ERRA Licensing and Competition Committee

Case Study Paper

POTENTIAL IMPLEMENTATION OF DEMAND SIDE APPROACH METHODS IN ERRA COUNTRIES

Prepared by Regional Centre for Energy Policy Research (REKK)

December 2008

Preface

Dear Colleagues:

I am honoured to present to you one of the results of our joint work and efforts during 2007 and 2008: a case study issue paper prepared by Regional Centre for Energy Policy Research (REKK) based on a request by the ERRA Licensing/Competition Committee. This paper is submitted to the 9th Annual Conference of ERRA.

The issue paper of Potential Implementations of Demand Side Approach in ERRA Countries examines and summarizes the different Demand Response methods, the Key Drivers for implementation, the Main Barriers to implementation and the implemented methods (in practice) together with a summary of available reports on this topic. It also evaluates the Demand Response methods on the potential implementation in ERRA (by analyzing the legal, regulatory framework and the market structure, the capacity balance situation and TSO/ISO' practice of three ERRA countries - *Hungary, Macedonia and Serbia* - with different regulatory framework and different market situation)

I would like to thank the continuous technical support received from the National Association of Regulatory Utility Commissioners (NARUC) and the U.S. Agency for International Development (USAID). And last but not least let me thank you the work and assistance of the three Licensing/Competition Committee members representing Hungary - Mr. Csaba Kovacs, Macedonia – Mr. Strasho Zafirovski and Serbia – Mr. Nikola Radovanovic, for their help in making available the case studies in the paper by answering the questions and giving assistance for the local issues to the authors.

I look forward to our successful work in the next years.

Sincerely:

Ms. Maria Manicuta
Chair, ERRA Licensing/Competition Committee
Commissioner, Romanian Energy Regulatory Authority (ANRE)

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ERRA Licensing/Competition Committee Case Study Paper

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Purpose of the Case Study paper

The objective of this study is to provide the ERRA regulatory community with an overview of the wide set of tools that enable more efficient use of current electricity infrastructures by making electricity demand more responsive to developments on the supply side of the market, especially tightening capacity and associated increase in production costs. The paper provides also three case-studies on the potential implementation of demand side approach methods in three ERRA countries, Former Yugoslav Republic of Macedonia, Hungary, and Republic of Serbia. The main purpose of the country-studies is to give an example on how demand response tools could be fitted to different market-structures and regulatory environments present in the ERRA community.

In some of the national markets there is capacity shortage (inadequate reserve capacity and insufficient installed generation capacity) at present that can cause national interruptions (even blackouts) which can impact the regionally interconnected systems. The possible reasons for this situation are the following:

- Increased demand
- Energy efficiency (energy conservation) programs are hardly effective. The customer demand increases very rapidly, customers' energy conservation consciousness is not widespread.
- Strict environmental protection and (nature) conservation requirements, rules and the administrative licensing procedures create difficulty for investors to build new power plants, new high voltage lines.
- Emerging market conditions (immature market rules) in national markets and the slowly developing regional markets could create types of risk elements for the investors which could postpone investment.
- In some cases - especially on relatively small national markets - the lack of transparent rules and predictable cross border capacity could increase the risk of new generation investment.

These issues, if not handled properly could create medium term security of supply problems in national markets.

It is the common intention of regulators that they:

- would like to maintain a good level of security of supply on national and regional markets,
- would encourage governments, the regulators and the TSOs to utilize more of the potential tools of demand response programs that could give incentives to end-users to

conserve electricity use overall, to implement energy efficiency programs for both large industrial users and residential customers, and to establish programs to encourage customers to shift their peak demand to off-peak hours in cases of system-regulation difficulties.

The Licensing/Competition Committee is one of the standing committees of ERRA, it operates since 1997. Each member organization of ERRA delegates a permanent representative to the committee which meets three times/year. The Committee compiles issue and discussion papers, puts together comparative surveys and analyzes burning issues of the regulatory industry. The work is conducted in English and Russian languages.

The 2008 Work plan of the Committee lists the issue of potential implementation of Demand Response methods in ERRA countries. The Regional Centre for Energy Policy Research (REKK) was commissioned by the National Association of Regulatory Utility Commissioners (NARUC) in cooperation with members of the Committee to prepare a case study on potential implementation of demand side approach methods in ERRA countries.

The scope of the issue paper covers:

- ♦ Summary of the different Demand Response (DR) methods, the Key Drivers for implementation, the Main Barriers to Implementation and the Implemented methods (in Practice) together with a summary of available Reports on this topic (like Research Report International: Demand Response Programs, etc.). In this summary, describe the roles of the TSO, distribution company, regulator and any external entity like traders, energy efficiency aggregators or others relevant to the EU electricity framework.
- ♦ Evaluation of DR methods on the potential implementation in ERRA (by analyzing the legal, regulatory framework and the market structure, the capacity balance situation and TSO/ISO' practice of 3 ERRA countries with different regulatory framework and different market situation)
- ♦ Suggestion of those DR methods for implementation which fit to the situation of the analyzed 3 ERRA countries (based on the common elements of the legal, regulatory framework and the market structure, the capacity balance situation).
- ♦ Collection of typical barriers, aspects, which make the implementation of different DR methods more complication (impossible) in the 3 ERRA countries. Suggest potential legal/regulatory and other (like license conditions, Grid Code elements, tariff structure, market structures, etc.) amendments in the deeply analyzed 3 country cases, which allow the implementation of suggested DR methods.
- ♦ Prepare arguments for the regulators assisting the implementation of such DR programs.

- Provide a concise summary in the Appendix of the U.S. experience using primarily the March 2007 report titled Demand Response Programs by Research Reports International.

Table of Contents

1. General overview of demand response [1]

The purpose of this chapter is to provide background and context for the three country case studies. This overview includes the introduction to the concept of demand response, the methods used in practice, and a general framework for evaluation, i.e. the main components of a cost-benefit analysis. The chapter ends with the discussion of advanced metering, a prerequisite for the implementation of most demand response programs.

1.1. Definition

For various reasons, today most consumers face seldom changing retail prices, while the cost of production, and thus the wholesale price of electricity changes considerably over short time intervals. This lack of connection between wholesale and retail markets results in inefficiencies that could be solved by creating the possibility for consumers to respond to wholesale level events, i.e. enabling demand response (DR). Broadly, demand response refers to voluntary changes in consumption, where the trigger for the response can be either price signals, incentives, or directions from the grid operator. More precisely, the US Department of Energy (DOE) defines demand response as:

„changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[2]

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[1] This first chapter as the terms of reference (TOR) of the contract outlines, is a summary of existing literature on demand response. The TOR suggests the use of the paper:

Research Reports International: Demand Response Programs. March 2007

In the preparation of this chapter besides the above paper and many other papers listed in the References we have strongly relied on the following important papers:

- FERC: Assessment of demand response and advanced metering. Staff report. August 2006
- US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006
- ERGEG: Smart metering with a focus on electricity regulation. E07-RMF-04-03. October 2007
- IEA DSM: DRR Valuation and market analysis Volume II: Assessing the DRR benefits and costs. January 2006

[2] US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. 6.

The ETSO definition adds the importance of mediator third parties, by defining demand response as

„a voluntary temporary adjustment of power demand taken by the end-user as a response to a price signal (market price or tariffs) or taken by a counter-party based on an agreement with the end-user."[3]

This latter definition also highlights the time dimension of demand response, distinguishing it from the closely related concept of energy efficiency. While both imply demand side reactions to price changes, demand response refers to short-term, discrete changes to demand profiles, while energy efficiency involves permanent changes, reducing demand in all hours of operation in the future. Consequently while demand response in some time periods can result in a growth in consumption (e.g. in off-peak times due to load shifting), energy efficiency, as a base load demand response, results always in less consumption. From the system's point of view demand response has an impact on the system power balance, contributing to economic optimization, whereas energy efficiency affects the energy balance of the system and may result in saving of energy. Despite the differences synergies may arise between the two, for example as consumers participating in demand response programs due to newly gained information on their consumption and technologies could decide to undertake actions that result in energy efficiency.

1.2. Types of demand response

There are many methods for inducing consumer response, which can be grouped into two main categories: **price-based** and **incentive-based demand response** programs. In the former case consumer response is triggered by price changes that reflect variations in the underlying costs of electricity generation. These time varying tariffs are an alternative to conventional flat rates and enable users to reduce their electricity bills by shifting their consumption to cheaper time periods. It is important to note that actual demand response in the case of price-based demand response programs depends solely on the economic decision of the consumer and it is always voluntary.

[3] ETSO (2007): Demand response as a resource for the adequacy and operational reliability of the power systems: Explanatory Note. January 2007, p. 2.

Price-based DR programs

Time-of-use tariff (TOU)

In these programs tariffs are predetermined and reflect the average cost of production in the given time periods. These tariffs vary within days (e.g. peak and off-peak prices) and usually also within seasons.

Critical peak pricing (CPP)

Consumers participating in CPP programs are either under TOU or flat rate programs and agree to face a pre-specified high rate in case of critical events (e.g. high wholesale prices or system contingencies). This high rate is imposed on relatively short notice and for a limited number of occasions. Consumers typically receive a discount on their consumption in non CPP periods.

Real time pricing (RTP)

In these programs prices vary hourly reflecting changes in the wholesale market. Prices are known to consumers either day-ahead or hour ahead, depending on the exact program.

1.2.1. Price-based DR programs

Three main program types can be listed in this category, which differ mainly in the frequency and predictivity of price changes: time of use tariffs (TOU), real-time pricing (RTP), and critical peak pricing (CPP). These programs expose consumers to different levels of wholesale price exposure, with TOU rates carrying the least and RTP the most.

TOU rates

Time of use rates are the most prevalent form of time-varying rates. The simplest form of TOU rates are seasonally varying tariffs, i.e. different tariffs for summer and winter. More sensitive and complicated forms are when rates vary within days according to different time periods, two or three a day. Off-peak periods are usually weekday nights and weekends while peak periods are the weekday mornings and afternoons. The actual hours of peak periods vary from program to program, just like the ratio of peak and off-peak tariffs.

TOU pilot programs were introduced in the US in the 1970's, and their number in the beginning has risen and fallen over time depending on the regulatory support and involvement. In the beginning mainly industrial consumers participated, but later many utilities started TOU programs for residential consumers as well. Cross-price elasticity between peak and off-peak periods was found to be around 0.07 - 0.21 among households suggesting that if prices in the peak period increase by 10%, consumption in the off-peak period will increase by 0,7 - 2.1%, due to load shifting between the two time periods. Of course these are average numbers and the elasticity differs from program to program, but it is evident that TOU tariffs do deter the consumption pattern induced by flat rates.

By now most utilities in the US have TOU programs, with many also involving residential consumers. European electricity companies also started to introduce TOU tariffs.

Important (regulatory) questions that arise with the implementation of TOU tariffs are, the number of time periods (e.g. weekdays: peak and off-peak, weekend: off-peak, seasonal changes, etc) and the size of the price spread. The time periods should be developed in a way that it reflects wholesale costs, but also allows customers to change the way in which they use electricity, i.e. a reduction after 11 pm will not trigger great response from residential and small-scale consumers. Regarding the price spread, the difference between the prices of peak and off-peak hours should be significant to induce demand response.

Regarding the technical issues arising with the implementation of time varying rates it has to be noted that most time-based rates require meters that can store data on the time of consumption, however the standard one-rate electromechanical meters that currently most small-scale consumers are equipped with cannot provide such function. Advanced meters are a prerequisite for most DR programs introduced in this paper, therefore we will discuss the problem of introducing advanced metering in more detail in the next section.

CPP

Critical peak pricing compared to TOU rates is a newer type of price-based DR method. In CPP programs peak prices are much higher than the peak prices applied in a TOU tariff system, but while TOU peak prices are applied almost daily the critical peak periods are less frequent, and are not designated in the tariff system but dispatched on a relatively short notice when needed. These critical periods are either times of system contingencies or high wholesale prices, or both, therefore CPP can also be viewed as a reliability-based DR program. CPP rates can be applied together with TOU rates or flat rates as well.

Depending on the predictivity of high priced periods, and the formation of the high-price itself, four main types of CPP rates can be distinguished:

- Fixed-period CPP:

  Time and duration of the critical period is predetermined, but the actual days are not known in advance, participants are usually notified day-ahead. The maximum number of critical periods per year is also usually fixed in advance.

- Variable-period CPP:

Everything, the time, the duration, and the day is variable, and notification is on a day-of basis. Devices that allow automatic responses to CPP are requisites.

- Variable peak pricing:

The actual price of the critical period is not predetermined, rather it is related to the corresponding day-ahead price of the hours when applied.

- Critical peak rebates:

Customers instead of paying higher rates in the critical peak periods, remain on their fixed rates and receive rebates for load reductions produced in the critical period.

France has been using CPP rates since the late 1980s, in the US it became common since 2000 and currently there are 25 utilities offering CPP programs. The experience of Californian CPP programs show that depending on the consumer group in critical periods 10-15% consumption reduction could be achieved.[4]

RTP

In case of real time pricing, the retail price directly reflects the prevailing wholesale price, therefore the retail tariff varies continuously. RTP programs can differ in the basis of price setting (day-of versus day-ahead pricing) the price structure (one part vs. two part tariffs) and design (mandatory vs. voluntary). The first RTP programs were introduced in the mid 1980s in the US and by now more than 70 utilities have offered voluntary RTP tariffs, while several restructured states have made RTP the default service for the largest consumer group unless they choose an alternative supplier. Many new entrant retailers also offer RTP tariffs.

Regarding the different types of RTP programs, in the case of day-ahead real time pricing participants are given one-day notice of the price for each of the hours of the next day. In two-part RTP programs a historical baseline is determined for each customer and the hourly varying prices only apply to the consumption that is above or below the baseline, thus RTP prices in the case of two-part RTP tariffs are only felt at the margin.

Own-price elasticities of commercial and industrial consumers participating in RTP programs was found to be in the range of -0.01 – -0.26 indicating a significant heterogeneity of this consumer group.

[4] FERC: Assessment of demand response and advanced metering. Staff report. August 2006, pp 58-59.

Faruqui and Mauldin[5] based on the experiences of RTP programs organised in the US summarizes the main lessons that can be learnt from these programs and should be considered when organizing new ones:

- RTP programs can offer significant load shifting benefits, but most of the load response comes from relatively few customers, and other customers might not respond at all.
- Certain types of customers are more likely to respond to RTP, i.e. customers with on-site generation, with discrete production process.
- Customers choose RTP programs to save money, therefore program rules should allow customers to generate bill savings.
- Customers do not like unmitigated price volatility. For this reason many utilities have integrated some kind of risk mitigation feature, like limit on the number of high-priced days, in their RTP programs.
- RTP programs create revenue stability issues for utilities and bill stability issues for customers. The possibility for utility losses could be mitigated by two-part RTP tariffs.
- With two-part RTP rates, utilities and customers often prefer simpler designs. Moving to a simpler customer base line can resolve this problem.
- RTP programs can be successfully combined with interruptible programs.
- The most important lesson: customer education is key.

1.2.2. Incentive-based DR programs

Incentive-based demand response programs are characterized by a contractual agreement between the consumer and the organizer of the program (TSO/DSOs, policy makers, or retailers). Consumers can voluntarily sign up to such programs, but after they joined, demand reduction is usually not an option but an obligation. In these programs in return for a reservation payment or separate incentive payments that are independent from the retail tariff, participants agree to reduce their electricity consumption or to be curtailed in critical hours (program events). A penalty for non-compliance in many cases is foreseen. Thus contrary to price-based DR programs where actual demand response depends solely on the economic decision of the consumer, in the case of incentive-based DR programs consumers decide upon the participation and not the actual demand response. The types of programs that belong to this category mainly differ in the manner of demand reduction (e.g. consumer is curtailed by

[5] Faruqui, A. – Mauldin, M.: Barriers to real-time pricing: separating fact from fiction. 2002

the program organizer or the consumer reduces its own consumption) and the definition of program events (e.g. every day in peak hours, in case of high wholesale prices, in system emergency events.). The six main incentive-based DR program types are: direct load control, interruptible/curtailable rates, demand bidding/buyback programs, emergency demand response programs, capacity market programs, and ancillary-service market programs.

Incentive-based DR programs

Direct load control

Consumption of small-scale consumer's electrical equipment is switched off remotely by the program organizer in system contingencies in return for a reliability payment. Opting out is rarely an option.

Ancillary services market programs

Loads are allowed to bid into ancillary services markets to provide operating reserves. They are paid reservation payments and in case of activation, energy payments as well.

Demand bidding buyback programs

Customers bid into the organized wholesale electricity market, or they offer their consumption to be curtailed for a price defined by the utility.

Capacity market programs

In return for reservation payments (determined by capacity markets) and energy payments paid after actual reduction, customers receiving a day-of notice reduce their consumption by a pre-specified amount. Penalties are usually foreseen.

Emergency DR programs

Consumers receive incentive payments for measured load reduction in emergency events.

Interruptible/curtailable service

Consumers reduce their load to a prespecified firm level in case of contingencies in return for a rate discount. Those that fail to reduce their demand pay penalties or are removed from the program.

Direct load control (DLC)

Direct load control programs have been introduced in the late 1960s in the US and at present 234 utilities are operating some kind of direct load program. Many European countries have also introduced such programs in the 1980s, and many are still in use, while new programs were also initiated.

In a DLC the program organizer remotely switches off or cycles the customer's electrical equipment to address system contingencies or large wholesale prices. Consumers receive incentive payment or bill credit in return. Typical participating appliances are water heaters, electrical heating and air conditioners. In recent years technological development has brought more sophisticated remote switches, which allow that individual switches can be controlled independently. Furthermore programmable, communicating thermostats have appeared: their temperature setting with the new switches can remotely be adjusted.

Interruptible/curtailable rates (I/C)

In I/C programs consumers receive bill credit or rate discount in return for reducing their load by either a prespecified amount or to a prespecified level when the utility notifies them. Customers are notified 30 to 60 minutes in advance and are penalized if they fail to reduce load. The maximum number of curtailments for a season or a year is set in advance. These programs are typically organized by utilities and the tariffs are generally filed by regulatory commissions. The I/C tariff program is designed for the largest consumers, the minimum sizes to be eligible for I/C tariffs vary between 200 kW and 3 MW in the US.

Emergency demand response programs (EDRP)

EDRP programs provide incentive payments if customers reduce their load during reliability-triggered events. However in these programs load reduction is voluntary, customers can decide to forgo the incentive payments and do not curtail their consumption. Since large customers' participation is voluntary there are no availability payments. These programs are typically suited for system operators.

Capacity-market programs

Just like in the previous cases, in the capacity-market programs consumers commit to reduce their load by a pre-specified amount when system contingencies arise, but in return they receive guaranteed availability payments. Participants are subject to penalties if they do not curtail. These programs are offered by market operators who also operate installed capacity markets. Capacity-market programs are also designed for the largest consumers.

Demand bidding/buyback programs

The demand bidding programs are one of the newest types of incentive-based DR programs. There are two forms of demand bidding programs, in the first consumers bid directly into the optimalization and scheduling process, e.g. bidding a price and a level of curtailment on a day-ahead basis, and if the bid is selected by the market operator, customers must execute curtailment. In the second form the customer acts as a price-taker, and reduces consumption when notified receiving the market-clearing price as payment. Both, vertically integrated utilities and market operators organize these programs. Demand bidding buyback programs are attractive to customers because they allow them to remain on fixed rates, while enable them to take advantage of their flexibility.

Nevertheless, debates arise round the operation of these programs, primarily on the issue of who is responsible for the costs associated with successful bids.

Ancillary services

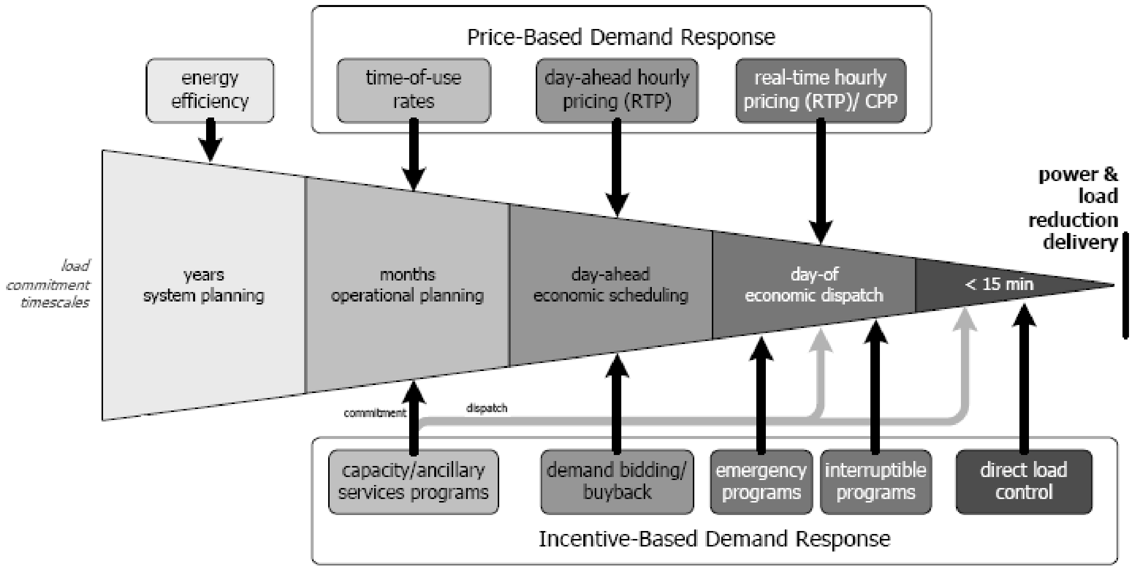
In this type of demand response loads competing with generators bid into the ancillary services market to provide operating reserves. Suppliers of reserves receive availability and energy payments as well. The number of consumers that could be eligible to provide ancillary services is very limited. Only the largest consumers with processes that could be frequently, safely, and very quickly curtailed can participate. Only two system operators have ancillary services markets with active consumer participation in the US, but many other system operators are currently developing their system to allow load participation, and organize pilot projects.

1.3. Benefits of implementing DR methods

1.3.1. The role of demand response in electric power systems

The time scales of system management range from several years to the last second before delivery of electricity. The role that each price-based or incentive-based DR program plays in electric systems depends on the timeframe of the response. For example real-time pricing and demand bidding/buyback programs affect supply scheduling in day-ahead markets, while critical peak pricing and interruptible programs affect real-time dispatch. Time of use rates and capacity programs by contrast do not induce as rapid response and therefore can be viewed as a resource during operational planning that takes place months before delivery. Energy efficiency as a base load demand response can affect long-term investment, capacity and system planning starting years before delivery. If different price-based or incentive-based DR programs are implemented, DR may be utilized in each time-scales of system management.

1.1. Figure: Role of demand response in electric system planning and operations[6]



1.3.2. Overall and individual benefits of demand response

The benefits of demand response can be categorized in many ways and a long list of value-creating elements could be constructed. The International Energy Agency's Demand Response Resources Task force identifies the following main categories of DR benefits:[7]

- System reliability – DR can enhance system reliability by reducing usage during emergency conditions.
- Cost reduction – DR enables avoidance of capacity costs, costs emerging from line losses, costs due to congestions, and costs of consumers by reducing wholesale prices and price volatility.
- Market efficiency – Without demand response tools markets use more power than they need to. Demand response provides a least-cost solution in constrained time periods.
- Risk management – Suppliers of electricity face hourly varying procurement prices on the wholesale level while provide electricity for consumers for prices that change in a much slower pace. DR can substantially reduce the risk of suppliers and customers by performing as a risk management product, allowing to hedge price risks by creating callable quantity options.

[6] US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. 15.

[7] IEA DRR Task XIII: DRR Valuation and market analysis volume II: Assessing the DRR benefits and costs. January 6, 2006.

- Environment – Electricity generation is a major polluter sector. By promoting a more efficient usage of the resources, DR reduces plant usage and defers new plant development and network capacity enhancements resulting in less pollution and land use benefits for neighborhoods and rural areas where power plants might be sited.
- Customer service – DR provides customers with greater control over their energy usage and thus bills.
- Market power mitigation – Suppliers tend to have significant market power in periods of tight supplies. In such hours providers can increase market prices well above generation costs. Demand response by reducing demand in these periods loosens the market and therefore reduces suppliers' market power resulting in prices closer to generation costs.

The U.S. Department of Energy classifies the described benefits according to how wide the benefitting consumer group is. They define three categories: direct, collateral and other benefits, where direct benefits accrue to consumers that undertake demand response actions, and collateral and other benefits are enjoyed by some or all groups of electricity consumers. Direct and collateral benefits can be monetized relatively easily while it is difficult to quantify other benefits.

