Grid Capacity

Challenges and Opportunities

Lundberg, Martin

2025

Document Version:
Publisher's PDF, also known as Version of record

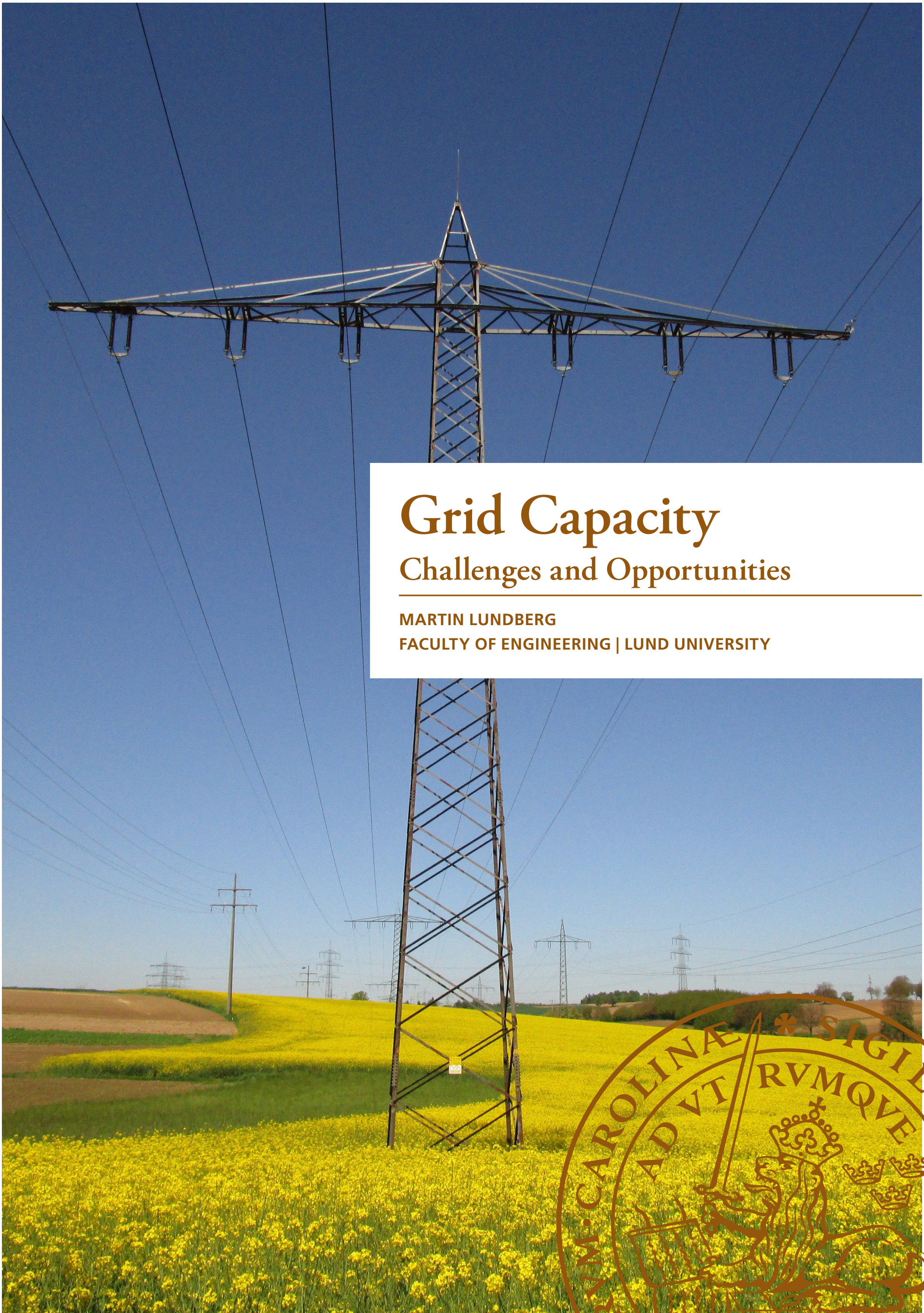
Link to publication

Citation for published version (APA):
Lundberg, M. (2025). *Grid Capacity: Challenges and Opportunities*. Division of Industrial Electrical Engineering and Automation, Faculty of Engineering, Lund University.

Total number of authors:
1

LUND UNIVERSITY

PO Box 117
221 00 Lund
+46 46-222 00 00



Grid Capacity

Challenges and Opportunities

MARTIN LUNDBERG
FACULTY OF ENGINEERING | LUND UNIVERSITY

Grid Capacity

Grid Capacity
Challenges and Opportunities

by Martin Lundberg

LUND
UNIVERSITY

Thesis for the degree of Doctor of Philosophy in Engineering
Thesis advisors: Prof. Olof Samuelsson, Dr. Emil Hillberg
Faculty opponent: Prof. Sami Repo

To be presented, with the permission of the Faculty of Engineering (LTH) of Lund University, for public criticism in the M:B lecture hall (M-Building, LTH) at the Division of Industrial Electrical Engineering and Automation on Friday, the 3rd of October 2025 at 09:00.

Organization **LUND UNIVERSITY** Division of Industrial Electrical Engineering and Automation Box 118 SE–221 00 LUND, Sweden	Document name **DOCTORAL DISSERTATION**
	Date of disputation 2025-10-03
	Sponsoring organization
Author(s) Martin Lundberg	

Title and subtitle

Grid Capacity: Challenges and Opportunities

Abstract

Electric power grids have a limited capacity for safe and reliable transfer of power. Due to the ongoing large-scale expansion of variable renewable energy sources, such as wind and solar, there is a growing need for rapid grid capacity increase.

This thesis explores methods for improving and expanding grid capacity through control of converter-interfaced energy resources, including wind and solar plants, and battery energy storage systems. The objective is to safely operate existing networks at their capacity limits, which improves grid utilisation and reduces reliance on slow infrastructure upgrades. Specifically, voltage and power flow constraints in distribution networks, and power flow limits in transmission networks are considered in the presented research.

The thesis contains two main research contributions. The first concerns development of new control methods for converter-interfaced resources. Three types of PI control based methods are proposed. First, voltage limitation strategies for distribution networks based are presented (Papers I and II). Through adjustments of both active and reactive power, mitigation of overvoltage is ensured in networks with low X/R ratios. Second, a method for congestion management in distribution networks is developed, for which control actions are organised through a flexibility dispatch list (Paper III). Third, a method for coordinated control of energy storage systems to form a virtual power line is investigated (Paper IV). The virtual power line allows for improved utilisation of existing transmission network capacity, as well as temporary increases in power transfer between different areas.

The second main research contribution concerns methods for modelling and analysis of grid capacity in power systems with large shares of renewable generation. The general characteristics of the renewable energy expansion are first introduced (Paper I). A modelling framework is developed for analysis of nonlinear dynamics of local voltage controllers in a quasi-static grid model (Paper II). Virtual power line control, sizing, and placement is analysed in a system model based on power transfer distribution factors (Paper IV). Finally, a capacity expansion model is developed, with a detailed representation of electricity market dynamics heavily influenced by weather variability (Paper V).

The results indicate that significant improvements to grid utilisation in existing power systems is possible through low-complexity decentralised control strategies for inverter-interfaced resources.

Key words

variable renewable energy integration, power system operation, capacity expansion

Classification system and/or index terms (if any)

Supplementary bibliographical information	Language English
ISSN and key title	ISBN 978-91-985110-7-9 (print) 978-91-985110-6-2 (pdf)

Recipient's notes	Number of pages 160	Price
	Security classification	

Signature ____________________ Date 2025-09-09

Grid Capacity
Challenges and Opportunities

by Martin Lundberg

LUND
UNIVERSITY

Cover illustration: Image by Kassandra, Pixabay. Used under the Pixabay content license.

Funding information: The thesis work was in part supported by EU H2020 grant agreement No 775970 through the ERA-Net SES initiative, and in part through the Swedish Electricity Storage and Balancing Centre (SESBC). The SESBC is funded by the Swedish Energy Agency together with five academic and twenty-eight non-academic partners. In particular, the author acknowledges DNV, E.ON, Göteborg Energi, Hitachi Energy, Svenska kraftnät, Vattenfall Eldistribution, Volvo Cars, and Volvo Energy, for their contribution and support to the research.

Faculty of Engineering (LTH), Division of Industrial Electrical Engineering and Automation

ISBN: 978-91-985110-7-9 (print)
ISBN: 978-91-985110-6-2 (pdf)
CODEN: LUTEDX/(TEIE-1101)/1-160/(2025)

Printed in Sweden by Media-Tryck, Lund University, Lund 2025

NORDIC SWAN ECOLABEL
Printed matter
3041 0903

Media-Tryck is a Nordic Swan Ecolabel certified provider of printed material. Read more about our environmental work at www.mediatryck.lu.se

MADE IN SWEDEN

Indulge your passion for science…, but let your science be human,
and such as may have a direct reference to action and society.

— David Hume

Contents

List of publications

This thesis is based on the following publications, referred to by their Roman numerals:

I **Alternative network development – need for flexible solutions for operation and planning of distribution and transmission grids**
E. Hillberg, **M. Lundberg**, and O. Samuelsson
2020 Virtual CIGRE Canada Conference, 20-21 October 2020

II **Local voltage control in distribution networks using PI control of active and reactive power**
M. Lundberg, O. Samuelsson, and E. Hillberg
Electric Power Systems Research, vol. 212, Art no. 108475, 2022, DOI: 10.1016/j.epsr.2022.108475

III **Congestion management in distribution systems with large presence of renewable energy sources**
M. Lundberg, O. Samuelsson, M. Mirz, E. Hillberg, and N. Hancock
CIGRE Science and Engineering, vol. 2023, no. 27, 2023

IV **Decentralized control of virtual power lines for increased transfer capacity**
M. Lundberg, O. Samuelsson, and E. Hillberg
Submitted for journal publication, 2025

V **Robust capacity expansion planning in hydro-dominated power systems: a Nordic case study**
D. M. Cox, D. Rodrigues Damasceno, J. Hagsten, C. Hellesen, M. Hjelmeland, J. Jurasz, A. Kies, O. Lagnelöv, **M. Lundberg**, L. Lundström, J. T. K. McKenna, P. Norberg, J. Kristiansen Nøland, A. Payaró Llisterri, S. Qvist, S. Svanström, A. Såmark-Roth, Y. Yang, M. Reza Hesamzadeh, and L. Bertling Tjernberg
Submitted for journal publication, 2025

Additional publications

Other peer-reviewed publications related to the subject by the author not included in the thesis:

Planning tools and methods for systems facing high levels of distributed energy resources
C. Higgins, J. Palermo, R. Sanz Lopez, X. Hu, C. Tang, P. Kamera, E. Farias, M. Goedde, F. Madia Mele, R. Ganguli, **M. Lundberg**, and A. Loukatou
CIGRE International Symposium Cairns 2023, Cairns, Australia, 4-7 Sept. 2023

Active Network Management to support increased grid utilisation – ANM4L project results
E. Hillberg, **M. Lundberg**, M. Edvall, O. Samuelsson, W. Tobiasson, G. Nakti, B. Borovic, M. Szél, J. Rosvall, N. Hancock, V. Milshyn, J. Weber, T. Borges, L-G. Fagerberg, and M. Jältås
CIGRE International Symposium Cairns 2023, Cairns, Australia, 4-7 Sept. 2023

Other publications related to the subject by the author:

Report on ANM control algorithm for active & reactive power

O. Samuelsson and **M. Lundberg**
ANM4L Deliverable 3.1, May 2021

Valuations of ANM methods and flexibility in short-term & long-term planning & future scenarios
M. Lundberg, O. Samuelsson, S. Nyström, and M. Edvall
ANM4L Deliverable 3.2/4.4, June 2022

Summary report on technical aspects of ANM

M. Lundberg and O. Samuelsson
ANM4L Deliverable 3.3, October 2022

Acknowledgements

One popular approach to personal development can be summarised by the phrase ”If you are the smartest person in the room, you are in the wrong room”. Without passing any judgment on that strategy in general, when looking back at my time as a PhD student, I can confidently say that I have had the pleasure of sharing rooms with many people who are much more knowledgeable than I am. Without their contributions, both great and small, this thesis would not exist. First and foremost, I would like to thank my supervisor, Professor Olof Samuelsson, for your tireless enthusiasm and patience as a mentor. Your guidance has been invaluable. I would also like to express my gratitude to Dr. Emil Hillberg for sharing your power system expertise and diligently providing insightful feedback as a co-supervisor.

I am grateful for my many chances to interact with the power system community. Particularly, I would like to thank Professor Nando Ochoa and his research group at the University of Melbourne; Dr. Staffan Quist, Dr. Anton Såmark-Roth, and coworkers at Quantified Carbon; Dr. Markus Mirz, then at RWTH Aachen; Professor Lars Nordström, KTH; and Dr. Emma Blomgren, Göteborg Energi, for engaging in stimulating discussions, research collaborations, and providing valuable advice and perspective. A special thanks goes to Adjunct Professor Daniel Karlsson for proofreading the thesis. I would also like to acknowledge the many industrial partners that supported and showed interest in the research through the ERA-Net and SESBC initiatives.

I have truly enjoyed working at the IEA division at LTH under Associate Professor Ulf Jeppson over the last years. Thank you to all colleagues at IEA for creating a great place for research. As an employee, I am grateful for all the administrative support from Carina Lindström and Ulrika Westerdahl. Thank you Drs. D. Wenander, S. Estenlund, M. Collins, and A. Karlsson for the lunch-based introductions to LTH and life as a PhD student. As a TA, I am grateful to Dr. Johan Björnstedt and Getachew Darge for teaching me the ways around the labs. Thank you Alice Callanan for bringing me as company on several quests to spread research outside academia. Thank you Leonardo Colombo and Mattias Ingelström for always being available for any technical and non-technical conversation. A big thanks to my office mates Imran, Gabriel, and Ghazal for entertaining my, at times, numerous questions, regardless of their quality. I also want to recognise my fellow PhD students at IEA: Hannes, Edvin, Hamoun, Amir, Abdullah, and Sebastian.

Finally, I am deeply grateful for the support I have received from family and friends throughout these years. To my wife Rachelle, thank you for your love and patience, and for helping me stay grounded in work and life.

Martin Lundberg
Lund, August 2025

Popular summary in English

If the ongoing energy transition in Sweden and Europe is to continue at the necessary pace to achieve ambitious climate goals, a large number of renewable energy sources must be quickly connected to the electricity grid. The expansion of this type of electricity generation is limited by a lack of grid capacity in the high-voltage transmission network and by bottlenecks in the distribution networks, which supply electricity to end customers, such as households and industries. To ensure sufficient grid capacity in the long term, the grid companies reinforce and expand the existing network infrastructure by constructing new lines and transformers. However, this process is often both costly and slow.

This thesis deals with alternative "non-wire" solutions to grid reinforcement, which allow the expansion rate of renewable energy sources to be increased with minimal need for infrastructure upgrades. To achieve this, control features already built into the power electronic converters that connect wind and solar power plants to the grid are utilised. Through control algorithms developed within the research project, the flexibility of these grid resources can be utilised to adapt production to respect the grid's current (or power) and voltage limits. If other flexible grid resources, such as energy storage systems, are available, they can also be used to optimise the grid capacity usage. By controlling the charging and discharging of energy storage systems in different parts of the grid, virtual power lines can be created, and the total grid capacity can be increased without the need for new lines.

The development of control algorithms has been central to the research presented in this thesis. The starting point has been to create simple but robust solutions that can be quickly deployed when there is a lack of grid capacity. This can be achieved through a decentralised control structure, i.e., network resources can act independently. An important part of the work has been to analyse how the control of different grid resources and interactions between these affect the surrounding power system. This has been done by developing mathematical models that describe the behaviour of controllable grid resources and consider the physical limitations in the control capabilities of the various resources. The models have been tested in power system simulations and used in case studies for Swedish, Nordic, and European conditions. The results show that, starting from simple control principles, it is possible to efficiently limit voltage and power increases from renewable electricity sources while utilising the full capacity of the existing network. The same basic control principles can also be applied to virtual power lines placed over bottlenecks in the transmission network. Suppose the bottleneck is caused by high thermal loading. In that case, the energy storages reduce the electrical power being transferred through the bottleneck itself while freeing up capacity in parallel lines that previously could not be utilised due to the presence of the bottleneck.

The extent to which the solutions presented in this thesis are needed and can be exploited is strongly linked to the expected production capacity from additional renewable energy sources. Forecasts of future production capacity must account for changes in electricity use and how investment and operating costs for different production facility types relate to fluctuating prices in the electricity market. It is also necessary to investigate the impact of the weather on the ability to produce electricity at different times of the year. The last part of the thesis describes how to build a simulation model that includes all these various aspects. The result is a tool that can be used to plan for a future electric power system that is both fossil-free and reliable.

Populärvetenskaplig sammanfattning på svenska

Om den pågående energiomställningen i Sverige och Europa ska kunna fortgå med oförminskad takt måste ett stort antal förnybara energikällor snabbt anslutas till elnätet. Utbyggnadstakten av denna typ av elproduktion begränsas ofta av brist på överföringskapacitet i transmissionsnätet, men också av flaskhalsar i distributionsnäten, vars huvudfunktion är att leverera elektricitet till slutkunder, som hushåll och industrier. För att säkerställa att det finns tillräckligt med nätkapacitet att tillgå på längre sikt utför nätbolagen nätförstärkningsåtgärder, som inkluderar nybyggnation av ledningar och transformatorer, och uppgraderingar av befintlig infrastruktur. Denna typ av åtgärder är ofta kostsamma och tidskrävande.

