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Sergey Klyapovskiy

Advanced Design Methods for Active Distribution Networks

Framework solutions for incorporating flexibility

Dissertation, April 2019
Kgs. Lyngby, Denmark

Center for Electric Power and Energy
Department of Electrical Engineering

DANMARKS TEKNISKE UNIVERSITET
Center for Electric Power and Energy (CEE)
DTU Electrical Engineering

Advanced Design Methods for Active Distribution Networks

Framework solutions for incorporating flexibility

Avancerede designmetoder til aktive distributionsnetværks

Framework-løsninger til at inkorporere fleksibilitet

Dissertation, by Sergey Klyapovskiy

Supervisors:

Senior Researcher Henrik W. Bindner, Technical University of Denmark

Senior Researcher Shi You, Technical University of Denmark

DTU - Technical University of Denmark, Kgs. Lyngby - April 2019

Advanced Design Methods for Active Distribution Networks

This thesis was prepared by:
Sergey Klyapovskiy

Supervisors:
Senior Researcher Henrik W. Bindner, Technical University of Denmark
Senior Researcher Shi You, Technical University of Denmark

Dissertation Examination Committee:
Examiner No. 1 (Chairman)
Department of Electrical Engineering, Technical University of Denmark, Denmark

Examiner No. 2
Department of XX, University of XX, Country

Examiner No. 3
Department of XY, Technical University of YY, Country

Center for Electric Power and Energy (CEE)
DTU Electrical Engineering
Elektrovej, Building 325
DK-2800 Kgs. Lyngby
Denmark

Tel: (+45) 4525 3500
Fax: (+45) 4588 6111
E-mail: cee@elektro.dtu.dk

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Preface

This thesis is prepared at the Department of Electrical Engineering of the Technical University of Denmark in partial fulfilment of the requirements for acquiring the degree of Doctor of Philosophy in Engineering. The Ph.D. project was funded by the project EnergyLab Nordhavn (grant: EUDP 64015-0055).

This dissertation summarizes the work carried out by the author during his Ph.D. project. It started on 1$^{\text{th}}$ May 2016, and it was completed on 30$^{\text{th}}$ April 2019. During this period, he was hired by the Technical University of Denmark as a Ph.D. student at the Center for Electric Power and Energy (CEE).

The thesis is composed of six chapters and five attached scientific papers, four of which have been peer-reviewed and published, whereas the remaining one is currently under review.

Кляповский

Sergey Klyapovskiy
30.04.2019

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I am grateful to the senior power grid specialist Carsten Buhl Nielsen from "Radius" for providing me with the information about planning procedures at the danish DSO and for his help in obtaining the necessary data for my project.

Thanks to all my colleagues at the Center for Electric Power and Energy both in Lyngby and Risø for the great time I had, while working as a PhD student.

Finally, I would like to thank my family and friends for their moral support and believe in me during the whole time of the PhD studies and especially during the last few months of writing this PhD thesis.

Sergey Klyapovskiy

Kgs. Lyngby, Denmark, 2019

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Abstract

Growing concerns about climate change and desire to reduce CO_2 emissions lead to the wide spread of distributed generation (DG) units based on renewable energy sources (RES) and electrification of the heat and transportation sectors. However, such measures result in the challenges experienced by the transmission system operator (TSO) and distribution system operator (DSO) in their networks. Negative generation prices, power congestions and the problem with voltages can be caused due to the adoption of environmentally-driven policies. Conventional solutions treating the networks as passive distribution networks (PDNs) will require large capital expenditures (CAPEX) into the network reinforcement. An alternative solution is to apply the approaches from the active distribution network (ADN) planning and use the flexibility services (FSs) from the active elements (AEs), that could be found at the distribution level. Customers participating in demand response (DR) programs, battery energy storage system (BESS), circuit breakers (CBs) used in the reconfiguration (RE) and underground cables providing dynamic line rating (DLR) are all examples of such AEs. This PhD thesis is focusing on the problem of integration of AEs into ADN planning. In order to achieve such integration, first, the influence of the inclusion of the FSs on the whole planning process should be determined. Second, different types of AEs providing FSs have to be compared with each other and conventional solutions on a common basis. A generic planning framework is proposed in order to streamline the planning process. The framework shows that ADN planning is a complex process consisting of multiple stages. Each stage includes different planning algorithms that focus on individual planning aspects (forecasting, verification, etc.). The framework could be used for the development of the various planning procedures, that combine different algorithms and allow to integrate new emerging technologies into ADN planning. The integration of AEs will evoke changes on each of the planning stages, such as the need for time-series power demand data and the ability to relax the design criteria applied to the network design (ND) part of the planning solution. Multiple AEs that can provide FSs useful for the DSO can be present in the network. The second methodology - flexibility characterization framework is proposed to enable the comparison between different AEs via cost. The framework allows to characterize the cost of any AE in a generic manner regardless of the AE's type and technology, using the combination of different parameters and cost functions to estimate its CAPEX and operational expenditures (OPEX). The estimated cost is then compared with the Value of Flexibility (VoF), which determines the maximum price DSO is ready to pay for the provision of FSs. VoF is estimated by analyzing conventional planning solutions (without application of FSs). The flexibility characterization framework serves as a decision support tool for the DSOs willing to implement FSs from AEs in planning. Case studies based on the real distribution network of Nordhavn in Copenhagen, Denmark show the validation of the proposed methodologies. Case studies 1 and 2 present the examples of integration of AEs in the ADN and integrated energy system (IES) planning, case study 2 shows how to compare FSs from DR, BESS, RE and DLR and select the best option for solving a power congestion. Case studies show that the application of the proposed methodologies can allow the easier integration of AEs, which results in a more cost-efficient solution.

Resumé

Voksende bekymringer om klimaændringer og ønsket om at reducere CO_2-udledningen fører til en bred spredning af distribueret generations (DG) enheder baseret på vedvarende energikilder (VE) og elektrificering af varme og transportsektorer. Sådanne foranstaltninger resulterer imidlertid i udfordringer hos operatørerne af transmissions- (TSO) og distributionssystemerne (DSO) i deres netværk. Negative produktionspriser, flaskehalsproblemer og spændingsproblemer kan skyldes vedtagelsen af miljømæssigt drevne politikker. Konventionelle løsninger, der behandler netværket som passive distributionsnet (PDN)s, vil kræve store investeringsudgifter (CAPEX) i netværksforstærkning. En alternativ løsning er at anvende tilgangene fra aktive distributionsnetværks (ADN) planlægning og bruge fleksibilitetstjenesterne (FS'er) fra de aktive elementer (AE'er), der kunne findes på distributionsniveauet. Kunder, der deltager i demand response (DR) programmer, batteri energilagringssystem (BESS), afbrydere (CB'er) der anvendes i rekonfigurationen (RE) og underjordiske kabler, der giver dynamisk linje rating (DLR) er alle eksempler af sådanne AE'er. Dette ph.d. projekt fokuserer på problemet med integration af AE'er i ADN planlægningen. For at opnå en sådan integration, for det første, skal indflydelsen af inddragelsen af FS'erne på hele planlægningsprocessen bestemmes. For det andet, skal de forskellige typer AE'er, der leverer FS'er, sammenlignes med hinanden og med konventionelle løsninger på fælles basis. Der foreslås et generisk planlægnings-framework for at strømline planlægningsprocessen. Frameworket viser, at ADN-planlægning er en kompleks proces bestående af flere trin. Hvert trin omfatter forskellige planlægningsalgoritmer, der fokuserer på individuelle planlægningsaspekter (prognoser, verifikation osv.). Frameworket kunne bruges til udvikling af de forskellige planlægningsprocedurer, der kombinerer forskellige algoritmer og giver mulighed for at integrere nye teknologier i ADN planlægning. Integrationen af AE'er vil fremkalde ændringer på hver af planlægningsfaserne, såsom behovet for tidsserie elforbrugsdata og evnen til at løsne de anvendte designkriterier til netværksdesign (ND) delen af planlægningsløsningen. Flere AE'er, der kan give FS'er nyttige for DSO'en kan være til stede i netværket. Den anden metode - fleksibilitetskarakteriseringframework er foreslået for at muliggøre sammenligningen mellem forskellige AE'er via omkostninger. Frameworket gør det muligt at karakterisere prisen for enhver AE på en generisk måde uanset AEs type og teknologi, ved hjælp af kombinationen af forskellige parametre og omkostningsfunktioner til at estimere sine CAPEX- og driftsudgifter (OPEX). Den estimerede pris sammenlignes derefter med værdien af fleksibilitet (VoF), som bestemmer den maksimumspris DSO'en er klar til at betale for levering af FS'er. VoF estimeres ved at analysere konventionelle planlægningsløsninger (uden anvendelse af FS'er). Fleksibilitetskarakteriseringsframeworket tjener som et beslutningsstøtteværktøj for DSO'erne som er villige til at implementere FS'er fra AE'er i planlægningen. Case studier baseret på det virkelige distributionsnetværk i Nordhavn i København, Danmark viser valideringen af de foreslåede metoder. Case studier 1 og 2 præsenterer eksemplerne på integration af AE'er i ADN og integreret energisystem (IES) planlægning og case studie 2 viser, hvordan man sammenligner FS'er fra DR, BESS, RE og DLR og vælg den bedste mulighed til løsning af flaskehalsproblemer. Case studier viser, at anvendelsen af de foreslåede metoder kan muliggøre en lettere integration af AE'er, hvilket resulterer i en mere omkostningseffektiv løsning.

Acronyms

ADN active distribution network

AE active element

BESS battery energy storage system

CAPEX capital expenditures

CB circuit breaker

CE congestion event

CHP combined heat and power

DG distributed generation

DHO district heating operator

DLR dynamic line rating

DR demand response

DSO distribution system operator

ENS energy not supplied

ESS energy storage system

EV electric vehicle

FS flexibility service

HP heat pump

IES integrated energy system

LDC load duration curve

LT lifetime

MCC maximum carrying capacity

MS main substation

ND network design

NPV net present value

OLTC on-load tap changer

OPEX operational expenditures

OS operational strategy

PDN passive distribution network

PSO particle swarm optimization

RE reconfiguration

RES renewable energy sources

SADN semi-active distribution network

SoC state of charge

TOTEX total expenditures

TSO transmission system operator

V2G Vehicle to Grid

VoF Value of Flexibility

Definitions

This section states and clarifies some definitions of functions, roles and responsibilities that are referred to in this thesis.

Active element (AE): any equipment or actor in the distribution network that could be called for or directly controlled in order to change its behaviour to adapt to the current need of the power system. Examples of AEs: customers participating in demand response programs, remotely-controlled circuit-breakers or switches, distributed generation units and battery energy storage systems.

Flexibility service (FS): - service provided by the AEs. Examples of FSs: demand response programmes, network reconfiguration, load shifting/peak reduction and voltage support are the FSs that could be contracted by a distribution system operator (DSO) to achieve economic, reliable and safe distribution network operation.

Planning exercise: a task that is performed by the DSO in order to reach one or multiple planning objectives.

Planning algorithm: a specific approach (e.g. forecasting, modelling) that aid distribution network planner to reach one or more planning objectives, such as loss reduction, voltage improvement or integration of distributed generation units.

Planning procedure: a sequential approach defining how different planning algorithms are integrated to reach selected planning objectives.

Framework: a generic approach that integrates different planning algorithms in order to deliver a streamlined planning procedure.

CHAPTER 1

Introduction

Growing concerns about climate change and desire to reduce CO_2 emissions have become the main items in the energy policies of many countries. Introduction of renewable energy sources (RES), minimization of fossil fuel usage and increased focus on energy efficiency are named as the main drivers for achieving sustainability [1–3]. The share of RES in the total energy generation mix in the world is constantly growing and is estimated to reach 22,5% by the year 2020 [4] with the 30% energy efficiency target set by EU countries [5] for the year 2030. Reduction of the fossil fuel consumption will require wide electrification of the various end-user sectors with the transportation and heating sectors be the most notable examples [6, 7]. While such electrification will reduce the overall energy consumption, it will also lead to a significant increase in the electricity consumption demand with the estimated 35% increase for the UK by the year 2050 [8].

1.1 Challenges in the power system

Environmentally-driven policies put a large emphasis on the electric power system to achieve their goals. The traditional power system consists of three levels: generation, transmission, and distribution. The distribution system operator (DSO) and transmission system operator (TSO) are utilities, that are in charge of distribution and transmission networks, respectively. Both DSO and TSO have to understand how the new green policies affect their networks and how to adapt to these changes. The challenges in the power system, that are caused due to the transition from the fossil fuels to the RES and electrification, could already be seen in the countries like Denmark [9], Germany [10] and Norway [11]. The examples of such challenges are negative power generation prices (affecting TSO), overvoltages and power congestions (affecting DSO), that are described below.

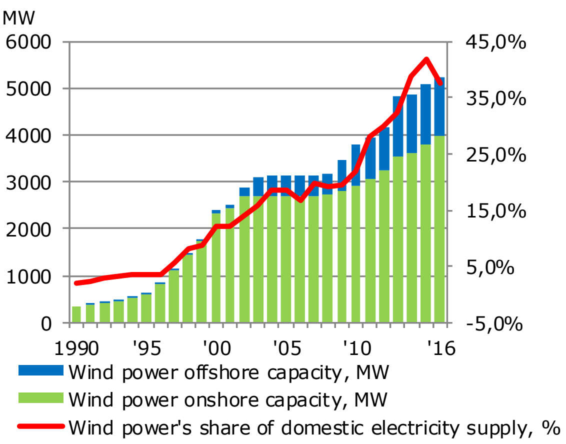

Figure 1.1: Wind power capacity and wind power share in Denmark's power supply. Source: [12]

In Denmark, the share of power generated by the RES based on wind has grown from 15% in 2000 to 37,5% in 2016 as shown in Figure 1.1. The trend is predicted to continue as Denmark set a goal of having

Table 1.1: Elspot prices in Denmark 2014-2017 [17]

	2014		2015		2016		2017	
	DK1	**DK2**	**DK1**	**DK2**	**DK1**	**DK2**	**DK1**	**DK2**
Min price, [€/MWh]	-60,26	-60,26	-31,4	-31,41	-53,62	-53,62	-50,04	-50,04
Max price, [€/MWh]	160,03	105,39	99,77	150,1	104,96	214,25	120,01	120,01
Hours with negative price, [h]	46	19	65	36	62	49	84	58

50% of its domestic power demand covered by the wind in the year 2020 [13]. The intermittent output of the wind generation requires careful balancing. Hours of excessive wind power generation may coincide with the period of low demand (e.g. early morning or night). In order to balance the system in such situations, the TSO can either curtail the wind power generation from turbines or sell the excesses of power via interconnections to the neighboring countries. Table 1.1 shows Elspot prices for two parts of the Danish energy system: DK1 and DK2. In the years 2014-2017 the minimum Elspot price at the Nordpool for Denmark was negative during several dozens of hours [14]. That indicates that TSO, who is in charge of keeping the balance between consumption and generation in the Danish power system is having problems with it due to the high share of RES. As stated in [15, 16], TSO can increase the number and capacity of the interconnections between Denmark and other countries and implement the flexible operation of the conventional power plants to improve the situation.

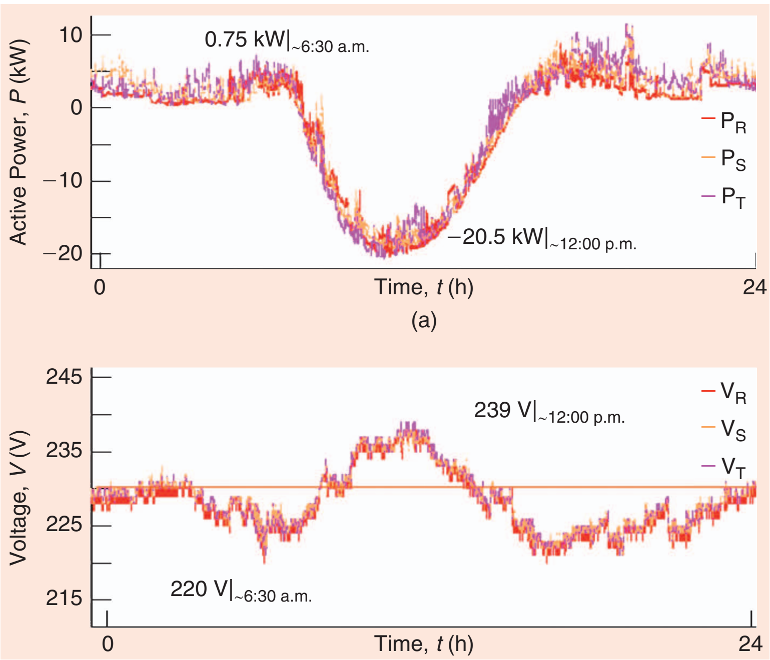

Figure 1.2: Load flow and voltage on the LV transformer in a distribution system with high share of PV generation. Source: [18]

The power generation from PV panels in Germany was estimated as 7,2% of the total power demand in the year 2017 [19]. The majority of the panels are under 30 kW and installed at the distribution level. In some distribution networks, their penetration could exceed 56% as stated in [10]. Substantial amounts of PV generation can change the directions of the power flows in the system and cause congestion and overvoltage problems as shown in Figure 1.2. As could be seen from Figure 1.2 on certain days the reverse power flowing back to the transformer at noon can be ca. 28 times higher than power demand during the day. The highest voltage is 1.08 pu, which exceeds the limit of 1.05 pu and cause overvoltage problems in the network. To mitigate the potential effects of the PV power production, the German DSOs updated the grid codes to be able to temporarily limit the PV feed-in and invested in the distribution network reinforcement such as replacement of the local transformers or addition of the voltage regulators [10].

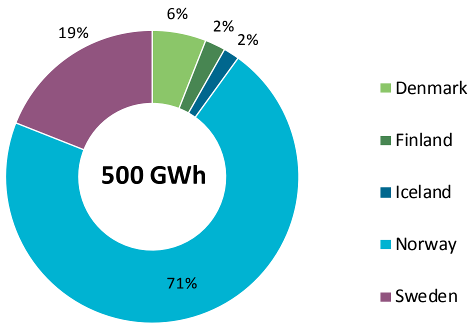

Figure 1.3: Total electricity consumption for EVs in the Nordic countries. Source: [20]

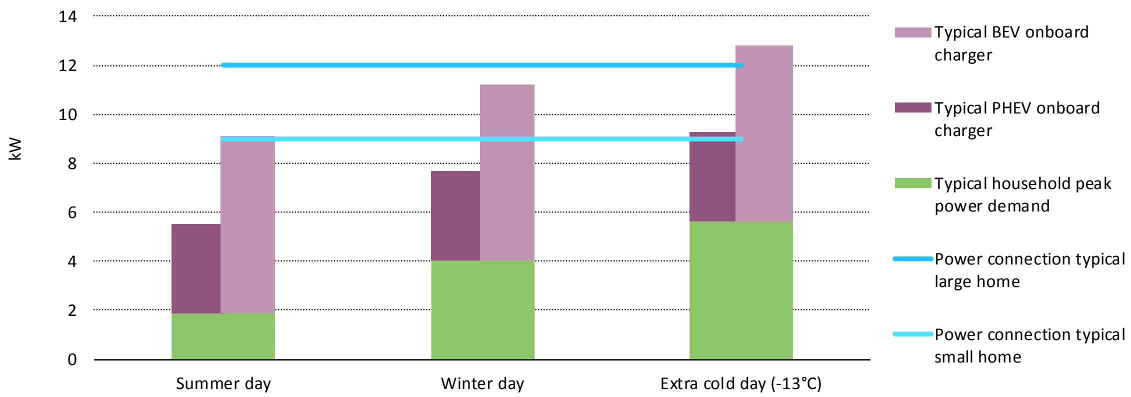

Figure 1.4: Peak power demand at Norwegian houses with EVs home charging. Source: [20]

Norway is one of the leaders in the electrification of the transportation sector and has the highest number of electric vehicles (EVs) per capita in the world. The total electricity consumption for EVs in the Nordic countries is shown in Figure 1.3. To charge EVs a combination of private and public charging stations is used. Since a DSO can choose the connection point of the public chargers, it can ensure that chargers are connected to the transformers with enough spare capacity. Home charging, however, represents a big challenge and can lead to the power congestions of local LV transformers [21]. In Figure 1.4 the peak power demand of Norwegian house with an installed home charger could be seen. Charging EV at home can increase the power demand more than 50%, the probability of overloading of the distribution network components increases with the drop in the outdoor temperature. According to [21, 22] 30% of all LV distribution transformers can be overloaded, if the power consumption increased by 5 kW per house due to the home charging of EVs.

1.2 Need for flexibility

Most of the solutions for overcoming challenges shown in the previous section involve constructing the new or reinforcing the existing power system components (e.g. interconnections for TSO, transformers, and cables for DSO). In many cases, such an approach will lead to significant capital expenditures (CAPEX) [24]

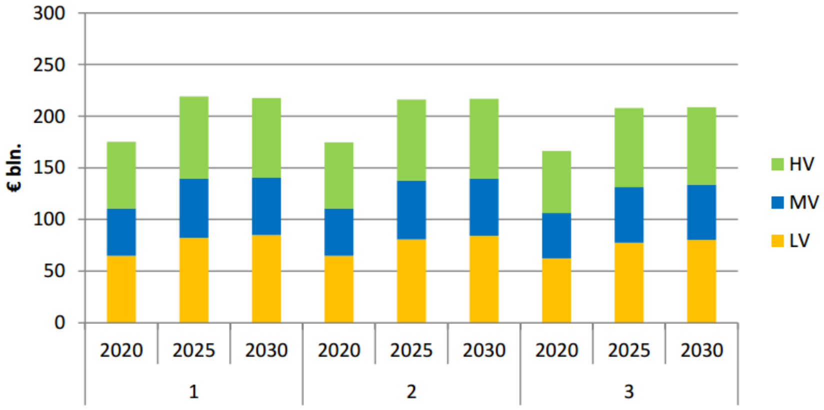

Figure 1.5: Cumulative distribution/transmission reinforcement cost scenarios in EU countries. Source: [23]

in the distribution and transmission networks as could be seen in Figure 1.5 for EU. The same trend could be observed in other countries. The extensive investments could slow down the implementation process of "clean" technologies.

An alternative solution is to utilize flexibility from the sources that are already present at the distribution network level [25]. Such sources are defined as active elements (AEs) in this work. Various distributed generation (DG) units, energy storage systems (ESSs), consumer equipment (such as EVs, heat pumps (HPs) and electric heaters) and distribution network components can be turned into AEs by enabling remote control capabilities over them. AEs can be used to solve most of the emerging challenges by proving flexibility services (FSs) - either by adjusting their power generation/demand according to the power system need or providing new power supply routes.

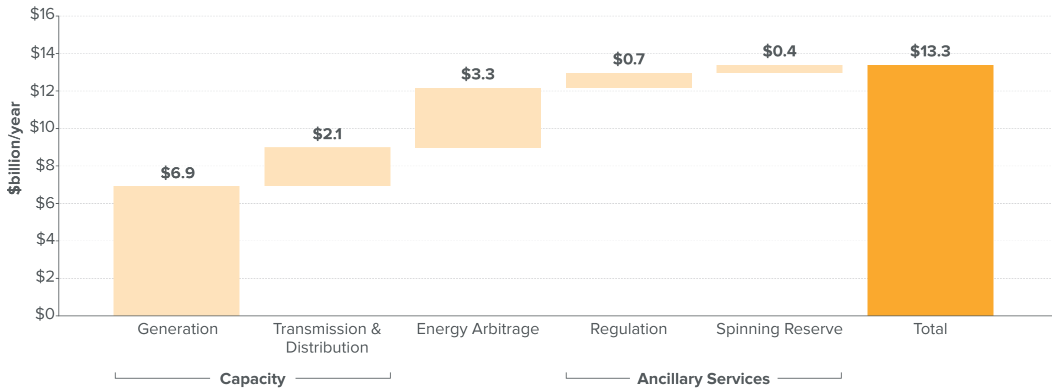

Figure 1.6: Estimated savings from incorporating residential DR in US. Source: [26]

FSs from AEs have the potential of alleviating both TSO and DSO challenges caused by environmental policies. Utilizing the full potential of the residential demand response (DR) in the US will allow to decrease the reinforcement costs in the transmission and distribution networks by 2.1 b$ (Figure 1.6). In Figure 1.7 the potential benefits from incorporating ESS in EU countries are shown. The benefits are created due to the reinforcement deferral, reduction of the power purchase costs and the number of outages. In the majority of the cases, including FSs from ESSs will provide a reduction of required investments at the distribution and transmission levels.

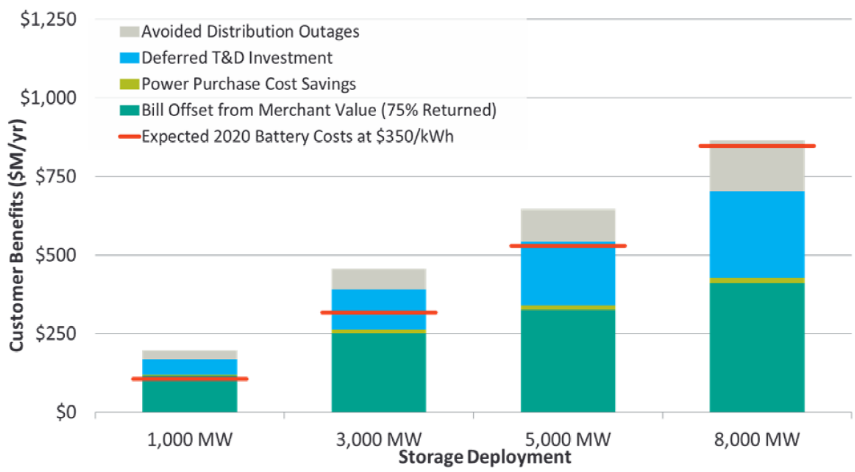

Figure 1.7: Estimated benefits from installing ESS in EU countries. Source: [27]

To achieve the benefits from using FSs DSO should integrate AEs into the planning and operation of its distribution network. It should be noted that in some situations both TSO and DSO would require FSs at the same time. Since the TSO is in charge of maintaining the overall system's stability, its requests are prioritized over DSO's. That is why it is also important for the DSO to enable as many AEs in its distribution network as possible to be able to provide enough FSs.

1.3 Distribution network types

Utilizing FSs from AEs requires certain changes in the way the distribution network is designed and operated. Regardless of what are the actual conditions in the given distribution network, it could be treated as one of the four types presented in Figure 1.8.

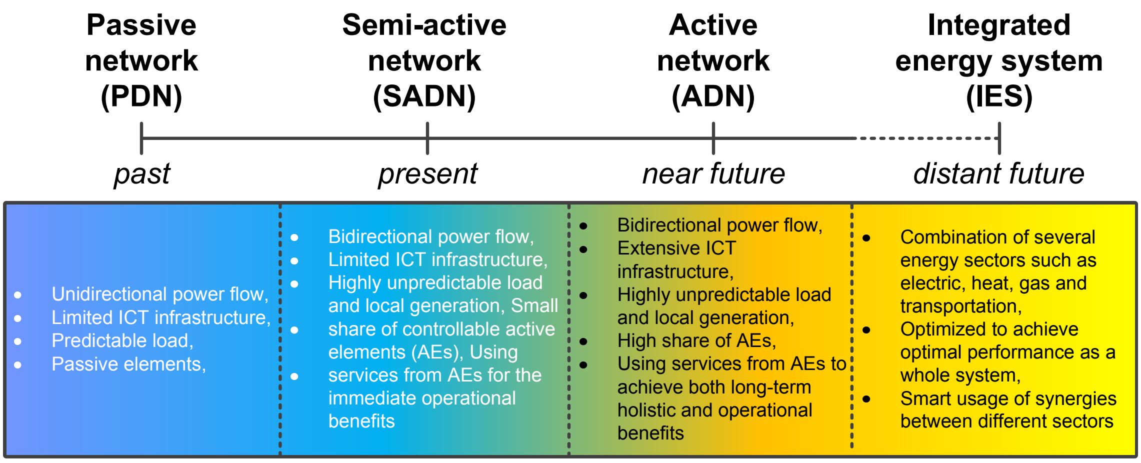

Figure 1.8: Types of distribution networks

The majority of the existing distribution networks are planned and operated as passive distribution networks (PDNs). PDN assumes a unidirectional power flow from the centralized power stations to the consumers. All consumers in PDN are treated as passive components, i.e. their power consumption cannot be changed. PDN is characterized by a lack of ICT infrastructure.

By acknowledging the presence of AEs, DSO could operate the network as semi-active distribution network (SADN). The power flow is considered bidirectional due to the presence of RES-based DGs. The small amounts of FSs are used to achieve short-term operational objectives.

An active distribution network (ADN) [28] is the further development of a distribution network planning and operation. In ADN DSO has large amounts of AEs that could provide FSs. The extensive ICT infrastructure enables a high level of observability and improves the control of AEs. FSs are used to achieve both long-term and short-term planning objectives.

ADN as a part of integrated energy system (IES) is the final type of network planning and operation. IES combines several energy sectors together such as electric, heat, gas, and transportation. The performance of each sector is optimized to help achieve the optimal performance of the whole IES. Synergies between sectors are utilized.

As could be seen the type of network operation and planning is to a large extent determined by the amounts of AEs and how they are utilized by the DSO. ADNs show a direction in which the distribution networks should evolve to be able to help in achieving the sustainability goals. However, since a large number of networks are still operated as PDNs, the thesis will often compare the two network types (PDN and ADN) together.

1.4 Problem definition and research questions

The long-term planning of ADNs is considered in this PhD project, since it is in the ADNs, where the solutions to the challenges caused by the RES and electrification could be found. Including FSs into ADN is expected to bring significant benefits for both customers and DSO. However, it is not yet clear, how such FSs can be integrated into the DSO's planning procedures.

Therefore this PhD thesis is focusing on the problem of the long-term planning of ADNs and more specifically on: **How to incorporate flexibility from AEs into ADN planning?**

The problem is further divided into the following research questions:

[**Q1**] *What are challenges in ADN planning?*

Planning of ADN is faced with many challenges. Distribution planners have to make an accurate forecast of power consumption and generation and integrate the ability to use FSs from AEs into planning solution. The final solution should be in line with all design criteria chosen by the DSO. A comprehensive literature review is required to understand all the planning stages and potential ADN planning issues. The review should also include analysis of PDN planning challenges, since they would also be present in the ADN.

[**Q2**] *How to integrate planning algorithms together in a streamlined planning process of ADN planning?*

Various planning algorithms are proposed as solutions to the planning exercises. However, the majority of the solutions are focusing on individual planning objectives in a specific distribution network under specific conditions. The existing planning practices should be analyzed to propose a streamlined planning process of ADN. Such a planning process will facilitate the integration of different planning algorithms, that are used to solve ADN challenges, into a generic framework, that could be adopted by any DSO based on its needs.

[**Q3**] *How to characterize the cost of using AEs in a generic way?*

There are many types of AEs: consumer devices, ESS, DGs, network components, etc. To ensure adequate comparison of all flexibility options present in the distribution network, each of them should be characterized using the same methodology. Such an assessment will allow DSOs to estimate the costs associated with using flexibility, regardless of what technology each individual AE is based on.

[**Q4**] *How to apply AEs in planning exercises?*

One of the most common solution in handling the issues occurring in the distribution networks is reinforcement. By providing an alternative - utilizing FSs from AEs, the cost of solving the planning exercise could be made lower.

1.5 Thesis outline and contributions

This PhD thesis consists of six chapters: an introduction, four technical chapters, and a conclusion. Five scientific publications are used as a basis for this work (Pub. A to E). They are attached at the end of the thesis and can be read independently from the main text. The description of each chapter with the corresponding scientific contributions is given below.

Chapter 2 describes the state-of-the-art of the distribution network planning. The contribution consists of the comprehensive literature review regarding following topics: PDN and ADN planning challenges; existing framework solutions; the role of AEs in the ADN, planning algorithms using AEs and AEs cost estimation models. Chapter 2 is based on papers [A] and [C].

In Chapter 3, the first part of the proposed methodology for integrating AEs in ADN is described. The proposed generic multi-stage planning framework contributes to the overall knowledge by systematizing and integrating the vast majority of existing planning algorithms in one system, that could easily be adopted by any DSO to suit its planning purposes. The framework can be applied for planning exercises in both PDNs and ADNs. The framework describes all phases of a planning process such as high-level utility strategy, preparation, design, and implementation. By observing the differences in planning between PDN and ADN, a DSO could develop its own strategy of upgrading its network, thus facilitating the transition from PDN to ADN. Chapter 3 is based on papers [A] and [B].

Second part of the methodology for integrating AEs in ADN is presented in chapter 4. This chapter shows the methodology for characterizing all FSs from AEs in a similar manner. The contribution includes the proposed flexibility characterization framework that provides a generic way to estimate the cost of using FSs by calculating their total expenditures (TOTEX) based on a few criteria. It can potentially be applied to any AE providing FSs, such as DGs, ESS, DR, network reconfiguration (RE) and dynamic line rating (DLR). Such a tool could be useful for the DSOs willing to incorporate a high share of FSs in their planning. The content of papers [B] and [C] is included in chapter 4.

Chapter 5 describes three case studies presented as examples of how frameworks developed during this PhD project are applied to the distribution network planning. The contribution of this chapter is a validation of the developed methodologies using the model of an actual distribution network of Nordhavn area in Copenhagen, Denmark. Chapter 5 is based on the materials from papers [A]-[E].

1.6 List of publications

Publications A-E form the core of this thesis:

[**A**] Klyapovskiy, Sergey and You, Shi and Cai, Hanmin and Bindner, Henrik W, "Incorporate flexibility in distribution grid planning through a framework solution" in *International Journal of Electrical Power and Energy Systems (IJEPES) - Elsevier*, 2019.

[**B**] Klyapovskiy, Sergey and You, Shi and Domens, Rafael Calpe and Bindner, Henrik W and Cai, Hanmin, "Utilizing Flexibility Services from a Large Heat Pump to Postpone Grid Reinforcement" in *2018 IEEE Student Conference on Electric Machines and Systems (SCEMS)*, Huzhou, China, December 2018.

[**C**] Klyapovskiy, Sergey and You, Shi and Michiorri, Andrea and Kariniotakis, George and Bindner, Henrik W, "Incorporating flexibility options into distribution grid reinforcement planning: A techno-economic framework approach" in *Applied Energy - Elsevier*, under review.

[**D**] Klyapovskiy, Sergey and You, Shi and Cai, Hanmin and Bindner, Henrik W, "Integrated Planning of a Large-Scale Heat Pump in View of Heat and Power Networks" in *IEEE Transactions on Industry Applications, vol: 55, issue: 1, pages: 5 - 15*, 2018.

[**E**] Klyapovskiy, Sergey and You, Shi and Bindner, Henrik W and Cai, Hanmin, "Optimal Placement of A Heat Pump in An Integrated Power and Heat Energy System" in *Proceedings of 2017 Ninth Annual IEEE Green Technologies (GreenTech) Conference*, Denver, USA, April 2017.

Additionally, number of technical reports were prepared as a result of PhD student's involvement in the EnergyLab Nordhavn project. They were peer reviewed by the technical specialist within EnergyLab Nordhavn consortium:

[**F**] Klyapovskiy, Sergey and You, Shi, "Delivery no.: D6.2.2.1. Report with technical and financial assessment of 5 new add-ons to the existing grid in Nordhavn. Part 1: Demand Response", technical report, EnergyLab Nordhavn, 2018.

[**G**] Klyapovskiy, Sergey and You, Shi, "Delivery no.: D6.2.2.2. Report with technical and financial assessment of 5 new add-ons to the existing grid in Nordhavn. Part 2: Reconfiguration", technical report, EnergyLab Nordhavn, 2018.

[**H**] Klyapovskiy, Sergey and You, Shi, "Delivery no.: D6.2.2.3. Report with technical and financial assessment of 5 new add-ons to the existing grid in Nordhavn. Part 3: Demand Response and Reconfiguration", technical report, EnergyLab Nordhavn, 2018.

[**I**] Klyapovskiy, Sergey and You, Shi, "Delivery no.: D6.2.2.4. Report with technical and financial assessment of 5 new add-ons to the existing grid in Nordhavn. Part 4: Battery", technical report, EnergyLab Nordhavn, 2018.

[**J**] Klyapovskiy, Sergey and You, Shi, "Delivery no.: D6.2.2.5. Report with technical and financial assessment of 5 new add-ons to the existing grid in Nordhavn. Part 5: Transformer with OLTC", technical report, EnergyLab Nordhavn, 2019.

The following publications have been prepared during this PhD study, but have not been included in the thesis since they are not directly related to the primary objective.

Peer reviewed journals:

[**K**] Cai, Hanmin and You, Shi and Wang, Jiawei and Bindner, Henrik W and Klyapovskiy, Sergey, "Technical assessment of electric heat boosters in low-temperature district heating based on combined heat and power analysis" in *Energy - Elsevier, vol: 150, pages: 938-49*, 2018.

Peer reviewed conference publications:

[**L**] Cai, Hanmin and You, Shi and Bindner, Henrik W and Klyapovskiy, Sergey, "Load situation awareness design for integration in multi-energy system" in *Proceedings of IEEE International Conference on Energy Internet, 2017, IEEE*, Beijing, China, April 2017.

[**M**] Cai, Hanmin and You, Shi and Bindner, Henrik W and Klyapovskiy, Sergey and Yang, Xiaochen and Li, Rongling, "Optimal scheduling for electric heat booster under day-ahead electricity and heat pricing" in *Proceedings of the Universities Power Engineering Conference (UPEC), 2017 52nd International, 2017, IEEE*, Heraklion, Crete, Greece, August 2017.

CHAPTER 2

State-of-the-art

To be able to incorporate the FSs from AEs in ADN planning, it is important to understand how the general process of planning is done and how the presence of AEs influences the distribution network operation. The state-of-the-art provided in this chapter is based on the comprehensive literature review covering the following topics: types of planning exercises, challenges in PDN and ADN planning and the roles of AEs in distribution networks.

2.1 Planning exercises

DSOs are in charge of distribution network planning since they have to ensure that their networks can sustain current and future power demand. Planning is performed by executing planning exercises and is divided into two parts: the long-term planning represented by the network design (ND) and short-term planning - operational strategy (OS). The result of the exercises is the planning solution that describes what new components should be installed (ND part) and how to operate them (OS). The installation or reinforcement of the transformers and cables and placement of the circuit breakers (CBs) and sectionalizing switches for network re-routing are among the most common actions DSOs could do during a planning exercise [29, 30].

Based on how flexible are the DSO planners in selecting different ND and OS options, there are three types of planning exercises:

1. *Greenfield planning* - a planning exercise used for the new areas with no existing electrical infrastructure. The input for the exercises is typically the locations of the load centres, that have to be supplied with electric power [31]. Greenfield planning exercises allow the distribution network planners to be very flexible with regards to topology and layout of the future distribution network (ND) and its operation (OS), however, such exercises are not common tasks in most of the developed areas;

2. *Network expansion planning* - an exercise initiated to expand the existing distribution network to a new area [32, 33]. The new area may already have some electric infrastructure in place. The proposed solutions would be based on historic information from similar areas and the area in question. Distribution planners are somewhat limited in the ND and OS options since the compatibility with the existing network has to be ensured;

3. *Network reinforcement planning* - a planning exercise, that aims at the upgrade and replacement of the existing distribution network components (e.g. transformers, cables, CBs) [34, 35]. The exercise is performed, when a DSO experiences or predicts an issue in its network like power congestion or equipment malfunction. The exercise is using the information obtained directly from the network in question. Reinforcement planning is the exercise that imposes the most limitations on ND and OS.

The planning objectives determine which type of planning exercise should be initiated. The exercises define the type of data, that can be collected and impose limitations on the potential solutions.

Table 2.1: Overview of the challenges in the distribution network planning

PDN	ADN
Forecast of passive demand	Forecast of DGs and new consumer equipment complicated due to: 1. intermittent nature of DGs; 2. cyclic operation of new equipment; 3. operation in the market environment.
Compliance with technical and economic criteria	Compliance with technical and economic criteria considering DSO's ability to influence demand
Scale of the problem	Integration of the new emerging technologies (microgrids, virtual power plant, etc.)
	All of the PDN challenges

2.2 Planning challenges

There are numerous challenges that are faced by the DSO planners, while performing ADN planning exercises. The planners should propose a planning solution that will be adequate in the presence of high uncertainty of power demand. ADN planning could be seen as an evolution of the PDN and thus it is necessary to address the question of PDN planning challenges as well as ADN. Table 2.1 provides the overview of the PDN and ADN planning challenges. By understanding the issues related to the forecast, design criteria and new emerging technologies, the optimal way of integrating FSs from AEs could be determined.

2.2.1 PDN planning challenges

PDNs planning is used for networks with unidirectional power flows and passive consumers. In order to dimension distribution network components, such as transformers, cables or protection devices the power demand from the consumers has to be forecasted [36]. In PDN planning, the forecasts are used to determine the maximum peak load, which refers to the "worst case" scenario. For example, in Denmark, the "worst case" scenario is Christmas night, when a large number of consumers simultaneously use power. Since the demand is stochastic in nature and DSO does not possess all the information about various consumer devices, accurate forecasting of the electricity demand represents a challenge. Methods such as spatial load forecasting, road-frontage and load distribution functions are suggested in [37–41] to tackle this problem and provide load forecast of sufficient quality. Different approaches often should be applied to the urban and rural areas.

Once the potential power demand is known, the planners have to find a suitable planning solution that would comply with the technical (such as voltage, current and reliability) and economic criteria set by the grid codes and DSO itself [42–44]. Often multiple solutions fitting the DSO criteria exist. Which of them will be selected depends on the parameters that DSO has decided to prioritize. Finding an optimal planning solution using fuzzy logic algorithms with single or multiple objectives or multi-stage stochastic models are proposed in [45–47]. Detailed descriptions of the different algorithms could be found in [48–50].

Distribution networks are complex systems with dozens of secondary substations (nodes). The high degree of interconnections in the distribution networks creates a challenge for the planners, since it is often very difficult to isolate the considered part of the network and disregard the rest of the system. The need to include additional nodes expands the scale of the problem and makes it harder to find an optimal solution. Many optimization algorithms, which work well with small networks, are unable to deliver accurate results, when the size of the problem scales up. [51–53] give examples of how traditional algorithms and models could be modified to enable them to handle large-scale planning exercises.

The attempt to build a system that satisfies the "worst-case" scenario planning algorithm, especially in the case of contingency (like N-1), could lead to overdimensioning of the distribution network. The "worst-case" PDN planning does not require an elaborate OS, which leads to the application of "fit and forget" algorithm [54]. The drawback of using such algorithm is a significant increase in CAPEX used for network reinforcement.

2.2.2 ADN planning challenges

ADN planning is applied to the networks with bidirectional power flow and a certain number of AEs. As in PDN planning, ADN planning includes a set of planning algorithms with the main goal of providing all customers with the electric power of sufficient quality and security of demand. Since ADN planning could be seen as the next step of PDN, all the challenges of PDN planning are also relevant here. The additional challenges come from the active demand, electricity markets and the presence of the new emerging technologies.

Similar to PDN, power demand forecasting plays an important role in ADN planning. Introduction of DG units, ESS and new consumer equipment, as well as the presence of the electricity markets, lead to increased uncertainty about the power demand in ADNs. Since many DG units are based on the intermittent RES, such as wind and solar, the accurate long-term estimation of DGs power output is problematic [55, 56]. Excessive power generation could lead to the voltage and congestion problems in the distribution network. Electric heaters, HPs and EVs are the new types of consumer devices that have irregular operational patterns (i.e. on/off cycles that do not tied to any specific time, but rather to external signals). When the devices are on, they can draw large amounts of power, thus contributing to the creation of the short-term peaks [57, 58], if enough of them are operational at the same time. Spatial forecasting algorithms capable of predicting DGs production are proposed in [59, 60]. The accuracy of the long-term forecasts could be improved by implementing regression models [61–63] and neural networks [64, 65]. [66–68] provide detailed information about methods for forecasting in ADN.

Due to the unbundling rules adopted in most of the countries [69], DSO cannot own any generation or ESS [70, 71]. This leads to the situations, where most of the AEs are owned and controlled by the entities independent from the DSO. By pursuing their own economic interests in the market environment, these entities will have a significant impact on the power demand in the distribution network, therefore essentially becoming stakeholders of the ADN. To be able to accurately forecast the power demand, DSO has to enable the information exchange between all the stakeholders and learn to predict their behaviour. This is further elaborated in subsection 2.3.1.

Since some AEs are already present in the distribution network, DSO should consider how it can utilize the FSs from AEs to influence the forecasted power demand and how it will affect the final solution of the planning exercise. The selected solution should comply with the technical and economic criteria similar to the solution for PDN planning. Genetic and heuristic evolutionary algorithms are proposed in [72–75] that could help the distribution planners to obtain an optimal solution in the presence of AEs. More details about the algorithms for ADN planning are given in [76, 77]. In order to solve the problems in the ADN, DSO can determine the most suitable locations for AEs and either installs them by itself (in case of network components - cables, switches, transformers) or encourages the independent entities to do it (for DGs, ESS, HPs, etc.). Genetic algorithms that consider optimal DGs' locations are proposed in [78, 79], [80, 81] discuss the application of particle swarm optimization (PSO) and chance-constrained optimization for determining the best locations for ESS.

Another challenge in the ADN planning is connected to the new emerging technologies such as virtual power plant, Vehicle to Grid (V2G) and microgrids. DSO has to consider their effect on the distribution network and how to integrate these technologies in the planning solution [82–86].

Due to the new elements added in the ADN planning in comparison to the PDN, the scale of the planning exercises could potentially get extremely large resulting in the even more complicated process of finding the most optimal solution.

If the DSO applies the PDN planning algorithms to the network with large numbers of RES-DGs and AEs such as HPs and EVs, it could lead to an overdimensioning of the network's components and increased CAPEX [87]. By incorporating planning approaches from the ADN planning, DSO could take advantage of the AEs in its network by providing FSs to control the generation/demand [88]. Contracting and controlling AEs will increase the operational expenditures (OPEX), but since the network does not have to be dimensioned based on the "worst case" scenario, the planning solution will have lower CAPEX. Higher degree of interconnection between ND and OS is required to integrate AEs into planning. The attempt to utilize AEs without changing the way distribution network is planned and operated could lead to such negative consequences as load kickback effect [89], voltage deviations [90] and even equipment failure.

2.2.3 Framework solutions

A lot of planning algorithms were proposed to help the distribution planners to achieve their planning objectives in both PDN and ADN planning. To be able to deliver a streamlined holistic planning process, algorithms addressing different challenges have to be combined with each other using a framework. Such a framework will facilitate the process of selecting the most optimal solution to the planning exercise among different alternatives. The existing framework solutions proposed for PDN and ADN planning are described below.

The framework for replacing assets based on the likelihood of negative events is proposed in [91]. In [92] a PDN framework for identification of the planning alternatives with network calculations and cost evaluation of each option is described. [93] proposes a framework that combines ND (sitting and sizing) and OS for the optimal energy production. The bi-level framework, where the first stage makes the decisions regarding equipment upgrades and reinforcement, while the time of implementing them is determined in stage two is shown in [94]. Frameworks in [95–97] describe the methodologies for implementing DGs in the distribution network. [98, 99] propose frameworks on how to integrate emerging technologies such as microgrids and virtual power plants into ADN, while [92] gives the methodology of how both ND and OS solutions could be used to get the final planning solution in ADN. Probabilistic system planning frameworks are given in [100, 101]. Finally, the framework that attempts to integrate generation, transmission and distribution with AEs in a regional smart grid is proposed in [102].

