Chapter 9
Centralized Charging Control of Plug-in Electric Vehicles and Effects on Day-Ahead Electricity Market Price

Pavan Balram, Le Anh Tuan and Lina Bertling Tjernberg

Abstract Global policy targets to reduce greenhouse gas emissions have led to increased interest in plug-in electric vehicles (PEV) and their integration into the electricity network. Existing electricity markets, however, are not well suited to encourage direct participation of flexible demand from small consumers such as PEV owners. The introduction of an aggregator agent with the functions of gathering, aggregating, controlling and representing the energy needs of PEV owners in the electricity market could prove useful in this regard. In this chapter, a mathematical model of PEV aggregator for participation in the day-ahead electricity market is described. The modeling is done by treating each of the individual vehicle batteries as a single large battery. The centralized charging and discharging of this battery is then scheduled based on the traveling needs of the PEV owners determined by an aggregated driving profile and the cumulative electrical energy needs of vehicles over the optimization horizon. Two methods for scheduling PEV demand named as joint scheduling method (JSM) and aggregator scheduling method (ASM) are presented. The two methods are subsequently used to observe the effects of introducing flexible scheduling of PEVs on the day-ahead market price in an IEEE test system and a Nordic test system. Results from the IEEE test system case studies will indicate that the scheduling of PEV energy through direct centralized control at high PEV penetration levels of 50 % or greater could lead to potential lowering of day-ahead market prices as compared to an indirect control method such as the use of fixed period charging. Results from the Nordic test

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system case study shows that controlled scheduling of PEV demand could lead to only a small increase in day-ahead market price of electricity.

Keywords Aggregator · Demand scheduling · Electricity markets · Day-ahead market · Plug-in electrical vehicles

9.1 Introduction

Today's electricity markets are typically designed based on the operational characteristics of large, conventional production units. The structural and operational rules of electricity markets are continuously being adapted to changes that are occurring due to the pro-active environmental policies in the energy sector [1]. In line with these policies, electricity generation from renewable energy sources has received much focus in the recent past and is only expected to increase in the coming decades as reported by the International Energy Agency [2]. Most of the newly installed generating capacity from wind and solar power sources are intermittent in nature, thereby giving rise to limited control over power generation. To maintain energy balance within the power system at all instances, it could become imperative to have controllability from other resources, which could be either non-renewable energy sources from the generation side, or control of resources on the demand side.

The introduction of smart metering systems at households, and integration of information and communication technologies (ICT) with power system components, gives rise to a potential for control of virtually any type of demand. This means that even the lowest power consuming devices within households could be collectively controlled to provide services during power system operation. Currently, many demand response programs delving into the control of household appliances have been launched and are being researched upon. It is imperative to understand the implications of investing in ICT and smart meters for end consumer demand control. The main question of whether demand control on small consumer level would benefit in any way would need to be answered. A starting point would be to categorically observe the effects of demand control on consumers. Two categories that could have a direct effect are:

i. *Social effects*—including the behavioral changes needed to be adopted by consumers to perform demand control, and consumer feeling of performing a common good by promoting and supporting environmentally friendly resources and participating in programs that could prove to be good for the society in general.
ii. *Economic effects*—the customers would need to know how demand response programs would affect their electricity bills. Investment in smart meters could result in better awareness for the consumers on their consumption patterns that could, in the long term, result in overall energy demand reduction. To observe the effects of demand response on the electricity market price would require further research to study the system level impacts.

Electrification within the transportation sector is considered to provide good opportunities for demand control in future power systems [3]. With battery energy storage systems, PEVs provide flexibility regarding the sources of electrical energy for charging. Hence, if global policies are driven towards tapping renewable resources such as wind, solar, biomass, biogas, wave, tidal for power production, then power sources with lower carbon footprint could be used to charge the vehicles. With battery systems in PEVs, greater flexibility could be achieved by storing renewable energy when it is available, and then re-using this energy during times of higher power imbalance. Hence, PEVs could also be utilized to offset some of the intermittency in power production from renewable sources.

9.2 The Nordic Electricity Market

The electricity market is an arrangement for sale of electrical energy as a commodity between various free players—producers, consumers, retailers and traders. Additional players such as transmission system operators (TSO) and DSO facilitate the functioning of electricity markets and the subsequent delivery of electrical energy to end consumers. The power generated by the producers is delivered to consumers through transmission and distribution networks. As the electricity network acts as a backbone for the delivery of energy, the network owners are generally established monopolies that are independent and neutral. The producers and consumers pay a fee known as the *point tariff* to the network owners for every kWh of electric energy produced into or consumed from the network [4]. This ensures that the market mechanism is facilitated, while assuring financial compensation to the TSO/DSO for managing network related operations.

The electricity markets within the European Union (EU) as well as and other parts of the world are constantly evolving. The basic structure is however similar to that of the Nord Pool, which was the first international electricity market [5]. Considering the EU level plan of a harmonized electricity market to facilitate cross-border trading [1], it could be reasonably assumed that future developments would not drastically change the framework of electricity markets from the present. Currently, market players can enter into various power contracts that are further described below in the context of the Nordic electricity market. Figure 9.1 shows an overview of market participants along with the various types of contracts they could enter into. A description of some important contracts that the players could enter into is described in the following subsections.

9.2.1 Bilateral Contracts

The market participants can enter into conventional bilateral contracts that involve a direct trade between a buyer and seller of electrical energy. Considering around

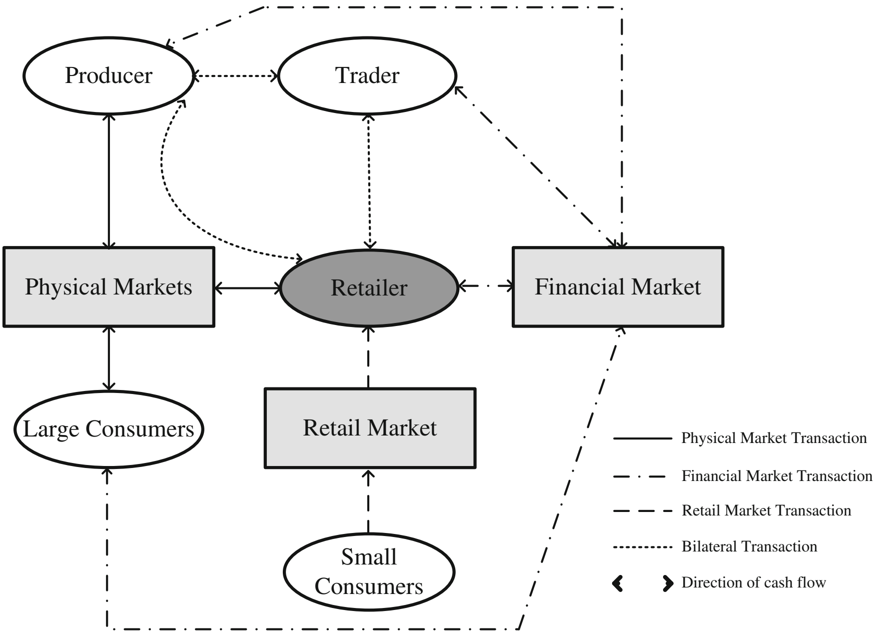

Fig. 9.1 Market players and their interactions within an electricity market framework

84 % of power consumption in the Nordic and Baltic countries are bought at the day-ahead market (DAM) [5], it could be observed that electricity market trading is becoming more appealing to the players. The physical markets including the DAM are described in the following subsection.

9.2.2 Physical Electricity Markets

Like many other commodities, electricity could also be traded within a wholesale market framework. A common DAM called *Elspot* exists for the Nordic and Baltic countries where the market players trade bulk of the electricity production and consumption. The clearing of Elspot results in a production and/or consumption plan for each market player with a delivery obligation, which requires the players to abide by their individual plans.

Electrical energy is however, dynamic, in the sense that electricity has to be instantaneously available when there is demand with few economically viable storage options. This singular characteristic along with the fact that Elspot is cleared ahead of the delivery time of electricity necessitates the use of forecasting methods by the players to estimate their production and consumption. The resulting power deviations that could occur due to forecasting errors, component failures etc., need to be rectified. Players are provided an opportunity to do this through the continuously traded *Elbas* market that is available to balance out the players' individual deviations from their Elspot plans.

It is still possible that last minute imbalances could occur due to failure of components or various faults within the power system. The responsibility of maintaining power balance within the power system during delivery period rests on the TSO who jointly operate the *regulating power market* (RPM) to provide a mechanism for correcting the resulting imbalance during delivery period and ensure the desired level of security of supply within the power system. This market is cleared retroactively as opposed to the Elbas market.

There is a physical obligation associated with the electricity markets, i.e., it has to be ensured that the energy traded in the market is delivered to the end consumers during the specified delivery period. Hence, the Elspot, Elbas and regulating power markets are collectively addressed as physical markets.

9.2.3 Financial Electricity Markets

It is imperative that the market players are able to quantify and hedge the financial risks associated with their participation in the physical markets. Financial markets provide a platform to manage risks by hedging against price fluctuations in the wholesale markets. Common contracts made available in financial markets are [6]: Futures, Forwards, Options and Contracts-for-difference.

It is also important to mention that the financial and physical markets have a specific time-line over which they are operated. Contracts in financial markets are cleared days, weeks, months or years ahead of delivery as opposed to physical markets that are generally cleared 45 min to 1 day-ahead. E.g., an overview of the time-line for Nordic electricity markets operation is shown in Fig. 9.2.