Denna avhandling behandlar alternativa lösningar till nätförstärkning, som gör att utbyggnadstakten av förnybara energikällor kan ökas utan att kapacitetsgränser i det befintliga elnätet överskrids. För att åstadkomma detta utnyttjas styregenskaper som redan är inbyggda i de kraftelektroniska omvandlarna som ansluter vind- och solkraftsanläggningar till nätet. Genom styralgoritmer som utvecklats inom forskningsprojektet kan flexibiliteten i dessa nätresurser utnyttjas för att anpassa produktionen efter nätets effekt- och spänningsgränser. Om andra flexibla nätresurser, som energilager, finns tillgängliga kan även de utnyttjas för att optimera utnyttjandet av elnätets överföringskapacitet. Genom att styra upp- och urladdning av energilager i olika elområden kan *virtuella elledningar* skapas och den totala överföringskapaciteten ökas utan att nya ledningar behöver byggas.

Utvecklingen av styralgoritmer har varit central i forskningen som presenteras i denna skrift. Utgångspunkten har varit att skapa enkla men robusta lösningar som snabbt kan sättas in vid kapacitetsbrist. Det kan uppnås genom decentralisering av styrningen: att nätresurser tillåts agera oberoende av varandra i hög grad. En viktig del av arbetet har varit att analysera hur styrningen av olika nätresurser och interaktioner mellan dessa påverkar det omgivande elkraftsystemet. Det har gjorts genom att ta fram matematiska modeller som både beskriver beteendet hos styrbara nätresurser och som tar hänsyn till fysikaliska begränsningar i de olika nätresursernas styrförmåga. Modellerna har sedan testats i kraftsystemsimuleringar och används i fallstudier för svenska, nordiska, och europeiska förhållanden. Resultaten visar att det utifrån enkla styrprinciper går att effektivt begränsa spännings- och effektökningarna från förnybar elproduktion och samtidigt utnyttja nätets fulla överföringskapacitet. Samma grundläggande styrprinciper kan även appliceras på virtuella ledningar som placerats vid flaskhalsar i transmissionsnätet. Om flaskhalsen orsakas av hög termisk påfrestning eller N-1-begräsningar bidrar energilagren dels själva till att mer eleffekt kan utnyttjas på andra sidan flaskhalsen, men frigör också kapacitet i parallella ledningar som tidigare inte kunnat utnyttjas på grund av flaskhalsen.

Till vilken grad lösningar av den typ som presenteras i denna avhandling behövs och kan utnyttjas är starkt sammankopplad med den förväntade framtida produktionskapaciteten från förnybara energikällor och var nya generatorer placeras. Prognoser om storlek och geografisk spridning av framtida produktionanläggningar måste ta hänsyn till förändringar i elanvändningen och hur investerings- och driftskostnader för olika typer av elproduktion förhåller sig till skiftande priser på elmarknaden. Det är också nödvändigt att undersöka vädrets inverkan på förmågan till elproduktion vid olika tidpunkter på året. I den sista delen av avhandlingen beskrivs hur man kan bygga en simuleringsmodell som inkluderar alla dessa olika aspekter. Resultatet är ett verktyg som kan användas för att planera för ett framtida elkraftsystem som är flexibelt, fossilfritt och tillförlitligt.

Nomenclature

ANM	Active network management
BESS	Battery energy storage systems
CEP	Capacity expansion planning
CNE	Critical network element
CNEC	Critical network element with contingencies
DER	Distributed energy resources
DLR	Dynamic line rating
DSO	Distribution system operator
DTR	Dynamic transformer rating
NP	Net position
PATL	Permanently admissible transmission loading
PI	Proportional-Integral
PID	Proportional-Integral-Derivative
PTDF	Power transfer distribution factor
PV	Photovoltaic
RAM	Remaining available margin
RAS	Remedial action scheme
STATCOM	Static synchronous compensator
TATL	Temporary admissible transmission loading

TSO	Transmission system operator
TTC	Total transfer capacity
VPL	Virtual power line
VRE	Variable renewable energy
WPP	Wind power plant

Chapter 1

Introduction

The ongoing societal decarbonisation efforts are fundamentally changing the electric power system. This fact is evident to most people, who have seen the gradual rise of wind and solar generation with their own eyes. In some countries, such as Sweden, electric vehicles are also a common sight as sales continue to increase. While public awareness about these developments is high, the general interest in the resulting impact on the power *grid* is equally low. Like most types of infrastructure, the power grid — the network of power lines, transformers, and other equipment needed to transfer electricity — seems to generate major headlines only when its operation is severely disrupted. Recently, *dunkelflaute*[1] conditions have made the news in northern Europe as power transfer capacity limits have caused temporary spikes in electricity prices in areas unable to import enough power to compensate for the temporary drop in local electricity generation.

Meanwhile, power system engineers are trying to figure out how to adapt and expand the grid to better meet the complex demands brought by the energy transition. One of those engineers has spent some time developing methods for increasing the transfer capacity of the existing network, specifically by improving the control of grid-connected distributed energy resources (DER), including wind, solar, and energy storage systems. The results of that process have been collected in this thesis.

[1]Dunkelflaute [German: 'dark lull'] refers to periods of very low wind and solar generation, which are caused by unfavourable weather conditions.

1.1 Motivation

The underlying motivation for this work is found by observing the conventional approach to increasing transfer capacity, which, simply put, equates to adding or upgrading lines and transformers in the network. This *network reinforcement* is a very robust method, although often both costly and slow. Currently, lead times for transmission line construction in Sweden are up to 15 years [1], and project completion times in distribution networks also average several years. Similar construction timelines are common across Europe and the USA [2]. European countries that aim to reach ambitious national and EU climate goals, such as net zero emissions by 2050 [3], are planning for a large-scale electrification of energy demand, with a parallel expansion of renewable electricity generation. A Swedish 2050 scenario for generation expansion is shown in Fig. 1.1. Given the current rate of network reinforcement, we are swiftly approaching a point where it is unfeasible to rely solely on network infrastructure upgrades to integrate additional generation and load. One alternative path forward, which is advocated for in this thesis, is to reduce the large transfer capacity margins put in place to ensure sufficient system security. To safely reduce operational margins, enhanced network monitoring and control of grid-connected DER is required. If system reliability can be maintained with reduced operational margins, additional grid capacity is made available. In turn, this would potentially i) allow for costly network reinforcements to be deferred or even avoided, and ii) permit faster connection of new generation units, including DER.

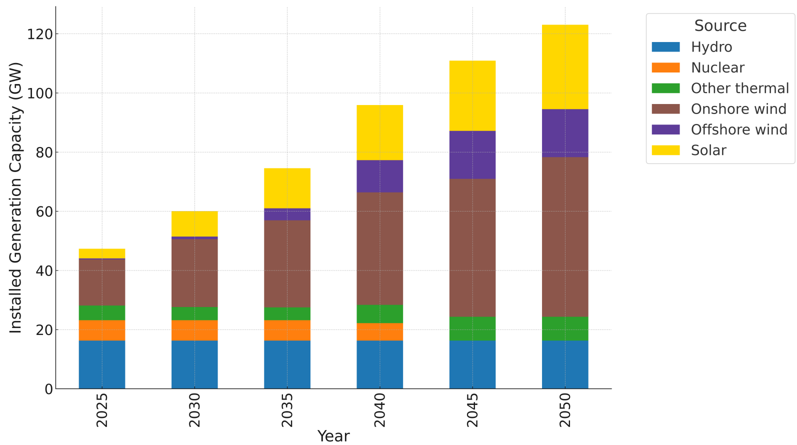


Figure 1.1: Long-term scenario for changes in generation capacity in Sweden, based on significant efforts towards electrification and decarbonisation of electricity production[4].

1.2 Aim and Purpose of Research

The main purpose of the work presented in this thesis was to find methods for controlling distributed energy resources that make it possible to safely and rapidly increase the electricity generation from variable renewable energy (VRE) resources. While large-scale generators are connected directly to the high voltage transmission system, DER are located at lower voltage levels, in the subtransmission and distribution networks. Therefore, addressing capacity bottlenecks in all parts of the system becomes necessary. With that in mind, a bottom-up perspective of the system was adopted, and the aim of the research was two-fold. First, to develop control methods for DER that allow for a safe increase in the total amount of DER in the existing distribution system. Second, to create a control method for battery energy storage systems (BESS) that increases the transfer capacity in transmission systems with high penetration of VRE.

As part of the development process, the following goals were considered:

- G1 Development of controller models that include adequate representation of DER power and energy limits.
- G2 Development of analytical power system models for evaluating the proposed control methods.
- G3 A simulation methodology for validation of analytical results.
- G4 Formulation of relevant case studies to assess the performance of control methods for different scenarios.
- G5 An evaluation of the share of VRE in the future Swedish power system.

1.3 Delimitations

Throughout the work, the Swedish and Nordic power systems have served as important references for applying the research results. However, the conclusions presented in this thesis should not be interpreted as limited to a specific geographical or regulatory context. More important is the technological environment in which the presented results are relevant. The general restrictions to which the work is subjected are listed below.

- The transfer capacity limits considered are based on the need to restrict variations in long-term voltage magnitude and limit power flow magnitudes.

- The studied transmission and distribution systems are three-phase networks, and control is restricted to the positive sequence components.
- The presented results are based solely on analytical and numerical work. Experimental work and implementation aspects are out of scope.

1.4 Research Contributions

The main results from the research have been presented in the five papers included in this compilation thesis. These are ordered as follows:

Paper I: Alternative network development – need for flexible solutions for operation and planning of distribution and transmission grids

Paper II: Local voltage control in distribution networks using PI control of active and reactive power

Paper III: Congestion management in distribution systems with large presence of renewable energy sources

Paper IV: Decentralized control of virtual power lines for increased transfer capacity

Paper V: Robust capacity expansion planning in hydro-dominated power systems: a Nordic case study

In Table 1.1, a summary of the research topics covered by each of the five appended papers is shown. The research provides five key contributions to knowledge, namely:

- A control methodology for limiting network voltages and power flows based on saturated PI control. This allows for the development of decentralised controllers that eliminate excessive voltages and flows, while acceptable operating conditions are not subject to any active control measures.
- Derivation of nonlinear dynamic representations of converter-interfaced DER where power and energy limits are converted into saturation of control signals. This allows for DER operational restrictions to be accurately represented in controller design.
- Two analytical modelling methodologies for voltage and congestion studies in VRE-dominated power systems. These are used to produce models that combine a static linear network representation with nonlinear DER controller dynamics.

- A quasi-static simulation method for validating the controller design and assessing interactions between decentralised controllers in iterated power flow studies.
- A capacity expansion simulation methodology that accounts for varying weather conditions over multiple years to forecast future generation capacity in decarbonised power systems.

Table 1.1: Research topics covered in the thesis.

	Paper I	Paper II	Paper III	Paper IV	Paper V
Distribution system planning and operation	✓	✓	✓		
Transmission system planning and operation				✓	✓
Voltage control	✓	✓			
Congestion management			✓	✓	
Power system modelling		✓		✓	✓
Stability analysis		✓			
Capacity expansion planning					✓
Contribution to research goals	G1	G1-G4	G1, G3, G4	G1-G4	G5

1.5 Thesis Outline

The first part of the thesis is divided into four chapters. Chapter 2 gives an overview of the grid capacity challenges facing distribution and transmission networks that have been addressed in the appended research papers. Chapter 3 introduces the proposed control methods and modelling considerations for VRE-dominated power systems. Finally, Chapter 4 contains some remarks on the conclusions of the work introduced in Chapters 1-3 and elaborated on in the second part of the thesis. The second part includes the appended papers, which form the main research contribution.

Chapter 2

Grid Capacity Challenges

In practical terms, a reliable synchronous AC power system is characterised by stable frequency, voltages, and currents that are all kept within strict operational limits. On a conceptual level, power system reliability is divided into two interdependent aspects: system security and *resource adequacy*. System security concerns the ability of the system to withstand sudden, unexpected disturbances. Resource adequacy is a measure of the capability to supply the required electric power at all times within the technical limits of the network [5]. Resource adequacy implies i) there exists enough generation capacity to continuously meet the instantaneous demand for electricity, ii) the transfer capacity[1] of the network is sufficient for delivery of all the generated power, and iii) adequate policies and practices for operation of the system and its resources have been implemented [6]. If the three criteria are fulfilled, balancing actions, e.g., through trading on the electricity market and various ancillary services markets, will keep the system frequency stable, while the resulting changes in network bus voltages and line currents do not violate any operational limits.

The system operator is responsible for operating the grid within the given constraints and planning for the continued resource adequacy of the future system, both in the short and long term. In the various European power systems, a transmission system operator, TSO, manages the operation of a transmission network, while one or more separate distribution system operators, DSOs, manage the many local distribution networks [7]. Importantly in the context of this thesis, the system operator responsibility specifically includes reinforcing the grid and implementing operational practice updates to meet changing transfer capacity needs.

[1]N.B. Grid capacity and transfer capacity are used interchangably throughout the thesis.

2.1 Grid capacity limits

The transfer capacity (or capability) from one part of a network to another is often thought of as the maximum power that can safely be transferred between them. This view is apparent in the 1995 definition of transfer capacity by the North American Electric Reliability Council (NERC) [8]:

Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one to another area by way of all transmission lines (or paths) between those areas under specified system conditions.

The European TSO organisation, ENTSO-E, has an ostensibly similar definition of ”total transfer capacity” [9]:

The Total Transfer Capacity TTC, that is the maximum exchange programme between two areas compatible with operational security standards applicable at each system if future network conditions, generation and load patterns were perfectly known in advance.

However, there is one key difference between the NERC and ENTSO-E definitions: the first refers to the physical flows in the network, while the second considers estimated flows used to determine trading volumes on the electricity market. While the network's physical characteristics ultimately determine the maximum transferable power, the two examples above indicate what the initiated reader already knows: that the transfer capacity between different parts of a network is usually restricted by some additional specified system conditions or limits, which should also be defined.

An overview of transfer capacity limits is given in Table 2.1. To highlight the different nature of the various constraints, and particularly the consequences of failing to adhere to them, they have here been divided into three categories: security limits, market limits, and power quality limits. Reliability limits are often derived directly from the laws of physics governing the behaviour of the system and its components. Such limits are considered critical for protecting system integrity. Therefore, emergency control actions, such as generator and line tripping, and load shedding (with resulting blackouts) are introduced to prevent severe damage to system components.

In contrast, market limits are typically soft, i.e., set with substantial margins to the physical limits of the system. However, market-imposed restrictions on transfer capacity directly influence energy trading and, thereby, the electricity price. Finally, power quality limits are introduced to avoid damage or performance deterioration in individual loads and generation units. Further division of these categories is possible: some of the limits, particularly associated with power quality, tend to be static, while system stability limits are dynamic in nature as they depend on the loading conditions (actual or forecasted).

Table 2.1: Examples of transfer capacity limits. **Bold text** indicates topics relevant to the research presented in this thesis.

Reliability limits

- Equipment ratings, which account for the **thermal limits** of power lines, cables and transformers [10, 11, 12].
- System stability limits relating to frequency stability, rotor angle stability, voltage stability, resonance stability, and **converter-driven stability** [13].
- **N-1** or similar criteria that account for temporary flow increases during contingency events [14].

Market limits

- Net transfer capacity, NTC, i.e., the share of TTC available to zonal electricity markets.
- Remaining available margin, RAM: in a **flow-based capacity calculation**, the RAM is the resulting capacity through a bottleneck available to the electricity market [15]
- **Bilateral agreements on flow limits** at the TSO/DSO interface [16].

Power quality limits

- Short-term voltage variation limits to prevent swells, sags, flicker, and spikes.
- Long-term voltage variation limits to prevent **overvoltage** and undervoltage [17].
- Harmonic contents limits to prevent excessive distortion of voltage and current waveforms.

Which of the constraints in Table 2.1 that constitutes an actual bottleneck depends on the actor and their responsibilities. System stability, N-1 contingencies, and power balancing are all operational concerns for a TSO, while many DSOs would argue that transfer capacity restrictions exclusively are the result of either external contractual limits imposed by the TSO or internal equipment loading limits and power quality issues, including long-term voltage variations. Considering a large-scale integration of VRE, the transfer capacity needs will thus be highly dependent on the point of VRE connection. Two parallel trends in generation capacity expansion have emerged in recent years: VRE for bulk-scale generation and VRE as DER. For example, in the U.S. in 2023, it was estimated that small-scale solar photovoltaic units (< 1 MW) made up 34.5% of the total solar photovoltaic generation capacity [18]. In Australia in 2024, rooftop solar represented 69.2% of the photovoltaic generation capacity and 25.5% of the total generation capacity in the country's National Electricity Market, [19]. To increase the total share of VRE in the system, the overarching challenge in terms of transfer capacity is to address the specific needs in distribution networks and transmission networks, while also managing the bidirectional power flows between the different voltage levels.