1.1. Table: Benefits of demand response[8]

Type of Benefit	Recipient(s)	Benefit		Description/ Source
Direct benefits	Customers participating in DR programs	Financial benefits		Bill savings
				Incentive payments
		Reliability benefits		Reduced exposure to forced outages
				Opportunity to assist in reducing risk of system outages
Collateral benefits	Some or all consumers	Market impacts	Short-term	Cost-effectively reduced marginal costs/prices during events
				Cascading impacts on short-term capacity requirements and supplier contracts
			Long-term	Avoided (or deferred) capacity costs
				Avoided (or deferred) network infrastructure upgrades
				Reduced need for market interventions (e.g. price caps) through restrained market power
		Reliability benefits		Reduced likelihood and consequences of forced outages
				Diversified resources available to maintain system reliability

8 US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. 27.

Other benefits	Some or all consumers, ISO/RTO, Supplier	More robust retail markets	Market-based options provide opportunities for innovation in competitive retail markets
		Improved choice	Customers and suppliers can choose desired degree of hedging
			Options for customers to manage their electricity costs, even when retail competition is prohibited
		Market performance	Elastic demand reduces capacity for market power
			Prospective demand response deters market power
		Possible environmental benefits	Reduced emissions in systems with high-polluting peaking plants
		Energy independence/security	Local resources within states or regions reduce dependence on outside supply

The level of direct benefits depends on the ability of the consumers to shift their load and incentives provided by the DR programs. While direct benefits are very important as they determine consumer participation, the system-wide - collateral - benefits of demand response provide the primary motivation for policymakers' interest in DR.

The DOE classification focuses primarily on consumer/society benefits, however private benefits of other entities like network companies and suppliers is also an important factor, as investment and organization of programs is carried out by these entities.

1.2. Table: Private entity benefits

Private entity	Source of benefit
Load aggregators	Payments for providing DR.
Distribution companies	Lowered distribution system operating and maintenance costs.
	Lowered capital costs for distribution.
	Payments from others for implementing DR programs.
Transmission companies	Lowered transmission and distribution operating and maintenance costs.
	Deferred capital costs.
Reliability entities (SO or power pools)	Increased system reliability.
Suppliers	Lowered costs of purchasing wholesale electricity, (in case of competitive market this might be zero.)
	Lower price risks.

Quantifying demand response benefits

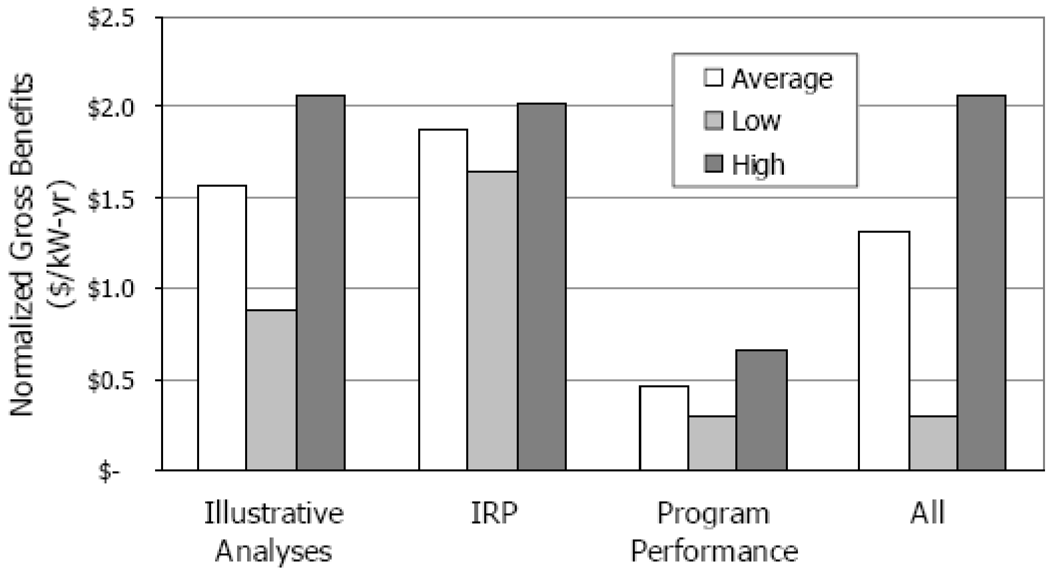
At present there is no consensus on what method and framework should be used to estimate demand response benefits, currently applied methods could be grouped into four large categories. The oldest method for evaluation of load management programs is the equivalence standard, where load management programs are evaluated against an avoided cost standard, i.e. the costs of implementing DR programs are compared to a generation capacity alternative on the basis of their costs per kW-year. A relatively newer way of quantifying DR benefits is to compare the operation of markets with and without DR programs. Experiments are the main tools of such analysis. A third group of methods are studies which take estimates of electricity supply elasticity and by simulating the market estimate the impact of price for a given reduction in demand. The last group consists of studies that quantify the achieved benefits of already introduced programs by analyzing the extent to which wholesale market prices were influenced by customer load curtailments induced by the DR program.

Regardless of the method used all analyses that aim to quantify the benefits of DR need two key inputs: (1) measures of customer acceptance and participation rates, and (2) measures of the extent to which individual consumers would curtail load in a given DR program. The former input depends on the direct costs and benefits of consumers therefore it can be affected by the program design and implementation process. Regarding the latter input many studies attempted to characterize the intensity of customer response. Results are typically reported in two measures: price elasticity and absolute or relative load impact. A summary of recent numerical evidence on these two key inputs is given in section 1.5.

Regarding estimated collateral benefit values, the DOE study summarized the results of ten analysis, where four studies quantified the benefits of DR in organized wholesale markets by simulating the market with and without load reduction programs, four other studies quantified benefits on markets without retail competition with a similar method, and three studies quantified benefits based on the experience of actual DR programs all based in organized wholesale markets.

Since the studies vary in very important factors that determine DR benefits, like market size, market structure, time horizon, assumed level of customer participation and customer responsiveness, analytic methods, the type and number of demand response resources represented, etc., the gross benefits varied significantly from \$1 million to \$52 billion. Therefore in the DOE paper these gross benefit values were normalized to account for many of the underlying differences yielding estimates of normalized gross benefits measured in \$/kW-year. The figure below depicts the resulting benefit estimations according to study type.

1.2. Figure: Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies by DOE[9]



1.4. Typical barriers and costs of DR

1.4.1. Costs of demand response

Costs of demand response programs emerge at two different levels, at the level of participants and at the system wide level. Individual customers that curtail their consumption incur costs when joining the program - initial costs - and presumably also during each load reduction event – ongoing costs. While the majority of initial costs are monetized, e.g. costs related to technology investments, the ongoing costs can only be quantified indirectly, as they are mainly opportunity costs related to foregone electricity use.

1.3. Table: Participant costs[10]

Initial costs	Enabling technology investments
	Establishing response plan or strategy
Event specific	Comfort/inconvenience costs

[9] Illustrative analysis refers to the four studies that simulate demand response benefits on organized electricity markets, IRP refers to the four studies that simulate demand response benefits on markets without retail competition, and program performance refers to the three studies that quantify DR benefits based on past experience of implemented DR programs.

US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. 46.

[10] Based on: US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006

costs	Reduced amenity/lost business
	Rescheduled costs
	Onsite generator fuel and maintenance costs

System wide costs incurred by DR program administrators can also be divided into initial and ongoing program costs. Initial costs relate to the DR program setup and include the costs of setting up a DR strategy and executing cost-benefit analysis, also testing the design through pilot programs. Marketing and customer education that is needed before the implementation of the program is also a cost driver. Finally, the costs of equipment - including computer hardware, signaling and measurement topped with the cost of installation - and the costs of the needed software account for the largest share of initial costs. The equipment and hardware costs become more significant as programs move towards smaller consumers. In case of demand response programs targeting the small-scale consumer segment the mass installation of advanced metering is necessary, which requires substantial investment and outlays of capital. The issue of advanced metering, due to its importance will be discussed in more detail in section 1.6.

Ongoing annual operating system wide costs include payments to participants of the DR programs, program administration and management, and metering and communications costs, e.g. the costs of wireless lines leased from telecommunications providers. System wide costs are usually born by the utilities and passed through to consumers in rates. The estimation of system wide costs is more straightforward then the estimation of benefits, as the costs emerge in a concentrated and monetized way, at the entities organizing the DR programs.

1.4. Table: System wide costs

Initial costs	Product design and testing costs
	Marketing and education costs
	Equipment costs
	Software costs
Ongoing costs	Payments to participants
	Program administration and management
	Metering and communication costs

1.4.2. Barriers of demand response

Implementing demand response programs requires that the involved entities, i.e. the organizer and the participating consumers be motivated towards the program organization and consumption reduction respectively. Motivation comes from a positive net value of the entity specific costs and benefits. Therefore most barriers can be identified as those circumstances that either increase the costs for the entities or reduce the benefits. Accordingly barriers can be separated as barriers to customer participation and active load reduction and barriers to entity promotion of demand side programs.

Barriers to customer participation

The barriers to customer participation can be grouped into two major categories. First of all consumers cannot carry out a realistic cost benefit calculation without enough information and knowledge about the programs, the functioning of the market and about their own potentials. Due to this lack of knowledge participants will not fully understand the financial benefits of such products. For example they might not recognize that high prices during a few days are more than offset by low prices during much of the year, resulting in a lower average electricity bill. Similarly the lack of knowledge on the customer's own electricity usage pattern and the ways it could be changed also results in miscalculation.

Consequently without sufficient knowledge consumers would likely exacerbate the costs and underestimate the benefits of participating in a DR program compared to its real size, and therefore would not participate. The first group of barriers therefore refers to lack of customer knowledge and information.

The second group of barriers relate to barriers that increase the real costs and decrease the real benefits of a program. The most relevant such barriers are low default flat tariffs and technical barriers. Default flat consumer tariffs that do not reflect market costs, and the insurance premium that the provision of fixed-price electricity includes provide the customer with inadequate incentives to participate in a demand response program. As for the technical barriers, most demand response programs require additional technology which could result in case of medium and small consumers in too high initial costs that outweigh the projected participation benefits.

The regulatory actions that could help overcome these barriers would be most importantly customer education in many ways, for example in case of large and medium consumers it could also include counseling of companies on how their consumption could become more flexible. In case of technological barriers the regulator should analyze whether the system-wide benefits would justify the procurement of the technology by the regulated companies.

Barriers to promotion of demand side programs

The main barriers for the promotion of demand response are the following:

- Although regulated utilities could benefit from introducing demand response, they could also realize substantial losses in the same time, which disincentives them in investing into such a program. One possible source of loss could be that bundled utilities make money from the sale of electricity, their revenue is proportional to the quantity sold. As demand response programs possibly result in reduction of overall customer consumption will likely reduce utility short-term revenues. A possible regulatory solution for eliminating such barrier would be decoupling profits from sales volume.

- Restructuring of the electricity industry also results in disincentives for distribution utilities, as the benefits of demand response for a solely distribution company is a lot smaller than the benefits for a company with retail, wholesale and generation assets as well. Regulators by enabling cost recovery, and/or performance based ratemaking could mitigate this problem.
- As mass introduction of demand response requires substantial investments regulatory uncertainty about the ways of how such investments could be recovered in the future would make entities reluctant to step forward.
- Even if the above mentioned barriers would not retain entities from setting up a demand response program, specific barriers such as acts that prohibit mandatory time-based rates, or acts that limit the ability to implement critical peak pricing could provide obstacles to implementing an effective program design.

1.5. Summary of implemented methods

In this section we give a brief overview of the status of DR program penetration in the US as the US electricity systems play a leading role in implementing DR methods and also show a variety in the implemented methods therefore provide a comprehensive picture and experience of demand response programs.

Participation

According to the findings of the Advanced Metering Survey that the Federal Energy Regulatory Commission (FERC) undertook in 2006,[11] the most common DR programs are direct load control programs, interruptible/curtailable programs and time-of-use rates.

1.5. Table: Number of entities offering incentive-based and price-based DR programs in the US, 2006

Incentive-based Demand Response	No of Entities	Price-based Demand Response	No of Entities
Direct load control	234	Time-of-Use	187
Interruptible/Curtailable	218	Real-time Pricing	47
Emergency Demand Response Program	27	Critical Peak Pricing	25
Capacity Market Program	16		
Demand Bidding/Buyback	18		
Ancillary Services	1		

[11] FERC: Assessment of demand response and advanced metering. Staff report. August 2006

Among the incentive-based demand response programs the percent of customers enrolled in direct load control programs in 2008 varies from 0.5% to 13% in the different regions of the US.[12] DLC programs are targeted primarily to residential consumers and only 33 percent of the DLC programs include also commercial customers,[13] whereas the interruptible/curtailable tariffs are primarily offered to large industrial consumers

In case of price-based DR programs, the most popular program, the TOU tariff is applied to residential consumers by 148 entities and 39 offer TOU tariffs to non-residential consumers. TOU tariff is typically offered as an optional tariff, in 2006 1.4 percent of residential customers signed up for such program. In contrary real time pricing is more common among large consumers, and several entities have mandated RTP tariff as the default tariff for large customers. CPP rates are relatively new compared to the other price-based DR programs, many of the reported critical peak pricing programs were pilot programs and the top five entities accounted for 96 percent of the total number of customers on CPP rates.[14]

A survey conducted by IEA among 40 U.S. utilities gives insight into the relationship between market structure and the kind of DR programs preferred.[15] The figure below shows that utilities that primarily operate in restructured states operate a higher percentage of DLC, TOU and RTP programs than the utilities serving traditionally regulated states. Furthermore no utilities operating in traditionally regulated states offer real-time pricing programs and no utilities operating in restructured states offer critical peak pricing programs.

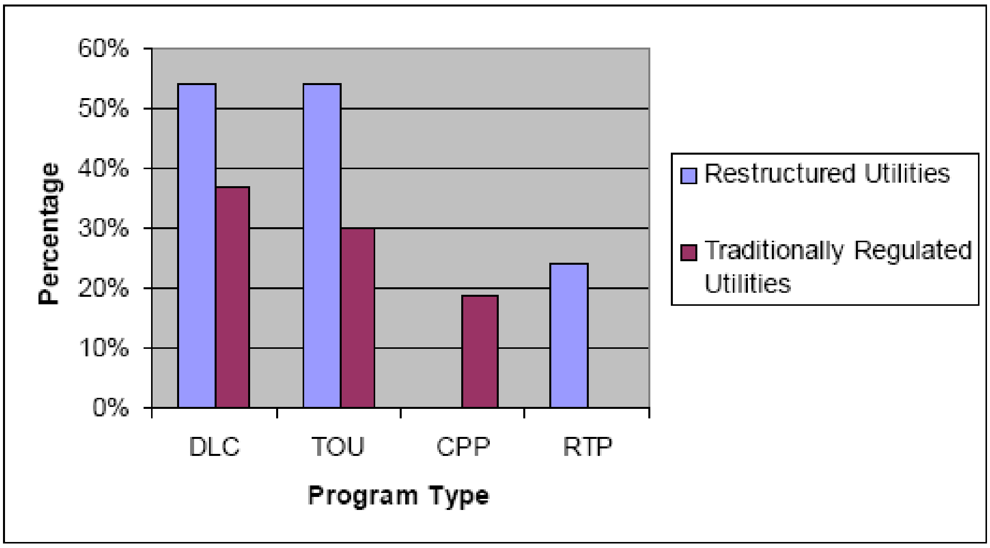
[12] FERC: Assessment of demand response and advanced metering. Staff report. December 2008

[13] The top five entities by customers enrolled in DLC programs are: Florida power light, Progress Energy Florida, Detroit Edison, Baltimore Gas and Electric, and Northern States Power.

[14] The top five entities by residential customers enrolled in TOU programs are: Public Service Co. Of Oklahoma, Arizona Public Service Company, Salt River Project, Southwestern Electric Power Co., and Pacific Gas and Electric Company. The top three entities by number of customers enrolled in CPP programs are: Gulf Power Company, Cass County Electric Cooperative, and Southern California Edison Company.

[15] IEA DSM Task XIII Project Guidebook November 2006 Chapter 4

1.3. Figure: Percentages of traditionally regulated and restructured utilities offering different tapes of residential DR programs (N=40) [16]

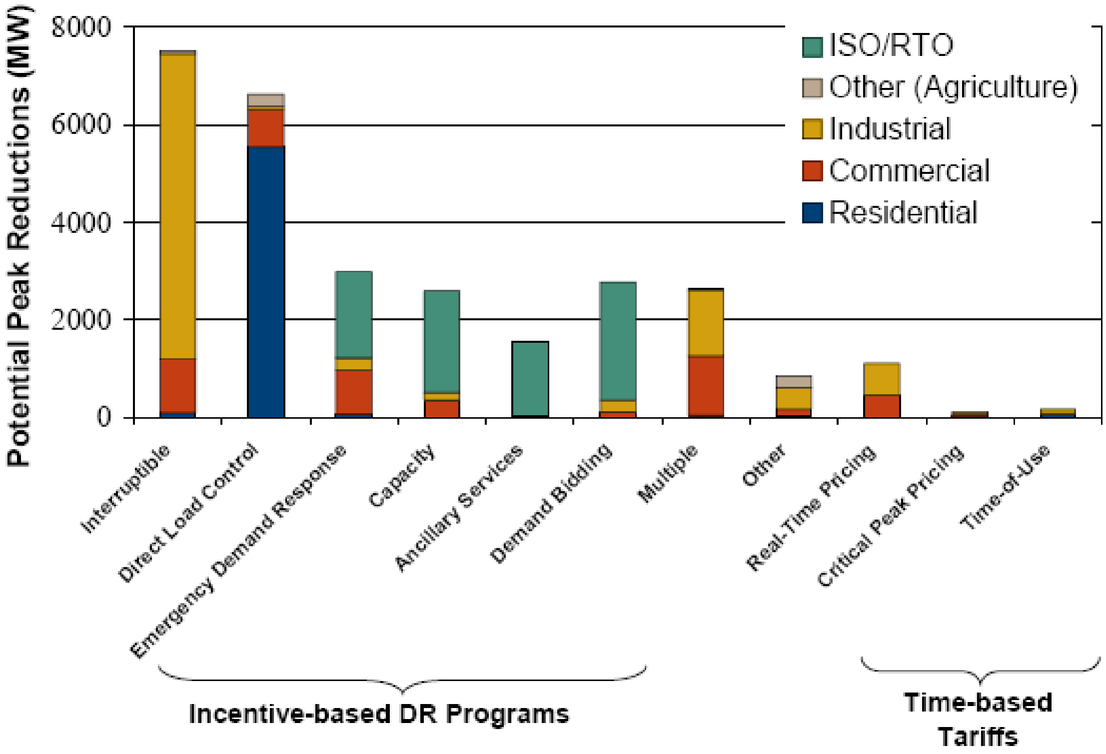


Customer response

The reported programs in the FERC survey provide a potential peak reduction of 29,655 MW which represents around four percent of summer peak demand in the U.S. As the figure below shows, the majority of the estimated demand response potential is associated with incentive-based demand response programs.

[16] IEA DSM Task XIII Project Guidebook November 2006 Chapter 4, p.7.

1.4. Figure: Resource potential of various types of demand response programs and time-based tariffs[17]

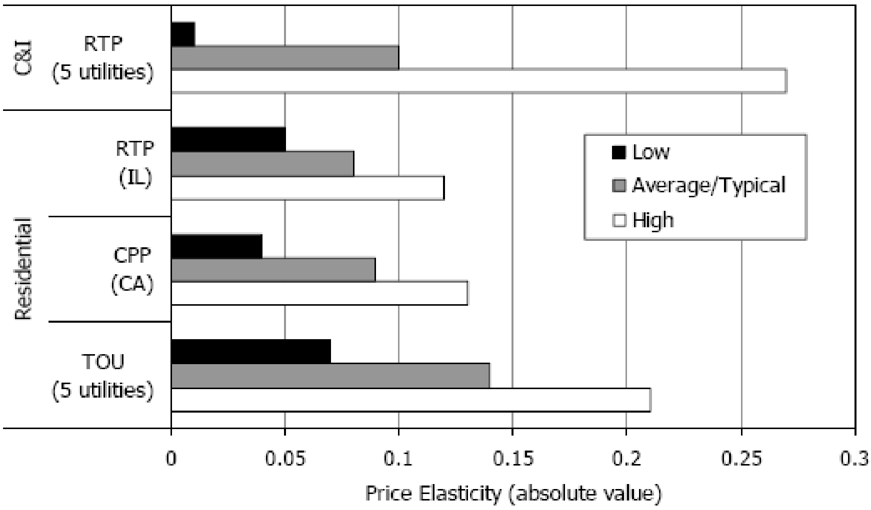


Elasticities

Regarding price elasticities associated with the different types of price-based programs, the U.S. Department of Energy's review of selected studies show that the measured price responses vary in a relatively wide range, but average own-price elasticities among the studies are fairly similar ranging from -0.08 to -0.14, meaning that a doubling of price results in an 8 – 14 percent reduction in electricity usage.

[17] FERC: Assessment of demand response and advanced metering. Staff report. August 2006, p. 83.

1.5. Figure: Customer response to time-varying prices: price elasticity estimates[18]



The significant difference between the low and high elasticity values for commercial and large industrial consumers reflects the heterogeneity of this segment. A study examining 150 customers on RTP tariffs reported the following average elasticity values for the different categories within the C&I consumer segment.

1.6. Table: Own-price elasticity estimates for different categories of Commercial & Industrial consumers[19]

C&I categories	Own-price elasticity
Manufacturing	-0.16
Government/education	-0.1
Commercial/retail	-0.06
Healthcare facilities	-0.04

Substitution elasticity estimates that show how consumers shift usage among time periods in response to a one percent change in relative prices of the time periods in the U.S. are summarized in the table below.

[18] US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. 32.

[19] Ernest Orlando Lawrence Berkeley National Laboratory: A survey of utility experience with real time pricing. December 2004.

1.7. Table: Estimated cross-price elasticities in different price-based DR programs[20]

Program	Customer group	Average	Range
TOU	Residential	0.14	0.07 - 0.21
CPP	Residential	0.09	0.04 - 0.13
RTP	Large C&I (>1 MW)	0.10 - 0.27	
RTP	Large C&I (>2 MW)	0.11	0.02 - 0.16

Based on the reviews the following main findings can be drawn regarding the intensity of consumer price-responsiveness:

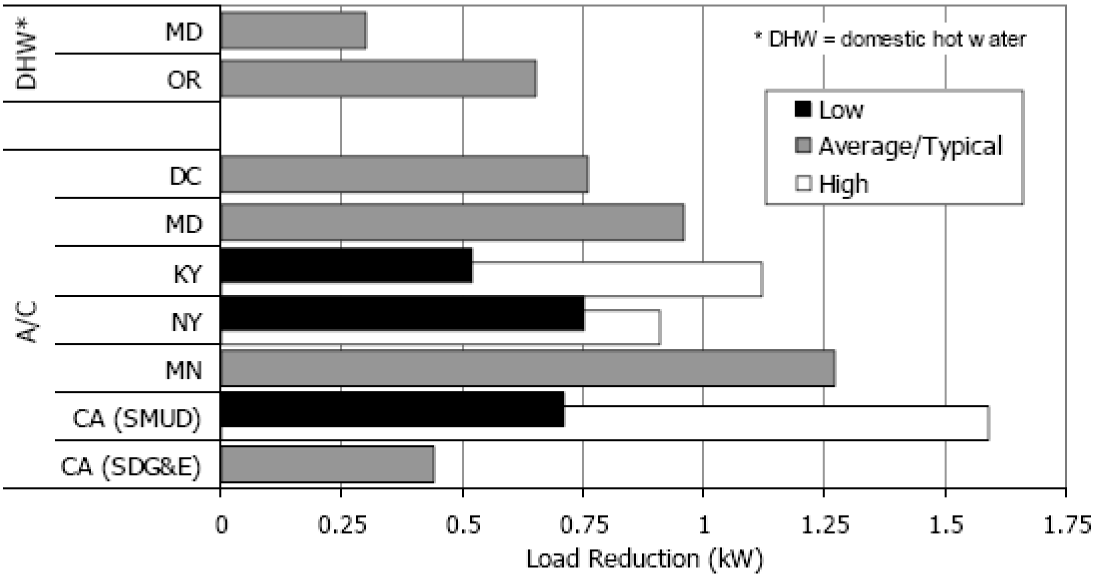
- If consumers are enabled to respond to prices, they will, the observed price elasticity absolute values are higher than zero.
- Elasticity differs for extremely high prices and average prices. Customers on very high CPP rates reduce load by a greater amount than on lower TOU rates.
- Elasticity varies according to consumers. There isn't one universal value of electricity demand elasticity, rather a very large range of elasticities is observed. However it is reasonable to assume that a group of large consumers under RTP tariffs have a substitution elasticity around 0.10 and residential consumers under TOU tariffs also exhibit substitution elasticities between peak and off-peak prices around 0.10 – 0.15.
- The different consumer groups favor different DR programs. Residential consumers tend to have a lower elasticity when exposed to RTP than when exposed to TOU rates. The explanation may be the higher complexity and monitoring need of the former, compared to the simplicity and stability of TOU rates.

