Efterfrågeflexibilitet på en energy-only marknad

Budgivning, nättariffer och avtal

Elforsk rapport 13:95

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Preface

Demand-side response - customers responding to a signal to change the amount of energy they consume at a particular time – has the potential to lower electricity bills, enhance security of supply and contribute to sustainable development.

Because demand-side response is likely to increase significantly in the years to come, Elforsk Market Design commissioned Sweco Energy Markets to investigate how demand reductions can best be integrated into electricity markets, and to provide insights on how the benefit from flexible consumption can be maximized. This report is a development on a previous study commissioned by the Swedish Ministry of Enterprise, Energy and Communications on the effects to the electricity system of hourly metering, and also carried out by Sweco Energy Markets.

The Elforsk Market Design research programme has been operating for more than 10 years. Over the time the focus has shifted from the national to the Nordic and to the European level. For more information about our research, finished reports please visit our website at www.marketdesign.se.

Johan Linnarsson,
Secretary of the Market Design programme

Stockholm, November 2013

Utökad svensk sammanfattning

I slutet av 2011 presentade Sweco Energy Markets en rapport om systemeffekterna av timvis mätning till Näringsdepartamentet[1]. I denna rapport påvisades en samhällsekonomisk vinst vid hjälp av så-kallad efterfrågeflexibilitet (DR). Studien indikerade en årsbesparingspotential motsvarande 3,7 miljarder kr för svenska slutanvändare av el. Den samhällsekonomiska vinsten uppskattades till 92 miljoner kr årligen. Samma studie pekade på stora svårigheter i att säkerställa denna potential, även om full tillgång fanns till budkurvor (köp- och säljbudkurvor) från spotmarknaden. Projektet 'Efterfrågeflexibilitet på en energy only-marknad' är en fortsättning på 'Systemeffekter av timvis mätning'. Frågeställningen som denna studie ämnar besvara är: hur kan det säkerställas att den fulla potentialen tillgodogörs marknaden, och hur ser en sådan integration ut. Denna studie inkluderar enbart hushåll och så-kallad återvändande last, alltså inte priskänslighet och energieffektivisering.

Det finns flera olika teknologier och tillämpningar av DR. I denna studie så har två olika simulerats i de kvantitativa analyserna. Den första metoden för att simulera DR har varit genom att utgå ifrån dagens kommersiellt tillgängliga produkter där användare erbjuds så-kallad smart utrustning som optimerar energianvändningen för ett hushåll genom att ta del av de publicerade spotpriserna på el, och konsumera mindre/mer under höga/låga priser. Den andra ansatsen var genom så kallad *demand-side management* (DSM). Detta motsvarar det som ofta benämns som aggregator, där en aktör centralt styr DR för de aggregerade hushållen.

En storskalig utrullning av DR är förväntad att ske gradvis. Därför har tre olika nivåer av antal aktiva (DR) hushåll simulerats, förutom bas-fallet (0 hushåll med DR). De tre olika nivåer motsvarar 10 000, 100 000 samt 700 000 hushåll. Skillnaden mellan dessa tre olika nivåer är volymen på flexibilitet, alltså hur många MWh/h som kan planeras om till omkringliggande timmar.

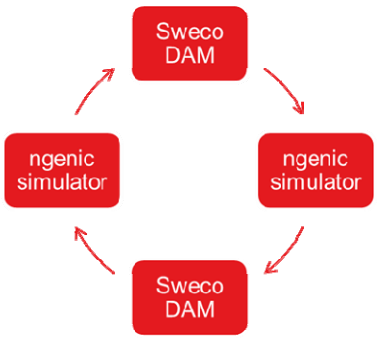
För att besvara frågeställningen har dels flera olika marknader (day-ahead, intradag, balansmarknaden) analyserats separat för att hitta vilken marknad som är mer gynnsam för efterfrågeflexibilitet, dels simuleringar av prispåverkan på day-ahead marknaden (spot). Med tanke på den termiska trögheten och känsligheten i ett sådant dynamiskt system (som det termiska klimatet utgör i ett hushåll) så har day-ahead marknaden identifierats som den marknaden med bäst förutsättningar för efterfrågeflexibilitet.

[1]Sweco Energy Markets: Systemeffekter av timvis mätning. En rapport till Näringsdepa rtementet, 2011

Två olika simuleringsansatser av DR har genomförts. Båda simuleringsansatserna bygger på marknadsdata från 16 olika referensveckor för de svenska elområdena under perioden 2010-2012. Dessa 16 referensveckor valdes ut för att representera såväl höga som låga priser, samt representera de olika säsongerna. Systemet som simulerades bortsåg från utlandsförbindelser, vilket gör att resultaten inte direkt kan överföras till dagens marknad och system. Praktiskt så resulterade denna förenkling av marknaden till ett mer volatilt system med avseende på prisbildningen. För simuleringarna så användes två modeller:

- Sweco DAM. En optimeringsmodell som efterliknar Nord Pool Spot. I Sweco DAM så beräknas marknadspriset mellan utbud och efterfrågan genom att maximera den så-kallade ”social benefit” funktionen.
- Ngenic DSM. En optimeringsmodell som minimerar uppvärmningskostnaden för slut-användare av el genom att ta hänsyn till rådande innetemperatur, framtida temperaturer (prognos) och styrning av värmepump.

Två olika metoder för simulering av DR på day-ahead marknaden simulerades. Dessa var ”reaktiv DR” och ”explicit DR”. Med reaktiv DR så antas slutanvändarna reagera på tidigare publicerade priser (från Day-ahead marknaden), vilket får en viss prispåverkan beroende på vald referensvecka och antal hushåll som antogs vara aktiva. Rent praktiskt så simulerades marknadspriset med hjälp av de historiska köp- och säljkurvorna från Nord Pool Spot, som sedan inkluderades i Ngenic DSM där nya konsumtionsprofiler beräknades, som importerades till Sweco DAM, etc. Se figur nedan för illustration av beräkningsmetodiken.



Figur 1. Schematisk illustration av metodiken för simulering av reaktiv DR och Sweco DAM och Ngenic DSM.

Hypotesen var att resultatet från de olika iterationerna skulle konvergera, alltså att jämvikt mellan elpris och DR skulle uppnås.

Med explicit DR så presenteras ett nytt slags bud som inkluderas i pris-formationen på spotmarknaden. I simuleringen av explicit DR så beräknade Ngenic DSM hur stor flexibilitet som hushållen kunde bidra med på marknaden, utan att ge avkall på komfortkriterier (±2˚C) med hänsyn tagen till nuvarande, framtida temperaturer (prognos) samt en maximal ackumulerad obalans. Den uppskattade flexibiliteten användes i 'Sweco DAM' för att maximera "social benefit", och för att ge ett nytt optimalt marknadspris. Schematiskt så var beräkningsmetodiken enligt figur nedan.

Figur 2. Schematisk illustration av metodiken för simulering av explicit DR och Sweco DAM+Flexbids och Ngenic DSM.

Hypotesen för explicit DR var att det skulle bli ned- och uppreglering på konsumtionen under de timmar som det var mest optimalt, d.v.s. att ta hänsyn till DR under prisbildningen på day-ahead marknaden.

Resultat och slutsatser reaktiv DR

Prispåverkan för reaktiv DR var modest för mindre penetrationsgrader av aktiva hushåll. Prispåverkan varierande mellan de olika referensveckorna, men det var först i fallet med 100 000 hushåll som en signifikant påverkan av prisbildningen kunde observeras i simuleringsresultaten. För fallet med 700 000 hushåll så var påverkan mycket betydande. En slutsats var även att resultaten inte konvergerade för de olika iterationerna, vilket kan vara problematiskt vid en storskalig implementering av DR enligt denna metodik (i grund och botten dagens marknadsdesign med priser som slutkonsumenter tillåts reagera på i efterhand). I ord så kan icke-konvergensen förklaras genom; det som är fördelaktigt och effektivt för den enskilde, är inte nödvändigtvis bra för kollektivet. Den samhällsekonomiska vinsten ökade för fallet 10 000 respektive 100 000 hushåll, vilket indikerar att det är gynnsamt från ett samhällsperspektiv såvida inte ett visst *tröskelvärde* överskrids. I fallet med 700 000 hushåll så minskade den samhällsekonomiska välfärden markant, primärt till följd av att lastförflyttning orsakade fler nya, högre prisspikar jämfört med ursprungsfallet.

Prispåverkan i fallen med höga penetrationsnivåer kommer eventuellt att leda till en misstro gentemot spotmarknaden vilket kan få dramatiska påföljder. Eftersom spotpriset används som referens för de finansiella marknaderna, vilket bygger på ett marknadsförtroende, så kommer ett minskat förtroende även leda till minskat förtroende för den finansiella marknaden. Detta kan senare leda till nya marknadsplatser för el alternativt nya produkter som referens, vilket är att betrakta som icke önskvärt.

En annan aspekt av reaktiv DR är utmaningen för systemoperatörerna att bibehålla den momentana balansen mellan produktion och konsumtion av el i transmissionsnätet. Vid en viss prisklarering på day-ahead marknaden så kommer en storskalig användning av DR sannolikt leda till spekulation på intradag samt balansmarknaden. Dagens likviditet och volymer på intradag marknaden i Norden bedöms inte kunna hantera volymer motsvarande fallen med 100 000 respektive 700 000 aktiva hushåll. Såvida dessa uppkomna ”obalanser” inte hanteras på intradag-marknaden så kommer stora volymer balanskraft behövas för att hantera obalansen mellan produktion och konsumtion för att upprätthålla kraftbalansen.

Resultat och slutsatser explicit DR

Prispåverkan för fallet med DR inkluderad explicit i marknadsklareringen på day-ahead marknaden var måttlig för fallet med 10 000 aktiva hushåll. I fallet med 100 000 hushåll så var påverkan betydande, och i 700 000 fallet så var prispåverkan mycket betydande. Med en ökad andel aktiva hushåll så ökade flexibiliteten, vilket ger ökad samhällsekonomisk vinst jämfört ursprungsfallet i simuleringarna. Värt att nämna så ger fallet med 700 000 (mycket) liten prisvariation vilket kannibaliserar på incitamenten för hushåll att tillämpa DR (besparingen/incitamenten sker genom minskade råkraftkostnader). Detta scenario kan därför tolkas som hypotetiskt eftersom på en sådan marknad kommer aldrig hushållen på marginalen att investera i nödvändig utrustning för att tillämpa DR. Detta gäller vid ersättning enbart via prisdifferenser mellan hög- och lågpristimmar. Värt att nämna är att det finns andra marknader/incitament som eventuellt kan vara aktuella för efterfrågeflexibilitet, t.ex. genom kapacitetsersättningar.

Budformaten som användes i simuleringarna är praktiskt tillämpningsbara både från ett tekniskt perspektiv (prisalgoritmen på dagens spotmarknad) och för aggregatorer (kompetens om kunders förbrukning och komfortbehov).

Utöver analysen och simuleringarna för day-ahead marknaden så har kvalitativa resonemang förts kring DR och potentialer för distributionsnät. Kostnaden av elnätsdistribution är inte obetydlig för totalkostnaden för en slut-användare av el. Det finns flera olika potentiella områden som kan gynnas av DR. Fyra av de potentiella användningsområdena diskuteras i denna studie:

A. Förenkling av integrering av intermittent förnybar elproduktion
B. Minimera kostnad mot överliggande nät
C. Minimera distributionsförluster av el
D. Undvika överbelastning vid spetslast på olika nivåer i distributionsnätet

Generellt för de olika potentiella användningsområdena av DR som en del av optimeringen av distributionsnät kan nämnas att nätregleringen troligtvis skulle behöva tydliggöras för att ”väcka” potentialen.

Förenkling av integrering av intermittent förnybar elproduktion

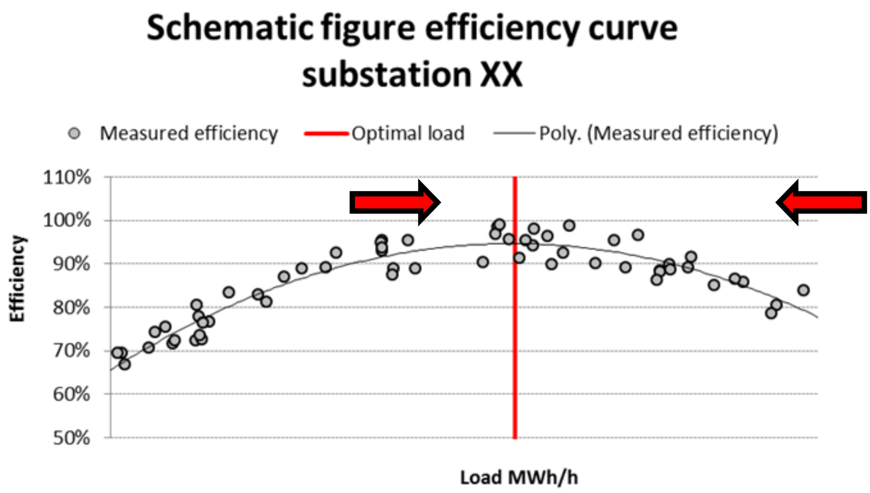
Vid integrering av intermittent förnybar kraftproduktion så som sol- eller vindkraft så ställs nya krav på distribution och transmissionsnäten till följd av mer distribuerad kraftproduktion. Näten byggdes ursprungligen principiellt för centraliserad produktion (kraftproducerande anläggningar), och decentraliserad last (konsumtion sker primärt distribuerat i elnäten). När så kallad decentraliserad produktion ökar kan kraftflöden förväntas "vända" i distributionsnäten vilket eventuellt kan vålla problem eftersom de inte dimensionerats/designats för detta användande. Vid dessa nya eventuella krav på näten är den klassiska lösningen att förstärka befintliga nät, dock kan DR vara ett eventuellt alternativ till klassisk förstärkning. Principiellt så används DR genom att öka konsumtionen under de timmar då den lokala produktionen är hög, samt minskas under de timmar då produktionen är låg. Detta kommer att avlasta nät och utrustning genom att den transmitterade effekten kommer att minska både vid inmatning samt uttag från nätet. En annan synergieffekt som uppkommer är minskade distributionsförluster, eftersom den transmitterade energin kommer att transmitteras kortare avstånd samt att den totala transmitterade energin kommer att minimeras.

Minimera kostnad mot överliggande nät

Genom att minska konsumtionen under de timmarna då maximal årseffekt uppnås (här förenklat definierat som årshögsta uppmätta genomsnittliga effekt under en given timme) så minskas även effektkostnadskomponenten för en lokalnätsägare. Detta ger incitament för kollektivet att reducera deras konsumtion under dessa timmar. Syftet är att denna kostnadsreduktion fördelas över kollektivet (elnätsbolag samt kunder genom minskade nättariffer).

Minimera distributionsförluster genom optimal last i transformatorstationer och ledningar

Vid distribution av elektricitet så är förluster oundvikliga. Det finns såväl tekniska som icke-tekniska (stölder, mätarfel, etc.), i denna rapport hanteras enbart tekniska förluster. De tekniska förlusterna i ett normalt, väl fungerande distributionsnät är ca 5 % av den totala inmatade energin. Totalverkningsgraden beror på en mängd olika parametrar, och vid varje driftläge så finns det en besparingspotential genom att öka eller minska konsumtion för att hamna närmare "optimum", vilket betyder en maximering av totalverkningsgraden för ett distributionsnät. En schematisk illustrering av totalverkningsgraden i en fördelningsstation kan ses i figuren nedan.



Figur 3. Schematisk illustrering av en verkningsgradskurva för en fördelningsstation. Den optimala lasten för fördelningsstationen är indikerad med den röda vertikala linjen. De röda pilarna indikerar önskad "förändring" av lasten för att minimera förlusterna över fördelningsstationen, detta kan i teorin ske genom DR.

Det som även bör poängteras är förlusterna i ledningar. Förlusterna i distributionskablar ökar med transmitterad energi, vilket betyder att desto mer energi som transmitteras, desto högre är ledningsförlusterna. Därför bör *totalverkningsgraden* (som inkluderar förluster i kablar) maximeras i ett sådant system.

Undvika överbelastningar under spetslast

Efterfrågeflexibilitet är intressant för att undvika överbelastningar i distributionsnät, och i värsta fall strömavbrott. Principiellt är metoden liknande som den beskriven under rubriken 'Minimera kostnad mot överliggande nät' ovan, dock så är incitamenten annorlunda. Generellt så är leveranssäkerhet och säker drift ansett som det mest fundamentala ur ett eldistributionsperspektiv, varför värdet av att undvika överbelastning/ strömavbrott är att betrakta som högre än den kortsiktiga kostnads-minimeringen beskriven under rubriken 'Minimera kostnad mot överliggande nät'. Istället bör värdet av DR representeras som ett alternativ till traditionell förstärkning av distributionsnätet.

Summary

This study is a continuation of a study conducted during 2011[2]. This study aims to address which markets are more beneficial, mainly from a technical perspective, for demand response (DR). The most suitable market for DR appears to be the day-ahead market. This is due to the planning horizon (12-36 hours planning horizon before the delivery hour) and the dynamic thermal system a residence consists of. The dynamic thermal system is sensitive to variations (price, energy, temperature fluctuations, etc.) why predictability is preferred for a stable and reliable inclusion of DR on the market.

This study includes simulation using two different models:

- **Sweco DAM.** An optimization model similar to the Nord Pool spot market model. This model maximizes the social benefit function, yielding the market price and turnover at equilibrium between supply and demand for a given hour.

- **Ngenic DSM.** An optimization model that minimizes the cost of electricity consumption for residential end-consumers. The model takes into account comfort criterion (temperature), forecasted temperatures, and efficiency curves in a given heat pump, etc.

There are several available technologies and methodologies for utilizing DR, where this study assesses and simulates two approaches; "reactive DR" where the consumers react to a pre-determined spot price, and "DR explicitly" where DR is explicitly included in the price algorithm. The first methodology, reactive DR, is to be considered similar to today's market setup where the end-consumers are exposed to a pre-defined (spot) price of electricity and left freely to react (revise consumption) upon these prices. In practice this typically decreases consumption during peak-load (high prices) and increases consumption during off-peak (low prices). In practice this was simulated using an iterative process where Sweco DAM was used to simulate spot price, and later Ngenic DSM was used for simulating the reactive DR on these previously calculated prices. The resulting DR from Ngenic was then imported into the Sweco DAM model, where new prices were calculated which later was inserted into the Ngenic DSM, and so on. The hypothesis was that the price would converge for the simulated hours within a number of iterations. If the solution would converge then the market would adapt and "learn" the behavior of end-consumers, yielding a market equilibrium equal to or near optimality. In the case of non-convergence the market is not able to "predict" end-consumer behavior, yielding systematic imbalances between the DAM market equilibrium and the "real" balance between demand (load) and supply.

[2] "Systemeffekter av timvis mätning", Sweco Energy Markets, 2011-12-30

The second methodology, including demand flexibility in the price formation, corresponds to an optimal allocation of demand response already in the day-ahead market, maximizing the social welfare function. The maximal *feasible* DR was estimated using Ngenic DSM taking comfort criterion and temperature forecasts into account. Furthermore, the maximal cumulative imbalance (deviation from the “normal” consumption pattern) was estimated. This flexibility was then inserted into Sweco DAM where an optimal market price was calculated taking the *feasible* DR into account and maximal accumulated imbalance. The objective function was still maximizing the social benefit function.

The two different simulation methodologies were simulated using three different scenarios of active households: 10.000, 100.000 and 700.000 active (DR) households.

For the simulations historical data from Nord Pool spot was used. 16 different weeks were chosen between year 2010 and 2012. The 16 weeks represented low and high prices, and the different seasons (summer, winter, etc.) in the Nordics. In order to keep complexity and data at a reasonable level, only the four different price areas in Sweden (SE1-4) were included in the simulations, meaning the other price areas on the Nord Pool market were excluded. Trade to neighboring regions was disregarded, yielding a hypothetical system. The system is more volatile than the actual Nord Pool market, which means absolute results and findings should be dealt with caution when compared directly to the Nordic market and historical market data.

The results from the two different simulation methodologies resulted in significantly different results. Alternative 1, reactive DR, yielded little impact on the price formation for the 10.000 scenario and since there was little impact the results converged. However for the larger penetration scenario, 100.000 active households, the results were more significant and the solution was non-converging for several of the simulated weeks. The spot price of electricity changed compared to the reference case (no DR) and depending on the iteration, the DR varied. For the 700.000 households scenario the price impact was severe, and the solution did not converge. The social benefit was larger compared to the reference case for both the 10.000 and 100.000 scenario, however was decreased for the 700.000 scenario. This was due to more incurred price spikes when consumption was rescheduled to other hours than at the reference case, thus reducing social welfare.

In alternative 2, where DR was explicitly included in the price formation, the results were more consistent. With an increased share of active households, a larger social benefit was attained. The price formation was, similar to the results in alternative 1, not affected significantly in the 10.000 scenario. In the 100.000 case there was a more significant effect on the price formation (reduced volatility and the avoidance of price spikes) compared to the reference scenario. In the 700.000 scenario, the price formation was severely affected, yielding very small volatility (as in near completely flat price structure). As DR was explicitly included in the price formation the problem with non-convergence was not applicable (no iterations). It should however be noted that the 700.000 scenario is highly hypothetical as with such small variations in the price pattern, there are no incentives for investing in technology needed for such a solution taking only the cost of electricity consumption into account.

Furthermore, the electricity spot price indications (high/low spot price) might be significantly different from local distribution grid congestion. The end-consumer costs for the distribution of electricity can be a significant share of the total end-consumer costs. Generally, in order to ensure the true potential of DR in a distribution grid a revision of the regulation of electricity distribution is needed. There are several different applications where DR could be utilized in order to improve efficiency on a local perspective, where the following four are elaborated upon:

A. Enabling integration of intermittent renewable energy sources

B. Minimizing the costs for transmitting energy from the transmission grid for a distribution grid company

C. Minimizing distribution losses by ensuring an (more) optimal load in both the primary substation and in the distribution lines (cables)

D. Avoiding black-outs during critical peak-load

The simulation results (both in alternative 1 and 2) indicates that a large penetration of DR should be included in the day-ahead market clearance. If it is not included in the price formation then a systematic deviation between the “real” demand (load) and supply situation and the market equilibrium in the DAM market clearance, possibly reducing the credibility in the spot price with the current market design.

Table of contents

1 Introduction

1.1 Background

A study[3] conducted during the end of 2011 by Sweco Energy Markets indicated that there was a significant potential of utilizing demand response on both the day-ahead market and balancing market(s). The generalized annual savings potential was estimated to 3.7 billion SEK for end-consumers. The increase in annual social benefit was estimated to 92 million SEK. The same study also indicated the complexity of utilizing demand response optimally; even when the information[4] was fully available. Market participants speculating in demand response and utilizing it via “speculation” will most likely lead to sub-optimal operation and poor performing market(s). This study aims to assess and compile recommendations of how consumption flexibility can be utilized in the power market, and suggestions on how the benefit from flexible consumption is maximized.

Since 1st of October 2012, customers with a fuse ampere rating below 63 Ampere, have the right to get their power consumption measured per hour instead of per month which has earlier been standard procedure. If the customer does not demand hourly measurement, it is up to the grid owner to decide whether the customer should be measured per hour or per month. Today almost all grid owners choose to keep these customers measured monthly since the benefit of hourly measurement is considered lower than the cost of changing to hourly measurement. However as new and better technical solutions reach the market; costs related to switching from monthly to hourly measurement will decrease. Most likely we will see a development where a significant share of end-consumers is hourly measured in a not too distant future. This creates an opportunity for retailers to offer customers power contracts in a combination with control equipment that can control when during the day power is consumed, so that customers can benefit from moving power consumption from hours with higher price to hours with lower price. With hourly measured power consumption it is also possible to set grid tariffs in a way that gives power consumers incentives to optimize grid usage by minimizing consumption during congested hours.

With changes like the ones mentioned above, major regulating resources are being brought to the market. One million power heated households with control equipment to regulate when during the day to turn on the heating

[3] Systemeffekter av timvis mätning: en rapport till Näringsdepartamentet, 2011-12-30
[4] Full access to both buy and sell curves.

system, would create a regulating resource of at least 2 000 MW up or down. Power consumers contributing to balance the power system is fundamentally positive as it reduces the risk of too much market power at the hands of some market players, it helps stabilizing power prices and it creates opportunities for intermittent power sources such as wind- and solar power. This can be described both as an opportunity and a risk for the TSO.