2.2 Impact of variable renewable energy

Any attempts to give a complete overview of the impact of large-scale VRE integration on power system operation and planning would include a discussion on a wide range of topics, from reduction of inertia and short-circuit power to grid-forming converters and electricity price volatility. In this section, the scope is limited to aspects of grid capacity.

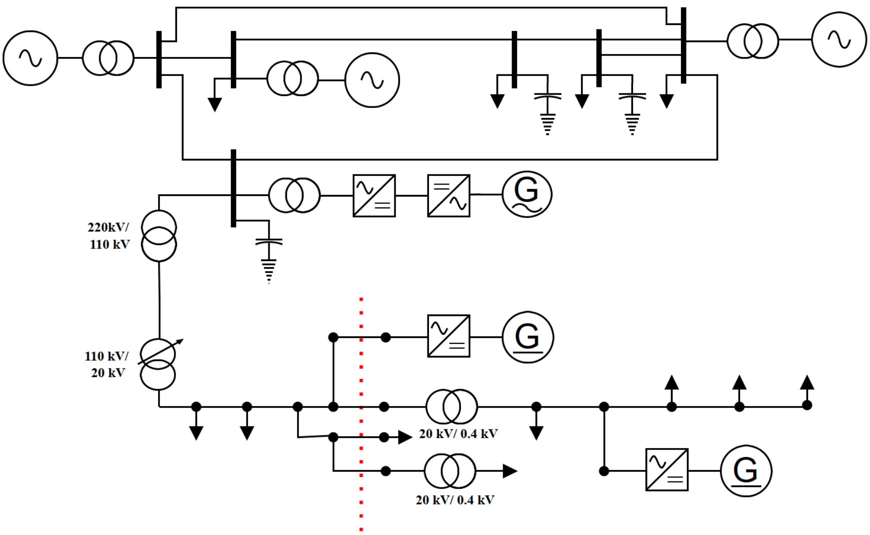


Figure 2.1: A single line diagram of a power system consisting of a transmission network (top), and a low and medium voltage distribution network (bottom) connected via a subtransmission line. The example is based on parts of the CIGRE European HV/MV/LV test systems [20]. The dotted line intersects the four MV feeders used in Example 1 in Section 2.3.1.

2.2.1 Impact of VRE on distribution systems

Distribution systems have, until recently, evolved with the sole purpose of cost-effectively supplying power to electrical loads. For this reason, distribution networks tend to have a radial grid topology and extend over several voltage levels, as shown in Fig. 2.1. For example, in Sweden, where the meshed subtransmission network is operated up to 130 kV, the medium voltage (MV) network voltage level(s) are typically selected in the 10-50 kV range. The nominal low voltage (LV) level in large parts of Europe is the well-known 400 V line-to-line.

The radial grid topology in the distribution network has allowed DSOs to employ a *fit-and-forget* strategy [21], where network reinforcement is the primary tool for ensuring the radial feeders are operated within their limits. By using the worst-case load and/or generation scenario as the design criterion for infrastructure upgrades, sufficient capacity and safe operation can be guaranteed. Accounting for modelling uncertainties and future changes in local demand and generation, additional capacity margins are typically included when reinforcing the network. In turn, this greatly reduces the need for active measures in operation. Therefore, such capabilities have historically been minimal among many DSOs. Standard DSO operational tools include manual adjustments of transformer tap-changers to avoid undervoltages, and automated voltage regulation using on-load tap changers (OLTCs) at the primary substation transformers [22].

With rising local generation capability, distribution networks may experience reverse power flows during peak production hours. This causes voltages to increase along feeders with large generation capacity. The amount of DER that can be connected to the existing network without adverse effects on reliability is known as the *hosting capacity* of the network. Hosting capacity is typically either limited by the aforementioned overvoltage issues, or by thermal overloading (congestion) of upstream lines and transformers due to aggregation of reverse power flows in the radial network [23].

The hosting capacity concept can also be applied to battery energy storage systems that, while technically not VRE resources, contribute as DER to improve reliability in VRE-dominated systems. In the Nordics, the rapid increase in the number of grid-connected BESS in recent years has been closely connected to the expansion of ancillary services markets for balancing in response to the reduction of system inertia [24].

In addition to voltage and thermal considerations within their network, the DSO may be subject to contractual limits on power exchange at the connection point to the subtransmission or transmission network. Such contractual limits influence limits on active power at the TSO-DSO interface, as well as transfer capacity limits in the transmission network. Limits on reactive power exchange are imposed due to voltage control considerations [25], with zero reactive power exchange being the norm historically.

To increase the hosting capacity without extensive network reinforcement, the DSO operational capabilities must be improved. Active network management (ANM) is a framework for improving utilisation of existing distribution network infrastructure [26]. ANM implies enhancing network monitoring and control of DER so that the installed generation capacity (or, equivalently, maximum load) can be increased above the capacity of the bottlenecks in the network. Several mechanisms that create financial incentives for the electricity consumers to comply with operational control objectives have been successfully implemented in distribution networks worldwide. These include local flexibility markets, demand response programs, and network tariffs. In parallel, regulatory efforts to improve the DSOs' ANM capabilities have facilitated the use of conditional connection agreements and more advanced control schemes such as dynamic operating envelopes [27]. From a control perspective, the ANM challenge is to maximise the utilisation of the existing network given a range of practical restrictions in system controllability and observability.

2.2.2 Impact of VRE on transmission systems

High voltage transmission systems[2] provide efficient transfer of power over long distances, facilitating power and energy balancing using resources in geographically distant regions.

[2]In the different synchronous areas of Europe, typical transmission system voltage levels are 220 kV, 380 kV, and 400 kV.

Ultimately, the transfer capacity needs in the transmission system are dependent on the balancing needs. With the large-scale expansion of VRE, balancing needs are expected to change significantly. The Nordics are affected by VRE expansion within their synchronous area and, to some degree, by the parallel developments in the neighbouring continental European and UK systems due to multiple interconnecting HVDC links.

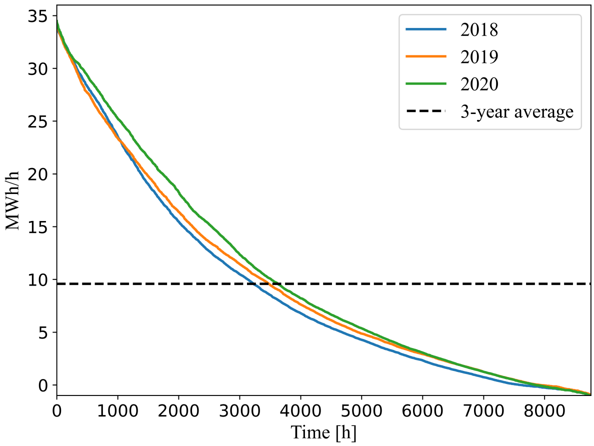


Figure 2.2: Yearly duration curve for an unnamed wind power plant in a Swedish distribution network [28].

How grid capacity needs in the transmission system are impacted by an expansion of converter-interfaced generation is a complex question. A general observation is that replacing a specific MWh/year of electricity from dispatchable generators with an equal amount of energy from weather-dependent sources increases the total installed MW generation capacity. The impact can be inferred from the capacity factors for different types of generation. In 2024, the capacity factor for onshore wind power in Sweden was 27.9 %. The corresponding number for nuclear power was 80.6 % [29, 30]. In other words, the MW onshore wind power capacity needed to produce one MWh of electricity in the Swedish power grid in 2024 was 2.9 times[3] the required MW nuclear capacity.

The low capacity factor for VRE also indicates that peak generation is far greater than the average output. This intuition is quickly confirmed by studying any VRE duration curve, such as the one presented in Fig. 2.2. If one disregards any power balancing actions, the expectation is that the maximum power flows in the VRE-dominated system would be substantially larger than the average flows. This scenario leads to reduced grid utilisation in the existing network, or, considering network expansion, significant grid capacity needs for the transfer of a certain amount of energy. Furthermore, the installed VRE generation capacity is not indicative of the aggregated peak generation by default due to the large

[3]Identical availability factors, or yearly uptime, is assumed. In fact, wind power typically has a slightly higher yearly uptime than nuclear [31, 32].

geographical dispersion of power plants. In Sweden, the installed wind power capacity in 2024 was 16,700 MW, while the hour of largest wind power production the same year generated 12,911 MWh [30]. The numbers suggest that maximum power flows are limited to some degree. This argument can be made for the system level and is limited to flow data with low time resolution, such as hourly averages. However, both transmission and distribution networks will still see generation at rated capacity by individual VRE units, leading to large power flows on adjacent lines and transmission corridors.

When we then take power balancing requirements into account, the picture becomes more nuanced. The long-established power balancing paradigm prescribes that in a designated control area of the network, generation (and imports) should be adjusted according to changes in load, including exports to other control areas. Historically, there has been little price elasticity in the short-term power demand [33], meaning that in systems with predominantly dispatchable generation, the need for both generation and transfer capacity has been dictated by the worst-case loading instance. In VRE-dominated systems, generation patterns are first and foremost determined by the weather conditions. Thus, balancing actions must account for parallel and lowly correlated variations in power supply and demand [34, 35]. In such systems, reliable operation under a wide range of heavy loading conditions is required. At the same time, reinforcing the network to accommodate generation at rated capacity will lead to low grid utilisation, as exemplified in Section 2.5. The challenge becomes to both improve utilisation of the existing network, while timely increasing transfer capacity when needed. This demands greater flexibility in both load and generation, and potentially a significant amount of energy storage [36, 37]. The need for flexibility spans over multiple time scales, as shown in Fig. 2.3.

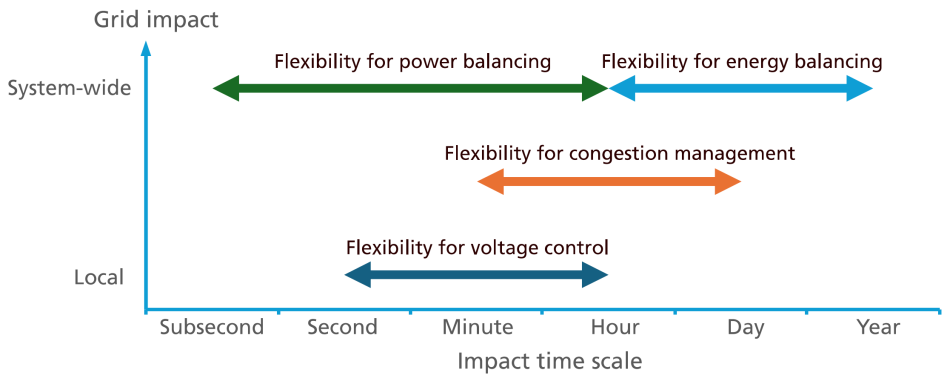


Figure 2.3: Flexibility needs in VRE-dominated power systems. The figure is based on *Figure 2* in **Paper I**.

2.3 Voltage limits

Long-term variations in voltage magnitude are normally subject to regualtory restrictions. In Sweden, the prescribed maximum deviation from nominal voltage is ± 10 % [38]. However, stricter limits can be imposed by the respective system operator. TSOs will further restrict the lower voltage limit for voltage stability purposes, while DSOs must consider the risk for both overvoltage and undervoltage in worst-case generation and load scenarios, respectively.

The steady state voltages in any AC electric power system can be expressed in terms of the active power (P) and the reactive power (Q) injected or consumed at the nodes, or buses, of the network. A simple 2-node system (Fig. 2.4) is used here to exemplify the basic principles. Consider a line represented by a π model with the lumped series impedance $\overline{Z}_{line} = R + jX$ and the shunt admittance Y. The line connects to a generator with a controlled constant voltage $\overline{E}$ and a load with a variable voltage $\overline{V}$. The line transfers the complex power $\overline{S} = P + jQ$ to the receiving end. The impact of the line shunt admittance is modelled implicitly and represented by the net Q transfer[39]. The voltage angle difference between the buses is denoted δ, and the voltage difference between the line ends as seen from the load is

$$\Delta\overline{V} = \overline{E} - \overline{V} = \overline{I}\overline{Z}_{line}. \tag{2.1}$$

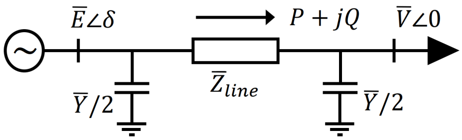


Figure 2.4: Single line diagram of 2-node example network.

The line current can be expressed as a function of the load power and voltage, such that

$$\overline{I} = \frac{\overline{S}^*}{\overline{V}^*} = \frac{P - jQ}{\overline{V}^*} = I_p - jI_q, \tag{2.2}$$

where P and Q are the active and reactive power transferred to the load. The complete expression for the sending end voltage is derived from the above figure together with Eq. 2.2:

$$\overline{E} = \overline{V} + \frac{1}{\overline{V}^*} \cdot [(RP + XQ) + j(XP - RQ)]. \tag{2.3}$$

The sending voltage magnitude is

$$|\overline{E}| = \left|\overline{V} + \frac{1}{\overline{V}^*} \cdot [(RP + XQ) + j(XP - RQ)]\right| \tag{2.4}$$

which yields

$$E^2 = \left(V + \frac{RP + XQ}{V}\right)^2 + \left(\frac{XP - RQ}{V}\right)^2. \tag{2.5}$$

From 2.5 the load voltage magnitude is extracted by solving for V^2 such that

$$V^2 = \frac{E^2}{2} - (RP + XQ) \pm \sqrt{\frac{E^4}{4} - E^2(RP + XQ) - (XP - RQ)^2}. \tag{2.6}$$

Feasible solutions $\{V \in \mathbb{R} : \; V \geq 0\}$ to 2.6 require

$$\frac{E^4}{4} \geq E^2(RP + XQ) + (XP - RQ)^2. \tag{2.7}$$

With the magnitude V known, the angle δ is obtained from 2.3, using $\overline{V}$ as reference. The angle can then be expressed as

$$\delta = \arcsin\left(\frac{XP - RQ}{EV}\right). \tag{2.8}$$

Through Eqs. 2.6-2.8[4], a complete picture of the steady state relation between voltage and power in the 2-node example is obtained. Zooming in on the issue of excessive deviations in voltage magnitude, what becomes clear from Eq. 2.6 is the voltage dependence of both line parameters and power injections. Therefore, the impact of increasing power flows on network voltages differs in transmission and distribution networks due to the different power line X/R ratios.

2.3.1 Distribution network voltages

For lightly loaded distribution lines, the voltage angle δ is small and consequently the imaginary components of Eq. 2.1 are left out in the commonly used simplification

$$\Delta\overline{V} \approx E - V \approx I_pR + I_qX = \frac{RP}{V} + \frac{XQ}{V}. \tag{2.9}$$

[4]Note that the domain of *arcsin* is $[-1, 1]$.

To get a more accurate description of voltages in a heavily loaded network, one might still prefer to use Eq. 2.3 over Eq. 2.9 to account for the angle shift contribution to the magnitude difference between the two buses.

The X/R ratio in distribution networks are often ≤ 2, and in low voltage networks, $X/R << 1$ is common [20]. Given $P >> Q$, active power is the primary cause for variations in voltage magnitudes, while reactive power injections have a limited impact, even during high loading situations. In larger distribution networks, overvoltage and undervoltage can occur simultaneously depending on the ratio of DER and load at different feeders, as the following example demonstrates.

Example I

Consider the four 20 kV feeders of the MV network depicted in Fig. 2.1, a worst-case (but acceptable) operational scenario is illustrated in Fig. 2.5. Assuming significant distributed photovoltaic (PV) generation at two of the feeders, here denoted feeder 1 *and feeder* 2*, and high load at the remaining two feeders, the voltages at the end of feeders* 1 *and* 2 *reach the allowed maximum limit. At the same time, the voltage at the feeder with the highest load is close to the minimum voltage limit. In this situation, it is impractical to use the OLTC at the 110 kV/20 kV transformer for voltage control, as tap-changing will increase or decrease voltages along all feeders.*

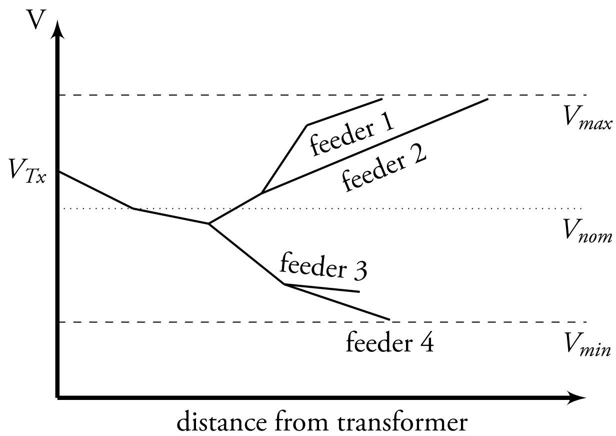
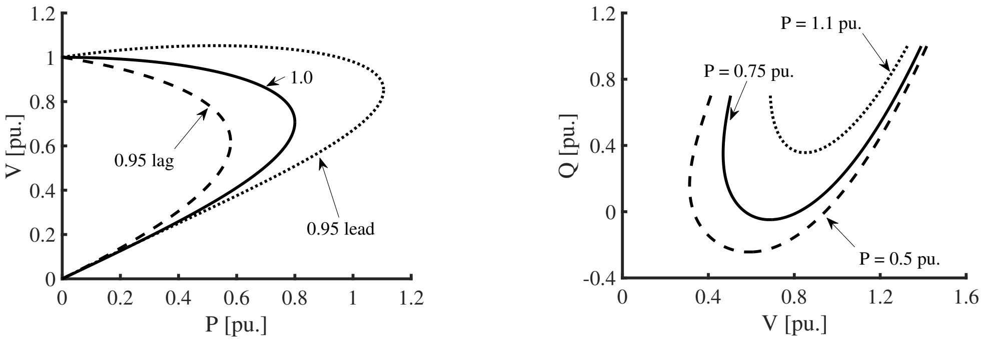


Figure 2.5: Example of a challenging voltage scenario for the MV feeders in the network in Fig. 2.1

In the above example, to increase the hosting capacity for generation without reinforcing the network, the OLTC must be complemented by additional voltage control capability. That capability can be offered by DER, provided adequate control of active and reactive power injections. The problem of limiting distribution network voltages is addressed in **Paper I** and **Paper II**.