Existing DSOs are using diverse planning procedures, that are based on their own experience and are tailored to fit specific networks. The majority of the existing frameworks seem to focus only on the limited number of planning objectives and are suitable for the distribution networks under specific conditions. Therefore, such frameworks are often not able to provide a generic picture of how different planning stages are connected with each other and how various planning elements should be integrated.

2.3 Active elements in distribution networks

Utilizing the potential of AEs in ADN is found to be one of the main solution for addressing the challenges covered in the section 2.2. More detailed overview of the role AEs in ADN is given in this section.

The FSs from AEs could be requested by both DSO and the TSO. Due to that, AEs could be considered as stakeholders in the ADN that have an impact on the network operation. Therefore the potential interactions between AEs and other entities in ADN have to be analyzed. Another important aspect of AEs is how their FSs could be used by the DSO to solve the distribution network problems. Finally, to be able to integrate the AEs in planning, the DSO should have an understanding of what are the factors, that affect the cost of using AEs.

2.3.1 Active elements and other stakeholders in ADN

As was mentioned earlier, due to the unbundling rules, DSOs are not allowed to own any generation and storage. While in PDN it was possible to operate the network with minimum attention to the external stakeholders, integrating AEs to transform the network into ADN means involvement of the new parties in the distribution planning. It is therefore important for the DSOs to analyze each of the new participants and determine what are their motivation, goals and concerns regarding participation in providing FSs [103, 104]. Performing such analysis helps to get insights into how to build mutually beneficial collaboration. The potential stakeholders in ADN planning and their potential interactions which each other are shown in Figure 2.1.

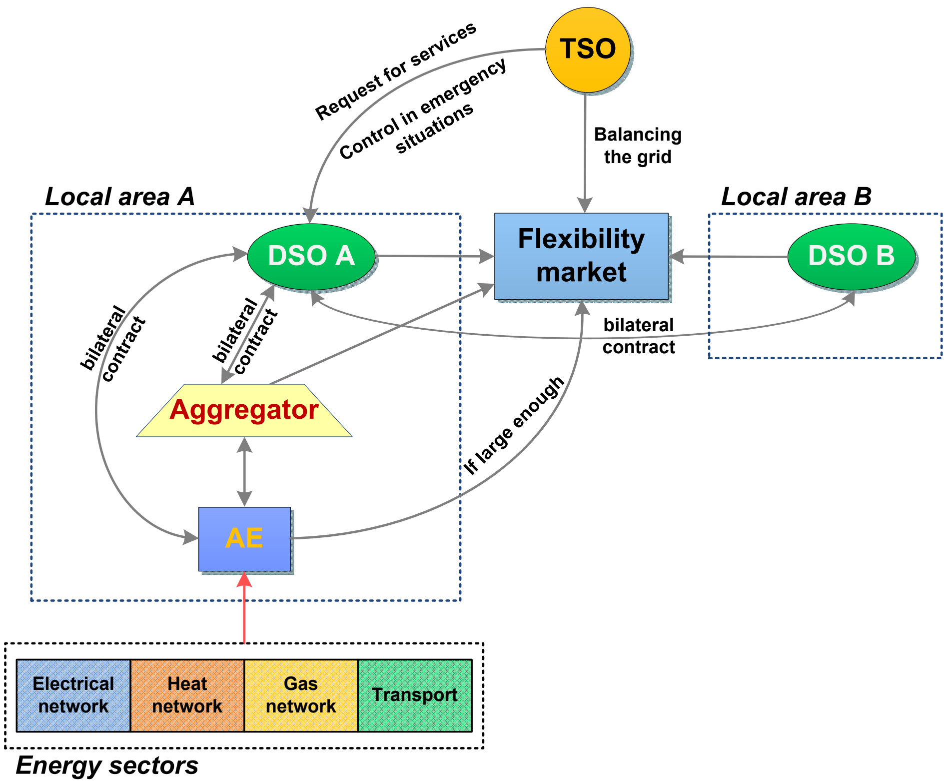

Figure 2.1: Interactions of the AEs with the other stakeholders in the power system

Independent AEs

Independent AEs are entities that do not belong to the DSO and can adjust their generation/consumption by either increasing or decreasing it. Independent AEs include various forms of consumer equipment, ESS and DGs.

In Denmark, most of the DGs are represented by the wind turbines that are connected to voltage levels of 60, 10-20 and 0.4 kV [105]. Another type of DGs connected to the distribution network that is widely spread in Denmark is combined heat and power (CHP) units that generate heat in addition to electricity.

Customers can use their equipment to participate in the DR programs, that have drawn a lot of attention in recent years as mentioned in [106]. While big industrial enterprises and commercial buildings are already participating in such DR schemes for a long time, DR programmes for residential customers appeared only in the recent years. It is expected that more residential customers will participate in DR in the future. Another type of independent AE is ESS used for storing any form of energy until its further extraction at the most suitable moment in time.

Through independent AEs, DSO interacts with different energy sectors: electrical network (traditional DR, battery energy storage system (BESS)), electrical/heat network (HPs), electrical/transport (EVs), heat and gas networks (storage tanks) [107]. Some of the AEs such as gas and heat storages and large-scale HPs are usually the assets of the gas or heating network operators. Such organizations may be interested in a different form of compensation for their services, not only financial.

From Figure 2.1 it could be seen, that independent AEs will be able to interact with the DSO in three ways: by providing their FSs through the flexibility market, via an aggregator [108] or by having bilateral agreements with the DSO. Bilateral agreements give more certainty to AEs owners and guarantee a certain profit, which, however, may not be as high as by offering FSs through the flexibility market. In most cases, DSO will only be interested in making bilateral agreements with large to medium scale AEs. Using the aggregator [109] can simplify the process of making profits for the AEs owners at the expense of the share paid to the aggregator. This can be a viable solution if AEs' capacity is small and they cannot provide their FSs through the flexibility market or bilateral agreements.

Aggregator

An aggregator is an entity that is taking the role of aggregating individual independent AEs into one portfolio and offering it to the DSO [108, 110]. The advantage for the DSO is that it only needs to work with one large company, which simplifies negotiations. The way of achieving flexibility should be determined by the aggregator depending on its portfolio. To improve its confidence in the ability to provide requested FSs and increase the number of provided services, aggregators have to attract different sources of flexibility with different characteristics (such as ramp rate, the maximum duration of service, active time, etc.).

Similar to the independent AEs, aggregators can either make a direct bilateral agreement with the DSO or use the flexibility market.

Flexibility market

In a deregulated electricity system, flexibility market will become a common place for trading different FSs. Since no such market yet exists, direct contracts or aggregators could be used until the new improved market designs will be implemented [111, 112].

Other DSOs

Most of the distribution network problems are of local nature and can only be solved with the resources in a specific area. However, the borders of operation areas between two DSOs can serve as a platform for collaboration. In such cases, one DSO can "rent out" some FSs that is contracted by it to the other DSOs [113, 114].

TSO

In most of the countries, TSO is in charge of maintaining the stability of the whole electric power system. That is why the requests from the TSO have priority over the DSO. In the future, competition between local DSOs and the TSO for the AEs can be expected [115, 116]. This situation will require better communication between involved parties and may provide a motivation for the DSO to enable as many AEs in its network as possible.

2.3.2 Application of the active elements in planning

Since utilizing the potential of AEs is identified as one of the key features of future ADN planning, it is important to know what benefits can be obtained by using them. The overview of the research done in the field of using AEs in the ADN context is provided here.

AEs are able to provide FSs, such as DR from customers, energy management from ESS and RE through switches and CBs. Though a lot of research has been done considering the effects of AEs in the distribution networks, most of it is focusing on their optimal control and their operational benefits. However, since in the ADN the long-term and operational planning are deeply interconnected, the improvement in the network day-to-day operation can be taken into account in the long-term planning as well, by relaxing some of the design criteria. Research papers investigating different planning algorithms with AEs are shown in Table 2.2. All the papers are grouped based on the planning stage and planning objectives they are covering:

1. Planning stage: the effects of AEs in the distribution networks can be studied from the positions of long-term planning (determined by ND), short-term planning (determined by OS) or both;
2. Planning objective:
    a) Reinforcement deferral: an application of peak reduction/load shifting techniques to postpone network reinforcement by using planning algorithms with DR, ESS or RE;
    b) Voltage profile improvement;
    c) Reliability improvement: the improvement of the system reliability due to the AEs can be assessed by two main sets of reliability indices [117]: customer-based (SAIDI, SAIFI) or load-based (energy not supplied (ENS), curtailment index);
    d) Power loss reduction;
    e) Energy cost reduction: the reduction of cost that the DSO has to pay to purchase the required energy from the upstream system;
    f) Coordination with DGs: since using AEs is a way to handle the uncertainty from the RES, an operation of AEs and DGs can be coordinated.

Table 2.2: Reviewed papers

Planning algorithm	Planning stage		Planning objective					
	Network design (ND)	Operational strategy (OS)	Reinforcement deferral	Voltage profile improvement	Reliability improvement	Power loss reduction	Energy cost reduction	Coordination with DGs
With DR	[118–121], [122–124]	[125–129], [130, 131]	[118, 119], [125–128], [122, 129], [123, 124, 131]	[120, 121], [124, 131]	[120, 128]	[120, 121], [129, 130]		[119, 127], [122]
With ESS	[118, 132, 133], [134–136]	[128, 137], [138, 139], [140]	[118, 128, 137], [134–136]	[132, 135, 137], [139, 140]	[128, 138]	[132, 136, 139]	[133, 135], [136]	[132, 133], [139, 140]
With RE	[117, 141], [124, 142]	[143–145], [146]	[124, 141]	[124, 142, 146]	[117, 144]	[117, 141–144], [146]	[143, 145], [142]	[117, 145]

DR

DR - is the FS provided by the customers (industrial, commercial or residential), when their demand is changed in response to the external signal. The signal can be sent due to different reasons, typically it is a direct signal from the DSO, but it could also be a signal in response to the change in price, system frequency or voltage.

A framework for estimating the effects of using DR both ex-ante and ex-post and evaluating the performance of provided services is given in [147]. [148] proposes the methodology for evaluating the potential trade-offs between the capital and social costs (such as carbon emissions and a number of interruptions), when using FSs from the DR in the distribution network.

The multi-stage distribution expansion model considering DR and ESS and taking into account the risks and uncertainty of the consumption and generation is proposed in [118]. The risk in the model is handled in a probabilistic manner with the purpose of finding the least-cost optimal planning solution. [119] considers integration of long-term ND and OS using both DG units and DR in order to reduce the total cost and CO_2 emissions. DR is modelled considering load recovery with the fading effect. Using DR to adjust the power demand and make it more close to the output of DGs was found to be a suitable combination to decrease fossil fuel consumption. [120, 121] propose the models for the optimal sitting and sizing of the charging stations for the hybrid EVs combined with DR programs that can be used to support the network via V2G. This allows to improve the voltage profile, increase reliability and reduce losses in the system.

[125] gives the overview of the different DR programs (critical peak pricing, variable peak pricing, fixed-period pricing, variable period pricing and multiple-group pricing) and proposes the optimal schedule algorithm for triggering different groups of customers with DR, when the cost of supplying the energy for the DSO becomes very high. [126] discusses the use of DR with real-time pricing of different elasticity to allow larger amounts of RES and better balancing of the generation with demand in the presence of uncertainties, which can lead to network expansion deferral. The algorithm for coordination between DGs and DR programs to deal with congestion issues is presented in [127]. Such coordination can be beneficial for the DSOs by providing network reinforcement deferral, although method requires the presence of the measurement and controlling infrastructure. Optimal management of participation in DR programs of a customer with DG unit and BESS is considered in [128]. In the first stage of optimization, the decisions regarding installation of equipment and participating in DR are made by maximizing the benefits, while the second stage provides the optimal dispatch of the resources chosen in stage 1 focusing on cost benefits, reliability and level of discomfort. The proposed model of such customers can be used by the DSO or an aggregator to understand how to better configure their DR programs. [129] proposes demand side management system for coordination between DGs, FSs from DR programmes and the amount of power that is bought from an upstream system with the purpose of minimizing the losses and cost for the DSO.

ESS

Many types of ESS exist today such as BESS, flywheels, compressed air, pumped hydro, etc. In this section, only articles related to BESS are considered. The main characteristic of BESS is the ability to store energy at a certain point in time and release it later, providing support to the network. The size of the BESS varies from small household units of few kWh to large industrial ones with the capacity of several MWh.

[149] provides the framework for estimating the benefits of using BESS in the distribution network. The proposed methodology identifies the savings from the energy costs and costs of reinforcement deferral and compares them with the investment and operational costs of ESS.

The model for identifying the optimal placement and sizing of the BESS is given in [132]. First, the optimal location is found according to the highest effect on power losses. The second stage is then used to determine the optimal size of the BESS to minimize both losses and improve the voltage profile in the presence of DG. [133] suggests the framework for considering the uncertainties regarding outputs of the loads and DGs based on the RES, while using BESS to maximize distribution network owner's profits. The model introduces an additional parameter - conditional value at risk, which is used to assess the trade-offs between profits and risks in installing BESS of different capacity.

[137] describes the potential application of the BESS for peak load shaving, power curve smoothing and improvement of the voltage profile. The optimization algorithm determines the amount of active power required from the BESS, with the possibility to inject reactive power to raise the power factor. Another application for using BESS - improving the system's reliability in terms of reducing outages and restoration times is considered in [138].

RE

RE is the process of changing the system topology and is done by opening/closing CBs and sectionalizing switches and using tie-lines.

The model for the coordinated distribution planning and RE is presented in [141]. By doing such coordination both deferral of network reinforcement and power loss reduction could be achieved, since the network becomes more flexible to different load situations. The optimal size and sitting of DG units, network losses and reliability can be greatly influenced by RE as shown in [117]. The cost of ENS is used to assess the effect different system topologies have on reliability. [142] presents the idea of "sensitive" switches, that are participating in the RE processes the most. Only these switches should be upgraded to the automatic smart switches. By utilizing them on an hourly, daily, weekly or monthly basis substantial energy savings can be achieved. The use of the return of investment was proposed to assess the best frequency of RE.

[143] describes how the RE can be used to achieve loss minimization and energy savings in both normal and post-fault events. The model for finding the optimal switching pattern for RE is presented in [144]. By optimizing the switching operations, the overall reliability of the network can be improved together with the power loss reduction. [145] shows a model for using RE together with DR, diesel and wind-based DGs to reduce the cost of energy for the DSO. The PSO method is used to provide an optimal schedule for the day-ahead considering prices for DG production and DR services. When the energy price from the upstream system is lower, diesel DGs are turned off, serving as a reserve in case of subnormal situations.

Overview of the ADN projects

There are numerous projects both in Europe [150, 151] and the US [152] working on using FSs from AEs to improve distribution network behavior. As opposed to the majority of the previous years' projects, that were focusing mostly on the operation and control of the single or groups of AEs, new projects are started using a more holistic approach and move towards the multi-domain IES.

"Energy Lab Nordhavn" [153] is a project in Copenhagen, Denmark. It aims at developing and demonstrating future energy solutions using Nordhavn area as a living lab. Among other things the project investigates the planning and operation of ADN with the DR from HPs, EVs and residential customers in a combined electrical and heat system and has a large BESS used for the peak shaving. The focus of the Nordhavn project is on the integration between three energy sectors together (electrical, heating and transportation). "RepliCable and InnovaTive Future Efficient Districts and cities" [154] is another project that deals with the planning and operation of the future cities. With the goal to facilitate the increase of the RES-based DGs and reduce energy demand, it works with individual buildings, electrical, heating and cooling networks and using AEs for the network management. Similarly "Resource Efficient cities implementing ADvanced smart citY solutions" [155] is considering the whole energy system with electrical, heating and transportation sectors. By using DR FSs from both commercial and residential customers, ESS and solar DGs, the project's goal is to reduce the energy demand and CO_2 emissions. Projects with similar approaches and objectives can be found in [156–158].

"Sustainable FERC project" [159] is a US federal project with the goal of formulating policies to introduce more RES-based DGs into the energy system, prepare new market regulations to support clean energy and phase-out carbon power plants. One distinctive feature, that is not typical for European projects is the focus on making energy system resilient towards extreme weather conditions. "LADWP Smart Grid Regional Demonstration Program" [160] uses DR from the different customer categories to reduce energy demand, CO_2 emission and improve grid resilience. In addition, the operation of microgrids is studied. "Smart Future Greater Philadelphia" project [161] is another big project regarding smart grids that supports the deployment of the measuring infrastructure to enable the utilization of the FSs from AEs and network automation. Like many other American projects, reliability and reduction of the restoration time after extreme weather conditions are among the project's focus areas.

2.3.3 Cost estimation of the flexibility from active elements

To be able to integrate different AEs in planning and compare them with conventional solutions, DSO has to find a way to estimate the cost of using AEs. This subsection will describe how the cost of using DR, BESS, RE and DLR is considered in the scientific literature.

The economic theory behind DR cost estimation based on the supply-demand curve done by the aggregator is presented in [162]. In [163] the variation of the amount of provided DR due to the price signal change is discussed through the use of self and cross-elasticity coefficients. Solving stochastic mix-integer optimization with conditional value at risk is proposed in [164] in order for the aggregator to minimize the cost of acquiring DR FSs. The bid price for the DR including the comfort level is discussed in [165]. [166–168] describe DR cost estimation models based on the average price, fixed incentives and dynamic pricing.

Levelized cost of storage model for BESS is described in [169]. The model takes into account CAPEX and OPEX from using the storage and includes the cost of recharge cycles. The analysis of the BESS CAPEX, that includes the costs of the storage unit, power conversion system and inefficiency factor (i.e. not all energy could be extracted from the unit) is given in [170]. [171] presents the BESS model for identifying its OPEX consisting of electrical and degradation parts. Electrical part determines the state of charge (SoC), while the reduction of the lifetime (LT) is calculated in the degradation part. Other models of the BESS utilization cost could be found in [172–174].

The cost of RE determined through the cost of switch motion is described in [175]. The model including operation time in addition to the number of activations for the switch in RE is presented in [176]. Similar models for estimating RE cost for achieving different planning objectives could be found in [177, 178].

DLR is a FS obtained from the cables or overhead lines (AEs owned by the DSO). It allows to determine the actual maximum carrying capacity (MCC) of the lines, which is in most cases higher than the fixed values specified in the data sheets. By applying DLR to the cables, a large amount of power could be transmitted through, thus potentially eliminating the congestions. The benefits of implementing DLR is described in [179]. The cost of implementing the DLR is estimated based on the cost of sensors, required to get the correct temperature measurements and the amounts of extra energy that can go through the cable. [180] presents the DLR cost model for the two scenarios: when only the real-time DLR measurements are available and when the forecast of DLR capabilities is added to the real-time values.

Methodologies presented in the majority of the scientific articles about AEs' cost estimation could only be applied to a specific case and specific technology. There is a need for the generic flexibility framework capable of characterizing different AEs using the same criteria to help the DSO in ADN planning.

CHAPTER 3

Planning framework

Existing framework solutions reviewed in the subsection 2.2.3 do not provide a sufficiently generic methodology, that could be adopted by any DSO to any network configuration. This chapter proposes a multi-stage framework that streamlines the planning process and serves as a foundation for the development of various planning procedures. The proposed framework shows how different planning algorithms could be integrated with each other and includes all planning stages from initial data collection to final roll-out plan. The framework could be applied to any type of distribution network shown in Figure 1.8, including PDN and ADN.

The proposed multi-stage planning framework is presented in Figure 3.1 and includes four main blocks: a separate "utility's strategy" block and three planning phases: preparation, design, and implementation. In the "utility's strategy" block the high-level strategy of the DSO regarding the distribution network in question is defined. After DSO decided upon the main characteristics of its network, starts the *preparation phase*. It consists of "data collection" and "forecasting" stages, which are needed to evaluate the potential power demand/generation in the area within the planning horizon. Preparation phase has two inputs: key features of the network and general strategy - from "utility's strategy" block and an objective (by specifying the task) for a planning exercise from the design phase. *Design phase* is a phase, where the planning solution fitting certain DSO criteria is identified. Stages "ND", "OS", "Verification" and "Selection" are included into the design phase. Design phase takes inputs from the "utility's strategy" block and preparation and implementation phases. Arrows inside the design phase in Figure 3.1 indicate interactions between "ND" and "OS" through a "Verification" stage, that are necessary to ensure that the produced solution is viable and will not lead to undesirable effects. Finally, *Implementation phase* takes inputs from "utility's strategy" block and design phase and provides a plan for the physical implementation of the selected planning solution determined in the design phase.

The detailed explanation of all stages and elements (planning algorithms) included in them is given below.

3.1 Utility's strategy

"Utility's strategy" block is the cornerstone of the proposed framework, since the decisions made here will affect all the planning phases. The block contains the high-level characteristics of the distribution network's planning and operation defined by the DSO. The proposed general strategy could be used to create guidelines and define necessary changes to transform the existing PDN into ADN.

In this block DSO decides the network operation: it can either be operated as passive (PDN) with no or very limited use of FSs from AEs, active (ADN), where the use of AEs is integrated into both long-term and operational planning levels or as a part of IES. In the latter, the planning and operation of the electric distribution network have to be coordinated with the other energy sectors.

The selection of planning criteria is another important aspect decided in the "utility's strategy" block. What criteria DSO is going to use for determining the optimal planning solution in the ND stage depends on the various factors, such as ownership of the DSO (e.g. private or public entity) and competition.

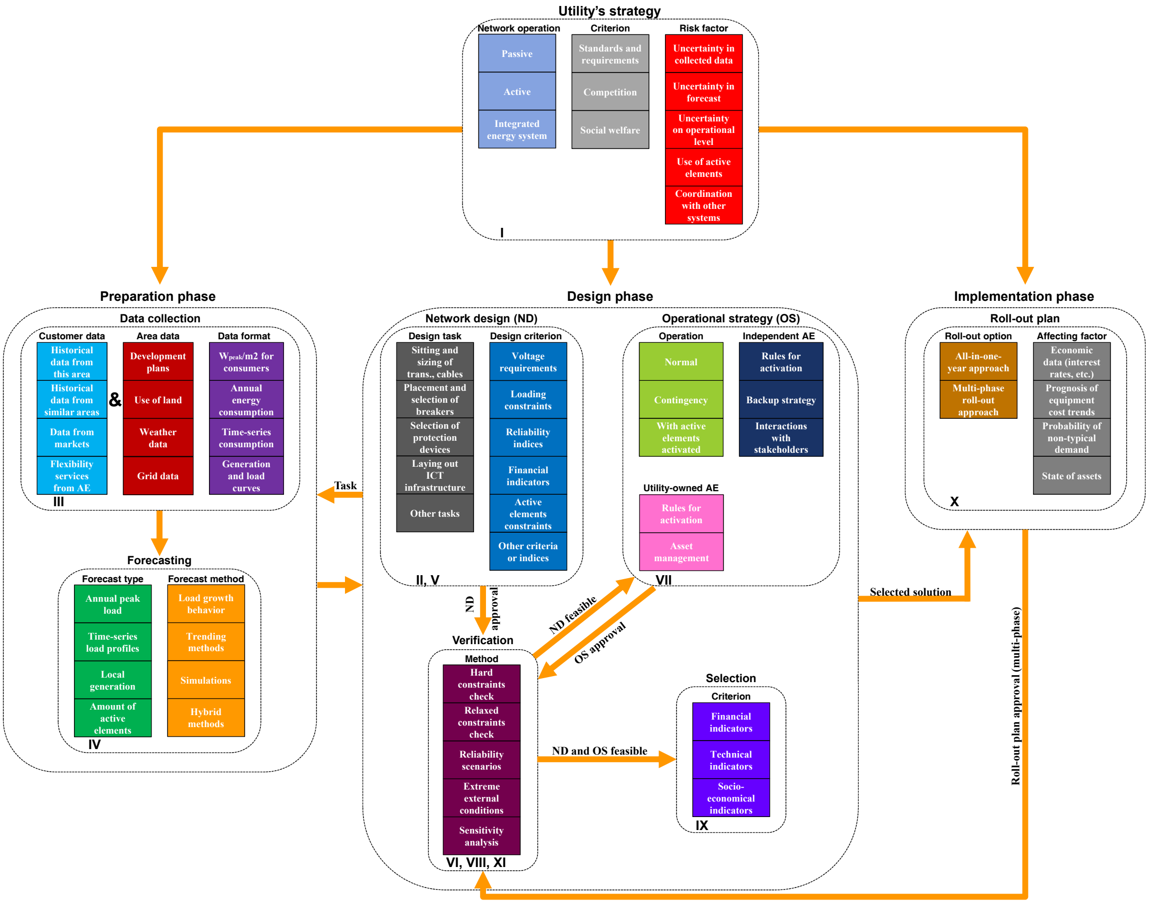

Figure 3.1: Proposed planning framework. Roman numbers indicate the order of the stages

Criteria could be selected using three algorithms. By using "standards and requirements" algorithm, the DSO is focusing on satisfying the required minimum of the technical criteria, such as voltage and reliability indices. Algorithm "competition" assumes that the DSO is competing for the customers connected to its distribution network. With the introduction of DG units and ESS, some of the customers will be able to go "off the grid" [181], i.e. they will generate enough power for their own needs without the use of DSO. In such a case, the natural monopoly of the DSO will be questioned and it has to be able to offer their customers higher quality of services, than the ones defined by the grid codes. Utilities in the "competition" mode, can, for instance, be interested in implementing a number of environmentally-friendly solutions and increase the share of RES power generation in their networks. In addition to that, competition can also exist between different DSOs as a result of benchmarking introduced in some countries. Benchmarking will compare the DSOs of different areas and penalize the ones showing the worst performance [182, 183], thus encouraging them to improve the quality of their services.. "Social welfare" planning algorithm can be selected by the publicly-owned DSOs, where they focus on maximizing the socio-economic benefits obtained from their networks [184].

Risk factors presented in the "utility's strategy" block are uncertainties associated with various aspects of ND and OS [185]. Uncertainty in the collected data reflects the DSO's awareness of the technical state and characteristics of its metering infrastructure. The knowledge of the DSO's customers is also included in this uncertainty. How confident the utility is in its long-term forecasting capabilities is expressed by uncertainty in the forecast, while uncertainty on operational level shows the confidence in day-to-day load prediction accuracy. If the distribution network was chosen to be operated as active or as a part of IES, uncertainties related to the use of AEs and coordination with other sectors have to be taken into consideration.

Uncertainties are the natural part of the planning process. However, some measures could be taken in order to lower them or reduce their effects on planning. How much uncertainty DSO is willing to accept is reflected in its attitude towards risk. Risk-averse behaviour [186] indicates that the DSO will try to eliminate all of the uncertainties at the design phase using the "ND" stage ("worst case" scenario), even though it may increase required CAPEX. This is typically done in the PDN planning. DSO that is willing to take some risks, on the other hand, can select planning solutions with the lower CAPEX, if it develops an OS that will show how to handle the abnormal situations, the distribution network is not made for. This could be a case in ADN planning.

3.2 Data collection

The preparation phase begins with the "data collection" stage. At this stage distribution planners are tasked with gathering information about what types of customers and AEs are present in the network, what is their power demand or capacity of the FSs that they can offer (e.g. information could be obtained from the electricity markets and weather data). Information about the general development of the area - whether it is fully developed or some major constructions could be expected in the future is also collected here. If the area is already supplied with electric power, which is a case with the network expansion and network reinforcement planning exercises, more or less detailed and accurate customer data could be already in the possession of the DSO. In contrast to that, greenfield planning exercises would have to be based only on the historical data from similar, already developed areas.

The data format of the gathered information is chosen based on the decisions made in "utility's strategy" block. For a new area developed under the greenfield project, approximate power demand in the form of W_{peak} per m^2 could be used. The annual energy consumption readings and load curves will provide the basis for the forecasting at the next stage for the "worst case" scenario algorithm [187] in PDN planning. If the DSO implemented smart meters in its distribution network, it can prefer to collect time-series power consumption [188], which will give a more accurate representation of the power demand and is essential for the integration of FSs from AEs in the ADN.

3.3 Forecasting

All previously collected data is sent to the "forecasting" stage. Distribution networks are traditionally designed to have sufficient capacity during the planning horizon of 15-20 years [189]. Forecasting is an essential part of making the network's capacity adequate to the power demand. Several things have to be taken into the considerations during forecasting: how the demand will change (increase, decrease or stay the same), how many DGs (mostly PV panels and wind turbines) will be present in the network in the future years and what amounts of AEs would be available for the DSO [190, 191]. If the DSO decided to use the FSs from AEs, the forecast of the time-series power demand will be required.

There are a great number of methods developed for forecasting power demand. The most common are load growth behaviour forecast, trending methods, simulations and hybrid methods (a combination of the previous two) [192–194]. Simulations usually provide the best results and can show how different factors will affect the power demand forecast, although making the simulations on a large network could be cumbersome. Uncertainty during forecasting is usually addressed by making multiple forecast scenarios.

3.4 Network design

"ND" is the first stage of the design phase and it is here, where the objective of the planning exercise is identified. Ensuring that the network has enough capacity, making the network resilient towards faults and improving the network's observability could be named as the most common planning objectives for the DSO. Connection requests from the large power consumers or DG units (e.g. HPs or wind turbines) is another example of planning objectives, since introducing a large load/generator without proper analysis can create disturbances in the network [195, 196]. Planning objectives are typically achieved by performing certain tasks such as placing and sizing transformers, cables, protection devices, and CBs, and laying out the ICT infrastructure. [29].

Distribution planners need to produce a planning solution that will comply with the number of technical and socio-economic design criteria. The technical criteria such as voltage, current (loading) and reliability have to be satisfied by the network at all times [36, 197]. Maximum loading represents the MCC of the network components and is traditionally treated as a fixed value. By introducing more sensors and measuring devices into the distribution network, DSO could move from the fixed values of the MCC to the dynamic ones (e.g. DLR described in the previous chapter). Dynamic MCC will depend on the physical state of the component and its surroundings (e.g. air, soil, etc.) [180]. Dynamic MCC will provide the DSO with additional sources of FSs, that will be explained in the next chapter.

Such criteria as losses, the maximum share of RES-based DGs that the network can accommodate, and the level of equipment utilization [198] are not mentioned in the regulations or grid codes, but could be chosen as design criteria by the DSO using "competition" or "social welfare" algorithms. In some cases, conflicting design criteria can be selected for finding the planning solution, like introducing a high share of RES-based DGs, while having a stable voltage at all times. In such situations, the trade-off between different design criteria should be made. If DSO wants to use AEs, the constraints for using them should also be considered at this stage. Finally, the financial indicators are used to ensure that the proposed planning solution is economically viable.

3.5 Verification

The purpose of the "verification" stage is to ensure that the proposed planning solution complies with all selected design criteria and constraints. This is done by performing the simulations and checking how the network, built in accordance to the proposed solution, behaves under contingency situations (e.g. faults, N-1 [199]) and extreme external conditions (e.g. storms, floods, hurricanes [200]). Sensitivity analysis used at this stage will allow planners to see how variations in different parameters affect the overall results and how to make the planning solution more robust.

The planning solution should go through the "verification" stage three times. The first round is after the "ND" stage, where the initial solution is formulated. The second round - after the corresponding OS is defined at the "OS" stage, in case if no appropriate OS could be proposed, the ND solution is deemed infeasible and have to be changed. The third round of verification will be initiated if the final solution has to be split into construction phases occurring at different times.

Planning solution consists of two parts: ND and OS. In PDN planning all the design criteria have to be satisfied by ND part alone, therefore, all the requirements and constraints applied to the ND part at the first round are hard - should be satisfied at all times. If the DSO chooses to utilize the potential of FSs - a case of ADN planning, the constraints applied to the ND part of the solution in the first round could be relaxed, which makes this part of the planning solution cheaper. The constraints that are not satisfied by the ND part alone, should now be satisfied by ND and OS parts together, when the solution passes the "verification" stage the second time.

3.6 Operational strategy

The strategy for operating network components and AEs is defined in the OS stage. As was mentioned in the previous section, PDN planning assumes that the ND part of the planning solution alone should be capable of handling the majority of the loading situations. The process of designing OS in PDN is, therefore, simplified. The integration of AEs into network planning in order to relax the criteria applied to the ND part of the planning solution will require a more sophisticated approach for defining OS. The role of OS is greatly increased in ADN planning.

The purpose of OS is to specify how all the involved elements will be used under the normal conditions, contingency situations (N-1, faults and equipment failures [201]) and when the AEs are activated (if active network operation was selected in the "utility's strategy" block). Simulations of the distribution network's behaviour with activated AEs should be done in order to ensure that no disturbances for the loads in the system are created, while trying to comply with selected design criteria.

If the DSO decided to rely on using FSs, then OS should define the rules for activation of AEs in different network conditions. The OS for activating AEs will depend on whether they are utility-owned (cables in case of DLR, CBs in RE, etc.) or independent (ESS, equipment providing DR, etc.). While utility-owned AEs could be controlled directly and the DSO could be certain in their availability, independent AEs should be contracted beforehand as described in subsection 2.3.1 and might require some advanced warning before activation.

To ensure that utility-owned AEs are available, their physical conditions (wear and tear) should be carefully observed and maintained through the asset management [202]. Availability and responsiveness of the independent AEs will always contain some uncertainty, therefore a backup strategy for the case when not enough FSs are available should be made to reduce the risks. Owners of AEs used in the planning solution will become stakeholders in the distribution network, which will require an information exchange between all of the involved entities and the DSO.

If ND part of the planning solution does not satisfy all the design criteria alone, the feasibility of the proposed OS should be checked during the second round of "verification". This ensures that the ND and OS combined are in line with all the requirements.

3.7 Selection

"Selection" is the final stage of the design phase and is used to identify the optimal planning solution. In many cases, more than one planning solution satisfying design criteria could be identified. The best option should be selected based on the financial, technical and socio-economic indicators [203]. Each DSO will have its own preferences concerning which of the three sets of criteria should be prioritized. The most important indicators should be defined based on the decisions in the "utility's strategy" block.

3.8 Roll-out plan

The implementation phase includes "roll-out plan" stage. This stage is used to decide how the selected planning solution should be executed. Roll-out could be done in two ways: "all-in-one-year" algorithm assumes that all the required installations are done simultaneously (i.e. the same year). In the "multi-phase" algorithm, the installations will be split into construction phases. This is done in order to reduce the uncertainty in the forecast and because of financial constraints. To make sure that the network will satisfy the design criteria at each construction phase, the multi-phase roll-out plan is sent through the "verification" stage. After each phase of the implementation, the evaluation of the forecasted and actual power demand is done and the planning solution is adjusted if necessary.

An "all-in-one-year" planning algorithm is suitable for planning solutions with a small number of installations and high confidence in the forecast. If a large number of installations are expected, the "multi-phase" algorithm is preferable.

CHAPTER 4

Flexibility characterization framework

The framework presented in chapter 3 shows the way AEs could be integrated into ADN planning. Whether the DSO is going to utilize the FSs they can provide, however, will depend on the economic viability of the proposed planning solutions with AEs. There are many different AEs capable of providing FSs in the distribution network. To be able to make an economic analysis and choose the most cost-efficient AEs, DSO has to compare them using the same set of criteria. The cost estimation should be based on the methodology that will allow to assess the cost of any AE regardless of its distinctive features. As was stated in subsection 2.3.3, the majority of existing cost models only focuses on specific AEs under the specific conditions and cannot be applied to a wide variety of AEs' types.

This chapter describes the flexibility characterization framework, that provides a generic way of comparing different AEs through their cost estimation. The framework could be applied to any AE regardless of its technology and allows to quantify the cost based on the TOTEX from using AE's FSs.

Value of Flexibility (VoF) is the maximum cost of acquiring FSs that assist the DSO in solving a specific issue in the distribution network. By comparing VoF and AE's TOTEX from flexibility characterization framework, the optimal planning solution could be found.

Power congestions and under- and overvoltages are among the most common issues found at the distribution level, as mentioned in [204–208]. Since components in the distribution network can sustain short-term overloading, most DSOs will more likely experience the congestion events (CEs) only in contingency situations such as N-1. Therefore power congestion during N-1 is considered while presenting the methodology for identifying VoF. N-1 contingency is caused by the failure of one of the networks components, where the rest of them have to take an additional electric load to compensate for the failure.

4.1 Value of flexibility

Two types of planning: PDN and ADN were described in chapter 2. PDN planning relies on conventional solutions such as reinforcement of the network's components, while ADN planning allows to use FSs to solve the network's problems.

VoF is an indicator showing how important FSs from AEs are for the DSO and how much it is ready to pay for obtaining them. If the cost of using any particular AE exceeds VoF, contracting this AE will not be an economically viable solution. To identify VoF, PDN planning alternatives should be considered. In order to resolve CEs that are expected to occur based on the forecasts, DSO can reinforce components, whose MCCs will be exceeded. An alternative is to curtail the loads, when the CEs occur. DSO will be penalized in case of the load curtailment by paying the cost of the ENS. If the DSO decides to curtail the loads, it can use the investments from the postponed reinforcement to obtain economic benefits (e.g. interest by putting them in the bank). Therefore, DSO is willing to contract the FSs from AEs, if their cost does not exceed the minimum cost of the two PDN planning alternatives. Based on this, the VoF can be calculated as follows:

$$VoF_{y,P\%} = min\begin{cases} C_{PDN,TOTEX,y,P\%}, \\ C_{ENS} * E_{flex,y,P\%} - B_{y,P\%}, \end{cases} \tag{4.1}$$

where $VoF_{y,P\%}$ - VoF at the year y in the $P\%$ percentile, [€]; $C_{PDN,TOTEX,y,P\%}$ - TOTEX of a PDN planning solution, [€]; C_{ENS} - cost per unit of ENS, [€/kVAh]; $E_{flex,y,P\%}$ - total requested energy from the FSs at the year y in ADN planning, [kVAh]; $B_{y,P\%}$ - benefits of postponing the reinforcement, [€].

VoF in Eq. 4.1 depends on the amount of energy required from the AEs in the ADN planning. Typically multiple forecast scenarios are made to predict potential power demand. A probabilistic approach is used in this chapter to estimate the required amounts of FSs. By using percentile $P\%$, the value which is higher than or equal to the values in the sample with $P\%$ probability is obtained.

The cost of ENS in the first years when the potential problem is expected to occur, is typically lower than the cost of making network upgrades. Thus VoF will be equal to the expression ($C_{ENS} * E_{flex,y,P\%} - B_{y,P\%}$). VoF will be influenced by the decisions made in the previous years. The longer DSO postpones the reinforcement, the higher VoF becomes.

The inputs for Eq. 4.1 are the information about TOTEX of the PDN solution and the amounts of energy $E_{flex,y,P\%}$ required from the AEs in the ADN planning. The description of how these parameters are obtained in PDN and ADN planning is presented below.

4.1.1 PDN planning

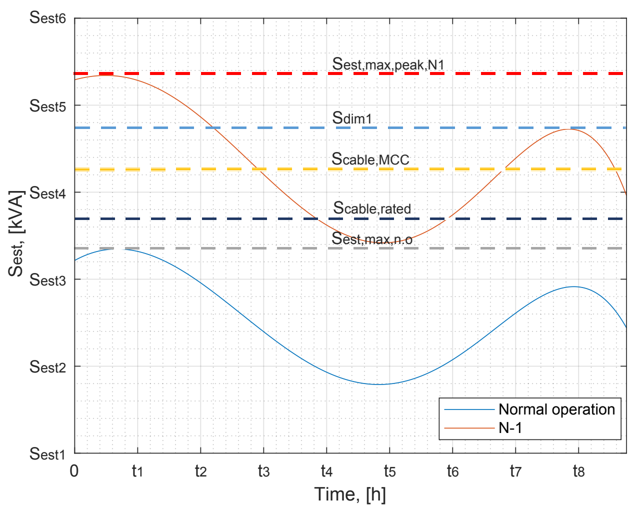

Figure 4.1: Estimated worst case power demand at year y for scenario SC according to the PDN planning to solve power congestion on a part of a feeder

To show how the cost of PDN planning $C_{PDN,TOTEX,y,P\%}$ for calculating VoF is obtained, the case of forecasted power congestion in N-1 is considered in Figure 4.1. At the "forecasting" stage, the yearly forecasts for each year y until the end of the planning horizon pl were produced. Multiple forecast scenarios are made to ensure that the variations of different parameters (e.g. general load growth trend, outside temperature, etc.) are properly taken into consideration. CEs are predicted in some of the forecasted scenarios SC, when the MCCs of some parts of the feeders (in individual cables) are exceeded by the power demand in N-1 contingency with the estimated peak:

$$S_{est,max,peak,N1,SC} = \max_{1 \leq y \leq pl} S_{est,max,N1,y,SC}, \tag{4.2}$$

where $S_{est,max,peak,N1,SC}$ - maximum peak value of a part of a feeder (single cable) during N-1 contingency during the whole planning horizon for scenario SC, [kVA]; pl - planning horizon, [year]; SC - scenario, [-]; $S_{est,max,N1,y,SC}$ - estimated peak power demand of a part of a feeder (single cable) during N-1 contingency at the year y for scenario SC, [kVA].

According to the PDN planning, the planning solution is to upgrade (reinforce) the cable to increase its MCC. The new cable should be chosen based on the dimensioning criteria S_{dim1}:

$$S_{dim1} \geq \frac{1}{L} * S_{est,max,peak,N1,P\%}, \tag{4.3}$$

where S_{dim1} - dimensioning criteria for a component in a PDN planning, [kVA]; L - short-term overloading coefficient, [-]; $S_{est,max,peak,N1,P\%}$ - the maximum peak value during N-1 contingency during the whole planning horizon among all the scenarios [209] in the $P\%$ percentile, [kVA].

L is the overloading coefficient that establishes the relationship between the component's MCC and its rated power. Parameter L is either specified in the component's technical documentation or defined by the DSO based on its practical experience with such components. The value of L depends on the overload duration, typically the shorter the overloading, the higher the parameter L is. For the planning purposes, the value of parameter L in Eq. 4.3 is chosen for the case of the longest possible overloading (i.e. component can be overloaded for hours during CE).

The cost of planning solution in both PDN and ADN planning is defined as TOTEX, which has two parts: CAPEX and OPEX:

$$C_{TOTEX,P\%} = C_{CAPEX,total,P\%} + C_{OPEX,total,P\%}, \tag{4.4}$$

where $C_{TOTEX,P\%}$ - TOTEX of either PDN or ADN planning solution in the $P\%$ percentile [€]; $C_{CAPEX,total,P\%}$ - total CAPEX part of the solution, [€]; $C_{OPEX,total,P\%}$ - total OPEX part of the solution, [€].

To obtain $C_{CAPEX,total,P\%}$ and $C_{OPEX,total,P\%}$, first the $C_{CAPEX,total,SC}$ and $C_{OPEX,total,SC}$ for each of the forecasted scenarios should be calculated. Both CAPEX and OPEX can occur at different years. To calculate the total cost, net present value (NPV) formula [210] is used to refer them to the current year:

$$C_{total,SC} = \sum_{y=0}^{pl} \frac{C_{y,SC}}{(1+r)^y}, \tag{4.5}$$

where $C_{total,SC}$ - total cost of either CAPEX or OPEX part of the solution for the scenario SC, [€]; $C_{y,SC}$ - CAPEX or OPEX of a solution for year y, [€]; - r - the discount rate, [-].

$C_{PDN,CAPEX,y,SC}$ in the PDN planning consists of the cost for components and their installation according to Eq. 4.6:

$$C_{PDN,CAPEX,y,SC} = f(S_{dim1}) = \\ = \sum_{n=1}^{N}(C_{comp,n,y,SC} + I_{comp,n,y} + A_{comp,n,y,SC}), \quad (4.6)$$

where $C_{PDN,CAPEX,y,SC}$ - CAPEX of the PDN solution at the year y according to the scenario SC, [€]; N - total number of components, [-]; $C_{comp,n,y,SC}$ - cost of an nth individual component, [€]; $I_{comp,n,SC}$ - installation cost of an individual component n, [€]; $A_{comp,n,SC}$ - additional expenses caused by the nth component (substation expansion in case of new transformer, construction of the new ICT network, etc.), [€].

Expenses that are proportional to the amounts of hours the components are operational are defined as OPEX. OPEX in PDN planning is calculated as follows:

$$C_{PDN,OPEX,y,SC} = f(S_{est,y,SC}, h_{operation,n,y,SC}) = \\ = \sum_{n=1}^{N} C_{M\&L,n,y,SC}, \quad (4.7)$$

where $C_{PDN,OPEX,y,SC}$ - OPEX in PDN planning at the year y for the scenario SC, [€]; $S_{est,y,SC}$ - estimated worst case power demand for specific operation mode (e.g. normal operation, N-1, etc.), [kVA]; $h_{operation,y,SC}$ - number of hours component n is in operation, [h]; $C_{M\&L,k,y,SC}$ - cost of the maintenance of an nth component and electrical losses caused by it, [€].

4.1.2 ADN planning

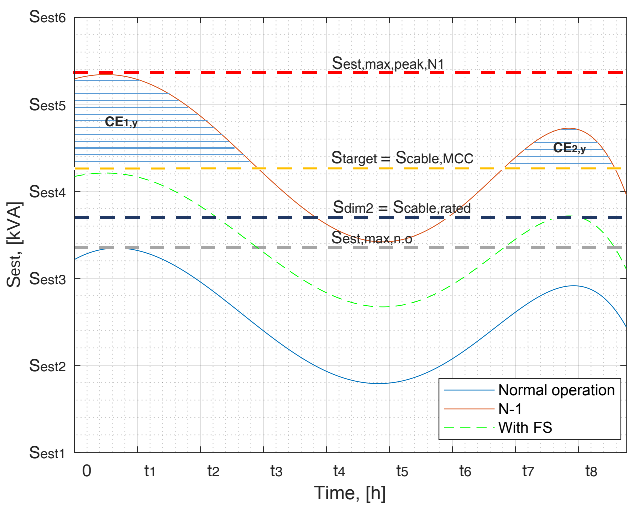

Figure 4.2: Estimated worst case power demand at year y for scenario SC according to the ADN planning to solve power congestion on a part of a feeder. CE - congestion event

ADN planning using AEs is an alternative to the PDN planning. By using FSs from AEs to influence the power demand the CEs could be avoided as shown in Figure 4.2. The congested component in ADN planning should be dimensioned using S_{dim2}:

$$S_{dim2} \geq \frac{1}{L} * S_{target}, \tag{4.8}$$

where S_{dim2} - dimensioning criteria for a component in ADN planning, [kVA]; S_{target} - target value of peak power maintained throughout the planning horizon, [kVA].

FSs should cover all the power demand that exceeds S_{target}. In case of multiple AEs providing FSs, the S_{target} should be split between them, so that:

$$S_{target} = \min_{1 \leq k \leq K_{SC}} S_{target,k,SC} \tag{4.9}$$

where K_{SC} - total number of AEs used for providing FSs in scenario SC, [-]; $S_{target,k,SC}$ - target value of peak power for the kth AE in scenario SC, [kVA].

By selecting $S_{target} = S_{cable,MCC}$, the dimensioning criteria S_{dim2} will be equal to cable's rated power $S_{cable,rated}$. Thus no reinforcement will be needed.

In ADN planning, potential CEs - shaded areas in Figure 4.2 should be analyzed and quantified. The following parameters have to be estimated in order to use the flexibility characterization framework to calculate the cost of using AEs and obtain the VoF: the duration of using FSs during each CE $D_{flex,i,y,SC}$, capacity $S_{flex,i,y,SC}$ and energy $E_{flex,i,y,SC}$ requested from FSs for each CE i and total number of times $NO_{flex,y,SC}$ FSs should be activated during year y. The description of how these parameters are used to obtain the AEs' TOTEX is given in the next section.

