DSO tool for quantification of flexibility benefit, service request and activation

EcoGrid 2.0, D4.1.1

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Main Authors:

Name/Partner	Email
Carsten L. Heinrich	cahei@elektro.dtu.dk
Angeliki Lydia A. Syrri	alasy@elektro.dtu.dk
Charalampos Ziras	chazi@elektro.dtu.dk
Michael G. Pertl	mpertl@elektro.dtu.dk
Henrik W. Bindner	hwbi@elektro.dtu.dk

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Executive Summary

Due to the increasing penetration of residential electric heating, electric vehicles and distributed generation, distribution networks are expected to become an active part of the electricity system. Historically, the assumption was, that the social benefit of a reliable and uninterrupted electricity distribution is at any time greater than the cost of grid reinforcements and expansions. Further measurement equipment and automation technology at the medium and low voltage level used to be too costly. Hence, grid expansions have generally been the answer to challenges in the distribution system. In the future, due to the combination of an already highly reliable network, together with potential synchronization of loads through central control strategies, e.g. by aggregators, this assumption might not at all times be valid any more. What is more, customer smart meter data allows DSOs to obtain an insight into the medium voltage and distribution grid state. Therefore, in the future social benefit of electricity consumption can and must be compared with network operational costs.

For this purpose, EcoGrid2.0 is developing and testing a market setup for distribution grid services facilitated by aggregators. This report proposes a method to quantify the benefit of DSO services in order to decide, which operational strategy is more viable for a DSO - overloading network equipment and expanding or replacing network equipment in the long run or requesting load reductions from aggregators.

1 Introduction

The EcoGrid2.0 project aims at utilizing flexible consumption of private households to develop flexibility services provided by aggregators to interested market participants. In this report we are exploring the case where a DSO is willing to buy a service to delay or avoid investments for replacement and reinforcement of transformers and lines.

The whole analysis carried out in this report is made from the perspective of the DSO, who is responsible to deliver electricity with appropriate quality to each consumer, while at the same time operating the network in a cost efficient and reliable way. Under the EcoGrid2.0 hypothesis, the DSO participates in a market which trades DSO flexibility services one to three months in advance. These services are local product, which offer temporary load reductions or increases at specified grid nodes. By participating in such a market, the DSO decides that for the next one to three months no reinforcements are materialized. Instead, reserve capacity is provided by aggregators. Therefore, the DSO has to be able to quantify how often, how much and for how long additional capacity is needed. Further, the DSO has to translate these results into standardized DSO service requests, which can be transmitted to a market together with a price, that the DSO is willing to pay for the requested service.

1.1 Definition of Distribution Service Requests

The DSO services, which are considered in EcoGrid2.0, have been defined in EcoGrid2.0 deliverable D2.2 [1] . The services can be split into two categories, relative and absolute services. Relative services are delivered as deviations from a baseline, representing the assumed power consumption of the flexible units, had the aggregator not delivered a service to the DSO. Absolute services are absolute limits to the total power consumption of the involved flexibility portfolio. Both of these types of services can be scheduled or conditional. Scheduled services have a predetermined activation time. Conditional services are only delivered if the DSO sees a necessity to activate the service, for example if the DSO observes that a transformer overloading as anticipated at the time of requesting the service, is actually going to materialize. After the delivery period of a DSO service, the aggregator is expected to increase the portfolio's power consumption to a total power exceeding the baseline. This is due to the fact, that energy which has not been consumed during the delivery period is now needed. This effect is called the rebound. To make sure that the effect of the rebound does not endanger the grid operation, the DSO can limit the maximal rebound power as well as the maximal rebound duration in a service request. The service requests are aimed at mitigating specific operational issues, mainly congestion, in the distribution network. It is therefore necessary to include the location information into the request. Each flexibility unit in the distribution network is assigned a unit ID. Hence, when formulating a service request, the DSO has to specify which units can deliver the service through a list of such unit IDs. This report focuses on relative services. A service request of a DSO will be defined by the following parameters:

- Delivery Start Time
- Delivery End Time
- Rebound End Time
- Delivery Duration
- Rebound Duration
- Service Power
- Maximal Rebound Power
- Start Date
- End Time
- List of Flexible unit IDs
- Maximal request price to be paid by the DSO
- Activation Probability

Each service request, forwarded to the market, contains these twelve parameters, which define each individual service request. Fig. 1 illustrates the meaning of the first seven parameters with the example of a load reduction service. Start and end date define the period, during which service delivery, e.g. 1st of January 2019 until 31st of January 2019. Since DSO services solve local problems, such as a temporary transformer overloading, only specific flexible units can facilitate each service. For a transformer or line overloading in a radial network, flexible units connected below the overloaded part qualify for services. In each service request, the DSO therefore has to specify which the units that are connected in the relevant part of the network and thus will be able to deliver a service request. This is expressed through the *List of Flexible unit IDs*. Apart from a benefit, which expresses the DSO's willingness to pay for a service request, each service request includes an activation probability. Through the activation probability, the DSO expresses how often they expect a conditional service to be activated. The activation probability for scheduled services is 1. Activation probability, delivery time and maximal request price were not included in the service specifications of EcoGrid2.0 deliverable D2.2 [1].

