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System Integration and Scenario Assessment Report

- Simulation-based Scenario Assessment -

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Executive Summary

The DREM trade permission system (TPS) is suggested to reduce the need for investments into distribution networks when more flexible production and consumption assets are rolled out. These Flexibility Assets (FA) are controlled by aggregators or balance responsible party (BRP), and with TPS the distribution system operator (DSO) shall have the opportunity to restrict the usable capacity of FA to avoid overloading grid assets in critical situations. These critical situations may become more frequent when a significant fraction of FA operate on the same feeder and operate more synchronized due to market stimuli or ancillary services activations. The main objective of this simulation-based assessment has been to quantify the overall impact of the TPS mechanism on flexibility asset operation as well as on distribution network operations, as opposed to scenarios where a TPS is not available. The system configuration for this assessment replicated the configuration of the end-to-end test with a grid loop based on an actual network feeder in Nordhavn, a DSO, an aggregator and a flexibility asset. The flexibility asset was modelled on HOFOR's FlexHeat system, with a two-level control system to represent both physical dynamics and predictive optimization. In order to emulate random faults locations, the model included the individual cable segments in the feeder. This setup allowed the simulation to be validated against the real-world FlexHeat configuration.

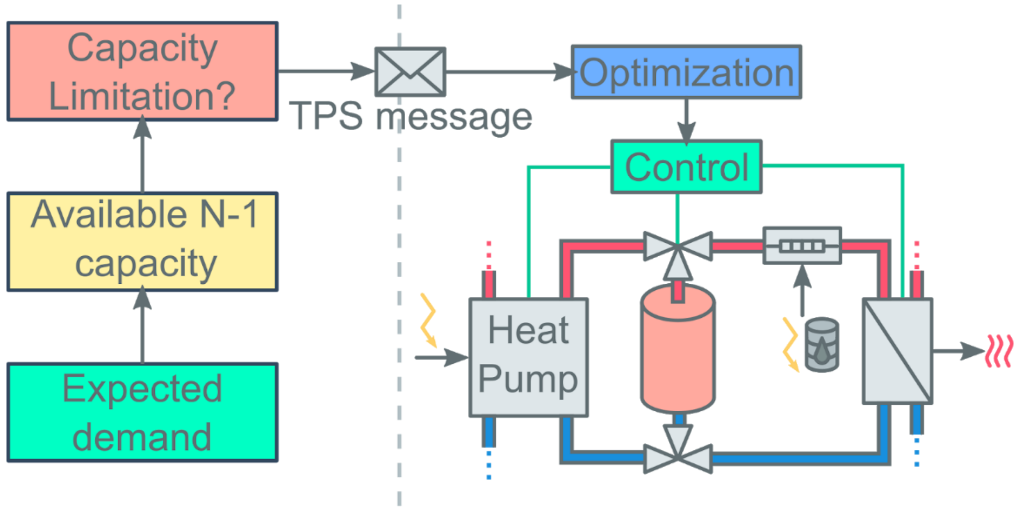

Figure ES1: Structure of the simulation tool

The simulator generates DSO requests automatically based on expected congestion. The TPS messaging functionality is emulated such that the aggregator (predictive optimization) receives DSO restrictions either on a day-ahead basis (foreseen capacity issue) or immediately (unforeseen capacity issue). Scheduled setpoints are exchanged with the local controller. In line with the overall project scope, the design of aggregator solutions for multiple household level flexibility assets has been excluded.

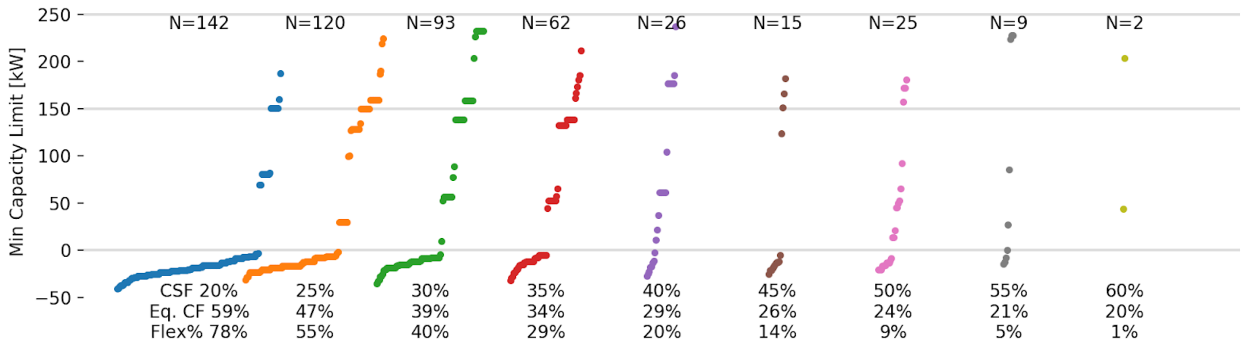

Figure ES2: Number and volume of capacity limit messages issue for reduced grid capacity (from right to left) or increasing coincidence factors due to increased flexibility assets. The simulated Flexibility Asset has a capacity of 250kW – negative values express a congestion value larger than this capacity (not to scale).

The study of congestion under increased pressure on the distribution network illustrates the dynamic of additional TPS messages being issued. The increased pressure in the distribution grid is modelled by reducing the available grid capacity, which corresponds to increasing coincidence factors caused by an increasing ratio of flexibility assets replacing non-flexible assets. Starting from a capacity scaling of 0.6, which is close to the current N-1 peak consumption (0.68), 2 of 150 N-1 scenarios lead to a TPS message being issued. At 45% capacity scaling (20% of load replaced by flexibility assets), 15 of 150 N-1 scenarios lead to a capacity reduction requests which can well be met by the available flexibility assets. A further reduction of capacity or coincidence factor increase leads to unreasonable levels of capacity limits.

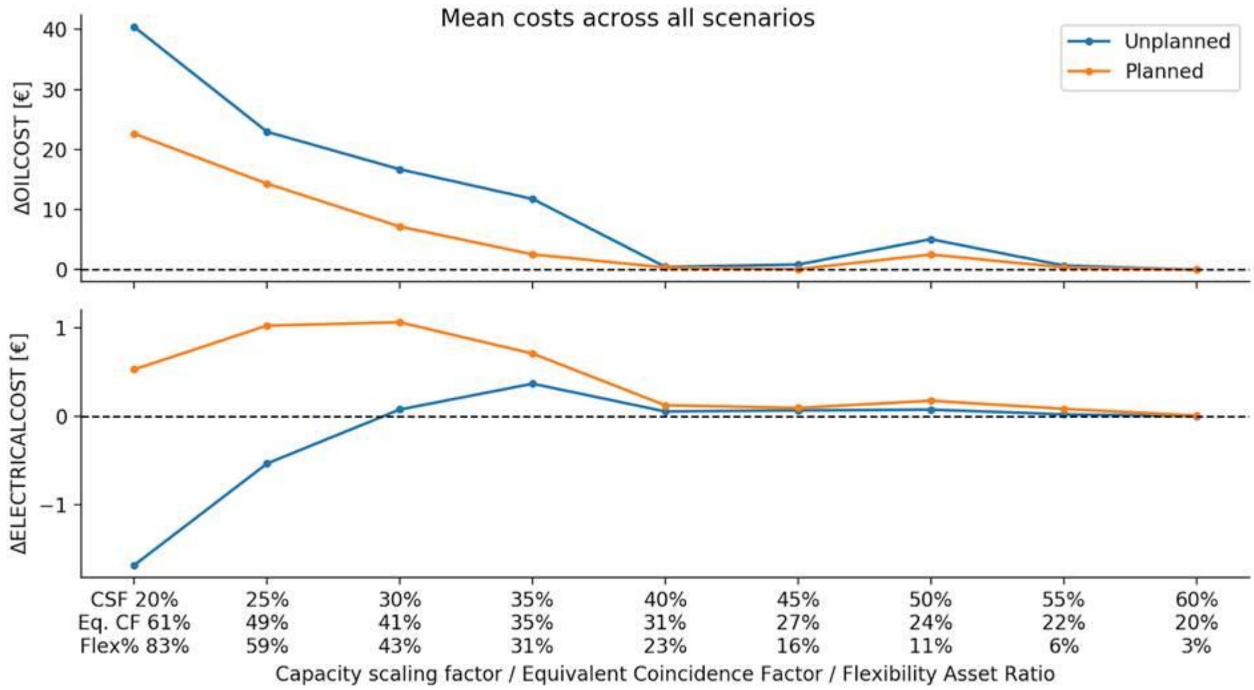

Figure ES3: Mean simulated operation cost increase per level of reduced grid capacity/increased coincidence factor (from right to left)

Figure ES3 shows the summarised (weighted mean) results of the operational impact of capacity restrictions on estimated FlexHeat operation cost, relative to the same scenario without restrictions. The cost increase is shown separately for changed electricity procurement cost and additional oil firing cost, which becomes necessary when electricity is restricted. Even once line capacities are reduced below 65%, costs to operate the FlexHeat system do not increase significantly until line capacities are reduced below ca. 40%. Thus, operating flexible assets to mitigate the need for flexibility asset driven grid reinforcement is expected to be feasible for this range down to about 45% of the present capacity (estimated 20% flexibility assets).

In the range of these 3%-20% of flexibility asset penetration, costs of a single capacity limitation are averaged 2€, or 7% of a daily operation cost of FlexHeat. With the low likelihood of an N-1 event happening approximately once every other year the cost come down to at 3€/year. It stands to conclude from that for low to medium penetration of flexibility assets, the benefits of coordination between distribution system operators and aggregators far outweigh the costs incurred.

1. Introduction

From the outset, DREM has been motivated by the expected changes in consumption (and production) patterns in distribution networks due to electrification and flexibility asset (FA) operation, resulting in increased coincidence factors. Such an outcome would either drive a massive need for investments [DE2019] or require new means of coordinating grid demand and utilization. Earlier work in DREM has shown how conflicts between stakeholders in the power system can emerge when customer flexibility from assets connected in distribution networks is offered in different power markets [D2.2-3.2]. Those conflicts can appear between TSO, BRP and DSO, e.g. when the TSO or BRPs activate flexibility at a moment where the full distribution grid capacity is not available for some reason. Earlier work in DREM developed the concept of a Trade Permission System (TPS) as a possible mechanism for conflict resolution. The TPS allows the DSO to announce grid limitations to customers with flexibility assets. This solution has been demonstrated in a laboratory setting in SYSLAB and proven feasible in field-tests from the Flexibility Asset point of view [D7a].

However, a key question important to DSOs and the operators of FAs (aggregators/BRPs) remained to be addressed: How often would high demand due to FA operation coincide with grid congestion, and thus, how could a trade-off be found between investments into additional grid capacity on one hand and the occasional limitation of FA operation? More specifically, could such a trade-off be economically attractive to both the DSO and the FA operator?

The effective impact of the proposed TPS in the medium and long term is not trivial to estimate, as several co-dependent factors are at play. This includes load patterns, price patterns as well as the mix of production and consumption capacity in a specific feeder. The purpose of this work is to provide a method and means to estimate this impact through simulation.

The operation of FAs is typically influenced by three factors:

1. The constraints imposed by the asset's primary purpose (e.g. the need to maintain the temperature of a heated space within a certain range),
2. The cost-optimal procurement of electricity (i.e. a market-based operational plan), and
3. Available storage capacity, either before or after energy conversion.

On the other hand, the available capacity of a distribution network is determined by another set of main factors:

1. The capacities of grid assets such as lines or transformers,
2. The overall baseline consumption, including non-flexible assets, and
3. Temporary limits to the available capacity due to possible contingencies.

This report summarizes the design and results of a simulation study which analyses the performance and impact of the proposed TPS in a realistic distribution network feeder.

1.1 Scope and limitations

The simulation study has been conducted as a substitute for a long-term field test in the Nordhavn grid, which had originally been planned as part of WP7. The planned test aimed to cover the entire chain from the DSO decision process all the way to the control of flexibility assets in the Nordhavn grid. The original plan had to be abandoned due to a lack of suitable flexibility assets. Instead, the WP7 objectives are addressed in two separate ways, reflected by a split of WP7 into WP7a/b. The end-to-end feasibility of signalling between DSO, TPS, BRP and FAs has been validated through testing at DTU Risø's SYSLAB laboratory. By conducting tests against the HOFOR FlexHeat heat pump in WP7a, the feasibility has been demonstrated against a real-world flexible asset. This report contains the results of WP7b which contribute to the description of the new DSO decision processes and which studies the potential long-term impacts of active congestion management on both network operation/dimensioning and flexibility asset operation. Initially modelling of aggregator infrastructure and multiple flexibility assets was considered. This aspect is now out-of-scope as the project has been modified to exclude the modelling of aggregators.

Two main causes of congestion in the distribution network are considered: increased coincidence factors[1], and temporary network reconfigurations (N-1 conditions). Increasing coincidence factors for flexible demand have been reported in numerous studies, such as for electric vehicle charging in [DE2019], [Calearo2019] and [Agora2019], and for coordinated heat demand in [Zhang2019], [Pedersen2008], and household battery storage [Wang2013]. The aspect of N-1 events has not been found addressed in prior studies, therefore a choice was made to prioritise the modelling of N-1 related DSO actions as a cause of temporarily reduced network capacity. The coincidence factor development is reflected trivially by a reduction of the available grid capacity.

This report describes the development of a methodology for the systematic assessment of the effects of congestion management. The methodology has been implemented in a proof-of-concept simulation tool. The simulated system consists of a distribution feeder in Radius' network on which N-1 situations can be created, a messaging model of the TPS and an operational simulation of the HOFOR FlexHeat unit. We report systematic simulation results which enable estimating the capacity impact and cost of the different congestion management measures facilitated by the Trade Permission System.

[1] The concept of coincidence factors was introduced in [Hamilton1944] and later confirmed by [Bary1945].

2. Causes of congestion and possible DSO interventions

This section outlines the relevant causes of distribution grid congestion, the stakeholders involved, intervention mechanisms available to a DSO, and the test cases considered for simulation tool development.

2.1 System actors and relevant scope

Interactions between the following actors have been considered in DREM in context of flexibility asset (FA) operation and distribution network congestion:

1. Distribution system operator (**DSO**) – to ensure that the capacity of the network is adequate to the power demand; interfaces with TPS to issue restrictions

2. Aggregator (**AGR**) – functional entity that can manage flexibility by controlling multiple flexible loads in its portfolio; AGR has a direct relation with FA and BRP;

3. Balance responsible party (**BRP**) – a market party, also able to offer ancillary services; financially liable for deviations from operational plans;

4. Transmission System Operator (**TSO**) – can issue ancillary service requests which may be fulfilled by a BRP through an Aggregator and realised by FA.

Here, AGR and BRP are viewed as integrated legal entities, where AGR fulfils the implementing role and BRP the legally responsible one, and thus AGR and BRP are practically interchangeable in the following. As DREM is not concerned with market design and coordination, both the TSO as well as the power markets are out of scope: both simply provide external stimuli for FA operation. The TPS system acts as a separate coordination tool to facilitate DSO coordination with market-based operations. In this context, the TPS also enables AGRs to share operational plans for individual FA on a day-ahead basis with the local DSO. As the operational plan submission is only optional, and schedules can only be considered indicative (non-binding), such operational plans are not considered in the following simulation-based assessment.

2.2 Causes of distribution network congestion

During day-to-day operation, the DSO forecasts the expected power demand for each part of its network. If the power demand exceeds the rated capacity of the components in a network section, the network becomes congested and the power flow in that section should be limited. A critical quantity in this context is the available network capacity, i.e. the rated capacity of the network minus the amount of expected load. Two factors influencing the amount of available capacity are the coincidence factor (CF) of the loads and the occurrence of contingency (N-1) situations.

2.2.1 Factors influencing available capacity

To perform its responsibilities and make sure that the network capacity is enough, a DSO plans their networks far ahead. To determine the rated capacities of components, such as cables, transformers and circuit-breakers, the DSO forecasts the future power demand and estimates network loading in normal and contingency situations.

Coincidence Factors

Not all the electric loads in the network would consume at rated power at the same time and therefore an actual capacity of components could be reduced by taking the load CF into account. The load CF is a measure (between 0.0 and 1.0) for the fraction of the electric load capacity connected to an electric network is consuming power at any point in time. The CF is equal to 1.0 exactly if all loads would be on (up to the fuse rated capacity). In practice not all loads in a distribution network are turned on at the same time. The CF for non-flexible loads is primarily determined by the type of load (residential, commercial, industrial), outside temperature, time of the day, day type (working day or weekend) and season. These factors can be estimated to a certain degree, making it possible to obtain CFs for non-flexible loads with enough accuracy. Typical values used by DSOs are in the range of 0.2 to 0.4 and higher depending on the load type and the DSO's own planning procedures.

For flexible loads, on the other hand, could be controlled by an AGR whose behaviour is determined by e.g. market prices or ancillary service activation by the TSO. Price volatility in bulk energy and ancillary services markets makes it difficult to accurately estimate CFs for flexible loads. If flexible loads constitute a significant part of the overall power demand, their coordinated operation due to favourable market prices could lead to a situation where flexible load CF increases, possibly approaching 1.0.

N-1 Situations

Available capacity of the network is influenced by contingencies, specifically N-1 situations where backup capacity is used. N-1 situations occur, when distribution network components are out of operation due to a fault, component malfunction or planned maintenance. In most networks, contingencies are handled by activating redundant branches, supplying the affected load through other available components. This procedure can be illustrated on the two feeders from the Nordhavn grid which were used in the present analysis. The two feeders can be interconnected to form a loop designed for load transfer during contingencies (Figure 1). The two feeders NGT-57 and NGT-26 are connected into a loop by a tie-line between substations 52800 and 53923. Under normal circumstances, the loop will be open (circuit breakers TL-SW1 and TL-SW2 not engaged).

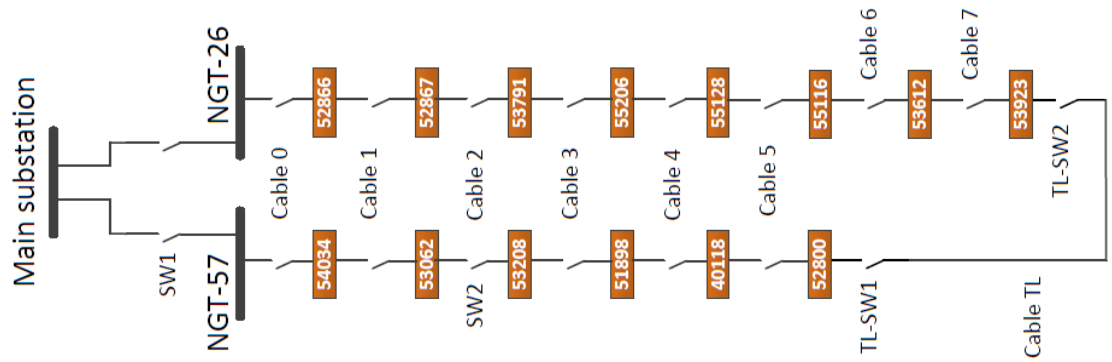

Figure 1: Schematic of the two-feeder loop design in the Nordhavn distribution network. Boxes mark secondary substations (10kV/0.4kV)

Consider a fault on the cable between substations 53062 and 53208. Initially the whole feeder NGT-57 would be disconnected as the circuit breaker SW1 trips, losing supply for all substations of NGT-57. A maintenance team would then be sent out to manually locate the fault. After approximately 40 minutes, the team would isolate the fault by opening SW2. Now the electrical loads located upstream of the fault location would be reconnected by reclosing SW1, and the loads downstream of the fault are transferred to the feeder NGT-26 by closing the tie-line breakers TL-SW1 and TL-SW2. NGT-26 would now see an increased power consumption until the fault is repaired. DSO networks are typically dimensioned to be able to sustain such N-1 reconfigurations.