9.3 Demand Response in Electricity Markets

Demand response could be defined as the independent variation in consumption made by consumers as a reaction to different possible incentives. An incentive could, e.g., be price signals from a market for electricity or a network signal

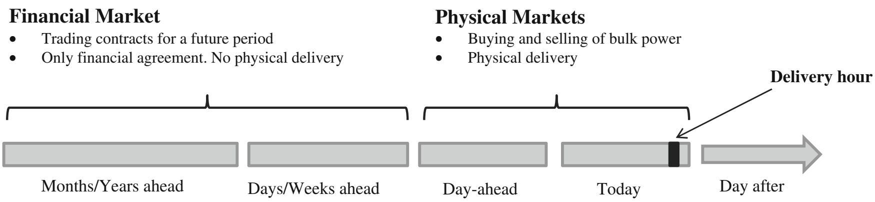

Fig. 9.2 Overview of timeline of Nordic physical and financial markets

provided by the distribution system operator (DSO) in order to maintain the security and reliability of the power system during emergency conditions. Regardless of the type of incentive used, the end result of demand response could be represented as one the load shaping objectives described in [7, 8]:

a. *Peak clipping*—implies the reduction of peak load by using direct load control over customers' appliances. This form of control could be used to reduce the overall cost and dependence on peaking generating units. A good example of peak clipping is the use of interruptible or curtailable tariffs for industrial customers in many vertically integrated power system architectures.
b. *Valley Filling*—implies the process where incentives are provided to increase new demand during off-peak hours. This could be accomplished, e.g., by providing price incentives to new space heating or electric vehicle demand to consume during off-peak hours.
c. *Load Shifting*—implies shifting part of the load from on-peak to off-peak periods. This could involve displacing loads during a particular hour that would otherwise normally be served by electricity.
d. *Flexible Load Shaping*—implies a combination of various incentives. These incentives could include interruptible load, integrated energy management systems or individual customers' load control, etc.

The consumers who are willing to respond to incentive-based signals could be referred to as active consumers. An active consumer could be either a large industrial consumer or a small domestic consumer. Since, the consumption levels of domestic consumers are small compared to the volumes traded in electricity markets, an agent similar to a retailer could become essential to represent the needs of domestic consumers in electricity markets. With controllable resources, however, this agent generally referred to as an 'aggregator' could possibly assume new functions that might require it to control consumer appliances in real-time.

Demands could respond to the price of electricity in the market to consume during low price hours as opposed to high price hours. Alternatively, response from demand could also be used to provide ancillary services to network operation such as frequency response, voltage and reactive power control, black start capability, voluntary load shedding etc. Such programs involving control of demand-side have historically been utilized but limited to large industrial consumers. With the roll out of smart meters, real-time control of domestic consumers' consumption could also be achieved. This could result in greater demand side participation in electricity markets possibly leading to more efficient use of generation resources while also reducing the stress on transmission network during peak consumption periods. Realizing its importance, many electricity markets have begun to open up for greater demand side participation—notable are the area-price based Nordic electricity market and the locational marginal pricing (LMP) based PJM market [9, 10].

9.3.1 Nordic Electricity Market

Features: The Nordic physical markets provide opportunities for price dependent demand to compete directly with price dependent generation. This is especially the case with large scale industrial consumers who have the flexibility to bid for energy directly on the market on an hourly basis and to adjust their consumption in order to prevent being exposed to very high prices. When it comes to small and medium sized consumers, there is a plan to move towards a common retail electricity market with the Nordic region that offers the option of variable retail pricing for consumers directly based on the wholesale price of electricity. In this regard, the installation of smart metering systems has been adapted to measure real-time consumption pattern of domestic and commercial consumers of electricity.

Challenges: Notable challenges exist for domestic consumer participation in the Nordic electricity markets. Though an aggregator agent could be a legal entity in current Nordic day-ahead, intra-day and financial electricity markets, barriers arise when the aggregator would want to participate in the regulating power market. This is due to the fact that aggregator would need to assume the role of a balance responsible party (BRP) in order to participate in RPM, or contract with another BRP. There could be further limitations due to the rules and regulation regarding aggregation of demand in general and also, regarding a new market player assuming the role of a BRP. Another barrier that could hinder the participation of an aggregator is the minimum bid volume requirement by the TSO in RPM, which is 5 MW. This could prove to be a large volume for aggregators, especially in bidding areas with surplus production resources.

9.3.2 Pennsylvania-Jersey-Maryland Market

Features: In the Pennsylvania-Jersey-Maryland (PJM) electricity market, the end-users can participate in PJM's day-ahead energy, capacity, reserves and regulation markets by reducing their demand for electricity. Currently, the mechanism provided through demand response programs only attempts to replicate electricity market price signals instead of exposing them directly to end-users. This is done through curtailment service provider (CSP). Specifically, the role of CSP is defined by PJM as [10], "the entity responsible for demand response activity for electricity consumers in the PJM wholesale markets." Some notable features about a CSP are:

- It may be a company that solely focuses on a customer's demand response capabilities, a local electricity utility, an energy service company or other type of company that offers these services.
- It identifies demand response opportunities for customers and implements the necessary equipment, operational processes and/or systems to enable demand response both at the customer's facility and directly into the appropriate wholesale market.

- It should have appropriate operational infrastructure and a full understanding of all the wholesale market rules and operational procedures.

Challenges: Some barriers [11] that limit customer exposure to wholesale electricity prices could be due to the inadequate metering infrastructure, lack of jurisdictional clarity among regulatory authorities, lack of clear business rules etc. Furthermore, retail prices are set by regional authorities whose operations are decoupled from federal agencies.

9.4 PEV Aggregator

Small and medium level consumers do not have means to directly trade in electricity markets due to the multi-MW size of minimum bid requirement imposed. In order to trade their flexibility, they would require the services of an aggregator agent that gather the flexibility offered by many consumers and builds or pools in active demand capacity to be traded as a single resource. Example of loads that could be aggregated include: fans, electric cooling and heating, electric boilers, refrigerators etc. The aggregators could also generate agreements with consumers to adjust their electricity consumption at moment's notice. A dedicated aggregator for trading flexibilities offered by electric vehicles is the 'PEV aggregator'. Within the context of electricity markets, the functions of a PEV aggregator are similar to that of an electricity retailer. Figure 9.3 describes the interaction of an aggregator with other market participants. The aggregator could purchase electricity from wholesale markets and subsequently sell them to PEV owners through retail contracts. However, it is imperative for the DSO to ensure that the electricity traded by the aggregator is within the capacity of the distribution network. Hence, there could be an additional need for the DSO to communicate and subsequently validate the energy trading performed by an aggregator.

There could be additional functions that need to be accommodated in order to include the concept of aggregator more efficiently within the electricity market [12]. Some of these have been listed as follows:

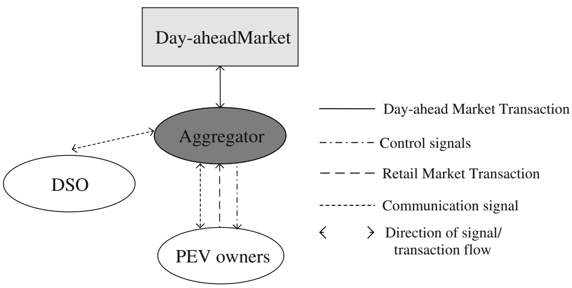

Fig. 9.3 Overview of the aggregator and its interaction in the physical markets

i. There should be necessary communication infrastructure in place for the aggregator to obtain near real-time electricity consumption measurement, vehicle battery state and consumption needs of PEV owners [13].
ii. There should be a mechanism in place for the control of PEV owner batteries. The batteries could be controlled directly by the aggregator with energy schedule validation by the DSO if the necessary automatic control infrastructure is established and market and power system operational rules permit the same. If the rules impose separation of the operational aspect and business aspect of the aggregator, then it could be possible for the DSO to take over the PEV battery control function based on the energy scheduling plan communicated to the DSO by the aggregator [12].
iii. For higher participation from small consumers, it could become essential to reduce minimum bid size in the market to values lower than 1 MW [14].
iv. It might become necessary to introduce shorter time periods of around 30 min or less between market closure and operating hour in order to reduce forecast errors by the aggregator [14].

In this chapter, (i) and (ii) described above are assumed to be available to the aggregator. It is also possible to incorporate (iii) could be incorporated within a RPM model by reducing the minimum bid size to be submitted by the aggregator to the market and (iv) within the DAM by modifying the time resolution for scheduling by the aggregator.

The following section presents two methods for incorporating PEV aggregator and their charge scheduling in DAM [15]. Firstly, the *Joint Scheduling Method* (JSM), where PEV energy is scheduled simultaneously with the generation units—the objective function being minimization of total generation cost. Secondly, the *Aggregator Scheduling Method* (ASM), where the PEV battery energy is first scheduled independently by an aggregator agent based on the estimated electricity market price. The charging schedule, which represents the PEV energy demand, is then submitted to the market in the same way as other conventional loads. Consequently, it is possible to assess the effects of PEV energy demand on electricity market price and compare the impacts among cases with and without PEVs, as well as among cases with the two different scheduling approaches.

9.5 Methods for PEV Energy Scheduling

9.5.1 Joint Scheduling Method

In JSM, the PEV energy scheduling is considered to be performed by a central entity like a system operator that also plans for the dispatch of the generators. The central operator is assumed to receive data related to the generators and PEV batteries. The operator could then schedule both the generators and the PEV charging energy demand by minimizing the total cost of generation. In a scenario where advanced methods of communication and control are feasible, individual PEV owners could directly interact with the market by submitting the necessary PEV data. In this scheduling method, the central operator is assumed to receive the following three sets of information:

(1) Generator costs along with its technical constraints.
(2) Daily PEV driving energy requirements, driving pattern data and aggregated PEV battery energy limits.
(3) Hourly conventional load data, which represents the inflexible demand from all other loads other than PEV demand.