The discussion on demand flexibility has so far been on an overall level without any further analyzes on how increased demand flexibility practically can be included in the market. It could be questioned how today's market institutions, regulatory framework, tariffs and contracts are adapted to the resource that demand flexibility represents. Today's market is mainly built on the assumption that power production is regulated to meet the non-flexible power demand – customers are passive and producers are active. This report intends to give a deeper understanding in what the effects of increased demand flexibility would be.

1.2 Current market model

Today's Swedish/Nordic market model is an "Energy Only Model". This model means that market participants get paid/charged per generated/consumed MWh, in contrast to a capacity market where market participants get paid for keeping capacity resources available to the market in addition to getting paid per generated/consumed MWh.

On today's day-ahead market hourly bids and offers are sent to Nord Pool Spot by all market participants each day at latest 12.00 o'clock. Based on these bids and offers, plus volumes coming in/going out on interconnectors to neighboring markets, a spot price for each hour of the next day (12-36 hours ahead) is settled in each bidding area.

Most consumers/producers do not consume/produce the exact amount of power that they forecasted when submitting their bids/offers to the spot market the previous day. This effectively means that there will be an imbalance between load and generation if no further trade is done. Since there has to be balance between load and generation at all points in time, secondary markets must be introduced. Therefore there is an intraday market where market participants can buy/sell power to settle forecast errors up to one hour before the delivery hour (called 'Elbas' in the Nordic power market). As a last resort the TSO balances the market within the delivery hour by ordering more/less power generation, or in some rare cases more/less power consumption, from the balancing power market(s). Below these three markets are explained more in detail. This report will study how increased demand flexibility is best handled in this process and what effects this would have on the market.

1.2.1 Day-ahead market

The spot price, which is the reference price for financial contracts, is settled on the day-ahead market at Nord Pool Spot. As mentioned above an hourly spot price for the days 24 hours is settled for each of the bidding areas based on bids/offers made at 12 o'clock the day before delivery and scheduled flow on the interconnectors to neighboring markets. The credibility of the spot price and that it actually reflects all power demand and supply on the market plays a key role on the Nordic power exchange, since the spot price works as a price reference for settlement of all financial contracts.

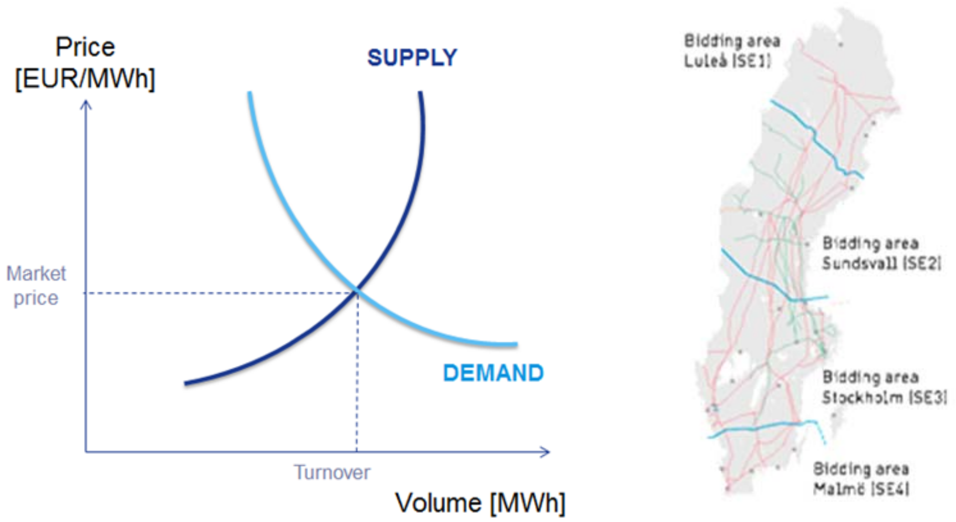


Figure 1. The four bidding areas in Sweden and the supply and demand curves on the Nord Pool Spot market. Source: Nord Pool Spot.

If forecasting errors regarding power consumption or generation are identified before the actual hour of delivery, there is still one chance for the market participants to compensate for this before being omitted to the TSO operated balancing power market(s). Up to one hour ahead of delivery, power can be traded on the intraday market called Elbas. The prices on Elbas are determined by what the market participants believe that the balancing price will become.

Elbas is a good tool to correct smaller deviations from scheduled consumption or generation. It should however be noted that volumes traded on Elbas is usually small, and it is at present not feasible to buy/sell larger volumes here at a reasonable price level.

The (average) unit price on the intraday market of Nord pool is generally in the close range of the previously set spot price. However, a major difference between the intraday market and the day ahead market is that the price is set bilaterally on the intraday market, in contrast to the marginal pricing applied on the day-ahead market. This means that “first come- first served” applies. The average price (of all the bilaterally cleared bids) on the intraday market for year 2012 can be observed in Figure 2 below.

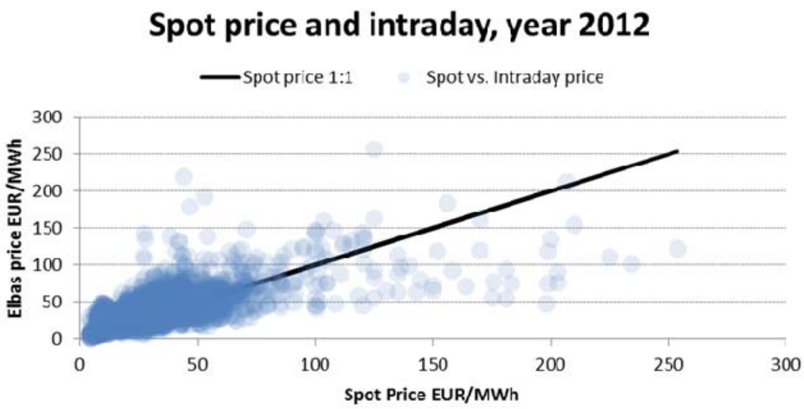


Figure 2. The average price on the intraday market for Sweden, Finland, Denmark(east and west), Norway and Kontek compared with the price on the day-ahead market (SE3) for year 2012.

In the figure above it can be observed that the average price of electricity on the intraday market is correlated to the spot price of electricity. The distribution around the spot price can be illustrated as a histogram, see the figure below. From the histogram it can be concluded that the price of electricity on the intraday market generally was higher than the price of electricity on the DAM 2012.

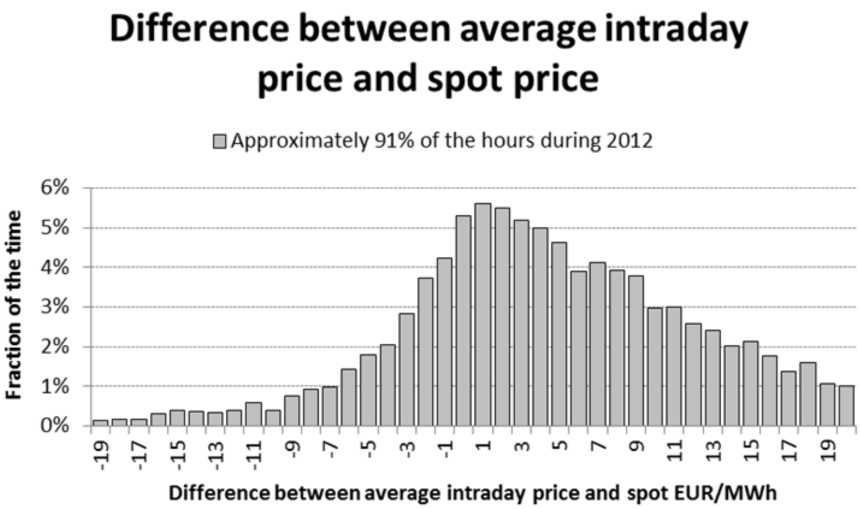


Figure 3. Difference between average intraday price and spot price during 2012. The distribution is slightly skewed towards the right tail (higher prices on intraday compared to the day-ahead).

1.2.2 Balancing power market

The imbalance during the hour of delivery is adjusted for by the TSO, by ordering more/less generation on the balancing power market. On the balancing power market participants (historically producers) offer increased/reduced generator load of a curtain volume and a certain price, so that a bid ladder is formed. The TSO then buys/sells the volumes of balancing power in order to balance the system according to Merit-order in the bidding ladder. The price of the last bought/sold MWh settles the balancing price for each specific hour. The distribution of up- and down regulation during year 2012 can be observed in the figure below. Approximately 45 % of the time during 2012 there was down regulation, 22 % of the time the system was in balance and 33% of the time there was up regulation.

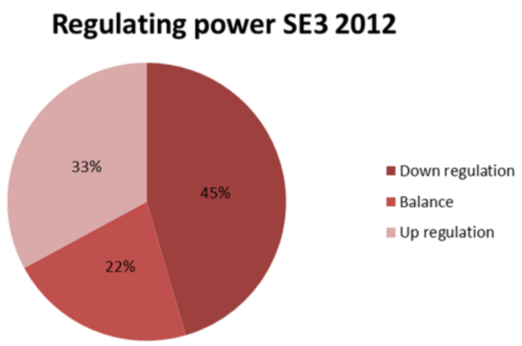


Figure 4. Share of the time with up and down regulation for SE3 during 2012.

If the TSO has to buy balancing power the market is up regulated and the balancing price is higher than the spot price. If the TSO has to sell balancing power the market is down regulated and the balancing price is lower than the spot price. Since 1 January 2009 different rules apply to producers and consumers on how balancing costs are calculated. If you're a consumer you get to buy/sell your balancing power at the balancing price, whether this is higher or lower than the spot price. As a producer you get to buy/sell your balancing power at the least beneficial of the spot- and the balancing price.

Consumers pay spot price for the volume bought on the day-ahead market. If no trades are made on the intraday-market, one of the following four alternatives applies to consumers that are imbalanced:

1. The actual consumption is higher than the volumes bought on the day-ahead market, while the market is up regulated. This means that the consumer will have to pay a higher price for the balancing power, than the power bought on the day-ahead market, and thus loses money on the forecasting error.
2. The actual consumption is higher than the volumes bought on the day-ahead market, while the market is down regulated. This means that the consumer will get to pay a lower price for the balancing power, than the power bought on the day-ahead market, and thus actually saves money on the forecasting error.

3. The actual consumption is lower than the volumes bought on the day-ahead market, while the market is up regulated. This means that the consumer will sell back balancing power at a higher price than the power was bought for at the spot market and therefore saves money on the forecasting error.
4. The actual consumption is lower than the volumes bought on the day-ahead market, while the market is down regulated. This means that the consumer will sell back balancing power at a lower price than the power was bought for at the spot market and therefore losses money on the forecasting error.

The price of regulating power is correlated to the spot price of electricity. The variation of the price of regulating power during year 2012 compared to the day-ahead price of electricity can be observed in the figure below.

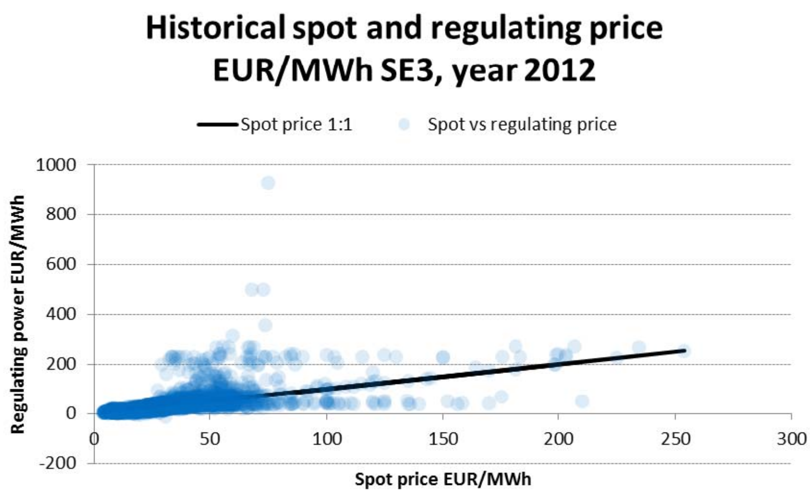


Figure 5. Figure illustrating the correlation between the spot and regulating power for SE3 during 2012.

The distribution of the difference between the price of regulating power compared to the spot price of electricity can be observed in Figure 6 below. From the figure it can be concluded that the difference in price relative to the DAM price is relatively symmetric, i.e. the price of down-regulation relative to the DAM price is relatively similar (in absolute terms) to the price difference of up regulating power. A tendency of a slightly larger price difference for the down regulation power (negative price difference) compared to the up regulation power price (positive price difference) can be observed in the figure below illustrating year 2012.

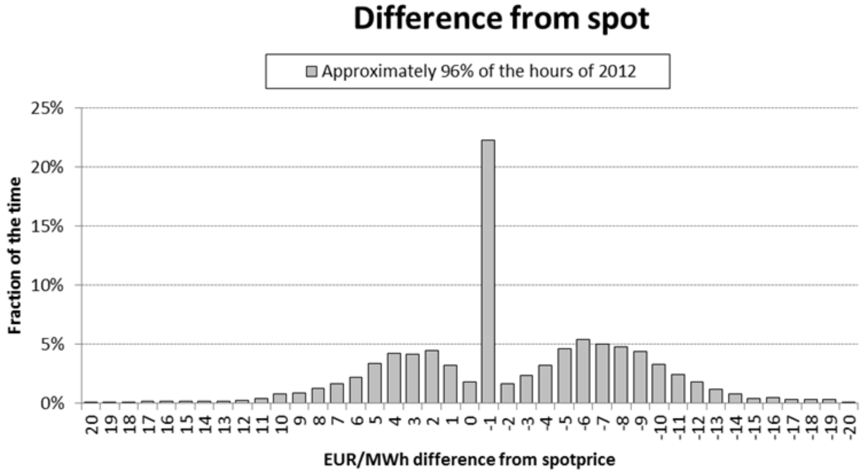


Figure 6. The difference in price for regulating power compared to the spot price of electricity during year 2012. During 22 % of the time the system was "balanced" (regulating price equal to spot price), hence the high column in middle (0 to -1 EUR/MWh).

1.3 Consumption flexibility – All parts must work

The spot price, since it's the reference for the financial market, is a fundamental part of the Nord Pool model. This is due to the spot price being the reference price for the financial market. The reason why is that it has credibility of being as the balance between supply and demand, and is considered to reflect the "true" equilibrium between these two entities. The actual equilibrium is *often* revised due to forecasting errors, which are inevitable (demand, supply via intermittent generation sources, outages, etc.). The imbalance between the day-ahead and the actual equilibrium is resolved via other markets (intraday, balancing markets) with a gate closure closer to delivery. If the spot price fails to adequately reflect the "true" situation (i.e. by neglecting considerable amounts of demand response due to price signals) there will be a systematic deviation from the "true" equilibrium, which then could result in reduced credibility in the spot price. The credibility of the spot price is a prerequisite for a well-functioning financial power market. If such a reality approaches, a reformulation of the spot price or an alternative reference price is possibly needed in order to ensure credibility in the market.

If increasing demand flexibility is used to reschedule demand during the day this has to be considered when placing the spot market bids, otherwise larger volumes will end up on the intraday or balancing power market. Not only would this constitute credibility problem for the day-ahead market, it would also cause very high balancing prices and make balancing of the system more challenging for the TSO. Worth mentioning is that the liquidity on today's intraday market is not sufficient to handle volumes of the size discussed in this study. Another challenge is that the end-consumers have no incentives to balance consumption against the consumption forecast. During a transition period, which is troublesome to quantify and forecast the length of, the different participants on the market will experience difficulties in forecasting end-consumer behavior when the consumption is significantly changed from the standard consumption curves. Any deviation (equivalent to a large degree of penetration of reactive end-consumers) from the forecasted consumption curves will most likely yield an imbalance on the market, which needs to be resolved via one of the available institutions (intraday, balancing market(s)). It is not apparent how fast the learning curve is for market participants, and how predictable this reactive demand response will be.

Instead increased demand flexibility will require the balance responsible parties to take demand flexibility into account when bidding on the day-ahead market. If balance responsible parties do this by using a price forecast to forecast how the demand flexibility will affect the total demand for each hour, a reliable price forecast becomes very important. A poor price forecast can lead to larger errors in the demand forecast, than not considering demand flexibility in the bids at all. For example, in the extreme case, if all balance responsible parties predict hour 1 to be more expensive than hour 2, they will assume that demand flexibility will increase demand by 2 000 MW hour 1 and reduce demand by 2 000 MW hour 2. If it then turns out that the price is higher during hour 2 the demand flexibility will move demand in the opposite direction from what was expected and create a forecast error of 4 000 MW during both hour 1 and hour 2.

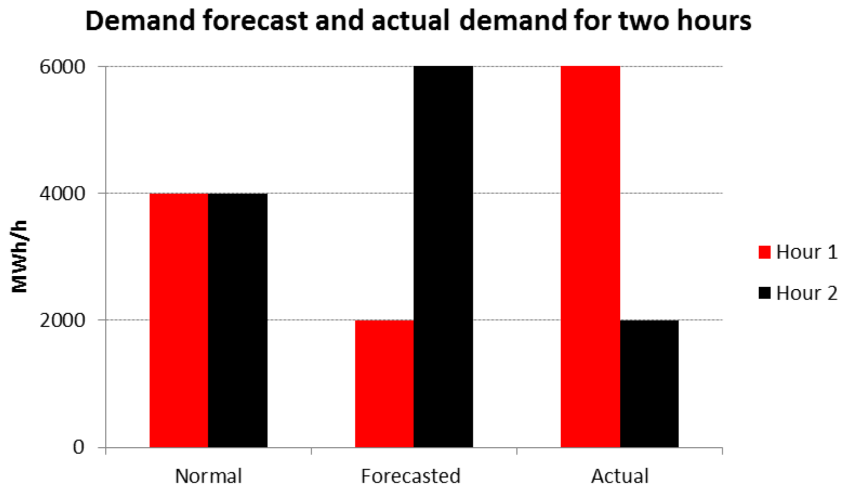


Figure 7. Forecast errors may increase as a result of demand flexibility. The figure above illustrates how a fault price forecast causes a forecast error of 4000 MWh/h for the two hours, since the balance responsible party has miscalculated in which direction the demand flexibility will move demand.

The illustrated example shows an extreme situation, and does not necessarily illustrate the outcome from demand response. The example rather illustrates a “worst case” scenario when market participants speculate in the future market price and reactive demand response.

A good alternative would be to use a bid which defines the total amount of energy needed over the day and a maximum of energy that can be bought during any single hour. The energy can then be bought at the lowest possible price, fulfilling the boundary conditions. This would minimize the volumes that end up on the balancing market. Today it exist not any type of bid similar to this at Nord Pool Spot.

1.4 The explanation of an imbalance – market by market

This chapter explains how an imbalance on the day-ahead market caused by reactive demand flexibility can be handled and what the effects are of the different possible solutions on the imbalance problem. The figure below illustrates the 36 hour period from the spot price auction at 12.00 day 0 until the end of day 1.

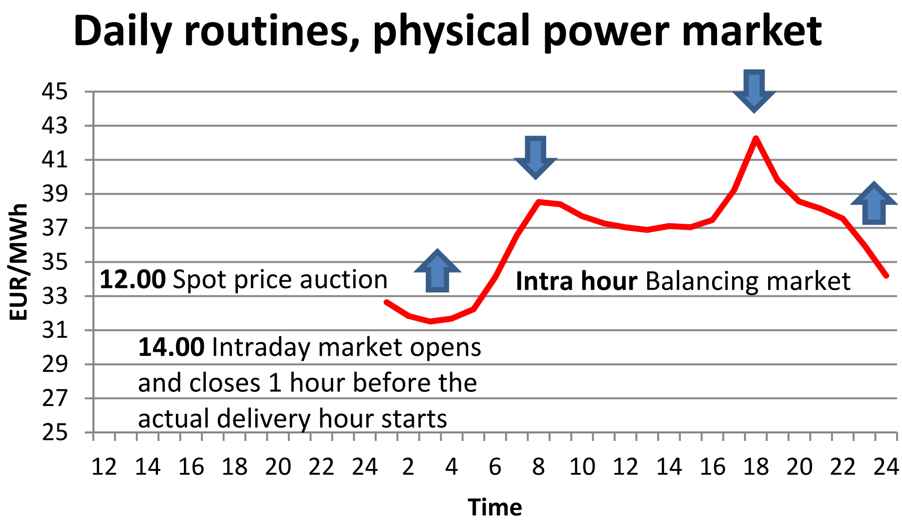


Figure 8. The figure above illustrates how the spot price is settled at 12.00 the day before delivery. At 14.00 the intraday market opens and closes one hour before the hour of delivery. Within the hour the balance between consumption and production is resolved by the TSO, whom buys/sells power on the balancing market(s). The arrows indicate the sign of the price impact demand response will have. Higher prices will yield a reduction of consumption, which yields a lower (than spot price) price of electricity on the intraday market. Lower prices will yield an increase of consumption, which yields a higher price level, etc.

With reactive demand response the balance responsible party has to take in to consideration an hourly price forecast, from which the effects of demand flexibility can be estimated, when placing its bids on the spot market. Assuming that the price forecast is perfect, the balance responsible party will be able to adequately predict the effects of reactive demand flexibility and keep forecast errors unaffected by the reactive demand response effect. The only market effect then will be smaller spot price differences in between hours during the day, as illustrated in figure 8 above, which is one of the benefits of demand flexibility.

When the spot prices are published at about half an hour after the spot auction at 12.00, the balance responsible party has a chance to revise the effects of demand responsibility based on the actual spot price and correct the errors created by a fault price forecast at the intraday market up to one hour ahead of delivery. If this is done, the demand flexibility will not create a higher demand for balancing power. However this still means that the spot price to a lesser degree reflects the actual demand/supply-situation, which is as discussed earlier negative for the reliability of the spot price and thus for the financial power market.

If the demand responsible party chose to or cannot, react on the known imbalance on the intraday market, the imbalance will remain in to the hour of delivery and the TSO will have to resolve the imbalance on the balancing market. This likely will lead to higher balancing power prices and a more difficult situation for the TSO to handle growing imbalances on the balancing market.

1.5 Demand Response (DR) vs. Demand Side Management (DSM)

Both terms are often used as equal in political as well as technical discussions. There is however a distinct difference between the two terms:

Demand Response (DR) is a **reactive** technology, mainly (but not only) with price as a trigger.

Demand Side Management (DSM) is a **forcing** technology, contracting consumers into allowing DSO's to control power consumption. DSM also includes elements of energy efficiency programs and Demand Response.

In order to handle all aspects of the energy system and be able to optimize on both single consumer *and* the social benefits we introduce a new term: **Collaborative Demand Response** (CDR). With CDR we mean that the inclusion is time-to-time voluntary, but if you join for a bid, you follow through that consumption pattern. This must be an automated system in order to work on a 24/7-basis. This is, to some extent, an instrument for including short-term price sensitivity of end-consumers.

1.6 Demand response/DSM technology

There are a number of commercially available methods to achieve DR and DSM:

Circulating cuts[5]

Technology that peaked during the 70's oil-crisis. This crude and simple technology switched electric boilers on during night time in order to even out load for small DSO's, limiting costs for DSO's and end-consumers. Still up and running at a few places in Sweden[6].

Large consumer

Load limitation and refrain production when price is too high. This is included as price sensitive bids on day-ahead market.

Power visualization

Is today the most popular way to describe DR. By visualizing the power consumption to end-consumers it often leads to energy consumption reductions as the awareness increases. However, it has been discussed how consistent and long-term these effects are.

Automated DR, day-ahead market price

A Nordic heat pump manufacturer just launched a "Smart Grid Ready" heat pump that optimizes consumption based on Nord Pool Spot prices. This is a reactive technology.

Energy storage

Expensive but effective technology in order to cope with intermittent production. For example battery storage technologies used in conjunction with distributed photovoltaic (PV) production in order to store solar power from day to night.

Load Controller

Evens out a single consumer's load by monitoring total load and controlling electric boiler/heat pump.

At present the only way of (partly) including DR/DSM on the Nord Pool spot market is by using so-called flexible hourly bids. These bids are strictly for sellers, which mean increased demand flexibility cannot be included. Furthermore, these bids do not take consecutive time steps into account, which make it difficult (if not impossible) to use for DR/DSM.

1.7 Market research

The research previously done on DR can be categorized into the following:

[5] **"Rundstyrningsrelä"**

1. Capacity of DR on a market
2. Pros and cons of DR
3. Regulation of DR
4. Remuneration of DR

Since we focus this report on the economic benefits and challenges we also have focused the market research around 2 and 4.

