Scenario analysis

In addition to the four infrastructure models, there are other elements that are defined as variables, and their likely impact on the outcome of the analysis was tested. They are:

- Communication channels used for the metering system – the number of meters working through different communication channels (GPRS/PLC/WiFi/WiMax),
- Communication channels used for the middleware system – the number of concentrators communicating through different communication channels (GPRS/PLC/WiMax),
- Discount rates used for utilities companies,
- Level of reduction in commercial losses,
- Option to choose or not the installation of balancing meters,
- The implementation pace (slow versus fast installations).

Figure 21 presents a summary of main assumptions for the implementation approach and reasons for selecting those assumptions.

Figure 21: Different scenarios assessed in the cost benefit analysis

Variable factor	Current level (normal scenario)		Underlying reasons	Impact on NPV
% of meters with integrated communication modules	100%		• Possibility to purchase communication modules separately from meters	Depending on meters and modules costs
% of meters communicating to concentrator via:	GPRS	1%	• Cost of meters is highly dependent on the communication technology used • (numbers from left valid for models with middleware)	
	PLC	99%		
	WiFi	0%		
	WiMAX	0%		
% of concentrators communicating from concentrator to central application:	GPRS	98%	• Cost of concentrators is highly dependent on the communication technology used • (numbers from left valid for models with middleware)	
	Others	2%		
% of sub-stations needing balancing meters/concentrators	100%		• Some transformers do not serve general households/LV customers considered	
Installation of balancing meters or not	Yes		• Without balancing meters, reduction of commercial losses is unlikely to be high	
Average number of manual reading per year before/after prices liberalization[1]	before	4	• An obligation of 12 reads/year after liberalization (since all customers will become eligible) would have a serious impact	
	after	4		
Annual increase in employment costs	4%		• Impact on costs of meter reading and installation	
% of installed meters by 2020	80%		• Recommendation of EC	

We assumed that all meters will be purchased with integrated communication modules. However, the cost-benefit analysis allows for testing results depending on this variable (for example, whether or not a certain percentage of meters will be acquired without communication modules, with the latter to be purchased separately). This is expected to impact not only the cost of the roll out, depending on meter and module purchase prices, but also the complexity of their installation. For this reason, we believe the most viable scenario would be the acquisition of meters with communication modules.

The installation of balancing meters is a very important variable: we recommend balancing meters be a mandatory requirement for the roll out in the electricity market, since their role is crucial in reducing commercial (and technical) losses. Without this device, it is highly unlikely commercial losses will be reduced sufficiently enough to offer a positive business case. Although smart meters need to be able to send alarms to the central application when its integrity is breached, minimizing thefts resulting from meter tampering and losses from illegal connections (or even from home appliances connected separately on the line before the meter was installed) would be hard to detect without balancing meters. The number of balancing meters needed is another factor in our analysis, since not all sub-stations and transformers where these would be installed serve the final customers (households and small commercial customers connected to the low-voltage grid.)

We did not address installation of balancing meters for the gas sector.

The number of manual readings required each year by the regulator after full market liberalization, yet no longer needed (2018 for electricity and 2019 for gas, considering no smart meters would be deployed) can significantly impact the business cases for both electricity and gas. The average number of unnecessary manual readings per year is currently 4 per year. However, avoiding 12 readings per year, once all consumers are eligible, would increase the NPV of the business cases significantly.

Last but not least, we have developed scenarios regarding benefits of the model. We considered three scenarios for the level of reduction in commercial losses, as this is the most important benefit included in our analysis and can have a high impact on the net present value.

Figure 22 briefly describes the three scenarios considered in the analysis, together with the NPV and return on investment (ROI). The results are presented for model 4 – common infrastructure with middleware – as this is seen as the most viable option for the roll out of smart meters in Romania.

Figure 22: Scenarios regarding reduction of commercial losses [‘000 RON]

	Reduction in commercial losses	*Reduction in commercial losses*	*NPV & ROI Electricity ['000 RON]*	*NPV & ROI Gas ['000 RON]*
Scenarios	Pessimistic 30%	In a pessimistic scenario, assuming the implementation is rolled-out properly, the benefits might be grasped only partially	222.459 8,34%	(102.480) -
	Realistic 60%	Based on A.T. Kearney project experience, following smart metering implementation a conservative yet realistic commercial losses reduction by 60% can be achieved	1.169.796 43,8%	(71.767) -
	Optimistic 80%	In an optimistic scenario, should all necessary effort to reduce commercial losses are made throughout the implementation an optimistic 80% reduction in commercial losses can be achieved	1.790.583 67,1%	(51.583) -

The business case for electricity yields positive results, if we take into consideration the three scenarios. Realistic and optimistic scenarios especially show very good return on investments overall (43,8% and 67,1% respectively). They can only be realized, however, under certain conditions when it comes to implementing state-of-the-art tools and processes to manage the reduction of grid losses. The bottom line: with insufficient effort to reduce commercial losses, it could lead to negative NPV for the electricity case.

In In the case of gas metering, the analysis does not show any positive results. This is not, however, to be seen as a “no go” decision from the utilities’ perspective, since the business case can vary widely, depending on each utility’s characteristics and conditions (for example, better purchasing power of smart meters through economies of scale, using leverage at the international level, different structure of losses, different distribution operation costs, and so on). Chances are that a business case calculated from the perspective of a specific company could be positive, especially with the potential of synergies between gas and electricity.

Costs incurred for the development of middleware become the responsibility of the electricity DSOs, as they own the power lines through which communication will be made from meters to data concentrators. The eventual split of these costs between electricity and gas DSOs, or possible recurring charges being imposed from the electricity DSO onto the gas DSO for rent or use of the infrastructure, will not change NPV from the country's perspective (a positive for the electricity DSO, and an expense for the gas DSO, would yield a neutral effect on the analysis).

Finally, for the scenario analysis, the implementation rate remains an important factor. In the normal scenario, we used an implementation rate that would achieve 80 percent coverage of the smart meters for all low-voltage customers and for all households in the gas sector by 2020, as is in line with suggested EC guidelines for the electricity sector. Thereafter, a full implementation would take place by 2022. Different implementation rates, however, can severely impact the business cases for both electricity and gas. While time is a significant factor in experiencing benefits, with capital expenditures occurring upfront, shifting can impact results.

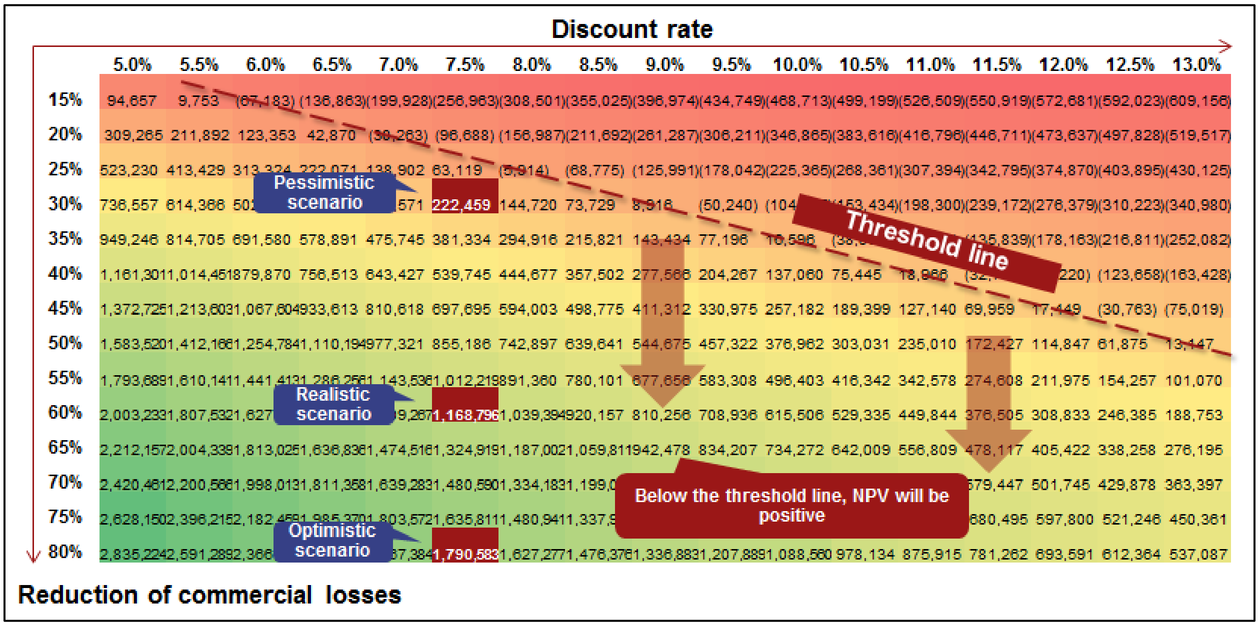
These options for implementation pace are further discussed in the chapter describing the implementation approach and schedule.

7.5 Sensitivity analysis

The two main elements considered as material for the sensitivity analysis were the reduction in commercial losses (on a range from 15 percent to 80 percent) and the weighted average cost of capital (on a range from 5 percent to 13 percent). The outcome of the sensitivity analysis depends on which scenario is analyzed.

It reveals that the trends occur depending on the implementation model selected. Figure 22 presents the result of the sensitivity analysis undertaken for the electricity market, in using implementation model 4: common communication infrastructure with gas and with middleware (as noted previously, this model yields the same results as model 2—independent communication infrastructure with middleware. That's because the analysis made from country's perspective, and the costs incurred with middleware devices are the responsibility of the electricity DSO).