Using these three sets of information, the market model jointly schedules the generators and PEV load to minimize the total generation cost within a unit commitment framework [16]. This is shown in Fig. 9.4.

The generators are assumed to bid their true marginal cost of generating electricity and the market is settled with the minimum generation cost objective [17]. Loads except PEVs are considered to be perfectly forecasted a priori, and are fixed for each hour.

The objective function of the market model is to minimize the total cost of generation to supply the load over the time horizon T. This cost also includes the start-up cost of generating units. This is formulated as shown in (9.1).

$$Minimize \quad DAMC = \left(\sum_{t \in T} \sum_{i \in N} VC_i p_{i,t} + y_{i,t} SC_i \right) \tag{9.1}$$

where, $DAMC$ is the total cost of scheduling the generators in the day-ahead market, VC_i is the variable cost of power production of generating unit i and $p_{i,t}$ is the power produced by unit i at time t, $y_{i,t}$ is a binary variable indicating the starting up of unit i at time t and SC_i is the start-up cost of unit i.

The objective function $DAMC$ in JSM as shown in (9.1) is subject to constraints (9.2)–(9.15) imposed by the generating units, (9.16)–(9.19) imposed by the aggregated PEV batteries and power balance constraint (9.20).

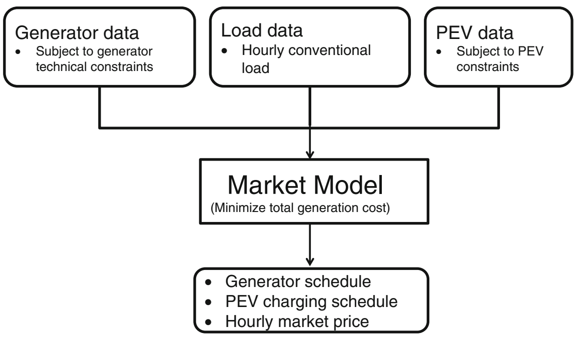

Fig. 9.4 Overview of the JSM

9.5.1.1 Generating Unit Constraints

The generating units should generate power greater than their minimum limits at all times t as shown in (9.2)

$$p_{i,t} \geq v_{i,t} P_i^{\min}; \quad \forall i \in N,\ t \in T \tag{9.2}$$

where, $p_{i,t}$ is the active power output of generator unit i at time t, $v_{i,t}$ is a binary variable indicating the online status of generator unit i at time t and $P_i^{\min}$ is the minimum active power output of generator unit i. The decision of whether the generating unit generates power at time t is taken using a binary variable $v_{i,t}$. The value of $v_{i,t} = 1$ indicates that the unit i is committed to generate power at time t whereas a value of $v_{i,t} = 0$ indicates that the unit i is de-committed from generating power at time t.

The constraints for maximum available power from the generating unit and its ramp rate limit are formulated as shown in (9.3) and (9.4). These constraints account for the generating unit capacity, start-up ramp rate limit, shut-down ramp rate limit and the ramp-up limit of the unit. The maximum available output from the generator becomes zero when $v_{i,t} = 0$, i.e., the unit is offline.

$$p_{i,t} \leq P_i^{\max}\left(v_{i,t} - z_{i,t+1}\right) + z_{i,t+1} SD_i; \quad \forall i \in N,\ t \in T \tag{9.3}$$

$$p_{i,t} - p_{i,t-1} \leq RU_i v_{i,t-1} + SU_i y_{i,t}; \quad \forall i \in N,\ t \in T \tag{9.4}$$

where, $P_i^{\max}$ is the maximum active power output of generator unit i, SD_i is the shut-down ramp limit of generating unit i, RU_i is the ramp-up limit of generating unit i, SU_i is the start-up ramp limit of generating unit i and $z_{i,t}$ is a binary variable indicating shut down status of generator unit i at time t (the unit is shut down if value of $z_{i,t}$ is 1 and online if its value is 0).

The constraint in (9.5) enforces the ramp-down rate limit and the shut-down ramp rate limit for the unit.

$$p_{i,t-1} - p_{i,t} \leq RD_i v_{i,t} + SD_i z_{i,t}; \quad \forall i \in N,\ t \in T \tag{9.5}$$

where, RD_i is the ramp-down ramp limit of generating unit i.

Expressions (9.6)–(9.9) impose minimum up time constraints on the generating units.

$$\sum_{t=1}^{GU_i} \left[1 - v_{i,t}\right] = 0; \quad \forall i \in N \tag{9.6}$$

$$GU_i = Min\left[T, \left(UT_i - U_i^0\right) V_i^0\right]; \quad \forall i \in N \tag{9.7}$$

$$\sum_{k=t}^{t+UT_i-1} v_{i,t} \geq UT_i y_{i,t}; \quad \forall i \in N,\ t \in \{GU_i + 1, \ldots, T - UT_i + 1\} \tag{9.8}$$

$$\sum_{k=t}^{T} \left[v_{i,t} - y_{i,t}\right] \geq 0; \quad \forall i \in N,\ t \in \{T - UT_i + 2, \ldots, T\} \tag{9.9}$$

where, GU_i is the number of period that generating unit i must be online at the beginning of the day-ahead market optimization horizon due to its minimum up time constraint, UT_i is the minimum up time of generating unit i, U_i^0 is the time periods that generating unit i has been online at the beginning of the day-ahead market optimization horizon, V_i^0 is the initial commitment status of generating unit i (1 if it is online and 0 if it is offline), $y_{i,t}$ is a binary variable indicating start-up status of generator unit i at time t (the unit is started up if its value is 1 and offline if it is 0).

Constraint (9.6) accounts for the initial status of the units. GU_i is the total number of initial periods during which the unit i must be online and is calculated as shown in (9.7). The constraint in (9.8) ensures that the minimum up time constraint during all the possible sets of UT_i consecutive periods is satisfied for each period following GU_i. If a generating unit is started up in one of the last $(UT_i - 1)$ periods, (9.9) ensures that it remains online during the rest of the periods until $t \in \{T\}$.

The set of expressions in (9.10)–(9.13) impose the minimum down time constraints on the generating units. These are similar to the minimum up time constraints with the difference that $(1 - v_{i,t})$, $y_{i,t}$, UT_i, U_i^0 in (9.6)–(9.9) are replace by $v_{i,t}$, $z_{i,t}$, DT_i, S_i^0 in (9.10)–(9.13), respectively.

$$\sum_{t=1}^{GD_i} v_{i,t} = 0; \quad \forall i \in N \tag{9.10}$$

$$GD_i = Min\left[T, \left(DT_i - S_i^0\right)\left(1 - V_i^0\right)\right]; \quad \forall i \in N \tag{9.11}$$

$$\sum_{k=t}^{t+DT_i-1} \left[1 - v_{i,t}\right] \geq DT_i z_{i,t}; \quad \forall i \in N,\ t \in \{GD_i + 1, \ldots, T - DT_i + 1\} \tag{9.12}$$

$$\sum_{k=t}^{T} \left[1 - v_{i,t} - z_{i,t}\right] \geq 0; \quad \forall i \in N,\ t \in \{T - DT_i + 2, \ldots, T\} \tag{9.13}$$

where, GD_i is the number of period that generating unit i must be offline at the beginning of the day-ahead market optimization horizon due to its minimum down time constraint, DT_i is the minimum down time of generating unit i and S_i^0 is the time periods that generating unit i has been online at the beginning of the day-ahead market optimization horizon.

The constraints in (9.14) and (9.15) are necessary to model the start-up and shut-down status of the units and avoid simultaneous commitment and de-commitment of a unit.

$$y_{i,t} - z_{i,t} = v_{i,t} - v_{i,t-1}; \quad \forall i \in N,\ t \in T \tag{9.14}$$

$$y_{i,t} + z_{i,t} \leq 1; \quad \forall i \in N,\ t \in T \tag{9.15}$$

9.5.1.2 PEV Battery Constraints

In the developed mathematical model, the individual batteries are assumed to be aggregated and treated as a single battery. The constraints essentially reflect the charging and discharging operation of the aggregated vehicle battery while accounting for the traveling energy needs of PEV owners based on their aggregated driving pattern. It is further assumed that the vehicles are available to the grid for charging at all times when they are not traveling.

Minimum Energy Requirement
It is assumed that the PEV owner gives the aggregator information about when and how much of traveling is intended for the next day. Based on this information, the battery is charged only that amount of energy necessary over its initial state.

$$SOC^{ini} + \sum_{t=1}^{T} E_t \geq SOC^{\min} + \sum_{t=1}^{T} E_t^{next} \tag{9.16}$$

where E_t^{next} is the MWh energy required by the PEV for next day travel during hour $t \in T$, SOC^{ini} is the initial state of energy in the battery in MWh and $SOC^{\min}$ is the minimum energy requirement imposed by the PEV owner on the battery in MWh. An example of minimum energy requirement input data of a single PEV provided to the aggregator is shown in Table 9.1.

Charging Period Limit
The PEV aggregator should ensure that the charging of the PEV occurs in such a way that the battery is charged during hours $tf = 1, 2, \ldots, (t-1)$ before it travels

Table 9.1 PEV related data [15, 19]

Battery capacity	24 kWh
Energy consumption	0.192 kWh/km
Distance travelled	40 km/day
Energy consumption per day	7.68 kWh/day
Charging power	3.7 kW

during hour t for all values of $t \in T$. This is formulated mathematically as shown in (9.17).

$$\sum_{tf=1}^{t-1} \left(E_{tf} - E_{tf}^{next} \right) \geq E_{t}^{next} \tag{9.17}$$

Battery State
Charging and discharging of the battery during consecutive hours results in a change in its energy level for all $t \in T$. This is formulated as shown in (9.18).

$$SOC_t = SOC_{t-1} + E_t - E_t^{next} \tag{9.18}$$

Battery Energy Limits
The energy state in the battery should not deviate from its minimum and maximum limits, $SOC^{\min}$ and $SOC^{\max}$, respectively for all $t \in T$ as shown in (9.19).

$$SOC^{\min} \leq SOC_t \leq SOC^{\max} \tag{9.19}$$

It could be noted that the aggregator could face uncertainty by obtaining input data from PEV owners. One method to plan for PEV charging scheduling while considering uncertainty in PEV demand as well as electricity price in the day-ahead market is proposed in [18] using a stochastic programming framework.