(a) P-V curve for different load cos(φ) values.

(b) V-Q curve for different constant MW loads.

Figure 2.6: Steady state voltage characteristics of 2-node system with $S_{base} = 1000$ MVA, $V_{base} = 400$ kV, $X_{line} = 0.625$ pu.

2.3.2 Transmission network voltages

For transmission lines[5], $X >> R$, a line is often modelled as lossless. Eq. 2.6 is then simplified to

$$V^2 = \frac{E^2}{2} - XQ \pm \sqrt{\frac{E^4}{4X^2} - Q\frac{E^2}{X} - P^2}, \tag{2.10}$$

with Eq. 2.7 reduced to

$$\frac{E^4}{4X^2} \geq Q\frac{E^2}{X} + P^2. \tag{2.11}$$

Eqs. 2.10 and 2.5 can be used to generate P-V and V-Q curves that visualise the steady state voltage characteristics of the 2-node system. Reactive power injections increase both the receiving end voltage and the maximum possible active power transfer, as seen in Fig. 2.6a. However, with heavier loading, the system is pushed closer to its long-term voltage stability limit, and the reactive power margins for a given operating voltage are reduced, as seen in Fig. 2.6b. In VRE-dominated systems, the absence of reactive power contributions from synchronous generators must be compensated by other resources, such as STATCOMs, synchronous condensers, and various converter-interfaced resources. To ensure voltage stability in the transmission system, it also becomes relevant to control, or at least limit, the flow of reactive power to lower voltage levels. With a large share of DER in the distribution system, the reactive power exchange at the TSO/DSO interface can be controlled by the distributed resources. This topic is treated in **Paper III**.

[5]For long transmission lines, the π model is based on distributed line parameters instead of lumped parameters.

2.4 Thermal limits

The flow of current in a network impacts the temperature in conducting components, such as overhead lines, cables, and transformers. Excessive operational temperatures increase the risk for a range of adverse effects, which at best lead to reduced equipment lifetime, and at worst to an immediate component failure [40]. Well-known risks of excessive operational temperatures include

- transmission line sag due to thermal expansion of the conductors, with increased risk of short circuits from low ground clearance,
- accelerated ageing of cable insulation,
- extreme hot-spot temperatures of transformer windings, leading to accelerated ageing or breakdown of winding insulation.

For this reason, thermal ratings for continuous operation are imposed. A thermal limit is given as the maximum current or power that is permissible at a specific temperature reference. For overhead lines, the rated current, the *ampacity*, is typically based on an ambient temperature. However, as conductor temperature is also dependent on local weather conditions, including wind speed and solar irradiance, operational margins are introduced to account for weather-related parameter uncertainties [10]. Some system operators adjust static thermal ratings depending on season, month, day-time, night-time, etc., while still maintaining significant margins. Finding the actual ampacity at a given moment requires accurate modelling or real-time monitoring of e.g, conductor temperatures and local weather conditions, a process known as dynamic line rating (DLR)[41]. The reasoning behind determining line loading limits can be applied to set the nameplate MVA or kVA rating for transformers. Dynamic transformer rating (DTR) methods can be used to increase power transfer during favourable operational conditions[42].

In addition to the continuous, or long-term, thermal ratings, equipment is subject to short-circuit current ratings and short-term or emergency ratings. The short-circuit current rating of, e.g., a cable gives the maximum current or power it should withstand for a limited duration of time (a few seconds at the most) during a fault, before it is disconnected. The emergency rating accounts for elevated power flow levels in the remaining parts of the network after a fault. The system must then be returned to an N-1 secure state sufficiently fast to avoid emergency limit violations. In the Nordics, the time limit is set to 15 mins [43]. The operational margin needed to comply with the emergency rating might restrict power flows further than the continuous thermal rating permits. In such cases, transfer capacity is restricted by system security rather than by individual network components.

2.4.1 Network congestion

When a component in the network reaches a constraint during continuous operation, it is referred to as network congestion. Thus, for thermally constrained lines and transmission corridors, congestion is limiting the usable grid capacity. The grid capacity available for continuous operation is known as the permanently admissible transmission loading (PATL).

In practice, as the wholesale electricity market puts limits on transfer capacity in terms of active power, it becomes relevant to express thermal and other PATL constraints into power flow constraints. The same argument can be made for distribution networks that are impacted by kW or MW bids on ancillary service markets and local flexibility providers. In this context, managing congestion, i.e., ensuring that the network is operated within or at its thermal limits, requires control of active power injections.

A good starting point for studying the impact of power injections on power flows in a system in a steady state is the standard power flow equations. Given a $\mathrm{Y}_{\mathrm{bus}} \in \mathbb{C}^{n \times n}$ matrix of a network, the power flow equations can be written as

$$P_i = \sum_{j=1}^{n} V_i V_j \left(G_{ij} \cos(\delta_i - \delta_j) + B_{ij} \sin(\delta_i - \delta_j) \right), \tag{2.12}$$

$$Q_i = \sum_{j=1}^{n} V_i V_j \left(G_{ij} \sin(\delta_i - \delta_j) - B_{ij} \cos(\delta_i - \delta_j) \right), \tag{2.13}$$

with the conductances, G, and susceptances, B, from $\mathrm{Y}_{\mathrm{bus}}$.

To simplify analysis in transmission systems, a linearised version of Eq. 2.12, namely the DC power flow equation, is often used. DC power flow is based on five assumptions: 1) lossless lines (all $G = 0$), 2) flat voltage profile with all $V = 1.0$ pu., 3) voltage angles are small, i.e., all $\cos(\delta) = 1$ and all $\sin(\delta)[\text{rad.}] = \delta$, and 4) no consideration of shunt admittances. The assumptions result in a model where active power flows are significantly larger than reactive flows, which is similar to actual operating conditions in the transmission systems. With $P >> Q$, Eq. 2.13 can be disregarded and Eq. 2.12 reformulated as

$$P_i = \sum_{j=1, i \neq j}^{n} B_{ij}(\delta_i - \delta_j), \tag{2.14}$$

or in the more compact matrix form

$$\mathbf{P} = \mathrm{B}_{\mathrm{bus}} \delta, \tag{2.15}$$

where $\mathbf{P}$ is a vector of nodal active power injections, $\mathrm{B}_{\text{bus}} \in \mathbb{R}^{n-1 \times n-1}$ the bus susceptance matrix, and δ a vector of bus voltage angles with respect to an angle reference, typically the slack bus. The bus row and column for the angle reference bus are removed from $\mathbf{Y}_{\text{bus}}$ when generating B_{bus}.

For a network with *k* lines or *branches*, the active power flow between any two buses is

$$\mathbf{P}_{\text{flow}} = \mathrm{B}_{\text{branch}} \delta, \tag{2.16}$$

where $\mathrm{B}_{\text{branch}} \in \mathbb{R}^{k \times n-1}$ is a matrix containing all branch susceptances.

Combining Eqs. 2.15 and 2.16, the angle vector is eliminated by inverting $\mathbf{B}_{\text{bus}}$. The power flow can then be expressed as

$$\mathbf{P}_{\text{flow}} = \mathrm{B}_{\text{branch}} \mathrm{B}_{\text{bus}}^{-1} \mathbf{P}, \tag{2.17}$$

The elements of the matrix $\mathrm{B}_{\text{branch}} \mathrm{B}_{\text{bus}}^{-1} \in \mathbb{R}^{k \times n-1}$ are known as injection shift factors (ISFs) or the node-to-slack power transfer distribution factors (PTDFs). The latter name stems from the fact that a matrix element $\mathrm{PTDF}_{l,m}^{N}$ gives the linear change of active power flow on the branch l from a shift in active power injection at the bus m and a corresponding negative active power injection (withdrawal) at the slack bus. The flow change at the branch l due to power injections at any two nodes i, j is

$$\mathrm{PTDF}_{l}^{i \to j} = \mathrm{PTDF}_{l,i}^{N} - \mathrm{PTDF}_{l,j}^{N}. \tag{2.18}$$

As the PTDFs used in Eq. 2.17 only depend on the network parameters, flow changes at a wide range of operating conditions can be reasonably approximated. Given a known power flow $\mathbf{P}_{\text{flow}}^{0}$ caused by the active power injections $\mathbf{P}^{0}$, a change in active power injections is then assumed to cause the linear flow change

$$\mathbf{P}_{\text{flow}} = \mathbf{P}_{\text{flow}}^{0} + \mathrm{PTDF}^{N} \Delta \mathbf{P}, \tag{2.19}$$

where PTDF^{N} is a node-to-slack PTDF matrix and $\Delta \mathbf{P}$ is a vector of deviations in active power injections from $\mathbf{P}^{0}$.

Returning to congestion management, the main objective can be formulated as

$$\mathbf{P}_{\text{flow}}^{\max} \geq \mathbf{P}_{\text{flow}}^{0} + \mathrm{PTDF}^{N} \Delta \mathbf{P}, \tag{2.20}$$

where $\mathbf{P}_{\text{flow}}^{\max}$ is the static or dynamic allocated transfer capacity. Congestion management in system operation and short-term planning mainly involves control of active power injections to limit power flows, but can also include temporary increases of transfer capacity through remedial action schemes (RAS). For long-term system planning, evolving resource adequacy requirements might warrant a permanent increase in the nominal $\mathbf{P}_{\text{flow}}^{\max}$.

2.4.2 Congestion in distribution networks

The bottlenecks occurring at the substation and adjacent lines during worst-case generation or load situations are understood from the addition of active power injections in a radial network, corresponding to the addition of currents using basic laws of circuit theory. A DC power flow formulation for a distribution network, with $X/R << 1$ for all lines and a constant voltage $V = 1.0$ pu. only at the primary substation, results in

$$P_i = \sum_{j=1}^{n} G_{ij} V_j, \tag{2.21}$$

and active power flows depending only on voltage magnitudes, i.e.,

$$\mathbf{P}_{\text{flow}} = G_{\text{branch}} \mathbf{V}, \tag{2.22}$$

with $\mathbf{V}$ being a vector of bus voltage magnitudes, and network voltages in turn dependent on active power injections.

The additive nature of active power injections in distribution system can also be seen by including the impact of $\mathbf{V}$, when studying the network PTDF^N matrix. As a radial feeder with n buses has $k = n - 1$ branches, for every feeder in the network there exists a strongly triangular $k \times k$ submatrix PTDF^{N,k} after the head-of-feeder bus column is removed.

For DSOs, active congestion management efforts are often impeded by a lack of network monitoring and a limited ability to control active power generation and demand. The problem of developing a simple and robust congestion management strategy for VRE-dominated distribution networks is treated in **Paper III**.

2.4.3 Congestion in transmission networks

In the Nordics, the recent shift to a flow-based (FB) capacity calculation method for the zonal electricity market has introduced the use of linearised power flow studies to determine the transfer capacity available for commercial exchange [44]. Using the FB method, inter-zonal flows are restricted by the transfer capacity of the most heavily loaded branch elements known as CNEs and CNECs — critical network elements (including contingencies). For CNEs, the PATL measure is used, while CNEC calculations include N-1 contingencies and must include short-term emergency limits, also known as temporary admissible transmission loading (TATL). Acceptable commercial flows must fulfil

$$\text{PTDF}^Z \mathbf{NP} \leq \mathbf{RAM}, \tag{2.23}$$

where PTDF^Z is the *zonal* PTDF matrix, and $\mathbf{NP}$ a vector of *net positions*, i.e., the net export or import of power for each bidding zone. The remaining available margin, RAM, at the CNECs is defined by the active power flow vectors $\mathbf{F}$ as

$$\mathbf{RAM} = \mathbf{F}_{\text{max}} + \mathbf{F}_{\text{RA}} - \mathbf{F}_0 - \mathbf{F}_{\text{RM}} - \mathbf{F}_{\text{AAC}}, \tag{2.24}$$

with the predetermined transfer capacity $\mathbf{F}_{\text{max}}$ with respect to PATL/TATL, to which the capacity increase provided by RAS and other remedial actions, $\mathbf{F}_{\text{RA}}$, is added. The approximated flows across CNEs/CNECs without any cross-zonal trade $\mathbf{F}_0$ are subtracted from the RAM, together with the reliability margins $\mathbf{F}_{\text{RM}}$ and any already allocated capacity $\mathbf{F}_{\text{AAC}}$. Together, Eqs. 2.23 and 2.24, represent an extension of Eq. 2.20, adapted for zonal markets.

Alleviating a CNE/CNEC constraint in one bidding zone will allow for certain intra-zonal commercial flows to increase. This corresponds to better utilisation of non-critical network elements and operation closer to the full transfer capacity of the system. The problem of rapidly increasing the transfer capacity on thermally-constrained lines using energy storage systems is treated in **Paper IV**.

2.5 Grid utilisation

Grid utilisation can be defined as the measure of the consistency of the total loading of the network[45], e.g., in terms of active power (P). A general formulation is shown in Eq. 2.25:

$$\text{Grid utilisation} = \frac{P^{avg}}{P^{max,n}}, \tag{2.25}$$

where P^{avg} is the average total MW loading for a given time period, and $P^{\text{max,n}}$ is the average of the n largest total MW loading instances during the same time period. To put the research presented in this thesis in a grid utilisation perspective, one would also like to more clearly define the utilisation of individual power lines and transformers. For individual electrical loads, the evenness in loading is quantified by the load factor, i.e., the ratio between the average load and the maximum load over a given time period. A similar formulation is here proposed for computing the bidirectional utilisation of a line (or any other branch element) between two buses i and j, such that

$$\text{Line utilisation (P)} = w_{ij}\frac{\frac{1}{n}\sum_{k=0}^{n} P_k^{ij}}{\max(P^{ij})} + w_{ji}\frac{\frac{1}{m}\sum_{l=0}^{m} P_l^{ji}}{\max(P^{ji})}, \tag{2.26}$$

where P^{ij} is a vector with n elements containing MW line flows from i to j entering bus i. Conversely, P^{ji} is a vector with m elements containing MW line flows from j to i entering bus i. Given a vector $P \in \mathbb{R}^{(n+m)\times 1}$ of timeseries data with MW line flows between i to j

entering i, ordered in order of descending magnitude, we have $|P| = [P^{ij}, P^{ji}]$. The weights w correspond to the prevalence of the respective flow direction, i.e., $w_{ij} = n/(n+m)$ etc.

Another aspect to consider is the relative loading with respect to transfer capacity. A (directional) loading level for a line between two buses i and j is given as

$$\text{Line loading level}(P^{ij}) = \frac{P^{ij}_{avg}}{\text{transfer capacity } i \rightarrow j \text{ [MW]}}, \tag{2.27}$$

with P^{ij}_{avg} computed as in Eq. 2.26. As the line loading level in Eq. 2.27 is expressed in terms of active power can easily be associated with market flows. It can also be noted that if the line is operated at its capacity limit, the line utilisation and line loading level are equal in the limiting flow direction. However, to reflect the actual thermal and voltage operational limits, Eq. 2.27 should be altered to express transfer capacity as a voltage limit or rated current (or apparent power). If the transfer capacity of a transmission corridor is to be considered, multiple lines should be included in the equation.

Example II

Consider a scenario where a new wind power plant (WPP) with the characteristics shown in Fig. 2.2 is to be connected to a distribution network. There is an existing power line that restricts transfer to 25 MW due to thermal limits. Construction of a new line with 40 MW guarantees that all generated power is transferred. From Eqs. 2.26 and 2.27, the forecasted line utilisation for the three years following the completion of a new line is 0.32, and the line loading level is 0.27. If the WPP is instead directly connected to the existing line and active power injections controlled to not exceed 25 MW, the line utilisation and line loading levels for the three weather-years would be 0.40 and 0.41, respectively. That corresponds to 241.8 GWh of renewable energy transferred over three years. The curtailed energy over the same time period would be 11.2 GWh, or 4.4% of the maximum potential generation.

Curtailment of peak generation in a VRE-dominated system results in relatively small revenue losses due to the strong correlation with low electricity prices[46]. *Conversely, network reinforcement comes with a sharply increasing marginal cost for every generated MW above the existing line capacity. That cost should be evaluated against alternative methods for curtailment reduction. Given the low line loading level, a potential option is to add local energy storage to shift the loading in time.*

This small example shows that with proper control capabilities in the distribution network, grid capacity expansion is no longer only a question of physical limits but includes a trade-off between the marginal utility and marginal cost for different technical solutions. In such distribution networks, grid development approaches the standard transmission network investment strategy. However, in transmission systems, where construction lead times for new lines are several years, the speed of connection of new large-scale VRE generation is becoming an increasingly important factor in the pursuit of alternative solutions to increase both line loading levels and transfer capacity. Planning for future grid capacity needs in a VRE-dominated transmission system heavily relies on the estimation of the location, size and type of new generators.

