FLEXIBILITY FOR CONGESTION MANAGEMENT: AN OPERATIONAL DECISION-MAKING PROCESS

Rik Fonteijn
Eindhoven University of Technology
the Netherlands
r.fonteijn@tue.nl

Raoul Bernards
Enexis Netbeheer
the Netherlands
raoul.bernards@enexis.nl

Phuong Nguyen
Eindhoven University of Technology
the Netherlands
p.nguyen.hong@tue.nl

Johan Morren
Eindhoven University of Technology & Enexis Netbeheer
the Netherlands
johan.morren@enexis.nl

Han Slootweg
Eindhoven University of Technology & Enexis Netbeheer
the Netherlands
han.slootweg@enexis.nl

ABSTRACT

Network operators are investigating new methods to mitigate congestions. Utilising flexibility, for example through a flexibility market, is considered an affordable method, among others. This paper introduces a decision-making process enabling the network operators to unlock the necessary flexibility for congestion management in an operational environment. This model relates the cost of an overloading and the financial risk of a blackout to the price a distribution system operator is willing to pay for flexibility.

INTRODUCTION

Background

As a result of decarbonising the electricity system, increasing amounts of distributed energy resources (DER), such as electric vehicles (EV), heat pumps, and solar photovoltaic (PV) find their way into the distribution networks. These DER change the traditional load patterns of the network, and may cause various challenges, such as congestion problems and voltage limit violations. The traditional solution of a distribution system operator (DSO) is reinforcing the networks. Since this is both cost and time intensive, flexibility in demand as an alternative approach is investigated.

Research so far has shown that, depending on the mechanism applied and available resources, flexibility can be used successfully for congestion management [1, 2, 3]. Irrespective of the mechanism in place (e.g. direct control, market-based flexibility), the DSO is now faced with an operational decision. A decision on when, where, how much, and at what cost flexibility should be obtained has to be embedded into the DSO's grid management systems.

This paper discusses an operational decision-making process from a DSO perspective, applied to the local flexibility market for congestion management in the Dutch H2020 InterFlex demonstrator.

Demonstrator

One of the demonstrators of the H2020 InterFlex project takes place in the district of Strijp-S, Eindhoven, the Netherlands. In this demonstrator, flexibility is utilised to resolve network congestion on low voltage (LV) feeders and medium-to-low voltage (MV/LV) transformers. A local flexibility market is one of the tools the DSO can use to obtain the necessary flexibility. This market consists of a day-ahead and intraday component, aligned with the wholesale markets. The DSO requests flexibility through aggregators. The aggregators are allowed to trade on multiple markets simultaneously, enabling competition [4].

The flexibility is provided by a battery energy storage system (BESS), EV charge points (CPs), and a PV installation. The inflexible loads in the area consist of around 350 households. Measurement equipment is installed on the MV feeders, MV/LV transformers, and LV feeders [5].

Outline

This paper is organised as follows: first the approach is explained, after which we elaborate on the decision-making process. Here, the underlaying model and cost components are explained, and simulations show some results from the model. The paper ends with a conclusions section.

APPROACH

Within the Dutch demonstrator of the InterFlex project, the operational decision process is part of the grid management system (GMS), also known as distribution management system. Figure 1 illustrates the process steps in the

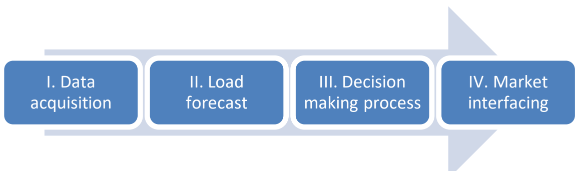

Figure 1: process steps in the GMS.

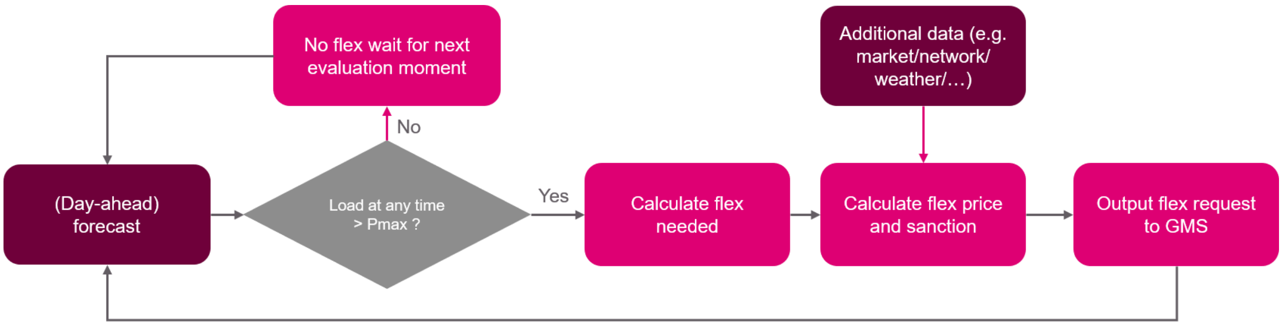

Figure 2: Steps in decision making process.