9.5.1.3 Power Balance Constraints

The power balance between generation and supply must be maintained. This is mathematically formulated as shown in (9.20).

$$\sum_{i} p_{i,t} = CL_t + E_t \tag{9.20}$$

The total demand consists of the conventional demand CL_t and the demand from the PEV charging energy E_t. The PEV charging energy is an endogenous variable when PEV scheduling is performed using the JSM. However, it is provided as an input parameter to the DAM model when the ASM is utilized.

9.5.2 Aggregator Scheduling Method

In ASM, the PEV aggregator is assumed to function similar to an electricity retailer in the market. The aggregator plans for DAM participation by independently scheduling PEV energy based on its objective of minimizing the total cost of

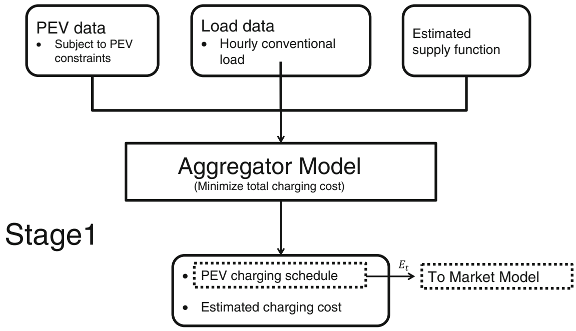

Fig. 9.5 Overview of the ASM: Stage-1

charging. For the scheduling, the PEV aggregator is assumed to have the following three sets of information:

(1) Daily PEV driving energy requirements, driving pattern data and aggregated PEV battery energy limits.
(2) Hourly conventional load data, which represents the inflexible demand from all other loads other than PEV demand.
(3) Estimated supply function to model the PEV aggregator as a price maker. If the aggregator needs to be modeled as a price taker, then the estimate supply function input data could be replaced directly with the forecasted electricity price profile.

Using the above sets of data, the aggregator schedules the charging energy of PEVs such that the total cost of charging is minimized as shown in Fig. 9.5.

9.5.2.1 The PEV Aggregator Model

The PEV aggregator ensures that the charging and discharging events of the vehicle's aggregated battery is scheduled considering the unavailability of PEVs due to driving needs. Batteries within electric vehicles are essentially loads that are required to be charged with sufficient energy to ensure smooth operation of the vehicle according to the driver's needs. Hence, it could be reasonable to assume that the main position held by the PEV aggregator is as a consumption entity within the electricity market. Considering such a stance, the objective function of the aggregator would then be to make sure that the cost from energy purchased for charging of all the PEVs is minimized while accounting for the driving needs of the PEVs. Due to its participation in the day-ahead market, the charging energy price would depend on the market price of electricity. If hourly charging costs are directly imposed on the PEV owners, the objective function could then be represented using (9.21).

$$Minimize \quad ACC = \left(\sum_{\forall t \in T} \pi_t^m * E_t \right) \tag{9.21}$$

where, ACC is the total cost of charging estimated by the PEV aggregator, π_t^m is the estimated market price from the estimated supply function and E_t is the charging energy to be scheduled at time t over the optimization horizon T. It is possible that the charging price used by the PEV aggregator is either an endogenous variable or an exogenous parameter. If the market is such that it requires the aggregator to plan the hourly charging needs before submitting its energy requirements to the market, then the electricity price would need to be estimated and it would identify itself as an exogenous parameter within the aggregator model.

The objective function of the PEV aggregator shown in (9.21) is subject to constraints imposed by the needs of vehicle owners along with the technical limitations of the battery as described in (9.16)–(9.19).

The estimated supply function gives an approximation of how the market price varies with changes in total demand. This function is important to identify the effect of total PEV demand on the market price when it is no longer a price taker. The estimated charging price could be modeled as a function of the total demand within the system as is shown in (9.22).

$$\pi_t^m = f(CL_t, E_t) \tag{9.22}$$

where, CL_t is the aggregator forecasted conventional load. The supply function can also be estimated from historical data on price and demand level cleared in the market.

9.5.2.2 The Market Model

The PEV charging schedule E_t from the ASM: Stage-1 is then input into the market model in the ASM: Stage-2 where the generators are scheduled to meet the total demand from the conventional load and the scheduled PEV energy in a way so as to minimize the total generation cost. This is shown in Fig. 9.6.

The objective function of the market model in ASM: Stage-2 is described by *DAMC* in (9.1) and is subject to constraints (9.2)–(9.15) imposed by the generating units and the power balance constraint (9.20).

9.6 Case Studies

In this section, the presented joint scheduling and aggregator scheduling methods are applied on a modified IEEE 30-bus test system and a Nordic test system to observe the effect of PEV demand scheduling on changes in price of electricity.

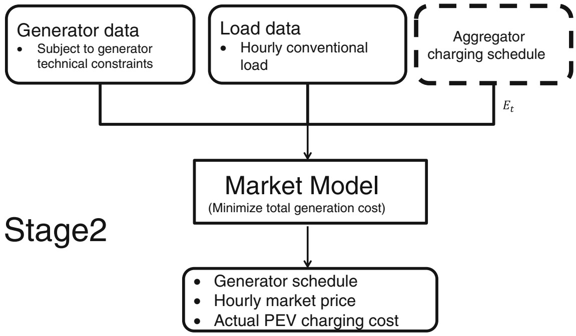

Fig. 9.6 Overview of the ASM: Stage-2

PEV related data shown in the following paragraphs is used that is common to all the case study simulations performed. The description of the IEEE 30-bus test systems and the representative Nordic system along with the results from the case studies are further described in Sects. 9.6.1 and 9.6.2, respectively.

The input data related to PEVs used for both the JSM and ASM case studies were obtained from a report published by the Grid for Vehicles (G4 V) project under the European Commission's 7th framework program [19], and are shown in Fig. 9.7 and Table 9.1.

The driving pattern in Fig. 9.7 is dependent on vehicle users and it is reasonable to assume that the driving behavior would not change drastically with the introduction of PEVs. Hence, the conventional vehicle user behavior is considered to be representative of the expected PEV user behavior.

The battery capacity and energy consumption in Table 9.1 are calculated based on the expected composition, at high penetration levels, of battery electric vehicles and plug-in hybrid electric vehicles, and represent a weighted average value [15, 19].

The battery charging and discharging characteristics are highly non-linear and depend on the type of battery. Li-ion batteries are considered as they appear to be the most promising type for PEV application [20]. Their charging curve indicates

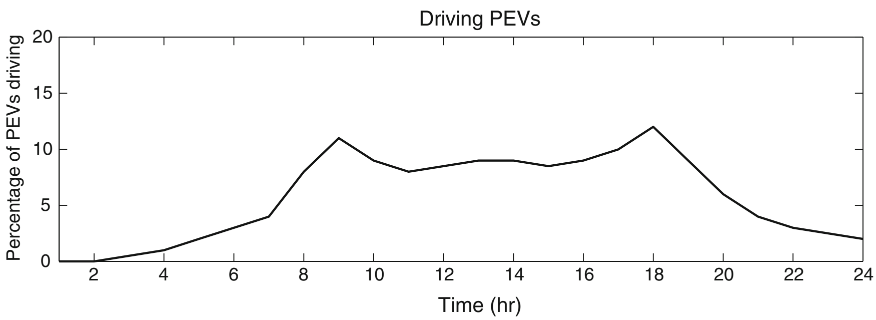

Fig. 9.7 Driving pattern of PEVs based on conventional vehicle data [15, 19]

that the charging power is nearly constant within a certain range of their state-of-charge [21]. Hence, the values of $SOC^{\min}$ and $SOC^{\max}$ are fixed at 20 and 85 % of the battery capacity for all simulations.

9.6.1 The IEEE 30-Bus Test System

The presented JSM and ASM have been applied to a modified IEEE 30-bus test system [22] to observe the effects of PEV aggregator demand scheduling on the price of electricity. The test system consists of nine generating units that are subjected to the following general technical constraints [16]:

- Min/Max generation limit
- Min up/down time
- Ramp up/down rate limits
- Start-up/Shut-down ramp rate limits

The penetration level of PEVs is defined as the ratio of total number of PEVs to the total number of vehicles in the system. It is estimated that a total of 170,000 PEVs would, in addition to the conventional load, result in energy requirements that would lead to the flattening of the daily load curve at a level corresponding to the peak demand. Since, information about vehicles in this test system is not readily available; it is assumed that there are a total of 170,000 vehicles in the system.

In ASM, the aggregator is considered to make use of the estimated supply function described in (9.23) to estimate the effect of PEV load on the market price and schedule the charging accordingly.

$$\pi_t^m = a_1 (CL_t + E_t) + a_0 \tag{9.23}$$

where, a_1 and a_0 are the constant coefficients. The estimated supply function for this system is shown in Fig. 9.8.

9.6.1.1 Fixed Period Charging

To obtain an idea of how the total load and market price will vary with the introduction of PEVs while the market has limited control over the charging, a fixed period charging method is described. A simple controlled charging mechanism of PEVs can be implemented by fixing their charging schedule during certain hours of the day when the conventional load is low. Figure 9.9 shows the variation of total hourly load at different levels of PEV penetration within the system when PEV charging is limited to hours 1–6.