Network dimensioning and topology

The connected load capacity and types and their effective CF, the expected load growth, and the expected loading under N-1 conditions are some of the key factors in setting the required network capacity for designing and dimensioning distribution networks. Many further factors, including the location and concentration of loads (e.g. rural or urban areas), voltage and power quality standards, as well as existing networks and local engineering practice influence the layout and design of distribution networks. Notably, in rural networks not the cable capacity but rather the voltage limits determine the critical dimensioning constraint. A discussion of the planning process and further modern planning options is found in [Klyapovskiy2020] .

2.2.2 Network congestion

High-CF and N-1 situations independently contribute to network congestion, i.e. the potential overloading of at least one of the network components, most commonly occurring for cables. Today, a high CF alone is rarely the reason for congestion-induced overloading of cables. Therefore, special attention is paid to the available capacity of the cables in N-1 situations, when the network is reconfigured, and reserve capacity is used.

If a congestion situation is anticipated, the congestion can be relieved by preventive measures. If the congestion turns into an overloading of components, protective equipment will disconnect the whole feeder load, thus leading to an outage for all customers connected to the respective feeder. In this view, we distinguish N-1 situations that can be **planned**, e.g. for maintenance purposes, or those that are **unplanned**, such as due to a fault or other component malfunctions. If the event is planned, it could be scheduled during a period of low power demand (and thus low CF), thus reducing the N-1 contribution to the electrical load increase on the components that are still in operation.

As outlined above and discussed in detail in [D2.2-3.2], there could be several reasons for a CF increase caused by flexibility assets (FA), such as:

1. The FAs are controlled to follow market prices to minimize electricity cost.
2. The FA operation follows a BRP response to ancillary service requests from the TSO.
3. The AGR/BRP performs internal portfolio balancing actions utilizing FA.

The actions of an AGR do not take network constraints into account, so these actions may lead to distribution network congestion. The likelihood of an increased CF depends on many factors such as market prices, ancillary service activations, but also on the specific mix of customer types connected to a distribution network and unit-specific usage patterns (EV: driving needs; Heating: seasons / outside temperature; PV: solar irradiation and temperature etc.). Different types of models of Flexibility Asset behaviour have been studied recently, e.g. on electric vehicle charging in [DE2019], [Calearo2019] and [Agora2019], where the results show that especially a massive roll-out of electric vehicles may require significant distribution network investments or alternative means of coordination [Agora2019]. In other words, network congestion is likely to appear more frequently in these scenarios of electrification.

To avoid outages resulting from changed load patterns, firstly DSOs need to dynamically anticipate the load, also from these flexible loads and flexibility assets, and derive the potential impact on DSO network constraints. Then, secondly, DSOs can consider new preventive measures applicable to flexible consumption.

2.2.3 Anticipating Capacity limitations

DREM introduced the Trade Permission System to facilitate communication between DSO and Flexibility assets. The DSO hereby has the option to limit the usable capacity for flexibility assets. In order to derive such a limitation, the DSO must anticipate the congestion and allocate a capacity limitation, restricting the maximum consumption of connected flexibility assets. The actions that a DSO can undertake in response to network congestion depend on it being a planned or unplanned N-1 situation, referred to as “foreseen” and “unforeseen” capacity limitations in the following.

A method for the DSO to determine the capacity limitations on a feeder on a day-ahead basis is illustrated in Figure 2.

First, the DSO forecasts the power consumption of both non-flexible and flexible customers on a feeder. Assuming that the individual FA schedules for the next 24 hours are not known, the DSO performs a worst case calculation, adding the maximum power output of the FAs on that feeder ($P_{flex,max,f}$) to the non-flexible consumption in order to obtain the total consumption (red dotted curve). If an AGR’s schedule is known, the schedule for these FAs can be included in the baseline instead, and capacity restrictions applied to the remaining flexibility. In a period where the total consumption is forecasted to exceed the feeder’s capacity ($P_{max,f}$), e.g. due to a planned temporary capacity reduction, there is a chance of congestion, and Pflex,max,f should be limited. This is done by specifying the limit Pflex,ul,f in the period between t1 and t2. After t2, there is no further risk of congestion and therefore no further limits on Pflex,max,f is imposed.

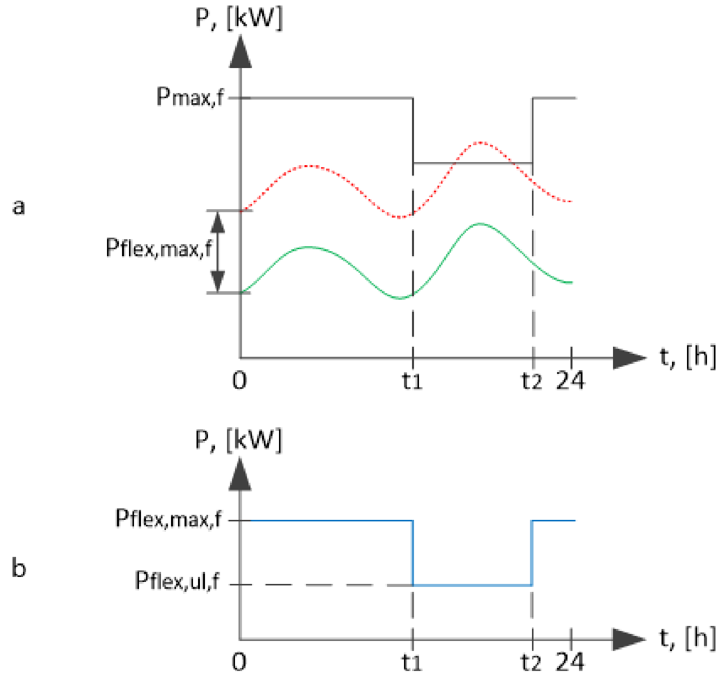

Figure 2: Illustration of the capacity limitations imposed by the DSO on the operation of the flexible loads in the respective feeder. **a** – power consumption on the feeder: green curve – consumption from non-flexible loads, red dotted curve – total consumption of non-flexible and flexible loads. **b** - total Flexibility Asset capacity and applied capacity limitation

Capacity limitations can be imposed both on the maximum power consumption (upper capacity limitations) and minimum power consumption/maximum power injection (lower capacity limitations). Both types of limitations could be planned and unplanned with regards to what type of N-1 situation had caused it.

2.3 Communication via the Trade Permission System

In the concept for a TPS outlined in D3.1 and detailed in D6.1, the TPS serves as an interface for dynamic updates between DSO and Aggregator/BRP, and a variant of the Datahub serves as a registry of flexibility assets (Static Information System). The registered data includes the flexible capacity of the connected assets.

When a DSO issues capacity limitation through the TPS, the capacity limitations are distributed[2] by the TPS as capacity restrictions applicable to the affected assets using information from the Static

[2] The distribution method was called "Fairness Filter" and considered beyond the scope of DREM. A weighting factor based proportional distribution may be considered intuitive choice, where the weighting factors could be based on registered flexible asset capacity.

Information System. The per-asset capacity limitations are communicated as a message to the responsible BRP/AGR. There are two types of restrictions:

1. **Foreseen** Capacity limitations (as a day-ahead message)
2. **Unforeseen** Capacity limitations (intra-day, response within 5-10minutes)

The message from the TPS system includes the starting time, ending time and magnitude of the restrictions. A detailed description can be found in deliverable [D6.1]. It is expected that the Aggregator, upon receiving the TPS message, modifies the FA dispatch schedule to include the restrictions. The communication of the updated schedules between Aggregator/BRP and FA operator are discussed in deliverable [D7a]. The compliance of FA operation with the imposed limits is the responsibility of the aggregator and are not verified in real time by the DSO, but it can be assessed afterwards based on smart meter readings.

2.4 Test scenario plan

The purpose of the test scenarios is to formulate the operational conditions under which a simulation tool will cover the functionality required from DSO, aggregators and TPS. The test cases have been detailed to cover the impact in all the conflict cases reported in [D2.2-3.2]. A complete coverage of these test cases would be interpreted as simulation-based validation of the TPS as a solution to the respective conflicts. However, this tool is focused on quantitative assessment and should be able to provide answers to the following questions:

Q1. How often would the TPS be activated in response to congestion?
Q2. What are the expected costs incurred by an AGR/BRP or FA as a result of TPS activation?

That is, the test coverage may not be required to be complete for the conflict cases, but enough for a) evaluating how large a capacity limitation would be required for different types of congestion situations, and b) to assess the impact on FA operation. The test scenarios are therefore going to be reduced as part of the tool design.

Several qualitative conflict cases were identified in deliverable [D2.2-3.2], listed in Table 1 (for the complete version see Table A3 in the Appendix). As each conflict would relate to congestion in the DSO's network, in principle all the conflict cases should be studied individually. However, from a perspective of developing a simulation tool, the number of actors (DSO, TSO, AGR, etc.), physical models (distribution network, FA) and functions (TPS, DSO day-ahead load forecasting, DSO – TPS communication, TPS – AGR communication, etc.) are similar across the conflict cases.

To clarify the required scope of the simulation tool, the above list of cases has been reduced to two main test scenarios:

1. Test scenario 1: The DSO forecasts network congestion and issues capacity limitations through the TPS;
2. Test scenario 2: The AGR or a single Flexibility Asset receives capacity limitations from the TPS and adjusts its day-ahead schedule (in case of *foreseen* capacity limitation) or immediate operation (in case of *unforeseen* capacity limitation).

Table 1: Conflict cases from DREM Deliverable 2.2

Conflict case nr.	Conflict case name
1.1	Spot price variations
2.1	AGR control of several customers
3.1	AGR offer energy management for customers
3.2	TSO activated customers
3.3	BRP Self balancing through AGR
4.1	TSO activated; several flexibility assets
4.2	TSO activated; one single flexibility asset but Alert/Emergency Grid Operation
5.1	DSO counteracting TSO activation
5.2	DSO counteracting TSO activation in A/E grid operation
6.1	DSO activated flexibility asset occasionally
7.1	BRP self-balancing cause overload. Several flexibility assets
7.2	BRP self-balancing cause overload. Single flexibility assets
8.1	TSO upward regulation of several flexibility assets
8.2	BRP upward regulation for self-balancing service
8.3	Opposite of (2) in Explicit Demand Response
8.4	Unexpected renewable in-feed power

Each test scenario has several test cases to express how specific interactions between entities should be modelled. Further, a base-case is defined for each of the conflict scenarios.

A model for simulating congestion due to planned and unplanned faults (N-1 situations) is created for test scenario 1. The model output is the capacity limitation for the flexible load under AGR control. A computational model for adjusting the behaviour of a flexible load - the HOFOR FlexHeat system - has been constructed for test scenario 2. This model allows the estimation of the cost of rescheduling due to capacity limitations.

By combining the models created for test scenarios 1 and 2, it was possible to simulate all conflict cases. A mapping between conflict cases and test cases is found in Appendix A3. The results from test scenario 1 provide information about how frequently the TPS should be activated (Q1). The results from test scenario 2 reveal the cost of TPS activation, answering Q2.

Table 2 lists the test cases and sub-cases of test scenario 2 (for more information see Tables A1-A2 in the appendix). Test cases highlighted in red simulate potential congestion due to the actions of an AGR. Test cases in green show the application of capacity limitations through the TPS to resolve these congestions. Figure 3 shows the naming convention for the Test cases and sub-cases in Table 2 and Tables A1-A2 in the appendix.

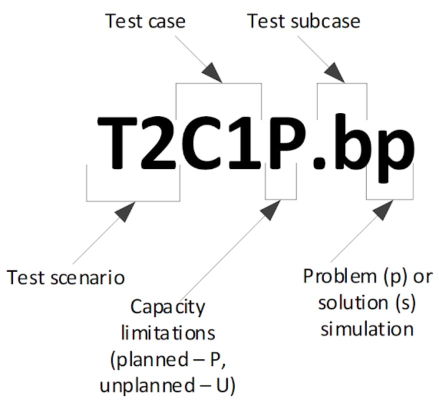

Figure 3: Test case naming convention

The naming code reflects the hierarchical structure of the test cases:

1. Test Scenario 1 or 2
2. Test case: Identifying the main interactions
3. TPS signalling type: Foreseen/unforeseen; here called Planned/Unplanned from DSO perspective;
4. Test case variant: for each test case several event sequences can be relevant, e.g. one for load increase and one for load decrease;
5. The base case ("p" -problem) or case with TPS involved (solution case "s")

The main test cases of test scenario 2 concern:

C1: Day-ahead market participation of AGR/BRP
C2: Regulating power market participation AGR/BRP in context of foreseen capacity limitation
C3: Regulating power market participation AGR/BRP in context of unforeseen capacity limitation

The cases **T2C1P.ap** and **T2C3U.ap** illustrate the potential congestion caused by an AGR pursuing its own economic interests without coordination with the DSO during planned and unplanned N-1 situations. These two cases represent the baseline for the following analysis. In cases **T2C1P.cs** and **T2C3U.bs**, the DSO forecasts/detects congestion during planned/unplanned N-1 (referred to as faults later in the report) and issues appropriate capacity limitations to the AGR through the TPS. The AGR changes its operational plans according to these limitations, which resolves the congestion issues.

Table 2: Test cases of test scenario 2

***T2C1P.ap** – The AGR creates a day-ahead schedule for dispatching the flexible loads (increased consumption) in its portfolio without receiving planned capacity limitations from the TPS. It then dispatches the loads according to the schedule.

The minimum simulation time frame is 25 hours: 1 hour for initialisation and 24 hours for executing the schedule.

T2C1P.bp – The AGR creates a day-ahead schedule for dispatching the flexible loads (decreased consumption) in its portfolio without receiving planned capacity limitations from the TPS. It then dispatches the loads according to the schedule. After the flexible loads are released from scheduled operation, they return to normal operation, causing a rebound effect.

The minimum simulation time frame is 26 hours: 1 hour for initialisation, 24 hours for executing the schedule and 1 hour beyond the end of the schedule for monitoring the rebound effect;

***T2C1P.cs** – The AGR creates a day-ahead schedule for dispatching the flexible loads (increased or decreased consumption) in its portfolio in accordance with the planned capacity limitations received from the TPS. It then dispatches the loads according to the schedule. The AGR takes the planned capacity limitations for the current and the next day into account in order to reduce the rebound effect.

The minimum simulation time frame is 26 hours: 1 hour for initialisation, 24 hours for executing the schedule and 1 hour beyond the end of the schedule for monitoring the rebound effect.

T2C2P.ap – The AGR bids the remaining flexibility in its portfolio (according to the day-ahead schedule prepared in **T2C1P.ap**) into the regulating power market without receiving any planned capacity limitations from the TPS. The TSO activates the bid, such that the AGR must provide flexibility services within 5-15 minutes from activation (aFRR or mFRR).

The minimum simulation time frame is 25 hours: The first bid is submitted within the first hour, and the TSO may activate bids at any time during the next 24 hours.

T2C2P.bp – There are two aggregators, AGR1 and AGR2. AGR1 bids the remaining flexibility in its portfolio (according to the day-ahead schedule prepared in **T2C1P.ap**) into the regulating power market without receiving any planned capacity limitations from the TPS. AGR2 submits a bid for a load reduction service to a DSO market. The TSO activates the bid, such that AGR1 must provide flexibility services within 5-15 minutes from activation. As a response to the load increase caused by AGR1, the DSO activates AGR2.

The minimum simulation time frame is 25 hours: The first bid is submitted within the first hour, and the TSO may activate bids at any time during the next 24 hours.

T2C2P.cs – The AGR considers the received planned capacity limitations received from the TPS in its bidding strategy for the regulating power market in relation to the already scheduled dispatch (from **T2C1P.cs**). The AGR rejects those TSO activation requests for which the bid was submitted prior to the reception of a planned capacity limitation, and which cannot be fulfilled due to the new limits.

The minimum simulation time frame is 25 hours: The first bid is submitted within the first hour, and the TSO may activate bids at any time during the next 24 hours.

***T2C3U.ap** – The AGR dispatches its flexible loads in accordance with a schedule (from **T2C1P.cs**) in real-time without receiving unplanned capacity limitations from the TPS.

The minimum simulation time frame is 24 hours. Unplanned capacity limitations may be imposed by the DSO at any time and the limits become effective immediately.

***T2C3U.bs** – The AGR adjusts its dispatch schedule (from **T2C1P.cs**) in real-time in accordance with unforeseen capacity limitations received from the TPS.

The minimum simulation time frame is 24 hours. Unplanned capacity limitations may be imposed by the DSO at any time, and the limits become effective immediately;

T2C3U.cp – The AGR dispatches its flexible loads in accordance with a schedule (from **T2C1P.cs**) and bids the remaining flexibility into the regulating power market without receiving any unplanned capacity limitations from the TPS. The TSO activates the bid, such that the AGR must provide flexibility services within 5-15 minutes from activation.

The minimum simulation time frame is 25 hours: The first bid is submitted within the first hour., and the TSO may activate bids at any time during the next 24 hours. Unplanned capacity limitations may be imposed by the DSO at any time during these 24 hours, and the limits become effective immediately;

T2C3U.dp – There are two aggregators, AGR1 and AGR2. AGR1 dispatches its flexible loads in accordance with a schedule (from **T2C1P.cs**) and bids the remaining flexibility into the regulating power market without receiving any unplanned capacity limitations from the TPS. AGR2 submits a bid for a load reduction service to a DSO market. The TSO activates the bid, such that AGR1 must provide flexibility services within 5-15 minutes from activation. As a response to the load increase caused by AGR1, the DSO activates AGR2.

The minimum simulation time frame is 25 hours: The first bid is submitted within the first hour, and the TSO may activate bids at any time during the next 24 hours. Unplanned capacity limitations may be imposed by the DSO at any time during these 24 hours, and the limits become effective immediately.

T2C3U.es – The AGR adjusts its dispatch schedule (from **T2C1P.cs**) and adjusts its bidding strategy in the regulating power market in real-time in accordance with the unplanned capacity limitations received from the TPS. The AGR rejects those TSO/BRP activation requests for which the bid was submitted prior to the reception of an unplanned capacity limitation, and which cannot be fulfilled due to the new limits.

