PRICE-BASED DEMAND-SIDE MANAGEMENT FOR REDUCING PEAK DEMAND IN ELECTRICAL DISTRIBUTION SYSTEMS – WITH EXAMPLES FROM GOTHENBURG

David Steen, Le Anh Tuan, Lina Bertling

Division of Electric Power Engineering, Department of Energy and Environment, Chalmers University of Technology, 41296 Gothenburg, Sweden

David.Steen@chalmers.se

ABSTRACT

The electricity sector is facing major challenges in the near future such as changes in the electricity usage, ageing infrastructure and increased amount of renewable intermittent electricity generation. To cope with these challenges demand side management may play an important role. This paper discuss different demand side management options and concludes that to achieve as optimal demand response as possible, without aggregating the demand, it is vital to combine different demand response option. Real-time pricing (RTP) appears to be the most suitable choice to increase the possible amount of renewable energy generation. However, to avoid increased peak demand locally, RTP could be combined with other programs. Other types of contracts where the retailer controls and aggregates the customers' loads, e.g. the heat system, could also be implemented but has not been discussed in this paper.

INTRODUCTION

Integration of intermittent renewable sources, such as wind power and photo voltaic in the power system will increase the demands for regulating power and transmission system capacity. These could in turn limit the amount of renewable electricity that could be absorbed by the power system. The need for regulating power can be reduced by using different demand response schemes such as real time pricing (RTP), time of use (TOU) tariffs and critical peak pricing (CPP) etc.

A RTP scheme would give the customers incentives to reduce their electricity consumption during times with high electricity price. Since the electricity price in an electricity market depends both on the demand and on available power production, the high price occurs usually when electricity demand is high and/or when there is shortage in production. Customers may, in an opposite situation, increase their demand during time with low electricity prices, *i.e.*, when electricity generation is excessive. This demand shifting could allow higher amount of renewable energy sources (RES) that could be integrated in the power system without increased need for curtailment [1].

From an electrical distribution system point of view, RTP could, depending on how it is designed, increase the peak demand locally resulting in increased need for reinforcements in the electrical distribution system [2]. To avoid increased peak demand RTP could be combined with other pricing scheme, such as Locational Marginal Price (LMP), Critical Peak Pricing (CPP) or power tariffs.

This paper presents a systematic review of some demand side management programs and their impacts on the peak power demand in an electrical distribution system. This paper also presents the results from a case study on the possible impacts of a RTP scheme on an electrical distribution system in the city of Gothenburg, Sweden.

DEMAND SIDE MANAGEMENT

Historically the power system has been designed with large centralized generation plants where the generation followed the electricity demand. Parts of the generation being installed today are based on intermittent sources which usually are smaller and more geographically distributed in the power system. To address the challenges arising from these changes, as mentioned above, the demand side management may play an important role.

The demand-side management programs can be broadly divided into time-based (price-based) and incentive-based programs [3]. The idea behind the time-based, or price-based, demand response is that a customer changes his/her electricity usage in response to changes in electricity prices. The incentive-based demand response program refers to incentives separated from the retail electricity rate and can be offered by the grid operator or utilities [4]. However, from the customer perspective, both time-based and incentive-based programs are of economic nature. In the following section, some of the most discussed demand side management options are summarized.

Time-based demand side management

In a deregulated electricity market the electricity price depends both on the demand and production resulting in high electricity price when electricity demand is high and/or when there is shortage in production. Figure 1 shows the spot market price at the Nordic day-ahead market Nord pool in the whole year of 2008 as well as the prices in one winter day. As can be seen in Figure 1, the price varies both during the day and during the year.

