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Electric Vehicles in future market models

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ELECTRIC VEHICLES IN A DISTRIBUTED AND INTEGRATED MARKET USING SUSTAINABLE ENERGY AND OPEN NETWORKS

ELECTRIC VEHICLES IN FUTURE MARKET MODELS

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1 INTRODUCTION

The previous WP2.3 report “Introducing electric vehicles into the current electricity markets” describes the current Nordic electricity market and addresses the challenges related to a large-scale introduction of electric vehicles. The report shows that if EVs are introduced in the spot market, the market set-up is simple and possible today with an interval meter. Either, the retailer can broadcast the electricity prices once a day and the end-user can make a charging strategy for the hours with known prices (12 to 36 hours ahead). The charging strategy can be a simple clock charging, or the cheapest hours can be selected with a local computer system (home automation system). Alternatively, the EVs can be a fleet operator customer and have the charging automated according to a contractual setup.

If EVs are to participate in both the spot market and the regulating market the report shows that a few more challenges have to be met. Requirements from the TSO regarding real time measurements of the individual unit and minimum bid size makes it impossible for individual EVs to participate in the regulating power market today. Furthermore, there are some challenges in connection with imbalances related to EVs in the regulating market, as the activation of regulating power at one hour can change the predicted charging at a later hour.

Some of these challenges can be met by introducing a fleet operator to aggregate the consumption of a number of EVs and handle their interaction with the electricity market as one unit with a centralized/direct control (see descriptions in other part of the EDISON project for example Deliverable D3.1 Distributed integration technology development from WP3, April 2011). This is the major concept in the EDISON project. However, this report mainly focusing on power markets, prices and price signals and how EVs can be an integrated part of the power market independent on the contract structure of the EVs (i.e. single market player or handled together through direct control be a fleet operator etc.).

In addition to the wholesale market solutions, there are some challenges in relation to the distribution grid. Congestions in the distribution grid have to be taken into account with respect to the behaviour of the end-user. This subject was briefly described within the previous report mostly with respect to mapping of the size of the congestions in the distribution grid.

This report handles future market models in order to fit in electric vehicles. Chapter 3 and 4 goes through different possibilities of alternative market models that could be relevant for a large-scale introduction of EVs and solve some of the challenges that are connected to the current market design. The thoughts somewhat take the starting point in large change of the existing Nordic market model.

In chapter 5 different methods to handle the challenges associated with congestions in the distribution grid are described.

Finally, in chapter 6 some thinking about integration of V2G is listed.

2 CONCLUSIONS

This report discusses various potential markets and actors that could be relevant for EV users allowing EVs to provide regulating power and automatic reserves and dealing with potential problems that large-scale EV integration may pose.

The report also deals with how to handle congestions in the distribution grid. A number of different types of approaches where both the wholesale market and the grid state are used to set the dispatch are listed.

Spot market

The easiest market for EVs to participate in is the spot market, as it simply requires an EV user to enter into an agreement with a load balance responsible and have a meter that can measure on an hourly basis. However, if a large number of EVs participate in the spot market, congestions in the distribution grid could arise, congestions that the current market structure cannot deal with. The so-called lemming effect can arise as all EVs can choose to charge in the same (and cheap) hour, if no (price) signal is provided from the distribution grid to avoid this. As such, the utilisation of a fleet operator and/or various market tools such as nodal pricing or congestion tariffs could be the solution.

Regulating power market

If EVs are to gain access to the regulating power market, then the existing additional requirement of real time measurement is problematic (e.g. expensive and complicated with respect to the handling of large amounts of information) and will either have to be relaxed or addressed. If the requirement is relaxed for smaller units, concepts such as FlexPower (described in section 3.4) will become viable. If the bid requirement is also relaxed, the Energinet.dk ‘self regulating’ concept will become relevant, as it places the responsibility for anticipating the demand response at the hand of the TSO and thus does not require the retailers to send bids for delivering regulating power. As was the case with EV participation in the spot market, congestions in the distribution grid will require a fleet operator and/or new various market tools.

Automatic reserves

In order for EV owners to participate in the market for automatic reserves they will either have to enter into an agreement where they receive compensation in return for allowing their vehicle to stop charging when the frequency drops (similar to the demonstration project with demand as frequency reserves as described in section 3.6), or enter into an agreement with a fleet operator who will be able to provide automatic reserves by pooling EV users. In the first concept, a device that automatically cuts out when the frequency drops below a pre-determined set point is required. The fleet operator concept meanwhile requires a technology to allow for the fleet operator to control the charging of the vehicles, and in this regard could provide frequency control in either direction (similar to the Delaware project described in section 3.7).

Congestions in the distribution grid

Congestions in the distribution grid can in principle be handled in two ways. Either by direct control or by a market price approach (in-direct control). How to handle congestions in the distribution grid depends on which market the EVs participate in. The more markets the EVs participate in, the more complicated solutions if the same accuracy should be obtained.

Involvement in the continuously regulating power market will also require continuously updated price signals corresponding to the congestions in the distribution grid, if for example dynamic tariffs are considered.

Simpler is it to handle congestions in the distribution grid by allowing direct control from the grid company. The direct control does have a cost in shape of measurement equipment and control devices. Alternatively, the distribution grid has to be reinforced which also has a cost. Comparing the cost of these two alternatives will give an indication of what instrument to use in which case.

Only voluntary methods are described in this report. Besides, other methods based on more or less involuntary participation (e.g. grid code based or DSO terms of delivery) are not considered in this report.

A mixed approached to handle system balance and distribution grid congestion is described suited for VPP in the Edison project which lives up to minimum requirements in such a way that the approach fits the current system with no need for changes, it considers EVs both in spot and in regulating power market, it is relatively socio-economic and relatively simple. The method is a combination of dynamic tariffs for spot market time slot combined with a first system balance/then grid congestion for regulating market time slot. The method can be somewhat simplified if congestions in the distribution grid are handled through direct control. E.g. distribution grid companies can choose its own method which fits best in their grid and the amount of congestions. All areas will not have to use the same method.

<u>The role of the DSO</u>

Management of congestion in the distribution grid with other tools than grid reinforcements and taking into account end-users reaction to price signals are a new and untested area. All methods require more knowledge of the distribution grid than available today. To obtain that knowledge also investments in measurement equipment have to be made.

Besides, new methods to handle congestions in the distribution grid and to predict the reaction of the consumers have to be developed. Especially mapping of congestions in the distribution grid, geographically differentiation of end-users, pricing through compensation mechanism, and developing new tools for including price dependent demand are obstacles to be overcome before distribution grid congestions can be handled in a new manner.

<u>V2G</u>

Introducing V2G conflicts with current market rules that call for consumption and production to be handled separately. Also taxation rules have to be considered so that taxes do not work against the use of V2G. Using the spot and regulating power markets seem to be straight forward with respect to V2G, e.g. the markets are used to handle both consumption and production.

3 ALTERNATIVE MARKETS FOR REGULATING POWER AND RESERVES FOR EV INTEGRATION

In order to facilitate greater integration of EVs, alternative electricity market models and aspects of the market are considered. Potential markets that could be relevant for EVs are the regulating power market and the markets for automatic reserves. The following sections 3.1 and 3.2 briefly describe the regulating power market and the market for automatic reserves. Sections 3.3 to 3.7 describe concrete proposals of how small scale consumption units such as EVs could potentially be incorporated into the Nordic regulating power market, and what potential changes to the market that would be necessary in order to make the market relevant for EVs.

3.1 THE REGULATING POWER MARKET

As electricity production and consumption always have to be in equilibrium, deviations in the final operating hour are left for the TSO to balance. In the Nordic countries it is done via the regulating power market. As renewable energy will become an increasingly important tool for reducing emissions from fossil fuels, production will become more intermittent (solar, wind, etc.), and therefore it is anticipated that the need for regulating power will increase.

In the Nordic countries there is a common regulating power market managed by the TSOs with a common merit order bidding list. The balance responsibles (for load or production) make bids consisting of amount (MW) and price (DKK/MWh). In Denmark the minimum bid size is 10 MW, and the maximum is 50 MW. All bids for delivering regulating power are collected in the common Nordic NOIS-list. These bids are sorted in a list with increasing prices for up-regulation (above spot price), and decreasing prices for down-regulation (below spot price). Bids can be submitted, adjusted, or removed until 45 minutes before the operational hour. Taking into consideration the potential congestions in the transmission system, the TSO manages the activation of the cheapest regulating power via this NOIS-list. Due to the fact that regulating power is specialised in nature (it must be fully activated within 15 minutes and the duration may vary), it demands a price premium with respect to the spot market. It is this greater price volatility that makes the regulating power market particularly interesting for EV users. With access to this market, EV users will be able to take advantage of these price variations and charge their vehicles when prices are low, and avoid charging when prices are high. Assuming prior knowledge of the prices the charging strategy can be handled as a simple optimization problem. For solution to a linear optimization problem see for example Olle Sundstöm and Carl Binding “Opimization Methods to Plan and Charging of Electric Vehicle Fleets” Sundstöm and Binding (2010).

Figure 1 below displays a duration curve of the hourly differences between the regulating power prices and the spot price for West and East Denmark from 2005 to 2010. The average spot price over the period was 309 DKK/MWh in DK West and 325 DKK/MWh in DK East. For illustrative purposes the vertical axis has been limited to +/- 500 DKK/MWh, however, maximum and minimum values greatly exceeded these values (see Table 1).

