Congestion in distribution grids

EVALUATION AND ANALYSIS OF DSO OPTIONS FOR CONGESTION MANAGEMENT IN SMART GRIDS

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Foreword

This report is part of the READY project, where large-scale control of individual heat pumps is developed and tested in real life. It is the second report from a work package that is focused on local congestions in the distribution grid. The first report is entitled ‘Managing congestion in distribution grids - Market design consideration’. The current report addresses the feedback received on the first report, and delves further into issues related to congestions in local distribution grids.

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

In preparation of this report, we have received important input from Galten Elværk. In addition, we received valuable feedback on the first report, including that from a number of participants whom participated in a Smart gird workshop held at Energinet.dk on November 5th, 2012. We are grateful for their time, insight and assistance.

1 Introduction

In Denmark, it is expected that the number of electric vehicles and heat pumps (the latter in particular) will rise substantially in the future, and as a result, so too will electricity consumption in the local DSO grids. In some of the local grids congestions might arise, and this report analyses how this problem can be solved using methods other than grid reinforcement, which is often an expensive solution.

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

Most grid companies in Denmark report that they expect to be challenged in their 0.4 kV grid in relation to the expected rise in consumption from EVs and heat pumps. However, the largest grid company in Denmark, Dong Eldistribution, reports that they expect challenges in the 10 kV grid. This relates back to the fact that each grid has its own story. Some grids have recently be cabled, and due to the large expenses and inconveniences related to burying cable, it is often worthwhile to incur the rather minor additional expense of over-dimensioning the cable.[1] The end result of this is that cable capacity is often abundant where overhead lines have recently been replaced with underground cables.

The solutions analysed in this report will be relevant for both the 0.4 kV and 10 kV voltage levels.

In order to implement any solutions to grid congestions that involve alternative pricing, and/or shifting of electricity consumption, varying hourly prices are required. In Denmark, on March 1st, 2016 "flexafregning" (flexpricing), is scheduled to be gradually rolled out to small end-users, thereby exposing them to individual hourly prices. Looking further into the future, this could open for the possibility of varying tariffs for the DSO costumers. (Arentsen, Danish Energy Agency, 2014) (Parbo, 2014).

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

Feedback on first report

There were a few issues raised, and feedback given, regarding a report previously released by the same working group entitled 'Managing congestion in distribution grids - Market design consideration'. The most prominent points raised are listed below, and each will be further addressed in the following chapters:

- Fairness, the question was posed whether it is fair that some people pay more for their electricity than others do.
- Incentives vs. penalties - Is it better to reward end-users for being flexible, rather than punishing end-users for being inflexible?
- A kW max solution has been pointed to by many actors as the most effective way of limiting net congestion. This begs the question, why not just implement such a maximum?
    - In order to better answer this last question (and in particular, compare it with alternative options), the report will look at state estimation, i.e. describe what it is, and outline how and where it is utilised today.
    - Lastly, a case will be presented where state estimation is used, which will look at the effectiveness of various congestion management options.

2 Fairness and carrot or whip?

2.1 Fairness – could some consumers pay more for electricity?

One of the discussions that is relevant for the handling of bottlenecks in the distribution grid is the question of fairness. Both the present and future loads on local grids will differ substantially in terms of geography. In the local grids, future problems in the grids will highly depend on the number of heat pumps and charging facilities for electric vehicles. In addition, the present state and load of the grid, as well as earlier strains on the grid, influence the potential of the grid to handle additional loads. As a result, not all grids will have congestions, and this raises the issue of fairness related to potential consumption constraints and varying tariffs. In order to contribute to this discussion, the analysis will first review other areas where varying prices exist.

Electricity prices

Present differences in electricity tariffs

In the electricity sector, there are already today differences in the prices paid by consumers according to where they live. For example, depending on where the DSO boundary is, end-users pay different amounts in distribution tariffs. For users with annual electricity demand greater than 4,000 kWh, the highest prices are over 55 øre/kWh, and the lowest prices are under 27 øre/kWh, (with an average of 40 øre/kWh) for grid and transmission tariffs, and fixed payments, with the various elements varying in cost. (Dansk Energi, 2013).

Øre/kWh	Annual usage in MWh							
	0.4 kV						10 kV	50/60 kV
	2	4	15	100	250	1,000	1,000	25,000
Highest price	89	56	36	35	30	29	23	18
Lowest price	30	26	19	14	13	12	12	10
Average price*	56	40	29	26	23	21	18	11

*Table 1: Grid and transmission tariff and fixed payments per DSO in Denmark 2013 (Dansk Energi, 2013). *Tariffs are weighted according to the various distribution company's transportation of electricity.*

Present time-of-use tariffs

Some distribution companies, for example DONG Energy Eldistribution, offer larger customers (i.e. businesses and industry) time of use difference in the electricity distribution tariff, but this is not available for small end-users.

Heating prices

Present differences in heating prices

Other forms of services also have varying prices for consumers based on their geographic location. One example is the price paid for heating a residence in Denmark. Between district heating companies there exists significant price differences. For example, the annual district heating cost for a standard house with a heat consumption of 18 MWh/year is under 8,000 DKK with the cheapest company, and nearly 32,000 DKK with the most expensive company (Energitilsynet, 2013). For those not connected to a district heating network, annual home heating prices range between 18,000 DKK for air/water heat pumps, to 25,000 DKK for heating with an oil boiler, and over 32,000 DKK for heating with direct electric heating (Dansk Fjernvarme, 2013).

Unfair differences in heating prices?

These differences may, to some extent, seem unfair, especially for those people living in areas with very expensive district heating and who are not allowed to disconnect from the district heating. Over the years, some political measures have been undertaken in an attempt to address these price differences. However, it is only the most expensive district heating companies that have gotten subventions, and/or have been allowed to choose other fuels. However, the fundamental differences in heating prices are generally accepted, or at the very least, acknowledged.

Other sectors

If we widen our scope beyond the power and heat sector, then there are a number of examples where differentiated prices are completely accepted. Transportation examples include road pricing or congestion taxes, where prices can differ according to the time of day, or parking, where it is quite normal that the car owner in effect pays according to the popularity of the parking space, its location, or time of use. The telecommunications sector is another that is rife with examples of costs differing according to time of use.

Conclusion on fairness of differentiated electric prices

As can be seen from the above discussion, there are already today large differences in the prices that consumers pay for electricity depending on their DSO, consumer size and/or time of use. The same can be said regarding a number of other sectors and areas, where price differences do not necessarily relate to differences in the product received.

If we return to the question of fairness regarding varying electricity prices, while there is no difference between one kWh and the other, there is however a difference related to congestions and to the historical circumstances regarding individual distribution nets. As such, relative to a number of other examples listed above, it seems no less ‘fair’ to vary electricity tariffs, thereby taking costs related to the constraints on specific grids into account.

2.2 Carrot or whip?

One of the elements of the first report that received the most feedback, and garnered the most discussion at a November workshop, was the concern that consumers that were not flexible were being punished by higher variable tariffs. It was often suggested that it would be much more equitable to instead reward those users that were flexible.

The primary reason for implementing variable distribution grid level tariffs is to have end-users reduce their electricity consumption in critical hours, and thereby allow DSOs to avoid investing in distribution grid expansions. As such, we can take as a point of departure that the funds available to a DSO to alter electricity consumption behaviour of end-users over the course of one year are equal to, or lower than, the savings that are derived from delaying investments in distribution grid infrastructure expansions.

Hypothetical example

If we take a fictional distribution grid (or perhaps Galten) with 40 end-users, we could make the following simplifying assumptions:

- Each end-user has an annual electricity demand of 4,000 kWh.
- There are 10 hours over the course of the year that will exceed the current capacity limits.
- For simplicity sake, each instance results in an electricity demand of 5 kWh/h above current limits (one could for example assume that the most critical portion of the distribution net can only tolerate a total demand of 55 kWh/h, but in these 10 critical hours the total demand is instead 60 kWh/h.).
    - Therefore, it is assumed that the 40 houses on average use 1.5 kWh/h during this most critical hour.
- It will cost 200,000 DKK to undertake an investment in infrastructure that will alleviate these congestions. These expansions can be amortised over a 35-year period at a discount rate of 3.5%.
    - This results in an annual cost of 10,000 DKK.
- The 10 congested hours are all equally critical, and the DSO therefore has at its disposal a maximum of 1,000 DKK for each hour, or 200 DKK per kWh (based on 10 hours, where in each hour the maximum is exceeded by 5 kWh/h).
- For a fee, there is a VPP in place that can aggregate and control a portion of the electricity demand in 10 of the houses.
    - The annual total cost for the VPP for these 40 houses is 5,000 DKK.

    - 10 end-users are able to shift 0.5 kWh/h each, and are willing to do so for a payment of 5 DKK per kWh.
- The solution arrived at must be revenue neutral for the DSO, i.e. the DSO must pass on all costs or savings to the 40 end-users.

If we look at one of these hours, the DSO then has a number of options:

Reinforcement of grid

1) Undertake a physical expansion of the grid and maintain a flat distribution tariff. The costs allocated for the first year of this expansion would be 10,000 DKK. Spread out over 40 houses and their respective 4,000 kWh usage, this would result in an increase to the distribution tariff of 6.25 øre/kWh, corresponding to an annual increase of <u>250 DKK per house</u>.

VPP Carrot

2) Maintain a flat tariff, but through a VPP, pay end-users to cumulatively reduce their consumption by 5 kWh for one hour by shifting it into a following hour. As 10 end-users are able to shift 0.5 kWh/h each, and are willing to do so for a payment of 5 DKK per kWh, this costs the DSO 250 DKK for the 10 hours during the year. In addition to the VPP cost of 5,000 DKK, this gives a total cost of 5,250 DKK.

   Spread out over the 40 houses this would result in the flat tariff increasing by 3.28 øre/kWh, corresponding to an annual increase of <u>131 DKK per house</u>. However, for the 10 houses that shifted their demand, they received a payment of 25 DKK over the course of the year, thus their net cost increase on an annual basis was <u>106 DKK</u>.

VPP Whip

3) Through a VPP, the DSO sends out a variable tariff to all 40 end-users that induces them to reduce/delay their consumption by the necessary amount during the 10 critical hours. As in the case above, it is determined that a payment of 5 DKK/kWh/h is required to shift the necessary amount of demand. Therefore, a variable tariff that is 5 DKK/kWh/h higher than the normal tariff is sent out to all end-users in the 10 critical hours.

   The cost associated with using the VPP is once again 5,000 DKK. For those 10 users that react to the price signal they now use 1.0 kWh/h instead of 1.5 kWh/h, and therefore pay an additional 5 DKK per hour during each of the critical 10 hours, for an additional annual cost of 50 DKK. Given 10 users, this corresponds to 500 DKK in additional tariffs for the 10 VPP participants. For the 30 end users that did not change their usage from 1.5 kWh/h, they pay 75 DKK more over the course of a year. Given 30 non-VPP end-users, this represents additional tariffs of 2,250 DKK. The DSO has now spent 5,000 DKK on the VPP and received 2750 DKK in revenue through the variable tariff. In order to maintain revenue neutrality, the difference, 2,250 DKK, shall be reflected in an increase in the normal flat tariff. Distributed over the annual 160,000 kWh (40 end-users at 4,000 kWh each), this results in an increase to the basic tariff of 1.41 øre/kWh. With a usage of 4,000 kWh, this results in an increase of 56 DKK/year for each user.

The bottom line is that for those that do not participate in the VPP, they will pay 131 DKK more per year, while those that do participate will pay 106 DKK more.

Direct price signal whip

4) The last variation involves sending a direct price signal to flexible end-users. As above, the DSO again sends out a variable tariff to all 40 end-users that induces them to reduce/delay their consumption by the necessary amount during the 10 critical hours. It is assumed that the annual cost to the DSO of sending out this signal is 2,500 DKK. Here the DSO does not utilise a VPP, and each of the 10 flexible end-users instead has to install equipment to receive the price signal. We assume that the equipment in the individual house costs 250 DKK per year, of which 200 DKK will be subsidised via the DSO and the rest is self-financed by the homeowner. Due to the self-financing, the homeowner now requires a larger incentive to shift the necessary amount of demand, i.e. 15 DKK/kWh/h instead of 5 DKK/kwh/h.[2] As such, a variable tariff that is 15 DKK/kWh/h higher than the normal tariff is sent out to all end-users in the 10 critical hours. The additional tariffs per non-flexible participant are thus 225 DKK per year[3], while for flexible participants they are 150 DKK higher per year[4]. This results in additional tariffs to the TSO of 8,250 DKK (6,750 and 1,500 DKK from non-flexible and flexible participants respectively). Meanwhile, for the DSO, the total annual costs are 4,500 DKK (the costs associated with sending out a price signal are 2,500 DKK, and the subsidised equipment were 2,000 DKK). Thus, the DSO must return this difference of 3,750 DKK to its customers on a per kWh basis. The end result is that non-flexible users pay 131 DKK more on an annual basis, and flexible users pay 106 DKK more.

[2] What is meant here, is that because the homeowner must first invest upfront in a home automation device, the previously promised 5 DKK/kWh/h tariff is not enough to encourage this investment. Instead, the homeowner now requires a tariff of 15 kWh DKK/kwh/h before they are willing to invest in this equipment.
[3] 10 critical peak hours each with a demand of 1.5 kWh/h, at an additional cost of 15 DKK/KWh/h.
[4] 10 critical peak hours each with a demand of 1.0 kWh/h, at an additional cost of 15 DKK/KWh/h.

The table below summarises the results from the above exercise.