2.6 Future power system scenarios

Key to maintaining resource adequacy is providing sufficient generation capacity to meet power and energy demands. Most green transition plans rely on intense electrification of the industrial and transportation sectors, which corresponds to a sharp increase in total electricity demand. In Sweden, current national planning goals include sufficient generation capacity to manage a doubling of the electricity consumption in the coming 20 years[47]. The planning for investments in new fossil-free generation is a crucial input to the parallel grid capacity expansion planning. Such (generation) *capacity expansion planning* (CEP) involves electricity market modelling based on forecasts of load and generation conditions. CEP models must also account for the uncertainty of predictions. Therefore, a scenario-based approach is typically adopted where the impact of different assumptions on resource adequacy is studied. The outcome for one such CEP scenario study is shown in Fig. 1.1.

CEP studies are typically formulated as optimisation problems where the objective is to find a generation mix that minimises the total generation costs. This comprises the investment and operating costs for all generators for a specified time period. A general objective function can be formulated as

$$\min \sum_{g \in \mathcal{G}} n_g P_g C_g^i + \sum_{g \in \mathcal{G}, t \in \mathcal{T}} p_{g,t} C_g^o, \tag{2.28}$$

where g is a generation type in the set of all generation types $\mathcal{G}$, and t is a point in time in the set of all considered time points $\mathcal{T}$. The first term represents the investment costs depending on n generators of type g, their installed MW generation capacity P, and their MW investment cost C^i. The second term reflects the operating costs for the said units as a product of their MWh production (p) and their cost per MWh (C^o). By adding more terms to Eq.2.28, more complex scenarios can be created. This includes modelling the impact of price formation in zonal electricity markets on placement and dispatch of generators. Modelling can also be extended to include grid capacity expansion as an alternative to generation investments[48].

Eq. 2.28 is normally subject to a range of constraints, including energy balance requirements. The formulation of an energy balance constraint is dependent on network model availability. In its most primitive form, it can be written as

$$\sum_{g \in \mathcal{G}} p_{g,t} = p_{l,t} \forall t \in \mathcal{T}, \tag{2.29}$$

that is, the total generation should be equal to the total load p_l at all times. In turn, this results in the installed generation capacity must be equal to or greater than the maximum load:

$$\sum_{g \in \mathcal{G}} n_g P_g \geq p_l^{max}. \tag{2.30}$$

Grid capacity constraints should be added to complement Eq. 2.29. If a full-scale $\mathrm{Y_{bus}}$ nodal network is available, such constraints can be derived from, e.g., Eq. 2.12 or Eq. 2.15. To reduce modelling complexity, a zonal network model can be used, and the resulting flows should simply not exceed any intra-zonal MW capacities.

In CEP modelling of decarbonised power systems, electricity prices are greatly influenced by the assumed weather conditions, which in turn impact the resulting optimal VRE generation investment strategy. In the Nordic system, hydropower is to a large extent expected to compensate for temporary shortfalls in VRE generation, and, naturally, reservoir levels are also affected by the weather-dependent inflows. With larger storage capability from hydrogen and BESS, and greater demand flexibility, resource adequacy can be improved. At the same time, system complexity increases significantly. Thus, one important CEP challenge is the trade-off between simplicity and accuracy in modelling of weather-related uncertainties and their impact on the operation and investment strategies of different actors. This issue is discussed in **Paper V**.

Chapter 3

Grid Capacity Opportunities

To ensure resource adequacy in VRE-dominated systems in a cost-effective manner, expansion of generation and grid capacity should be complemented by other solutions. These include increased reliance on

- demand flexibility,
- curtailment of variable renewable generation,
- energy storage capabilities,
- use of grid capacity enhancing measures, such as DLR and remedial actions,
- spinning reserves and/or other generation capacity mechanisms.

The above capabilities can all be used to actively manage voltage and thermal limits over different timescales. What is ultimately deemed a feasible tool by a system operator is influenced by a combination of technological, regulatory, and financial considerations. Regardless, in power systems where electricity is mainly generated by variable, renewable, and often distributed resources, it is crucial to obtain the capability to coordinate and control active and reactive power injections of DER. In this chapter, research on such control capabilities and their potential is outlined together with modelling considerations for analysis of DER and system performance.

3.1 Control strategies for grid capacity management

Grid capacity management involves both system operation and planning. This section introduces the selection and modelling of control strategies over different timescales.

3.1.1 Control system configuration

Voltage and thermal constraints are highly localised, meaning a local, or *decentralised* control structure may be sufficient for relieving a bottleneck. Decentralised control using feedback of measured signals is generally a low-cost, low-complexity solution that offers good performance provided that i) controllable resources are present locally, and ii) that control actions are not detrimental to the operation of the wider system. The latter point stems from the fact that the power grid is an interconnected network, and as such, any nodal power injections to some degree affect the operating state. Furthermore, adding multiple decentralised feedback controllers across the network without proper consideration of potential loop interactions may negatively impact system performance and stability. If the the locally measured signal has a global characteristic, as is the case with system frequency, coordination of decentralised controllers becomes relatively straightforward (The prime example in this case is droop speed control of turbine governors for synchronous generators.).

Management of multiple parallel grid capacity constraints can also be done through a *centralised* control scheme. This increases requirements on digital communications infrastructure and system modelling, including forecasting of future generation and demand. With greater modelling and control capabilities, system-wide coordination of resources is possible, which opens up for both global multi-objective optimisation schemes and a shift to more open-loop control strategies. Model-driven grid capacity management is prevalent in transmission system operation. For example, the flow-based capacity calculation in the Nordic zonal day-ahead market is a model-based open-loop method. To account for modelling errors and forecasting uncertainties, a reliability margin is introduced (Eq. 2.24). Further adjustments can be made in the intra-day market calculation and finally in real-time through counter-trading and redispatch of generators. By contrast, distribution system operation is restricted by low data availability and quality, making decentralised and local measurement-based control strategies attractive due to minimal needs for infrastructure investments and updates in operational procedures. With the introduction of smart meters and converter-interfaced distributed generation, more data-driven approaches are becoming increasingly relevant also in distribution networks.

Implementing a unified model-based control structure covering operation across all voltage levels is unfeasible in large-scale power systems. This is not only due to the scale and complexity of the system — the separation of TSO and DSO ownership and responsibilities in

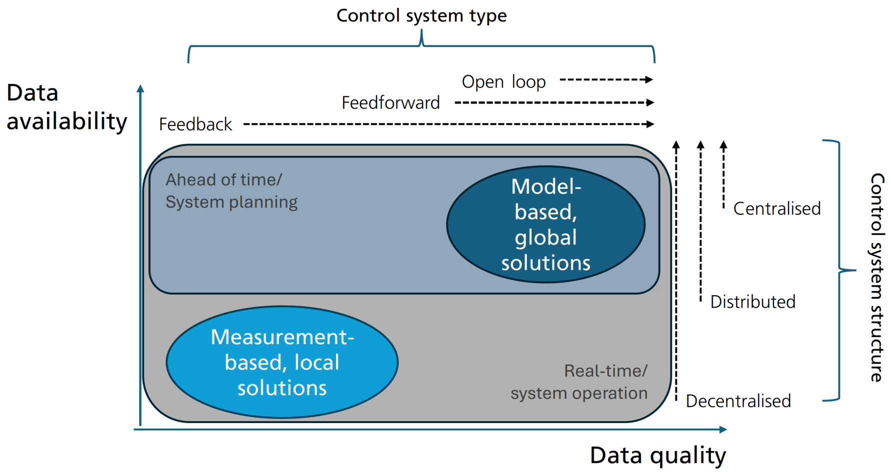


Figure 3.1: Network planning and operation considerations for grid capacity management based on data availability and data quality. Here, data availability refers to the ability to obtain and communicate measurements, models, and control signals for system operation. Data quality refers to the level of precision and accuracy of said data.

the deregulated energy market effectively prevents such efforts. However, to manage large-scale DER integration, decentralised or *distributed* control structures for management of segments or entire distribution systems is needed. With improved TSO/DSO coordination, control objectives can then at the very least be aligned at the TSO/DSO interface.

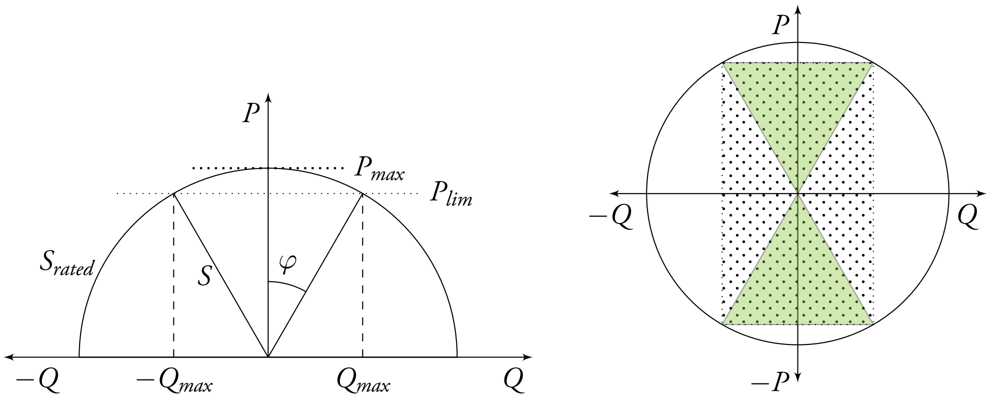
3.1.2 Capacity management in system planning and operation

An overview of network planning and operation considerations for grid capacity management is shown in Fig. 3.1. The guiding principle for the research presented in **Papers I-IV** can be summarised as *decentralised control when possible, distributed control when necessary*. This approach is motivated by the characteristics of VRE expansion. With an increasing focus on distribution networks and a high degree of uncertainty regarding the timing and location of new DER connections, control strategies that demand minimal infrastructure upgrades and changes in operational practices reduce investment risks. Flexible, scalable, and cost-effective solutions are needed for systems subject to rapid VRE expansion. The main drawback of the decentralised approach is perhaps the limited ability to enforce arbitrary optimality criteria in system operation. However, while optimal operating states are desirable, achieving operational safety at all times is the key objective that must be fulfilled by any control strategy. In general, decentralised controllers may be advantageous with respect to power system resilience, as operation is less susceptible to disruptions in the cyber-physical domain.

As indicated by Fig. 3.1, effective system planning requires high data availability to capture future potential operational scenarios. When conducting long-term planning tasks involving multi-year optimisation, such as CEP, there is a need to reduce model complexity to lower the computational burden. In **Paper V**, modelling of power system operation is reduced to market-based energy balancing actions across the bidding zones in the Nordics and surrounding countries. This leaves the electricity market as the sole control mechanism for managing grid capacity constraints, which makes realistic market modelling a key component in CEP.

3.2 Control of DER

Voltage source converters (VSCs) are the most widespread type of power-electronic inverters used to connect photovoltaic generators and BESS to the grid. Type 4 wind power plant designs are based on back-to-back VSCs for grid connection. Through a series of current control loops, the active and reactive power output of a VSC can be adjusted independently. For VRE generators, where it is desired to maximise power production, the active power reference is typically obtained from a maximum power point tracking (MPPT) algorithm. The reactive power reference is adjusted based on voltage control requirements. A capability curve illustrates feasible P and Q within the apparent power (S) rating of the inverter at a given grid voltage level — a capability curve for a generic PV inverter is shown in Fig. 3.2a. For Type 4 wind generators and WPPs, capability curves can generally be represented by Fig. 3.2a. However, depending on plant topology, additional internal voltage and current constraints may further limit the reactive power capability[49].



(a) A generic PV-inverter capability curve.

(b) BESS capability curve, with operating areas for decoupled P and Q (dotted), and constant cos(φ) (green).

Figure 3.2: Capability curves for PV and BESS inverters.

By letting $S_{rated} = P_{max}$, with P_{max} corresponding to the maximum potential power input to the inverter, the minimum inverter size needed to connect a generator with a given installed MW capacity is found. Peak generation then always results in a unity power factor, i.e., $\cos(\varphi) = 1$. This design choice is common for small-scale PV inverters. The voltage control capability can be improved by either curtailing active power injections or by "oversizing" the inverter through selection of a larger MVA rating than the maximum MW generation. Both curtailment and oversizing correspond to a capability curve with the active power limit $P_{lim} < P_{max}$, which allows $|Q| > 0$ at P_{lim}. In the European network code on requirements for generators (RfG), a mandated reactive power capability at P_{lim} for large converter-interfaced generators is defined. In the Swedish adaptation of the RfG, generators ≥ 10 MW should be able to inject and absorb reactive power amounting to 33 % of the active power output, or roughly $\cos(\varphi) = 0.95$. This requirement translates to a triangle-shaped operating area under the capability curve. A complete decoupling of P and Q injections is achieved in the extended rectangle-shaped area under the curve. For BESS, the capability curve is extended to a circle, as shown in Fig. 3.2b.

3.2.1 Curtailment

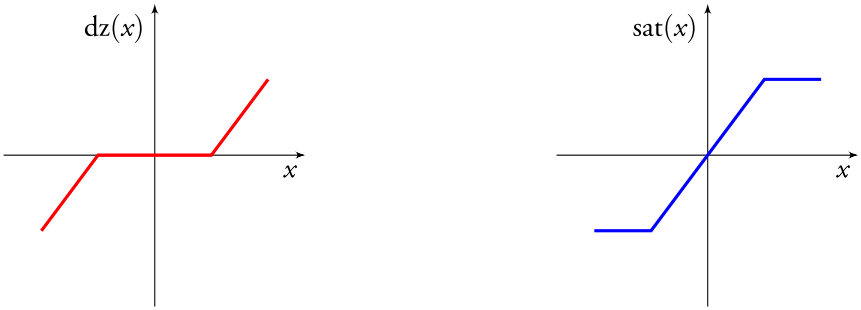
Although curtailment leads to a reduction of power generation, it is an effective method for active power control for VRE generators. In principle, it can be achieved by adjusting the active power reference value to the grid-connected converter. However, the implementation varies for different generator types. PV units with MPPT controllers adjust the PV cell or array operating voltage to maximise the output power, and curtailment is then introduced through a voltage offset in the MPPT algorithm. For wind plants, both the electrical power output from the converter and the kinetic energy of the wind turbine should be considered. Therefore, coordinated control of the converter and the pitch angle of the turbine blades may be required to achieve rapid and accurate curtailment of active power.

Curtailment can be modelled as a dead zone function or a saturation function (Fig. 3.3). For a variable x and a specified dead zone range, a corresponding saturation function is found by $\mathrm{sat}(x) = x - \mathrm{dz}(x)$. Thus, the active power output P_{out} from a PV unit can be written as a function of the potential active power generation P_{PV} and the curtailed power $\mathrm{dz}(P_{PV})$, such that

$$P_{out} = P_{PV} - \mathrm{dz}(P_{PV}), \tag{3.1}$$

or directly as a limitation of the PV active power, in which curtailment is implicit:

$$P_{out} = \mathrm{sat}(P_{PV}) = \begin{cases} P_{lim} & \text{if } P_{PV} > P_{lim} \\ P_{PV} & \text{if } P_{PV} \leq P_{lim} \end{cases}. \tag{3.2}$$



(a) Dead zone function

(b) Saturation function

Figure 3.3: Nonlinear functions for modelling of converter power limits.

Voltage-dependent curtailment of DER, known as *volt-Watt control*, is typically implemented using a $P(V)$ characteristic together with a dead zone function. Controllers utilising *volt-var control* instead utilise a dead zone function to create a $Q(V)$ voltage droop characteristic for reactive power injections at predefined voltages.

3.2.2 PI Control

The proportional-integral-derivative (PID) controller is a widely used (negative) feedback control mechanism that is deployed to keep selected system variables at specific values despite disturbances affecting the system. The derivative part is often dropped to limit the negative impact from signal noise on control performance. The result is a PI controller, and it is the key ingredient in the DER control algorithms discussed in this thesis. In its simplest continuous form, the PI controller takes an input control error $e(t) = y^{\text{sp}} - y(t)$ corresponding to the difference between a measured process variable and its desired value, or set point. The result is a control signal $u(t)$ as a process input according to

$$u(t) = K_P\, e(t) + K_I \int_0^t e(\tau) d\tau, \tag{3.3}$$

where K_P and K_I are constant proportional and integral gains. For the implementation of a digital PI controller with sampled measurements, Eq. 3.3 can be discretised as

$$u(t+1) = K_P\, e(t) + K_I \sum_0^t e(\tau). \tag{3.4}$$

In actual operation, the controller is restricted by the physical limits of the controlled actuator. Considering decentralised PI control of P and/or Q injections from a VRE generator, the converter rating and the instantaneous maximum generation are two such actuator limits that can be modelled as saturations of the controller input to the system. To prevent *windup* of the controller integrator in case of actuator saturation, an *anti-windup* mechanism is added. Typically, the condition $\text{sat}(u(t)) - u(t) \neq 0$ is used to trigger an adjustment of the integrated error, e.g., through feedback of the difference between the wanted and actual control signal, or by simply freezing the integrated error updates.