4.2 Flexibility characterization framework

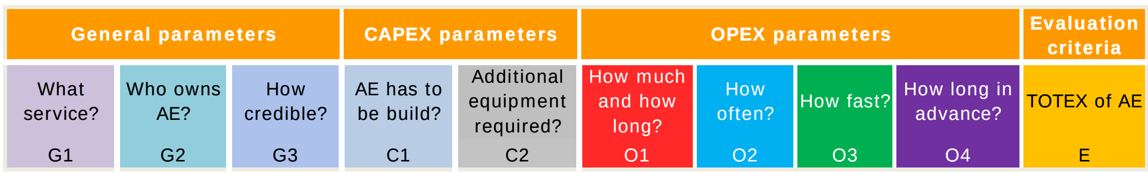

Figure 4.3: Flexibility characterization framework

Proposed flexibility characterization framework is presented in Figure 4.3. It allows the DSO to perform cost estimation of any AE by determining its general, CAPEX and OPEX parameters. The evaluation is done by assessing TOTEX of each AE.

4.2.1 General parameters

Questions in the "General parameters" section serve as the pre-qualification stage. Based on the answers DSO can identify the most suitable AEs based on the following:

What service? ($G1$)

AEs could provide different FSs with different effects on the network. Some of them might impact the power consumption, while the others have an influence on the voltage. If the FS from a particular AE could be used to solve a required distribution network issue parameter $G1 = 1$, otherwise $G1 = 0$;

Who owns AE? ($G2$)

AE's ownership is determined by the parameter $G2$. As was mentioned before in chapters 2 and 3, AE could be utility-owned - belong to the DSO, or independent - owned by a company, another utility or an aggregator. The amounts of available information, required CAPEX and OPEX for using the AE, the degree to which the DSO can rely on AE's performance, the notification period for its activation and the control strategies are influenced by the AE's ownership. Parameter $G2 = 1$ if AE is utility-owned and 0 if AE is independent;

How credible? ($G3$)

When sending the activation request to the AE, DSO is not guaranteed to receive the requested FSs. The degree to which the DSO can be confident, that AE will provide its FSs represents the credibility of that AE and is evaluated by the parameter $G3$. If DSO decides that AE is credible enough to provide FSs, parameter $G3 = 1$, if not - $G3 = 0$.

The following considerations should be used, when assessing credibility of any AE:

1. Historical records - the history of previous activation requests showing the ratio between the amounts of requested and received FSs provided by this AE;
2. AE's ownership type - as described above;
3. State of AE - how much resource does this AE has (estimation of the asset condition);
4. Penalty for not fulfilling activation request - the size of the penalty determines how important to the AE's owner to respond to the activation request.

4.2.2 CAPEX parameters

The CAPEX part of AE's cost $C_{ADN,CAPEX,y,SC}$ in the ADN planning is determined by the questions in "CAPEX parameters":

AE has to be built? ($C1$)

If AE has to be constructed in order to receive its FSs, parameter $C1 = 1$. If no construction is required $C1 = 0$. If the AE is utility-owned, this cost is added to the CAPEX, otherwise the costs should be carried out by the independent entities;

Additional equipment required? ($C2$)

In some cases an installation of an additional equipment is required to be able to receive FSs from a particular AE. It could be an ICT infrastructure for enabling DR, soil humidity sensors for DLR or transformer substation expansion in the case of transformer with on-load tap changer (OLTC). Parameter $C2 = 1$ if there is a need for additional equipment and 0 otherwise.

4.2.3 OPEX parameters

"OPEX parameters" determine the OPEX part $C_{ADN,OPEX,y,SC}$ of AE's cost estimation. It is proposed here to use cost functions to estimate OPEX. Each of the cost functions answer to one of the questions below:

How much and how long? ($O1$)

Cost function $F_{O1}(S_{flex,k,i,y,mean,SC}, D_{flex,k,i,y,SC})$ determines the cost of the requested energy from the kth AE during ith CE in year y for scenario SC, where $S_{flex,k,i,y,mean,SC}$ - mean capacity requested from the kth AE, [kVA]; $D_{flex,k,i,y,SC}$ - duration of using kth AE, [h].

How often? ($O2$)

Cost function $F_{O2}(NO_{flex,k,y,SC})$ determines the cost of the total number of AE's activations, where $NO_{flex,k,y,SC}$ - total number of times FSs from the kth AE are used during the year y for scenario SC, [-];

How fast? ($O3$)

The cost of AE's ramping up and down capabilities is defined by cost function $F_{O3}(ROC_{flex,k,i,y,SC})$, where $ROC_{flex,k,i,y,SC}$ - rate-of-change of requested capacity from kth AE during ith CE at year y for scenario SC, [kVA/h];

How long in advance? ($O4$)

Cost function $O4$ determines the cost of activation request for different notification periods: $F_{O4}(NP_{flex,k,i,y,SC})$, where $NP_{flex,k,i,y,SC}$ - notification period for requesting FSs from kth AE during ith CE at year y for scenario SC, [h].

4.2.4 Evaluation criteria

Different evaluation criteria could be used by the DSO to compare AEs and other planning alternatives with each other. The selection of the evaluation criteria was discussed in chapter 3 and is dependent on the planning objectives and DSO's high-level goals.

TOTEX of AE (E)

The TOTEX $C_{ADN,TOPEX,y,SC}$ from using AEs is selected as an evaluation criterion in the current framework.

4.2.5 Cost of using flexibility services from active elements

Based on the flexibility characterization framework shown in Figure 4.3, the CAPEX of the ADN planning solution $C_{ADN,CAPEX,y,SC}$ can be calculated as follows:

$$C_{ADN,CAPEX,y,SC} = \sum_{\substack{k=1,\\ G1_k,G3_k\neq 0}}^{K_{SC}} C_{ADN,CAPEX,k,y,SC} = \sum_{\substack{k=1,\\ G1_k,G3_k\neq 0}}^{K_{SC}} (G2_k * C1_k * C_{AE,k,y,SC} + C2_k * A_{AE,k,y,SC}), \tag{4.10}$$

where $C_{ADN,CAPEX,k,y,SC}$ - CAPEX of using kth AE in year y in scenario SC, [€]; $G1_k$, $G2_k$ and $G3_k$ - general parameters from the framework, [-]; $C1_k$ and $C2_k$ - CAPEX parameters, [-]; $C_{AE,k,y,SC}$ - cost of construction of the kth AE, is a function of the chosen $S_{target,k,SC}$, [€]; $A_{AE,k,y,SC}$ - cost of an additional equipment, [€].

$C_{ADN,CAPEX,P\%}$ is obtained from the values of $C_{ADN,CAPEX,y,SC}$ for all planning scenarios and years and the $P\%$ percentile (Eq. 4.5).

Eq. 4.12 shows the OPEX part of the solution $C_{ADN,OPEX,y,SC}$ at the year y in scenario SC as the combination of the cost functions and framework parameters. OPEX includes the costs for all involved AEs.

$$
\begin{aligned}
&C_{ADN,OPEX,y,SC} = \sum_{k=1}^{K_{SC}} C_{ADN,OPEX,k,y,SC} = \\
&= \sum_{k=1}^{K_{SC}} f(G1_k, G2_k, G3_k, C(F_{O1_{k,y}})_{SC}, \\
&C(F_{O2_{k,y}})_{SC}, C(F_{O3_{k,y}})_{SC}, C(F_{O4_{k,y}})_{SC}),
\end{aligned}
\tag{4.11}
$$

where $C(F_{O1_{k,y}})_{SC}$, $C(F_{O2_{k,y}})_{SC}$, $C(F_{O3_{k,y}})_{SC}$ and $C(F_{O4_{k,y}})_{SC}$ - OPEX from using kth AE at the year y in scenario SC, determined by the cost functions, [€].

To represent the relations between cost functions and framework parameters shown in Eq. 4.12, the following expression is used in this thesis:

$$
\begin{aligned}
&C_{ADN,OPEX,y,SC} = \sum_{\substack{k=1,\\ G1_k,G3_k \neq 0}}^{K_{SC}} C_{ADN,OPEX,y,SC} = \\
&= \sum_{\substack{k=1,\\ G1_k,G3_k \neq 0}}^{K_{SC}} [C(F_{O1_{k,y}})_{SC} + C(F_{O2_{k,y}})_{SC} + \\
&+ C(F_{O3_{k,y}})_{SC} + C(F_{O4_{k,y}})_{SC} + C_{add,k,y,SC} + \\
&+ G2_k * C_{M\&L,k,y,SC}],
\end{aligned}
\tag{4.12}
$$

where $C_{add,k,y,SC}$ - additional cost due to the unique features of the kth AE at the year y in scenario SC, [€].

Similar to the CAPEX of using AEs in ADN planning, $C_{ADN,OPEX,P\%}$ is obtained from Eq. 4.4-4.5.

The generic methodology presented here aids the DSOs in making a comparison between different AEs and in understanding what are the costs that should be included in the cost estimation of FSs they provide. The framework serves as a decision tool for the DSOs willing to integrate AEs in their planning procedures.

CHAPTER 5
Validation of the proposed methodologies

This chapter describes how the proposed methodologies from chapters 3 and 4 are validated through case studies using a real distribution network of Nordhavn. A description of the 10 kV Nordhavn distribution network model and its operation is given in section 5.1. The case study 1 in section 5.2 shows the application of the planning framework to design ADN and PDN planning procedures. An example of IES planning - electric and heat utility working together to install a large HP is described in case study 2 in section 5.3. Section 5.4 presents a case study 3, that describes how the costs of AEs are estimated using flexibility characterization framework.

5.1 Nordhavn distribution network

10 kV distribution network of Nordhavn area in Copenhagen, Denmark is shown in Figure 5.1. The network is used in the scientific articles and technical reports prepared during this PhD project. Different parts of Nordhavn network topology are used in the case studies presented further.

Nordhavn network has a radial structure with 10 feeders that start at the main substation (MS) 8. Every two feeders are organized in loops that are connected with each other via tie-lines and CBs 1-5. During normal operation, these CBs are open, so that the feeders of each loop are operated separately. By closing loop's CB during the failure at one of the feeders in that loop, the other can take its electrical load, thus reducing the number and duration of interruptions of power supply. The cables in the feeders could be overloaded up to 117% of their rated power.

Each coloured rectangular in Figure 5.1 depicts the 10/0.4 kV secondary substation that can have one, two or three transformers with a typical capacity of up to 1000 kVA. All transformers are operated separately. Residential, commercial and light industrial customers are connected to the 0.4 kV side of the secondary substations.

MS 8 connects the 10 kV Nordhavn network with the upstream 30 kV system. MS has four 16 MVA power transformers with OLTC. To ensure that even the remote customers have sufficient voltage, the voltage setpoints at the transformers are set to 1.04 pu to account for the potential voltage drop. Three of the power transformers are constantly in operation with one transformer being in reserve.

Matlab and Matpower software package [211] are used to make a model of Nordhavn distribution network presented in Figure 5.2. Both 10 and 0.4 kV voltage levels are modelled as PQ buses. Transformers are represented as branches due to the limitations of the Matpower package. MS 8 designated as a slack bus, for which both voltage magnitude and voltage angle are known (set to 1.04 pu and 0 deg, respectively). To perform power flow calculations, values for active and reactive power should be specified for all the PQ buses (with exception of the slack bus). To obtain these values the time-series power demand is synthesized

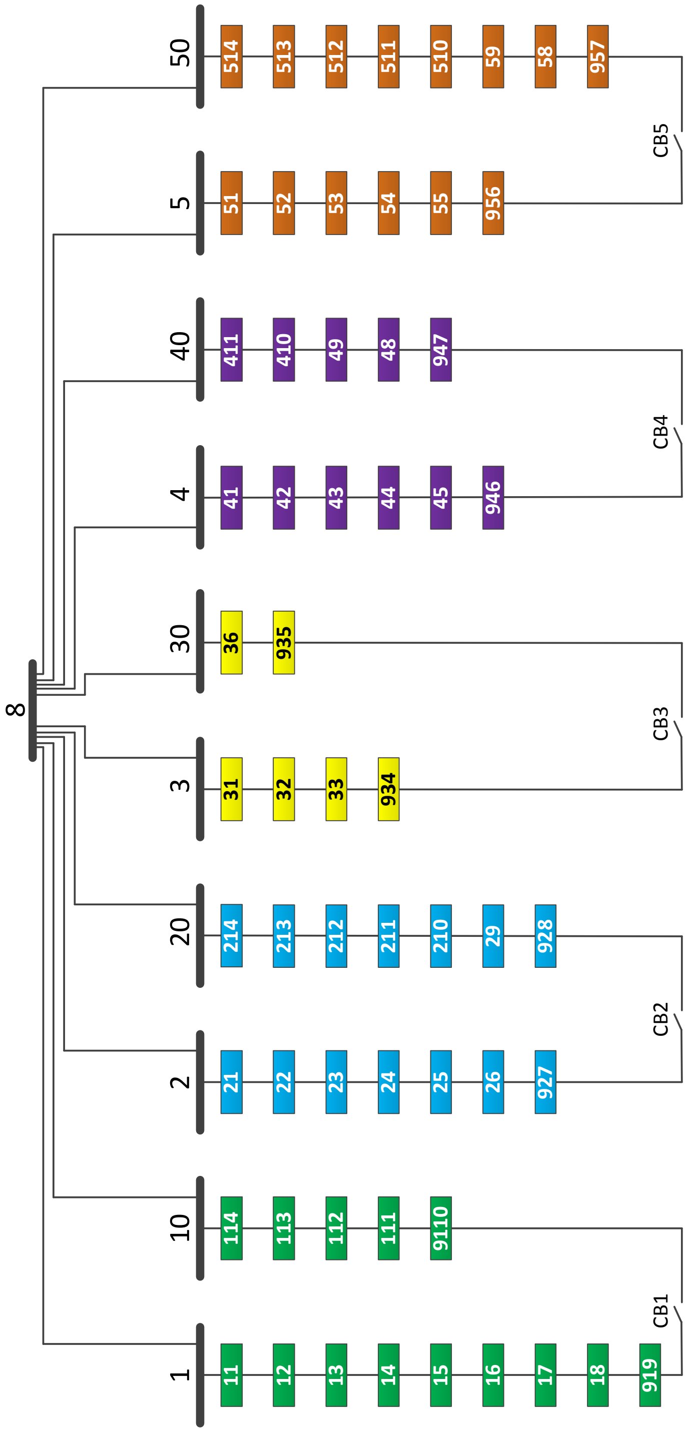

Figure 5.1: Nordhavn 10/0.4 kV distribution network. Substation names explanation: 8 - main substation (MS), first digit 1-5 - loop number, 9 in front of substation name - last substation of each feeder, connected with another feeder of the same loop via tie-line

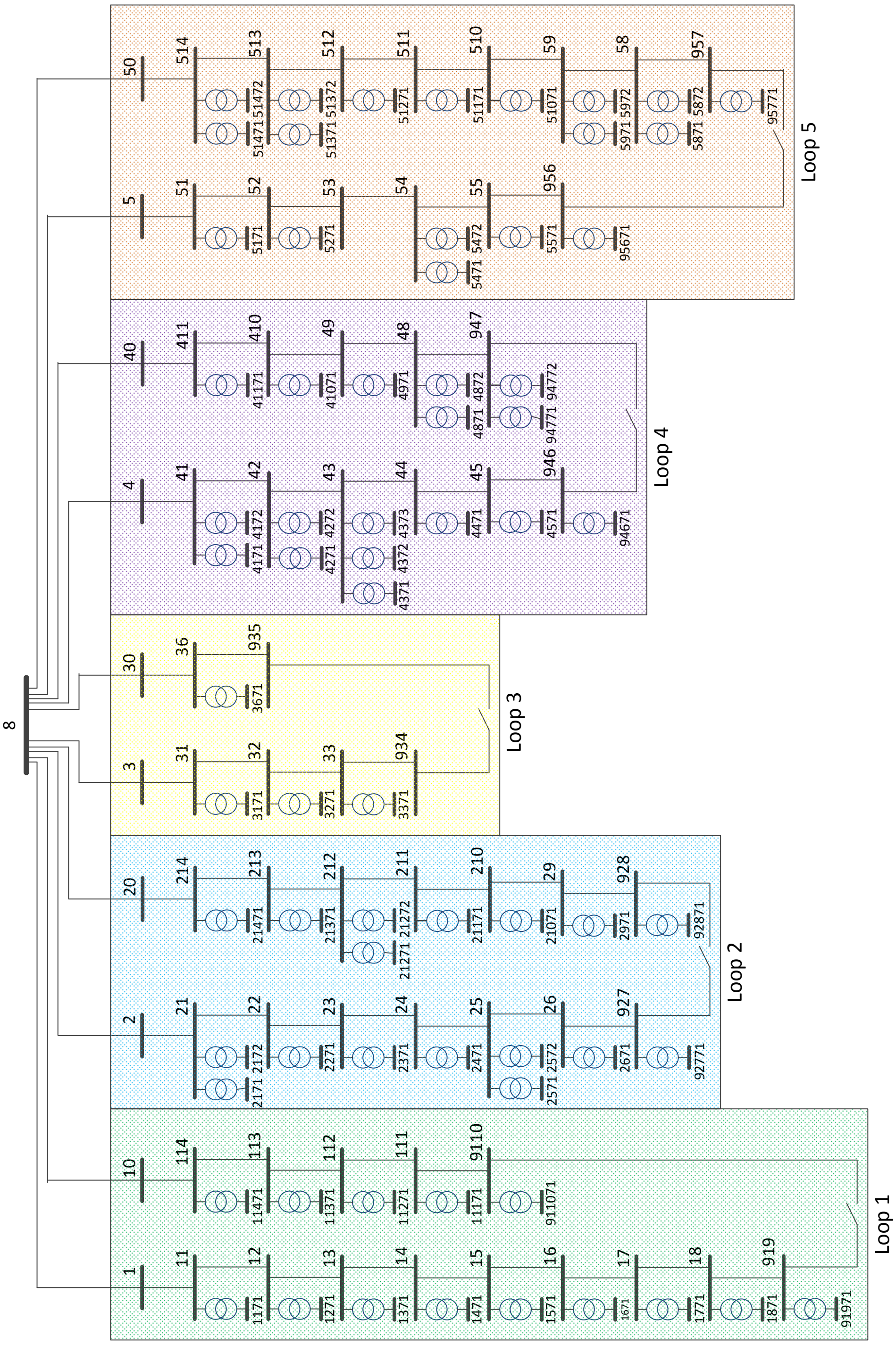

Figure 5.2: Nordhavn 10/0.4 kV distribution network model - one line diagram. Bus names explanation: second to last digit 7 describes that this is 0.4 kV bus with transformer, last digit shows the transformer number

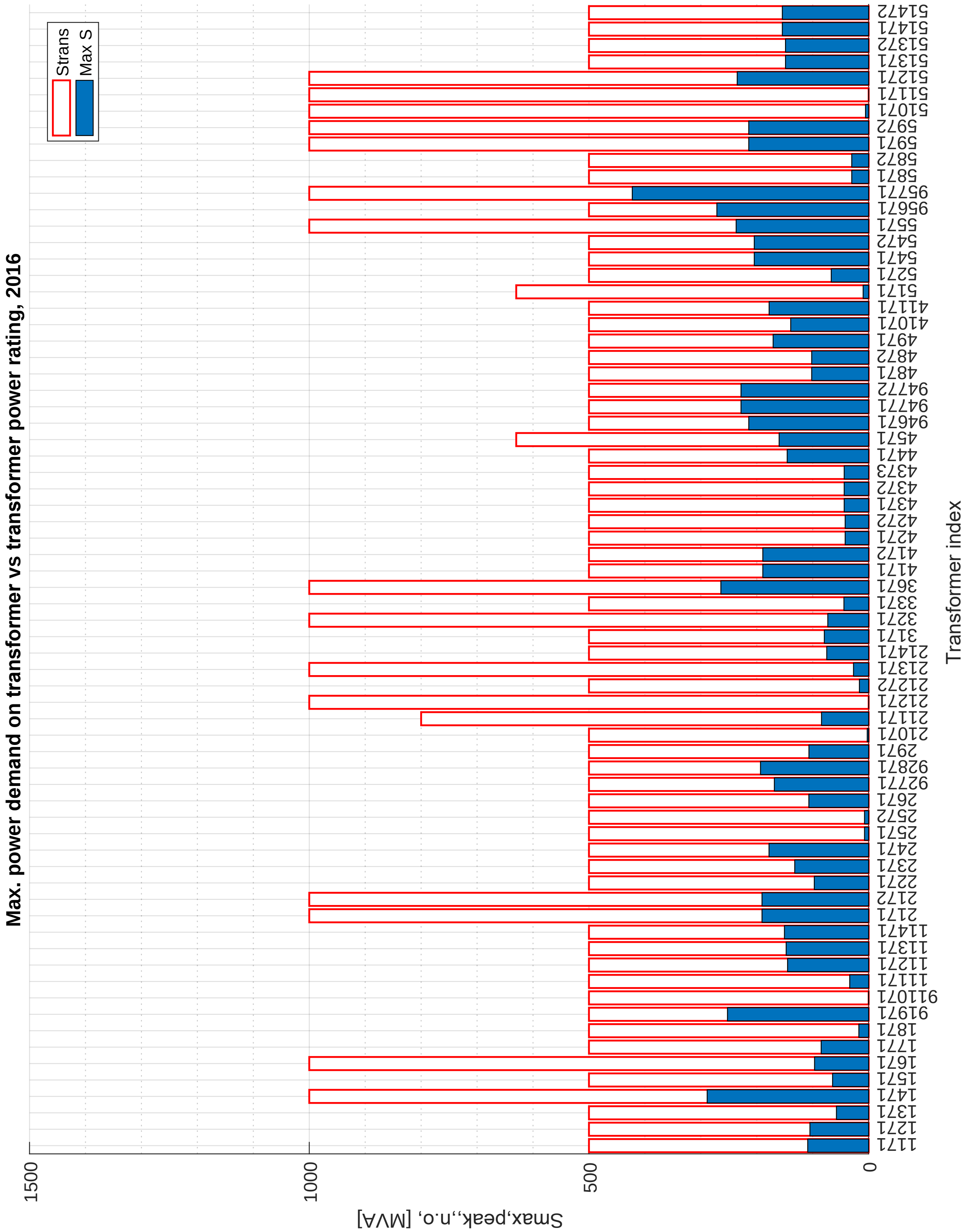

Figure 5.3: Maximum loading of 10/0.4 kV transformers in Nordhavn in normal operation - year 2016

based on the annual energy readings and demand curves for the year 2016 supplied by the Danish DSO "Radius". Figure 5.3 shows the example of the power flow analysis for every 10/0.4 kV transformer present in Nordhavn network. The figure shows that transformers in Nordhavn network have a lot of spare capacity to accommodate new loads.

5.2 Case study 1: application of the planning framework

Case study 1 shows how the planning framework described in chapter 3 can be applied to develop ADN planning procedure that is used to solve network reinforcement planning exercise. The planning procedure is made using the elements from the preparation and design phases of the framework in Figure 3.1. The detailed explanation of how the AEs are integrated into ADN planning and how such integration affects different planning stages is given in this case study.

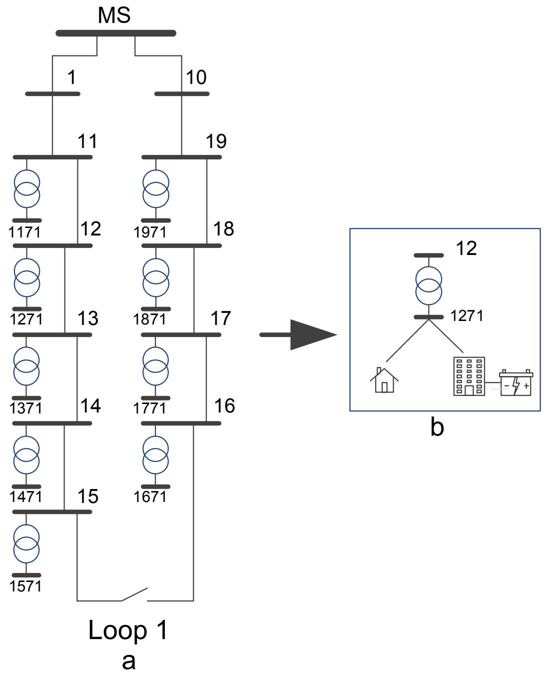

Figure 5.4: Case study 1 - distribution network. a - 10 kV network topology with two feeders, b - composition of the loads on a selected substation

5.2.1 System description

The network topology shown in Figure 5.4a is considered in this case study. It is a part of the 10 kV Nordhavn distribution network described in section 5.1. The network has two feeders combined in a loop, which is normally open. Nine 10/0.4 kV substations are supplying customers with power.

The transformer at the secondary substation 1271 is operating close to its MCC, which is equal to 500 kVA. Based on the forecast made for this area, the power demand at this substation is expected to exceed the transformer's MCC within next few years. A network reinforcement planning exercise with an objective to ensure that customers will have a sufficient power supply is initiated to resolve the potential CEs. The electrical load at substation 1271 is a combination of power demand from residential and commercial customers. There are two sources of FSs at substation: some of the residential customers could participate in DR programs and there are BESS units owned by the commercial customers as shown in Figure 5.4b.

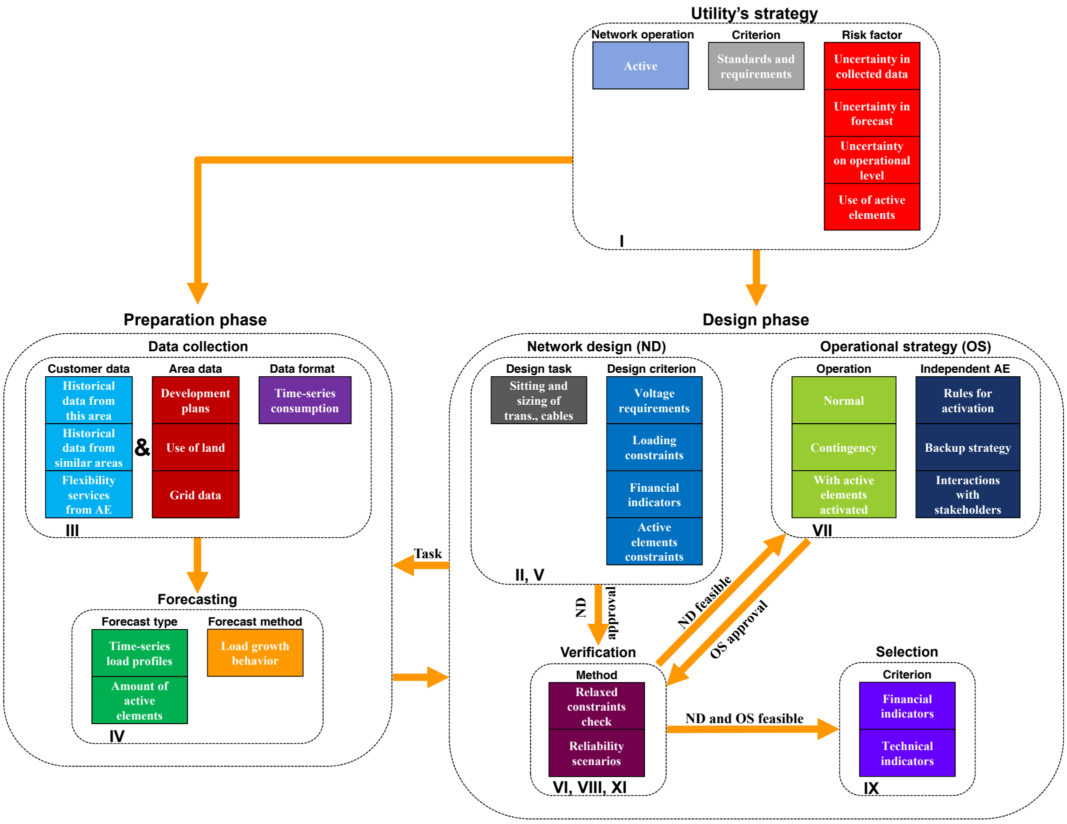

Figure 5.5: Elements of ADN planning procedure based on the framework in chapter 3

5.2.2 ADN planning procedure

ADN planning procedure is shown in Figure 5.5. According to it, the DSO chooses to use the active operation of the network with a reliance on FSs from AEs to obtain the planning solution for handling potential CEs. By relying on AEs uncertainty regarding the provision of their FSs is added to the uncertainties in the collected data, forecasting and operational level.

In order to integrate AEs in planning, time-series historical data should be gathered at the "data collection" stage. At least 1-h data resolution is required for the DSO planners to see how the power demand changes throughout the day and to propose a suitable OS for using FSs from AEs. Implementation of smart meters and other measuring devices could help the DSO in acquiring such data [212]. Time-series power consumption at substation 12 used in this case study is shown in Figure 5.6. In addition to the information about power demand, the data regarding sources and capabilities of AEs present in the distribution network should be obtained.

Multiple forecasts are made in the "forecasting" stage based on the previously collected information. Forecasting is done to predict the time-series power demand and the amounts of available AEs that could be contracted by the DSO during the whole planning horizon. The load duration curves (LDCs) can be used to visualize the time-series power consumption as shown in Figure 5.7 for the heavy loading scenario. Forecasting of AEs shows the potential amounts of capacity that could be reduced via FSs and the maximum energy obtained from them. Negative, standard and positive scenarios predicting the changes in amounts of AEs are shown in Figure 5.8. The scenarios indicate the amounts of aggregated FSs that could be obtained

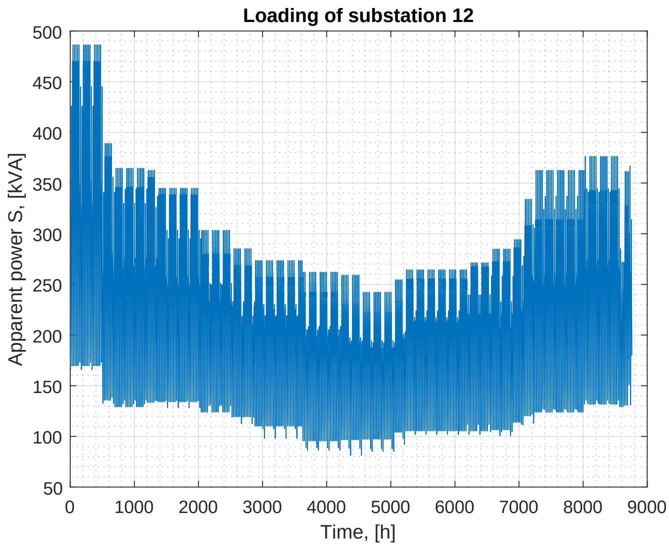

Figure 5.6: Historical power demand for 1 year with 1-hour resolution at single transformer substation 12

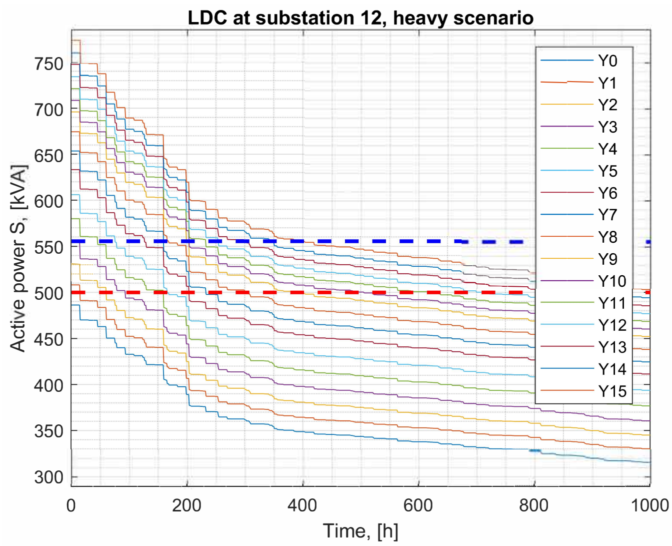

Figure 5.7: LDC for heavy load scenario for 15 years at single transformer substation 12, (hours from 0 to 1000). Red dashed line represent current transformer rated power, blue dashed line - chosen design value

from DR and BESS at substation 12. The minimum depth of discharge is taken into consideration, when estimating the potential available capacity of the BESS units.

In planning based on the ADN planning procedure, loading criterion could be relaxed, i.e. ND part of the solution does not have to satisfy it alone. In this case study, DSO chooses to set a limit for the amounts of FSs it can use in the network based on the potential risks. The dimensioning criterion for the transformer is selected in such a way, that the transformer's MCC is equal to at least 90% of the peak power demand at the substation 12. Therefore the transformer should be reinforced, when the forecasted power demand is expected to exceed 555.6 kVA. The reinforcement should be done in Y8 for the light scenario and in Y4 for the heavy and medium loading scenarios (Figure 5.7). The ND part of the planning solution is to install a transformer with rated power 630 kVA in the light case, or 800 kVA transformer for the power demand in medium and heavy scenarios.

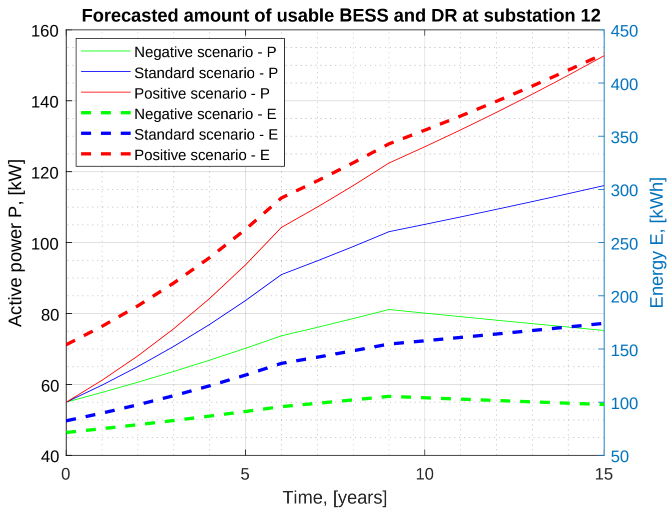

Figure 5.8: Three forecast scenarios for the amount of available aggregated capacity (solid line) and energy (dashed line) from BESS and DR at single transformer substation 12

Proper control strategy for AEs should be designed as part of OS to ensure that design criteria are satisfied. The operation parameters of the FSs from AEs are shown in Table 5.1. Due to risk-averse behaviour of the DSO the negative forecast scenario for available amounts of AEs is used for comparison with parameters in Table 5.1. As could be seen the required energy that has to be provided by the AEs in Y3 and Y4 is higher than the available energy in Figure 5.8. Therefore the FSs from AEs can only be used until the end of Y2. If an insufficient amount of FSs is responding at the time of CE, the DSO accepts the short-term overloading of the transformer up to 117% as a backup strategy.

Table 5.1: Operation parameters of using FSs from AEs

Year	**Number of hours consumption is higher than transformer rated capacity**	**Expected peak power, [kVA]**	**Expected peak reduction from AEs, [kW]**	**Expected max energy from AEs, [kWh]**	**Total energy from AEs, [kWh]**
Y0	0	486.3	0.0	0.0	0.0
Y1	15	508.2	8.2	8.2	122.9
Y2	60	531.1	31.1	44.0	942.7
Y3	93	555.0	55.0	105.0	2597.8
Y4	159	579.9	79.9	349.9	5400.1

The feasibility of both ND and OS parts of the solution is confirmed at the "verification" stage. Therefore the final solution is to use FSs until the end of the Y2 and then install an 800 kVA transformer at Y3. Estimated costs of using FSs is given in Table 5.2. The cost of the transformer unit is 25000 $.

5.2.3 Economic comparison

The solution based on the PDN planning procedure proposes to install 800 kVA transformer at Y1. Since solutions in both PDN and ADN planning include reinforcement of the existing transformer, the benefits B from reinforcement deferral (from Y1 to Y3) should be calculated to determine which of planning procedures is the most optimal. Benefits are calculated using Eq. 5.1 based on the NPV formula:

$$B_y = C_{transformer} * r^y - C_{FS,y}, \tag{5.1}$$

Table 5.2: Economic comparison between PDN and ADN solution

Year	**Benefit of deferring reinforcement, [k$]**	**Expected cost of AEs, [k$]**	**Total benefit, [k$]**
Y0	0.0	0.0	0,0
Y1	1.3	0.3	1,0
Y2	2.6	1.7	0,8
Y3	3.9	4.4	-0,5
Y4	5.4	8.9	-3,5

where $C_{transformer}$ - cost of transformer reinforcement at Y0, [$]; y - year, r - discount rate, [%], here 5 %; $C_{FS,y}$ - cost of using FSs from AEs at year y, [$].

Cost of using FSs from AEs C_{FS} is calculated as follows:

$$C_{FS,y} = E_{reduced,y} \cdot C_{E_{FS}} + P_{reduced,y} \cdot C_{P_{FS}}, \tag{5.2}$$

where $E_{reduced}$ - energy required from FSs of AEs, [kWh]; $C_{E_{FS}}$ - cost of kWh reduced, [$], here 1.5 $ per kWh; $P_{reduced}$ - amount of power reduction required from FSs of AEs, [kW]; $C_{P_{FS}}$ - cost of kW reduced, [$], here 10 $ per kW.

The final results could be seen in Table 5.2. Based on the cost comparison, the postponement of the reinforcement achieved by applying ADN planning procedure will result in 1.8 k$ benefits.

5.2.4 Conclusions

Case study 1 shows how the planning framework presented in chapter 3 could be applied to develop ADN planning procedure. The integration of FSs from AEs into ADN planning requires the planners to make adjustments to the whole planning procedure. Different algorithms should be applied at the "data collection", "forecasting", "ND" and "OS" stages, if the DSO decides to use FSs.

The development of a concrete procedure is based on the characteristics of the distribution network and/or desired features DSO would like to implement. Following different planning procedures will result in different results. The best planning solution is the one obtained by the planning procedure that suits the characteristics of the network itself (i.e. applying the ADN procedure for the planning of ADN).

5.3 Case study 2: IES planning

Integration of AEs could be done not only in ADN planning alone, but in situations when several energy sectors are operated as one system referred to as IES. The IES operation mode could be chosen by the DSO in the "utility's strategy" block in the planning framework from chapter 3. IES assumes that parts of the system are optimized to work most efficiently as a whole. Case study 2 describes the example of such IES planning, where two utilities: electrical DSO and district heating operator (DHO) perform a joint planning exercise to determine the optimal location for installation of a large HP.

Conventionally, DHO selects the HP's location based on its own interests. However, since this HP will require the connection to the electrical distribution network, the selected location may result in large CAPEX required from the DSO for the network reinforcement. This situation creates a place for cooperation between DSO and DHO in finding the optimal location for the HP installation together, thus minimizing the total cost. The inclusion of the FSs from HPs may reduce the final cost of the solution even further.

5.3.1 System description

The part of a Nordhavn distribution network shown in Figure 5.3.3 is used in this case study. The electric network consists of two loops, that include four feeders with the 28 secondary substations connected to them. Each substation has one or several 10/0.4 kV transformers. MS 8 connects the Nordhavn distribution network to the upstream system. Electrical customers in the network are located in the residential, commercial and light industrial buildings.

Figure 5.9: Case study 2 - Nordhavn city district. Electrical network: green and light blue lines - electrical distribution system layout (simplified), red lines - tie-lines between feeders; gray rectangle (8) - MS, circles - secondary substations 10/0.4 kV. Heat network: the asterisk * - heat customer, purple * - group of single houses, red * - apartment block, blue * - office building; shaded square - possible location of HP

DHO is planning to install a HP to supply customers with heat. Three types of heat customers are considered in this case study: single houses, apartment blocks and office buildings. They are denoted with asterisk sign in Figure 5.3.3 (1*, 11*, etc.). In total, 10 apartment blocks, 4 office buildings and one block consisting of 13 single houses have to be supplied with heat.

The IES planning methodology is shown in a flowchart in Figure 5.10. The optimal HP location is the one that gives minimum CAPEX and OPEX for both DSO and DHO. The planning exercise is split into three parts: heat system planning, electrical system planning and economic calculations.

Both heat system and electrical system planning are using the stages described in the planning framework in chapter 3. First, initial data is collected, which is followed by the forecast. After it, the ND and OS parts of the planning solution are made in order to assess the CAPEX and OPEX. The sets of potential solutions from both DSO and DHO are then brought together to determine the most cost-efficient one for the IES as a whole.

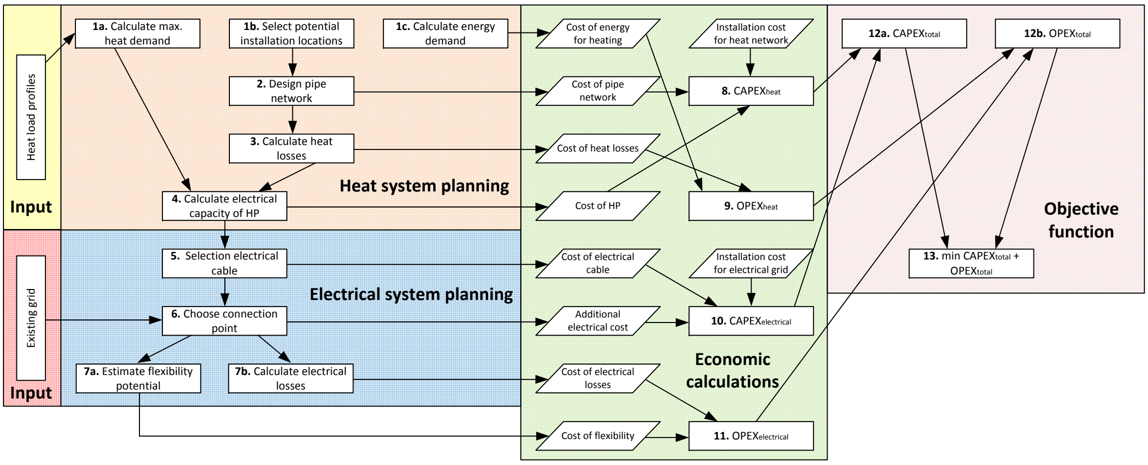

Figure 5.10: IES planning flowchart showing the methodology used for heat system planning, electrical system planning, economic calculations and final objective function

5.3.2 Heat system planning

Based on the calculations made in accordance to the heat system planning part of the flowchart in Figure 5.10, the HP should be able to provide 1.6260 MW of peak heat demand $Q_{heat,peak}$ with annual energy $E_{heat,y}$ equal to 4872.1 MWh.

Five potential locations for installation of HP are selected based on the availability of the heat source, proximity to the heat customers and safety regulations. The seawater heat source is used at locations 1, 3-5, while location 2 has a groundwater source. The optimal topology of the heat network is determined for each potential location with results presented in Table 5.3. The associated heat losses for the heat network with HP installed at different locations are given in Table 5.4. Finally, the required electrical capacity of the HP is estimated in Table 5.5.

Table 5.3: Total length, average pipe diameter and total cost of district heating network for different HP locations

Location	L_{pipe}, $[m]$	D_a, $[m]$	$\sum C_{pipe,ft}$, $[k\$]$
1	1240	0.1062	364.8
2	1424	0.0969	410.6
3	1511	0.0938	427.8
4	1354	0.0933	359.1
5	1310	0.0938	363.1

Table 5.4: Yearly and relative heat losses

Location	$E_{heat,loss,y}$, $[MWh]$	$q_{loss,relative}$, $[\%]$
1	170.13	3.37
2	188.73	3.73
3	197.69	3.90
4	171.42	3.40
5	171.35	3.40

Table 5.5: Electrical capacity and cost of HP unit

Location	P_{HP}, $[kW]$	$P_{HP,rated}$, $[kW]$	**Heat source**	C_{HP}, $[k\$]$
1	468.2	500	Seawater	50
2	494.6	500	Groundwater	80
3	470.6	500	Seawater	50
4	468.3	500	Seawater	50
5	468.3	500	Seawater	50

5.3.3 Electrical system planning

After the DHO determines the potential installation locations and the required HP's electrical capacity, it can be used as an input for the electrical system planning performed by the DSO.

The DSO has several options for connecting the HP depending on the available spare capacity of the feeders in the system. In each case, besides the cost of the cable connecting the HP to the power source, the DSO has an additional electrical cost - the cost of additional equipment, such as an individual transformer or reinforced cable needed to connect HP. Three scenarios are considered below: scenario A - feeders of the distribution network in Figure have enough capacity and HP can be connected to one of them; scenario B - feeders of the distribution network do not have enough capacity and HP should be connected directly to MS via dedicated cable; scenario C - FSs from HP are used to lower the required peak power and avoid constructing a direct cable to MS, HP is connected to one of the feeders.

Scenario A

HP could be connected to one of the secondary substations located on the feeders, if the feeders have enough spare capacity. The cost of additional equipment $C_{additional}$ in scenario A is the cost of designated transformer installed at the already existing substation. Based on the HP's capacity the 10/0.4 kV 630 kVA transformer with the cost of 20000 \$ should be installed.

The CAPEX and OPEX of DSO and DHO for scenario A are shown in Table 5.6. A large difference in OPEX of the DSO and DHO is due to the fact that $OPEX_{heat}$ includes both the cost of heat losses and the cost of energy bought from the DSO, while $OPEX_{el}$ only consists of the cost of electrical losses.

As could be seen, from the DHO perspective, to install HP at location 4 would be the most optimal solution, while DSO will have the lowest costs, if HP is installed at location 2. In the IES planning, where the interests of both utilities are considered, HP should be placed at location 1 as shown in Table 5.9.

Table 5.6: Scenario A

Location	$CAPEX_{heat}$, $[k\$]$	$OPEX_{heat}$, $[k\$]$	**PC**	$CAPEX_{el}$, $[k\$]$	$OPEX_{el}$, $[k\$]$
1	456.3	2135.4	16	25.7	10.5
2	539.7	2256.4	21	19.9	5.4
3	525.5	2147.1	21	46.8	5.2
4	450.0	2136.0	214	68.8	4.5
5	454.4	2135.9	212	45.1	4.8

Scenario B

If there is not enough spare capacity on the feeders, HP cannot be connected to the loops directly. DSO has to either upgrade the feeders to the ones with higher capacity or make a direct connection from the HP to the MS. Both of these options will greatly increase the CAPEX, however, if a lot of cables have to be reinforced, building the direct connection might be preferable. Electrical losses become lower since HP is now electrically closer to the power source.

CAPEX and OPEX of the HP installation for both utilities in scenario B are given in Table 5.7. Similar to scenario A, the optimal HP location shifts, when the interests of both DSO and DHO are considered. Location 1 is the preferred location for HP in the IES planning as could be seen from TOTEX that are incurred by both DSO and DHO in Table 5.9.

Table 5.7: Scenario B

Location	$CAPEX_{heat}$, [k\$]	$OPEX_{heat}$, [k\$]	**PC**	$CAPEX_{el}$, [k\$]	$OPEX_{el}$, [k\$]
1	456.3	2135.4	8	202.5	0.89
2	539.7	2256.4	8	162.9	0.78
3	525.5	2147.1	8	209.9	0.93
4	450.0	2136.0	8	247.5	1.10
5	454.4	2135.9	8	301.06	1.35

Scenario C

Different energy sectors in the IES provide opportunities to obtain new AEs and FSs. In some cases it is possible for the DSO to lower the requested electrical capacity from the HP by contracting peak reduction and load shifting FSs from the HP [124]. This will allow DSO to avoid the need to reinforce the feeders or to construct direct cable connection from HP to the MS as is the case in Scenario B. If the smart control of a HP is implemented together with the measurements of customers' indoor temperatures, provision of FSs from HP will not lead to any loss of customers' comfort. DHO can also install heat storage to ensure that the customers' heat demand is always satisfied [213–215].