Pros and Cons of DR

Most studies focus on the technical aspects of DR, also when including more intermittent production (wind and PV) and the cost of introducing this kind of technology [“Economic comparison of technical options to increase power system flexibility” by Juha Kiviluoma, Erkka Rinne, Niina Helistö, Wind Integration, Energy Systems, VTT Technical Research Centre of Finland]. There are several reports with simpler simulations of the change of market prices when introducing large scale DR [“Load Profile Reformation through Demand Response Programs”, Pouyan Khajavi and Hassan Monsef, School Of Electrical Engineering, University of Tehran]. Much previous work in calculating social welfare benefit is primarily done in a Capacity market model [An Economic Welfare Analysis of Demand Response in the PJM Electricity Market, Rahul Walawalkara, Seth Blumsack, Jay Apt, Stephen Fernands, Carnegie Mellon Electricity Industry Center, Department of Engineering & Public Policy and Tepper School of Business, Carnegie Mellon University].

The only report we found that addresses the same problem domain as we have investigated is based on a model made of theoretical assumptions instead of live data. The results presented in the report comes to the same conclusion and shows that under certain conditions the reactive DR can cause a non-converging price curve and actually increase the total cost for the consumer. [“Markets 3.0 - The Impact on Market Behavior of Integrated Demand Side Resources”, Ralph Masiello, Fellow, IEEE; Farnaz Farzan, Jessica Harrison, Kristie DeIuliis.

Renumeration of DR and Market design

The common theme about remuneration of DR is that it should be driven by the economic benefits of moving consumption to off–peak hours and therefore it is hard to find enough benefits for the investments of distributed DR into the household sector. [“Economic comparison of technical options to increase power system flexibility” by Juha Kiviluoma, Erkka Rinne, Niina Helistö, Wind Integration, Energy Systems, VTT Technical Research Centre of Finland]. The paradox doing this is that the larger penetration, the flatter price curve, the less economic benefit will be for the consumer to invest in DR equipment, even if the social benefit is increasing the flatter the price curve gets. In order to compensate for that paradox several DR programs have tried to offer extra compensation to participants [An Economic Welfare Analysis of Demand

Response in the PJM Electricity Market, Rahul Walawalkara, Seth Blumsack, Jay Apt, Stephen Fernands, Carnegie Mellon Electricity Industry Center, Department of Engineering & Public Policy and Tepper School of Business, Carnegie Mellon University].

There are also a few recent works done addressing pros and cons of Energy-only vs Capacity market models in respect of DR [“Real-Time Pricing and Electricity Market Design”, Hunt Allcott, New York University, March 2013].

1.8 Outline of report

This report is divided into two parts. One where different scenarios are outlined and one where these scenarios are being simulated and the results are discussed. The scenarios are based on the current market design where different amount of flexible power demand is simulated. The quantitative analysis is based on two separate models, and historical data is used for both modeling of consumption flexibility as for calculating the impact on the spot market.

2 Conditions for the scenarios

In order to determine how sensitive for disturbances the day-ahead market system is we need to create a number of scenarios for a future power system. The hypothesis in the initial phase of this study was that we need to work with both granularities on the demand side as well as increased intermittent power production.

Initially several different scenarios were discussed within this project. Due to limitations of accessible market information the simulated spot market had to omit trade to exogenous regions. Therefore the system already becomes more sensitive than the actual situation today. E.g. adding 20 TWh intermittent wind power production by replacing firm capacity production would make an already volatile system even more sensitive and volatile. Keeping in mind that we are simulating a hypothetical market (SE1-4 excluding trade to neighboring regions) with a (extremely) volatile price pattern for several of the simulated weeks without modifying the supply/demand curve as is. Adding 20 TWh of wind power will approximately yield an average generation per hour of 2283 MWh/h. Simplified this will then is assumed to replace the corresponding “firm” capacity in the supply curve (for all time steps). This will add volatility to the system, making it further decoupled from the actual situation and push towards an even more hypothetical environment. Therefore, in order to keep things graspable and at a reasonable level it was decided to disregard these sensitivity scenarios and only analyze the “current” setup without revising the supply curve. The reference group therefore asked for more detailed simulations on the DR scenarios and omitting other possible DSM/DR source as well as power production. This to, further assess how to efficiently include the usage of DR/DSM on the price on day-ahead, intraday and balancing market(s).

2.1 Scenarios

Model simulations have been made for three different scenarios.

The scenarios with different levels of demand flexibility have been simulated based on three different levels of demand flexibility: 10.000, 100.000 and 700.000 residential households using demand flexibility in their heating systems.

2.2 Distribution of flexibility

This report is focused on the contribution of DR from residential stand-alone houses. This segment of the DR is frequently discussed within politics, and under consideration for legislation (European grid codes). At the same time this might be the hardest one to take control over and therefore is very interesting to have as a ground for simulation.

Stand-alone houses with heating by an electric energy source (electric radiator, electric boiler, geothermal heating, air/water heat pumps etc.) are distributed as the second row in Table 1, based on SCB municipality statistics from 2011.

- All municipalities have been attached to a price area
    - In the case a municipality is split in two areas, the area where the county town is will apply for the total municipality, this due to lack of granularity in statistics.
- The standardized consumption in these houses has then been deducted with 5000 kWh for non-heating consumption[7].
- The distribution of power consumption per price area have then been adjusted for heating power consumption

This gives the distribution of DR capacity per price area according to the table below.

Region	# Houses	Distributio	Total energy usage (MWh)	Distributed energy usag	Auxilliary usage deducted hushållsel	Distributed usage of heating energy
SE01	85 454	4,3%	1 358 809	4,9%	931 539	5,2%
SE02	178 143	8,9%	2 613 681	9,4%	1 722 966	9,7%
SE03	1 270 919	63,4%	17 841 650	64,1%	11 487 055	64,5%
SE04	468 619	23,4%	6 024 532	21,6%	3 681 437	20,7%
Total	2 003 135	100,0%	27 838 672	100,0%	17 822 997	100,0%

Table 1. Table showing the share of energy usage per bidding area in Sweden, the distribution of heating energy.

We assume in this project that penetration of DR-technology will be evenly distributed between the different price areas in Sweden. This will of course not be the case in reality, but it is still the best guess for now.

Of the two million single houses in Sweden, the capacity to utilize DR differs. Foremost are indirect heating (boilers) with electricity the most suitable, both from a storage but secondly of the energy consumption (1 kWh electricity = 1 kWh heat). Second most suitable are heat pumps connected to indirect heating (geothermal, air/water), and thirdly most suitable is direct electric heating (air/air heat pump, electric radiator).

[7] According to energirådgivaren.se

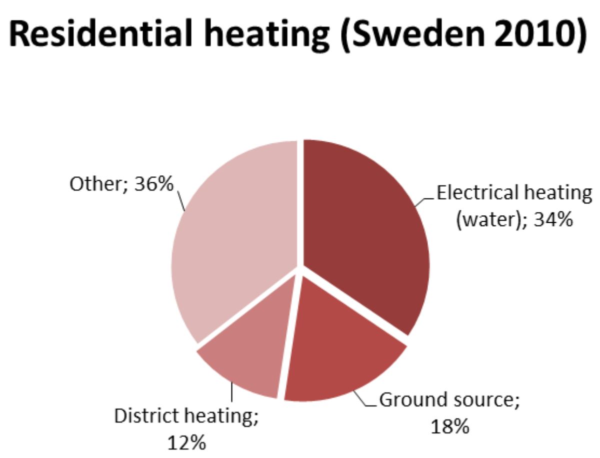


Figure 9. Distribution of residential heating technologies in Sweden.

2.3 Demand response, distribution of electricity and price incentives

This chapter includes a qualitative description of how the distribution grid can take advantage of the DR resources, and which benefits a distribution grid operator can attain via DR. It is important to emphasize that these different DR applications are not necessarily harmonized with the optimal usage of DR on the DAM, which is briefly elaborated upon under paragraph 3.9.2.

Four different applications are discussed in this chapter; however these do not represent the complete list of relevant applications for DR. The optimal operation of a distribution grid is complex, and depending on the instantaneous state of a grid, different changes of load is expected to be more or less beneficial. Example benefits are often limited to monetary terms but one could in theory also include security of supply (“reliability”), the avoidance of infrastructure investments (sometimes derived into monetary terms), electricity quality parameters, etc. The four various cases we discuss in this chapter are:

A. Enabling integration of intermittent renewable energy sources

B. Minimizing the costs for transmitting energy from the transmission grid for a distribution grid company

C. Minimizing distribution losses by ensuring an (more) optimal load in both the primary substation and in the distribution lines (cables)

D. Avoiding black-outs during critical peak-load

The potential for demand response is different during winter time than summer time, mainly because thermal inertia requires an underlying demand for electricity heating which mainly exists during the winter time. In theory this means that the ability for up regulation during summer time is large (e.g. the entire installed capacity in the heat pump) and readily available, however the demand for heating electricity is relatively low. This means that even if it is in theory possible to increase consumption, the real need for electricity will not be reduced for future time steps (i.e. electricity demand for light bulbs are instantaneous). Real consumption that is possible to reschedule (washing machine, dish washer, water heater, etc.) is central for load rescheduling.

When discussing different applications and benefits from using demand response resources in the distribution grid, it is important to distinguish between pass through and non-pass through cost components. Pass-through components are costs that are eligible for passing through to end-consumers, i.e. meaning that they do not affect the revenue of a distribution company since the full cost are being passed on to the end-consumers. The economic incentives for a distribution grid company to minimize these pass-through costs are therefore (very) small.

Generally, in order to ensure the true potential of DR in a distribution grid a revision of the regulation of electricity distribution is needed.

Enabling the integration of intermittent renewable energy sources

In general the larger production units (e.g. solar power farms, wind farms, etc.) are connected at higher voltage levels in the grid (typically the transmission grid) than the distribution grid. There is a distinction between regional generation units and electricity generation in the distribution grid. Even though there is a distinction, the theory behind the utilization of DR is similar. The main idea is to increase consumption whenever local generation is high, and decrease consumption whenever the local generation is small. This will reduce the load in the grid, in both “upstream” and “downstream” direction. Also worth mentioning is for substations where there is an optimal load mainly depending on equipment type, temperature and rated capacity. See section 3.3 for further information.

Intermittent renewable energy sources are different depending on the technology. E.g. biomass is adjustable and therefore not considered intermittent. Furthermore, biomass is at present not identified as an eligible large scale technology for distributed generation. Two more suitable technologies are photo voltaic (PV) and wind power. PVs are often considered more attractive compared to wind power in residential areas as they are relatively easily integrated in the existing architecture and does not rotate/vibrate/generate noise. However PVs are relatively area intense (i.e. a large area is needed per kW installed capacity) and have limited financial scalability compared to wind power. The generation output from these two technologies is both strongly dependent on weather and the prevailing climate, however they differ significantly. The daily PV generation seasonality is correlated with the load curve (peak load/generation during day time), and non-existent during night time. The seasonal variation of the generation for PVs is that during the winter months generation is small, and during the summer months generation is large. See the figure below for a generation output scheme per week.

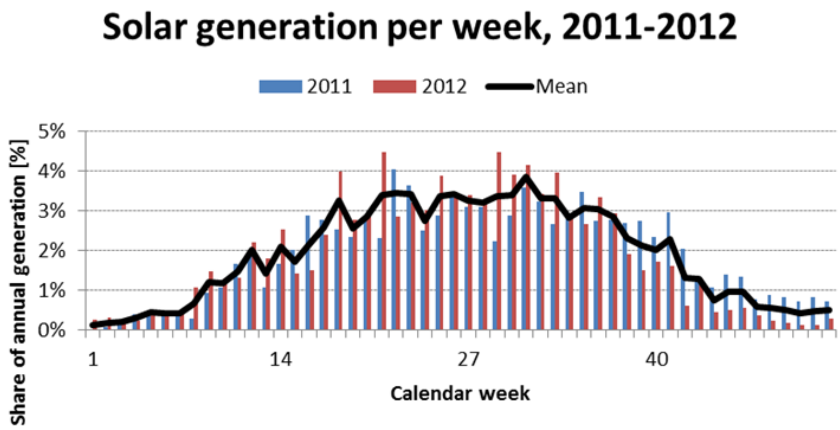


Figure 10. The distribution per week of annual generation from solar power (photo voltaics) in Sweden for year 2011 and 2012. A strong seasonality can be observed. A larger share of the annual generation occurs during summer time. Source: Svenska kraftnät.

The daily seasonality of PV generation is beneficial from a power system point of view as it is correlated with the daily consumption profile. On the other hand, the season seasonality is less beneficial since the majority of the consumption (load) occurs during winter time when there is little generation from PV. For the wind power generation, the situation is not the same. The wind power generation is actually higher during the winter period and lower during the summer period. This is correlated with the consumption. The daily seasonality is less significant as for the solar power generation; however there is a slight tendency that the wind power generation is higher during night time than day time. In general the wind power generation is more variable than solar generation, and the seasonality is not as significant as with the solar generation. See the figure below for an illustration of generation and consumption seasonality for PV, wind power and consumption per week.

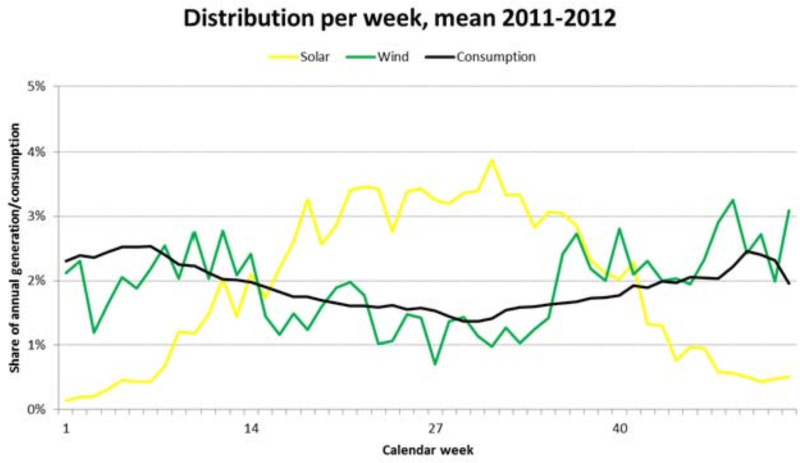


Figure 11. Seasonal variability of average generation for wind power and solar power and average consumption as share of annual generation/consumption per calendar week during year 2011-2012. The seasonality for wind power and consumption is positively correlated, whereas the generation from solar power and consumption is negatively correlated.

If the net load ("original" load minus the local generation) is smaller during the hours when local generation is reduced, it is beneficial to increase consumption during these hours in order to dampen the load curve volatility (increase low-load hours, decrease peak-load hours). This is mainly due to;

A. It will smoothen out the load in the distribution grid, making the use of resources more efficient (flatter duration curve) and possibly reduce the need for infrastructure investments.

B. Transmission loss is a function of transmitted distance and to the power flow, i.e. the longer the distance/higher the energy flow of transmission the larger transmission losses. Local generation and consumption will reduce the transmitted distance and level of energy flow, i.e. reduce the transmission losses.

The concept of net load is important to understand, as it might change the traditional peak/off-peak hours (day and night time historically) in a grid where distributed generation is significant. For instance if one is looking at a distribution grid with a large penetration PV-modules, it is expected that the annual peak-load will occur during winter time (no change in consumption, little solar power generation expected during the winter period). However, during the summer period, the peak-load in a distribution grid with a large share of PV-modules, is expected to occur during the summer holiday period when the consumption is low and generation is high (July month). This peak will most likely be smaller than the annual peak during the winter period assuming most of the generation capacity is roof-mounted PV-modules. If one assumes that the majority of the distributed generation capacity is wind power (not likely in densely populated areas, however feasible in less densely populated areas, etc.) then the summer peak-load can in theory exceed the winter peak load, since the installed capacity can be greater than the peak-load. The integration of intermittent renewable energy sources (RES) can in these cases require investments into grid infrastructure and equipment, which might hinder the development of intermittent RES. The general idea of utilizing DR when integrating RES into the grid is illustrated in the figure below.

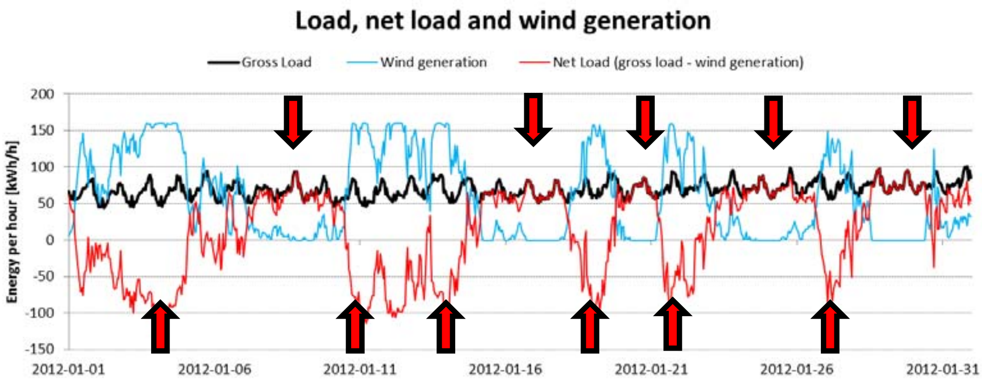


Figure 12. Schematic illustration of how to ease the integration of RES in a distribution grid. The curves illustrate original (gross) load, net load and local generation. The example illustrates wind power generation. The red arrows indicate whether consumption should be increased (arrow facing upwards) or decreased (arrows facing downwards) depending on the local generation.

If the grid infrastructure is insufficient during these time periods with large local generation, the alternative is to curtail the excess generation.

Minimizing the costs for transmitting energy from the transmission grid for a distribution grid company

A distribution grid company has several cost components, however here in this chapter we will elaborate on distribution losses and peak load tariff.

If one considers the tariffs for a distribution grid company towards the transmission grid it is often composed of the components included in the table below

Name	Unit	Description
Annual fee	SEK/year	A fixed annual fee which is independent of the energy and power volume.
Yearly Power Fee	SEK/kW/year	A fee dependent on the expected maximal power feed throughout the year ("peak-load")
Transmission Fee	SEK/kWh	A variable fee which is dependent on the volume of transmitted energy during the settlement period

Table 2. The three most common cost components in the rate plan for distribution grid towards higher voltage levels (transmission grid).

In theory, it is possible to minimize the peak-load for each year by utilizing DR. In practice it is harder since the annual-peak(s) driven by cold temperatures (at least in the Nordics) occurs during several consecutive hours and under uncertainty. The peak-load is recorded during one single hour, however the preceding and succeeding hours often have significant loads as well. In order to utilize DR during these cold days it is crucial that a) the peak load is forecasted before it occurs and b) the thermal inertia is sufficient so that no comfort criterion is violated during the event. In practice this will be hard to both forecast and cope with, since the peak load (in the Nordics) often occurs during colder, relatively long, periods. The thermal inertia (and thermal time constant) is crucial for estimating the flexibility and “flexibility” in a given distribution grid.

For each MW/annum reduction of the peak load a reduction of cost is expected, depending on the grid location and voltage level(s), to decrease with 81 000 – 350 000 SEK/annum . The number of active households needed for such an operation is dependent on temperature, infrastructure and equipment however if one assumes an average down regulation flexibility of 2 kWh/h per household the number of households needed for a reduction of 1 MWh/h corresponds to 500. Assuming an efficiency of 75 % yields 667 active households. If these households “share” the revenue 50/50% with the distribution grid company, then revenue per household corresponds to 61 – 262 SEK/annum depending on voltage levels and location. Assuming an efficiency of 100% then the revenue per household corresponds to 81 – 350 SEK/annum.

Minimizing distribution losses by ensuring (more) optimal load in substations and distribution lines (cables)

In the distribution of electricity losses are inevitable. These losses originate from both technical losses (heat losses, reactive power, etc.) and non-technical losses (malfunctioning meters, theft, etc.). This chapter will only consider the technical losses. The total distribution losses in a well-functioning distribution grid is somewhere around 5 %. The technical losses can partly be derived from two parts of the distribution chain; the substation and the transmission lines. The substation has an efficiency which is dependent on temperature and load. In general, the colder the outside temperature the better efficiency can be expected from a substation. The efficiency as a function of load can be approximated with a second order polynomial. Second order polynomials have one global maximum at optimal load. Any deviation from this “optimal” load will yield a decrease of efficiency. See the figure below for a schematic overview of the efficiency curve for a substation.

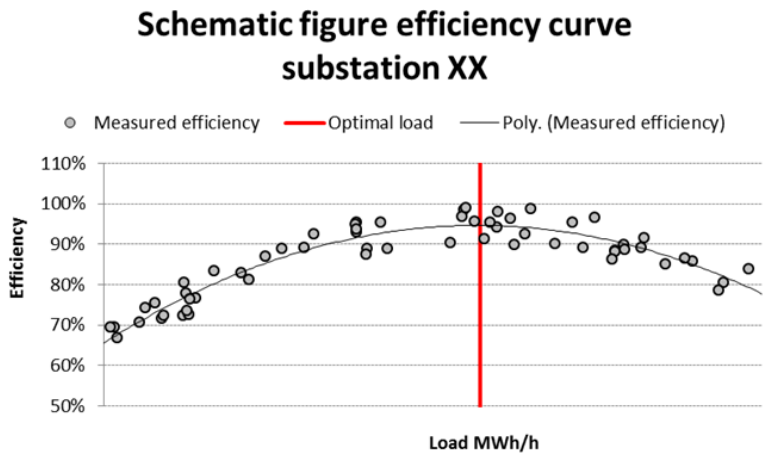


Figure 13. Schematic illustration of an efficiency curve for a substation. The optimal load is illustrated by the red vertical curve. Any deviation from this optimal load point will yield an (increase) of distribution losses relative to the optimal load point. The horizontal arrows indicate the preferred change of load in order to minimize substation losses.

The transmission losses in the distribution cables are correlated with the transmitted power. The theoretical losses are a quadratic function of the throughput power, i.e. the higher the transmitted power the higher the instantaneous losses. Furthermore, this is also dependent on the cross-sectional area and transmitted distance of a given cable. With a larger cross-sectional area the losses decrease. Both the distance and cross-sectional area are considered non-changeable in the short-term.

Both of the technical losses mentioned above(substation and transmission losses) are dependent on the load and the current temperature (with colder temperature, the losses decrease) which means there is an “optimal” load taking demand response flexibility and load/weather forecasts into account.

Depending on the present climate, and forecasts of both load and temperature there is a beneficial increase/decrease of consumption taking both substation and transmission line cables into account. The minimized variable is the transmission losses of electricity, taking into consideration pre-defined comfort-criterion.

Depending on the existing infrastructure and technical losses the potential savings/benefits from utilizing DR for loss minimization varies.

Avoiding black-outs during critical peak-load

The methodology for minimizing the risk of black-outs during critical peak-load is similar to the methodology presented under the heading ‘Minimizing the costs for transmitting energy from the transmission grid for a distribution grid company’ where the main objective is to reduce the load during critical peak-load hours. The incentives for DR is however different, where avoiding black-outs can mainly be derived to increase security of supply, and potentially avoid grid re-enforcement investments. The value of security of supply is to be considered superior to short-term cost minimization (minimizing the annual power tariff). The value of DR can be assumed to be represented by the alternative investment costs needed for ensuring a sufficient level of security of supply.

3 Simulation of the price formation on Nord Pool Spot

3.1 Introduction

This section describes how the day-ahead market (DAM) model is formulated and implemented. The model was implemented in two similar versions; the DAM setup (alternative 1) and the DAM with flexible bids (alternative 2) setup. These two different setups are referred to as alternative 1 and 2, respectively. The model was implemented as a linear optimization problem (LP). The LP objective is maximizing the so-called social benefit function. For the full mathematical formulation for the two alternatives see appendix A.

The DAM consists of several market participants (called 'members'). The members include both buyers and sellers of electricity. The DAM model computes, in simplified terms, the equilibrium between the supply and demand bid curves. The market price corresponds to the price of the last (marginal) accepted bid. This is often referred to as marginal pricing. See figure below for a schematic overview of the supply and demand equilibrium and the price formation.