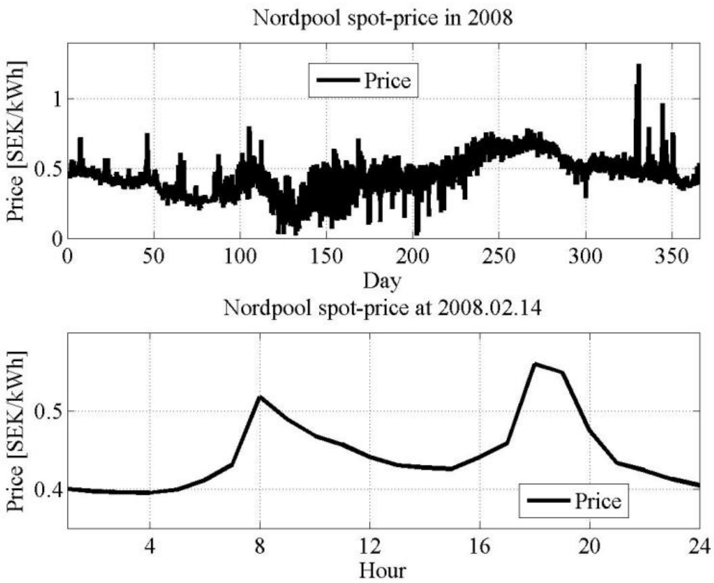

Figure 1 Spot-price at Nord pool spot in 2008

For most countries, household customers are not directly exposed to these price fluctuations resulting in no incentives to change their electricity usage pattern. This section presents some time-based demand response programs that reflect the demand/supply issue in different ways.

Real-time pricing

The main idea of a RTP program is to give the customer access to the above mentioned fluctuation in the electricity price. RTP scheme could be designed in several different ways. A simple way, which was proposed in [2], is to bill the customer on an hourly basis for all electricity the customer used during this hour. However, according to [5], many customers are worried that the high volatility in the electricity price would increase their total electricity cost. To reduce the anxiety, some RTP programs allow the customer to pay a fixed price for part of their consumption ("baseline consumption") and any consumption above that is billed according to the real time price [5].

One important aspect regarding the design of a RTP scheme is the time difference between the announcement of the price to the customers and the actual consumption. A long time lag, *e.g.* using day-ahead price, would result in a price that less accurately reflects the demand/supply, which may result in increased need for balancing power. A shorter time lag would result in better reflection of the demand/supply but with more difficulties for the customer to plan their electricity consumption [5], since they must forecast the electricity price for the coming day.

A number of studies on real-time pricing (RTP) has been conducted in different countries, *e.g*. Portugal [4], Spain [6], USA [7], Singapore [8] and in the Nordic countries (Northern Europe) [9]. Most studies indicate that RTP would have a significant impact on the peak demand, even for power system with low price elasticity of demand. Many of these studies assume a short time lag between the price announcement and the implemented price or some kind of feedback from the customer, *e.g.* participations by the customers on the spot market, either on their owns or by a representative agent [7], so that equilibrium between demand and supply could be reached without increasing the need for balancing power. However, according to [5], most RTP schemes available today announce the prices one day in advance.

By designing the RTP program so that the customer price is based on the price at the day-ahead market, the total power system peak for each area may be reduced and/or the amount of renewable electricity generation that could be integrated to the power system may be increased. However, in the Nordic countries the price areas are large, *e.g.* Sweden is divided into four different areas, the total power system peak does not necessary occurs simultaneously everywhere in each area and certain parts of the power system may experience an increased peak demand. Additionally, the technical infrastructure, *e.g.* metering and communication, needed for RTP programs is extensive. Although about 95% of all meters in Sweden can handle hourly metering, only about 29% have the possibility to store their meter readings in a database, which is needed for a RTP program [10].

One way to avoid possible problems on a local level of the power system is to use different prices for different areas, *i.e.* industrial and residential area, or to combine the RTP with other measures.

Time of use tariffs (TOU)

As shown in Figure 1, the price of electricity varies on a daily- and yearly-basis. A less complicated way of introducing the variations in electricity price to the customer is the time-of-use (TOU) tariffs. The TOU can be seen as a RTP tariff with a very long time lag. Usually TOU tariffs offer two or three different predefined price periods per day, *i.e.* on-peak tariffs and off-peak tariffs. These tariffs are more commonly used compared to RTP-tariffs [5]. As for RTP schemes with long time lag, TOU-tariffs do not reflect the wholesale price precisely. According to [5], only about 14% of the wholesale price variation would be reflected in the TOU tariffs as compared to the RTP. This would result in that TOU tariffs do not capture the total peak demand in the power system. As for RTP, additional measures may be needed to avoid congestions in the electrical distribution system and to handle the total peak demand in the power system, which is further described below.