GMS. The GMS obtains measurement data from the field (step I), and translates this into a load forecast for each congestion point in the distribution network, including a probability of overloading (step II). Based on the load forecast, the operational decision process determines the need for flexibility for each 15-minute time interval. This can be done both in a day-ahead and intraday setting, for each congestion point (step III). The results are passed on to the market interface, which sends a flexibility request to the local flexibility market and handles the response from the market (step IV).

Additionally, as the flexibility is to be obtained from a local market, the operational decision model relates the flexibility need to a maximum price to procure this flexibility, depending on local network characteristics. This is then translated into market requests by the grid management system.

DECISION MAKING PROCESS

Model

The model underlaying the decision-making process consists of a number of steps, visualised in figure 2. A load forecast (48 hours, on a 15-minute resolution) is used as input for the decision-making process. Based on this forecast, the need for flexibility is determined for every program-time unit (PTU) for the next day (day-ahead). In the future, this is expanded with intraday evaluation moments.

The needed amount of flexibility is determined by the difference between the transformer's rated power and magnitude of overloading (if no overloading occurs, no flexibility is needed). Then, for the needed amount of flexibility, the price and sanction are determined. The price indicates the maximum price (per kWh) the DSO is willing to pay for flexibility, the sanction is the price (per kWh) an aggregator has to pay the DSO in case of non-delivery of agreed flexibility. Additional data (e.g. the outdoor temperature) is imported into the model to compute these prices.

In the last step, the relevant information is passed along the GMS, where a flexibility request is sent to the aggregators through the market interfaces.

Price of flexibility

The maximal price of flexibility is determined using two pathways, namely the cost of transformer lifetime reductions, and the financial risk of an outage. The sum of the costs in the pathways is set as the maximal price of flexibility

Cost of transformer lifetime reduction

Violating the rated power of a transformer does not always immediately result in a blackout. Transformer overloadings lead to increasing internal temperatures. Insulation hot-spot temperatures up to 140 ºC result to a reduction in lifetime, with an attached cost. Higher temperatures result to permanent damage on the transformer [6]. In practice, Dutch DSOs assume a temporary overloading up to 130% of the rated power is acceptable. The DSO can use cost of lifetime reduction as a reference to determine the price it is willing to pay on the local flexibility market, for an alternative.

Transformers in the Dutch distribution network are typically oil-immersed. [7] provides a methodology to determine the loss-of-life in relation to the oil temperature. [3] introduces a simplified loss-of-life method, which is adopted in the decision-making process.

The transformer loss-of-life is related to the oil temperature, and the temperature of the insulation, which in turn depend on the loss and temperature constants in table 1, the changing transformer loading and outdoor temperature, and a time-dependency due to the thermal inertia of the oil.

The loss of life is used as input for the total lifetime cost method described by [3]. Here, the purchase cost, economic lifetime, and energy costs (table 1) are used as input. The costs of an overloading are computed by determining the difference between the total lifetime costs in case of aging at rated power, with the costs in case of aging at overloading power.

Figure 3 visualises the relation between costs of an overloading as function of the percentage rated power, and the

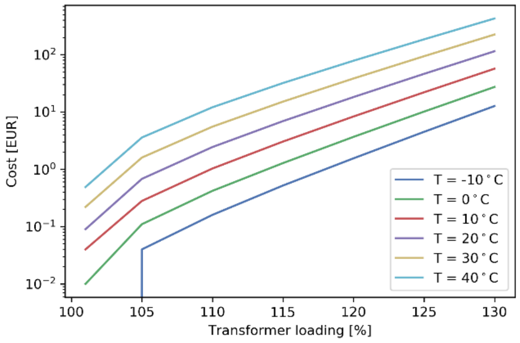

Figure 3: Transformer overloading costs in relation to loading percentage of rated power and outdoor temperature.

Table 1: Assumed transformer constants in loss-of-life and total lifetime cost calculations.