Figure 23: Sensitivity analysis for electricity business case – model 4, with common infrastructure and with middleware ['000 RON]



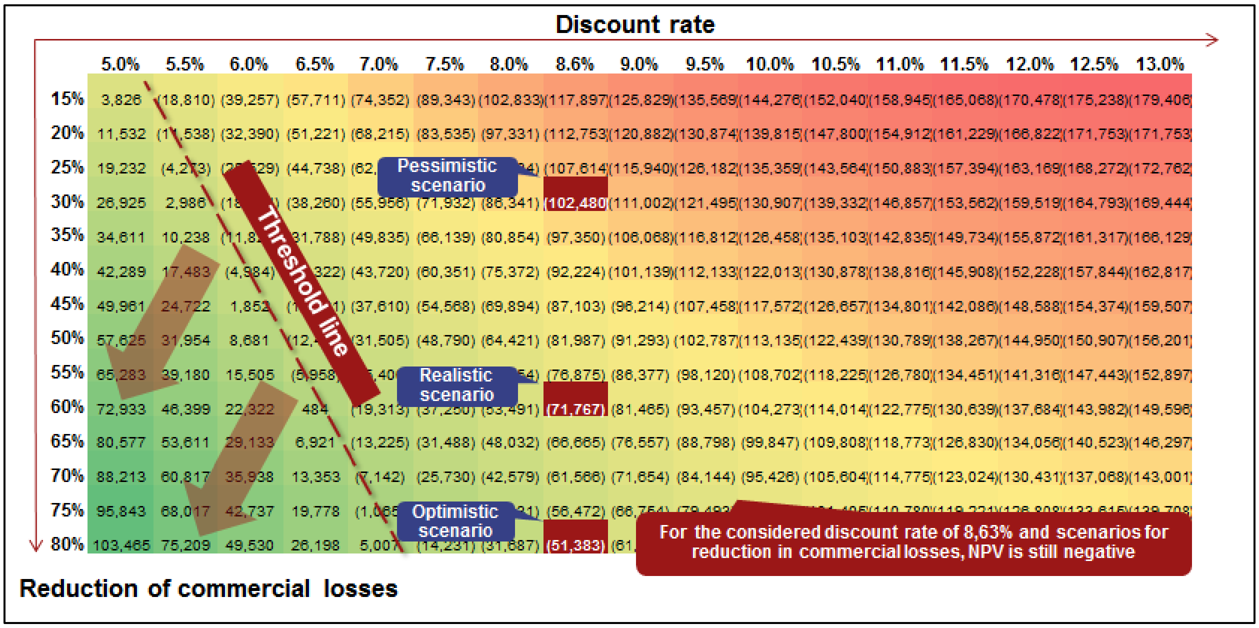
	5.0%	5.5%	6.0%	6.5%	7.0%	7.5%	8.0%	8.5%	9.0%	9.5%	10.0%	10.5%	11.0%	11.5%	12.0%	12.5%	13.0%
15%	94,657	9,753	(67,183)	(136,863)	(199,928)	(256,963)	(308,501)	(355,025)	(396,974)	(434,749)	(468,713)	(499,199)	(526,509)	(550,919)	(572,681)	(592,023)	(609,156)
20%	309,265	211,892	123,353	42,870	(36,263)	(96,688)	(156,987)	(211,692)	(261,287)	(306,211)	(346,865)	(383,616)	(416,796)	(446,711)	(473,637)	(497,828)	(519,517)
25%	523,230	413,429	313,324	222,071	138,902	63,119	(5,914)	(68,775)	(125,991)	(178,042)	(225,365)	(268,361)	(307,394)	(342,795)	(374,870)	(403,895)	(430,125)
30%	736,557	614,366	[illegible]	[illegible]	[illegible]	222,459	144,720	73,729	8,916	(50,240)	[illegible]	(153,434)	(198,300)	(239,172)	(276,379)	(310,223)	(340,980)
35%	949,246	814,705	691,580	578,891	475,745	381,334	294,916	215,821	143,434	77,196	16,596	[illegible]	[illegible]	(135,839)	(178,163)	(216,811)	(252,082)
40%	1,161,301	1,014,451	879,870	756,513	643,427	539,745	444,677	357,502	277,566	204,267	137,060	75,445	18,966	[illegible]	[illegible]	(123,658)	(163,428)
45%	1,372,725	1,213,603	1,067,604	933,613	810,618	697,695	594,003	498,775	411,312	330,975	257,182	189,399	127,140	69,959	17,449	(30,763)	(75,019)
50%	1,583,520	1,412,166	1,254,784	1,110,194	977,321	855,186	742,897	639,641	544,675	457,322	376,962	303,031	235,010	172,427	114,847	61,875	13,447
55%	1,793,689	1,610,141	1,441,413	1,286,256	1,143,536	1,012,219	891,360	780,101	677,656	583,308	496,403	416,342	342,578	274,608	211,975	154,257	101,070
60%	2,003,233	1,807,532	[illegible]	[illegible]	[illegible]	1,168,796	1,039,394	920,157	810,256	708,936	615,506	529,335	449,844	376,505	308,833	246,385	188,753
65%	2,212,157	2,004,339	1,813,025	1,636,836	1,474,516	1,324,919	1,187,002	1,059,811	942,478	834,207	734,272	642,009	556,809	478,117	405,422	338,258	276,195
70%	2,420,461	2,200,566	1,998,013	1,811,358	1,639,283	1,480,590	1,334,183	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	501,745	429,878	363,397
75%	2,628,150	2,396,215	[illegible]	[illegible]	1,803,572	1,635,811	1,480,941	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	680,495	597,800	521,246	450,361
80%	2,835,224	2,591,289	[illegible]	[illegible]	[illegible]	1,790,583	1,627,277	1,476,376	1,336,883	1,207,889	1,088,560	978,134	875,915	781,262	693,591	612,364	537,087

As figure 23 describes, there is a certain threshold, under which the business case returns positive results. If smart metering is deployed without middleware, ensuring communication from the meter directly to the central application through GPRS, the analysis shows that NPV is negative, regardless of the level of reduced commercial losses (using a discount rate of 7,5 percent).

For the gas business case, using the model with common infrastructure and middleware devices installed, the net present value of the investment is negative. Due to low levels of commercial and technical losses when compared to electricity, the results remains negative regardless of the losses reduction level or the discount rate considered in this sensitivity analysis. Similar to electricity case, using a different model with independent infrastructure or communication without any middleware layer, the results are lower than in best case of model 4.

Figure 24 presents the sensitivity analysis for the gas smart meters deployment under model 4.

Figure 24: Sensitivity analysis for gas business case – model with common infrastructure and with middleware ['000 RON]



	5.0%	5.5%	6.0%	6.5%	7.0%	7.5%	8.0%	8.6%	9.0%	9.5%	10.0%	10.5%	11.0%	11.5%	12.0%	12.5%	13.0%
15%	3,826	(18,810)	(39,257)	(57,711)	(74,352)	(89,343)	(102,833)	(117,897)	(125,829)	(135,569)	(144,276)	(152,040)	(158,945)	(165,068)	(170,478)	(175,238)	(179,406)
20%	11,532	[illegible]	(32,390)	(51,221)	(68,215)	(83,535)	(97,331)	(112,753)	(120,882)	(130,874)	(139,815)	(147,800)	(154,912)	(161,229)	(166,822)	(171,753)	(171,753)
25%	19,232	(4,273)	[illegible]	(44,738)	[illegible]	[illegible]	[illegible]	(107,614)	(115,940)	(126,182)	(135,359)	(143,564)	(150,883)	(157,394)	(163,169)	(168,272)	(172,762)
30%	26,925	2,986	[illegible]	(38,260)	(55,956)	(71,932)	(86,341)	(102,480)	(111,002)	(121,495)	(130,907)	(139,332)	(146,857)	(153,562)	(159,519)	(164,793)	(169,444)
35%	34,611	10,238	[illegible]	[illegible]	(49,835)	(66,139)	(80,854)	(97,350)	(106,068)	(116,812)	(126,458)	(135,103)	(142,835)	(149,734)	(155,872)	(161,317)	(166,129)
40%	42,289	17,483	(4,984)	[illegible]	(43,720)	(60,351)	(75,372)	(92,224)	(101,139)	(112,133)	(122,013)	(130,878)	(138,816)	(145,908)	(152,228)	(157,844)	(162,817)
45%	49,961	24,722	1,852	[illegible]	(37,610)	(54,568)	(69,894)	(87,103)	(96,214)	(107,458)	(117,572)	(126,657)	(134,801)	(142,086)	(148,588)	(154,374)	(159,507)
50%	57,625	31,954	8,681	[illegible]	(31,505)	(48,790)	(64,421)	(81,987)	(91,293)	(102,787)	(113,135)	(122,439)	(130,789)	(138,267)	(144,950)	(150,907)	(156,201)
55%	65,283	39,180	15,505	(5,958)	[illegible]	[illegible]	[illegible]	(76,875)	(86,377)	(98,120)	(108,702)	(118,225)	(126,780)	(134,451)	(141,316)	(147,443)	(152,897)
60%	72,933	46,399	22,322	484	(19,313)	[illegible]	[illegible]	(71,767)	(81,465)	(93,457)	(104,273)	(114,014)	(122,775)	(130,639)	(137,684)	(143,982)	(149,596)
65%	80,577	53,611	29,133	6,921	(13,225)	(31,488)	(48,032)	(66,665)	(76,557)	(88,798)	(99,847)	(109,808)	(118,773)	(126,830)	(134,056)	(140,523)	(146,297)
70%	88,213	60,817	35,938	13,353	(7,142)	(25,730)	(42,579)	(61,566)	(71,654)	(84,144)	(95,426)	(105,604)	(114,775)	(123,024)	(130,431)	(137,068)	(143,001)
75%	95,843	68,017	42,737	19,778	[illegible]	[illegible]	[illegible]	(56,472)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
80%	103,465	75,209	49,530	26,198	5,007	(14,231)	(31,687)	(51,383)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