Critical Peak Pricing (CPP)

In the Nordic power system the total cost of the power system depends to large extend on the maximal peak demand in the power system since the power system are designed to handle the peak demand, both regarding transmission and generation capacity. The number of hours during one year when the Nordic power system is constrained is usually quite low and by reducing the demand during these hours the total system cost could be reduced. To deal with the peak demand a demand response program called critical peak pricing (CPP) was found. The idea of CPP is to offer customers reduced electricity rates under normal circumstances while the retailer has the possibility to increase the electricity rates for some hours every year when the total power demand is high. The CPP hours are usually the same for the whole region but with advances in metering technology CPP could also be based on the peak demand in a local electrical distribution system. One main disadvantage with CPP is that the number of hours to apply the CPP is limited during a year [5].

Incentive-based demand response

Incentive-based demand response programs are usually based on economic incentives and are often not included in the electricity rates [4]. This section describes the some of the programs available today. In addition to the programs described below other alternative involving customer participation in the electricity market, such as demand bidding/buyback, emergency demand response, capacity market and ancillary service market has been proposed [4].

Direct Load Control (DLC)

The idea of DLC is to compensate customers economically if they in return offer the DSO to remotely turn off some of their electrical loads, *e.g.* AC equipment, during contingencies in the power system. Although this method is easy to implement, e.g. no advanced metering system is needed, there are some drawbacks. For example, since no measurements are conducted all customers participating in the program are compensated although the device was not in use even before the contingency [11]. Additionally, when the load is connected again the power demand can increase due to the cold load pick-up (CLPU) and additional measures such as controlled reconnection may be needed [12].

Interruptible/Curtailable Service (ICS)

Similar to DLC, the ICS is based on curtailment of electrical loads when the power system is under stress [5]. Unlike DLC, the loads are not remotely controlled and ICSs are traditionally only offered to large industrial customers [4]. Participants are offered a discount on the retail tariff but if they fail to provide the load reduction they signed up for they are penalized [4].

Power tariffs

The idea of power tariffs, or demand charges, is to give incentives for customers to reduce their peak demand by increasing the network tariff as their peak demand increases. Traditionally, power tariffs are based on the monthly peak demand but could be varying hour by hour [5]. In many countries the formulation of the power tariffs is critical due to the legal framework [13]. Additionally, the peak demand of a single customer does not necessarily increase the total peak demand in the power system since the customer’s peak may occur at a different time compared to the total peak in the power system.

Locational Marginal Price (LMP)

Traditionally, the network cost of an electrical distribution system has been uniformly distributed between the DSO’s customers. However, on a transmission system level, LMP has been used to reflect congestions in different nodes of the transmission system [13]. This approach could also be used to charge the customer connected to the electrical distribution system. In [13], LMP is divided into locational energy price (LEP) and locational network price (LNP), where LEP reflects the cost associated with congestion in the electrical distribution system (*e.g.* nodal pricing) while LNP reflects the long term cost, *e.g.* connection fees of a generator. To implement network tariffs solely base on LEP may be problematic since customer with similar behavior may pay different network tariffs depending on their location [14].

LOAD MANAGEMENT OF PEV AND HEAT LOADS IN GOTHENBURG

Within this research work the impact of PEVs on the electrical distribution system has been evaluated under two different load management strategies [15]. In addition, load management of heat loads has been evaluated [2], [16]. This section will present initial results focusing on the different load management strategies; the methodology is further described in [2], [15] and [16]. For the simulations, it was assumed that the electricity price was based on the spot price at the Nordic day-ahead market, Nord pool. However, the hourly electricity tariffs were only assumed to be implemented in certain areas. Due to this, the change in total power demand on national level was assumed to be small and thereby not reflected in the spot price at Nord pool. According to [17] about half of the electricity consumption in Sweden is used in the domestic and service sector and for the investigated area about 20-30% of the power demand was estimated to be flexible, based on results from a metering campaign [18].