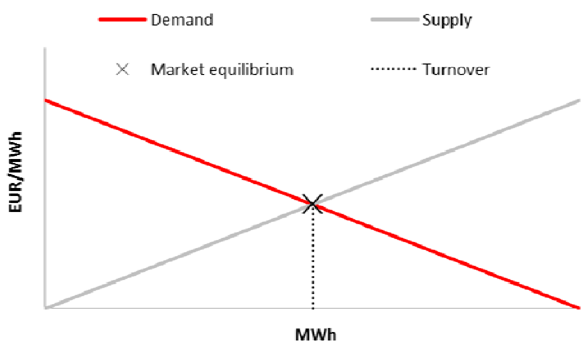


Figure 14. Schematic illustration of supply- and demand bid curves.

3.2 Day-ahead market

In practice the marginal price on the DAM is more complex than just the intersection between the supply and demand curves. The "classical" bid format on the Nord Pool Spot market consists of a price interval (EUR/MWh) and a volume interval (MWh). A particular bid is then interpolated to one continuous bid between the upper and lower bounds over the price and volume range. The full supply curve is an aggregation of the separate interpolated bids. A schematic overview of the bid format and methodology can be observed in the table and Figure 15 below.

Bid ID	Price EUR/MWh	Price EUR/MWh	Volume MWh	Volume MWh
	Lower	Upper	Lower	Upper
Bid0	0.0	1.0	150.0	151.0
Bid1	10.0	12.0	100.0	150.0
Bid2	11.0	13.0	80.0	120.0
Bid3	20.0	25.0	50.0	60.0

Table 3. There are four (supply) bids that are placed on the market, bid0 – bid4. A bid is ranging from a lower price to an upper price and a lower volume to an upper volume.

Each bid is interpolated between its two points ($Volume_{lower/upper}$,$Price_{lower/upper}$). The full aggregated supply curve for the table above can be observed in the figure below.

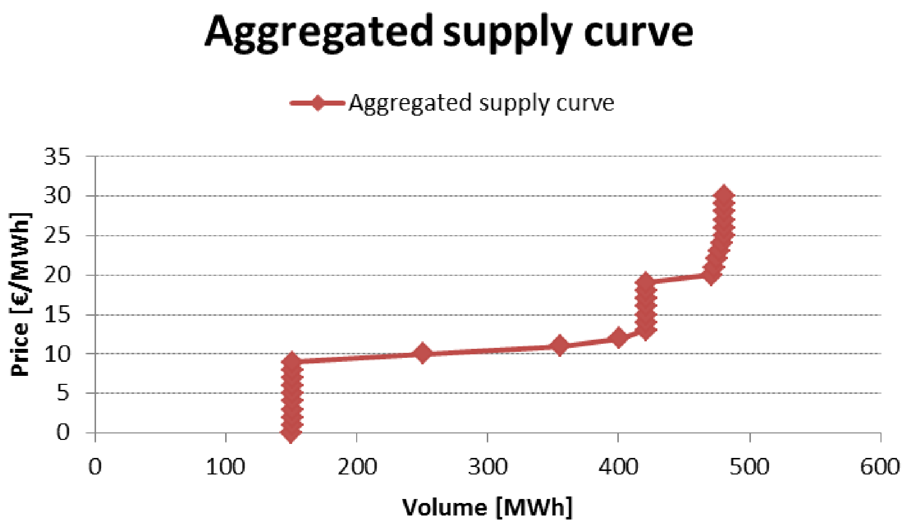


Figure 15. Schematic figure of the interpolated aggregated supply curve. In the Nord Pool spot market each bid is interpolated as explained above (y-resolution set to 0.01€/MWh), however in order to reduce computational time for generating and solving the optimization problem this study disregarded the interpolation for all simulations with the exception of one sensitivity analysis (see chapter 3.9.1).

In addition to the aggregated "classical" bid curve, the full bid curve includes more complex bid structures. The Nord Pool Spot market has support for handling of more complex bid structures than the "classical" bids (e.g. conditional bids, flexible hourly bids, etc.) as bids in separate price areas. The bid curves for all the regions on the Nord Pool Spot market are fully integrated, which means that trade (subject to transmission constraints) is allowed between price areas. At present there are 15 different price areas on Nord Pool with fully integrated supply and demand curves. The conditional bids (block bids) and flexible hourly bids (only for sellers) are disregarded in this study.

3.3 DAM reactive demand response (alternative 1)

The full mathematical formulation of alternative 1 can be found in appendix A. The DAM in alternative 1 includes the simulated demand response implicitly by including the simulated volumes (MWh/h), from Ngenic DSM, in the price formation. The demand response is not a decision variable in the DAM, but an input parameter. Instead, the level of demand response is a decision variable in the Ngenic DSM-model. For a graphical illustration of the original demand (turnover without any DR) and the new demand used for the demand/supply equilibrium can be observed in Figure 16.

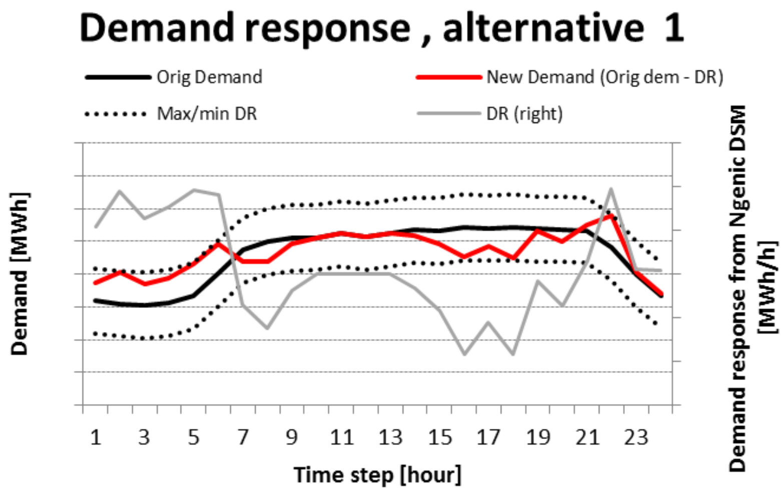


Figure 16. Illustration of how demand response is implicitly included in the price formation in the DAM. An optimal DR is simulated in Ngenic DSM, which is inserted into the DAM. A new equilibrium (relative to the previous market equilibrium) is found which yields a new spot price of electricity. Note that the level of the grey curve is not in the same absolute range as the other curves (less MWh, right axis).

3.4 DAM Flexible bids (alternative 2)

The DAM flexible bids model is similar to the DAM model, however with an added feature. In order to include DR in the price formation on the DAM time steps must be linked in order not to overestimate the flexibility and violate any comfort criteria for residential end-consumers. The reason for this is further described under chapter 3.8. The flexible bids can be seen as “flexible bands" on the buy curves, subject to certain balance constraints within the optimized time period (24 h). In DAM the different time steps were not linked as there were no bid constraints including linkage between time steps. See Figure 17 below for a schematic illustration of the buy curve with "flexible consumption".

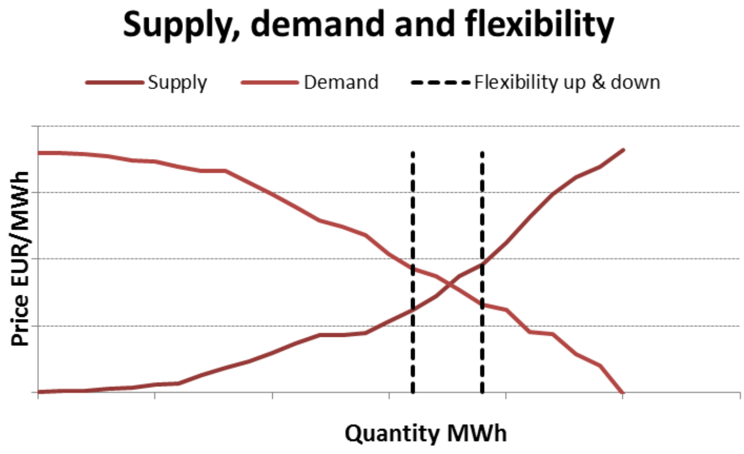


Figure 17. The demand and supply curve for one time step. The dashed lines correspond to the up and down regulating capacity taking into account comfort criterion and thermal inertia.

A schematic illustration of flexible bids during one day (24 hours) can be observed in Figure 18 below. The demand during any of these hours can be changed by utilizing the flexible bids, yielding a new price and turnover.

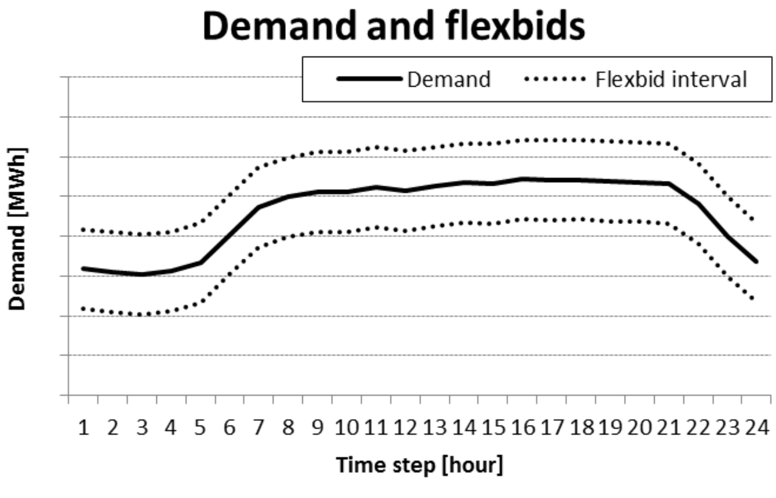


Figure 18. Schematic illustration what the flexible bids looks like graphically. The dotted curves represents up and down regulating flexibility (in this example symmetric +/- 1000 MWh/h)

The full mathematical formulation can be found in Appendix A under alternative 2.

3.5 Data and parameters

The DAM and DAM flexible bids assumes that the user supplies the model with data and defines several parameters. The data for the simulations included:

- Bids from the Nord Pool spot. Both demand and supply curves were calculated using this data (both price and quantities)
- Accepted block bids from Nord Pool spot (quantities)
- Available capacities for interconnectors
- The Demand Response per time step and region (only for alternative 1)
- The available flexible volume per time step and region (only for alternative 2)
- The cost of flexible consumption (EUR/MWh) per time step (in this study set to 10 EUR/MWh throughout all the time steps and simulated weeks). Simplified this can be interpret as “the minimum price difference between hour X and hour Y in order to justify rescheduling of consumption”.

3.6 Model verification

The DAM model was verified using publicly available system price curves. The model output was close to identical to the historical market data. See Figure 19 and Figure 20 below for system turnover and prices for six days during February 2013. The bid curves were not interpolated in the verification simulations.

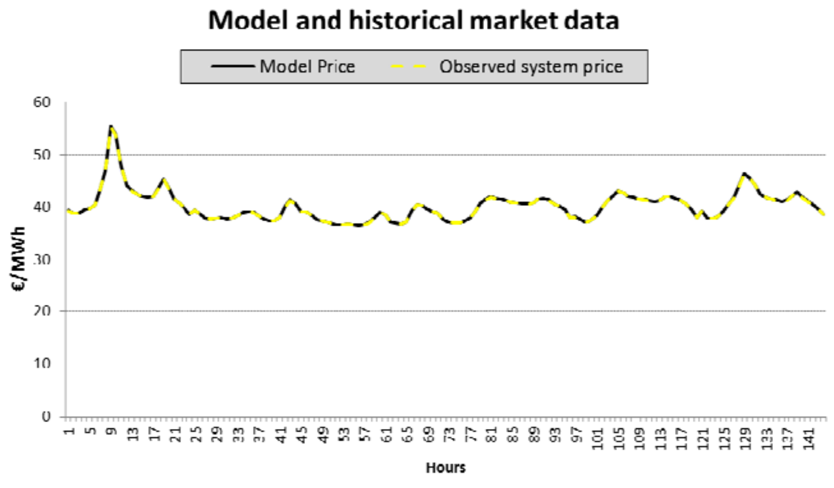


Figure 19. The simulated and published system price during six days during February 2013. The model appears to perform well compared to the actual market prices.

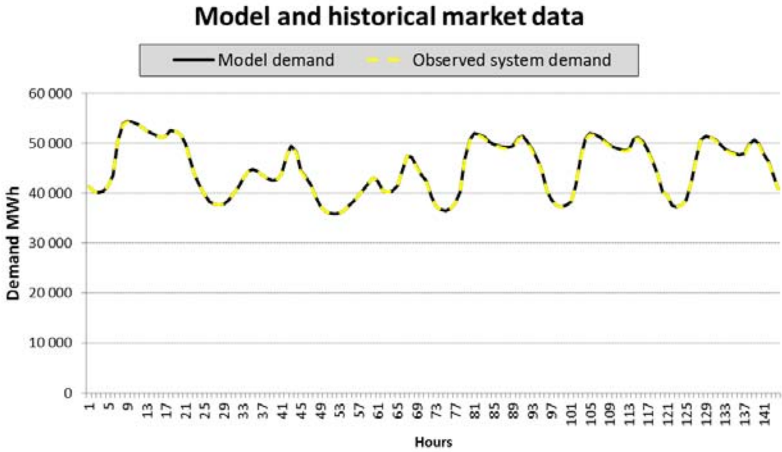


Figure 20. The simulated and published system turnover during six days during February 2013. The model performs well compared to the historical turnover.

3.6.1 Maximal price and implications in the model

The maximal price on Nord Pool spot is currently set to 2000 €/MWh. This is also included in the Sweco DAM model, and has some implications on both results and on the demand response in both alternative 1 and 2. Whenever the maximal price applies, the supply is insufficient for the corresponding demand. See Figure 21 for a schematic overview.

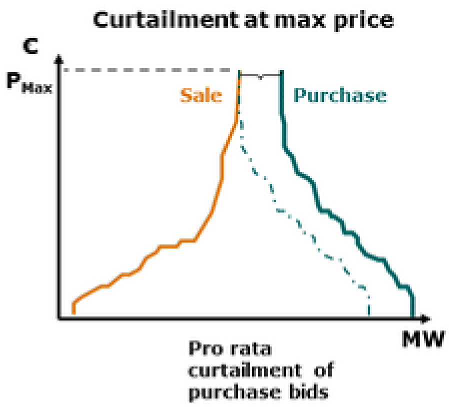


Figure 21. Curtailment at maximal price whenever supply (sale) is insufficient to meet purchase (demand). Source: Nord Pool Spot.

Whenever the supply is insufficient to meet the demand, a phenomenon occurs in the price formation and DR. The daily average price can increase due to more hours with higher prices (the hours before and after the maximum price), while the curtailment price is maintained (the volume of utilized DR is insufficient to reduce the marginal price) for the shortage hours.

See Figure 22 below for illustration of the simulation results and price formation for 2012-01-31 and Figure 23 for a schematic figure when the maximal price applies and the DR volume is insufficient to reduce total demand so that an intersection (below maximal price) can be found.

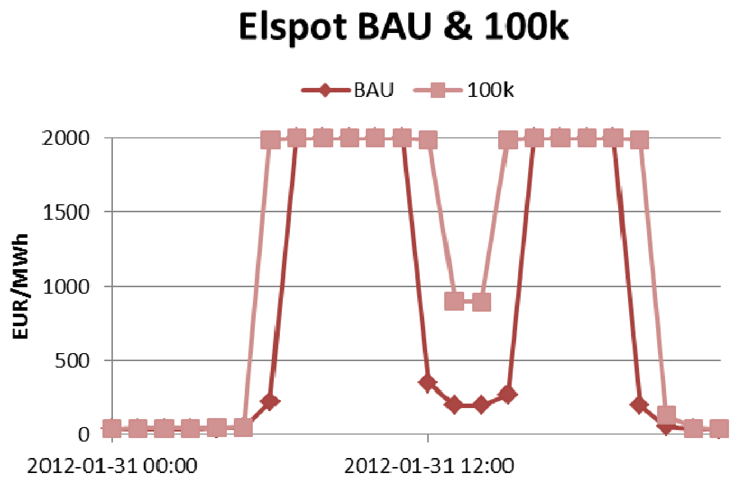


Figure 22. The price formation in the BAU and 100k scenario. The DR is not sufficient to make supply meet demand, however the price is increased during the hours before and after the hours with maximum price, hence yielding an increased social welfare but an increase of the price of electricity for end-consumers. See figure below for a schematic illustration during one hour.

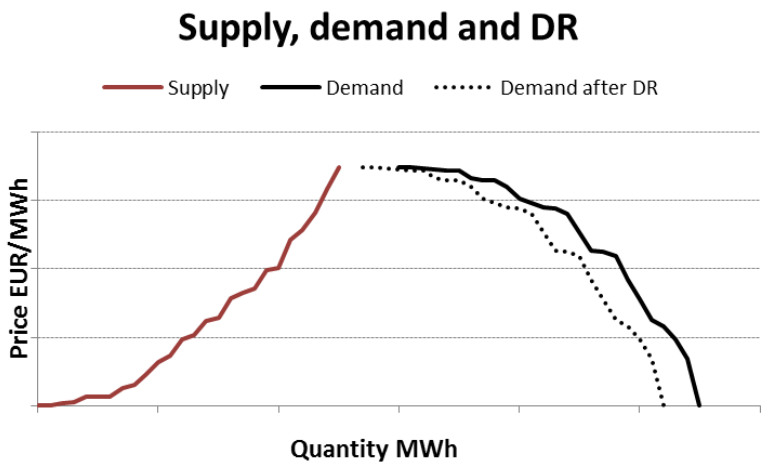


Figure 23. A schematic figure of curtailment, DR, and maximal price. It can be observed in the figure that the price will still be at maximal price (curtailment) since the utilized DR is not sufficient in order for the demand curve to meet the supply curve. The reduced consumption will be rescheduled to other (neighboring hours) which might also increase the price during these hours.

3.7 Simulation of demand response (alternative 1)

To simulate demand response, a model of the how consumption flexibility affects the residential climate is needed. This work has focused on demand response in control systems for electricity based heating (heat pumps and electric boilers) in residential buildings. These, due to the thermal inertia of the buildings and the ability of retrofit automation, are well suited for this type of application. The essential components to the simulation can be separated into two main areas: modeling the heating system, including the building's thermal characteristics, and simulating the control system.

3.8 Modeling the heat system

In modeling the buildings response to various outside temperatures and heating system outputs, dynamical models from NgGenic were used. Modeling of the heat pumps was based on an approximation where the efficiency follows the so called Carnot cycle, scaled by a constant factor, i.e.

$$COP = \alpha \cdot \frac{T_{hot}}{T_{hot} - T_{cold}}$$

where $\alpha = 0.5$ (normal for Swedish heat pump). T_{hot} corresponds to the forward water temperature in the heating system and T_{cold} corresponds to the temperature in the ground. All temperatures in the equations are in the unit of Kelvin. The electric power needed to deliver a given amount of heating power is then given by.

$$P_{electric} = P_{heat} \cdot \frac{T_{water} - T_{ground}}{0.5 * T_{water}}$$

In this work, the ground temperature has been assumed to be around 0^{o} C. So, for example, to deliver 3 kW of heating power at 40^{o} C water temperature, the electric power needed is given by

$$P_{electric} = 3000 \cdot \frac{(273.15+40)-(273.15+0)}{0.5(273.15+40)} = 3000 \cdot \frac{40}{156.575} \approx 766\,W$$

The heat pumps used in the simulation were assumed to cover 60-70% of the buildings power demand at the dimensioning outside temperature, the rest was covered by an electric boiler. This a standard set up for a geothermal heat pump in Sweden.

3.8.1 Simulation prerequisites

To run a simulation, the model has to be fed with a variety of data, including weather data, electricity prices, number of active consumers and the geographical spread of the participating houses.

Prices

Hourly electricity prices for all price areas were supplied by the Sweco DAM model.

Weather

As an approximation, the weather in the different price areas was assumed to be represented by the weather in one town from each area. Hourly weather data was gathered from SMHI for the following locations:

SE1	Arjeplog
SE2	Sundsvall
SE3	Stockholm
SE4	Lund

Number of active consumers

Since the effect on market prices is dependent on the number of customers that react to market data, three different levels were assessed, 10.000 houses, 100.000 houses and 700.000 houses.

Geographical spread

The population density in Sweden varies substantially, so this of course has to be taken into account when estimating volumes of flexible consumption. From analyzing statistics from Statistics Sweden (SCB), estimation on the geographical spread of single family houses could be made. The results are shown below.

Region	Share of population
SE1	5%
SE2	10%
SE3	65%
SE4	20%

Customer preferences

The level of load shift capacity is dependent on how much impact on the comfort that the end-consumers can accept. In this study it was assumed that end-consumers would allow the temperature to vary +/- 2^{o} C from their set point, e.g. a set point of 21 ^{o}C would lead to acceptable temperatures in the range of 19-23 ^{o}C.

3.8.2 Simulation Platform

The simulation software was written in Microsoft's .Net platform. The optimization was done partly using the open source DotNumerics library, and partly self-developed software.

The control system that was used in the simulation is capable of taking in the parameters discussed above and, by using models of the thermal inertia, computes a control signal that aims at minimizing the cost, within the comfort restrictions being set by the customer. By aggregating the data, the simulator produces a per hour consumption demand. This demand is then compared to the simulation results using flat prices, rendering an estimation of the demand response for the population examined.

Results were separated into the price regions and then formatted to match the Excel models used by the Sweco DAM model in order to execute a new iteration. See Figure 26 for an illustration of the simulation work flow.

3.9 Simulation of demand response (alternative 2)

In alternative 2, what was requested was an estimation of the *maximum* potential demand response per hour taking comfort criterion into account.

To compute this, the same heat system modeling and temperature data as in Alternative 1 was used, but instead of simulating how consumers would react to a certain price, the model calculated how much load each house could physically move at a given hour. In addition, the maximum amount of energy that could be shifted while still remaining in the comfort span of ±2 ^{o}C, was calculated.

The maximum amount of load capable of shifting is of course highly temperature dependent. One can't decrease the load if there's no heating demand, and vice versa, one can't increase the load if the heat system is already running at its maximum capacity.

Because of this temperature dependency, there will almost always be an asymmetry between the up vs. down shifting capacities. Also, when dealing with geothermal heat pumps, this asymmetry is further exaggerated. This is because of the fact that almost all geothermal heat pumps are equipped with electric boilers, that assists when the compressor can no longer supply enough heat to the building. Since the electric boilers have a much lower coefficient of performance compared to the heat pump, the amount of electricity needed at cold temperatures is very much higher than at more moderate temperatures. So, at temperatures higher than where the electric boilers are needed, all their full capacity is available for load increase. The size of the boilers is typically 6-9 kW, compared to the heat pumps compressors that is about 2-3 kW. This means that for the vast majority of the time, the maximum upshift capacity is substantially higher than the downshift capacity.

3.9.1 Sensitivities when modeling heating systems

When dealing with a system that has inherent inertia, like a heating system, the state will hardly ever be in equilibrium, even without the use of dynamic pricing. When basing the control upon volatile prices, the ability to react and strive to save money will depend highly on what has been done prior to the time point in question. Due to the inertia, what is done in a specific instance will effect what can be done in the future, leading to a cascading effect where the choices to react to a given prize can affect the behavior of the system for days to come. One can easily realize that this will give rise to a substantial difficulty in predicting an active consumer’s demand, because it is dependent on the prices, as well as the weather conditions, in the preceding days. Residential houses can have a thermal time constant of more than 50 hours, so there will have to be a long period of time with relatively flat prices before the system will stabilize.

It should also be noted, that the longer period of time with cold weather and high prices, the smaller the ability to shift loads will be, given that there are comfort restrictions. Several days in a row with high prizes will basically remove the demand response capability of heating systems completely.

3.9.2 Contradicting price signals for end-consumers

This study has mainly focused on acting on Nord Pool Spot-prices but time dependent grid tariffs were also used. The model for distribution grid rate plans was that of Vattenfall’s where there is a higher price from 06-22 on weekdays during the winter months.

Price types used
Flat prices
Dynamic grid tariffs
Spot prices
Spot prices + dynamic grid tariffs

Table 4. Different rate plans for distribution of electricity.

These are of course not the only price signals that affect the total costs for residential end-consumers. One can have a maximum power pricing tariff on the grid for instance, or different types of dynamic pricing from the supplier that are not (necessarily) harmonized with the Nordpool prices.

