NEAS ENERGY

Ea Energy Analyses

Managing congestion in distribution grids - Market design consideration

How heat pumps can deliver flexibility though well-designed markets and virtual power plant technology

12-11-2012

This report has been prepared by Lotte Holmberg Rasmussen, NEAS Energy, Christian Bang and Mikael Togeby, Ea Energy Analyses as part of the READY project.

Published by:
Ea Energy Analyses
Frederiksholms Kanal 4, 3. th.
1220 Copenhagen K
Denmark
T: +45 88 70 70 83
F: +45 33 32 16 61
Email: info@eaea.dk
Web: www.eaea.dk

Contents

Introduction

This report is part of the READY-project, where large scale control of individual heat pumps are developed and tested in real life.

READY is a ForskEL project supported by PSO funds administered by Energinet.dk. The project team is: Nordjysk Elhandel (project leader), Aalborg University, Aarhus University, Neogrid, PlanEnergi and Ea Energy Analyses.

In preparation of this report we have received important input from the Danish Energy association, DONG Energy Eldistribution, SEAS/NVE, Galten Elværk and EnergiMidt. We are grateful for their time, insight and assistance.

We hope with this report to start a dialogue with other projects working with market design, such as iPower, TotalFlex, FlexPower and Innovation Fur.

1 Executive summary

Heat pumps can be used to reduce oil and natural gas consumption and can assist in the integration of increased amounts of wind power in the electricity system. The new electricity demand may increase the value of electricity generated by wind power. This can be the result even without any advanced control of the heat pumps. However, heat pumps can also be controlled according to prices, and this can both reduce the energy cost for end-users and be beneficial for the energy system.

Variable prices can reflect spot prices, and in the future, operation of heat pumps may also reflect more dynamic prices, for example by delivering regulating power or other ancillary services. Regulating power prices can be attractive for the end-user because the variation is considerable and includes many low prices.

Heat pumps (and also electric vehicles) may potentially create overloading of electricity lines. Distribution grids in particular may be challenged if a large number of these units draw electricity at the same time. This challenge can be amplified when heat pumps (and other price responsive units) react to price signals. **The economic optimisation of the heat pump operation may result in an increased correlation of their electricity demand.** The price signal may lead to a loss of diversity in the on/off cycles of the control.

Cold load pick-up

One example of this this increased correlation could be during a winter day when day-ahead spot prices may be unusually high for a number of hours. This would motivate the price controlled heat pumps (and other price responsive units) to postpone demand. When prices are normalised a high “cold load pick-up” effect could result, thus straining the local distribution grid.

Heat pumps as regulating power

In the future it is quite foreseeable that heat pumps could deliver regulating power, thereby assisting in the maintenance of the balance in an overall system with significant wind power. Thus another example of a potential problem would be if all heat pumps react to the same price signal at the same time (i.e. delivering down regulation by switching on), as this could also result in the overloading of local distribution networks.

Two main solutions to congestions

The above examples would not be problematic in all distribution grids – because some have substantial over capacity. For potential problem areas DSOs essentially have two options:[1]

1. Increase grid capacity by investing in additional grid infrastructure, or
2. Investing in demand response tools i.e. smart grid tools that can shift and/or reduce demand.

In a recent study where the above two options were investigated, it was concluded that relative to simply investing in the expansion of transmission and distribution grids, savings of over 6 billion DKK could be realised by investing in smart grid technologies (Energinet.dk and Danish Energy Association, 2010). It is exactly such findings which give rise to studies such as this, which attempt to deal with local congestions via the implementation of various demand response tools.

Ideal response: local tariffs

Seen in light of the focus on smart grid solutions, the ideal response to the above congestion examples would be to send a high distribution tariff for the relevant time to the areas where congestion is likely. This would solve the local problem, while at the same time allow the large majority of end-users to react to price fluctuations e.g. spot prices, thus enabling them to save on their electricity bill, and contribute to the overall system balance.

Investigation questions

The aim of this report is to discuss challenges with congestions in the distribution grids and how these can be solved through different tariffs and connection agreements, and how a market can be designed to manage congestion in local grids. A part of this is the investigation of the principal questions: Does the DSO have information about potential congestions, and what should the geographic scope of such a signal be?

Direct or indirect control

End-user demand can be controlled by a computer in each home which responds to a price signal that originates from the DSO, or it could be controlled by a centralised system, e.g. a virtual-power-plant (VPP) setup. Nordjysk Elhandel et al. (2012) have demonstrated the practical performance of a VPP to control heap pumps. The VPP set-up is in focus in this project, but the signal from the DSO should likely be useable in relation to both control solutions.[2]

[1] A third 'option' for the DSO could be to invest in and utilise additional metering equipment, thus allowing the DSO to reduce their safety margins. This is possible due to the greater knowledge regarding the capacity usage in the local grids.

[2] This assumption is meant as a compromise between the decentralised and centralised control schools. It is the authors' point of view that the DSO should not take side in this discussion. By sending a price signal

Different tariff signals

How future signals from the DSO to the consumer would work in practice is open to discussion as there are a number of potential options, each which vary with respect to their geographic scope, timing, notice, and price level. Table 1 displays four of the more discussed options.

	Time-of-use tariffs (TOU)	Critical peak pricing (CPP)	Variable tariff	Dynamic tariff
Notice	Before spot			After spot
Activation	Weekly pattern regardless of needed relief	Activated when relevant		
Timing of price determination	Year ahead	Year ahead + day ahead	Day ahead	Intra day
Tariff characteristics	Tariff fixed one year in advance	Fixed low and high tariff for one year. Announcement of use the day before	Varying tariff for each hour. Announcement of use the day before	Varying. Announcement up to actual operation time
Price variations	Moderate	Typically large		
Advantages	Simple to use. May help to activate e.g. manual control or simple clock control	Can be designed to limit end-user risk, e.g. with a maximum number of times the high prices can be activated	More flexible than CPP because of hourly tariff. Greater incentives for those targeted	Can be used if congestions are motivated by calls for regulating power
Dis-advantages	TOU tariffs are general in nature and do not target specific problems	More complex. Would typically require automated control.		
Open questions		Risk for DSO?		How to coordinate with spot market?
Geographical scope	DSO area	Tariff for whole DSO area or only congested grid?		

Table 1: Examples of potential tariff regimes for the use in distribution grids

As seen in Table 1, the various options have different advantages. In addition, they also have varying investment and operational costs. This will be elaborated upon throughout this report.

both methods can be used – and they can compete for end-user interest. Examples of the centralised approach can be found in Sundström and Binding (2012).

Preliminary findings

Our initial findings indicate a number of issues that appear to be clear:

- The signal indicating a potential congestion in distribution grids must originate from the DSO, and this signal will be directed to the retailer/aggregator/balance responsible, which will pass it on to end-users.
- Ideally, the signal with grid tariffs should be sent to all end-users (not only heat pumps) in the congested area (i.e. possibly a small fraction of the DSO area). However, with more than 10,000 potential grids this may not be practical, and costs may not allow for this ideal solution. It is an open question how detailed the geographical scale in practise should be: Can price signals solely be sent to the end-users contributing to a congested line; or must the price signal be sent to larger areas?
- Simple time-of-use tariffs can be an important first step in the direction of dynamic tariffs. Time-of-use tariffs can motivate behavioural change, i.e. computers and communication are not a requirement. It has not been analysed in detail how far in the direction of the ideal dynamic tariff it is relevant to go. Many practical aspects may lead to the result that very simple solutions, such as time-of-use tariffs, will be preferred, particularly in the short to medium term.
- Via the use of modern techniques that are already available today, substantial investments in metering equipment may not be necessary and grid investments may be reduced. DSOs can use these techniques to predict potential congestions. These techniques include state estimators, load flow estimators, and other methods which utilise a variety of information types. For example, meter reading of hourly demand holds a rich amount of information that is particularly useful when combined with grid topology.

There are also other issues that must be studied in greater detail before a conclusion can be drawn:

- Is it possible to construct a market for congestions in the low voltage grid – or is the number of potential suppliers of flexibility too small to make this possible?
- Would bilateral agreements with the few suppliers be more efficient?
- How could such bilateral agreements be designed?