Load reductions

In case of load control programs, where customers are not directly responding to prices, responsiveness of consumers is measured in terms of an absolute or relative load impact. The following figure shows estimated values for load reduction of residential customers with water heating (DHW), and air conditioning (A/C). The values vary from 0.3 to 0.6 kW reduction per house in case of residential water heating DLC programs, and from 0.4 to 1.5 kW reduction per customer per course of an event in case of DLC programs targeting residential air conditioning.

[20] US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. 88.

1.6. Figure: Estimated load impacts from DLC programs[21]



1.6. Advanced metering

Advanced metering is one of the key issues in implementing DR programs among middle and small-scale consumers. This section addresses the problem of advanced metering to the extent it is necessary to provide background for the retail market analysis parts of the country studies.

The Federal Energy Regulatory Commission (FERC) defines advanced metering as:[22]

„a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point"

As the definition shows, advanced metering is not just the meter that can store data on consumption but the whole measurement and collection system including the **meter**, the **communication network** and **data management**, the full system is called advanced metering infrastructure (AMI).

[21] US Department of Energy (2006): Benefits of demand response in electricity markets and recommendations for achieving them: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. 34.

[22] FERC: Assessment of demand response and advanced metering. Staff report. August 2006. p. 17.

At present at most small-scale consumers standard electromechanical meters are used to measure the consumption of electricity. These meters mostly measure the kWh consumption which is then read manually yearly or monthly depending on the regulation. Meters of larger commercial and industrial consumers besides the kWh of consumption also measure the maximum demand in kW and other power quality parameters. In some countries two rate meters, which are standard electromechanical meters, except that they give two readings: one for daytime and one for nighttime electricity usage were also installed. Due to technological progress, in recent years solid state electronic meters have appeared which besides enabling automatic meter reading have many additional functionalities compared to standard electromechanical meters, such as the ability to measure loads at lower levels, increased measurement frequency, increased accuracy, data storage capability, measurement of additional parameters, etc. These functionalities besides enabling the use of time differentiated tariffs enhance customer service and facilitate the work of the distribution companies in not just metering but in many other dimensions as well.

Regarding the collection of data in the AMI system typically a fixed network is used for the collection and retrieval of meter data without visiting or driving by the meter location. There are four main types of AMI systems that are used today: broadband over power line, power line communications, fixed radio frequency network, and systems utilizing public networks. All four have their advantages and disadvantages and the decision usually depends on the density of consumers, the availability of public networks, and expected functionalities.

The third major component of AMI is meter data management. Meter data management consists of setting up a place to store the substantial number of collected meter data – in case of hourly meter reading it means 8760 data per customer compared to the 1 or 12 data per customer in case of yearly or monthly reading. Furthermore besides the storage data, meter data management refers to the configuration of metered data to meet specific needs of other utility activities, like billing, forecasting, consumer segmenting, evaluation of demand response programs, tariff packages, etc.

1.6.1. Current deployment of smart meters

A FERC survey in 2005 has found that deployment of advanced metering in the United States was less than six percent.[23] This small percentage is however an average number, and there are states, although very few, which by 2005 already had AMI penetration higher than 20%. Small percentage of installed smart meters characterizes Europe as well, with some frontrunner countries like Italy and France where the percentage of advanced meters was already significant in 2006. Furthermore Italy and Sweden are planning the full roll-out of

[23] FERC: Assessment of demand response and advanced metering. Staff report. August 2006. p. 31.

smart meters by 2011 and 2009 respectively. Denmark, Spain and Finland also have significant plans by 2010 and 2015.[24]

1.8. Table: Smart meter penetration in the US (2005) and in Europe (2006)[25]

United States	
Pennsylvania	52.50%
Wisconsin	40.20%
Connecticut	21.40%
Kansas	20.00%
Idaho	16.20%
Maine	14.30%
Missouri	13.40%
Arkansas	12.90%

Europe	
Italy	86.2%
France	25.0%
Sweden	21.0%
Finland	18.0%

1.6.2. Smart metering from the regulators' perspective

Since the majority of large customers have already installed smart metering, the main regulatory questions concerning advanced metering relate to the introduction of AMI for households and small business customers.

Introducing smart metering for small-scale consumers is not an objective in itself. The first issue that has to be assessed before policy decisions regarding the full roll-out of smart meters to all customers is the costs and benefits of smart metering deployment. In the remainder part of this section we will describe the main costs and benefits of AMI, the issue of cost recovery, and at the end of the section briefly summarize other relevant regulatory issues related to AMI.

1.6.3. Assessment of costs and benefits

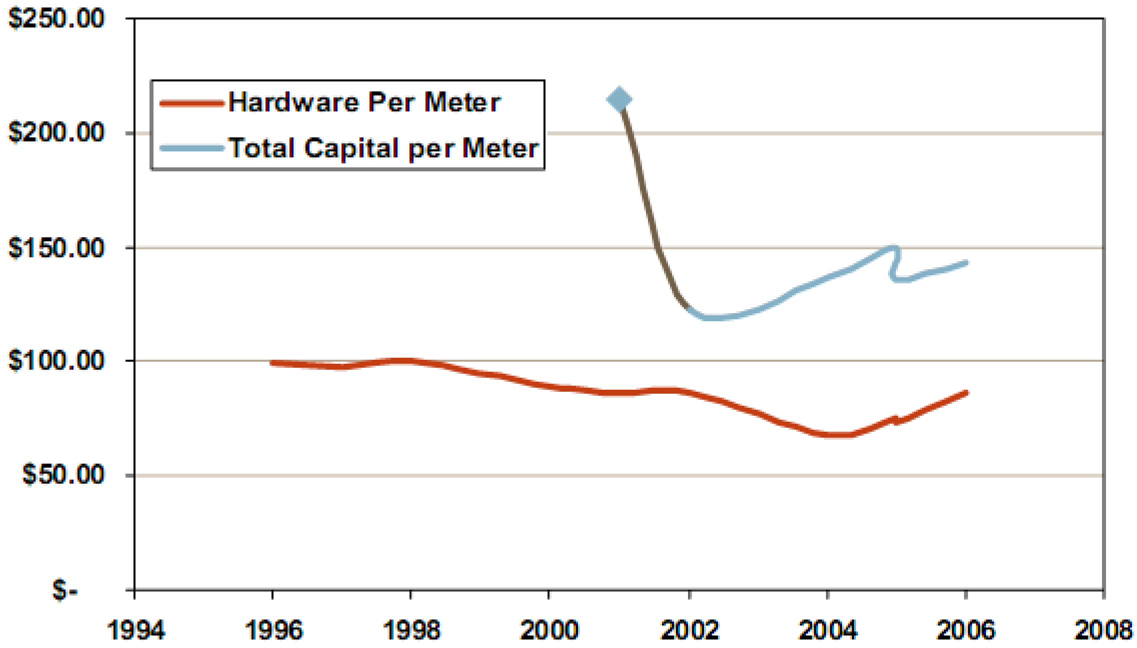
Costs

[24] ERGEG: Smart metering with a focus on electricity regulation. October 2007.

[25] Source of US data: FERC: Assessment of demand response and advanced metering. Staff report. August 2006. p. 30.Source of European data: ERGEG: Smart metering with a focus on electricity regulation. October 2007. p. 43.

The costs of smart meter deployment can be classified into two main categories, the new capital and operation and management costs, and the stranded costs referring to the equipment and system that is going to be displaced by the roll out of AMI. Capital costs include the hardware costs, installation costs, meter data management, and information technology integration costs. The value of capital costs greatly depends on the timing and scale of the roll-out, the lifetime of the meters, and the installation costs. US based estimates of total AMI capital costs and only hardware costs show that while hardware costs have decreased over time total capital costs are rather stable.

1.7. Figure: Total AMI capital and hardware costs per meter[26]



Regarding O&M costs – which include meter reading, service and re-verification - since there is only a limited operating experience, and since implemented technologies vary significantly it is hard to estimate accurately O&M costs in advance. However it is important to know that besides savings on the visits of meter reading, many operating costs like data storage and management, presenting smart metering data to customers, and metering re-verification might become more significant cost items than they are presently.

Stranded costs compared to the new costs are expected to be of minor importance.

Benefits

The benefits of smart metering deployment from the viewpoint of this paper can be grouped into two main categories: benefits from demand response enabled by advanced metering, and

[26] FERC: Assessment of demand response and advanced metering. Staff report. August 2006. p. 34.

additional benefits of smart metering including cost savings on remote meter reading, remote connection and disconnection, reduced theft and technical losses, asset management benefits, outage management benefits, increased customer information and awareness, increased retail competition, etc. The following table shows the benefits realized by different actors in the sector where only 'savings on the electricity bills' relates to benefits from enabling demand response.

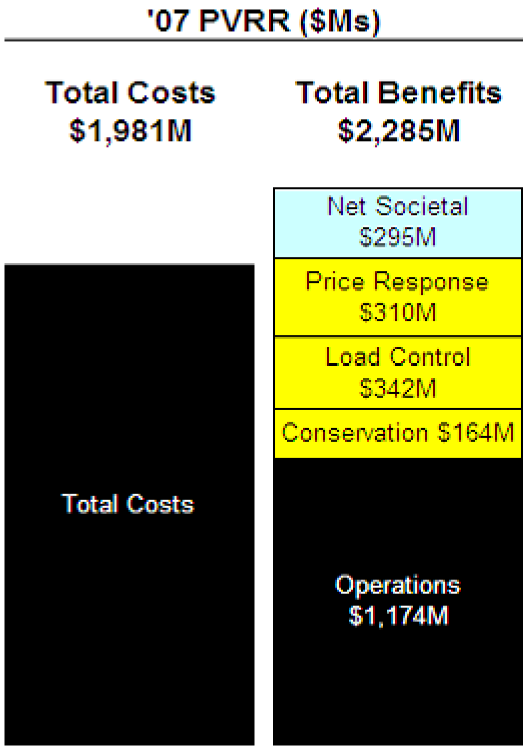
1.9. Table: Benefits of demand response according to different actors in the sector[27]

Consumers	Distribution companies		Retailors
	Network operators	Metering operators	
Savings on electricity bills	Remote connections and disconnections	Cost savings by avoiding manual meter reading	Better input data for designing pricing options and energy management services
Quicker and easier supplier switching	Faster fault location and faster reconnection after outages	More accurate data	Reduction in costs of managing queries regarding bills
Increased competition among retailors	More accurate calculation of network losses and reactive power		Reduced theft
More accurate billing	More accurate monitoring of continuity of supply and voltage quality		Reduced bad debt costs by allowing remote de-energisation
Prepayment options			Cost savings on the administration of switching
			Better planning for balancing

Regarding the quantification of benefits, the Southern California Edison Company (SCE) which plans to install smart meters in every household and business under 200 kW throughout its service territory over a five-year period beginning in 2008 has carried out a thorough cost-benefit analysis (discussed in more detail in the Appendix). According to the calculations, solely the O&M benefits of an advanced meter will be around $1.3601 per activated meter per month, which implies that 59% of the total costs could be saved by O&M benefits. Benefits from demand response and societal benefits would make up for the rest of the costs, yielding a slightly positive net present value for the project.

[27] Based on ERGEG: Smart metering with a focus on electricity regulation. E07-RMF-04-03. October 2007

1.8. Figure: 20 year cost-benefit analysis of the Edison Smartconnect project[28]



Cost recovery

From a regulator's perspective, special attention must be paid to the issue of cost recovery. In this context the regulatory framework becomes relevant. In many countries – including the majority of ERRA countries - the metering service is the exclusive responsibility of the network operators. In this environment, metering is treated as part of the overall network business and is remunerated as part of the network price control. This means that the distributor incurs the cost of purchasing and installing the meters, and these costs as approved by the regulator are recovered from all customers through the network charge, thus at the end all the costs are borne by the consumers. However potential benefits of smart meters are spread across the distributor, retailer and the customers. But assuming that benefits of distributors can be tailored to customers through price regulation, and retail competition will also pass through the retailers' benefits to customers, eventually not just the costs, but also the benefits will find their way back to the customers.

In the international experience it is a frequent solution in such a setting for cost recovery of full roll-out of smart metering, to implement a metering charge that is separate from the distribution tariff. This metering tariff can either be unique on the national level, but then through an equalization mechanism be given to only those DSOs who really invest, and be

[28] Southern California Edison: Edison Smartconnect. CEC AMI Workshop. May 27, 2008.

shared based on the investments they made, or the charge can directly be different for each distribution company, depending on the level of their realized investments.

It is also important to note that while benefits may outweigh costs over the longer term, it is probable that in the early years costs will be higher than benefits due to the high capital costs of installation. It is a question therefore how to recover these costs over time. There are three main approaches dealing with the recovery of metering costs through network tariffs:

- Charges smoothed to reflect costs and benefits over time: The regulated company in this case would incur the costs in the early years but would not be allowed to increase network charges by the same amount. The recovery is rather smoothed out over a number of years. This would result in under-recovery for the network company in the early years, customers on the other hand would face a lower increase in network charges at this time. This solution however could result in financing difficulties for the companies.
- Charges reflective of costs and benefits in any year: In this case charges in each year would be reflective of the costs and benefits of the given year. In the first years the network charge would probably rise and drop steadily thereafter.
- Upfront charge to customer followed by lower charges: Under such regime customers are required to make an upfront payment to cover in part or whole the cost of the meter and the display. The network charge is expected to fall shortly right after to reflect the cost savings.

Other regulatory issues

The European Regulators Group for Electricity and Gas (ERGEG) in its 2007 report on *Smart Metering with a Focus on Electricity Regulation* discusses besides cost-benefit analysis other relevant issues of smart metering and also formulates recommendations that have to be considered by the Member States before forming policy decisions in this question. This paper does not aim to discuss this issue in its full length, however in all three country studies of the paper the issue of implementing smart metering among small consumers will emerge therefore in the following we briefly summarize the main recommendations of ERGEG.

Access to meter data

Detailed and frequent data provision and the access to data by the customer, the suppliers the customer authorizes, and the grid operator has to be provided. Incomplete unbundling however in most countries at present results in an unsatisfactory level of data availability by third parties. One way – according to ERGEG – to ensure non-discriminatory data access is the introduction of an independent meter service provider, responsible for meter data collection and meter data management, other ways could be the introduction of third party accessible data platforms, or complete IT system related unbundling of grid and supply business or a combination of these measures.

Minimum functionality

Since the metering systems are in constant evolution and there are many technologies on the market regulators rather than requiring exact equipments should make minimum requirements on the system level. These requirements should be such that govern operators to implement technologies that entail the pursuance of the objectives of smart metering implementation. At the same time the pursuance of these objectives should not create barriers to innovation and technological progress. AMI systems are characterized by functional and performance characteristics

According to ERGEG the following functions should be considered by the national regulators when determining the required minimum functionalities:

- Remote meter reading
- Load profile data
- On demand meter data access for consumer
- On demand meter data access for 3rd party
- Provision of variable time-of-use tariffs
- Remote meter management
- Remote demand reduction and connection/disconnection
- Price signal to customer

Non-discriminatory use of additional functionalities e.g. remote disconnection has to be carefully outlined by the regulator as well.

Since various communication interfaces will evolve depending on the number of roles and functionalities – e.g. communication between meters and control centres, communication between the meters and the building energy manager system, communications with external display - and due to constant technological evolution several different technologies might be used in parallel with ERGEG recommends that in order to ensure interoperability between different players and applications standards should be defined and used.

2. Country case studies

The purpose of this chapter is to suggest DR methods for implementation which generally fit to the situation of the analyzed three ERRA countries, collect typical barriers, aspects which make the implementation of different DR methods complicated and suggest amendments which allow the implementation of DR methods. To achieve this goal we analyze the capacity balance situation, market structure, legal and regulatory framework and TSO practice of the countries: Hungary, Republic of Serbia and Former Yugoslav Republic of Macedonia. The potential implementation of DR methods is analyzed at three different levels of the electricity market. We first analyze the wholesale market arrangements and current load participation and future possibilities with the focus on making wholesale demand more price responsive and therefore enabling lower wholesale prices in *normal conditions*. The second part focuses on the role of demand-side resources in providing reliability services. The Federal Energy Regulatory Commission distinguishes the provision of regulation services and operating reserves from the operation of the basic price-based energy markets, while recognizing that there are very important linkages between them. We also think that wholesale energy markets and ancillary services markets should be discussed separately from the viewpoint of load participation, since in the analyzed countries, and in the majority of ERRA countries the two markets operate separately. The last part deals with potential DR programs at the level of small-scale consumers.

2.1. Hungary

2.1.1. Country overview

Status of restructuring, the structure of the sector

The Hungarian power sector during the 1990's had been privatized and restructured. Only the nuclear power plant and one small coal fired power plant remained majority government owned, while the remaining 75%[29] of generation is now in private ownership. The distribution and also supplier companies were privatized as well, these six regional monopole companies are now owned by three foreign firms, E.ON (3 discos), RWE (2 discos) and EdF (1 disco). Distribution is by now legally unbundled from supply. After privatisation a 'single buyer' model was implemented (1994-2002), where MVM the remained public company as the public utility wholesaler bought the energy from the generation companies under long term power purchase agreements and sold it to the then monopole supplier companies at regulated prices while suppliers sold the energy to the end users also on tariffs set by the responsible

[29] % measured in reliably available capacity.

minister. Market opening started in January 2003 and by today all customers are free to choose suppliers. Regulated prices however remained as an option for small consumers in the form of universal supply (US): under the universal supply scheme households and other small consumers have the right to be supplied for a price set by the government. The Hungarian universal suppliers are the former monopole supplier/distribution companies. The TSO is legally unbundled from MVM, where the former due to the long term power purchase agreements (PPAs) still in force, had decision power over more than 80% of domestic generation in Hungary in the beginning of 2008. Recently the European DG Competition has declared these long term agreements to be a form of illegal state aid and has ordered their termination by the end of 2008.[30] At the same time the Hungarian Energy Office (HEO) has identified MVM as a market player with Significant Market Power (SMP) and in this relation it had imposed strict rules on its sales activity including a price cap, an obligation to organize an auction and also an obligation to supply the universal suppliers on a price set by the HEO.[31] The figure below illustrates the current structure of the Hungarian electricity market.

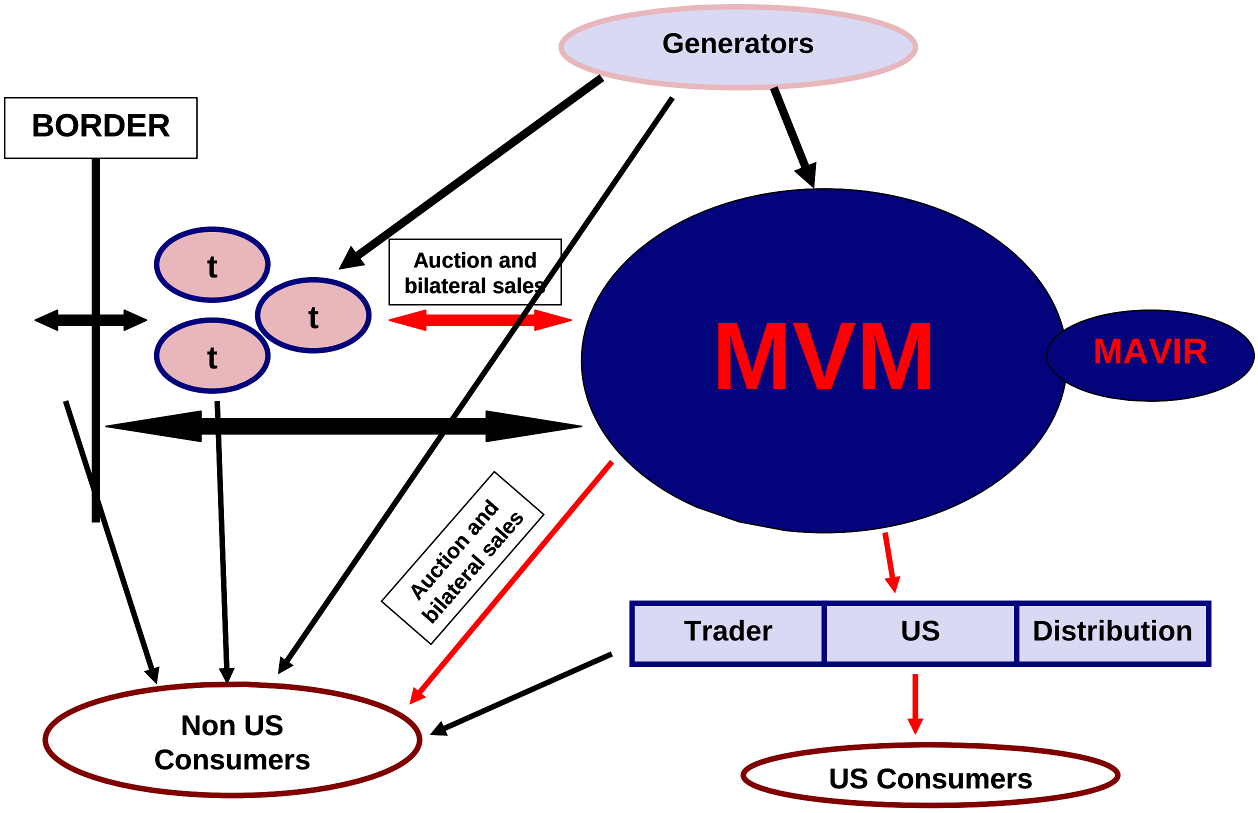
[30] State Aid Decision on Hungarian stranded costs. Case no C41/2005. Decision on 04/06/2008

[31] Regarding the supply of universal suppliers by MVM, the SMP regulation published on July 9, 2008 of the HEO states that the average sale price from January 1, 2009 cannot be higher than 16,5 x (1+FG1/4) x (1+FG2/4) HUF/kWh (1 euro is currently between 260 – 270 HUF) where FG1 is the % change of the regulated gas price in October for consumers with demand higher than 500 m3/h and FG2 is the % change of this price that will take place in January 2009.

Furthermore the Significant Market Player regulation of the HEO states that the weighted average price of all the sales of MVM (including the sales for the USs) for the year 2009 cannot be higher than the weighted average price of the transactions made on the European Stock Exchange between January 1, 2008 – June 30, 2008 for the future delivery period of 2009 for base load – Phelix Baseload Year Futures (with a weight of 70%) - and for peak load - Phelix Peakload Year Futures (with a weight of 30%).

The regulation also states that MVM has to organize an auction on October 27, where the capacity auctioned has to be at least the amount that is needed to decrease the wholesale market share of MVM below 40%.

2.1. Figure: The structure of the Hungarian electricity market from 2009.[32][33]



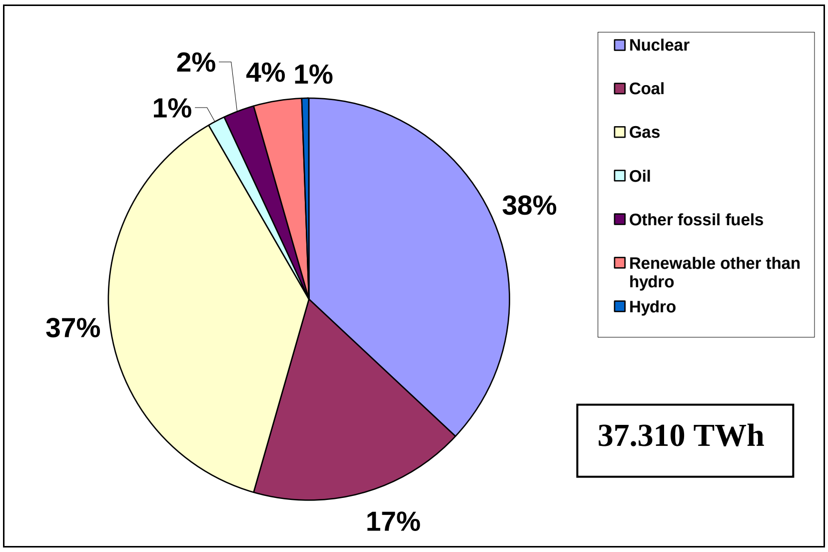
Energy and power balance of the Hungarian electricity system

In 2007 Hungarian net generation was 37.310 TWh while consumption was 41.3 TWh, net import was almost 10%, 3.99 TWh. The structure of generation - shown in the table below – is pretty diversified, and the share of generation depending on weather conditions is negligible.