In this scenario, the 10% peak reduction allows the HP to be connected to the feeders without the need to upgrade them. Based on the analysis of the periods, when the FSs from
acHP should be used - CEs, the peak reduction FSs should only be requested for 9 hours, that are split into the periods with a duration of 3, 4 and 2 hours, respectively. The price for contracting FSs from the HP is assumed to be 10 $\$/kWh$ for the morning peak period and 7 $\$/kWh$ for the off-peak plus additional payment of 100 \$ for the total number of times FSs are requested.

CAPEX and OPEX for scenario C are given in Table 5.8. The combined TOTEX are shown in Table 5.9.

5.3.4 Conclusions

An IES planning based on the framework proposed in chapter 3 is shown in case study 2. Components related to several energy sectors, such as HPs or EVs could serve as natural points of collaboration between all involved utilities. By considering the interests of all parties, the combined TOTEX could be made lower, than if the utilities were acting on their own. The integration of peak reduction/load shifting FSs from AE - a HP could make the overall solution even more cost-efficient.

Table 5.8: Scenario C

Location	$CAPEX_{heat}$, [k\$]	$OPEX_{heat}$, [k\$]	**PC**	$CAPEX_{el}$, [k\$]	$OPEX_{el}$, [k\$]
1	456.3	2135.4	16	25.7	47.0
2	539.7	2256.4	21	19.9	38.1
3	525.5	2147.1	21	46.8	36.4
4	450.0	2136.0	214	68.8	34.9
5	454.4	2135.9	212	45.1	35.6

Table 5.9: Total combined cost of DSO and DHO for the different HP locations

	Scenario A	**Scenario B**	**Scenario C**
Location	**Total, [k\$]**	**Total, [k\$]**	**Total, [k\$]**
1	2627.9	2795.1	2664.4
2	2821.4	2959.8	2854.1
3	2724.6	2883.5	2755.9
4	2659.3	2834.6	2689.7
5	2640.2	2892.7	2671.0

5.4 Case study 3: applying flexibility characterization framework to planning

This case study shows the application of the flexibility characterization framework from chapter 4 for estimation of the costs of utilizing the FSs from AEs in the solution of the planning exercise.

5.4.1 System description

The network topology used in case study 3 is given in Figure 5.11. The system is a part of the Nordhavn distribution network shown in section 5.1. The customers are distributed on four feeders, that are connected through the main cables MS-1, MS-1, MS-2 and MS-20 to the 30/10 kV MS. Four feeders are combined in loops, that allow performing internal RE via tie-lines T19-T110 or T27-T28. A more detailed description of loop design is given in section 5.1.

Each network's bus in Figure 5.11 is a 10 kV side of the secondary substation, that can have one or two transformers. Electric loads are connected to the 0.4 kV side. Residential, commercial and light industrial customers represent the power demand in the system. Based on the data from the actual Nordhavn distribution network, time-series consumption profiles are synthesized to estimate the power demand at each substation. Profiles are aggregated on a transformer level.

5.4.2 Flexibility sources

There are multiple existing and potential sources of FSs in the network depicted in Figure 5.11. Customers can participate in the DR programs with some of them having BESS units installed. In addition to the internal RE within the same loop, there is a possibility of enabling RE between different loops and expand the cables' capacity through DLR.

Customers providing DR and BESS units are independent AEs. In the system in Figure 5.11, customers located at the 111L1, 114L1, 24L1, 26L1, 29L1, 211L1 and 214L1 nodes of the 0.4 kV side are participating in DR programs. The maximum capacity of such FSs is changing from year to year and depends on the total

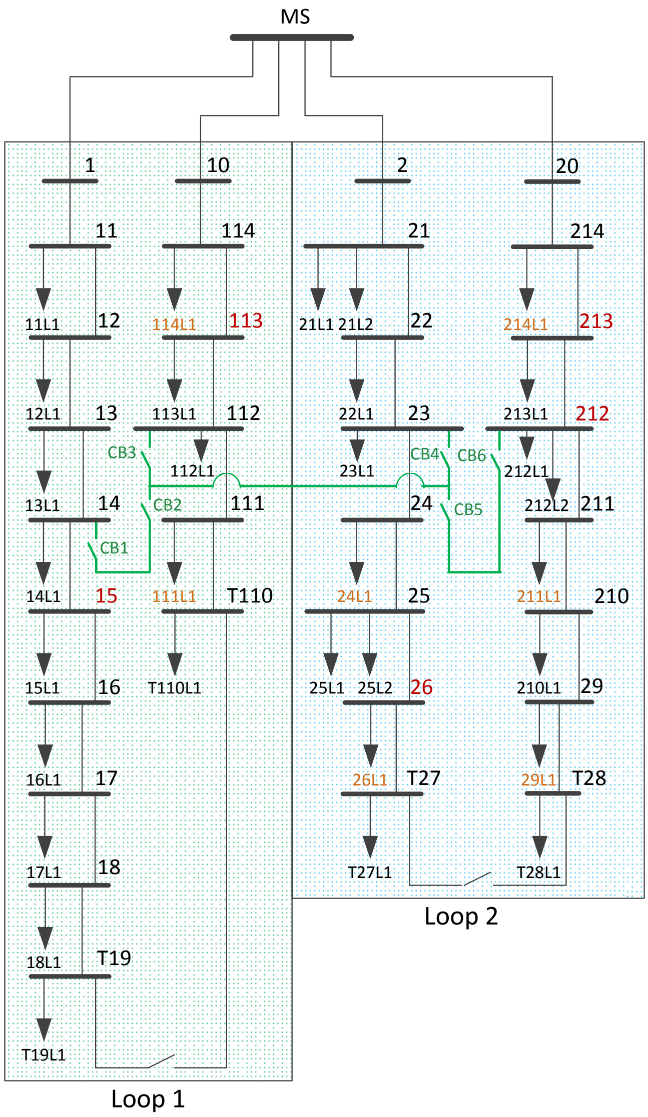

Figure 5.11: Case study 3 - Part of the 10 kV distribution network of Nordhavn area, nodes with loads are 0.4 kV. Figure explanations: MS - main substation; L - load node; T - node with tie-line; CB - circuit-breaker; nodes with red font have BESS; nodes with orange font have DR; new supply paths to enable RE with external loop is highlighted in green

substation load. Several BESS units are installed at the nodes 15, 113, 26, 212 and 213. BESS connected to these 10 kV nodes through their own designated transformers.

CBs and underground cables are utility-owned AEs, that can provide FSs via RE and DLR, respectively. External RE could be used to shift part of electrical loads from one loop to the other. This could be beneficial in case if another loop has extra spare capacity. To enable FS from external RE in the considered system six CBs and three tie-lines should be constructed. New supply paths for external RE are highlighted in green in Figure 5.11. DLR is dynamic MCC that is determined based on external conditions the component is in. To apply DLR for underground cables, sensors for detecting soil temperature and humidity should be installed to provide inputs for the cable's thermal model. DLR can potentially be applied to any cable, the actual capacity of such FS varies every year and depends on the amounts of rainfall, type of soil and burial depth for the cable.

In this case study, the long-term contracts between AEs and the DSO for providing FSs are assumed. This is done in order to increase the DSO's confidence in acquiring needed FSs during the CEs and not compromise DSO's results during benchmark [216, 217], thus facilitating the integration of AEs in the long-term planning. The contracts specify the maximum amount of FS's capacity, maximum duration and the maximum number of times FS could be activated during a certain time (e.g. one year). No market is assumed in the current case study.

5.4.3 Forecast analysis

Yearly forecasts are made to predict the changes in the time-series load profiles for the planning horizon of 4 years. Each power demand profile from a customer is represented as a combination of base trend, seasonal variation, and a stochastic component. Ten sets of different values for base trend and seasonal variation are considered during each year, resulting in a total of 100 forecast scenarios. Several potential scenarios for the power demand of load 11L1 at year 3 are shown in Figure 5.12.

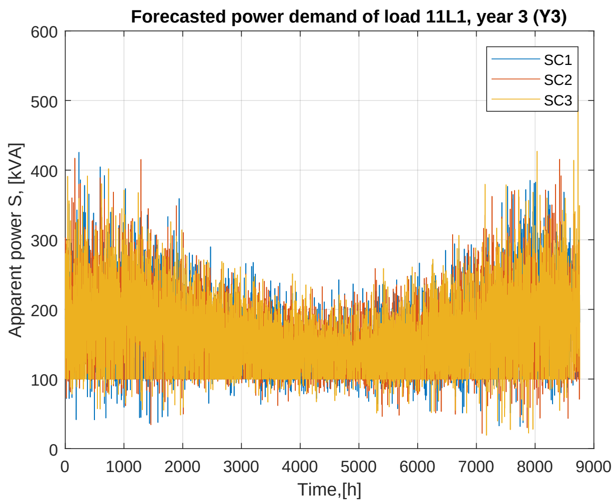

Figure 5.12: Example of power demand forecast. SC - scenario

The analysis of the forecasting scenarios reveals potential CEs due to the overloading of some of the cables in Y3 and Y4. The overloading might occur during the worst case N-1 contingency, when one of the main cables in the system in Figure 5.11 is failed. In that case, the remaining main cable should be able to supply the load of the whole loop. Detailed information about potential CEs is given in Table 5.10. The 95th percentile corresponding to the conservative "worst case" scenario planning algorithm is chosen to evaluate data from different scenarios.

Table 5.10: Detected CEs in cables. Values for power, energy, number of CEs and duration are obtained by using 95th percentile

Year 3						Year 4					
Cable	**SC with CE, [-]**	$S_{flex,95}$, **[kVA]**	$E_{flex,95}$, **[kVAh]**	$NO_{flex,95}$, **[-]**	$D_{flex,95}$, **[h]**	**Cable**	**SC with CE, [-]**	$S_{flex,95}$, **[kVA]**	$E_{flex,95}$, **[kVAh]**	$NO_{flex,95}$, **[-]**	$D_{flex,95}$, **[h]**
C2-21	99	1334.4	3578.5	8	2	**C2-21**	99	1538.3	4867.9	11	2
C214-213	93	975.8	1543.9	4	2	**C213-212**	16	166.7	166.7	1	1
C20-214	99	1334.4	3578.5	8	2	**C214-213**	95	1158.1	2359.3	5	2
						C20-214	99	1538.3	4867.9	11	2

Table 5.11: Cost of reinforcing the cables in the PDN planning

Cable	**Length, [km]**	**Old cable**	**New cable**	**Cost, [k€]**	**Year to invest**
C2-21	1.15	3x240	3x300	122.3	2
C213-212	0.17	3x240	3x300	17.8	3
C214-213	0.12	3x240	3x300	12.5	2
C20-214	1.77	3x240	3x300	189.1	2

Table 5.12: Cost of the PDN planning

	Year 3	**Year 4**
$C_{PDN,CAPEX,y,95}$, **[k€]**	293.7	15.4
$C_{PDN,OPEX,y,95}$, **[k€]**	4.6	0.2
$C_{PDN,TOTEX,y,95}$, **[k€]**	298.3	15.6
$VoF_{y,95}$, **[k€]**	128.2	5.9/163.3

5.4.4 PDN planning

The planning solution according to the PDN planning is to resolve potential CEs by reinforcing the overloaded component. Table 5.11 shows the information about overloaded cables, the cost of the upgrade and when the investment decision should be made. The total of four underground cables with a total length of 3.21 km should be reinforced in the Y3 and Y4. The costs of the PDN planning solution, calculated with expressions in chapter 4, are shown in table 5.12. The investment decision should be taken one year before the actual problem might arise to give sufficient time for installation of the component.

VoF is calculated for both Y3 and Y4 based on Eq. 4.1. As was discussed in chapter 4, VoF depends on the decision made in the previous years. The first VoF in Y4 represents the case, when all the necessary reinforcements in Y3 are done, while the second value - the case when the DSO decides to postpone cables' upgrade.

5.4.5 ADN planning

The probability of events, where the worst case N-1 contingency coincides with the high power demand from the customers is not very high. Due to that, applying ADN planning algorithms could result in a more cost-efficient solution.

In ADN planning the FSs from AEs are used to solve the potential CEs. Four AEs/FSs are present or could be enabled in considered system: DR, BESS, RE and DLR. Table 5.13 shows how the cost of these AEs could be represented using the flexibility characterization framework from chapter 4. Installations of the main (AE itself) and additional equipment are the CAPEX costs. Time-dependent costs, such as cost of supplied energy or cost of component's LT reduction are included in OPEX.

The costs of using such AEs/FSs as BESS, RE and DLR are based on the physical processes occurring in them (degradation or reduction of LT). The cost of DR is related to the customer's comfort and therefore more subjective. An additional OPEX cost is a distinctive cost for a particular AE. In the case of BESS, the additional cost is the cost of recharge cycles that occur due to the requested FSs, such cost should be taken into consideration since BESS has a limited number of charging/discharging cycles during its LT. In addition

Table 5.13: Costs included in the CAPEX and OPEX of different AE/FSs according to the flexibility characterization framework

AE/FS	AE	Costs included in CAPEX		Costs included in OPEX		Cost functions
		Main	Additional	Main	Additional	
DR	Consumer's equipment	-	ICT and control infrastructure	Supplied energy	Energy difference	O1-O4
BESS	BESS	-	ICT and control infrastructure	Supplied energy	Recharge cycles, recovery cost of BESS unit	O1-O2
RE	Circuit-breaker (CB)	CBs	Tie-lines (TLs)	Number of switchings (SWs)	-	O2
DLR	Cable	-	Soil temperature sensors	Reduction in LT	-	O1

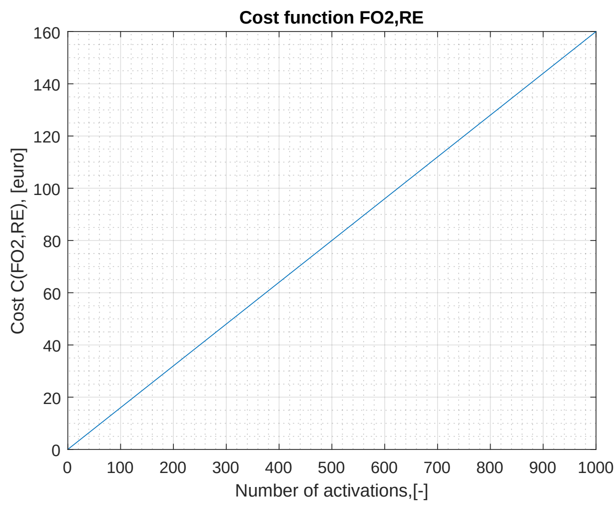

Figure 5.13: Cost function FO2 for RE in Y3 and Y4

to that, a partial recovery cost has to be added to the BESS OPEX estimation, which allows the unit's owner to recover its expenses in acquiring such AE. The difference in the price of energy, before requesting DR and after the request is completed, represents the additional OPEX cost for DR owners. Including this cost in OPEX would ensure, that DR owner does not have to pay extra energy cost as a result of participating in the DR programs.

Based on the costs included in Table 5.13, each AE is represented by a set of cost functions. Examples of cost functions for RE and DLR are given in Figures 5.13-5.14.

The results of cost estimations of using individual AEs are summarized in Table 5.14. The costs for Y4 are given in assumption that the same AE is used in Y3. That is why, the CAPEX for RE in Y4 is zero, since the equipment for enabling external RE was already constructed one year earlier. Although the OPEX from using DLR is very low, it is still similar TOTEX compared to DR and BESS in Y3. RE is a much more expensive solution, that has higher TOTEX than the DSO's VoF. However, if the longer planning horizon is considered, external RE could become beneficial due to its ability to shift large amounts of power.

The amounts of FSs offered by DR, BESS and DLR are not enough to avoid potential CEs in the network during Y3 and Y4. Applying external RE allows to resolve the situation with CEs, but this solution is not economically viable. Therefore a combination of AEs should be used in each year. Table 5.15 presents the

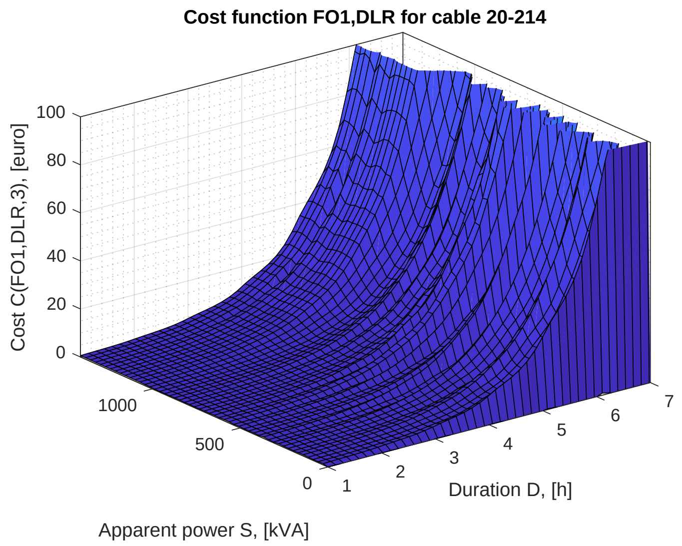

Figure 5.14: Cost function FO1 for DLR of cable 20-214 in Y3

Table 5.14: Costs of each AE/FS available in the distribution network

	Parameter	DR	BESS	RE	DLR
Year 3	$C_{ADN,CAPEX,3,95}$, [k€]	2.3	1.6	194.3	3.0
	$C_{ADN,OPEX,3,95}$, [k€]	1.0	1.5	0.002	0.008
	$C_{ADN,TOTEX,3,95}$, [-]	3.3	3.1	194.3	3.0
Year 4	$C_{ADN,CAPEX,4,95}$, [k€]	0.9	0.9	0	0.2
	$C_{ADN,OPEX,4,95}$, [k€]	1.7	1.4	0.003	0.01
	$C_{ADN,TOTEX,4,95}$, [-]	2.6	2.3	0.003	0.21

Table 5.15: Cost of the ADN planning solution

	Parameter	
Year 3 (DLR & BESS)	$C_{ADN,CAPEX,3,95}$, [k€]	4.2
	$C_{ADN,OPEX,3,95}$, [k€]	0.1
	$C_{ADN,TOTEX,3,95}$, [-]	4.2
Year 4 (DLR & BESS)	$C_{ADN,CAPEX,4,95}$, [k€]	0.2
	$C_{ADN,OPEX,4,95}$, [k€]	0.06
	$C_{ADN,TOTEX,4,95}$, [-]	0.3

TOTEX of the final solution made according to the ADN planning. The combination of DLR and BESS is used in both Y3 and Y4. Comparison of the final planning solution's TOTEX with the VoF in Table 5.12 shows the DSO's potential savings that could be achieved by utilizing the FSs instead of traditional reinforcement.

5.4.6 Conclusions

Case study 3 describes how FSs from different AEs could be integrated in a planning solution. By identifying VoF and using the flexibility characterization framework presented in chapter 4, DSO can select the most cost-efficient AEs or decide to rely on conventional reinforcement. The cost estimation methodology of AEs is based on generic sets of parameters and could be applied to any AE regardless of technology used.

5.5 General conclusions

Case studies 1 and 2 show how the FSs from AEs are integrated into ADN and IES planning. The integration of AEs in the planning allows to make the network more robust towards uncertainties of power demand/generation and to achieve a more cost-efficient planning solution. However, the estimation of the FSs cost in both case studies is simplified with the fixed values for kW of capacity and kWh of energy used. Case study 3 shows the application of the methodology for identification of the VoF, which is the maximum price the DSO is ready to pay for the FS, and the framework enabling the comparison of different types of AEs. The cost of each AE is determined through the calculation of its CAPEX and OPEX, which are then compared to the VoF from the DSO's side. Combining the detailed planning procedures in case studies 1 and 2 with the methodology for estimation of VoF and comparing different AEs in case study 3, could result in a more optimal ADN planning solution.

CHAPTER 6

Conclusion and future work

This PhD project focuses on the planning of ADNs and more specifically on the integration of AEs into the ADN planning. The presented work considers two aspects for AEs' integration: first - the methodology for the generic planning process that allows the integration of AEs is presented in chapter 3, second - the methodology for comparing different types of AEs via cost estimation and identifying the VoF from the DSO's perspective is given in chapter 4. The findings after addressing each of the four research questions stated in section 1.4 are summarized below:

[**Q1**] *What are challenges in ADN planning?*

The challenges in ADN planning are related to the diversity of elements that have to be integrated and uncertainty of the power demand and generation. The planning begins with the forecast of power demand and generation of the considered distribution network. Due to the presence of RES-based DGs that have intermittent power output and such equipment as HPs and EVs with uneven operational patterns, the accurate prediction of both is very challenging. The presence of the electricity markets and aggregators means, that many AEs can have a direct impact on the distribution network performance by pursuing their own economic benefits. That adds additional complexity to the demand/generation forecasting made by the DSO. Emerging technologies such as microgrids and virtual power plants have to be considered from the perspective of their potential impact on network performance and the planners should find a way to integrate them in planning. In addition to that, the behaviour of passive consumers should also be analyzed and forecasted. After the forecasts are prepared, the DSO should consider how to use FSs from AEs to find such a planning solution that satisfies all the design criteria at the lowest cost. Since some of the criteria could contradict each other, the necessary trade-offs should be made. Due to the size of the typical distribution networks, the number of elements and interconnections between them, the problem of ADN planning is extremely complex and requires a holistic approach.

[**Q2**] *How to integrate planning algorithms together in a streamlined planning process of ADN planning?*

Many algorithms are proposed to handle individual aspects of ADN planning. Some of the algorithms are focusing on forecasting, while the other allows to reach certain planning objectives such as reducing the power losses, improving the voltage profile or increasing the reliability. However, the majority of existing methodologies for the integration of different planning algorithms do not provide the sufficiently generic picture and could only be applied to the one or several stages of the ADN planning under specific conditions. Therefore a generic planning framework is proposed in chapter 3. It serves as a basis for developing the planning procedures that include different planning algorithms and allow to integrate various emerging technologies into ADN planning. The framework addresses every planning stage combined into three phases, such as preparation, design, and implementation. Before the preparation stage is initiated, the DSO should define the high-level objectives which will affect the final planning solution. The framework allows to integrate the AEs and show the effect such integration has on different planning stages. To integrate AEs into the planning solution, the DSO needs to have a time-series power demand forecast as opposed to the forecast of only peak values, that is enough in PDN planning. The design criteria applied to the ND part of the solution in ADN planning could be relaxed, since now the design criteria should be satisfied by the combination of ND and OS together.

[**Q3**] *How to characterize the cost of using AEs in a generic way?*

When selecting the final planning solution in the ADN planning, the DSO compares the solutions involving FSs from AEs with the traditional ones such as reinforcement. There could be multiple AEs ready to provide FSs in a considered distribution network, both utility-owned such as CBs for providing RE and underground cables for DLR and independent AEs like BESS and customers participating in DR programs. To select the most cost-efficient AEs and compare it with other solutions, it is important to adequately estimate the costs of using FSs. Chapter 4 proposes a generic methodology for characterizing the cost of AEs. First, the conventional planning solutions (i.e. solutions without FSs) are analyzed and VoF, which is the maximum price DSO is ready to pay for the FSs is determined. The second part of the methodology is a flexibility characterization framework. The framework helps the DSO in the process of pre-selecting AEs and estimating the costs for those AEs, that could be used to solve the distribution network issues. The cost is estimated via generic parameters and cost functions, that capture the most important characteristics of the required FSs. It is possible to apply the proposed methodology to any AE regardless of the technology and type it has. Correct estimation of the FSs' costs facilitates the integration of them in long-term planning.

[**Q4**] *How to apply AEs in planning exercises?*

Case studies performed on an actual distribution network of Nordhavn are presented in chapter 5. They show the application of AEs for validation of the proposed methodologies in different planning exercises. The effect of the FSs from AEs could be seen on the power demand and voltage profiles in the network. In most cases, significant savings in TOTEX could be achieved by utilizing FSs from AEs to shift/reduce the peak power or to correct voltage. The integration of FSs in a planning solution makes the network more adaptable towards highly uncertain power demand with rapid variations, since the requested amounts of FSs could be increased if necessary. In addition to that, in the cases when the power demand was overestimated, it is possible to save the large share of expenses planned for the usage of the FSs from the AEs. This makes the ADN planning solutions more cost-efficient.

6.1 Future work

Due to the high complexity of the chosen topic, some of the aspects of AEs' integration in the ADN planning were only briefly considered in the current work. More research could be done in the following areas:

1. Reliability and credibility of AEs - one of the concerns for the DSOs willing to integrate AEs into their planning procedures is how to make sure the FSs would be provided, when needed;
2. ADN as a part of the IES - a large number of the potential source of FSs for the electrical distribution network could be found in the heat, gas and transportation sectors. The integration of ADN together with other energy sectors would require elaborate planning and control of each part of such IES;
3. Identification of the parameters in the cost functions - the cost functions are used to estimate the cost of FSs. By analyzing data from the DSOs that are using different types of FSs in practice, the parameters for constructing such cost functions could be determined with higher accuracy.

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Collection of relevant publications

[**A**] Klyapovskiy, Sergey and You, Shi and Cai, Hanmin and Bindner, Henrik W, "Incorporate flexibility in distribution grid planning through a framework solution" in *International Journal of Electrical Power and Energy Systems (IJEPES) - Elsevier*, 2019.

[**B**] Klyapovskiy, Sergey and You, Shi and Domens, Rafael Calpe and Bindner, Henrik W and Cai, Hanmin, "Utilizing Flexibility Services from a Large Heat Pump to Postpone Grid Reinforcement" in *2018 IEEE Student Conference on Electric Machines and Systems (SCEMS)*, Huzhou, China, December 2018.

[**C**] Klyapovskiy, Sergey and You, Shi and Michiorri, Andrea and Kariniotakis, George and Bindner, Henrik W, "Incorporating flexibility options into distribution grid reinforcement planning: A techno-economic framework approach" in *Applied Energy - Elsevier*, under review.

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[A] Incorporate flexibility in distribution grid planning through a framework solution

Incorporate flexibility in distribution grid planning through a framework solution

Sergey Klyapovskiy, Shi You*, Hanmin Cai, Henrik W. Bindner

Center for Electric Power and Energy (CEE)
Technical University of Denmark (DTU)
2800 Kgs. Lyngby, Denmark

Abstract

Introduction of the distributed energy resources (DER) and new types of consumer equipment greatly increased the uncertainty in the distribution grid. Due to these changes traditional "worst case" planning algorithm from the passive distribution networks (PDN) will requires extensive capital investments with a high probability that the resulted network would be largely underutilized. A prominent solution is to involve active elements (AEs) that can be found on a local level into the grid planning. A generic multi-stage planning framework for incorporating the flexibility from AEs in the distribution grid planning is proposed in this paper. The framework facilitates the transition from PDN to active distribution networks (ADN) and considers all planning stages starting from the data collection to implementation plan. An example involving flexible demand shows how to use the framework in grid planning and demonstrates the benefits of ADN planning over PDN planning.

Keywords: Active distribution network, distribution planning framework, flexibility services, active elements.

1. Introduction

The last decade had brought tremendous changes to the electrical power systems. Previously based on unidirectional flow of power from large power stations through transmission lines to end customers, power systems were operated in a straightforward manner [1]. Due to the fact that consumer profiles were known and followed certain patterns, it was possible to achieve a good balance between consumption and generation of power without additional expenses.

This way of operating power system was challenged with the introduction of distributed energy resources (DER, [2, 3]), which includes distributed generation (DG) sources and energy storage systems (ESS). DGs are typically small-to-medium range power production

*Corresponding author
Email address: sy@elektro.dtu.dk (Shi You)

facilities scattered across the large area. Some of the DGs are based on renewable energy such as wind, hydro and solar and are specifically promoted by authorities for connection to existing power systems in response to environmental concerns. While hydro-based DGs can provide stable, reliable and controllable power supply, the intermittent nature of other widely spread green sources like wind and solar make it difficult to maintain power balance in the system. In addition, the presence of DGs in the system may cause the reverse power flow that creates problems for protection systems.

Continuous growth of heat pumps (HPs) and electric vehicles (EVs) at consumer side introduces additional problems for power systems. Load profiles become more and more unpredictable and do not coincide with the peaks of maximum power production from DG-RES. Charging of EVs at home can require expensive distribution grid reinforcement [4], while the presence of HPs can cause voltages in distribution system exceed its limits, during their start-up [5]. Emerging technologies such as microgrids, virtual power plans and aggregation complicate the forecasting and distribution operation even further.

Integration and control of the DER and active demand in the distribution networks is a challenge since most of them owned and operated by the independent parties acting in accordance to their own strategies and interests. In the presence of all these elements, a special attention should be brought to the distribution systems that serves as an interface between generation and consumption. With changes on both sides, the attempt to operate the distribution grids in a traditional matter will require significant investments to strengthen the grid, accommodate DER and deal with the increased uncertainty. At the same time distribution system operators (DSOs), that are responsible for operating the distribution grids are required to reduce the capital investments in grid extension due to the presence of penalty/reward schemes, while maintaining same quality of service [6].

Different types of distribution networks with their distinctive features are shown in Fig. 1. At present the majority of the networks could be considered as either Passive Distribution Networks (PDN) with only passive consumers or Semi-active Distribution Networks (SADN) with a small share of controllable devices and highly uncertain load and generation. A concept of Active Distribution Network (ADN) [7] was introduced as an attempt to show the direction for changing the traditional PDN in such a way that new elements, their operation and control possibilities could be taken into account, resulting in potential savings for DSOs. Fig. 1 also shows the potential final stage in the electrical distribution network development as being a part of an integrated energy system (IES), that combines together several energy sectors and the associated network infrastructures.

Planning of the modern distribution networks represents a substantial challenge. In order to guide the transition from PDN to ADN, it is essential to understand how both types of networks are being planned and what are the new information and knowledge that will emerge due to the inclusion of the active elements (AEs) in the grid planning. While many algorithms and studies addressing these issues exist, the majority of them is based on a specific cases and cannot be applied to whole range of distribution grids. Utilities are in need of the standardized/generic framework solutions with holistic view on a planning problem in order to develop coherent planning procedures.

A generic multi-stage planning framework for incorporating flexibility from AEs in dis-

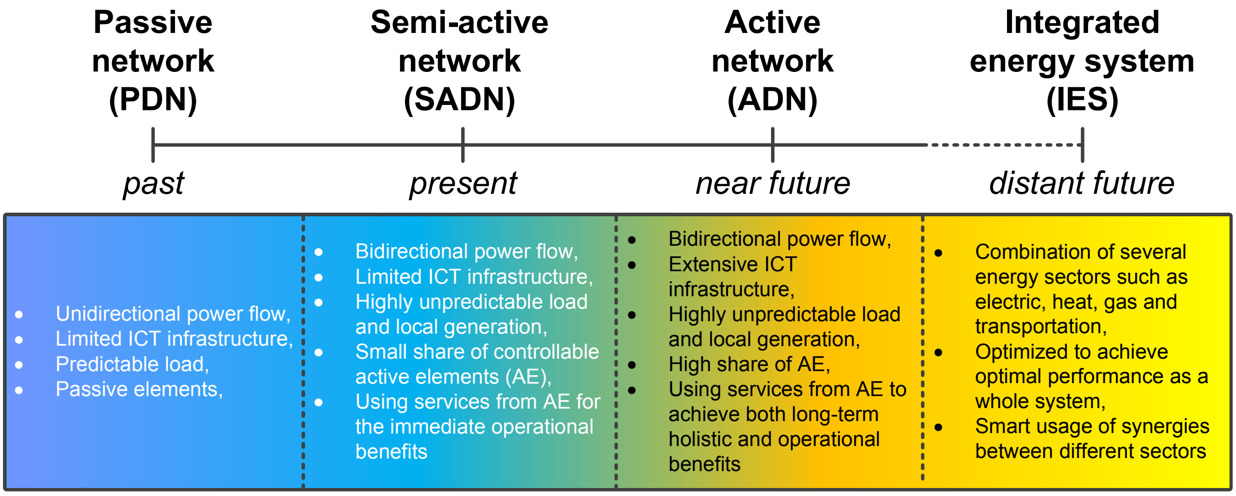

Figure 1: Evolution of distribution networks

tribution grid planning, which facilitates the transition from PDN to ADN is proposed in the current paper. Proposed framework considers all planning stages starting from the data collection to implementation plan and describes changes going from PDN to ADN planning.

Following definitions are used in this paper:

1. *Planning algorithm* is a specific approach (e.g. forecasting, modelling) that enables planner to reach one or more planning objectives, such as DG integration, voltage profile improvement, loss reduction, etc.;
2. *Planning procedure* is a sequential approach that defines how different planning algorithms are integrated to reach selected planning objectives;
3. *Framework* - a generic approach that integrates different planning algorithms in order to deliver streamlined planning procedure;
4. *AEs* - any equipment or actors in the distribution grid that have a possibility to be called for or directly controlled in order to change their behaviour to better suit the current need of the power system. Customers participating in demand response (DR) programs, remotely-controlled switches, battery energy storage system (BESS) and DGs are examples of AEs;
5. *Flexibility services (FSs)* - services provided by the AEs. Services like peak reduction/load shifting/voltage support which are requested by the DSO to achieve economic, reliable and safe electricity distribution or various DR programmes and reconfiguration (RE) are examples of FSs.

The paper is organized in the following manner. State-of-the-art in distribution planning is given in Section II. The proposed framework is presented in Section III. Section IV provides an example of using planning procedures based on the proposed framework in a planning exercise. Finally, conclusions are drawn in Section V.

2. Distribution planning. State-of-the-art

In this section, description of the different challenges associated with the PDN and ADN planning is given together with the explanation of the types of planning exercises. Both PDN and ADN frameworks are reviewed and the proposed framework approach is explained.

Generally distribution grid planning can be further divided into two parts: long-term and operational planning. In this paper, long-term planning is referred as network design (ND), while operational planning is called operational strategy (OS). The most common tasks for the DSO in the distribution planning is the installation/reinforcement of the transformers, cables and placement of the circuit-breakers and sectionalizing switches for network re-routing [8, 9].

2.1. Types of planning exercises

Planning exercises can be divided into three categories.

Greenfield planning refers to the planning of new areas, where no previous electrical infrastructure exists, the input data could be in a form of load centers that should be supplied with power [10]. Greenfield projects give the most flexibility to the distribution grid planner in terms of topology and layout selection, but are not common tasks in most of the developed areas.

The second type of planning is distribution *grid expansion* [11, 12]. Expansion assumes that the existing network is just expanded to a new area (where some electric infrastructure can already be located). In some cases the new area can be supplied from the main substation located somewhere in the old grid. Since the new area is a part of the bigger distribution grid (like district is a part of a city), the limitations of the bigger network (existing ND and OS) is imposed in such planning.

Lastly, *grid reinforcement planning* [4, 13] is not necessarily aiming at introducing some new elements in the already existing grid, but rather on replacing/upgrading the old ones (transformers, cables), when the DSO experiences or foresees any operational issues such as network congestion or equipment malfunction. This is the planning exercise with the most of limitations.

It should be noted, that the proposed division is not fixed, since in some cases the difference between different types could be very small. All of the mentioned planning projects can be described using the framework below, with the differences found in amounts of information, uncertainty and efforts needed in each of the stages.

2.2. PDN planning challenges

PDN planning is used for the distribution networks with the unidirectional power flows and where the demand cannot be actively controlled.

In such planning, one of the challenges is to adequately forecast the highest power consumption - the peak load from the passive consumers, so that the corresponding equipment (transformers, cables, protection devices, etc.) can be properly dimensioned [14]. The peak load represents the "worst case scenario" - a cold Christmas night in Danish context, where high power demand from individual residences coincides with the large number of simultaneous users. Due to the inherited unpredictability of the demand and often the lack of the information about the consumer devices, the accurate forecasting within a long time span is not a trivial task. Spatial load forecasting based on the small-area [15, 16] for urban districts or road-frontage method for rural areas [17] or various load distribution functions [18, 19] can be used for this task.

After the forecast is done, another challenge for the planner is how to obtain a planning solution based on it that would comply with the utility's set of operational (voltage, current, reliability, etc.) and economic criteria [20–22]. Some of the criteria could be in contradiction to each other and therefore a tradeoff between them is required. Typically more than one solution can exist that fits the DSO's planning criteria. Algorithms using fuzzy logic approach with single or multi-objectives or multi-stage stochastic programming models can be applied for finding the optimal solution [23–25]. More information about algorithms and models can be found in [26–28].

The size of the distribution networks, that can include hundreds of nodes (e.g. secondary substations) with many interconnections poses an additional issue. The scale of the planning problem typically depends on what type of planning exercise is needed. In some cases it is very difficult to isolate small part of the network for considering it during planning exercise in order to simplify the problem. Large number of variables will further complicates the process of finding the best planning solution. Traditional algorithms and models often have to be modified in order to work with the large-scale problems [29–31].

The disadvantage of the PDN planning is that it can potentially lead to a large overdimensioning of the grid components in order to comply with the "worst-case" scenario algorithm and requirements for spare capacity in case of contingency (e.g. N-1 criterion). Using larger cables and transformers than needed will increase the capital expenditures (CAPEX), but will ensure the more robust distribution system, that does not require a tedious and precise operational control - "fit and forget" planning algorithm [32].

2.3. ADN planning challenges

ADN planning is a set of planning algorithms for the distribution networks with bidirectional power flows and varying amount of AEs among its electrical power consumers. The goal of ADN planning is the same as for the PDN - to ensure the adequate supply of the electric power to all of the customers.

The challenges described in the PDN planning subsection concerning forecasting of the passive demand, finding the optimal solution respecting all the constraints and scale of the problem are still relevant for the ADN planning. However, additional issues arise related to the demand forecasting and finding the optimal solution in the presence of new technologies in ADN.

The introduction of DER (DGs, ESS) and new types of consumer devices further increases the level of uncertainty regarding the power demand forecasting. This uncertainty can be divided into two parts: due to the intermittent power production of the DGs based on renewable energy (mainly solar and wind) [33, 34] and due to the operation of the various consumer devices. New devices often have uneven operational patterns (e.g. devices that can draw a high power, but for a limited amount of time, turn on/off cycle - heaters, HPs, boilers, EVs), that might contribute to the creation of the short-term peaks of power [35, 36]. That makes the accurate forecasting even more important than in the case of PDN planning. Algorithms based on the spatial forecasting to predict DGs installation and their production [37, 38], regression models [39–41] and neural networks [42, 43] are proposed to improve the long-term forecasting accuracy. More about methods for forecasting in ADN can be found in [44–46].

In a power system where the unbundling rules are applied [47], DSOs are not allowed to own any generation or ESS, which can be used to make profit [48, 49]. Therefore most of the AEs (with exception of cables providing dynamic line rating (DLR) or switches used in RE) are controlled by the independent entities. Fig. 2 shows the potential ways AEs could provide their FSs to the different parties on the distribution or even transmission level in the nearest future [50, 51]. AEs can be providing their FSs from different energy sectors (purely electric - ESS, switches in RE; heat - HPs and heat storage; gas - gas storage; transportation - EVs) [52]. As could be seen that depending on their size, AEs could sell their FSs to the DSO directly or via aggregator [53–55] or a special flexibility market [56, 57]. It could also be possible for the transmission system operator (TSO) and other DSOs to compete for the FSs from the AEs with the DSO from the area, where AEs are physically located [58, 59]. DSO has to have knowledge about how different AEs operate to improve the quality of their forecasts. [60, 61] provide an overview of the different interactions of AEs with other parties and describe market policies.

After the forecasts taken into the account new devices and their potential interactions are made, DSO should consider how its own ability to influence the behavior of the AEs in the network will affect the final planning solution, that has to comply with the technical and economic criteria. Heuristic evolutionary [62–64] or genetic algorithms [65] can be used to obtain a final solution. More information about algorithms used in ADN planning can be found in [66, 67]. In addition to the typical DSO tasks mentioned in the beginning of the section, DSO can now determine the best locations for the AEs installation and either construct them itself (switches, cables) or attract independent parties (for DGs, ESS, etc.). [68, 69] propose genetic algorithms that consider probability of every individual scenario for optimal DG installation, PSO and chain-constrained optimization algorithms are used for ESS installation in [70, 71].

New emerging technologies like microgrids, virtual power plant, vehicle to grid (V2G), etc. have to be considered by the DSO and integrated into their planning solution as discussed in [102–106]. All of the above makes the scale of the planning problems even large than in the case of PDN planning and extremely complicates the process of finding the optimal solution.

An attempt to disregard the changes on the generation and consumption sides and plan the ADN using PDN planning algorithms could lead to the tremendous overdimensioning of the grids components and substantial increase in CAPEX [107]. In order to decrease the necessary investments in the grid, DSOs have to better utilize the potential of AEs in their networks interacting with them as shown in Fig. 2. Table 1 provides an overview of the research papers describing planning algorithms that use AEs (ESS) or FSs (DR, RE) to

Table 1: Table of references

Planning algorithm	Planning stage		Planning objective					
	Network design (ND)	Operational strategy (OS)	Investment reduction/ Reinforcement deferral	Voltage profile improvement	Reliability improvement	Power loss reduction	Energy cost reduction	Coordination with DGs
with DR	[72], [73], [74], [75], [76], [77], [78]	[79], [80], [81], [82], [83], [84], [85]	[72], [73], [79], [80], [81], [82], [83], [76], [85], [77], [78]	[74], [75], [85], [78]	[74], [82]	[74], [75], [83], [84]		[73], [81], [76]
with ESS	[72], [86], [87], [88], [89], [90]	[82], [91], [92], [93], [94]	[72], [82], [91], [88], [89], [90]	[91],[86], [89], [93], [94]	[82], [92]	[86], [93], [90]	[87], [89], [90]	[86], [87], [93], [94]
with RE	[95], [96], [97], [78]	[98], [99], [100], [101]	[95], [78]	[97], [101]	[99], [96]	[98], [95], [99], [96], [97], [101]	[98], [100], [97]	[100], [96]

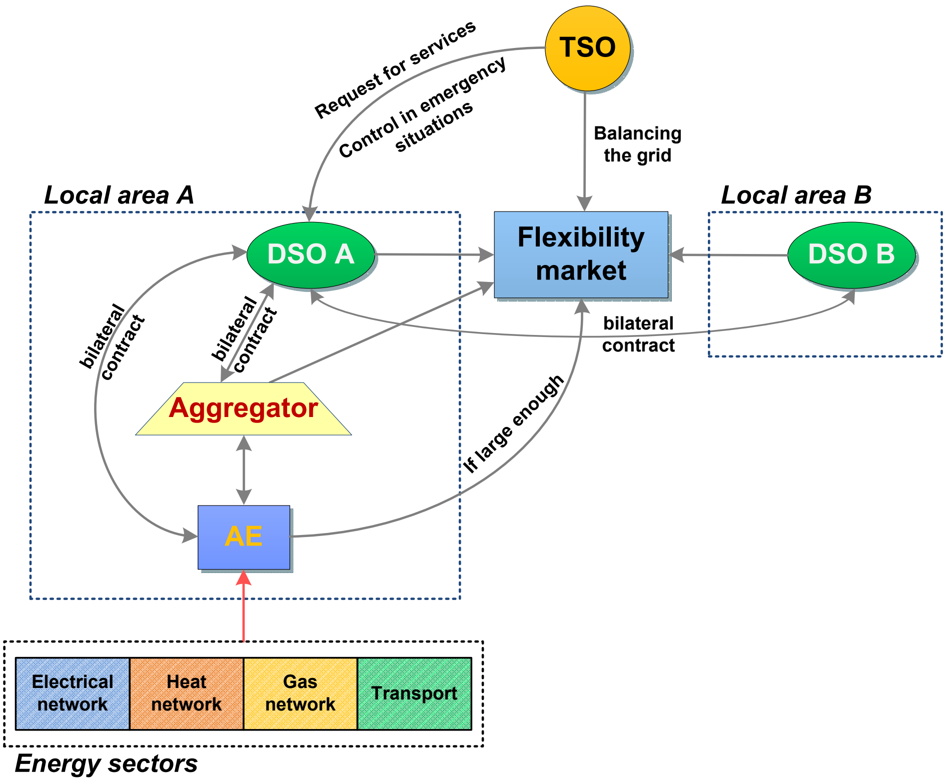

Figure 2: Interactions of the AEs with the other parties in the power system

achieve different planning objectives. AEs and the FSs they provide are also investigated in a number of projects both in Europe [108–115] and US [116–119] ranging from their integration with ND or OS in a single building to the more holistic system level.

If AEs are integrated into ADN planning, the grid does not have to be dimensioned for a "worst case scenario", since the peak loading situations can be handled by controlling generation and/or demand [120]. This will require an increase of operational expenditures (OPEX), but will allow to lower CAPEX at the same time. Introducing AEs in the ADN planning will demand higher degree of interconnection between ND and OS planning in contrast to PDN. Using AEs to benefit the ND planning without proper coordination with OS can lead to appearance of a new negative effects such as load kickback [121], voltage deviations [122] and even cause failure to the equipment.

By using ADN approach to the grid planning, the grid planners will have more time for deciding upon the optimal reinforcement plan, using flexibility as a temporary solution in the problem areas.

2.4. Framework solution

Numerous planning algorithms exist that aim at achieving one of several planning objectives. However, it is not always clear how such algorithms should be combined together in order to use it in a holistic planning process. Therefore a framework solution is needed, that shows how to integrate different planning algorithms together to facilitate the process of

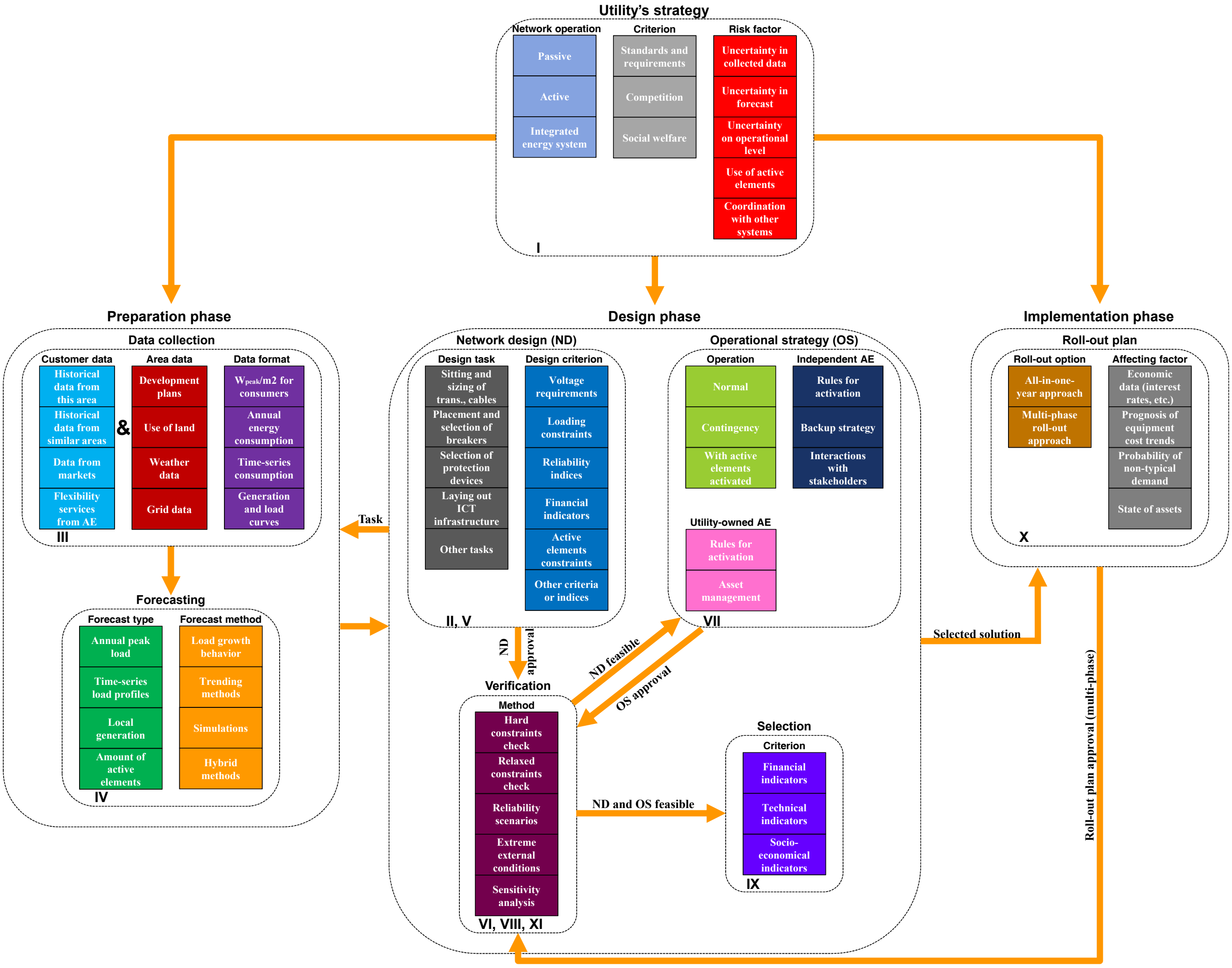

Figure 3: Proposed planning framework. Roman numbers indicate the order of the stages

finding the optimal solution among great number of potential options. Framework solutions proposed for both PDN and ADN are shortly described below.

