



Integrated Power-Telecom Modeling for Resilience Quantification and Optimization in Smart Distribution Grids

Youba Nait Belaid

► To cite this version:

Youba Nait Belaid. Integrated Power-Telecom Modeling for Resilience Quantification and Optimization in Smart Distribution Grids. Electric power. Université Paris-Saclay, 2023. English. NNT : 2023UPAST120 . tel-04473863

HAL Id: tel-04473863

<https://theses.hal.science/tel-04473863>

Submitted on 22 Feb 2024

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.

Integrated Power-Telecom Modeling for Resilience Quantification and Optimization in Smart Distribution Grids

*Modélisation Intégrée Electrique-Télécom pour la
Quantification et l'Optimisation de la Résilience des
Réseaux Electriques Intelligents*

Thèse de doctorat de l'université Paris-Saclay

École doctorale n°573 Interfaces : Matériaux, Systèmes, et Usages

Spécialité de doctorat : Ingénierie des Systèmes Complexes

Graduate School : Sciences de l'Ingénierie et des Systèmes

Référent : CentraleSupélec

Thèse préparée dans le Laboratoire Génie Industriel (Université Paris Saclay, CentraleSupélec) et Electricité de France R&D, sous la direction de **Anne BARROS**, Professeure, la co-direction de **Yi-Ping FANG**, Professeur, la co-direction de **Zhiguo ZENG**, Professeur, et l'encadrement de **Patrick COUDRAY**, Chercheur Expert.

Thèse soutenue à Paris-Saclay, le 18 Septembre 2023, par

Youba NAIT BELAID

Composition du jury

Membres du jury avec voix délibérative

Hiba BAROUD

Assistant Professor, Vanderbilt University

Poul Einar HEEGAARD

Professor, Norwegian University of Science & Technology

Mathaios PANTELI

Assistant Professor, University of Cyprus

Guillaume SANDOU

Professeur, CentraleSupélec, Université Paris Saclay

Giovanni SANSAVINI

Professor, ETH Zürich

Présidente et Examinatrice

Rapporteur & Examineur

Rapporteur & Examineur

Examineur

Examineur

To Belkacem Nait Belaid, my beloved father and role model.

Acknowledgment

First and foremost, I express my heartfelt appreciation to my PhD advisors at University Paris Saclay - Laboratory of Industrial Engineering, Prof. Anne Barros, Prof. Yiping Fang, and Prof. Zhiguo Zeng; for their unparalleled mentorship, invaluable insights, and continuous encouragement. Their expertise, patience, dedication, and sharing of life-experience have been an inspiration for my growth as a person and a researcher. It has been a privilege to be part of the amazing research group led by Prof. Anne Barros - Risk, Reliability, and Resilience (R^3); conveying here my admiration to its dedicated members for their collaborative spirit and tireless research efforts. The synergy within our team has been a driving force, and I am fortunate to have worked alongside such bright minds and authentic souls.

I am immensely grateful to Patrick Coudray and José Sanchez-Torres for initiating this PhD project, consistently having faith in me, and offering continuous guidance with utmost kindness. My warmest thanks to Grégory Michel, Anthony Legendre, and all members of R48-R4F group at EDF R&D for their unwavering support. I extend my thanks to Enrique Kremers (ElfER, IABG), Jean-Marc Do Livramento, Emmanuel Villalta, Mariam Ait-Ou-Kharraz, and Maryse Le Jeune (Enedis) for providing a unique perspective and real-world insights that enriched my research. Their wealth of experience and commitment to bridging the gap between academia and industry has helped to shape the practical implications of my work.

My sincere appreciation goes to the distinguished jury members, committee president Dr. Assist. Prof. Hiba Baroud, reviewers Prof. Poul Einar Heegaard and Dr. Assist. Prof. Mathaios Panteli, as well as esteemed examiners Prof. Guillaume Sandou, Prof. Giovanni Sansavini, and Mr. Jean-Marc Do Livramento. I appreciate their time, expertise, and thought-

ful feedback during the defense process. Their constructive critiques and insightful suggestions have significantly contributed to the refinement and strengthening of this work.