2 Congestion challenges in distribution grids

In the future, electricity demand in residential areas may change quite dramatically. Heat pumps may be introduced in large numbers to reduce oil consumption and individual heating costs. Electric vehicles may in the same way be introduced to reduce gasoline and diesel consumption, and both of these trends will increase electricity consumption. For example, a typical single family Danish household (without electric heating) uses 4,000 kWh/year today, and this may be increased by 5,000-10,000 kWh if a heat pump is installed, and by another 2,000-3,000 kWh/year with an electric vehicle.

The nature of heat pumps electricity consumption

Flexibility of heat pumps

Heat pumps are highly efficient (having a COP[3] of 3-4) but have relatively high investment costs. Therefore heat pumps are often sized to cover only 95-98% of the heat demand (Jensen, 2010). Peak demand is therefore covered by an electric heater which has a COP of 1. This is illustrated for a single heat pump unit in Figure 1 where the red line indicates the outdoor temperature, and the blue line the electricity use. The compressor is operated via on/off mode and the 'on' periods get longer as the temperature decreases (e.g. 3. to 7 February). Typical electricity demand is 3.5 kW for the compressor. During the coldest hours the electric heater starts, adding an extra 2 kW in consumption.

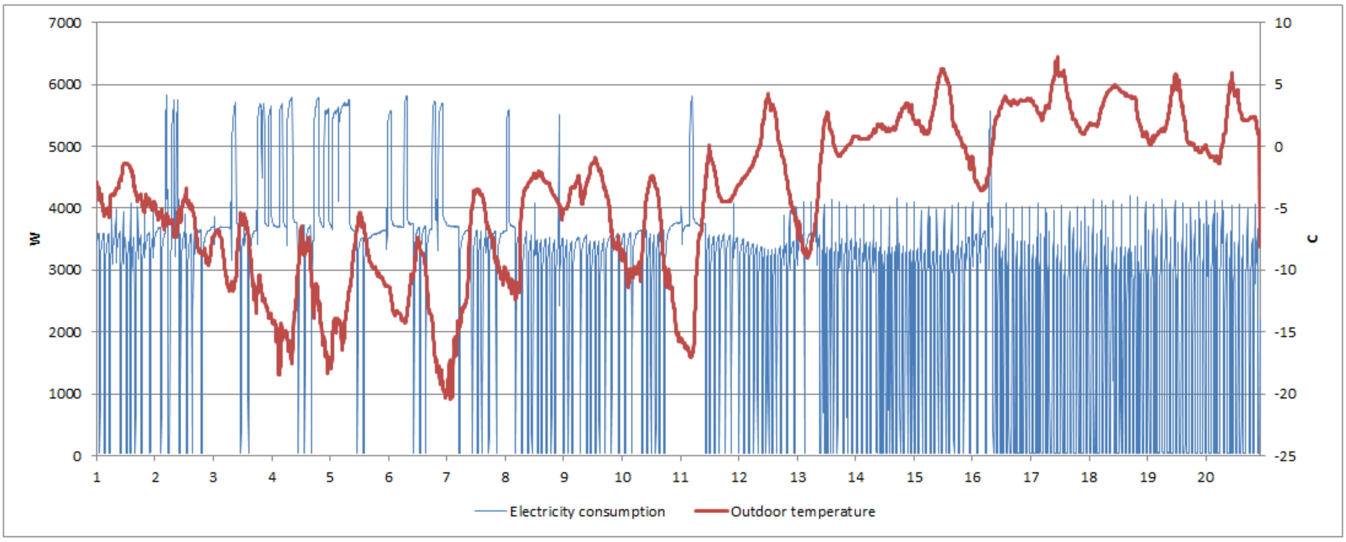

Figure 1: Outdoor temperature (red line) and electricity demand (blue line) for a heat pump unit. Data are 5 minute values from 1st to 20th February 2012. This period includes the coldest day in the winter 2011/2012. Data from unit 118 from StyrDinVarmepumpe.

[3] COP stands for coefficient of performance, and a COP of 3 essentially means that for each unit of electrical input, the unit produces 3 units of heat.

It is clear from the figure that when the outdoor temperature is at its coldest (on the 4th, 5th, 7th, and 11th) the compressor is rarely in the 'off' position (depicted by the lack of blue lines below 4,000 W), and it is also during these same periods that the additional electric heater is employed (depicted by the blue lines from 4,000 – 6,000 W).

Electricity consumption as a function of outdoor temperature

In Figure 2 the electricity consumption for the same heat pump unit is shown as a function of outdoor temperature. This also indicates the degree of flexibility available to the heat pump depending on the temperature. With outdoor temperatures of -10°C the compressor is fully loaded, and there are few options for controlling the run time. If the compressor is stopped at temperatures below -10°C the electric heater, with its much lower COP value, would be needed to re-establish comfort. This would not be economically attractive since the extra electricity consumption is exposed to taxes.

Flexibility

At +2°C and above the run time of the compressor is in the order of 50% and considerable flexibility exists. During summer the flexibility is limited by the low heat demand.

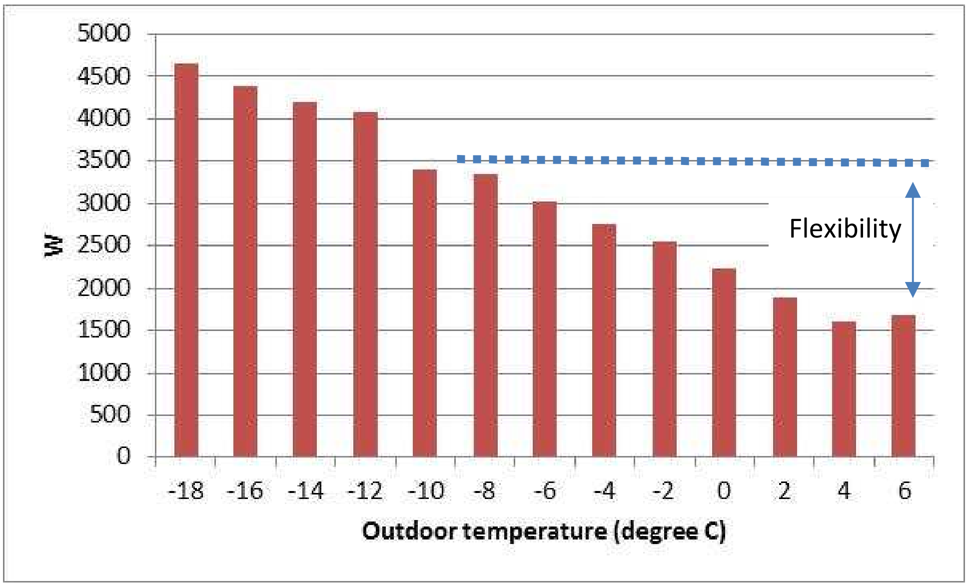

Figure 2: Electricity consumption as a function of outdoor temperature. Same data set as Figure 1. Only temperatures with more than 50 observations are included.

From a database with 40 years of temperatures it is known that daily average temperatures in Denmark are below -10°C on 0.43% of days, and below +2°C on 7% of days.

Control of demand response might increase congestion

Diversity

The partly random nature of the electricity demand for a single end-user has the effect that the maximum demand of, for example, 100 end-users is much less than the sum of the individual maximum loads. A strong smoothing takes place when demand from individual end-users are added, e.g. on a distribution line. It is not unusual that the maximum grid load is only 25% of the sum of the individual maximum load (see e.g. Dickert and Schegner, 2010).

Electric vehicles may typically be charged late on weekday afternoons, and this is coincident with the traditional peak load on the distribution grid. However, compared to heat pumps a smoothing factor can still be expected because of the varied use of the cars, with different return times and diverse charging needs.

The resulting new electricity demand from heat pumps and electric vehicles may lead to challenges of the grid capacity.

Demand response may increase maximum load

If electricity demand is developed to be price sensitive the challenges for the distribution grid may actually *increase*. Demand response is promoted to help balance the overall electricity system, and spot and regulating power prices are determined at the larger price area level. However, extreme prices may consolidate end-user demand and create capacity problems, especially in the distribution grid. This may be a particular problem in hours with very low (and sometimes even negative) spot prices. It can also be a challenge after several hours with a very high price; when prices are normalised the pick-up demand from price sensitive demand may be large.