3.3 Voltage limitation

This thesis treats voltage control methods in distribution networks. To introduce the topic, one can first consider the more common application in transmission systems. The objective of voltage control in transmission systems is to maintain network voltages at, or close to, the nominal voltage. The high X/R ratio of the network means reactive power injection and absorption are effective for adjusting voltage magnitudes. However, large reactive power flows in the network increase both active and reactive power losses. Furthermore, due to the large reactive losses, and the small difference in voltage magnitudes throughout the network, transfer of reactive power over long distances is not feasible[50]. Hence, voltage control in transmission systems is synonymous with decentralised control of reactive power, albeit with a more or less centralised coordination. For generators, general requirements for control capabilities are typically found in a grid code, such as the RfG. Feedback control systems, often including PI and PID controllers, can be found in STATCOMs, as well as in automatic voltage regulators (AVRs) in excitation systems for synchronous generators.

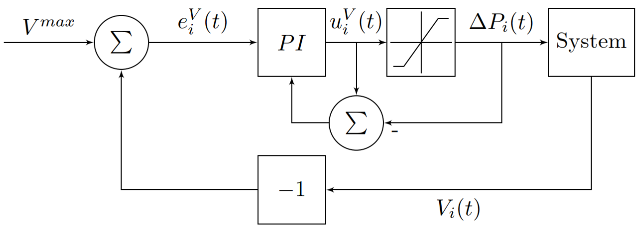
In distribution networks, deviations in voltage magnitude from the nominal value is primarily a power quality issue and not a stability issue. Therefore, forcing bus voltages to specific set points during continuous operation is overly restrictive, and, occasionally, unfeasible[51]. Instead, for a distribution network with n nodes, voltage control that restricts magnitudes to $V_{min} \leq V_i(t) \leq V_{max}, i = 1, \ldots, n$ is sufficient. This voltage control approach is here referred to as *voltage limitation*. Considering active power injections from DER at a network node j, the grid capacity in terms of voltage is reached when $V_j = V_{max}$.

As outlined in Section 2.3.1, reactive power has a limited impact on voltages for low X/R ratios. However, decentralised voltage limitation using DER converters for reactive power adjustments is still an attractive option in distribution networks, for at least three reasons:

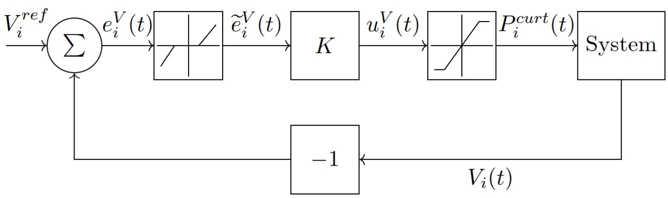
- Converter reactive power capability is a ”free” resource included for grid-connected DER.
- In MV networks with substantial series inductance, reactive power flows have a notable impact on voltages[52].

- If decentralised control can limit large reactive power flows, more grid capacity is allocated for active power transfer.

In low voltage networks, as well as in many MV networks, where Q-based voltage control is insufficient to mitigate large voltage deviations[53], curtailment or flexibility schemes are added. For converter-interfaced DER, a combination of volt-var and volt-Watt control is a prevalent and standardised solution[54]. The advantage of standardising Q(V) and P(V) characteristics is *plug-and-play*, which means identical controller parameters are selected for all DERs in the system, which then can be directly implemented by the converter manufacturer. The accompanying drawback is the need for conservative selection of curve characteristics to avoid high-gain instability issues[55]. To avoid voltage limit violations due to slow convergence rates, control actions must then be taken well within the acceptable voltage range[56], leading to at least one of the two following outcomes: i) excessive reactive power flows and/or curtailment, ii) underutilisation of grid capacity, as $\max(V_i) < V_{max}, i = 1, \ldots, n$.



(a) Control of VRE generator active power, as presented in **Paper II**.



(b) Volt-Watt control, represented as a proportional controller with gain K, subject to input and output limitations.

Figure 3.4: Block diagram representation of decentralised voltage limitation strategies.

Through individual selection or adjustments of volt-var and volt-Watt parameters, operation can be improved[57], at the expense of full plug-and-play functionality. The two decentralised voltage control strategies proposed in **Papers I** and **II** aim to maximise the grid capacity at each controlled node using distributed VRE generation. This is done by using V_{max} as a reference for a local PI controller adjusting power injections. For VRE generators, any active power adjustments are derived from curtailment. By adding a limit on reactive power adjustments to lagging power factors, limitation of overvoltage is then achieved with

$V_i \leq V_{max}, \forall i$ in steady state, with curtailment only occurring when $V(t) > V_{max}$. In Fig. 3.4, an overview of a PI-based voltage control scheme and volt-Watt control is shown.

3.4 Congestion management

The fundamental requirement for congestion management is to limit currents or power flows in the network. For transmission systems, congestion management is typically directly integrated in the market-clearing process, as was outlined in Sections 2.4.3 and 3.1. For VRE-dominated distribution systems with growing grid capacity shortage, improving flexibility in both electricity demand and distributed generation is increasingly seen as a necessary measure, also by regulators[58]. Congestion management and network tariff adjustments are the two main options for DSOs to reduce power flows in their networks[59]. Network tariffs are financial schemes aimed at controlling end-user behaviour. The network tariff rate can be used as a disincentive for extreme power demand, while the elimination of excessive power flows can typically not be guaranteed. In contrast, congestion management strategies are typically designed with guarantees on power flow limits. This is achieved either through direct control of flexibility resources in the network by the DSO, or via a local flexibility market, where network resources are remunerated by the DSO for relieving grid congestion. Direct control methods include dynamic operating envelopes[27], which are well-established among Australian DSOs. In Europe, local flexibility markets are instead the preferred method for congestion management in distribution networks.

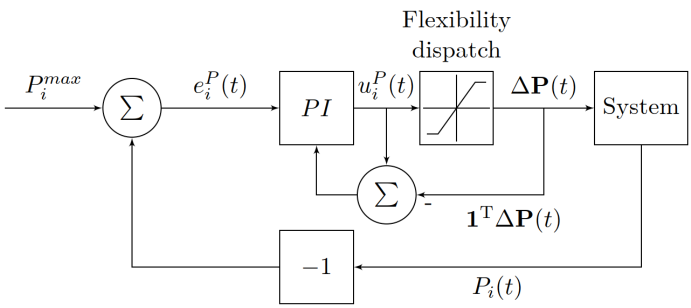


Figure 3.5: Control of active power of k flexibility resources based on a single active power constraint, as presented in **Paper III**. **1** is a vector of ones, with **1**, $\Delta\mathbf{P} \in \mathbb{R}^{k\times 1}$.

Given the stated power limitation requirement, for distribution networks, the PI controller-based voltage limitation strategy outlined in the previous section can, with appropriate modifications, be applied to limit active and reactive power flows at upstream substations or adjacent power lines impacted by large reverse power flows caused by DER generation. An overview of such a control system is shown in Fig. 3.5. The distributed nature of the control problem results in requirements on real-time communication of control signals as well as information on the DER flexibility capabilities and location with respect to network topology. Network topology information can be provided a priori, meaning no detailed network model is needed during either the planning or operation stages. A key part of such a setup is the distribution of control signals to available flexibility resources. This *flexibility dispatch* is independent of the DSO's choice of direct control or a local flexibility market for congestion management. By creating a flexibility dispatch list, different resources, including distributed generation and flexible loads, can easily be ranked in merit order, based on price signals in the local market, or minimisation of the total control effort to alleviate a bottleneck. These options are explored in **Paper III**, where the approach is extended to include control of multiple bottlenecks in a radial network. For a flexible resource at a node j participating in congestion management of m branches due to large distributed generation, the active power adjustments can simply be selected among m PI controller outputs as $\Delta P_j = \max(\Delta P_{1,j}, ..., \Delta P_{m,j})$.

For control of reactive power flows in radial networks, the process is analogous to the method outlined in Fig. 3.5. This control capability has direct relevance for distribution network voltages and power loss reduction. However, the perhaps greatest potential benefit comes from control of reactive flows at the TSO/DSO interface, which allows for maintained or even improved local voltage control capability in the transmission system.

3.4.1 Virtual power lines

In this thesis, the discussion on congestion management in transmission networks is restricted to coordinated operation of energy storage systems, referred to as *virtual power lines* (VPLs)[60]. VPL operation aims not only at restricting power flows at selected thermally constrained power lines, but also to increase the grid capacity between different areas of the network. The capacity increase can be temporary or permanent, depending on the mode of operation. In case of VRE generation, the VPL uses a local energy storage to absorb temporary increases in active power injections to restrict power flows across a monitored bottleneck to a limit less or equal to the PATL. Simultaneously, an energy storage on the other side of the bottleneck injects an equal amount of active power, virtually increasing the transferred power over PATL. When physical grid capacity is again available, the depleted energy storage is recharged using the stored energy from the first storage system.

The VPL can also be deployed to ensure TATL is not exceeded during contingencies [61]. This means capacity margins imposed on CNEs during continuous operation can be reduced as the VPL provides the capacity necessary to maintain resource adequacy. Thus, line loading levels can permanently be safely increased all the way up to the PATL.

The VPL capability for congestion management is restricted by the energy storage power and energy limits. In **Paper IV**, a PI-based VPL control strategy is proposed, where energy storage limits are modelled as static nonlinearities during the design process. The overall structure of the scheme is illustrated in Fig. 3.6.

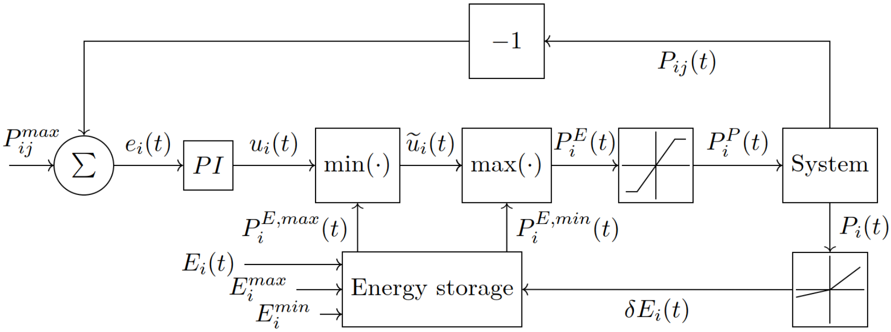


Figure 3.6: Model of an energy storage system at a bus i as part of a virtual power line from bus i to bus j. Based on **Paper IV**. PI control of active power flows is subject to output constraints based on the real-time energy level of the storage system (through min-max selection) and power limits (the saturation block). The impact of a power injection P_i for a time interval t, the change in energy storage level δE_i is obtained through a nonlinear ramp function to account for differing charging and discharging losses. Note that controller anti-windup is not included in the illustration.

3.5 Modelling of VRE-dominated systems

System modelling and simulations are necessary tools for analysing the impact of VRE on operation and planning. The choice of modelling approach is a trade-off between the need to accurately capture physical processes that are to be studied, and the need to reduce model complexity for faster simulations. In this section, modelling aspects related to the research presented in this thesis are discussed.

3.5.1 Modelling timescales

The time separation of different power system dynamics facilitates the creation of separate modelling regimes with different levels of complexity. An overview of timescales for a range of power system phenomena is given in Fig. 3.7. For the study of voltage magnitude variations and thermodynamic processes, with time constants ranging from seconds to minutes, much faster power electronic and electro-mechanical interactions are typically neglected. That leaves a static representation of the system, such as described by Eqs. 2.12 and 2.13, or a quasi-static system representation, with timeseries data as inputs. The quasi-static representation has the structure of a discrete-time dynamic model, while the system states have no explicit time dependence. Based on the system time characteristics, appropriate sampling time intervals for measurements and control signals can be determined.

By expressing controllers for limitation of bus voltages and power flows in discrete time, such as in Eq. 3.4, controller models can be combined with a quasi-static network model, and a discrete-time system model is obtained. With the resulting model as a starting point, controller dynamics during system operation can then be evaluated and simulated.

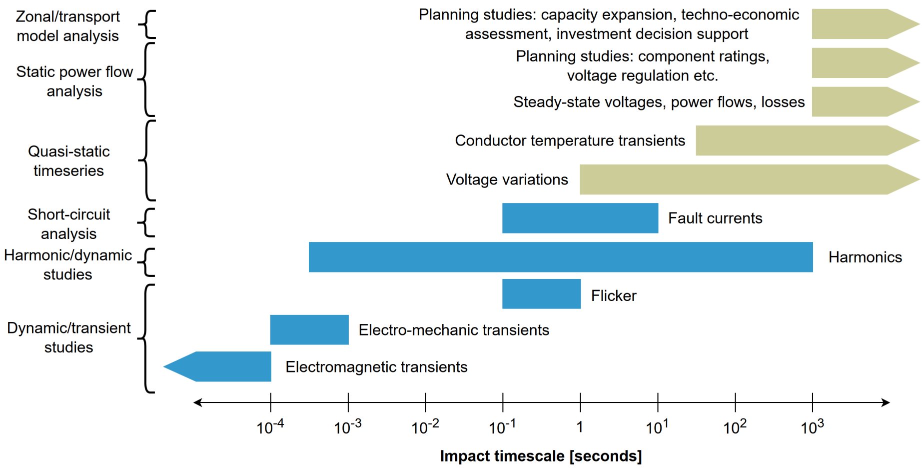


Figure 3.7: Time characteristics of different power system phenomena and associated modelling approaches[62]. Topics considered in this thesis are marked in green.

In CEP studies, static modelling is prevalent due to the low time resolution of many electricity markets. Furthermore, for multi-year analysis, linear and zonal network representations replace physical power flow models to reduce computational burden.

3.5.2 System modelling

When studying the operational impact of the outlined voltage limitation and congestion management strategies with the appropriate time characteristics, the relevant functions to consider have the general formulations

$$f_1 : \{P, Q\} \rightarrow \{V, \theta\}, \tag{3.5}$$

$$f_2 : \{P, Q\} \rightarrow \{P_{\text{flow}}, Q_{\text{flow}}\}. \tag{3.6}$$

In other words, a function that maps power injections to bus voltages and branch power flows, respectively. For quasi-static simulation studies, the power flow equations (2.12 and 2.13) are sufficient to satisfy Eqs. 3.5 and 3.6. In **Papers II** and **IV**, the following mappings are used for the development of analytical models of decentralised control systems:

$$g_1 : \{P, Q\} \to V, \tag{3.7}$$
$$g_2 : P \to P_{\text{flow}}. \tag{3.8}$$

In the analysis, a discrete-time state-space representation of the studied system is derived, which takes the general form

$$\begin{aligned} x(t+1) &= Ax(t) + Bu(t) \\ y(t) &= Cx(t) + Du(t), \end{aligned} \tag{3.9}$$

with the state vector x, input vector u, output vectors y, and matrices A, B, C, D of appropriate dimensions. To retrieve Eq. 3.9, first the power flow equations are linearised around a selected system operating point. For bus voltages, Eq. 3.7 is then expressed using the voltage sensitivity matrices $\frac{\delta V}{\delta P}$, and $\frac{\delta V}{\delta Q}$, such that

$$V \approx \frac{\delta V}{\delta P} P + \frac{\delta V}{\delta Q} Q. \tag{3.10}$$

The voltage sensitivity matrices can be derived from the power flow Jacobian matrix. The corresponding linear expression for Eq. 3.8 involves power flow sensitivities, i.e., PTDFs, and is given by Eq. 2.19.

A state-space representation of a discrete-time controller with anti-windup for control of DER power injections can be formulated as

$$\begin{aligned} z(t+1) &= z(t) + e(t) - \mathrm{dz}(u(t)) \\ u(t) &= K_p e(t) + K_I z(t). \end{aligned} \tag{3.11}$$

Here, z is the integrator error state, and anti-windup is provided by the inclusion of the deadzone function. Combining multiple instances of 3.11 with 3.9, a closed loop system is obtained. The limits in the DER power injection capabilities introduce additional modelling complexity that must be managed. The fact that nonlinearities of the type presented in Fig. 3.3 are *piecewise linear* is utilised in the modelling approach in **Paper II**. A discrete-time state-space representation of a piecewise linear system involves subdividing the state space into separate linear regions[63], where the system dynamics in each region i can be expressed as

$$\begin{aligned} x(t+1) &= A_i x(t) + a_i + B_i u(t) \\ y(t) &= C_i x(t) + c_i + D_i u(t). \end{aligned} \tag{3.12}$$

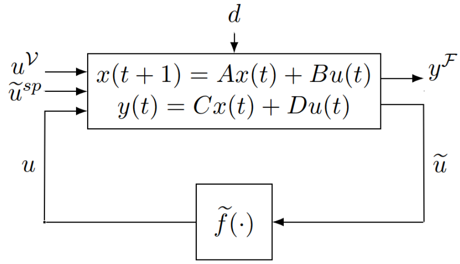


Figure 3.8: Closed loop system model for a network with decentralised virtual power line control, based on **Paper IV**. The decentralised controllers take the nonlinear input u based on the linear system output $\widetilde{u}$.

For the voltage limitation model presented in this thesis, each region of the piecewise linear system corresponds to a specific combination of controller output saturation.