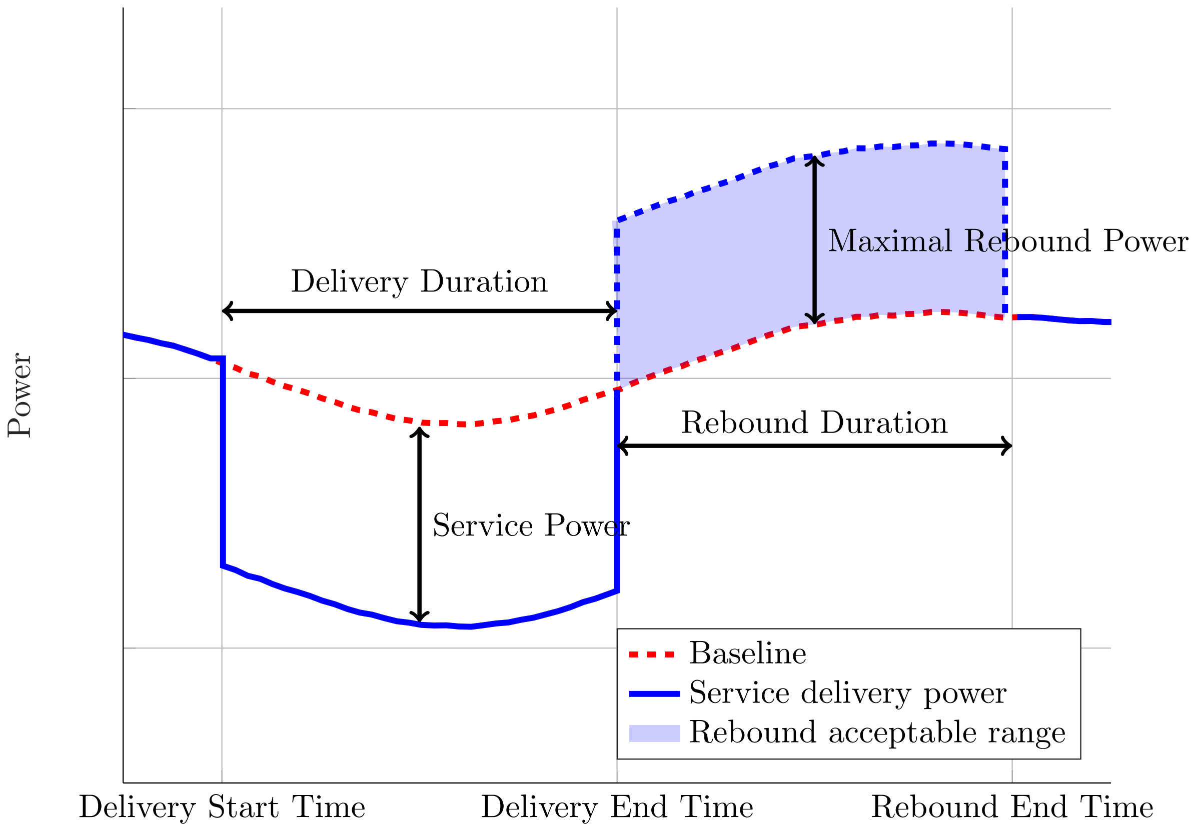

Figure 1: Sketch of a relative DSO-service request. The blue line depicts desired power consumption of the aggregator, in order to deliver the service. During the rebound period, a maximal rebound power is defined and each power profile laying within the blue area is acceptable. The red dashed lined depicts the baseline, representing the power the aggregation is assumed to have had, had no service been delivered.

In order to find the most viable solution, the DSO sends a list of service request to the market, which all solve the same network issue at a particular time step. All service request on such a list are mutually exclusive and only one is finally sold.

2 Network Description and Specification

For the EcoGrid2.0 project, a representative medium voltage feeder has been selected to demonstrate DSO services. An overview of this distribution feeder can be seen in Fig. 2. The feeder has seven substations, one with a 60/10kV transformer and six transformer stations connecting the 10kV level to the 400V network serving a total of 564 customers. A total amount of 5077 meters of medium voltage network and a total of 3003 meters of low voltage network have been modelled, in order to perform power flow calculations. In reality, a total number of 27 consumers on the feeder are EcoGrid2.0 participants. Since 27 participants are too few to lead to reliable DSO services, additional EcoGrid2.0 participants are assumed to be located on the feeder as well. Furthermore, the 400 V grid at transformer node 769-2 has been modeled. The other low voltage feeders in the distribution grid have not been modeled. Customer loads are lumped at the corresponding 10 kV - 400 V transformer stations.

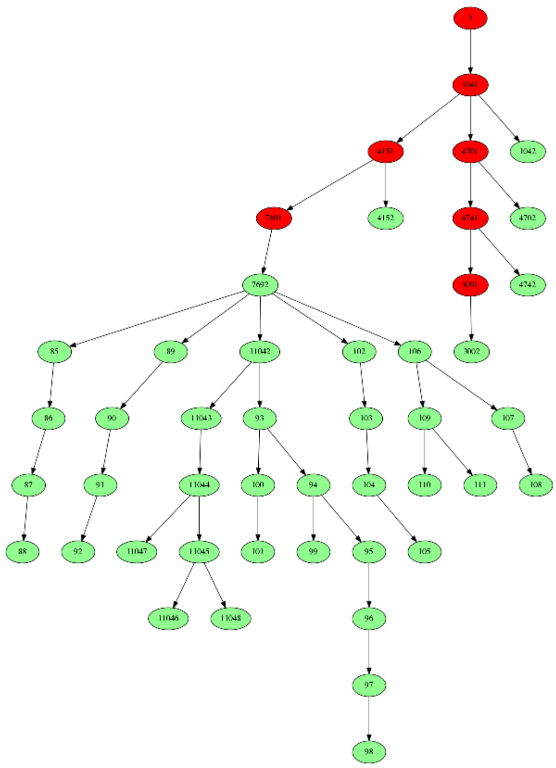

Figure 2: Distribution grid model. Medium voltage nodes are represented in red, low voltage nodes are represented in green.

3 Methodology

This section proposes a method for two DSO tools, Service request decision tool, which defines a method to decide whether or not to request services from the market and the conditional service activation tool, which assists the DSO in the decision, whether or not to activate a acquired conditional load service during network operation.

3.1 Service request decision tool

Figure 3 gives an overview of the different steps, necessary to make a decision, whether or not to request a service from the DSO market. The DSO has to make service requests one months in advance. For such a long time horizon, DSOs are unable to accurately predict the electric load in the distribution network, but might be able to estimate the range in which the load will most likely lie. Hence, a Probabilistic Network Operational Assessment is carried out. Load scenarios are derived, which realistically portray the uncertainty and volatility of the the demand. This process is based on historical load data, which is used to assess the customer behaviour in the trading period (black box).

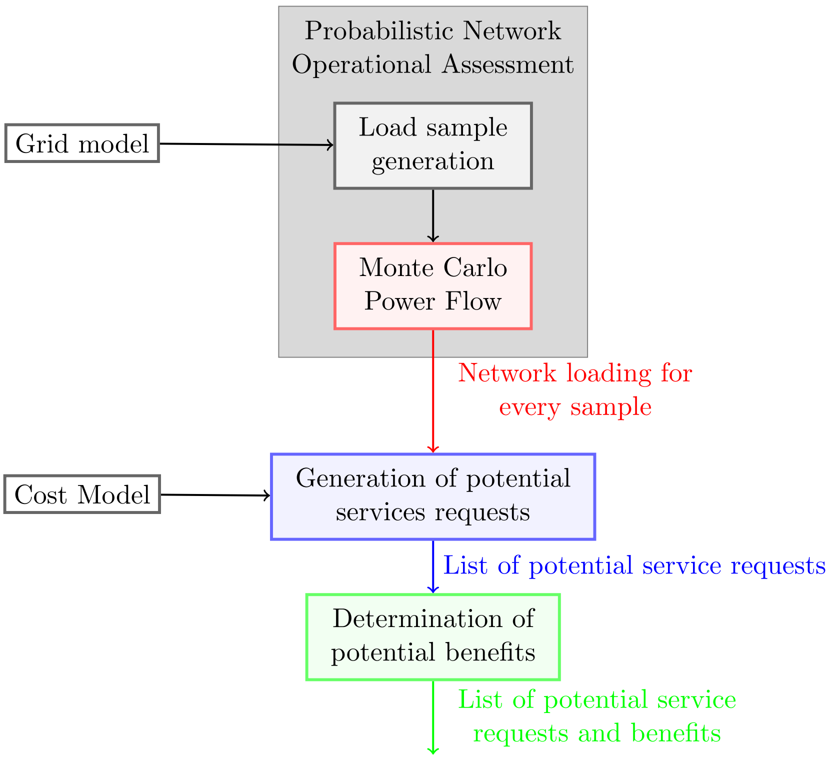

Figure 3: Overview of the processes DSO service request decision tool

These load samples are translated into network loadings of each MV-node in the network using a Sequential Monte Carlo Power Flow Calculation (red box). Next, using a cost model for network loading, the cost of each load scenario can be estimated. Finally, the total expected overloading, duration and cost for the considered trading period is calculated using the individual sample probability. These indices are then used to define a list of potential service requests (blue box). The network operational cost with and without service delivery is used to define the individual service request benefits (green). Finally, the resulting list is forwarded to the DSO market. All serive requests in on the list of potential service requests are mutually exclusive and only one service is finally sold.