Aspect	Unit	Option			
		1	2	3	4
Annual infrastructure expansion costs	DKK	10,000	-	-	-
Annual VPP costs	DKK	-	5,000	5,000	-
Annual cost of sending out price signals	DKK	-	-	-	2,500
Annual subsidy for equipment – total	DKK	-	-	-	2,000
End-user equipment cost – all flexible users	DKK	-	-	-	500
Total costs	**DKK**	**10,000**	**5,000**	**5,000**	**5,000**
Additional DSO revenues	DKK	-	-	-2,750	-8,250
Additional DSO expenses	DKK	-	250	-	-
DSO funds to be collected/dispersed (-)	**DKK**	**10,000**	**5,250**	**2,250**	**-3,750**
Annual DSO subsidy for equipment - per user	DKK	-	-	-	200
End-user equipment cost - per user	DKK	-	-	-	50
Increase in base tariff - non flexible user	øre/kWh	6.25	3.28	1.41	-2.34
Increase in base tariff - flexible user	øre/kWh	6.25	3.28	1.41	-2.34
Annual cost increase - per non flexible user	**DKK**	**250**	**131**	**131**	**131**
Annual cost increase - per flexible user	**DKK**	**250**	**106**	**106**	**106**

Table 2: Costs for end-users under four different hypothetical scenarios intended to deal with peak demand congestions during 10 critical hours.

The figures in the above exercise were selected so that the total cost of a VPP solution would equal those of a direct price signal situation (i.e. the total cost of options 2-4 are the same), and in practice this is not likely to be the case. However, the focus of this hypothetical is to illustrate the fact that if a congestion management solution must be revenue neutral, i.e. the DSO must pass on all costs or savings to end-users, then from a financial stand point it does not necessarily matter whether flexible customers are 'rewarded', or non-flexible customers are 'punished'. However, while the above argumentation likely holds from a financial standpoint, this is not necessarily the case from a political or public acceptance viewpoint.

2.3 Conclusion

Regarding the discussion of whether grid enforcement, or "carrot" or "whip" solutions should be used in relation to handling congestion bottlenecks, the analysis and calculations (given the selected assumptions) in this report conclude that from an economic viewpoint, it makes no difference for the consumer whether the implemented VPP solution is based on "carrot" or "whip" solutions, or direct price signals.

3 Measurements and state estimation

The following chapter describes what state estimation is, how and where it is utilised today, as well as the possibility of using remotely read data to provide the necessary data as input to state estimation.

Background

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

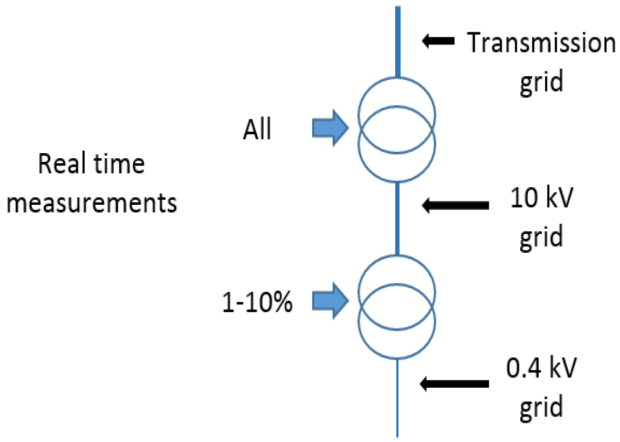

Figure 1: Measurements in the different grids in Denmark

In the future, greater knowledge about the state of the low voltage grids will be required. It would require significant investments in meter equipment if all 10 kV and 0.4 kV lines should be monitored in real time. However, use of powerful computers and state and flow estimators may deliver a detailed picture of the flow in all grid components.

Data for state estimation

State estimators use maximum likelihood methods to compute the state of the grid. The method can use measurements of varying quality, use information of the physical topology of the grid, and utilise user profiles for consumer groups to calculate the most probable state of all grid elements. State estimators are often used in relation to transmission grids, but could also be developed for distribution grids. Some DSOs already have projects developing this method. In a transmission system, there are sufficient measurements[5], while in distribution systems the measurements are usually much sparser.

[5] In fact, in transmission systems there are often more measurements than degrees of freedom, which essentially means that not all measurements can be used.

However, the installation of new interval meters will change this, as they will provide a number of new measurements.

Transmission grid state estimation

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

Dong's state estimator

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

Time delay

Currently the calculation is done three days after the operation day. This time delay is due to the time required for collecting the demand data from customers with hourly metering. If needed, the computation could be done after one day, in real time (with input about the expected demand), or even as a prognosis for the next day. However, this is not possible with the current system and a new system is currently on the drawing board.

10 kV or 0.4 kV?

While Dong is using state estimation on their 10 kV grid, most other DSOs report that they expect grid constraints on the 0.4 kV grid. These DSOs will need to develop and implement state estimators for this voltage level.

Meters for state estimation

Interval meters located at every consumer can help make the use of state and/or load flow estimators more viable and precise. These meters are typically read each night (with at least 24 values per day). This information can be used to construct the power flow in the distribution grid. In a grid without generation, the flow can be calculated by adding the demand from the relevant end-users.[6]

Location of meters?

Not all DSOs have an exact mapping of how and where individual meters are physically connected to the grid, but activities are underway to ensure the quality of such information. As such, implementation of state estimators, etc. can provide other benefits related to, for example, developing a better understanding of the physical grid.

Production from PV's

It is worth noting that generation from PVs are included in the measurements, so this generation does not disturb the calculation. However, in order to predict the state of the grid ahead of time, a sunshine prognosis must be included.

Real time or delayed measurements?

In order to determine the need for real time measurements it is important to consider the purpose of the measurements. If the purpose is the control of flexible demand, or changing flow in the grid to avoid overload in the immediate future then it is important to have real time measurements. However, if the primary purpose is grid planning, then a time delay of state estimation measurement is of much less significance, and the logging and collection of data can be much scarcer and thereby lower in cost.

Are the current meters sufficient?

A question that requires answering is whether it will be sufficient to measure with the meters that roughly half of Danish consumers already have installed, and that the rest of consumers will have installed before 2020 (Klima-, Energi- og Bygningsministeriet, 2013). This means that by 2020, there will be remote metering of every consumer. This begs the question: Will these meters (which generally can provide hourly metering) be sufficient for estimation of the grid

[6] Note that losses can be calculated based on the flow and cable properties, however in the more simplified calculations that are undertaken in Chapter 4, distribution losses are ignored.

state? As part of the answer, there are a number of noteworthy aspects that will be considered below.

IT systems

If the meters are to be used for operational purposes such as flexible demand, then increased data handling capacity will be required at the distribution companies. In many cases, this would mean that the IT systems would have to be upgraded in order to handle the large amount of data, especially if near-real time data are needed.

Critical areas

Another potential solution could be locating the critical radials. Measurements of critical grid areas may be read more frequently than once a day, and with a working state estimator, a map of critical elements can be computed. The DSO may also chose to use a sample of the end-users and measure their demand in real-time, or with a short delay.

Conclusion

In order to determine if they could provide all the necessary data for grid planning, and even real time grid activities, more knowledge is required regarding remotely read meters. Implementing real time reading of meters and upgrading IT systems would likely mean higher costs. At this point in time, it is not possible to say with 100% certainty if remote read meters will prove sufficient, or if meters in the cable boxes will also be required. However, as the next chapter will highlight, state estimators based on current meter technology can go a long way towards assisting distribution companies in managing potential grid congestions.

4 Demand control strategies

The two main control strategies that will be analysed in this chapter are a kW max-solution with and without heat pumps, and a strategy with a VPP. The analysis is based on real world data from Galten Elværk.

Galten Elværk

Galten Elværk (GE Net A/S) is a grid company West of Aarhus with 24,000 customers. The grid includes 10 kV (638 km) and 0.4 kV (899 km) distribution grids – all utilising underground cables. Total annual consumption in the area for 2011 was 293 GWh. In 2011, the utility started rolling out smart meters to all of its customers.

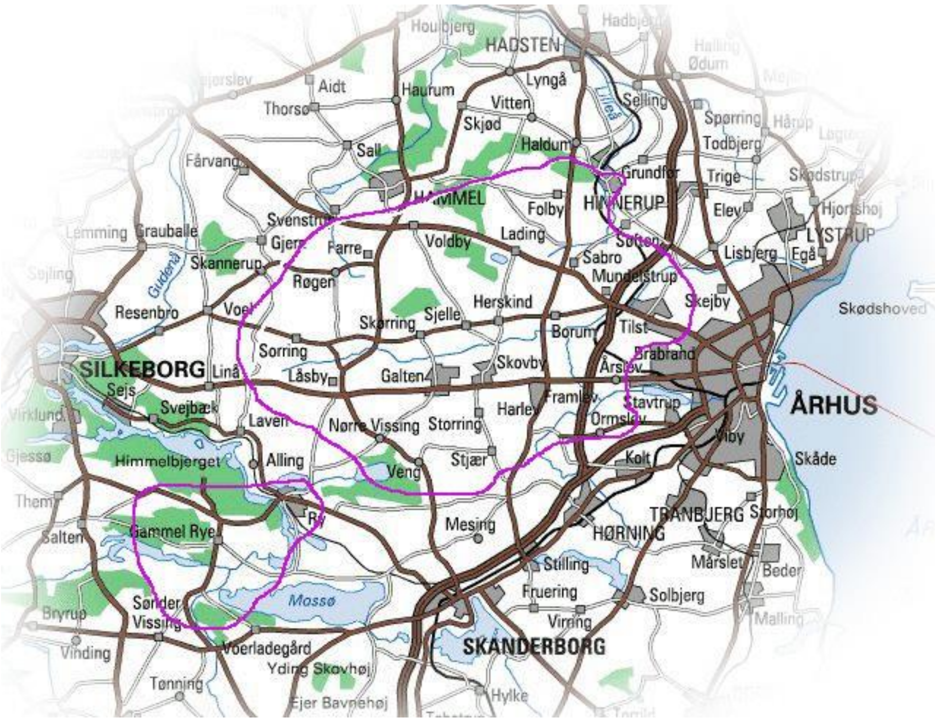

Figure 2: The purple lines indicate the two supply areas for Galten Elværk. The total area comprises 375 km².

Galten Elværk is able to read all meters with a notice of 3-4 hours and a hit-rate of approximately 90% of all meters. After 7-8 hours, the hit-rate rises to ca. 99.9%. Reading of e.g. 50 meters can be completed in 3-10 minutes with a hit-rate of 99.9%. The sampling period for the meters is typically 1 hour, but can be 5 minutes if needed. Currently it is only kWh/h data for each meter that is collected, but meters are capable of transmitting more information, e.g. consumption per phase and voltage (however, the phase ID (L1, L2, L3) is not synchronised for all installations). (Rasmussen, 2012 & 2013).

4.1 Substation 52 – Galten Elværk

To illustrate the potential of using a simplified version of a state estimator we have been permitted access to actual demand data from Galten Elværk. The raw dataset includes hourly consumption from March 1st, 2011 until October 19th, 2012 for 530 customers. The covered area is dominated by single-family houses without electric heating. There are a few cases with new PV installations. The dataset includes six stations (secondary sub-stations) each with a 0.4 kV distribution grid. These six sub grids are operated as radials (not meshed), and as such, can be seen as independent.

Substation 52

The dataset was not complete for all 6 secondary substations, and as a result the data for substation 52, where the data was complete, was selected for the analysis. There are 62 end-users that are supplied through station 52 in the grid. This sub-grid includes 25 cable boxes and 26 cable units (not including the 62 cables to the end-users). Note that the maximum effect that an average individual Danish house may utilise is 25 amps. This is roughly 17 kW, and figures within this report are given in kW as opposed to amps as the usage measurements received are in kW.

Sector	Number of customers[7]	Average hourly use per type	Average maximum load per customer	Customer with max. demand	Sector's contribution to max load	Average contribution to system max	"Smoothing"
Construction	2	0.5	3.6	4.0	2.5	1.2	66%
Trade	1	2.3	13.3	13.3	4.6	4.6	65%
Street lighting	1	1.7	4.9	4.9	4.6	4.6	7%
Single family house with electric heating	4	0.8	5.4	7.7	11.2	2.8	48%
Single family house with heat pump and PV	1	1.6	7.9	7.9	4.8	4.8	39%
Single family house	40	0.5	3.9	6.2	48.3	1.2	69%
Cultural activity	3	1.2	8.8	12.7	5.8	1.9	78%
Agriculture with PV	1	1.0	8.3	8.3	2.8	2.8	66%
Agriculture	6	1.2	9.8	16.5	15.7	2.6	73%
Institution	3	1.0	6.5	8.2	12.7	4.2	35%
Total	**62**	0.7	**5.2**	**16.5**	**113.1**	**1.9**	**65%**
	-	kWh/h	kWh/h	kWh/h	kWh/h	kWh/h	%

Table 3: Demand and smoothing for customers on station 52. The smoothing factor is calculated as: 1 – (the total maximum demand at the station / the sum of the individual maximum demand per customer[8]). E.g. for single family houses without electric heating a smoothing of 69% means that 69% of the individual maximum demand disappears when aggregated with the other 40

[7] Please note that the number of end-users in the groups are so small so they cannot be considered representative of average values.
[8] This individual demand maximums are at different times.

end-users. In essence, a high smoothing factor means that the average usage of that category during the peak hour is considerably lower than the sum of its individual maximums. The aggregated maximum is only 35% (100-65%) of the individual maximums.

The topology of the grid is described in a simple figure below. Each cable is described by its material, length and diameter. Based on this information the thermal capacity is calculated for the hour with peak demand on station 52. The demand data is hourly values.