In **Paper IV**, the power and energy limits for the VPL energy storage systems are in focus. The resulting nonlinearities introduced in the system model, shown in Fig, 3.6 , can be separated from the linear system dynamics. For a set of static nonlinearities $\widetilde{f}$, this yields the closed-loop system in Fig. 3.8 consisting of a linear system with nonlinear feedback. The resulting model allows for the design and performance evaluation of decentralised VPL controllers.

3.5.3 Test systems

Both distribution and transmission test systems have been utilised for testing and evaluation of the developed control strategies. This includes a radial LV feeder[64], and radial MV feeders[20], in part shown in Fig. 2.1. The test system selection reflects the research focus on three-phase European distribution systems and the stated purpose for VRE integration studies.

For simulations of the VPL control design in a transmission network, the Nordic 44 test system (Fig. 3.9) is used[65]. It provides a simplified representation of the Nordic transmission system. Still, it maintains a realistic number of inter-zonal tie-lines, making the model suitable for studying congestion management between bidding zones.

The actual Nordic transmission system, depicted in Fig. 3.10, consists of a significantly larger number of buses and branches than the low-resolution Nordic 44 model. For market-centred long-term analysis, a zonal market resolution is often sufficient, which allows for further model reduction. The model used in the CEP case study in **Paper V**, shown in Fig. 3.11, establishes power balance through net zonal active power injections and inter-zonal active power flows.

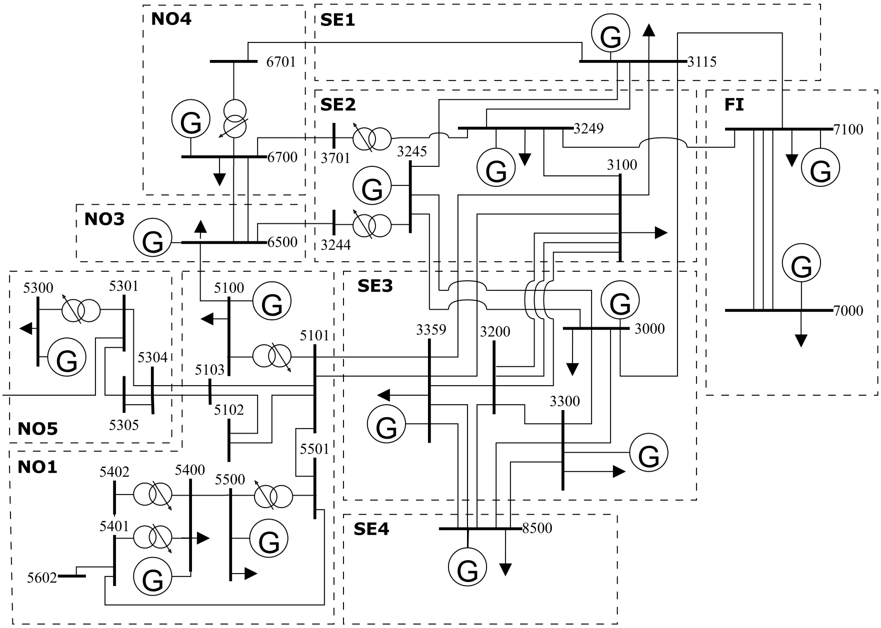


Figure 3.9: Single line diagram of the Nordic 44 test system, including the representation of bidding zones in the Nordic synchronous area, excluding Denmark (DK2).

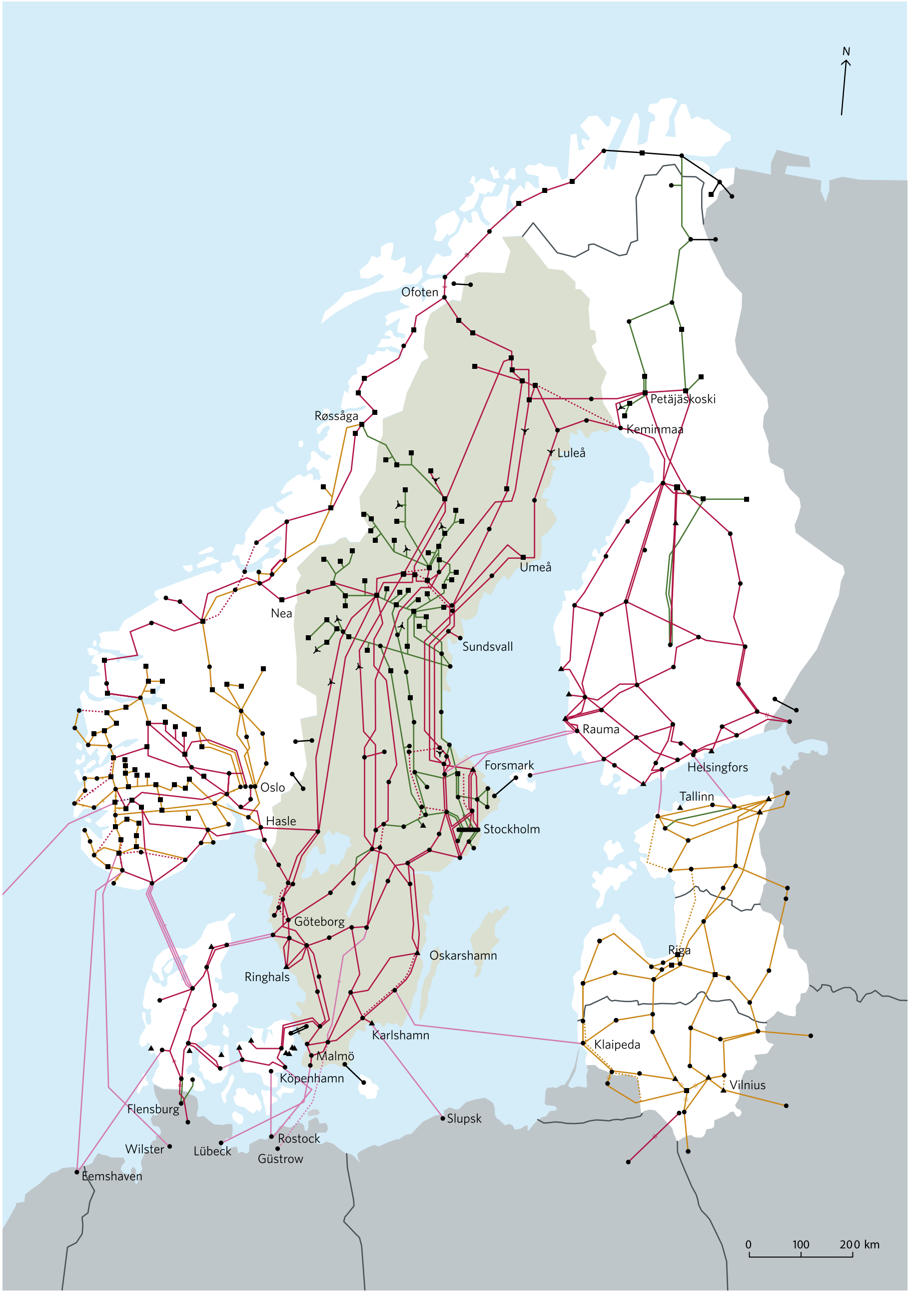


Figure 3.10: Map of the Nordic transmission system. This includes the Nordic synchronous area (Sweden, Norway, Finland, and Eastern Denmark) and parts of the continental European system (Estonia, Latvia, Lithuania, and Western Denmark)[66].

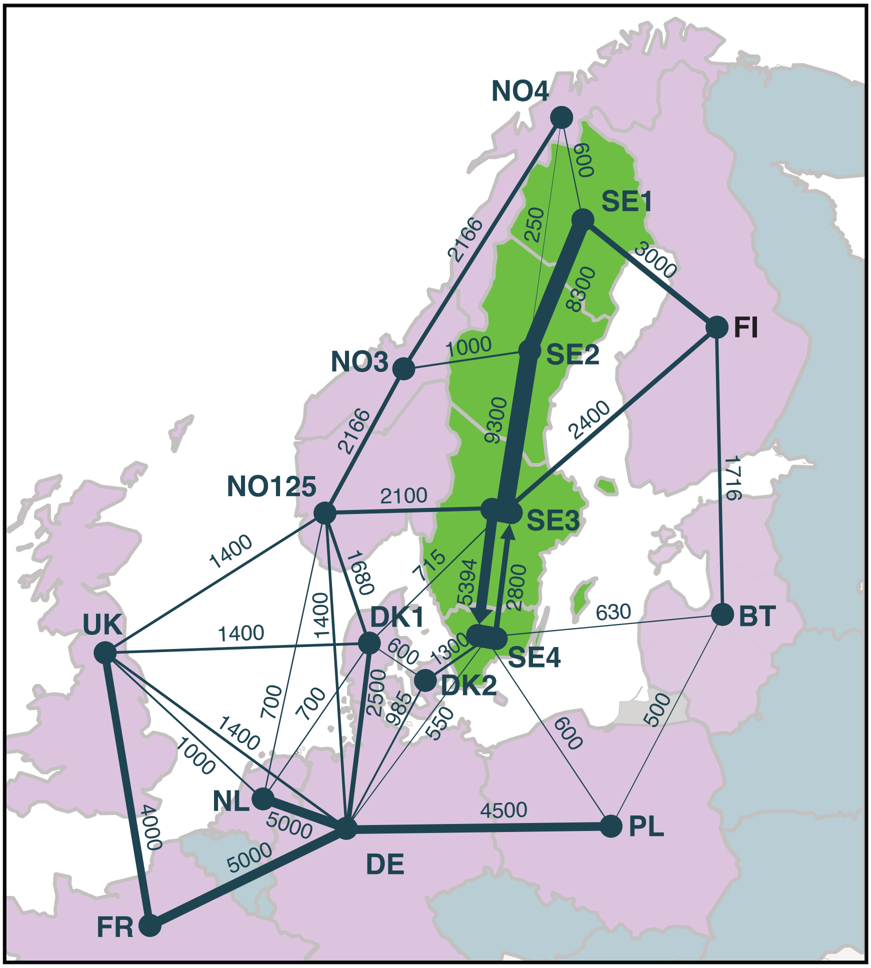


Figure 3.11: Model of bidding zones in the Nordic electricity market and surrounding areas, together with intra-zonal grid capacities. The three Baltic bidding zones are modelled as one (BT), as are the three southwestern-most Norwegian zones (NO125).

Chapter 4

Conclusions and future work

This chapter summarises the main conclusions of the presented research and proposes areas for future work.

4.1 Conclusions

This thesis presents a bottom-up approach for improving grid capacity in electric power systems dominated by variable renewable energy (VRE) generation, including a large share of distributed energy resources (DER). The starting point of this work was voltage limitation in radial distribution networks, for which two PI-based control schemes for decentralised control schemes using distributed generators were developed. The proposed methods account for the limited impact of reactive power on bus voltage magnitudes in grids with low X/R ratios by allowing for curtailment of distributed generation in case of overvoltage. A discrete-time piecewise linear state space model was developed to evaluate the method from a stability perspective, combining the nonlinear dynamics of output-restricted PI controllers with a linearised network model. Instabilities related to integrator saturation and controller interactions are detected by analysing the impact of the controller parameter selection in the model. When implementing local voltage control for converter-interfaced DER, implementing a plug-and-play solution allows control parameters to be selected before deployment and then left unchanged during operation. Using the developed model, it is possible to determine if a range of feasible static control parameters exists, and then provide guarantees for secure long-term operation within given voltage limits. With respect to long-term voltage variations, it is not only possible to maximise grid capacity locally, but the permitted amount of new distributed generation connections is unlimited, barring any externally imposed limits on curtailment. Ideally, the technical issue is then transformed into a purely financial one. In practice, other technical constraints, such as short circuit ratio or harmonics, replace voltage magnitude as the root cause of the capacity bottleneck.

On an aggregate level, distributed generation may cause large reverse power flows in a radial distribution network. These flows must be limited to avoid thermal overloading. The problem translates to control requirements of the same nature as for the proposed decentralised voltage controllers, again making a PI controller-based scheme an attractive option. However, with the inherently distributed nature of the problem, communication of measurement and control signals is introduced as an additional requirement. To minimise operational complexity, a flexibility dispatch list was introduced to integrate multiple geographically dispersed control objectives and DER control actions. By determining the activation order of available flexible assets in a predefined dispatch list, the control structure can easily be integrated into various remuneration schemes, such as a local flexibility market. The minimum network data requirements for determining flexibility asset selection are locations with respect to network topology. As such data does not need to be available in real-time, the control scheme is model-free during operation, and suitable for distribution networks with limited grid visibility. To reduce the total control effort under limited data availability, this thesis investigated a sensitivity-based ranking order, determined by the power transfer distribution factors (PTDFs) of the system. It was shown, using the CIGRE European MV test system, that only limited improvements for active power flow control are possible, indicating that the control scheme can fully decouple the technical and economic considerations in the design process.

With the proposed scheme for coordinated control of active power flows in place, it is possible to limit flows at the TSO/DSO interface from downstream control actions. This ensures secure TSO activation of frequency balancing services from distribution networks. What then remains is to secure sufficient grid capacity for power balancing in the transmission system itself, which was the third topic treated in this thesis. To improve transfer capacity in the existing network, the configuration of two large-scale BESS as a so-called virtual power line (VPL) was considered. It was shown how the issue of VPL placement and sizing can be reformulated as a PTDF-based linear program, with solutions guaranteed to alleviate bottlenecks without adverse effects in adjacent regions of a meshed network. A state space model with nonlinear feedback was developed to study systems including multiple VPLs with power and energy-constrained BESS. It was shown how the stability of such a system can be studied analytically, and both 2-norm and infinity-norm approaches for controller parameter tuning were formulated. The model was validated in the Nordic 44 test system. Finally, it was shown in simulations that the developed VPL concept, without any modifications, can be extended to power injections during contingency events to avoid thermal overloading. This points to the two benefits of the VPL: virtually increasing transfer capacity through coordinated charging and discharging of the BESS, and freeing up physical transfer capacity, previously reserved for contingencies.

The final topic treated in this thesis concerned the modelling of capacity needs in future VRE-dominated power system scenarios. A capacity expansion planning (CEP) tool was created by combining a linear generation and transmission expansion model and a capacity adjustment model that includes a nonlinear market representation restricted to short-term price forecasts. This allows for better capture of hydropower dispatch, which is constrained by both reservoir levels and limited foresight into future market conditions. In the Nordics, hydropower is seen as a key balancing resource in a future decarbonised power system. However, weather variability affects both VRE generation and hydro reservoir inflow, potentially reducing the balancing capability of hydropower and increasing the need for demand flexibility. To capture a wide range of operating conditions, there is a need to include multi-year weather data in the analysis. This was done in a Nordic case study, where 33 weather-years were used to investigate different scenarios for a fully decarbonised Swedish power system in 2050. The results indicate that forecasted investments in inter-zonal grid capacity expansion allow for a cost-effective large-scale expansion of VRE, mainly onshore wind power. It was also shown that the choice of weather year heavily influences the total system costs, as well as the cost-optimal generation mix.

4.2 Future work

Four areas of further research have been identified during the work on this thesis:

Benchmarking

To assist in comparative performance assessment of the proposed control methods, benchmarking simulation studies should be considered. This is particularly relevant for the proposed voltage limitation strategy for distribution networks, where existing standards for decentralised voltage control for converter-interfaced generation can be used. Other relevant benchmarks include OLTC operating strategies and dynamic operating envelopes.

Development

Based on the presented control methods and system modelling approaches, further developments that should be considered of particular interest include:

- Integration of the voltage limitation and congestion management strategies for distribution networks. Given the distributed control strategy used for congestion management, an equivalent voltage limitation strategy would lead to easier integration.

- An extension of the proposed system model for VPL to include PTDFs for contingencies. The inclusion of such sensitivities, known as line outage distribution factors (LODFs), generalises the analysis of VPL operation under any N-1 contingency.

- Co-simulation studies involving distribution and transmission models for analysis of DER contributions to transmission system voltage control and congestion management.

- Representative models of the proposed control strategies for use in system planning. To facilitate inclusion of grid capacity increasing measures in the planning process, static representations of the dynamic control models should be defined.

Analysis

To expand the analytical foundation of the presented research, it is suggested that the two presented discrete-time system models are subjected to an in-depth stability analysis. With stability guarantees for a wide range of controller parameter settings and operating conditions, the design criteria for decentralised solutions can be significantly relaxed, simplifying plug-and-play implementation.

Other topics relevant for further analysis include:

- Evaluation of control loop interactions involving internal converter dynamics.

- The impact of control actions on power losses.

- Cost estimations of proposed solutions for long-term planning studies.

Implementation

To enable full-scale deployment of the proposed voltage limitation and congestion management strategies, several practical issues must first be resolved. This includes integration of the control algorithms in the inverter control systems, and in case of a distributed control approach, integration in DSO SCADA and/or DER management systems. Furthermore, the impact of operational adjustments with respect to existing protection system configurations should be carefully studied before implementation.

4.3 Final remarks

In summary, this thesis has identified the grid capacity needs in VRE-dominated power systems and proposed methods to maximise the grid capacity of the existing network with respect to voltage and thermal limits through control of converter-interfaced flexible resources. The research indicates that grid capacity management strategies based on simple control principles can deliver robust and scalable performance. This makes such solutions suitable for temporary or permanent deployment in electric power systems under rapid decarbonisation.