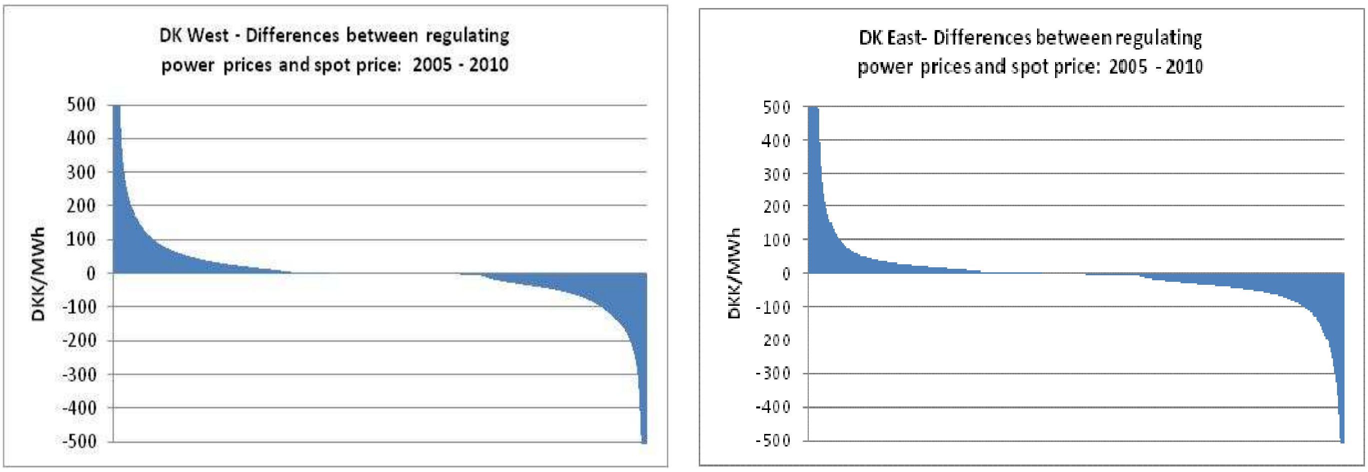

Figure 1: Historical differences between regulating power prices and spot price in West and East Denmark from 2005 to medium August 2010. The horizontal axis represents sorted hourly prices. For ease of illustration the vertical axis has been limited to +/- 500 DKK/MWh, thus visually affecting a total of roughly 2% of hours in both of the graphs.

	DK West	DK East
Average Spot Price (DKK/MWh)	309	325
Average Absolute Difference (DKK/MWh)	65	65
Minimum difference (DKK/MWh)	- 6566	- 10136
Maximum difference (DKK/MWh)	7034	14712
Hours with a difference less than +/- 1 DKK/MWh	33%	25%

Table 1: Historical differences between regulating power prices and spot price in West and East Denmark from 2005 to medium August 2010. Note that the spot price is the wholesale market price. This is only a minor share of the end-users price to which have to be included taxes etc.

Figure 1 and the accompanying table highlight a number of relevant aspects. Firstly, in roughly 25-33% of the hours the regulating power price has deviated less than +/- 1 DKK/MWh from the spot price. However, when there have been deviations they have been rather sizeable. This is reflected by the fact that 12-15% of the hours saw deviations greater than +/- 100 DKK/MWh, with well over half of these occurring in down regulating power hours - namely those hours with low (or negative) regulating power prices, and as such those that are particularly interesting for EV owners. Lastly, it is interesting to note that the tips at both ends of the duration curves are very steep, and as such while rare in number, those hours with large variations are extremely large indeed.

Given that there have been rather large variations between the spot price and regulating power price over a good share of the time, and any given hour has on average deviated by 66 DKK/MWh, attracting EV users to this market could be a viable approach to both encouraging EV penetration and providing a necessary balancing service.

3.2 MARKET FOR AUTOMATIC RESERVES

While the regulating power market is used to deal with the larger deviations within the operational hour, smaller deviations are dealt with by the fast acting automatic reserves. There are different types of automatic reserves, and depending on the type, they can receive both a reserve payment, and an energy payment if activated. As the name indicates, they are activated automatically, and are done so to ensure that the system frequency is kept within 49.9 and 50.1 Hz. They are expensive and have limited capacity, and therefore they are potentially relevant for EVs.

3.3 ENERGINET.DK PROPOSAL

In order to increase the opportunities for small scale consumption units to participate in the regulating power market the Danish Transmission System Operator, Energinet.dk, in 2010 published a paper entitled 'Udvikling af rammer for regulerkraft - Indpasning af mindre forbrugsenheder og andre mindre enheder i regulerkraft-markedet' Energinet.dk, 2010 (Development of a framework for regulating power - Incorporation of minor consumption units and other smaller units in the regulating power market, May 2010).

Energinet.dk's proposal takes its basis in the fact that increasing amounts of wind power will require more regulating power and/or large investments in new reserves and expansion of the transmission network. Energinet.dk deems that the costs associated with large transmission expansions are much higher than those related to increasing the amount of regulating power. As part of its obligation to secure the best possible conditions for competition in the market, Energinet.dk therefore investigates opportunities for expanding the framework for the regulating power market so electricity demand and smaller units can be more active in the regulating market. Energinet.dk (2010) describes the proposal of Energinet.dk regarding how the framework for regulating power in particular can be adjusted. Energinet.dk envisions that these proposals shall be implemented in the upcoming years as part of a larger move towards a 'Smart Grid', which is expected to develop over the next 10-20 years.

When discussing possible alterations to the regulating power market framework it is important to keep in mind that today the regulating power market is common for the Nordic countries. Thus any suggested changes to the Danish market have to be seen in this larger context, a context that is expected to grow even larger as the Nordic market becomes further integrated with the European market. That being said, Energinet.dk does foresee some potential changes. Firstly, it is likely that timeframes for regulating power will become shorter, thus increasing the flexibility of the market and moving the price setting of regulating power closer to the actual operating time. Another change could be the publication of the regulating power price during the hour of operation (as opposed to now where this price is published an hour after the operational hour). Particularly the publication of the regulating power price within the hour could allow for greater EV participation in the market, a possibility that will be discussed in greater extent below.

Generally speaking, Energinet.dk outlines two methods of incorporating demand into the regulating power market:

1. Participate in the regulating power market under the current rules with bids to a common merit order list.
2. Self regulating.

Energinet.dk does not describe the needed contract between end-user and retailer. Probably, a plan for the expected electricity demand is needed in order to give the end-user an economic benefit of move demand.

3.3.1 PARTICIPATION IN MARKET UNDER CURRENT RULES

As long as the bids fulfil the existing criteria (minimum bid size, real-time measurement, ability to re-activate, etc.), the existing market rules do allow for demand to participate in the regulating power market. However, the criteria can be quite problematic for smaller units. For example, the above-mentioned minimum 10 MW size restricts individual unit participation such as EVs from participating in the regulating power market. To work around this problem, on the production side there is already a tradition of pooling assets by the balance responsibles, thus enabling smaller units to participate in the regulating power market. Energinet.dk expects, and will support, a similar development on the demand side (Energinet.dk, 2010).

3.3.2 SELF REGULATION

A more novel approach suggested by Energinet.dk is what it refers to as self regulation[1]. The concept proposes to give small scale consumption units the possibility to react on a regulating power price. It is intended that the regulating power price will be published within the actual operating hour as the price of the most recently activated bid on the common Nordic market. By using this model the consumption units will have the opportunity to earn profits in the regulating power market by self regulation (via the balance settlement). To benefit from this system end-users must have interval meters installed, however they do not need real time measurement.

This self regulation can also be broken down into two main categories. In the first, the balance responsible has remote control of some of the end-users consumption units according to a pre-defined agreement, for example the charging of EVs, or activation of heat pumps, etc. In exchange for relinquishing day to day control of these devices, end-users will in some way be compensated with lower electricity prices. Based on these agreements, the balance responsible can utilise these units to participate in the regulating power market and generate additional revenue.

In the other category the load balance responsible settles the electricity usage according to the regulating power price. The key aspect under this approach is that no bid from smaller demands is submitted to Energinet.dk. The end-user (ex through a trader, fleet operator etc.) simply receives a price signal and acts accordingly. As above, the price signal would be based on the latest activated regulating power bid from the larger power plant (plus an additional price), one each for DK1 and DK2. However, the regulating price sent out in the hour will not necessarily be the final regulating power price for that hour as this can first be determined after the fact when bottlenecks between various areas have been factored in. The risk caused by the potential difference between the price signal and actual regulating power price is one that in Energinet.dk (2010) is stated should be orientated by the commercial actors in the market as part of their business model. Under this model Energinet.dk

[1] Self regulation is defined by Energinet.dk as a reaction that is not planned in advance, but is an intentional action, that aids the system balance. Self regulation is carried out based on the valuation of actual prices in the electricity market and the direction of current system unbalances. (Energinet.dk, 2010).

will have the task of predicting the amount of power activated by self regulating [2]. Data for self regulating would be compiled and utilised by Energinet.dk in its prognosis models, i.e. determine how much self regulation will occur given a certain price signal.

In Energinet.dk (2010) it is pointed out that even under the current system it is possible for load balance responsibles to undertake self regulation based on estimates of what the regulating power price is likely to be. This of course involves a risk, a risk that would be decreased if the regulating power price was publicised during the operational hour.

3.3.3 AUTOMATIC RESERVES

While the Energinet.dk proposal mainly focuses on manual reserves and the regulating power market, it also mentions that if they can display the required flexibility and can react to the signals that are used to activate reserves, then consumption devices can also participate in the market for automatic reserves. Section 3.7 below describes a market in the American state of Delaware where EVs are participating in such a market.

3.4 FLEXPOWER

Supported by Energinet.dk, Flexpower (2010), the FlexPower project investigates the potential for using demand as a stable and low cost resource for regulating power. As a starting point, current regulating power will exist and function as today, and contribute with the main volume of the regulation market. The idea is to develop a price signal that changes every five minutes and is broadcasted to all end-users interested in participating. Response should be voluntary and the price signal acts as the final settlement. The end-users that could be interested in participating in this system would have some electrical appliances that are suitable for control, with EVs being a prime example. End-users would typically install some automated control system that could receive the broadcasted price and realise the relevant control.

Within the project a simple and efficient market will be designed and tested. The concept is similar to the above described self regulation variation, in that the market will make use of one-way price signals to activate electricity demand and small-scale generation as regulating power. When up regulation is required the price will be high, and when down regulation is required the price will be low. The price shall correspond to the latest bid activated in the traditional regulating power market. The major difference between the FlexPower project and the self regulation proposal above (Energinet.dk, 2010), is that in FlexPower it is the balance responsibles that will predict the aggregated impact based on historical data, and based on this send bids to Energinet.dk.