This situation is well known as cold load pick-up, and is also found after a blackout. The demand after reconnection will typically exceed the prior demand because of 'loss of load diversity'. For example, in IEEE (2009), heat pumps are shown to use twice as much electricity after a blackout, and heat pumps with direct electric heat can use up to five times more if the direct electric heater is activated[4] (see also Lawhead et al, 2006).

Well-designed markets needed

In this way price signals may reduce the random smoothing effect normally observed in distribution grids. Well-designed markets for capacity (that is markets that determine how the physical capacity in electricity lines is best utilised) may solve problems related to the overloading of distribution grids, and at the same time allow for the activation of demand as a resource in balancing the overall electricity system.

[4] In the example heat pumps are loaded with 25% of full load before disconnection, while heat pumps with electric heating are loaded only 10% of their full capacity. After reconnection both technologies are loaded 50%.

Grid operation

There are significant differences in how congestions are handled in the transmission and distribution grids, Table 2 highlights some of these aspects.

Transmission net (TSO)	Distribution net (DSO)

• Mature system
• Congestions are solved as part of daily calculation of spot prices
• TSO publishes transmission capacities for the following day
  o Based on anticipated power flows
• Prices and thereby power flows are based on bids in spot market
• Regulating power can be utilised within the hour of operation to manage imbalances
• Large degree of congestions (high congestion rent) – dictates investment in capacity expansion
	• Over capacity built-in when establishing lines
	• Few measurements
	• Few practical experiences with congestions
	• When the capacity is fully utilised capacity expansion is planned.
	• Development of new methods can save investments in additional capacity
	  o The distribution grid is on average underutilised (dimensioning according to maximum use results in low average utilisation rates)

Table 2: Overview of TSO and DSO practices in relation to congestion management.

Distribution grids

Distribution grids are typically operated at 10 kV and 0.4 kV, and both grids are generally operated as radials. In some cases the grid is meshed, but breakers are held open to maintain the topology as radials. This is done to ensure a safe operation, including operation of the protection system. Operating a distribution grid in a meshed format is more complicated. One example of this relates to the geographic isolation of a fault, which is more difficult to determine with a meshed network.

Congestion – where?

Each distribution grid has a different history, and in some cases congestion is first expected to emerge in the medium voltage grid, while in other grids the low voltage grid is considered to be more critical. Congestion can also be related to the cables or the transformers.

In interviews with grid companies, DONG Energy Eldistribution pointed at the medium voltage grid (10.0kV), while SEAS/NVE, Galten and EnergiMidt expected the low voltage grid (0.4kV) to be more critical. This relates back to the fact that each grid has its own story. Some grids have recently be cabled, and due to the large expenses and inconveniences related to burying cable, it is often worthwhile to incur the rather minor additional expense of over-dimensioning the cable.[5] The end result of this is that cable capacity is often abundant where overhead lines have recently been replaced with under-ground cables.

An example of the 0.4 kV net in the Galten distribution grid is displayed in Figure 3. The Galten distribution company is a relatively small DSO with roughly 830 transformers, 10,000 cable boxes and 24,000 end-users. Currently two thirds of these customers have remote meters installed, and by 2015 all customers will have one. Since 2004 they have undergone a complete cabling of their 0.4 net. In addition, their 10.0 kV net is quite strong, and as such they do not foresee potential problems with capacity in the actual cables, but more so in the transformers.

Figure 3: A portion of Galten's 0.4 kV distribution grid

On the other end of the size spectrum is DONG Energy Eldistribution A/S' distribution grid which serves nearly one million end-users and has roughly 10,000 transformers (10/0.4 kV). Figure 4 displays the portion of Dong's 10 kV distribution grid outside of Copenhagen, with each colour representing a different radial.

[5] It is worth noting that this represents a slight shift in thinking. In the past local grids were to a greater extent optimised based on high utilisation rates of the cable capacity. However, as wages and other 'non cable' costs associated with cable replacement have grown much faster than the cost of the physical cable, it is now more cost-effective to install larger cables.

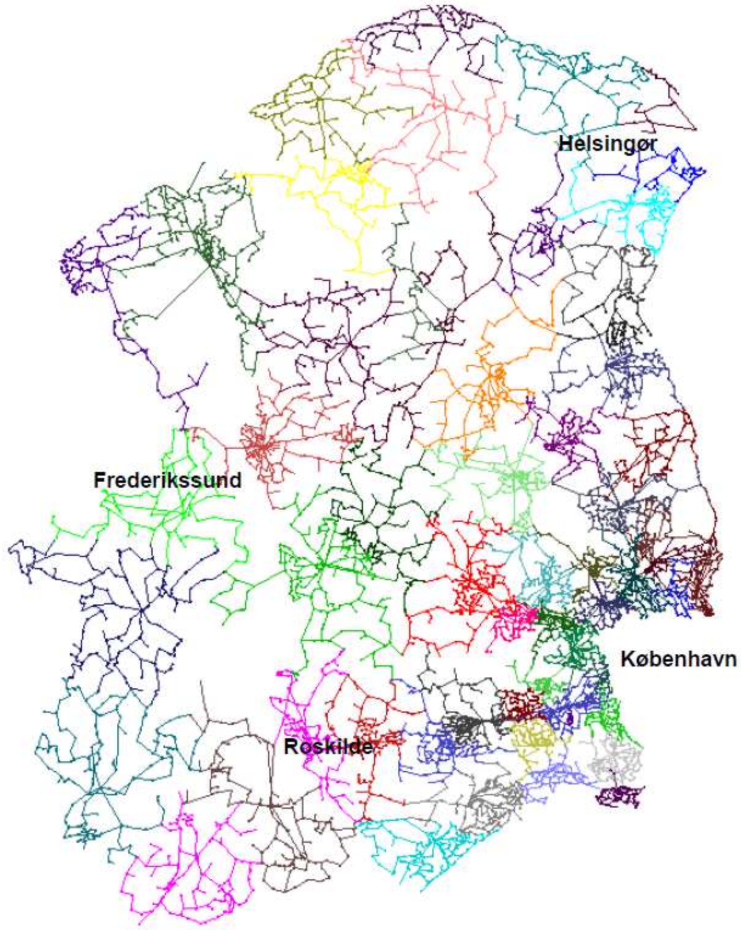

Figure 4: DONG Energy Eldistribution A/S' non-city 10 kV distribution grid

How to solve congestion?

Congestion has traditionally been solved by expanding the capacity of the grid, e.g. new cables, a larger transformer, or by modifying the topology of the grid. Modification of grid topology can be done by adding additional lines and thus reconfiguring a radial(s) permanently. A new approach that has been undertaken in some instances is to insert automatic breakers that allow for remote and/or automatic reconfiguration of the grid.

In the future new FACTS[6] components may also be used to increase the capacity of existing grids (however it is worth noting that the primary driver for their implementation may be the ability to control voltage).

The focus in this report is to control demand as a measure to avoid local distribution grid congestion. Ideally the DSO should choose between these many

[6] FACTS (Flexible Alternating Current Transmission Systems) is an umbrella term that encompasses several technologies designed to enhance the security, capacity and flexibility of power systems, e.g. Static Var Compensator (SVC) can be used to increase voltage stability.

alternatives in a cost efficient way, and perhaps demand response is the best solution up to a point, and then investments in new capacity may be the best solution. If congestion only occurs a few hours per year, demand response is most likely to be the more attractive alternative.

A typical approach undertaken by DSO's in determining whether to expand the net or invest in demand response is to compare the value of delaying an investment (i.e. the interest on a loan), vs. the cost of paying end-users to reduce their demand. In a grid with growing electricity demand the value of delaying the expansion does not grow much each year, however the reduction that the end-user must make does grow. For example, if in year 1 the DSO could save 100,000 DKK by delaying an investment and required a 10 MW reduction, it would pay up to 100,000 DKK for these services. In year two, due to increased electricity demand the required reduction is now 20 MW, but the savings generated from delaying an investment have only grown to 105,000. Thus on a per MW basis the amount that the DSO can offer end-users is greatly reduced, and at some point will not be enough, thus resulting in a decision to instead expand the grid.[7]

Evaluating tariff models

Alternative solutions to managing congestions in local grids can be evaluated by their simplicity, their accuracy (needed overhead for secure operation), as well as their economic cost.