[32] t refers to traders, US is the abbreviation of Universal Supply, the three connected boxes of trader-US-distribution refer to the 6 incumbent companies that have been legally unbundled to a universal supplier, a distribution company and a trader/supplier company that participates on the competitive market segment, the red lines indicate regulated sales defined by the Significant Market Player Regulation of the Hungarian Energy Office, and the Ministerial Decree on Universal Supply,.

[33] Although usually there is a distinction between the meaning of traders and suppliers, as suppliers are those traders that sell to end-users, while the term trader refers to those actors, who trade energy but do not supply end-users, in this figure we only use the term supplier to the Universal Suppliers, and we use the term trader for also those actors who sell energy to end-users, but on the competitive market segment. In the rest of the study we will use the two words according to this description.

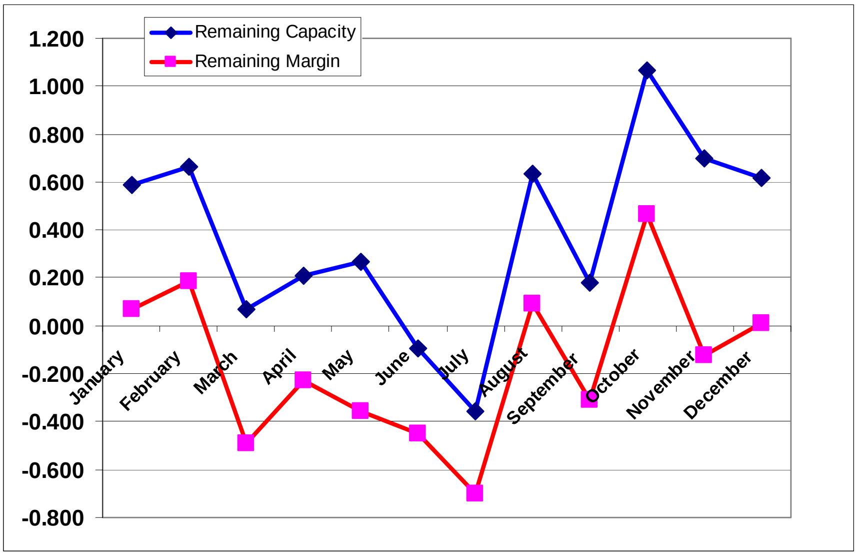
2.2. Figure: Generation mix, 2007



Source: UCTE: System Adequacy Retrospect, 2007

As for the power balance of the Hungarian system remaining capacity which is the difference of reliably available capacity and load, in 2007 was close to zero and in July it was even negative, indicating that the power system is likely to be short of generating capacity under normal conditions. Furthermore, according to the UCTE system adequacy forecast for 2008-2020, before 2017 without load management Hungary is not expected to have the adequate level of generation adequacy.

2.3. Figure: Remaining capacity and remaining margin, 2007, GW[34]



Source: UCTE: System Adequacy Retrospect, 2007

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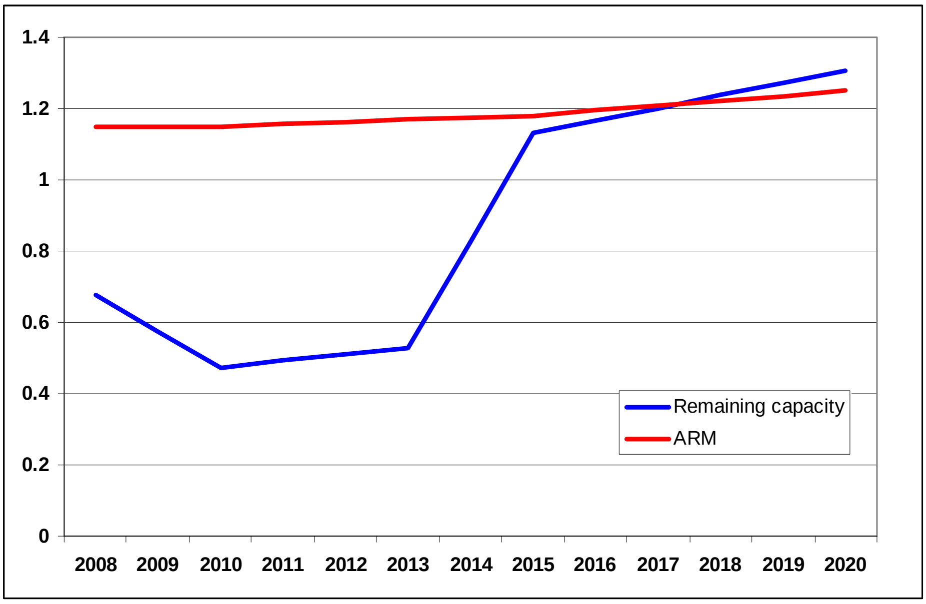
[34] Remaining capacity is calculated as the difference between reliably available capacity and load. Reliably available capacity is the difference between net generating capacity and unavailable capacity. Load is defined as the net consumption corresponding to hourly average active power absorbed by all installations connected to the transmission or distribution grid, excluding the pumps of the pumped storage stations.

Remaining margin is the difference between remaining capacity and margin against peak load, which is the difference between load at the reference point and the peak load over the period the reference point is representative of.

2.4. Figure: Forecasted remaining capacity and adequacy reference margin in the reference point July 11:00[35]

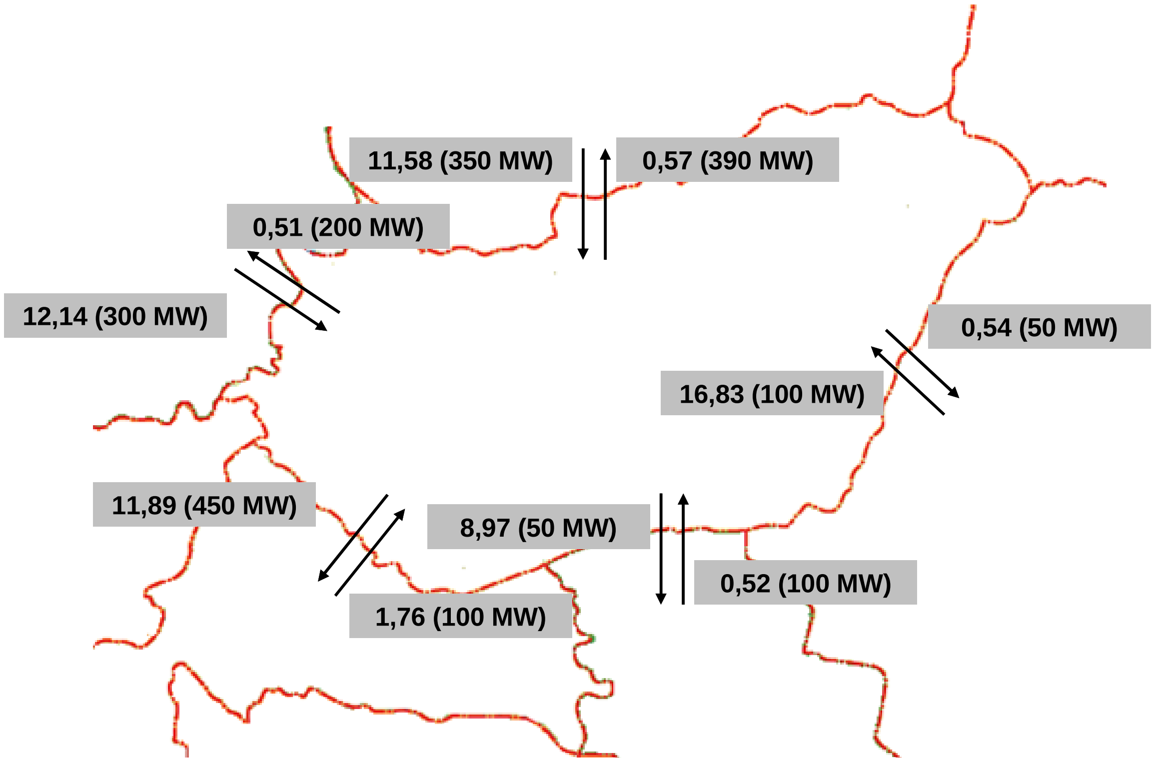


Source: UCTE: System Adequacy Forecast 2008 - 2020

However Hungary is strongly connected to the neighboring grids therefore it is able and is predicted to remain able to import the necessary amount of power to serve load. The results of the 2008 yearly cross border auctions illustrate the typical direction of the international exchanges.

[35] Adequacy reference margin is equal to spare capacity plus the related margin against peak load. Spare capacity is the part of Net Generating Capacity which should be kept available at Reference Points to ensure the security of supply in most of the situations. Spare Capacity is supposed to cover a 1% risk of shortfall on a power system i.e. to guarantee the operation on 99% of the situations. UCTE studies concluded that Spare Capacity could be characterised in each individual country as 5% or 10% of NGC, depending on its system's features; and for a set of countries (regional blocks or whole UCTE) as 5% of NGC.

2.5. Figure: The results of the cross boarder capacity auction for 2008, €/MWh



Source: auction prices: Mavir

Summarizing the above, the adequacy of the Hungarian power system without imports is below and is going to be below the adequate level in the near future. Load management as a domestic source therefore is a great possibility for the Hungarian system to reduce its exposure to international circumstances.

2.1.2. Possible participation of load in the wholesale market

Description and analysis of the wholesale market

The Hungarian System Operator (Mavir) is planning to establish a power exchange from 2010, currently in the wholesale level electricity is bought and sold through bilateral contracts, while at the end of October 2008 MVM - as already mentioned - had to organize an auction for 2009. Bilateral contracts – except for the price set in the contracts between MVM and the universal suppliers, and the final price of the auction – are confidential, therefore prices are not available on an hourly or daily bases to other parties, nor traded quantities or lengths of the contracts. Only historical average monthly prices and quantities are published by the Hungarian Energy office, which unfortunately does not reveal the time structure of the trades.

Time schedule

Mavir is responsible for collecting the schedules submitted daily for each 15 minute settlement period by the balancing responsible parties. In principle not just traders but generators and large consumers can also decide to form an own balancing circle for balancing their own generation and consumption respectively, however in practice out of the 49 balancing responsible parties (BRP) there is only one generator, the rest of the BRPs are managed by traders and suppliers. BRPs submit the schedules by 12:30 and finalize it together with Mavir by 15:15. If a BRP after the finalization of its schedule realizes that it will deviate from it, it can perform modifications until 1 hour before real time, but modification is very restricted, the minimum quantity is at least 5MW, and it has to be reasoned[36] unless Mavir has the right to reject it. This way bilateral intraday trading is also restricted. Mavir procures the reserves needed for ancillary services, and performs intraday balancing and regulation.

From the above it is apparent that short term trades are mostly performed before 12:30 day ahead, after this date only very limited trading is possible. It is also apparent that only traders have knowledge about the hourly (day ahead) price of electricity, consumers do not have any information, therefore do not even have the chance to respond to actual prices by for example selling back their previously bought energy, unless their supplier asks them. Furthermore consumers without a trading license cannot sell energy, thus their supplier is in a monopsonic position in buying back energy, which can result in less demand response than in cases when there is competition for the consumer's surplus energy.

The role of large industrial consumers

Currently 2 of the largest industrial consumers are also licensed traders managing their supply with own procurement and conducting sales when they have surplus, (or when electricity is valued more to the market than for themselves) on the wholesale market. Regarding the contracts made between suppliers and the rest of the large industrial consumers based on a survey REKK conducted in the Summer of 2008 with 11[37] large electricity consumers whose consumption pattern was previously assumed to be more flexible than the average large consumer's, we can state that even more flexible than average consumers enter into fixed price contracts instead of flexible ones. In these contracts the same price is set for the whole year (including fixed price for peak and off-peak periods as well) and usually a schedule is also set which is upgraded weekly, and depending on the consumer's choice a penalty is set if

[36] Acceptable reasons are: the intended modification is larger than 1% of the scheduled quantity, and/or the reason for modification is unavailability of previously obtained cross border capacities.

[37] We approached 14 companies, but two were distrustful and did not want to give an interview, and in another company the engineer did not have spare time for us.

it deviates from the schedule more than an agreed percentage. Consumers receive offers depending on their past profiles and the assumed penalty for imbalance therefore consumer responsiveness and ability to transfer consumption to off-peak periods is only indirectly valued. Regarding curtailment arrangements with suppliers, only 2 consumers said that they have such arrangements and receive discounts for being curtailable, however they did not specify these arrangements due to confidentiality reasons. From our sample 4 consumers said that their supply arrangements directly incentivize them to deter consumption to off-peak periods and one consumer also stated that it is common that its supplier in peak hours offers them to buy back energy and they usually find it profitable to sell the electricity and postpone their production.

Besides energy prices large industrial consumers could be motivated to consume less in peak periods by the structure of the network tariffs. However the Hungarian network tariffs are flat regarding the time of use.

As for the metering technology, we found large consumers to be well equipped with metering and controlling systems, therefore requirements regarding telecommunication and metering for participation in the wholesale market would not be a relevant obstacle.

Regarding the exact amount of curtailability potential of large industrial consumers the table below summarizes the answers of the interviewed consumers. However we find these numbers to be very conservative estimates since only 5 companies had carried out in house curtailability studies recently, the others were unprepared to answer such questions and therefore were very cautious when answering. An other reason for treating these numbers as a lower limit is that one respondent company after the interview in August has offered twice the amount they told us on the yearly tender for ancillary services in September, which could refer to their cautiousness due to strategic reasons. Altogether we can state that there would be a potential for demand response on the wholesale markets if market arrangements would be supportive for consumer participation.

2.1. Table: Curtailability of 11 Hungarian large industrial consumers

Response speed	Curtailable load (MW)	Duration	Frequency
15 minutes	5	2-3 hours	daily
15 minutes	4.5	1-2 hours	monthly
1 hour	30	24 hours	monthly
2 hours	4	48 hours	monthly
2 hours	1	15 minutes	weekly
12 hours	2	30 minutes	weekly
14 hours	6	48 hours	monthly
	52.5		

The role of aggregators

In Hungary small consumers can indirectly contribute to wholesale demand responsiveness by letting their suppliers/DSOs directly control electrical appliances that can be turned off without major inconvenience during peak demand periods (mainly water heaters). The supplier/DSOs in winter must provide electricity for these appliances at least 8 hours a day (6 hours in summer), and from the 8 hours at least 2 have to be during peak hours. These consumers in return receive tariff discounts for the part of electricity that is consumed by the controlled appliances. This system was introduced when the sector was vertically integrated. Today these appliances are controlled by those companies which have bought the distribution/supplier companies during privatisation.[38] The tariff for this direct load control is set in the ministerial decree for Universal Supply. The tariff is more than 50% lower for this consumption than for the consumption which is not directly controlled. This 50% discount is given in both the energy and the distribution network part of the tariff, (which shows that not just the distribution companies but the legally unbundled supplier companies also have an interest in some way in this load).

These companies this way can work as aggregators and use the responsiveness of small consumers to react to high intraday prices by directly cutting off these appliances. Unfortunately recent data on the consumption pattern and details on the controllability of this load is not available. A report prepared in 2003 suggests that around 1604 MW load participates in this program. Also according to the report, the appliances reach their maximum load within 30 seconds after the switch on by the supplier/DSOs and after that consumption starts to decrease in an exponential manner reaching zero after 6 hours. About the practice of usage of these appliances the report suggests that these appliances cannot be individually controlled but only within larger groups and usually the groups are turned on twice a day, in the afternoon and at night.

Other aggregators besides these supplier/DSOs are not present yet in the Hungarian market, however after market opening it becomes a relevant question, what will happen to the rights of controlling this already established system if the individual consumers leave the universal supplier. On one hand an option could be that the distribution network company controls and publishes in advance the timeframe, profile of this load. This way alternative suppliers could also calculate the costs of supplying this energy and could give an offer for this profile similarly to the incumbent universal suppliers. However with such a practice the potentials in the controllable load will not be fully exploited, it would serve only as a time of use tariff, and reaction to spot prices or ancillary service calls will not be an option.

[38] By now distribution had been legally unbundled from supply. Today the control of these appliances is done by the distribution companies, however since the distribution, universal supply and the trading and supply activities on the competitive market segment are all under one ownership it can be assumed that the distribution company controls this load in a manner that best fits the needs of the holding, i.e. the supplier companies' interests are also taken into account.

Another possibility for aggregators to emerge is to create a portfolio consisting of some large industrial consumers. Since our interviews showed that most of them do not have the necessary knowledge about the electricity market, and they do not want to build up an own trader, neither want to assume risks regarding electricity, a company could specialize in aggregating 3-4 such consumers and offer them a product that has clear rules and a predictable revenue stream.

International experience of load participation at wholesale level

Theoretically load can participate in the wholesale market or it can make wholesale demand more price responsive by participating in real-time pricing programs, or in demand bidding/buyback programs, or indirectly by contracting with aggregators for direct load control. Implemented programs are described in more detail in Section 1.5 and in the Appendix, however we can state that real-time pricing programs and demand bidding/buyback programs related to high prices not security reasons, are usually still not common, although there is a positive trend in participation.

Usual barriers for such participation found in West-European countries, Finland, Netherlands, Norway, Spain, Sweden, and UK can be classified into six groups: technical, structural, legal, ignorance, financial and tradition. Technical barriers are the need to control and monitor demand. While this requisite imposes only modest costs on large consumers, smaller consumers could find it a real obstacle. Structural and legal barriers in these countries refer to program rules and obligations that usually do not permit the participation of small consumers. Ignorance is one of the major obstacles of DR, since participation in a DR program requires a significant change of mind-set and processes for a firm: they have to change from a production maximizing mode to a short-term variable cost optimization. Financial benefit is the key driver for demand response, therefore low prices will not trigger DR. Tradition is the final main category of barriers found. Consumers locked in long term contracts and accustomed to fix prices are hardly willing to change, and also the other side of the market, suppliers and market operators, do not yet consider DR as a real market participant.

Evaluation of load participation possibilities in the Hungarian wholesale market and identifying barriers

International experience and implemented programs of other countries cannot be simply applied to the Hungarian wholesale market. Real time pricing and demand side bidding programs requisite that consumers are provided with price information, i.e. price transparency which is currently absent in Hungary. Furthermore for demand side bidding, organized pools provide more direct possibilities than bilateral markets. As we have noted, in a bilateral market only those consumers can actively sell back their energy, who also have trader license, or who are offered such a possibility by their own suppliers. Aggregators however as suppliers, who aggregate directly controllable consumption could be able to operate effectively on a bilateral market as well. Although as discussed in the previous part, in Hungary there are actors who can be called aggregators, their actions do not clearly reflect the theoretical aggregator behavior. Their control of consumption is too rigid, does not react to daily prices but is decided in advance, and they do not use their controlled load as a bid to the daily market. Also due to the inheritage of the vertically integrated years, the ownership and rights for controlling this load is not clear.

The barriers identified by the Western-European countries also pertain to the Hungarian market most importantly ignorance and tradition. Many large consumers in our survey said that they do not want to bother with electricity, because their main activity is production, and they do not want to spend money and time on such a different activity than their main focus. This attitude further enhances financial barriers, since these consumers require higher financial benefits then a more open minded only profit maximizing actor would, to engage in projects dealing with electricity daily. Another psychological fact also hinders the spread of active consumers on the wholesale market: if a firm pays high prices, then it is a realised cost the firm focuses on, however if a firm misses the opportunity to sell energy at high prices this opportunity cost gets almost no attention. Such factors altogether create higher financial barriers. The obstructive effects of tradition are even greater in Hungary than in western-European countries, since the Hungarian market only opened up recently, and market participants are only learning the functioning of the electricity market since recently.

Altogether we can state that load participation on the Hungarian wholesale market is currently restricted to very few large consumers, who either trade themselves, or sell back their energy to their suppliers and to the quasi aggregators, who do not really exploit the possibilities they have. The main barriers for further load participation are **lack of price information, consumers' disability to sell back energy to other than their suppliers, the absence of a centralized market which could facilitate consumer sell-back to any participant, consumer ignorance, tradition, lack of knowledge about the electricity market, and the unclear setting of the established direct load control system**.

Role of policymakers, regulators, and system operators in promoting load participation and suggestion of potential amendment

As it is apparent from the identified barriers, the existence of a power exchange could solve the current problems of price information, transparency, and alleviate consumer sell-back. Furthermore a power exchange, with accessible price information would make the alternative costs emerging from not selling back energy when prices are high more visible and therefore sensible for consumers.

- Thus assisting and advocating the establishment of an electricity exchange would be reasonable for the policymakers, the regulator and the TSO (currently in charge to set up the exchange) from the point of view of facilitating demand response as well.

Until and besides the operation of the exchange the policymakers and regulators could make the following actions to overcome the current barriers to demand response:

- Organize workshops for large consumers to inform them about the operation of the electricity market, the structure of the tariff, etc.
- Try to give as recent and as many price information as it is possible
- Examine the possibility for providing a simplified trading license that could allow consumers to sellback to any player, with lower costs than the current trading license.
- Analyze and clarify the ownership of the established small consumers' load curtailment system, with regards to the legal unbundling of the DSO and the supplier and also regards to the possibility of new entrants.

From the interviews with large consumers we found that although theoretically there is possibility for making time differentiated prices, i.e. advanced metering is in place, most large consumers were on a fixed rate. This situation we think is on one part due to the consumers' unwillingness to change their earlier practice, but on the other part was also due to the lack of competition on the market, traders were not motivated to compete, and to offer different possibilities. This situation arose due to the high level concentration of the wholesale market, MVM's dominance, and also the priority given to MVM on the Slovakian interconnection which is one of the main import source. Very few traders had the possibility to procure energy for the year 2008 besides MVM. And this situation led to lack of competition for consumers on the competitive market, and resulted in high trader margins.

The situation due to the described decision of DG Competition and the auction ordered in the HEO's SMP regulation, and the expected non-discriminative allocation of the cross-border capacities this year hopefully will decrease the market concentration for the year 2009, and might result in more time-differentiated contracts. Therefore we think that further regulatory action is currently not needed besides the above described steps to inform and educate large consumers with workshops so that they would be better prepared when negotiating with traders.

A possible role for the TSO in facilitating load participation on the wholesale market could be

- To loosen the time structure of scheduling, and the terms for schedule changing, allowing for more intraday trading. In this way price responsive loads could have more possibility to offer their curtailability for traders.

2.1.3. Possible participation of loads in providing ancillary services

Typology of ancillary services

Reviewing international markets shows that there are many possible arrangements for providing ancillary services. Hungary when creating its arrangements as the member of UCTE takes into account the UCTE guidelines and minimum rules, however within the limits it has created unique Hungarian elements as well. The following ancillary services are specified in the Operation Code of the TSO, Mavir.

Primary control of load – primary regulation

Primary regulation is the first attempt to restore frequency deviation after an imbalance between demand and generation occurs. The primary regulation generation unit automatically modifies its capacity level (MW) downwards in the case of higher frequency than nominal, and upwards in the case of lower frequency than nominal. Its maximal amount per unit is around 5% of the installed capacity. The response speed of the primary reserves is less than 30 seconds, where half of the reserves should be available after 15 seconds.

Secondary control of load – secondary regulation

The function of secondary control is to keep or restore the power balance, to restore the system frequency, ensuring that the full reserve of primary control power activated will be made available again. Secondary control reserves are provided by generators and are activated centrally within 30 seconds – 5 minutes. Is minimum value is 10 MW.

Tertiary control of load

In Hungary there are two types of reserves specified for providing tertiary regulation:

- Minute reserve
- Hourly reserve

Minute reserve

Minute reserves are reserves supplied by either generators or consumers, which have a regulating speed greater than 10 MW/15 min and can be used through one or more settlement periods.[39] The system operator notifies the supplier at least 15 minutes before its use. It supports secondary regulation. Is minimum value is 5 MW.

Hourly reserve

[39] A settlement period is 15-minute-long.

It is a reserve that is either operating or is ready to operate, is provided by either generators or consumers, and its response time is more than 15 min. Its minimum value is 10 MW. It supports minute regulation.

Other services

Emergency reserve

This is a Hungarian specialty. MVM has three gas turbine plants at Lőrinc, Litér and Sajószöged with 410 MW installed capacity. There is a long term purchase agreement between Mavir and MVM where Mavir pays for the availability of these reserves throughout their life-span. These plants provide service close to secondary reserves they can be used within 15 minutes and are used for regulation when other regulating reserves are not enough to keep the system in balance. Black start service is also provided by one of the three plants.

Black start, and Voltage-reactive power control

As loads will not sell black start and voltage reactive control services, while providing emergency reserve is not an option for any participant besides the mentioned three MVM power plants, in the proceeding analysis we will only focus on the first four types of services (primary control, secondary control, and the two tertiary control services) that theoretically could be also supplied by electricity consumers.