What makes the FlexPower project particularly interesting is that it can develop in either of the two directions highlighted by Energinet.dk, i.e. a) by fitting into the existing market, or b) via a form of self regulation. Under the first format a balance responsible is utilised to pool items and make bids that comply with the existing 10 MW bid size. When bids are activated by

[2] It is somewhat unclear whether Energinet.dk's first self regulation variation involves the balance responsible submitting bids, however given that the balance responsible has control of the units it would seem natural that they could do so. In effect, this could also place the responsibility for demand response prognosis on the balance responsible, not Energinet.dk, as is envisioned in the second self regulation variation.

the TSO the balance responsible then sends out a price signal it deems to be sufficient to activate its small end-users to deliver the amount of regulation required by the TSO. These individual units are then monitored to ensure delivery of bids, thus again complying with existing rules.

Under the self regulation variation, the price signal sent by the TSO is sent directly to the end-user. There is no activation of bids as the end-user simply reacts to the price signal and the TSO is responsible for forecasting what this reaction will be. The major difference between the two forms is that in the former the responsibility for predicting the demand response (and therefore the responsibility if actual demand deviates from the bid) falls to the balance responsible, while in the latter it falls to Energinet.dk. There are valid arguments for placing this responsibility at the hands of either party. Energinet.dk has access to more data regarding the system as a whole, and therefore it could be argued that it is better suited to undertake the prognosis and prediction associated with determining the aggregated demand response (e.g. from customers from different balance responsible). On the other hand, in an increasingly more liberalised electricity market it could also be argued that this task should be undertaken by private market actors, and the risks associated with forecasting inaccuracies should be incorporated into their business models. The self regulation variation is also complicated by the fact that a balance responsible agent could be responsible for unbalances (deviations between the amount of electricity it purchased on the spot market, and the amount that was actually used by its customers) that are caused by price signals sent by Energinet.dk, thus signals that the balance responsible has no control over.

The current FlexPower setup utilising a balance responsible that bids in on the regulating power market is displayed below.

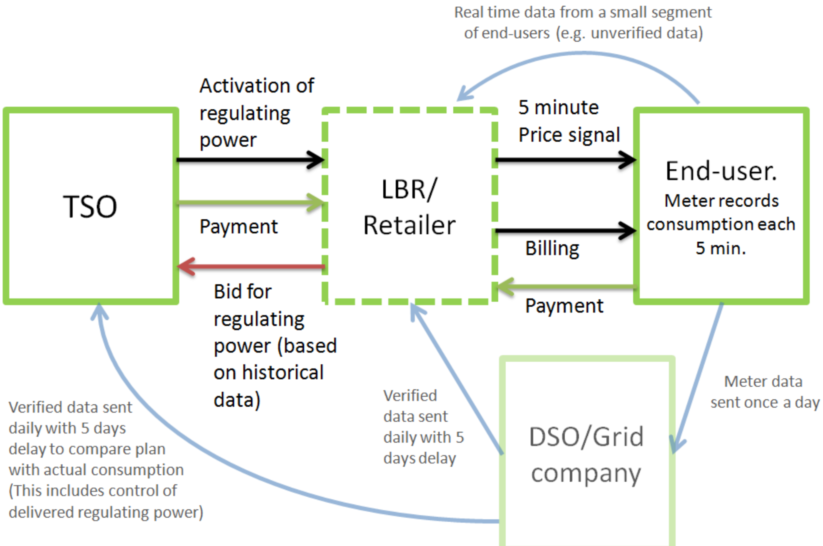

Figure 2 Overview of FlexPower Concept. Green arrows indicate monetary flows, black arrows signals and billing, blue arrows data flows and the red arrow bidding.

The above figure displays a FlexPower setup that with one exception could fit within the existing market rules (this exception refers to the current requirement that all regulating power unites be measured in real-time. The FlexPower concept loosens this restriction, and instead allows for the end-user data to be sent to the DSO once a day). After having purchased the anticipated amount of required electricity on the spot market, the load balance responsible (LBR) submits a bid(s) to the regulating power market based on the historical price data available at its disposal. Along with all other regulating power bids it is sorted on the Nordic merit order list, NOIS-list. When the TSO activates the bid it informs the LBR as it would with any other regulating power bid. Based on historical data and the newest information available to it, the LBR determines what price signal shall be sent to its FlexPower end-users in order to achieve the desired amount of regulation.

The end-user, most likely via some form of automation, then adjusts their consumption in accordance with the price signal. If the TSO has activated up regulation, a price higher than the spot price will be sent to the end-user and if down regulation, a price lower than the spot price will be received. Response by the end-user is voluntary and the consumption is metered in 5 minute intervals corresponding to the received price signals. This data is stored locally and sent to the DSO once a day. Taking into consideration a delay of up to 5 days to ensure quality control, this data is then forwarded to the LBR and TSO. Though, it is also possible that unverified data will be sent earlier to both the LBR and TSO for use in data analysis.

Based on this data the TSO can then settle any unbalances between the amount of regulation promised and the amount actually delivered. A timeline of the events under FlexPower in a situation where a bid is activated at 8:22 is shown in Figure 3 below.

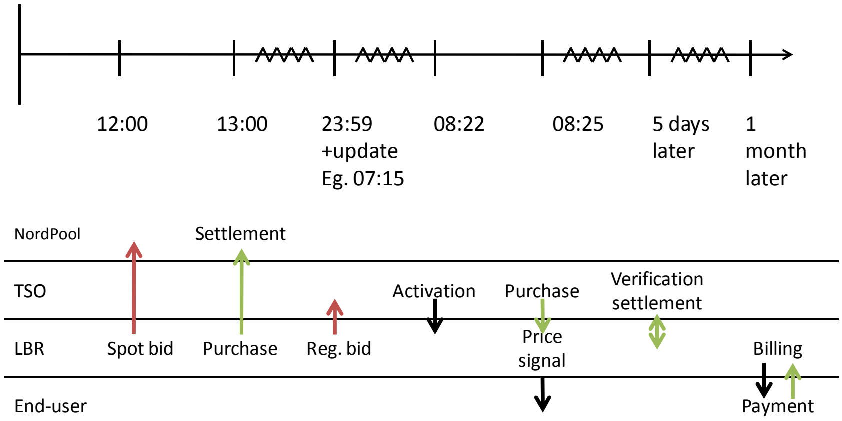

Figure 3: Timeline of the events under FlexPower in an example where a bid is activated by the TSO at 8:22, and this price signal is sent from the LBR to the end-user at 8:25. Bids can be updated continuously, until three quarters before the operating hour. Updating bids at 7:15 would be the last possible update before the operational hour starting 8:00.

Figure 3 highlights the fact that a number of hours can pass from the time when the spot market has settled (13:00) and when the first activation takes place (8:22). It is therefore practical for the LBR that regulating bids can be updated up until 45 minutes before the operating hour. In the above example the latest update for the 8:22 activated bid could thereby have been sent in at 7:15.

FlexPower Summary

The advantage of the FlexPower concept as described above is its simplicity for the end-user and Energinet.dk, and its ability to fit into the existing regulating power framework and rule set. An EV user participating in FlexPower simply pre-defines the charging needs and the automation will respond to price signals accordingly. Meanwhile, for Energinet.dk FlexPower merely represents an additional regulating power bid that can be activated in the same way that existing bids are activated. It is possible that FlexPower activations will be less accurate than traditional activations, thus potentially resulting in an additional bid having to be activated. This is an area that will be investigated within the FlexPower project.

The complexity in the above concept lies with the balance responsible as they must generate price curves and address a number of financial and forecast related risks. A key part of the FlexPower project involves the design and testing of the various prognosis and modelling tools and technologies that will be utilised by the balance responsible and the end-users.

3.5 OTHER POTENTIAL ALTERATIONS TO REGULATING POWER MARKET (NORDEL REPORT)

In addition to the Energinet.dk and FlexPower proposals outlined above, other changes to the current market rules have also been suggested. In December 2008 Nordel[3] released a report entitled 'Harmonisation of Balance Regulation in the Nordic Countries' (Nordel, 2008) that provided an analysis of differences between the Nordic regulating power markets and suggestions for how they can be further harmonised. In addition, the report also referred to future potential changes.

While the minimum bid size in Denmark is currently 10 MW, Energinet.dk can activate part of a bid after agreement with the bidder. This could be particularly applicable for EVs, as bids based on a number of EV users are well suited to reacting on partial bid sizes. In addition, Nordel also opened the door to smaller bid sizes in the future, another aspect that suits small end-users such as EVs. Until today bids in the Nordic countries have to a large extent been handled manually. Particularly as more of the Nordic countries move to automated communications of bids (Denmark did so in 2008, Sweden has introduced it, and Norway has a project to address automation), this will allow for smaller bid sizes, something that the report indicates would help to promote demand-side bidding. (Nordel, 2008)

Another topic that the above mentioned report touched upon was the potential for other types of bids being included in the common Nordic lists of regulating bids, the NOIS-list. Faster responding bids for example could be earmarked on the bid list and utilised as special regulation. The idea being that these faster bids should not receive any preferential treatment on the NOIS-list when used for normal balance regulation, but could be utilised in special situations and thus taken out of order. Related to this, the report also suggested that slower bids could be placed on the NOIS-list and also utilised as a special regulation, however in this case only when all normal bids have been used.

3.6 DEMAND AS FREQUENCY CONTROLLED RESERVES – A DEMONSTRATION PROJECT

The frequency has to be kept between 49.9 and 50.1 Hz to ensure balance between production and demand in the Nordic electricity system. When a breakdown somewhere in the system occurs the frequency will drop, and the balance must quickly be re-established by using reserves. Today, these reserves are provided mainly by generation side resources, including extra

[3] Nordel was a co-operation body for the Danish, Swedish, Norwegian and Finish TSOs until it was disbanded on July 1st of 2009 and its tasks transferred to ENTSO-E (European network of transmission system operators for electricity).

capacity of generators and interconnection lines with reservation that could otherwise be used for transactions in the electricity market.