Constant	Value
Rated power	630 kVA
Losses during load	5.1 kW
Losses during no-load	0.53 kW
Top oil temperature	50 ºC
Top winding temperature	55 ºC
Purchase costs	€8000
Economic lifetime	40 yr
Energy costs	0.032 €/kWh

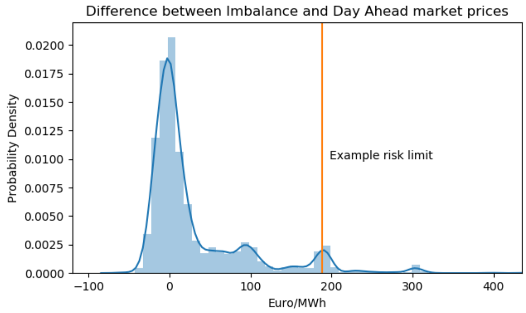

Figure 4: Probability distribution of the difference between imbalance and day ahead prices.

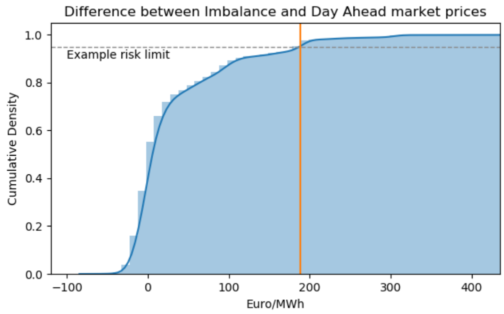

Figure 5: Cumulative probability distribution of the difference between imbalance and day ahead prices.

outdoor temperature. The time-dependency due to the thermal inertia of the oil is neglected in this figure. It can be observed that for lower outdoor temperatures (= winter), the overloading costs are significantly lower than for the warmer outdoor temperatures (= summer).

Financial risk of an outage

Transformer loadings above 130% rated power result in a blackout risk for the distribution network behind the transformer. For those PTUs the transformer loading is above 130% rated power, the DSO can use its risk-matrix to identify the financial risk of a blackout behind the transformer. This financial risk can be used to determine the price the DSO is willing to pay for flexibility during those PTUs.

Typically, Dutch DSOs use a risk matrix to determine the risk the DSO is exposed to. This matrix relates impact and frequency with a risk. The financial impact of an outage is linked to the amount of customer outage minutes. An outage of a MV/LV transformer typically takes 120 minutes, and is assumed to cost €0.50 per customer outage minute. Calculating the costs per customer per PTU, this results in €7.50. At the congestion point in Strijp-S the typical number of connected customers per transformer is around 150-200, thus a financial risk of overloading of around €1125-1500.

In order not to value an overloading of 131% rated power and 200% rated power equally, it is assumed that the (financial) risk of an overloading increases linear between 130% and 200% rated power. The maximum price of €7.50 per customer per PTU is set for a transformer loading of 200% rated power. Consequently, this results per customer per PTU in €0.11 for each % overloading between 130% and 200% rated power.

Total price of flexibility

Adding up the two components of the price of flexibility, results in eq. 1, where P_l the transformer loading, P_{rated} the rated power of the transformer, C_{flex} is the maximum cost of flexibility, C_{ovl} the cost of lifetime reduction due to overloading, and C_{risk} the financial risk of a blackout.

$$C_{flex} = \begin{cases} 0, & \text{if } P_l \leq P_{rated} \\ C_{ovl}(P_l, T), & \text{if } P_{rated} < P_l < 1.3 \cdot P_{rated} \\ C_{ovl}(P_l, T) + C_{risk}(P_l, T), & \text{if } P_l \geq 1.3 \cdot P_{rated} \end{cases} \quad (1)$$

The maximum cost of flexibility (C_{flex}) is the value forwarded to the flexibility market through the market interface of the GMS.

Sanction price

As the aggregators are allowed to trade on multiple markets simultaneously, some mechanism needs to be in place to ensure they follow their committed flexibility profile. To achieve this a sanction price is determined, which should be paid by the aggregator if he fails to comply with the flexibility profile that was settled on. This sanction price is determined by the difference between the settled flexibility price in the local market and the expected revenues an aggregator could achieve on other markets (e.g. the imbalance market) which operate on shorter notice-times. In this way the incentive to divert from the promised flexibility profile is taken away.

Figure 4 shows the probability distribution of the difference between prices on the imbalance and day-ahead market. Based on the forecasted probability of overloading a risk limit can be set. For this, the forecasted probability of overloading is matched with the cumulative probability of the difference between prices on the imbalance and day-ahead market (figure 5). This allows the choice of a suitable, varying sanction price, which reduces the risk that an aggregator could benefit from deviating from the agreed upon flexibility profile to an acceptable level.

Simulations

The transformer loading of August 2018 is used to run a number of simulations, regarding the price definition of flexibility. The capacity of the transformer is virtually set at 100kVA. Figure 6 shows the load profile, including the 100% rated power and 130% rated power limits. It can be observed that during a number of times the load exceeds the rated power, whereas in two occasions, the load exceeds the critical limit of 130% rated power.