I would like to acknowledge EDF R&D, the Chair Risk and Resilience of Complex Systems, Institute RISEGrid, and the Laboratory of Industrial Engineering for providing me with an exceptional setting of intellectual and financial support to pursue this research with dedication and focus. My warmest feelings to all supporting staff, colleagues, and fellow PhD students at these institutions.

Finally, I owe a debt of gratitude and a word in Tamazight to my mom and siblings - *tanmirt s tusda i yemma ezizen atas "Daouya" tafat n tudert-iw; yessetma iyi-d yemlan abrid Ouerdia, Malha, Sylina, Dihia; akk d watmaten-iw yellan ar tuyat-iw Dada Achour, Dada Madjid, Mohand Ouamer* : your encouragement and belief in my abilities have been a source of inspiration, my deepest gratitude for the love and understanding you showed me since ever. My special recognition extends to Sofiane, Fatma, Aris, Nelya, Hafidh, Maylis and Samira, as well as my dear friends for their relentless support during this challenging endeavor.

To all those mentioned and the countless others who have played a role from near or far, Thank you !

Abstract

Recent years have seen the power grid continue evolving through the introduction of information and communication technologies (ICTs) that enable a whole new package of functionalities such as automated control, smart metering, demand optimization, fault detection, and asset availability. Yet, as the grid is transforming from a traditionally one-way power flow (PF) and limited-control system into a two-way PF, intelligent, and mesh networked system; the resultant smart grid can guarantee improved service for all connected loads, although at the expense of increased complexity. As a result, grid reliability and resilience are highly challenged, especially at the distribution level due to increased vulnerabilities and limited recovery and restoration resources.

This dissertation proposes two modeling approaches to quantify the resilience of smart grids taking into account power-telecom interdependencies. First, a model based on complex network (CN) theory is proposed to capture the operation of the interdependent power-telecom system, track the impact of events including failure propagation, and most importantly optimize the allocation of recovery resources to achieve the best level of resilience with minimal costs. As the standpoint of a power operator is adopted, considered resources include: fast reconfiguration using remote switches, manual operation of switches by technicians, repair by specialized crews, and mobile distributed-generators placement. Second, this work is extended using agent-based modeling (ABM) and discrete-events (DE) to account for more complex system dynamics (hardly tractable analytically), such as battery discharge, crew displacement in roads, and communication messages. The resulting hybrid CN-ABM-DE model serves as an environment to evaluate the solution from the initial optimization and enhance it.

Overall, the coupling between resilience resources is leveraged to coordinate the allocation using the telecommunication network, which exhibits many cyber-physical interdependencies with the power domain. Different applications in realistic settings are introduced to investigate the contribution of information and communication technologies (ICTs) to grid management and restoration operations. Major results highlight the enhancement in the grid resilience brought by communication-aware restoration and co-optimization of resilience resources, as well as demonstrate the applicability of the proposed framework for resilience quantification.

Résumé

Le réseau électrique continue d'évoluer grâce à l'introduction des technologies de l'information et de la communication (TIC) qui permettent un tout nouvel ensemble de fonctionnalités telles que le contrôle automatisé, le comptage intelligent, l'optimisation de la demande, la détection des pannes, et la supervision de la disponibilité des actifs. Ceci contribue au passage d'un système électrique à flux de puissance (Power Flow - PF) traditionnellement unidirectionnel avec un contrôle limité, en un système bidirectionnel, intelligent, et maillé. Le réseau intelligent qui en résulte peut garantir un service amélioré pour toutes les charges connectées au prix d'une complexité accrue. En conséquence, la fiabilité et la résilience du réseau sont fortement mises à l'épreuve, en particulier au niveau de la distribution en raison des vulnérabilités élevées et des ressources de remise en service assez limitées.