Price-optimal strategy

The price-optimal strategy assumes that the customers were price sensitive and tried to minimize their electricity cost. As the Nordic electricity market is designed today, the day-ahead spot price at Nord pool is known 12-36 hours in advance [19]. In the simulations, the customers were assumed to know the electricity price for the coming day and could plan their electricity usage according to the spot price.

Loss-optimal strategy

The loss-optimal strategy is seen as an optimal strategy from an electrical distribution system operator (DSO) perspective. In the simulations, the electricity demand is assumed known in advanced and the DSOs have the possibility to control the loads in such manner that the total losses in the electrical distribution system are minimized. The loss-optimal strategy does not include any specific suggestions on how to design an appropriate business model and should be considered as an approach to estimate the potential of load management in the simulated area.

Results

Figure 2 presents the load profiles for uncontrolled charging, *i.e.* charging immediately when the PEV is parked, and for charging according to the price-optimal and loss-optimal strategies, for a full penetration of PEVs in a residential part of the electrical distribution system in Gothenburg. Two different scenarios are shown, *i.e.* charging only at home (scenario A) and charging both at home and at work (scenario B).

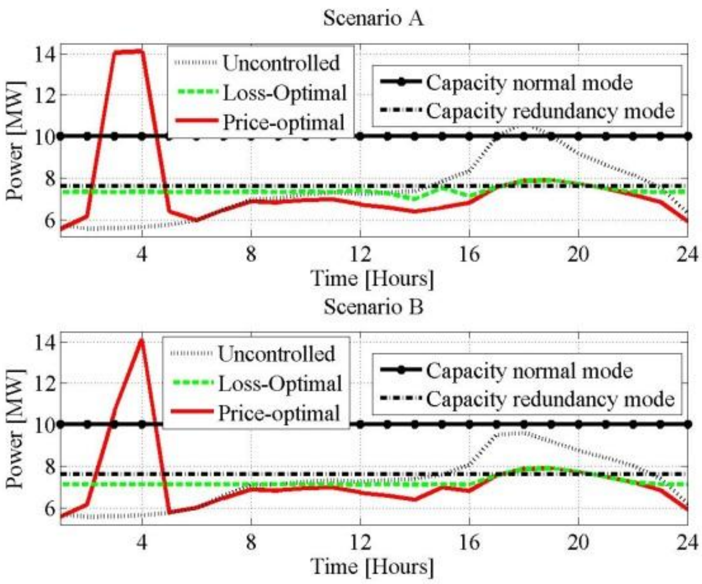

Figure 2 Residential load profile with a full penetration of PEVs under different demand response strategies **[15]**.

As can be seen, the peak demand would increase for both the uncontrolled and the price optimal control strategy. For the price-optimal strategy the charging takes place during the night but due to the high number of PEVs and since all PEVs start charging simultaneously this would result in a new peak. The loss-optimal strategy would charge the vehicles in such manner that the peak demand would not be increased.

The cost savings achieved by charging according to the price-optimal strategy was about 10-15%. However, the savings would vary for different days since the spot price at Nord pool varies.

The losses in the electrical distribution system were reduced by charging according to the loss-optimal strategy. The losses were reduced by about 4% of the total losses in the electrical distribution system, compared to the uncontrolled strategy. Additionally, the number of PEVs that could be supported was increased, indicating that the main advantage of the loss-optimal strategy is to reduce the need for reinforcement in the electrical distribution system.

If the customers would pay hourly electricity tariffs they might consider shifting other loads in time as well. In the studies heat loads have been considered as flexible loads that could be shifted in time. To avoid inconvenience for the customers the variations in the indoor temperature has been limited and a simplified thermal model of a house has also been designed [2].