In [123] framework for asset replacement based on the risk and likelihood of negative events is described. [124] presents the framework for the PDN planning consisting of the identification of the planning alternatives, network calculations and cost evaluations. In [125] the framework combining the long-term sitting and sizing plan (ND) with the short-term OS for energy production is proposed. The bi-level planning framework, where in the first stage the necessary equipment upgrades are decided, while the actual time of installation is determined in stage two is given in [126]. [127–129] propose the frameworks for the introduction of DGs in the distribution grid. The frameworks for integrating microgrids and virtual power plants into the ADN are given in [130, 131]. [124] describes the framework for the ADN, that allows to use both network (ND) and no-network (OS) solutions to be used in the final plan. The frameworks for the probabilistic system planning are presented in [132, 133]. Finally, the framework for the regional smart grid, which attempts to integrate generation, transmission, distribution and AEs (e.g. EVs) is proposed in [134].

The planning procedures used by the DSOs are very diversified and made based on the specific network and according to each DSO's best practices. The majority of the existing frameworks focuses on individual planning objectives and only applicable for the specific distribution grids under special conditions. They therefore do not provide a sufficiently generic picture about how planning stages are related to each other and how all new elements and emerging technologies described in the previous sections could be integrated together.

The framework solution proposed in this paper is generic and could serve as a basis for development of the planning procedures for both PDN and ADN. It helps to streamline the planning process, making it easier to integrate different planning algorithms with each other.

3. Planning framework

The proposed multi-stage planning framework is shown in Fig. 3. The framework consists of three phases preceded by the block defining "utility's strategy".

After the strategy is defined, starts the *preparation phase* consisting of "data collection" and "forecasting" stages. Here the work on the specific area is initiated. The arrow from the design phase means, that the objective of the planning exercise should be provided in addition to the features defined by the strategy to perform an adequate preparation.

"ND", "OS", "Verification" and "Selection" stages form a *design phase*, with the aim of creating solutions for the planning exercise, verify them and select the one, that suits the electric utility the most. The design phase combines both long-term and short-term operational planning and assumes that the process of finding the solution involves iterations between "ND", "Verification" and "OS" stages in order to avoid negative consequences of using AEs.

Implementation phase deals with proposing actual plan for building the proposed solution.

3.1. Utility's strategy

"Utility's strategy" represents a first step of a multi-stage planning process and is used to clearly define high-level features of the considered electric power system and to give general guidelines for moving towards target (desired) modern power system or ADN.

In this stage the utility decides upon the way to operate its network - passive (no or limited involvement of AEs), active (AEs are incorporated in ND and OS) or as part of IES via integration and coordination with other energy sectors.

Another important aspect of utility's strategy is to decide what kind of criteria are going to be used during ND stage. This could be influenced by several factors, one of them being ownership of the electric utility (e.g. private or community).

In "standards and regulations" algorithm the focus is on satisfying all the necessary technical criteria (reliability, voltage, etc.) specified in the grid codes, but not exceeding them.

Since electric utility is a natural monopoly, as a rule, there is no competition for the customers. However, wider spread of DG and storage technologies together with decrease in their cost will allow customers to go off the grid [135]. In such situation, utilities can be operating in a "competition" mode, where they will strive to improve the criteria even if they are already lie within acceptable range. Such utilities can be apt for trying new environmentally-friendly solutions and encouraging renewable generation in their grid. In addition to that, many countries introduce benchmarking of their electric utilities, where they are compared with each other and could be penalized for inferior performance [136, 137].

Publicly owned utilities can select the "social welfare" criteria as a basis for their planning [138], where they try to maximize the socio-economic benefits from their grids.

Risk factors show the uncertainties that could be present in the planning process and the utility's way of handling them. Depending on the type of network operation that was chosen, several uncertainties may arise [139].

Uncertainty in the collected data expresses the utilities awareness of their metering infrastructure capabilities, precision and its current state, as well as company's general knowledge of its customer base. Uncertainty in the forecast describes the confidence in the methods used to predict the future power demand in the long term, while operational level uncertainty represents the degree to which the day-to-day load changes could be precisely estimated.

If active or IES network operation is chosen, uncertainties regarding availability and responsiveness of AEs and coordination with other energy sectors are added.

The level of uncertainty acceptance is directly related to the risk. If, for instance, certain utility has adopted a risk averse behavior [140] (could be seen as a "conservative approach"), it will have low tolerance towards risks associated with uncertainty and will try to completely eliminate them on later planning stages even at the cost of higher CAPEX (PDN planning). On the contrary, companies that are ready to accept some degree of risk can lower their CAPEX, if they have a strategy how to handle the situations their grids are not designed for. Therefore, their OPEX will raise, but on a lower scale than decrease in CAPEX (ADN planning).

3.2. Data collection

The data collected in the "data collection" stage form a basis for the forecast in the next stage. The aim is to get an understanding of what is located in this area in terms of types of customers, their power demand, existing and potential sources of DER (f.e. estimated from electricity market data) and FSs from AEs and whether the area is fully developed or some major constructions are expected. In case of grid extension and reinforcement the data can often be gathered directly from the area in question, making it somewhat more realistic and precise, while greenfield project has to rely on historical information obtained from similar previously developed areas.

Several data formats can be used during "data collection" phase. W_{peak} per m^2 is used to approximately estimate future power demand for a new area. Customers annual energy consumption obtained from metering infrastructure together with load curves form a basis for the next stage of forecasting ("the worst case" algorithm) [141]. With the advances in the metering devices and gradual implementation of Smart Meters, electric utilities have an opportunity to get time-series consumption measurements from their customers [142], that are essential, if utility wants to utilize FSs from AEs in its system.

3.3. Forecasting

"Forecasting" stage is an obvious step after "data collection". Since typical planning horizon is around 15-20 years [143], it is necessary to try to predict the evolution of the considered area. Several aspects need to be forecasted: changes in the demand (potential growth, stagnation or decline), local generation (mostly how many PVs and wind turbines this area likely to have in the future, using the weather data collected in the previous phase) and amounts of AEs [144, 145]. If the option of contracting FSs from AEs is considered, then forecast of time-series load power consumption is required.

Forecast methods that utilities can use consist of load growth behavior prediction, trending methods, simulations and hybrid methods, which are combinations of the latter two [146–148]. While simulations are somewhat more cumbersome to use, they usually provide better results and can give insights into how certain factors affect the forecast. Using multiple scenarios provides a way to encompass the uncertainty related to evolution of parameters and shows several potential outcomes.

3.4. Network design

"ND" stage starts with identification of the tasks for the planning exercise. Placing and sizing of transformers, cables, breakers, protection devices and laying out ICT infrastructre are among the main objectives for DSO planning [8]. In addition to the introducing new components, ways of connecting them to the existing network have to be thought through. The other tasks could include the connection of the big customers (f.e. large HP, wind turbine), which if not done properly can bring disturbances to the other users [149, 150].

The desired planning solution for the distribution grid will be the one that is fulfilling number of technical and socio-economic criteria. Voltage, loading (current) and reliability criteria are the basic technical criteria of the power system and have to be satisfied [14, 151]. Typically the maximum loading of the network's components are treated as constant values. However by implementing more measuring devices and sensors, it is possible to come from the fixed values to the dynamic ones, that are determined by the physical state of each component and its surroundings (e.g. DLR, [152]). This will provide distribution grid planners with more flexibility and components with dynamic loading can be treated as AEs.

Other criteria are not specified in the grid codes and regulations, but could be used by electric utilities in competition or social welfare mode. Examples of such criteria could be level of losses, ability to accommodate renewable generation, certain level of equipment utilization and the loading under N-1 situation [153]. In some case, as with the attempt to build a network able to integrate a large portion of renewable generation, focusing on one design factor can compromise other important parameters such as voltage, therefore the resulting design is always a compromise between different design criteria. Lastly, the overall budget of utility should be considered in order to make a reasonable grid design.

3.5. Verification

"Verification" stage is used to check, whether all the constraints and requirements are satisfied. Simulations should be made, analyzing the behavior of the proposed solution during different contingency situations (calculating reliability indices [154]) and extreme external conditions (mainly weather such as storms, snowfalls, hurricanes [155]). The sensitivity analysis is performed to show how the variations in one of the parameters will affect the overall plan and may indicate some necessary adjustments to make the design more robust.

In the proposed framework the "Verification" stage is used three times. First - after ND planning is made: if ND plan is not feasible, than another ND solution has to be made. Second time - after OS is defined: if no feasible OS solution has been found for proposed ND, new ND has to be made and the process starts again. Third time - after establishing the roll-out plan: in case of the need to split the implementation into different construction phases, each of such phases should still satisfy selected criteria.

All constraints and requirements in PDN planning are considered as hard, meaning they have to be satisfied all the time by proposed ND planning solution. By utilizing FSs in ADN constraints could be relaxed, i.e. they do not have to be satisfied by solely the chosen network configuration or layout (ND planning), but in combination with AEs in the grid (ND & OS planning). By relaxing the criteria that are violated only for a very limited amount of time the grid planning could be made more cost-efficient under the condition of having an adequate OS to handle sub-normal situations, when they occur.

3.6. Operational strategy

"OS" stage is where the strategy for controlling the network's assets in different operation modes is designed.

If ND is done in accordance to PDN planning logic, than the resulted solution is strong enough to handle most of the possible loading situations. That makes designing OS a rather straightforward process.

In ADN planning, however, with integration of AEs and FSs into planning process and potential relaxation of criteria mentioned above, "OS" stage becomes much more critical and complex.

Several operation modes should be considered: normal, contingency situations (faults, equipment failures, etc.) [156] and operation with activated AEs, if reliance on AEs and FSs had been defined in the utility's strategy. To simulate the operation with AEs is essential to avoid creating new disturbances, while attempting to satisfy design constraints.

To understand how to operate the network under different conditions, the rules for when, how and how much different AEs or FSs from AEs should be activated have to be established [157]. All AEs are categorized by the way they can be operated: utility-owned AEs (e.g. breakers, on-load tap changers) can be controlled directly, while independent or non-utility assets have to be contracted prior to be able to obtain FSs from them.

During operation of utility-owned AEs, their state (wear and tear) should be taken into consideration through asset management [158]. Operation of independent AEs will always possess some inherent uncertainty regarding their availability and responsiveness, therefore the backup strategy should be formulated to hedge the risks. By involving owners of independent AEs in ADN planning and operating process, they become new stakeholders of the ADN and interaction with them is crucial to enable information exchange.

When OS is defined, it is send to the "verification" stage to check for its feasibility.

3.7. Selection

The selection of the most optimal network design is made in the "Selection" stage. Often, more than one feasible solution are produced for the planning exercise. The best option is decided by comparing financial, technical and socio-economic indicators of each proposal [159]. What criteria to prioritize and to which extent is decided by each electric utility individually and should be defined in "utility's strategy" stage.

3.8. Roll-out plan

"Roll-out plan" stage represents the implementation phase, showing how the proposed solution will be executed. Due to the financial constraints and in order to minimize uncertainty in terms of evolution of demand, it is common to split the implementation plan into several construction phases. Each of these phases are followed up by the evaluation of the actual power demand vs forecasted one, and the further plan is adjusted, if needed. This stage combines technical and economic considerations together to get technically viable and cost-efficient roll-out plan. Once a suitable roll-out plan has been found it is send to "verification" stage, after successfully passing which the distribution planning exercise is completed.

4. Example of using planning framework

This section provides an example of how a typical grid reinforcement exercise is performed according to the PDN and ADN planning procedures. Both procedures are based on the planning framework in Fig. 3. Only elements from the preparation and design phases of the proposed framework are considered.

The studied system is shown in Fig. 4a. It consists of one loop with two feeders that are operated radially in normal mode, but can be connected to each other via an open switch in case of contingency. The network represents a part of a newly built urban distribution system in central Copenhagen, that includes five loops with more than 40 secondary substations.

The following situation is assumed: presently 10/0.4 kV secondary transformer 1271 on the one-transformer substation 12 is operated close to its maximum capacity of 500 kVA. Due to the potential load growth in this area, the power demand on that transformer could exceed the rated capacity in a few years. Therefore a planning exercise is initialized to handle this situation. Customers connected to the substation represent a combination of residential and commercial load. Residential customers can be contracted to provide DR FSs, while some of the commercial customers have BESS, that could be used to help the grid (Fig. 4b).

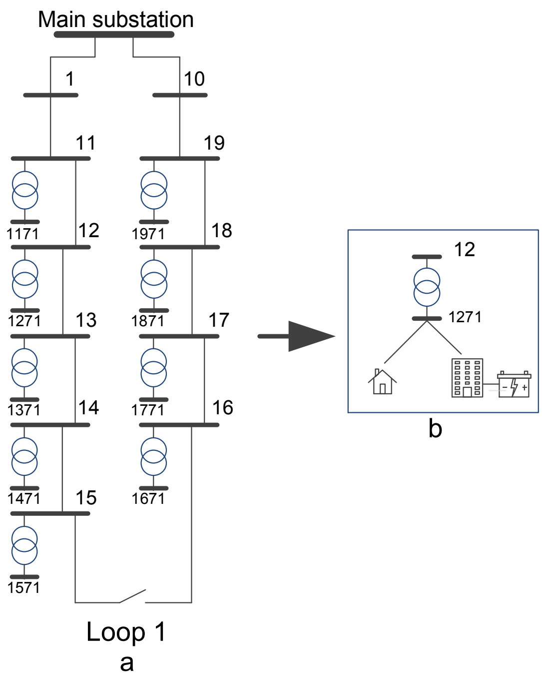

Figure 4: Distribution system. a - part of 10 kV network with two feeders, b - composition of the loads on a selected substation

4.1. PDN planning procedure

PDN planning procedure involves elements shown in Fig. 5. Utility's strategy in that case is to operate network as passive, according to the standards and requirements. Risk factors are uncertainties associated with data collection, forecast and operation.

Since PDN is characterized by the lack of metering infrastructure, a lot of data cannot be obtained directly and can only be estimated with the certain accuracy. In the preparation phase historical data from the area is used as a basis for the forecasting in the form of yearly energy consumption measurements for each customer connected to the given substation. Provided patterns for different customer categories (built on historical data from other areas) are known, the aggregated peak power on a transformer can be estimated using statistical methods, Velander's formula or simultaneity factors [160]. This peak corresponds to a worst case consumption during considered historical period and serves as a basis for further forecast. Uncertainties about data accuracy and during operation is generally included in that value.

Fig. 6 presents three forecasted scenarios of the evolution of load growth behaviour for the next 15 years on the studied substation: light, medium and heavy. The parameters used for each scenario are gathered in Table 2. All scenarios assume same trend of the power increase (due to the availability of empty land giving place for more constructions), which slows down after first 7 years.

Based on the forecasts ND solution is to replace the transformer by the one with higher capacity, 630 kVA in light scenario or 800 kVA - according to medium and heavy scenarios

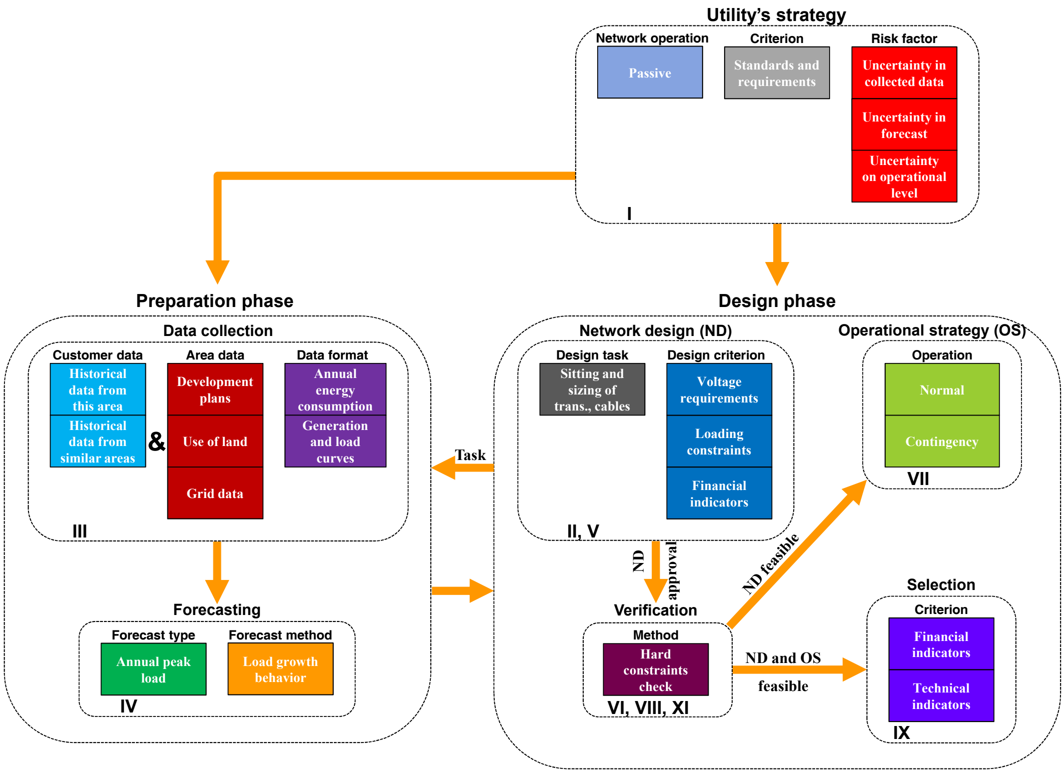

Figure 5: Elements of PDN planning procedure based on the proposed framework

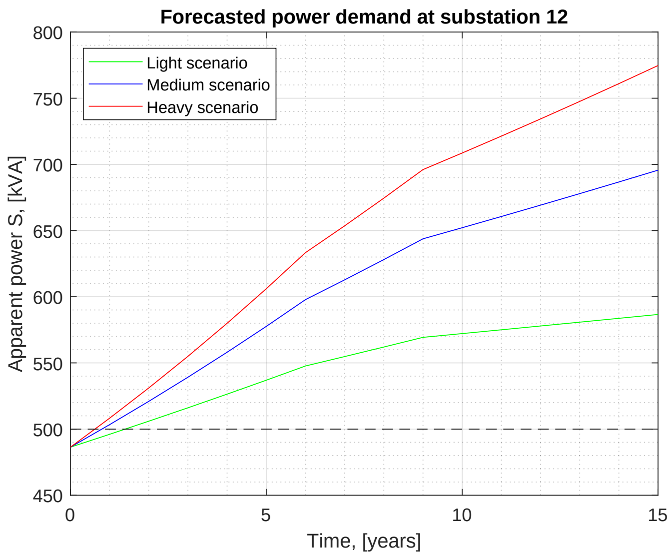

Figure 6: Three forecast scenarios for power demand at substation, dashed line represents the current transformer rated power

(using preferred values of rated power from standard IEC 60076-1 [161]), which will be enough to handle the worst case consumption (confirmed at "verification" stage). Assuming

Table 2: Forecast parameters

Scenario	**Change in % to a previous year**		
	From Y1 to Y7	From Y8 to Y10	From Y11 to Y15
Light	2	1.3	0.5
Medium	3.5	2.5	1.3
Heavy	5	3.5	2

one year delay between making a decision and actual installation of a new transformer, the decision to upgrade the transformer has to be made at year 0 (Y0) for medium and heavy scenario and at Y1 for light scenario.

Since constraints (in this case loading) are already satisfied by ND solution alone, design of OS is needed just to form a strategy of using this new transformer during normal and contingency operation modes. According to the operational criteria used at danish electric distribution company "Radius" [162], the maximum loading for a component is 100 % of its maximum capacity during normal operation, while in contingency situation (fault, N-1, etc.) it can be overloaded for a short time. Since there is only one transformer on a substation, in case of its failure all the customers will be disconnected during the repair time. Due to the transformer having enough spare capacity during most years of its operation, once the transformer is installed and fully operational, no special operational strategy in normal mode is needed, making it "fit and forget" planning algorithm.

In the final "selection" stage 800 kVA transformer was selected for installation at Y0, since it can handle both medium and heavy loading scenario. The cost of 10/0.4 kV 800 kVA distribution transformer is estimated to be 25000 $, which include both the cost of unit and cost of installation works (10 % of total cost).

4.2. ADN planning procedure

Elements of ADN planning procedure are shown in Fig. 7. Utility's strategy in ADN planning procedure is based on the active involvement of AEs in the ND and OS. This will add uncertainty from AEs in addition to the risks present in PDN.

The decision to involve AEs in planning requires collection of the time-series historical data with at least 1-hour resolution (Fig. 8) to be able to see how the actual demand changes during day-to-day operation and make the strategy for using FSs from AEs in the further stages. Such data could be provided by ICT devices such as smart meters installed at each customer [163]. The higher the data resolution the more precise the amount of FSs needed could be estimated, which will be reflected in the overall cost of contracting AEs. In addition to that an assessment of already present AEs and the FSs capabilities from them should be made.

The forecasting stage consists of making several forecasts regarding the aggregated power demand evolution and the amount of AEs that will be available for FSs to support DSO. Load duration curves (LDC) can be used to plot the forecasts of future power demand in the light, medium and heavy loading scenarios. Fig. 9 shows the heavy loading scenario built using parameters from Table 2. Since only the values close and above the current

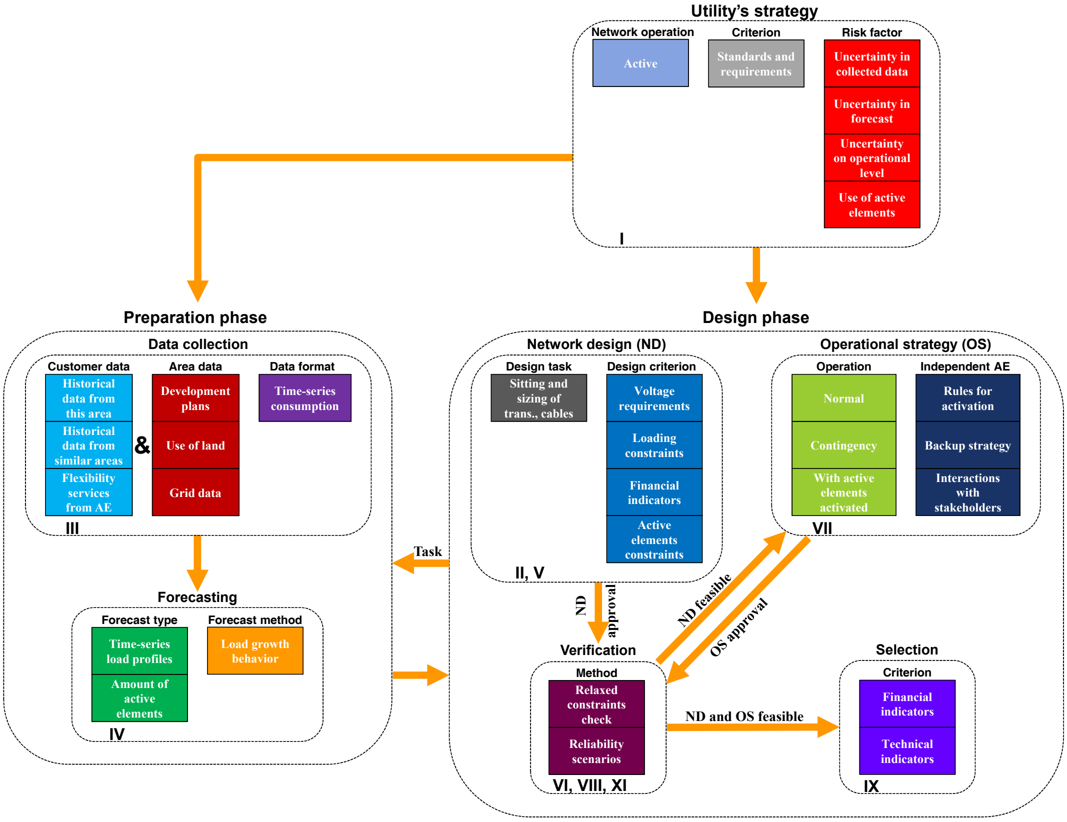

Figure 7: Elements of ADN planning procedure based on the proposed framework

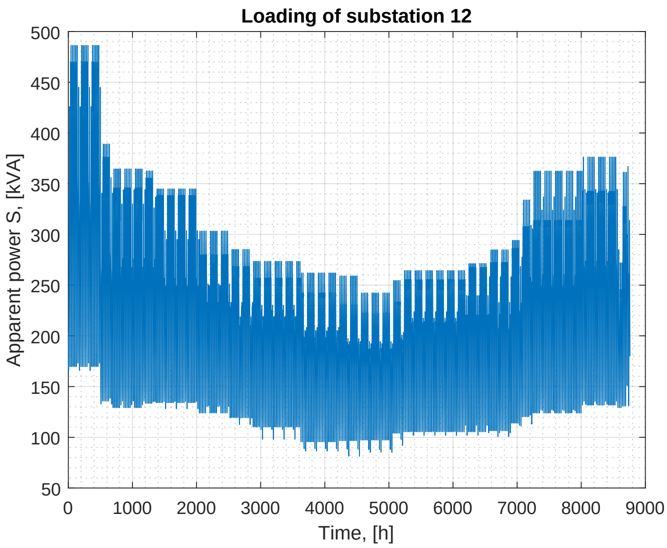

Figure 8: Historical power demand for 1 year with 1-hour resolution

transformer rated power represent interest for the planning, only the first 1000 hours are shown.

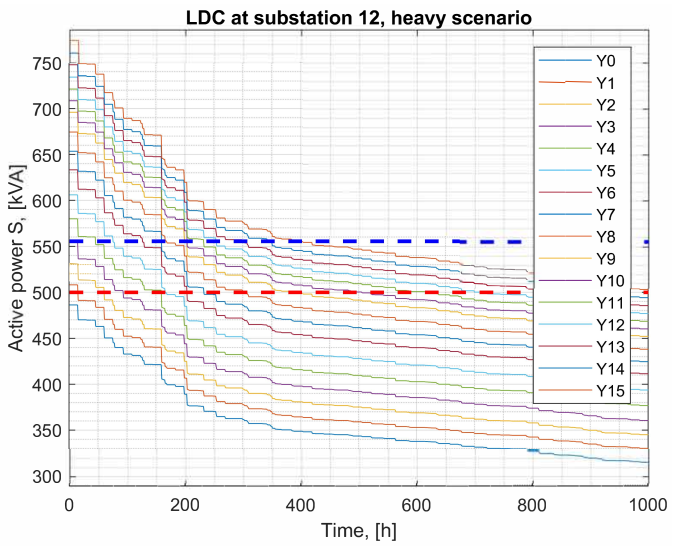

Figure 9: LDC for heavy load scenario for 15 years, (hours from 0 to 1000). Red dashed line represent - current transformer rated power, blue dashed line - chosen design value

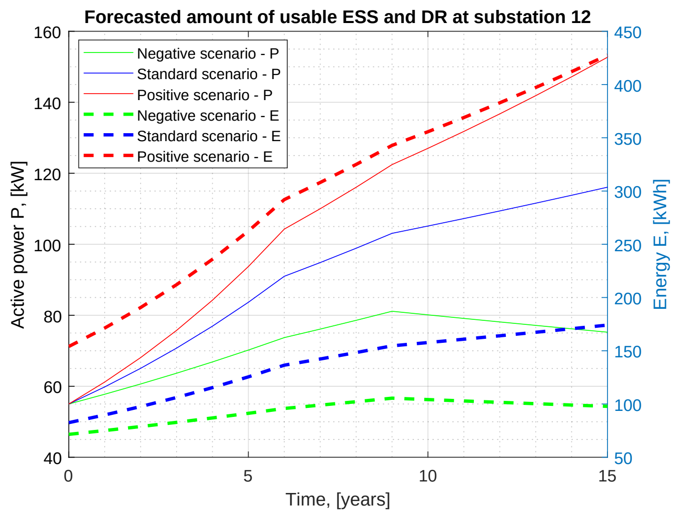

Figure 10: Three forecast scenarios for the amount of available aggregated ESS and DR capacity (solid line) and energy (dashed line)

Table 3: Forecast parameters for the amount of AEs

Scenario	**Change in % to a previous year**		
	From Y1 to Y7	From Y8 to Y10	From Y11 to Y15
Negative	5	3.25	1.25
Standard	8.75	4.25	2
Positive	11.25	5.5	3.75

Table 4: Operation parameters of using FSs from AEs

Year	Number of hours consumption is higher than transformer rated capacity	Expected peak power, [kVA]	Expected peak reduction from AEs, [kW]	Expected max energy from AEs, [kWh]	Total energy from AEs, [kWh]
Y0	0	486.3	0.0	0.0	0.0
Y1	15	508.2	8.2	8.2	122.9
Y2	60	531.1	31.1	44.0	942.7
Y3	93	555.0	55.0	105.0	2597.8
Y4	159	579.9	79.9	349.9	5400.1

Two parameters are important for assessing AEs ability to provide FSs for the grid: amount of power reduced in kW and maximum reduced energy (kWh). Fig. 10 shows three potential scenarios of the amount of usable ESS and DR capacity for peak reduction and energy based on parameters in Table 3. Available energy from ESS takes into account the minimum depth of discharge of the different BESS units and represents the actual available capacity for DSO purposes.

According to the presented ADN planning procedure, transformer in ND planning stage does not have to satisfy loading constraints entirely, if there are some AEs in the system. Utility decided, that the current transformer capacity should cover at least 90 % of the peak at the substation, which leads to the new design value equal to 555.6 kVA. Design value is selected based on the DSO's attitude towards risk, amount of available AEs and DSO's confidence in the availability and responsiveness of FSs. When the load is forecasted to exceed this value, the transformer will be reinforced. From Fig. 9 for the heavy scenario this is expected to happen at Y4, Y8 - for light and Y4 - for medium. Based on the forecasts and chosen design criteria, 630 kVA transformer is selected to be installed at Y8 in the light scenario, while medium and heavy scenarios require 800 kVA transformer to be installed at Y4.

After ND solution is found, it is important to design OS for controlling AEs and ensure that design criteria are satisfied with the combination of ND and OS. Table 4 shows details of operation of AEs. Using negative scenario from Fig. 10, it could be seen that the amount of energy that has to be reduced in Y3 and Y4 cannot be provided by AEs on the substation, therefore FSs from AEs can be used until the end of Y2. The backup strategy in the case if some of the FSs will be unavailable is to allow overloading of the transformer for a short time up to 117 % of its rated capacity.

Feasibility of both ND and OS solution is confirmed at the "verification" stage after which, it is proposed to use FSs until the end of Y2 and install the 800 kVA transformer at Y3 (construction start Y2). Cost of FSs is given in Table 5.

4.3. Economic comparison

To compare solutions based on PDN and ADN planning procedures, a total benefit B of deferring a reinforcement of a transformer can be calculated using the net present value (NPV) [164] and equation below:

$$B_n = C_{transformer} * r^n - C_{FS,n}, \tag{1}$$

Table 5: Economic comparison between PDN and ADN solution

Year	**Benefit of deferring reinforcement, [k$]**	**Expected cost of AEs, [k$]**	**Total benefit, [k$]**
Y0	0.0	0.0	0,0
Y1	1.3	0.3	1,0
Y2	2.6	1.7	0,8
Y3	3.9	4.4	-0,5
Y4	5.4	8.9	-3,5

where $C_{transformer}$ - cost of transformer reinforcement at Y0, [$]; n - year, r - discount rate, [%], here 5 %; C_{FS} - cost of using FSs from AEs, [$].

Cost of using FSs from AEs C_{FS} is estimated using following expression:

$$C_{FS,n} = E_{reduced,n} \cdot C_{E_{FS}} + P_{reduced,n} \cdot C_{P_{FS}}, \tag{2}$$

where $E_{reduced}$ - energy required from FSs of AEs, [kWh]; $C_{E_{FS}}$ - cost of kWh reduced, [$], here 1.5 $ per kWh; $P_{reduced}$ - amount of power reduction required from FSs of AEs, [kW]; $C_{P_{FS}}$ - cost of kW reduced, [$], here 10 $ per kW.

The results are gathered in Table 5. It could be seen that the deferral of a transformer reinforcement by two years will get the best total benefit of 1.8 k$.

5. Conclusion

A generic planning framework is proposed in this paper. The framework serves as a basis for forming planning procedures that combine different algorithms and allow to integrate various emerging technologies into distribution grid planning.

Planning is a complex multi-stage process that should be started by setting clear well-defined high level objectives. Changes in any of the stage should be considered from the system point of view with evaluation of their potential influence on the other stages.

It was demonstrated how planning procedures for both PDN and ADN can be made based on the proposed framework. While PDN planning procedure is often straight-forward and can result in a robust network, it will require extensive CAPEX in order to handle the uncertainty created by the generation and consumption. The ADN planning procedure is based on using the FSs from AEs and can potentially lead to significant savings and make the grid more closely dimensioned to the real power demand.

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[B] Utilizing Flexibility Services from a Large Heat Pump to Postpone Grid Reinforcement

Utilizing Flexibility Services from a Large Heat Pump to Postpone Grid Reinforcement

Sergey Klyapovskiy, Shi You*, Rafael Calpe Domens, Henrik W. Bindner, Hanmin Cai
Center for Electric Power and Energy (CEE)
Technical University of Denmark (DTU)
2800 Kgs. Lyngby, Denmark
Email: sy@elektro.dtu.dk

***Abstract*—Distribution grid reinforcement problem is considered in this paper. Annual growth of the electric loads may lead to the congestion situations in the distribution network, where current flowing through components exceed their maximum current carrying capacity (MCCC). A conventional solution is to reinforce overloaded components, i.e. to replace it with the one with higher capacity. However, this will lead to the additional investments for the distribution system operator (DSO). An alternative solution is to utilize flexibility services (FS) such as reconfiguration (RE) and demand response (DR) to provide peak reduction from the large controllable loads (e.g. a heat pump) in the system. Several forecasts of the future load growth simulated in the MATPOWER are used to study the proposed solutions and identify their feasibility. The results show that both FS can be used to defer grid reinforcement providing economic benefits for the DSO.**

***Index Terms*—Distribution planning, flexibility service, heat pump, reinforcement, MATPOWER.**

I. Introduction

For decades planning of distribution networks was based on two assumptions: unidirectional power flow from the large power plants down to the end users and passive consumers with well-predictable load patterns [1]. No possibility for changing the consumer behavior in response to the change in the system state was considered. The network was treated as a passive distribution network (PDN) - a passive part of the power system.

The introduction of distributed generation (DG) [2] units on the production side and new types of consumer equipment such as heat pumps (HPs), electric vehicles (EVs) [3] and energy storage (ES) on the distribution level led to the situation where previous planning assumptions from passive networks do not hold anymore. The presence of new elements increase the uncertainties related to the amount of power flowing through network components [4]. Additionally HPs, EVs and ES have a cyclic operation mode, where they draw large amount of power (turn-on cycle), but only during limited number of hours [5], which is followed by the turn-off cycles with low or no power demand at all.

Uncertainties and cyclic nature of operation of new generation units and loads could potentially result in the cases, where the maximum current carrying capacity (MCCC) of some network components is exceeded throughout the year. When the power flowing through the component exceeds its MCCC, the component is considered overloaded and causes congestions in the part of the network [6].

Distribution system operator (DSO) is responsible for providing customers with requested power of sufficient quality and one of its main task is to plan the distribution system, that can handle the power demand for years ahead including all the uncertainties. Traditional solution to solve the congestion situation in the network is reinforcement of the component, whose MCCC is going to be exceeded. However, if the number of hours the MCCC is violated is relatively low, the reinforcement of the component will lead to the network being overdimension most of the time with low grid utilization and high capital expenditures (CAPEX) [7].

In order to reduce the necessary CAPEX, the flexibility potential of the new generation and loads present in the grid has to be utilized. By installing more control and communication systems, all the aforementioned new types of equipment can be turned into active elements (AE). AE is an element whose behavior can be directly or indirectly controlled, if needed, thus providing flexibility services (FS). Such FS have different nature, some of them originate from the customers in the grid like peak reduction/shifting through demand response (DR) [8] or by using battery energy system storage (BESS) [9] - *consumer-based FS*, while peak reduction through reconfiguration (RE) or voltage support via transformers with on-load tap changer (OLTC) [10] are examples of the *grid-based FS*, which depend not only on the customers but also on the technical characteristics of the distribution network.

Using FS from AE could be used as an alternative to traditional reinforcement. This will allow to make the grid more flexible, improve power or voltage quality and provide deferral of grid reinforcement. Utilizing the potential of AE is a step towards active distribution network (ADN) [11].

Current paper investigates the congestion situations in a 10 kV electrical distribution system. Congestions are assumed to occur due to the presence of a large HP, installed at the end of one of the feeders and its cyclic nature. The paper proposes to achieve peak reductions to mitigate congestions by utilizing FS from the system via RE or from HP itself with DR. Costs of both of these solutions are then compared with the cost of traditional grid reinforcement to identify the best option. A part of the existing distribution grid of Nordhavn area in Copenhagen, Denmark is used to test the proposed solutions.

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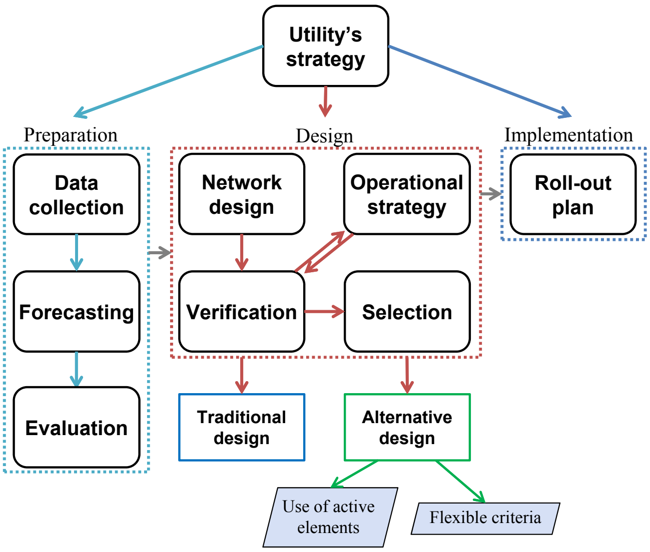

Fig. 1: Generic planning framework

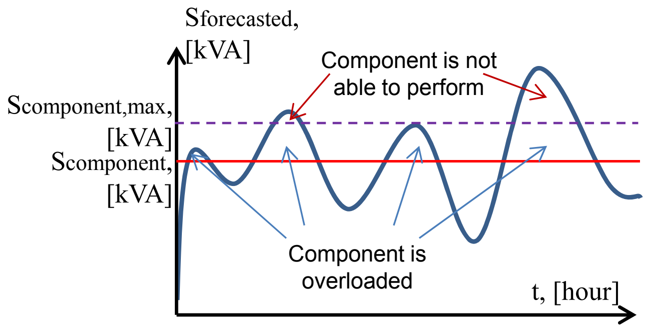

Fig. 2: Detection of excessive loading of component

Paper is organized in the following manner: generic planning framework supporting the integration of the FS from AE in the traditional planning is presented and explained in Section II; Section III describes methodology used to study the selected problem; study system is described in Section IV with study cases and results in Section V. Finally, conclusions are drawn and future work is outlined in Section VI.

II. Planning framework

Generic planning framework is shown on Fig. 1. While performing any planning exercises such as grid reinforcement, grid expansion and greenfield planning in PDN or ADN, the typical process could be represented as a series of phases (typically consisting of multiple stages) focusing on different activities.

"Utility's strategy" stage is the main block of the depicted framework. There the decisions about network operation mode, used design criteria and risk factors should be made. All choices made in that stage will affect the further phases.

"Preparation" phase consists of "data collection", "forecasting" and "evaluation" stages. Based on the title of the stages, the main activities there are to gather information about the network and its customers, forecast the changes in power demand and evaluate the obtained forecasts for potential problems.

"Design" phase includes "network design", "operational strategy", "verification" and "selection". In this phase the problems found in the previous stage should be solved and the plans for what, where and how much to construct and how to operate the resulted system are made. "Verification" stage is used to verify whether the obtained solution satisfy all the criteria, while comparison of the all technically acceptable options is performed in "Selection" block.

Finally, the "Implementation" phase task is to create a roll-out plan. The plan indicates when the actual construction and installation of all new components should be carried out.

The planning of PDN is traditionally done by considering the worst case scenario [12], i.e. the worst possible power consumption and passive customers with predictable behavior. These assumptions combined with the new generation and load types could potentially lead to the power ratings of components being higher than economically necessary, which will require additional CAPEX. The advantage of the "fit and forget" approach is that the operational expenditures (OPEX) could be kept at a relatively low level.

If the network is chosen to be planned as ADN, then the FS from AE could be used to satisfy the grid loading requirements. This will complicate the operational strategy and raise the OPEX, because satisfying the long-term design criteria is now laid upon both "network design" and "operational strategy" planning stages. However, since in certain situations the reinforcement deferral is achieved, CAPEX could be lower than in the case with PDN.

It should be noted, that in order to fully utilize the FS from AE, it is best to plan the network in accordance to the framework on Fig. 1 from the beginning. This is due to the fact, that the introduction of FS will require changes in most of the planning stages, like the need for different data format (e.g. time-series measurements vs annual energy readings), different forecast techniques or additional interactions between stages. At the same time, simple contracting of FS and their incorrect utilization can potentially lead to the creation of additional problems, like kick-back effect [13] or overvoltages.

More information about the planning framework and the description of what elements are included in each of the stages could be found in [14].

III. Methodology

A. Forecasting

Power demand in the same area has a tendency to grow, due to the new consumers and introduction of the new loads at the already existing ones. The growth rate is typically expressed in percentages and is very area dependent. While new areas' power demand can grow fast, old well-established neighbourhoods can have a negative load increase, because of the energy efficiency measures. Connection of the DGs in the area will also affect the power demand, potentially supplying all the extra demand without visible load increase.

To check whether the load changes could potentially create issues in the distribution grid, the load profiles are projected in the future. Since there are a lot of uncertainties regarding future power demand, number of different scenarios are typically generated.

B. Detecting power congestion

The forecasted power flows should be compared with the equipment rated power $S_{component,rated}$ to detect potential overloading as shown on Fig. 2. Most of the components have an ability to withstand loading, which exceeds their rated values for a certain time period and therefore the light overload is not likely to cause congestion problems in the network. The maximum allowable power that component is able to withstand is denoted $S_{component,max}$ and is a function of MCCC. If the loading exceed $S_{component,max}$, then component is not able to perform its functions and the network can be congested as a result.

The task of the DSO is to identify how many times per year and how long the congestion events will occur, so that the cost of using FS from AE could be estimated more accurately.

C. Applying flexibility services

If some AE are present in the network, FS from them can be used to lower the peak load during the congestion periods (CONP), when the network components are not able to perform their functions (each period typically consisting of several consecutive congestion hours (CONH)). FS from some AE can be contracted on the monthly or even yearly basis, where their flexibility could be utilized after giving a short notice period, while for other FS DSO may have to compete and can only contract them for short-term.

Two types of FS services are described below. RE is partly grid-based FS, which is performed using combination of AE that are network components and customer AE. DR is a purely consumer-based FS, where the AE refers to flexible electricity loads.

1) Reconfiguration: RE is a process of changing system topology. AE in the case of RE is a circuit-breaker or switch (SW). If the load or group of loads are connected to the two feeders, with one connection being primary and second one as a reserve option, it is possible to shift these loads between feeders, thus changing the power demand on both ends. Thus FS of peak reduction via RE could be achieved. RE between feeder 1 (F1) and 2 (F2) could be achieved if:

$$S_{F1,max} \geq S_{F1,forecasted} - S_{load,RE}, \tag{1}$$

$$S_{F2,max} \geq S_{F2,forecasted} + S_{load,RE}, \tag{2}$$

where $S_{F1,max}, S_{F2,max}$ - the maximum allowable loading of F1 and F2, respectively, [kVA]; $S_{F1,forecasted}, S_{F2,forecasted}$ - the forecasted loading of F1 and F2, respectively, [kVA]; $S_{load,RE}$ - reconfigurable load, [kVA].

The reconfigurable load should be switched to F2 during the CONP and switched back, when they are over. As could be seen from Eq. 2, using RE requires that feeder F2 has enough spare capacity to accommodate additional load.

2) Demand response: DR represents a consumer-based FS with consumers' equipment as AE. Certain types of customers have the possibility to change their power consumption, either by reducing it or increasing, if there is a need from the DSO side. Such services are called DR. The change in power consumption is activated by sending signals to the DR participants (e.g. price or direct control signal). From control perspective, it is easier to get DR from the large customers, such as HPs or a fleet of EVs, however, FS from DR can be obtained from individual small-scale customers, as well.

Peak reduction via DR on feeder F1 can be achieved if:

$$S_{F1,max} \geq S_{F1,forecasted} - S_{load,DR}, \tag{3}$$

where $S_{load,DR}$ - reduced load by DR, [kVA].

Similar to RE, DR FS should be used, when the peak power is expected to exceed MCCC of the equipment. Special attention should be brought to the amount of DR loads, that are released from providing FS. If too many loads will start drawing power that was postponed by DR at the same time, it could lead to creation of another peak, i.e. so called "kickback effect". To avoid that, there should be some delay in stopping DR FS from different providers at each instance.

3) FS cost: Cost of each FS can be characterized by two components: CAPEX and OPEX as shown in Eq. 4. CAPEX represents a fixed amount of investments independent of the number of hours FS is operated. OPEX, on the other hand, is a function of time.

$$C_{FS,total} = C_{FS,CAPEX} + C_{FS,OPEX}, \tag{4}$$

where $C_{FS,total}, C_{FS,CAPEX}, C_{FS,OPEX}$ - total, CAPEX and OPEX of FS, respectively, [$].

DR can be obtained with no or relatively low CAPEX at all, if DSO decides to invest in building the ICT infrastructure for control purposes. OPEX of DR is cost of providing FS.

RE requires a connection between two feeders to be able to shift the loads. The cost of building such connection is a significant part of RE's CAPEX. In addition to that the installation of any additional SWs is covered by CAPEX as well. OPEX include the cost of switchings and maintenance.