3.2 Conditional service activation tool

Figure 4 summarizes the proposed methodology necessary to decide, whether or not to activate a conditional service request with an activation cost.
In the near future, DSOs will have access to smart meter data of their customers. However, the collected smart meter data has to be transferred to the DSO. This process is likely to take enough time, to make online observations of the distribution grid impossible. In EcoGrid2.0, smart meter data is available to the DSO within 24 hours. Online observation of the medium and distribution network is not possible. Thus, the decision whether or not to activate a service request is therefore based on estimates and forecasts.
The procedure is very similar to the service request decision procedure. Load samples are generated to cover the uncertainty around the load. The load samples are translated to equipment loading samples, using a Monte Carlo Power Flow calculation. Finally, the grid operation cost with an activated conditional service request are compared to grid operation cost without activation and the more viable option is chosen. Finally the according trigger signal is sent to the aggregators.

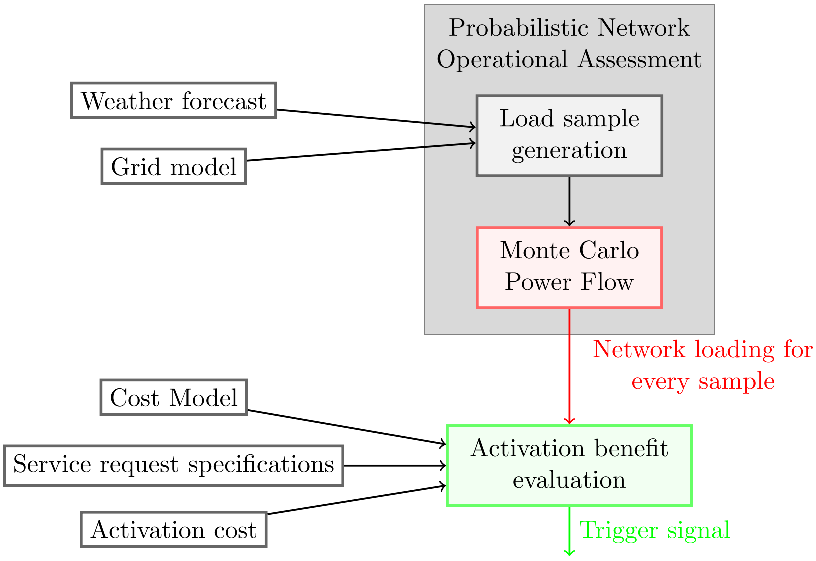

Figure 4: Overview of activation decision

For the *Conditional service activation tool* load samples are generated in a similar manner as in the previous section. However, the uncertainty around the weather conditions is significantly smaller since the service has to be triggered shortly before the service start time. Specifically the ambient temperature forecast is used as an input when generating load samples. The uncertainty that the load samples are covering is mainly due to the unpredictable customer behavior.

3.3 Probabilistic Network Operational Assessment

Load samples are generated for both the DSO service request decision tool and the DSO service activation tool. This section outlines the method used to create such load sample time series.
The approach is based on the assumption that the trading horizon is fairly short and the load profile for the coming period is a natural continuation of the immediate past year.

3.3.1 Decomposition of Historical Load Shape

A DSO has historical data of residential load. However, this data should not be directly used for modelling purposes. During the grid planning stage, DSOs are interested in extreme scenarios, which by definition occur rarely and are therefore not necessarily represented in the historical data set. Unprecedented events, such as particularly cold and cloudy winter days, are not represented in the historical data at all. Instead of trying to forecast the actual load, DSOs can identify the range and probabilities for network overloading. This section proposes a method which based on historical data creates representative load scenarios including rare or unprecedented load events.

To create representative load profiles we use the smart meter data of the past year aggregated

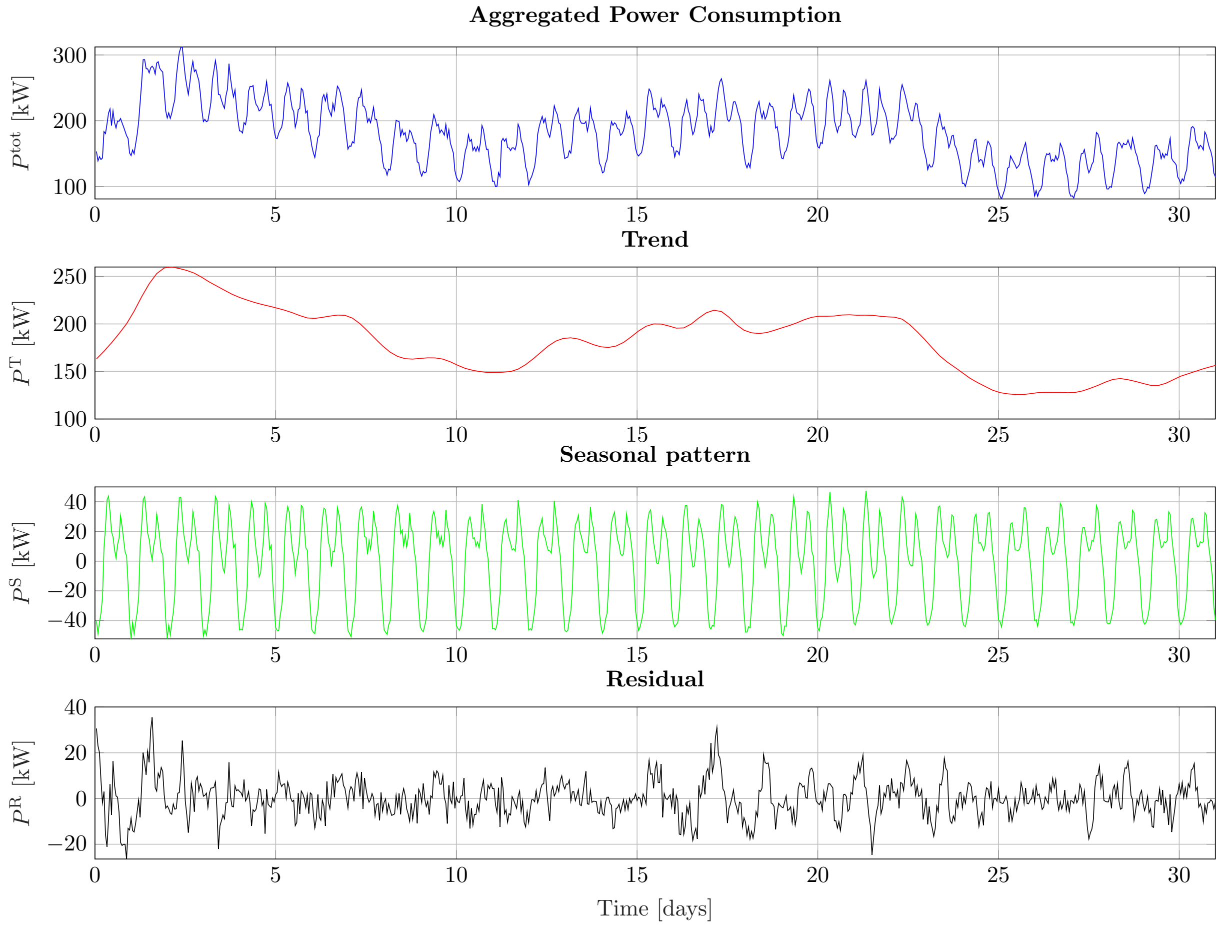

Figure 5: Decomposition of aggregated consumption profile of 191 households for January. The profile (top) is split into a seasonal (daily) pattern, a trend as well as a residual term. The three terms together add up to the total power consumption.