The economic cost of regulating demand to alleviate congestion can have investment costs (e.g. control equipment at the DSO, retailer/balance responsible and end-user level) and operational costs. Focusing on the operational cost for end-users, a simple indication could be to calculate the product of price, times the demand affected. The market model that solves the problem, and has the lowest extra revenue for the DSO can be considered the most economical efficient solution (ignoring investments). In a market based system the price should – ideally – be equal to the marginal cost of balancing the grid. This could be understood as the most expensive demand reduction.[8]

---

[7] The example illustrates the problem that might occur in a bilateral agreement. The DSO can calculate its avoided costs, and if competition existed the DSO could select among a number of potential suppliers – and would in general find a solution below the avoided costs. With only one supplier of flexibility the price may increase to the avoided costs.

[8] This is the principle of marginal pricing. Any reduction in demand has a value corresponding to the most expensive reduction. Because the possibilities are used in merit order (cheapest first), it is always the most expensive action utilised that indicates the value.

Scenarios for tariffs

Congestion management – geographic consequences

It is worth discussing whether tariffs should be local at line or radial level, or if the tariffs should apply to a larger area i.e. the whole DSO area. Both solutions have advantages and disadvantages. In the example below three scenarios illustrate how the cost of addressing congestion can increase when more demand than needed is exposed to the high tariff, and when not all relevant demand is exposed. The idea behind the example is that all end-users have a required price for adjusting their demand (a willingness to alter their comfort level given a particular price), and that the market price is equal to the most expensive demand that is needed to be adjusted (marginal pricing). This is a theoretical perspective that assumes that each end-user can deliver a price (i.e. react to a price signal) and ignores transaction costs.

In the example there are two areas, area A and area B, which have respective electricity demands of 100 and 900 kW. In area A there is a congested line that requires end-users to reduce their consumption. It is assumed that both areas A and B are comprised of three different types of end-use, with the % of electrical effect from each group indicated in brackets:

1. Heat pumps that will react to price signals (50%)
2. Other devices that will react to price signals (i.e. electric vehicles, electric heating, swimming pools, industrial demands and other flexible demand) (30%)
3. Demand that is not price sensitive (i.e. lighting, television, etc.) (20%)

Scenario 1

In scenario 1 a price signal in the form of an additional of 0.50 DKK/kWh[9] is sent to all end-users in a large geographic area consisting of Area A and area B. As a result, both heat pumps and other price flexible devices reduce their consumption in both areas, and the congestion within Area A is alleviated. It is worth noting that a large number of end-users in Area B received and reacted on a higher price, even though there was no actual need for a reaction in Area B.

Scenario 2

In scenario 2, the tariff is only sent to the affected area, Area A, and only to heat pumps. As a result of not including the other price flexible devices in Area A it is now necessary to send a higher signal, e.g. 1.50 DKK/kWh to allevi-

[9] 1 Euro = 7.44 DKK, 1 DKK = 100 øre.

ate the congestion.[10] Here only the heat pumps in Area A are affected by the tariff and no end-users in Area B are affected.

Scenario 3

Similar to the situation in scenario 1, in scenario 3 a tariff of 0.50 DKK/kWh is sent out to all end-users in area A. However, in this scenario the geographic reach of the tariff is much reduced as area B is not affected by the additional tariff.

The table below summaries the tariffs and geographic reach of the tariffs in the 3 scenarios, and an indicator of how much the tariff has affected the end-user price. Under each scenario the congestion has been solved.

	Tariff (DKK/kWh)	Effected demand (kWh/h)	Indicator (DKK/h)
Scenario 1	+0.50	100 (100%) + 900 (100%) =1,000	500
Scenario 2	+1.50	100 (50%) = 50	75
Scenario 3	+0.50	100 (100%) = 100	50

Table 3: Effect of demand based on tariff selected. 'Indicator' is calculated as the product of the tariff level and the number of users affected, and also represents the revenue that would be generated by the DSO (before end-users reaction).

The table illustrates that under scenario 1 a significant amount of demand is affected to bring about the desired response. The indicator in scenario 1 is 500 DKK/h, whereas this reduced to just 75 DKK/h in scenario 2, and only 50 DKK/h in scenario 3. Two conclusions that can be drawn from this example are that in an ideal situation:

1. All types of load should be exposed to a price signal. Only price depended demand will react, but it is difficult to determine which types of loads will react. In some cases behavioural change may change the pattern of traditional non-flexible demand – this may be in the form of avoiding traditional peak periods (not necessarily the exact real-time price, but based on an understanding on when the price would typically be high). It is also worth noting that extra meters are needed if demand should be divided into flexible and non-flexible demand.[11]
2. The price signal should only be sent out to the geographic area where the congestion is taking place.

[10] In the example a price 3 times higher is required to achieve only twice the effect from the heat pumps. This is due to the fact that each unit of response from an end-user requires a greater incentive than the previous.
[11] In O'Connell et al (2012) a tariff is suggested only for flexible demand (in this case electric vehicles). It is argued that this would "avoid… unfair penalties for non-flexible demand". However a marginal price is not a penalty, but a reflection of the true value of electricity. Also in Pleat (2012) special tariffs for electric vehicles are discussed.

The vast majority of the demand response provided in the scenarios above is in the form of a time shift, i.e. end-users reduce their electricity consumption in one time period, and increase it by a corresponding amount in a proceeding (or potentially previous) period. This can potentially be problematic for balance responsibles if they have submitted a plan for a particular period and wish to maintain it. Therefore, an additional benefit of having geographically varying tariffs such as those in scenarios 2 and 3 is that the aggregator has the ability to maintain the overall electricity use of an area for a period, while at the same time eliminating the potential local congestion. This could for example be done by sending a high tariff out to Area A, and a low tariff to Area B during period 1, thus ensuring that the overall demand for A+B in period 1 is maintained. In period 2, a moderately low tariff could then be sent out to area A, and moderately high tariff to area B, thus resulting in all end-users utilising the total desired amount of electricity in periods 1 and 2, while the balance responsible's operation plan for both periods would also be maintained.

The above example is a theoretical scenario where transaction costs are ignored. In practice it may very well be that the transaction costs associated with identifying, isolating, and determining the tariff required to address the exact congestion area are too high to warrant a scenario 3 approach. As a first step it could therefore be more cost-effective to deal with the congestion with a broader geographical approach along the lines of scenario 1.

Electricity generation in local grids

During the past few years an increasing number of end-users have installed local electricity generation in the form of photovoltaics (PV). These resources, also referred to as distributed energy resource (DER) systems are often grid connected, thus allowing end-users to sell their 'excess' electricity back to the grid. Growing levels of DER production can give rise to a number of issues in local grids, with one of the most significant being the voltage quality challenges associated with PV systems.

With respect to congestions in the local grids, if a significant amount of end-users on a particular line install DER systems, this could overload the line. However, given that a typical PV installation can deliver a maximum effect of 5 kW, and all the end-users on a line will also be using electricity at a given time, quite a substantial fraction of end-users on the same line (likely over

1/3) would have to have DER systems for a line to be congested (in the direction of export).[12]

Due to PVs explosive growth in Germany, some portions of the local grid are experiencing congestion issues. These congestion issues give rise to costs that must be passed on to the end-user. As the end-users electricity costs increase, this creates further incentive to instead invest in a DER system, and in this fashion the congestion issues help to perpetuate themselves (Schleicher-Tappeser, 2012). In Denmark however, while PV installations have grown tremendously in the past years, total installed capacity is expected to be around 150 MW (by December of 2012), and therefore makes up only a small portion of Danish demand (Dansk Energi, 2012).

As such, in the Danish context it is anticipated that the largest challenges from a grid congestion standpoint will not arise from distributed production, but due to excessive demand, particularly during times with low electricity prices, cold temperatures, and/or traditional electricity demand peaks. Thus while local grid issues other than those related to congestions because of new demand are also important to address, they are not the focus of this particular study.

[12] According to Dansk Energi (2008) and Elforbrugspanel.dk (2009), in 2007 a typical Danish house without electric heating on average used roughly 383 Watts during the summer weekday hours of 11-15 (based on data from July 2007). If one out of every 13 houses had a 5 kW PV installation, a fully producing PV installation's production would be utilised by these houses. Meanwhile, we know that during the hour of the year in 2007 with the highest hourly average consumption, these same houses used 1,225 Watts, and therefore the local lines can sustain this. Thus we can set up a simple hypothetical distribution line with 100 houses where:

- Total demand is 38.3 kW (100 houses * 383 Watts)
- Total line capacity is 122.5 kW (100 houses * 1,125 Watts)
- This allows for 'production' on this line of 160.8 kW

At an average size of 5 kW, this would allow for 32 PV installations on a 100 house line. This is of course a very simple example using average figures; however it does give a relative idea of how many houses would likely have to have a PV system before it is a problem for local distribution lines (capacity wise).