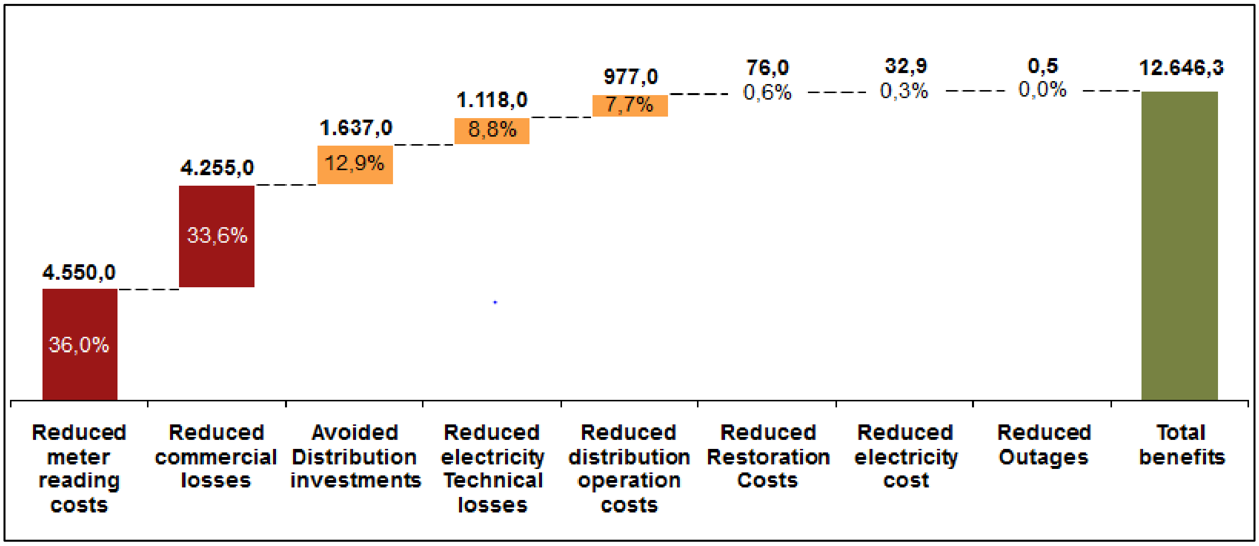
The sensitivity analysis for the gas sector, for model 4, reveals that only for very low discount rates, combined with a high reduction achieved in commercial losses, the analysis would turn positive results. While sustained and disciplined effort can be taken to reduce commercial losses, discount rate is an external factor in a business case like this. Therefore, the analysis might show positive results, under certain conditions, but changing other varyinf factors, as we will see in chapter 8 – Recommended model for Romania.

7.6 Expected impact on electricity and gas

The cost-benefit analysis for Romania indicates that, for the electricity sector, implementation of smart metering is beneficial for the society as a whole, under certain considerations and conditions.

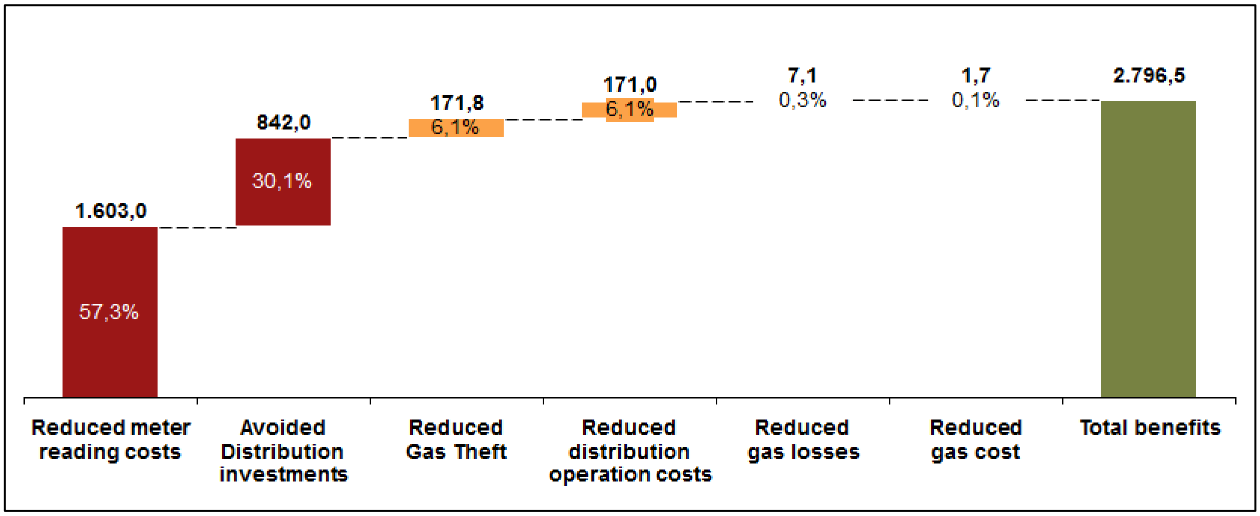
The biggest impact brought by smart meters in this market is the reduction of meter reading costs and commercial losses. Figure 25 below shows the total benefits calculated for the electricity market, by category, over the analyzed period of time.

Figure 25: Total benefits by category for the electricity market [Mln RON]



In the case of gas deployment, the biggest impact comes from the reduced meter reading costs and the avoided investments in replacing the traditional meters (see figure 26).

Figure 26: Total benefits by category for the gas market ['000 RON]



On top of the benefits quantified in our cost-benefit analysis, there are also a number of other benefits realized indirectly for the market as a whole. These benefits are described qualitatively in Chapter 5, and play an important role in understanding the overall impact of smart metering roll out for all markets analyzed.

7.7 Other quantified benefits

In addition to the benefits calculated above, there are a number of other benefits that smart metering can bring, which we addressed from a qualitative point of view.

Two major qualitative benefits can be quantified without being monetized (and without being included in the cost-benefit analysis). These major benefits are:

- Reduction of CO_2 (and other greenhouse gases),
- Energy efficiency improvement – reduction of overall energy consumption.

Energy efficiency improvement

In the case of electricity market, we expect that the introduction of smart metering will make the consumers much more aware of their consumption behavior, leading to a decrease in electricity consumption and consumption profile smoothing.

Experience in other markets, as described in Chapter 2, has shown that smart meter deployment can help save electricity by modifying consumer consumption behavior. As for putting a number on this reduction for Romanian consumers, compared to the baseline in which no smart meters are installed, we can predict a conservative average based on limited results from studies and pilot projects done in other markets (the average reduction in consumption was minimal—we did not include in this average the reduction registered in Denmark, as this Nordic country has very different characteristics compared to Romania. However, the value is shown here for comparison purposes, arguing that the final average considered for Romania is possible).

Table 16: Electricity consumption reduction – examples from other markets and average for Romania

	Electricity consumption reduction	
Country	**min**	**max**
Ireland	**2.5%**	9.4%
UK	**2.8%**	10%
US	**4%**	6%
Canada	**6%**	
Denmark	17%	
Average	**3,825%**	

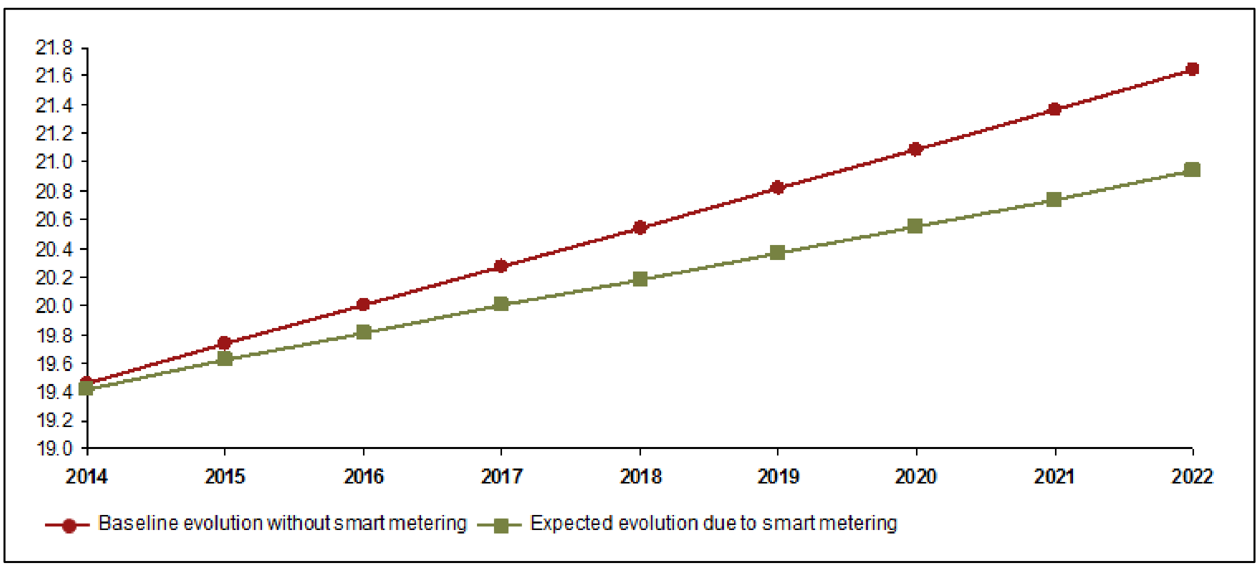
A reduction of 3,825% of electricity consumption, compared to baseline where no smart meters would be deployed, would occur gradually over time, as smart metering is progressively installed. In the normal scenario, the target percentage would finally be achieved in 2022, when 100 percent of smart meters would be fully introduced to all low-voltage customers.