at the secondary substations, and apply a decomposition technique from [2] which is built on local regression smoothing. The decomposition divides the load into 3 parts, overall trend, seasonal variation and residual. The trend component is mainly determined by ambient temperature. The seasonal component represents the daily variations. The result of such a decomposition for an aggregation of 191 households during January is shown in Fig. 5. The top shows the total aggregated power consumption for one month P^{tot} (blue). This power consumption is split into 3 parts, a general trend P^{T} (red), a seasonal daily part P^{S} (green) and a residual P^{R} (black).

$$P^{\mathrm{tot}} = P^{\mathrm{T}} + P^{\mathrm{S}} + P^{\mathrm{R}} \tag{1}$$

In order to generate load scenarios, historic load data is decomposed and the resulting 3 parts are modelled individually. The trend modelling is used to capture the uncertainty around the ambient temperature. The model of the residual part is used to capture uncertainty around customer behavior and other random influences.

3.3.2 Generating Load Profiles at Grid Nodes

Table 1 shows the correlation of ambient temperature and solar radiation with the different components of the decomposition based on the data from 2016.

	$P^{\mathbf{T}}$	$P^{\mathbf{S}}$	$P^{\mathbf{R}}$
Ambient Temperature	-0.91	0.013	-0.15
Solar radiation	-0.001	0.17	-0.10

Table 1: Correlation of solar radiation and ambient temperature with trend, seasonal and residual part of decomposition evaluated based on the entire 2016 data.

The trend P^{T} in the power consumption is strongly correlated with the ambient temperature. Each month a linear model is fitted, such that the trend P^{T} can be expressed as a function of the ambient temperature T^{ambient}. In order to smoothen the temperature profile, loess-smoother is applied to the profile. Details about the smoother can be found in [3]. The algorithm takes into account data from 13 hours into the future and into the past.

$$P^{\mathrm{T}}(t) = \alpha_1 T^{\text{ambient}}(t) + \alpha_0 \tag{2}$$

For the considered January month, this can be seen in Fig. 6. The top graph depicts the ambient temperature, both the collected data (black), as well as the smoothed profile (red). The lower graph shows the trend part from the decomposition. The blue line is the same as the second plot in Fig. 5. The red line represents the fitted model during the same month on the basis of smoothed ambient temperature profile. To test the procedure, we apply the model from January to the February data. The resulting trend is depicted in Fig. 7.
Apart from ambient temperature and trend P^{T}, none of the other are significantly correlated, hence the remaining uncertainties in the load will be captured through the Monte Carlo Simulation. Feeders with a strong PV-penetration might have a stronger influence of the solar radiation on the trend and seasonal component of the decomposition. In this case, a similar approach as for the temperature can be introduced to capture the effect of solar radiation on the load.

The residual in the decomposition part P^{R} is however autocorrelated. In order to capture this feature, we fit a seasonal ARIMA model with hourly averaged data. The resulting auto correlation function, the differenced autocorrelation function and the partial autocorrelation function is shown in Fig. 8. The plots show a strong autocorrelation and strong seasonal components. Using the AIC-criterion, a $(2,0,2)$x$(2,0,2)_{24}$ is chosen to model the residual part of the decomposition. Since hourly averaged data is considered, the time steps considered are hours and the ARIMA model has a seasonal component of 24 hours. The model can be expressed with backwards shift operator B and interpreted as the lagged variable as,

$$\left(1+\Phi_1 B^{24}+\Phi_2 B^{48}\right)\left(1+\phi_1 B+\phi_2 B^2\right) P_t^{\mathrm{R}} = \left(1+\Theta_1 B^{24}+\Theta_2 B^{48}\right)\left(1+\theta_1 B+\theta_2 B^2\right) Z_t, \tag{3}$$

where P_t^{R} is the Residual Power consumption at time t and Z_t the corresponding normally distributed noise. Φ and Θ are the seasonal parameters, ϕ and θ the non-seasonal parameters. Fig. 9 shows the quantile-quantile plot of the ARIMA-residuals. There seems to be only a very slight deviation from perfect random distribution and we can assume, that the ARIMA-residuals are

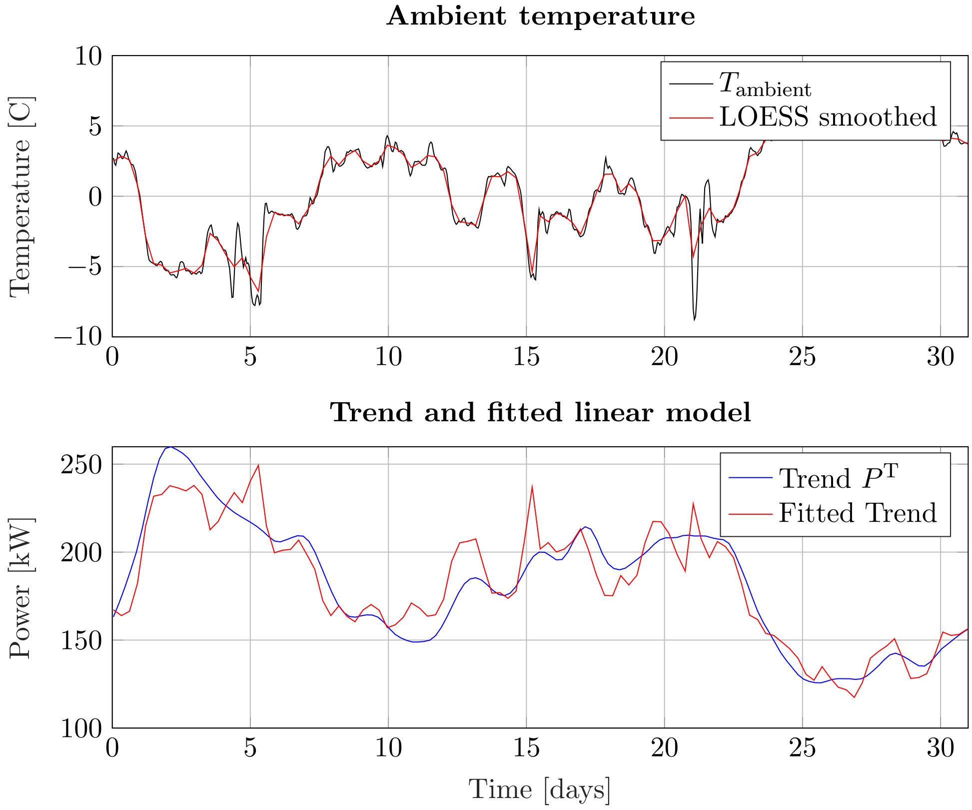

Figure 6: The bottom plot depicts the decomposition trend P^{T} for January (blue) together with the fitted linear function of the ambient temperature (red) - the top plot shows the ambient temperature data for the same month.