It is important to notice that these prices are not by default harmonized. There could very well be a conflict between the different actors involved in setting the prices for the end-consumer. A simple example would be the time dependent grid tariffs and the spot prices. A majority of the time these will co-vary, after all, the grid prices are just a crude example of pricing based on expected consumption. But even if they do co-vary, it might not be beneficial for the system on a large scale level. Let's say that there is a price peak on the spot market from 8-9, meaning that there would be beneficial to move a large portion of the consumption to the hours before 8 and after 9. If the grid prices increases at 6, the incentive to move the consumption to the hours between 6 and 8 will decrease, leading to a decreased spot-price demand response. But for the local grid owner, this might not at all be a bad thing, who may have the consumption peak from 07-08, and therefore not at all wanting any more load being shifted to that period.

In today's Nordic power market, the dominating force of volatile prices differs from time to time. In the fall and spring, the dynamic grid tariffs is often the more dominating one, with, in Vattenfall's case, a price difference of 0.255 SEK/kWh between high and low price times. During the colder months, though, it is not uncommon for the difference between maximum and minimum price on the spot market to differ more than that.

3.10 DAM Model setup

In order to keep data and model size reasonable the model would only include the four different Swedish price areas (SE 1-4), and disregards the other 11 regions of the Nord Pool market. See figure below for an overview of the model setup compared to the "real" Nord Pool market.

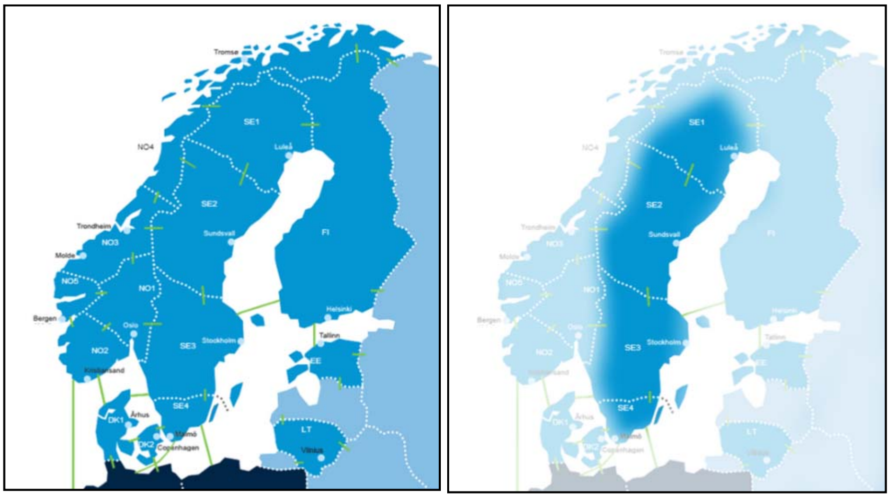


Figure 24. The simulated system consists of the Swedish price regions SE1-4. Source: edited images from Nord Pool spot.

This results in a substantially different simulated system than to the actual system, resulting in significantly different market prices than the historical prices which makes it impossible to verify and compare against historical data (except for system prices/turnover, see model verification chapter 3.6).

Historical market data from Nord Pool Spot was used for the simulations. The Nord Pool Spot price together with *some* market information between 2010-01-01 and 2012-12-31 can be observed in Figure 25. The price on Nordpool Spot is affected by many different factors, some of which are:

- The availability of hydro power
- The availability of nuclear power
- The availability of wind power generation
- The weather (temperature)

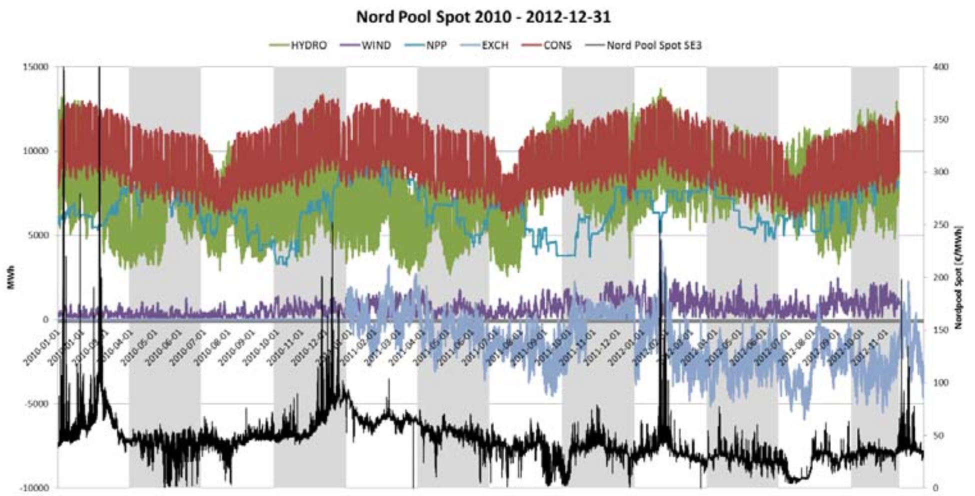


Figure 25. Figure including the historical spot price (for SE / SE3), the consumption (for Sweden), nuclear power plant availability, hydropower generation and exchange to neighboring markets. The greyed areas represent a quarter.

The historical market data used for this study were based on the weeks specified in Table 5 below.

Period	Description	Weeks
2w Q1-10	High prices, price spikes	w2, w9
2w Q2-10	Low price, large spread between peak and off-peak	w21, w23
2w Q3-10	”Normal prices”	w27, w37
2w Q4-11	High prices, restrictions on trade for SE3	w42, w47
2w Q1-12	High price level, price spikes	w5, w6
2w Q2-12	”Normal prices and demand”	w15, w24
2w Q3-12	Low prices, small spread peak/off-peak	w30, w34
2w Q4-12	Large demand, relatively high prices	w49, w50

Table 5. Table over the simulated time periods.

3.10.1 Interconnector capacity

Nominal capacity for each of the interconnectors between the four simulated regions was used for the simulations. Within each region it was assumed that there was no congestion.

From / to [MW]	SE1	SE2	SE3	SE4
SE1	-	3300	0	0
SE2	3300	-	7300	0
SE3	0	7300	-	5300
SE4	0	0	2000	-

Table 6. Interconnector capacity in the Sweco DAM model. All units in MW.

3.11 Two setups – alternative 1 & 2

Two different setups of including demand response in the market clearing procedure was modeled; alternative 1 and 2.

3.11.1 Alternative 1 – reactive demand response

Alternative 1 was a simulation of the price impact different levels of demand response (DR) would yield. This corresponds to a setup similar to today’s market regime where consumers adjust their consumption based on the published market price (in the DAM). The change of load then yields new prices since the consumption is reallocated within the day, and therefore leading to a new market clearing price. The simulated market prices were then used to optimize a new consumption for each iteration. The hypothesis was that the price would converge to equilibrium.
The sequential flow was as:

A. Preliminary market prices were calculated using the DAM model presented in chapter 3.2 above.

B. The market prices were then imported into the Ngenic DSM (see chapter 3.8) which calculated the preliminary optimal DR by taking into account several variables and parameters (distribution costs, spot prices, temperature, etc.)

C. The resulting preliminary DR was then imported into the DAM model and a new market clearing price was calculated (step A above). The new preliminary market prices were imported into the Ngenic DSM, which yielded a new DR, and so-on. The number of iterations performed in each scenario was approximately 10.

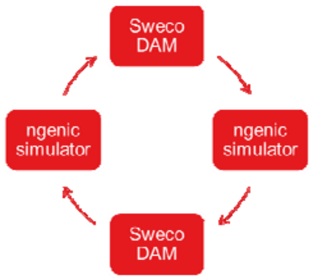


Figure 26. Schematic illustration of work process in alternative 1, demand response as a result from market prices.

3.11.2 Alternative 2 – integrated demand response

Alternative 2 included DR in the DAM price formation via the so-called flexible bids. Flexible bids consists of *feasible* rescheduling of load, which should be interpret as the maximal potential of DR for a given hour taking into account pre-determined comfort criterion (see chapter 3.8 for further explanation) and weather temperature forecasts. See Figure 27 below for an illustration of the feasible DR for a given week.

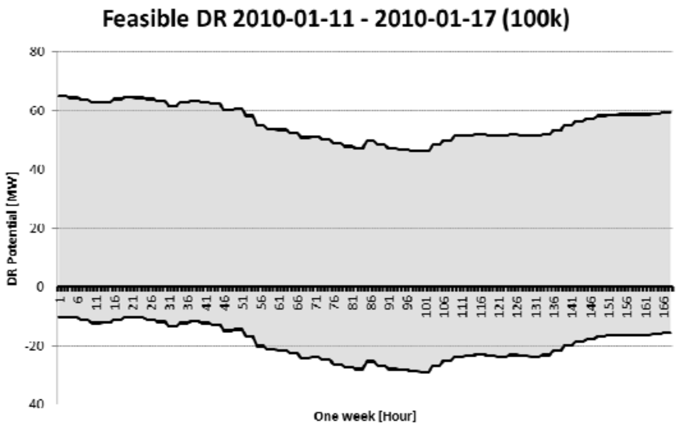


Figure 27. The feasible rescheduling of load per hour during one week for the 100.000 active households scenario.

In addition to the maximal feasible potential of DR, a maximal imbalance ("credit" or "debt" of consumption for end-consumers) criterion for up and

down regulation was included in the price formation. This balance criterion is the maximal accumulated “imbalance” the aggregator can cope with, without violating the predefined underlying end-consumer comfort criterion. The maximal cumulative “imbalance” was set per time step taking actual and forecasted temperature into account.
By using the pre-calculated feasible DR interval in the price formation the optimal demand response (yielding maximal welfare benefit) could be calculated using the Sweco DAM flexible bids model.

Figure 28. Simulation work flow for alternative 2.

3.12 Model results

This section includes simulation results from alternative 1 and 2. The bid curves from region SE1-4 were all used “as is” in the Business As Usual (BAU) scenario. Scenario 10k, 100k, 700k represents 10.000, 100.000 and 700.000 active residential households, respectively. Furthermore, the total costs for end-consumers relative to the BAU scenario were calculated for each scenario. The costs were calculated separately for BAU (reference), free riders (end-consumers not actively planning their consumption but get benefit from a reduction of peak-prices when consumption is high) and active end-consumers. These calculations were only made for alternative 2.

3.12.1 Results – Alternative 1- reactive demand response

Alternative 1 was simulated for all the weeks presented in Table 5. The methodology applied was as explained under chapter 3.11.1.

The simulation of the reactive consumer flexibility appears to be sensitive to high degrees of penetration and large price differences within a day (hour to hour). This suggests two conclusions, either:

A. The degree of penetration (<100.000 households) yields no or little effect on the price formation. This indicates there is an inability to utilize consumer flexibility in order to avoid price spikes.
B. With a larger degree of penetration (>100.000 households) prices spikes are incurred due to a significant increase of consumption during hours before and after the initial price spikes. This yields a volatile solution which does not appear to converge towards equilibrium.

The level of penetration plays an important role in the implicit price formation on the DAM. The price per hour for the simulated date 2010-01-16 illustrates this effectively. The price formation for the BAU (no DR applied) scenario can be observed in Figure 29 below.

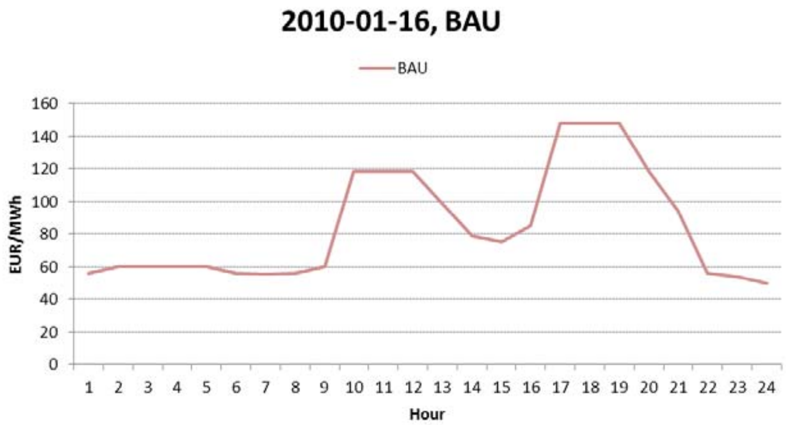


Figure 29. The simulated price per hour for 2010-01-16. The price during off-peak varies around 60 EUR/MWh, with two well-distinguished peaks around 120 and 150 EUR/MWh during the peak-load periods (at 10-12 & 17-18, respectively).

The impact on the price formation is negligible in the 10.000 (10k) active households scenario for the various iterations. See Figure 30 below for an illustration of the price formation for the various iterations during 2010-01-16.

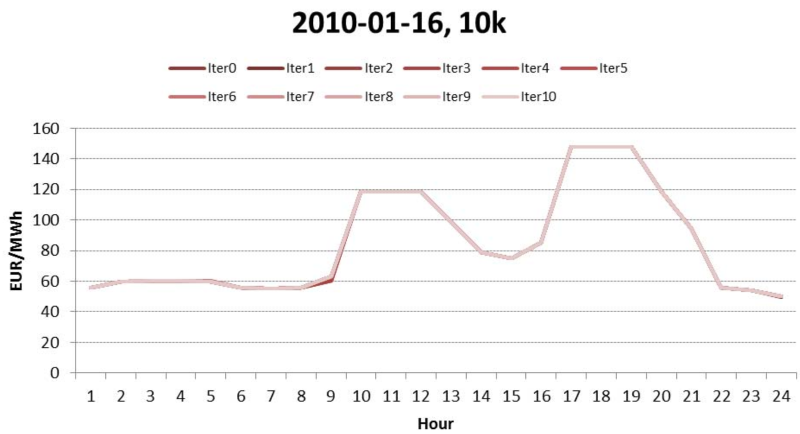


Figure 30. The price formation for 11 different iterations. The impact from DR is negligible. A small change in the hourly market price can be observed durin g hour 09-10 for some of the iterations.

With a level of penetration corresponding to 100.000 (100k) households there is an impact on the price formation. See Figure 31 below for the price formation for the different iterations. The result from the various iterations indicates that a level of penetration of 100.000 can affect the price formation significantly and that new (higher) price spikes can occur.

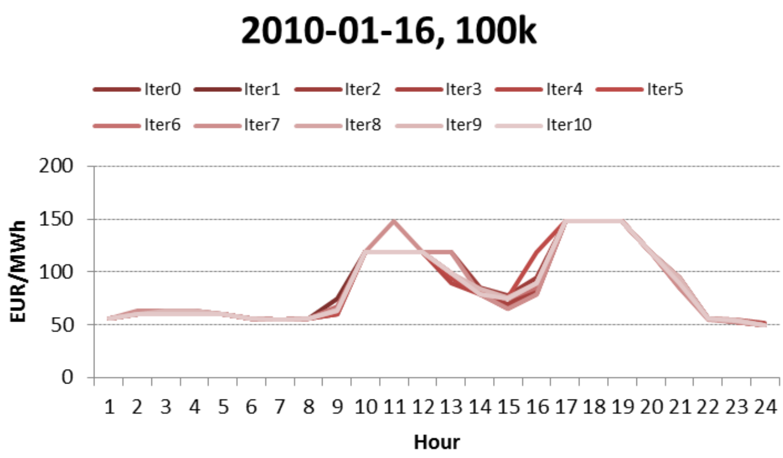


Figure 31. The price formation for 11 different iterations. The impact from consumer flexibility is significant. The hours with the highest differences in price formation are between hours 08-17.

In the scenario with 700.000 (700k) households a dramatic impact on the price formation can be observed. The change in consumption during certain hours incurs changes in the consumption for several hours and the price becomes more volatile than without any change of consumption. The price formation begins to oscillate and it appears to be non-converging. See Figure 32 below for an illustration of the result from the various iterations during 2010-01-16.

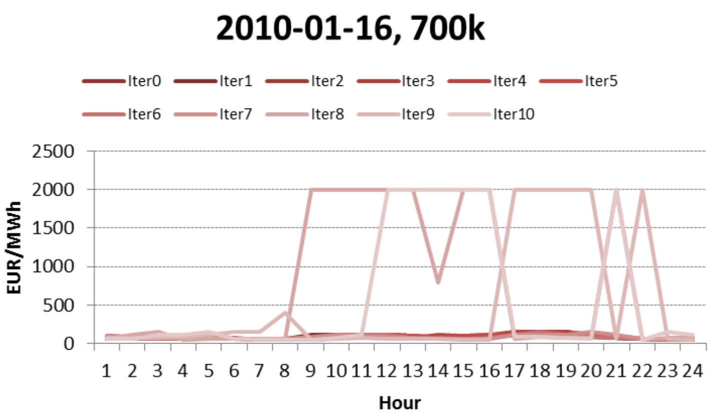


Figure 32. The price formation for ten iterations. The impact on the price formation from demand response is significant. The change of consumption during certain hours incurs extreme price spikes with a deficit in supply as a result (yielding maximum price).

The scenario with a 700.000 penetration does not converge for 2010-01-16. The change of consumption varies completely between the different iterations, which is due to price spikes in the previous iteration. The response for these price spikes leads to new price spikes as the load is rescheduled.

The demand response hour by hour during 2010-01-16 for the 100k and 700k scenario can be observed in Figure 33 and Figure 34 below.

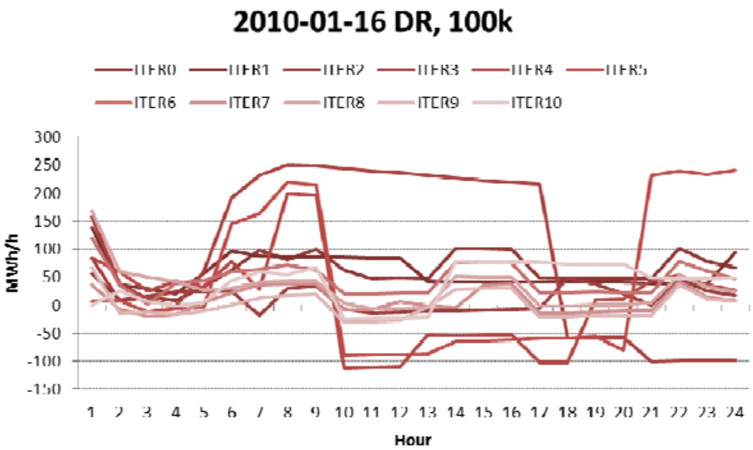


Figure 33. The demand response for the various iterations in the 100k-scenario. The demand response between the different scenarios varies considerably, resulting in an significant impact on the price formation.

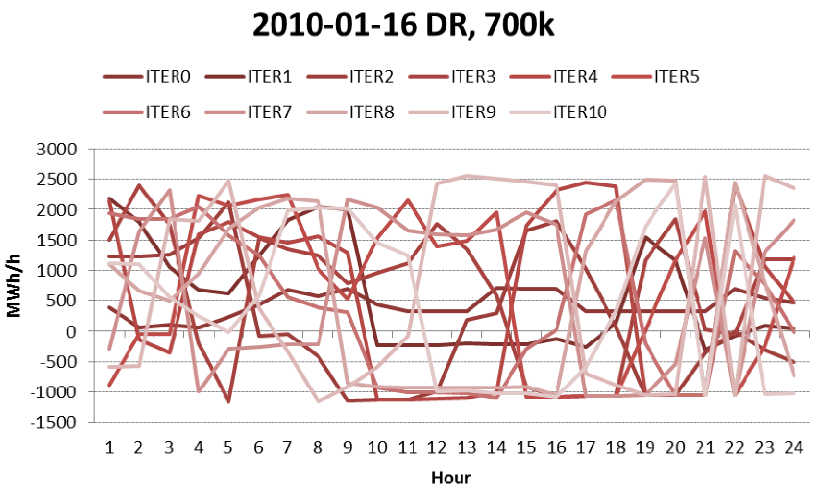


Figure 34. The demand response for the various iterations in the 700k-scenario. The consumption response between the different scenarios varies significantly, resulting in a severe impact on the price formation.

3.12.2 Simulating alternative 1 with an interpolation of the bid curves

In practice on the Nord Pool day-ahead market all bids are interpolated between the lower and upper price and volume (see chapter 3.2 above) levels. In order to keep computational time reasonable for this study the interpolation of the bid curves was disregarded in the simulations. Not interpolating the various bids might hinder the convergence of the price formation for the various iterations. It was tested whether an interpolation would yield better convergence for the various scenarios in alternative 1.

One week was simulated using the aggregated interpolated bid curves (both the sell and buy curves were interpolated). The chosen week was 2012-12-03 – 2012-12-09. This week was particularly cold, yielding high demand, and the price level was relatively high. Only the scenario with 100.000 active households was simulated.

In the simulation using the non-interpolated bid curves the solution did not converge during the week of 2012-12-03 – 2012-12-09, see Figure 35 & Figure 36 below for an illustration of the simulated demand-response in alternative 1 during 2012-12-03. The solution does not converge for any of the two simulated setups; however the interpolated bid curves appears to behave smoother than for the non-interpolated bid curves.

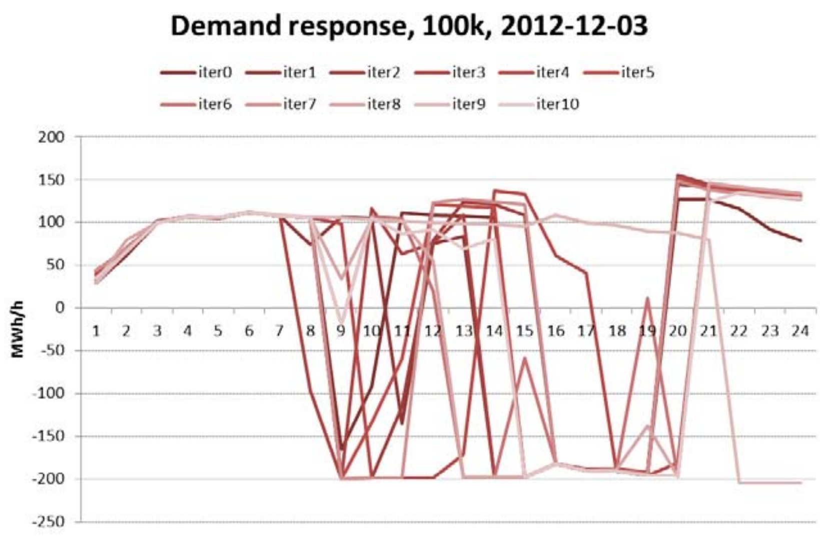


Figure 35. Simulated response during 2012-12-03 in alternative 1 for the non-interpolated bid curves. The solution does not appear to converge.

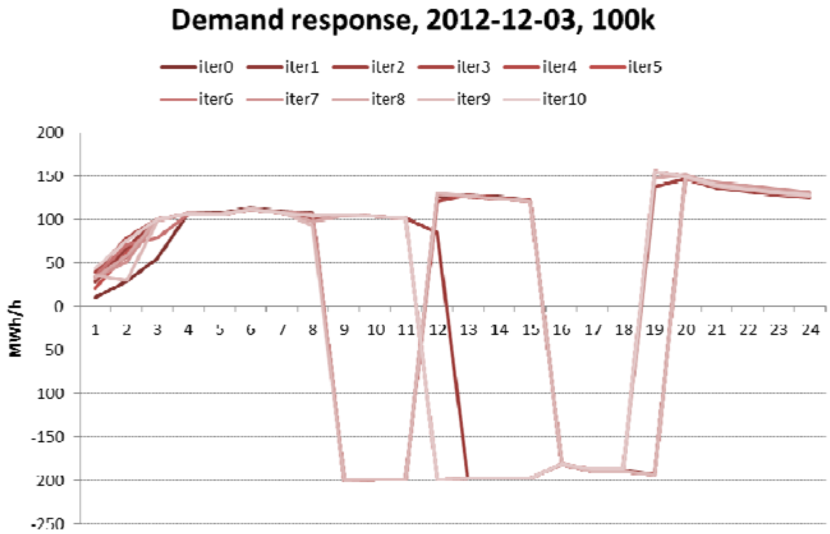


Figure 36. Simulated response during 2012-12-03 in alternative 1 for the interpolated bid curves. The solution does not converge for the interpolated bid curves.

The price formation does not to converge for the interpolated bid curves. The price formation for 2012-12-03 is illustrated for both of the simulated setups in Figure 37 and Figure 38 below.