The minimum simulation time frame is 25 hours: The first bid is submitted within the first hour, and the TSO may activate bids at any time during the next 24 hours. Unplanned capacity limitations may be imposed by the DSO at any time during these 24 hours, and the limits become effective immediately.

4. Test Scenario Design and Implementation

This section describes the design and implementation of a simulation tool capable of quantifying the impact of DSO operations with TPS restrictions on the operation of flexibility assets. The goal of this work is to demonstrate the viability of the developed simulation tool for deriving a quantitative analysis of relative operation cost increase for flexibility assets, as well as the frequency of volume of capacity limitation requests. These metrics will depend on available grid structure and capacity, load mix and seasonal load patterns, as well as the likelihood and location of grid faults, and the operation principles of the considered flexibility asset.

This section is structured with incremental detail, as Section 3.1 gives an overview of the study design, Section 3.2 outlines the tool component design, and Sections 3.4 to 3.5 report technical details on the simulation and analysis components.

4.1 Test Scenario Scope and Approach

To assess the impact of the DREM concept and Trade Permission System, a new simulation setup was designed that reflects the key steps of the TPS communication between DSO and aggregator as well as the domains upon which DSO and aggregator base their decisions. Figure 4 outlines the message sequence which is realised by the TPS. Here step 1 is performed offline, ensuring correct registration of flexibility assets in the static database, and thus does not require simulations or dynamic updates. Step 2 has an optional element where, in the future, aggregators shall have the opportunity to submit operational plans to inform a possible DSO intervention. If no operational plans are submitted, only steps 3 and 4 occur in relation specific congestion events and warrant a simulation. In step 3 the DSO performs the analysis for expected congestion for a given grid area, and step 4 is the transmission of a message with calculated DSO limits to the AGR.

The steps and information content between the unforeseen (right) and foreseen (left) sequences are equivalent, especially if 4b is considered. The naming “Limits” or “Emergency signal” used in the left and right sequence respectively only refers to the difference in timing: a ‘foreseen’ message applies to the following day and can thus be viewed as a request to adjust plans for the following day, if required. in case of a ‘unforeseen’ message (right, ‘Emergency signal’) the AGR is supposed to respond within approximately 5 minutes.

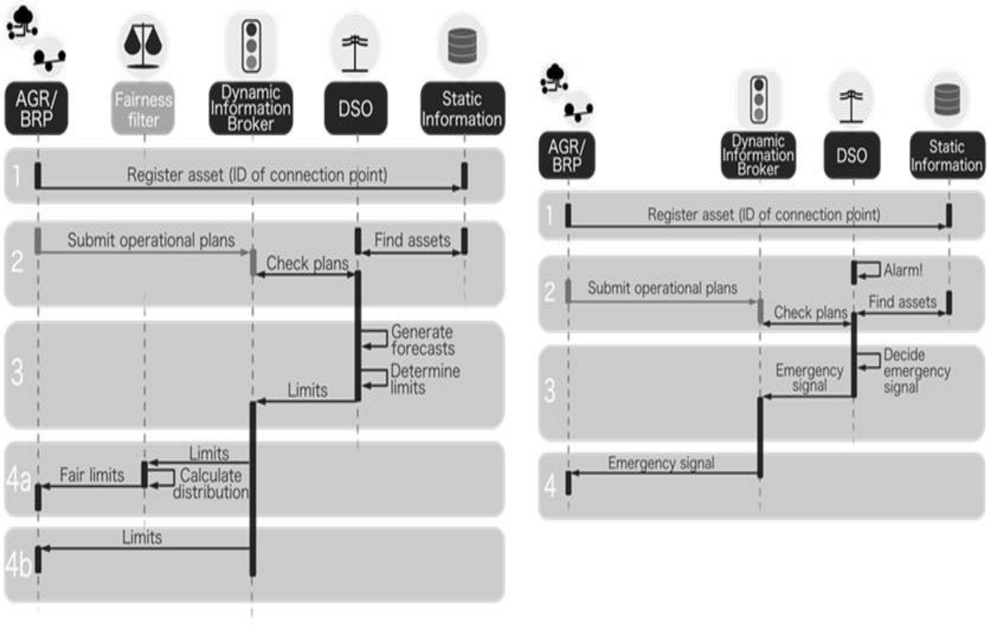

Figure 4: Communication sequences from the Trade Permission System design: left Foreseen DSO limitation on the left, right Unforeseen DSO limitation on the right. (source [D2.2-3.2])

Several options have been considered for the simulation, considering several distribution feeders from Radius' network, from within the Nordhavn area where models and data are partly available as a result of the Nordhavn project [Klyapovskiy2018]. Of the distribution loops in Figure 5, the loops with light blue and brown coloured substations were considered. For the light blue loop, substations are co-located with the larger district heat distribution network and one large battery is connected. It was considered to add artificial electric heat loads such as individual heat pumps to this feeder. The brown loop has both the HOFOR FlexHeat and some decentral solar production connected.

The simulation should be close enough to reality for results to be considered valid, yet the objective is also to generate insights that can be transferable to other cases than the simulated one. The systems selected for simulation are therefore based on systems where data for model calibration and expertise for model validation is available within the project. The light blue feeder would require additional models and an artificial aggregator setup, which otherwise has been excluded from the DREM scope. Further, the battery system is not a typical device for Radius' networks. Considering these considerations, the light blue loop was excluded, and the brown loop was chosen.

The chosen feeder loop also contains several industrial loads as well as the Copenhagen international school (CIS) which has a large PV installation. The combination of conventional load, solar PV and a major flexibility asset make it a relevant study case. Feeders without significant flexibility assets connected would not be affected by a Trade Permission System. As can be seen in Figure 5, the other feeder loops in the area have a similar design, so the study results should at least be transferable to these in case further flexibility assets are deployed in the same area.

From a perspective of electrical network topology, the chosen network is typical for urban distribution networks, even though the networks in Nordhavn have been designed with expectation of a significant load growth - the Nordhavn district development is still ongoing. The available cable capacities therefore significantly exceed the usual surplus capacities, which will need to be accounted for in the assessment. The impact of reconfiguration events on congestion can differ depending on reconfiguration topology and connected loads. In general, the applicability of case study results to other geographies is limited, as e.g. rural networks are reconfigured differently and observe different types of constraints than urban networks (e.g. voltage limits).

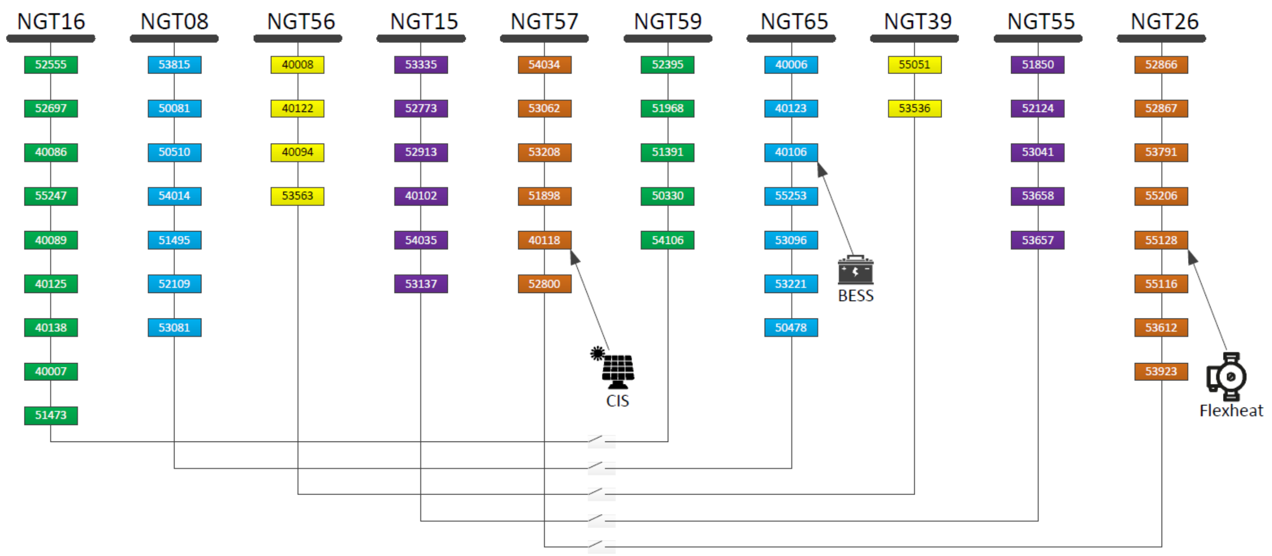

Figure 5: One-line diagram of the 10-kV distribution network in Nordhavn. Coloured rectangular boxes represent secondary substations 10/0,4 kV. Substations of the same colour belong to the same loop.

The chosen flexibility asset, the FlexHeat system is a district heat pump supplying an isolated heat network in the Nordhavn district of Copenhagen.

The actual FlexHeat system is described in detail in DREM Deliverable D7a. Figure 6 offers conceptual illustrations of the location of FlexHeat in context of heat and electricity networks. Quoting [D7a]:

> [...] the specifications for the FlexHeat facility are the following:
>
> - 800 kJ/s two-stage heat pump as the primary heat supply
> - 2x 100 kJ/s electric boilers as secondary heat supply, ensuring increased flexibility
> - A 100 m3 stratified heat storage tank with a storage potential from 4-5 MWh
> - The heat pump has a minimum level of 34 %
>
> The heat pump is intelligently optimized to take advantage of low electricity prices and electricity distribution tariffs by utilizing optimization models with MPC-solvers to plan the heat production at lowest possible costs. Time-shift of heat production is viable at this facility due to the flexibility from the district heating grid at the storage tank, grid and consumers.

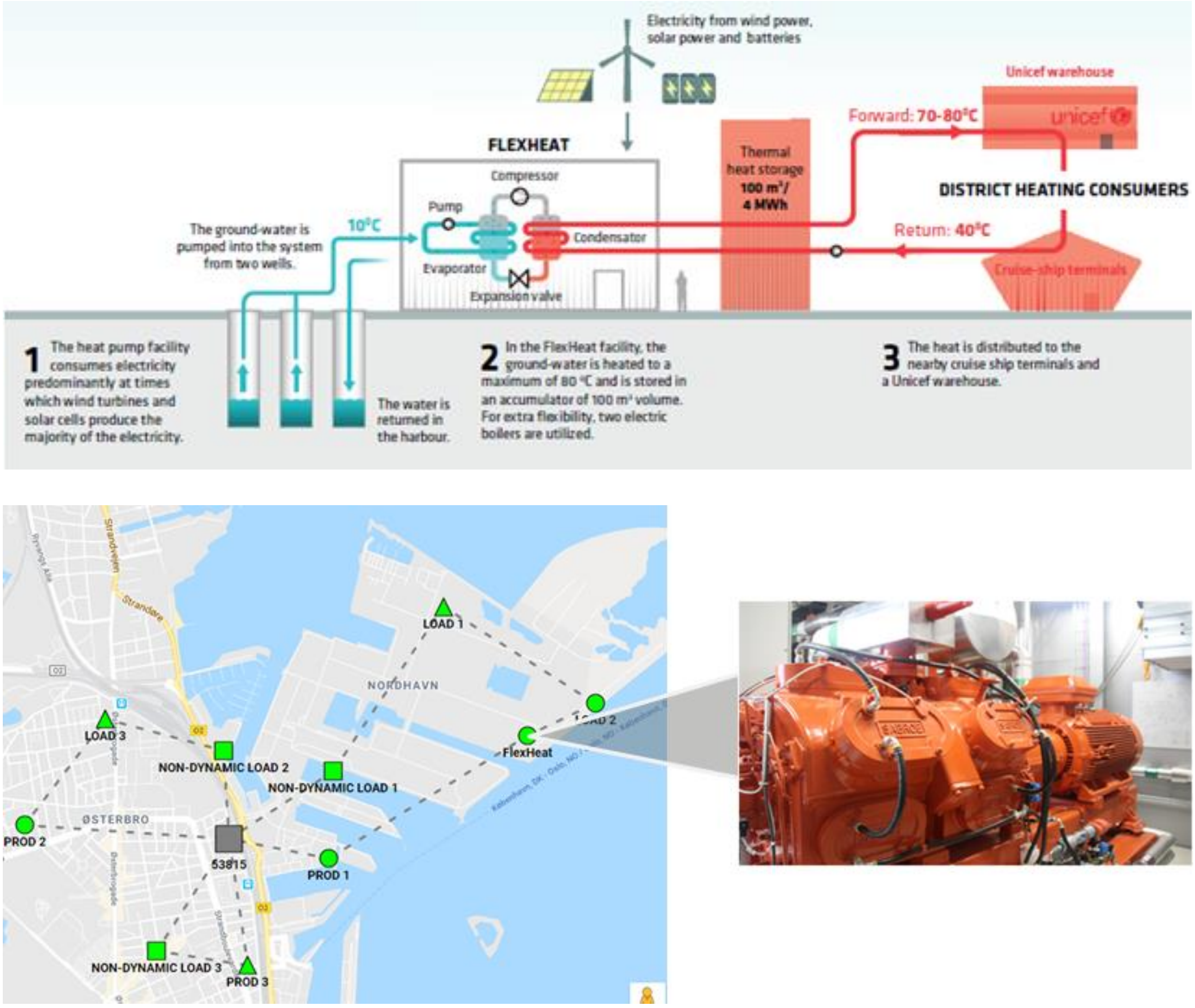

Figure 6: FlexHeat system location with respect to heat consumers (top) and with respect to electricity grid (bottom), showing the FlexHeat compressor in the cut-out. Locations and substations of the illustrated feeder loop are conceptual.

For assessment of TPS message generation and their impact on flexibility asset operation, the simulation model needs to cover steps 3 and for of the above listed TPS sequence and follow up with a simulation of the operational impact of the message on the FlexHeat operation. The assessment tool has therefore been built up in three components (Figure 7):

- a component for generating grid limitation events giving rise to TPS messages
- a component for simulating the operational impact of these messages
- the scenario evaluation component.

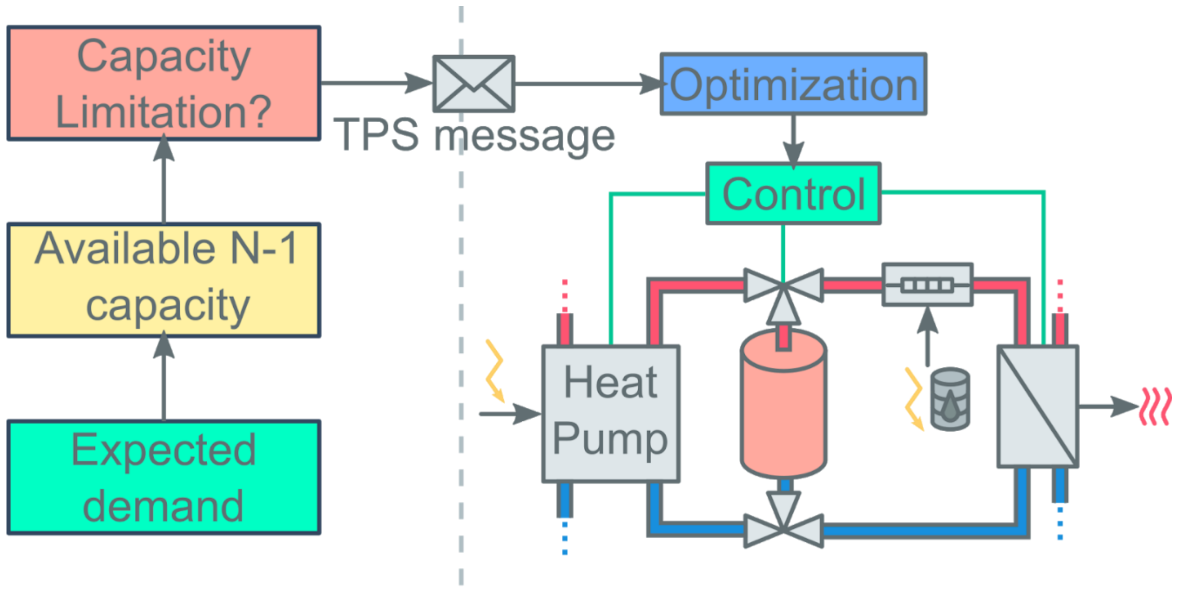

Figure 7: Conceptual flow of the simulation process.

A large set of scenarios can be evaluated with this tool chain, to be able to simulate the interaction effects of random fault occurrence and various load patterns. The faults are defined by location (a cable segment btw. two substations), start time (within the 24h of the simulated day) and duration (any amount of time in the day, starting with the start time; faults don't transfer to the next day). To avoid simulating all days of the year, a systematic reduction of the load patterns to 15 typical patterns, 'representative days' was carried out.

A key consideration and motivation for the DREM concept has been that coincidence factors (CF) are expected to increase when more FA get connected and activated by the same signals. To emulate this increase of CF with respect to limited feeder capacities, a capacity scaling factor (CSF) was introduced, artificially reducing the available feeder capacity to emulate an increased CF.

4.2 Essential simulation components and Test Scenarios

Since the functionality in most of the test cases outlined in Section 2.4 is similar, the simulation setup has been chosen to address the shared key functionality first. To this end, four test cases (Table 3) have been selected for constructing a simulation scenario with this key functionality, which is also referred to as the minimum viable product (MVP).

Table 3: Test Cases selected for MVP

T2C1P.ap	The AGR creates a day-ahead schedule for dispatching the flexible loads (increased consumption) in its portfolio without receiving planned capacity limitations from the TPS. It then dispatches the loads according to the schedule.
	The minimum simulation time frame is 25 hours: 1 hour for initialisation and 24 hours for executing the schedule.
T2C1P.cs	The AGR creates a day-ahead schedule for dispatching the flexible loads (increased or decreased consumption) in its portfolio in accordance with the planned capacity limitations received from the TPS. It then dispatches the loads according to the schedule. The AGR takes the planned capacity limitations for the current and the next day into account in order to reduce the rebound effect.
	The minimum simulation time frame – 26 hours: 1 hour for preparing schedule for the other 24 hours, 1 hour after the last potential dispatch is done for monitoring rebound effect;
T2C3U.ap	The AGR dispatches its flexible loads in accordance with a schedule (from **T2C1P.cs**) in real-time without receiving unplanned capacity limitations from the TPS.
	The minimum simulation time frame is 24 hours. Unplanned capacity limitations may be imposed by the DSO at any time and the limits become effective immediately.
T2C3U.bs	AGR adjusts its dispatch schedule (from T2C1P.cs) in real-time in accordance to the received unplanned upper/lower capacity limitations from TPS.
	The minimum simulation time frame is 24 hours, unplanned capacity limitations could appear at any point within 24 hours, limits become effective immediately.