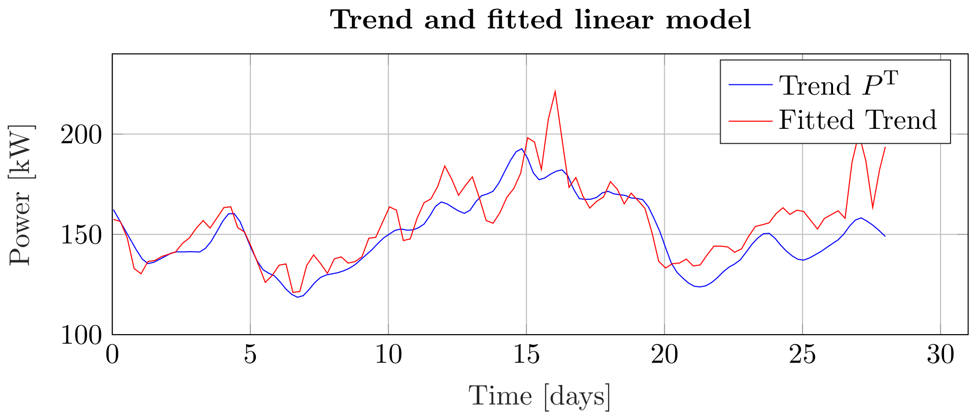

Figure 7: Linear trend modelling of the month January applied to the trend profile of February for test-purposes.

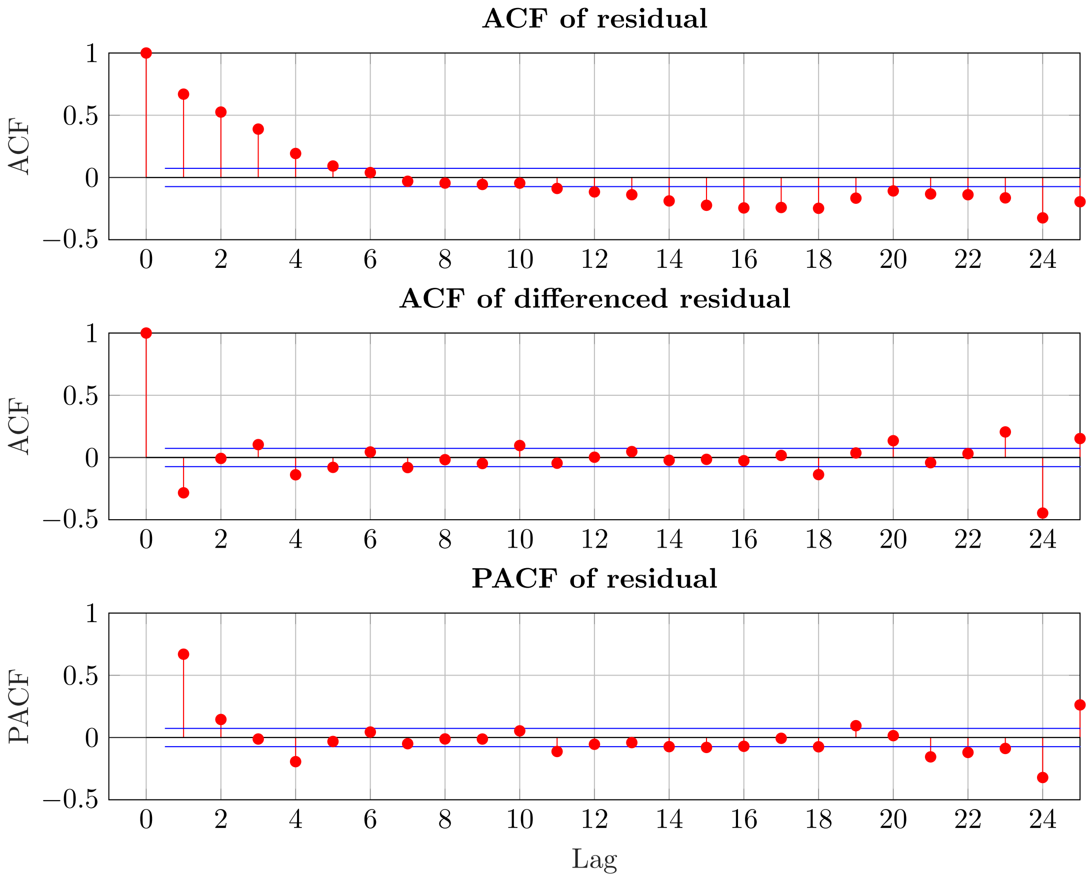

Figure 8: Auto correlation function of P^{R} (top), ΔP^{R} (middle), and partial auto correlation function of P^{R} (bottom).

normally distributed. The Ljung-Box test of the residuals leads to a p value of 0.4, indicating that the ARIMA-residuals are uncorrelated.

In order to generate time series load samples, n^{temp} scenarios for the ambient temperature are created and translated into trend samples using (2). To each time series sample, the seasonal part is added. Finally, n^{residual} residual profiles are created by choosing a set of random variables Z_t for each temperature sample resulting in a total of $n^{\mathrm{temp}} n^{\mathrm{residual}}$ load patterns for the Sequential Monte Carlo Probabilistic assessment.

3.4 Network Operational Cost Function

Losses, which occur in the network, heat up the equipment. In order not to damage the network, each network component is given a rating, which is usually expressed in the form of a nominal current or power. Exceeding these limits is often not a problem for short time intervals, but a continuous violation of these limits can reduce the life time of the equipment.
Models for the reduction of life of transformers are widely used and based on the concept of hottest

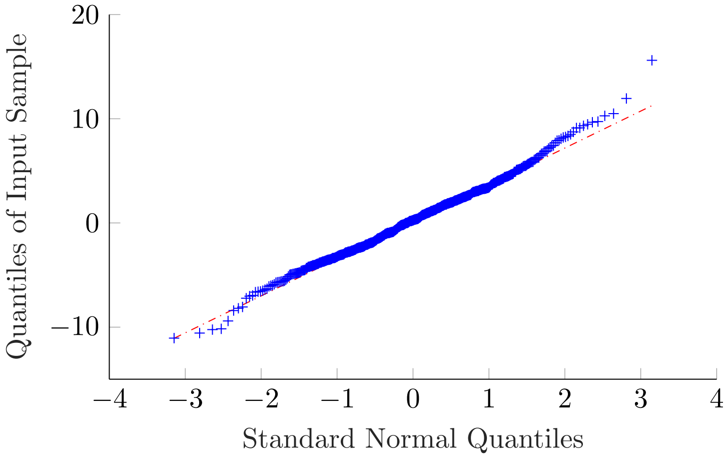

Figure 9: Quantile-quantile plot of the residuals of the fitted ARIMA model.