An overview of the costs of each lifetime reduction, and the corresponding value per MWh is provided in figure 7. It can be observed that the price of an overloading relates to the size of the overloading. A relatively small overloading has a cost in the order of magnitude of 10-20€/MWh, whereas the price of a relatively large overloading can grow significantly, up to around 900€/MWh.

Figure 8 shows a comparison of the lifetime reduction costs for the month August 2018, in relation with the day-ahead and imbalance market prices at the times of the congestion. It can be observed that in a number of instances, the market value of flexibility (i.e. the DAM and imbalance market prices) is higher than the costs of the lifetime reduction of the transformer. This particularly applies to relatively small congestions (up to 10% overloading). It is likely that during these moments no flexibility will be offered to the DSO.

During other moments, the overloading approximates the 120% (120kW) of the transformer's rated power. Now, the combination of the relatively warm August outdoor temperatures, and increased loading cause higher internal temperatures in the transformer, which lead to more significant lifetime reductions. It can be observed that this is pushing the cost of lifetime reduction above the current market value of flexibility. In the pilot phase, it can now be expected the DSO is able to obtain flexibility at a price lower than, or equal to, the lifetime reduction costs.

For the two instances in which the congestion exceeds the limit of 130% rated power, the financial risk of an outage

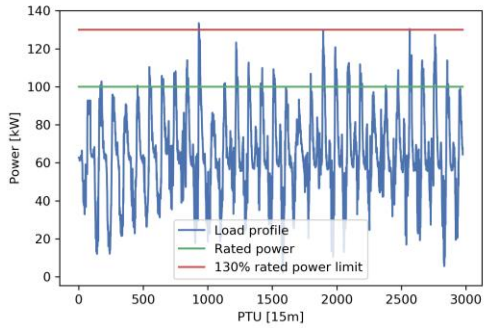

Figure 6: Transformer load profile of August 2018, with the rated power and 130% rated power lines plotted.

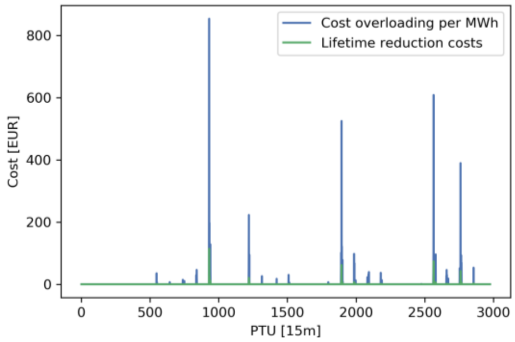

Figure 7: Cost of transformer lifetime reduction and cost per MWh.

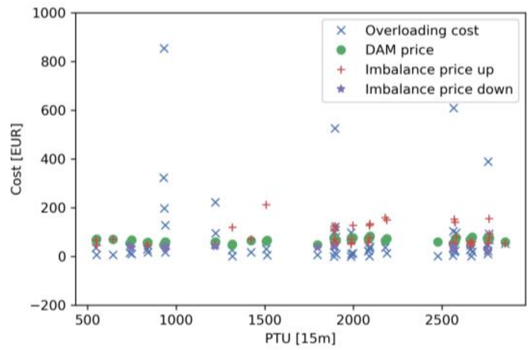

Figure 8: Cost of lifetime reduction in August 2018, related to the day-ahead and imbalance prices at the same moment.

is computed. During these moments, the financial risk of an outage is calculated to be 1875€/MWh (in both cases). This is well above the market value of flexibility; thus, it is expected that in the pilot phase, the load can at least be reduced to below the critical limit of 130% rated power.

CONCLUSIONS

This paper discusses an operational decision-making process with which the DSO can decide when and where to apply flexibility for congestion management, and at what cost. This flexibility is requested through aggregators acting on a flexibility market. Currently, two elements form the total price a DSO is willing to pay, namely the cost of loss of lifetime of a transformer, and the risk of an outage.

We have shown that these costs rise for increasing transformer loadings, which should increasingly incentivise the aggregators on the market to provide the needed flexibility.

The sanction for non-delivery of flexibility is linked to the alternative source of income for the aggregator. The probability distribution of the difference between the imbalance and day-ahead market facilitates this price.

The decision-making process is currently implemented in the demonstrator on Strijp-S, where the first results are expected to be presented from the beginning of 2019 onwards. In the course of 2019 additional aspects that can still be added to the decision-making process are an intraday component, the loss of lifetime costs of a feeder, and an expansion on the forecast interpretation such that the probability of an overloading is included in the weighing.

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