The figure below illustrates a random frequency drop in the electricity system.

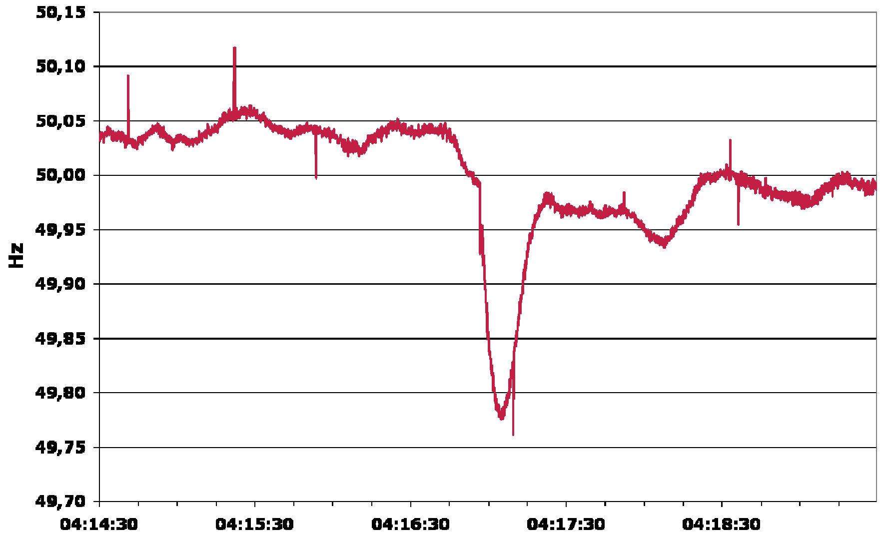

Figure 4: The figure illustrates an example of a serious defect in the electricity system caused by a fault on the transmission line between DK2 and Germany. This results in a frequency drop in the entire Nordic system. For about 15 seconds the frequency is below the normal level of 49.9 Hz.

In the future, frequency reserves could also be provided by demand units reducing their consumption. This can be provided by using frequency controlled demands. In particular, thermostatically controlled loads such as heaters and refrigerators have cyclic on/off characteristics with considerable volume, which makes them ideal for use as frequency controlled reserves. Domestic demands with small electricity consumption, such as electric vehicles, can also provide reserves.

A demonstration project entitled 'Electricity Demand as Frequency Controlled Reserve (DFR)' (Demonstration project, 2011) funded by Energinet.dk will be carried out on Bornholm in 2011 and 2012[4]. In this project, automatic control devices will be installed at approximately 200 electricity customers, involving consumption units that are suitable for automatic deactivation or reduced consumption for short periods (typically between a few seconds and one minute). Four types of consumption will participate in the demonstration project:

- 50 bottle coolers placed in shops with a built-in automation that increases the temperature set-point of the cooler by up to 2°C according to the current frequency.

[4] More details can be fund: Theory project: http://www.dtu.dk/centre/cet/English/research/projects/06-ea.aspx and Demonstration project: http://www.dtu.dk/centre/cet/English/research/projects/26_Demand_as_frequency_controlled_reserve.aspx.

- 50 Danfoss thermostat control units in houses with electrical heating that will adjust the temperature set-point according to the current frequency.
- 30 Electronic Housekeepers, which are wireless home-automation units that can control selected consumption units, such as refrigerators, freezers, electrical heating, heat pumps, etc. The control units will turn off the connected devices during frequency drops.
- 50 intelligent control units suited for larger consumptions in companies, institutions, etc., with suitable consumption for frequency control.

The demand response obtained by the participating consumers will be recorded and analysed during the project in order to evaluate the performance of the demonstration units. The project is carried out by Østkraft, DTU, Danfoss, Vestfrost and Ea Energy Analysis.

More details can be fund:

Theory project: http://www.dtu.dk/centre/cet/English/research/projects/06-ea.aspx

Demonstration project:
http://www.dtu.dk/centre/cet/English/research/projects/26_Demand_as_frequency_controlled_reserve.aspx

3.7 FREQUENCY REGULATION VIA V2G – UNIVERSITY OF DELAWARE PROJECT

At the University of Delaware in the Eastern United States, research groups working on Grid-Integrated Vehicles (GIV) and Vehicle-to-Grid (V2G) Power have undertaken a project where EVs provide frequency reserve services for the local TSO.

The central idea behind the project is that with the electrification of the vehicle fleet, an extremely large storage capacity in EVs will exist, a capacity that can be utilised to provide various ancillary services. This capacity exists due to the fact that most EVs drive considerably less km per day than the battery capacity allows for, and because EVs are parked roughly 22-23 hours per day. This second point is also relevant with respect to the ability to provide ancillary services, as it means that if plugged in, an EV is available to provide these services 22-23 hours per day. In terms of effect, an EV is capable of producing over 100 kW. However, distribution grid and charging restrictions restrict this number. In the US, the effect that can be delivered back to the grid is generally between 10-20 kW. In Denmark this figure is currently lower, at around 3.6 kW (single phase 16 amp connection), however it is expected that three phase 16 amp connections capable of delivering an effect of 11 kW will be available to EV users in the near future.

The Delaware group highlighted 3 main components for their Grid-Integrated Vehicles (GIV) project which they developed (Kempton, 2010):

- A Vehicle Smart Link (VSL) that is tasked with controlling the charging, reporting to the server (capacity and current state), and logging/predicting future trips and times. This small unit was installed under the dash of the EVs.

- Electric Vehicle Supply Equipment (EVSE) which encompasses grid location, internet portal, power connections.
- An Aggregation Server to coordinate the real time operation of the EVs.

TSOs require a predictable and secure power resource to provide frequency reserve services, and as such the third of the above highlighted aspects, the aggregator, is a vital aspect of the project. While individual EV behaviour is not always very predictable, the aggregation of a large number of EVs is quite predicable, and thus provides a single, large, stable and reliable power source (Kempton, 2010). With this power resource at its disposal the aggregator can bid in on the frequency reserves market. The TSO does not have access to information regarding all the individual EVs but only the aggregate as a whole.

Delaware is part of the regional transmission organisation (RTO), which also includes Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. In this region the frequency regulation is controlled by the regional transmission organisation via an Automatic Generation Control signal (AGC). Actors (typically generators) in the region submit hourly capacity bids with a minimum size of 1 MW, and via the AGC signal, accepted bids are then activated by the regional transmission organisation as needed. An accepted bid requires the actor to provide up or down regulation within 5 minutes, and an actor can be called upon to do so numerous times within an hour. While there is a small separate payment for the amount of electricity provided, the contract consists primarily of a capacity payment, with the actor receiving the same capacity payment regardless of how many times it is activated.

As part of the Delaware project, a number of legislative hurdles had to be addressed with respect to standards, incorporating the terms ‘aggregator’ and ‘grid-integrated electric vehicles’ into state laws, as well as issues relating to net metering, interconnection etc. In addition, the local distribution company has to approve each EV so they know how many vehicles will potentially be on each transformer. However, once all of this was in place the aggregator could bid in on the frequency reserve market.

When the TSO informs the aggregator that regulation is required the aggregator utilises an algorithm that calculates how the load should be distributed, and sends a ‘request’ to the various EVs. The algorithm is rerun every 4 seconds, and depending on the individual EVs reply, the dispatch is adjusted accordingly. For example, if an EV is not able to actually provide what it earlier indicated to the aggregator it could, the algorithm is re-run, and a new dispatch is sent.

Project Results

So far the project has revealed that the power response has been very close to the command signal. As silicon is extremely quick to react, it has a higher fidelity than any rotating equipment and is thus extremely well suited to frequency balancing. Due to the fact that the individual batteries are providing very small amounts of up and down regulation, the individual car batteries state of charges can be kept within an interval that does not cause excessive wear on the batteries. Financially speaking, the aggregator receives payment by the TSO, and then passes on payments to the individual car owners.

4 ALTERNATIVE MARKET MODELS FOR EV INTEGRATION

Today's market places are built on large power production units, and particularly the Nordic market is built on large hydro power production units. This circumstance has lead to market characteristics that fit this type of production. If for instance demand response had been the basis of the Nordic market place, the market design probably would have looked much different from today. This chapter describes fundamentally different market approaches compared with the Nordic setup (market splitting).

4.1 LOCATIONAL PRICES (NODAL PRICING IN THE TRANSMISSION GRID)

Locational Marginal Pricing (LMP), often referred to as Nodal Pricing, involves calculating market clearing prices for a number of physical locations (referred to as nodes) within a transmission grid. To calculate the nodal price, the generation, load and transmission characteristics for each node are required. Based on this, the nodal price represents the value of electricity in that node, including losses associated with distribution and congestion. This is quite different from the Nordic setup where electricity prices are calculated for an entire bidding area and congestions are handled through the division into price areas (market splitting). In both cases the transmission capacity is given fact-of-life, which is taken into account in the energy pricing. While both are market based, nodal pricing factors are the costs of delivering electricity to a more specific area, which more accurately reflect the cost of electricity at a specific point. However, this accuracy is obtained at the cost of a correspondingly higher complexity.[5]

The idea behind nodal pricing is that the overall system balance is handled in the same iteration as grid congestions. According to Stoft (2002), nodal pricing therefore has two main benefits, 1) it minimise the cost of production, 2) and provide the end-user with the true cost of their consumption. Seen from an EV standpoint, their main benefit may lie in their potential to be utilised in the distribution grids without causing congestions and at the same time help to obtain the overall system balance.

By providing the actual cost of electricity at each location nodal pricing allows for a more efficient total dispatch, and it sends price signals that better represent the cost in each node. As such, end-users are exposed to the true price of their electricity, and thus can react accordingly.