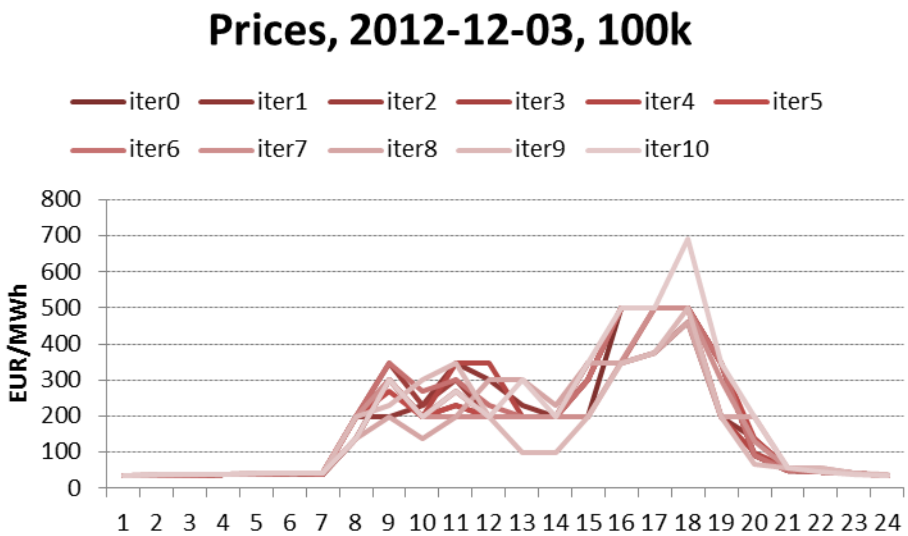


Figure 37. The simulated price formation for the non-interpolated bid curves. The solution does not appear to converge for the various iterations.

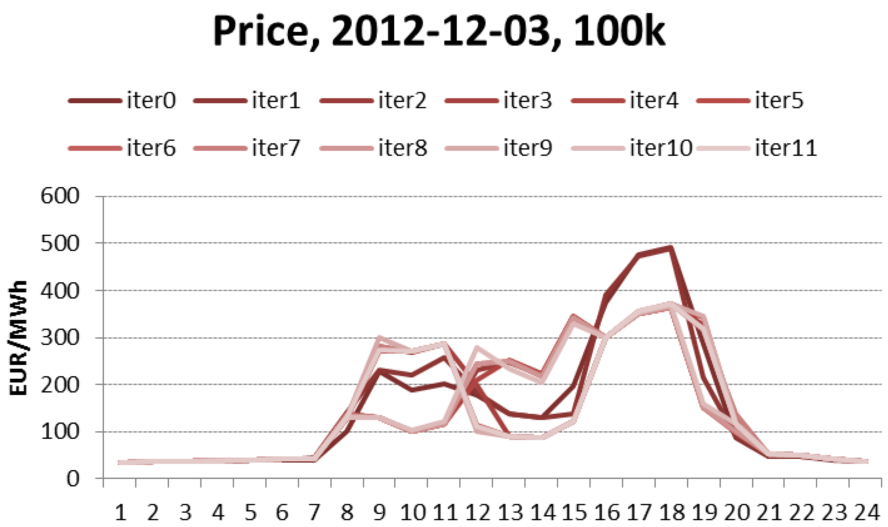


Figure 38. The simulated price for the interpolated bid curves during 2012-12-03. The price formation is smoother than the non-interpolated bid curves however the solution does not appear to converge.

The conclusion from the sensitivity analysis is that the interpolation of the bid curve does not bring convergence to the solution. The price formation is slightly smoother compared to the non-interpolated simulation. The hypothesis is that this will stimulate a smoother DR, however does not guarantee that the solution is converging.

3.12.3 Results – alternative 2 – integrated demand response / DSM

Alternative 2 was simulated on all the weeks presented in Table 5. The flexible consumption and the maximal imposed imbalance were included in the price formation and maximization of the social welfare. The results varied for the various scenarios and weeks, see appendix B for illustrations of price formation per week for the simulated scenarios.

Alternative 2 successfully manages to avoid so-called price spikes during some of the simulated weeks. See Figure 39 below for an illustration of 2010-01-16, during 24 hours.

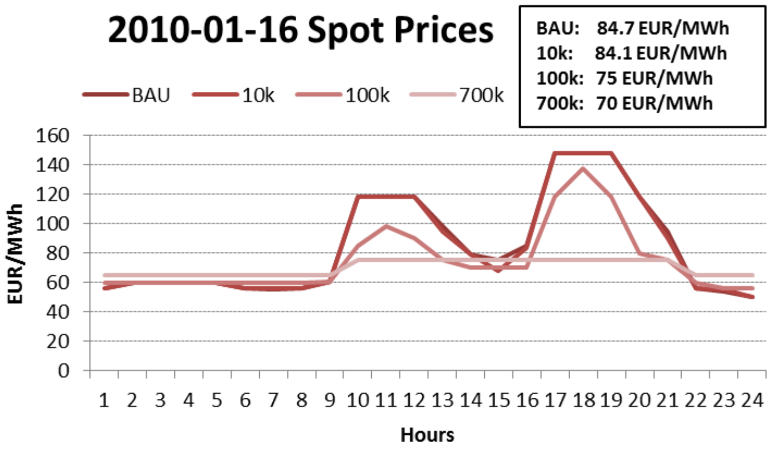


Figure 39. Simulated price formation from the four different scenarios during 2012-01-16. The price volatility is effectively reduced with an increase of DR penetration.

The average price per hour for all the simulated weeks can be observed in Figure 40 below.

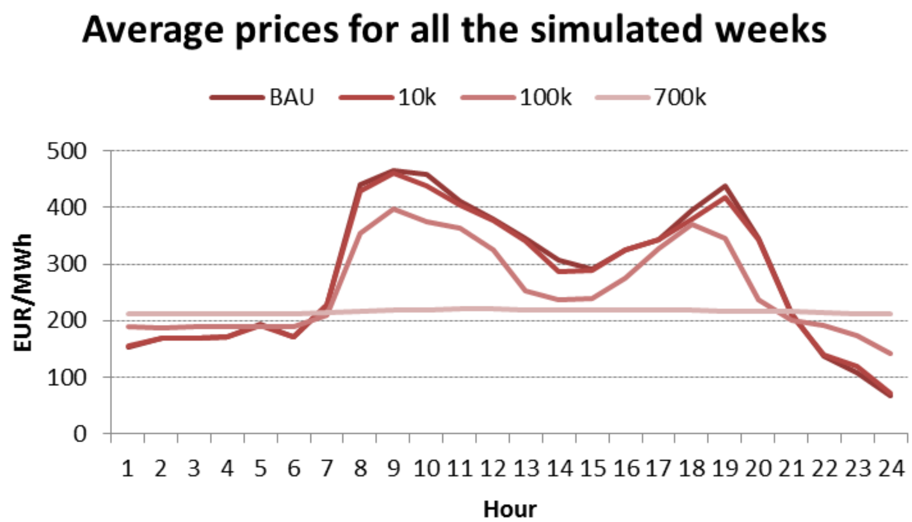


Figure 40. The average price per hour for the simulated weeks. The BAU and 10k scenario are relatively similar whereas the impact is significant for the 100k and 700k scenario.

Isolated price spikes were affected and effectively avoided with the use of DR in the price formation. See Figure 41 below for an example from 2010-09-15.

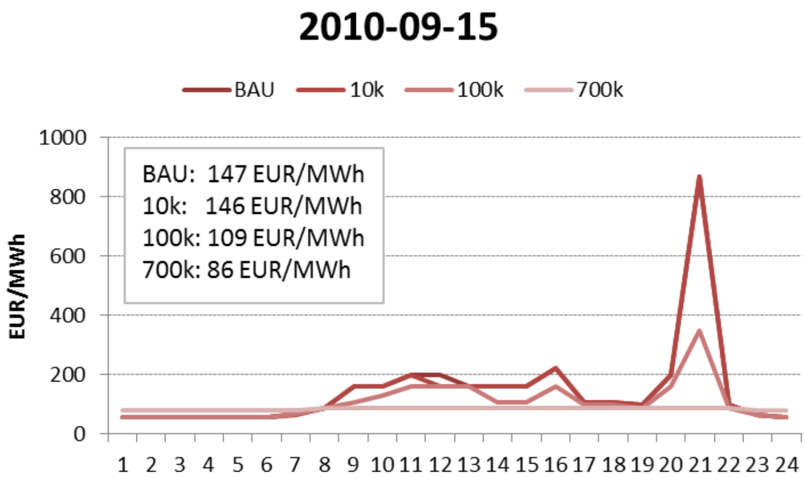


Figure 41. Price formation for the various scenarios during 2010-09-15.

The average prices for the different scenarios are decreasing with an increased penetration of DR. See figure below for an illustration of average prices per scenario.

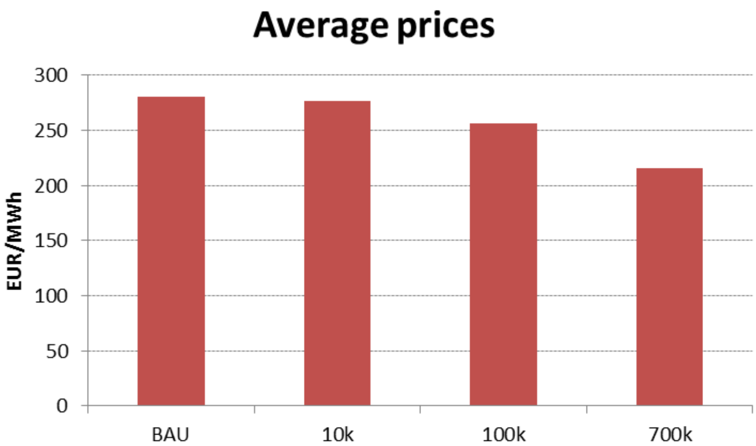


Figure 42. The average spot price for all the simulated weeks for the various scenarios. It can be observed that the average price is decreased (mainly due to avoidance of price spikes and/or max price) for an increased share of DR.

The impact on the price formation varies between the different weeks, see appendix B for results.

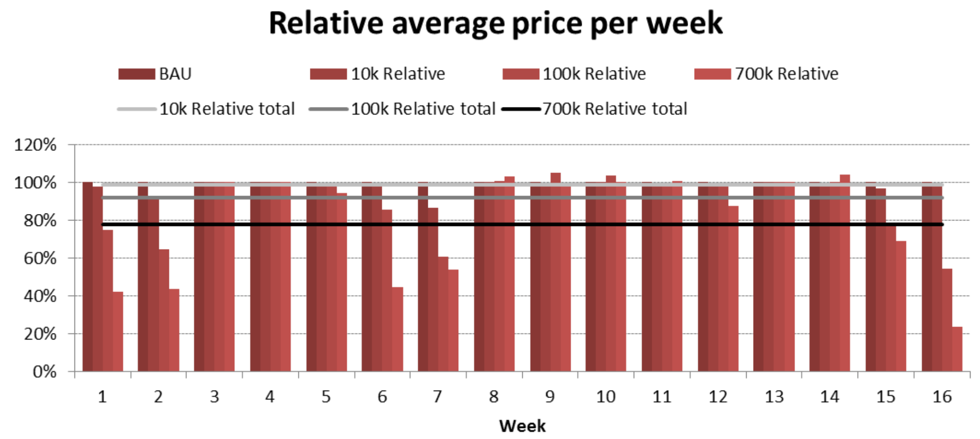


Figure 43. The average price for the simulated weeks compared to the BAU case. It can be seen that the price is significantly reduced for most of the weeks.

The simulation results show, not very surprisingly, that it is more optimal to reschedule energy consumption from peak load (day time) towards off-peak (night time). The relative up- and downwards energy varies for the different scenarios(10k, 100k and 700k) where the 700k scenario has the largest proportion of the demand. See Figure 44 &

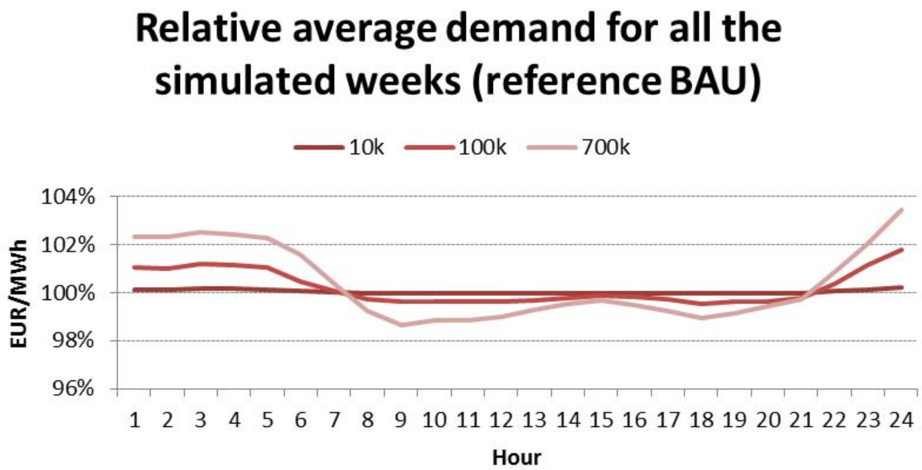


Figure 45 below for average absolute and relative changes per scenario in demand per hour for the simulated time periods compared to the BAU scenario.

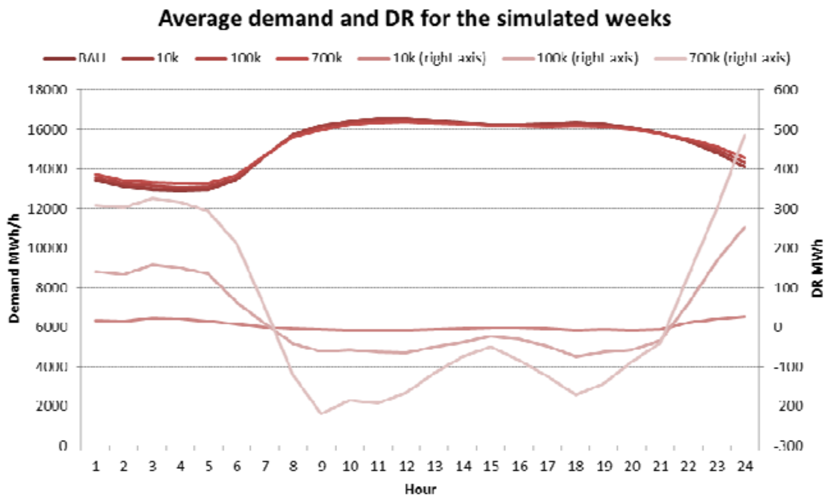


Figure 44. The average demand per hour for all the simulated weeks and scenarios. The DR shows a significant trend of increasing load during off-peak(night time) and decreased load during peak-load (day time).

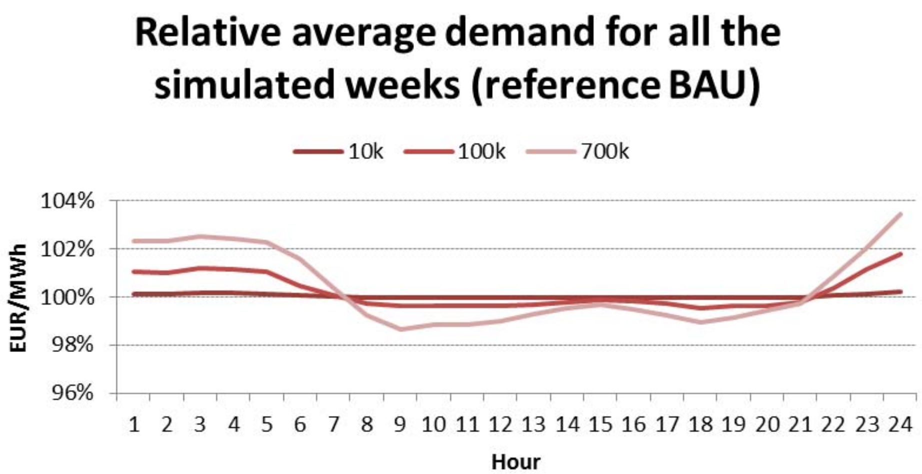


Figure 45. The average relative load per hour for the simulated weeks and scenarios.

3.12.4 Social benefit for the different scenarios and alternatives

This section includes the social benefit, or mathematically "the value of the objective function", from the DAM flexible bids model. Simplified this is the integral between the buy curve (positive, benefit) and the sell curve (negative, cost). Schematically this can be illustrated as in Figure 46 below for a given time step.

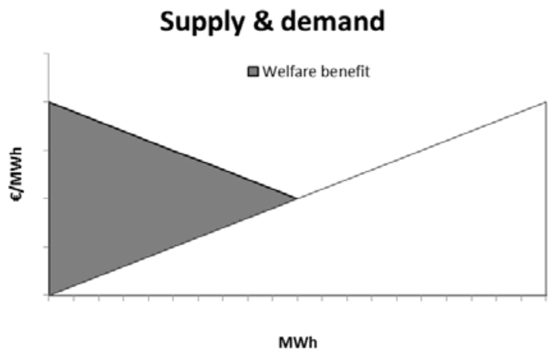


Figure 46. Schematic figure of the welfare benefit. The greyed area corresponds to the social benefit.

Value of objective function for alternative 1

For the simulated scenarios (BAU, 10k, 100k and 700k) different values of the objective function was extracted from the simulations. The social benefit increased with a larger share of households compared to the BAU case. Not all of the scenarios yielded an increase of social benefit compared to the BAU scenario. The 10k and 100k scenario yielded an increased social benefit compared to the BAU scenario. The 700k scenario yielded a negative social benefit compared to the BAU scenario. The different levels of the objective function and a comparison to the BAU scenario can be observed in Table 7 below.

Scenario	Value of objective function compared to BAU [MEUR]	Value of objective function relative to BAU [%]
10k	3.4	100.004%
100k	25.9	100.030%
700k	-426.5	99.499%

Table 7. Table of the value of the objective function compared to the BAU case for alternative 1.

The increased benefit was found to be larger for weeks with higher price levels for scenario 10k and 100k. For the 700k scenario the largest **negative** relative benefit was found. For illustration of the social benefit in the different scenarios using alternative 2 can be observed in Figure 47 & Figure 48 below.

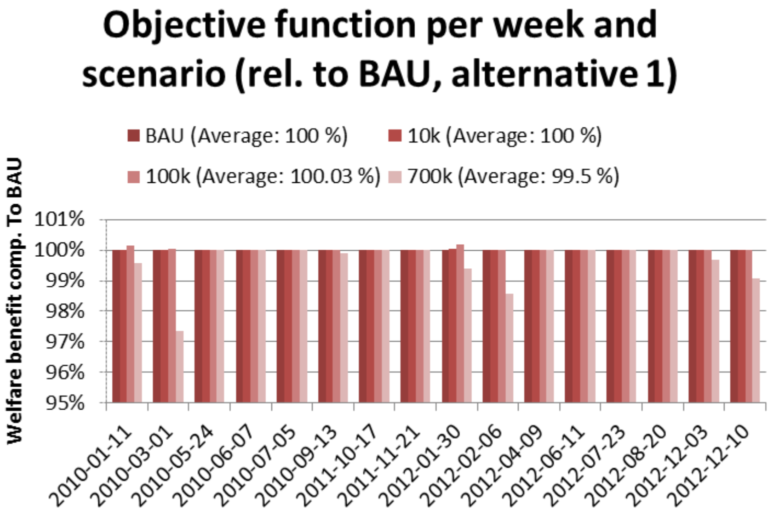


Figure 47. The value of the objective function for all the simulated weeks and scenarios in alternative 1. The value of the objective function increases up until scenario 100k, and decreases in scenario 700k compared to the BAU scenario. The average increase of the social benefit relative to the BAU case can be observed in the legend.

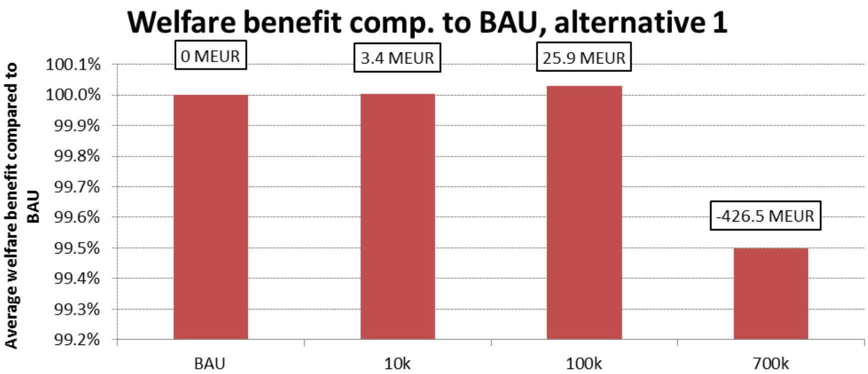


Figure 48. The average social benefit for the various scenarios relative to the BAU case. The data labels corresponds to the absolute increase of welfare benefit (in MEUR) compared to the BAU case.

Value of objective function for alternative 2

For the simulated scenarios (BAU, 10k, 100k and 700k) different values of the objective function was extracted from the simulations. The social revenue increased with a larger share of households compared to the BAU case. All of the scenarios yielded an increase of social benefit compared to the BAU scenario. All the simulated scenarios yielded an increased social welfare compared to the BAU scenario. See Table 8 below for a summary of the changes in social welfare.

Scenario	Value of objective function compared to BAU [MEUR]	Value of objective function relative to BAU [%]
10k	13.4	100.02%
100k	100.7	100.12%
700k	165.1	100.19%

Table 8. Table of the value of the objective function compared to the BAU case for alternative 2.

The increased benefit was found to be larger for weeks with higher price levels. For illustration of the social benefit in the different scenarios using alternative 2 can be observed in Figure 49 and Figure 50 on the next page.

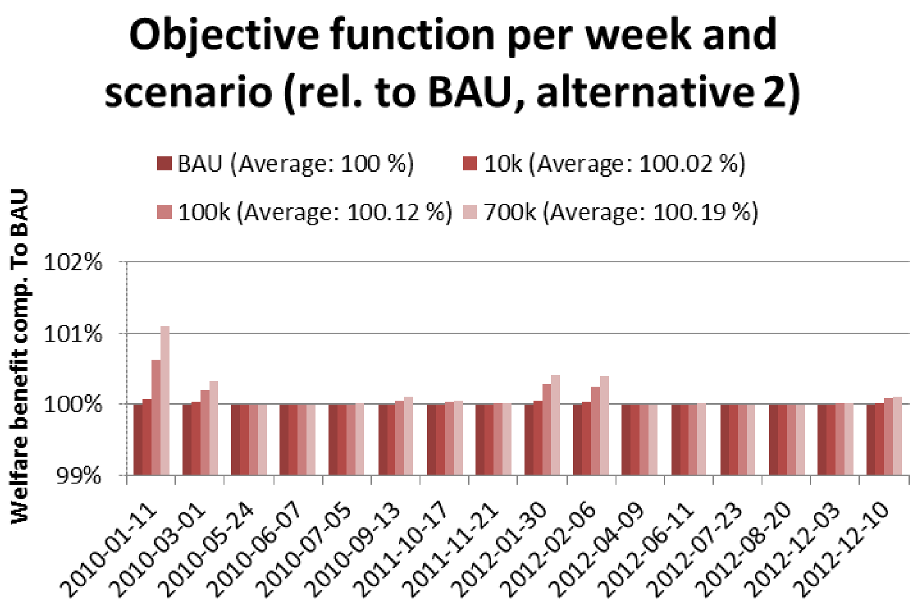


Figure 49. The value of the objective function for all the simulated weeks and scenarios in alternative 2. The value of the objective function increases with an increase of households available for DSM, and the largest relative increase was observed for the weeks with high(er) prices. The average increase of the social benefit relative to the BAU case can be observed in the legend.

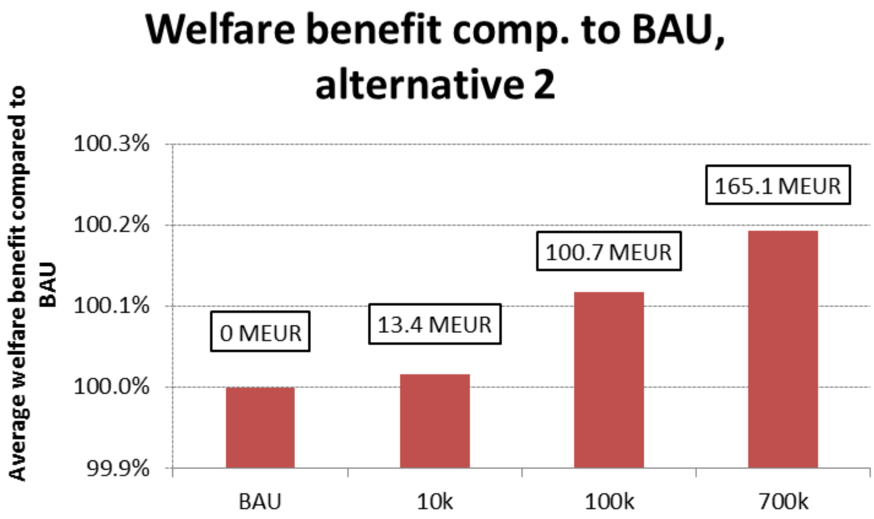


Figure 50. The average benefit for the various scenarios relative to the BAU case. The data labels corresponds to the absolute increase of welfare benefit (in MEUR) compared to the BAU case.