4.2.1 Reduced test scenario

Under the reduced scope, the full test can be reduced to these two simulation steps:

- First, generate sets of TPS messages based on faults and load patterns, then
- simulate the operational impact of those TPS messages using a model of the FlexHeat system.

The results from all the scenarios run in the two simulation components are then evaluated. As we are interested in the TPS system from the FlexHeat operator perspective, there is no need to dynamically simulate the rest of the grid during operation. We can thus decouple the generation from the evaluation of TPS messages, significantly speeding up the full scenario simulation.

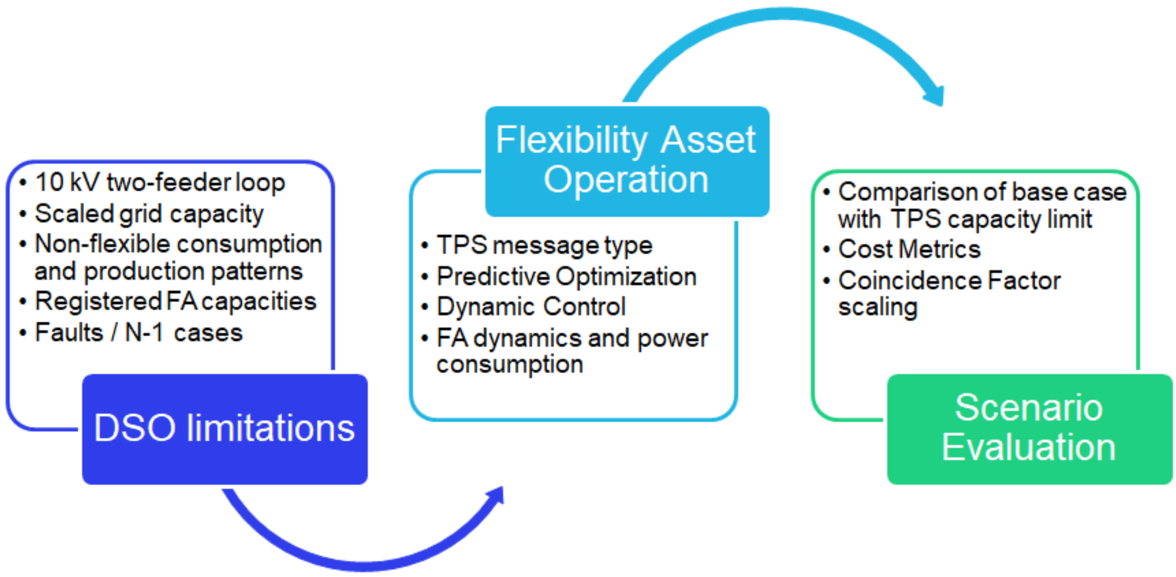

Figure 8: Main parameters, inputs, functions of the simulation tool components.

The overall process is illustrated on Figure 8 which shows the two main sections of the simulation and their main inputs:

Required input data for generating TPS messages:

- Typical daily operating schedules for all units
- Grid topology data to calculate the change in power flows before and after reconfiguration
- Location and duration of network faults to be simulated.

Using these inputs, TPS messages are generated. This is described in Section 3.2.2, with further technical details provided in Section 3.3.

The inputs required for simulating the operational impact of TPS messages are:

- Sequences of messages sent to the FlexHeat system
- Time series of heat demand

Each simulation results in an output time series of the unit's response under the given scenario. This is described in Section 3.2.3, with further technical details provided in Section 3.4. Finally, the evaluation of these scenarios is discussed in Section 3.5.

4.2.2 Overview of TPS message generation

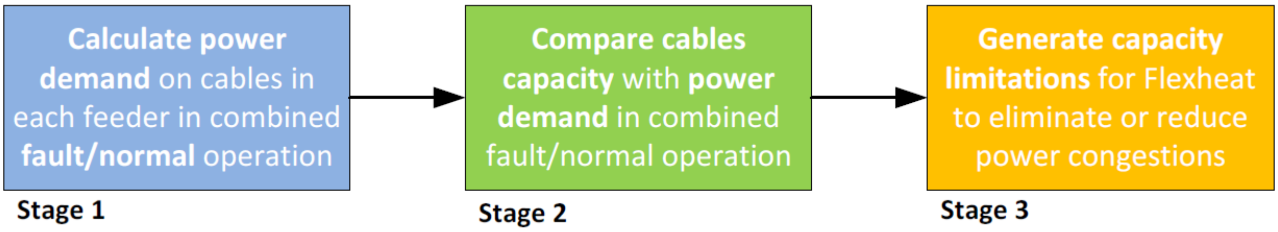

Figure 9: Overview of TPS message generation process

TPS message generation process is performed in three stages as shown in Figure 9:

- Stage 1: Power demand is calculated for each cable of the considered feeders. Both power demand during normal and fault situations is calculated. Normal situation implies that feeders in the loop are separated from each other, while during the fault situation a tie-line is used to reconfigure parts of the load from the affected feeder (the one with a fault) to the second one.
- Stage 2: Resulted power demand is compared with cables capacities to identify time periods with potential power congestions. Due to the radial network configuration, congestion most probably to occurs in the main cables, i.e. the cables that come from the main transformer substation and carry the whole load of the feeder in normal operation.
- Stage 3: If during some time periods, power demand exceeds cable capacities, it is assumed to be a power congestion. To limit or eliminate power congestions, FlexHeat power consumption is limited by generating capacity limitations to be submitted via TPS. Capacity limitations will only be issued, if reduction in FlexHeat's consumption can affect the power congestion situation (i.e. if FlexHeat is electrically connected to the affected feeder).

More detailed explanation of TPS message generation is given in Sections 3.3.2 and 3.3.3

4.2.3 Overview of TPS message evaluation

For each scenario, the operation of the FlexHeat system is simulated under the restrictions imposed by the message.

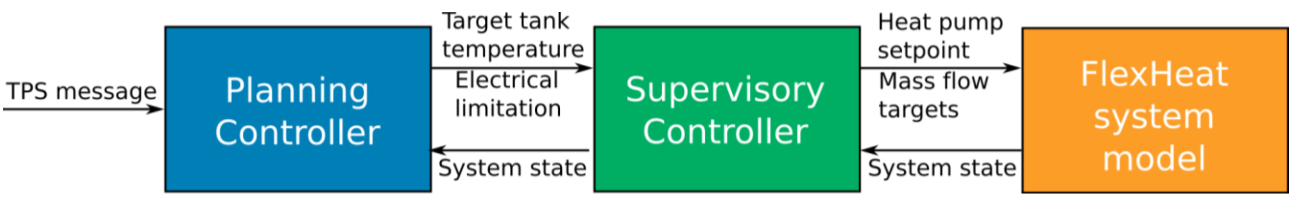

Figure 10: Overview of scenario

This evaluation scenario consists of three main parts, as illustrated on Figure 10:

- A planning controller finds an optimal schedule for the following 72 hours, including the constraints imposed by a TPS message, if any, determining a new schedule every 5 minutes.

- A supervisory controller translates this optimal schedule into setpoints per unit and communicates these to the units every 10 seconds.
- Each unit adapts its operation to these setpoints, where, e.g. the heat pump adjusts its output to match the received setpoint.

More details on the system model used are given in Section 3.4.

4.3 Technical details of how to generate TPS messages

The DREM concept suggests a DSO observing congestion in a distribution network feeder, can issue "foreseen" and "unforeseen" TPS capacity limitation messages, respectively. To reflect this mechanism and create a realistic triggering of such messages, a simulation of N-1 congestion events has been devised. A key input to the congestion analysis for the DSO is a forecast of the demand for the next day. In the same way, simulating the real-time effect of faults on loading of cables requires data on the present loading. In the scope of the long-term study, the analysis of these two operationally distinct situations is performed based on the same dataset. Section 3.3.1 describes the generation of the non-flexible consumption and PV production profiles and Section 3.3.2 details the method of identifying congestion and required capacity limitations based on grid faults based, finally Section 3.3.3 describes how TPS messages are generated.

4.3.1 Non-flexible consumption and production profiles and Representative days

For planning studies and assessments as the one required here, it is important to capture the variability of load patterns and peaks, while reducing the amount of processed data for the simulations. An approach suggested in [Poncelet2016] and [Nahmacher2016] is the concept of 'representative days' which was adopted here. To identify load patterns that are representative, a clustering method (K-means) was applied to group different days with similar power profiles, both for the demand profiles and the PV consumption.

Daily load patterns from non-flexible loads

To simulate the load patterns from non-flexible loads, a year of time-series power demand profiles for each of the secondary substations on feeders NGT-57 and NGT-26 (Figure 5) were synthesized using annual energy readings from an actual Nordhavn distribution network for 2017. The daily consumption patterns from this dataset has 365 days, which were reduced to 15 representative load patterns. Table 3 shows how calendar days of 2017 refer to the clusters. 15 clusters (from 0 to 14) are found to be sufficient to represent the data for one year: most of the working days (from Monday to Friday) are grouped together in individual clusters, while power demand for the Saturdays and Sundays differ from each other enough to be put into a separate cluster. From each cluster one day had been selected as a representative day used in the simulation. Table 4 shows what representative days had been selected for each cluster.

The power demand has been synthesized based on Radius' typical load profiles and the number and types of connected loads. Since the usage of representative days does not provide 100%

coverage of the power demand peaks, the accuracy of the model regarding reflecting actual power demand peaks is limited: the peaks could be either not high enough or too wide if scaled. It is possible that periods of highest power consumption are under-estimated and thus to the power demand peaks, while over-estimating the frequency of observed peak events (i.e. since 1 representative day represents approximately 25 days of the year).

A comparison with real network measurements is performed In Section 4.1, where the validity of the outcomes is reflected.

PV production profiles

In addition to the power demand profiles for the non-flexible loads, power generation profiles for the PV system installed at Copenhagen International School (CIS) were used as input to the simulation model. It is assumed that the PV system cannot be controlled as a flexible unit. Therefore, non-flexible power demand and power generation are combined into one set of data.

A flowchart describing the construction of power demand profiles for non-flexible loads is shown in Figure 10. The process consists of 8 steps, with user-defined inputs given at some of them. Explanations or direct values for these user-defined inputs are presented in Table 5. The outcome is plotted in Figure 11.

The flowchart for the PV power generation profile at CIS and description of the corresponding user-defined inputs are shown in Figure 12 and Table 6, respectively.

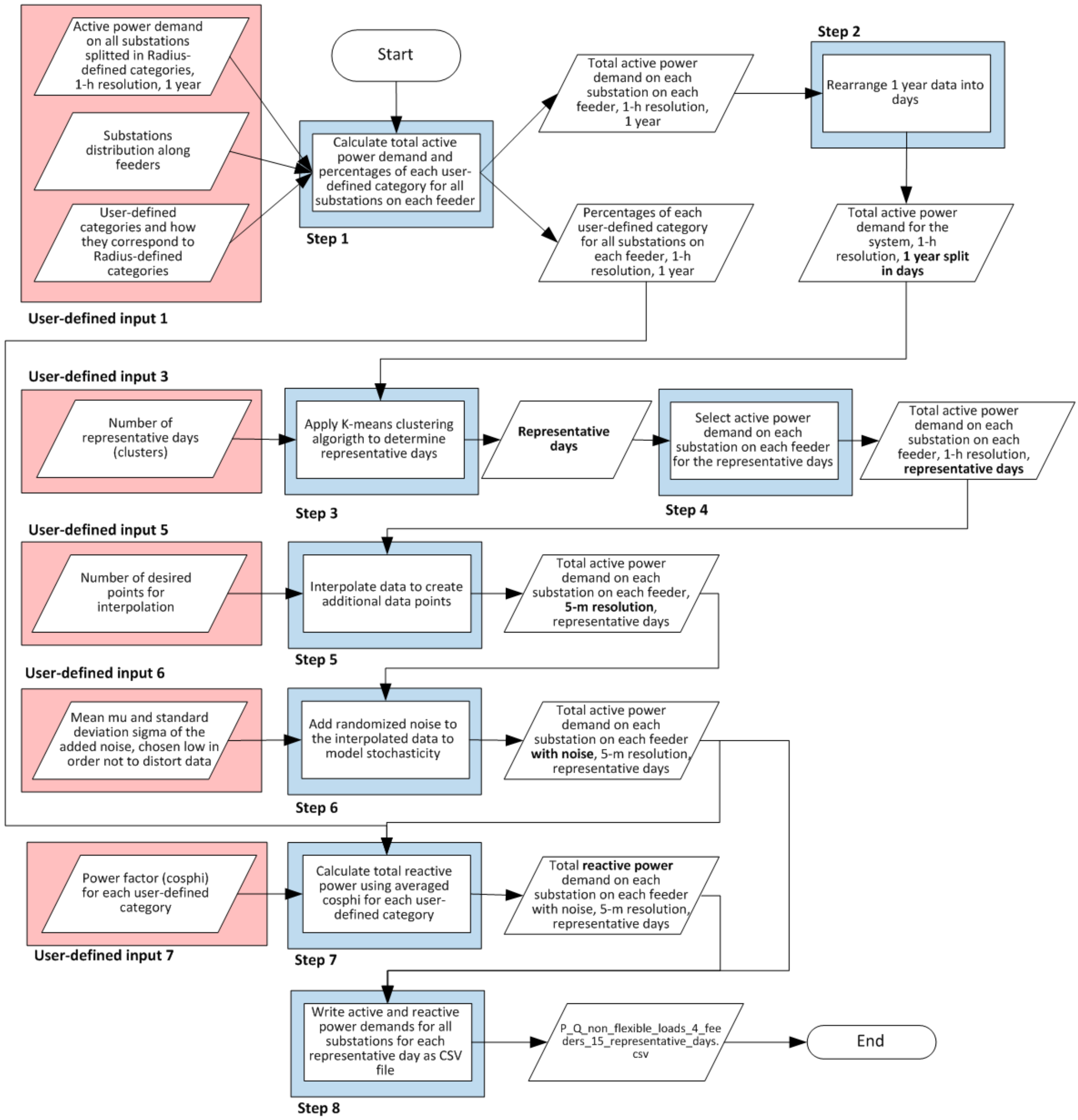

Figure 10: Flowchart showing the construction of power demand profiles for non-flexible loads

Table 5: User-defined inputs (parameters) for the construction of non-flexible load profiles

User-defined input №	Description	Value/Explanation
1	Active power demand on all substations splitted in Radius-defined categories, 1-h resolution, 1 year	Synthesized power demand based on actual Nordhavn energy measurements and Radius demand curves

	Substations distribution along feeders	The order in which substations are connected to feeders NGT-57, NGT-26, NGT-08, NGT-65
	User-defined categories and how they correspond to Radius-defined categories	Internal Radius categories (~30 customer categories) are grouped into residential, commercial, industrial, public and common (e.g. street lighting) categories
3	Number of representative days (clusters)	15
5	Number of desired points for interpolation	288
6	Mean mu and standard deviation sigma of the added noise	Mu = 0; sigma = 0.2
7	Power factor (cos phi) for each user-defined category	0.95

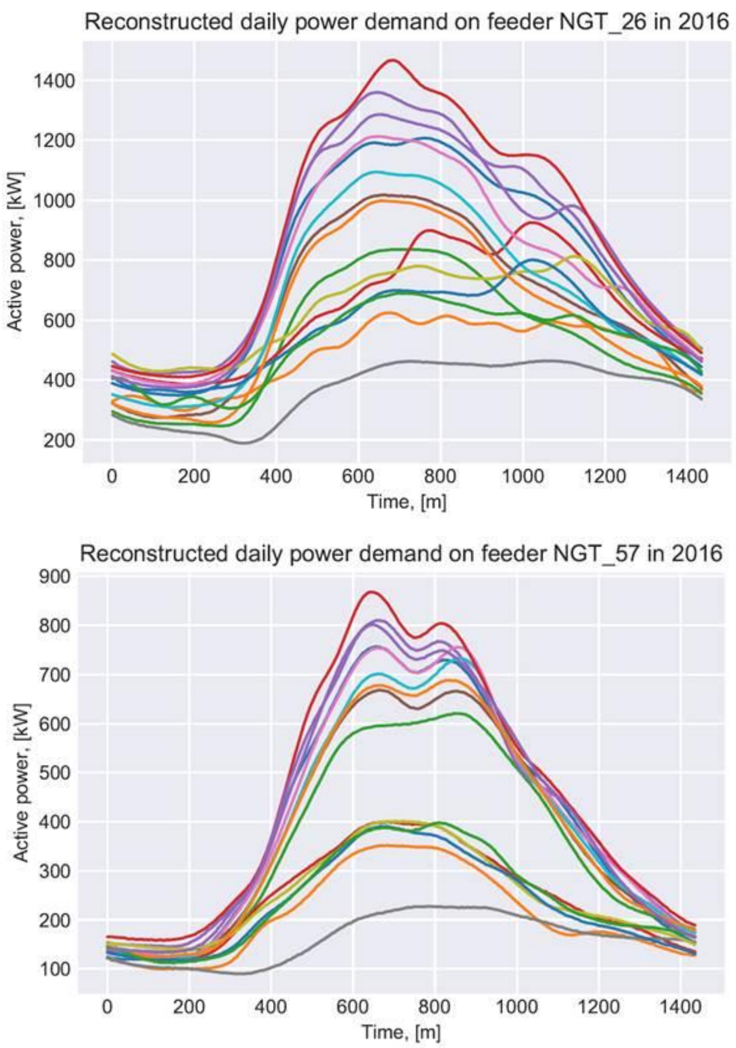

Figure 11: Daily load profiles of the representative days for the two feeders NGT26 and NGT57.