Figure 9.10 shows the variation of hourly market price with different levels of PEV penetration within the system. It can be observed that at penetration levels of 20 and 50 %, increase in market price is not significant indicating that even a simple

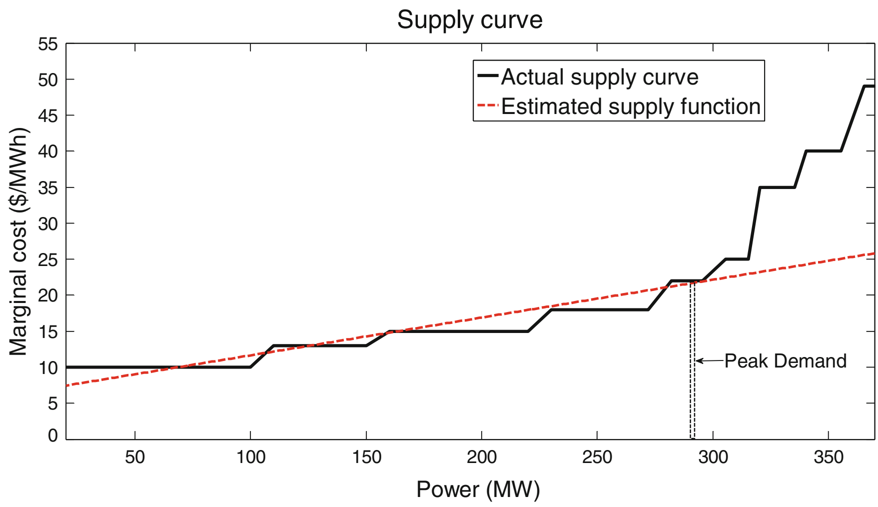

Fig. 9.8 Actual supply curve and estimated supply function used for modified IEEE 30-bus system

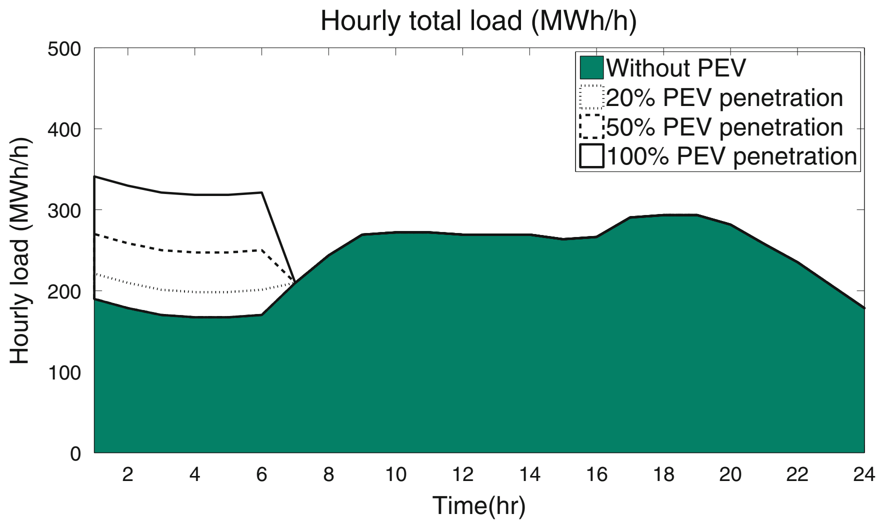

Fig. 9.9 Fixed period charging result—hourly total load

charging mechanism could be effective in maintaining an acceptable increase in market price by the introduction of PEVs. But at higher penetration levels, i.e., 100 %, Fig. 9.9 indicates that the total load during early hours exceeds the peak demand due to conventional load alone (hour-18). The increase in market price can

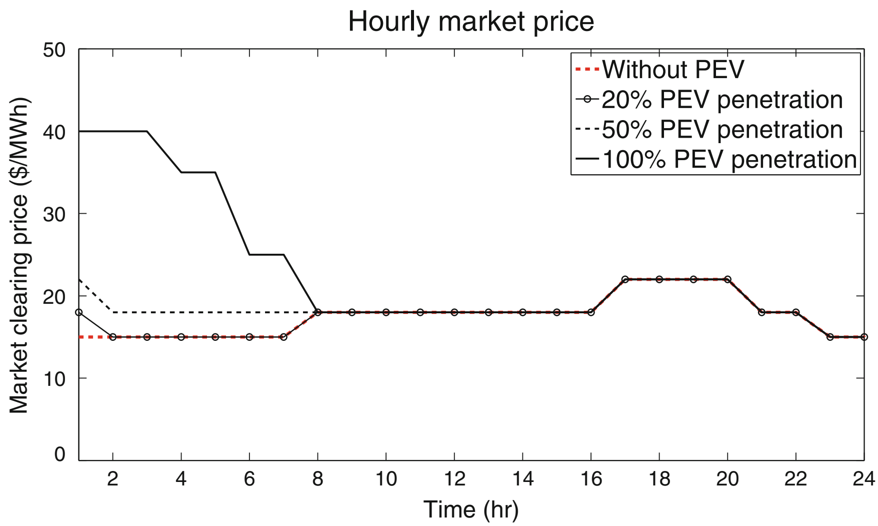

Fig. 9.10 Fixed period charging result—hourly market price

also be seen in Fig. 9.10 as more expensive generators need to be scheduled to supply the additional PEV load resulting in a market price as high as 40 $/MWh during the first 3 h.

9.6.1.2 Joint Scheduling Method

The JSM is implemented for this test system and the resulting market price for various penetration levels of PEVs is shown in Fig. 9.11. Comparing Figs. 9.10 and 9.11, it can be seen that at lower penetration levels of 20 and 50 %, there is no significant difference in the increase of market price between fixed period charging and joint scheduling. But, at higher penetration level of 100 %, joint scheduling results in a more uniform market price of 22 $/MWh, indicating better utilization of generating resources.

Figure 9.12 shows the hourly total load at 100 % PEV penetration. It can be seen that the total load in the system does not exceed the peak load at hour 18 even at 100 % PEV penetration. This can be significant in systems that are stressed and might need network reinforcement in the case of fixed period charging, but the same can be avoided using joint scheduling. It is interesting to note that little or no charging takes place during the hours 23 and 24. This could possibly be due to two reasons—one, the optimization horizon in the model is limited to 24 h and two, the PEV energy requirements need to be respected before their hour of travel.

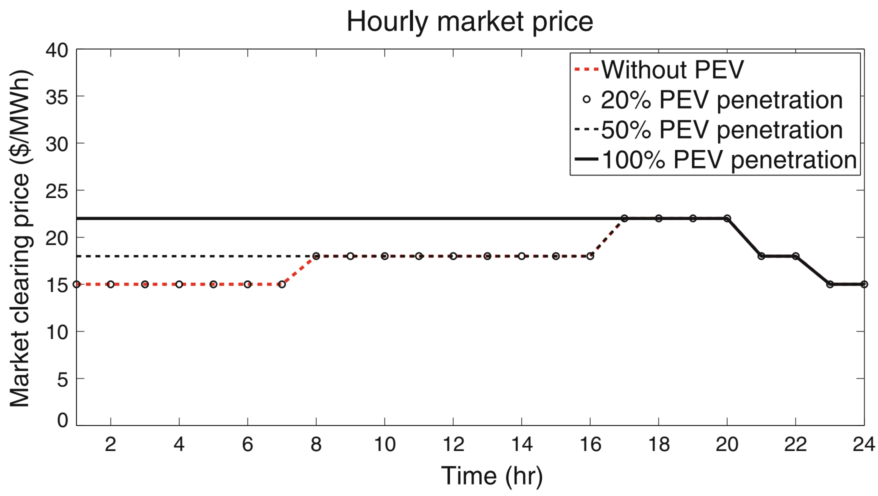

Fig. 9.11 JSM result: market price at zero and 100 % PEV penetration

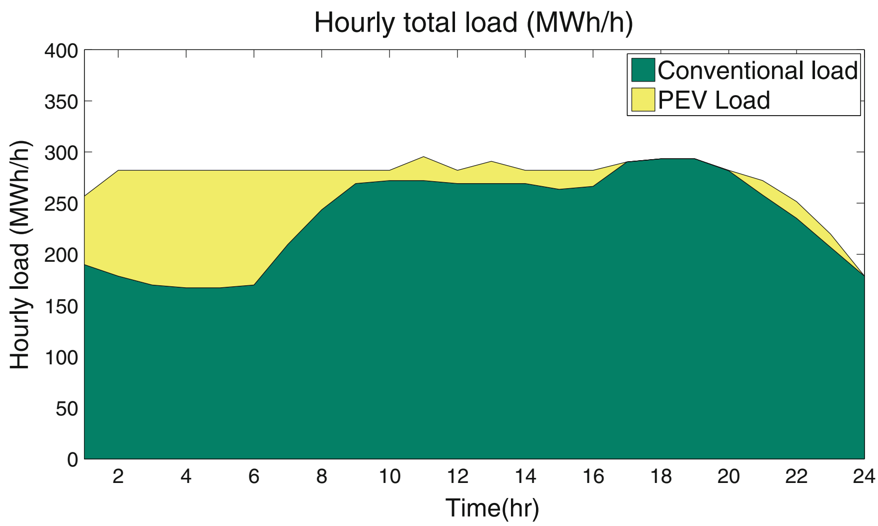

Fig. 9.12 JSM result: system demand at zero and 100 % PEV penetration

9.6.1.3 Aggregator Scheduling Method

The results obtained from ASM are shown in Fig. 9.13 for various PEV penetration levels. Comparing Figs. 9.10 and 9.13, it can be seen that at 20 % penetration, the market price during the day increases similarly in both models. However, at 50 % penetration level, the aggregator model results in an increase of market price by