Nodal pricing can also be designed to incorporate transmission losses into a local price, something that is not currently done in the Nordic System. As a result, if for example the electricity produced from a generator in Northern Norway is just slightly

[5] It should be noted that in Denmark geographically price differencing of grid tariffs within the same grid company is probably not possible according to the Danish Electricity law ('Elforsyningsloven' §73). Several considerations are described in the law: The tariffs must be: Fair, objective and non-discriminating. This is seen in relation to the costs each costumer group causes. It is also mentioned that different prices in relation to location only can be used in special cases. Since some EVs in a specific grid area cause extra cost (for grid expansion) it could be argued that higher tariff for this area is objective. However, updating of the law text is needed.

cheaper than that produced in Southern Denmark, this electricity could in theory be the marginal electricity that is sent to a consumer in southern Denmark. This is inefficient for the market as a whole, and savings could be realised if transmission costs were also reflected in local prices.

Locational prices are already utilised in a number of markets, for example in New England (ISO New England, web page[6]). Although New England has 900 different pricing nodes, it only has 8 different price areas, but the calculated nodal prices are used as shadow prices. Using only 8 different price areas means less price differences between consumers. On the other hand the precise prises and the fluctuation will not be fully utilised. If the consumers are very active more than 8 areas have to be considered.

4.2 COMPLEX BIDDING

In the Nordic electricity markets only a few and relatively simple bid types are used. For example, on the Nord Pool Spot market there are three types of bids available, an hourly bid, a block bid, and a flexible hourly bid. Meanwhile, in the regulating power market, only a single bid type exists (X MW at Y DKK/MWh). This can be a challenge for demand response such as the charging of EVs, since a change in charging (e.g. interrupting charging) will change the electricity demand at a later time (same day or next day).

Generators in the Nordic market determine their marginal costs of production individually, and based on these calculations, submit their bids. Nord Pool then aggregates these bids which is benchmarked against the corresponding aggregated demand and publicises the resulting price for every individual hour.

In other regions, more complex bidding forms are utilised, where generators must submit bids consisting of numerous parameters. Complex bidding is characterised by two factors that differs from the present Nordic market. Firstly, the bid types are more technical and can be more detailed. Secondly, unit commitment is handled by the market unlike the Nordic market where the actors send in bid lists only with information about price and size, and where the unit commitment to some extend is made by the actor before sending bids to the market place.

In New England for example, generators include (Coutu, 2010):

- The economic minimum and economic maximum ($)
- Up to 10 offer blocks (MW and $)
- Minimum run and down times (fractions of hours)
    - When an asset is committed it must run for at least this amount of time before being shut down
    - When an asset is decommitted it must be down for at least this amount of time
- The no load cost ($)
    - Fixed cost incurred every hour the resource is running

[6] http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index.html.

- The amount of energy that must be taken (MWh)
- The maximum daily energy available (MWh)
- Ramp rates (MW/minute)
- Notification time – Time to Start (hot, cold, intermediate)
- Start-up costs (hot, cold, intermediate)
    - Costs incurred per start-up of the resource

In the day-ahead market in New England, based on the above inputs, as well as purchase bids and reserve requirements, the TSO carries out a system-wide unit commitment calculation at 12:00 the day before operation. Referred to as the Resources, Scheduling and Commitment (RSC), this unit commitment calculation determines which resources should be committed to run for which hours, at a load somewhere between the resources minimum and maximum every hour, but the actual volume of the load is not determined at this time. During the next step, the Scheduling, Pricing and Dispatch (SPD), this commitment schedule is run through an economic dispatch algorithm that respects the line and interface limits, and determines the loading levels, demand clearing costs, final costs, and locational marginal prices. This new commitment plan then undergoes a Simultaneous Feasibility Test (SFT), and the constraints created are fed into a new Resources, Scheduling and Commitment (RSC). When this cycle has been successfully completed the day-ahead market is cleared and the day-ahead commitment and dispatch are published at 16:00. The result is financially binding schedules for demand and generation that are based on a least-cost security-constrained unit commitment, day-ahead hourly locational marginal pricing and binding constraints (Turner, 2010).

After the day-ahead market has been cleared and the results published at 16:00, there is a two hour re-offer period that generally closes at 18:00. During this time, market participants can submit revised supply offers and revisions to demand bids for any dispatchable asset-related demand resources.

The vast majority of electric market activity in New England is done so via the day-ahead market, where the bids and offers result in binding financial commitments. Deviations from these energy positions are dealt with in the real-time market which is the balancing market. Offers in the day-ahead market, and revisions to this offers during the re-offer period, are carried over to the real-time market where they are combined with the actual load, actual external transactions, and updated constraints. In the real-time market the dispatch is re-run and new locational marginal pricing are published every 5 minutes. After the closure of the operating day, finalised hourly real-time locational marginal pricing are also published. Real time settlements are based on deviations between the day-ahead schedule and actual operations.

Figure 5 below displays a time overview of the New England market.

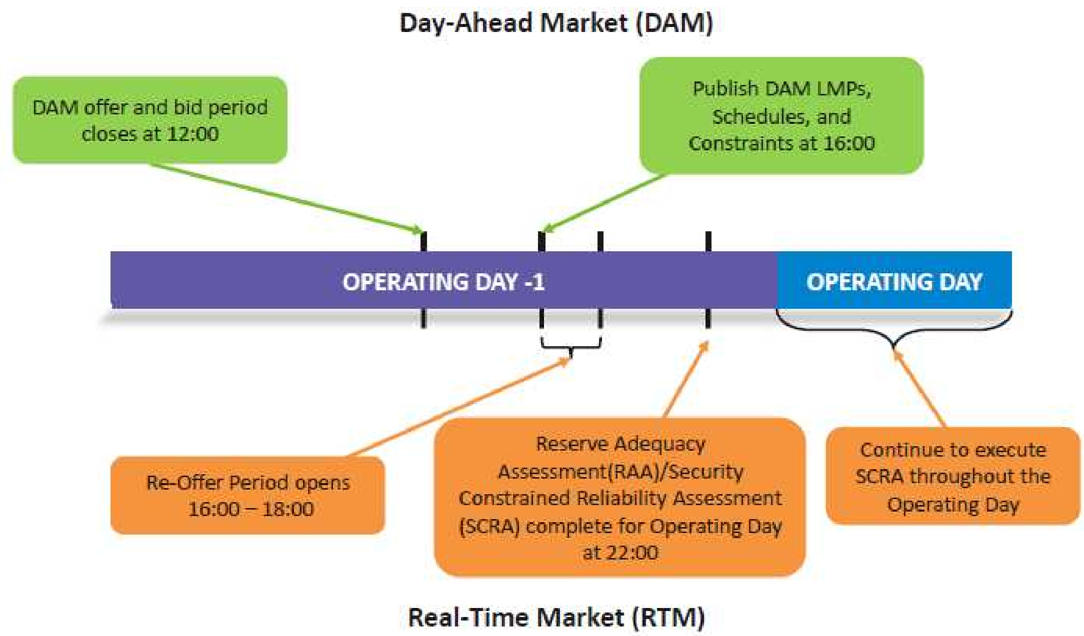

Figure 5: Aspects of the New England Day-Ahead Market (DAM), and Real-Time Market (RTM) (Turner, 2010)

<u>Summary</u>

One of the major differences between the New England and the Nordic market is that in the Nordic market, in terms of their bidding, actors must independently make an informed guess (and act strategically for example in case of hydro power), whereas in New England, all the relevant parameters are delivered to the TSO, who then optimises the dispatch and unit commitment. Due to the fact that the TSO has access to more information in the New England market, and less is left to educating guessing, it is expected that the co-optimisation that is undertaken will lead to a more efficient dispatch. The ability to include additional parameters in the bidding process, as well as the direct coupling of the Day-Ahead Market with the Real-Time Market, is well suited to more complex offers, for example 'energy storage' or 'demand response', two aspects that would be particularly relevant for EVs.

5 MANAGEMENT OF CONGESTIONS IN THE DISTRIBUTION GRID

In a future with a large share of wind power, many heat pumps and electric vehicles the capacity of the distribution grid may be challenged. The increased electricity consumption from heat pumps and EVs can in itself create problems with insufficient capacity in peak hours in some distribution grids. Besides, the combination of a large electricity consumption and price controlled demand may in some cases create problems. This is the case if the demands reaction on wholesale market prices implies larger movement of demand than the distribution grid can sustain.

The following thoughts only consider low-power charging of EVs where the EVs are connected to the grid and a freedom of operation to optimize the charging corresponding to for example a price signal is possible. Other ways to charge an EV as fast charging or battery swapping are not considered. These kind of charging possibilities are described in other EDISON working groups.

Traditionally, demand takes place when needed and the challenges in the distribution grid caused by demand spikes are solved by expanding the grid to fit the size and patterns of demand. As an alternative – if the demand is flexible - demand can be reduced (=moved to another hour of the day to avoid short-term overloading of grid components). EVs reacting on wholesale market prices is a way of introducing demand to fit in the overall power system.

Flexibility in demand from private households (and EVs) must be included in a simple and automated manner so that consumers easily can contribute with the flexibility. Besides, if demand cannot be controlled (e.g. if no customers or fleet operators want to change plans) and, if no local generation exists, the only alternative is to expand the capacity of the grid.

CONDITION: The demand can be controlled.

To enable distribution congestion management during operation the dispatch of demand and generation must not only be based on the power system balance (the conventional electricity wholesale market) but also on the operational state of the grid (information from the DSO). Today the dispatch is set only based on the electricity market and of course the end-users need for energy services. Therefore a new process, using both the market and the grid state to set the dispatch, must be established.

CONDITION: Information representing the state of the distribution grid has to be included in the basis for reaction of the EV.

Controlling of demand can be done locally at customer site or remotely. It can also be done using price signals or using a more direct control approach for example through a fleet operator.

CONDITION: Introducing price based methods requires rational behaviour from the end-user (though retailer etc.)

A fleet operator aggregating and controlling a fleet of EVs would typically control the EVs by direct control. The principles in the following are, though, described more generally and can be used with or without a fleet operator. It is important to notice that the presence of more fleet operators will be necessary in several of the described methods because if only one fleet operator reacts, statistic methods to predict the consumption and effect cannot be used.