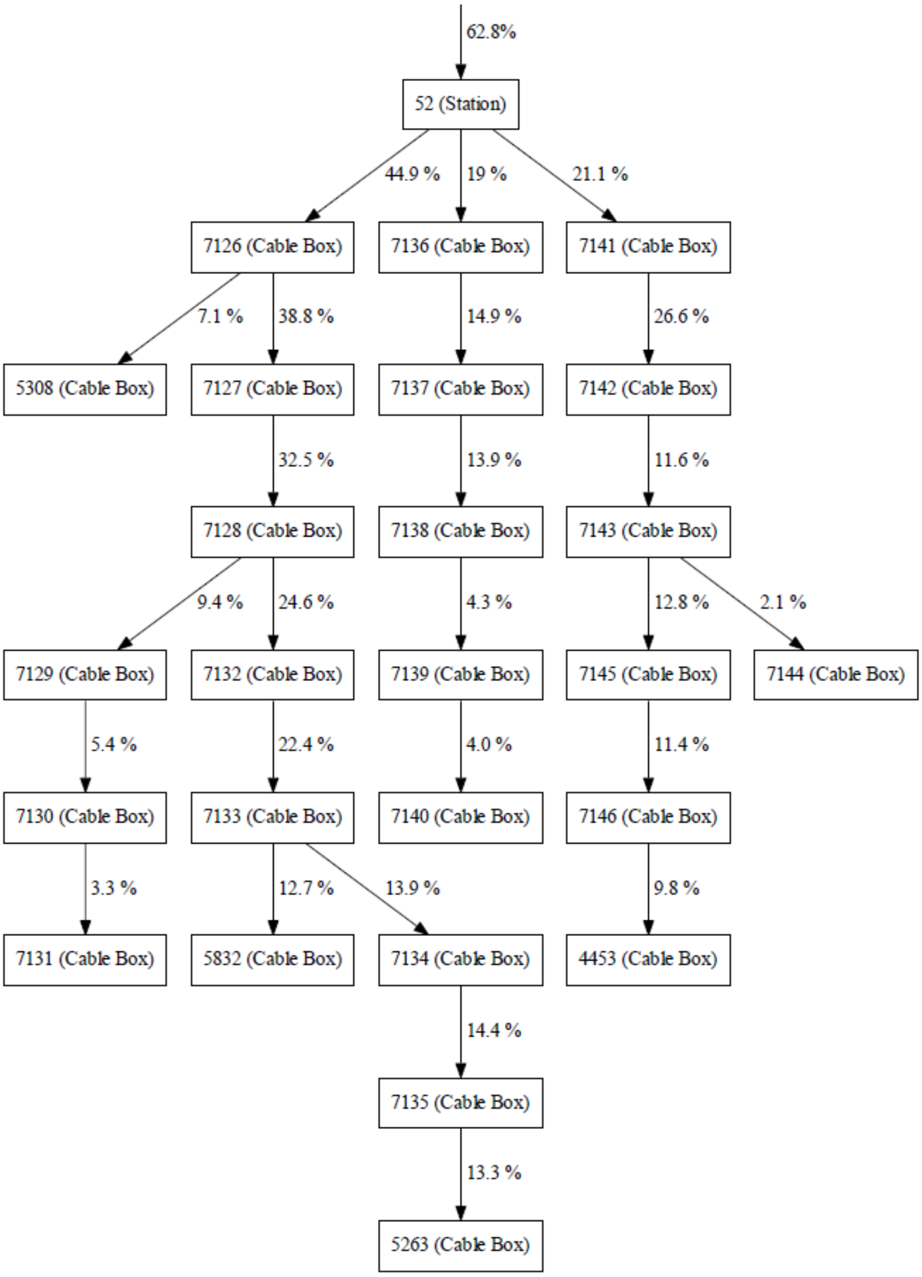

Figure 3: Capacity utilisation in the hour with peak demand for station 52 (February 7th, 2012, 18.00-19.00) assuming no losses. Numbers indicate the flow compared to the capacity of the cables. Asymmetric load on the phases, intra-hours variations and general security margin is not considered. The total load is 113 kWh/h.

Assumptions and observations

Assumption regarding symmetric load

Several factors should be included in a final evaluation of the results. The first is with respect to the load on the cables. For the sake of simplicity, this analysis assumes a symmetric load on the three phases. In practice, load will be asymmetric, and a security factor to reflect this should be included. This could reduce the available capacity with e.g. 10%. At the moment, little information exists about this issue. Special measurements, e.g. at a station, could describe the actual situation.[9]

Assumption regarding intra hour values

The current dataset is based on hourly values (average kWh/h). This means that maximum intra hour load always will be higher than that recorded for an hour. A security factor should also be used to reflect this. (For short periods, i.e. minutes, the stated capacity can also be exceeded). The ratio between highest demand (e.g. on five minute values) and hourly average can be expected to be highest at the end of the grid. Smoothing will reduce the factor at the station.

Assumption regarding losses

The computation could be expanded to include losses in the grid. Based on the power flow in each element, and the properties of the element, losses can be computed. This would increase the maximum demand. Typical values would be 1% loss in the transmission grid, and 5-6% in distribution grids.

Relative loads higher near the station

The relative loads of the cables are higher near the station. Closer to the customers, extra capacity (% wise) is needed because little smoothing takes place. At station 52, there is significant extra capacity closer to the consumers. In the current dataset, the highest relative loading on a cable is 45%[10], and this is on one of the three cables leaving the station (from 52 to 7126). The four next highest loads are connected to the same line (7126-7127-7128-7132-7133) with loads of 39-22%.

Affect of 'smoothing'

If no smoothing took place (all customers used their maximum demand at the same time) three cables would have been overloaded[11] (52-7126-7127-7128) and five cables would have had a loading above 50% (7141-7142; 8128-7132-7133; 52-7136).

Duration curve

The station is loaded with 63% of its capacity in the hour of maximum consumption. Note that the duration curve is rather steep at the beginning.

[9] Detailed information on the load per phase could be collected from each meter. This could be used to indicate the minimum and maximum asymmetry at the critical elements.
[10] Note that this value is before the inclusion of losses, asymmetric load on phases, and intra-hour variation.
[11] By 'overloading' it is meant that the average hourly demand exceeds the stated physical line capacity.

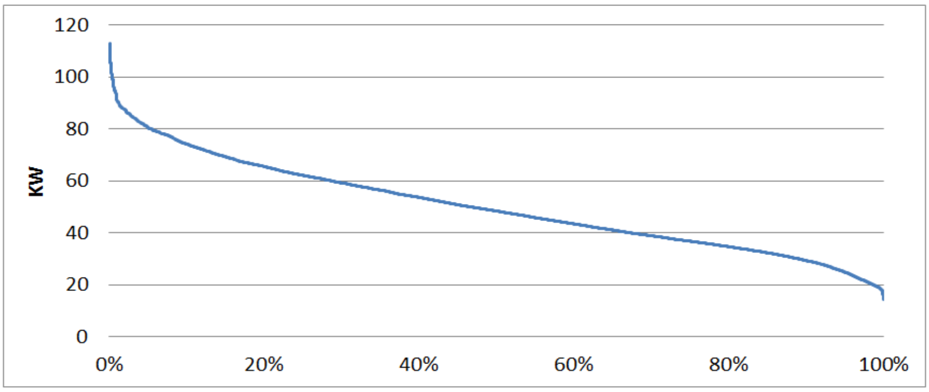

Figure 4: Duration curve for the load on station 52. Note that the maximum is 113 kW.

Voltage

Within the current exercise only power flow and maximum capacity is considered. In a 2012 study, both power flow and voltage were studied for three distribution grids (Pillai, 2012). Here it was concluded that keeping the voltage within the acceptable limits (+/- 6%) is more critical than overloading of cables and transformers.

It should be noted that based on the data available from Galten Elværk, the voltage can be computed in all grid elements. This would require a grid model (e.g. in PowerFactory). In a 2012 study (Pillai, 2012), the starting point was the load on the transformer, and assumptions were made regarding the distribution of load to the individual end-users. With the Galten case, information exists about the load from each individual end-user. The Galten case could therefore be more accurate in computing the voltage. However, computing voltage requires a great deal more computations than simply adding the individual demand as presented here.

4.2 Case study - A kW maximum rule

One of the measures that is often cited as being a potential option for reducing congestions in distribution grids is a 'kW maximum', which places a limit on the amount of electricity a customer may draw at any one time. The current contract allows each private end-user in Denmark to draw 17 kW, and more for some user categories. To test the effect of a kW maximum limit, end-user data from late June of 2011 to October of 2012 from station 52 within the Galten network was utilised.[12]

As was outlined in the previous section, station 52 consists of 62 end-use customers with a combined hourly load of 113 kWh/h during the hour of the year with the highest load. Of these 62 end-users, 40 are regular single family

[12] Raw data for the months March-June did not have individual readings and was therefore not used.

houses without heat pumps, electric heating or PV installations, which combined have a load of 48 kWh/h in the hour of the year with the highest load. In the following analysis, a fictional kWh/h maximum will be placed on these 40 units to see how this affects the congestion on lines and transformer boxes under station 52.

Current electricity demand

Hourly kW maximum – no time shift

In the first example, a series of hourly maximums are placed on the 40 regular single-family houses to see how this affects the hour with the maximum load, February 7th, from 18:00 to 19:00. With no individual maximum, the total load for these 40 houses is 48 kWh/h. Individual maximums ranging from 2.0 kWh/h to 6.0 kWh/h in intervals of 0.1 kWh/h were implemented and the results are displayed in Figure 5.[13]

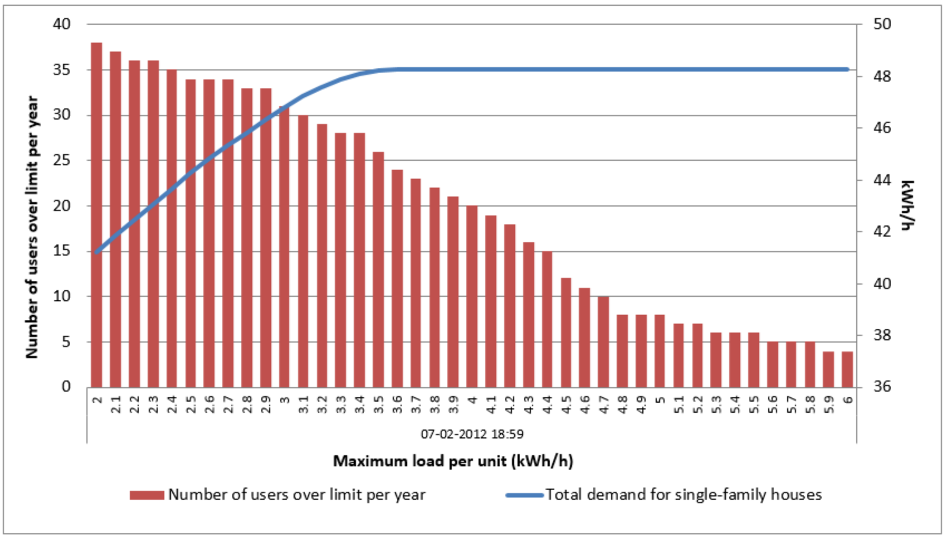

Figure 5: Effect of a maximum hourly load restriction on total load from 40 Single-family houses during the most congested hour (right axis), and number of users affected given a load restriction (left axis).[14] Please note that the right axis starts at 36 kWh/h.

It is important to reiterate that in this example, the restriction is only placed on the 40 single-family houses, which in total account for 48 of 113 kWh/h during the hour with the peak load.

A number of interesting observations can be learned from this exercise:

1) Firstly, it is not until the maximum hourly limit was reduced to 3.5 kWh/h that the total combined hourly load was reduced, and at this point, it was only reduced by 0.02 kWh/h. This means that if the hourly limit were set

[13] The reason for selecting 6.0 kWh/h as the highest maximum limit is due to the fact that the highest demand hour from one of the 40 houses during the year was 6.2 kWh/h.

[14] One of the houses had little to no electricity usage over the course of the year, and thus was unaffected by a capacity limit above 0.2 kWh.

to 3.6 kWh/h for each of the 40 single family homes, the hour with the highest load would not see a reduction in the congestion, despite the fact that 24 of the 40 users would see their electricity usage limited in at least one other hour during the course of the year. In fact, electricity consumption would on average be reduced in 25 other hours for each of these houses during the course of the year, despite the fact that no reduction to the most strained hour takes place.[15]

2) In Italy a 3 kW maximum is in place in some areas. If the same kWh/h maximum were put in place for the single-family houses in Galten, then the total load from these 40 single-family houses in the highest loaded hour would be 47 kWh/h, a reduction of roughly 1 kWh/h. This would involve 31 end-users having their electricity consumption capped at some point, with an average of over 63 instances per affected user per year.
3) Even with a maximum of 2 kWh/h, the new total single-family house load is only reduced by 7 kWh/h for a total of 41 kWh/h. This hourly maximum results in 38 of the 40 end-users having their consumption capped in at least one hour during the year, and an average of over 328 hours per affected user per year.

The above example demonstrates the fact that a kW maximum value (implemented for the whole year) can reduce the total load in the hour with the highest demand. However, in order to do so, the maximum must be set extremely low, and will affect a number of users in hours where there is no need for them to reduce their demand. The figures from the above exercise are summarised in Table 4.

kW max limit	Reduction in total demand (kWh/h)	Reduction in 40 end-user demand (kWh/h)	Affected # of houses during year	Average annual affected hours	Max hour date
17.0	0	0	0	0	Feb 7th, 18-19
3.6	0	0	24	25	Feb 7th, 18-19
3.0	1	1	31	63	Feb 7th, 18-19
2.3	5	5	36	229	Feb 7th, 18-19
2.0	7	7	38	328	Feb 7th, 18-19

Table 4: Summary of figures when a kW max solution without shifting of demand is implemented for a situation where the maximum demand hour during the year has a value of 113 kWh/h for all 62 end-users, and the 40 private houses share is 48 kWh/h.

[15] With an hourly maximum of 3.6 kWh/h, there are 598 instances in total where an end-user's demand is reduced. With 24 houses, this represents an average of 25 instances per user.

In the above example, any electricity demand beyond the hourly maximum was simply disallowed. In practice however, it is very likely that end-users would attempt to shift their usage instead of simply forgoing its usage. The next example therefore takes this into consideration.

Hourly kW maximum – shift of demand

In this example, the same conditions as above apply, however now any electricity usage from an hour where it exceeds the maximum is shifted forward to the next hour(s) with available capacity. With this set-up, the yearly demand is unchanged, but the dispersal is altered according to the individual maximum. The figure below displays how this shift in demand occurs for one of the houses during four days in February of 2012 assuming a kWh/h maximum of 2 kWh/h.