IV. System description

A. Topology

Part of the actual 10 kV radial distribution system in the urban area of Nordhavn in Copenhagen is used in the current paper. The system is shown on Fig. 3 and has four feeders forming two loops. Feeders in each loop are connected with each other via tie-lines, that enable the RE within that loop. The network is connected to the upstream system at node 8, which represents the main substation 60/10 kV.

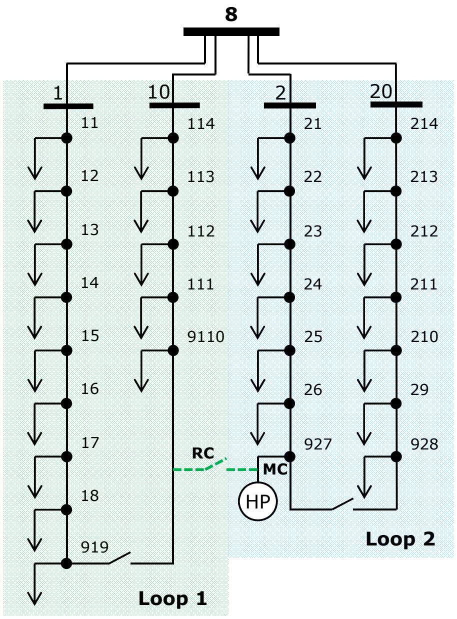

Fig. 3: Part of the 10 kV distribution grid of Nordhavn area. 8 - main substation, nodes starting with 9 indicate the last point of the feeder; MC - main cable for supplying HP; RC - HP's reserve cable

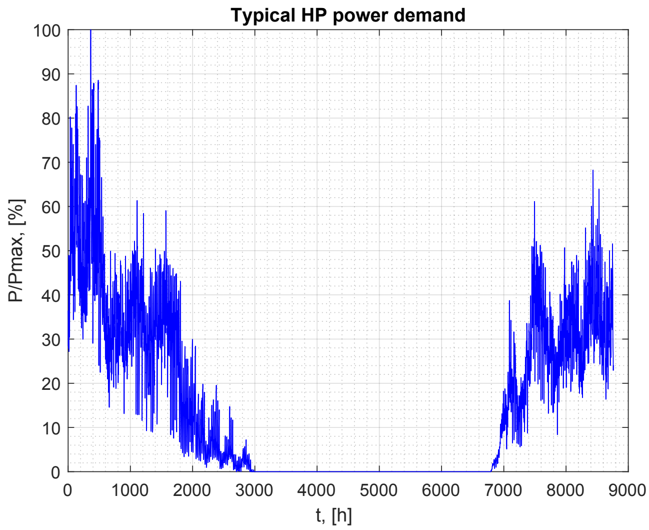

Fig. 4: HP demand profile for one year

TABLE I: Forecast parameters

	Change in % to a previous year	
Scenario	**Loop 1**	**Loop 2**
Light SC	3	5
Medium SC	3.5	6
Heavy SC	4	7

The feeders are made of a series of underground cables with maximum allowable power that can flow through main cables (i.e. 8-1, 8-10, 8-2 and 8-20) estimated to be $S_{cable,max}$ = 1700, [kVA].

B. Electric loads

Each node in Fig. 3 is a 10/0.4 kV secondary substation with load connected to the LV side. All loads consist of different residential, commercial and light industrial customer categories. The power demand on each feeder is spread unevenly throughout the year, with peaks typically occurring during winter months due to the dominance of the residential loads.

A large HP with rated power $P_{HP,rated}$ = 500, [kW] is installed at the end of the feeder 8-2 with power demand following the trend on the Fig. 4 [15]. HP is operated only during the colder months with absolutely no consumption in summer. HP can be supplied with power via two routes: MC denotes the main (primary) connection to the feeder 8-2, while an additional reserve connection (RC) to the feedere 8-10 is used to improve HP's reliability. In addition to that HP can also provide DR FS.

C. System modelling

The system in Fig. 3 is modelled using Matlab and MATPOWER software [16]. MATPOWER uses the iteration process to solve power flow equations and determine the nodes' voltages and exact power flows between branches.

The system is modelled using MATPOWER. Time-series data synthesized from the actual Nordhavn energy measurements for 2016 is used to simulate the demand for 1 year for each customer type at each substation. The total load of the substation is then aggregated.

PQ buses are used to represent all nodes, except of main substation node 8 designated as a slack bus.

The transformers 10/0.4 kV are modelled as branches in accordance to the MATPOWER logic.

V. Results

The results section is using methodology and planning framework on Fig. 1 to solve congestion problems in the distribution network. The costs used in DR and RE calculations are assumed values based on the assumptions due to the difficulties in obtaining actual costs.

A. Forecast scenarios

Based on the power demand data gathered at the "Data collection" stage for the year 2016, three scenarios are made in "Forecasting" stage for the next 5 years. Light, medium and heavy load growth scenario (SC) represent the potential changes in the electrical load of every secondary substations at every feeder. Since constructions in the area with feeders of loop 1 is almost finished their load growth is estimated to be slower than the feeders in loop 2. The parameters of load increase are shown in Table I. Randomized values of power demand were added to the resulted forecasts in order to introduce some stochasticity.

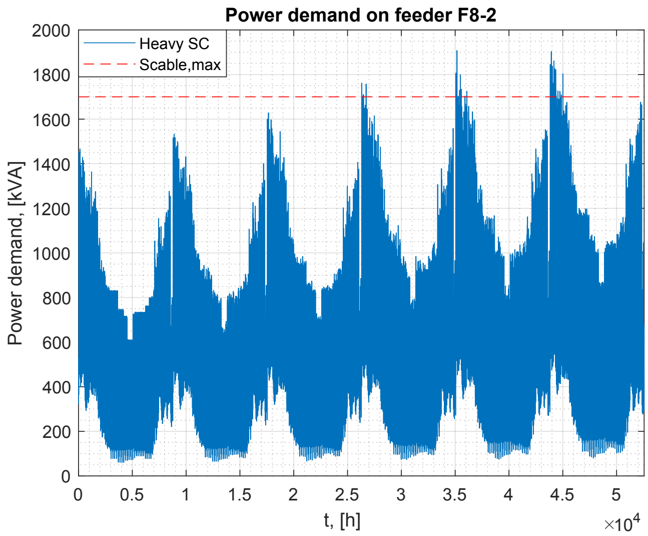

Fig. 5: Base case. Red dashed line - maximum allowable power through main cable 8-2 (function of MCCC)

TABLE II: Results of base case

Scenario	CONH, [h]	CONP	Cable length, [km]	$C_{reinf,total}$, [k$]
Light SC	5	4	1.2	108
Medium SC	24	19	1.8	162
Heavy SC	63	39	2.1	189

B. Base case

The "evaluation" stage is performed by calculating power flows for the current and 5 next years to obtain the power demand on the feeders and identify the potential problems.

The example of power demand at feeder 8-2 for the heavy SC is shown on Fig. 5.

Feeder 8-2 will start experiencing congestion situations starting in the year 2019 in the medium and heavy SC and in the year 2020 according to the light SC. The number of CONH and CONP is shown in Table II.

Conventional solution for network congestion is to reinforce overloaded components. Table II shows the total length and approximate total cost related to such reinforcement. The cost of 90000 $ per km (approximate cost for Denmark) is assumed for calculations. Since the cable installation is the dominating part of the CAPEX, the differences in cable sizes are omitted. OPEX for the reinforcement option is equal to zero, so that the total cost is purely CAPEX.

As could be seen the number and duration of congestion events are relatively low, which makes traditional reinforcement (solving problem by using "Network design" alone) an expensive solution.

C. Case A: applying RE

By shifting the load of HP during CONP the congestion could be avoided. Since RE involves moving HP load to another feeder, it could be considered by FS partly provided by HP owner, which has to be compensated for its services. The resulted power demand on feeder 8-2 after applying RE indicates that congestion situations are successfully prevented.

To calculate the total cost of RE in Case A three options are considered:

1) HP owner has a RC cable already in place and the SWs do not have to be upgraded: the total cost will be the cost of OPEX from the number of switchings. DSO will have to compensate the HP owner for the equipment usage and the potential brief interruptions due to RE. Cost of contracting HP services $C_{HP,contract}$ is estimated to be 3000 $ for the whole period;
2) SWs have to be upgraded: the total cost will include CAPEX on the new SWs and OPEX as well. $C_{HP,contract}$ in this case is 1500 $;
3) DSO will have to construct RC cable by itself: the total cost include CAPEX on the new cable and OPEX from the switchings. $C_{HP,contract}$ is 500 $ to compensate the HP owner for potential interruptions;

Each time RE is performed three SWs have to be activated. At the end of each CONP SWs are used again. The total number of switchings is therefore equal to 3*2*CONP. After every 50 switchings for each switch 500 $ is added to the total cost to indicate the cost of additional maintenance. The cost of each new SW is set to be 8000 $, while the length of RC is 0.8 km with cost of 90000 $ per km. Costs of all of the options are summarized in Table III.

By comparing costs of reinforcement and RE, it could be seen that using RE has lower total cost. The amount of benefits obtained from RE is highly dependent on the number of SWs and connection cables the HP owner has.

D. Case B: applying DR

Second FS involving HP is DR. HP owner is participating in three DR programs, where it can reduce HP consumption in steps by 10, 15 and 20 %, respectively for the duration of maximum 4 hours. Each of the program has its own cost per each activation.

The results of using DR for the power demand in heavy SC is shown on Fig. 6. Combination of all three DR programs is used to prevent the congestion situations. Comparing Fig. 6 with power demand on Fig. 5 it could be seen that the number of CONH is reduced, but not eliminated. It was found that in the medium and heavy SC using DR is not sufficient to solve the congestion problems.

The cost of DR services is shown in Table IV. The fix cost of each activation is set to be equal to 150 $, 200 $ and 250 $ for DR10, DR15, DR20, respectively.

The cost of DR has only OPEX part and does not require high expenses in comparison with traditional reinforcement. However, the amount of power reduction HP can provide is only sufficient to handle power demand in the light SC.

VI. Conclusions and future work

Two FS from the large consumer - HP were considered in this paper. While DR is purely consumer-based FS, RE is also dependent on the grid characteristics. The amount of flexibility

TABLE III: Results of Case A

Scenario	# of switchings	$C_{RE1,OPEX}$, [k$]	$C_{RE2,CAPEX}$, [k$]	$C_{RE2,OPEX}$, [k$]	$C_{RE3,CAPEX}$, [k$]	$C_{RE3,OPEX}$, [k$]
Light SC	24	4.2	24	2.7	72	1.7
Medium SC	114	8.7	24	7.2	72	6.2
Heavy SC	234	16.2	24	14.7	72	13.7

TABLE IV: Results of Case B

Scenario	DR10, [times]	DR15, [times]	DR20, [times]	CONH, [h]	Remaining CONH, [h]	$C_{DR1,OPEX}$, [k$]
Light SC	2	2	1	5	0	1.0
Medium SC	8	6	2	24	8	2.9
Heavy SC	12	22	13	63	16	9.5

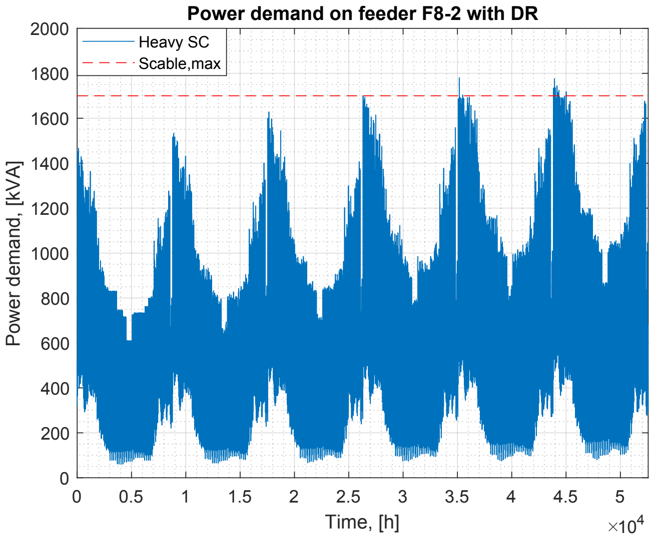

Fig. 6: Case B. Resulted power flow after applying DR. Red dashed line - maximum allowable power through main cable 8-2 (function of MCCC)

needed to solve the congestion problems are dependent on the forecast. Three different predictions for load growth were used in the paper to identify the potential overloading problems.

DR is FS that does not require high expenses and is the cheapest option in comparison to RE. However, the amount of power that can be reduced by DR is limited. The cost of RE is very dependent on the equipment (SWs and presence of RC) that the HP owner has. If the DSO has to construct a RC cable itself, than the cost of RE becomes close to the cost of traditional reinforcement.

By applying DR or RE potential savings could be achieved. The system components will be working more close to their limits, making the system utilization ratio higher.

Future work can include more detailed explanation of the FS modelling and cost estimation. The cost of additional losses caused by RE could be taken into the consideration. More AE providing FS should be considered.

Acknowledgment

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[C] Incorporating flexibility options into distribution grid reinforcement planning: A techno-economic framework approach

Incorporating flexibility options into distribution grid reinforcement planning: A techno-economic framework approach

Sergey Klyapovskiy[1], Shi You[1*], Andrea Michiorri[2], George Kariniotakis[2], Henrik W. Bindner[1]

1 - Center for Electric Power and Energy (CEE)
Technical University of Denmark (DTU)
2800 Kgs. Lyngby, Denmark

2 - Centre for Processes, Renewable Energies and Energy Systems (PERSEE)
MINES ParisTech
06904 Sophia Antipolis, France

sy@elektro.dtu.dk

***Abstract*—Distributed energy resources (DER) and new types of consumer equipment create many challenges for the distribution system operators (DSOs). Power congestions that can potentially be created during normal or contingency situations will lead to increased investments into grid reinforcement. An alternative solution is to use the flexibility provided by the local resources in the grid. In this paper value of flexibility (VoF) is used as an indicator that can be utilized by the DSO to compare it against costs of the different active elements (AEs) providing flexibility services (FSs). The paper proposes flexibility characterization framework that allows to generalize the process of the cost estimations of any AE by using combinations of cost functions. A case study based on an actual distribution grid is provided to demonstrate the potential application of the framework. Results show that by comparing VoF and total cost of the flexibility the most cost-efficient solution could be found.**

***Index Terms*—Active distribution network, flexibility characterization framework, active elements, flexibility services.**

I. Introduction

The intensifying efforts to reduce CO_2 emissions and increase energy efficiency are bringing large number of distributed energy resources (DER), such as distributed generation (DG) [1], [2], energy storage systems (ESS) [3]–[5] and new types of consumer devices like heat pumps (HPs) [6] and electric vehicles (EVs) [7], [8] to the distribution grids. The presence of these new components is changing the way distribution networks operate. The electric power congestions [9], [10] or out-of-range voltages [11] that could be predicted in previously passive networks now appear with a very short warning, requiring immediate actions.

In order to make the distribution networks more flexible and resilient towards demand profiles with high uncertainties and rapid variations, one of the most prominent solution for the distribution system operator (DSO) is to use flexibility [12] provided by the consumers or grid's components, known as active elements (AEs) [13], [14]. Devices like HPs, EVs, ESS or even circuit-breakers (CBs) and transformers with on-load tap changer (OLTC) can be treated as AEs. The services they offer to the system are flexibility services (FSs) [15], since they allow the distribution system to better adapt to the current power demand situation and potentially evolve into active distribution network (ADN) [16]. Long-term planning of the distribution networks which before was considered almost independent of the system's daily operation, will become deeply intertwined with the operational planning if DSO chooses to utilize FSs [17]–[19].

Different AEs possess different characteristics and can be operated in various ways, while still providing the same FSs, like voltage regulation or peak reduction. Therefore distribution grid planners could potentially face the situations, where there is a need to choose between different AEs to achieve the same planning objective. In order to do that, AEs should be compared on the same basis. From the DSO perspective, such common ground for most cases is the cost of implementing the solution.

In most cases, FSs from AEs, that are used to solve distribution network problems are alternatives to conventional solutions, such as grid reinforcement, load curtailment, installation of voltage correction equipment, etc. The value of flexibility (VoF) is the maximum cost that the DSO is ready to pay for the FSs and is determined for each case individually. If the cost of using AEs exceeds the VoF, contracting the corresponding FSs will not be economically viable for the DSO.

The paper proposes a flexibility characterization framework that provides a generic approach to the cost estimation of typical AEs, while taking into account AE's distinctive features. Quantification of the benefits and expenses from each AE through the framework will enable the comparison between different AEs and conventional solution and help the distribution planner in the related decision-making process.

The paper is structured as follows: Section II contains the state-of-the-art concerning typical grid issues, description of AEs used in the paper and their cost estimation. Four types of AEs/FSs are considered: demand response (DR), battery energy storage system (BESS), reconfiguration (RE) and dynamic line rating (DLR). Section III describes the methodology for determining the VoF. The general description of the flexibility characterization framework is given in Section IV. Section V presents the case study highlighting the potential application of the proposed framework, the results of which are shown in Section VI. Finally, conclusions are drawn in Section VII.

II. STATE-OF-THE-ART

A. Distribution grid issues

AEs could provide flexibility, that can be used by the DSO to solve issues in the distribution grid.

The most common issues at the distribution level are power congestions and out-of-range voltages [20], [21]. The out-of-range voltages could be either under- or overvoltages caused by various reasons, such as voltage drop, DGs (e.g. PV panels), motor start-ups, etc. Power congestion occur when the power flowing through a grid component exceeds its maximum carrying capacity (MCC), thus blocking a part of the network. Power congestion issues will be used as an example throughout this paper.

Typically distribution grid components, such as transformers and cables allow short-term overloading [22], [23] without jeopardizing the system performance, which is used by the DSOs. That is why from the DSO experience congestions are more likely to occur during contingency situations, such as N-1 [24]. N-1 contingency is a system state, where one of the grid's components is out of operation due to a fault or a failure. To minimize the loss of load in N-1, some of the remaining grid components will have to accommodate the increased power flows. With the increasing number of consumer devices with the cyclic operation modes (HPs, electric heaters, EVs, etc.), it could be expected to have power congestions even in the normal operation, if a large number of such devices are to turn on simultaneously.

Planning horizons used by most of the DSOs lie within 10-20 years - long-term planning. However, estimation of the power consumption and parameters of the potential congestion events (CEs) requires high accuracy forecasting, which is problematic to achieve within a long time range. To be able to utilize the benefits provided by the FSs of AEs more efficiently, the planning horizons could potentially be reduced to a medium-term range (ca. 5 years).

B. Cost estimation of AEs

In order to obtain the most cost-efficient planning solution, DSO has to compare different planning alternatives such as traditional reinforcement and using FSs from AEs. A comprehensive review of planning algorithms involving AEs could be found in [25].

Cost estimation of AEs is based on an understanding of what factors form the final cost and allow the DSO to decide whether it is economically viable to use AEs in planning. The literature review of the cost models for DR, BESS, RE and DLR is given below.

1) DR: Consumer devices are typically turned on based on the user's necessity or convenience. In the case of the latter, it is possible to postpone the moment when the device starts to operate. The change in the device's operational pattern caused by an external signal from the DSO or an aggregator is called DR. DR is an FS that can be provided by a wide range of electric devices (EVs, HPs, electric heaters, electric boilers, lighting, etc.).

[26] shows the DR cost model based on the supply-demand curves made by an aggregator. [27] describes how the capacity of DR FSs is changing following the corresponding change in price signal. The change depends on the self- and cross-elasticity coefficients of each type of DR. Calculating the bid price of the DR by taken its comfort level into account is described in [28]. In [29] stochastic mix-integer optimization algorithm is proposed to optimize the cost of acquiring DR FSs for an aggregator. [30]–[32] show the cost models based on the fixed incentives, average or dynamic pricing. More examples of methodologies for modelling DR are given in [33]–[35].

2) BESS: BESS is a device for storing electrical energy, which can be used at a later point in time. From the DSO's perspective, BESS could be considered as a local generator, able to provide power to the nearby electrical loads during the CEs in the distribution networks, thus potentially alleviating components' overloading. BESS is an AE, typically owned by an independent party due to the unbundling rules in the power systems (e.g. aggregator) [36].

[37] describes the BESS cost model based on the levelized cost of storage. The model estimates both capital (CAPEX) and operational (OPEX) expenditures of using BESS. The cost of recharging cycles that are diminishing the BESS resource is included in OPEX estimation. In [38] the detailed analysis of the BESS CAPEX that consists of storage unit cost, power conversion system and inefficiency factor is given. Inefficiency factor represents a relation between the rated and actual energy that could be extracted from the BESS. OPEX model of BESS is shown in [39]. The model is split into an electrical part, where the state of charge is determined and a degradation part which estimates the reduction of a unit's lifetime (LT). Other cost models for BESS are described in [40]–[45].

3) RE: Process of changing system topology via altering its power supply routes is called RE. By using RE in the distribution grid, it is possible to shift the electrical load from the congested part of the network to the part with the spare capacity, thus ensuring that all electrical customers are provided with power, and system itself is not in jeopardy. RE is an FS provided by the CBs. Since CBs are an integral part of the distribution networks, CBs are the example of utility-owned AEs.

[46] determines the cost of RE via the cost of switchings (SWs). The model is further expanded in [47] by adding the CB's operation time to the number of SWs. [48]–[51] present similar cost models for utilizing RE in planning.

4) DLR: In a traditional operation of distribution networks, the power ratings of overhead lines and cables are considered as fixed values independent of the external conditions. However, the exact MCCs of the lines are constantly changing and determined by the ability to dissipate the heat created by the electric current. Dynamically changing MCC based on the external conditions is referred to as DLR. By applying DLR in the ADN, a larger degree of overloading could be allowed, thus potentially eliminating CEs. DLR is an FS provided by the lines (overhead or cables), which are utility-owned AEs.

[52] describes the methodology for identifying the benefits and costs of using DLR. The cost is the cost of sensors (e.g. for soil temperature) needed to enable DLR, while the benefits are the amounts of extra energy that could flow through the cable. The DLR cost model presented in [53] shows how adding the forecast of DLR capabilities to the real-time measurements might increase the value of DLR FSs. The degradation model of cables under different loading conditions is given in [54]. More DLR cost models could be found in [55]–[58].

The majority of the existing literature regarding the cost estimation of AEs is focusing on specific technology under specific conditions. To facilitate the integration of AEs in planning, DSO needs a generic framework, that could be used to characterize the cost of any AE using the set of same criteria.

III. VALUE OF FLEXIBILITY

VoF represents the highest price DSO is ready to pay to the FS providers for their aid in solving a specific issue in a distribution grid. Since VoF depends on the amount of energy that should be requested from FS provider, in the current paper a probabilistic approach is applied to evaluate its value under different demand forecasting scenarios in long-term planning. The percentile $P\%$ will produce the value, which is higher than or equal to the values in the sample with $P\%$ probability. By choosing the 95th percentile, the values for the worst case could be evaluated (highest cost, largest power demand, etc.).

VoF can be determined as the minimum cost of the DSO's conventional planning alternatives. In case of potential congestion in the distribution network, DSO can either reinforce the grid or curtail the loads. In the latter case, DSO will have to pay the penalty for the energy not supplied (ENS), but it will also get the benefits from the saved investments in the reinforcement (e.g. interest in the bank). VoF can be calculated as follows:

$$VoF_{y,P\%} = min \begin{cases} C_{conv,TOTEX,y,P\%}, \\ C_{ENS} * E_{flex,y,P\%} - B_{y,P\%}, \end{cases} \tag{1}$$

where $VoF_{y,P\%}$ - VoF at the year y in the $P\%$ percentile, [€]; $C_{conv,TOTEX,y,P\%}$ - total expenditures (TOTEX) of a conventional planning solution, [€]; C_{ENS} - cost per unit of ENS, [€/kVAh]; $E_{flex,y,P\%}$ - total requested energy from the flexibility at the year y, [kVAh]; $B_{y,P\%}$ - benefits of postponing the reinforcement, [€].

In the first years, when the need for reinforcement occurs, the cost of ENS is lower than the cost of reinforcement. This makes the VoF a function of $C_{ENS} * E_{flex,y,P\%}$. VoF for the next year will depend on the decisions made in the previous years. By reinforcing the grid, the cost of ENS in the next year will be lower thus reducing the VoF for that year.

As could be seen from Eq. 1, TOTEX $C_{conv,TOTEX}$ of the conventional planning solution and the amounts of energy E_{flex} requested from the AEs in a flexibility planning are required to calculate VoF. By comparing VoF with the cost of flexibility planning $C_{flex,TOTEX}$, the most cost-efficient solution could be determined. Both conventional and flexibility planning types are described below.

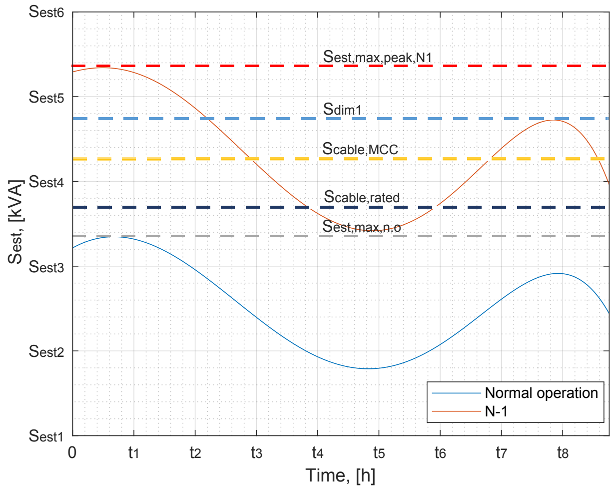

Fig. 1: Estimated worst case power demand on the feeder at year y for scenario SC - conventional planning to solve power congestion on a feeder

A. Conventional planning

To illustrate how the cost of a conventional planning solution is obtained, Fig. 1 showing a potential congestion situation during N-1 is considered. Based on the forecasts made for each year until the end of the planning horizon pl, in some of the scenarios SC power flow on one of the feeders in the distribution system is expected to exceed cable's MCC $S_{cable,MCC}$ during an N-1 contingency with estimated peak demand:

$$S_{est,max,peak,N1,SC} = \max_{1 \leq y \leq pl} S_{est,max,N1,y,SC}, \tag{2}$$

where $S_{est,max,peak,N1,SC}$ - maximum peak value during N-1 contingency during the whole planning horizon for scenario SC, [kVA]; pl - planning horizon, [year]; SC - scenario, [-]; $S_{est,max,N1,y,SC}$ - estimated peak power demand during N-1 contingency at the year y for scenario SC, [kVA].

The conventional solution, in this case, will be to reinforce that feeder with a cable with higher MCC according to the dimensioning criteria S_{dim1}, which is determined using the following expression:

$$S_{dim1} \geq \frac{1}{L} * S_{est,max,peak,N1,P\%}, \tag{3}$$

where S_{dim1} - dimensioning criteria for a component in a conventional planning, [kVA]; L - short-term overloading coefficient, [-]; $S_{est,max,peak,N1,P\%}$ - the maximum peak values during N-1 contingency during the whole planning horizon among all the scenarios [59] in the $P\%$ percentile, [kVA]:

Parameter L links component's rated power and its MCC. Short-term overloading coefficient is either obtained from the component's specification or determined by the DSO based on its own experience. Different values of L could be used for different durations of the overload, the shorter it is, the

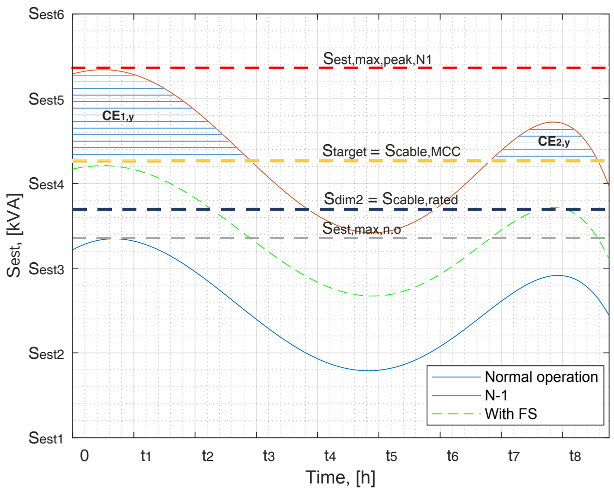

Fig. 2: Estimated worst case power demand on the feeder at year y for scenario SC - flexibility planning to solve power congestion on a feeder. CE - congestion event

higher the value of L. For the long-term planning purposes, L corresponds to the duration of the longest possible overloading event (i.e. in the range of hours).

TOTEX of any planning solutions consist of two parts - CAPEX and OPEX according to the following equation:

$$C_{TOTEX,P\%} = C_{CAPEX,total,P\%} + C_{OPEX,total,P\%}, \quad (4)$$

where $C_{TOTEX,P\%}$ - TOTEX of a planning solution in the $P\%$ percentile [€]; $C_{CAPEX,total,P\%}$ - total CAPEX part of the solution, [€]; $C_{OPEX,total,P\%}$ - total OPEX part of the solution, [€].

$C_{CAPEX,total,P\%}$ and $C_{OPEX,total,P\%}$ are calculated using $C_{CAPEX,total,SC}$ and $C_{OPEX,total,SC}$ for all planning scenarios and value of percentile $P\%$.

Since both CAPEX and OPEX can occur at different years, the net present value (NPV) formula should be used to sum them together. NPV allows to refer all the expenses to a current year:

$$C_{total,SC} = \sum_{y=0}^{pl} \frac{C_{y,SC}}{(1+r)^y}, \quad (5)$$

where $C_{total,SC}$ - total cost of either CAPEX or OPEX part of the solution for the scenario SC, [€]; $C_{y,SC}$ - CAPEX or OPEX of a solution for year y, [€]; - r - the discount rate, [-].

$C_{conv,CAPEX,y,SC}$ includes the fixed costs for equipment and could be estimated with Eq 6:

$$C_{conv,CAPEX,y,SC} = f(S_{dim1}) = \quad (6)$$
$$= \textstyle\sum_{n=1}^{N} (C_{comp,n,y,SC} + I_{comp,n,y} + A_{comp,n,y,SC}),$$

where $C_{conv,CAPEX,y,SC}$ - CAPEX of the conventional solution at the year y according to the scenario SC, [€]; N - total number of components, [-]; $C_{comp,n,y,SC}$ - cost of an nth individual component, [€]; $I_{comp,n,SC}$ - installation cost of an individual component n, [€]; $A_{comp,n,SC}$ - additional expenses caused by the nth component (expanding of substation in case of new transformer, new ICT network, etc.), [€].

OPEX are expenses that depend on the number of hours components are in operation and are distributed throughout components LT. OPEX will vary for each scenario. Future OPEX for the year y for scenario SC:

$$C_{conv,OPEX,y,SC} = f(S_{est,y,SC}, h_{operation,n,y,SC}) = \quad (7)$$
$$= \textstyle\sum_{n=1}^{N} C_{M\&L,n,y,SC},$$

where $C_{conv,OPEX,y,SC}$ - OPEX at the year y for the scenario SC, [€]; $S_{est,y,SC}$ - estimated worst case power demand for specific operation mode (e.g. normal operation, N-1, etc.), [kVA]; $h_{operation,y,SC}$ - number of hours component n is in operation, [h]; $C_{M\&L,k,y,SC}$ - cost of the maintenance of an nth component and electrical losses caused by it, [€].

B. Flexibility planning

An alternative to the conventional approach is flexibility planning. It utilizes the potential of FSs from AEs to achieve peak reduction during the congestion hours as shown in Fig. 2. The dimensioning criteria for flexibility planning will be S_{dim2}:

$$S_{dim2} \geq \frac{1}{L} * S_{target}, \quad (8)$$

where S_{dim2} - dimensioning criteria for a component in a planning with flexibility, [kVA]; S_{target} - target peak power limit maintained throughout the planning horizon, [kVA].

The power demand exceeding S_{target} should be covered by the FSs. Eq. 8 is provided for the case, when only one AE is used to provide all the flexibility needed. In the situations when multiple AEs are used, additional subindex k denoting the kth AE should be used together with updated power demand curves $S_{est,k,y,SC}$ that takes into account the effect of each AE and different values of S_{target} for each k, so that:

$$S_{target} = \min_{1 \leq k \leq K_{SC}} S_{target,k,SC} \quad (9)$$

where K_{SC} - total number of AEs used for providing flexibility in scenario SC, [-]; $S_{target,k,SC}$ - target peak power limit for the kth AE in scenario SC, [kVA].

If S_{target} is chosen to be equal to $S_{cable,MCC}$, S_{dim2} will be equal to $S_{cable,rated}$ and cable reinforcement could be postponed.

In the flexibility planning, the periods when CEs are supposed to occur (shaded areas on Fig. 2) at each year y of the planning horizon should be analysed and the following parameters determined for each scenario SC: duration of using flexibility during each CE $D_{flex,i,y,SC}$, capacity $S_{flex,i,y,SC}$ and energy $E_{flex,i,y,SC}$ requested from flexibility for each CE i and total number of times flexibility should be used $NO_{flex,y,SC}$ during year y. These parameters are used for determining VoF and the costs of using AEs.

The calculation of $C_{flex,CAPEX,y,SC}$ and $C_{flex,OPEX,y,SC}$ parts of the flexibility solution is described in the next section.

General parameters			CAPEX parameters		OPEX parameters				Evaluation criteria
What service? G1	Who owns AE? G2	How credible? G3	AE has to be build? C1	Additional equipment required? C2	How much and how long? O1	How often? O2	How fast? O3	How long in advance? O4	TOTEX of AE E

Fig. 3: Flexibility characterization framework

IV. Flexibility Characterization Framework

Proposed flexibility characterization framework is shown in Fig. 3. It is made in the form of a table, where each AE capable of providing FS to the DSO is assessed with the help of different questions identifying its general, CAPEX and OPEX parameters.

A. General parameters

These questions are used as a pre-qualification stage to select only suitable AEs:

1) What service? ($G1$): $G1$ identifies what potential distribution grid issue could be solved using FSs provided by a specific AE. If FSs from AE can be used to solve considered issue, parameter $G1 = 1$, otherwise $G1 = 0$;

2) Who owns AE? ($G2$): $G2$ determines AE's ownership - AE can be owned either by a DSO (electrical utility) or a third party (independent - another utility, aggregator, etc.). AE's ownership will determine how much information about AE is available in general, its CAPEX and OPEX and DSO's confidence in AE's performance. The ownership also influences the notice period for requesting FSs and control options (e.g. direct, indirect, etc.). Parameter $G2 = 1$ if AE is owned by the utility and 0 if AE belongs to a third party;

3) How credible? ($G3$): $G3$ estimates the credibility of AE - how confident DSO about receiving FSs from AE upon an activation request. If AE can be used for providing FSs parameter $G3 = 1$, if not - $G3 = 0$.

The credibility of each AE should be estimated by the DSO based on the following considerations:

1) Historical records - previous records of requesting and receiving FSs from an AE, if available. Information like number of requested/answered activation requests and the ratio between amounts of requested and fulfilled requests;
2) AE's ownership - described above in $G2$;
3) State of AE - indicates the wear and tear of AE providing FSs;
4) The penalty for not fulfilling activation request - will determine how important the activation request is for the FSs provider.

B. CAPEX parameters

"CAPEX parameters" are used to determine the potential CAPEX part of the $C_{flex,TOTEX,P\%}$:

1) AE has to be built? ($C1$): $C1$ identifies whether AE has to be built prior to the provision of FSs, parameter $C1 = 1$ if construction is required and 0 otherwise. Based on the answer to the question $G2$ about AE's ownership, this cost may be included in the CAPEX;

2) Additional equipment required? ($C2$): Additional equipment such as ICT infrastructure for DR or transformer substation expansion to fit the transformer with OLTC could be required to enable the provision of FSs from a specific AE. Parameter $C2 = 1$ if there is a need for additional equipment and 0 otherwise.

C. OPEX parameters

OPEX part of the total cost of the flexibility planning $C_{flex,TOTEX,P\%}$ is determined through "OPEX parameters". It is proposed to estimate OPEX via cost functions corresponding to the questions below. The cost from each cost function is determined for each planning scenario, the final value is then chosen using the $P\%$ percentile.

1) How much and how long? ($O1$): The cost of the requested energy from FS for ith CE can be described by a cost function $F_{O1}(S_{flex,k,i,y,mean,SC}, D_{flex,k,i,y,SC})$, where $S_{flex,k,i,y,mean,SC}$ - mean capacity requested from the kth AE during ith CE at the year y for scenario SC, [kVA]; $D_{flex,k,i,y,SC}$ - duration of using kth AE, [h].

2) How often? ($O2$): $F_{O2}(NO_{flex,k,y,SC})$ is a cost function showing the cost of total number of times FS is used, where $NO_{flex,k,y,SC}$ - total number of times flexibility from the kth AE is used during the year y for scenario SC, [-];

3) How fast? ($O3$): Cost function $F_{O3}(ROC_{flex,k,i,y,SC})$ determines the cost of AE's ramping up/down capabilities in providing FSs, where $ROC_{flex,k,i,y,SC}$ - rate-of-change of requested capacity from kth AE during ith CE at year y for scenario SC, [kVA/h];

4) How long in advance? ($O4$): $O4$ determines how much in advance warning has to be given to the AE for providing FS: $F_{O4}(NP_{flex,k,i,y,SC})$, where $NP_{flex,k,i,y,SC}$ - notification period for requesting FS from kth AE during ith CE at year y for scenario SC, [h].

D. Evaluation criteria

1) TOTEX of AE (E): Total cost of a solution with one or several AEs $C_{flex,TOTEX,y,P\%}$ is used as an evaluation criteria in the proposed framework.

TABLE I: Costs included in the CAPEX and OPEX of different AE/FSs according to the flexibility characterization framework

AE/FS	AE	Costs included in CAPEX		Costs included in OPEX		Cost functions
		Main	Additional	Main	Additional	
DR	Consumer's equipment	-	ICT and control infrastructure	Supplied energy	Energy difference	O1-O4
BESS	BESS	-	ICT and control infrastructure	Supplied energy	Recharge cycles, recovery cost of BESS unit	O1-O2
RE	Circuit-breaker (CB)	CBs	Tie-lines (TLs)	Number of switchings (SWs)	-	O2
DLR	Cable	-	Soil temperature sensors	Reduction in LT	-	O1

E. AE/FS costs

Based on the proposed flexibility characterization framework, CAPEX of the flexibility solution $C_{flex,CAPEX,y,SC}$ can be calculated as follows:

$$C_{flex,CAPEX,y,SC} = \sum_{\substack{k=1,\\ G1_k,G3_k\neq 0}}^{K_{SC}} C_{flex,CAPEX,k,y,SC} = \tag{10}$$

$$\sum_{\substack{k=1,\\ G1_k,G3_k\neq 0}}^{K_{SC}} (G2_k * C1_k * C_{AE,k,y,SC} + C2_k * A_{AE,k,y,SC}),$$

where $C_{flex,CAPEX,k,y,SC}$ - CAPEX of using kth AE in year y in scenario SC, [€]; $G1_k$, $G2_k$ and $G3_k$ - general parameters from the framework, [-]; $C1_k$ and $C2_k$ - CAPEX parameters, [-]; $C_{AE,k,y,SC}$ - cost of construction of the kth AE, is a function of the chosen $S_{target,k,SC}$, [€]; $A_{AE,k,y,SC}$ - cost of an additional equipment, [€].

$C_{flex,CAPEX,P\%}$ is calculated using $C_{flex,CAPEX,y,SC}$ for all planning scenarios and years and the $P\%$ percentile (Eq. 4-5).

OPEX from all used AEs $C_{flex,OPEX,y,SC}$ at the year y in scenario SC is dependent on the following cost functions and parameters:

$$C_{flex,OPEX,y,SC} = \sum_{k=1}^{K_{SC}} C_{flex,OPEX,k,y,SC} = \tag{11}$$
$$= \sum_{k=1}^{K_{SC}} f(G1_k, G2_k, G3_k, C(F_{O1_{k,y}})_{SC},$$
$$C(F_{O2_{k,y}})_{SC}, C(F_{O3_{k,y}})_{SC}, C(F_{O4_{k,y}})_{SC}),$$

where $C(F_{O1_{k,y}})_{SC}$, $C(F_{O2_{k,y}})_{SC}$, $C(F_{O3_{k,y}})_{SC}$ and $C(F_{O4_{k,y}})_{SC}$ - OPEX from using kth AE at the year y in scenario SC, determined by the cost functions, [€].

In the current paper, the following expression is used to represent the relationship between all the parameters and cost functions for OPEX calculation:

$$C_{flex,OPEX,y,SC} = \sum_{\substack{k=1,\\ G1_k,G3_k\neq 0}}^{K_{SC}} C_{flex,OPEX,y,SC} = \tag{12}$$
$$= \sum_{\substack{k=1,\\ G1_k,G3_k\neq 0}}^{K_{SC}} [C(F_{O1_{k,y}})_{SC} + C(F_{O2_{k,y}})_{SC} +$$
$$+ C(F_{O3_{k,y}})_{SC} + C(F_{O4_{k,y}})_{SC} + C_{add,k,y,SC} +$$
$$+ G2_k * C_{M\&L,k,y,SC}],$$

where $C_{add,k,y,SC}$ - additional cost due to the unique features of the kth AE at the year y in scenario SC, [€].

Similar to the CAPEX part, $C_{flex,OPEX,P\%}$ is calculated using $C_{flex,OPEX,y,SC}$ and Eq. 4-5.

Table I shows what costs are included in CAPEX and OPEX for each of the four considered AEs/FSs. CAPEX costs are related to the installations of the main and additional components, where the main component is an AE itself. OPEX would typically include the cost of the supplied energy or the cost of the extra degradation caused by using a particular AE/FS. The detailed explanation of how the cost of one of FS - DLR is modelled is given in the Appendix as an example.

For BESS, RE and DLR the costs could be to a certain degree linked to the physical processes occurring in the devices, while the cost of the DR is more subjective. An extra cost that should be added to the DR is the difference in the energy cost at original time (when the customer intends to use equipment) and later time (when equipment is actually used due to postponement). This would ensure, that the DR owner will not have to pay higher energy costs for postponing its power consumption. An extra cost for the BESS includes a cost of a number of recharging cycles used to provide requested energy (since each cycle will cause BESS degradation) and the partial cost recovery of a BESS unit cost.

V. CASE STUDY

A. System topology

The system considered in a case study is shown in Fig. 4. It is a part of the real 10 kV distribution network of a Nordhavn area in Copenhagen, Denmark. The system is supplied from the 30/10 kV main substation (MS) through four main cables MS-1, MS-10, MS-2, and MS-20. The topology is organized in two loops with the possibility to shift the electrical load from one feeder to the other in case of failure or a fault (internal RE via tie-line T19-T110 or T27-T28).

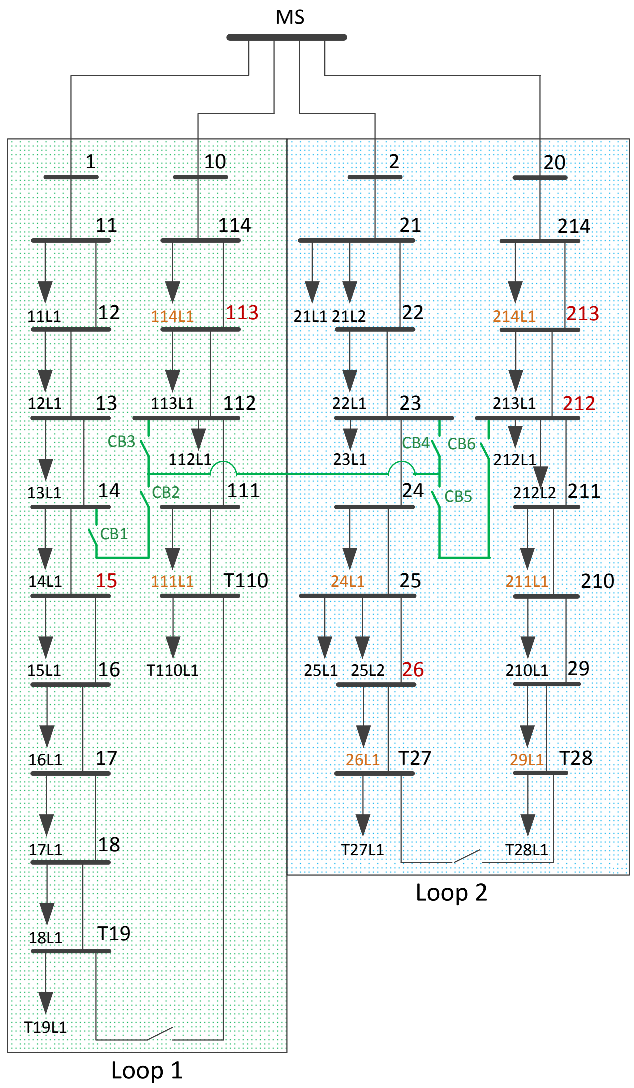

Fig. 4: Part of the 10 kV distribution system of Nordhavn area used in case study, nodes with loads are 0.4 kV. Figure explanations: MS - main substation; L - load node; T - node with tie-line; CB - circuit-breaker; nodes with red font have BESS; nodes with orange font have DR; new supply paths to enable RE with external loop is highlighted in green

Each bus represents a 10 kV side of the secondary substation and the loads are connected to its 0.4 kV side. The power demand at each substation is formed by a combination of various residential, commercial and light industrial consumers. The time-series consumption data with 1-h resolution is synthesized using the annual energy measurements from actual Nordhavn consumers for the year 2016 and corresponding demand curves for each load category. Maximum power of the substations is given in Table AI in the Appendix.

B. *Flexibility sources*

The system has a number of FSs providers. DR and BESS utilize the consumers' equipment present in the grid to provide FSs. RE and DLR use the distribution network components as the source of FSs.

Loads at the 0.4 kV nodes 111L1, 114L1, 24L1, 26L1, 29L1, 211L1 and 214L1 can provide DR. In the current paper the capacity of DR is considered as a percentage of the total substation load and change from year to year with the upper limit of 10% of the total load.

BESS units of various capacity and energy are connected through their own designated transformers to the 10 kV nodes of 15, 113, 26, 212 and 213. Parameters of BESS are given in Table AII in Appendix.

Flexibility could be obtained by shifting part of electrical loads to the feeders in another loop (external RE). To enable external RE three tie-lines and six CBs have to be constructed (shown in green in Fig. 4).

By installing sensors to measure soil temperature and making a thermal model of the cable it is possible to apply DLR at any cable. The extra capacity given by the DLR is changing from year to year depending on the temperature and the number of rainfall with the upper limit of 15% for the cables in clay.

In order to facilitate the integration of the FSs providers in the long-term planning, without compromising DSO's performance in a benchmarking [60], [61] and its ability to supply customers with power, it is assumed that the FSs from AEs are provided based on the long-term contracts. Those contracts specify the maximum amount of provided capacity, the maximum duration of FSs and limit the number of times, services are provided during a specified time interval (e.g. a year). It is assumed that there is no market, where DSO can contract the FSs from.

VI. Results

Time-series load profiles for the year 2016 are used as a base for creating forecasts for the period of 4 years with yearly interval. Each load is decomposed into base trend, seasonal variation and stochastic component. At each year ten different scenarios of how the base trend and the seasonal variations will change are considered, resulting in the total of 100 forecasts. Example of the different scenarios of power demand evolution is given in Fig. A1 in Appendix.