In this section several methods to handle and avoid overload of the distribution grid will be described. It is taken as a starting point that all methods require a voluntary participation of customers. Some of the approaches are compensation based (‘carrot’) and some are penalty based (‘stick’). Other methods based on more or less involuntary participation (e.g. grid code based or DSO terms of delivery) are however not considered in this report.

Firstly, the obstacles which have to be overcome from the DSO point of view to be able to handle congestions in the distribution grid in a new manner are described. Secondly, overall thinking about how to handle grid congestions is described in section 5.2. Then principles, advantages and disadvantages behind following types of solutions to handle congestions in the distribution grid are described:

1. Payment for the right to use capacity
2. Time-of-use tariffs
3. Direct control (“cycling”)
4. A bid system
5. Dynamic distribution grid tariffs
    - spot price
    - spot and regulating power price
    - Actual power consumption

In the end, section 5.9, a mixed approached is described suited for VPP in the Edison project which live up to minimum requirements so that the approach fits the current system without need for changes, it considers EVs both in spot and in regulating power market, it is relatively socio-economic and relatively simple. Besides, different method of handling grid congestions can be chosen dependent on the level of problems to solve in the different grid areas.

5.1 THE ROLE OF THE DSO

In the transmission grid the congestions in the spot marked are handled through a price signal. This implies that if congestions exist, the spot price increases in the area behind the congestion (and the cheaper bid from the area in front of the congestion cannot be used). In the regulating market congestions are handled by jumping over a bid in the merit order list implying using a more expensive bid. In principle the TSOs ‘remove’ congestions by grid reinforcement in the transmission grid if a socio-economic business case can be showed. This means that the TSOs invest if the price for removing the congestion (by grid expansions or technical solutions) is less than the cost ‘punishment’ in the spot market and the regulating power market for not using the cheapest bids.

Can you do the same in the distribution grid? Yes, in principle. In practice several obstacles have to be overcome.

<u>Mapping congestions in the distribution grid</u>

It is necessary that the distribution company has fully insight in the distribution grids in order to identify the congestions. The knowledge of the details in the distribution grid is investigated and will probably extend these years for example using more communication equipments. This implies investments in measurement equipment.

It is also necessary that the distribution company identifies the long-term marginal costs of reinforcement of the grid in order to be able to compare these costs with the cost involved to make the end-users to reduce demand in a given period to avoid congestions in the distribution grid. The comparison of these two figures can give a signal of when to reinforce and when to reduce/move demand dependent on which is cheapest for the DSO.

Depending on how demand side response is implemented and to what degree the response is voluntary or not the cost for the distribution company may include an additional overhead to provide an incentive for the end-user to move demand.

It should be noted that methods must be developed to compare the long-term marginal costs of reinforcement to the cost of dynamic tariffs. A similar method is used in the transmission system where annual congestion rents are compared with annual cost of the investment in grid expansion. If congestion rents (clearly) exceed investment, expansion is expected to be relevant.

<u>Geographically differentiating</u>
Firstly, if conditions in the distribution grid have to be taken into account finding a way to include a signal representing the distribution grid will be necessary. This signal is by nature both time and geographically dependent. But the Danish Electricity law does not clearly give the possibility for the distribution company to make a geographically differentiated price[7]. It might therefore involve changes in the legislation before several of the described method implying geographically prices can be used.

Besides, it is also a challenge to explain to the end-user that two houses close to each other have to pay different prices for charging an EV because of older decisions for extending the grid.

<u>Development for new tools for price dependent demand to be used by the DSO</u>
Today, consumption in Denmark is in general not flexible. Models for price dependency in demand remain therefore to be developed and included in all aspect of the balancing on the energy system. If the DSO is to play an active demand-controlling role the DSO has to develop models for the costumer's price flexible behaviour. Alternatively, the demand side response can be handled by the aggregators/retailer/fleet operators, who know their customers the best, and the DSO may only provide information about the capacity available for flexible consumption in the distribution grid. In both cases the contractual and legal framework has to be in place to specify rights, obligations and pricing mechanisms for all involved parties.

The models for price dependency in demand take its basic in historical data. Using measurements of historical demand might be more difficult at lower grid levels (and thereby fewer consumers).

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[7] It should be noted that in Denmark geographically price differencing of grid tariffs within the same grid company is probably not possible according to the Danish Electricity law ('Elforsyningsloven' §73). Several considerations are described in the law: The tariffs must be: Fair, objective and non-discriminating. This is seen in relation to the costs each costumer group causes. It is also mentioned that different prices in relation to location only can be used in special cases. Since some EVs in a specific grid area cause extra cost (for grid expansion) it could be argued that higher tariff for this area is objective. However, updating of the law text is needed.

Today, congestions in the distribution grid are handled by reinforcing the grid. Alternatively, demand should be removed from where it causes the congestion. To decide when to reinforce and when to move demand requires a description of the connection between costs of the two alternatives. If the socio-economic cost from grid reinforcement is lower than the socio-economic cost from end-users reacting flexible the grid should be reinforced. Such an approach requires that the DSO can establish relatively straight forward business case calculations. Methods for this have to be developed and it might not be straight forward.

Pricing by the DSO

An important pre-requisite for a business case is the existing economic regulation of the DSO. The regulation should allow for both i) full cost-recovery of the grid-investments including return on an invested capital, and ii) flexible tariffs and compensation schemes allowing the DSO to provide its services on the basis of the Long Run Marginal Costs. The latter will probably lead to increased tariff differentiation.

Current regulation does not account for these elements to a sufficient extent, and will - in its existing form - be an obstacle for further facilitation of electric vehicles and heat pumps.

5.2 OVERALL APPROACH – THE ORDER OF SYSTEM BALANCE AND GRID CONGESTIONS

Firstly, handling of grid congestion can be more or less integrated with the handling of the system balance in the overall energy system. Secondly, handling of congestions in the distribution grid in the processes can be more or less market-based. In this section the categorising of the different approaches takes its basic in the integration of grid congestions and system balance. The descriptions involve the level of market involvement. Three approaches are handled:

1) Integrated process.

2) Stepwise process - first system balance, then grid congestion.

3) Stepwise process - first grid congestion, then system balance.

Besides, iterative processes or a mix of the above processes can be considered.

5.2.1 INTEGRATED PROCESS

In an integrated process the dispatch of demand and generation according to system balance and grid constrains are set at the same time and/or in the same procedure. A principal example of an integrated process (at transmission level) is the current Nordic spot market where the system balance and congestion of inter-area connections are handled in a market splitting process.

Such an integrated process is one (and maybe the only) way to get an optimal or close to optimal socio-economic operation in all situations.

The disadvantage of an integrated process can be that it is complex to understand and perform. Besides, if distribution grid congestion should be managed to be integrated with the global system balance, it will require handling a huge amount of grid nodes in one optimisation process.

The largest challenge might be that an integrated process requires modification of the current electricity markets (or even introduction of a completely new approach). This will not be an easy task as the current market is a common Nordic market moving to a common European market which means that lots of coordination work has to be done. At least it will take years to obtain a common European solution.

Examples of possible implementations:

- Nodal pricing (locational marginal prices, LMP[8]), also described in section 4.1.

- Hieratical market (aggregation) aligned with the grid topology. DSO can interact with the local market levels to avoid congestions, e.g. through a bid-based system (local adder bids to avoid grid constraints)

- Control-by-price based system with locational adder prices to avoid grid constraints.

- Market for grid capacity (seller: DSO, buyer: end-users, the selling price curve will be steep around the capacity limit) operating in parallel with the spot market.

5.2.2 STEPWISE PROCESS – FIRST SYSTEM BALANCE, THEN GRID CONGESTIONS

In this stepwise process the system balance is handled in a separate step before handling of grid congestions. It is expected that (the main part of) the dispatch have to be handled in the first system balance step. This is reasonable due to the energy volumes involved in the system balancing and an assumption that grid congestions will not be the normal operating situation.

This dictates that the grid congestion management has to be an adjustment to the dispatch in the first step. As an example the system balancing is handled in the current spot market, which may lead to a dispatch of demand and generation where the grid is overloaded in critical locations and times. This overload can be handled in a second step, e.g. a market where the DSO can activate specific bids provided by the users, and thereby relieve the overloaded parts of the grid. Also non-market-based methods (direct control) can be used e.g. direct control of demand/generation based on contractual agreements between DSO and retailer can be used.

[8] *Steps toward a Danish power system with 50% wind energy - EcoGrid.dk Phase 1 WP4: New measures for integration of large scale renewable energy*, report, ForskEL project no. 2007-1-7816, 2009.

The advantage of a stepwise process - with first system balance, then grid congestion – is that it is relatively easy to understand. That the solution can be made as an extension of the current market system is also an advantage as the current wholesale markets do not have to be modified.

The disadvantage of a stepwise process is that an optimal solution cannot be obtained especially in cases where grid constraints are so large that the normal market is influenced. In principle the system balance has to be run again and then the method in the next section can be considered.

5.2.3 STEPWISE PROCESS – FIRST GRID CONGESTIONS, THEN SYSTEM BALANCE

In this stepwise process the grid congestion is handled in a separate step before handling of the system balance. The dispatch is expected, as today, to be set in the step handling the system balance. The very simple (and probably not very efficient) example of such a process is that the DSO in the first step announces capacity limitations to all end-users (through fleet operators or retailers), and that the consumption in the second step trade in the current market within these capacity limitations.

A more sophisticated (but still simplified) process in line with this approach could be that the DSO first sets a grid tariff for each time slot and each grid node for the coming day of operation – like dynamic tariffs. Secondly the end-users bid in the current spot market taking into account the dynamic grid tariff. If congestion is expected to take place, the DSO will set an expensive tariff for the specific time slot and location. This will lead to a tendency that demand does not bid in the involved time slots, and thereby grid overload is avoided. If local generation exits the tariff will also send a signal to produce when needed. One must note that this concept includes a time variable and geographically dependent tariff, see section 5.1.