Procurement arrangements

Quantities

Regarding the regulation and reserves volumes due to the interdependency of the neighboring countries, UCTE has set formulas to determine the indicative volumes that have to be procured in its member states. From the following table it is apparent that Mavir takes into account these protocols but while it procures a bit less in downward regulation, it procures almost two times more upward regulation as UCTE suggests. This shows that the Hungarian TSO finds the need for upward regulation a lot more severe than its basic technical parameters would indicate. Load as a resource for upward regulation therefore has good possibilities in the Hungarian system.

2.2. Table: Comparison of UCTE protocol and Mavir's practice in ancillary services procurement

	UCTE protocol	Mavir procurement for 2009

<table>
<tr><th>Reserve type</th><th>Volume / Direction</th><th>Volume / Direction</th></tr>
<tr><td>Primary</td><td>± 50 MW</td><td>± 40 MW</td></tr>
<tr><td>Secondary</td><td>± 150 MW</td><td>+ 270 MW
- 150 MW</td></tr>
<tr><td rowspan="2">Tertiary</td><td rowspan="2">+ 450 MW
- 150 MW</td><td>Minute reserve:
+ 101 MW
- 50 MW</td></tr>
<tr><td>Hourly reserve:
+ 500 MW</td></tr>
<tr><td>Emergency reserve</td><td>-</td><td>+ 410 MW</td></tr>
</table>

Procurement and Compensation

In order for a supplier to be able to make bids for supplying ancillary services it has to have accreditation which can be obtained through the accreditation process conducted by the system operator. In this process the TSO checks the parameters needed to provide a given ancillary service, and investigates how the applicant could be connected to its information system, and how it could be controlled by the TSO.

For the procurement of ancillary services mentioned above, with the exception of the emergency reserve, the system operator organizes a tender in September/October every year to assure the availability of offers for the next year. In the case of primary reserves, black start and voltage-reactive power control services the winners of the yearly tender are the suppliers of next year. In the case of secondary, minute and hourly reserves the system operator in the yearly tender of these services selects 'the winners' with whom it signs a 'marketmaker' contract which means that these actors are obliged to bid on the daily market and the TSO is also obliged to accept these offers. The TSO can also decide to sign 'optional' contracts with the not selected applicants which means that these suppliers can – if they want to – participate on the daily market and Mavir has the right not to contract with them daily, it will mainly depend on their offered availability and energy price.

Thus on the daily market those with a marketmaker contract offer an availability and an energy price - where both prices cannot be higher than the ones set in the marketmaker yearly contract. This implies, that there is no real competition among these actors, therefore they will not compete with their availability price bids. However they might be motivated to compete in the energy price, because Mavir activates the available reserves in the least cost manner, i.e. those providers will be activated with larger probability who offer a lower energy price. Furthermore if there is not enough capacity offered by the marketmakers for a given day those actors with an optional contract can bid into the daily market an availability and an energy price (both subject to the price ceilings set in their yearly contract) and these actors could have a motivation to compete. Nevertheless in this procurement setting there is not much space for real competition on the daily level.

As for the bidding parameters, in the yearly tender the suppliers in their bid state their price of availability per hour (HUF/MW/h) for up and downward regulation (the availability price for the downward regulation is set to maximum zero HUF/MW/h), in the case of secondary, minute, and hourly reserve the energy price has to be stated as well, taking into account the maximal limit prices set in the tender specifications. For secondary and minute reserve bidders have to give their gradients, and for hourly reserve the response time and maximum duration has to be stated. Regarding the offered capacities, bidders have to indicate for each day of the year their offered capacity volume (MW), which for those who earn marketmaker contracts has to be the same in each hour of a given day, but bidders can offer different volumes for different days. The tender specification also sets minimum levels for the bids, which interestingly have doubled from 2008 to 2009, and are also twice as high as the minimum levels defined in the operational code:

2.3. Table: The minimum bid requirements for the 2008 and 2009 tender for ancillary services

Reserve type	2008	2009
Primary reserve	+3/-3 MW; +10/-10 MW; +16/-4 MW; -16/+4 MW	+3/-3 MW; +10/-10 MW; +16/-4 MW; -16/+4 MW
Secondary reserve	10.0 MW	20.0 MW
Minute reserve	5.0 MW	10.0 MW
Hourly reserve	10.0 MW	20.0 MW

The selection criteria for secondary and minute reserves are the availability prices (80%/75%), and the gradients (20%/25%), for the hourly reserve the availability price (70%), the maximum duration (20%), and the response time (10%).

Technical requirements for load

As it is explicitly written in the ancillary services definitions of the Operation Code of Mavir introduced above, primary and secondary regulation can only be provided by generators. For minute and hourly regulation the TSO can award accreditation to consumers as well. In the case of these two services technical requirements are the same for loads and generators, the specifications summarized in the table below are source neutral. Primary regulation currently is unlikely to be provided by load, however secondary regulation as international experience shows could be an option in the near future, therefore we also show the technical requirements for secondary regulation even though currently loads are not allowed to provide it.

2.4. Table: Technical requirements for ancillary services

Regulation	Minimum size	Communication	Activation	Response time	Duration
Secondary	2009 tender: 20 MW (operation code: 10 MW)	SCADA	Controlled by TSO	0.30 - 5 minutes	Few minutes

Minute	2009 tender: 10 MW (operation code: 5 MW)	Real time metering	Manual, by consumer	< 15 min	Few settlement periods
Hourly	2009 tender: 20 MW (operation code: 10 MW)	Real time metering	Manual, by consumer	> 15 min	Hours

Technical requirements for communication and activation in the case of minute and hourly reserves can be easily met by large industrial consumers, control requirement of secondary regulation however needs special investments from consumers, and it is not straightforward as it is for generators, how the consumers' units could be equipped to provide this service.

The results of the 2009 tender and past experience of load participation

The yearly tender for the procurement of reserves for 2009 was held in September 2008. For the first time a consumer also participated by bidding in the hourly reserves market. The consumer Borsodchem (also has a trading license) gave bids for its production units in its chlorine plants. The bid sizes were surprisingly high and all won in the tender. The results of the 2009 hourly tender published by Mavir are the following:

2.5. Table: Results of the yearly tender for hourly reserves for 2009

Bidder	Quantity	Number of availability hours	Availability price	
	[MW]	[h]	[HUF/MW/h]	[~EUR/MW/h]
EFT Budapest	40	8760	1409	5.22
	40	8760	1458	5.40
	40	8760	1482	5.49
	40	8760	1507	5.58
	40	8760	1531	5.67
	80	8760	1555	5.76
Rudnap - Hungary	35	8760	1555	5.76
Borsodchem	95	2808	1550	5.74
	85	1464	1550	5.74
	80	2928	1550	5.74
	55	1056	1550	5.74
	45	504	1550	5.74
Dunamenti power plant	90	2808	1850	6.85
	100	1440	1850	6.85
	130	1056	1850	6.85
	140	504	1850	6.85
	105	2808	1850	6.85
	159	144	1850	6.85

As the table shows Borsodchem gave a compeititve bid, and was even cheaper than the last bidder whose bid was accepted, showing that consumer participation can increase competition and efficiency by driving down prices also in the ancillary services markets. After the announcement of the results of the tender we conducted a second interview with Borsodchem. To the question why did not they bid before in this market, the answer was that the person who organized the bidding from their part was only hired in the beginning of this year, and he has reformed the electricity procurement and trading of the company since then. This is again a proof for the importance of ignorance and lack of information and knowledge of the staff at industrial consumers: they had the capability before, but not the knowledge and willingness. They told us how they had to fight for this bid within the company and that convincing the staff and explaining them how the ancillary market works took the most time. They also know the other consumers' staff, and they also think that the biggest reason for their non-participation is the same as it was at Borsodchem previously. Table 2.2 on the curtailability of consumers participating in the survey shows, that there are more consumers who could participate on the hourly reserve market but somehow they did not appear on the tenders so far.

As for the minute reserves, consumers have not made any bids yet on this market, however in 2005 Mavir started negotiations with the aluminum producing company MAL (which refused to give us an interview). Furthermore, Borsodchem said that they were thinking in providing minute regulation, the only problem was that the required gradient was too fast for them, and it would have caused too many inconvenience, however they will reconsider the participation next year. Borsodchem did not find secondary regulation attractive due to the frequent modifications it requires and the necessary technical investments.

International experience

Since almost each country has a different arrangement for ancillary services, we cannot compare directly the different markets and products, but we can say that international experience - discussed in detail in the Appendix – shows, that there is evidence for active load participation in providing ancillary services that are very similar to the Hungarian secondary, minute and hourly regulation services. These loads participate in pilot projects and even on markets where they compete with generators. Therefore we believe that with strong support from the regulator and the TSO, Hungarian consumer participation could also flourish in the future.

Identifying barriers to load participation in the Hungarian ancillary services market

From the surveys we found that although there are technical limitations for many load to provide ancillary services, for those that would be capable to do so, the main barrier is the lack of knowledge and the mind-set and willingness of the staff. Besides this problem other parameters from the procurement process can also be identified, which would hinder the participation of loads willing to provide the services. These are the following:

- In the case of hourly reserves
    - The minimum bid size (20 MW) set in the tender is unduly high, excluding possibly most of the potential consumers. The operation code sets the minimum size at 10 MW and the earlier tenders for example the tender for 2008 also set the required minimum reserve size at 10 MW. Thus there is no valid reason for setting such high minimum levels. Furthermore smaller but more reserves are considered to be more secure than fewer but larger ones, since the fallout of one participant would have a smaller reliability effect in the former than in the latter case.
    - The requirement of the marketmaker contract, that only those bids are accepted which offer the same reserve size for each hour of the day can be a barrier to many load since the costs of participation could be significantly different during the day and the night. Many international pilot projects not surprisingly limit the requirement for participation to e.g. 7:00 – 21:00.
- In the case of minute reserves
    - Besides the high minimum bid size and the mentioned requirement for providing the same reserve size for 24 hours, the gradient size can also be considered as a too stringent requirement. The same gradient is expected from the reserves providing secondary regulation as from the reserves providing minute regulation. The only main difference is the way of notification and activation of the reserve. It is not clear why is it necessary for a tertiary reserve to have the same potential as a secondary one. Based on the interviews we can say that a bit slower gradient requirement for the minute reserve could foster load participation on the minute reserve market as well.
- In the case of secondary reserves
    - The main barrier is the definition of the operation code, allowing only generators to provide such service. While currently consumers do not find the provision of these reserves attractive, the chance should be given.

Role of policymakers, regulators, and system operators in promoting load participation and suggestion of potential amendments

Based on the identified barriers we think that one of the most important role of the regulator and the TSO is to change the current attitude of industrial consumers by providing information on how ancillary services markets operate and what are the participants' opportunities on these markets. This information provision could be delivered in the form of workshops.

The TSO together with the regulator should also reconsider the above identified barriers in the operating protocols regarding minimum sizes, tender requirements, gradients, and source neutrality.

Furthermore, setting up a pilot project (in the first phase for a product similar to the hourly reserve) would build confidence and provide experience for both the consumers and also the system operators who also have to learn how to handle these type of service providers. A pilot project could also help the system operator to fine-tune the technical requirements of ancillary services and thus create a 'consumer friendly' environment. Regulators could actively participate in the pilot project by monitoring its operation, consulting and if needed by providing financial support.

Even without the organization of the pilot project a stakeholder process should be developed, where potential providers together with the system operator and the regulator work through the participation details: technical requirements and business rules.

Finally the system operator should conduct test runs and technical assessment with the controllers of the current direct load control system to find out whether it could be used for providing ancillary services or not. Furthermore the definition of secondary regulation in the operation code could be changed to allow also consumers to provide such service.

2.1.4. Possible load participation on the retail level

Description of the retail market

According to the second electricity Directive – 2003/54/EC – electricity markets of EU Member States should have been fully opened from July 1, 2007. In Hungary full market opening commenced with a small delay in January 2008. Before this date all consumers except households were already eligible to choose suppliers, however they also had the right to buy electricity from the public supplier for a price set by the government. Therefore a kind of hybrid model was in operation, where eligible consumers switched back and forth between the competitive and the public sector depending on the prices of the two. After full market opening the market structure changed and the public suppliers became simple traders and suppliers. However the Directive left the opportunity of setting governmental prices to small consumers in the form of universal service, in Hungary the former public suppliers obtained the license for providing this service on their former territories. The Hungarian universal service is currently very similar to the former public service, the prices are set in a ministerial decree and they can be considered modest, since no other supplier has given offers to these consumers. Furthermore universal suppliers obtain the necessary amount of electricity from MVM in an administered way already discussed in the previous part. The biggest change that the full market opening has brought to the market therefore was not the households' introduced eligibility to choose suppliers but the termination of the possibility for larger consumers to obtain electricity for governmental prices. Governmental prices are only available now to those consumers who are eligible for universal service, which in 2008 was mainly households and few non-household but small consumers, covering around one-fourth of total electricity consumption. From 2009 the limit of eligibility for universal supply for electricity was raised in the new Gas Act, and it is expected that the consumption of eligible consumers' will amount up to one-third of Hungarian consumption. On the whole, we can say that at least two-third of the Hungarian retail market (amounting to 26 TWh) is now open for competition, contestable for new entrants.

Prices – price structures

Energy part

Regarding the price structures for retail consumers not eligible for universal supply, there is no public information on the relating contracts, but due to the current scarcity of advanced meters that can store data on consumption, probably the majority of these consumers are supplied for a fixed price, and since fixed price contracts are the most common even within the largest consumers who have advanced metering, this kind of inflexibility should characterize this consumer group on the whole.

In the case of universal supply, the relating ministerial decree defines three tariff categories. A1 is a fixed priced tariff (36.01 HUF/kWh), A2 is a time of use tariff (40.25 HUF/kWh in peak: 6:00-22:00. and 30.25 HUF/kWh in off-peak: 22:00 – 6:00), and B is the tariff for curtailable load described in the previous section. The majority of consumers is under the A1 tariff and one third of the household consumers also has some appliances that are connected to the direct load control system under tariff B. There are very few small consumers, who were historically equipped with two rate meters, they can choose the A2 tariff.

2.6. Figure: Tariffs for consumers eligible to Universal Supply, 2008 (HUF/kWh)

	A1 tariff	A2 tariff		B tariff
		peak	off-peak	
Price of Universal Supply				
Energy price	18	22.24	12.24	9.81
Suuport for green energy and cogeneration	2	2	2	2
Margin of Universal Suppliers	1.9	1.9	1.9	1.9
Total	20.59	26.14	16.14	13.71
Network charges				
Transmission system operation charge	1	1	1	1
Ancyllary services	0.672	0.672	0.672	0.672
Distribution energy charge	8.9	8.9	8.9	2.68
Distribution network losses	2.7	2.7	2.7	2.07
Balancing of distribution schedule	0.5	0.5	0.5	0.5
Total	13.77	13.77	13.77	6.92
Others				
Supporting the coal industry	0.225	0.225	0.225	0.225
Fund for the pensioners of the electricity industry	0.11	0.11	0.11	0.11
Total	0.34	0.34	0.34	0.34
Total net Universal Supply tariff	**36.01**	**40.25**	**30.25**	**20.97**

The network components of the tariffs in Hungary are flat regarding the time of use, thus they do not provide incentives for lower consumption in system peaks.

Possibilities for introducing demand response among small-scale consumers

Out of the demand response methods discussed in the first section of this paper for small-scale consumers the operation of direct-load control and price-based demand response programs could be relevant options for facilitating load participation. In the following parts we will discuss the possibilities of introducing and/or further enhancing these methods in Hungary.

Possibilities for price-based demand response

The prerequisite for the mass introduction of price-based demand response are the mass roll-out of meters that can store data on the time of consumption, therefore the issue of metering, its current arrangements and future plans is the key question of the introduction of price-based demand response in Hungary.

Status and future plans in metering

In Hungary currently almost all household and small scale consumers are equipped with standard electromechanical meters which are read annually. Metering services are by default delivered by the distribution network operator, they own the meters and carry out maintenance. Network companies are also responsible for making metering data accessible to third parties. Data has to be stored for a minimum of two years, and has to be provided to the customer – if requested - free of charge. The network companies' costs on metering are recuperated through the network tariff, there is no separate metering charge.

Regarding smart meter penetration network operators proposed in the distribution network code (which has been approved by the regulator) that all consumers besides households, consumers below 3*80 Amp, and public lighting, have to be equipped with meters minimally needed to remotely measure the energy usage in 15-minute intervals. For these consumers the costs of the meter and other associated costs are borne by the network company. However regarding the functionalities of these meters remote meter reading and load profile data measurement are just two of the recommended minimum functionalities of ERGEG, the other minimum functionalities are not provided by these meters. If consumers want additional functionalities they have to assume the costs themselves.

If a household consumer wants to have an interval meter, it has to pay the associated costs. At present there is no technical or legal requirement for network operators to install smart meters in households. Furthermore besides the described provisions in the network code, there isn't any stance of the Hungarian Energy Office on the issue of metering functionalities and roll out of smart meters. The energy office plans to launch a tender for consultancy on the issue of smart metering and demand response, including the discussion of possibilities in metering and a cost-benefit analysis. The HEO already had organized a seminar in January on the issue, but since then no further steps have been taken.

Evaluation and suggestion for regulators and policymakers to facilitate price-based demand response among small-scale consumers

Since price-based demand response programs cannot be conducted without appropriate metering, the issue of smart metering has to be clarified first. Therefore the plan of the Hungarian Energy Office to consult in the issue of demand response and metering would be a good action, however this plan has been on the agenda since the Autumn of 2007 and so far, besides the workshop, no steps have been taken. Furthermore besides hiring consultants, a wider consultation procedure should be launched.

In the discussion not just the new implementation of smart meters among small scale consumers should be addressed, but the current practice of distribution companies, that they install interval meters that have very few functionalities should be debated. Installing new meters has a large fix cost, and installing meters that do not even provide the minimum functionalities recommended by ERGEG might not be a forward looking solution.

The issue of metering as a monopoly service could also be investigated. Many other actors, like telecommunication companies, could also provide the metering service. And competition could drive down prices and bring new technology faster than regulation. Therefore deregulation could also be considered.

ERGEG recommendations regarding standardization and defining minimum functionality requirements rather than requiring exact equipments and technology should be considered, and worked out.

If the issue of metering has been clarified and the cost-benefit analysis suggests that such meters should be installed among all consumers, the regulator could discuss the possibilities to offer a TOU tariff or few TOU tariff options under Universal Supply. In this case a field-trial could be carried out to assess what kind of tariff structures would drive the greatest demand response and cost savings to consumers, and whether different consumer segments should be offered different type of tariffs.

Regarding the current TOU tariff offered under Universal Supply, the A2 tariff (energy part: 26.14 HUF/kWh in peak: 6:00-22:00. and 16.14 HUF/kWh in off-peak: 22:00 – 6:00) we think is not a well defined TOU tariff for small consumers since a reduction after 22:00 does not trigger substantial response from residential and small-scale consumers. We suggest its reconsideration.

Possibilities for direct-load control

As it was already discussed in the section on the Hungarian potential aggregators, in Hungary a substantial amount of load participates in a direct load control system, which was established before the restructuring. There is not much data on the potentials of this load, however it is known that the loads cannot be individually controlled, but only in larger groups, and the actual amount of load that could be turned on cannot be monitored, only estimated. The six distribution companies operate these systems in their regional territory. RWE, which owns two distribution companies does not invest in the improvement and development of its system, while E.ON (owning three DSOs) has started major investments to change the communication system to radio frequency, which enables individual remote control.

There isn't any provision by the HEO - besides the price of the service – regarding the technology and controlling of this system, neither any plans for future regulation.

Evaluation and suggestion for regulators and policymakers to enhance direct-load control among small scale consumers

There are many questions regarding the direct load control system that should be analyzed and assessed. Firstly, the price of direct load control is set in the Ministerial Decree for Universal Supply with a 50% discount compared to non controllable load. This discount however is not based on in-depth cost analysis, rather represents a rule-of–thumb methodology. An assessment of cost savings before price setting could be delivered.

Second, a policy regarding the current direct-load control system's future should be developed. The first group of questions relate to the operation, whether the network companies should be required to improve their system, should they further develop it, should they change the technology so that each load could be controlled individually, etc. The second group of questions are related to the ownership of this infrastructure. Can network companies sell the system if they do not want to operate it? Who owns the system, and who controls it – which companies interests are considered when controlling – the suppliers' or the DSOs'? Is it fair that the costs of installation and maintenance are bared by the regulated distribution company and the control maybe done in a way that it helps the supplier who also participates on the competitive market? How should the system work if a consumer contracts with a new entrant? With such a setting do new entrants have a level-playing field to establish their own direct-load control system?

Currently these questions are not addressed, which might result in an inefficient way of the operation of the system. Therefore we suggest an in-depth analysis of the current state and future of this valuable demand response method.

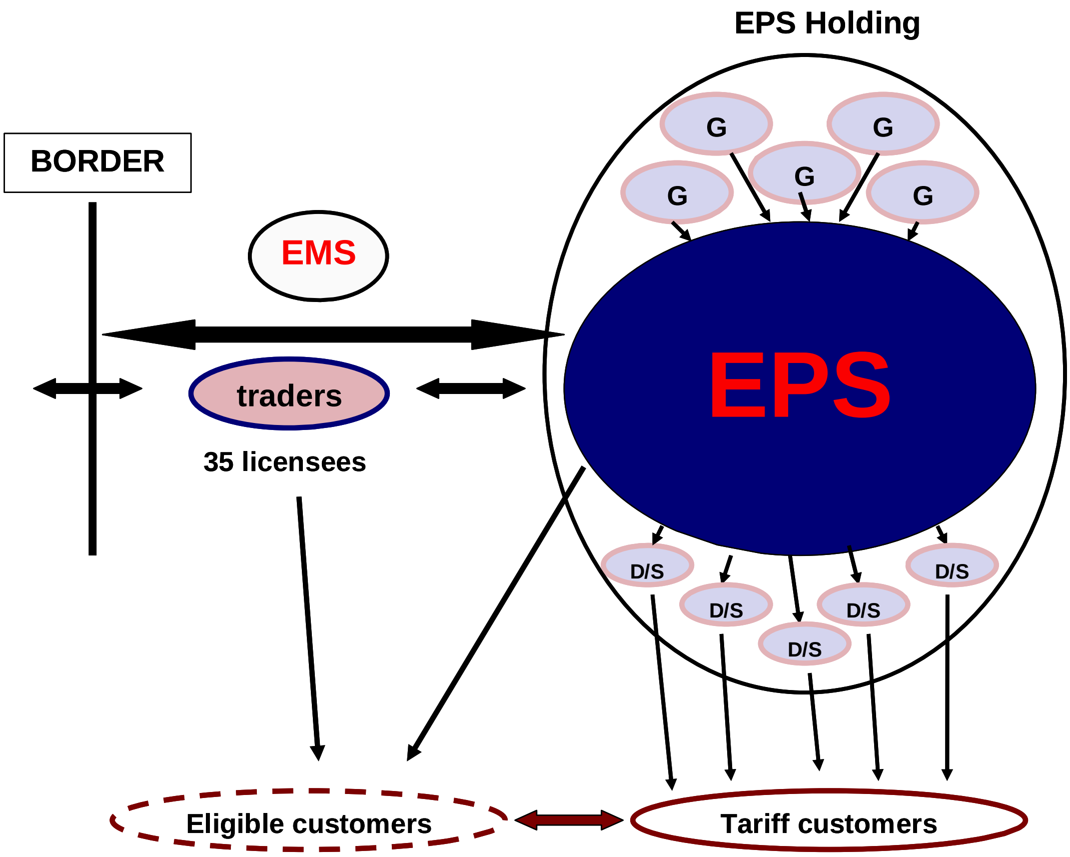
2.2. Serbia

2.2.1. Country overview

Status of restructuring the structure of the sector

The Serbian electricity industry is under the process of restructuring. The former vertically integrated utility is now performing as a (100% state owned) holding company, PE EPS, where generation, distribution and supply are all carried out in different daughter companies. There are five generation companies, a wholesaler PE EPS, and five distribution companies, which in case of regulated tariff consumers – currently all consumers - are also the retailers. Transmission system operation is carried out by PE EMS, which is fully unbundled from PE EPS, however also owned by the State. At present there are no plans for privatization but the investment plans of EPS are foreseen on a public-private partnership basis. Market rules and distribution code are currently in a drafting phase.