3 Tariffs and connection agreements

Many buyers and sellers

In many different markets there are numerous buyers and sellers. This is also the case for the spot market in the Nordic electricity market. Typically there is strong competition and the resulting price is well-defined. By well-defined it infers that no single market participant can influence the price, and buyers can be assured that they will receive the amount of desired electricity. As such, the price may vary, but the needed amount is available. Congestion in the transmission grid can reduce competition and make it possible for individual generators to influence the price.[13]

One buyer

In other markets, e.g. the Nordic market for regulating power, there is only one buyer, but many sellers. The TSO is the sole buyer in a specific area, and decides when and what amount of regulating power to activate. A Nordic list of bids for delivering regulating power is consulted, and the lowest cost bids are activated. In general, competition is good in this market; however the prices vary much more than in the spot market and this could be an indicator of the need for more sellers. For example, electricity demand only participates in this market to a very limited extent; with the only example of demand delivering regulating power being electric boilers in district heating systems.

Can a market be established?

Designing a market for managing congestions in distribution grids has some similarity to the TSO regulating power market: Only one buyer (the DSO responsible for that area) and potentially many sellers (all end-users with flexible demand, as well as local generators). However, it may be a challenge to reach these ‘many sellers’. If congestion is a problem on a low voltage grid, perhaps 10-100 end-users are affected. If only a few end-users have heat pumps, electric heating, electric vehicles or other demand that can easily be controlled, then it is not a traditional market with sufficient market players present in order to establish a ‘well-defined’ price. With only one buyer (the DSO), and a few sellers, the price may not be found by traditional market mechanisms. For example, the individual seller may dictate the price, and the risk exists that no seller will reduce their demand.[14]

Bilateral agreements

The above discussion describes a situation where there is not a sufficient market in place, and as such bilateral agreements are required. Regulatory rules could therefore guide what prices the DSO could use. Depending on how

[13] That there has only been two instances in the last 10 years where the market has not been able to define a price illustrates the fact that in general the spot market is very liquid.
[14] See example in chapter 2 about avoided costs.

these are structured, the general and inflexible nature of such guidelines can result in them being a poor substitute for a real market price.

Electricity price elements

In Denmark the price that a typical end-user sees on their electrical bill is roughly 2 DKK/kWh, of which 20% is VAT. The table below displays how the end-user price is comprised.

Element	Characteristic	Typical value
Wholesale electricity	Usually fixed, can be variable price (spot)	35 øre/kWh
Transmission	Flat tariff (could be dynamic)	5 øre/kWh
Distribution	Flat tariff (could be dynamic)	15 øre/kWh
Ancillary services	Flat tariff	4 øre/kWh
Public service obligation	Flat tariff (revised each quarter)	10 øre/kWh
Trade	Negotiated price	3 øre/kWh
Taxes	Flat rate	81 øre/kWh
VAT	25%	38 øre/kWh
Total		**191 øre/kWh**

Table 4. Typical elements in the end-user electricity price

When designing a congestion market it is important that this composition is kept in mind because the end-user has to receive an adequate incentive to shift their electricity demand. For example, a 100% increase in the distribution tariff only results in a 10% increase in the total end-user price.[15]

Distribution tariffs today vary greatly between different DSO areas, and can be as high as 50 øre/kWh. However, according to the 'Law on Energy Supply', it is not allowed to discriminate within a DSO area. While the same law also states that tariffs must reflect the costs of distributing electricity, generally a DSO is not permitted to apply what is referred to as 'geographically varying tariffs' within their area. The curious result of these two dynamics is that for a DSO with a very large geographic area, one price will apply, while a smaller geographic area comprised of several DSOs may have different tariffs.

From October of 2014 DSOs will be able to send out time varying tariffs, but geographically varying tariffs are not yet explicitly permitted. However, this has to be permitted if DSOs are to differentiate tariffs according to congestions. Since January of 2012 DONG Energy has been allowed to introduce time varying tariffs, see Table 5.

[15] The 15 øre/kWh increase is subject to VAT. 0.15 * 1.25/1.91 = 10%

Network tariff	*Off-peak*	*Shoulder*	*Peak*
Value	*20.8 øre/kWh*	*25.5 øre/kWh*	*30.3 øre/kWh*
Timing	*21-06 and week-ends and holidays*	*Summer: 6-8 and 12-21 Winter: 6-8, 12-17 and 19-21*	*Summer: 8-12 Winter: 8-12 and 17-19*

Table 5: Example of a time-of-use tariff. DONG Energy Eldistribution, January 2012. The tariff includes 7.4 øre/kWh for transmission. Tariff applies for users with a demand greater than 100,000 kWh/year.

Interval meters

Today, half of all households have an interval meter that is read remotely and can deliver hourly demand values to the DSO and end-users. These meters may record hourly demand, but are primarily used for yearly billing. New procedures are underway for how hourly values can be used for billing in households (3. afregningsgruppe).

It is important to note that hourly billing of customers is necessary in order for the different tariffs to have any effect. In this report it is assumed that all end-users have an interval meter and that they are used for hourly billing.

Fairness

Different tariffs for neighbours?

In our dialogue with DSOs fairness has often been raised as an argument against varying and/or detailed dynamic tariffs, e.g. with strong geographical variation. Questions such as: Would it be politically and/or legally acceptable with a high price for one end-user, and not for the neighbour?

A system using temporary high grid tariffs could be designed in such a way that the overall annual payment would be the same (revenue neutral). The revenue gained by the high tariffs could be returned in hours without capacity problems, and as such the authors deem this to be more of a political issue with regard to fairness and acceptance.[16]

Potential tariff regimes or contract options

In designing and operating potential congestion markets there are a number of conceivable tariff and contractual options. Table 6 lists and describes a number of potential tariffs and agreements.[17] It is worth noting that it is possible to combine many of the various types of contracts and mechanisms.

[16] Fairness and customer accept will not be discussed in further detail within this report, however another WP within the READY project will delve further into these issues.
[17] See also: Arbejdsgruppen vedrørende udvikling af salgsprodukter på elmarkedet, der understøtter det intelligente elforbrug (2009)

Type of tariff	Description
Flat tariff	As today
Time-of-Use	Can for example have three prices, and may include a seasonal component as was the case with the “treledstarif”, which was used in Denmark prior to 2003. The number of price levels could be two or more (day/night/weekend, etc.).[18]
Critical Peak Price	A high (and/or low) price can be activated with short notice, e.g. the day before. Can have a maximum number of activations per year.[19]
Variable tariff	DSO may be allowed to send a day ahead tariff that is expected to solve congestion in the local grid.
Dynamic tariff	DSO may be allowed to send a real-time tariff that is expected to solve congestion in the local grid.
Connection agreements / contracts	
Disconnection, without notice	A reduced grid connection fee can be combined with the right of the DSO to disconnect demand. This is used in relation to electric boilers in district heating systems. When the DSO disconnects this may introduce imbalances because the planned demand cannot be realised.
Disconnection, with notice	If a days’ notice were instead given, the end-user could avoid imbalances. The notice could be firm, or could be a notice of ‘risk of disconnection’.
kW max	The potential problems of overloading of distribution grids are related to the fact that end-users today are allowed to draw a large amount of power. Typically a household may use 25 A (~17 kW). A new system could provide incentives to reduce the maximum effect. E.g. extra cost could be added for each 5 kW that the end-users would be allowed to use. For example an annual capacity tariff.[20]
kW max at peak	The kW max tariff could be refined so the reduced capacity only applied during peak load periods. During the night there is excess capacity and no reason to restrict the use. Note that with demand response peak load may be difficult to predict.