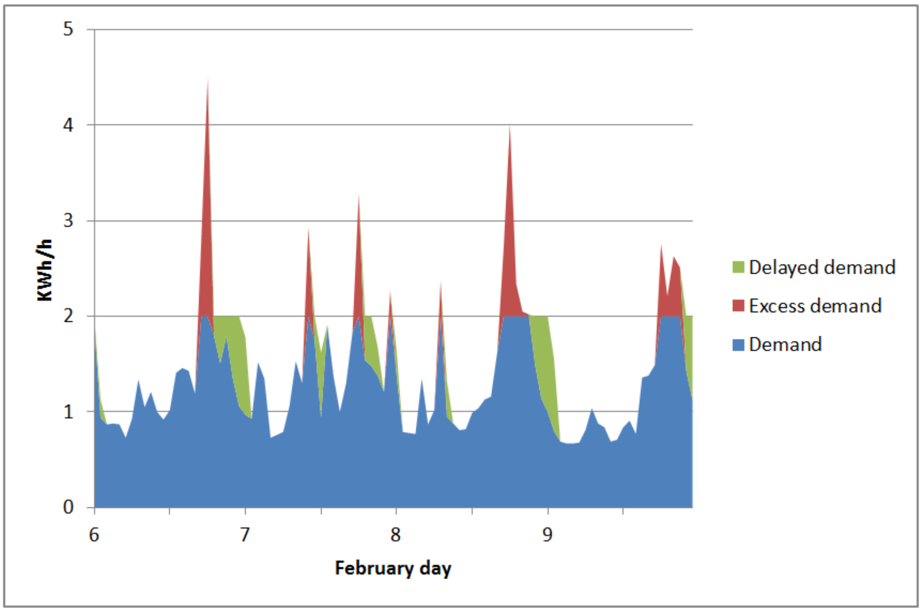

Figure 6. Illustration of restricted demand for one end-user for four days in February of 2012. Demand over 2 kWh/h is delayed until the next available period. Excess demand (red) represents demand that is greater than the 2 kWh/h and is therefore pushed into the next available hour(s).'Delayed demand' is excessive demand from a previous time period that could be accommodated in a future period.

As in the first example, there is no impact on the total maximum demand when restrictions above 3.6 kWh/h are put in place, and 24 houses are still restricted at some time during the year with a 3.6 kWh/h limit (please see Figure 7 below).

With a 3 kWh/h maximum, 31 houses are affected and the total from single family houses has been reduced by 1 kWh/h, resulting in new single-family and system totals of 47, and 112 kWh/h, respectively. These values are all unchanged from the former example, which did not include a shift in demand.

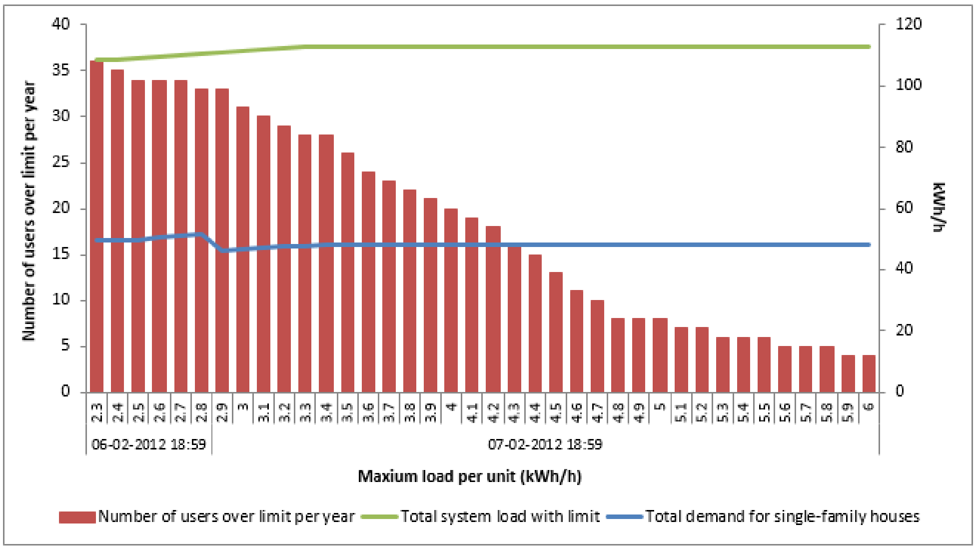

Figure 7: Effect of a maximum hourly load restriction on total system load, and total load from single-family houses (right axis), during the most congested hour, as well as the number of users affected over the entire time period (left axis), given a load restriction when load exceeding the limit can be shifted to the next available hour. Note that the secondary horizontal axis now includes both total single-family user load, and total system load, but the kWh/h maximum restriction only affects single-family houses. Also, note that when the restriction is decreased below 2.8 kWh/h, the hour with the highest system load shifts to February 6th, resulting in an increased contribution from single-family houses. However overall demand still falls, because this increase is offset by a lower contribution from the residual demand (non-single family houses demand).

If yearly demand is to be maintained it is not possible to reduce the maximum demand below 2.3 kWh/h. This is because the house with the highest demand has an average demand of 2.2 kWh/h during winter, so a restriction equal to this value would require a constant demand over the winter months. With the restriction set to 2.3 kWh/h, the total load maximum would be 109 kWh/h. This is the result of 6 of the 40 houses having demand shifted to a future period in this particular hour. These figures are summarised in Table 5.

kW max limit	Reduction in total demand (kWh/h)	Reduction in 40 end-user demand (kWh/h)	Affected # of houses during year	Average annual affected hours	Max hour date
17.0	0	0	0	0	Feb 7th, 18-19
3.6	0	0	24	25	Feb 7th, 18-19
3.0	1	1	31	63	Feb 7th, 18-19
2.8	2	-3*	33	92	Feb 6th, 18-19
2.3	4	-1*	36	229	Feb 6th, 18-19

Table 5: Summary of figures when a kW max solution with shifting of demand is implemented for a situation where the maximum demand hour during the year has a value of 113 kWh/h for

*all 62 end-users, and the 40 private houses share is 48 kWh/h. *These figures are negative, because when the maximum demand hour shifts from Feb 7th, to Feb 6th, the contribution from the 40 houses is higher (i.e. non-single family houses contribution decreases by roughly 5 kWh/h).*

As displayed in Table 5, with a 2.3 kWh/h maximum, 36 of the 40 users in the sample have their electricity demand restricted for at least one hour during the course of the year, with the number of instances totalling over 8,200, for an average of nearly 230 for each of the 36 end-users.

In the first example where excess demand was simply limited, but not shifted forward, a 2.3 kWh/h restriction resulted in a single-family house total of 43 kWh/h, and total maximum load of 108 kWh/h, i.e. a reduction of 5 kWh/h. As such, the impact of shifting demand is a marginal increase in the total maximum demand of only 1 kWh/h. This is perhaps somewhat surprising, but indicates that very little net demand from previous hours were moved forward. This finding is displayed in the figure below, which depicts the hourly demand for 40 houses without electric heating on February 7th, 2012 from 18:00-19:00. The red portions indicate demand in excess of 2.3 kWh/h that becomes shifted forward, and can comprise excess demand from the current hour and/or demand carried forward from a previous hour. Meanwhile the green portions portray demand that has been moved forward from a previous hour(s). During this particular hour, the green 'received' demand was all from the hour previous.

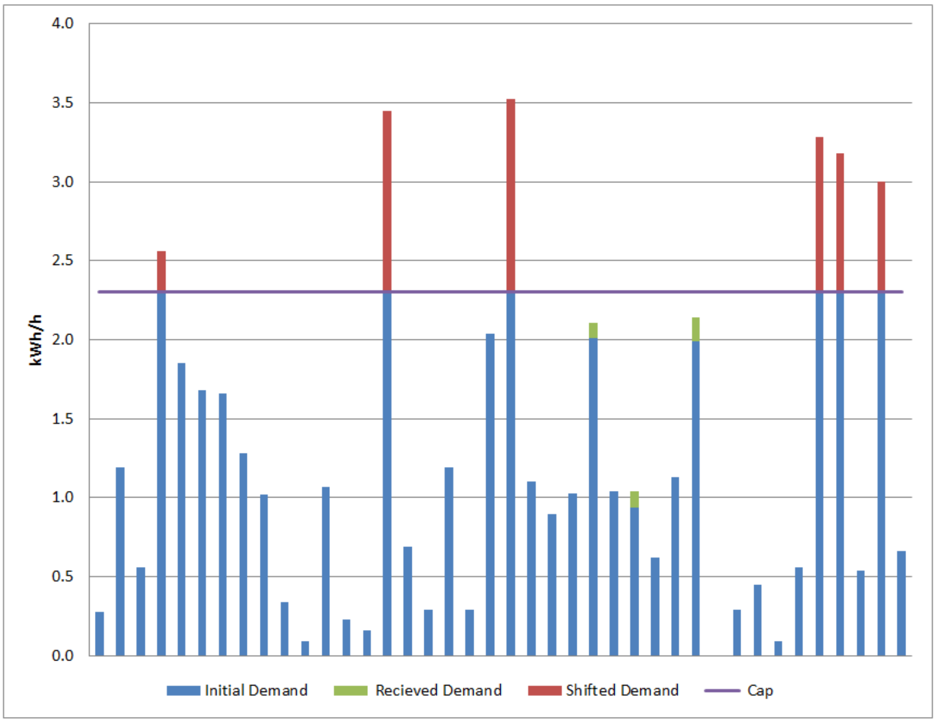

Figure 8: Electricity demand for 40 houses without electrical heating on Feb 7th, 2012 from 18:00-19:00 assuming a cap of 2.3 kWh/h. The red portion indicates demand in excess of 2.3

kWh/h that becomes shifted forward, while the green indicates demand that has been moved forward from a previous hour. The red portion can comprise excess demand from the current hour and/or demand carried forward from a previous hour. During this particular hour, the green 'received' demand was all from the hour previous. Of the houses that were in excess of the 2.3 kWh/h maximum, only the unit furthest to the left in the picture (number 4) was also in excess the hour previous as well.

The reason that the highest demand hour with a 2.3 kWh/h maximum shifts from Feb 7th to Feb 6th when we introduce the possibility to shift demand forward becomes clear when we compare Figure 8 with Figure 9. In Figure 8 we saw that rather little demand was brought forward into the hour on Feb 7th, 2012 from 18:00 till 19:00, but a great deal of demand was shifted forward. Meanwhile, when looking at Feb 6th, 2012 from 18:00-19:00, Figure 9 below shows that while there is still quite a lot of demand shifted forward, there is also a good deal of demand brought forward into the hour. It is due to the fact that the 'shifted demand - received demand' (depicted by the red and green portions respectively in the figures) is much larger on Feb 7th, as compared to Feb 6th from 18:00 to 19:00, that Feb 6th now becomes the hour during the year with highest total demand.

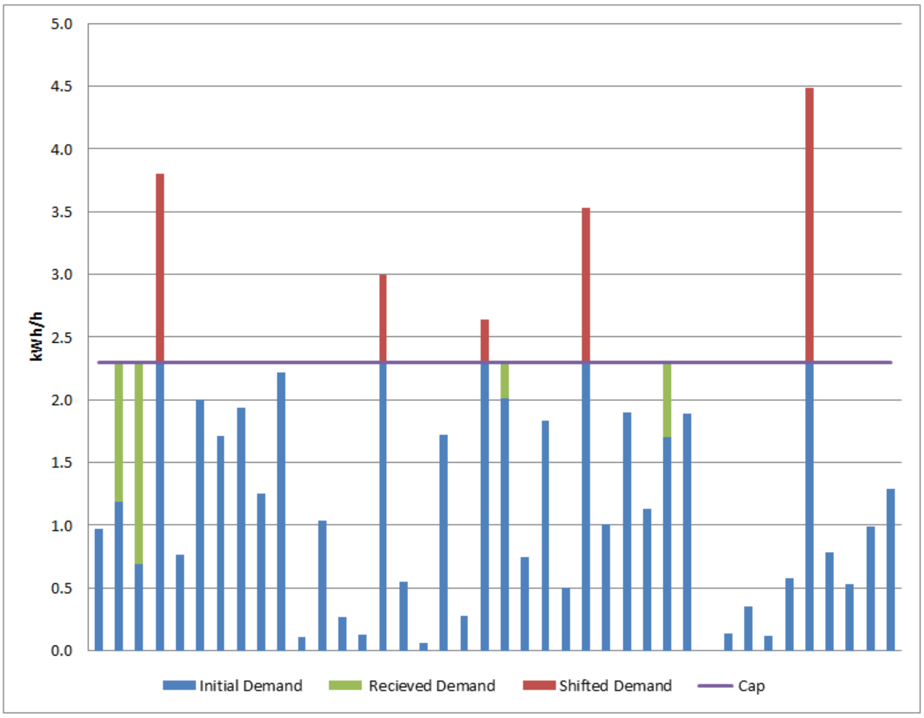

Figure 9: Electricity demand for 40 houses without electrical heating on Feb 6th, 2012 from 18:00-19:00 assuming a cap of 2.3 kWh/h. The red portion indicates demand in excess of 2.3 kWh/h, while the green indicates demand that has been moved forward from previous hours. The red portion can comprise excess demand from the current hour and/or demand carried forward from a previous hour. The four houses with demand shifted to this hour also have demand that is shifted further to the following hour. Of the houses that were in excess of the 2.3 kWh/h maximum, all were also in excess the hour previous.

To further understand the dynamics behind the shifting of demand to and from the hour comprising Feb 6th, 2012 from 18:00-19:00, Figure 10 displays the same data provided in Figure 9, but now also includes data for one hour before and after 18:00-19:00.

The figure displays the fact that if flexible, both houses 2 and 3 can shift a considerable amount of electricity demand from previous hours in the hours 18:00-19:00, and 19:00-20:00. Meanwhile, we see that a 2.3 kWh/h limit is very problematic for houses such as 4 and 25, which are not able to shift any demand into these 3 hours, and therefore would have to have significant flexibility if they were to maintain their overall electricity demand.