2.7. Figure: The structure of the Serbian electricity market



At present, there is a multi-level price regulation in the sector, the production, wholesale and retail prices are all regulated. Regarding market opening Serbia has fulfilled and even went beyond the obligations taken over via the Treaty establishing the Energy Community, as by February 2008 all non-household consumers, and household consumers consuming over

200,000 kWh annually are free to choose a supplier. With market opening a hybrid model has been put into operation which has the following main characteristics. PE EPS holds the special license of wholesale trade for tariff customers, by which it procures all the energy needed for tariff customers and sells it to the distribution/supplier companies (D/S), the DSO/supplier companies are only licensed for the supply of tariff customers, and they are only allowed to purchase electricity for the supply of tariff customers, from PE EPS wholesaler of tariff customers. PE EPS holds also a general trading license with which it can also supply eligible customers just like all (new entrant) traders.

Although de jure 47% of consumption is related to eligible consumers and therefore is contestable for new entrants, due to low regulated retail tariffs compared to the prices in the neighboring countries[40] the de facto degree of market opening is currently zero, there isn't any consumer who would purchase outside the public utility segment. Thus there are no participants supplying end users besides the DSO/supplier companies, eligible consumers are not exercising their eligibility.[41] Furthermore if some consumers would decide to leave the regulated segment and consume from a new entrant supplier they could return to the regulated market if they want to, the only requirement is to stay in the chosen segment for at least 12 months.

In spite of the rigidness of the retail level, the wholesale level is pretty vivid with 35 active traders transacting business bilaterally with the public wholesaler PE EPS, other traders or transiting through the country. Serbia is an important transit country in the region connecting significant importers – like Croatia, Macedonia, Montenegro, Albania and Greece - to significant exporters – Bulgaria, Romania.

Energy and power balance of the Serbian electricity system

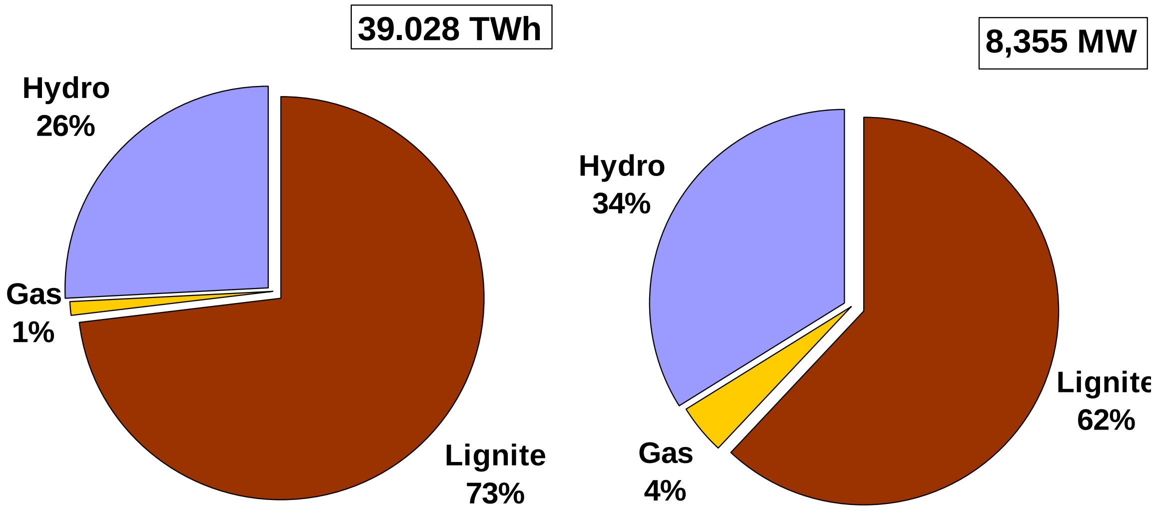
In 2007 gross consumption was 39.27 TWh (of which 0.86 TWh is the consumption of pumped storage) while generation amounted to 38.98 TWh,[42] which means in 2007 Serbia was slightly a net importer country. The majority of production is coal based, however the balance of international exchanges greatly depends on the weather conditions, since hydro generation is the second main source of electricity generation.

[40] The regulated tariffs were set on the basis of the proposal of EPS (which did not include full depreciation and WACC was set to zero). However even a tariff calculated with full depreciation and a reasonable WACC would be at most 35% higher then the current tariff, which would still result in one of the lowest tariffs in the region.

[41] This fact is illustrated in figure 2.7 with dashed line around eligible consumers.

[42] UCTE: System Adequacy Retrospect, 2007

2.8. Figure: Generation and power mix of the Serbian electricity industry, 2007

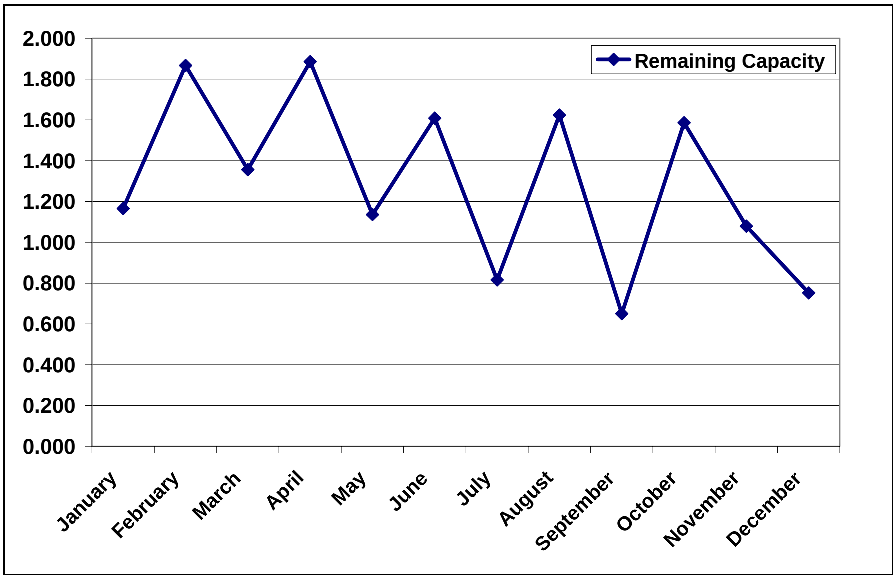


Source: UCTE: System Adequacy Retrospect, 2007

As for the power balance of the Serbian electricity system remaining capacity in 2007 was always well above zero, and according to the forecasts of UCTE remaining capacity will stably exceed the adequacy reference margin, suggesting that domestic generation capacity will have the adequate level to serve domestic load.

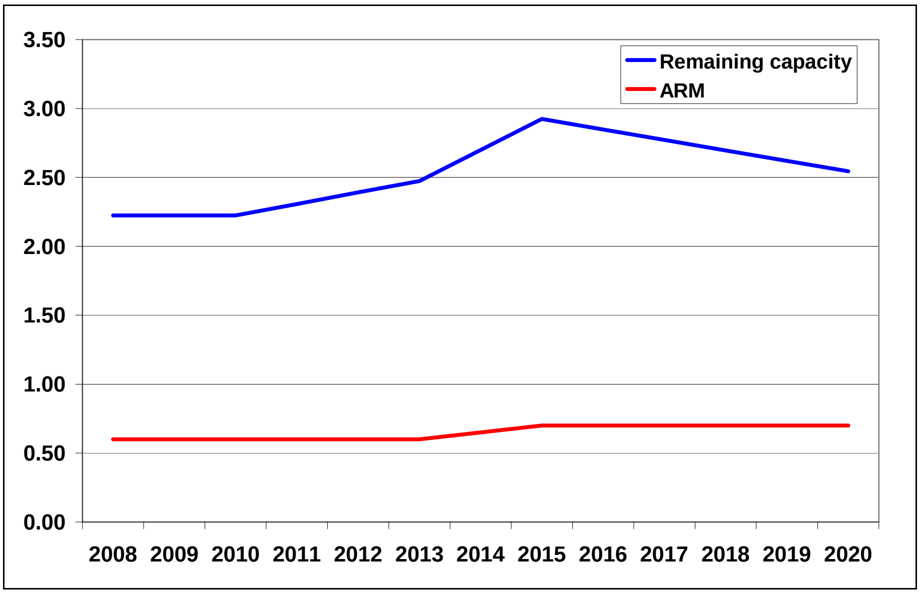
The current power balance is not only the result of adequate generation capacity, but is also the result of the already introduced TOU tariff that will be discussed in detail in the following sections. Therefore load management is already supporting the Serbian electricity power balance. Further load management programs although will not be indispensable in the near future for the Serbian electricity system, however bad weather conditions - due to the high dependency on hydro generation - could cause seasonal shortages in which case further demand response could become valuable.

2.9. Figure: Remaining capacity in Serbia, 2007, GW



Source: UCTE: System Adequacy Retrospect, 2007

2.10. Figure: Forecasted remaining capacity and adequacy reference margin in the reference point: July 11:00, Serbia, GW



Source: UCTE: System Adequacy Forecast 2008 - 2020

2.2.2. Possible participation of loads in the wholesale market

Organization of the market

As it was described previously, the Serbian wholesale market is currently dominated by PE EPS wholesaler of tariff consumers, where the domestic generation companies - its daughter companies - can only sell to PE EPS wholesaler of tariff customers, for regulated prices, and PE EPS procures the shortage or sells the surplus that emerged when serving domestic consumption of tariff consumers, to importing and exporting traders usually through monthly contracts. Since importing prices are 2.8 times higher (according to planned values in 2008) than regulated domestic generation prices, new entrant traders cannot offer prices to consumers that could compete with the regulated prices. Thus currently the actors of the wholesale market are not connected directly to even large industrial consumers, as consumers in the regulated segment can only buy from the DSO/Supplier companies.

The situation would change if regulated retail tariffs would either be higher than those that new entrants could provide from the competitive market, or if many consumers would be obliged to procure from the competitive market, without the option of consuming from the regulated segment.

Since there are no provisions for such actions we can assume that in the near future (at least in the next three years) this structure of the wholesale market will not change.

The balancing mechanism is under preparation and probably will be published together with other market rules in 2009.

From the above it is apparent, that in the current Serbian wholesale market theoretically load participation could have two forms. One possibility could be that a large industrial consumer becomes a trader[43] and conducts its own procurement from import and exports or sells its excess, and flexibility to general traders of the competitive market segment. However in the current setting this is not a relevant option, since the regulated price is considerably lower than what a consumer could realize from imports. (The same applies to the situation when a large industrial consumer chooses a trader from the competitive market and sells its flexibility to this actor.)

A more possible form of load participation on the wholesale level could be that large industrial consumers remain within the regulated ’supply chain’ and participate in a program which enables PE EPS wholesaler of tariff consumers to directly or indirectly use their flexibility.

Large industrial consumers

According to data for 2007 there are 3,778 industrial consumers in Serbia, accounting for 27.65% of domestic consumption. Regarding the current incentives of industrial consumers to consume in less costly time periods, the active energy part of the regulated tariff - which at

[43] The conditions for obtaining a trading license in Serbia is not burdensome for a consumer, the fee is relatively low, and the approval process is short, 5-15 days from application.

present applies to all users – varies with the time of use. Tariff rate for active energy is higher (HT) in the hours between 7:00 and 23:00, and a lower tariff (LT) applies in the rest of the hours. For industrial users the ratio of the two tariffs applied in the two time periods is HT:LT = 3:1. Regarding the metering equipments, industrial consumers connected to the transmission system are equipped with smart meters, those industrial consumers who are connected to the distribution network have metering systems of various quality. However such a time of use tariff could be implemented with simple two rate meters as well, which is prevalent in Serbia.

Regarding the curtailability and price flexibility of large industrial consumers there isn't any recent experience or any other information, such as surveys, on the potentials of these consumers.

Evaluation of load participation possibilities in the Serbian wholesale market

The current TOU rates in place directly give incentives to large industrial consumers to shift consumption to the off-peak period. However this HT, LT tariff does not exploit most of the potentials of large industrial consumers, as it is too rigid, only applies two time periods and is set for a long time in advance. As these consumers are equipped with advanced meters, their demand response potentials could be further exploited by more complex price-based demand response programs. The Regulator with the assistance of PE EPS wholesaler of tariff consumers could enhance the current TOU rate systems for these consumers by for example adding an additional block during the day in the most intense hours, this way the peak period between 7:00 to 23:00 could be divided into a higher peak and a lower peak period that better reflects wholesale costs.[44] Furthermore adding critical peak pricing to the TOU rate system in the few really expensive periods could also enhance the strength of the connection between retail and wholesale markets. Real-time pricing programs would be an unimplementable alternative for the current Serbian market, since they not only require transparent hourly wholesale prices, and a high level of customer awareness, but also a change in the current regulated tariff system which is based on yearly set tariffs.

A more direct form of utilizing demand responsiveness of large consumers on the wholesale level would be the organization of an incentive-based program. The incentive-based program could have the advantage compared to the price-based programs, that the demand reduction valuable to the wholesale market could be directly insured by penalties, and therefore the curtailed amount would be more predictable. A possible way of introducing such program is that the Regulator files discounted rates which could be applied for the participating large industrial consumers supplied from the regulated segment. In return for the discounted rates

[44] The decision on which time periods should be defined as higher peak and as lower peak time periods should be based on the past experience and forecasts of PE EPS wholesaler of tariff consumers' costs, i.e. in which hours it is regularly most costly to supply tariff consumers' consumption within the currently defined peak time period.

large industrial consumers would reduce their load according to predetermined rules (regarding the needed load reduction, maximum number of events per year, penalty for non compliance, etc) when PE EPS wholesaler of tariff consumers notifies them (in case of high wholesale costs). However currently only the distribution/supplier companies are in direct (legal) connection with consumers, therefore the implementation of such a program would either require a change in the legal framework that allows a direct connection between the large industrial consumers and the wholesaler of tariff consumers, or a strong cooperation between PE EPS wholesaler of tariff consumers and the DSO/Supplier companies, where the DSO/Supplier companies would be intermediaries between the wholesaler and the consumers, and in a special way they could be considered as aggregators.

As for the possibilities for emergence of aggregators with other kind of DR sources currently the distribution network/supplier companies organize two direct load control programs for residential consumers, however the volume of controlled consumption is not significant yet, to be a useful DR tool on the wholesale level. As the number of participants increases its use in a wholesale DR program could be reconsidered.

Role of policymakers, regulators, in promoting load participation and suggestion of potential amendments

Policy makers and the Regulator should together with PE EPS wholesaler of tariff consumers analyze the possibilities and decide which DR program organized for tariff consumers would fit the needs of the (regulated) wholesale level the most.

In case of time of use rates the number of time periods and the size of the price spread should be developed in a way that the time periods reflect wholesale costs, but also allow customers to change the way in which they use electricity. Also the difference between the prices of (high-peak), peak, and off-peak hours should be significant to induce demand response.

In case of critical peak pricing since consumers are not used to such programs at first the most predictable form of CPP the fixed-period CPP program should be considered instead of the variable type of programs.

Regarding the application of incentive-based programs, among the questions that have to be discussed are the definition of program events, the penalty, the basis for the price discount, and the basis for determining the maximum number of use. Furthermore as discussed above in the case of incentive based DR programs the Regulator should decide how to enable the connection between the wholesaler of tariff consumers and the large industrial consumers. A possible solution could be that these consumers remain at the DSO/Suppliers, and they receive a new tariff with defined program rules, and PE EPS calls them on through the DSO/supplier companies who act as intermediaries.

When assessing which DR method would fit best the needs of the wholesale market and whether such a program should be implemented at all, one of the most important inputs is the expected load reduction that could be induced by the programs. International experience presented in section 1.5. on the use of these programs suggest that consumers reduce their consumption in the high-priced time periods and program events significantly, however the exact values cannot be applied directly to the Serbian market. Therefore pilot projects and surveys should be conducted to assess the potential load reducing effects of such measures.

To sum up, the Regulator together with EPS should consider the DR possibilities and make pre-assessment studies on the potential load reductions, comparing it to the wholesaler's needs. Cost assessment should also be carried out. Furthermore it should be considered what level of regulatory involvement is needed. Benefits of DR programs usually outweigh the costs, however most benefits in this case would come from avoiding high import prices, which is a benefit that is not materialized, therefore the issue of who is baring the costs, and when a program should be considered successful should be decided. Whether the DR program should be mandatory or voluntary for industrial consumers is also a relevant question.

When implementing the programs, the large consumers should receive education and workshops should be organized periodically.

2.2.3. Possible participation of loads in providing ancillary services

Operation, typology and procurement of ancillary services

Ancillary services in the Serbian system are defined according to the UCTE Operation Handbook recommendations. The following services are listed in the Grid Code:

- Primary control
- Secondary control
- Tertiary control
- Voltage control
- Transmission losses
- Black start

We will restrict our focus to secondary and tertiary control, since load participation is not relevant in the other services. The technological requirements and procurement amounts of these services are summarized in the table below.

2.6. Table: Main technological requirements for secondary and tertiary regulation

	Procured amount (MW)	Activation	Response time
Secondary Regulation	130 - 170 calculated monthly in accordance with UCTE rules	Automatic	30s < < 15 min
Tertiary Regulation	+ 450 - 150	Manual	< 15 minutes

Regarding the procurement process, currently the TSO EMS procures ancillary services from the domestic generation companies by yearly agreements. Payments for ancillary services (RASt) are regulated and calculated on cost basis: fixed operation costs (FOt), depreciation costs (Dt) and the share of capacity intended for provision of ancillary services (CASt) compared to the total installed capacity (IC) of the power plant is considered in the following way: [45]

$$RAS_t = (FO_t + D_t) * CAS_t/IC$$

The Market Code is under development, in which shorter term ancillary services markets will probably be defined.

Possibilities of load participation in providing ancillary services

Summarizing the above, ancillary services currently are not procured on a market, but rather arranged through bilateral contracts between the TSO EMS and EPS (in the name and for the account of the generators within its holding structure), where payment is regulated on a cost basis. In such a setting many benefits of load participation in providing ancillary services that are usually mentioned – improved market efficiency and market power mitigation - do not apply. Due to the cost based regulation, and the low retail prices, it is likely that consumers would provide ancillary services for much higher payments than the generators currently receive.[46]

It is a question whether improved system reliability and system efficiency accompanied by load participation would bring enough benefits in the current setting to justify the efforts needed to facilitate direct load participation on ancillary services markets. We think that instead of changing the grid code to allow loads to supply ancillary services, a program similar to the emergency demand response programs of the US based ISOs organized by the TSO EMS (where the system events would be reliability-triggered events) could better suit the current procurement setting and the needs of the TSO. Such a program could target consumers from both the regulated and the competitive market segment. For the TSO to be able to pay availability payments to consumers and command them legal changes that enable direct connection between the TSO and consumers are necessary.

In the future, if the procurement of ancillary services will be exercised on a market basis, the setting and rules of such market should be developed in a way that it does not discriminate

[45] t refers to the regulatory period

[46] This could be seen also from the Hungarian case, where power plants provide ancillary services for not cost based tariffs but market bids. Still in this case many generators usually providing ancillary services gave lower bids than the first consumer that entered the market in 2008.

load, but facilitates its presence to compete with generators. The biggest barriers for load participation in such markets – based on international experience - are the high-minimum load requirements, real-time telemetry, and the non-source neutral reliability rules and dispatch practices. Since ancillary services are provided by generators, the rules are usually defined in a way that they reflect the capabilities of the generation units and therefore could result in barriers for other resources. Since the Serbian Market Code is currently under preparation it is a good opportunity to revise the current setting and create market and reliability rules that provide a level playing field for participation by both load and generation resources. Specifications should be performance based rather than resource based. The following reliability rules are examples when the settings reflect generator limitations rather than reliability needs:[47]

- Minimum run times
- Minimum off times
- Minimum load
- Ramp time for spinning reserve
- Accommodation of inaccurate response

Participation of load could be facilitated by considering specific accommodations for demand side resources as well. Some load attributes that should be considered:

- Maximum run time
- Value of capacity that is coincident with system load
- Value of response speed
- Value of response accuracy

Role of policymakers, regulators, and system operators in promoting load participation and suggestion of potential amendments

In the current setting the Regulator together with the TSO could consider whether an emergency demand response program would be beneficial for the system. If yes, the TSO should organize the program, and the program rules, especially the incentive payments and its recovery for the TSO should be developed together with the Regulator.

If Serbia decides to create a market setting for the procurement of ancillary services the Regulator and the TSO should create the rules in a performance based, source-neutral way. A survey should be carried out among large industrial consumers to find out their potentials, and their willingness to participate. Pilot project could be the next step that would help establish and/or refine technical requirements that would suit demand response.

[47] Ernest Orlando Lawrence Berkeley National Laboratory: Loads providing ancillary services: review of international experience. May 2007. p. 33.

2.2.4. Possible load participation on the retail level

Description of the retail market

As it was already described in the country overview, the Serbian retail market although is opened for all non-household consumers, and household consumers with an annual consumption above 200,000 kWh, the full market is currently operating under regulated tariffs, as no consumers have exercised their eligibility to procure from the competitive market segment. As a result, currently all small-scale consumers are supplied by the five distribution companies, which are all daughter companies of the PE EPS holding. This situation is likely to remain in the near future until the option of consumers to stay in the regulated market segment is maintained and regulated tariffs are lower than the cost of import possibilities.

Prices – price structures

Regarding the regulated retail prices of small scale consumers, there are two types of tariffs, a single-tariff, that does not depend on the time of consumption and a two-rate tariff with higher tariff (HT) rate applying between 7:00 and 23:00 and a lower tariff rate which applies in the rest of the time.[48] The two-rate tariff evidently could only be charged to consumers equipped with at least mechanical two-rate meters.

Regarding metering equipment customers connected to the high and medium voltage level network are all equipped with (at least) two rate meters. For these consumers the relative ratio of prices under lower (LT) and higher tariff (HT) rates of active energy is LT:HT = 1 : 3. In case of consumers connected to the low voltage level network there are two categories defined:

(1) „Low voltage consumption" category: For the consumers of this group monthly maximum active power, reactive and active energy are metered. All these customers are equipped with two rate meters, and the relative ratio of prices under lower (LT) and higher tariff (HT) rates of active energy is also LT:HT = 1 : 3.

[48] The HT 7:00 – 23:00 and LT 23:00 – 7:00 time periods are defined in the tariff system. But, the time of application of tariff rates in certain parts of the distribution/supply system may be established in some other time of day. LT time period can start between 22:00 and 24:00, lasting continuously for eight hours (it is also defined in the tariff system). Energy entity for electricity distribution/supply decides when LT time period is started and has to inform customers on all changes via mass media or in some other suitable way.

Furthermore In the past there were other different LT periods, for example between 14:00 and 17:00, but according to the Regulator this lead to this period becoming the peak period, therefore it was abolished.

(2) „Consumer spending" category: For these consumers only active energy is metered and two rate and single rate meters are also common. For these consumers the relative ratio of prices under lower tariff rates (LT) higher tariff rates (HT) and the single daily tariff rate (ST) is LT:HT:ST = 1 : 4 : 3.5.

Consumers equipped with two-rate meters can also choose to pay under the single-tariff regime, i.e. the TOU price system is optional. The number of residential consumers in the different tariff categories is shown in the table below.

2.7. Table: Number of residential consumers receiving single and two-rate tariffs at the end of 2007.

Residential consumer groups	No. Of customers	MWh
Single-tariff metering consumption	1,222,487	4,128,536
Two-tariff metering consumption	1,793,813	9,997,255

Current other DR programs

Besides the above described two-rate tariff system there are two recently introduced direct load control programs for households operated by the distribution network companies. Both programs are direct load control programs where the supply of boilers and storage heaters and single-point water heaters are controlled by the remote control system. Consumers can choose between the two programs. The programs differ in the following characteristics:

1. Supply may be interrupted two times, each for three hours at most daily and between two interruptions supply lasting at least four hours shall be provided. Consumers are given an 85% discount on the HT and LT regular tariff for active energy in return.
2. Electricity is supplied for ten hours a day, of which 8 hours have to be supplied continuously. If daily temperature measured at 7:00 AM is -10°C or lower in the relevant area, an additional two hours of supply has to be provided between 12:00 and 22:00. Consumers in return receive discount on the LT part of the two-part tariff.

The volume of controlled capacity is currently very small, but more extensive introduction is planned.

	No. Of customers	MWh
Controlled consumption (both groups)	4,290	19,470

Costs of the equipments needed for the controlled load programs are recovered through the distribution part of the tariff.

Metering

As discussed above, most of the consumers are equipped with (at least) two-rate electromechanical meters, only a part of small consumers connected to the low voltage level have one rate electromechanical meters. Two rate meters were installed during the last 30 years with the intention of enhancing demand response. Customers could decide which type of meters, one-rate or two-rate meters they want to have, two rate meters are more expensive than one-rate meters but the difference between the costs is not significant.