References

[1] Svenska kraftnät, “Nätutvecklingsplan 2024-2033,” Tech. Rep., 2023.

[2] International Energy Agency (IEA), “Energy Technology Perspectives 2023,” Paris, Tech. Rep., 2023.

[3] “Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 (‘European Climate Law’),” Jun. 2021.

[4] Svenska kraftnät, “Long-term market analysis 2024 - Scenarios of the power system development until 2050 (in Swedish),” Tech. Rep. Svk 2023/4164, Jan. 2024.

[5] E. Ciapessoni, D. Cirio, A. Pitto, M. van Harte, M. Panteli, “Power System Resilience: definition, features and properties,” *CIGRE Science and Engineering*, vol. 2023, no. 30, Oct. 2023.

[6] EPRI, “Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches,” Palo Alto, CA:, Tech. Rep. 3002024368, 2022.

[7] Energy Systems Integration Group (ESIG), “Electricity Market Visions to Support a Reliable and Affordable Electric Grid Under Electricity Decarbonization,” Reston, VA, Tech. Rep., 2025.

[8] North American Electric Reliability Council (NERC), “Transmission Transfer Capability,” Tech. Rep., May 1995.

[9] ETSO, “Definitions of Transfer Capacities in liberalised Electricity Markets,” Tech. Rep., Apr. 2001.

[10] IEEE Std 738-2012, “IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors,” Standard, 2013, DOI: 10.1109/IEEESTD.2013.6692858.

[11] CIGRE, “A guide for rating calculations of insulated cables,” Tech. Rep. TB 640, 2015.

[12] IEC 60076-7:2018, "Power transformers - Part 7: Loading guide for mineral-oil-immersed power transformers," Standard, 2018.

[13] N. Hatziargyriou, J. Milanovic, C. Rahmann, V. Ajjarapu, C. Canizares, I. Erlich, D. Hill, I. Hiskens, I. Kamwa, B. Pal, P. Pourbeik, J. Sanchez-Gasca, A. Stankovic, T. Van Cutsem, V. Vittal, and C. Vournas, "Definition and Classification of Power System Stability – Revisited & Extended," *IEEE Transactions on Power Systems*, vol. 36, no. 4, pp. 3271–3281, Jul. 2021, DOI: 10.1109/TPWRS.2020.3041774.

[14] Q. Chen and J. McCalley, "Identifying high risk N-k contingencies for online security assessment," *IEEE Transactions on Power Systems*, vol. 20, no. 2, pp. 823–834, May 2005, DOI: 10.1109/TPWRS.2005.846065.

[15] P. Sőrés, D. Divényi, and D. Raisz, "Flow-based capacity calculation method used in electricity market coupling," in *2013 10th International Conference on the European Energy Market (EEM)*, May 2013, pp. 1–7, DOI: 10.1109/EEM.2013.6607285.

[16] Y. Ruwaida, J. P. Chaves-Avila, N. Etherden, I. Gomez-Arriola, G. Gürses-Tran, K. Kessels, C. Madina, A. Sanjab, M. Santos-Mugica, D. N. Trakas, and M. Troncia, "TSO-DSO-Customer Coordination for Purchasing Flexibility System Services: Challenges and Lessons Learned from a Demonstration in Sweden," *IEEE Transactions on Power Systems*, vol. 38, no. 2, pp. 1883–1895, Mar. 2023, DOI: 10.1109/TPWRS.2022.3188261.

[17] P. Barker, "Overvoltage considerations in applying distributed resources on power systems," in *IEEE Power Engineering Society Summer Meeting,*, vol. 1, Jul. 2002, pp. 109–114 vol.1, DOI: 10.1109/PESS.2002.1043188.

[18] U.S. Energy Information Administration, "Electric Power Annual 2023," Tech. Rep., Oct. 2024.

[19] Australian Energy Market Operator (AEMO), "The National Electricity Market Fact sheet," May 2025.

[20] CIGRE, "Benchmark Systems for Network Integration of Renewable and Distributed Energy Resources," Tech. Rep. 575, 2014.

[21] S. Y. Hadush and L. Meeus, "DSO-TSO cooperation issues and solutions for distribution grid congestion management," *Energy Policy*, vol. 120, pp. 610–621, Sep. 2018, DOI: 10.1016/j.enpol.2018.05.065.

[22] X. Hu, S. Yang, L. Wang, Z. Meng, F. Shi, and S. Liao, "Evaluation Method for Voltage Regulation Range of Medium-Voltage Substations Based on OLTC Pre-Dispatch," *Energies*, vol. 17, no. 17, p. 4494, Sep. 2024, DOI: 10.3390/en17174494.

[23] B. B. Navarro and M. M. Navarro, "A comprehensive solar PV hosting capacity in MV and LV radial distribution networks," in *2017 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe)*, Sep. 2017, pp. 1–6, DOI: 10.1109/ISGTEurope.2017.8260210.

[24] A. Thingvad, C. Ziras, G. L. Ray, J. Engelhardt, R. R. Mosbæk, and M. Marinelli, "Economic Value of Multi-Market Bidding in Nordic Frequency Markets," in *2022 International Conference on Renewable Energies and Smart Technologies (REST)*, vol. I, Jul. 2022, pp. 1–5, DOI: 10.1109/REST54687.2022.10023471.

[25] S. Ali and J. Mutale, "Reactive power management at Transmission/Distribution interface," in *2015 50th International Universities Power Engineering Conference (UPEC)*, Sep. 2015, pp. 1–6, DOI: 10.1109/UPEC.2015.7339816.

[26] S. Jupe, S. Hoda, A. Park, M. Wright, and S. Hodgson, "Active management of generation in low-voltage networks," *CIRED*, vol. 2017, no. 1, pp. 916–919, Oct. 2017, DOI: 10.1049/oap-cired.2017.0490.

[27] M. Z. Liu, L. F. Ochoa, P. K. C. Wong, and J. Theunissen, "Using OPF-Based Operating Envelopes to Facilitate Residential DER Services," *IEEE Transactions on Smart Grid*, vol. 13, no. 6, pp. 4494–4504, Nov. 2022, DOI: 10.1109/TSG.2022.3188927.

[28] Eon Energidistribution, "Hourly generation data for anonymized wind park module," Dataset, 2022.

[29] ENTSO-E, "Installed Capacity per Production Type, Sweden 2024," Dataset, 2025.

[30] Svenska kraftnät, "Statistik hela landet per månad, 2024," Dataset, 2025.

[31] D. Cevasco, S. Koukoura, and A. J. Kolios, "Reliability, availability, maintainability data review for the identification of trends in offshore wind energy applications," *Renewable and Sustainable Energy Reviews*, vol. 136, p. 110414, Feb. 2021, DOI: 10.1016/j.rser.2020.110414.

[32] IAEA, "Energy Availability Factor 2021-2023."

[33] Z. Csereklyei, "Price and income elasticities of residential and industrial electricity demand in the European Union," *Energy Policy*, vol. 137, p. 111079, Feb. 2020, DOI: 10.1016/j.enpol.2019.111079.

[34] M. Lave and A. Ellis, "Comparison of solar and wind power generation impact on net load across a utility balancing area," in *2016 IEEE 43rd Photovoltaic Specialists Conference (PVSC)*, Jun. 2016, pp. 1837–1842, DOI: 10.1109/PVSC.2016.7749939.

[35] W. Sun, S. Harrison, and G. Harrison, "Value of Local Offshore Renewable Resource Diversity for Network Hosting Capacity," *Energies*, vol. 13, p. 5913, Nov. 2020, DOI: 10.3390/en13225913.

[36] I. Konstantelos and G. Strbac, "Valuation of Flexible Transmission Investment Options Under Uncertainty," *IEEE Transactions on Power Systems*, vol. 30, no. 2, pp. 1047–1055, Mar. 2015, DOI: 10.1109/TPWRS.2014.2363364.

[37] X. Zhang and A. J. Conejo, "Coordinated Investment in Transmission and Storage Systems Representing Long- and Short-Term Uncertainty," *IEEE Transactions on Power Systems*, vol. 33, no. 6, pp. 7143–7151, Nov. 2018, DOI: 10.1109/TPWRS.2018.2842045.

[38] EIFS 2023:3, "Energimarknadsinspektionens föreskrifter och allmänna råd om krav som ska vara uppfyllda för att överföringen av el ska vara av god kvalitet," Regulation, 2023.

[39] Prabha Kundur, *Power System Voltage Stability*, international edition ed., ser. The EPRI Power Systems Engineering Series. McGraw-Hill Inc., 1994.

[40] K. Morozovska, "Dynamic Rating with Applications to Renewable Energy," Doctoral Thesis, Royal Institute of Technology, KTH, 2020, URN: urn:nbn:se:kth:diva-266363.

[41] J. Kosmač, A. Matko, F. Kropec, and A. Deželak, "Use of Dynamic Line Rating System in System Operation and Planning - Session Materials," in *CIGRE Paris Session*, 2020.

[42] IEEE Std C57.91-2011, "IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators," standard, Mar. 2012, DOI: 10.1109/IEEESTD.2012.6166928.

[43] Svenska kraftnät, Energinet, Fingrid, Statnett, Kraftnät Åland, "Nordic System Operation Agreement (SOA) – Annex Operational Security (OS)," 2019.

[44] Svenska kraftnät, Energinet, Fingrid, Statnett, "Nordic Capacity Calculation Region capacity calculation methodology in accordance with Article 20(2) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management," 2020.

[45] M. Swenman, M. Dalheim, C. Wallnerström, L. Sjöström, A. Emanuelsson, and S. Wikstedt, "Incentive scheme for efficient grid utilization and use of flexibility services," in *27th International Conference on Electricity Distribution (CIRED 2023)*, vol. 2023, Jun. 2023, pp. 1798–1801, DOI: 10.1049/icp.2023.1021.

[46] J. López Prol, K. W. Steininger, and D. Zilberman, "The cannibalization effect of wind and solar in the California wholesale electricity market," *Energy Economics*, vol. 85, p. 104552, Jan. 2020, DOI: 10.1016/j.eneco.2019.104552.

[47] Regeringen [The Government of Sweden], "Prop. 2023/24:105 energipolitikens långsiktiga inriktning," Bill, Mar. 2024.

[48] "GenX: a configurable power system capacity expansion model for studying low-carbon energy futures," Software. [Online]. Available: https://github.com/GenXProject/GenX)

[49] A. Ellis, R. Nelson, L. Casey, E. Seymour, W. Peter, C. Barker, B. Kirby, E. Von Engeln, R. Walling, and J. McDowell, "Reactive Power Interconnection Requirements for PV and Wind Plants – Recommendations to NERC," Sandia National Laboratories, Tech. Rep. SAND2012-1098, Feb. 2012.

[50] Carson W. Taylor, *Power System Voltage Stability*, international edition ed., ser. The EPRI Power Systems Engineering Series. McGraw-Hill Inc., 1994.

[51] A. Samadi, R. Eriksson, and L. Söder, "Evaluation of Reactive Power Support Interactions Among PV Systems Using Sensitivity Analysis," *Proc. 2nd International Workshop on Integration of Solar Power into Power Systems*, vol. 2012, pp. 245–252.

[52] I. Leisse, "Efficient integration of distributed generation in electricity distribution networks - voltage control and network design," Doctoral Thesis (monograph), Division for Industrial Electrical Engineering and Automation, Lund University, 2013, ISBN: 978-91-88934-63-5.

[53] S. Bolognani, R. Carli, G. Cavraro, and S. Zampieri, "On the Need for Communication for Voltage Regulation of Power Distribution Grids," *IEEE Transactions on Control of Network Systems*, vol. 6, no. 3, pp. 1111–1123, Sep. 2019, DOI: 10.1109/TCNS.2019.2921268.

[54] Standards Australia, Standards New Zealand, "As/nzs-4777-2:2020, grid connection of energy systems via inverters, part 2: Inverter requirements," 2020.

[55] A. Eggli, S. Karagiannopoulos, S. Bolognani, and G. Hug, "Stability Analysis and Design of Local Control Schemes in Active Distribution Grids," *IEEE Transactions on Power Systems*, vol. 36, no. 3, pp. 1900–1909, May 2021, DOI: 10.1109/TPWRS.2020.3026448.

[56] IEEE Std 1547-2018, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," Standard, Apr. 2018, DOI: 10.1109/IEEESTD.2018.8332112.

[57] S. Allahmoradi, S. Afrasiabi, X. Liang, J. Zhao, and M. Shahidehpour, "Data-Driven Volt/VAR Optimization for Modern Distribution Networks: A Review," *IEEE Access*, vol. 12, pp. 71 184–71 204, 2024, DOI: 10.1109/ACCESS.2024.3403035.

[58] "Regulation - EU - 2024/1747."

[59] R. J. Hennig, L. J. de Vries, and S. H. Tindemans, "Congestion management in electricity distribution networks: Smart tariffs, local markets and direct control," *Utilities Policy*, vol. 85, p. 101660, Dec. 2023, DOI: 10.1016/j.jup.2023.101660.

[60] International Renewable Energy Agency (IRENA), "Virtual power lines," Abu Dhabi, Tech. Rep., 2020.

[61] M. Lindner, J. Peper, N. Offermann, C. Biele, M. Teodosic, O. Pohl, J. Menne, and U. Häger, "Operation strategies of battery energy storage systems for preventive and curative congestion management in transmission grids," *IET Generation, Transmission & Distribution*, vol. 17, no. 3, pp. 589–603, 2023, DOI: 10.1049/gtd2.12739.

[62] CIGRE, "Distributed Energy Resource Benchmark Models for Quasi- Static Time-Series Power Flow Simulations," Tech. Rep. 906, Jun. 2023.

[63] M. Johansson, "Piecewise Linear Control Systems," Doctoral Thesis (monograph), Department of Automatic Control, Lund University, 1999.

[64] E. Demirok, D. Sera, R. Teodorescu, P. Rodriguez, and U. Borup, "Evaluation of the voltage support strategies for the low voltage grid connected PV," in *Proceedings of the IEEE energy conversion congress and expo, ECCE 2010*. IEEE Press, Sep. 2010, pp. 710–717, DOI: 10.1109/ECCE.2010.5617937.

[65] L. Vanfretti, S. H. Olsen, V. S. N. Arava, G. Laera, A. Bidadfar, T. Rabuzin, S. H. Jakobsen, J. Lavenius, M. Baudette, and F. J. Gómez-López, "An open data repository and a data processing software toolset of an equivalent Nordic grid model matched to historical electricity market data," *Data in Brief*, vol. 11, pp. 349–357, Apr. 2017, DOI: 10.1016/j.dib.2017.02.021.

[66] Svenska kraftnät, "Karta över transmissionsnätet," 2025.

Scientific publications

Author contributions

Paper I: Alternative network development – need for flexible solutions for operation and planning of distribution and transmission grids

The strategy for sequential control of reactive and active power was jointly developed by M. Lundberg and O. Samuelsson based on a concept provided by O. Samuelsson. Case study simulations were performed by M. Lundberg. The definition of active network management was jointly formulated by M. Lundberg, E. Hillberg, and O. Samuelsson. E. Hillberg was the main author of sections 1-3, and M. Lundberg the main author of section 4.

Paper II: Local voltage control in distribution networks using PI control of active and reactive power

The main concept of **Paper II** builds on the initial study in **Paper I**. M. Lundberg formulated the local voltage control strategy under discussions with O. Samuelsson. M. Lundberg developed the piecewise linear system model, and provided the stability and performance analysis. The simulation case study was developed by M. Lundberg after discussions with O. Samuelsson and E. Hillberg. The manuscript was fully authored by M. Lundberg, with inputs and review by O. Samuelsson and E. Hillberg.

Paper III: Congestion management in distribution systems with large presence of renewable energy sources

The congestion management and reactive power limitation strategies were developed by M. Lundberg, including the sequential activation of flexibility resources. The merit-order based activation according to PTDFs was proposed by O. Samuelsson. The simulation case study was developed by M. Lundberg. The operation and planning toolbox was developed by M. Mirz with support from M. Lundberg. The manuscript was authored by M. Lundberg, with contributions from M. Mirz to section 5 and review by O. Samuelsson, E. Hillberg, and N. Hancock.

Paper IV: Decentralized control of virtual power lines for increased transfer capacity

M. Lundberg developed the virtual power line control strategy and formulated the dynamic ESS model, and the PTDF-based system model. The simulation case study was made by M. Lundberg under discussions with O. Samuelsson and E. Hillberg, with conceptualizing the use of virtual power lines during contingency events. The manuscript was fully authored by M. Lundberg, with inputs and review by O. Samuelsson and E. Hillberg.

Paper V: Robust capacity expansion planning in hydro-dominated power systems: a Nordic case study

Work on developing the cGrid model and the Nordic case study was led by A. Såmark-Roth and C. Hellesen. All co-authors provided inputs for the Nordic case study, which for M. Lundberg included provision of transmission network data. M. Lundberg contributed to the writing and reviewing the manuscript.

Printed by Media-Tryck, Lund 2025 NORDIC SWAN ECOLABEL 3041 0903

LUND UNIVERSITY

Division of Industrial Electrical Engineering and Automation
Department of Biomedical Engineering
Faculty of Engineering

ISBN 978-91-985110-7-9
CODEN: LuTEDx/(TEIE-1101)/1-160/(2025)

9 789198 511079