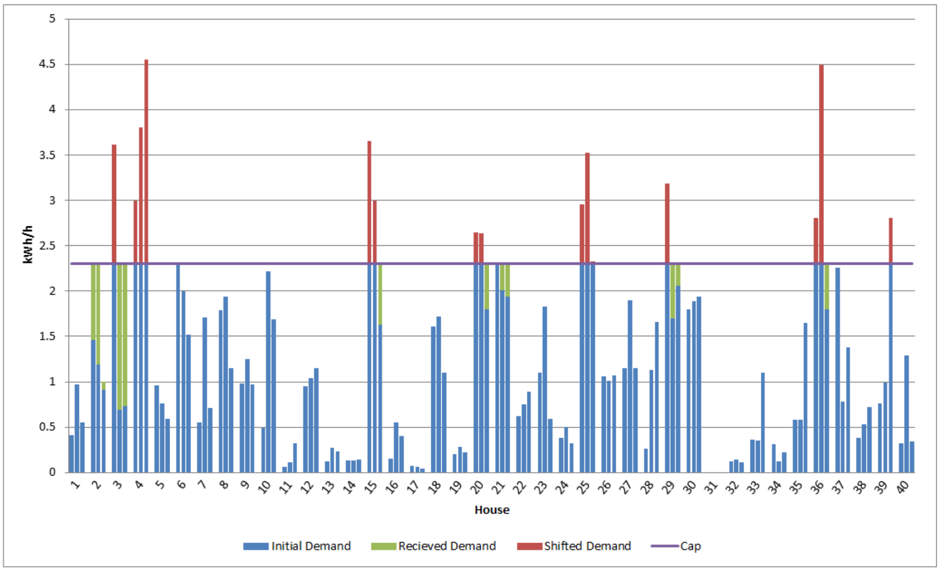

Figure 10: Electricity demand for 40 houses without electrical heating on Feb 6th, 2012 from 17:00-18:00, 18:00-19:00, and 19:00-20:00, assuming a cap of 2.3 kWh/h. The red portion indicates demand in excess of 2.3 kWh/h, while the green indicates demand that has been moved forward from previous hours. The red portion can comprise excess demand from the current hour and/or demand carried forward from a previous hour.

4.3 kW max – with additional heat pumps

As was displayed in Figure 3, given current loads, the distribution feeders from station 52 on the Galten grid do not have any major congestion issues at this time. However, in the future more houses are likely to convert to heat pumps as their primary source of heat.[16] Annual electricity usage from heat pumps differ according to size and type, but an annual additional consumption from the heat pump of 5,000 - 6,000 kWh is typical for a Danish house. As an average Danish house without electric heating typically uses 4,000 kWh today, the

[16] Heap pumps may not be relevant for this actual grid as most users have district heating and/or natural gas heating, but data from this grid will be used to illustrate issues that may be relevant in other grids.

addition of a heat pump represents an increase of well over 125%. This demand primarily takes place during the winter months were distribution lines are already most congested, and as such can provide a challenge to distribution grids.

To simulate how the Galten grid could potentially be affected, in the following example, 20% of houses that currently do not have electric heating are equipped with a heat pump.[17]

The electricity demand from the heat pumps is recorded demand from actual heat pumps that were part of the project 'Styr din varmepumpe' ('Control your heat pump'). One heat pump is from the Galten area and the other seven are from elsewhere in East Jutland. The eight heat pumps consume between 2,500 and 12,600 kWh/year (averaging 6,200 kWh/year). Due to the fact that actual measurements for the entire year were available it is possible to add the heat pumps consumption to individual house consumption and simulate a new load for the station 52 grid.

Figure 11 displays an updated version of Figure 3 after the demand from the 8 heat pumps has been added, thus revealing the load on each of the lines during the most congested hour of the year.

[17] The Danish government has indicated that it wishes to encourage a switch from natural gas or oil to heat pumps or district heating, and as such, some areas will likely see a number of heat pumps installed, while others less. The selection of 20% is therefore somewhat arbitrary, but it is deemed realistic for use in this example.

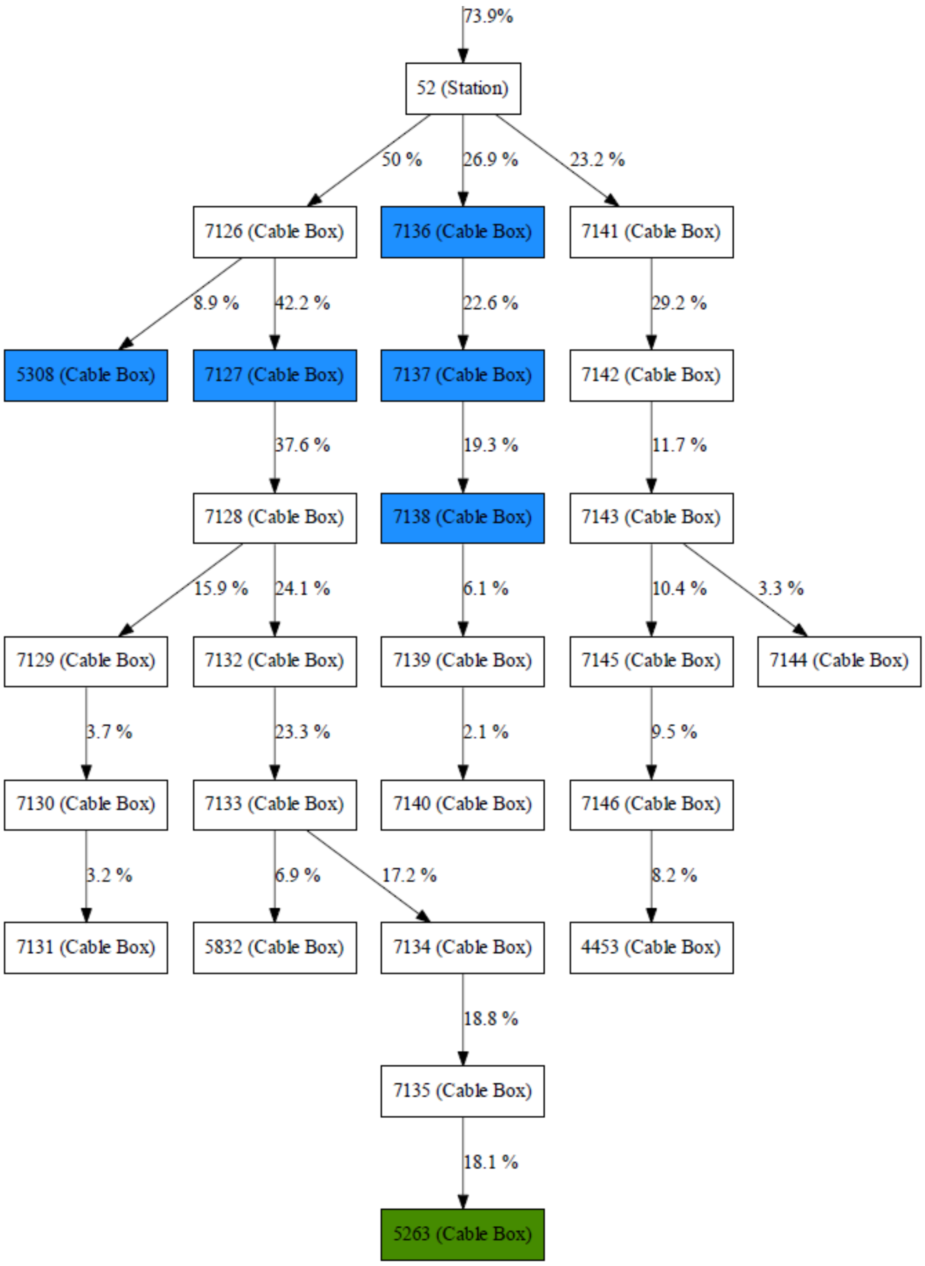

Figure 11: Capacity utilisation in the hour with peak demand for station 52 (February 4th, 2012, 18.00-19.00) after the addition of eight heat pumps assuming no losses. Blue boxes indicate those cable boxes where a single heat pump was directly added, while the green box indicates a cable box where 3 heat pumps were added. Numbers indicate the flow compared to the capacity of the cables. Asymmetric load on the phases, intra-hours variations and general security margin is not considered. The total load is 133 kWh/h (70 kWh/h from the 40 selected houses).

An updated duration curve including the demand from the eight new heat pumps is displayed below. While the hour maximum is now increased by 20 kW, the overall shape of the curve is unchanged.

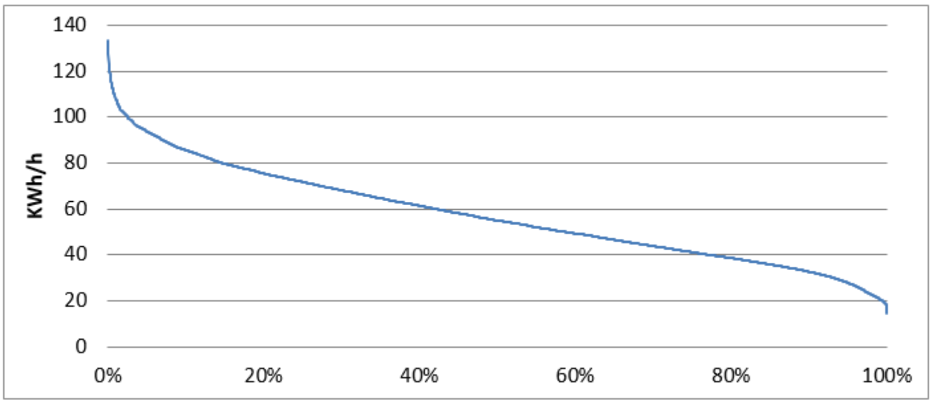

Figure 12: Duration curve for the load on station 52. Note that the maximum is 133kWh/h.

Hourly kW maximum – no time shift

A series of hourly maximums were again placed on the 40 regular single family houses to see how this affects the hour with the overall hourly maximum (see figure on following page). With no individual maximum, the hour with the highest system load is February 4th, 18:00-19:00, with a total load of 133 kWh/h, and total demand from single family houses of 70 kWh/h. Interestingly enough, none of the 40 single family houses, nor any of the other demand units under sub-station 52, has their individual yearly maximum demand during this hour.

As seen in figure 13, individual maximum restrictions ranging from 10.0 kWh/h to 2.4 kWh/h in intervals of 0.1 kWh/h were implemented.

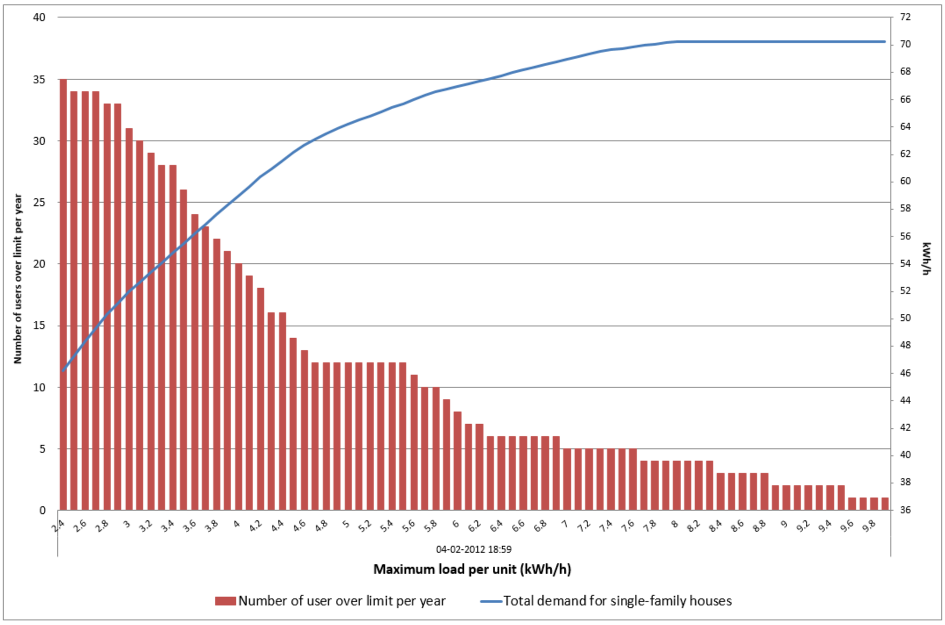

Figure 13: Effect of a maximum hourly load restriction on total load from 40 Single-family houses during the most congested hour (right axis) after eight houses have installed a heat

pump, and number of users affected given a load restriction (left axis).[18] Please note that the right axis starts at 36 kWh/h.

With a maximum individual hourly limit ranging from 8 and 10 kWh/h, the total maximum load during the most congested hour is not reduced, despite the fact that four, and one household(s) respectively, see limits on other hours during the year.

With an individual limit set between 6 and 8 kWh/h the total hourly maximum on February 4th from 18:00 to 19:00 falls slightly in tact with the restriction limiting two houses, namely unit #4 which had a demand of 7.3 kWh/h, and unit #21, which had a demand of 8.0 kWh/h.

kW max limit	Reduction in total demand (kWh/h)	Reduction in 40 end-user demand (kWh/h)	Affected # of houses during year	Average annual affected hours	Max hour date
17.0	0	0	0	0	Feb 4th, 18-19
8.0	0	0	4	7	Feb 4th, 18-19
4.0[19]	4	11	20	275	Feb 4th, 18-19

Table 6: Summary of figures when a kW max solution, with additional demand from heat pumps, without shifting of demand is implemented for a situation where the maximum demand hour during the year has a value of 133 kWh/h for all 62 end-users, and the 40 private houses share is 70 kWh/h.

As displayed in Table 6, to reduce the contribution from the 40 single-family houses by at least 10 kWh/h (that is to say below 60 kWh/h) would require an individual hourly limit close to 4 kWh/h. This would result in over half of the houses at some point during the year seeing their electricity demand reduced, with each house on average seeing more than 275 hours with restrictions.

Hourly kW maximum – shift of demand

When the excess hourly demand is instead shifted to future available hours, as opposed to simply being limited, it is deemed that the hourly kW maximum cannot be lowered below 6 kWh/h, as one of the houses with heat pumps cannot shift its electricity demand within a reasonable timeframe (see below).

[18] One of the houses had little to no electricity usage over the course of the year, and thus was unaffected by a capacity limit above 0.2 kWh.

[19] However, as will be highlighted in the following section, the implementation of a 4.0 kWh/h limit is not feasible if heating comfort is to be maintained.