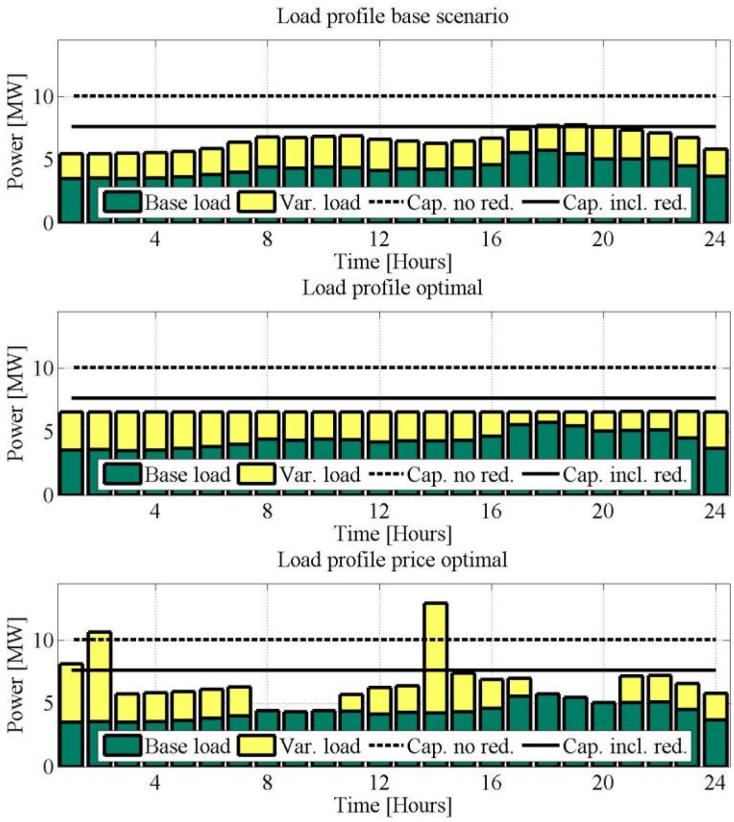

Figure 3 Residential load profile with flexible heat loads under different demand response strategies **[2]**.

Figure 3 presents the resulting load profiles with flexible heat loads for the price-optimal and loss-optimal strategies and without any demand response (base scenario). As can be seen, peak demand could be substantially reduced if the DSO has the possibility to control the heat loads for the customers, *i.e.* loss-optimal strategy. For the price-optimal strategy, the peak power is increased since most of the electricity used for heating is used simultaneously.

Figure 4 presents the same results but together with PEVs. As can be seen, the peak demand increases even further for the price-optimal strategy. For the loss-optimal strategy the peak demand was reduced and a flat load profile could be achieved.

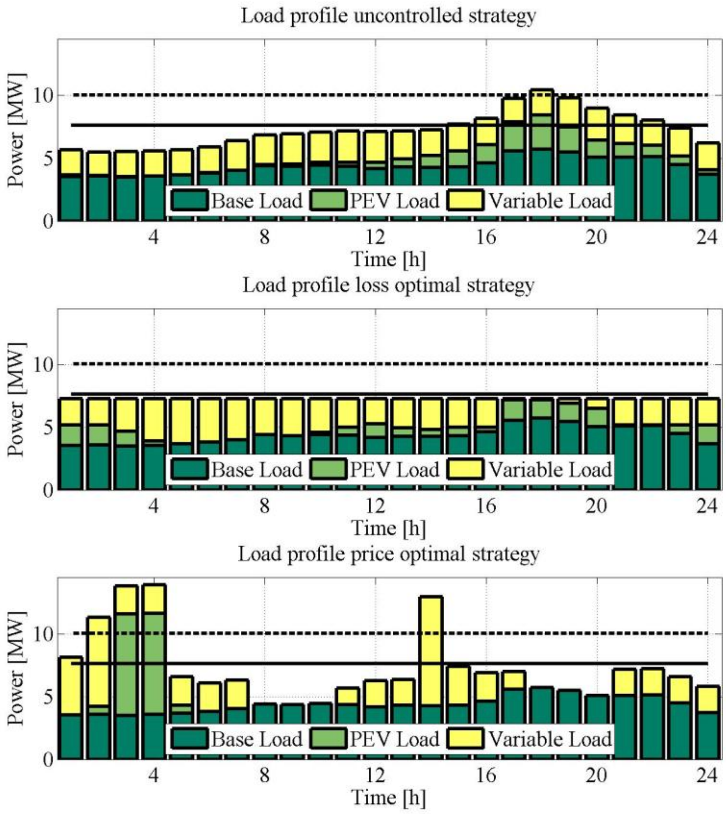

Figure 4 Residential load profile with flexible PEV and heat loads under different demand response strategies **[2]**.