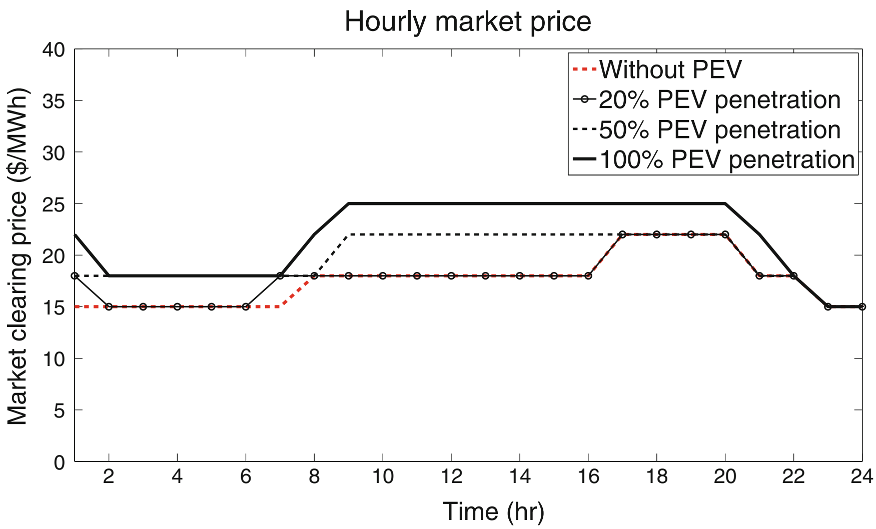

Fig. 9.13 ASM result: market price at various PEV penetration levels

4 $/MWh during hours 9–20. This could be attributed to the aggregator not being able to perfectly forecast the dependency of price on changes in demand. Since, forecasting brings about an error in the estimated price, the aggregator schedules higher or lower charging energy during an hour, depending on whether the demand dependency was underestimated or overestimated, respectively.

The hourly load for ASM is compared with the result from JSM for 100 % PEV penetration and is shown in Fig. 9.14. It can be seen that the error in estimation by the aggregator results in lower PEV load to be scheduled between hours 2 and 7 when compared with the JSM. Due to this under-scheduling of PEV load during the early hours, greater PEV load is scheduled between hours 9 and 21.

The corresponding changes in market price can be seen in Fig. 9.15. This price directly reflects the errors in forecasting by the aggregator on market price. It is lower by about 4 $/MWh during hours 2–7 but, consequently, increases by 4 $/MWh during the later hours 9–21 when compared to JSM results.

9.6.2 The Nordic Test System

The joint scheduling approach is used to simulate the participation of PEV aggregator and its charging energy scheduling in the Nordic day-ahead market, which consists of four participating countries from the Nordic region, namely—Norway, Sweden, Finland and Denmark. The market players who want to trade electricity on the Elspot market must submit their sell offers and/or buy bids for every hour of trading to the market, no later than 12:00 h, on the day before the power delivery.

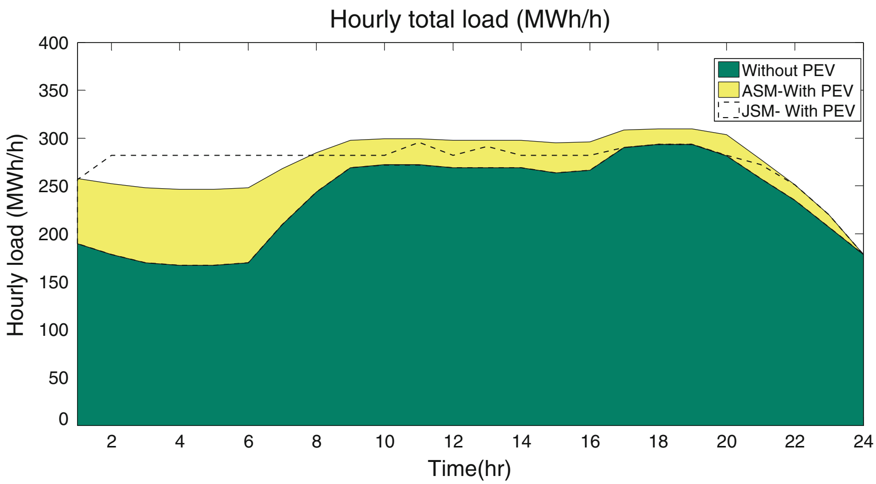

Fig. 9.14 ASM result: system demand at various PEV penetration levels

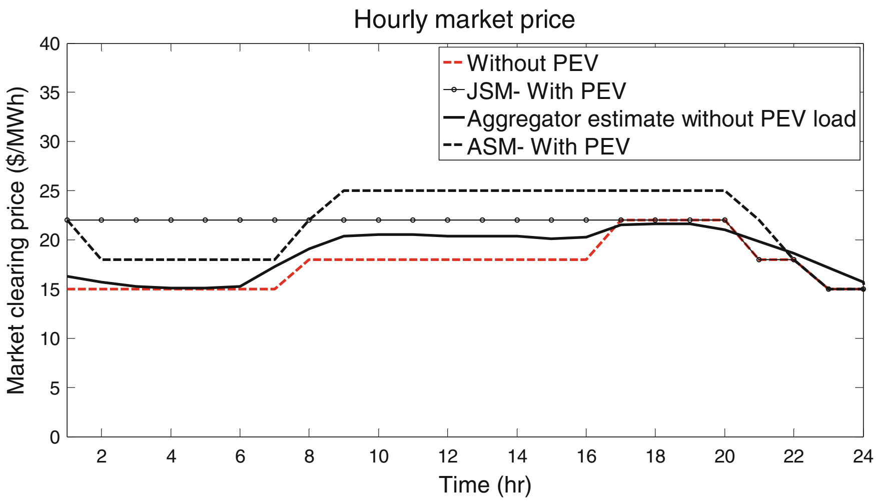

Fig. 9.15 Comparison of resulting market price with aggregator and joint scheduling methods

These bids are submitted via the internet to the website of Nord Pool Spot. The collected sell bids are cumulated in increasing order of price to form a supply curve and the buy bids are cumulated in decreasing order of price to form a demand curve —for every hour. The intersection of the two curves gives the market price of electricity for that hour. More information on the operation of Elspot can be found in [4].

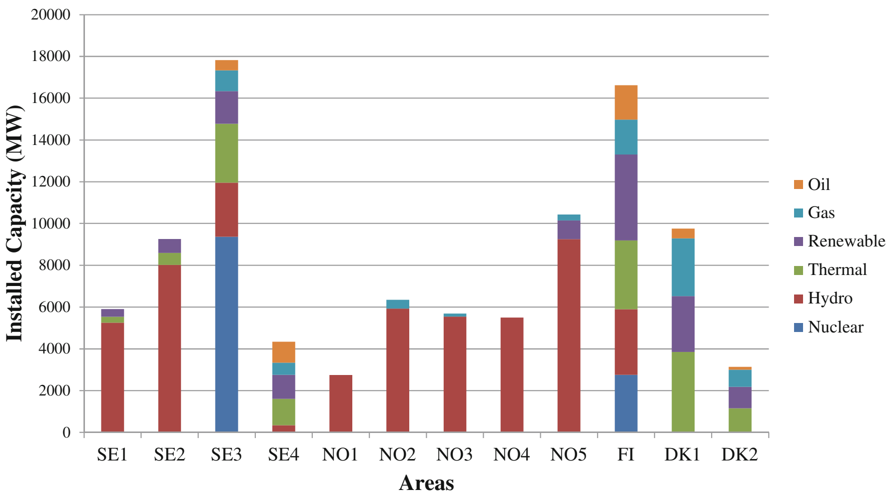

Fig. 9.16 Generating capacity distribution by bidding area in the Nordic region [23]

Due to the physical restrictions imposed on energy trading by transmission lines, the Nordic electricity market area is divided into a number of bidding areas. The TSO decides on the criteria and number of bidding areas. Since, the operation of a TSO is generally limited to one country; a bidding area does not traverse political boundaries between countries. Currently, Norway is split into 5 bidding areas—NO1 to NO5; Sweden into four—SE1 to SE4; Denmark into two—DK1 and DK2; and Finland into one—FI.

The total installed generating capacity in the Nordic region is around 96 GW [23]. Figure 9.16 shows the share of total installed generation capacity based on the bidding areas in the Nordic region (excluding Estonia, Latvia and Lithuania).

Installed generation capacity data for units greater than 100 MW including the type of generating technology for all four countries is obtained from [24]. The variable cost of power generation based on different technologies in [25] is used and scaled to reflect the average system prices in Nord Pool Spot for the year 2012 [26], after which the aggregated supply curve in the Nordic market can be obtained as shown in Fig. 9.17.