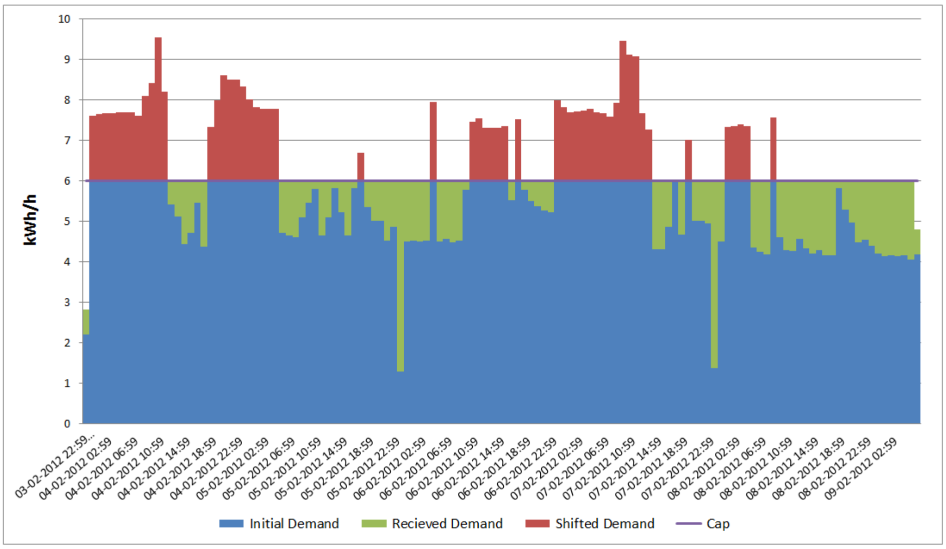

Figure 14: Hourly demand for house number 21 after the simulated electricity consumption from a heat pump has been added. As indicated by the green portion of the diagram (which covers over 125 hours), with an hourly maximum of 6.0 kWh/h it takes over 125 hours of shifting consumption forward before total hourly demand once again comes under 6.0 kWh/h.

With 6.0 kWh/h representing the lowest hourly maximum per unit, the total demand from the 40 single-family houses with this limit is reduced from 70 kWh/h to 67 kWh/h, and the maximum total system load is reduced to just under 130 kWh/h.

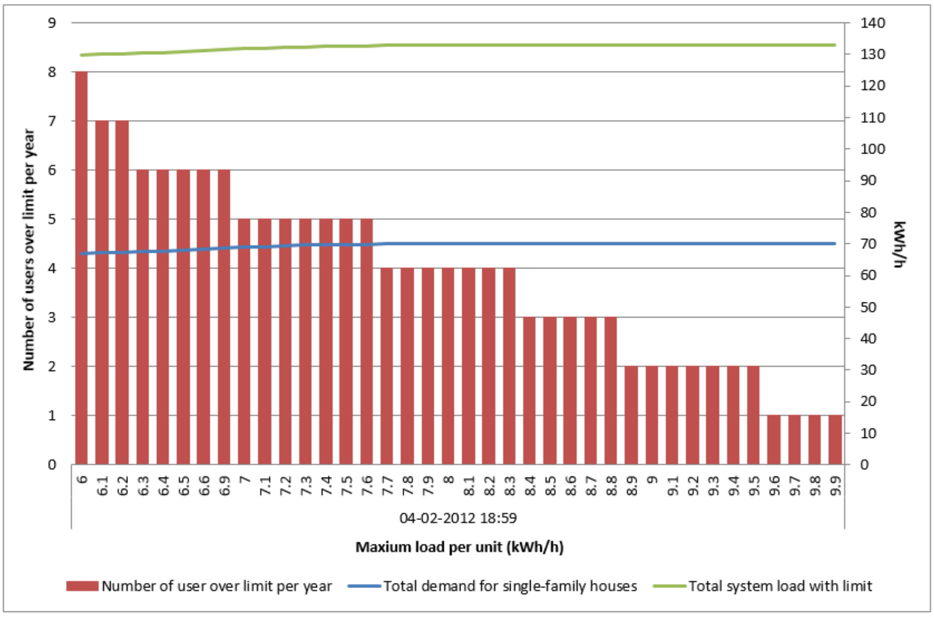

Figure 15: Effect of a maximum hourly load restriction on total load from 40 Single-family houses, and total system load during the most congested hour (right axis) after eight houses have installed a heat pump, and number of users affected given a load restriction (left axis), when load exceeding limit can be shifted to the next available hour. Please note that values for a max of 6.7 and 6.8 kWh/h are not included in the graph as there is a max hour shift for these two limits, which only serves to confuse the overall graph.

The 3 kWh/h reduction is brought about solely by shifting demand in unit numbers 4 and 21. Over the course of the year, despite the fact that it would not reduce the peak demand, six other users would also have to shift their demand in at least one hour. The total number of hours were shifts of demand would be undertaken by these eight end-users, without it resulting in a reduction in the overall system maximum, is over 400, for an average of over 50 instances for each of these eights end-users per year.

The figures from the latest version of the exercise are summarised in Table 7.

kW max limit	Reduction in total demand (kWh/h)	Reduction in 40 end-user demand (kWh/h)	Affected # of houses during year	Average annual affected hours	Max hour date
17.0	0	0	0	0	Feb 4th, 18-19
6.0	3	3	8	50	Feb 4th, 18-19

Table 7: Summary of figures when a kW max solution, with additional demand from heat pumps, with shifting of demand is implemented for a situation where the maximum demand hour during the year has a value of 133 kWh/h for all 62 end-users, and the 40 private houses share is 70 kWh/h.

If we zoom in on the highest demand hour under this scenario (Feb 4th, 2012 from 18:00-19:00), as well as the 2 hours prior and after it, we can see the effect of the limit on both the individual houses, and the overall station 52 load. The figure below displays the hourly electricity demand for the 40 houses in focus during this time span.

For each unit it is the middle of the five bars that is the most relevant, as this is the hour with the highest annual demand hour for station 52 as a whole. During this hour, we see that house numbers 4 and 21 have demand moved forward to a future hour. However, with the 6 kWh/h cap, there is no demand pushed *into* the most congested hour (as depicted by the lack of green in any of the middle bars for the 40 houses). As a result, when a 6 kWh/h hourly limit is imposed, the overall load on station 52 during this hour is the same regardless if excess demand is shifted forward, or simply cut-off.

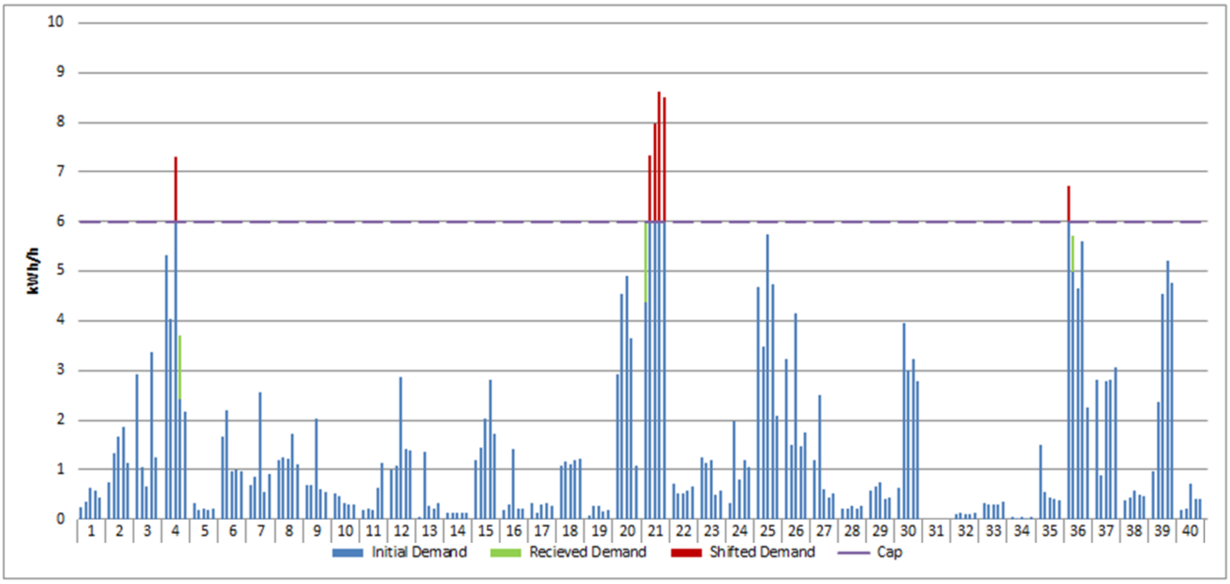

Figure 16: Electricity demand for 32 houses without electrical heating, and 8 houses with simulated heat pumps on Feb 4th, 2012 from 16:00-17:00, 17:00-18:00, 18:00-19:00, 19:00-20:00 and 20:00-21:00, assuming a cap of 6.0 kWh/h. The red portion indicates demand in excess of 6.0 kWh/h, while the green indicates demand that has been moved forward from previous hours. The red portion can comprise excess demand from the current hour and/or demand carried forward from a previous hour.

While the above figure illustrated the effect of the limit on the individual houses, the following figure illustrates the effect of the limit on the distribution grid related to station 52.

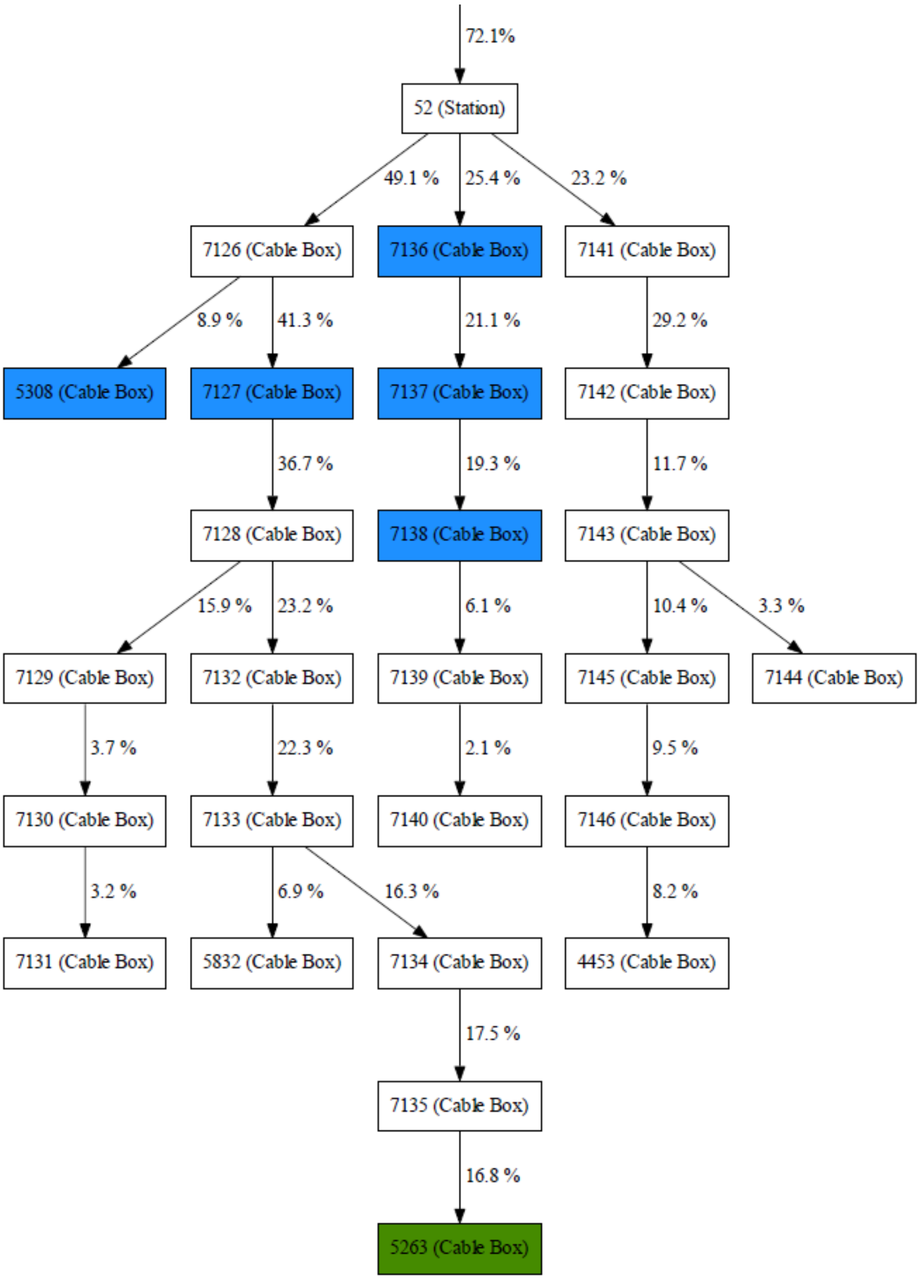

Figure 17: Capacity utilisation in the hour with peak demand for station 52 (February 4th, 2012, 18.00-19.00) after the addition of eight heat pumps assuming no losses. An individual maximum limit of 6.0 kWh/h has been imposed, and any excess demand is pushed forward to available hours. Blue boxes indicate those cable boxes where a single heat pump was directly added, while the green box indicates a cable box where three heat pumps were added. Numbers indicate the flow compared to the capacity of the cables. Asymmetric load on the phases, intra-hours variations and general security margin is not considered. The total load has been reduced from 133 kWh/h to 130 kWh/h.

In comparing Figure 17 with Figure 11, it is seen that the introduction of a 6 kW maximum limit (the largest that is deemed at all reasonable given the need to shift demand), reduces the most congested line under station 52 (52-7126) from 50% to 49%.

Conclusions

The implementation of a kW maximum on single-family houses without electric heating in an area such as Galten would have to be considerably lower than the current maximum (roughly 17 kW) before it would have any noticeable effect on the peak demand hour.

Current electricity demand

Without any additional electricity demand, a demand restriction above 3.6 kW would have no effect on the peak hour demand, but would still result in 60% of houses having their electricity demand restricted at some point during the year. The estimated maximum feasible cap under the current situation would be 2.3 kW, and such a cap would reduce the peak demand by 4 kWh/h (roughly 8.3% of single family houses usage and 3.5% of total peak demand on station 52). Meanwhile, this would involve 90% of the houses having to alter their demand at some point during the year.