DISCUSSIONS AND CONCLUSIONS

This paper presented the initial results from a case study investigating the impact of real-time pricing (RTP) based on the day-ahead market. The results showed that RTP may increase the peak demand on an electrical distribution system but also that there is a great potential to reduce the stress on the electrical distribution system by properly designing the demand response program.

Further, some demand side management (DSM) programs that are available today have been described. Table I and Table II presents the resulting advantages and disadvantages with different DSM programs. From the tables it can be seen that only RTP would favor the integration of renewable electricity generation, since RTP is the only program reflecting the supply/demand. However, to be able to fully utilize the capacity of the customer's flexible loads the customers must know the electricity price in advance which could result in increased peak demand. The shorter in advance the customer knows the electricity price the more difficult it gets for the customer to plan their electricity usage since they must rely on historical or forecast electricity price. On the other hand the risk of increased peak demand decreases. Additionally, day-ahead spot prices are commonly set for a large area and by using the spot price in the RTP program; the program would not assess issues related to the local electrical distribution system. To assess local issues the RTP program must be combined with other tariffs or define the electricity price more locally.

Table I TIME BASED DEMAND RESPONSE COMPARISION

Time-based Demand Response	Advantages	Disadvantages
RTP, long time lag, e.g. > 12 h	+ Good planning possibilities for customers + Support integration of renewable energy sources (RES).	– Risk for increased peak demand. – Need for communication and metering
RTP, short time lag, e.g. < 12 h	+ Reduced peak demand + Support integration of RES.	– Difficult for customers to plan their electricity usage. – Limited impact on the peak demand locally. – Need for communication and metering.
Time of use (TOU)	+ Good planning possibilities for customers + Easy to implement.	– Limited reflection on the supply/demand. – Limited support for RES integration.
Critical peak pricing (CPP)	+ Reduce the total power system peak	– Limited number of hours to be used – Preset price levels. – Limited impact on the peak demand locally. – No support for RES integration.

Table II INCENTIVE-BASED DEMAND RESPONSE COMPARISION

Incentive-based Demand Response	Advantages	Disadvantages
Direct Load Control (DLC)	+ Easy to implement. + Reduce peak demand.	– Limited number of hours to be used. – Cold load pick-up. – No support for RES integration.
Interruptible/ Curtailable Service (ICS)	+ Reduce peak demand.	– Limited number of hours to be used. – Cold load pick up. – No support for RES integration.
Power tariffs	+ Reduce peak demand locally. + Good planning possibilities for customers. + May reduce total system losses.	– Limited affect the total power system peak. – Difficult to implement due to legal framework. – No support for RES integration.
Locational Marginal Price (LMP)	+ Reduce peak demand locally. + Support distributed generation.	– Limited affect the total system peak. – Difficult to implement due to equinity principle and legal framework.. – Limited support for RES integration.

Programs such as CPP, DLC and ICS are only available for a limited time every year and would only affect the power system for these hours. LMP and power tariffs would have an impact on the power system all year around but may be difficult to implement or may not cope directly with the total peak demand in the power system.

From an electrical distribution system point of view LMP would be preferable since it assess the local constrains in the electrical distribution system. Additionally, it is the only program that would have an impact on distributed generation, since it would encourage customer close to the DG to increase their electricity when the DG is producing electricity.

Some important aspects when formulating demand side management strategies are; simplicity and transparency, the customer must understand why the price is varying and be noticed what price that is expected. Additionally, the strategy must give good incentives for the customer to participate. It is also important to see what consequences the different strategies would have at different voltage levels.

The optimal strategy would most likely vary from country to country, depending on the electricity usage, electricity market and the design of the power system. In Sweden there is a large amount of smart meters installed and it is proposed that the Swedish government would promote real time measurement, enabling the implementation of RTP programs. For local distribution system in Sweden it may be most beneficial to combine the RTP programs either with LMP or power tariffs while it may be more beneficial to use CPP on a transmission system level.