Metering service is provided as a regulated monopoly service by the distribution companies and there is no separate charge within the distribution part of the tariff for metering. All meters are read once a month. According to the Energy Law meters are owned by the distribution companies, however in the previous time customers could also own the meters. To clarify the setting the Energy Law set out a deadline (expired in late 2006) for distribution companies to conclude contracts with all those consumers that as a heritage own their meters. By now only a small number of consumers remained formal owners of the metering devices.

Distribution Code is under preparation and when approved it will contain what kind of functionalities should new meters (when changing the old ones) have, there is no explicit and clear decision yet about this issue, and about the deadlines for changing new meters to old ones. However there is a concept that almost three million meters will be replaced during the next ten years in the distribution network. Several projects were realized during 2007 by the distribution companies regarding installing 150,000 meters and 12,000 metering sites were equipped with load remote reading and management systems.

Regarding the current deployment of smart meters, as mentioned previously consumers connected to the transmission system all have smart meters installed, and the current deployment of smart meters is around 3-5%. However this share could increase to approximately 30% in the next five years, the pace of growth will depend on the distribution companies' tender procedures for metering purchase.

Regarding the financing of the smart meters that were installed in the previous years the mother company EPS got credit and it was decided that part of these funds should be directed to the distribution companies to finance new smart meters. These expenses will be later recovered through the regulated tariff. Regarding the procurement of these meters, Technical Board of Distribution companies proposed what kind of functionalities should be introduced with new meters and EPS Managing Board approved this proposal. Producer of new meters was selected according to public tender procedure, published by EPS.

Possibilities for introducing demand response among small-scale consumers and suggestions for policymakers and regulators

It is apparent from the above description that with the two part tariffs for two rate metered consumers together with the initiation of the two direct load control programs, demand response for small-scale consumers in Serbia is in a relatively developed phase compared to other countries of the region. The question therefore that has to be analyzed regarding the possibilities of demand response enhancement among small scale consumers in Serbia is whether these current programs could be improved with the current metering equipment and what further benefits could the mass introduction of smart metering bring in the area of demand response.

With the use of the two-rate meters the possibilities to further enhance demand response among this consumer group could be the consideration of implementing seasonal tariffs, i.e. a higher tariff in the winter, a smaller in the summer and in the spring-autumn seasons. However in the past seasonal tariffs were introduced, but then abolished since according to the Regulator practice showed that they were not a good solution in the Serbian case. Therefore seasonal tariffs might not be a relevant option.

Within the TOU tariff system the time periods of HT and LT could be reconsidered for the consumer groups especially for households, as a price reducing at 23:00 does not give residential consumers much opportunity to change their usage pattern, a tariff with a lower price at for example 20:00 might be more effective.

Regarding the implementation of further price based demand response programs, the first issue that has to be clarified is the question of mass introduction of smart metering among small-scale consumers. A cost-benefit analysis that also relies on data gained from the mentioned installation projects has to be delivered and suggestions of the summarized ERGEG working document and also experience gained by other countries could be considered.

If there is a decision over the time-scale, and way of smart metering deployment among this consumer group the work out of a portfolio of price based programs instead of one universal program is suggested which takes into account the diversity of the small-scale consumer group and targets within this group smaller more homogeneous segments with different TOU programs that could be enhanced with CPP programs. The implementation of smart meters could not only help in defining different HT and LT periods to different consumer groups but would also enable the adoption of more than two types of periods, including a very high tariff period and a very low tariff period. Adopting a TOU tariff as a default service option among these consumers could also be considered.

Regarding the two incentive-based DR programs, the Regulator should closely follow the performance of these programs, what value they create and whether they are beneficial compared to the costs, would further implementation be justified. Furthermore as the equipment and installation costs are recovered through the distribution tariff, it should be clarified what should happen if the consumers participating in these programs would want to leave the regulated market segment and be supplied from the free market. Which actor would have the right to control the devices, the new trader or the related DSO/supplier company.

2.3. Macedonia

2.3.1. Country overview

Status of restructuring, the structure of the sector

The Macedonian electricity sector has been restructured, production and distribution/supply of tariff consumers is unbundled from transmission system operation. Power generation is performed mainly by the state owned AD ELEM which is owner of the big hydro and thermal power plants in Macedonia, and there are also independent power plants (IPP) like the fuel based TPP Negotino and other small generators. Transmission system operation is performed by the 100% state owned AD MEPSO, which is also the electricity market operator (EMO).[49]

Distribution and retail supply of tariff consumers is exercised by AD EVN Macedonia, which also owns few hydro power plants and other small power generators. These licensed energy activities - distribution system operation, retail tariff customer supply, and distributed electricity generation - are separated legally and on accounting basis. AD EVN is 90% owned by the Austrian EVN AG, while the other 10% is owned by the Macedonian state. The generation company AD ELEM has an obligation to sell all the electricity it produces to AD EVN for the supply of tariff customers for prices set by the Regulatory Commission, and if its generation is not enough AD ELEM has to procure additional (import) electricity from the free market. AD ELEM has the right to import only for the captive consumers, and it can sell

[49] AD MEPSO performs three licensed energy activities:

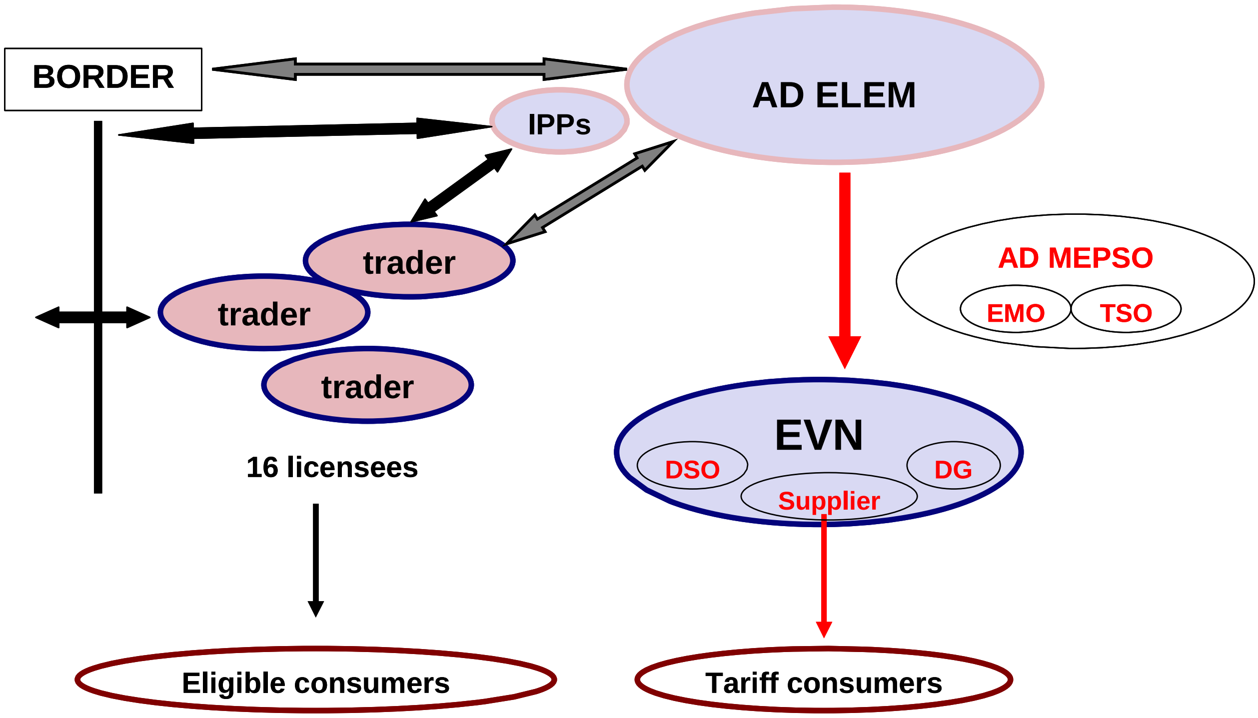
1. As the **Owner of the Transmission network** assets, AD MEPSO is obliged to provide maintenance, development, expansion and upgrade of transmission network. It is obliged to provide physical connection between generators and distribution systems and customers connected to the transmission network. Also it provides connection with transmission grids of the neighboring countries.
2. As a **Transmission System Operator** AD MEPSO is obliged to provide access and utilization of the transmission network for third parties and to meter and calculate acquired and transmitted electricity through the transmission network. It is obliged to provide operational governance of the electricity system of the Republic of Macedonia.
3. As an **Electricity Market Operator** AD MEPSO is obliged to organize and manage the electricity market and particularly to organize, establish and control power, electricity and ancillary services trading including international trading. It annually prepares and submits to the Ministry and the Regulatory Commission each year, one-year, five-year and ten-year electricity demand forecasts for the Republic of Macedonia. The electricity market operator forecasts and plans the demand and the supply based on scheduled sale and purchase agreements and spot market purchases and sales, in order to provide security in the electricity supply. The electricity market operator prepares and submits on a daily basis to the electricity system operator a dispatch schedule for meeting the load and updates the schedule in regular time intervals. The electricity market operator keeps a record and a schedule of physical electricity transactions, pursuant to all electricity sales and purchase agreements and invoices the market participants, excluding the regulated participants, for the transmission services and regulated services, pursuant to the valid tariff system. Furthermore the electricity market operator is obliged to buy the total amount of electricity generated from renewable sources under the feed in tariffs determined by the Regulatory Commission.

electricity on the free market for unregulated prices only if the need of tariff customers for electricity is satisfied.[50]

Regarding market opening, since January 1st 2008 all consumers connected to the transmission network (110 kV and above) are eligible to choose a supplier. These consumers can buy electricity only from the free market and consequently their consumption is supplied by import. Import prices are currently 2-3 times higher than regulated tariffs.

Market code is under preparation.

0.1. Figure: The structure of the Macedonian electricity sector[51]



Energy and power balance of the Macedonian electricity market

Consumption in 2007 was 8.553 TWh of which 6.070 TWh was produced by domestic generators, and net export amounted to 2.483 TWh,[52] which means that Macedonia covers a significant, 29% of its consumption through import. As the figure below shows the majority

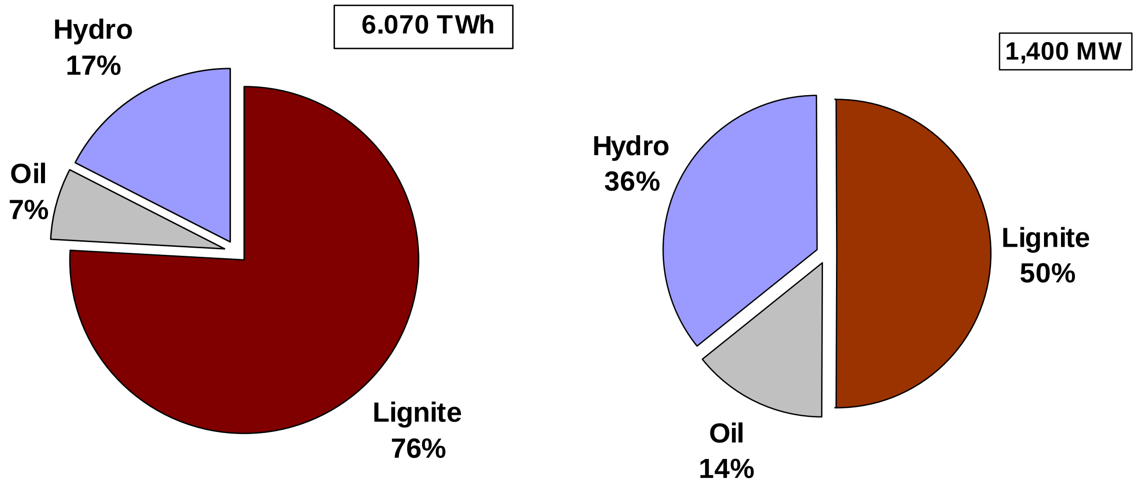
[50] The IPP TPP Negotino which is a 210 MW fuel oil based power plant is also state owned but due to high operation costs is not operating on a daily basis, rather it serves as a cold reserve of AD ELEM and it is also free to go to the free market and sell electricity for unregulated prices.

[51] The red arrows indicate regulated prices, the grey arrows illustrate the fact that AD ELEM can only buy and sell electricity on the free market to cover the shortage and sell the surplus emerged from the supply of tariff consumers. DG refers to distributed generator.

[52] UCTE: System Adequacy Retrospect, 2007

of domestic production is based on lignite, and hydro energy is the second most important source of electricity generation, leading to a crucial dependence on weather conditions.

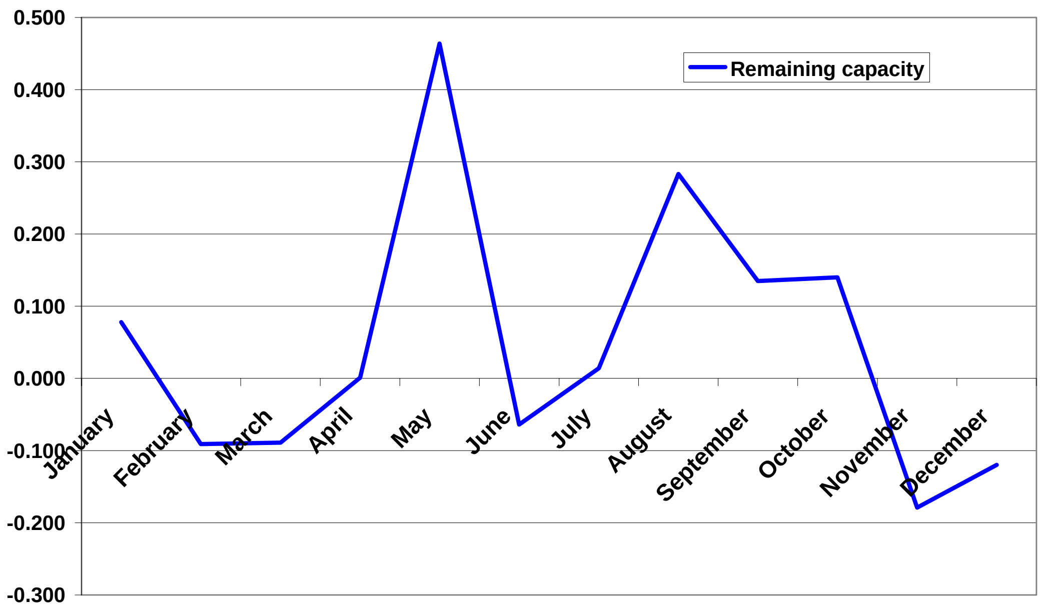
0.2. Figure: Generation and power mix of the Macedonian electricity industry, 2007



Source: UCTE: System Adequacy Retrospect, 2007

Regarding the power balance of Macedonia, remaining capacity during the winter months of 2007 was below zero indicating that the power system was short of domestic generation capacity under normal conditions. UCTE system adequacy forecast for the period 2008 – 2020 expects that remaining capacity will remain close to zero in the future as well.

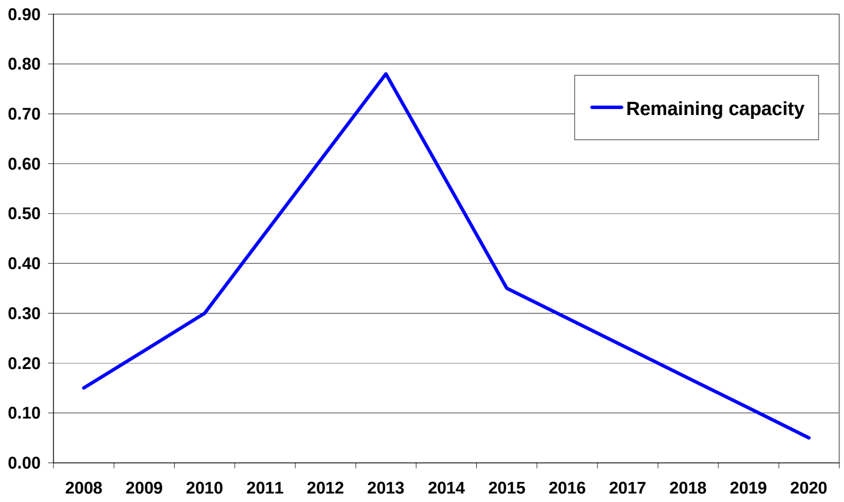
0.3. Figure: Remaining capacity, 2007, GW



Source: UCTE: System Adequacy Retrospect, 2007[53]

53 3rd Wednesday of the given month at 11:00 am.

0.4. Figure: Forecasted remaining capacity in the reference point July 11:00



Source: UCTE: System Adequacy Forecast 2008 - 2020

Macedonia's dependence on import is satisfied from the Republic of Serbia and Bulgaria, in 2007 Macedonia's import from the two countries amounted to 2463.8 GWh and 814.8 GWh respectively. Macedonia also transits power, as it exports significant amount of electricity - 788.5 GWh in 2007 - to Greece.

Summarizing the above, Macedonia relies heavily on import, due to the overall low level of remaining generation capacity, and additionally due to seasonal shortages caused by the dependence on hydro generation. Although Macedonia has already implemented time of use tariffs, further actions aiming at a more responsive demand side could ease both the seasonal, and the overall shortage problems, resulting in lower dependence on international circumstances.

2.3.2. Possible participation of load on the wholesale market

Description and analysis of the wholesale market

Currently the wholesale market has two main drivers: the activities related to the supply of tariff consumers and the activities on the free market which are related to the eligible consumers and international circumstances. AD ELEM sells its generated electricity to the retailer of tariff consumers, AD EVN, and also procures the excess need and sells the surplus on the free market or directly to foreign players. New entrant traders import electricity or buy from IPPs and supply the eligible consumers. Currently there are 16 new entrant traders, but only a few of them are active. None of the eligible consumers have applied for a trading license. AD EVN cannot provide electricity for eligible consumers.

Regarding the activeness and liquidity of the wholesale market besides long term contracts there is also active day ahead trading. However currently there isn't any publicly available hourly price signal, as the trading parameters are confidential, i.e. only traders know the hourly value of electricity.

Large industrial consumers

Large consumers that are connected directly to the transmission network have to procure electricity from the free market, which primarily relies on imported electricity that is 2-3 times more expensive than the regulated tariff for tariff consumers. All the contracts between traders and eligible consumers are 1 year long contracts and the prices are flat regarding the time of consumption. These consumers currently are equipped with standard meters measuring active and reactive energy and peak demand. There is no information on the ability of these consumers to deter consumption to less expensive time periods.

Possibility of load participation in the Macedonian wholesale electricity market and the role of the regulator and policymakers in promoting it

From the above description it is apparent that the demand response potentials of large industrial consumers are not exploited yet in the Macedonian market as all the consumers have contracts with prices that do not vary with the time of use. The main reason behind this phenomenon could be that these consumers have only entered the free market this year and therefore both the customers and the traders do not have enough knowledge and experience yet on how these potentials could be used. As these consumers are on the free market one way for using their responsiveness is to sign a responsive contract with their traders where either the price depends on the time of use, and/or where the trader has the possibility to order the consumer to reduce load for a defined number of times per year in return for a discount in price. This option will probably be exploited in the near future as the free market becomes more mature. Another possibility for active demand response on the wholesale market is that the consumers with relatively high flexibility become also licensed traders, this way they could actively market their responsiveness.

As large consumers participate on the unregulated free market the Regulator and policymakers could best foster wholesale demand responsiveness by indirect methods that help the evolution of responsive contracts between the private entities instead of imposing direct rules on them. Such methods are:

- Supporting transparency, most importantly price transparency – with some kind of a platform - on hourly prices, so that consumers become aware how much their responsiveness really worth, and also contracts could be linked to these prices.

- Rules and actions that support the competitiveness of the market, e.g. small entry costs for traders, non-discriminatory and easy access to transmission capacities, clear settlement and balancing rules. Competition between traders will result in contracts that better fit consumers and also contracts that better exploit the possibilities.
- Educating of consumers. As consumers have just entered the free market providing information on how a competitive electricity market works, and what are their possibilities, how could they become more flexible, etc, would be very important in overcoming barriers from the consumer side mentioned in Section 1.4.

2.3.3. Possible participation of loads in providing ancillary services

Typology of ancillary services

The operating reserves for balancing services are defined in the Grid Code according to UCTE protocol:

- Primary control reserve
- Secondary control reserve
- Tertiary control reserve

Regarding the procurement of ancillary services, according to the latest changes in the Energy Law, regulated generator AD ELEM is obliged to provide public service and upon prior approval by the Energy Regulatory Commission is obliged to sign a yearly contract with the TSO MEPSO according to regulated prices and tariffs approved and announced by the Energy Regulatory Commission. The volumes procured in the year 2008 were 7 MW for primary reserve, 60 MW for secondary reserve and 225 MW for tertiary reserve. As AD ELEM is not capable to satisfy the total yearly need of tertiary reserves MEPSO will organize a tender on yearly basis for this product where all market players could participate. At the moment the tender specifications have not yet been stated, they will be decided in the near future.

Possibility of load participation in providing ancillary services and the role of the TSO Regulator and policymakers in promoting it

International experience shows, that loads could also be used to provide ancillary services. As the procurement of tertiary reserves is planned to be delivered through a tender process that is open for all market players, it is a very good chance for the Regulator and the TSO to define the rules of the tendering process in a way that enables load participation and furthermore is attractive for consumers. As it was already discussed in the Serbian case these rules should be set in a source-neutral way. As ancillary services were before always provided by generators, the TSOs usually define rules in a way that they reflect the capabilities of the generation units and therefore could result in barriers for other resources such as loads. Interviews with possible demand side providers and a pilot project conducted by MEPSO could help establish source-neutral technical requirements.

Besides creating a 'load-friendly' tendering process load participation on the ancillary services market could also be fostered by the organization of an incentive-based demand response program, for example an emergency DR program with reservation payments, separate from the above mentioned tender for tertiary reserves. Such a program could result in higher level of security, as loads would complement the sometimes insufficient domestic generation reserves.

2.3.4. Possible load participation on the retail level

Description of the retail market, price structures

Currently all consumers connected to the distribution network are tariff consumers supplied by AD EVN. However all consumers will be eligible to choose a supplier by 2010. The following table provides an overview of all consumers connected to the distribution network, i.e. all tariff consumers.

0.1. Table: Overview of consumers connected to the distribution network in Macedonia

MIDDLE VOLTAGE				LOW VOLTAGE						
INDUSTRIAL CONSUMERS				RESIDENTIAL			INDUSTRIAL			
35KV Direct	35 KV	10 KV	TOTAL	I- TARIFF	II- TARIFF	TOTAL	I- TARIFF	II- TARIFF	STREET LIGHT	TOTAL
4	22	1,239	**1,265**	176,687	372,381	**549,068**	1,168	80,799	5,646	**87,613**

Currently more than two-thirds of residential consumers are being supplied under a time of use (TOU) tariff (II-TARIFF), the rest of the residential consumers are paying a flat tariff (I-TARIFF). Under the time of use tariff the tariff is higher (HT) between 7:00 and 13:00 and also between 17:00 and 22:00, while lower tariff (LT) is charged in the rest of the hours. The use of TOU tariff among residential consumers is enabled by two-rate three-phase standard electromechanical meters metering active energy which include the possibility to meter also low weekend tariff (usually used by urban residents with 3*380V net).

The current tariff for households paying the flat rate (I-TARIFF) is 3.96 €cents/kWh, while the HT tariff in the TOU tariff system is 4.94 €cents/kWh and the LT is 2.47 €cents/kWh, the ratio of the two tariffs HT:LT is 2:1. Customers under the TOU tariff can also choose to be charged the flat tariff, i.e. the TOU tariff is not mandatory for them.

Industrial consumers connected to the low voltage level in the categories TARIFF-I and TARIFF-II are also under the TOU tariff system where the ratio of the tariffs HT:LT is also kept at approximately 2:1. Consumers in the I-TARIFF category and also industrial consumers connected to the middle voltage level of the distribution network have a two-rate meter for the active energy and a two-rate meter for the reactive energy and a meter for demand as well. Industrial consumers in the II-TARIFF category are equipped with two-rate meters for only active energy. Street light is metered with a one-rate meter.[54]

All network charges are flat, independent of the time of use.

Seasonal tariffs were applied before 2003, but since then regardless of the high seasonal variation of electricity demand there is no seasonal tariff in force.

Status and future plans in metering

As the above description shows the use of two-rate standard electromechanical meters is widespread. These meters were installed more than 30 years ago. The equipment was bought directly by the consumers - those consumers who wanted to be charged the two rate tariff instead of the flat tariff invested into a two-rate meter - therefore currently these two-rate meters are the private property of the consumers.

Metering in Macedonia is delivered by the distribution company AD EVN as a monopoly service. It is not unbundled from the other services provided by the distribution company, and the costs of metering are recuperated through the network tariff, there is no separate metering charge.