The analysis of the forecasted scenarios shows that several cables can be potentially overloaded in the years 3 and 4, if the worst case of N-1 contingency will occur (fault at one of the main cables in a loop, when the remaining main cable take the whole load of the loop). The information about detected CEs is summarized in the Table II.

A. *Conventional planning*

As was previously mentioned, the conventional solution to handle CEs is to invest in the reinforcement of the cables. The costs of changing the cables in the conventional planning and CAPEX, OPEX and VoF are given in the Tables III - IV, respectively. The entire process of changing cables is assumed to take one year, therefore the investment decision should be taken one year before the CEs could occur. Two values for the VoF are given for year 4. The first value assumes that the

TABLE II: Detected CEs in cables. Values for power, energy, number of CEs and duration are obtained by using 95th percentile

Year 3						Year 4					
Cable	**SC with CE, [-]**	$S_{flex,95}$, **[kVA]**	$E_{flex,95}$, **[kVAh]**	$NO_{flex,95}$, **[-]**	$D_{flex,95}$, **[h]**	**Cable**	**SC with CE, [-]**	$S_{flex,95}$, **[kVA]**	$E_{flex,95}$, **[kVAh]**	$NO_{flex,95}$, **[-]**	$D_{flex,95}$, **[h]**
C2-21	99	1334.4	3578.5	8	2	**C2-21**	99	1538.3	4867.9	11	2
C214-213	93	975.8	1543.9	4	2	**C213-212**	16	166.7	166.7	1	1
C20-214	99	1334.4	3578.5	8	2	**C214-213**	95	1158.1	2359.3	5	2
						C20-214	99	1538.3	4867.9	11	2

TABLE III: Cost of changing the cables in the conventional planning

Cable	**Length, [km]**	**Old cable**	**New cable**	**Cost, [k€]**	**Yaer to invest**
C2-21	1.15	3x240	3x300	122.3	2
C213-212	0.17	3x240	3x300	17.8	3
C214-213	0.12	3x240	3x300	12.5	2
C20-214	1.77	3x240	3x300	189.1	2

TABLE IV: Cost of the conventional planning solution

	Year 3	**Year 4**
$C_{conv,CAPEX,y,95}$, **[k€]**	293.7	15.4
$C_{conv,OPEX,y,95}$, **[k€]**	4.6	0.2
$C_{conv,TOTEX,y,95}$, **[k€]**	298.3	15.6
$VoF_{y,95}$, **[k€]**	128.2	5.9/163.3

TABLE V: Parameters used in the cost functions

Parameter	**Value**
Cost of ENS, [€/kVAh]	40
Cost of losses, [€/ kWh]	0.1
Discount rate, [-]	0.05
Base cost of energy provided by DR, [€/ kWh]	0.1
Cost of ICT for DR, BESS, [k€/ unit]	0.5
Base cost of energy provided by BESS, [€/ kWh]	0.5
Cost of CB, [k€]	8
Max. number of switchings, [-]	50000
Cost of sensors for DLR, [k€/ km]	1.0
Cable LT, [year]	40

DSO decided to reinforce the cables in year 3, the second - decided to postpone it. As could be seen from Tables IV, the longer reinforcement is deferred the higher is the VoF.

B. Flexibility planning

Since the probability that the worst case of N-1 will coincide with the high power demand is not high, it may be more economically beneficial to rely on the flexibility options that require much lower CAPEX investments. The flexibility planning is used to identify which AEs could potentially help in handling detected CEs. The calculation of the total cost of AE is done as described in the flexibility characterization framework using cost function as the one for RE in Fig. 5. Other cost functions for DR, BESS and DLR could be found in Appendix (Fig. A2 - A8) with parameters used to define them given in Table V.

The cost of each AE along with the other parameters from the flexibility framework is summarized in Table VI. The cost is calculated in the assumption that the same AE is used in both years 3 and 4. This allows having zero CAPEX for RE in year 4, after it was constructed in year 3.

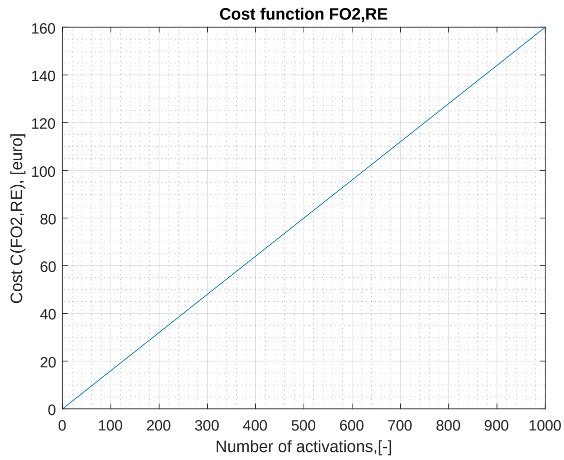

Fig. 5: Cost function FO2 for RE in years 3 and 4

TABLE VI: Costs of each AE/FS available in the distribution network

	Parameter	**DR**	**BESS**	**RE**	**DLR**
Year 3	$C_{flex,CAPEX,3,95}$, [k€]	2.3	1.6	194.3	3.0
	$C_{flex,OPEX,3,95}$, [k€]	1.0	1.5	0.002	0.008
	$C_{flex,TOTEX,3,95}$, [-]	3.3	3.1	194.3	3.0
Year 4	$C_{flex,CAPEX,4,95}$, [k€]	0.9	0.9	0	0.2
	$C_{flex,OPEX,4,95}$, [k€]	1.7	1.4	0.003	0.01
	$C_{flex,TOTEX,4,95}$, [-]	2.6	2.3	0.003	0.21

TABLE VII: Cost of the solution using flexibility

	Parameter	
Year 3 (DLR & BESS)	$C_{flex,CAPEX,3,95}$, [k€]	4.2
	$C_{flex,OPEX,3,95}$, [k€]	0.1
	$C_{flex,TOTEX,3,95}$, [-]	4.2
Year 4 (DLR & BESS)	$C_{flex,CAPEX,4,95}$, [k€]	0.2
	$C_{flex,OPEX,4,95}$, [k€]	0.06
	$C_{flex,TOTEX,4,95}$, [-]	0.3

With the exception of RE in year 3, no AE/FS can provide the required capacity and energy alone. Therefore a combination of multiple AEs should be used. The final solution, which is using the combination of DLR and BESS is given in Table VII. Comparison of the TOTEX for both years shown in Table VII with the VoF in Table IV reveals the amount of potential savings for the DSO that could be achieved.

VII. Conclusions

The paper proposes the flexibility characterization framework. The aim of the framework is to generalize the process of cost estimation of various AEs/FSs that could be used as an alternative to the traditional grid reinforcement. Comparing TOTEX from using AEs with the VoF, the DSO planners will have a useful tool to aid them in the decision making process. Provided case study demonstrates the application of the framework in the part of the actual 10 kV distribution system of Nordhavn area in Copenhagen.

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APPENDIX

A. Initial data

TABLE AI: Maximum apparent power of electrical loads, assuming $cos\phi$ = 0.9

Loop 1		Loop 2	
Electrical load	**Max. apparent power, [kVA]**	**Electrical load**	**Max. apparent power, [kVA]**
11L1	350	21L1	746
12L1	336	21L2	739
13L1	430	22L1	362
14L1	414	23L1	376
15L1	406	24L1	276
16L1	874	25L1	436
17L1	408	25L2	431
18L1	435	26L1	421
T19L1	85	T27L1	148
T110L1	437	T28L1	184
111L1	419	29L1	328
112L1	413	210L1	437
113L1	346	211L1	662
114L1	397	212L1	50
		212L2	421
		213L1	875
		214L1	378

TABLE AII: Parameters of the BESS units

BESS node	Apparent power, [kVA]	Energy, [kVAh]	Cost of BESS unit, [k€]	Number of cycles, [-]
1571	326	326	228.2	5000
11371	392	1176	274.4	2000
2671	284	568	198.8	3000
21271	346	1384	242.2	5000
21371	381	762	266.7	3000

B. Forecasting

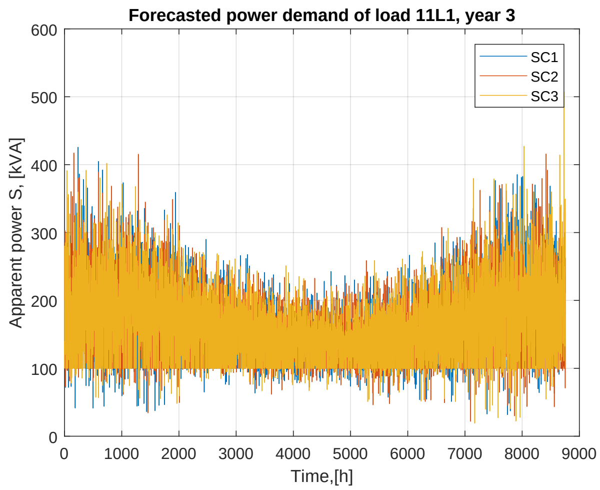

Fig. A1: Example of power demand forecast. SC - scenario

C. Modelling of cost functions - Dynamic line rating

In a traditional operation of distribution networks, the power ratings of overhead lines and cables are considered as fixed values independent of the external conditions. The degree of overloading defined by the coefficient L is typically also set as a constant either for the whole operation period or for a specific season.

However, the exact MCCs of the lines are constantly changing and determined by the ability to dissipate the heat created by the electric current. Dynamically changing MCC based on the external conditions is referred to as DLR. For the cables buried in the soil, DLR is a function of the soil properties, soil temperature, precipitation and cable's burial depth.

By applying DLR in the ADN, a larger degree of overloading could be allowed, thus potentially eliminating CEs. DLR is an FS provided by the lines (overhead or cables), which are utility-owned AEs. Similar to RE, DLR can potentially provide medium to long-term reinforcement deferral. The expressions given below are provided for underground cables, with overhead lines covered in [55]. Similar to RE, the potential of DLR in regards to solving congestions at the secondary substations is limited. DLR is best suited to eliminate CEs at the large cables.

1) CAPEX: CAPEX of using DLR is generally very low, since DLR is applied to the already existing cables. The main cost included in CAPEX is an installation of the additional equipment - sensors for recording soil temperature, precipitation, etc.

2) OPEX: Before estimating the OPEX of applying DLR, the amount of extra capacity provided by DLR has to be determined. This is done by creating a thermal model of the buried cable and determining the cable temperature T_C, which will affect cable's resistance. The first step is to solve Richards equation to obtain moisture content distribution in time and across all soil layers [56]:

$$\frac{\partial\theta(t,z)}{\partial t} = \frac{\partial}{\partial z}[\delta_\theta(t,z)\frac{\partial\theta(t,z)}{\partial z} + k_\theta(t,z)], \quad \text{(A1)}$$

where θ - moisture content, [-]; z - soil layer, [cm]; δ_θ - soil hydraulic diffusivity, $[m^2/s]$; k_θ - soil hydraulic conductivity, $[m/s]$.

Knowing moisture content, the soil thermal diffusivity δ_T can be found:

$$\delta_T(t,z) = -14.8 + 0.209N + 4.79\theta(t,z), \quad \text{(A2)}$$

where δ_T - soil thermal diffusivity, $[m^2/s]$; N - soil composition, [-].

Soil thermal resistivity:

$$\rho_T(t,z) = \frac{1}{\delta_T(t,z)\,\sigma_{S,dry}\,C_{ST}(t,z)}, \quad \text{(A3)}$$

where ρ_T - soil thermal resistivity, $[m°C/W]$; $\sigma_{S,dry}$ - dry-soil density, $[kg/m^3]$; C_{ST} - soil specific heat, $[Ws/kg°C]$.

Eq. A4 shows how the distribution of the soil temperature can be calculated:

$$\frac{\partial T_S(t,z)}{\partial t} = \frac{\partial}{\partial z}[\delta_T(t,z)\frac{\partial T_S(t,z)}{\partial z}], \quad \text{(A4)}$$

where T_S - soil temperature, $[°C]$.

The cable temperature can then be found as follows:

$$T_{cable}(t) = T_S(t, z_b) + T_{internal} + \alpha(t)T_{external}(t), \quad \text{(A5)}$$

where $T_{cable}, T_{internal}, T_{external}$ - temperatures of the cable, its internal and external parts, respectively, $[°C]$; α - attainment factor, [-].

Using the cable's actual temperature it is possible to estimate DLR using the following expression from [55]:

$$I_{cable}(t) = \sqrt{\frac{\Delta T - q_d[0.5R_{T,1} + n(R_{T,2} + R_{T,3} + R_T)]}{r(T_{cable}(t))[R_{T,1} + j(1+\lambda_1)R_{T,2} + n(1+\lambda_1+\lambda_2)(R_{T,3}+R_T)]}}, \quad \text{(A6)}$$

where I_{cable} - DLR of the cable, [A]; ΔT - difference of temperatures, $[°C]$; q_d - dielectric loss, [W/m]; $R_{T,1}, R_{T,2}, R_{T,3}$ - thermal resistance of cable's insulating layers, $[m°C/W]$; R_T - soil thermal resistance, $[m°C/W]$; r - resistance of conductor, $[\Omega/m]$; j - number of conductors in the cable, [-]; λ_1, λ_2 - ratios between losses in the metal sheaths of the cable and its total losses, [-].

Detailed explanations of how to calculate all the parameters shown above could be found in [55]–[57].

Since in most cases using DLR assumes applying higher than rated electrical stresses to the cable, its LT will be reduced because of that. Such reduction can be used to estimate the cost of DLR via cost function F_{O1}, showing the cost of LT's reduction depending on duration and power required from DLR at CE:

$$C_{LT_{cable}} = \frac{C_{cable,total}}{LT_{cable,rated}}, \quad \text{(A7)}$$

where $C_{LT_{cable}}$ - cost of an hour of cable's LT, [€/h]; $C_{cable,total}$ - total cost of cable, [€]; $LT_{cable,rated}$ - cable's LT at rated conditions, [h].

Using Arrhenius model from Eq. A8 [58] the change in the LT of the cable due to the temperature T_{cable} during ith CE is estimated, with T_{cable} is proportional to I_{cable} and S_{flex}:

$$LT'_{cable,D_{flex,i,start}} = LT_{cable,rated} * e^{(-B*T)}, \quad \text{(A8)}$$

where $LT'_{cable,D_{flex,i,start}}$ - cable's LT at the start of ith CE with $T_{cable,i,mean}$, [h]; B - coefficient depending on the activation energy of the degradation process, [°C]; T - temperature ratio, [1/°C]:

$$T = \frac{1}{T_{cable,i,mean}} - \frac{1}{T_{cable,rated}}, \quad \text{(A9)}$$

where $T_{cable,i,mean}$ - mean temperature of the cable during ith CE, [°C]; $T_{cable,rated}$ - rated temperature for the cable, [°C].

$$\Delta LT'_{cable,i} = LT'_{cable,D_{flex,i,start}} - D_{flex,i,end}, \quad \text{(A10)}$$

where $\Delta LT'_{cable,i}$ - reduced LT due to ith CE with $T_{cable,i,mean}$, [h]; $D_{flex,i,end}$ - ending point of FS usage during ith CE, [h].

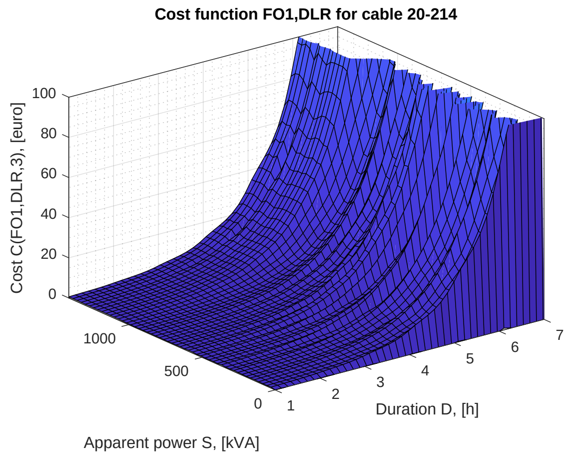

Fig. A2: Cost function FO1 for DLR of cable 20-214 in year 3

LT after ith CE referred to the rated temperature $LT_{cable,D_{flex,i,end}}$ is calculated using Eq. A8 and replacing $LT_{cable,rated}$ with $\Delta LT'_{cable,i}$. Finally, $\Delta LT_{cable,i}$:

$$\Delta LT_{cable,i} = LT_{cable,D_{flex,i,end}} - LT'_{cable,D_{flex,i,start}}, \quad \text{(A11)}$$

where $\Delta LT_{cable,i}$ - reduction in cable's LT due to using DLR, referred to the rated temperature, [h].

Using $\Delta LT_{cable,i}$ and $C_{LT_{cable}}$ cost function F_{O1} for DLR is constructed as shown in Fig. A2.

D. Example of cost functions for other AE/FS

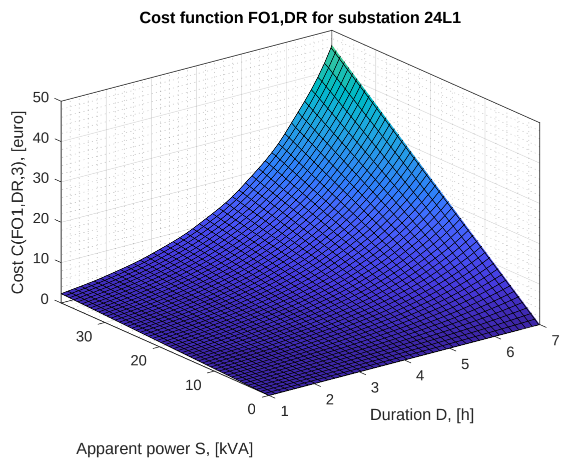

Fig. A3: Cost function FO1 for DR at substation 24L1 in year 3

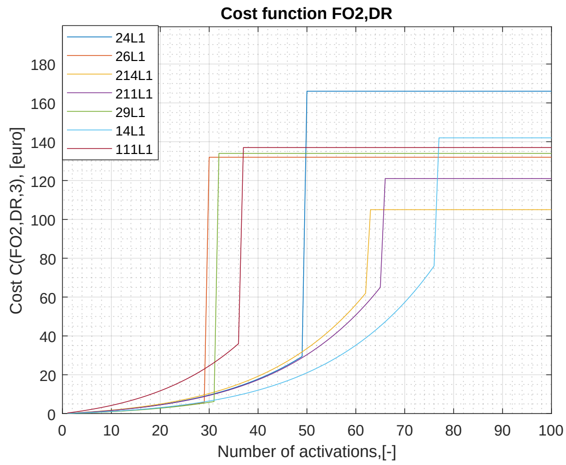

Fig. A4: Cost function FO2 for DR in year 3

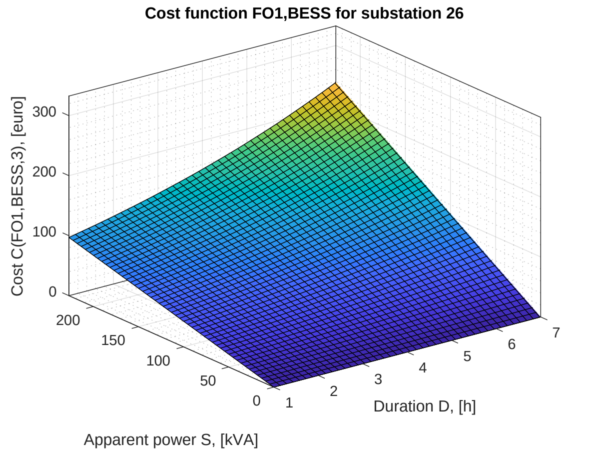

Fig. A7: Cost function FO1 for BESS at substation 26 in year 3

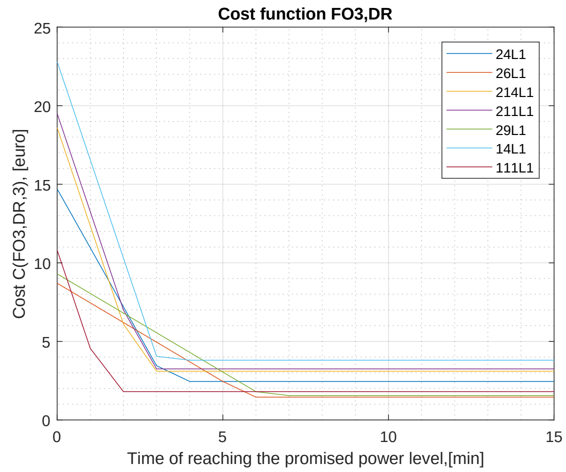

Fig. A5: Cost function FO3 for DR in year 3

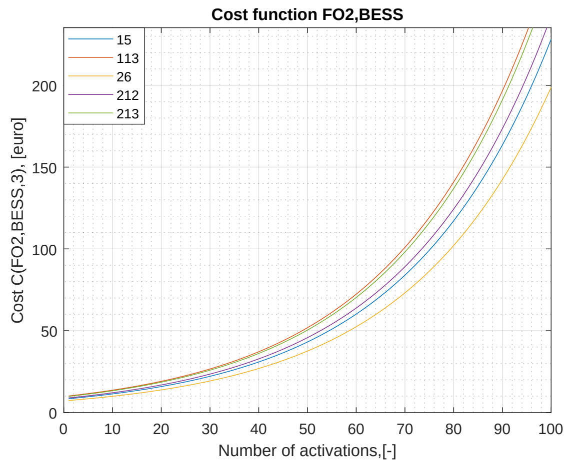

Fig. A8: Cost function FO2 for BESS in year 3

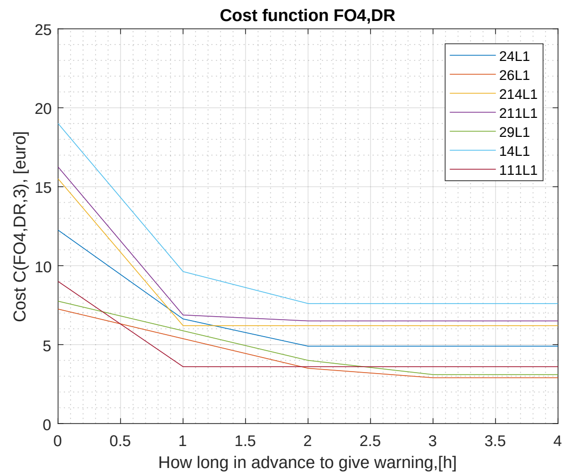

Fig. A6: Cost function FO4 for DR in year 3

[D] Integrated Planning of a Large-Scale Heat Pump in View of Heat and Power Networks

Integrated Planning of A Large-scale Heat Pump In View of Heat and Power Networks

Sergey Klyapovskiy, Shi You, Hanmin Cai, Henrik W. Bindner Center for Electric Power and Energy (CEE)
Technical University of Denmark (DTU)
2800 Kgs. Lyngby, Denmark
Email: seklya@elektro.dtu.dk

Abstract—**With the present trend towards smart grid and integrated energy systems, the potential benefits achieved by developing integrated planning and operation solutions crossing multiple energy sectors become recently recognizable. This paper investigates the problem of optimal planning for a large-scale heat pump (HP) - a component that links electric and heat utilities together, from an integrated perspective. The proposed method assures an optimal system design with the minimum expense on both capital expenditure (CAPEX) and operating expense (OPEX) for the heat network and the electrical network, given that the optional HP locations are already provided together with other technical and economic information needed for executing the planning exercise. The operational flexibility of the HP, i.e., the ability of reducing its electricity consumption from time to time, is also integrated into the planning method. The value of the proposed solution is demonstrated throughout a case study that resembles a live planning exercise conducted for a green field area in Denmark.**

Index Terms—**Flexibility, heat pump, integrated energy system, integrated planning, heat and power networks**

I. Introduction

The increased focus on the efficiency in the energy sectors and CO2 emission reduction in the recent years bring attention toward an integrated energy system (IES) [1], [2]. IES is the system comprising of multiple energy sectors, such as electricity, heat, transportation and gas. Ideally, an IES can be optimized for a performance as a whole system using synergies between the sectors for the common benefits at both planning and operation stages [3], [4].

The integration between electricity sector and heat sector has been recently recognized as a prominent example for creating add-on values for both sectors, enabled by the fact that the two sectors have been loosely interconnected for many years through a variety of technologies, such as combined heat and power generation (CHP), electric heat pump (HP) and boiler [5], [6]. Together with the significant energy storage potential in the heat sector, the value of these electric heating solutions have been widely demonstrated to address challenges such as power balancing [7] and congestion management [8] in the electricity sector and to facilitate the development of the heat sector towards a better system, e.g. the 4th generation of district heating (DH) [9].

Among several technologies that can transform electrical power to heat, HP is the one that draws the most of attention due to its supreme operational characteristics and potential benefits it could bring to the system [10]. In countries like Denmark with widespread use of DH systems and CHPs, using large-scale HP for DH can supplement or even to certain level replace the existing DH solution [11]. In early 2018, Denmark is set to support 13 large HP projects with DKK23m ($3.7m) in funding [12]. To ensure the deployment of HPs can result in a maximum societal benefit, i.e., the total benefit achieved by the involved stakeholders in different energy sectors, developing optimal planning solutions from an integrated perspective is significantly necessary.

At present, the common practice of large-scale HP planning is an exercise that involves a limited degree of collaboration between the two energy bodies, i.e., the district heating operator (DHO) and the electricity distribution grid operator (DSO). This exercise is often initiated by the DHO who produces a plan for sitting and sizing of the HP with little consideration of its impacts on the electrical network, and followed by the DSO who provides a connection plan with little influence on the heat system planning. An early work conducted in [13] investigated this issue by proposing an integrated planning method, and demonstrated its value in achieving a more economic solutions when the two bodies work collaboratively.

This paper extends the method proposed in [13] by giving much more elaboration on the integrated planning method and by including the flexibility potential (i.e., the ability of the HP reducing its electricity consumption from time to time) into the integrated optimal planning. Provided all relevant information is accessible, the proposed method assures an optimal system design with the minimum expense on both capital expenditure (CAPEX) and operating expense (OPEX) for the heat network and the electrical network.

The validity of the proposed solution is demonstrated throughout a case study that resembles a live planning exercise conducted for an urban green field area in Denmark. A large-scale HP, as the single heat source for this area, is to be deployed to meet the end users heat demand through a heat network with an optimal layout. Several potential locations are already provided, and each location has a preferable HP technology that can take the best use of the local energy resources. Electrically, the HP will be connected to an existing 10 kV distribution network which offers a number of optional connection points.

Paper is organized as follows. The methodology for studying the problem is given in sections II-V and presented on the flowchart on Fig. 1. Section II provides the general explanation of how the different calculation parts of the flowchart are

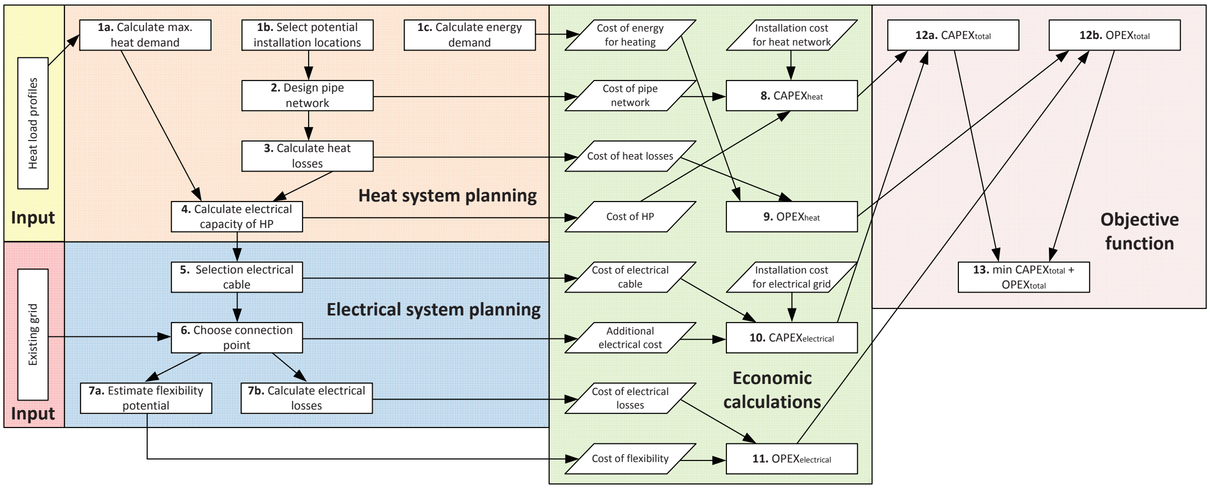

Fig. 1: Flowchart showing the methodology used for heat system planning, electrical system planning, economic calculations and final objective function

performed. Sections III, IV describe the methodology used for heat and electrical network planning respectively, with Section V explaining the calculations of the economical parameters. The case study is presented in Section VI, with results given in Section VII. Finally, conclusions are drawn in Section VIII.

II. General description

The flowchart showing the proposed methodology is given on Fig. 1.

The problem solved by this study is about optimal sitting and sizing of a large HP in a view of integrated energy networks. In practice, the number of scenarios that has to be considered is not high because of the constraining factors like landscape, availability of different kinds of heat sources and the economy.

The problem is formulated as a trilevel optimization. First level is the heat system planning. It is formulated as a linear integer optimization with the connectivity and pipe sizes as decision variables. The lookup table is used to check for the pressure constraint. Only CAPEX cost is considered on that stage.

Electrical system planning represents a second level. It is a linear integer optimization that is solved by brute force search due to the limited number of scenarios. The decision variables are the size of electrical cables and the connection point to the existing electrical grid. The constraints are the voltage and maximum apparent power, that are checked after the best solution is found. Similar to the first level, only CAPEX of the electric utility is considered.

The third level is an optimization of both CAPEX and OPEX for both utilities combined, which is solved by brute force.

III. Heat system planning

This section describes the methodology concerning heat system planning used in studying this problem.

To successfully execute the project of supplying heating to the city district via HP, DHO needs to estimate the heat demand, evaluate and select several potential locations for HP installation, determine the pipe network configuration, pipe lengths and diameters and calculate the heat losses. After all these parameters are obtained, the electrical capacity needed to run a HP can be identified. The methodology for acquiring all these parameters is shown in the subsection.

A. Estimation of heat demand

Typical city district mainly consists of buidings belonging to either residential or commercial (office) customer categories, which could be characterised among other things by their demand for space heating (SP) and domestic hot water (DHW). Fig. 2 shows the example of monthly energy demand to provide SP and DHW to an apartment block in Copenhagen (data is extrapolated from [14]). Energy demand profiles for other building types show similar trend with high demand in the fall and winter months and with low demand in spring and summer. This is mainly due to the changes in the SP needs, while DHW demand can be considered almost constant throughout the year. The exact amount of required energy for SP depends on a climate, insulation type and building location (sunny side or not, etc.) [15].

If HP is assumed to be the only source of heat for the urban district, its capacity should be able to fully cover the peak heat demand plus heat losses. Using the historic time-series data of the heat demand for the buildings of similar type as should be supplied allows to forecast the peak heat demand with good precision. However, such data may not always be available, so monthly averaged heat demand shown on Fig. 2 can be used instead. The peak-to-average ratio is used to estimate the peak value for each month.

Diversity factor *DF* is used to take into account, that not all of the buildings require heat at any given time.

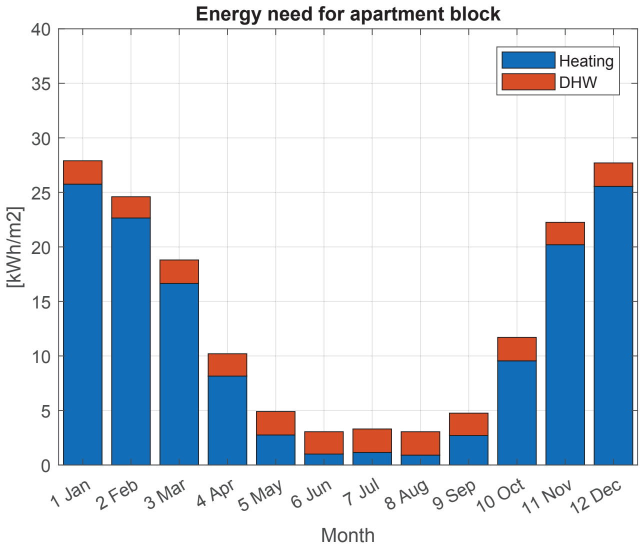

Fig. 2: Example of monthly energy demand for SP and DHW for an apartment block in Copenhagen

The forecasted peak demand for the heat load is then calculated as follows:

$$Q_{heat,peak} = max\{DF \sum_{i=1}^{n} \sum_{j=1}^{r} N_j S_j \frac{E_{ij}}{H_i} PTA_{ij}\}, \tag{1}$$

where $Q_{heat,peak}$ - peak demand, $[W]$; DF - diversity factor; i - month, n - number of months with available data; j - building type, r - number of building types; N - number of buildings of certain type, S - size of a heated area for a specific building type, $[m^2]$; E - average monthly heat demand, $[Wh/m^2]$; H - number of hours in each month; PTA - peak-to-average ratio.

The amount of energy DHO should provide during a year:

$$E_{heat,year} = \sum_{i=1}^{n} DF \sum_{j=1}^{r} N_j S_j E_{ij}, \tag{2}$$

where $E_{heat,year}$ - total energy required for heating, $[Wh]$.

B. Selecting installation location of HP

The locations for installing HP are traditionally determined by DHO after comprehensive technico-economic analysis. One of the main factor is the availability of the heat source (groundwater, seawater, air, exhaust heat, etc.), which could be easily extracted without the need for expensive engineering procedures. Due to the high building density in the urban areas, finding an available place that is large enough for installation and respecting all the safety regulations is another concern. Third desired criteria is the proximity to the heat customers to decrease the total length of the pipe network. Combining these three factors together result in a very limited number of possible locations for HP installation.

In this paper, the installation location is considered to affect coefficient of performance (COP) of HP, due to the different heat source utilized at each spot. It will also influence the heat losses, which are dependant on pipe network length among other factors as will be shown below.

C. Designing DH pipe network

Design pipe network for DH represents an optimization (minimization) problem with several parameters that have to be determined. First, the pipe network layout have to be established, which determines how to connect HP with customers. After this, the flow rate is calculated and used to select appropriate pipes diameter to be able to supply the peak heat demand from Eq. 1. The goal is to achieve the least cost solution, while satisfying the constraint for allowable pressure drop [16]. The decision variables are length and diameter of the pipes. The optimization problem can be expressed as follows:

$$\min \quad \sum C_{pipe,ft} = f(l_{pipe,ft}, d_{pipe,ft}), \tag{3}$$

$$s.t. \quad \Delta Pr \leq \Delta Pr_{max}, \tag{4}$$

where C_{pipe} - cost of the pipe, [\$]; f, t - from and to nodes of the heating network respectively; l_{pipe} - length of the pipe, $[m]$; d_{pipe} - pipe inner diameter, $[m]$; ΔPr - pressure drop, $[Pa/m]$; ΔPr_{max} - maximum allowable pressure drop, $[Pa/m]$.

The pipe diameter is selected according to the volume of the water flow V_{max} that should go through it. V_{max} can be calculated as shown below [16]:

$$V_{flow,max_k} = \frac{Q_{pipe,peak_k}}{c_p \rho (T_{supply} - T_{return})}, \tag{5}$$

where $V_{flow,max}$ - volume of the water flow, $[m^3/s]$; k - pipe number; $Q_{pipe,peak}$ - peak demand for a particular pipe, calculated using Eq. 1, $[W]$; c_p - heat capacity of water, $[J/kgK]$; ρ - density of water, $[kg/m^3]$; T_{supply}, T_{return} - average supply and return temperature respectively, $[°C]$.

D. Calculation of the heat losses

Heat losses is an important parameter that will affect HP OPEX and influence the amount of required electric power HP is using. Heat losses are dependant on the supply and return temperatures of the water, the temperature of the surroundings around the pipe, the pipe's material, length and diameter. To estimate annual heat losses Eq. 6 is used [17]:

$$E_{heat,loss,year} = 2\pi D_a L_{pipe} K \cdot G, \tag{6}$$

where $E_{heat,loss,year}$ - annual heat losses, $[Wh]$; D_a - average inner diameter of the pipes in the network, $[m]$; L - network route length of the pipe system, $[m]$; K - average heat transmission coefficient, $[W/m^2K]$; G - coefficient showing annual integration of the average distribution temperature difference, $[°Ch]$.

Average pipe inner diameter D_a is calculated:

$$D_a = \frac{\sum_{k=1}^{p} d_{pipe,k}}{p}, \tag{7}$$

where p - total number of pipes.

Network route length L:

$$L_{pipe} = \sum_{k=1}^{p} l_{pipe,k}, \tag{8}$$

Average heat transmission coefficient K depends on the insulation materials of the pipes and their inner diameter. Typically higher values of K correspond to the high-quality pipes. K for the whole network lies in the following range:

$$0.1088 \cdot D_a^{-0.619} \leq K \leq 0.7676 \cdot D_a^{-0.341}, \tag{9}$$

Coefficient G:

$$G = \frac{1}{2}((T_{supply} + T_{return}) - T_{surround}) \cdot h_{heat}, \tag{10}$$

where $T_{surround}$ - average surroundings temperature, $[°C]$; h_{heat} - number of heating hours in a year, $[h]$.

Relative losses $q_{loss,relative}$ are used as an average estimation of the heat losses, that occur at any certain point in time:

$$q_{loss,relative} = \frac{1}{(1 + \frac{E_{heat,year}}{E_{heat,loss,year}})} \cdot 100, \tag{11}$$

where $q_{loss,relative}$ - relative heat losses.

E. Determining electrical capacity of HP

Knowing the forecasted maximum heat demand $Q_{heat,peak}$ and relative heat losses $q_{loss,relative}$, the required electrical capacity for running HP can be estimated using Eq. 12 [18]:

$$P_{HP} = \frac{Q_{heat,peak} \cdot (1 + \frac{q_{loss,relative}}{100})}{COP_{avg}}, \tag{12}$$

where P_{HP} - electrical capacity of HP, $[W]$; COP_{avg} - average coefficient of performance.

COP of a HP is changing throughout the year, therefore the average COP is used to calculate the electrical capacity. Typical COP for different heat sources is: seawater - 3.59, groundwater - 3.41, air - 3.52 [19]. Different heat sources and therefore different values of COP are considered in the planning process.

IV. Electrical system planning

This section describes the methodology concerning electrical system planning used in studying this problem.

After P_{HP} has been estimated, DSO's task is to provide the required capacity. It is done by selecting the proper electrical cable and performing power flow calculations to find a proper connection spot, that will not cause any disturbance to the nearby electrical customers and the distribution network in general.

A. Selection of supplying cable

The supplying cable will carry the power from the connection point to the HP. The full (apparent) power should be used for cable selection.

Additional reactive power required to run HP can be calculated as follows:

$$Q_{HP} = \frac{P_{HP}}{PF} \cdot sin(arcos(PF)), \tag{13}$$

where Q_{HP} - reactive power needed to run HP, $[VAr]$; PF - power factor.

The full apparent power required by HP is found according to Eq. 14:

$$S_{HP} = \sqrt{P_{HP}^2 + Q_{HP}^2}, \tag{14}$$

where S_{HP} - apparent power of HP, $[VA]$.

Cable's capacity is chosen according to:

$$S_{cable,rated} \geq S_{HP} \cdot RM, \tag{15}$$

where $S_{cable,rated}$ - rated electrical capacity of cable, $[VA]$; RM - reserve margin, coefficient taking into account uncertainty regarding maximum HP power consumption.

B. Selection of the connection point

Depending on the electrical capacity of HP, there could be various ways to connect it to the electrical distribution system. It could be connected to one of the already existed secondary substations (low P_{HP}), have an individual substation connected to the common feeder (medium P_{HP}) or have a dedicated direct connection from the main substation (high P_{HP}). Similar with the case of DHO heat network design, selection of the connection point for the DSO is an optimization problem:

$$\begin{aligned} \min \quad & C_{cable,HP} + C_{additional}, & (16)\\ s.t. \quad & V_{min} \leq V_f \leq V_{max}, \ for\ \forall f & (17)\\ & S_{ft} \leq S_{cable,rated}, \ for\ \forall ft & (18) \end{aligned}$$

where $C_{cable,HP}$ - cost of the cable for HP, [\$]; $C_{additional}$ - cost of additional equipment, like transformer substation or reinforced cable needed to connect HP [\$]; V_{min} and V_{max} - minimal and maximum allowable voltage range, $[V]$; f, t - from and to nodes of the electrical network respectively; S_{ft} - apparent power through cable, $[VA]$.

Cost of cable among other parameter is related to its length and cross-section:

$$C_{cable,ft} = f(l_{cable,ft}, J_{cable,ft}), \tag{19}$$

where l_{cable} - length of the cable, $[m]$; J_{cable} - cable cross-section, $[mm^2]$.

As would be explained below it is possible for DSO to reduce the additional cost for connecting HP, if flexibility services from HP could be contracted and therefore:

$$C_{additional} = f(\sum_{PL=1}^{PL_{max}} C_{flexibility,year,PL}), \tag{20}$$

where PL - year in the planning horizon, $[year]$, PL_{max} - total number of years in the planning horizon, $[year]$; $C_{flexibility,year}$ - cost of flexibility services for one year, [$].

C. Power flow analysis

In order to verify that connection of the HP does not bring any disturbance to the current customers in electrical network the power flow analysis is made. The goal is to find values of voltages and active and reactive power at each node in the system. This can be done using Newton-Raphson iterative method and Eq. 21-23 [20]:

$$V_f^{(m+1)} = \frac{\frac{P_{ft}^{sch} - jQ_{ft}^{sch}}{V_f^{*(m)}} - \sum_{t \neq f} Y_{ft} V_t^{(m)}}{Y_{ft}}, \tag{21}$$

$$P_{ft}^{(m+1)} = \mathbb{R}(V_f^{*(m)}[V_f^{(m)} Y_{ff} + \sum_{t=1, t \neq f} Y_{ft} V_t^{(m)}]), \tag{22}$$

$$Q_{ft}^{(m+1)} = -\mathbb{I}(V_f^{*(m)}[V_f^{(m)} Y_{ff} + \sum_{t=1, t \neq f} Y_{ft} V_t^{(m)}]), \tag{23}$$

where V_f and V_f^* - complex voltage at node f and its complex conjugate, respectively, $[V]$; V_t - complex voltage at node t, $[V]$; m - iteration number; P_{ft}^{sch} and Q_{ft}^{sch} - net active $[W]$ and reactive $[VAr]$ power, respectively; P_{ft} and Q_{ft} - active $[W]$ and reactive $[VAr]$ power flow through cable, respectively; Y_{ff} and Y_{ft} - elements of the bus admittance matrix.

The solution of the power flow equations is an iterative process, which is completed, when the difference between the current and the previous iteration is less than specified threshold. Various software programs exist for calculating the power flow, providing the network parameters and values of electrical loads are given.

Voltage V_f in the distribution grid should respect the constraint 17 and be within the range of 0.95 pu to 1.1 pu [21]. Apparent power S_{ft} flowing through each cable is calculated using Eq. 14 and should be in line with constraint 18.

D. Estimation of electrical losses

According to [20] electrical losses at a specific time moment can be determined as follows:

$$S_{el,loss,z} = S_{ft} + S_{tf}, \tag{24}$$

where $S_{el,loss}$ - electrical loss, $[VA]$; z - cable number.

Annual electrical losses:

$$E_{el,loss,year} = \sum_{h=1}^{h_{el}} \sum_{z=1} S_{el,loss,zh}, \tag{25}$$

where $E_{el,loss,year}$ - annual electrical losses, $[VAh]$; h - hour number; h_{el} - number of hours, when HP is supplied with power, $[h]$.

V. Economic calculations

This section describes the economic calculations for determining the optimal location of the HP. CAPEX represents the capital investments that are required before HP becomes operational. CAPEX include the cost of HP, cost of the installation, the cost of heat network and electrical connection. Operational costs such as electricity cost, costs of heat and electrical losses, and maintenance are included in OPEX. OPEX depends on the actual number of hours HP is operational.

A. CAPEX

Total investments are calculated according to Eq. 26:

$$CAPEX_{total} = CAPEX_{el} + CAPEX_{heat}, \tag{26}$$

where $CAPEX_{total}$ - total investments of both DSO and DHO, [$]; $CAPEX_{el}$ and $CAPEX_{heat}$ - investments of electric and heating utility respectively, [$].

$$CAPEX_{el} = C_{cable,HP} + C_{additional} + C_{el,inst}, \tag{27}$$

$$CAPEX_{heat} = C_{HP} + C_{heat,inst} + \sum C_{pipe,ft}, \tag{28}$$

where C_{HP} - cost of HP unit, [$]; $C_{el,inst}$ and $C_{heat,inst}$ - installation cost in the electrical and heat network respectively, [$].

B. OPEX

Similar to CAPEX total operational costs consist of an electrical and heat part:

$$OPEX_{total} = OPEX_{el} + OPEX_{heat}, \tag{29}$$

where $OPEX_{total}$ - total operational costs of both DSO and DHO, [$]; $OPEX_{el}$ and $OPEX_{heat}$ - operational costs of electric and heating utility respectively, [$].

While CAPEX is the amount of investments that has to be spent immediately, OPEX represents the expenses made over the planning horizon. To be able to compare both economic indicators, the future values of OPEX are recalculated to the present values using the annuity formula:

$$OPEX_{el} = \sum_{PL=1}^{PL_{max}} (\frac{C_{el,price,avg,PL} \cdot E_{el,loss,year,PL}}{(1+r)^{PL}} + \frac{C_{flexibility,year,PL}}{(1+r)^{PL}}), \tag{30}$$

where $C_{el,price,DSO,avg}$ - average price for electricity for DSO, [$]; r - discount rate.

Before calculating $OPEX_{heat}$, annual heat demand and annual heat losses should be converted to electrical power values by using Eq. 31:

$$E_{hte,year} = \frac{E_{heat,year}}{COP_{avg}}, \tag{31}$$

where $E_{hte,year}$ - energy demand converted from heat to electrical (hte), $[Wh]$.

$$OPEX_{heat} = \sum_{PL=1}^{PL_{max}} \Big(\frac{C_{el,price,HSO,avg,PL} \cdot (E_{hte,year,PL}}{(1+r)^{PL}} + \frac{E_{hte,loss,year,PL}}{(1+r)^{PL}} \Big), \tag{32}$$

where $C_{el,price,DSO,avg}$ - average price for electricity for HSO, [$].

C. Estimating the cost of flexibility

As was mentioned in the introduction, the reason to move towards IES is the potential synergies between various energy sectors. In case the additional cost for connection the HP to electrical network $C_{additional}$ becomes very high, due to the need to reinforce the main cable, build or expand a secondary substation, DSO could try to contract the DR services from this HP. Such services will mainly include peak reduction or load shifting during the peak demand hours of the electrical distribution system [22]. By incorporating the smart control of HP, monitoring customers indoor temperature and using methods for demand anticipation, DR services for electrical grid could be provided without compromising the heat customers comfort levels. In addition to that, it is assumed that DHO installs heat storage tank together with the source of DH [23]–[25].

The cost of using flexibility services from HP is difficult to establish due to the uncertainty in the amount of services that would be needed. One of the way to estimate the cost is using Eq. 33:

$$C_{flexibility,year} = \Big(\sum_{T=1}^{T_{max}} P_{reduction,avg,T} \cdot D_T \cdot C_{avg,T}\Big) + C_{frequency}, \tag{33}$$

where T - period of using flexibility (period consists of consecutive hours) within one year; T_{max} - maximum number of periods; $P_{reduction,avg,T}$ - average peak reduction during period T, $[W]$; D_T - duration of a period T, $[h]$; $C_{avg,T}$ - average price for the period T, $C_{avg,T} = f(P_{reduction,avg,T}, D_T)$, [$]; $C_{frequency}$ - additional cost, depending on how often the flexibility services were used, $C_{frequency} = f(T_{max})$, [$].