spot temperature Θ^{H} [4].

$$\Theta^{\mathrm{H}} = \Theta^{\mathrm{A}} + \Delta\Theta^{\mathrm{TO}} + \Delta\Theta^{\mathrm{H}} \tag{4}$$

Here Θ^{A} represents the ambient temperature, $\Delta\Theta^{\mathrm{TO}}$ represents the top-oil rise over ambient temperature and $\Delta\Theta^{\mathrm{H}}$ is the winding hottest-spot rise over top-oil temperature. $\Delta\Theta^{\mathrm{TO}}$ at time $t+1$ can be formulated as

$$\Delta\Theta^{\mathrm{TO}}_{t+1} = \Delta\Theta^{\mathrm{TO}}_{t} + \left(\Delta\Theta^{\mathrm{TO,final}}_{t+1} - \Delta\Theta^{\mathrm{TO}}_{t}\right) f^1(\Delta t), \tag{5}$$

where

$$f^1(t) = \left(1 - e^{-t/k^{11}\tau^0}\right), \tag{6}$$

and

$$\Delta\Theta^{\mathrm{TO,final}}_{t} = \Delta\Theta^{\mathrm{TO,R}} \left[\frac{K_t^2 R + 1}{R + 1}\right]^n. \tag{7}$$

Here K_t represents the transformer loading at time t. τ^0, k^{11}, and R are transformer specific parameters, which can be extracted from the transformer manual. [4] suggests standard values if the parameters are unknown. The winding hottest-spot rise at time $t+1$ is given as

$$\Delta\Theta^{\mathrm{H}}_{t+1} = \begin{cases} \Delta\Theta^{\mathrm{H}}_{t} + \left(\Delta\Theta^{\mathrm{H,final}}_{t+1} - \Delta\Theta^{\mathrm{TO}}_{t}\right) f^2(\Delta t) & \text{if } K_{t+1} > K_t \\ \Delta\Theta^{\mathrm{H},final}_{t} & \text{if } K_{t+1} \leq K_t \end{cases}$$

where

$$f^2(t) = \left[k^{21}\left(1 - e^{-t/k^{22}\tau^{\mathrm{w}}}\right) - \left(k^{21} - 1\right)\left(1 - e^{-tk^{22}/\tau^0}\right)\right] \tag{8}$$

and

$$\Delta\Theta_t^{\mathrm{H,final}} = \Delta\Theta^{\mathrm{H,R}} K_t^{2m}. \tag{9}$$

Again, k^{22}, k^{21}, τ^{w} are transformer specific parameters, which can be extracted from the manual or from [4]. Every transformer temperature is dependent on the temperature in the previous time step. The change in temperature can be modelled at every time step, using (5) to (9), based on the transformer specific parameters τ^0, τ^{w}, both describing heat flow time constants, the per unit loading of the transformer K. According to [4], the aging acceleration factor in percent F_{tr}^{aa} at time step t is described by

$$F_{tr}^{\mathrm{aa}}(t) = \exp\left[\frac{15000}{383} - \frac{15000}{\theta^{\mathrm{H}}(t) + 273}\right] \tag{10}$$

Assuming that transformer replacement costs C_{tr} DKK, each transformer loading can be assigned a cost $OC_{tr}(t)$.

$$OC_{tr}(t) = \frac{F_{tr}^{\mathrm{aa}}(t)}{100} C_{tr} \tag{11}$$

Assuming a life time of about 20 years, the average aging per time step $F_{tr}^{\mathrm{aa}*}$ together with the expected average operational cost EOC^* can be calculated using (11). Time steps, with a network operational cost above EOC^* indicate times, when the acquisition of DSO service could potentially be a more viable solution. Models for the aging of network cables usually include input parameters, which are unknown in our case, such as ambient soil temperature. For simplicity, we assume a quadratic relation between line loading and line temperature $\theta_l\,(I)$. The line aging F_l^{aa} can then be expressed in the following way:

$$F_l^{\mathrm{aa}}(I) = \exp\left(\frac{\beta}{\theta^{\mathrm{ambient}} + \theta_l\,(I) + 273}\right) \tag{12}$$

Equation (12) can be tuned such that average line aging occurs when the cable is operated at the line rating I^{rat}

$$F_l^{\mathrm{aa}}(I^{\mathrm{rat}}) = F_l^{\mathrm{aa}*}. \tag{13}$$

In addition $\theta_{\mathrm{l}}\,(I)$ has to fulfill the condition

$$\theta_l\left(I^{\mathrm{rat}}\right) = \theta^{\mathrm{rat}}. \tag{14}$$

Where θ^{rat} is a parameter from the cable specifications. Cable loading cost can then be calculated in the same manner as for transformers.

$$OC_l(t) = \frac{F_l^{\mathrm{aa}}(t)}{100} C_l \tag{15}$$

3.5 Assessing grid operational performance including uncertainty around demand and flexibility from DERs through Risk Indices

During the Sequential Monte Carlo Simulation, a variety of indices are recorded. These indices are based on the chronological events happening in each simulated sampling period. Average values of all the samples can afterwards be calculated together with the corresponding probability

distributions.
The equipment loading indices are given below. Here s denotes a particular sample, S is the total number of samples, t denotes a particular time step, T is the total number of time steps in a sample. The index eq represents different types of network equipment, either transformers or lines.

- Expected equipment loading at time t (MVA):

$$EP_{eq}(t) = \sum_{s=1}^{S} P_{eq,s}(t)/S \tag{16}$$

Here $P_{eq,s}(t)$ stands for the loading of equipment eq in sample s at time t.

- Expected frequency of equipment overloading (occ/period), where $\zeta_{eq,s}$ is the total number of overloading events in a sampling period s:

$$EFP_{eq}^{\text{overl}} = \sum_{s=1}^{S} \zeta_{eq,s}/S \tag{17}$$

- Expected duration of equipment overloading (hours/period), where Z is the set of overloading events, indexed as z, $d_{eq,s,z}$ is the duration of the overloading event z in the sample period s:

$$EDLP_{eq}^{\text{overl}} = \sum_{s=1}^{S} \sum_{z=1}^{\zeta_{eq,s}} d_{eq,s,z}/S \tag{18}$$

And the system indices for all the equipment:

- Total expected frequency of overloading (occ/period):

$$EFP^{\text{overl}} = \sum_{eq=1}^{N_{eq}} EFP_{eq}^{\text{overl}} \tag{19}$$

- Expected network operational costs (DKK/period), where

$$EOC = \sum_{s=1}^{S} \sum_{t=1}^{T} \sum_{eq=1}^{N_{eq}} OC_{eq,s,t}/S \tag{20}$$

Here $OC_{\text{eq,s,t}}$ represents the operational costs of equipment eq in sample s during timestep t.

Each sampling period is simulated in 15 minute, therefore expected values for equipment loading and network operational costs can be calculated also on a 15 minute basis. Expected risk indices described above, represent the expected values of the measured indices over a period. Finally, the probability distribution of the risk indices will be calculated, which will illustrate the volatility of the risk indices.