The advantage of a stepwise process - with first grid congestion, then system balance – is that it is relatively easy to understand. That the solution can be made as an extension of the current market system is also a quite large advantage as the current markets do not have to be modified.

The disadvantage of a stepwise process is that an optimal solution cannot be obtained, especially in cases where grid constraints are so large that the normal market is influenced. Another disadvantage taking the grid congestions first is that it can be difficult to set incentives at a sufficiently accurate level to avoid congestion.

In the following different type of approaches are described in more detail.

5.3 PAYMENT FOR THE RIGHT TO USE CAPACITY

Today the consumers are entitled to draw a high power from the distribution grid. This might not be suitable if grid congestions exist. A special payment could be introduced for users in need of more than a certain maximum. An example of this exists in Italy where the standard limit is 3 kW per household. This system is simple and also easy for the consumers to understand. It requires a form of local control of demand, e.g. making the charging of the EV dependent on the actual consumption by the rest of the household.

Capacity payment could be the same year around or could be adjusted by season to reflect the capacity scarcity.

It is important that the payment is set so that capacities are not exceeded at any time. This means that local optimisation within every household is made. This is a non flexible solution that will probably not lead to a cost efficient solution as reduction at the individual level does not always coincide with system peaks. If the payment was configured for long periods, e.g. months, then capacity would also be expensive in periods with no capacity problems (e.g. nights).

A more adjusted solution could be to split consumption into non-flexible and flexible consumption and only announce capacity limitations for the flexible consumption. This requires a fleet operator with a large portfolio of EVs so that they, within the limitations, for example can load all the EVs in an optimal manner either by sending price signals to the end-users or an on/off-signal.

In this approach the grid congestions are handled separately from the system balance and the wholesale market. Though, a connection will still be expressed through the payment mechanism. The method can be extended to be more sophisticated, see section 5.2.3.

5.4 VARIABLE TARIFFS (TIME-OF-USE)

Time-of-use type of grid tariffs (fixed day/night/weekend tariffs) can be used in the management of congestions in the distribution grid in peak hours. Time-of-use tariffs could shift certain habitual consumption like e.g. the start of a washing machine from expensive to cheap hours. Time-of-use tariffs can be used by retailers, but in this context the distribution tariff is brought into focus.

With time-of-use tariffs the end-user will be able to react, for example by using a simple timer device. However, time-of-use tariffs do not support any variable response and therefore they cannot be used to avoid price introduced peaks (e.g. activating down-regulating power – increased demand – in the night). The time-of-use tariff will provide an incentive in the right direction but it will not be enough to solve grid congestion in all time. It might lead to constrains in the distribution grid especially in low-tariff periods or there is a risk that the peak is moved to another hour instead of reduced by smoothing demand through out the day.

5.4.1 PROGRESSIVE POWER TARIFFS

A more simple method could be to set up fixed tariffs depending on the actual power consumption, also known as power tariffs. The progressive power tariff is fixed and has known relation to the actual power consumption. High power consumption is equal to high tariff and low power consumption is equal to low tariff. This creates incentives for customers to smoothen out the demand through out the day. Therefore, tariffs based on the actual consumption focus on smoothen the demand and therefore do contribute to increase the amount of energy, which can be transferred in the distribution grid, especially in the low voltage grid.

Power tariffs do not directly support the overall balancing of the system. This can be done if the fixed tariffs are used in combination with other market models for example by end-users participation in the regulating power market or market for reserves. Power tariffs in combination with another market model do contribute to get more end-users - with smaller share -

participating in the regulating power market. The ancillary services to the transmission grid will thereby be spread more evenly in the distribution grid.

In case that the power tariffs are not sufficient to handle local grid congestion, reinforcement of the local grid is needed.

The advantages of the method are that it is simple and relatively easy for the DSO to implement because all customers do have the same tariffs and the tariffs are fixed and known beforehand,

The method has no direct link to the system balance but indirectly assuming that the demand curve expresses the need for balancing and the (over)load in the grid. In case that the shape of the actual consumption express the need for balancing it is a well-suited method. This is often the case today where spot prices are strongly correlated to demand. But in a future with much more wind this method will be more inaccurate in relation to fit in the wind in the overall system.

5.5 DIRECT CONTROL – REGULATORY MANAGEMENT

A way to manage congestions in the distribution grid is to allow direct control from the grid company. This can be done by reducing the electricity consumption for selected units, e.g. EVs and heat pumps, by use of remote control. The control can be used more systematic in a cycle to avoid continuous overload.

One example is in the US where cycling is often used for air conditioning. When load must be reduced, air conditioners are only allowed with on/off cycle of e.g. 50% on. The fraction of on-periods and the payment can be adjusted to balance the need and the willingness for customers to sign up. The US system is often applied to solve large area power balancing. The cycling of consumption is only activated when needed, so this type of control can be said to be accurate. However, the system is often only activated in relation to one or a few standardised technologies e.g. air-condition. Other types of demand – that also could hold potential for control – are not considered.

Another example often referred to as “brown outs” can be used at system level to comply with lack of generation capacity in certain peak load situations.

The same concept could be applied for management of congestions in the distribution grid. This would require signal – geographically dependent to the level of interest – based on market prices or technical measurements for example the (over)load of the grid.

The market aspect of this method is related to a possible introduction of a compensation mechanism. Ideally the compensation should be divided to a level that take into account the risk of congestion and should also reflect the potential reduction in effect and/or time. The compensation can be calculated as the difference between the wholesale market prices in the hours from which the demand is moved from and moved to plus a loss from “pain and suffering”. The compensation will reflect the alternative cost for expanding the grid i.e. if the payment is too high the grid company will reinforce the grid instead.

One should note that deciding the compensation is not straight forward as it demands fully insight in the grid and the cost etc. Besides, today’s regulation of the DSOs in Denmark does not directly allow that kind of compensation calculated within the tariffs, see section 5.1.

In this approach the grid congestions are handled separately from the system balance and the wholesale market. Though there will still be a connection expressed through the compensation mechanism. The method can be extended to be more sophisticated, see section 5.2.3.

5.6 A BID SYSTEM

In the transmission system a bid system is used to manage congestions in the spot market. Based on bids for generation and demand, the prices are calculated so the transmission capacity is used to its maximum, but not more. This is supplemented with another type of bid system in the regulating power market where generation and demand are bid into a merit order list where the TSO activates bid when needed taken the cheapest bid first. Congestions are handled by leaving a bid out from the merit order if it cannot be used because of congestions in the transmission grid.

In theory the same concept could be used in relation to distribution grids. E.g. individual customers or fleet operators could send bids to the grid company describing the amount of demand they can reduce and the requested price in the relevant geographical areas. When needed the grid company could activate the cheapest bids taking into account the geographic.

A bid system could also be used to handle automatic reserves.

Many bids concerning demand reductions (or generation) are required. Besides, it will give individual prices in all parts of the distribution grid.

In contrast to the transmission grid, this market type for the distribution grid would have few participants. The competition may be very small. Therefore gaming could occur.

The challenge is to design a bid system that gives incentives for smart grid investments rather than grid reinforcements.

5.7 DYNAMIC DISTRIBUTION GRID TARIFFS

Dynamic tariffs reflecting the underlying marginal costs can give a price signal to the end-users about the real costs in the total system from the congestions induced by the specific end-user. Such a dynamic tariff varies in time and location. A basic principle for dynamic tariffs could be to let the tariffs reflect the marginal cost by increased demand (or generation) on a specific time and in the specific part of the grid. This will be in line with the principles in the Danish regulations regarding “true costs”.

A dynamic tariff will give end-users an incentive to adjust their demand/generation depending on the costs of their contribution to their grid load. Thus end-users, who get price signals based on marginal costs, get a clear incentive to act efficiently - both from a socio-economic and individual point of view. Socio-economic optimal decisions regarding grid reinforcement and flexible demand/generation can in principle be made.

If the socio-economic cost from grid reinforcement is lower than the socio-economic cost from end-users reacting flexible, the grid shall be reinforced. One should though be aware that this requires that the DSO can establish relatively straight forward business case calculations (see section 5.1), in order to be able to incorporate the short-term flexibility in the long-term planning (the complexity of this should not be underestimated).

A working group under the Danish Energy Authorities has made a report investigating the possibilities for and impacts of dynamic tariffs[9], Energistyrelsen (2010). The report states that the DSO's task is, as far as possible, to identify their long-term marginal costs and establish tariffs according to that. When the tariffs reflect the long-term marginal costs, the end-users decisions will ensure efficiency in the costs for both customers and DSO. The DSO will not reinforce the grid unnecessarily and the end-users will not pay more than the shadow price for increased grid capacity. It should be noted that it can though be somewhat problematic that the long-term marginal costs per definition are average condition and that dynamic tariffs are short term hourly figures. Developing a method for when to invest must include a connection between those to figures.

The set-up could consist of the following elements:

- It is accepted that the payment for distribution grids are dynamic and may vary over time and location.
- Normal grid tariff is paid in locations without congestions.
- When capacity problems are expected, the grid company broadcasts an additional tariff in each hour for each location. The size of the tariff should be just large enough to solve the capacity problems (before or after handling of the system balance).
- When the profit from this congestion management exceeds the periodic costs of grid extensions, the grid extensions will be carried out.

The price level is dependent on a balance between the size of the capacity problems and the costumers' willingness to reduce their electricity consumption. The profit from the transitory high grid tariffs could be used to reduce the tariff in the affected areas in periods with no constrains, so that the average tariff is the same in all areas. This might not be straight forward and methods for this have to be developed.

The dynamic tariffs representing grid congestions could be on the top of the ordinary grid tariffs – if no congestions then the dynamic tariff is zero. This could for example be calculated from a division of demand in ordinary demand and flexible demand.

[9] Energistyrelsen, *Redegørelse om mulighederne for og virkningerne af dynamiske tariffer for elektricitet*, June 2010. The working group recommends: Den lokale nettarif på netvirksomhedernes initiativ kan udformes således, at denne afspejler netvirksomhedens marginalomkostninger, dvs. at en dynamisk tarif fx indeholder: i. en nettabstarif (kortsigtede omkostninger), ii. omkostninger, herunder evt. sparede, til netudbygning (langsigtede marginal omkostninger), iii. dækning af generelle omkostninger og forrentning udover marginale omkostninger på en måde, der mindst forstyrrer rette pris-signal.