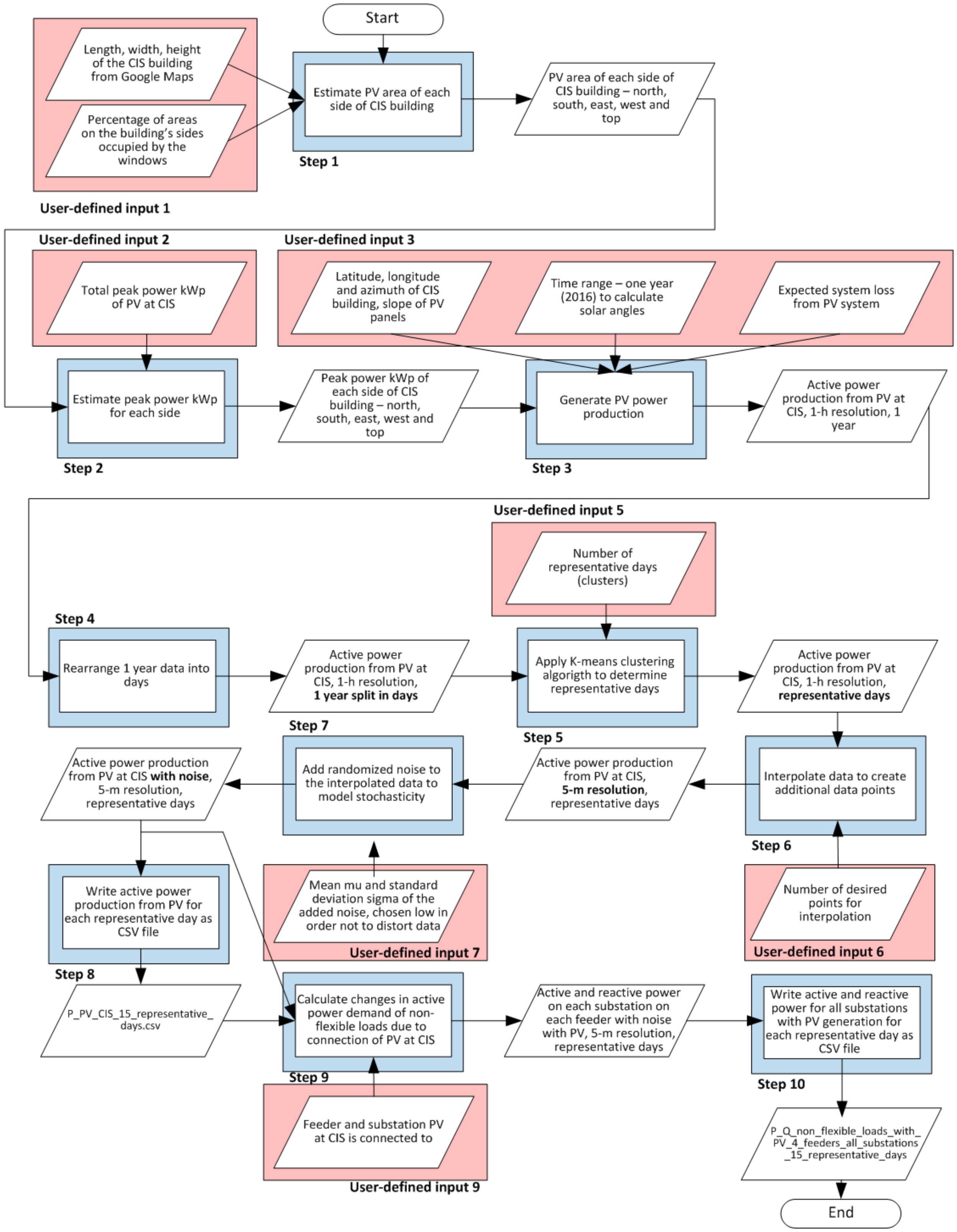

Figure 12: Flowchart describing the construction of the PV power generation profiles for the PV system at CIS

Table 6: User-defined inputs (parameters) for the construction of PV power generation profiles

User-defined input №	Description	Value/Explanation
1	Length, width, height of the CIS building from Google Maps	CIS building is divided into four blocks with the following parameters: Length = 17.4; 28.8; 29.6; 20.7 [m]; Width = 37.2; 23.6; 22.2; 38.8 [m]; Height = 10; 8; 7.5; 10 [m] (measured in Google Maps)
	Percentage of areas on the building's sides occupied by the windows	16%
2	Total peak power kWp of PV at CIS	730 kW
3	Latitude, longitude and azimuth of CIS building, slope of PV panels	Latitude = 55.712; longitude = 12.598; azimuth = -20º; slope = 90º
	Time range – one year to calculate solar angles	Range of dates
	Expected system loss from PV system	14%
5	Number of representative days (clusters)	15
6	Number of desired points for interpolation	288
7	Mean mu and standard deviation sigma of the added noise, chosen low in order not to distort data	Mu = 0; sigma = 0.2
9	Feeder and substation PV at CIS are connected to	Feeder = NGT-57; substation = 40118

4.3.2 Grid representation and Fault Scenarios

For simulation purposes, each feeder is divided into individual cables running between substations, as shown in Figure 1 and Figure 5. Cable 0 at each feeder is the cable from the main substation (index NGT##) to the first substation on the feeder. Cable 0 always carries the highest electrical load under the given network topology. In this network, all cables have the same rated capacity. Therefore, considering the minimal production infeed, congestion is most likely to appear in this section first.

Faults could occur at any of the cables of the feeder. Different cables have different probabilities of fault occurrence, depending on the physical characteristics of the cable. Contributing factors are cable's age affecting insulation, the type of medium it is buried in and the electrical stress it is subjected to. The probability of faults in different cables have been estimated using fault statistics provided by Radius.

The model for simulating the impact of faults uses the two-feeder loop shown in Figure 1 and follows the calculation steps detailed in the flowchart in Figure 13 until step 5 (user-defined inputs are explained in Table 7). First, the power demands for each cable are calculated to determine their remaining capacity. Then, the fault is simulated by randomly selecting a fault location, a time of occurrence and a time duration. After the occurrence of the fault, the network is reconfigured such that all loads upstream of the fault are supplied from the original feeder and all loads downstream are transferred to the other feeder in the loop. Since there are no automatic circuit breakers for fast reconfiguration, the maintenance team must physically identify the fault location. To represent this delay, a 40-minute downtime (blackout) duration was added between the occurrence (starting time) of the fault and the reconfiguration.

The faults are defined by location (a cable segment between two substations), starting time (within the 24h of the simulated day) and duration (any amount of time in the day, starting with the starting time; faults don't transfer to the next day). For each day,10 new random uniformly distributed faults are sampled within the above constraints, with new fault samples selected per CSF level (16 levels).

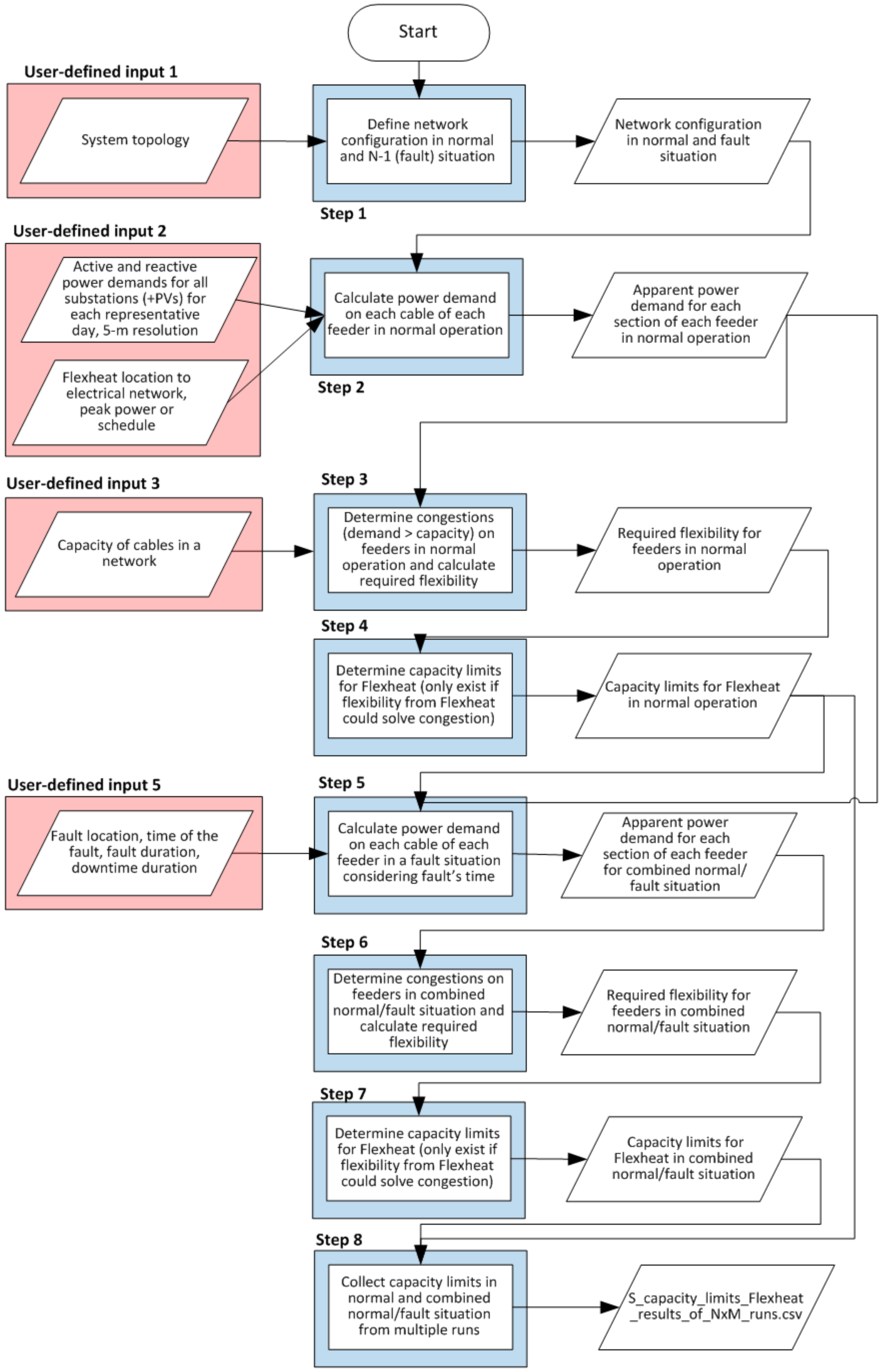

Figure 13: Flowchart of the fault impact, power congestion and capacity limitation calculation

Table 7: User-defined inputs for the fault impact, power congestion and capacity limitation calculation

User-defined input №	Description	Value/Explanation
1	System topology	Substations and the order in which substations are connected to feeders NGT-57, NGT-26, NGT-08, NGT-65
2	Active and reactive power demands for all substations (+PVs) for each representative day, 5-m resolution	Outputs from non-flexible load and PV models
	FlexHeat location to electrical network, peak power (if FlexHeat operational schedule is not provided) or a schedule	Feeder_FlexHeat = NGT_26; substation_FlexHeat = 55128; peak power = 250 kW
3	Capacity of cables in a network	All cables have a capacity of 4052 kW = 4,052 MW. This is later scaled to obtain different cable capacities
5	Fault location, time of the fault, fault duration, downtime duration	Fault location – ID of a cable on the loop; time of the fault – any 5-minute interval for one day; fault duration – time from fault occurrence to fault clearance; downtime duration = 40 minutes

4.3.3 DSO congestion model and TPS message generation

To interact with the TPS system, the DSO needs to be able to detect congestion. The present model is used in the simulation for generating the same message as either Foreseen or Unforeseen capacity limitation.

DSO congestion identification

The identification of power congestion and the calculation of the resulting capacity limitations is based on the method outlined in Section 2.2.3. The congestion calculation steps are detailed in Figure 13, steps 6-8. DSO congestion identification considers the position of the FlexHeat generates capacity limitations if the FlexHeat can contribute to reducing the congestion. The calculation result is a time series of anticipated capacity limitations of the FlexHeat (blue line in Figure 14), which relates to the cable capacity of the most restricted cable.

If no power congestion is detected, the capacity limitation is equal to either the FlexHeat peak power (here 250kW) or a FlexHeat power demand from the operational schedule. During the congestion event, more restrictive capacity limitations are introduced, as the projected congestion would be continuously changing based on the power demand. Therefore, it was decided to generate a step-based signal, where the capacity limitation submitted to the TPS is the minimum value of this time series (red line in Figure 14).

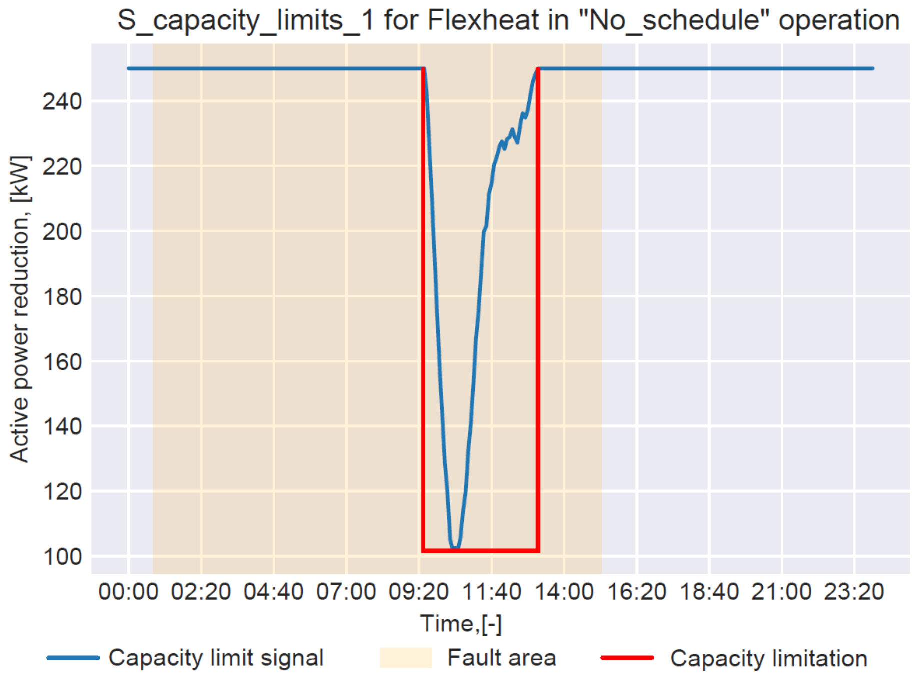

Figure 14: Example of calculated capacity limit (red line). The blue line is the time series congestion projected on the FlexHeat peak capacity as continuous capacity reduction; the red line, is the simplified capacity limit signal, which is translated into a TPS message.

TPS message generation

If congestion is detected either in normal operation, during planned faults, or as a result of unplanned faults, the capacity limitations for the AGRs controlling the affected flexibility assets are issued through the TPS.

Two types of messages can be delivered by the TPS system to an AGR, as defined in deliverable [D6.1]:

- Foreseen capacity limitations: These arise e.g. due to maintenance work. A message defines the capacity available for flexible assets *pe_max* for a duration from *t_start* to *t_stop*.
- Unforeseen capacity limitations: These arise e.g. due to grid faults.

These messages contain a prescribed action (i.e. for flexible loads: ramp down/hold/ramp up) for each unit.

The simulation model only implements TPS messages defining a capacity limitation, and thus does not model ramp up/ramp down/hold signals for power producers. Messages requesting a stop of operation during a certain time period can be emulated by sending a capacity limitation message of 0kW, applicable to the affected period.

In any given scenario, TPS messages will be sent depending on the circumstances:

- No fault: The system operates without restrictions. No messages are sent.

- Foreseen capacity limitation: A TPS message is issued at the beginning of the simulation. The simulated system will respond to comply with the limitation.
- Unforeseen capacity restriction: A TPS message is issued at the time at which the capacity limitation comes into effect. The simulated system is in an unrestricted operating state when the capacity limitation occurs.

The simulation uses an electricity price signal as an extrinsic parameter for optimal scheduling of flexible consumption. By comparing the electricity costs of the same scenarios without and with TPS messages (of either type), the response cost and thereby suitable compensation for the FlexHeat system operator can be determined.

4.4 Evaluating the operational impact on flexibility assets

The following subsections detail the model of the FlexHeat system and how the model is implemented. The model is designed to evaluate the impact of a capacity limit on the FlexHeat system and is therefore simplified as compared to a full physical model. For technical details about the actual HOFOR FlexHeat system, refer to [D7a].

4.4.1 FlexHeat simulation components

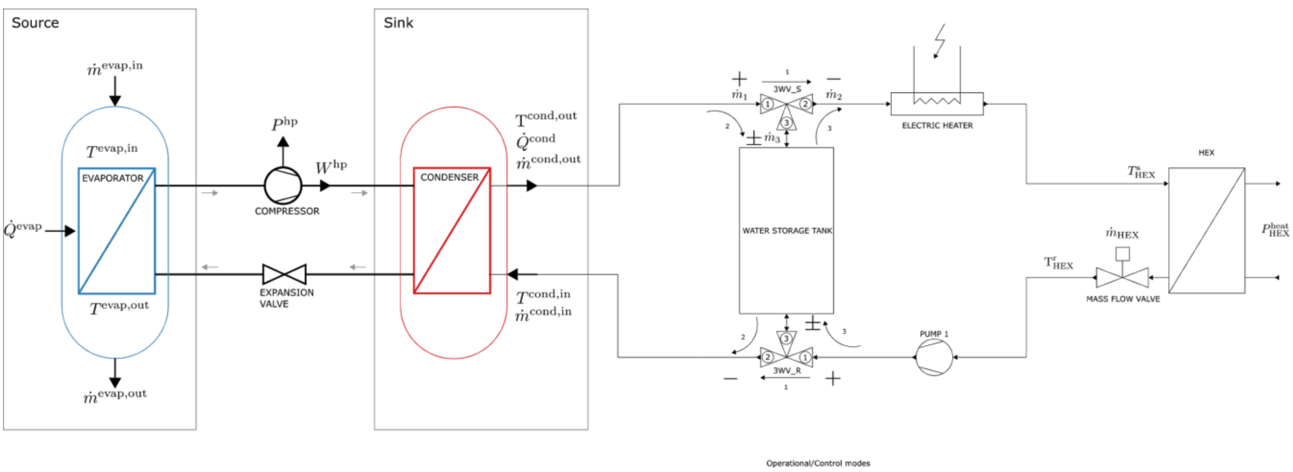

Figure 15: Schematic representation of FlexHeat system

The physical FlexHeat system is represented as in Figure 15. Each component of the system is modelled as follows:

Consumer Heat Exchanger (HEX) and mass flow: This component forms the interface between extrinsic heat demand signal (based on measured data), and the intrinsic parameters of supply temperature and mass flow.

Water storage tank: A stratified water tank model with 10 equally spaced temperature strata, using the layer mixing and thermal loss models from [Cruickshank2009]. The total tank volume is 98000 liters, with the heat loss model assuming a cylindrical tank in a 15ºC, constant-temperature environment.

Ground-water source heat pump: The heat pump (HP) input is modelled as a reservoir at a fixed temperature of 10ºC on the evaporator side. On the condenser side, heat is delivered at the temperature of the condenser side mass flow. The pump is rated for 250kW of electric power and assumed to have a maximum output temperature of 85ºC. The model equations are based on [Richert2020].

The COP is calculated based on the Lorenz efficiency between evaporator and condenser, assuming a compression efficiency of 70% for the conversion of electrical power to hydrodynamic work, and an efficiency of 80% for the conversion of hydrodynamic work to available thermodynamic work. This yields an overall system efficiency of 56%, compared to the 51% found in tests of the physical system. At typical operating temperatures, this results in a COP of approximately 3.4, which corresponds to the efficiency measured on the physical FlexHeat system of 2.9 - 3.5 depending on operating temperature.

3-way valves: These simulation components use externally imposed mass flow rates to calculate mass flows and temperatures on the output ports. Port 1 always has inflow , port 2 always has outflow , and port 3 has either inflow or outflow.