Table 6: Tariff and contract options

[18] The implementation of price levels can lead to new peaks, e.g. when a low price level starts each evening at 21:00. As such, the more price levels that are implemented, the less likely they are to introduce peaks.
[19] EdF in France has for years used the Tempo tariff, a CPP tariff. Systems for automatic control of electric heating are available.
[20] The problem with overloading of distribution grids is related to the fact that the maximum power end-users are allowed to draw from the grid is quite high. The sum of the allowed demand is much higher than the capacity of the grid. This may lead to the idea: Why not reduce the maximum allowed power the individual end-user may draw from the grid? This could be done for all end-users, or the capacity could be auctioned. In Italy many end-users can at most draw 3 kW. If they use more, the connection is interrupted. Systems have been developed to balance the load in a household, so e.g. a water heater is not used at the same time as a dishwasher. Such kW-max tariffs may be inefficient. They may put restrictions on end-users in situations where there is available capacity in the grid. The technical nature of this type of tariff can lead to very different marginal cost of reductions. For some end-users it may be easy to live with the restrictions (low costs), while others need to employ a lot of effort to stay below the limit (high costs).

4 Designing a market for local grid congestions

Tariffs and market models

Many different market structures can be relevant in relation to management of congestions in local grids. Here three sets of market models will be described and discussed. The three models are examples of how markets with different tariff structures could function. The categorisation of the model according to tariff structure can be seen in Table 7.

Tariff structure	TOU	CPP	Variable tariff	Dynamic tariff
Model 1		(X)	X	
Model 2				X
Model 3				X

Table 7: Categorisation of model according to tariff structure

The models can all be used in an environment where several balance reponsibles/retailers are active in a local area. The DSO has the responsibility of detecting when overloading of local transformers or cables can occur. The price or activation signal is then sent to the balance responsible/retailer, and finally the heat pumps are controlled via the VPP. All three models can also cope with other types of demand control, e.g. local control based on price signals and operated via automation systems in the home.

Model 1

Figure 5 illustrates a simple model, where congestion is predicted the day before (this is similar to the tariff described in O'Connell et al, 2012). This could for example be via a variable tariff as described in Table 6. The DSO uses historical values of e.g. demand, weather and spot prices to predict if congestion may occur tomorrow. Information indicating a high distribution tariff is then sent to the balance responsible. In this model the DSO must know what level of tariff is needed to reduce the load so that the congestion is avoided. As such this calculation may include a safety margin. The balance responsible receives this distribution tariff before the deadline for buying electricity at the spot market, and can include the information in its Nord Pool bids.

This market model can be relevant to avoid spot price induced congestions, such as the described cold load pick-up after a number of hours with a high spot price. The result will be a smoothing of the demand so the pick-up is prolonged in time and grid capacity is respected. The price is market based because the price required to alleviate the congestion is based on end-user behaviour.

The VPP approach has the additional benefit in that it also allows for the smoothing out of demand within the hour. For example, if a balance responsible/retailer has purchased electricity for 100 heat pumps within a particular hour, via the VPP it can manage the heat pumps so that e.g. 25 run for the first 15 minutes, 25 run for the next 15 minutes, etc. By smoothing the usage out over the hour this helps to avoid peaks within the hour, particularly at the hour change.

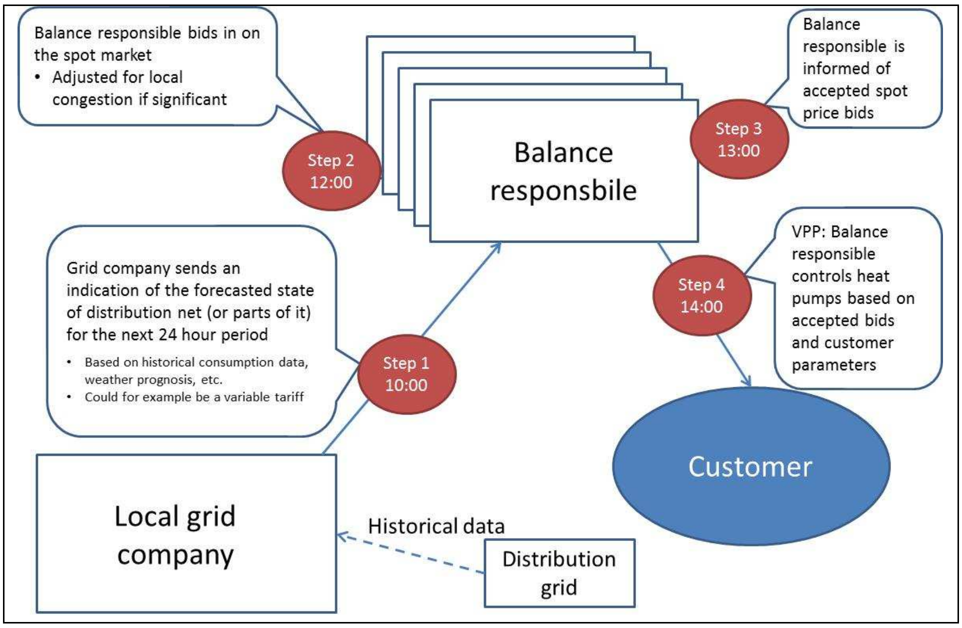

Figure 5: Model 1 - A bid-less, day-ahead setup

Model 2

An alternative is to use a market setup similar to the TSO's current market for regulating power. This option is illustrated in Figure 6 on the following page. In this setup the balance responsible sends bids to the DSO offering to reduce demand if needed. These bids are sorted according to price, and then accepted and activated as needed by the DSO. Compared to model 1, this model to a higher degree represents a traditional market as it is very similar to the current regulating power market.

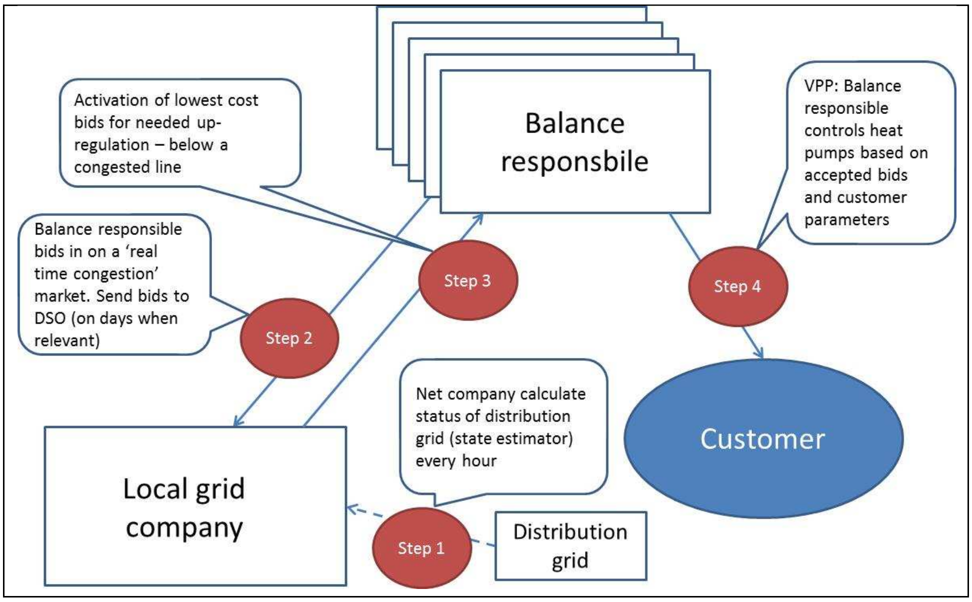

Figure 6: Model 2 - A real time, bid based market.

Model 3

Figure 7 represents an alternative to model 2, where instead of the balance responsible submitting bids, the DSO estimates the additional price that is required to reduce the demand and sends this out in real time (perhaps every 15 minutes). Similar to the day-ahead version for model 1, the level of the additional tariff is determined based on historical pricing data, but can also be augmented with current weather conditions, electricity prices, grid conditions, etc. The type of signal sent from the DSO here would be what is referred to as a dynamic tariff in Table 6.