Reduction in electricity consumption has to be interpreted with caution. To achieve this energy efficiency enhancement, other investments will have to be made, such as installation of in-home displays, especially for customers with above-average invoice values. The creation of Internet portals for consumers would also be necessary, from which they could access and analyze their consumption behavior. In addition, suppliers would need to educate consumers about their consumption behavior, and instruct them as to how they can optimize their energy use.

By considering a total reduction in electricity consumption of 3,825%, the amount of electricity saved by the end of 2022, when full implementation is considered to be finished, would be about 3,4 TWh (and 826.000 MWh on average per year after year 2022). This value is revealed starting from a consumption of 18,85 million MWh per year in 2011 and considering all other assumptions included in the cost benefit analysis and described in previous sub-chapters: 1,6 percent growth of consumption in the baseline and a total 2,1 percent reduction as a result of commercial losses reduction.

Figure 27 shows the expected evolution of consumption, estimating a 3,825% reduction by 2022, compared to the baseline (no smart meters to be deployed). After year 2022, we predict both evolutions to be constant, as smart metering is already deployed 100 percent.

Figure 27: Evolution of electricity consumption – baseline and due to smart metering [mln MWh]



In the case of the smart metering deployment in the gas market, the analysis is similar to the one above, with the expected impact to also be similar—a reduction in gas consumption due to increased customer awareness of consumption behavior.

Although there are significantly less pilot or deployment projects in the gas sector than in the electricity sector, we consider an incremental reduction of 2,2 percent in total gas consumption to be conservative. This is based on a cost-benefit analysis undertaken by the Commission for Energy Regulation in Ireland (CER).

With a reduction at the level of 2,2% by 2022, total gas consumption saved is expected to amount to about 2,2 TWh (and about 461.000 MWh on average per year after year 2022).

Reduction of CO_2 emissions

One of the biggest non-monetary impacts for the society as a whole from introduction of smart metering is reduction of CO_2 emissions.

In case of electricity, reduction of CO_2 emissions comes from two major areas:

- Reduction of losses (commercial and technical),
- Energy efficiency improvement.

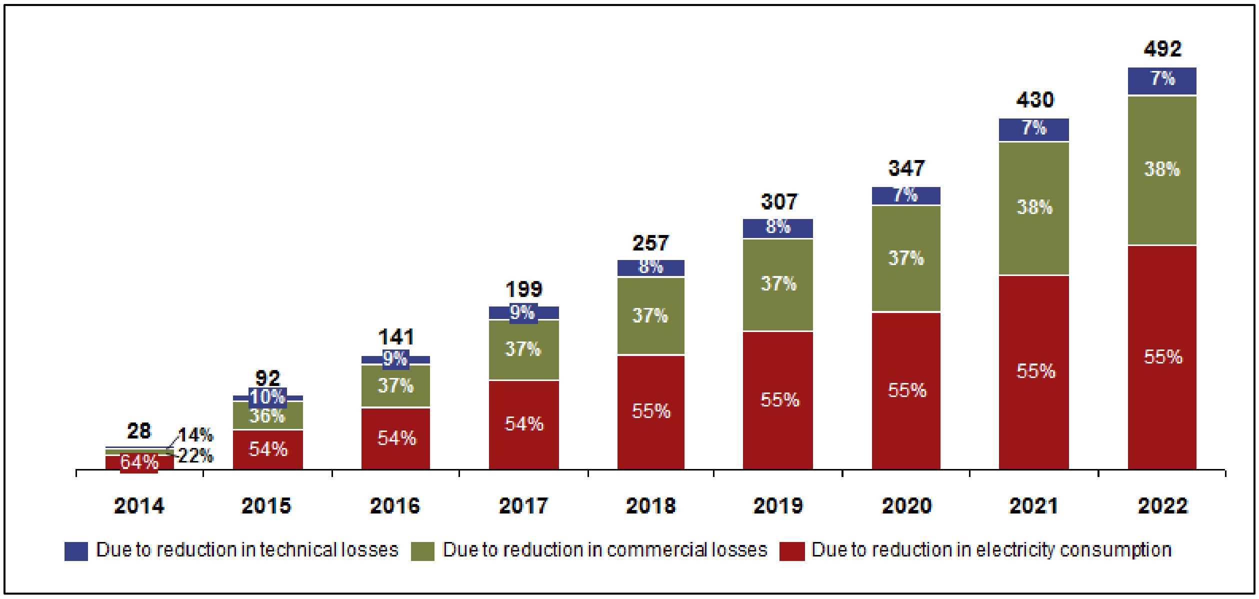
In both cases, less final electricity consumed means less electricity produced and hence lower emissions of CO_2. In case of electricity it is also possible to account for the reduction in SO_2. To quantify these emissions and better understand the amount saved from being released into the atmosphere, we used the ESRI/EPA ISus model emission factors for calculating tons of CO_2 and SO_2 per each MWh.

Table 17: CO_2 and SO_2 emission factors for electricity

t CO_2/MWh	t SO_2/MWh
0.402	0.000685
0.406	0.000659
0.384	0.000633
0.389	0.000608
0.381	0.000584
0.365	0.000560
0.344	0.000537
0.364	0.000515
0.366	0.000493

Given the above emission factors considered for tone of CO_2 and SO_2 per 1MWh and the reductions in commercial and technical losses considered in the cost benefit analysis, we estimate that by end of 2022, when smart metering is fully deployed, a total of 491.763 tons of CO_2 and 662 tons of SO_2 will be kept from entering the atmosphere. Figure 28 presents the cumulated reduction in CO_2 emissions by source, showing that the biggest role in reducing CO_2 emissions is played by the reduction in commercial losses, as expected.

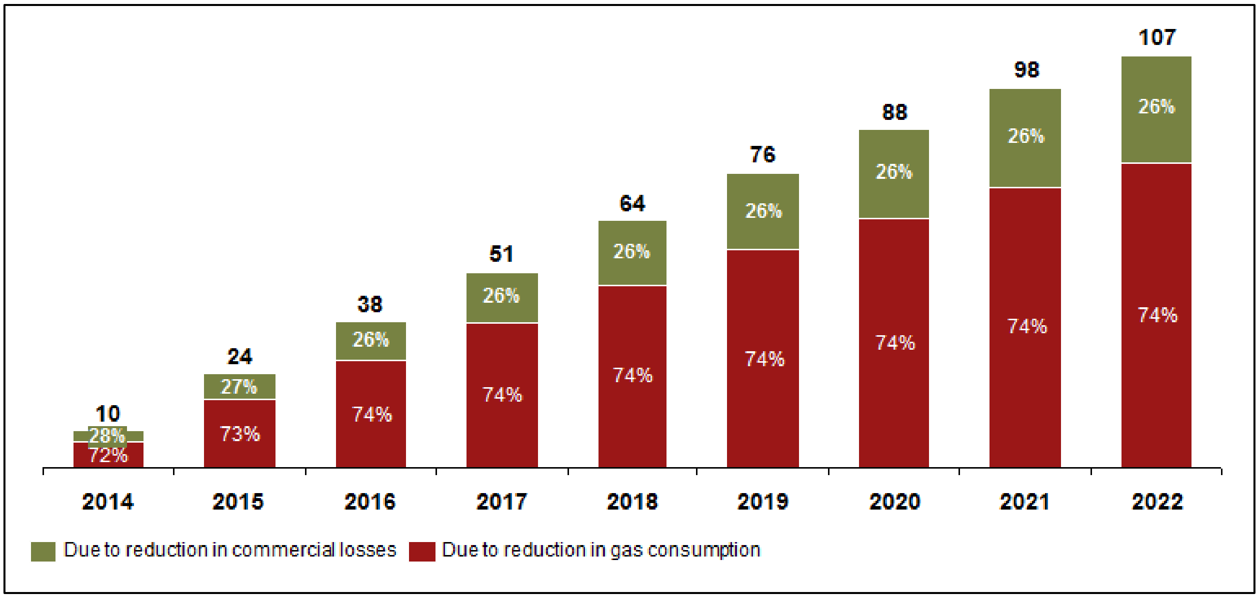
Figure 28: Cumulated reduction of CO_2 emissions due to smart metering in electricity ['000 t CO_2]



Regarding the reduction of CO_2 emissions coming from cutback in commercial losses, we have reasoned that 50 percent of the discovered commercial losses will still be consumed after detection.

In the gas market, the reduction of CO_2 emissions due to smart meters introduction happens in a similar way, mainly from reduction of gas consumption and commercial losses. Acknowledging the CO_2 emissions intensity factor for natural gas of 0,19 kg of CO_2 / kWh (as indicated by CarbonTrust.co.uk conversion factors), the total amount of CO_2 saved by the end of 2022 would be 106.671 tons. Figure 28 shows the cumulative reduction of CO_2 due to smart metering introduction.