Booster heater: When active, the 200kW electric heater delivers heat directly to the water flowing through it. Activation occurs when the inflow temperature drops below 68 degrees Celsius, tracking this lower supply temperature bound as setpoint. The heater is assumed to have a efficiency of 0.98.

4.4.2 Integrated simulation model overview

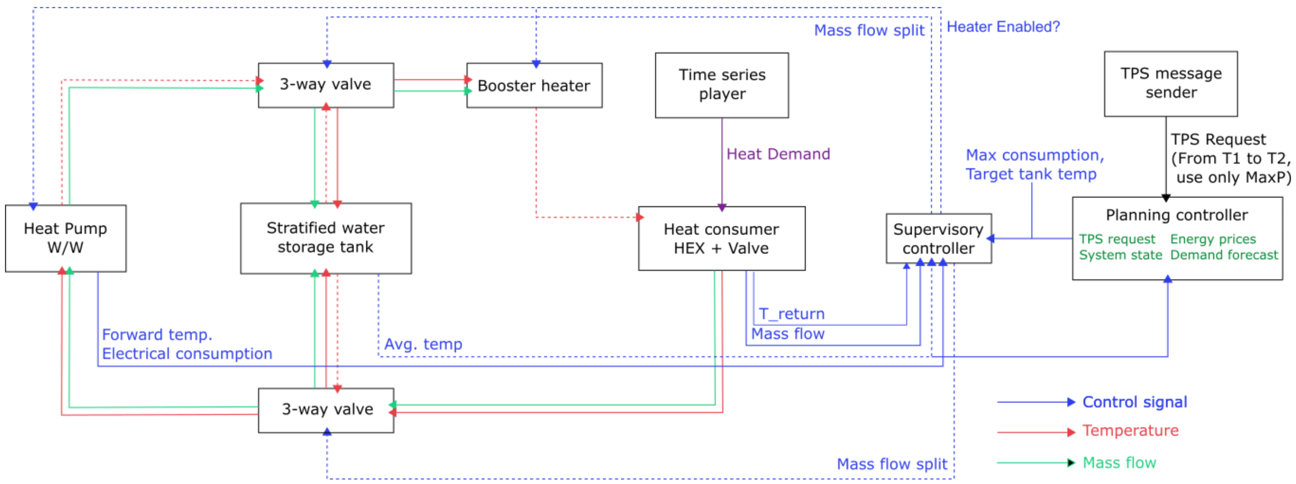

Figure 16: FlexHeat simulation model overview.

Figure 16 provides an overview of the main components of the integrated FlexHeat simulation model. The model is implemented in Python using the Mosaik co-simulation orchestrator which enables the interconnection of individual simulators. Each box in Figure 16 is implemented as a standalone simulator which stores and handles its own physical state in response to external signals. Each component executes 10 simulation steps at 1-second resolution at a time. An exception is the planning controller which sends new setpoints every 5 minutes. A stabilization period of 24 hours of simulation time is used to ensure proper initialization before the actual simulation start.

The main part of the simulation is the FlexHeat components, and controllers which are further described below. The external signals are Heat Demand, Price Signal, and the TPS Requests. Incoming TPS messages are represented by three parameters:

1. Starting time of the capacity restriction.
2. Ending time of the capacity restriction.
3. Capacity restriction amount in kVA.

The TPSMessageSender component is initialized with the messages to be sent and will submit these messages every 10 seconds in accordance with the chosen fault mode, i.e. planned/unplanned outage. If the messages describe a foreseen limitation, all messages will be sent at midnight the night before the limitation occurs. Unforeseen limitation messages are sent at the starting time defined in the message, i.e. the FlexHeat system receives no advance warning of the restriction.

4.4.3 FlexHeat high-level planning controller and TPS messaging

The high-level planning controller derives optimal operation schedules using a simplified system representation (Figure 17). System operation is optimized in 5-minute intervals over a time horizon of 72 hours.

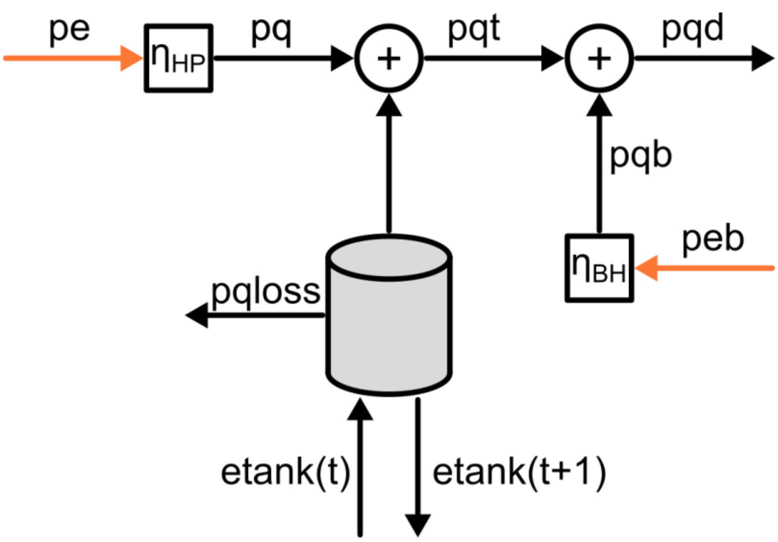

Figure 17: Equivalent model of FlexHeat system used for optimization

The following assumptions allow representing the system as a set of linear constraints:

- Energy stored in the tank (etank) relates linearly to the temperature in the tank, with the zero point for energy taken to be the consumer's target return temperature of 40ºC.
- Heat losses (pqloss) are proportional to the difference between the tank temperature and the ambient temperature.
- The tank temperature is limited to 85ºC, which is the maximum output temperature of the heat pump.
- Outflow from the tank and heat pump models (pqt) are non-negative. This ensures that the booster heater cannot be used to heat the tank.
- A binary variable indicates whether the heat pump is operating and prevents simultaneous use of the heat pump and the tank to supply the load.
- The temperature seen by the consumer is represented by the temperature in the tank; a mean tank temperature of 60ºC is assumed to lead to a consumer temperature of 65ºC. This is consistent with the tank's output temperature under operation.

The following simplifying assumptions are made for the modelling of the heat pump and booster heater, as required for faster evaluation:

- The heat pump efficiency ηHP is assumed to be a constant 3.4, representing an average case efficiency.
- The booster heater efficiency ηBH is taken to be 0.98, accounting for heat losses under operation.

Since the optimization forms part of a closed loop with the storage tank and booster heater, inaccuracies in these numbers are expected to have little impact on simulation results, compared with those arising from the simplified model employed.

Finally, the planning controller is assumed to have a perfect forecast of the heat demand, primarily to reduce the complexity of the simulation. This is expected to have little impact on the evaluation overall, as heat demands day-to-day do not vary greatly; mean daily heat demand varies on the order of 10% day-to-day for the heating season based on the input data used here. The heat demand data used here is the measured heat demand for the FlexHeat system for the period of 2017.

The objective function of the optimization consists of the following terms:

- Total cost of electricity consumption (Price per time step multiplied by electrical consumption of both heat pump and booster heater)
- Total cost of temperature error (Squared violation of consumer temperature bounds, multiplied by a factor taken to be 40 €K^2/h; i.e. a temperature violation of 2ºC over 1 hour incurs a penalty of 160€.)
- Total startup cost of heat pump, taken to be 5€ per start up.

We note that the temperature error is a model-related trick to ensure a robust model; In practice, any temperature deficit is covered by an oil-fired backup energy source .

Due to time constraints, the prices used here are taken to be simple sinusoidal curves, scaled to a 5€/MWh mean price with a daily variation of 20%. These prices are comparable to mean daily prices in the DK2 bidding zone, though the variations in hourly prices are clearly not captured by this assumption.

Based on the optimization outcome, the planning controller then sends to the supervisory controller:

- The expected average tank temperature 1 hour ahead
- The electrical limitation imposed for the next hour (if any)
- The maximal operating point for the heat pump over the next hour

These subsequently inform the actions of the supervisory controller.

4.4.4 FlexHeat supervisory controller

The supervisory controller coordinates the heat pump (HP), tank (valves) and electric heater controllers in order to both supply the heat load and to track the optimal path and grid limitations imposed by the TPS system. As a simplification it tracks the consumer side heat-exchanger (HEX) mass flow and sets all the mass-flows through the two 3-way valves, based on the current control mode. The FlexHeat system is operated in the following control modes (CM):

- CM1: HEX is directly supplied by heat pump
- CM3: HEX supplied only from Tank (no Electric Heater activation)
- CM4: HP is charging Tank and supplying HEX
- CM6: HEX supplied from Tank with decentral Electric Heater activation

In modes 1, 3, and 6 the respective control variable is determined by the mass-flow required from the consumer, which is determined at the consumer HEX. In Mode 4 there is a degree of freedom in the mass flow of tank charging in parallel to supplying the load. A PI controller here controls the output of the heat pump and mass flows, either tracking the optimal tank reference temperature or the maximum power as following the power limit set by the high-level planning controller (e.g. due to a TPS message). Further, in case there is a maximum power limit (due to TPS message), the ratio is further adapted to satisfy the consumer heat supply. These modes correspond to the operating modes of the FlexHeat system (FM1-7) reported in D7a as follows:

- Simulated CM4 represents FlexHeat modes FM1/FM2/FM3 and FM7: HP supplies both tank and heat consumers, with optional boost from electric heater
- CM6 represents FM5 (tank discharging with electric heater)
- CM3 represents FM4 (pure tank discharge)
- FM6 is not implemented in simulation (no relevant in practice)

The state machine governing the transitions between operating modes is provided in Figure 18.

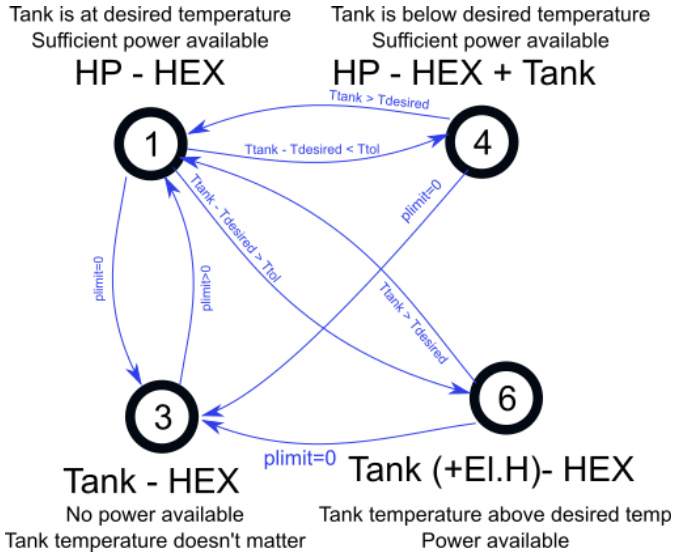

Figure 18: State machine of the supervisory controller. The initial state is Mode 1.

4.4.5 FlexHeat unit-level control behaviour

Along with the two high-level controllers discussed in the previous subsection, each component has a built-in controlled behaviour, which is summarised below.

Electric Heater: The electric heater is utilised to boost the temperature supplied to the consumer heat exchanger to the desired minimum temperature in case the lower bound is violated. The available electric power is further constrained by a limit signal from the Supervisory Controller. when the limit is reached, the controller limits heat injection; alternatively, it may account for the required heat as stemming from another source (oil boiler with efficiency 85%).

Heat Pump: The heat pump either computes the required power input based on a fixed output temperature and given mass flow, or it tracks a received heat setpoint within its capability limits. The required compressor work is derived from the thermal efficiency and updated with a low-pass filter with a rate of 0.2 l/s. The required electrical power is computed as the sum of auxiliary consumption (0.3kW) and compressor electrical power which is calculated from the compressor work with constant efficiency of 0.7.

HEX valve: A mass flow valve and pump on the return path adjust the HEX mass flow to track a constant return temperature of 45ºC. The mass flow change is rate-limited to model the valve response, effectively mitigating oscillatory interactions with supply temperature variations.

3-way valve: The valve operates in one of 3 modes, depending on the flow imposed for port 3:

1. Port 3 flow is zero: Outflow and temperature on port 2 is equal to the inflow on port 1.

2. Port 3 has outflow: Split the mass flow on port 1 according to imposed mass flow split. All output temperatures equal the in flow temperature on port 1.
3. Port 3 has inflow: Mass flow on port 2 is the sum of mass flows on ports 1 and 3. Temperature on port 2 is the mass-flow-weighted temperature average of ports 1 and 3.

4.5 Metrics for evaluation of outcomes

We wish to characterize how the operation of the FlexHeat system is impacted due to TPS messages generated by the DSO. Since use of a TPS system complements grid reinforcement to adapt to changing load, we apply a *capacity scaling factor* to the DSOs electrical grid model, which uniformly scales the carrying capacity of all lines in the distribution grid. As discussed in Section 4.1, a capacity scaling factor can be reinterpreted as a coincidence factor or as resulting from increased penetration of flexible units, which naturally have a higher coincidence factor.

For each combination of a representative day and capacity scaling factor, we generate 10 fault scenarios as described in Section 3.5.1. For each fault scenario, resulting TPS messages are generated as described in Section 3.3, and evaluated as described in Section 3.4. Each fault scenario is simulated both as a foreseen fault and as an unforeseen fault. The outcomes of this simulation are then evaluated as described in Section 3.5.2.

4.5.1 Selection of Fault scenarios

Each fault is characterized by its location, the start time of the fault, and its end time.

[Scenario defined by Fault location, start time, end time, capacity scaling factor, day of operation.]

It was found that messages do not appear at capacity scaling factors above 60%, while capacity scaling factors below 20% lead to infeasibility in the power flow calculation, i.e. no injection at the site of the FlexHeat system is enough to achieve a feasible power flow for some faults. Thus, scaling factors from 20% to 60% (inclusive) in steps of 5% are chosen for examination.

Prior to evaluation in the simulated system, the TPS messages in a scenario may be characterized by two factors: First, the minimum capacity limitation indicates to which extent the capacity limitation influences operation; limitations close to the heat pump's installed capacity are unlikely to impact operation, while limitations close to 0 kW may even prevent the heat pump from operating. Second, complementary information is provided by the total energy limitation of the scenario, defined as the capacity reduction from rated capacity times the duration of the limitation, summed over all messages. This indicates whether the limitation is short and deep, which may be covered using the storage tank, or long and shallow, which may allow partial use of the heat pump, or long and deep, which may necessitate use of the oil-fired backup system.

When looking at sets of TPS messages in the abstract, these two factors allow assessing the relative impact of these messages.

4.5.2 Metrics for relative operation impact: cost comparison

The output of the integrated assessment model consists of time series of system variables, which must be aggregated to allow concise comparison between scenarios. With a view to the purpose of the method, we here compare the following axes, each for the day during which a restriction is imposed, and for the two surrounding days:

Total electrical cost of operation (ELECTRICALCOST) [€]: Defined as the total cost for electricity used by both booster heater and heat pump.

Electrical bound violation (BOUNDV) [kWs]: Defined as the electrical consumption of the system above the electrical bound defined by TPS messages.

Total cost of oil use for backup (OILCOST) [€]: An oil boiler is used to supplement the FlexHeat system if temperature drops below usable temperature. The cost of oil import is proportional to the total missing heat, defined as the integrated temperature deviation of temperature at the consumer heat sink input below usable consumer temperature of 68ºC multiplied by the mass flow at the consumer side and water's specific heat capacity. This total temperature error is multiplied with the efficiency of the oil boiler (87%) and cost for fuel oil (taken to be 40€/MWh) to produce the final oil cost estimate.

These metrics will in general not allow for trivial optimization; providing good heat quality may come at high cost due to high electricity demands or violate the electrical bound. Conversely, complying with an electrical bound may mean lowering the heat quality for the consumer. For each metric, a low score is considered good.

5. Scenario-based Assessment

The following sections summarise the results of the scenario assessment, which are based on 150 congestion simulation runs (10 N-1 cases for 15 representative days) for 16 capacity scale factors (2400 total). The scenarios where the congestion simulation outputs a capacity limitation (501 cases) have then been simulated three times: as base case, as Foreseen and as Unforeseen capacity restrictions (1503 runs).

The results are reported in sequence of the simulation process. In Section 4.1 the capacity limitation messages generated are analysed to review the frequency and depth of the generated capacity limits. The simulation of FlexHeat operation is first illustrated in Section 4.2 and then results are aggregated and quantified in Section 4.3.

5.1 TPS Capacity limitation messages generated by DSO congestion evaluation

The capacity limitation messages are computed based on observed congestions. Figure 19 provides an overview of all the generated congestion events from the N-1 scenario simulations based on the same feeder loop. The number of events should be contrasted with the number of simulated scenarios per grid capacity scaling factor level (150).

Messages were generated only for capacity scaling factors (CSF) of 0.6 and below, indicating that the network has enough capacity for current use. At scaling factors above 0.6, capacity limitations due to N-1 events are below the FlexHeat system’s maximum consumption, and as such are not included here. For scaling factors below 0.45 these congestion events may also directly be caused by peak demand, without a coinciding N-1 event, we cannot separate messages coming from high demand from those due to N-1 events. However, also these scenarios offer insight of possible effects once the coincidence factors increase due to an alignment of flexibility assets.

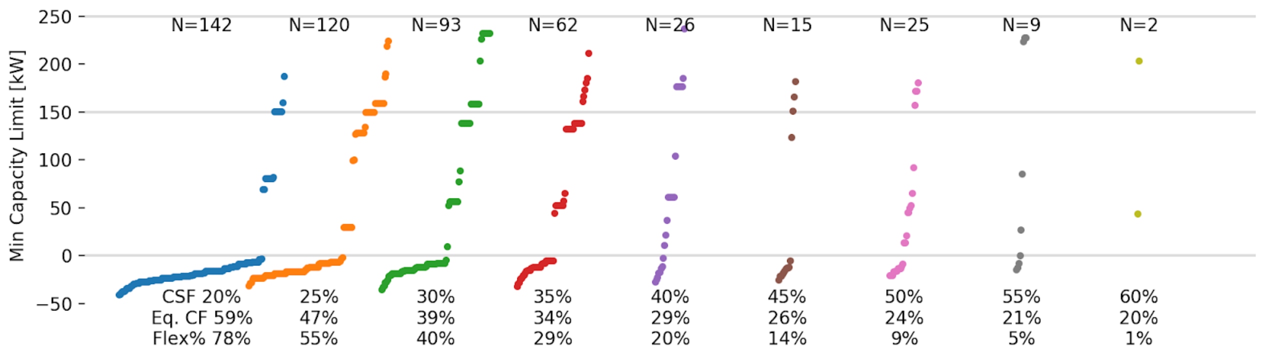

Figure 19: Extrema of capacity restriction for each scenario with messages, grouped by capacity scaling factor (CSF). N indicates the number of scenarios with messages. Messages with capacity limit <0 are not shown to scale.