The aggregated supply curve is based on installed generation capacity in four countries—Norway, Sweden, Finland and Denmark. A normal market situation is considered, where, all the installed generation capacity is available. Two generation technologies that influence this assumption critically in the Nordic market are—hydro and nuclear power. With respect to hydro power, it reflects a situation when there is sufficient inflow to the hydro power station reservoirs in Norway and Sweden. This can further be classified as a normal winter that occurs every other year. This is in line with a study on vulnerabilities of the Nordic power system where, 90 % hydro availability is assumed in Norway and Sweden during normal

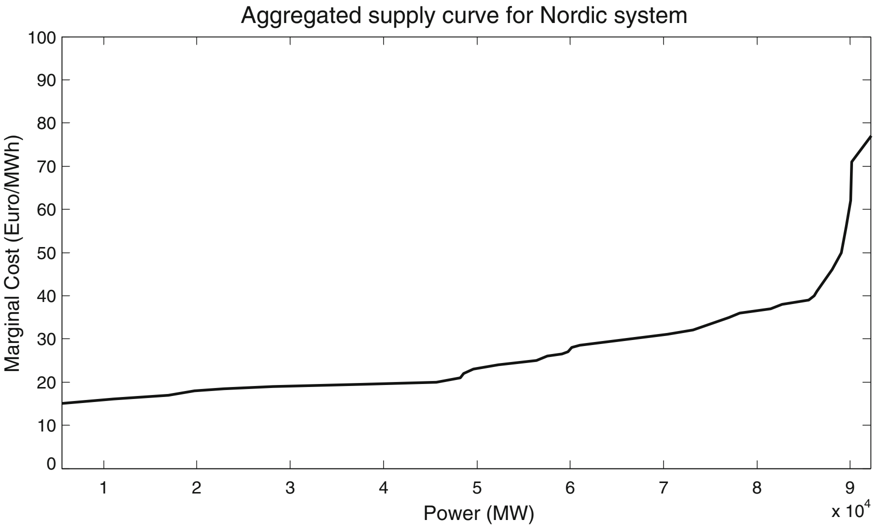

Fig. 9.17 Supply curve in the representative Nordic market [25]

hydro conditions [27]. Similarly, due to the low probability of forced outages of nuclear power generation in Sweden and Finland, 100 % availability is assumed.

The vehicle data required to simulate the participation of PEVs in the Nordic market is based on statistics available for conventional fuel driven vehicles and is obtained from [28–31]. The resolution of this data currently available is for each county present in each of these countries. The total number of conventional vehicles in the Nordic area is found to be around 12.7 million. These are approximately segmented according to bidding areas and the resulting distribution is shown in Fig. 9.18.

It is difficult to estimate the elasticity of conventional demand in the short-term since this elasticity would occur in special circumstances, where, the price of electricity is very high over a sustained period of time (days or weeks). Hence, the conventional demand is assumed to be inelastic. The impact of the assumptions made in this study on the final results and its analysis is optimistic, while at the same time, reflecting a highly expected market situation. It is imperative to mention that the simulation models are designed for a single auction market while the Nordic market is, in fact, a double auction market where a number of market players determine the outcome. A direct consequence of this may be a lower resulting market price due to better utilization of generating resources.

The external interconnection capacities between countries within and outside of the Nordic area are included as inelastic demand thereby representing an export scenario from the Nordic countries. This is indicative of an anticipated market situation, though, in reality, the complete transmission capacity may not be utilized.

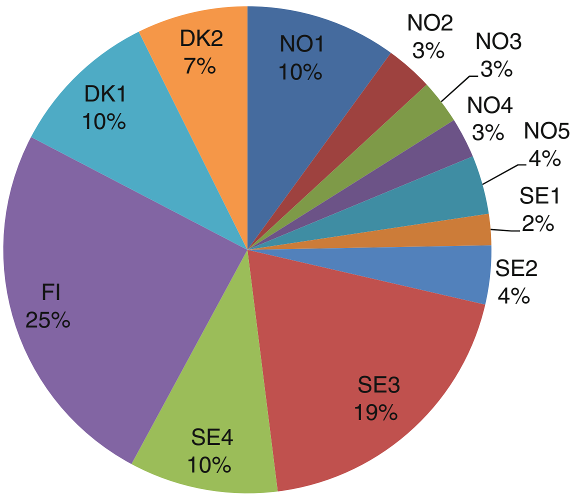

Fig. 9.18 Conventional vehicles' distribution in Nordic region based on bidding areas [28–31]

The JSM will be applied to the following two cases of the Nordic market:

(1) *Unconstrained case*: When the trading of electricity is not limited by the interconnection capacities between different bidding areas in the Nordic region.
(2) *Constrained case*: Trading of electricity is limited by the interconnection capacities between different bidding areas in the Nordic region, which are modeled based on the net transfer capacity (NTC) values [32].

Only joint scheduling is used for the case study of the Nordic market, because the aggregator scheduling is heavily dependent on the accuracy of the estimated supply function given by (9.23). The accuracy of this function could be improved by modeling the price as a polynomial function of demand, although, by doing so, the complexity of the optimization function increases and the resulting model might not necessarily provide a solution. The consequence of such an assumption is the results being more optimistic, where the available generation and flexible demand are utilized more resourcefully.

9.6.2.1 Unconstrained Case

If there were no upper limits on interconnection capacities, one supply and one demand curve could in theory be used for the clearing of the whole Nordic DAM. In a single auction market, it would translate into a single supply curve for the entire Nordic market. This would then be matched with the demand curve during that particular hour to obtain the market price for electricity.

The demand profile for this system was obtained using the data in [33] for a Tuesday during week 51 with an aggregated peak demand of 69 GW [23]. In such a context, if EVs are introduced into the system and their charging energy traded in

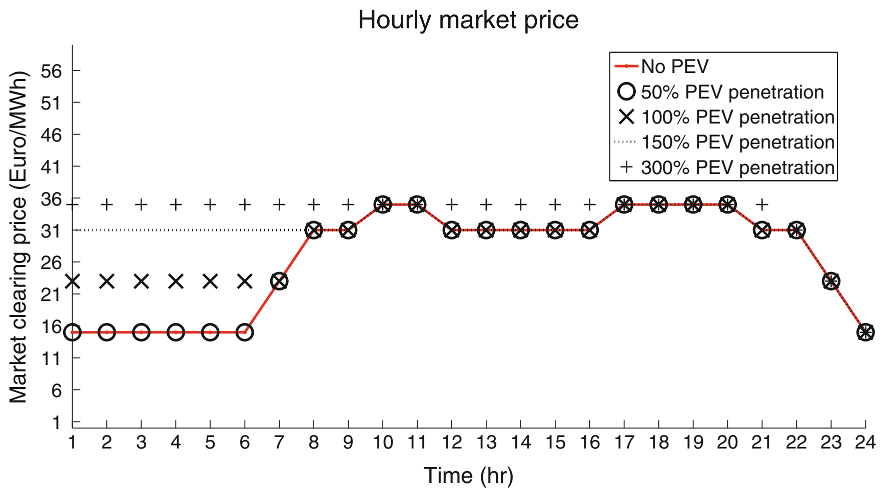

Fig. 9.19 Unconstrained case result—changes in market price by the introduction of PEVs

the Nordic market as flexible demands, the corresponding changes to the electricity price in the day-ahead market, for various penetration levels of PEVs, can be obtained as shown in Fig. 9.19.

It could be observed that even if all the 12.7 million conventional vehicles were replaced by PEVs, the market price would increase by 8 €/MWh during low demand periods. It would require an introduction of at least 37 million PEVs before the system price during most hours corresponds to the peak load price of 35 €/MWh during hour 18. Hence, the Nordic market could be considered to be highly resilient towards the introduction of PEVs. The changes in hourly total load and market price, with the introduction of 12.7 million PEVs in the Nordic region, are shown in Figs. 9.20 and 9.21, respectively. Since, only a single auction market is considered, it could be seen that JSM schedules the charging energy of PEVs during low demand periods as shown in Fig. 9.20, when the price of electricity is low as shown in Fig. 9.21. The impact of this is a minimal increase in total demand and corresponding electricity price.

9.6.2.2 Constrained Case

With interconnection capacities in place, area prices apply when power traded between at least two areas in the market exceeds the total available transmission capacity between those areas. The area market prices in the Nordic market for the constrained case are shown in Fig. 9.22. Y-axis denotes the area prices; x-axis denotes the 12 bidding areas and the colored bars from blue to red denote the 24 h under consideration for each area.

It can be seen in Fig. 9.22 that areas FI, SE4 and DK2 already suffer from high prices compared to other areas primarily due to the dominant fossil fuel-based local

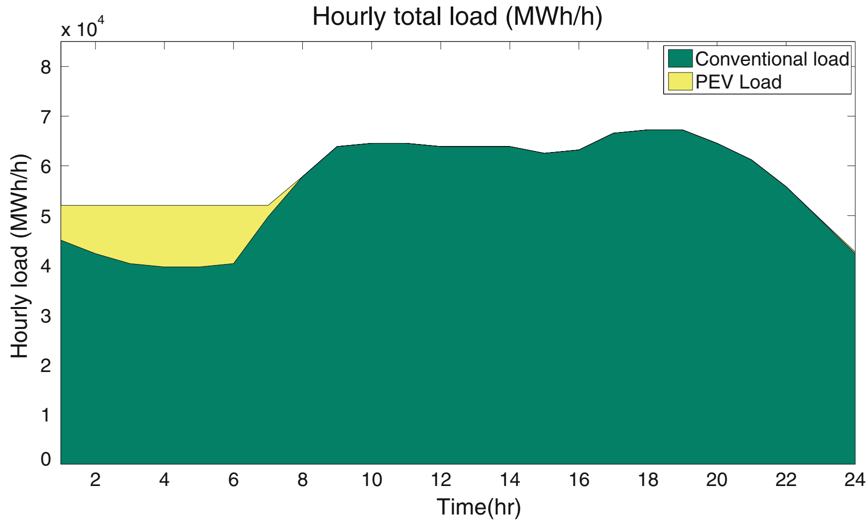

Fig. 9.20 Unconstrained case result—total load at 100 % PEV penetration

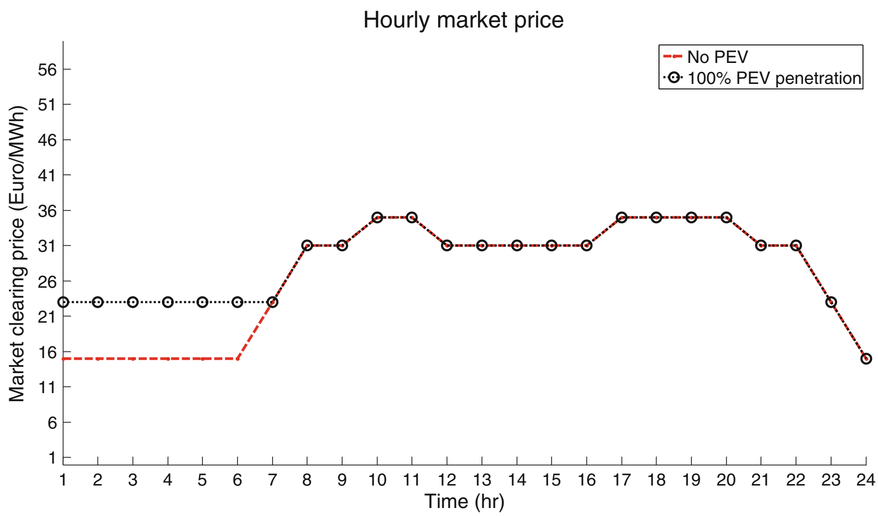

Fig. 9.21 Unconstrained case result—market price at 100 % PEV penetration

generation. Prices in most of the areas are different indicating that the interconnections between these areas have been fully utilized. In areas NO1 and NO2, it can be observed that the prices during all of the 24 h are the same indicating that the available transmission capacity is not completely utilized.