4 Forming a Market Request

In each time step of the simulation of the sampling period, network operational cost, calculated as an output from the power flow analysis, indicate during which time steps acquisition of services could be beneficial to the DSO. Apart from this main indicator, the following parameter are also recorded as described in section 3.5:

- Network operational cost of overloading equipment eq
- Amount equipment overloading

The following steps define, how the list of potential DSO service requests will be created:

1. Identify the hour, when the $EOC(t)$ is maximal and the expected network overloading is $EP^{\text{overl}}(t)$
2. Define a load reduction services starting from 10 kW, in steps of 10 kW until $2EP^{\text{overl}}$
3. Define a rebound duration of 30 min, for 5 different maximal rebound values of $0\%, 20\%, 40\%, ..., 100\%$ of $EP^{\text{overl}}(t)$. 30 min is chosen here since tests in EcoGrid2.0 have shown, that given the EcoGrid2.0 setup, rebounds usually do not last longer.
4. Define the same DSO service requests for the previous hour

4.1 Probabilistic assessment of the Service benefit

The different sampling periods, created in Section 3.3 each lead to a typical time series loading of the network for the sampled period. In order to quantify, which loading is acceptable and when a service request is more viable, these values have been translated into network operational costs. The cost of each sample can then be evaluated both with and without a DSO service request and the difference in the distribution cost can be interpreted as the DSOs benefit of that particular service request. In the context of EcoGrid2.0, only the cost of network overloading is taken into account represented through equipment replacement cost. However, more complex network operation cost functions representing voltage violation cost, expansion cost, network reconfiguration cost etc. could potentially be developed.

The benefit of a flexibility service request is defined as the savings that the DSO would have during network operation if it was applying the flexibility service. Hence, the reference case is represented through grid operation without DSO services leading to expected network operational cost EOC^{ref} and a case where the DSO has requested a flexibility service fs_{i}, with an expected network operational cost EOC^{fsi}, then the expected benefit for the specified service request is given by the difference of these two costs:

$$EC^{\text{benefit}}(fs_{\text{i}}) = EOC^{\text{ref}} - EOC^{\text{fsi}} \tag{21}$$

The process can be summarized in the steps below:

1. The Sequential Monte Carlo Simulation is performed under the assumption that no DSO services have been requested(reference case), hence the DSO only relies on its own capacity adequacy.

2. All the simulation results of the reference case are stored in order to be used for offline calculations for other cases under the assumption that the DSO has requested a particular flexibility service fs_{i}, (e.g.scheduled or conditional demand response on a weekday between 20.00 to 22.00). Potential flexibility service requests are identified through the process described in section 4

3. The expected benefit of each service request fs_{i} is calculated as $EC^{\mathrm{benefit}}(fs_{\mathrm{i}})$.

Evidently, a service would not be requested, in case it has a negative expected benefit, which could be for example the case through the consequences of a rebound.

4.1.1 Scheduled service

To illustrate the process of a service request benefit calculation, but also the nature of the services, we assume that a scheduled DSO service is selected from the list, to tackle high network operational cost and overloading. The potential service request is defined by the three times t_1, t_2, t_3, as well as the load reduction amount $P^{\mathrm{reduction}}$ and the rebound overshoot P^{rebound}. Figure 10 illustrates the procedure. For simplicity, the procedure is plotted for 3 instead of 31 days.
The scheduled service request (black dashed line) has to be applied to all the sampling periods of the reference case (depicted in blue,red and green), regardless of the fact, that it is not very beneficial for many sampling periods.
The resulting expected cost after the introduction of the scheduled service request can be calculated in the same manner using the cost functions presented in section 3.4. The expected cost including the load change and rebound lead to a different cost EOC^{fsi}. The expected benefit for the specified scheduled service request is then given by the difference of these two costs.

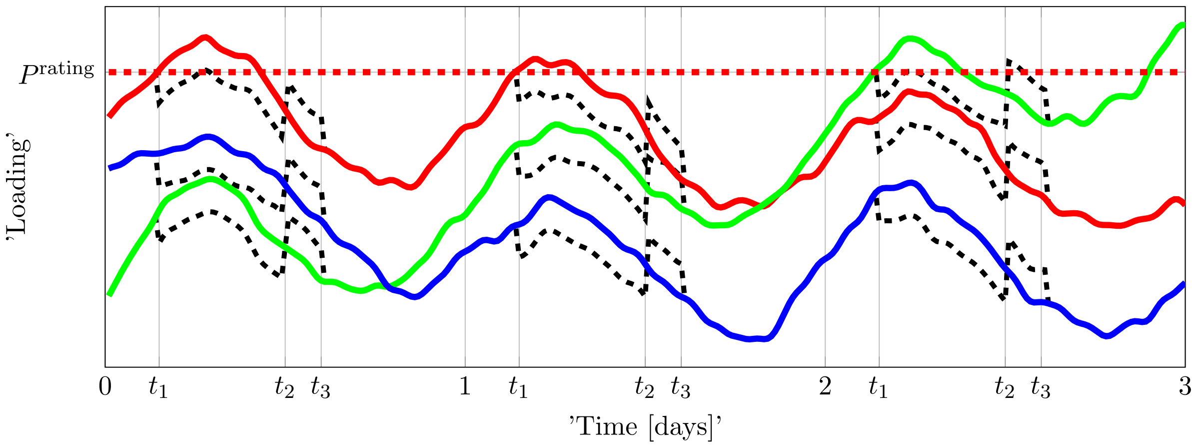

Figure 10: Sketch of scheduled load reduction for a period of 3 days - blue,green and red lines depict load samples without a DSO service, leading to expected grid operation cost EOC^{ref}, the black lines represent the load samples, which were manipulated with a load service, leading to different grid operation cost EOC^{fsi}.

4.1.2 Conditional service

The benefit of a conditional service can be calculated in a similar fashion. Assuming, that the DSO would only request an activation in the case, where they expect an overloading, the service request benefit is only defined through the benefit of the scenarios, when the load exceeded the equipment rating. This fact is illustrated in the Fig. 11. The probability of service activation, which is forwarded as part of the service request, is defined as the ratio of amount of service activations of all load samples and the number of activation time steps of all load samples.