It is worth noting that CSF=0.6 is an expected level of capacity scaling for congestion events to appear. The capacity of the installed cable in the modelled Nordhavn feeder loop is about 4MVA, whereas the modelled peak load is at about 2.5 MW in the most loaded feeder, thus with a N-1 worst case capacity utilisation of ca. 0.62, or with the modelled FlexHeat about 0.68. In other words, the modelled feeders are over dimensioned for the current loading (due to expected load growth in the Nordhavn district). It can therefore be observed that relevant congestion events start to show at a feeder cable capacity scaling factor of CSF=0.60 (Figure 19), which corresponds to the approximate dimensioning of the feeder without FlexHeat. To understand this effect, we must recall that the *coincidence factor* (CF) of non-flexible load is a critical dimensioning criterion in the cable design. If the Nordhavn loop were designed for the existing load in perpetuity, we can assume that a capacity scaling factor of 0.62, or 0.7 to be robust, would offer enough capacity for the present load.

Based on available network data, the CF of the modelled load is estimated to 0.19, which is close to the CF observed in measured data of about 0.18. Assuming a dimensioning with rated capacity the CSF = 0.68 with a corresponding observed CF = 0.18, the cable capacity is held constant at CSF=0.68 (2.7MW). Instead of adjusting capacity we assume an increase of the peak load against the fixed capacity, thus defining a hypothetical equivalent coincidence factor for the simulated load:

Equivalent Coincidence Factor = 0.18 * (0.68 / Capacity Scaling Factor)

This equivalent coincidence factor allows another interpretation of the congestion scenarios in Figures 19, as listed in the x-axis. Going one step further we may assume that this coincidence factor is driven by flexibility assets which are replacing non-flexible load. Setting a nominal CF for flexibility assets to 0.7 (like results in [Calearo2019] or [Zhang2019]), we can interpret the capacity scaling factor instead as measure for flexibility asset penetration. For a hypothetical replacement of non-flexible loads with flexibility assets in the simulated feeder, we can therefore anticipate an increase of coincidence factors. For new flexibility assets we assume a CF = 0.7, replacing the existing load of CF =0.18:

Equivalent Coincidence Factor = Flexible Unit Ratio * Flexible Unit Coincidence Factor + (1 - Flexible Unit Ratio) * Non-flexible Unit Coincidence Factor

Flexible Unit Ratio = (Equivalent Coincidence Factor - 0.18)/(0.7 - 0.18)

A full treatment to equate Capacity Scaling Factor with Flexible Unit Ratio would involve calculations of the correlation between flexible and non-flexible loads, so the above equations serve only as an estimate for illustration.

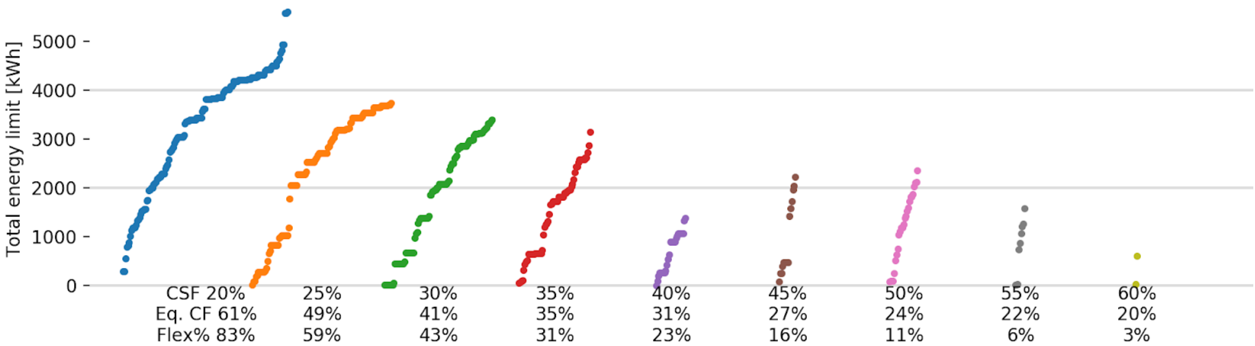

Figure 20: Total reduction in energy requested over the day per scenario, grouped by capacity scaling factor.

In addition to the ‘depth’ of capacity limits reported in Figure 19, Figure 20 reports the ‘width’ or energy volume of the restriction per CSF level.

The total energy content of TPS system messages, calculated as SUM(duration of message * reduction relative to maximum capacity) also increases with reduced capacity scaling factor.

Messages for scaling factors of 0.5 and below show negative values for reduction required by the FlexHeat system, indicating that the FlexHeat system on its own is insufficient to balance the system in these cases. During operation evaluation of these scenarios, these messages are taken to restrict the capacity of the FlexHeat system to 0kVA.

5.2 Example simulation outcome for flexible operation with fault scenario

For each TPS message reported in the previous subsection, operation of the FlexHeat system is simulated. An example outcome of such a simulation is shown on Figure 21.

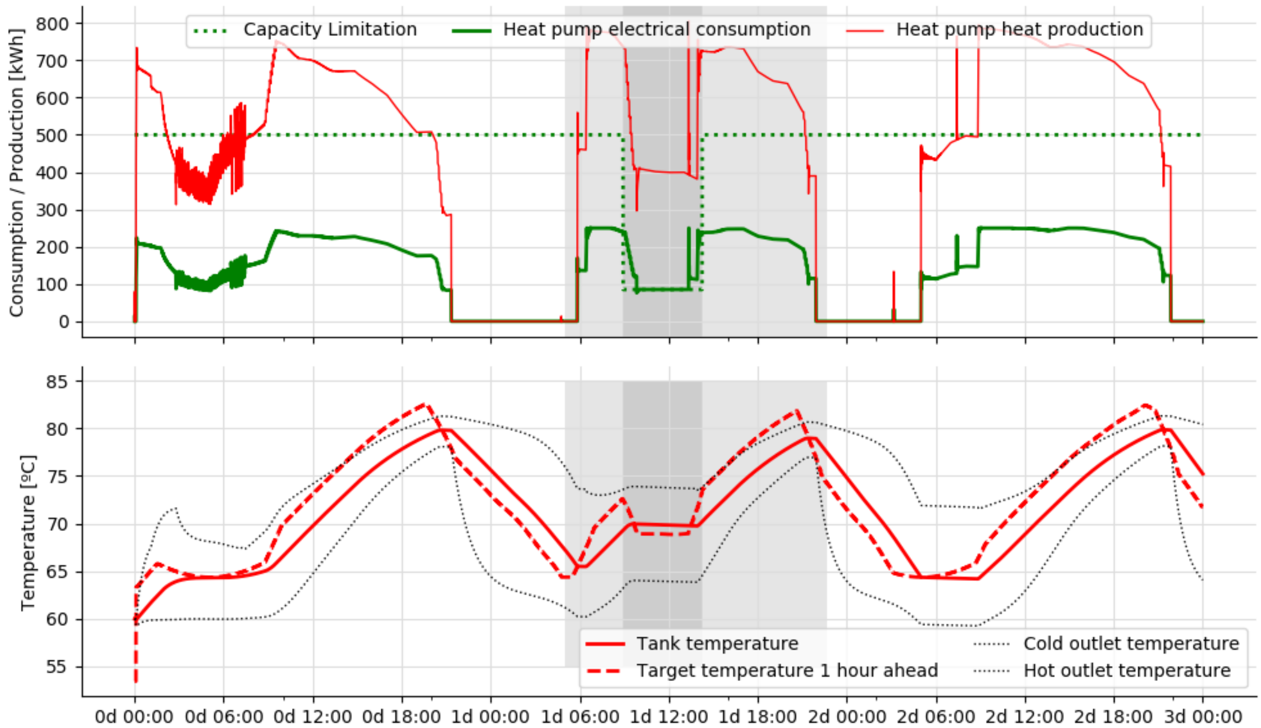

Figure 21: Example run for capacity scaling factor of 0.5 under foreseen fault. (Top) Heat pump operation (Bottom) Tank temperature and targets. The light shaded area indicates duration of the fault, while the dark shaded area indicates the duration for which a capacity limitation is in effect.

Two periods with no activation of the heat pump flank either side of the fault period. These are times where the electricity price as modelled here is high, and the planning controller subsequently reduces consumption to limit the cost of electrical import.

Just prior to the capacity limitation coming into effect, the planning controller raises the temperature of the tank. This allows an increase in the tank temperature prior to the second period just after the fault clears, thus avoiding importing electricity during this period. Equivalent plots for the case of unforeseen capacity limitation show no such increase, leading to a higher overall cost of electricity import.

A point of note is that the capacity limitation coming into effect is not immediately followed by a reduction in the electrical consumption of the heat pump. This is an artefact of the simulated controller. As reported in [D7a], the actual FlexHeat system can follow such steep setpoint reductions. For this reason, results on the metric "boundary violation" are not reported, as these show an unrealistically high error as a result of this slow controller response.

3. Scenario outcomes for flexible operation under foreseen and unforeseen capacity limitation

We here compare scenario outcomes for varying capacity scaling factors. For each outcome, we report the increase in cost compared to the baseline scenario where no TPS messages are received. Two costs are reported; (1) the cost of supplementing the electrical system with oil boilers to provide usable temperature at the consumer side (ΔOILCOST), and (2) the cost of supplying the system with electricity (ΔELECTRICALCOST).

Two figures are provided: A graph that compares costs averaged over only the scenarios where TPS messages are sent (Figure 22), and a graph that compares costs averaged over all scenarios (Figure 23). The former figure reveals costs depending on the chosen scenarios, while the latter figure shows the expected costs due to operation of the system.

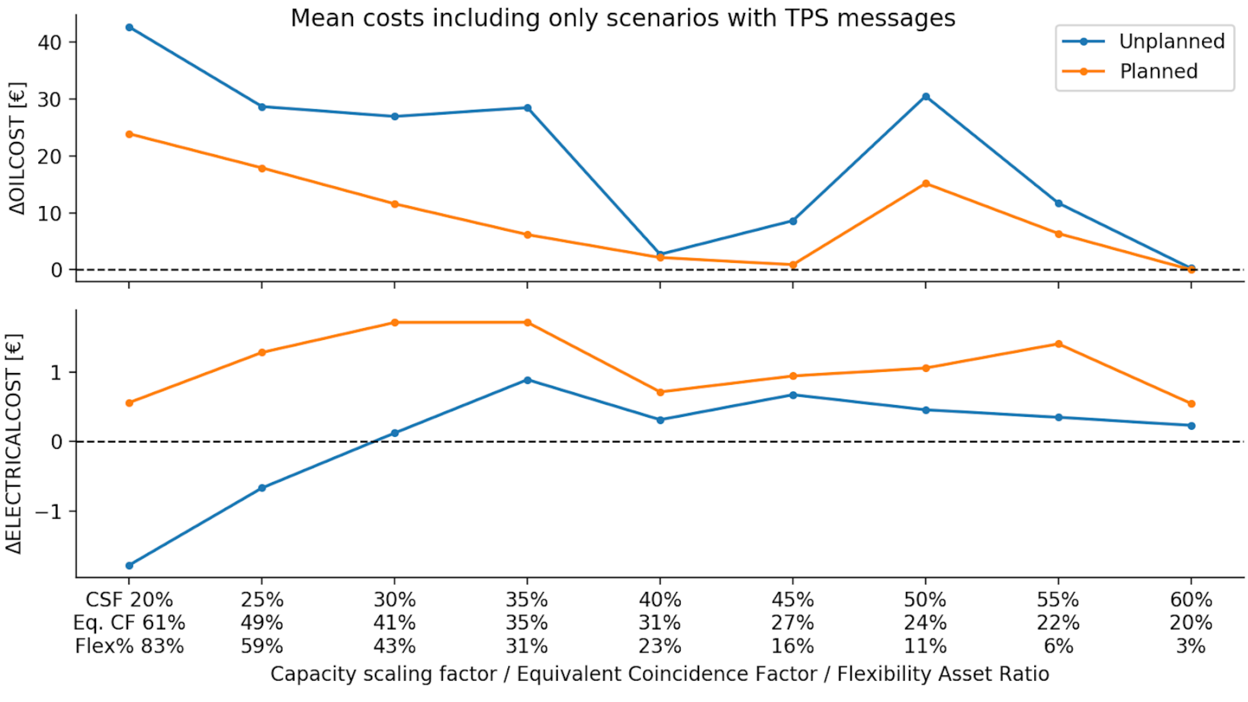

Figure 22: Mean cost including only scenarios with TPS messages

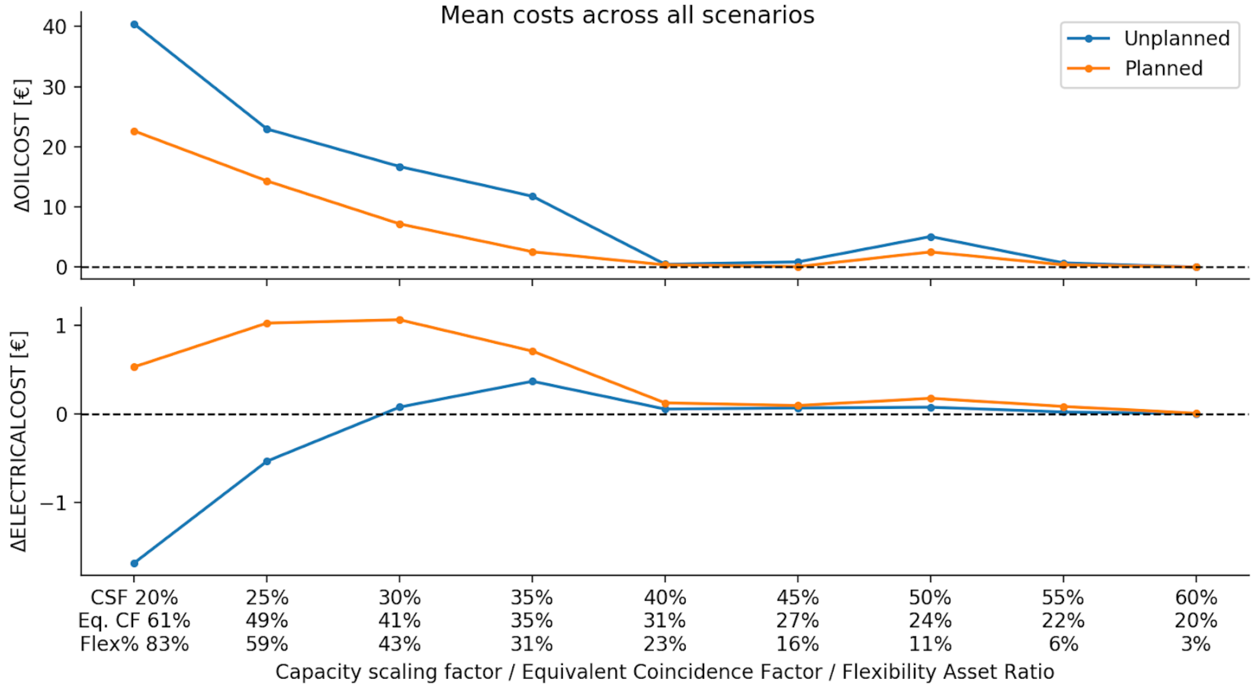

Figure 23: Mean costs across all scenarios given that a fault occurs

As seen on Figure 22, oil costs for a capacity scaling factor of 50% are much higher than those for adjacent capacity scaling factors. This is a modelling artefact, as fault scenarios are chosen independently for each capacity scaling factor. By chance, the faults chosen for a capacity scaling factor of 50% are more severe than those chosen for adjacent capacity scaling factors; an observation that is also borne out by Figure 20 in Section 4.1, where messages for a capacity factor of 50% have higher average energy content than for adjacent capacity factors.

Further, note that electrical costs *decrease* below baseline costs for the “Unplanned” scenarios as the capacity scaling factor is reduced below 30% on Figure 23. In this range, long periods for which the electrical portion of the FlexHeat system is turned off shift costs to using oil heaters instead, as indicated by the increase in oil costs. By contrast, in the “Planned” scenarios the Planning controller can anticipate the capacity limit and pre-charge the electrical storage tank before the disconnection, limiting use of the oil backup.

Table 8: Costs incurred in scenarios for capacity scale of 60%

CSF = 0.6	Base scenario cost /day	Foreseen Capacity Limit delta	Unforeseen Capacity Limit delta
Case 1 (Limit: 203 kW, day nr.: 4)	34.249 €	0.003 €	0.002 €
Case 2 (Limit = 44 kW; day nr.: 13)	29.81 €	0.36 €	0.15 €

The typical distribution grid customer should expect to see a foreseen fault somewhere between once every other year and once every several years, with a similar frequency for unforeseen faults. Given this frequency and the expected change in operational costs for the faults reported in Table 8, the operator’s increase in costs due to TPS messages sent as a result of faults in the distribution network is negligible compared to typical operating costs; Even at a capacity scaling factor of 50%, these costs would across a year correspond to less than 1% of 1% of the total operating costs.

6. Result Summary and Observations

With the current system configuration and electrical demand, and for the situation examined here, no TPS messages are sent until line capacities are reduced below 65% of their current capacity. The current electrical system thus has more than enough capacity to operate with the FlexHeat system as a non-active asset.

Even once line capacities are reduced below 65%, costs to operate the FlexHeat system do not increase appreciably until line capacities are reduced below ca. 40%. Thus, operating flexible assets to offset grid investment is expected to be feasible for this range.

Cost estimates for the model should be representative, rather than authoritative. This is due to 3 factors:

First, the relative incidence of faults, i.e. the number of faults one sees per year of each type, has not been included in the analysis. The costs reported here assume each fault is equally likely, and do not account for the large background of days where there is no fault in the system. Given the probability that a fault occurs on any given day, p, the costs given here must be scaled by p to represent actual system costs, on top of weighting scenarios according to their relative occurrence. As some faults are more costly than others, a more complete analysis should attempt to locate and quantify the faults with the greatest impact on operation.

Second, the price signal is, due to time pressure, not based on actual power system prices, but a simplified signal. Thus, actual electrical costs will vary compared to those used here, and especially in times of electrical scarcity, the cost to operate the system will be much higher than that reported here.

Third, the optimization performed by the Planning Controller relies on perfect forecasts of demand and prices; in practice, this optimization would necessarily rely on forecasts which would lead to worse tracking of demands, and subsequent higher costs. Relevant uncertainties include the uncertainty of electricity prices in the day-ahead market and hour-ahead markets, the uncertainty in heat demand and the uncertainty in whether messages could arrive from the TPS system. Each of these would tend to increase the overall cost of operation.

7. Conclusion and Future Work

Even given the simplified nature of the model, accounting for potential sources of cost misestimation, and under severe capacity restriction, increases to operational costs due to TPS messages arising from foreseen and unforeseen faults were found to be negligible in comparison with typical operating costs.