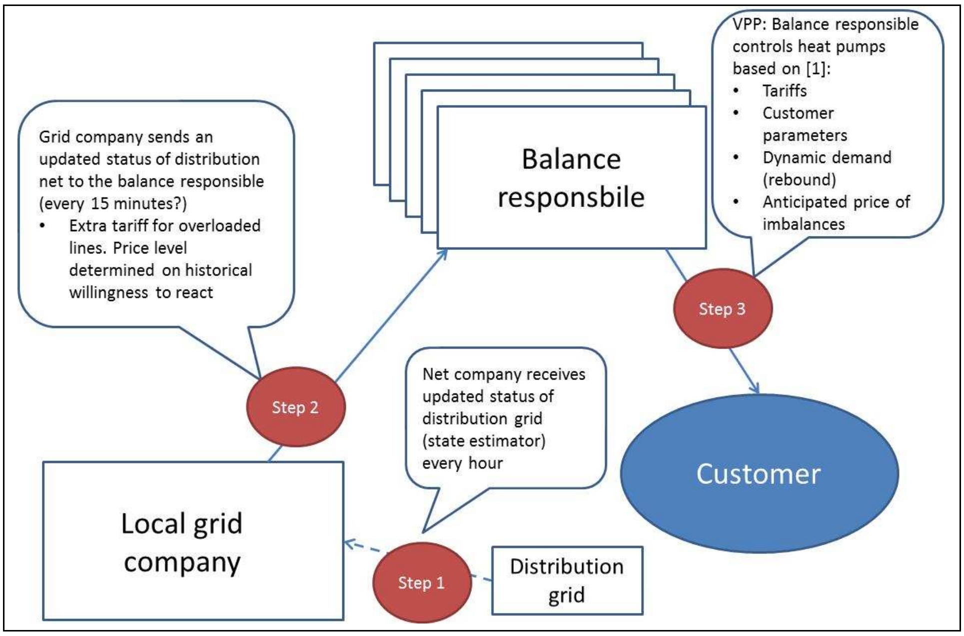

Figure 7: Model 3 - A real-time, bid-less market.

Plans for the demand

None of the three markets requires end-users to send plans for their demand the next day. The use of plans is well-established on the generation side of the market, but it is considered unrealistic for the demand side users as it places an unreasonable burden upon them. If plans are needed these should come from the balance responsible and be based on historical information regarding demand, prices, time of day, weather, etc.

Potential DSO marketplace

A national DSO market

There are in the order of 70 DSOs in Denmark and 11 demand balance responsibles. The communication infrastructure for a local congestion marketplace could be arranged at the national level, for example via a web service, where DSOs could forward information about grid conditions (for example in the form of tariffs). This could be a simple string of text indicating a DSO ID, ID for sub grids, tariffs, and time when the tariffs are applicable. This set-up would (much like the DataHub) require that the balance responsible only need to deal with one system – even with 70 different DSOs.

The most challenging part of this could be agreement on common IDs for sections of a DSO grid – and to know the relation between all end-users and these codes. This is a task that would require intensive work for both DSOs and balance responsibles.

Inspiration for such an endeavour can be found in the FlexPower project where a standard for communicating price information has been developed (FlexPrice).

Retailers purchase of electricity for consumers with price sensitive demand

Prediction of demand

In the Nordic area electricity is bought at NordPool the day before operation. A part of a market solution is therefore prediction of the electricity consumption of demand response devices.

It is relatively easy to predict demand that is not price dependent. Based on historical data accurate prognoses can be developed, e.g. based on time of day, day of the week, time of year, and temperature. Price dependent demand however, poses more of a challenge. Extreme price patterns may be so rare that they do not exist in the historical database (for example a high price very early Sunday morning, with medium-cold temperature). In a situation with rapid growth in price dependent demand it may be difficult to have a sufficient amount of data to predict the next day's behaviour.

If consumers have price dependent demand, e.g. heat pumps, an electricity purchase strategy needs to be developed by the retailer. One possibility is that the retailer starts by predicting the most probable demand, and thereafter estimates the impact of different prices. The result could be that the retailer uses price dependent bids on Nord Pool.

Demand imbalances

As in the traditional situation imbalances can occur when the prediction of demand is inaccurate. With price dependent demand imbalances can also occur. For example, in the case of using price dependent bids, if the general price level is lower than expected for an entire day, the retailer may end up buying too much electricity for that period, and the opposite is true if the general price level is higher for the entire day.

New bid types might be needed

A special aspect of predicting heat pump demand is related to the rebound effect, i.e. the extra electricity used after a period of reduced demand because of high prices. This could be the case if the dynamic tariff is used, as this is an intra-day tariff. It is possible – by use of price dependent bids – to plan for the reduced demand in case of high prices. However, no bid types exist on Nord Pool in the form “I will buy more electricity in hour X, if the price in the preceding hour was high”. This gives rise to the discussion of whether a number of smart grid solutions could benefit from additional bid forms on Nord Pool. The above described bid, or a bid form along the lines of ‘XX MWh during the cheapest Y hours’ would be ideal for heat pumps and electric vehicles.[21]

Discussion

Our initial conclusion is that the implementation of a simple time-of-use tariff can be a very good first step. It is relatively simple to implement, it is well known within the Danish context, and it can provide a mild incentive to shift demand.

If greater amounts of demand need to be shifted, we see Model 1 (bid-less , day-ahead) as a good candidate. This is due to the fact that this model is relatively simple and fits in well with the current markets.

[21] At Nord Pool bids can be placed as 1) Single hourly orders, 2) Block orders and 3) Flexible hourly order. The flexible hourly order is a single hour sales order where the members specify a fixed price and volume. The hour is not specified. This can be used to reduce the consumption in the most expensive hour. However, only one hour is in play. Heat pumps would be interested in a similar bid type with more hours. CHP generators could also use this bid type.
See: nordpoolspot.com/TAS/Day-ahead-market-Elspot/Order-types/Flexible-hourly-bid/

Model 2 (real-time, bid based system) may on first glance seem appealing as it is simply a more localised version of the current regulating power market. However, the extremely large amount of bids, transactions, and communications may prove to make it overly complex, thus resulting in very few market players choosing to participate.

Model 3 (real-time, bid-less) is a good candidate for a real-time system. However, this system could potentially introduce imbalances in relation to Nord-Pool and the TSO plans. If the volume of controlled load is relatively small, these imbalances may be ignored. In addition, the geographic scope of such a market is also a challenge. If too large, many end-users may react to a signal that requires only a few to reply to, and if too small, there may not be enough end-users with flexible demand within the area to establish a fair market price.

Some of the pros and cons of the three approaches are summarised in the table below.

Markets for local congestions	Pros	Cons
1. Day ahead without bids	• Simple • No real time measurements needed	• No real time control
2. Real time with bids	• More accurate than day ahead (less dependent on prognosis) • Dynamic adjustments possible • Possibility to use real time measurements at end users • Activation of bids results in specific amount required by DSO	• Need for real time measurements of congestion • Extensive communication • Risks for imbalances • Requires bids • Every grid company needs to activate bids from the balance responsibles
3. Real time without bids	• More accurate than day ahead (not dependent on prognosis) • Dynamic adjustments possible • Greater possibility to use real time measurements at end users • Does not require bids	• Need for real time measurements of congestion • Extensive communication • Tariff signal sent by the DSO is a price estimated to bring about desired effect • DSO must make this estimation • May not bring about the desired effect

Table 8: Pros and Cons of the three congestion market approaches

5 Predicting congestion in local grids

Little real time information exists about the power flow in distribution grids. In the medium voltage grid (10 kV) real-time measurements may exist in all transformers delivering electricity from the transmission grid, and for 1-10% of the transformers delivering electricity to the low voltage grid (0.4 kV).

It would require significant investments in meter equipment if all lines should be monitored in real time. However, use of powerful computers in the form of state and flow estimators may deliver a detailed picture of the flow in all grid components.

State estimators use maximum likelihood methods to compute the state of the grid. The method can use measurements of different quality, and use information of the physical topology to calculate the most probable solution. State estimators are often used in relation to transmission grids, but could also be developed for distribution grids. In a transmission system there are often more measurements than degrees of freedom, while in distribution systems the measurements are much sparser.

In terms of the transmission grid, the Danish TSO, Energinet.dk, utilises a state estimator as a decision support tool to evaluate how critical a situation is, or how critical it may potentially become. State estimator calculations are supplemented with measurements from Phasor Measurement Units (PMUs) thereby providing Energinet.dk enough time within which to operate before faults or situations in the transmission grid evolve to a critical level. The state estimator provides information of where in the transmission grid the potentially critical situations can be expected, and based on this information Energinet.dk can dictate alterations in import/export from neighbouring countries, determine the need for up/down regulation, regulate variable transformers, or activate flexible consumption (Johansen, 2012).