Figure 29: Cumulated reduction of CO_2 emissions due to smart metering in gas ['000 t CO_2]



We assumed that half of the illegal gas consumption will still be consumed and invoiced after commercial losses are discovered.

7.8 Expected impact on heat

Current heat market in Romania is very fragmented, with numerous central district heating companies operating in different counties around the country.

We believe that the introduction of smart meters at this point would not bring any net economic benefits for the market, based on the following few arguments:

- Due to the economic downturn in 2009, the state budget could no longer support the district heating systems. Numerous companies in the sector were unable to pay back their loans and finance the minimum investments needed for the operation of their systems. The financial situation of these companies depends on the type of fuel they use—natural gas or coal, the latter being more expensive —the use of cogeneration, the income level of customers in the area served by each company, and the state of the grid. The grids in the majority of companies are in very poor condition, the modernization of which should be an investment priority.
- Designed during the communist regime to support massive industrial production, old infrastructure and grid overcapacity has led to high technical losses. Modification of the grid is another important investment priority.
- District heating is an extremely price-sensitive market, unlike electricity and gas, where the demand is more static. This market is in direct competition with other forms of heating systems, such as gas, oil boilers, and renewable sources. That

makes any form of cost recovery through tariffs almost impossible, as any sensible increase in tariffs would make DH companies lose clients. Moreover, delays in payments, subsidies, and aids from the government put added pressure on the finance balance of these district heating companies.

- The meters in district heating companies are usually installed at the entrance to the pipe in the condominium. This is the only consumption point of interest for the company at the moment. From there, the inhabitants may share the costs by using submeters, installed in each apartment (but not all buildings have adopted this). This hinders the installation of smart meters in two ways:
    - The need for two-way communication is low, since remote disconnection of an entire condominium building in the even that inhabitants don't pay their share, would have a tremendous social impact. Usually companies avoid disconnecting an entire building, doing it only in extreme cases. This also helps them avoid the cost of deploying employees to disconnect and reconnect the building,
    - The installation of smart heat meters in each apartment of the building would be a tremendous investment for any company, and the benefits would not offset the cost.

What we see as a potential solution for the heat market, more viable than installation of smart meters is the **deployment of submetering**. Submetering roll-out, for blocks of flats, where heat comes from the central heating systems, is expected to bring major benefits compared to current situation, such as:

- Accurate measurement of consumption based on the actual heat used and split between different consumers, hence accurate billing and fewer consumers complaints,
- Better control of heat consumption and optimization of energy use, since part of heat may be wasted at consumer premises – simple submetering can enable a more systematic control of the heat supply in times when client does not need it, compared to continuous consumption as in present,
- As a result of the above benefit, an overall reduction in heat consumption is expected, as consumers will become more aware of their energy use (as an example, following mandatory roll out of submetering for water usage, average consumption decreased by approximately 70 percent. Consumers minimized their usage, as invoices became based on actual data, rather than estimation for the entire building.

Submetering can be done with simple traditional meters. However, in more advanced cases, depending on market conditions, submeters can have smart functions (as described in Chapter 5). In this case, we would recommend that smart submeters be connected to the electricity smart metering infrastructure, and from there the information could be sent to the central application. This option would optimize investment costs.

7.9 Possibilities to improve the business case

Looking at the analysis, it could be significantly improved if we consider the following triggers:

- **Outsourcing of the metering function and realization of the investment by an external party** (an external investor can be considered, such as a smart metering equipment supplier). This will not only help handle the investments in the system, but also the operations. The general rule is that when operations are outsourced, better monetary conditions may be achieved. Moreover, having one company dealing with several investments would provide improved operations from the market stakeholders' point of view. As contractors, they can take certain quality standards into their own hands, without having to deal with the implementation. Finally, this option could be viable, since all the CAPEX is going to be shouldered by third parties, while the DSOs would be a stable operational expenditure for rendered services once the infrastructure is put in place. Consequently, this option might have an even larger positive impact over the business if a company with greater purchasing power in other markets comes into play.

- **Realization of synergies within capital groups.** Several utilities in Romania have their parent companies outside of Romania. For cases, where parent companies have experience with smart metering additional synergies can be realized. For example, operators present in Romania that are already doing smart metering implementation in other countries might benefit additional economies of scale and might manage to receive better prices for the smart metering infrastructure than the ones assumed in our analysis. Another example would be operators that have the opportunity to implement the smart metering in parallel for their electricity and gas business, benefiting from additional synergies (for example lower installation cost).

7.10 Best practices in reduction of grid losses

As we have previously discussed under the scenario and sensitivity analysis performed in this model, a key success factor to the results of smart metering business case is the level of reduction in commercial losses.

For companies it will become a must to ensure they are making all necessary efforts to set-up new processes, plans and actions to maximize the reduction of losses in parallel with smart metering deployment. These efforts will allow them to grasp on the full benefits from smart meters roll-out and obtain a return on investment even higher, as they will maximize the percentage of reduction.

Best practices in the area of grid losses reduction recommend few efforts that corporate players investing in smart metering systems should focus on, efforts that can be grouped in three areas:

- **Data analytics (including logical algorithms)**: revision of the algorithms used to process the new amount of data; revision of the models used for calculating split between technical and commercial losses and by voltage level; analysis of the IT tools used to support energy balance calculations, in the current set-up and when smart meters will be in place and the volume of data from the meters will increase tremendously,

- **Processes (discovery and dealing with reduction)**: standardization of processes, minimization of manual work (accurate definition when and how it is needed); review of interfaces and interactions between departments and overall meter-to-cash process to identify areas of improvement,

- **Litigation support**: definition of accurate and standard methodologies on how to use data and findings from smart metering analysis in litigation, with the purpose of fast and favorable closing all cases.

8. Recommended smart metering model for Romania

8.1 Recommended model

Based on the draft results of the CBA conducted so far, our recommendation can be summarized as follows:

For electricity market:

- The most beneficial model is either model 2 or model 4, models that include middleware layer (data concentrators and balancing meters),
- PLC technology is recommended for communication between meters and data concentrators. We expect that in some cases (about 1 percent) communication from meters will be made through other channels, as PLC might not work properly if there is too much interference. Communication from concentrators can be done via various communication channels.

For the gas market:

- The most reasonable model seems to be model 4, with common communication infrastructure and middleware layer. In middleware layer, however, the balancing meter will serve for its purpose only to the electricity distributor,
- It is recommended to provide communication from gas meters to electricity smart metering infrastructure through various methods, such as M-Bus, WiFi, Radio,
- Gas data can be transmitted by the electricity metering infrastructure, together with electricity consumption data being sent to data concentrators, and then to the central application of an electricity distributor or directly to the central application of a gas distributor. It depends on the technology chosen and market stakeholder preferences. Data regarding gas consumption can be sent from the electricity central application to the gas central application. Any option is valid and viable. However, in the first case, different challenges might appear between the two value chains, and may also make one vulnerable to the other's technical integrity.

The implementation for gas has to be treated carefully, however. As the first findings of this report suggest, none of the models analyzed shows a positive NPV for gas roll out, given our assumptions. This result has to be interpreted on average and from a country-specific perspective. Depending on purchasing power, the possibility of achieving economies of scale by leveraging international scale of the group, and commercial and technical losses, the result may be different for each gas distributor and should be treated separately.

8.2 Customer segments to be covered

The electricity market cost-benefit analysis has taken into consideration the implementation of smart meters for all low-voltage customers (mainly households, but also small and medium commercial customers). We did not make any distinction between different segments of customers with regards to amount of consumption, small industrial versus households, or regional coverage due to a major reason related to reduction of grid losses. In order to fully realize this benefit, energy must be balanced between all consumers. Our recommendation is to supply areas of low consumption with smart meters, since only in this way will distributors be able to make a detailed analysis and better identify grid losses.

Regarding other clients, such as commercial consumers on medium voltage or big industrial consumers on high-voltage lines, they already have advanced metering equipment installed by distributors, or installation is in progress for the near future.

With regards to clients who have already installed advanced metering infrastructure, as some pilot projects have already been undertaken in the market, we did not make any distinction between them and normal consumers in our analysis because our minimum functional requirements refer to AMI meters, and the current AMR meters do not fulfill our requirements. An upgrade of currently installed AMR meters is difficult, since the AMR and AMI meters have different technical characteristics (the difference is not only in the communication module). Also, from our meetings with distributors, we understand that some advanced meter reading systems were actually installed simply by adding a communication module to existing traditional meters. This led to a need for their replacement when installation of smart metering began.

As a result, the CBA is highly sensitive when it comes to the reduction of losses (both in percentage and absolute value). It is possible, however, that an analysis of different regions in the country might lead to different results, as there are regions in Romania where commercial losses are much higher than in other regions.

For gas, the cost-benefit analysis considered implementation for all household consumers. Although preliminary findings do not show positive results in the gas sector, further segmentation of the target customers could lead to different results, depending on considerations already made in the report.

8.3 Implementation approach and schedule

Implementation approach will have a significant impact on the feasibility and profitability of smart metering. First, it is important to locate relevant piloting areas, to verify assumptions and to create an overview of the expected impact that full implementation might have. Second, the area to be covered through smart metering implementation should generally start with these areas, so that the implementation cost can be optimized. Testing of the communication technologies to be used under different conditions also needs to be included in pilot projects.