3.12.5 The total cost for end-consumers

In principle there are three different kind of end-consumers included in the calculation of the total costs;

- BAU end-consumer. The cost for these end-consumers were used as reference (if nothing is done this is the total cost of electricity for end-consumers)
- Free rider end-consumers. These consumers don't actively reschedule their consumption, yet they receive a benefit since the price of electricity is reduced during peak-load when their consumption is large(r).
- Active DR end-consumers. The active DR end-consumers revise their load according to alternative 2, hence have a different consumption pattern than the free riders.

The total costs were only calculated for alternative 2. The three simulated scenarios were used in the total-cost calculations, 10k, 100k and 700k. The total end-consumer costs were compared to the BAU case in order to see the relative change of consumer costs.

The total cost for end-consumers is effectively reduced for both the free riders and DR end-consumers. The largest decrease of the total costs was for the 700k scenario and the smallest for the 10k scenario for the free riders. The largest decrease of costs for the active end-consumers was the largest for the smallest penetration of active households (10k), and the smallest for the 700k scenario. A more volatile price pattern will yield larger benefits for active consumers, whereas a flat price pattern will yield similar benefits for both the free loaders and the active end-consumers (no price difference means no difference in total costs no matter whether the end-consumers consumes electricity during off-peak or peak since the price of electricity is similar). The total costs compared to the BAU case can be seen in Figure 51.

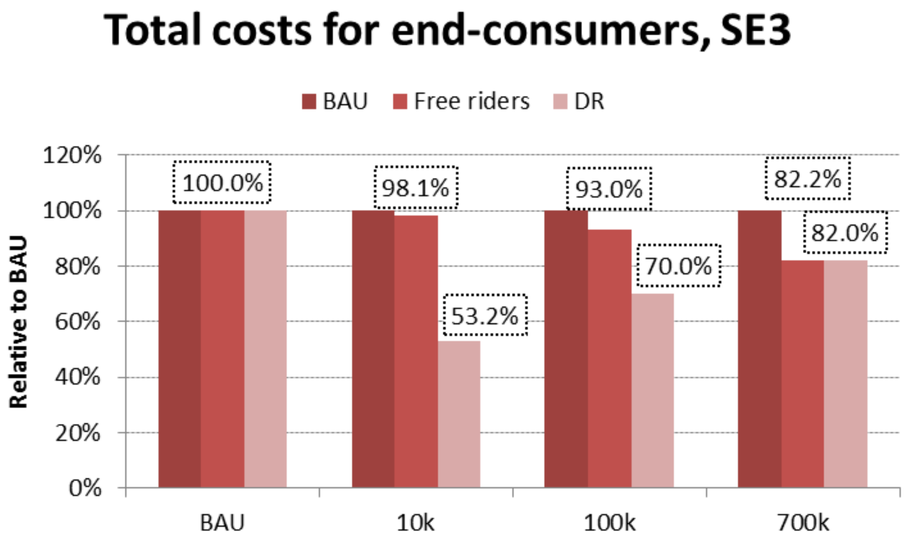


Figure 51. The total costs for end-consumers. The largest decrease of costs for free riders is for the largest penetration of active households (700k). In the 700k scenario the total costs for free riders and active households (DR) is very similar, due to a (very) flat price structure. The largest price reduction for active households is for the smallest penetration scenario (10k), whereas the yielded relative benefit is reduced as the degree of penetration of active households is increase (100k and 700k).

4 Conclusion & findings

Two alternatives for including DR in the day-ahead price formation has been simulated. Alternative 1 included a “reactive” DR which is similar to today’s setup where the price of electricity is made publicly available for consumers and left freely to react upon. The reaction of end-consumers revising their consumption based on high(er) and low(er) electricity prices taking comfort criterion into account was simulated. During hours with (relatively) lower price of electricity the consumption is increased, whereas during hours with (relatively) higher price of electricity the consumption is reduced.

The results from the simulation using the setup of alternative 1 resulted in converging results during hours/weeks with low penetration of DR households, small volatility and low price levels. However, during weeks/days with a large share of active households, high prices (“price spikes”) and large price volatility the results did not converge. The non-convergence implies that new price spikes might be incurred by large volumes of DR, which was also found in the study conducted during end of 2011[8]. Furthermore, the non-convergence means that the market will not be able to “learn” and adapt to the end-consumer behavior, indicating that large penetrations of DR should be included explicitly in the price formation rather than implicitly via reactive DR. The non-converging results can be explained by a steeper section of the supply curve (in general the further “up” on the supply curve, the steeper it gets) and volumes of consumption is being rescheduled, which leads to new price spikes, hence new prices to react upon for end-consumers, etc. Simulation results indicate that this becomes an issue in the 100k scenario, meaning the critical mass is above 10.000 households, but below 100.000 for the simulated system. In reality, where the price is less volatile, the threshold is expected to be *higher* than for the simulated system. The impact on the price formation is not considered severe in the 10k scenario, indicating that the critical mass is above 10.000 households. In the scenario with 700.000 households it becomes apparent that the solution does not converge. In the 700k scenario the maximal price level is reached during several of the simulated weeks due to massive DR and a lack of supply to meet demand.

In alternative 2, where the demand response is explicitly included in the price formation, the risk of getting new price spikes due to rescheduled load is effectively reduced. Alternative 2 corresponds to a ‘Demand Side Management’ (DSM) solution, where the resources are utilized where they are

[8] Sweco Energy Markets: Systemeffekter av timvis mätning. En rapport till Näringsdepartementet, 2011

more beneficial (in the social benefit function which is maximized). This alternative yielded greater benefit the larger the amount of active households, and the ability to avoid price spikes, and smoothening out the price formation, was significant for the 700k scenario. The critical mass appears to occur between 10.000 and 100.000 households, although there can be observed some impact on the price formation during some of the simulated weeks in the 10k scenario. The value of the social benefit (maximized objective value in the DAM model) increases with an increase of active households.

The most suitable market for DR and DSM appears to be the day-ahead market. The main reason is the predictability of prices and the ability to include flexible bids in the price formation (alternative 2). Another reason for preferring the day-ahead market instead of Intraday would be sensitivities in a dynamic system (like the thermal system of a residence) and not incurring (further) imbalances during future delivery hours. An example of this would be if DR is utilized to resolve up regulation (reduction in consumption) during time step t. Then there is a “debt” in consumption which needs to be resolved during for instance the following hour. The following hour there is still need for up regulation which cannot be resolved by using demand response since predefined comfort then will be violated. Instead the opposite of what the system “needs” occurs, hence consumption is increased in order to satisfy the comfort criteria. The imbalance imposed on the system will then be larger compared to the “status quo” leading to a demand for more balancing resources. For a modest penetration of let’s say 10.000 households this might be non-problematic. However with larger penetrations this could lead to a poor performing sub-optimal market. Or even worse; curtailment and problems operating the grid for the TSO due to insufficient balancing resources. This combined with the sensitivity of thermal systems pushes towards the day-ahead market.

One of the challenges with including flexible consumption on the day-ahead market lies within making the aggregators comfortable in quantifying (both in monetary and energy terms) the resources so that end-consumers do not experience any reduction in comfort (could be temperature). Another aspect related to this is the commitment of fulfilling DR. In order to ensure this the cost of being imbalanced has to be large enough for aggregators to stay within the scheduled consumption plan, yet not too high so that it prevents new market participants from entering the market. This balance is believed to be delicate, however is considered *key* to ensure optimality and a well-functioning market.

The current market model where end-consumers are able to revise their load based on the current price of electricity will most likely not have a severe impact on the day-ahead market initially, however simulation results from this and other studies[9] indicate that a large penetration of active households can significantly affect the price formation. The results from this study indicate a severe reduction in the welfare benefit compared to the BAU scenario for a penetration of 700.000 households if excluded from the price formation on the day-ahead market. It should be mentioned that this is based on a hypothetical situation since the incentives for households to start with reactive DR most likely will be penalized before reaching such a penetration due to market failure with the current market design. This probably also yields significant problems for the TSO to maintain balance in the grid, which then enforces a significant increase of cost of imbalances in order to ensure a continuous and reliable operation of the grid.

The simulation results indicate potential of savings for end-consumer costs. The total costs for alternative 2 indicates savings for both active households, but also for free riders (households not active in the DR). As the penetration of households increase the savings for active households is reduced (the price pattern gets less volatile) while the cost reduction for free riders is increased. The maximal reduction of costs (relative to the BAU case) for active households is for a smaller share of active households, which is simply explained by a more volatile price pattern (more beneficial to reschedule load to off-peak).

[9] ”Systemeffekter av timvis mätning”, Sweco Energy Markets, 2011-12-30

5 Recommendations & discussion

During this study we have assessed two different kinds of DR, one reactive (similar to today's setup where end-consumers react on the published hourly spot prices) and one where demand response is included in the price formation. Simulation results indicate that a significant share of active households (>100.000) will substantially affect the price formation on the day-ahead market. If such volumes starts to react on the day-ahead market this will severely increase the need for regulating resources (either on the intraday market or balancing markets). Additionally, it might reduce the credibility on the spot price as a reference (for financial contracts, etc.). However, on the contrary, the market could *eventually* react and cope with large volumes of energy being rescheduled in such a reality. The credibility on the day-ahead market will likely be reduced and alternative markets and/or exchanges will become more attractive. Another feasible reaction to this change of consumption behavior is increasing incentives of being in balance. This will most likely materialize in higher balancing costs for balancing parties (penalty for being imbalanced), which at the end of the day will be paid for by the end-consumers.

On the contrary, DR has been shown to provide a powerful and important instrument to prevent price spikes and to reduce the volatility of the electricity price when used explicitly in the price formation. The need for "controlling" this resource is apparent for larger penetrations of active households.

Across Europe the need for capacity mechanisms is discussed frequently. The need for capacity mechanisms would be a major change of the market regime and would push the perspective of an energy-only deregulated market into a (more) regulated regime. The (short-term) need for capacity is mainly based on a lack of short-term price sensitivity. A future study related to this could assess the eligibility of using DR resources in order to cope with a lack of supply instead of introducing capacity markets mainly designed for firm capacity. One of many challenges related to this would be to assess both the reliability of DR, as how many consecutive hours DR can be utilized in order for the supply to meet demand. The longer the time period, the smaller the probability (reliability) of having available DR resources readily available.

Another highly relevant topic to be studied is how to share the yielded benefit between different stakeholders. We have in this study presented a feasible "format" of including DR in the price formation which both the price algorithms and aggregators can apply (alternative 2). A study using the full market-setup up of the Nord Pool exchange would provide *very* useful in developing the power exchanges of tomorrow, why this is recommended as a continuation of this study.

The fact that the solution does not converge for alternative 1 (similar to status quo) is interesting. This means in practice that the benefit for the system does not (necessarily) correlate with the benefit for a single end-consumer. The reason behind this is simply that a single end-consumer does not take into account the impact of his single decision, which within economic theory usually is called an *externality*. In this case the externality would be the affect an end-consumers decision has on the price formation. The optimization algorithm in alternative 1 does not take this into account, hence the externality and in-optimality. The general view on DR is positive; however this study indicates that this is not something that would easily be included on the market with high degrees of penetration and price spikes. If the degree of penetration would exceed a given *critical mass* consequences are to be expected. One aspect to take into account would be the incurred price spikes due to DR, another one would be reduced confidence in the spot price of electricity. The worst-case scenario here would be a dis-trust in the spot price, which is used for financial trade and exchange. The monetary terms related to this is hard to determine, however are to be estimated as very significant.

6 Appendix A - Mathematical formulation of Sweco DAM

6.1 Simulation of the Day-ahead market (alternative 1)

Mathematically the LP is formulated as:

$$\max z = \sum_{b=0}^{bMax} (P_b \cdot Q_b) - \sum_{s=0}^{sMax} (P_s \cdot Q_s)$$

S.t.

Eq. (1)

$$\sum_{s=0}^{sMax} (Q_{s,t,r}) - \sum_{b=0}^{bMax} (Q_{b,t,r}) + BlockSell_{t,r} - BlockBuy_{t,r} - DR_{t,r} - \sum_{r-r\prime=0}^{rMax} (Exch_{r-r\prime,t}) \geq 0$$

$$0 \leq Q_s \leq Q_{s,Max}$$
$$0 \leq Q_b \leq Q_{b,Max}$$

$$ExchNominal_{r\prime-r,t} \leq Exch_{r-r',t} \leq ExchNominal_{r-r\prime,t}$$

Where

Name	Description	Decision variable	Unit
P_x	Price of bid *x*	No	€/MWh
Q_b	Accepted quantity of buy bid b	Yes	MWh
Q_s	Accepted quantity of sell bid s	Yes	MWh
sMax	Number of sell bids	No	Integer
bMax	Number of buy bids	No	Integer
$BlockSell_{t,r}$	Accepted blockbid volume sell, time step t	No	MWh
$BlockBuy_{t,r}$	Accepted blockbid volume buy region r, time step t	No	MWh
$Exch_{r-r',t}$	The exchange between region r and r' for time step t	Yes	MWh
$DR_{t,r}$	Demand response time	No	MWh

	step t, region r		
$Q_{x,MAX}$	The maximal volume of bid x	No	MWh
$ExchNominal_{x-x'}$	The available transmission capacity in the direction from region x to region x'.	No	MWh

6.2 DAM Flexible bids (alternative 2)

The DAM flexible bids model is similar to the DAM model, however with an added feature. In order to include DR in the price formation on the DAM time steps must be linked in order not to overestimate the flexibility and violate any comfort criteria for residential end-consumers. The reason for this is further explained under chapter 3.8. The flexible bids can be seen as "flexible bands" on the buy curves, subject to certain balance constraints within the optimized time period (24 h). In DAM the different time steps were not linked as there were no bid constraints including linkage between time steps. See Figure 17 below for a schematic illustration of the buy curve with "flexible consumption".

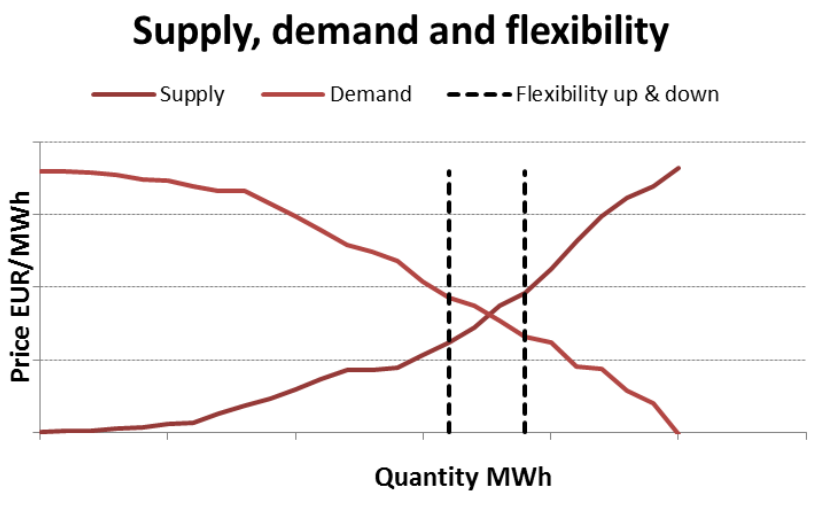


Figure 52. A schematic illustration of flexible bids during one day (24 hours) can be observed in Figure 18 below. The demand during any of these hours can be changed by utilizing the flexible bids, yielding a new price and turnover.

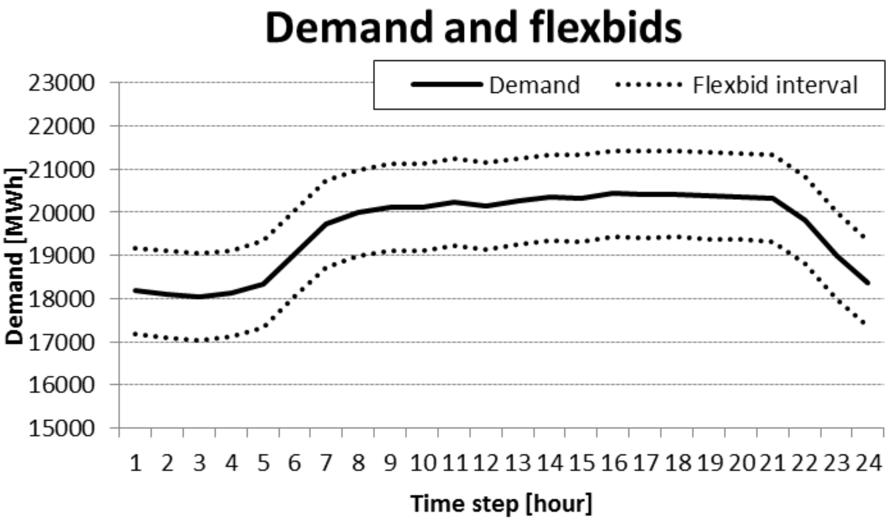


Figure 53. Schematic illustration what the flexible bids looks like graphically. The dotted curves represents up and down regulating flexibility (in this example symmetric +/- 1000 MWh/h)

The objective function in DAM flexible bids is formulated as

$$\max z = \sum_{t=0}^{tMax}\left(\sum_{s=0}^{sMax}(P_{s,t}\cdot Q_{s,t}) - \sum_{b=0}^{bMax}(P_{b,t}\cdot Q_{b,t}) - \sum_{r=0}^{rMax} P_{flexBidUP,t,r}\cdot Q_{flexBidUP,t,r}\right)$$

The previous constraints in DAM also apply for DAM flexible bids, with the following revision of ***Eq. 1 (above)***:

$$\sum_{s=0}^{sMax} Q_{s,t,r} - \sum_{b=0}^{bMax} Q_{b,t,r} + BlockSell_{t,r} - BlockBuy_{t,r} + Q_{flexBidDOWN,t,r} - Q_{flexBidUP,t,r} - \sum_{r-r\prime=0}^{rMax} Exch_{r-r\prime,t} \geq 0$$

And with the added constraints

$$\sum_{t=0}^{tMax}(Q_{flexBidDOWN,t,r} - Q_{flexBidUP,t,r}) = 0$$

$$\forall\, X \in \{0..tMax\} \sum_{t=0}^{X}(Q_{flexBidDOWN,t,r} - Q_{flexBidUP,t,r}) \leq MaxBalanceUp_{r,X}$$

$$\forall\, X \in \{0..tMax\} \sum_{t=0}^{X}(Q_{flexBidDOWN,t,r} - Q_{flexBidUP,t,r}) \geq MaxBalanceDown_{r,X}$$

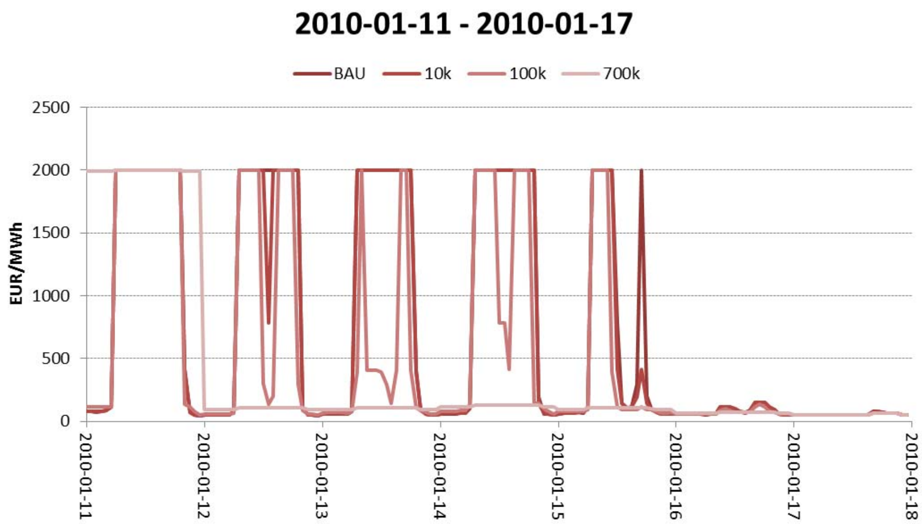
$$Q_{flexBidDOWN,t,r} \leq FlexDown_{MAX,t,r}$$

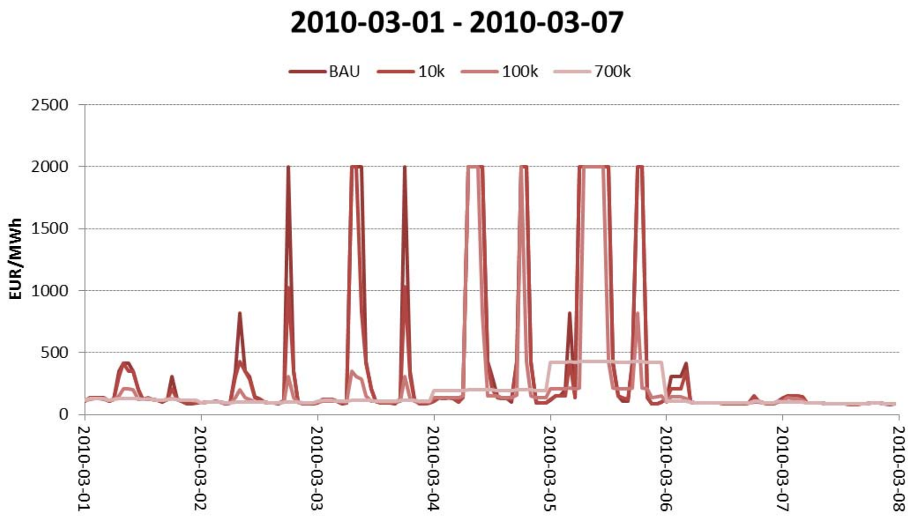
$$Q_{flexBidUP,t,r} \leq FlexUp_{MAX,t,r}$$

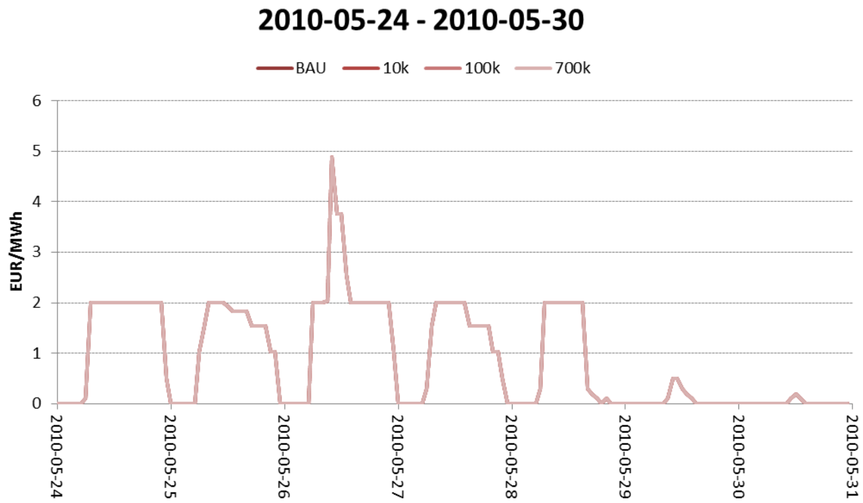
where

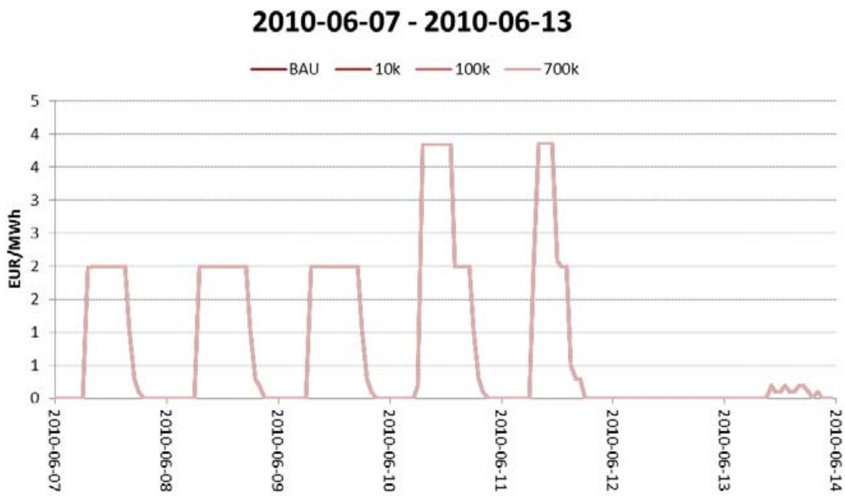
Name	Description	Decision variable	Unit
$\mathbf{P}_{\mathbf{flexBidUP,t,r}}$	Price of flexbid in time step t, region r	No	€/MWh
$\mathbf{Q}_{\mathbf{flexbidDOWN,t,r}}$	Accepted quantity of flexbid down	Yes	MWh
$\mathbf{Q}_{\mathbf{flexbidUP,t,r}}$	Accepted quantity of flexbid up	Yes	MWh
$\mathbf{FlexDown}_{\mathbf{MAX,t,r}}$	Maximal down regulation in time step t, region r	No	MWh
$\mathbf{FlexUp}_{\mathbf{MAX,t,r}}$	Maximal up regulation in time step t, region r	No	MWh
$\mathbf{MaxBalanceUp}_{\mathbf{r,x}}$	Maximal imbalance up regulation for time step X, region r	No	MWh
$\mathbf{MaxBalanceDown}_{\mathbf{r,x}}$	Maximal imbalance down regulation for time step X, region r	No	MWh