To estimate the cost of flexibility, DSO should identify the periods T, when such services could be required and the amount of power $P_{reduction}$, that have to be reduced. The concept is shown on Fig. 3.

To be able to build the demand curves depicted on Fig. 3, a reliable forecast based on historical data from the area is required. The cost for each period depends on the amount of power reduced, period's duration and the time of day when the service is activated. To simplify the calculations, the average values are used in Eq. 33.

D. Objective function

In the IES the interest of all stakeholders need to be taken into consideration. In case of integrated electric and heat networks, this could be accomplished by optimizing the expenses of both DSO and DHO as shown in the following expression:

$$\begin{aligned} \min \quad & CAPEX_{total} + OPEX_{total}, \\ s.t. \quad & Eq.\ 4, \\ & Eq.\ 17, \\ & Eq.\ 18, \end{aligned} \tag{34}$$

Constraints for this objective function are only reflecting the operational limitations for the heat and electrical networks, since it is assumed that other constraints such as heat source availability or the availability of the proper space for physical HP installation are already handled by assessing predefined locations.

Eq. 34 could be rewritten to include weighting factors:

$$\begin{aligned} \min \quad & w_{el} \cdot (CAPEX_{el} + OPEX_{el}) \\ & + w_{heat} \cdot (CAPEX_{heat} + OPEX_{heat}), \end{aligned} \tag{35}$$

where w_{el} and w_{heat} - weighting factors for electrical and heat utilities, respectively, $w \in \{0, 1\}$.

Setting $w_{el} = 0$ and $w_{heat} = 1$ will correspond to the conventional way of approaching the task of HP installation, when only expenses of DHO are taken into account. When both weighting factors equal to 1, the expenses of both DHO and DSO are considered equally.

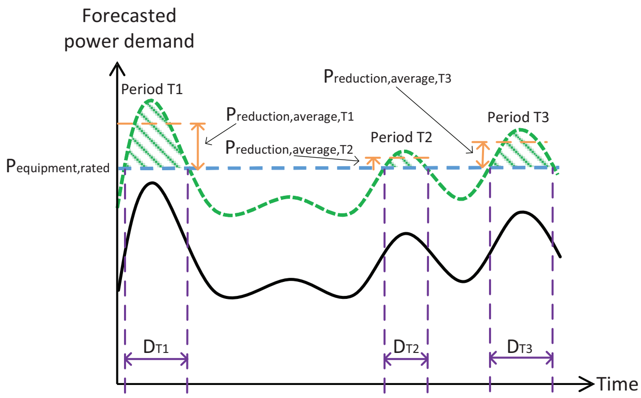

Fig. 3: Concept showing how to identify the periods for requesting flexibility services and amounts of power, that should be reduced. Black curve - forecasted electrical power flowing through component without HP connected; green dotted curve - new forecasted electrical power with connected HP

VI. Case study description

The case of installing a HP to supply heat demand of an urban district is considered in this paper. The city district of Nordhavn (Fig. 4), located in Copenhagen, Denmark is used as an example.

Three types of heat customers are considered: single houses, apartment blocks and office buildings. All of them are marked on Fig. 4 in bold font and will be referred to with both their

Fig. 4: Nordhavn city district. Electrical network: green and light blue lines - electrical distribution system layout (simplified), red lines - tie-lines between feeders; gray rectangle (8) - main substation, circles - secondary substations 10/0.4 kV. Heat network: the asterisk * - heat customer, purple * - group of single houses, red * - apartment block, blue * - office building; shaded square - possible location of HP

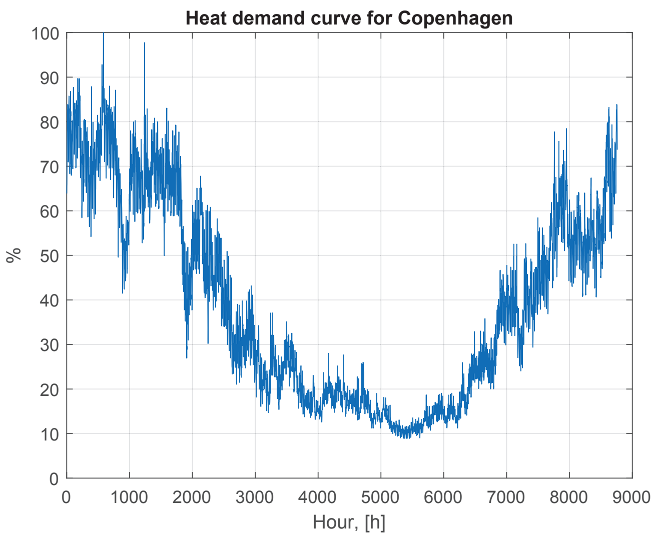

Fig. 5: General heat demand curve for Copenhagen

number and asterisk symbol, i.e. 8* or 11*. Single houses are grouped in a small block of 13 buildings, the rest of the district consists of 10 apartment blocks and 4 office multi-storey office buildings. The sizes of these types of buildings are obtained from [14], [26]–[28]. The average size of single house is chosen to be 120 m^2, apartment block - 3500 m^2 and office building - 2400 m^2.

The heat demand of each of the building is similar to the one shown on Fig 2 and represent the average monthly energy per m^2 needed to provide SP and DHW. In order to obtain the forecasted maximum peak demand, peak-to-average ratio PTA is calculated from the heat demand curve on Fig. 5, which is based on a real data provided by DHO "HOFOR" [29] for Copenhagen area with hourly resolution.

5 possible locations have been chosen to install a HP. Location 2 will use groundwater as a heat source, while seawater will be used at locations 1, 3-5 due to the soil property in Nordhavn.

The considered DH operates with 80/45°C supply and return temperatures, respectively. Due to the changes in the temperature of the environment in the spring and summer months, the supply and return temperatures are also vary. This makes the average supply temperature T_{supply} lower and

TABLE I: Parameters for the case study

Parameter	Value	Remarks
S_1 - single house	120 $[m^2]$	[26]
S_2 - apartment block	3500 $[m^2]$	[27], [28]
S_3 - office building	2400 $[m^2]$	[14]
N_1 - single house	13	
N_2 - apartment block	10	
N_3 - office building	4	
DF	0.7	[30]
PTA	1.33 - 1.90	from DHO data
ΔPr_{max}	100 $[Pa/m]$	[16]
c_p	4200 $[J/kgK]$	
ρ	971.8 $[kg/m^3]$	for water at 80 $°C$
T_{supply}	75 $[°C]$	[31]
T_{return}	47.5 $[°C]$	[31]
$T_{surround}$	8 $[°C]$	[32]
h_{heat}	8760 $[h]$	from Fig. 5
$COP_{seawater,avg}$	3.59	[19]
$COP_{groundwater,avg}$	3.41	[19]
PF	0.95 lagging	[33]
RM	15 [%]	
h_{el}	8760 $[h]$	
PL	20 $[year]$	
r	5 [%]	
$C_{el,price,HSO,avg,PL}$	0.12 $[\$/kWh]$	[34]
$C_{el,price,DSO,avg,PL}$	0.10 $[\$/kWh]$	
$C_{el,inst}$	10 [%]	of $C_{cable,HP}$+$C_{additional}$
$C_{heat,inst}$	10 [%]	of C_{HP}+$\sum C_{pipe,ft}$

average return temperature T_{return} higher than the nominal values. The number of heating hours h_{heat} in a year were set to 8760, since due to the DHW the heat demand still exists even during the summer months.

The electrical grid of Nordhavn is a 10 kV medium voltage (MV) distribution grid. It is supplied from the main substation 30/10 kV (8 on Fig. 4) and consists of 4 feeders, connected in two loops. Feeders of each loop are connected to each other via a normally open tie-line. Each feeder has certain number of secondary substations 10/0.4 kV that are used to supply customers. The power demand for these substations is a combination of different types of residential, commercial and light industrial demand based on the data from Nordhavn area. It is modeled as time-series load profiles with 1-hour resolution aggregated on the secondary substation level and is synthesized from the actual annual energy measurements of each customer obtained from electric utility and its historical power demand curve.

The values of the parameters used in calculations are shown in Table I.

Three cases are considered: A). distribution network has enough electrical capacity for HP, so that HP can be connected to one of the loops; B). there is not enough electrical capacity to connect HP to one of the loops, so that HP should be connected via dedicated line to the main substation; C). flexibility from HP is used to solve the electrical capacity problem and avoid building a dedicated connection.

VII. Results

The peak heat demand $Q_{heat,peak}$ for the DH network is 1.6260 MW, with 4872.1 MWh of annual energy $E_{heat,year}$, that has to be provided for heating purposes.

Based on the volumes of water flow required to supply individual buildings, 4 types of heat pipes are selected for the DH design with their parameters shown in Table II. The cost of the pipes is estimated from [35]. The pipes are chosen, so that they can supply the necessary volume of water for 1, 4, 8 and all buildings respectively.

TABLE II: Nominal pipe sizes

Pipe nominal size	d_{pipe}, $[m]$	C_{pipe}, $[\$/m]$
DN 50	0.0530	261
DN 90	0.0960	472
DN 125	0.1280	629
DN 150	0.1540	757

The optimal DH network design is performed, where both pipe sizes and network length are minimized. The total length L_{pipe} and cost of DH network $\sum C_{pipe,ft}$ for each of the HP locations are given in Table III. The corresponding yearly heat losses $E_{heat,loss,year}$ and relative losses $q_{loss,relative}$ are shown in Table IV.

TABLE III: Total length, average pipe diameter and total cost of DH network for different HP locations

Location	L_{pipe}, $[m]$	D_a, $[m]$	$\sum C_{pipe,ft}$, $[k\$]$
1	1240	0.1062	364.8
2	1424	0.0969	410.6
3	1511	0.0938	427.8
4	1354	0.0933	359.1
5	1310	0.0938	363.1

Table V shows the required and rated electrical capacity for the HP depending on the heat source at different locations. Since the difference in power is relatively small, the rated power is the same for all locations. The cost of electrical cable to connect the HP to 10 kV network is estimated to be: 200 $\$/m$.

A. Case A

If the feeders in the distribution network have enough capacity, the HP can be connected to one of the loops. The additional cost $C_{additional}$ in this case is the cost of an additional transformer that will be placed at one of the already existed substations. Using P_{HP} and calculating apparent power S_{HP}, 630 kVA 10/0.4 kV three-phase transformer was estimated to be enough to connect HP to the electrical network. The cost of the transformer is estimated to be 20000 \$. $C_{additional}$ for substations 14, 17 and 21 is equal to zero, since the transformers on these substations have enough spare capacity to connect HP.

TABLE IV: Yearly and relative heat losses

Location	$E_{heat,loss,year}$, $[MWh]$	$q_{loss,relative}$, [%]
1	170.13	3.37
2	188.73	3.73
3	197.69	3.90
4	171.42	3.40
5	171.35	3.40

TABLE V: Electrical capacity and cost of HP unit

Location	P_{HP}, $[kW]$	$P_{HP,rated}$, $[kW]$	Heat source	C_{HP}, $[k\$]$
1	468.2	500	Seawater	50
2	494.6	500	Groundwater	80
3	470.6	500	Seawater	50
4	468.3	500	Seawater	50
5	468.3	500	Seawater	50

TABLE VI: Case A

Location	$CAPEX_{heat}$, [k\$]	$OPEX_{heat}$, [k\$]	PC	$CAPEX_{el}$, [k\$]	$OPEX_{el}$, [k\$]
1	456.3	2135.4	16	25.7	10.5
2	539.7	2256.4	21	19.9	5.4
3	525.5	2147.1	21	46.8	5.2
4	450.0	2136.0	214	68.8	4.5
5	454.4	2135.9	212	45.1	4.8

TABLE VII: Case B

Location	$CAPEX_{heat}$, [k\$]	$OPEX_{heat}$, [k\$]	PC	$CAPEX_{el}$, [k\$]	$OPEX_{el}$, [k\$]
1	456.3	2135.4	8	202.5	0.89
2	539.7	2256.4	8	162.9	0.78
3	525.5	2147.1	8	209.9	0.93
4	450.0	2136.0	8	247.5	1.10
5	454.4	2135.9	8	301.06	1.35

The power flow analysis using software package for Matlab - MATPOWER [36] is performed for all the potential points of connection (PC) in order to check the constraints of Eq. 17 and 18. It is assumed that the power demand curve for HP has the same shape as the one on Fig. 5.

The individual CAPEX and OPEX for DSO and DHO are shown in Table VI. From DHO perspective, it is better to install HP in Location 4, while DSO preferred Location 2. $OPEX_{heat}$ dominates the expenses due to the fact, that it includes the cost of total energy bought from DSO, while $OPEX_{el}$ only includes the cost of additional electrical losses caused in the system by the connection of HP.

The total combined cost of both utilities together are summarized in Table IX and shown that when the interests of both parties are taken into account, the optimal HP location shifts to Location 1.

B. Case B

If the distribution feeders do not have enough electrical capacity to accommodate the connection of HP, they have to be reinforced, i.e. changed to the ones with higher capacity. Since the total cables length and the amount of engineering work could be quite significant, an alternative - to supply HP through a dedicated line from the main substation could be preferred. This will increase the total cost for the DSO as compared to Case A as could be seen from Table VII.

Since now the HP is electrically closer to the source of electrical power, the electrical losses are lower than in Case A. Similar to the previous case, the optimal location is shifted from the one preferred by DHO alone as follows from the total costs in Table IX.

C. Case C

In some cases, the flexibility services from HP such as peak reduction or load shifting can be used to connect it to the distribution feeders without the need for reinforcement. It is dependant on the amount of power that has to be reduced from the HP side and the duration of the reduction.

In the current example, the calculations were made in order to reduce the peak electrical power of HP by 10 %, which will allow to connect the HP to one of the feeders. If the HP power demand throughout the year is following the same shape as a curve on Fig. 5, flexibility services from HP should only be called 9 hours per year, making 3 periods of 3,4 and 2 hours in duration, respectively. The first two periods occur around morning peak hours from 06:00 to 09:00 [37] and the last one is in the off-peak period. The price for providing flexibility is assumed to be 10 $\$/kWh$ for the morning peak period and 7 $\$/kWh$ plus additional 100 \$ as $C_{frequency}$.

TABLE VIII: Case C

Location	$CAPEX_{heat}$, [k\$]	$OPEX_{heat}$, [k\$]	PC	$CAPEX_{el}$, [k\$]	$OPEX_{el}$, [k\$]
1	456.3	2135.4	16	25.7	47.0
2	539.7	2256.4	21	19.9	38.1
3	525.5	2147.1	21	46.8	36.4
4	450.0	2136.0	214	68.8	34.9
5	454.4	2135.9	212	45.1	35.6

TABLE IX: Total combined cost of DSO and DHO for the different HP locations

Location	Case A	Case B	Case C
	Total, [k\$]	Total, [k\$]	Total, [k\$]
1	2627.9	2795.1	2664.4
2	2821.4	2959.8	2854.1
3	2724.6	2883.5	2755.9
4	2659.3	2834.6	2689.7
5	2640.2	2892.7	2671.0

CAPEX and OPEX for Case C are given in Table VIII. The combined cost are shown in Table IX.

Use of flexibility services allows to connect HP to the one of the already existing substation, which is located close to the HP installation site, thus significantly lowering $CAPEX_{el}$ as opposed to Case B. From the other hand, $OPEX_{el}$ will increase, because of the price for flexibility services.

VIII. Conclusions

The methodology for integrated planning for a large HP in the heat and electrical networks is presented in this paper. It was shown that by considering the interests of both stakeholders (DSO and DHO), the optimal installation location for HP is shifted from the one that would be preferred by DHO alone. The new location will provide a higher societal benefit - the reduced total cost and allows to better utilize the synergy between heat and power sectors via flexibility services. The optimal HP location is highly dependent on the costs associated with each stakeholder, the availability of the heat sources and spare capacity of the electrical network and has to be analysed on a case-by-case basis.

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[E] Optimal Placement of A Heat Pump in An Integrated Power and Heat Energy System

Optimal Placement of A Heat Pump in An Integrated Power and Heat Energy System

Sergey Klyapovskiy, Shi You, Henrik W. Bindner, Hanmin Cai
Center for Electric Power and Energy (CEE)
Technical University of Denmark (DTU)
2800 Kgs. Lyngby, Denmark
{seklya, sy, hwbi, hacai}@elektro.dtu.dk

***Abstract*—With the present trend towards Smart Grids and Smart Energy Systems it is important to look for the opportunities for integrated development between different energy sectors, such as electricity, heating, gas and transportation. This paper investigates the problem of optimal placement of a heat pump – a component that links electric and heating utilities together. The system used to demonstrate the integrated planning approach has two neighboring 10kV feeders and several distribution substations with loads that require central heating from the heat pump. The optimal location is found with the help of mathematical optimization that minimizes investments of both electric and heating utilities, achieving the reduction of the total investment. The optimization is performed in Matlab using built-in Genetic Algorithm function and Matpower software package for calculating power flow equations.**

Keywords-heat pump; district heating; optimal location; optimization; flexibility; MATPOWER; genetic algorithm

I. INTRODUCTION

At present approximately 63% of Danish private houses use district heating (DH) [1]. The DH system in Denmark mainly consists of combined heat and power plants (CHP) of different sizes, producing both electric and heat power. Most of CHPs are working on natural gas or biomass following the trend of replacing coal due to CO_2 reduction efforts. Detailed description of DH systems can be found in [2]. By cogenerating heat and power, the overall system efficiency is improved from 42% for typical power station to over 85% [3]. However, with the increasing penetration of renewable energy sources, such as solar and wind, it can be sometimes beneficial to use that electricity directly to produce required heat. In addition the electricity generation is becoming more and more intermittent in nature and the peak of power production does not always coincide with the heat demand profile. There is therefore a need to decouple the production of heat power from electricity.

Using heat pumps in DH system provides a number of advantages in comparison with traditional heating solutions in a DH system. First, heat pumps allow to achieve the decoupling between heat and power production [4]. Second, as mentioned in [5] heat pumps greatly reduce the amount of CO_2 emissions for each kWh of delivered heat. As stated in [6], heat pumps are found to be a suitable alternative to using carbon-free fuel sources in DH, as there are certain concerns regarding the availability of biomass and biogas in the future. Third, from the distribution grid planning perspective, heat pump can serve as a source of flexibility in terms of power and heat consumption. Fourth, typical heat pump coefficient of performance (COP) is around 3-4, which exceeds COP of electric boilers that also produce heat using electricity [7]. Lastly, heat pump efficiency will increase, if required DH supply temperature is reduced, which makes it an ideal candidate in the Low Temperature DH networks [8].

The present practice of installing a heat pump for creating DH system does not involve the cooperation between electric and heating utilities. The heating utility decides on the location according to the availability of heat sources (air, water or exhaust industrial heat), type of soil to ease the drilling process in case of water heat source and minimal investments in a new heating infrastructure. As indicated in [9], often the main concern for heating utility is to find a location for DH plant which will allow the most optimal configuration of the DH pipe network or to optimize the pipe network itself as shown in [10]. Investments from electrical side typically are not considered in the literature.

Given the specific location from heating utility an electric utility then needs to provide the necessary electrical infrastructure. Such approach, however, may result in "less optimal social infrastructure investment" and may not be optimal if both electrical and heating networks are considered.

This paper therefore presents an idea where integration between electrical and heating networks can be implemented: an approach, where the location of heat pump is determined as a result of optimization of both electric and heating utility expenses. This is particularly relevant, when both infrastructures belongs to one municipality and therefore will lead to potential saving. In a deregulated system, the amount of saving achieved from the integrated planning can be split between parties involved in using market-based approach.

II. METHODOLOGY

A. System description

In order to study the optimal placing of a heat pump the system in Fig. 1 is considered. The system consists of two feeders that are supplied from separate main substations (MS) with 50/10 kV transformers. Switch (SW) is open during normal operation, but can be used to connect two MS together in case of fault or for system reconfiguration. Each feeder has several 10/0.4 kV distribution substations (DS) and loads (L) connected at 0.4 kV level. Such feeder configuration can be found in rural areas and small cities. Parameters for transformers and cables used for modelling the system are given in Table I and Table II respectively.

B. Electrical loads

Loads are connected to the low voltage 0.4 kV network on each DS and represent different types of industrial and residential customers. Fig. 2 shows total load profiles for typical January week day at DS1-7. These profiles are made by summation of load profiles of individual categories. The morning and evening peaks in power consumption indicate that the residential consumers constitute the significant part of the total load, which shown in Table III.

C. Heat pump capacity

In the current study houses and apartments without electrical heating are two load categories that are going to be heated using a heat pump through a DH network. Values for the annual energy consumption known for each DS are used to identify approximate number of these buildings connected at each substation, as shown in (1).

$$\#\,Houses = \frac{AEC_{DS} \times CATP_{DS}}{TAEC_{Cat}} \tag{1}$$

#Houses – number of houses; AEC_{DS} – annual energy consumption at DS, [MWh]; $CATP_{DS}$ – percentage of this category in total DS load; $TAEC_{Cat}$ – typical annual energy consumption for this category, [MWh], found in [11].

For the considered system a 400 kW heat pump is estimated to be sufficient for providing heat to all houses and apartments. It can be seen that heat pump capacity is significant in comparison with the power ratings of transformers at DS and ensuring its power supply can represent a challenge for an electric utility.

TABLE I. TRANSFORMER PARAMETERS

Transformer at substation	Parameter			
	Apparent power, kVA	*Nominal voltage, kV*	u_k, %	u_r, %
DS1, DS5	100	10/0.4	4.3	1.972
DS2, DS6	200	10.5/0.42	3.89	1.164
DS3, DS4, DS7	100	10/0.4	3.7	1.567

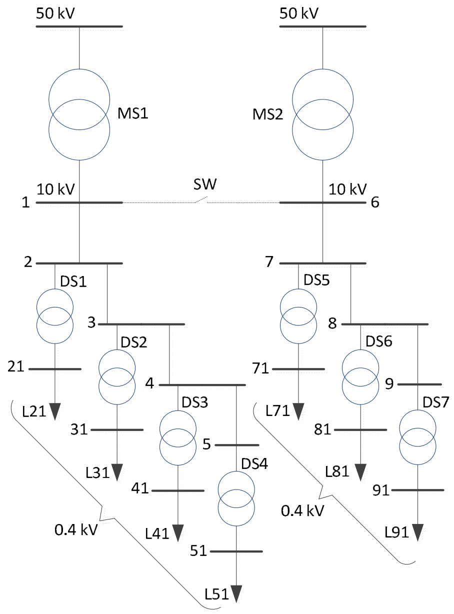

Figure 1. System with two feeders

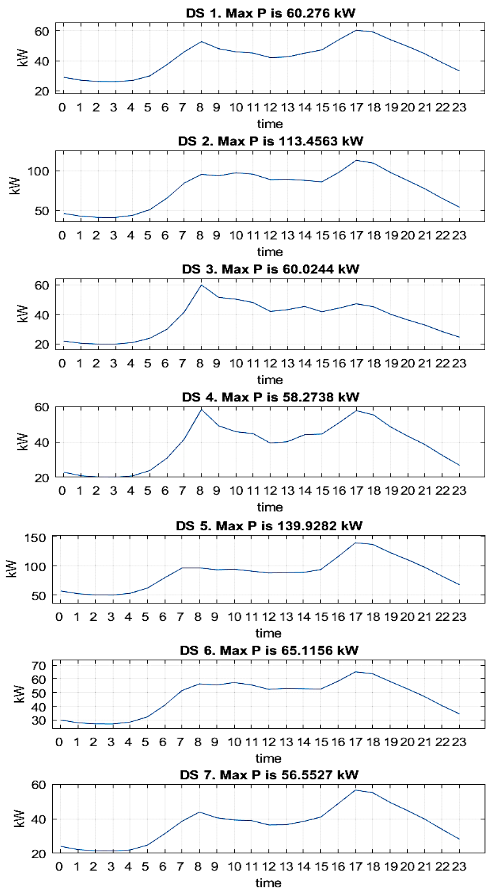

Figure 2. Load profiles of DS1-7

TABLE II. CABLE PARAMETERS

Cable	Parameter						
	Length, km	***R, Ohm/km***	***X, Ohm/km***	***C, uF/km***	***B, uS/km***	***Type***	***Max current, A***
1 – 2	3.292	0.128	0.069	0.4954	155.635	240 mm^2 Al	341
2 – 3	0.903	0.128	0.068	0.5	157.08	240 mm^2 Al	341
6 – 7	4.2						
3 – 4	1.0	0.208	0.09	0.37	116.239	150 mm^2 Al	311
7 – 8	1.39						
4 – 5	1.544	0.32	0.098	0.31	97.389	95 mm^2 Al	241

TABLE III. LOAD CATEGORIES AT DISTRIBUTION SUBSTATIONS

	Category (in % of the total load)			
	Houses with el. heating	***Houses without el. heating***	***Apartments without el. heating***	***Other categories***
DS1	43.7	17.6	23.0	15.7
DS2	4.4	55.0	2.5	38.1
DS3	25.0	30.4	0.0	60.0
DS4	10.4	52.3	0.0	37.2
DS5	10.0	62.0	11.0	17.0
DS6	36.1	23.8	16.6	23.5
DS7	16.3	46.4	15.2	22.1

III. MATHEMATICAL FORMULATION

A. Objective function and constraints

The problem of finding optimal heat pump location is formulated using nonlinear integer programming. The objective is to minimize the investment of both electric and heating utilities due to the heat pump installation. The objective function is:

$$C = \sum_{ns=1}^{2}\sum_{nl=1}^{3} MS_{ns} \cdot HP_{nl} \cdot \left(m_{nl} \cdot d_{nl,ns} \cdot CC + CCON\right) + \\ + \sum_{ns=1}^{2}\sum_{nl=1}^{3} MS_{ns} \cdot HP_{nl} \cdot n_{nl} \cdot \left(lHPSN_{SN,nl} + lpipes\right) \cdot CP \quad (2)$$

Decision variables: *MS* is a set of binary variables showing to which MS the heat pump is connected; *HP* is a set of binary variables showing which location for heat pump was chosen; *SN* – starting node, indicate heat load at which DS will be connected to the heat pump and become a center of a heating network.

Parameters: *m, n* – are the weighting factors given to locations by electric and heating utilities respectively; *d* – distance from heat pump location to chosen MS, [km]; *lHPSN* – length of the pipes from chosen location of HP to starting node SN, [km]; *lpipes* – length of pipes in the heating network, [km]; *CC* – cost of laying out electrical cables, [\$]; *CCON* – cost of connection to MS, [\$] is calculated according to (3):

$$CCON = CI + AS_{ns} \cdot CSl \quad (3)$$

CI – installation cost for connecting heat pump to MS, [\$]; AS_{ns} – binary parameter indicating available slots for new connection in switchgear of MS; *ns* – number of substations heat pump can be connected to; *CSl* – cost of adding new connection into switchgear of MS; *nl* – number of locations.

The objective function is subject to the following constraints:

$$S_{DS} \le S_{DS\max} \quad (4)$$

$$S_{Transmitted} \le S_{Cable\max} \quad (5)$$

$$0.95 \le V_{Node} \le 1.05 \quad (6)$$

S_{DS} – power coming through transformer at DS, i.e. loading of transformer, [kVA]; S_{DSmax} – power rating of transformer at DS, [kVA]; $S_{Transmitted}$ – power coming through cables, [kVA]; $S_{Cablemax}$ – cable power rating, [kVA]; V_{Node} – voltage at each node, [pu].

Equations (4) and (5) show the capacity constraints for the transformers and cables and indicate that they should not be loaded more than their power ratings allow. Node voltage constraints are given in (6) and lower and upper boundaries are ±5% of nominal value.

Additional constraints that have no physical meaning, but are due to binary programming for problem formulation are shown below:

$$MS_{ns} \in \{0,1\} \tag{7}$$

$$\sum_{ns=1}^{2} MS_{ns} = 1 \tag{8}$$

$$HP_{nl} \in \{0,1\} \tag{9}$$

$$\sum_{nl=1}^{3} HP_{nl} = 1 \tag{10}$$

Equations (8) and (10) indicate that heat pump can only be connected to one substation and installed at one location.

The optimization is carried out in Matlab. The external software package – Matpower [12] is used for power flow calculations and checking constraints (4) – (6). Power balance constraints [13] are already embedded into the Matpower power flow function and therefore not shown here.

B. *Heating network topology*

When deciding upon the optimal location of the heat pump it is also important to consider the configuration of the resulted heating network. The most common practice is to connect the heating loads in a radial network, thus imposing the radiality constraint on the solution. As stated in [14] the radiality constraint is identical to constraint of the spanning tree in graph theory. By using minimum spanning tree approach it is possible to come up with the optimal topology that will give the minimum length of pipes. The minimum spanning tree for the studied system with distances in km is shown on Fig. 3.

C. *Optimization method*

The use of integers in problem formulation imposes certain limitations on the optimization methods that can be selected. In addition not all built-in optimization functions in Matlab allow to use external packages (such as Matpower) for checking the constraints. The schematic diagram in Fig. 4 illustrates the proposed approach of finding the optimal location of the heat pump.

Matpower requires the information about system topology and components to be written in a specific way in a structure array. That is why block that builds such array is shown in Fig. 3 in an initialization part of the diagram.

The built-in Matlab function of Genetic Algorithm (GA) was used as an optimization method. GA is a heuristic algorithm that uses selection, crossover and mutation processes to find the best solution [13]. If the solution does not satisfy the constraints, GA will use the mechanisms of crossover and mutation to find another one. If there is still no possible solution, the hard constraints can be changed to soft ones, which could be violated with a certain penalty.

Although not considered in the current paper, but in some cases all available substations, where heat pump can be connected, may be at the limit of their capacity. Therefore connecting heat pump to any of them will violate the capacity constraints. In such situation network reinforcement or utilizing of flexibility should be considered as a part of the solution.

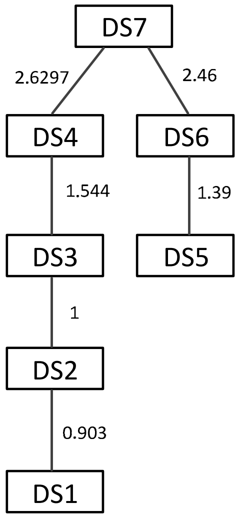

Figure 3. Minimum spanning tree for building optimal heating network

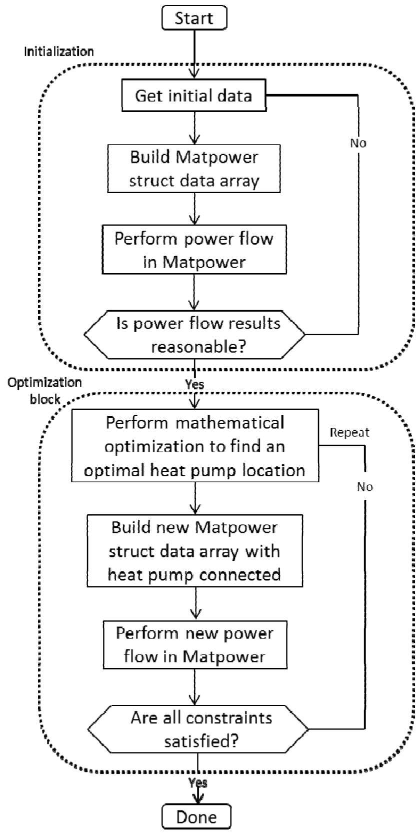

Figure 4. Schematic diagram of solving optimization problem

IV. Case Study

Four study cases (SC) are considered in this paper:

SC1 – only heating utility investments are considered;

SC2 – only electric utility investments are considered;

SC3 – both electric utility and heating utility investments are considered, different cost of connection *CCON* to MS1 and MS2;

SC4 – both electric utility and heating utility investments are considered, cost of connection *CCON* to MS1 and MS2 is the same.

A. Potential locations and weighting factors

Three potential locations for installing heat pump are considered: 1 – location close to the loads with heat demand (preferred by heating utility); 2 – location close to main transformer substations (beneficial for electric utility), 3 – middle point of locations 1 and 2, which can be acceptable for both utilities.

Each utility assigns weighting factors to each location, which expresses the potential increase of operational cost if heat pump is installed there, due to the higher losses, if the cable or pipe network has to be extended. Potential locations are shown on Fig. 5 and Table IV gives the overview of weighting factors for electric and heating utilities.

B. Estimation of investments

Typically electric utilities only install limited number of cable types in their grid. Therefore 95 mm^2 Al XLPE cable is chosen for connecting the heat pump to one of the MS. The cost of cable together with its installation was estimated to be 60 000 $ per km.

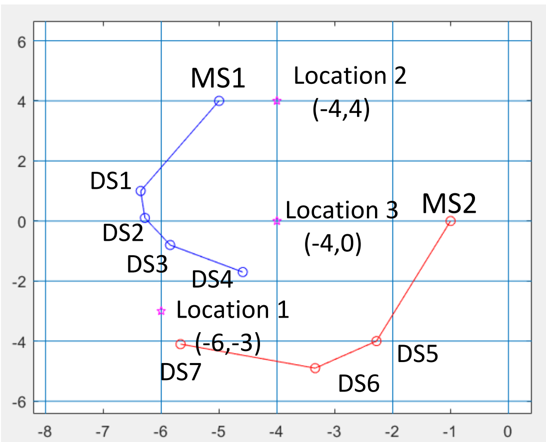

Figure 5. System with two feeders on the coordinate grid (km) and potential location for heat pump installation

TABLE IV. Weighting Factors For Locations

Utility	Weighting factors (m and n)		
	Location 1:	*Location 2:*	*Location 3:*
Electric	1.5	1.0	1.25
Heating	1.0	1.5	1.25

Since heat pump capacity exceeds the rated capacity of all DS, it can only be connected to either MS1 or MS2. For SC3 the cost of connection is different for each substation. The cost for MS1 includes just the installation expenses, while if MS2 is chosen to connect a heat pump a new slot for the switchgear (with circuit-breaker) should be bought. The cost for MS1 and MS2 were estimated to be 30 000 $ and 150 000 $ respectively.

The cost for laying heat pipes is set to be 50 000 $ per km.

C. Simulation results

Before connecting a heat pump, power flow calculations are performed using Matpower software package to check the current status of the grid. Values of the loads for power flow calculations are taken from Fig. 2 for the evening peak (17:30 on the figure) in such a way, that they represent the worst case scenario that can happen in the grid. Results are shown on Fig. 6 and Fig. 7.

Bus names follow the notation given on Fig. 1. MS1 (Bus 1) and MS2 (Bus 2) are considered to be slack buses for this system. The voltages for all system nodes are within limits, due to the relative closeness to main substations, with the minimal voltage 0.997 pu observed at DS1 (Bus 71) on 0.4 kV side after distribution grid transformer. There are no problems of line congestions as well.

Considering the optimal heat pump location, optimization is first run for cases when electric and heating utilities are considered separately. The results are shown on Fig. 8 and Fig. 9 for heating and electric utilities respectively. Magenta line shows the electrical connection from installation point of heat pump to the chosen MS. Dashed black lines indicate heating pipes.

```
================================================================================
|     Bus Data
================================================================================
 Bus      Voltage          Generation             Load
  #   Mag(pu) Ang(deg)   P (MW)   Q (MVAr)   P (MW)   Q (MVAr)
----- ------- --------  --------  --------  --------  --------
    1  1.020    0.000*     0.25      0.03        -         -
    2  1.019   -0.018       -         -          -         -
   21  0.997 -151.039       -         -        0.05      0.03
    3  1.019   -0.021       -         -          -         -
   31  1.004 -150.936       -         -        0.10      0.05
    4  1.018   -0.022       -         -          -         -
   41  1.003 -150.754       -         -        0.04      0.02
    5  1.018   -0.022       -         -          -         -
   51  1.001 -150.861       -         -        0.05      0.02
    6  1.020    0.000*     0.23      0.00        -         -
    7  1.019   -0.024       -         -          -         -
   71  1.001 -151.108       -         -        0.12      0.06
    8  1.018   -0.028       -         -          -         -
   81  0.999 -150.995       -         -        0.06      0.03
    9  1.018   -0.029       -         -          -         -
   91  1.002 -150.834       -         -        0.05      0.02
                        --------  --------  --------  --------
               Total:      0.48      0.03      0.47      0.23
```

Figure 6. Node voltages obtained from Matpower

Branch Data

Brnch #	From Bus	To Bus	From Bus Injection P (MW)	From Bus Injection Q (MVAr)	To Bus Injection P (MW)	To Bus Injection Q (MVAr)	Loss (I^2 * Z) P (MW)	Loss (I^2 * Z) Q (MVAr)
1	1	2	0.25	0.03	-0.25	-0.08	0.000	0.00
2	2	21	0.05	0.03	-0.05	-0.03	0.001	0.00
3	2	3	0.19	0.06	-0.19	-0.07	0.000	0.00
4	3	31	0.10	0.05	-0.10	-0.05	0.001	0.00
5	3	4	0.10	0.02	-0.10	-0.03	0.000	0.00
6	4	41	0.04	0.02	-0.04	-0.02	0.000	0.00
7	4	5	0.05	0.01	-0.05	-0.03	0.000	0.00
8	5	51	0.05	0.03	-0.05	-0.02	0.000	0.00
9	6	7	0.23	0.00	-0.23	-0.07	0.000	0.00
10	7	71	0.12	0.06	-0.12	-0.06	0.001	0.00
11	7	8	0.11	0.01	-0.11	-0.03	0.000	0.00
12	8	81	0.06	0.03	-0.06	-0.03	0.001	0.00
13	8	9	0.05	-0.00	-0.05	-0.02	0.000	0.00
14	9	91	0.05	0.02	-0.05	-0.02	0.000	0.00
						Total:	0.005	0.01

Figure 7. Power flow results obtained from Matpower

As expected when the planning exercises are considered separately, the best location for heating utility is the one that is closest to loads, while electric utility prefers the location which is closer to power supply.

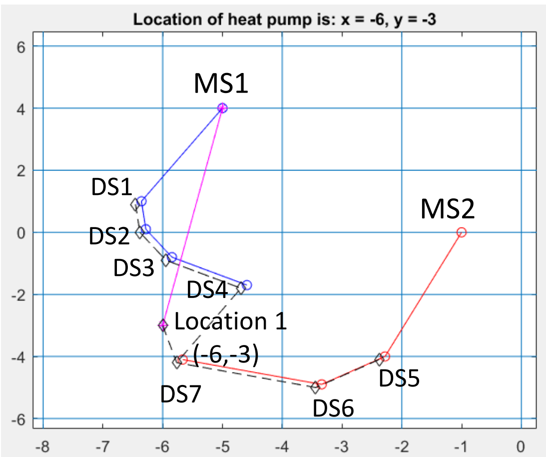

Figure 8. Preferred location for heating utility (SC1)

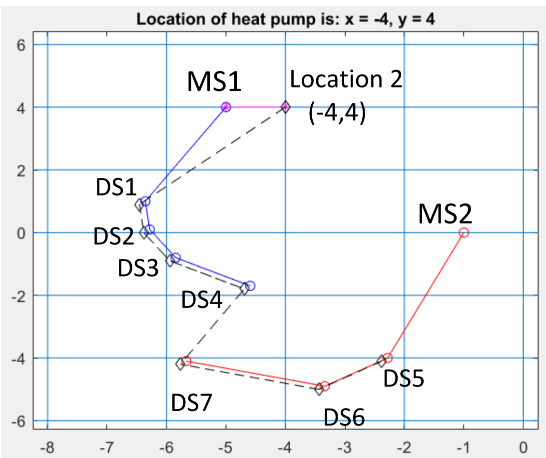

Figure 9. Preferred location for electric utility (SC2)

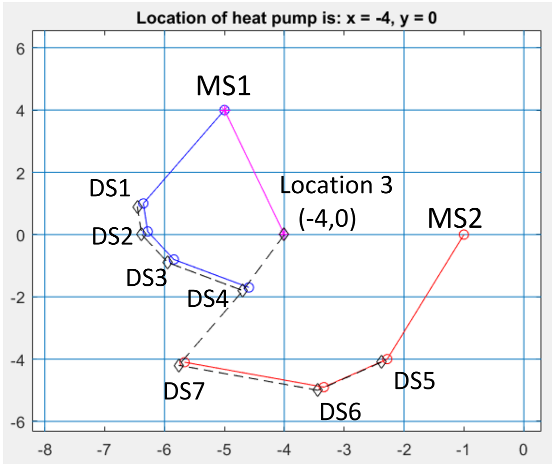

Figure 10. Optimal location for both electric and heating utility (SC3)

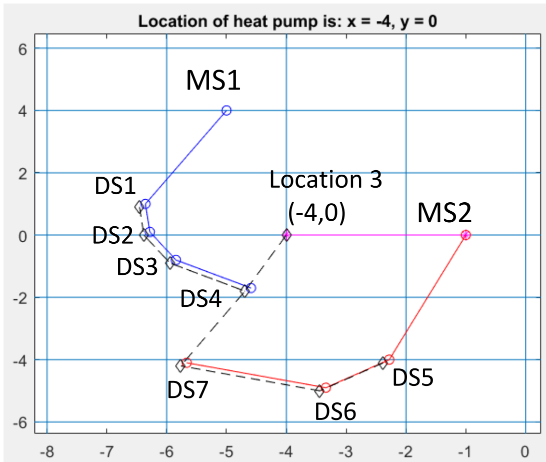

Figure 11. Optimal location for both electric and heating utility with connection to MS2 (SC4)

If both electric and heating utility investments are considered in the objective function, the optimal heat pump location will shift as can be seen in Fig. 10.

In case MS2 has enough slots in the switchgear for new connection, then its connection cost CCON will be the same as MS1 and the optimal system configuration will change as shown on Fig. 11. In that case the total investment can even further be decreased.

The investments for electric and heating utilities for each location are given in Table V. It shows that by choosing location which is suitable for both utilities the overall investment can be reduced by 7.85% (SC3) or 19.04% (SC4) compared to choosing SC1, when heating utility determines heat pump location by itself.

Node voltages and power flows in the system with heat pump connected to MS2 are shown on Fig. 12 and Fig. 13 respectively. Bus 10 is the connection point of HP to the system. The last branch #15 in Fig. 13 represents the cable connecting HP and MS2.

Results show that connection of a heat pump does not affect the system and cause only slight increase in the system losses.

TABLE V. INVESTMENT OF ELECTRIC AND HEATING UTILITIES

Utility	Investments			
	Location 1:	*Location 2:*	*Location 3:*	
	MS1	MS1	**MS1**	**MS2**
Electric	666 400 $	90 000 $	**339 230 $**	**255 000 $**
Heating	553 810 $	1 030 600 $	**732 910 $**	**732 910 $**
Total	1 220 200 $	1 120 600 $	**1 072 140 $**	**987 910 $**

```
================================================================
|     Bus Data
================================================================
 Bus      Voltage          Generation             Load
  #   Mag(pu) Ang(deg)   P (MW)   Q (MVAr)   P (MW)   Q (MVAr)
----- ------- --------  --------  --------  --------  --------
    1  1.020    0.000*    0.25      0.03        -         -
    2  1.019   -0.018       -         -         -         -
   21  0.997 -151.039       -         -       0.05      0.03
    3  1.019   -0.021       -         -         -         -
   31  1.004 -150.936       -         -       0.10      0.05
    4  1.018   -0.022       -         -         -         -
   41  1.003 -150.754       -         -       0.04      0.02
    5  1.018   -0.022       -         -         -         -
   51  1.001 -150.861       -         -       0.05      0.02
    6  1.020    0.000*    0.62      0.17        -         -
    7  1.019   -0.024       -         -         -         -
   71  1.001 -151.108       -         -       0.12      0.06
    8  1.018   -0.028       -         -         -         -
   81  0.999 -150.995       -         -       0.06      0.03
    9  1.018   -0.029       -         -         -         -
   91  1.002 -150.834       -         -       0.05      0.02
   10  1.016    0.030       -         -       0.40      0.19
                        --------  --------  --------  --------
               Total:     0.87      0.20      0.87      0.42
```

Figure 12. Node voltages obtained from Matpower

```
==========================================================================
|     Branch Data                                                        |
==========================================================================
Brnch   From   To    From Bus Injection   To Bus Injection    Loss (I^2 * Z)
  #     Bus    Bus    P (MW)   Q (MVAr)   P (MW)   Q (MVAr)   P (MW)   Q (MVAr)
-----  -----  -----  --------  --------  --------  --------  --------  --------
   1      1      2     0.25      0.03     -0.25     -0.08     0.000      0.00
   2      2     21     0.05      0.03     -0.05     -0.03     0.001      0.00
   3      2      3     0.19      0.06     -0.19     -0.07     0.000      0.00
   4      3     31     0.10      0.05     -0.10     -0.05     0.001      0.00
   5      3      4     0.10      0.02     -0.10     -0.03     0.000      0.00
   6      4     41     0.04      0.02     -0.04     -0.02     0.000      0.00
   7      4      5     0.05      0.01     -0.05     -0.03     0.000      0.00
   8      5     51     0.05      0.03     -0.05     -0.02     0.000      0.00
   9      6      7     0.23      0.00     -0.23     -0.07     0.000      0.00
  10      7     71     0.12      0.06     -0.12     -0.06     0.001      0.00
  11      7      8     0.11      0.01     -0.11     -0.03     0.000      0.00
  12      8     81     0.06      0.03     -0.06     -0.03     0.001      0.00
  13      8      9     0.05     -0.00     -0.05     -0.02     0.000      0.00
  14      9     91     0.05      0.02     -0.05     -0.02     0.000      0.00
  15      6     10     0.40      0.16     -0.40     -0.19     0.002      0.00
                                                             --------  --------
                                                   Total:     0.007      0.01
```

Figure 13. Power flow results obtained from Matpower

V. CONCLUSION

The problem of optimal placement of heat pump is considered in this paper. It was shown that by optimizing necessary investments of electric and heating utilities together in one objective function it is possible to achieve the solution when the total investment will be reduced. This integrated decision making will not only be beneficial for the cases when both electrical and heating infrastructure belongs one entity, it will also be a win-win solutions for different utilities when they cooperate.

GA optimization algorithm together with Matpower software package is used to determine an optimal location of a heat pump in a system with two feeders, while ensuring that no constraints are violated. Computational time will increase with increase in the size of the system due to the larger number of possible solutions that need to be investigated. In such case GA may not always be able to reach the global minimum of objective function, but will show one of the local minimum. To ensure that the solution is close to optimal, GA could be run multiple times and results from different runs should be compared to identify the best solutions.

This paper is intended to be a starting point in investigation of using flexibility in an integrated energy system from a long-term planning perspective. Following aspects will be considered in the future studies:

1. Energy loss is currently reflected by weighting factors in Table IV; the specific value of loss should be taken into account during planning.
2. Reconfiguration of electrical network through the normal-open-switch SW would enable load shifting across feeders, therefore providing planning alternatives to the electric utility.
3. The HP as a central heating solution can offer additional flexibility to the electric utility, when it works together with local heating systems at the end-user side. This brings in extra value, because the heat network facilitate heat load shift cross different regions.

ACKNOWLEDGMENT

This work was supported by the Danish Energy Development Programme (EUDP) through the EnergyLab Nordhavn project.

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Department of Electrical Engineering
Center for Electric Power and Energy (CEE)
Technical University of Denmark
Elektrovej, Building 325
DK-2800 Kgs. Lyngby
Denmark

www.elektro.dtu.dk/cee
Tel: (+45) 45 25 35 00
Fax: (+45) 45 88 61 11
E-mail: cee@elektro.dtu.dk