There are different strategies that could be considered when deploying smart meters and middleware:

- One potential strategy could be to install the middleware in all areas first, including the concentrators and the balancing meters, and then replacing the meters,
- Another strategy could be to install middleware equipment and meters simultaneously, substation by substation. This localization and legalization approach assumes the installation will start with the greatest number of meters to be legalized (replaced), with no regards to the location, and to continue mass installation until full coverage of the chosen area is completed, regardless of the meter legalization period. Working traditional meters, which have a long legalization period, would be reinstalled, where smart meters implementation would be conducted later. Other meters will be scrapped.

When designing the implementation approach, things such as risk management, to-be organization, change management, and key success factors need to be considered. Continuous monitoring of the project status and state-of-the-art project management methodology are necessary to ensure a successful roll out.

The implementation schedule is another major factor in the smart metering business case, especially when calculating the correct amount of time and effort needed to have a successful roll out in terms of installation, project management, and other teams. Since the results of the analysis are highly sensitive to these factors, for the purpose of this report, we analyzed different implementation scenarios for both electricity and gas.

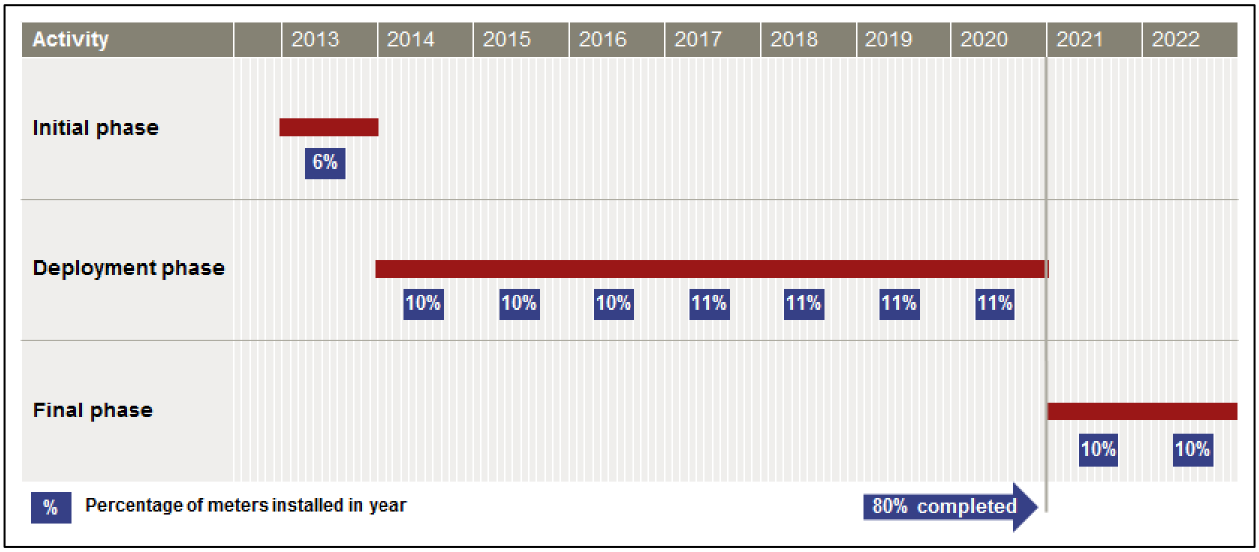
1. Implementation schedule for the electricity sector:

For the electricity sector there are three different scenarios that were tested:

- A “balanced implementation” with a relatively linear yearly evolution targeting 80 percent smart metering implementation by 2020 and full roll-out by 2022,
- An “accelerated implementation” pace aiming at full roll-out in 5 years’ time, by 2017,
- An “exponential implementation”, with a lower number of meters replaced during the first years to allow for companies to adjust, plan and learn from the implementation, and then a gradual increase to finalize the full roll-out by 2022 as in the balance implementation scenario.

The **balanced implementation** scenario, the most feasible at this point, assumes a target of 80 percent replacement of traditional meters by 2020 (as requested by European Commission to be evaluated for electricity market), following a full-completion by 2022, at the pace indicated on figure 30.

Figure 30: Implementation schedule for the balanced scenario



During the first year of implementation, due to the learning curve and necessary pilot projects, we assumed an installation rate of 6 percent. Following this period, an increased number of meters could be replaced, as the learning curve steepens and distributors become more experienced in installing smart meters. Additionally, resources participating in the implementation process are assumed to be trained and ready to proceed with implementation at full speed.

Under the current proposed balanced implementation scenario for electricity, based on the assumptions stated in previous chapters this approach is leading to a positive NPV of amounting to 1.168 mln RON for model 4.

Accelerated implementation, the second scenario considered in the project, is assuming a more aggressive implementation pace, targeting a 100 percent smart meters installation by 2017, as indicated below:

% of smart meters	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electricity	8%	20%	22%	25%	25%	0%	0%	0%	0%	0%

The analysis indicates that, due to the accelerated negative impact at the beginning of the considered timeline, the NPV for the analyzed period is lower, with an average value of 823 mln RON. Moreover, this scenario would be also difficult to realize, given potential constraints of skilled resources for installation and management of smart metering infrastructure.

In the **final scenario, an "exponential implementation"**, we assume that in the first years only a low percentage of the meters will be replaced with smart ones, scenario for which some companies, especially with limited experience in smart metering pilot projects, might choose to adopt.

% of smart meters	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electricity	3%	5%	7%	9%	10%	11%	15%	20%	10%	10%

The results in the scenario show however a similar results to the normal scenario, leading to a net present value of the investment of around 1.113 mln RON. The small difference can be explained by the fact that the implementation is supposed to finalized in 2022, the same as in the initial scheduled considered, with 80% of meters being deployed before 2020 as European Union requests.

The benefits of adopting such an exponential implementation pace come from two sides:

- The opportunity to test different options and implementation models, at the beginning, and make necessary adjustments to initial approach,
- The opportunity to allow time for obtaining non-refundable funds to finance the investments, such as funds from the EU.

2. Implementation schedule for the gas sector

As indicated in previous chapters the gas business case results, considering a balanced implementation pace is not yielding positive impact for the gas industry. Given this results, several other gas roll-out scenarios have been tested in order to identify the implementation pace at which the gas smart metering implementation would become an attractive option from the country perspective. Consequently we tested the following scenarios:

- The **balanced implementation** scenario takes into consideration a gas roll out that runs parallel with that of electricity, and targets an 80 percent replacement of traditional meters by 2020 (no imposed deadline by the EC exists), with complete installation by 2022. The biggest benefits from smart metering are derived from reduced meter reading costs and reduced commercial losses. But since losses for gas are at a much lower level than electricity, benefits do not outpace the investments needed. Thus, at this implementation pace, the business case would yield a negative result of -72 mln RON, as presented in the previous chapters.

- **Accelerated implementation plan** was tested as well, assuming an implementation phase covering a period of only five years, with full roll-out assumed until 2017, as indicated below.

% of smart meters	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gas	8%	20%	22%	25%	25%	0%	0%	0%	0%	0%

The analysis indicates that because of the accelerated negative impact at the beginning of the considered timeline, the NPV for the analyzed period is negative with an average value of -176 mln RON, being even lower than in the balanced scenario. We learn from this that in the case of gas market, smart metering business case might improve by actually slowing down the implementation pace. Therefore, we have analyzed the final scenario:

- **A mild scenario** was considered to test results for the situation in which gas smart meters would be installed in a period much longer than the one for electricity meters.

% of smart meters	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gas	0%	5%	5%	5%	5%	5%	5%	10%	10%	10%	10%	15%	15%

The mild scenario is covering a period of implementation between 2014 and 2025, with a progressive implementation pace that will start one year after the start of electricity roll-out. In this approach, gas operators could leverage better experience and infrastructure built in the electricity sector. Based on these assumptions, the result of the analysis for gas improves significantly, leading to a slightly positive net present value of 14 mln RON.

We consider that opting for a mild implementation such as this one, combined with specific characteristics of the gas distributors (for example purchasing power leading to decreased purchasing cost of smart meters, or specific customer base specifics), could actually turn the business case positive for companies. In addition to that, this mild scenario could be seen as an even more viable option, in case the electricity DSOs decide to go for the exponential implementation pace.

9. Regulatory requirements

Analysis shows that investments in Romanian electricity smart metering can be profitable (with the risks and the considerations included in this report), and in gas, the final profitability will depend on the purchasing power of utilities and the implementation rate. But, there is a significant risk that the profitability could be negative.

Therefore, investments in an electricity smart grid should be incentivized to bring benefits to several energy market stakeholders, and also to the society as a whole. The target set by EC for an 80 percent completion of implementation should be considered for Romania, which needs to have supporting regulations put in place.

Given the uncertain profitability for gas smart metering, it is recommended that there should not be a deadline for implementation. However, investments should be incentivized. Such investments should be made so that corporate synergies are leveraged, and the implementation rate is adjusted to approaches with optimal cost structures.

The distribution of benefits will depend to a large extent on what final laws the regulator is required to enact to ensure a fair distribution of benefits. The most important thing to keep in mind is the proper ROI for investors (distributors). Such investments may bring benefits to distributors, but they should also have the chance to help maintain tariffs. Society will realize other benefits, such as lower electrical bills and lower CO_2 emissions.

In order to incentivize distributors to invest in smart metering, we recommend changes in three major areas:

- Energy regulations,
- Data security regulation,
- Metrology law.

9.1 Changes in energy regulatory framework

A general framework description for seeking smart metering investments is important in Romania. This formal description should cover three main areas regarding the roll out of smart metering:

1. Definition and rules regarding the implementation approach,
2. Impact on regulated revenues,
3. Reporting of project progress.