In looking at the distribution level, DONG Energy Eldistribution A/S (the largest DSO in Denmark) uses a load flow estimator to compute the state for the 10 kV medium voltage grid (Vinter and Knudsen, 2009, Visits 2012). The current system is based on a standard tool for power flow calculation (NEPLAN). Based on real-time measurement from selected transformers, information about demand from larger end-users with interval metres, and standard profiles for 27 other end-user groups, the complete information about the grid is calculated every 10 minutes and stored in a database. This data can be used for planning and analysis. DONG reports that due to this much better data, savings in relation to grid investment have been realised. For example, standard rules of thumb regarding required capacity margins could be relaxed when actual grid utilisation figures are now available.

Currently the calculation is done three days after the operation day. This time delay is due to the time required for collecting the demand data from customers with hourly metering. If needed, the computation could be done after only one day, in real time (with input about the expected demand), or even as a prognosis for the next day.

New interval meters can help to make the use of state and/or load flow estimators more viable and precise. These meters are typically read each night (with 24 values per day). This information can be used to construct the power flow in the distribution grid. In a grid without generation the flow can be calculated by adding the demand from the relevant end-users. Not all utilities have an exact mapping of how individual meters are connected to the grid, but activities are underway to ensure the quality of such information. It is worth noting that the generation from PVs are included in the measurements, so this generation does not disturb the calculation. However, in order to predict the state of the grid a sunshine prognosis must be included.

Measurement of critical grid areas may be read more frequently than once a day, and with a working state estimator a map of critical elements can be computed. The DSO may choose to use a sample of the end-users and measure the demand from them in real-time, or with a short delay. Galten Elværk (a utility with 25,000 end-users) is able to read all meters with a notice of only 1-2 minutes. The sampling period for the meters is typically 1 hour, but can be 5 minutes if needed.

6 Next steps

This draft report will be presented to a number of relevant researchers and stakeholders. Based on their feedback the report will be completed and critical issues will be further analysed in a subsequent report.

Business cases

Based on the recommend market design, business cases will be developed. This can be realised by computing the cost of operating heat pumps in a number of environments:

- Without any price control (but exposed to spot market prices)
- Without any price control (but exposed to spot prices and dynamic net tariffs)
- With optimal control based on spot prices
- With optimal control based on spot prices and regulating power prices.
- With optimal control based on spot prices, regulating power and dynamic net tariffs.

The calculations could be made for a set of values describing comfort settings, as well as time constants for the house.

By using optimal control to calculate the results it is easy to compare scenarios. With two optimal control scenarios, the difference in cost can directly be assigned to the difference between the scenarios, e.g. the price. Optimal control can be realised with a simple model and by using a linear solver such as CPLEX. It could for example be required that the average temperature in all model runs should be the same (= same comfort).

Several studies have indicated that the economic benefit of controlling demand according to spot prices is limited. To make a positive business case an appropriate economic benefit must exist. A business case will describe how this can be distributed among the different market players.

State estimator

The utilisation of various existing information such as end-user hourly consumption data to describe the state of a distribution system is a promising idea. An attempt to demonstrate this in simple distribution grids, e.g. a distribution line with several end-users will be undertaken.

Road map

Another potential next step could be the development of local grid road map. Below is a first sketch of input to such a road map.

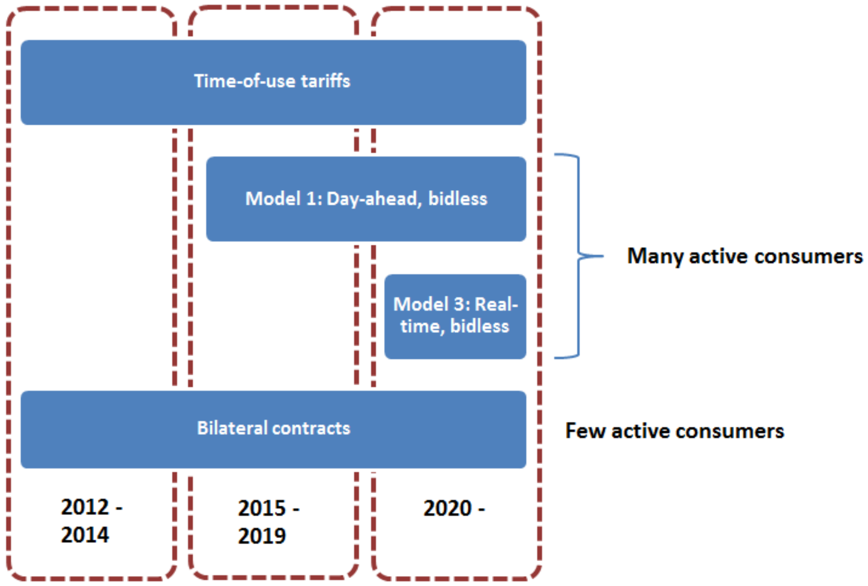

Figure 8. A possible road map for development of markets for local grids. Dates are only indicative.

Price signal or power signal

Another discussion that could be interesting is the question of whether the signal from the DSO to the aggregator or balance responsible party should be a price signal or a power signal. Essentially what the DSO is interested in is a reduction in the load. It could be a task for the aggregator to solve the question of what price should be sent to the consumers. This could be calculated as part of the VPP (Virtual Power Plant) that controls the heat pumps, and possibly other kinds of flexible demand.

Actor input

With all the above questions still in need of being answered it will be interesting to receive inputs from the different actors that participate in the development of technical and market solutions for congestions in the distribution grid, and observe the developments in this area.

References

Arbejdsgruppen vedrørende udvikling af salgsprodukter på elmarkedet, der understøtter det intelligente elforbrug (2009): Det intelligente elforbrug - Salgsprodukter på elmarkedet.
www.ens.dk/da-DK/Info/Nyheder/Nyhedsarkiv/2009/Documents/200907_Notat_om_salgsprodukter.pdf

Dansk Energi (2008): Dansk elforsyning – Statistik ´07, April 2008.

Dickert, J. , P. Schegner (2010): Residential Load Models for Network Planning Purposes. Modern Electric Power Systems 2010, Wroclaw, Poland.

Elforbrugspanel.dk (2009): www.elforbrugspanel.dk

Energinet.dk and Danish Energy Association (2012): DanGrid reports. Working groups 22, 23 and 24. Danish versions available at:
http://www.danskenergi.dk/Aktuelt/Arkiv/2012/Oktober/12_10_08B.aspx

IEEE (2009): Cold Load Pickup Issues. A report to the Line Protection Subcommittee of the Power System Relay Committee of The IEEE Power Engineering Society prepared by working group D1

Jensen, K. A. (2010): Dimensionering af varmepumpen er vigtigst.
www.tekniq.dk/PresseOgNyheder/Nyheder/2010/Marts/Dimensionering-af-varmepumper-er-vigtigst.aspx

Johansen, K. (2012). Email correspondence

Lawhead, L., J. Horak, V. Madani and M. Vaziri (2006): Cold Load Pick-Up – Theory and Industry Practices

Nordjysk Elhandel, Neogrid Technologies, Aalborg Universitet, Aros Teknik og Eurisco (2012): Intelligent fjernstyring af individuelle varmepumper (IFIV).

O'Connell, N., Q. Wu, J. Østergaard, A. H. Nielsen, S. Tae Cha, Y. Ding (2012): Day-ahead tariffs for the alleviation of distribution grid congestion from electric vehicles. Electric Power Systems Research 92 (2012) 106–114.

Pleat, G. (2012): Allowing for Off-Peak Price Incentives to Reduce Electric Vehicle Distribution Grid Congestion. The electricity Journal, Vol. 25, Issue 6.

Schleicher-Tappeser, R. (2012): *How renewables will change electricity markets in the next five years*. Energy Policy 48 (2012) 64–75.

Sundström, C. and C. Binding (2012): Flexible Charging optimization for electric vehicles considering distribution grid constraints. IEEE transactions on smart grid, vol. 3, no. 1, march 2012

Vinter, P. and H. Knudsen (2009): Using continuous state estimation in grid planning. CIRED 20th International Conference on Electricity Distribution Prague, 8-11 June 2009. Paper 435.

Interviews and discussions

- Danish Energy association
- DONG Energy Eldistribution
- EnergiMidt
- Galten Elværk
- SEAS/NVE