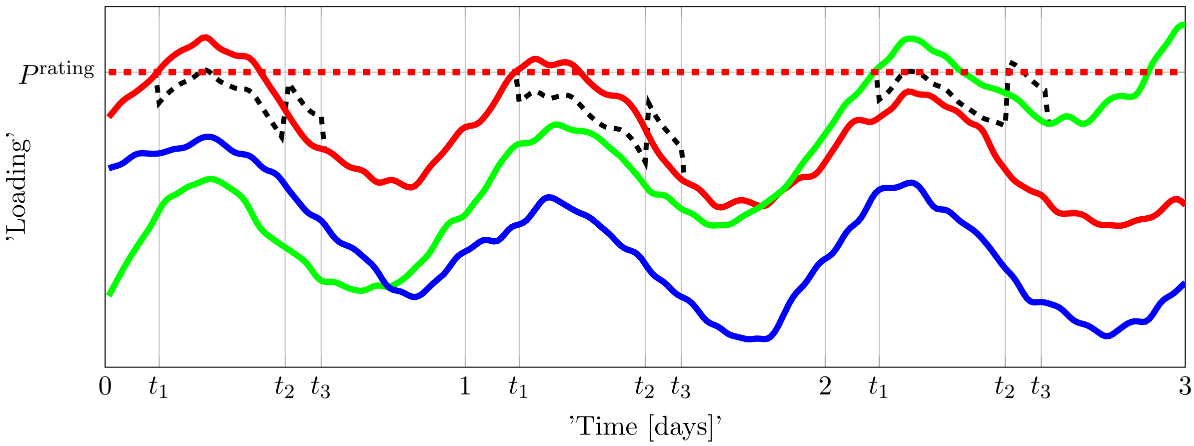

Figure 11: Sketch of a conditional load reduction for a period of 3 days - blue,red and green lines depict load samples without a DSO service, leading to expected grid operation cost EOC^{ref}. To evaluate the benefit of the conditional load reduction, only the sample, which really leads to grid violations is manipulated with a reduction service. This then leads to grid operation cost EOC^{fsi}.

Since the cost of operating the equipment below its rating is very low, conditional service requests and schedules service requests grant a very similar benefit to the DSO. This does not necessarily mean, that these two service requests will cost the same, since the cost for offering a conditional load reduction or increase might be significantly lower on the aggregator side, but only represents the fact, that the DSOs willingness to pay is fairly similar for both service requests. This is due to the fact, that both services, in principle, successfully prevent grid violations.

5 Conditional service request activation

If at some point in the past, a DSO has acquired a conditional service for a month, each day, the DSO has the option to activate the service. Each time the DSO activates the service, it has to pay an activation fee to the aggregator. In order to decide, whether or not to activate a service request, the DSO has to compare the expected service activation benefit to the activation cost. Activation costs are specified by the aggregators as part of their bids, hence the final activation cost is determined by the outcome of the market clearing . Fig. 12 illustrates the procedure.

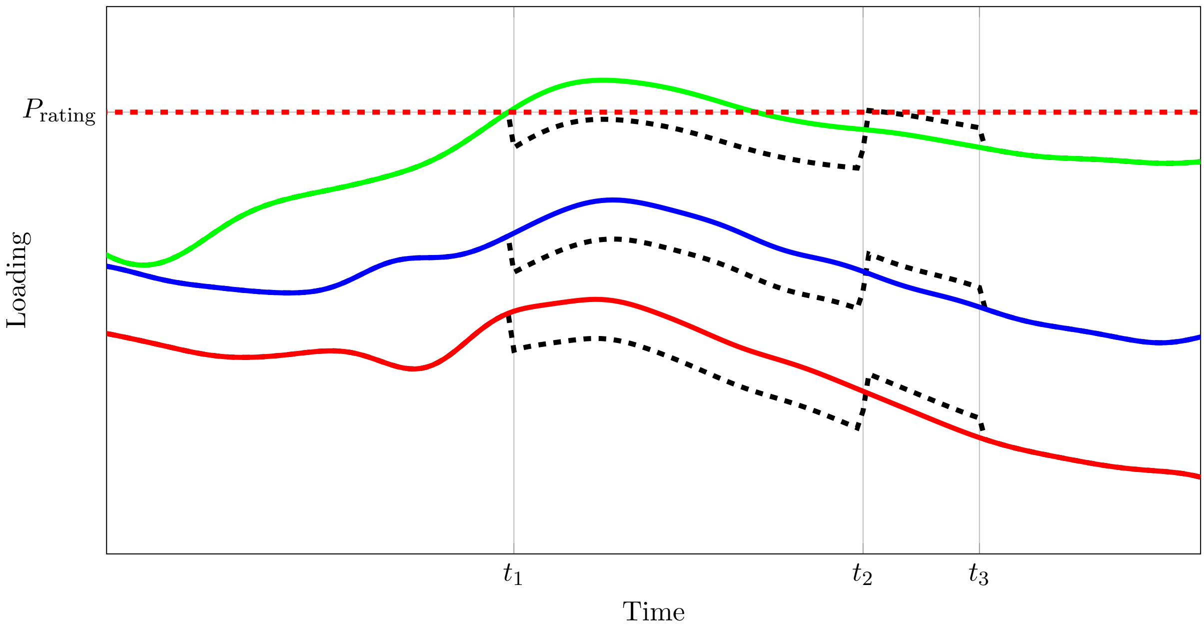

Figure 12: Load samples, created for the service request activation decision tool. Network operational costs for both, activation and no activation are calculated. The difference represents the service activation benefit.

The DSO has again created load sample time series. In Fig. 12 three such samples are depicted in red, blue and green, respectively. The samples have a much smaller uncertainty, than during the network operational planning stage, since now reliable weather forecasts are available. Also, the samples are not generated for an entire month, since only the next couple of hours are of interest.

To estimate the service activation benefit, the expected network operational costs are calculated (by evaluating the costs for all load samples without service activation, which corresponds in Fig. 12 to the red, green and blue line). Then the expected network operational costs with service activation are calculated (in Fig. 12 this corresponds to dashed profiles). The difference is defined as the expected service activation benefit. If the expected service activation benefit exceeds the activation cost, the DSO will send a trigger signal to activate the service. The service activation probability is not taken into account when calculating the service activation benefit.

In the EcoGrid 2.0 market setup, DSO specify an activation probability for conditional service requests. The risk of DSO deviating from this specified activation probability, by activating conditional services more or less often, is carried by the aggregators. Thus, aggregators have the incentive to specify their real reserve cost as well as their real service activation cost in their bids. In EcoGrid 2.0 the fact, that activation and reserve cost might depend on number of activations is neglected.

6 Discussion and Conclusion

In this report, a method to quantify the benefit of DSO services has been proposed. This benefit can then be used to decide whether or not to request services on a DSO service market platform. In the same manner service activation benefit was defined, which is used to decide, whether or not to activate a conditional load service.

In EcoGrid2.0 a market approach was chosen. The main benefits of a market approach are that products, in this case flexibility, are allocated in an optimal way, maximizing the social benefit of the system as a whole. In the market description D2.2, it was specified, that a DSO only sends one market request together with its maximal willingness to pay for this particular service request. However, as this report shows, there are many different potential service solutions to network equipment overloading. Regular network overloading can be tackled with different service powers, rebound powers, service duration, and even different delivery hours. The DSO is only able to quantify its benefit of a service request. Without taking into account, the costs, which arise on the aggregator side, the DSO is not able to reasonably reduce the list of potential service requests to a single service request. Due to this fact we have moved away from the market specification in D2.2, such that the DSO sends a list of DSO service requests to the DSO market. These service requests are mutually exclusive and only one service will be sold. Aggregators make bids for all service requests and finally the market is cleared through a optimization problem, such that the social benefit is maximized.

While the proposed method was developed to tackle congestion issues only, but can be expanded to tackle voltage issues in the distribution grid as well. It is also suitable if the DSO does not have online information about the distribution grid state available.

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