Regarding smart meters, currently there are no customers equipped with such meters however according to the new Distribution Code the distribution licensee AD EVN is obliged to change the electromechanical meters of the residential consumers for free to smart meters. The owner of these new meters will be the distribution company. The process of installing the new meters has just begun.

Possibilities for further demand response among small-scale consumers and suggestions for policymakers and the Regulator

In Macedonia a demand response program has been running since a long time ago among small-scale consumers in the form of time of use tariffs which was enabled by the use of two-rate meters. Therefore in Macedonia even small-scale consumers already have significant experience with price-based tariffs which provides a good basis for implementing further demand response programs in the future. As the installation of smart meters within this

[54] All consumers that have a one-rate or a two-rate meter only for metering active energy pay for the usage of capacity an additional amount that equals the 33 percent of the value of the metered active energy.

consumer group has recently commenced the possibilities for additional price-based demand response programs will open up shortly.

The Regulator therefore will have many price-based DR options to choose from and could create a portfolio of DR programs that would consider the heterogeneity of small-scale consumers by offering more different options that fit different consumer groups.

Since there is a high difference between the summer, winter and the autumn-spring consumption pattern a reconsideration of using seasonal tariffs again could be made. The implementation of seasonal tariffs would not have to wait for the implementation of new meters.

After the implementation of new meters for consumers under regulated prices different price-based programs could be offered.

- In the current system the diversity of medium and small industrial consumers is not addressed. The regulatory commission could investigate strategies for segmenting these customers to identify relatively homogeneous sub-sectors that could be better targeted with a unique price-based DR program. E.g. the HT and LT time periods could be accustomed, weekend tariffs could be applied, the ratio of the prices under HT and LT could be changed, there could be three blocks, and also critical-peak pricing could be added. For the largest tariff consumers with the future development of an hourly price signal also real time pricing could be considered.
- In case of residential consumers an optional critical peak pricing system superimposed on a TOU tariff could be considered. Also the adoption of a TOU system as a default service option could be taken into consideration.

Regarding the possibilities of incentive-based DR programs, as the mass introduction of smart meters among small-scale consumers would allow the advanced use and significant exploitation of price-based demand response programs and therefore the overall DR potentials of small-scale consumers, making further investments under regulated circumstances into equipments enabling the implementation of incentive-based DR programs among these consumers is not a straightforward issue. The cost-benefit analysis of such a project should consider the effects and counter-effects of the price-based DR programs that are or will be in place and the given incentive-based program. Of course if a private entity after full market opening decides to invest into such a program to become an aggregator baring all the costs and risks is an action that should be welcomed.

3. APPENDIX

3.1. Demand Response program examples

In this section of the Appendix we provide examples of current DR programs that are organized in the US and in the EU countries at the wholesale level, ancillary services markets and at the level of small-scale consumers.

3.1.1. Programs organized at wholesale level

In this part we provide two examples where loads are participating actively at the wholesale level, and where the purpose of participation is mainly price-reduction not reliability service.

New York ISO Day-ahead demand response program (DADRP)[55]

The New York Independent System Operator (NYISO) operates several demand response programs including the day-ahead demand response program. Customers can participate in the DADRP program through a qualified program provider, such as a regulated utility, energy service company or curtailment service providers. Within the program customers specify the hours of the next day they would be willing to reduce electricity use, the amount of that reduction, and the compensation required. That bid is submitted by the customer's DADRP provider to the New York ISO. The bid is then evaluated by NYISO and compared with supply bids submitted by generators. If a demand reduction bid is selected, or scheduled, NYISO expects the customer to reduce consumption during the appointed time. In turn, the customer is paid the day-ahead market-clearing price for the demand reduction amount scheduled. However participants may specify a minimum payment, called the curtailment initiation cost, as a condition for being scheduled for one or more hours in a specified block of consecutive hours. The participant receives the higher of the curtailment initiation cost or the hourly locational-based marginal prices times the scheduled load.

Load reduction is determined as the difference between metered load during the event hours and a customer baseline load (CBL). The CBL represents the customer's average level of use, during the time period equivalent to that of the curtailment bid period, during the 10 days prior to the day the bid was submitted.

[55] Source:

- Research Reports International: Demand Response Programs. March 2007
- Homepage of NYISO: http://www.nyiso.com/public/products/demand_response/index.jsp

If the customer does not reduce its load scheduled, consumption during the scheduled curtailment is billed at the higher of the day-ahead price or the real time price. Penalty rates are applied to the difference between the customer's CBL assigned to each hour of the bid period and its metered use in that hour.

Regarding eligibility requirements, most providers require that customers be able to reduce their use by a minimum of 100 kW per facility in each hour of the bid. Hourly interval meter is also required.

ISO New England Real-Time Price Response Program[56]

The ISO New England (ISO-NE) operates among others a real-time price response program for loads since 2003. The customers enroll in the program through an Enrolling Participant which can be a local distribution company, an energy service provider or an independent demand response provider. In the real-time price response program load reduction is voluntary when ISO-NE activates a price event. Price events are activated when either an hourly Day-Ahead locational market price (LMP) or a forecasted hourly LMP is greater than or equal to $0.10/kWh during the hours 7:00 – 18:00 on nonholiday weekdays, but the starting time has been modified several times from 7:00 to 12:00 and to 14:00 to better reflect high price time periods. Participants are notified of the price events via email and by a posting on the ISO-NE's website late in the day prior to the event day. Any load that is curtailed during the entire period is eligible for payments which is the greater of $0.10/kWh or the real-time LMP. There are no availability payments. The minimum reduction for a load to be qualified in this program is 100 kW. Regarding metering requirements, hourly data has to be submitted to ISO-NE either daily or monthly.

According to ISO-NE's last published program evaluation which refers to the period between September 2004 and August 2005, price events on average were declared 14 days per month, and the program provided a total of 45,436 MWh of load relief during the period. The number of responding resources steadily grew from 235 in September 2004 to 385 in May 2005, but then dropped considerably between May and August. Overall, assets in this voluntary program provided 31% of what they enrolled, which varied across the twelve-moth period from a low 18% in September 2004 to a high 38% in December of 2004.

3.1.2. Loads providing reliability services

[56] Source:

- ISO-NE: Demand Response Program Evaluation. Annual Report 2005.

In this part first we provide two examples where loads participate on the general ancillary services markets competing with generators and then two examples on programs where loads are used by system operators for reliability reasons and the programs are directed solely at consumers, i.e. there is no competition with generators.

Loads providing ancillary services at ERCOT[57]

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator for the State of Texas. ERCOT holds auctions on a daily basis to satisfy requirements for regulation, instantaneous contingency reserves, and replacement reserves.

Load is allowed to provide regulation up and down, responsive reserve (spinning reserve), non-spinning reserve, replacement reserve under the Load Acting as a Resource (LaaR) program.[58] Furthermore they can provide imbalance energy through the Balancing-Up Load program. Over 1100 MW of loads are qualified to provide spinning reserve and over 1200 MW of loads are qualified to provide non-spinning reserve. Any provider of operating reserves selected through an ERCOT ancillary services market is eligible for a capacity payment and if it is activated also energy payment. Responsive load is currently limited to providing half of the contingency reserves until system operator experience is gained (1200 MW out of 2400 MW procured). In 2005 the LaaR program was oversubscribed.

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[57] Source:

- Ernest Orlando Lawrence Berkeley National Laboratory: Loads providing ancillary services: review of international experience. May 2007
- Research Reports International: Demand Response Programs. March 2007

[58] <u>Responsive reserve:</u> Requires that an Under Frequency Relay (UFR) be installed that opens the load feeder breaker on automatic detection of an under frequency condition. Reserves are required to be manually interrupted within a 10 minute notice. Real time telemetry to ERCOT is needed. Loads qualified to the responsive reserve market are automatically qualified to the non-spinning reserve market, replacement reserve market, and balancing energy market.

<u>Non-spinning reserve:</u> Requires that the reserves be manually interrupted within 30 minutes notice. Real-time telemetry is needed.

<u>Regulation Up and Down service:</u> Requires that through loads through automatic controls respond to signals provided by ERCOT to increase and decrease load. Rigorous performance monitoring criteria is in place and real-time telemetry is needed. Loads qualified to regulation up and down service are automatically qualified to the non-spinning reserve market, replacement reserve market, and balancing energy market.

<u>Balancing energy up:</u> Requires manual or automatic response within 10 minutes. Real-time telemetry is needed.

<u>Replacement reserve service:</u> Loads that are planning to be on-line but not providing ancillary service.

Loads providing ancillary services in the Nordic countries[59]

The four countries comprising the NORDEL region (Denmark, Finland, Norway and Sweden) have been actively promoting demand response in their markets. Regarding the ancillary services arrangements each country procures their own reserves in the case of automatic reserves (frequency controlled normal operation reserve and frequency controlled disturbance reserve)[60] while manual reserves (fast active operating and disturbance reserve that shall be available within 15 minutes) are procured through a common regulation market of the four countries, however system operators also secure the availability of such reserves through agreements or ownership.

In Finland from 2005 frequency controlled disturbance reserves include 120 MW of demand side resources. From 2009 the total active amount of demand participation is projected to be 200 MW.

Requirements in Finland for frequency controlled disturbance reserves are the following: minimum volume is 15 MW, minimum duration is 3 hours, and SCADA is necessary for communication.

The Norwegian TSO Statnett established the Regulating Capacity Market (RKOM) for fast active reserves in 2000 to mobilize additional reserves to bid into the common regulation market during the capacity-short winter season when capacity is very tight. The RKOM program mobilizes additional capacity both from generators and loads (iron, steel and ferroalloys, primary aluminum, paper and paper products, and other non ferrous metals) via weekly bidding process over the period November – March. Each bid accepted receives a reservation payment and is required to bid into the common regulation market every weekday between 5:00 and 23:00. The mix of generation and loads procured varies according to price, as load is represented more heavily in the more-expensive portion of the bid sack. During the

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[59] Source:

- Ernest Orlando Lawrence Berkeley National Laboratory: Loads providing ancillary services: review of international experience. May 2007
- Nordel: Enhancement of Demand Response. April 2006
- Vognild, I: DR utilization in balancing markets (the reserves option market in Norway). Presentation at International Demand Response Seminar, February 4th 2005.
- Nordic Grid Code

[60] Frequency controlled normal operation reserve: In the event of a rapid change of frequency to 49.9/50.1 Hz, the reserve shall be regulated upwards/downwards within 2-3 minutes.

Frequency controlled disturbance reserve: The reserve shall be activated at 49.9 Hz and be completely activated at 49.5 Hz. In the event of a frequency drop to 49.5 Hz, 50% of the frequency controlled disturbance reserve shall be regulated upwards within 5 seconds and 100% of the reserve shall be regulated upwards within 30 seconds.

coldest winter weeks, when demand is high and generation capacity is tight, load can comprise half or more of the weekly RKOM volume.

The requirements toward fast active disturbance reserves in Norway are the following: activation time shall be within 15 minutes, the minimum volume of a bid is 25 MW, the minimum duration is 1 hour, maximum resting time 8 hours, and SCADA is required for communication.

Furthermore Statnett has initiated five pilots to facilitate participation from medium-sized resources in RKOM. Two of the RKOM-pilot contractors are retail companies acting as aggregators of smaller consumers' curtailability.

Loads providing reliability services in Spain[61]

Since 1988 industrial end-users (aluminium, paper, metal, chemical industry) have the opportunity to choose a special tariff in return for being available for load reductions requested by the TSO REE of 45 minutes, 3 hours, 6 hours or 12 hours. About 200 customers are participating with a total demand of about 2000 MW. The annual maximum duration and number of demand reductions that could be requested by the TSO from a participant is defined separately for each end-user. Depending on the times they are requested to limit their demand in a year the end-users receive a discount both in fixed and variable charges.

Demand reductions can only be requested in case of physical imbalances, never due to economic reasons, and each reduction has to be justified by the Industry Ministry. The yearly number of days when REE has requested demand reduction has been varying between 0-4 days.

ISO New England Real-Time Demand Response Program

The ISO-NE also organizes DR programs that directly aim at increasing system security. Under the real-time demand response program customers have to be able to reduce their electricity consumption within either 30 minutes or two hours of a request by ISO-NE. These requests are called reliability events, which occur when there is an expected shortfall in reserve resources on the wholesale electricity grid. Participants that reduce their consumption under a reliability event receive the greater of the real-time locational marginal price (LMP) of a Floor Price which is \$0.50/kWh for participants that agree to respond within 30 minutes and \$0.35/kWh for those that agree to respond within two hours. ISO-NE guarantees a minimum of two-hours curtailment for each reliability event. Participants also earn an availability payment in the form of installed capacity (ICAP) credits, which they can monetize in several ways, for example by selling them in the monthly ICAP auction. The quantity of a

[61] ETSO (2007): Demand response as a resource for the adequacy and operational reliability of the power systems: Explanatory Note. January 2007

participant's ICAP credit is based on their committed reduction or actual performance in a reliability event. Failure to reduce load during a reliability event results in the loss of ICAP credit for the given month and also a de-rating of ICAP credit earnings in the following months.

Participation requirements include a minimum of 100 kW offered reduction, and installation of internet based communication systems capable of recording the participant's electricity consumption in five-minute intervals.

3.1.3. DR programs organized for small-scale consumers

In this part we provide two examples where DR programs are targeted at residential and other small-scale consumers. The examples cover a price-based program and a direct load control program.

France – TEMPO tariff[62]

Since 1960s EDF has been moving toward real-time pricing of electricity linked to marginal costs of supply. Tempo is considered one of the most sophisticated tariffs for mass market customers.

In France electricity bills for residential and small business consumers include a standing charge determined by the level of maximum demand nominated by the customer, and an energy usage charge based on the type of tariff chosen by the customer. The options are the following:

- Flat rate – Option Base
- Two part tariff – Option Heures Creuses
- Tempo

The flat rate carries a low standing charge and a flat rate for all time throughout the day and year. The two-part TOU tariff has normal and off-peak rates, where the off-peak period is normally fixed at between 10 pm and 6 am. The standing charge is slightly higher than that of Option Base, but the off peak rate is reduced by 40%.

The Tempo system works by varying prices per kWh based upon the actual weather on particular days. The year is split up to 300 blue days when the price is advantageous; every Sunday is a blue day. There are 43 white days when the price is increased, and then most expensive days are termed red days and there are 22 of these in a year and are kept between

[62] Source: IEA: Case Studies of network driven DSM. October 2008

November 1 and March 31, occurring between Monday and Friday, never at weekend or on public holidays.

Each day it is decided what color the following day is to be and this is sent to the control box of the consumers at 8 pm, and is also communicated on the web site of EDF, or at the request of the consumer through a daily email or telephone.

In addition to the three color bands the Tempo system also includes the two-part tariff system, each color has a normal and an off-peak rate as well.

The Tempo year starts at 1st September and the Tempo day starts at 6 am.

The standing charge is slightly higher in case of the Tempo rate compared to that of the flat rate. The tariff for blue days is by far the lowest, it is about the half of the flat rate. The price on a white day is higher than the higher rate of the two-part tariff in Option Heures Creuses. On red days the price is really high, the tariff is about five times higher than the flat rate.

There are four different versions of Option Tempo, depending on the metering, communications and load control equipment installed at the customer's premises:

- standard Tempo (the customer has only an electronic interval meter);
- dual energy Tempo (the customer's space-heating boiler can be switched from one energy source to another);
- thermostat Tempo (the customer has load control equipment which is able to adjust space heating and water heating loads according to the electricity price);
- comfort Tempo (the customer has a sophisticated energy controller).

While the Tempo tariff has been successful, less than 20% of electricity customers in France have chosen Tempo. Tempo customers have very particular customer profiles and are interested in managing their energy use.

Progress Energy Florida – Residential Energy Management program[63]

The Residential Energy Management program is a voluntary customer direct load control program organized by Progress Energy Florida (PEF), that commenced in 1981 and was modified in 1995, 2000 and 2004.

[63] Source: IEA: Case Studies of network driven DSM. October 2008

Peak demand is reduced by PEF using radio controlled switches installed on the customer's premises to turn off selected electrical equipment. These controlled interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand.

Commencing in 2004, PEF is currently only accepting new enrollments in a winter-only component of the Residential Energy Management program. The winter-only component represents a modified, cost-effective version of the previous year-round program. It provides for direct load control of customers' electric water heater and centrally ducted electric space heating systems during the period November through March.

To participate in the winter-only component of the Residential Energy Management Program, customers must:

- ♦ utilize both an electric water heater and a centrally ducted electric space heating system; and
- ♦ have a minimum average monthly usage of 600 kWh for the months of November through March.

Participants in the winter-only component must include both a central heating system and a water heater in the load control program. Participants in the year-round component were previously able to include any or all of a central heating system, a central air conditioning system, a water heater and a pool pump in the load control program.

PEF installs free of charge a control unit, called an "Energy Management Box", in participants' dwellings. The control unit receives radio signals from PEF's control centre which instructs it to switch the controlled equipment off and on.

During the period November to March, PEF may implement the following interruptions during peak usage periods (6 am to 10 am and 6 pm to 10 pm):

- ♦ water heaters: continuous interruption for up to five hours;
- ♦ space heating systems: up to 16.5 minutes out of each 30 minute interval.

Participants do not have the ability to override the control unit during a load control event. Participants receive credits on their electricity bills of up to $11.50 per month from November to March. Credits are pro-rated according to monthly usage above 600 kWh. No credits are given for months when usage is below 600 kWh.

There are approximately 400,000 residential customers participating in the program with a peak load of 10,500 MW, and a peak load reduction of 1,000 MW.

3.2. Cost-benefit method of the Smartconnect project[64]

Southern California Edison Company (SCE) has carried out a thorough cost-benefit analysis regarding the installation of smart meters in every household and business with consumption less than 200 kW throughout its service territory over a five-year period beginning in 2008. The project is called Edison SmartConnect™. In this section after a brief introduction of the project we summarize the main steps of the cost-benefit analysis to provide an example of how such analysis could be delivered.

3.2.1. Description of the project

The execution of the Edison SmartConnect™ project is divided into three phases. Phase one began in December 2005 and lasted until the end of 2006. During that time SCE made a full revision of its cost benefit analysis. Phase two, which lasted from January 2007 until 2008, was the time of pre-deployment activities and also a new cost-benefit analysis was presented using the results of the initial product tests from the lab, preliminary scale tests and the first field test. Within phase three, which lasts from January 2008 until December 2012, the system development is to be done in three releases. In the first release there will be the final development and testing of the Meter Data Management System and telecommunications network management system along with their integration with the costumer billing system. A second field test will also be executed. In the two following releases the aim is to reach a higher and more complex functionality of the system as before.

The technical specification of the meters is essential. At first, with the technology available in 2005 there seemed to be no cost effective way to execute the project. By now, due to joint research efforts the costs could be reduced and new capabilities generating new benefits could be added with longer lifetime and increased reliability of the system, making the project possible with positive net benefits. As a result Edison SmartConnect™ is able to measure interval electricity usage and voltage, it supports non-proprietary open standard communication interfaces enabling remote switches of certain devices, improves reliability due to remote outage detection, improves services and reduces costs through remote service activation and it makes possible contract gas and water meter reads. Further on, the system is compatible with broadband over powerline use by third parties, there is a possibility for remote updates and it has industry-leading security capabilities.

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[64] Source:

- EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY Errata to Exhibit 3: Financial Assessment And Cost Benefit Analysis Before the Public Utilities Commission of the State of California Rosemead, California December 5, 2007
- Southern California Edison: Edison Smartconnect. CEC AMI Workshop. May 27, 2008.

According to the estimations, operational savings will only cover around 60% of related costs. However, also considering further energy conservation and customer participation in dynamic rates and demand response programs, the total net benefits of the project over time are expected to be $2,285 million (where operational savings account for $1,174 million), as opposed to the estimated $1,981 million costs, both in 2007 present value.

In order to recover the revenue requirement for the costs (subtracting the operational benefits) of phase three SCE proposed an Edison SmartConnect™ balancing account mechanism. According to that the required revenue should be recovered by the distribution rates from 2009 to 2012, by taking into consideration depreciation, taxes and the allowed return on rate as well besides the estimated expenses. Only the actual monthly revenue requirement recorded in the balancing account (together with probable previous undercollection) will be transferred to the Base Revenue Requirement Balancing Account. If actual costs exceeded the forecasted ones, SCE needs to request additional approval of the activities and the recovery of these further costs (after-the-fact reasonableness review). The majority of the operational benefits are proportional to the number of meters installed ($1.3601 calculated per activated meter per month), so the benefits are also recorded monthly taking into consideration the already activated meters. Further capital benefits have to be subtracted due to avoided cost of electro-mechanical meters, deferred projects and computers. However, benefits coming from demand response are not included in the net revenue requirements, because these depend on customer behavior. The costs related to phase one ($12 million), and partly to phase two were recovered with the help of an Advanced Metering Infrastructure Balancing Account (AMIBA)

3.2.2. Main steps and concepts of the cost-benefit analysis

Costs are collected separately for pre-deployment period, deployment period (phase three) and post-deployment period (2013-2032). Benefits come from deployment and post-deployment period and can be divided into operational benefits and demand response benefits. Among these there are also non-quantified societal benefits which are likely to result and are important to taken into consideration. These are for example improved customer experience, reduced energy theft, reduced green house gases and other environmental benefits, customer security. The economic value is determined on a present value of revenue requirement (PVRR) basis. The ratio of costs and benefits over time is also calculated, as the majority of the benefits occur later.

Each operating department specified their labor and nonlabor impacts resulting from the project giving the time of occurance as well. Using common assumptions for annual meter growth, cost escalating factors and inflation, and assuming a substantial increase of meter failures after they reached a lifetime of 20 years the expected costs and benefits could be calculated. Labor costs are calculated by multiplying the number of full-time employees with the annual labor rate, taking into consideration payroll loadings as well. All calculated costs are incremental, thus they don't include the costs that would occur also without the project. The costs eliminated due to the project are taken into account as benefits.

Costs of the deployment period are organized into the following functional areas:

- aquisition of meters and communication network equipment,
- installation of meters and communication network equipment,
- implementation and operation of new back office systems,
- customer tariffs, programs and services,
- customer service operations,
- overall program management,
- contingency.

The majority of the estimated post-deployment costs are O&M expenses coming from maintenence of the system and customer growth. The affected five operational areas are:

- billing (new bill presentation and processes; exception processing – due to more advanced tariffs),
- call center (increased call volume; reconnection order handling – service activation, more disconnections and reconnections, pre-payment service),
- meter services (meter operations and maintenance; meter purchases – due to customer growth and replacement of failed meters, longer travel time because larger territory for field service),
- back office systems and customer tariffs (load control systems; back office maintenance; Meter Data Management System and Network Management System maintenance – due to expansion of automated data management, need for new software etc.),
- programs and services (marketing; market research; demand response administration; PCT rebates).

Benefits can be divided into operational benefits and demand response benefits along with energy conservation. Operational benefits come from:

- meter services (meter reading, field services, avoided cost of procuring interval and electromechanical meters, field vehicles, workers compensation – due to automated meter reading, disconnection and reconnection with supervision),
- billing operations (cash flow improvement, bad debt reduction, billing exceptions reduction – due to more efficient billing process, prepayment service),
- call center (billing inquiry reductions, service restoration inquiry reductions – due to accurate billing, faster service connections)

- transmission and distribution (reduced overtime costs for emergency transformer repairs, reduced field visits for „no-power" calls – due to reductions in peak demand, better „peak load" estimates, remote verification of „no-power" situation)
- and others related to the elimination of the existing Customer Data Acquisition System and to the availability of near real-time system load data (energy supply and management, back office systems).

Demand response and energy conservation benefits are attributed to dynamic pricing opportunity, better customer information and load control programs enhanced by two-way communications. Also energy procurement cost savings and savings from transmission and distribution infrastructure (capacity costs, TDBU) are accounted for as well. These benefits can be divided into two groups: Price Response (TOU tariffs for customers above 20 kW, Critical Peak Pricing voluntary for customers above 20 kW) and Load Control (load curtailing devices answering to utility signal because of economic or system stability purposes – Programmable Communicating Thermostats (PCT), response of customers to a pay-for-performance rebate program – Peak Time Rebate (PTR) for all customers). Price-based tariffs represent 13.5% of the estimated total benefits, load control programs are responsible for 15% and energy conservation for 7% of the total estimated benefits. The benefit drivers can be the number of consumers willing to participate in these programs, the value of avoided energy and capacity purchases, the amount of energy savings, level of responsiveness of customers participating in these programs. These are estimated with the help of the results from the Statewide Pricing Pilot, which was conducted over a two-year period. This could be adjusted by the fact that long-term price-elasticity might be higher. According to the estimates the projected growth in peak demand will be less by 20% due to these demand response programs.