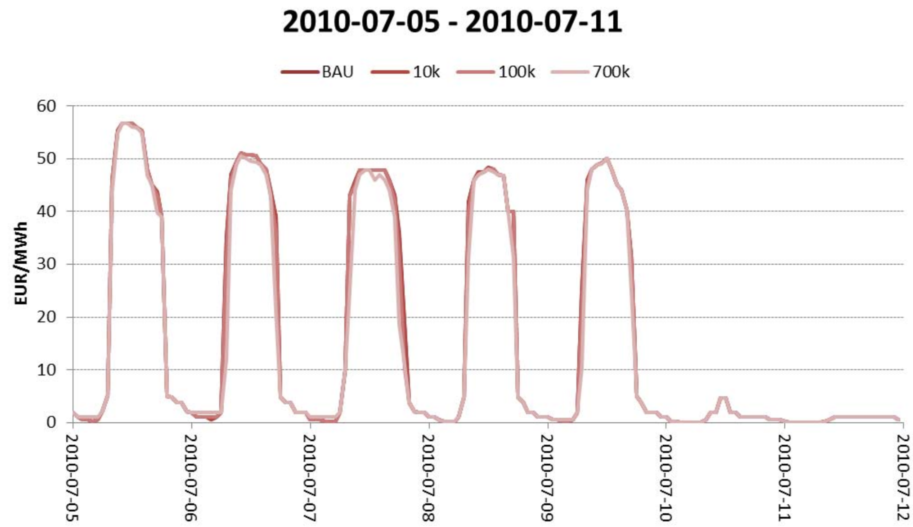
7 Appendix B – prices for alternative 2

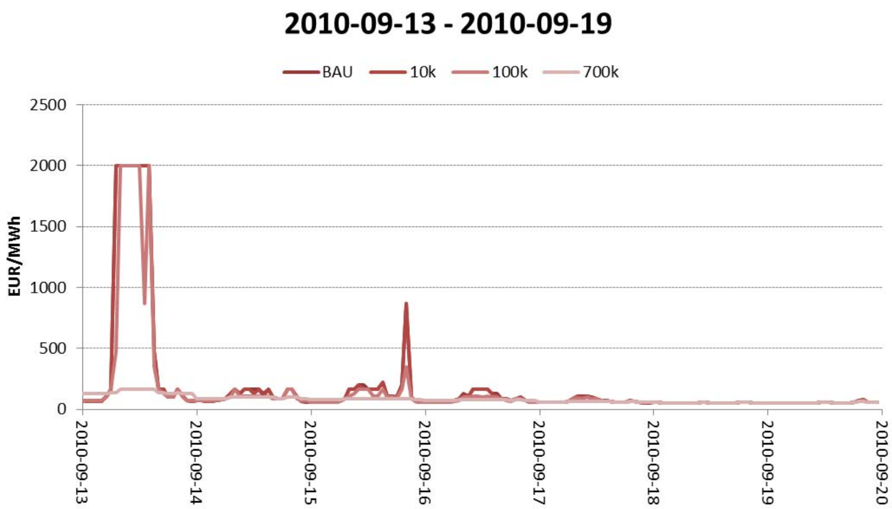


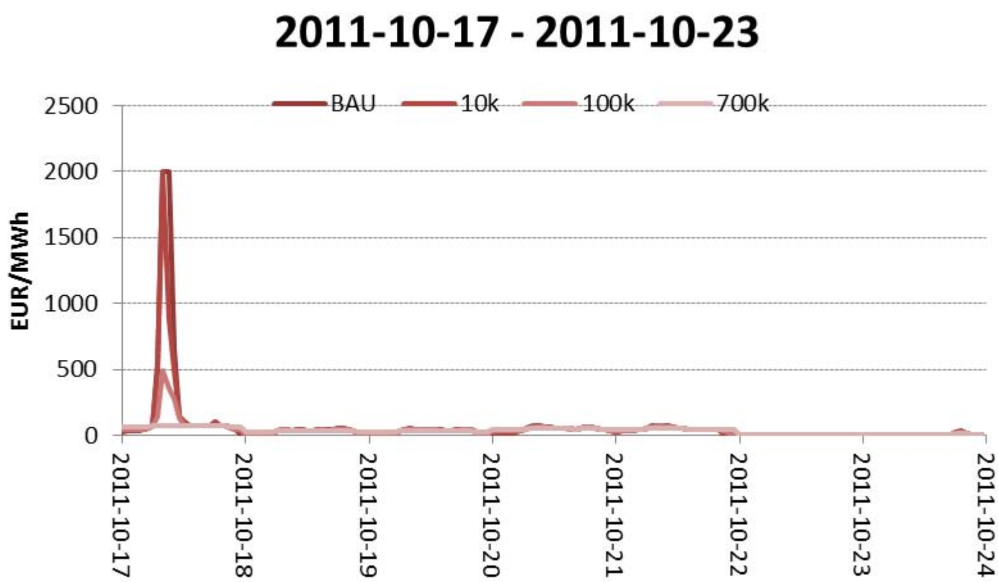


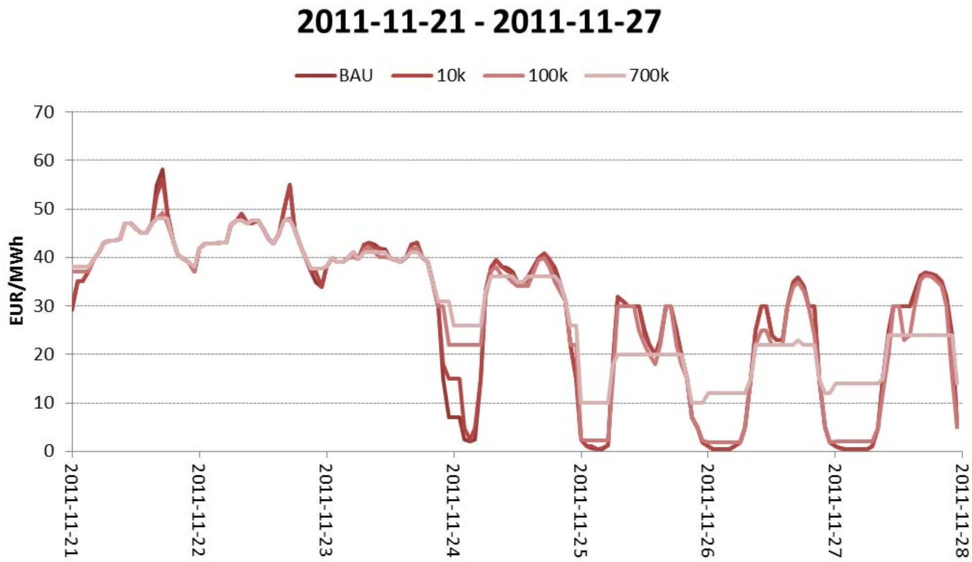

2010-05-24 - 2010-05-30
BAU
10k
100k
700k
EUR/MWh
6
5
4
3
2
1
0
2010-05-24
2010-05-25
2010-05-26
2010-05-27
2010-05-28
2010-05-29
2010-05-30
2010-05-31

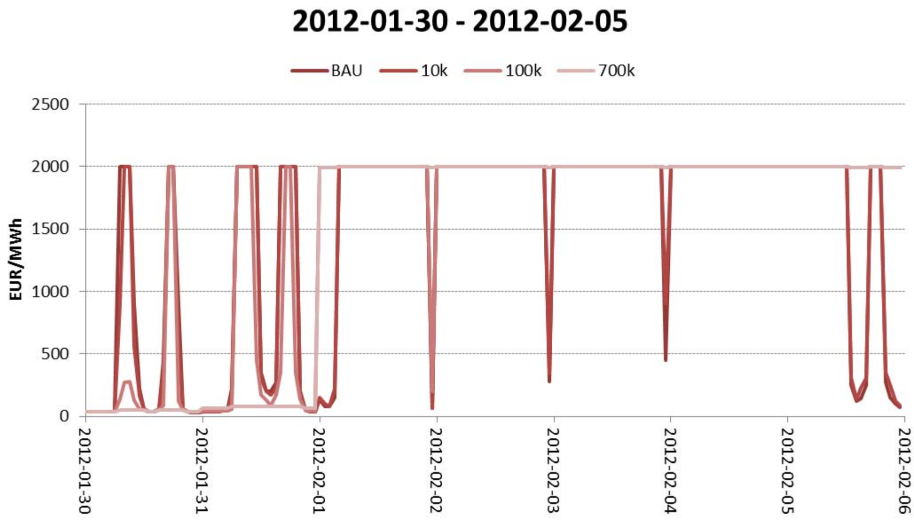

2010-06-07 - 2010-06-13
BAU
10k
100k
700k
EUR/MWh
5
4
4
3
3
2
2
1
1
0
2010-06-07
2010-06-08
2010-06-09
2010-06-10
2010-06-11
2010-06-12
2010-06-13
2010-06-14

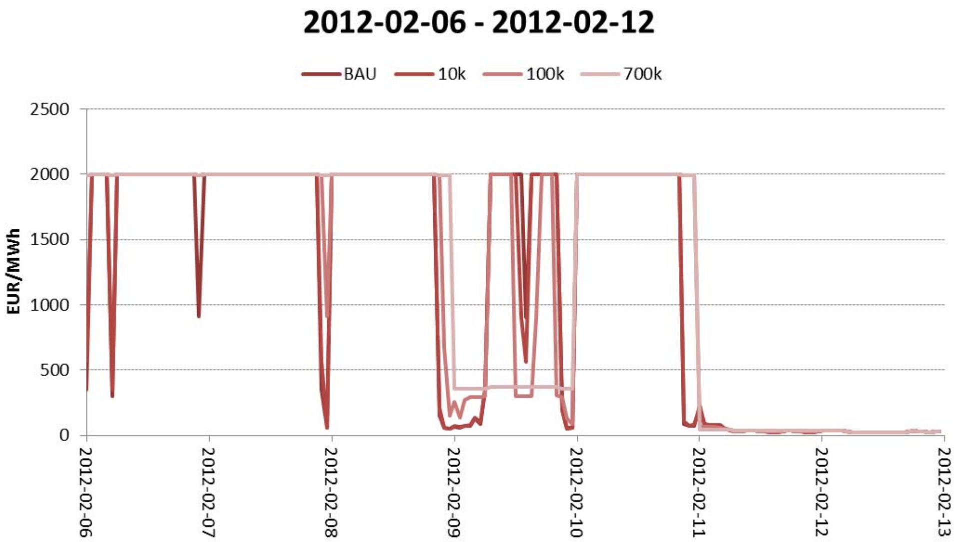

2010-07-05 - 2010-07-11
BAU
10k
100k
700k
EUR/MWh
60
50
40
30
20
10
0
2010-07-05
2010-07-06
2010-07-07
2010-07-08
2010-07-09
2010-07-10
2010-07-11
2010-07-12

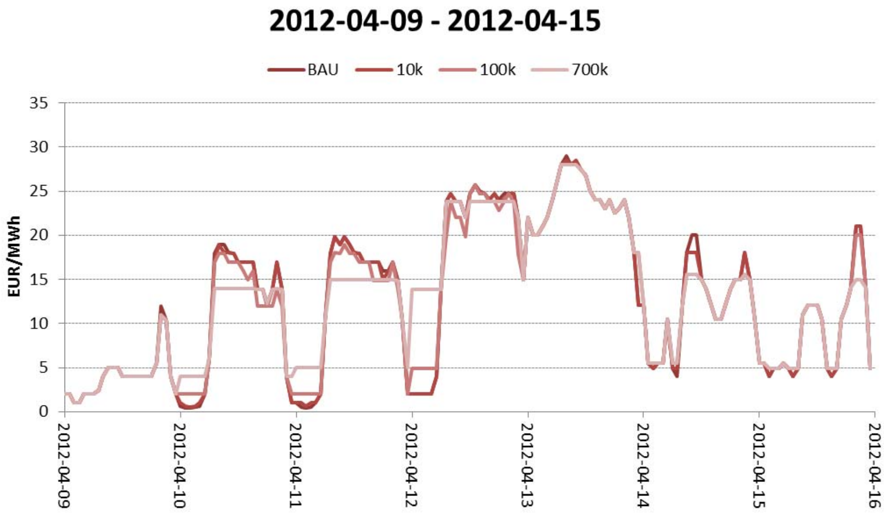

2010-09-13 - 2010-09-19
BAU
10k
100k
700k
EUR/MWh
2500
2000
1500
1000
500
0
2010-09-13
2010-09-14
2010-09-15
2010-09-16
2010-09-17
2010-09-18
2010-09-19
2010-09-20


2011-10-17 - 2011-10-23
BAU
10k
100k
700k
EUR/MWh
2500
2000
1500
1000
500
0
2011-10-17
2011-10-18
2011-10-19
2011-10-20
2011-10-21
2011-10-22
2011-10-23
2011-10-24

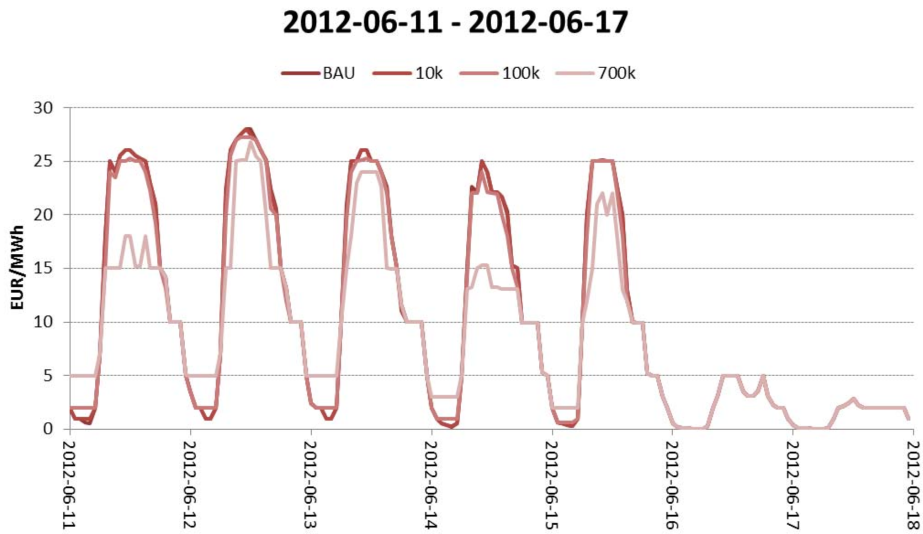

2011-11-21 - 2011-11-27
BAU
10k
100k
700k
EUR/MWh
70
60
50
40
30
20
10
0
2011-11-21
2011-11-22
2011-11-23
2011-11-24
2011-11-25
2011-11-26
2011-11-27
2011-11-28


2012-01-30 - 2012-02-05
BAU
10k
100k
700k
EUR/MWh
2500
2000
1500
1000
500
0
2012-01-30
2012-01-31
2012-02-01
2012-02-02
2012-02-03
2012-02-04
2012-02-05
2012-02-06


2012-02-06 - 2012-02-12
BAU
10k
100k
700k
EUR/MWh
2500
2000
1500
1000
500
0
2012-02-06
2012-02-07
2012-02-08
2012-02-09
2012-02-10
2012-02-11
2012-02-12
2012-02-13



2012-04-09 - 2012-04-15
BAU
10k
100k
700k
EUR/MWh
35
30
25
20
15
10
5
0
2012-04-09
2012-04-10
2012-04-11
2012-04-12
2012-04-13
2012-04-14
2012-04-15
2012-04-16



2012-06-11 - 2012-06-17
BAU
10k
100k
700k
EUR/MWh
30
25
20
15
10
5
0
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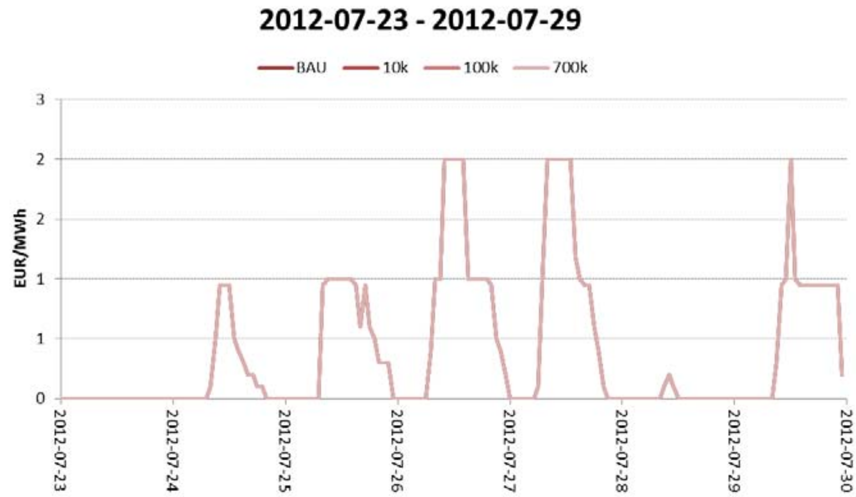
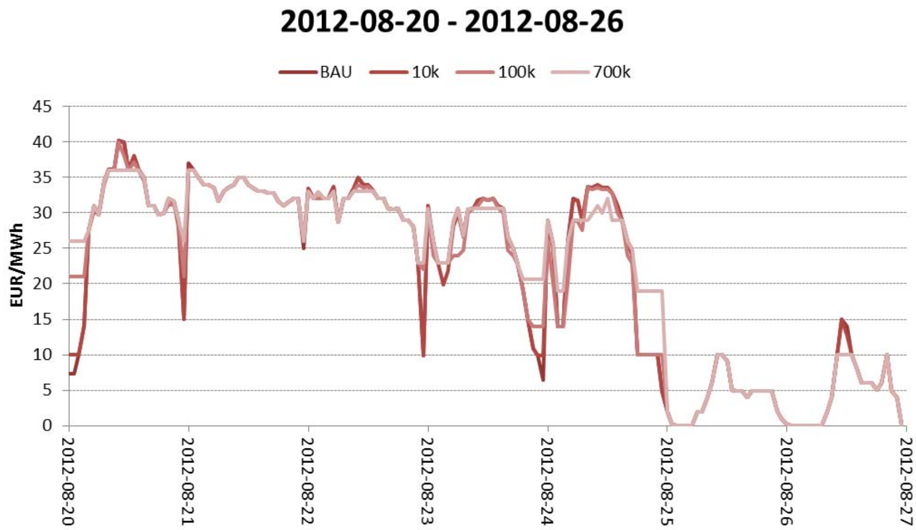
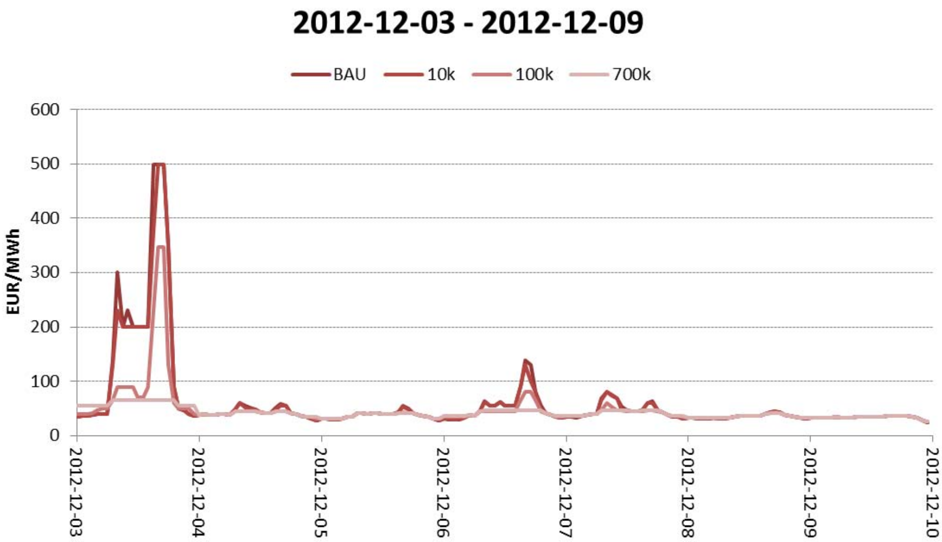
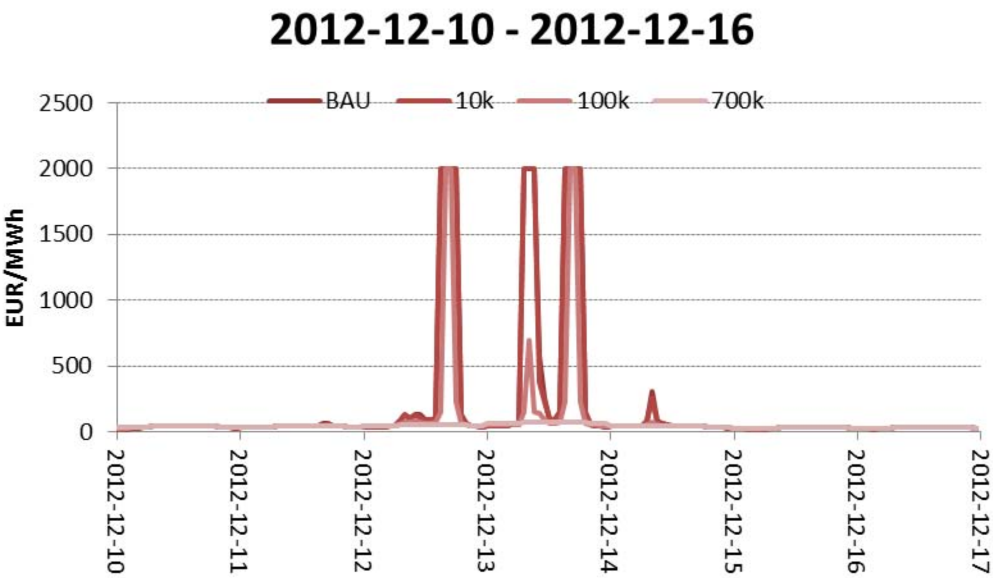
2012-06-16
2012-06-17
2012-06-18


2012-07-23 - 2012-07-29
BAU
10k
100k
700k
EUR/MWh
3
2
2
1
1
0
2012-07-23
2012-07-24
2012-07-25
2012-07-26
2012-07-27
2012-07-28
2012-07-29
2012-07-30


2012-08-20 - 2012-08-26
BAU
10k
100k
700k
EUR/MWh
45
40
35
30
25
20
15
10
5
0
2012-08-20
2012-08-21
2012-08-22
2012-08-23
2012-08-24
2012-08-25
2012-08-26
2012-08-27


2012-12-03 - 2012-12-09
BAU
10k
100k
700k
EUR/MWh
600
500
400
300
200
100
0
2012-12-03
2012-12-04
2012-12-05
2012-12-06
2012-12-07
2012-12-08
2012-12-09
2012-12-10


2012-12-10 - 2012-12-16
BAU
10k
100k
700k
EUR/MWh
2500
2000
1500
1000
500
0
2012-12-10
2012-12-11
2012-12-12
2012-12-13
2012-12-14
2012-12-15
2012-12-16
2012-12-17

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