This paper has focused on demand response strategies where the electricity usage is controlled by the customer itself (except DLC). However, advances in metering and communication technology enable new business opportunities, such as agent based demand response. By aggregating several customers' flexible loads the agent could participate in the balancing market reducing the cost for the customer but also for the system operator. In future these models would likely become more common and the customers would probably have several different demand side management programs to choose from.

REFERENCES

[1] R. Sioshansi och W. Short, ”Evaluating the Impacts of Real-Time Pricing on the Usage of Wind Generation,” *IEEE transactions on power systems ,* vol. 24, nr 2, pp. 516-524, 2009.

[2] D. Steen, ”Impact on the Distribution System due to Plug-In Electric Vehicles and Changes in Electricity Usage,” Lic. Thesis, Chalmers University of Technology, Gothenburg, 2012.

[3] R. Aazami, K. Aflaki och M. R. Haghifam, ”A demand response based solution for LMP management in power markets,” *International Journal of Electrical Power & Energy Systems,* p. 1125–1132, June 2011.

[4] P. Faria och Z. Vale, ”Demand response in electrical energy supply: An optimal real time pricing approach,” *Journal of Energy,* vol. 36, pp. 5374-5384, 2011.

[5] B. Severin, J. Michael och A. Rosenfeld, ”Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets,” (Report), The Energy Foundation, San Francisco, 2002.

[6] J. M. Lujano-Rojas, C. Monteiro, R. Dufo-López och J. L. Bernal-Agustıín, ”Optimum residential load management strategy for real time pricing (RTP) demand response programs,” *Journal of Energy Policy,* vol. 45, pp. 671-679, 2012.

[7] S. Yousefi, M. P. Moghaddam och V. J. Majd, ”Optimal real time pricing in an agent-based retail market using a comprehensive demand response model,” *Journal of Energy,* vol. 36, nr 9, pp. 5716-5727, September 2011.

[8] R. Yu, W. Yang and S. Rahardja, "Optimal Real-Time Price Based on a Statistical Demand Elasticity Model of Electricity," in *IEEE PES ISGT Asia*, Tianjin, 2012.

[9] M. Kopsakangas Savolainen och R. Svento, ”Real-Time Pricing in the Nordic Power markets,” *Journal of Energy Economics,* 2011.

[10] J. Lundgren, S. Granström och M. Pålsson, ”Ökat inflytande för kunderna på elmarknaden,” (Report in Swedish), Energy markets Inspectorate, Eskilstuna, 2010.

[11] E. Koch and M. A. Piette, "Direct versus Facility Centric Load Control for Automated Demand Response," in *Grid-Interop Forum*, Denver, 2009.

[12] N. Saker, M. Petit and J. Coullon, "Demand side management of electrical water heaters and evaluation of the Cold Load Pick-Up characteristics (CLPU)," in *IEEE PowerTech*, Trondheim, 2011.

[13] C. Brandstätt, G. Brunekreeft and N. Friedrichsen, "Locational signals to reduce network investments in smart distribution grids: What works and what not?," *Journal of Utilities Policy,* vol. 19, no. 4, pp. 244-254, December 2011.

[14] F. Lévêque, Transport pricing of electricity networks, Kluwer Academic Publishers, 2003.

[15] D. Steen, T. Le, O. Carlson och L. Bertling, ”Assessment of Electric Vehicle Charging Scenarios Based on Demographical Data,” *Accepted for publication in IEEE Transactions on Smart Grid.*

[16] D. Steen, S. Al-Yami, T. Le, O. Carlson and L. Bertling, "Optimal Load Management of Electric Heating and PEV Loads in a Residential Distribution System in Sweden," in *IEEE PES Conference on ISGT Europe*, Manchester, 2011.

[17] "Energy statistics for one- and two-dwelling buildings in 2009," (Report), Swedish Energy Agency, Eskilstuna, 2011.

[18] J. P. Zimmermann, ”End-use Metering Campaign in 400 households In Sweden Assessment of the Potential Electricity Savings,” (Report), ENERTECH, 2009.

[19] "The day-ahead market - Elspot," [Online]. Available: http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/. [Accessed 21 May 2012].