Future electricity demand

In a simulated situation where eight of the forty houses in Galten have a heat pump installed, the maximum feasible hourly limit is deemed to be 6.0 kWh/h.[20] In this situation, the peak demand is reduced by roughly 3 kWh/h (corresponding to approximately 4.7% of single family houses usage and 2.4% of total peak demand on station 52), while 25% of all houses would see their consumption reduced in at least one hour during the year.

Given the extensive kWh/h maximum limit required, the rather small accompanying reduction in peak demand, and correspondingly high number of hours where end-users are affected, it is quite questionable whether a kW maximum solution is the most cost-effective way for reducing peak demand. The following section will look at alternative potential solutions.

4.4 Control of Galten end-users via VPP

In order to reduce overall system demand, an alternative option to the above kW max limit is a virtual power plant (VPP), where end-users agree to allow an aggregator control a certain portion of their electricity demand. In practice, there are number of ways this could be carried out, both via indirect (i.e. sending of price signals to end-users), or direct, control strategies. A plausible first generation VPP would likely be given permission to regulate particular devices in the house given agreed upon parameters. Non-heat related usages could include washing machines, dryers, dishwashers, electric vehicles, etc., all of which can often have their use postponed resulting in little or no reduction in customer comfort. In addition to this is heat-related electricity use, for

[20] Whether a limit this low is reasonable given that it requires a shifting of electricity demand for one of the house over 125 hours is in of itself highly debatable.

example from heat pumps or direct electric heating, where electricity usage can be altered with little or no loss in customer comfort.

Current electricity demand

As was done in the previous kWh/h maximum case, data from 40 Galten end-users under sub-station 52 was utilised to simulate the implementation of a VPP given current electricity demand. In practice, the amount of electricity that will be able to be shifted forward will depend on a number of factors, including: the hour of the day, day of the week, time of year, weather, and will vary greatly from user to user. For the sake of simplicity, in this exercise it has been assumed that for each of the 40 houses without electric heating, 30% of their hourly electricity demand is flexible, and that it can be shifted a maximum of 3 hours forward into the future. Given the aforementioned restrictions, the goal of the exercise was to minimise electricity usage in the hour with the highest overall system demand. The results of the exercise are displayed in Table 8.

	Current electricity usage				Current electricity usage + VPP			
	40 houses	Rest of system	Total	% system load	40 houses	Rest of system	Total	% system load
Electricity usage (kWh/h)	48.3	64.8	113.1	62.8%	36.5	64.8	101.3	56.3%

Table 8: Effect of implementing a VPP solution on 40 end-users given their current electricity demand. In both situations, the maximum demand hour was February 7th, 18-19:00. Figure 19 below displays how much each of the 40 houses reduced their individual demand during this hour.

As can be seen from the table, the implementation of a VPP on 40 end-users in Galten reduces the maximum load on the system by nearly 12 kWh/h. The hour of February 7th, 18-19:00, is still the maximum system demand hour. The corresponding reduction in the simulated '% system load', as previously displayed in Figure 3, as compared with Figure 18 below, has now been reduced by 6.5 percentage points.

As was the case in the previous example, the VPP was only implemented on 40 end-users, which are responsible for ca. 48 of the 113 kWh/h of demand during the maximum demand hour. If the VPP were to be implemented on the system as a whole, the overall reduction in the maximum demand hour would likely be a deal greater.

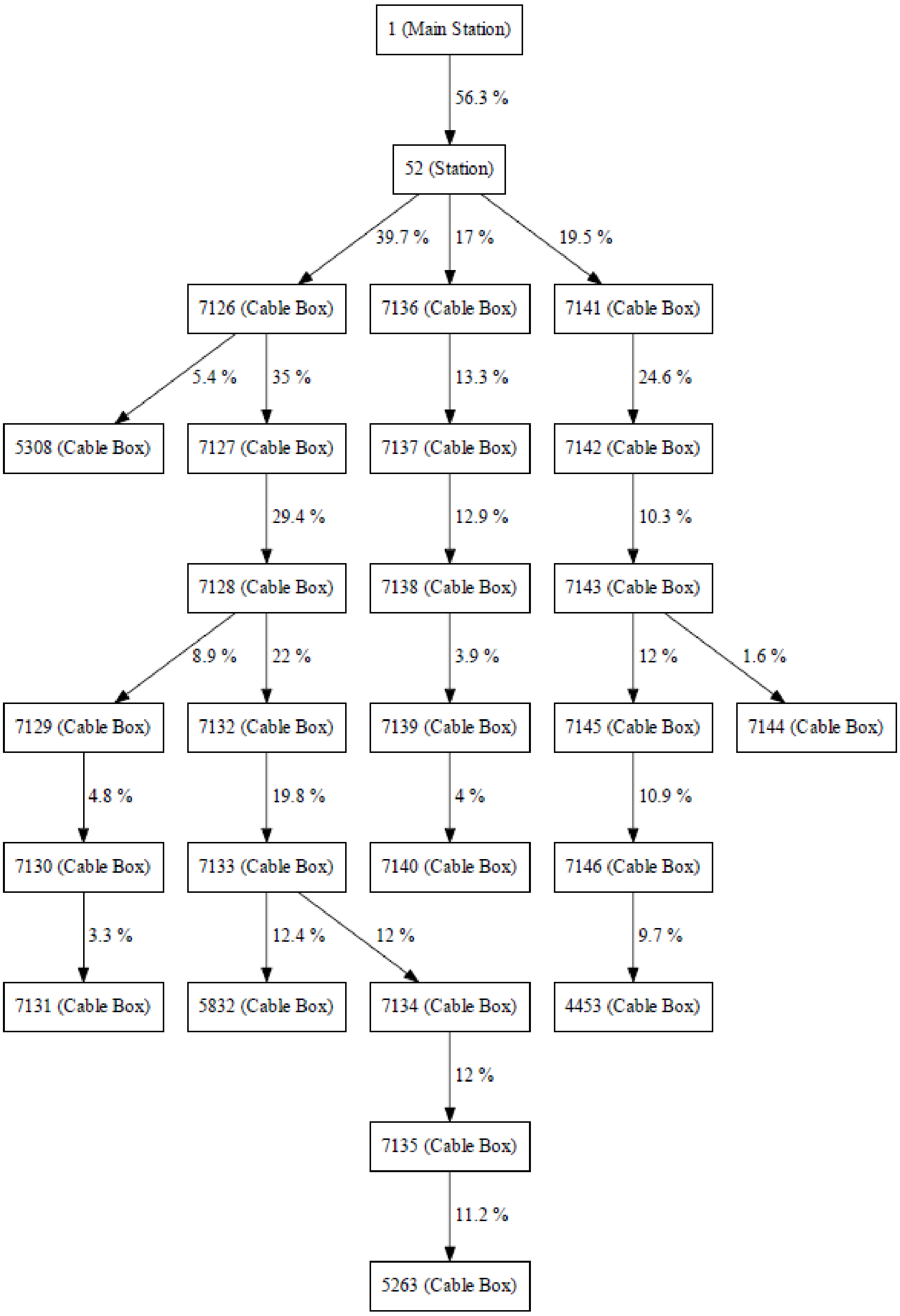

Figure 18: Capacity utilisation in the hour with peak demand for station 52 (February 7th, 2012, 18.00-19.00) assuming no losses, with the implementation of a simulated VPP. Numbers indicate the flow compared to the capacity of the cables. Asymmetric load on the phases, intra-hours variations and general security margin is not considered. The total load is 101 kWh/h.

To simplify the modelling, the same % reduction of an individual hour was applied to all 40 units. This simplification is reflected in Figure 19, which displays the effect of implementing the VPP on each of the 40 end-users during the hour Feb 7th, 18-19:00. From the figure, it is clear that the same proportion of demand is shifted from each unit. In practice, some units would be able to shift more or less in a particular hour, and thereby may be able to reduce the overall system load to a greater extent than displayed here.

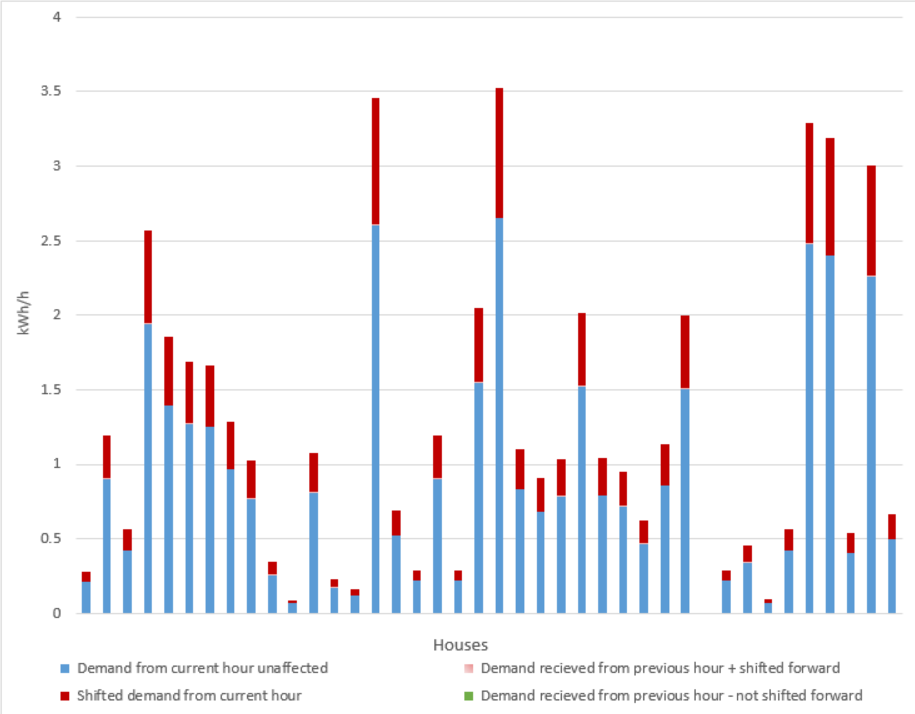

Figure 19: Simulated effect of implementing a VPP on 40 end-users in Galten during the hour Feb 7th, 18-19:00. With a VPP in place, nearly 12 kWh/h (depicted by the red) have been shifted from the current hour to a future hour.

While the previous two figures reflected on the impact of a VPP for the overall system under sub-station 52, Figure 20 looks at house #4 for a 24-hour period.

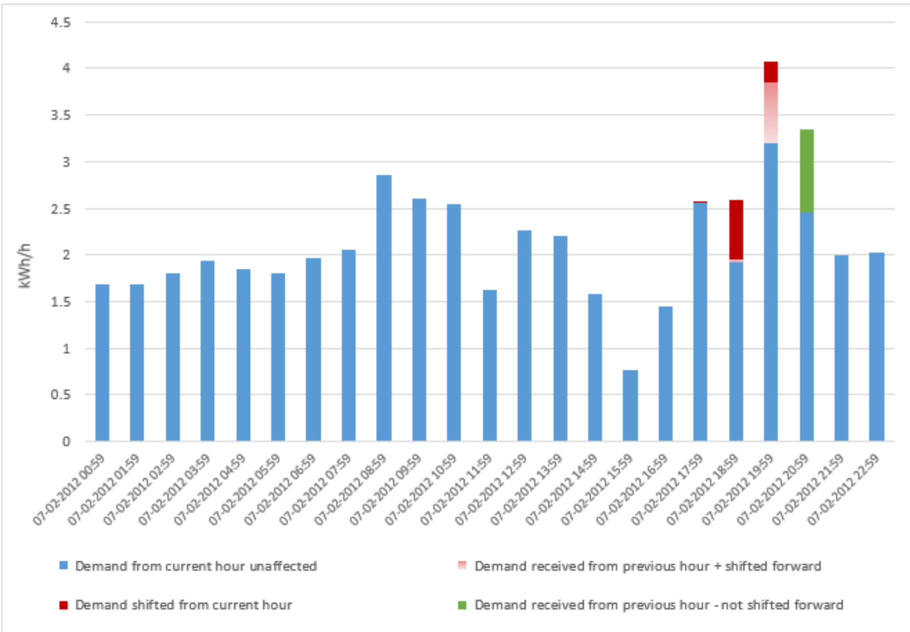

Figure 20: Simulated effect of implementing a VPP on house #4 during a 24-hour period on Feb 7th, 2012.

The figure displays how electricity demand was delayed via the modelling. It shows that a small amount of electricity was shifted from hour 17 (the thin sliver of red), further to hour 18 (the thin sliver of pink), further to hour 19 (a small portion of the large pink bar during this hour), and finally into hour 20 (part of the large green portion). Meanwhile, in hour 18, a good deal of electricity demand from this hour (the large red portion) is transferred further to hour 19 (the vast majority of the pink bar during hour 19), and further to hour 20 (again, as represented by the majority of the green). Lastly, during hour 19 we see that some of the electricity demand from this hour is sent forward (the red portion), but the majority (pink portion) is simply transferred forward from early hours.

In practice, the postponement would likely be more simple than described above, as it could for example involve the postponement of a device that would utilise 0.5 kWh/h from hour 18 to 20, and the postponement of a smaller device from hour 19 to 20.

The final figure in this section combines Figure 19 and Figure 20, by displaying the effect of a VPP on Feb 7th, and the two following hours, for all 40 houses.