1. **Rules regarding the implementation approach** should be outlined, covering the complete formal and technical definition of the minimum functionalities that smart meters have to meet. Minimum functional requirements have to be specific in terms of:

- **Performance requirements**: frequency of meter reading and transmission of information from different layers of the system, period of data storage, etc.,
- **Metering functions**: minimal requirements to be met by meters installed on the balancing nodes and at end-user premises, requirements related to communication with HAN devices, reactive energy measurement and other quality indicators, information about prices to be sent to customers at a decided time interval (e.g.: hourly), etc.,
- **Reporting and information functions**: provision of data to the DSO and end-users, control messages delivery to meters and their occurrence intervals, etc.,
- **Technical properties**: security, scalability and standards used, availability of the collected data to the external systems (including systems of other entities) at least at the level of 95%, meters installed at customers premises to have an USB port to be connected with HAN devices in the near future, **open communication protocols** to allow integration of other types of meters (e.g.: gas), etc.

Second, the recommendations towards the implementation models should be also defined, including:

- **General recommendations**: interoperability of the systems and expectations towards DSOs,
- **The approach to contracting vendors**: DSOs must have possibility of diversification with different suppliers, however respecting the general recommendation/obligation of interoperability of systems, DSOs can use their own resources and assets to implement parts of the system, infrastructure providers must provide sufficient documentation so that DSOs can implement communication protocols independently, source code of the application must be provided to the DSO, etc.,
- **Terms of delivery**: with regards to requirements towards suppliers,
- **Prioritization of areas of deployment**: guidelines on how to choose in which areas of the network system should smart meters be deployed first (e.g.: areas with high level of losses, areas with high number of meters legalizations, areas with high level of SAIDI and SAIFI, areas with high number of new connections).

2. Impact on regulated revenues

Regulators will need to set forth clear principles for including costs in the distribution tariffs, and the extent of this inclusion, covering:

- **Fair operating expenses**: these are generally lower than actual expenses, which then creates the potential to pay benefits,
- **Dependent expenses**: such as technical and commercial losses, and the maximum level recognized and covered by the distribution tariff; this level will need to be adjusted based on the progress of implementation and the potential for loss reduction created by smart metering,

- **Depreciation of the assets**: this amount depends directly on the investments made in the year previous to the one in which the depreciation occurs, and no means should exist to increase its value as a result of the benefits achieved,
- **Return on capital**: although this will start being calculated based on the WACC and CAPM methodology, investments which, in general, bring greater benefits to consumers and to the energy system could be rewarded with a higher return on equity. Also, this annual higher return on equity will have to be evaluated and compared by the regulators to the values declared at the beginning of the implementation and handover of the investment plan.

These changes should be considered in the methodology for setting up distribution tariffs. The inclusion of costs (and benefits) in the distribution tariff should be based on the investment plans reported by the DSOs and adjusted annually, leading to the final area to be covered by energy regulatory framework.

3. Reporting on project progress

Regulator will need to define a set of key performance indicators for the DSOs that can be tracked during implementation and for a certain period thereafter; indicators such as:

- Reduction of commercial losses in the area of AMI implementation,
- Reduction of technical losses,
- Lowering the cost of meter reading,
- Minimization of theft of infrastructure.

DSOs will need to report the following information to regulators:

- Progress on the implementation: update the general implementation schedule (time frame and pace, planned values of the benefits), detailed implementation schedule for next year, analysis and mitigation of risks,
- Value of benefits achieved: losses and reading costs,
- Values of KPIs achieved: levels, reasons for lying below the KPIs (if case), mitigation measures.

The above regulation changes should be considered in the performance standards for the distribution system, which needs to be revised annually based on the results and progress of implementation.

9.2 Social acceptance and data protection considerations

Social acceptance is one of the most important success factors, and should be nurtured from the beginning of the implementation process. When there’s a lack of social acceptance, there’s a significant risk of increasing implementation costs and not realizing the full program benefits. One of the most critical aspects of social acceptance is to assure private data protection and security.

Data protection and security are very crucial to a smart metering program roll out. Customers assume that utility companies will depend on many different IT systems and functions, and thus making their personal data more vulnerable to potential hacking threats. An attack of this kind would have a negative impact on all network operators and their consumers, not just on the operator that allowed the incident to happen.

Therefore, common agreements and recommendations need to be considered for the security of the network, and all market players and operators need to lend them their support. The purpose of such security measures would be to mitigate the risk of breaching integrity of data and customer information confidentiality.

When discussing about data protection and security, certain aspects need to be considered in order to ensure client data protection:

- **Confidentiality** – ensure that the data processed by metering operators are only visible to authorized parties, without disclosure to any other third party without prior consent of the customer; ensure monitoring of such data leakages,
- **Integrity –** ensure data reliability since the information registered by the smart metering system is used for invoice processing the accuracy, time-synchronization and completeness of the information must be ensured,
- **Data availability –** at all times to those parties entitled to process it.

However, data protection is just one dimension of smart metering social acceptance. **Customer education** is also highly critical to overcoming resistance to the program. In the initial phase of smart meter implementation, consumers may be reluctant to join because they don't understand the concept, and they can't foresee the benefits associated with it. What they do see, however, is how much this new technology will cost them. Thus, for a successful roll out and to avoid customer resistance, public relations campaigns should be considered.

Typically, detailed social acceptance campaigns are put in place for all stages of the roll out, starting with an early awareness phase (including education of employees, opinion leaders, and customers prior to investments), through the initial installation phase (media coverage), web portal access, and so on. The general message to be conveyed is that in the long run, benefits from the new technology will far outweigh the cost, focusing specifically on the solutions the program has to offer customers in real-time, including meaningful data on prices and consumption that would allow them to make optimal decisions on energy usage.

9.3 Metrology law considerations

The main change that we recommend to be made is the legalization period for the new smart meters. A change in the regulated period of legalization for the electricity meters was already made, from 8 to 10 years, corresponding also to the average amortization period for meters used by major distributors. However, in gas no such change has been considered so far.

Considering potential future smart metering implementation, the **legalization period might be further increased** to reflect the life duration of the new equipment to be installed, above 10 years. This could also bring an ease on distributors' shoulders from a cost perspective, having less meters to be legalized annually. The roll-out effect on lower costs could be in the end a lower pressure on the distribution tariff and hence, on the consumers. Statistical approach for the legalization process could also be considered to lower the cost of operations of the new smart metering infrastructure.

In addition to this, introduction of **statistical legalization** for the new smart meters is expected to bring additional benefits, leading to a decrease in the cost of legalization for the DSOs. This method should be put in place, as it assumes a statistical significant sample of meters for the entire population. Extension of legalization period for traditional meters to be replaced in the coming years can also bring additional benefits (for example lower stranded costs) and should be taken into consideration.

Conclusions

The purpose of this study was to assess the feasibility of smart meter implementation in Romania by means of market analysis, international benchmarks, legislative review, and through a detailed cost-benefit analysis. In developing this report, A.T. Kearney has collaborated with both national regulators and key market stakeholders.

The business case developed is a solid economic appraisal of the major costs and benefits resulting from the national roll out of a smart metering initiative, discussed from a quantitative perspective and completed through a non-monetary assessment of other factors impacting the initiative. The intent of the analysis was to have a comprehensive study of the likely impact of introducing smart metering in Romania, without studying the isolated implications, such as development of the tariff distribution structure, components, or recognition of various costs or benefits that could be attributed to this initiative.

The assessment took into consideration various scenarios for implementation, both in terms of market models to be used, but also in terms of implementation schedules. Smart metering at the market level is impacting several utility companies that can leverage potential synergies by using a common communication infrastructure. Thus, for the purpose of this analysis, four main market model propositions have been analyzed in detail.

For the heat sector, we believe smart metering does not bring sufficient benefits when compared to the cost incurred for the roll out. In fact, major benefits in the heat market could be achieved by submeters deployment, and installation of traditional submeters should be the first priority in this sector in the area of metering.

In building the analysis, several assumptions have been made and were validated with both National Regulator and key stakeholders on the market. But there are two significant variables that are impacting the results of the analysis: reduction in commercial losses – that was estimated to have a realistic potential of 60% on the Romanian market - and the discount rate – that was assumed at the level of Weighted average cost of capital (WACC) regulated by the National Regulator for each of the utilities (electricity and gas distribution).

Under these assumptions, in an implementation plan designed to meet the European Commission requirements of an 80 percent smart metering implementation by 2020 and full roll-out by 2022, the results of the business case for **electricity indicate a positive NPV** of 1.168 mln RON, with a ROI estimated at 43,8% over the analyzed period of 20 years.

However, considering same conditions and roll-out plan for the gas market, a negative NPV is obtained, of minus 72 mln RON. With regards to gas there are no imposed targets by the European Commission however. Several scenarios for implementation have been considered. The conclusion is that a mild scenario, where gas roll-out would start later than the one for electricity and would last from 2014 to 2025, could move the business case to slightly positive values.

Moreover, the business cases could be even more positive when done at a company level, since the differentiator factors, such as purchasing power, economies of scale, or electricity-gas bundle could generate additional benefits. In any case, to ensure business plan benefits are met, the implementation program must ensure implementation of state-of-the-art processes and procedures.