Extension of the model to include scheduling of PEV charging results in area prices as shown in Fig. 9.23, for 100 % penetration of PEVs in the market. In hydro power

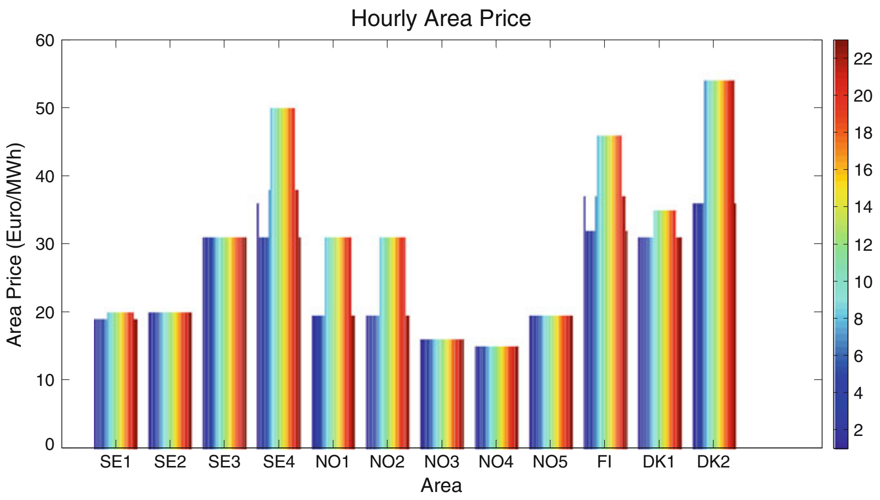

Fig. 9.22 Constrained case result—area prices with only conventional load

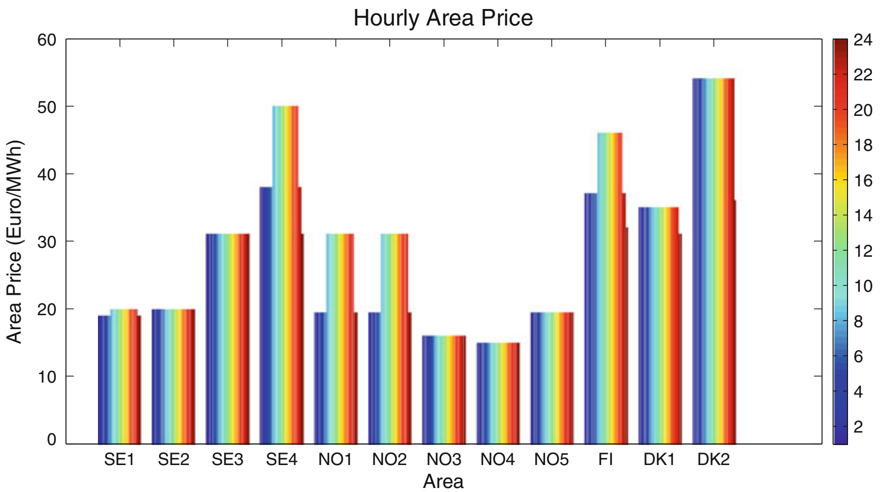

Fig. 9.23 Constrained case result—area prices with 100 % PEV penetration

dominated areas—SE1, SE2, NO1-NO5, it can be seen that the market price remains relatively the same during all hours even with a high penetration of PEVs. It is also found that mainly two areas, namely—SE4 and DK2 are affected by the high levels of PEV penetration. At 100 % PEV penetration level, the electricity price in DK2 increases to 54 €/MWh even during the low demand hours 1–7, whereas it increases to 38 €/MWh during the same hours. Further introduction of PEVs would result in a market price higher than 54 €/MWh in DK2 that corresponds to the price at peak demand with only conventional demand.

Area price for SE4 at different penetration levels is shown in Fig. 9.24a. Similarly, for the bidding area DK2, the area price at different penetration levels is shown in Fig. 9.24b. It can be seen that the area prices in SE4 and DK2 increase with an increased penetration of PEVs in the Nordic system. This may be attributed

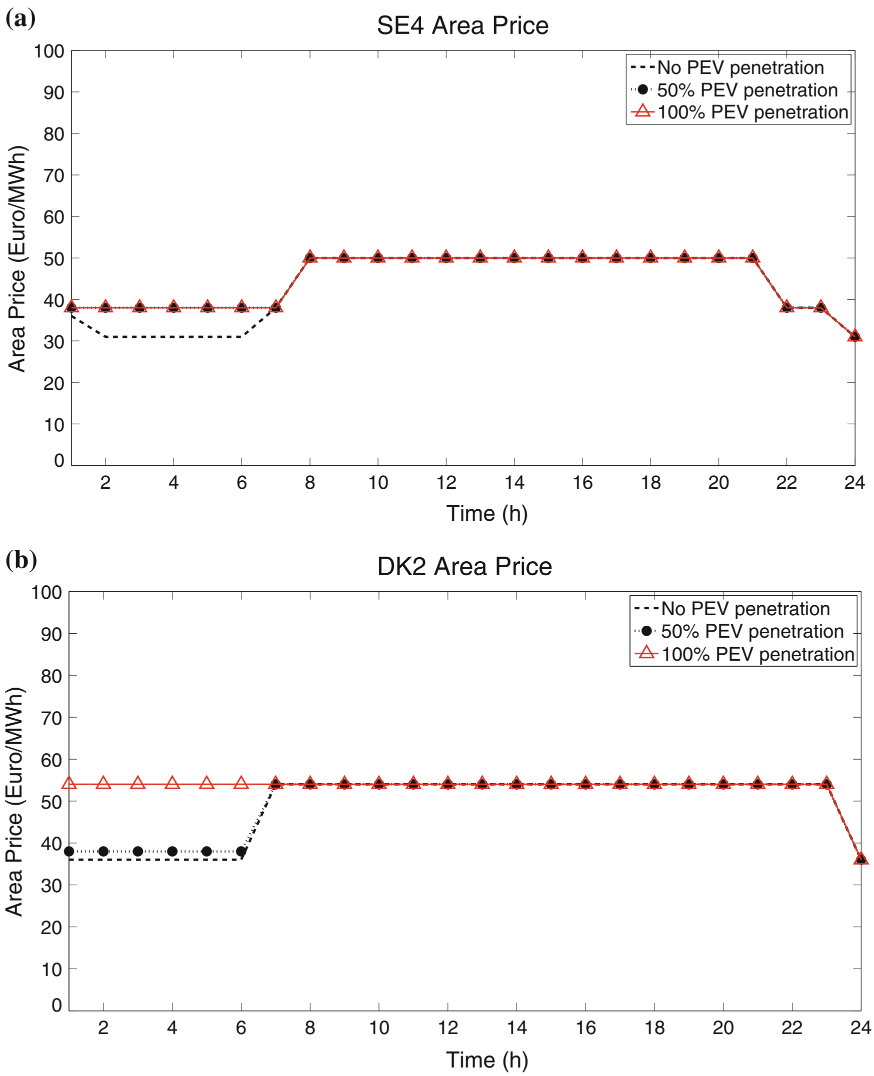

Fig. 9.24 Constrained case result: **a** SE4 area price at different PEV penetration levels, **b** DK2 area price at different PEV penetration levels

to a number of factors, e.g., these two areas are dominated by thermal generators which are generally more expensive, capacity of transmission lines connecting them to generator surplus areas are insufficient and greater population in these areas account for relatively higher number of PEVs being integrated at higher penetration levels.

9.7 Conclusions

In this chapter, two methods for scheduling PEV demand named as JSM and ASM have been presented. These methods could be used to evaluate the effects of PEVs scheduling on the overall system load shape and the effects on electricity market price. The JSM could prove useful in a market setup where there is a possibility to schedule both the generation and demand side resources; whereas the ASM could be useful where individual market players would require performing their individual energy scheduling. The two methods were applied to an IEEE 30-bus test system and the Nordic test system to find the effects of PEV energy scheduling on market price of electricity. From the case study on the IEEE 30-bus test system, it was found that market integration of PEVs might lead to an increase in market price at higher penetration levels using fixed period charging, at which point, advanced methods of scheduling of PEV fleet charging could become necessary. The JSM may require changes in the operational structure of electricity markets, but the model could result in better utilization of resources as it simultaneously schedules both the generation and demand resources. In the unconstrained case, the Nordic market was found to be highly resilient toward integration of PEVs. Transmission network constraints form an important factor on the system level which could influence the actual flow of power, and hence, directly influence the penetration level of the PEVs that could be accommodated in the system before a significant increase in market price.

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