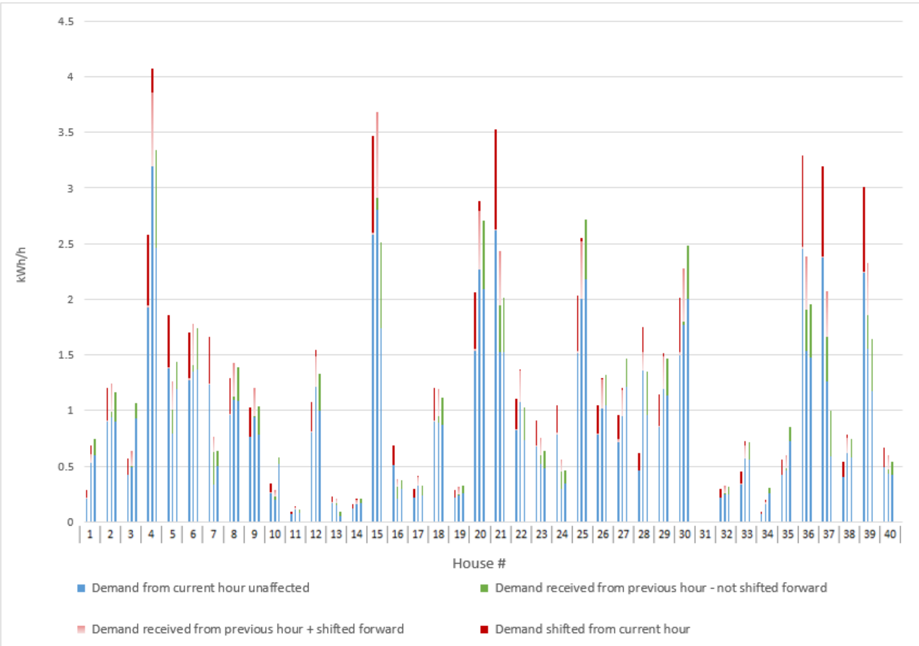

Figure 21: Simulated effect of implementing a VPP on 40 houses during a 3-hour period on Feb 7th, 2012, starting with hour 18-19:00.

In looking at Figure 21, it is interesting to note how the electricity from hour 18-19:00 is shifted forward depending on the house. For example, unit #4 reduces its demand in hour 18 (red portion in hour 18), reduces its demand in hour 19 (red portion in hour 19), as well as shifting forward the previous reduction (pink portion in hour 19), and finally utilises this shifted demand in hour 20 (green portion of hour 20). This is quite different from unit #36, where the reduction from hour 18 (red portion), is almost equally shifted to hours 19 and 20 (green portion of these two hours).

Future electricity demand

If we introduce heat pumps to the scenario, then there is a greater proportion of demand that is likely to be flexible. As such, the same eight houses that received a heat pump in the previous kWh/h max scenario, also received a heat pump in a VPP scenario. For this scenario, it is again assumed that 30% of the existing electricity demand is flexible, and can be shifted 3 hours in time. In addition, it is assumed that 50% of the additional demand from heat pumps is flexible, and can be shifted up to 3 hours. In practice, heat pumps generally operate 100% on or off, however, this 50% figure is an average for the eight heat pumps, and is also an hourly average, so they could in principle run for 30 minutes of a given hour in this modelled scenario. The results of this scenario are displayed in Table 9.

	Heat pumps				Heat pumps + VPP			
	40 houses	Rest of system	Total	% system load	40 houses	Rest of system	Total	% system load
Electricity usage (kWh/h)	70.2	62.9	133.1	73.9%	54.8	62.9	117.7	65.4%

Table 9: Effect of implementing a VPP solution on 40 end-users given their current electricity demand. In both situations, the maximum demand hour was February 4th, 18-19:00.

After eight users have electricity demand from heat pumps added, the implementation of a VPP on 40 end-users in Galten reduces the maximum system load by more than 15 kWh/h during the maximum system load hour, February 4th, 18-19:00. This reduces the computed system load on the sub-station from 73.9% to 65.4%, as displayed in the figure below.

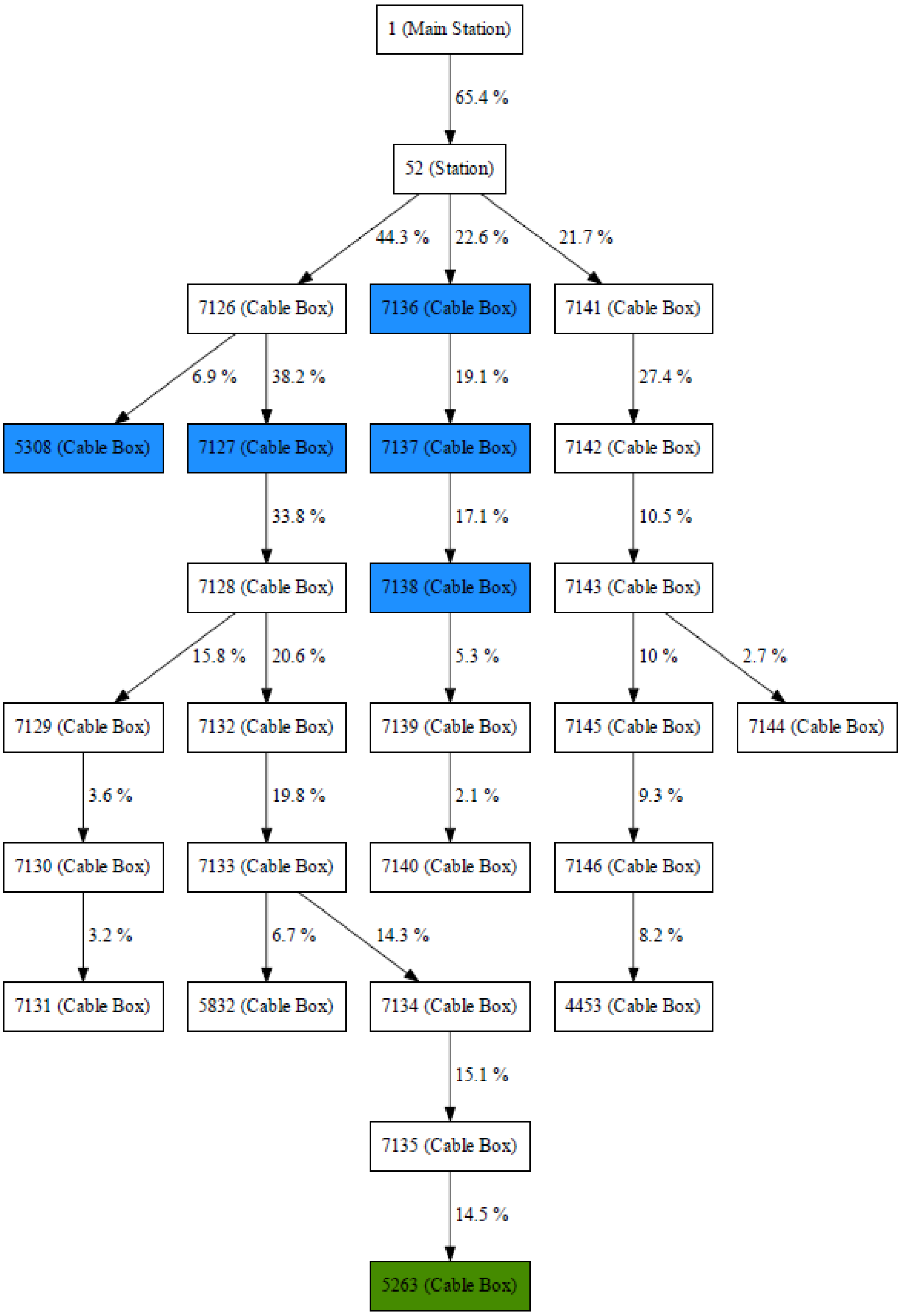

Figure 22: Capacity utilisation in the hour with peak demand for station 52 (February 7th, 2012, 18.00-19.00) assuming no losses, with the implementation of a simulated VPP, and 8 heat pumps added. Blue boxes indicate those cable boxes where a single heat pump was directly added, while the green box indicates a cable box where three heat pumps were added. Numbers indicate the flow compared to the capacity of the cables. Asymmetric load on the phases, intra-hours variations and general security margin is not considered. The total load is 118 kWh/h.

If we once again zoom in on house #4 for a 24-hour period, (see Figure 23 below) we can see how the electricity demand is dispersed before and after the implementation of a VPP in a situation where house #4 has received a heat pump.

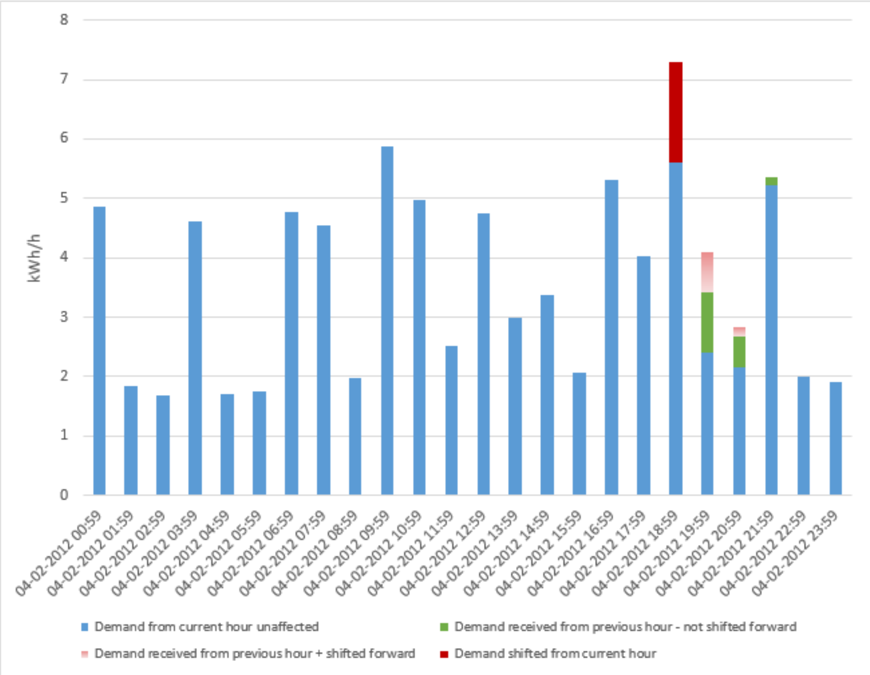

Figure 23: Simulated effect of implementing a VPP on house #4 during a 24-hour period on Feb 4th, 2012 after this house, and 7 others have received a heat pump.

Meanwhile, Figure 24 highlights how the implementation of a VPP affects each of the 40 houses over a 4-hour period, starting on Feb 4th, 2012.

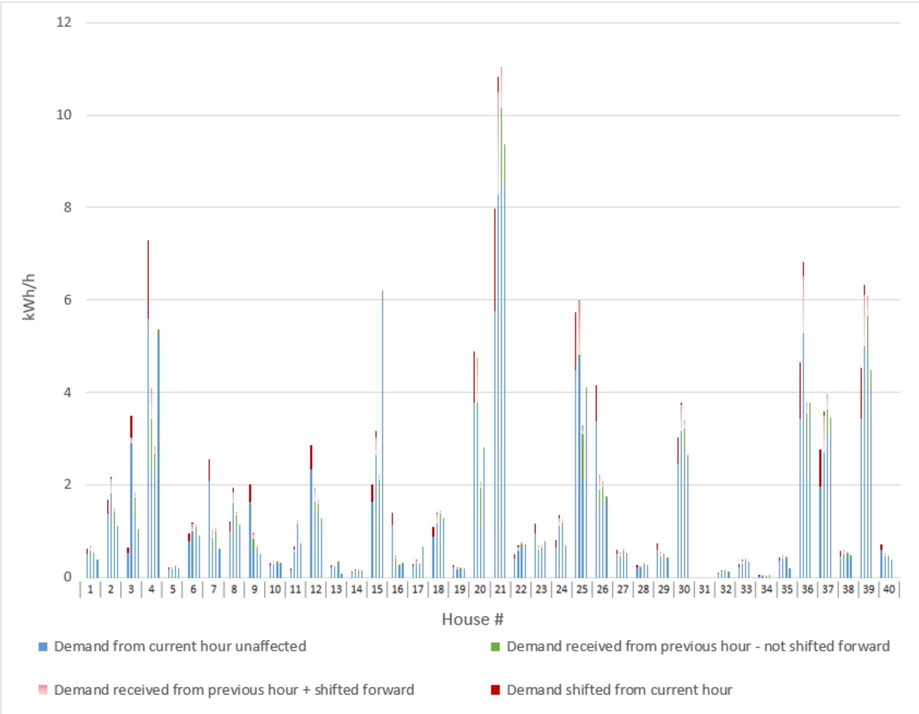

Figure 24: Simulated effect of implementing a VPP on 40 houses, after 8 have received a heat pump, during a 4-hour period on Feb 4th, 2012, starting with hour 18-19:00.

4.5 A kW max solution or VPP – Effective or not?

Sections 4.2 and 4.4 above looked at the effectiveness of reducing the maximum load on sub-station 52 via two respective solutions, i.e. via a kW max solution, and via a VPP. The findings of the two solutions are displayed in Table 10.

	No Cap				kWh max + shift [Z]				VPP with shift			
	40 houses	Rest of system	Total	% system load	40 houses	Rest of system	Total	% system load	40 houses	Rest of system	Total	% system load
Current electricity usage	48.3 [A]	64.8	113.1	62.8%	49.5 [B]	59.2	108.7	60.4%	36.5 [C]	64.8	101.3	56.3%
Current electricity usage + heat pumps	70.2 [D]	62.9	133.1	73.9%	67.0 [E]	62.9	129.8	72.1%	54.8 [F]	62.9	117.7	65.4%

Table 10: Comparison of a kWh/h max with a VPP solution. [Z] For current electricity usage, and current electricity usage + heat pumps, the respective maximums were 2.3 and 6.0 kWh/h.
[A] February 7th, 18-19:00. [B] February 6th, 18-19:00. [C] February 7th, 18-19:00.
[D] February 4th, 18-19:00. [E] February 4th, 18-19:00. [F] February 4th, 18-19:00.

From the table it is clear that if a VPP can be successful in shifting a particular amount of demand forward, then this is a significantly superior solution than that involving a kW maximum. In addition, the VPP has the added benefit in that it does not result in lost welfare for the customer at other times during the year, as is the case with the kW maximum, which reduces electricity usage for a number of users in hours where there is no need for a reduction. The VPP solution is however not without its drawbacks, as it requires infrastructure and communication technology in order to function properly. How large these required investments are relative to the costs associated with having to expand the capacity of the distribution system will ultimately determine the viability of a VPP in local distribution grids.

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