Ved en eventuel omlægning af den lokale nettarif skal hensynet til forbrugeren overvejes nøje, så afregningen fortsat kan ske ud fra rimelige, gennemsigtige og ikke-diskriminerende principper. Herunder skal el-forbrugernes regninger ved en eventuel omlægning vedvarende udformes, så de fortsat er forståelige for modtagerne, og oplysninger om net-tarifferingsprincipperne og tariferingen skal være tilgængelige.

5.7.1 DYNAMIC DISTRIBUTION GRID TARIFFS – SPOT PRICE

The method that is described in the following takes its basis in a distribution grid tariff that interacts with the spot market.

Overall, when capacity problems are expected, the grid company broadcasts an additional tariff the day before, for each hour and for each location. The size of the tariff should be just large enough to solve the capacity problems.

The method implies that the spot price and the grid tariff are set the day before and therefore can interact, and the costumer can react on the sum of these two price signals. The signal received by the consumer consists of two parts (besides taxes etc.):

- TOTAL PRICE = SPOT PRICE + DISTRIBUTION GRID TARIFF.

The method is relatively simple, as it does not imply that the customers must submit bids or plans for their expected electricity consumption. Real time measurements of consumption are not required. The method is quite similar to the way congestions are handled in the transmission grid, but is somewhat simplified. The expected consumption has to be estimated by the grid company. A model taking basic in historical data can be used. The challenge is to create a reliable set of data for small amount of consumers. The lower the level (and the fewer customers) in the geographical area it might be difficult to obtain a robust set of data.

Whether or not to handle the congestions in the distribution grid before or after the spot or in a mixed approach will depend on whether the volumes are sufficiently small so imbalances can be ignored. An analysis must be made. If the imbalances can be ignored, the grid congestion can for example be handled before spot. In case the imbalances cannot be ignored the tariffs must somewhat be predicted before 12:00 the day before operation and indirectly included in the bids to the spot market. In case the imbalances can be ignored because of small volumes the tariff can be published after spot prices are announced.

5.7.2 DYNAMIC DISTRIBUTION GRID TARIFFS – SPOT AND REGULATING POWER PRICE

If the EV (or demand in general) reacts on spot prices set the day before, it will be sufficient as described above to react on grid congestions once a day. But if the EVs also are to react on continuously updated regulating power prices, it can cause grid congestions if the grid constraints are only considered once a day. For example, an unexpected wind front would cause very low (e.g. negative) prices in the regulation power market. This could motivate price signal based consumption units to increase their demand (e.g. EVs start charging). If grid constraints are not handled at the same point of time, a risk of overloading distribution grids exists. This implies that the signal received by the consumer must consist in three parts (besides taxes etc.):

- TOTAL PRICE = SPOT PRICE + REGULATING POWER PRICE + DISTRIBUTION GRID TARIFF.

In the case of EVs reacting on both spot and regulating power price the distribution grid tariff will have to be updated continuously with updates in the regulating power price. The method compared to the case using spot prices only is more complicated as consumption has to receive updated price signals several times a day. Still the method does not imply that the customers have to submit bids or plans for their expected electricity consumption.

As in the case of using only spot price, real time measurements of consumption are not required. The expected consumption has to be estimated by the grid company. A model taking basic in historical data can be used. The challenge is to create a reliable set of data for small amount of consumers. The lower the level (and the fewer customers) in the geographical area it might be difficult to obtain a robust set of data.

5.8 COMPARISON

Several solutions for grid congestion management can be considered as outlined above. The characteristic of the methods are showed in the table. Some methods can be described as simple but some also with a low accuracy whereas others are more accurate but also more complex.

Note that all the shown methods are based on a voluntary participation of customers. Other methods based on more or less involuntary participation (e.g. grid code based and/or DSO terms of delivery) are however not considered in this report.

Some factors are important in the selection of which method to use:

- The solution can be integrated into the current energy market concepts with limited modifications (or at least an evolutionary development of existing market concepts into a new approach should be possible).
- The solution must be able to handle the different type of actors – commercial and non commercial – as well as several commercial actors (traders, VPPs etc.) responsible for customers in the same grid location.
- The solution should include best as possible socio-economic aspect in the dispatch and decisions regarding grid reinforcements.
- The solution should be easy to understand for owners of EVs among others.

Management of congestion in the distribution grid with other tools than grid reinforcements and take into account end-users reaction to price signals are a new and untested area. All methods require more knowledge of the distribution grid than available today. Besides, new methods to handle congestions in the distribution grid and to predict the reaction of the consumers have to be developed. Especially mapping of congestions in the distribution grid, geographically differentiation of end-users, pricing through compensation mechanism and developing new tools for including price dependent demand is obstacles to be overcome before distribution grid congestions can be handled in a new manner.

	Solve traditional peak load and/or price induced peak?	Accuracy: Does reduction of demand only occur when needed, and with a reasonable amount?	Simple or complex	Comments
Payment for the right to use capacity	Both	Not accurate	Simple	Would affect demand even at times without capacity constrains
Direct control ("cycling")	Both	Accurate	Simple	Typically only for a limited number of technologies
Time-of-use tariffs	Traditional peak	Not accurate	Simple	Most useful for behavioural change
A bid system	Both	Accurate	Complex	Can be too complicated to manage by individual end-users. A fleet operator may be needed
Dynamic tariffs (in relation to spot price)	Traditional peak	Accurate	Simple	Demand is relatively easy to predict, even if influenced by spot prices
Dynamic grid tariffs (in relation to spot and regulating power price)	Both	Accurate	Complex	The combination of high price incentives in the regulating power market and that e.g. very low prices can occur at any time is a challenge

5.9 OPERATION OF A VIRTUAL POWER PLANT (VPP) FOR EVS

A method for operating a virtual power plant (VPP) in a scenario with power system balancing (spot market and regulating power market) and grid congestion management (dynamic tariffs) could be like this:

1) Grid congestions in coming 24 hours are forecasted and tariffs are set in specific geographically area and hours so congestion is expected to be avoided (dynamic tariffs).

2) VPP bids[10] in spot market taking i) forecasted spot market prices and ii) grid tariffs for each hour and each location into account (for each hour and location: total price = forecasted spot market price + grid tariff)

3) Spot prices are set by Nord Pool Spot and VPP overall fleet charging schedule will be established based on activated bids.

4) VPP establishes individual charging schedules and distribute them to EVs.

5) VPP and other retailers offer up and down regulating power in different grid locations previously appointed by the DSO.

6) During operation, grid constraints may occur due to deviations of demand and generation from the plan (or "wrongly" set tariffs by the DSO)

7) DSO activates locational specific regulating power offers from step 4) if congested lines occur ("counter activation" may be needed to avoid influence of the system balance, and a method for coordination with the TSO and the conventional regulating power market for balancing must be developed).

This method is a combination of dynamic tariffs for spot market time slot combined with a first system balance/then grid congestion for regulating market timeslot. The steps 5)-7) can be replaced with a control-by-price approach. This requires that a control-by-prices approach is implemented as supplement for conventional regulating power provision (currently under development – Csetvei, 2010 [11]).

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[10] Bid types on Nord Pool Spot are relatively limited. Only one type of flexible hourly bid is possible e.g. one can bid in to have the bid accepted in the hour with the highest price. Bid types more suitable to flexible demand for EVs etc. have to be developed.

[11] Zsuzsa Csetvei, *Real-time market-based controlling schemes in Power Systems*, December 2010.

6 INTEGRATION OF V2G IN ELECTRICTY MARKETS

It is anticipated that EVs in the future will be able to use their batteries to send electricity back to the grid when electricity prices are high, and/or there is a need for regulating power or ancillary services. Often referred to as Vehicle to Grid (V2G), this concept still has a number of technical and practical issues that must be dealt with before it can be implemented on a large-scale basis. For example, more details must be known regarding the effects of repeated discharging on battery performance and battery life, as a number of car manufactures warranties will currently not cover the battery if it is utilised in V2G applications.

The current market rules prescribe consumption and production to be handled separately. This requires that charging and discharging must be handled by using two meters, i.e. that the delivery of electricity to the grid must be measured by a separate meter. Furthermore the balance responsible would have to change between a consumption balance responsible and a production balance responsible. Today, only small scale photovoltaic units are allowed to use net-metering. It is not known +++whether this exemption could be extended to EVs.

Also, the current tax rules complicate the V2G practise. Taxes are paid for consumption, which includes charging of the EV battery. With a two meter system (one for demand and one for delivery to grid) the tax on demand would hinder an economic charge/discharge plan. If net-metering was allowed the EV could deliver electricity to the owner (not exporting to grid) without tax distortion.

To overcome some of these challenges an option is that V2G is utilised by households to cover their own consumption. This version of the concept is simpler because it would not require electricity to be fed back to the grid, nor would it allow the EV user to deliver electricity to any of the above mentioned markets. However, as described it is not part of the present possibilities.

To be able to use the EV battery in a market concept for charging and discharging the EV, a set of rules have to be set up for how the battery can be used. The rules are based on technical restrictions for the battery and have to be transferred into rules that can be used in a market based charging for example through a price component.

WP 1.5 in the Edison project is working on a battery model that aims to describe the impact on battery life as a function of charging power, state of charge, cell temperature etc. Combined with the price of the battery, this model is intended to give the marginal value reduction of the battery pack when charging and discharging.

Once EVs have started to participate in the markets for regulating power and automatic reserves, the addition of V2G to these markets is quite straight forward. The same is the case for the spot market. Though with the present rules, a fleet operator or production balance responsible will be needed to aggregate end-users to meet the Nord Pool Spot minimum bid of 10 MWh/h. On the technical side, the installation of equipment that will allow for the battery to feed electricity back to the grid will be required.

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