In the range of these 3%-20% of flexibility asset penetration, costs of a single capacity limitation are averaged 2€, or 7% of a daily operation cost of FlexHeat. With the low likelihood of an N-1 event happening approximately once every other year the cost come down to at 3€/year. It stands to conclude from that for low to medium penetration of flexibility assets, the benefits of coordination between distribution system operators and aggregators far outweigh the costs incurred.

The developed model forms a basis for future studies on congestion and coordination in distribution networks.

Several avenues for improvements and substantiation of the results should be considered. The operation model of FlexHeat can be further improved to reflect also its dynamic response correctly. Naturally, the consideration of fault statistics and alternative distribution feeder topologies and reconfiguration strategies can be studied. Alternative distribution network models that also account for voltage issues would be required in order to study congestion effects in rural networks. Further, the current study is limited to a single large flexibility asset. In future works, the assessment of coordination with fleets of flexibility assets (e.g. Electric vehicles) would be of interest as well.

The modelling of coincidence factors for flexibility assets with different types of loads requires further investigation. Considering market-based flexibility asset operation with the objective to reduce electrical import cost. In practice, this operating mode tends to align with the objectives of the TSO and DSO, as it shifts load to periods of lower demand, reducing overall stress on the system. This should be reflected also in the simulation of congestion effects as these will tend to further reduce peaks in the overall consumption profile. An extension of the presented model could introduce a closed loop between the congestion model and the operation model to include the operational plans of flexibility assets.

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Appendix

Table A1: Testing scenario 1 (T1)

Name of the test case	Testing of DSO – TPS communication

Narrative	Congestions occur when the power flow exceeds the capacity of the distribution network components (mainly transformers and cables). This leads to the overloading of the components resulting in their increased degradation and may even cause a components' failure. Therefore, congestions should be avoided. While the distribution network is generally designed to handle the power, flows caused by the non-flexible loads, the operation of the flexible components coordinated by the AGR/ BRP could cause congestions in the system with both FCI and UCI. In the system with FCI congestions could be caused by the increased concurrency factor in a perfectly operational network or due to the planned maintenance of some of the components. In the system with UCI congestions could be caused by the fault or component malfunction (N1 contingency). To avoid potential congestions on the feeders with flexible components, DSO should determine the limits imposed on their power output (see Figure 2). The limits will only be imposed, if there is a chance of congestion. These limits are then sent to the TPS, where limits could be further seen via "fairness filter" by any AGR/BRP that has flexible components affected by them. AGR/BRP then uses the limits to update its scheduling/dispatching. The format of the limits the AGR/BRP observes is specified in D6.1. The limits can be applied as both lower (e.g. *min 500* in the period from *t1* to *t2* – do not reduce the load lower than 500 kVA in the period from *t1* to *t2*) and upper (e.g. *max 500* in the period from *t1* to *t2* – do not increase the load higher than 500 kVA in the period from *t1* to *t2*) limits of power output from the flexible components on the feeder (see Figure 2). In T1 it is assumed that the AGR can communicate its schedule to the DSO and that AGR's behaviour is driven by the prices on a wholesale (day-ahead) market. T1 focuses on the DSO – TPS communication and includes the following test cases: **T1C1P.ap** – DSO determines the upper limits of its network for the day-ahead for the system with FCI without the knowledge of the AGR day-ahead scheduling. DSO uses the database of the flexible components registered in its network to make a power demand forecast. DSO then sends the network limits to the TPS. Minimum simulation time frame – 25 hours: 1 hour for determining limits for the other 24 hours; **T1C1P.bp** – DSO determines the upper limits of its network for the day-ahead for the system with FCI with the knowledge of the AGR day-ahead scheduling. DSO then sends them to the TPS. Minimum simulation time frame – 25 hours: 1 hour for determining limits for the other 24 hours; **T1C1P.cp** – DSO determines the lower limits of its network for the day-ahead for the system with FCI with the knowledge of the AGR day-ahead scheduling. The lower limits are imposed due to the forecasted renewable generation. DSO then sends the network limits to the TPS. Minimum simulation time frame – 25 hours: 1 hour for determining limits for the other 24 hours; **T1C2U.ap** – DSO determines the upper limits of its network in the real-time for the system with UCI. The UCI are caused by the fault/component malfunction. DSO then sends the network limits to the TPS. Minimum simulation time frame – 24 hours: determining limits after system encounter UCI somewhere for 24 hours. Limits become effective immediately; **T1C2U.bp** – DSO determines both upper and lower limits of its network in the real-time for the system with UCI. First, UCI are caused by the fault/component malfunction, following the unexpected increase in

	renewable generation. The DSO then sends the updated network limits to the TPS. Minimum simulation time frame – 24 hours: determining limits after system encounter UCI somewhere for 24 hours. Limits become effective immediately.

System under Test (SuT)		Nordhavn network, non-flexible loads, renewable generation units (multiple PVs), flexible components (FlexHeat, battery, individual heat pumps), DSO, TPS, AGR, wholesale electricity market (simplified)
	Object under Investigation (OuI)	Feeders of the Nordhavn network, TPS
	Domain under Investigation (DuI)	Power demand forecasting, communication, load scheduling
Function under Test (FuT)		DSO day-ahead load forecasting of power demand considering non-flexible loads, renewable generation units and flexible components; DSO real-time load forecasting of power demand considering non-flexible loads, renewable generation units and flexible components; DSO determining the network limits in the day-ahead; DSO determining the network limits in the real-time; DSO – TPS communication (limits information transfer); scheduling of the flexible components by the AGR; AGR – flexible components communication (dispatch); AGR – DSO communication (scheduling sharing)
	Function(s) under Investigation (FuI)	DSO day-ahead load forecasting of power demand considering non-flexible loads, renewable generation units and flexible components; DSO real-time load forecasting of power demand considering non-flexible loads, renewable generation units and flexible components; DSO – TPS communication (limits information transfer)
Purpose of Investigation (PoI)		Validate the ability of the DSO to determine the network limits day-ahead and real-time on different feeders and communicate it to the TPS
Test criteria		DSO successfully determines the network limits and sends them to TPS
	target metrics (criteria)	TPS contains the upper/lower network limits sent by the DSO

	variability attributs (test factors)	*Non-flexible loads* – different non-flexible load profiles in all scenarios; *PV generation* – different PV generation profiles in all scenarios; *Scheduling* – no schedule is sent to the DSO (**T1C1P.ap**); different scheduling of non-flexible components by the AGR (**T1C1P.bp**, **T1C1P.cp**); *Cause of capacity limits* – upper limits because of demand (**T1C1P.ap**); upper limits due to the planned maintenance (**T1C1P.bp**); upper limits due to the sudden component malfunction (**T1C2U.ap**, **T1C2U.bp); **lower limits due to the renewable generation (**T1C1F.cp**, **T1C2U.bp**)
	quality attributes (thresholds)	

Table A2: Testing scenario 2 (T2)

Name of the test case	Testing of TPS – AGR communication

Narrative		Congestions occur when the power flow exceeds the capacity of the distribution network components (mainly transformers and cables). This leads to the overloading of the components resulting in their increased degradation and may even cause a components' failure. Therefore, congestions should be avoided. While the distribution network is generally designed to handle the power, flows caused by the non-flexible loads, the operation of the flexible components coordinated by the AGR/ BRP could cause congestions in the system with both FCI and UCI. In the system with FCI congestions could be caused by the increased concurrency factor in a perfectly operational network or due to the planned maintenance of some of the components. In the system with UCI congestions could be caused by the fault or component malfunction (N1 contingency). To avoid potential congestions on the feeders with flexible components, DSO should determine the limits imposed on their power output (see Figure 2). The limits will only be imposed, if there is a chance of congestion. These limits are then sent to the TPS, where limits could be further seen via "fairness filter" by any AGR/BRP that has flexible components affected by them. AGR/BRP then uses the limits to update its scheduling/dispatching. The format of the limits the AGR/BRP observes is specified in D6.1. The limits can be applied as both lower (e.g. *min 500* in the period from *t1* to *t2* – do not reduce the load lower than 500 kVA in the period from *t1* to *t2*) and upper (e.g. *max 500* in the period from *t1* to *t2* – do not increase the load higher than 500 kVA in the period from *t1* to *t2*) limits of power output from the flexible components on the feeder. In T2 it is assumed that DSO limits sent to the TPS are already determined (see T1), only one AGR is present in the network (unless mentioned otherwise) and that AGR's behaviour is mainly driven by the price at the wholesale (day-ahead) market. In addition to the bids in the wholesale market, AGR can also bid in the regulating power market (hour-ahead) with the activation within 5-15 minutes after the request. The AGR bids at this market could be activated by the transmission system operator (TSO). Since functionally TSO and BRP requests are performed in the same way, in T2 they are treated by the same test cases. T2 focuses on the TPS – AGR communication and include the following test cases: **T2C1P.ap** – AGR creates a day-ahead schedule for dispatching flexible loads (increased consumption) in its portfolio without receiving planned upper capacity limitations from TPS and then dispatch them.
System under Test (SuT)		Nordhavn network, non-flexible loads, renewable generation units (multiple PVs), flexible components (FlexHeat, battery, individual heat pumps), DSO, TPS, AGR, wholesale electricity market (simplified), TSO, BRP
	Object under Investigation (OuI)	Feeders of the Nordhavn network, AGR day-ahead scheduling/dispatch, AGR bidding in the hour-ahead market
	Domain under Investigation (DuI)	Communication, control, load scheduling, hour-ahead market bidding

Function under Test (FuT)		DSO – TPS communication (limits information transfer); scheduling of the flexible components by the AGR; AGR – flexible components communication (dispatch); AGR – TSP communication (limits information receiving); TSO – AGR communication (activation of the flexibility services bids); BRP – AGR communication (activation of the flexibility services bids)
	Function(s) under Investigation (FuI)	Scheduling of the flexible components by the AGR; AGR – flexible components communication (dispatch); AGR – TSP communication (limits information receiving); TSO – AGR communication (activation of the flexibility services bids); BRP – AGR communication (activation of the flexibility services bids)
Purpose of Investigation (PoI)		Validate the ability of the AGR to obtain the information about the network limits from the TPS and change its day-ahead scheduling, real-time dispatch, hour-ahead regulating power market bidding strategy and/or response to activation requests according to the network's limits
Test criteria		AGR changes its behaviour based on the network limits
	target metrics (criteria)	AGR changes its scheduling/dispatch/hour-ahead bidding/response to activation requests based on the network limits
	variability attributes (test factors)	*Non-flexible loads* – same non-flexible load profiles in all scenarios as in T1; *PV generation* – same PV generation profiles in all scenarios as in T1; *Network limits* – day-ahead limits exist, but information about them is not available (**T2C1P.ap, T2C1P.bp, T2C2P.ap, T2C2P.bp, T2C3U.ap, T2C3U.cp, T2C3U.dp**); day-ahead limits exist, information about them is available (**T2C1P.cs, T2C2P.cs**); real-time limits exist, information about them is available (**T2C3U.bs, T2C3U.es**); *Bidding to the regulating power market* – no bidding (**T2C1P.ap, T2C1P.bp, T2C1P.cs, T2C3U.ap, T2C3U.bs**); AGR submits bids (**T2C2P.ap, T2C2P.bp, T2C2P.cs, T2C3U.cp, T2C3U.dp, T2C3U.es**)
	quality attributes (thresholds)	

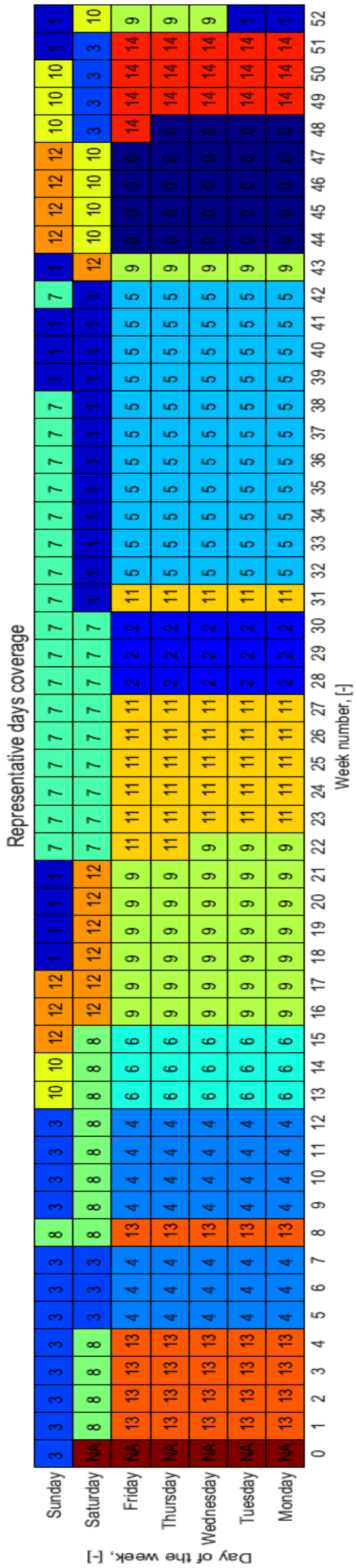
Table A3: Conflict cases vs. Test cases

Conflict case	Conflict case name	Associated Test cases	Remarks
1.1	Spot price variations	Not applicable to TPS	This conflict case is not a problem solved by TPS functionality because the overload situation is assumed to be caused by unregistered (unmanaged) resources with ability to respond to real-time market prices; the expected system behaviour is similar to the test cases **T2C1P.bp** (showing rebound problem) and **T2C1P.cs**, however here flexibility assets are managed by an aggregator.
2.1	AGR control of several customers	**T2C1P.ap, T2C1P.cs**	This conflict case corresponds to the **T2C1P.ap**, which simulates the congestion due to the load increase caused by AGR operation
3.1	AGR offer energy management for customers	**T2C1P.bp, T2C1P.cs**	Same remark as in 2.1
3.2	TSO activated customers	**T2C2P.ap, T2C2P.cs**	This conflict case corresponds to the **T2C2P.ap**, where AGR cause congestion due to TSO activating AGR's bid in the regulating power market
3.3	BRP Self balancing through AGR	**T2C2P.ap, T2C2P.cs**	As mentioned in T2, TSO/BRP requests are simulated by the same cases
4.1	TSO activated; several flexibility assets	**T2C2P.ap, T2C2P.cs**	Same remark as in 3.2
4.2	TSO activated; one single flexibility asset but Alert/Emergency Grid Operation	**T2C3U.cp, T2C3U.es**	This conflict case corresponds to the **T2C3U.cp**, where AGR cause congestion due to TSO activating the AGR's bid in the regulating power market, while the system has UCI

5.1	DSO counteracting TSO activation	T2C2P.bp, T2C2P.cs	This conflict case corresponds to the T2C2P.bp, that simulates the activation of the AGR1 by the TSO and the following activation of AGR2 by the DSO to counteract the effect of AGR1
5.2	DSO counteracting TSO activation in A/E grid operation	T2C3U.dp, T2C3U.es	This conflict case corresponds to the T2C3U.dp, that simulates the activation of the AGR1 by the TSO and the following activation of AGR2 by the DSO to counteract the effect of AGR1, while the system has UCI
6.1	DSO activated flexibility asset occasionally	Not applicable to TPS	This conflict case is not a problem case for showing the TPS and therefore not addressed by the test cases
7.1	BRP self-balancing cause over-load. Several flexibility assets	T2C2P.ap, T2C2P.cs	Same remark as in 3.2
7.2	BRP self-balancing cause over-load. Single flexibility assets	T2C3U.cp, T2C3U.es	Same remark as in 4.2
8.1	TSO upward regulation of several flexibility assets	T2C2P.ap, T2C2P.cs, T2C3U.cp, T2C3U.es	Same remarks as in 3.2 and 4.2
8.2	BRP upward regulation for self-balancing service	T2C2P.ap, T2C2P.cs, T2C3U.cp, T2C3U.es	Same remarks as in 3.2 and 4.2
8.3	Opposite of (2) in Explicit Demand Response	T1C1P.cp, T2C1P.cs	This conflict case corresponds to the T1C1P.cp, that simulates effect of the renewable generation on the lower network limits imposed by the DSO

8.4	Unexpected renewable in-feed power	**T1C2U.bp**, **T2C3U.bs**	This conflict case corresponds to the **T1C2U.bp**, that simulates effect of the renewable generation on the lower network limits imposed by the DSO in the real-time

Table A4: Calendar days included in each cluster



Week number	Sunday	Saturday	Friday	Thursday	Wednesday	Tuesday	Monday
0	3	NA	NA	NA	NA	NA	NA
1	3	8	13	13	13	13	13
2	3	8	13	13	13	13	13
3	3	8	13	13	13	13	13
4	3	8	13	13	13	13	13
5	3	3	4	4	4	4	4
6	3	3	4	4	4	4	4
7	3	3	4	4	4	4	4
8	8	8	13	13	13	13	13
9	3	8	4	4	4	4	4
10	3	8	4	4	4	4	4
11	3	8	4	4	4	4	4
12	3	8	4	4	4	4	4
13	10	8	6	6	6	6	6
14	10	8	6	6	6	6	6
15	12	8	6	6	6	6	6
16	12	12	9	9	9	9	9
17	12	12	9	9	9	9	9
18	1	12	9	9	9	9	9
19	1	12	9	9	9	9	9
20	1	12	9	9	9	9	9
21	1	12	9	9	9	9	9
22	7	7	11	11	9	9	9
23	7	7	11	11	11	11	11
24	7	7	11	11	11	11	11
25	7	7	11	11	11	11	11
26	7	7	11	11	11	11	11
27	7	7	11	11	11	11	11
28	7	7	2	2	2	2	2
29	7	7	2	2	2	2	2
30	7	7	2	2	2	2	2
31	7	1	11	11	11	11	11
32	7	1	5	5	5	5	5
33	7	1	5	5	5	5	5
34	7	1	5	5	5	5	5
35	7	1	5	5	5	5	5
36	7	1	5	5	5	5	5
37	7	1	5	5	5	5	5
38	7	1	5	5	5	5	5
39	1	1	5	5	5	5	5
40	1	1	5	5	5	5	5
41	1	1	5	5	5	5	5
42	7	1	5	5	5	5	5
43	1	12	9	9	9	9	9
44	12	10	0	0	0	0	0
45	12	10	0	0	0	0	0
46	12	10	0	0	0	0	0
47	12	10	0	0	0	0	0
48	10	3	14	0	0	0	0
49	10	3	14	14	14	14	14
50	10	3	14	14	14	14	14
51	1	3	14	14	14	14	14
52	1	10	9	9	9	1	1

Table A5: Representative days selected for each cluster

Cluster	Day number	Emulated date
0	196	16/07/2017
1	134	15/05/2017
2	68	10/03/2017
3	63	05/03/2017
4	172	22/06/2017
5	94	05/04/2017
6	265	23/09/2017
7	345	12/12/2017
8	255	13/09/2017
9	62	04/03/2017
10	317	14/11/2017
11	199	19/07/2017
12	300	28/10/2017
13	17	18/01/2017
14	38	08/02/2017