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Appendix 1

List of 33 recommended functionalities by European Commission for smart grids (EC Task Force for Smart grids 2010)

Scope	No.	Functionality
Integrate users with new requirements	1	Facilitate connection at all voltages/locations for any kind of devices
	2	Facilitate the use of the meter for the users at all voltages/locations
	3	Use of network control systems for network purposes
	4	Update network performance data on continuity of supply and voltage quality
Enhancing energy efficiency in day-to -day grid operations	5	Automated fault identification/grid reconfiguration, reducing outages times
	6	Enhance monitoring and control of power flows and voltages
	7	Enhance monitoring and observability of grids down to low voltage levels
	8	Improve monitoring of network assets
	9	Identification of technical and non-technical losses by power flow analysis
	10	Frequent information exchange on actual active/reactive generation/consumption
Ensuring network security, system control and quality for supply	11	Allow grid users and aggregators to participate in ancillary services market
	12	Operation schemes for voltage/current control
	13	Intermittent sources of generation to contribute to system security
	14	System security assessment and management of remedies
	15	Monitoring of safety, particularly in public areas
	16	Solutions for demand response for system security in the required time
Better planning of future network investments	17	Better models of DG, storage, flexible loads, ancillary services
	18	improve asset management and replacement strategies
	19	Additional information on grid quality and consumption by metering for planning
Improving market functioning and customer service	20	Participation of all connected generators in the electricity market
	21	Participation of VPP and aggregators in the electricity market
	22	Facilitate consumer participation in the electricity market
	23	Open platform grid infrastructure for EV recharge purposes
	24	Improvement to industry systems (for settlement, system balance, scheduling)
	25	Support in the adoption of intelligent home/facilities automation and smart devices
	26	Provide grid users with individual advanced notice for planned interruptions
	27	Improve customer level reporting in the case of interruption
More direct involvement of consumers in their energy usage	28	Sufficient frequency of meter readings
	29	Remote management of systems
	30	Consumption/injection data and price signals by different means
	31	Improved energy information
	32	Improved information on energy sources
	33	Availability of individual continuity of supply and voltage quality indicators

Appendix 2

Assumptions related to benefits for electricity

Used for calculating:	Variable	Value	Unit	Reasoning
Reduced meter reading cost	Average number of readings per meter/year	4	[pcs]	On average, meter readings for household customers are done once every 3 months (4 times a year).
	Average cost of single reading (per meter per year)	0.005	['000 RON]	Average value based on the questionnaires received from distributors
Reduced Electricity Commercial losses	Commercial losses level	7	[%]	Average value based on the questionnaires received from distributors and ANRE.
	Increase in distribution tariff to cover network losses	3	[%]	We assumed an average increase in the distribution tariff to cover network losses by 3% in the assumed years of implementation
Reduced electricity Technical losses	The average annual volume of energy not registered in the inductive meter	0.0025	[MWh]	A.T. Kearney project experience
	Average inductive meter power	4	[W]	A.T. Kearney project experience
	Average electronic meter power	0,7	[W]	A.T. Kearney project experience
Reduced distribution operation costs	Meter legalization cost (including installation/de-installation)	0.053	['000 RON]	Average value based on the questionnaires received from distributors
	No of meters connections/ disconnections per day per employee	10	[pcs]	On average 10 connections or disconnections operations can be performed per day
	% of employment cost in total cost of connections/disconnection	40	[%]	The difference is represented by other costs like cars, fuel etc.
Reduced outages	System average interruption frequency index (SAIFI) - unplanned	6,1	[pcs]	Average value based on the questionnaires received from distributors; ANRE
	System average interruption duration index (SAIDI) - unplanned	7,97	[h]	Average value based on the questionnaires received from distributors; ANRE
	Potential of reduction of average time needed to identify and fix the failure	1	[%]	A.T. Kearney project experience
Deferred Distribution capacity investments	Purchasing cost of 1phase traditional electronic meter	0,1	[‘000 RON]	Average value based on the questionnaires received from distributors
	Purchasing cost of 3phase traditional electronic meter	0,47	[‘000 RON]	Average value based on the questionnaires received from distributors
	Average no of traditional meters that can be installed per day	8	[pcs]	A.T. Kearney project experience

Appendix 3

Assumptions related to costs for electricity

Used for calculating:	Variable	Value	Unit	Reasoning
Meter layer	Depreciation period of smart meters	10	years	Maximum depreciation period permitted
	Legalization period of smart meters	10	years	This is the new legalization period for electricity meters
	Number of smart meters installed per day	8	Pcs	Same rate as for the traditional meters
	Number of FTE for installation of 1 smart meters	1	FTE	No need for installation team to be composed of 2 people
Middleware layer	Number of installed balancing meters and concentrators	68.117	Pcs	Equal to the number of substations. We have assumed a measurement and protection block for each concentrator
	Depreciation period of balancing meters, concentrators	10	years	Same depreciation period also for couplers, modems
	Depreciation period of WiFi, WiMAX towers, fiber optic	15	years	More complex assets, longer depreciation period
Application layer	Depreciation of computer hardware and applications	5	years	
System maintenance	Average power of meter	0,9	W	Benchmark from similar projects of A.T. Kearney
	Average power of concentrator	2,5	W	Benchmark from similar projects of A.T. Kearney
	% of meters damaged	1	%	Benchmark from similar projects of A.T. Kearney
	Failure rate for remote connection/disconnection	2	%	Benchmark from similar projects of A.T. Kearney – 1% after 2018 onward due to learning curve
	Number of connections/disconnections per day by one team	8	pcs	Benchmark from similar projects of A.T. Kearney
	% of concentrators damaged	1,5	%	Benchmark from similar projects of A.T. Kearney
	% of automatic read requiring manual verifications	1	%	Benchmark from similar projects of A.T. Kearney – constant decrease to 0.35% in 2032 due to learning curve
	Number of maintenance operations per concentrator	1	Pcs/year	At least once a year a concentrator has to be verified that it functions properly to grasp on the benefits from having it
	Events occurrence rate	3	%	Benchmark from similar projects of A.T. Kearney – constant decrease to 0.12% in 2022 due to learning curve
Costs of financing	% of capital from external sources (debt)	90	%	Majority of the investment to be supported with debt, since investment budgets are not high
	Loan interest rate	6	%	1% external financing interest rate plus 5% ROBOR

Appendix 4

Assumptions related to benefits for gas

Used for calculating:	Variable	Value	Unit	Reasoning
Reduced meter reading cost	Average number of readings per meter/year	4	[pcs]	On average, meter readings for household customers are done once every 3 months (4 times a year). To decide if once market is liberalized 12 yearly readings will be necessary, due to current legislation for eligible clients
	Average cost of single reading (per meter per year)	0.0057	['000 RON]	Average value based on the questionnaires received from distributors
Reduced Electricity Commercial losses	Commercial losses level	2,5	[%]	Average value based on the questionnaires received from distributors
	Increase in distribution tariff to cover network losses	3	[%]	Avg. increase in the distribution tariff to cover network losses by 3%
Reduced gas Technical losses	Average annual volume of gas not registered by inductive meter	0,025	[MWh]	A.T. Kearney project experience
Reduced distribution operation costs	Meter legalization cost (including installation/de-installation)	0,053	['000 RON]	Average value based on the questionnaires received from distributors
	No of meters connections/ disconnections per day	10	[pcs]	On average 10 connections or disconnections operations can be performed per day
	% of employment cost in total connections/disconnection cost	40	[%]	The difference is represented by other costs like cars, fuel etc.
Deferred Distribution capacity investments	Purchasing cost of gas traditional electronic meter	0,18	['000 RON]	Average value based on the questionnaires received from distributors
	Average no of traditional meters that can be installed per day	7	[pcs]	A.T. Kearney project experience
	No of people needed in the team	1,5	[pcs]	A.T. Kearney project experience
Reduced gas cost	% of gas that can be forecasted better due to reduced losses	10	[%]	A.T. Kearney project experience

Appendix 5

Assumptions related to costs for gas

Used for calculating:	Variable	Value	Unit	Reasoning
Meter layer	Depreciation period of smart meters	8	years	Maximum depreciation period permitted
	Legalization period of smart meters	8	years	
	Number of smart meters installed per day	5	Pcs	New meters might require more complex operations (changing position, junctions in the installation, etc.) compared to electricity meters
	Number of FTE for installation of 1 smart meters	1,5	FTE	Some teams are composed of two people, some of only one person
Middleware layer	Number of installed balancing meters and concentrators			Balancing meters are not required for gas market. Number of concentrators is assumed the same as in electricity, for the common infrastructure (costs being assumed for electricity only).
	Depreciation period of WiFi, WiMAX towers, fiber optic	15	years	More complex assets, longer depreciation period
Application layer	Depreciation of computer hardware and applications	5	years	
System maintenance	Average power of meter	0,9	W	Benchmark from similar projects of A.T. Kearney
	% of meters damaged	1	%	Benchmark from similar projects of A.T. Kearney
	Failure rate for remote connection/disconnection	2	%	Benchmark from similar projects of A.T. Kearney – 1% after 2018 onward due to learning curve
	Number of connections/disconnections per day by one team	20	pcs	Benchmark from similar projects of A.T. Kearney
	% of automatic read requiring manual verifications	1	%	Benchmark from similar projects of A.T. Kearney – constant decrease to 0.35% in 2032 due to learning curve
	Events occurrence rate	3	%	Benchmark from similar projects of A.T. Kearney – constant decrease to 0.12% in 2022 due to learning curve
Costs of financing	% of capital from external sources (debt)	90	%	Majority of the investment to be supported with debt, since investment budgets are not high
	Loan interest rate	6	%	1% external financing interest rate plus 5% ROBOR