Cette thèse propose deux approches de modélisation pour quantifier la résilience des réseaux électriques intelligents en tenant compte des interdépendances électricité-télécom. Tout d'abord, un modèle basé sur la théorie des réseaux complexes (Complex Network - CN) est proposé pour décrire le fonctionnement du système interdépendant électricité-télécom, suivre l'impact des événements, y compris la propagation des pannes, et surtout optimiser l'affectation des ressources de remise en service pour un meilleur niveau de résilience à moindre coût. Le point de vue d'un opérateur électrique est adopté, et les ressources envisagées incluent: la reconfiguration rapide à l'aide d'interrupteurs télécommandés, la manoeuvre des interrupteurs manuels par techniciens, la réparation par des équipes spécialisées, et le dépôt de groupes électrogènes. Ce travail est étendu à l'aide de la modélisation à base d'agents (Agent-based Modeling - ABM) et des événements discrets (Discrete-Events - DE) pour tenir compte de dynamiques plus complexes du système (difficilement traitables analytiquement), telles que la décharge de la batterie, le déplacement des équipes sur les routes, et les communications. Le modèle hybride CN-ABM-DE qui en résulte sert d'environnement pour évaluer la solution à partir de l'optimisation initiale et l'améliorer.

Globalement, le couplage entre les ressources de résilience est mis à profit pour coordonner l'affectation en prenant en compte la couche télécom, qui présente de nombreuses interdépendances cyber-physiques avec la couche électrique. Différentes applications en contexte réel sont introduites pour étudier la contribution des technologies de l'information et de la communication (TIC) à la gestion du réseau et aux opérations de reprise. Les principaux résultats mettent en évidence l'amélioration de la résilience du réseau apportée par la remise en service sensible aux télécoms et la co-optimisation des ressources de

résilience, et démontrent l'applicabilité du cadre proposé pour la quantification de la résilience.

Contents

List of Figures	12
List of Tables	13
Acronyms	14
Nomenclature	16
Appended Papers	19
1 Introduction	20
1.1 Problem Statement and Research Questions	21
1.2 Literature Review and Research Gap	22
1.3 General Contributions	23
1.3.1 System modeling	23
1.3.2 Optimization	24
1.3.3 Simulation	24
1.3.4 Resilience Analysis	25
1.4 Thesis Organization	25
2 Integrated Modeling of Smart Distribution Grids	28
2.1 Distribution Grid Operation	28
2.2 Complex Network Theory and Flow-based Model	30
2.2.1 Interdependence	31
2.2.2 Telecom Availability	34
2.2.3 Grid Failure Propagation	35
2.2.4 Radiality	38
2.2.5 Power Flow	39
2.2.6 Dispatch of Intervention Crews	40

2.3	Model Extension: Agent-based and Discrete-Events	41
2.3.1	Model Layout	43
2.3.2	Telecom Service	44
2.3.3	Power Supply Analysis	46
2.3.4	Crew Interventions	46
2.3.5	Model Consistency	47
2.4	Summary	49
3	Telecom-aware Optimization of Distribution System Restoration	50
3.1	Optimization of Distribution System Restoration	50
3.1.1	Resilience-based Objective	52
3.1.2	Key Constraints	54
3.1.3	Solution Methodology	57
3.2	Example Case Study	58
3.2.1	System Setting	58
3.2.2	Results and Discussion	58
3.3	Summary	60
4	Improved Distribution System Restoration using Hybrid Modeling	61
4.1	Sensitivity Analysis	62
4.2	Solution Evaluation Under Uncertain Repair Time	64
4.3	Solution Enhancement	65
4.3.1	Simulation Model	66
4.3.2	Optimization Model	67
4.3.3	Iterative Algorithm	67
4.4	Summary	68
5	Applications	70
5.1	Telecom-aware Optimal Planning and Restoration	70
5.1.1	Planning new RCS Deployments for Faster Response	70
5.1.2	Restoration in Larger-Scale Distribution Grids	74
5.2	Grid-scale Simulation	78
5.2.1	Service Level Agreement Definition	78
5.2.2	Grid Monitoring and Resource Sizing	83
5.3	Summary	89

6 Conclusion	90
Appendix A	93
Appendix B	93
Bibliography	104

List of Figures

1.1	Summary of thesis contributions	26
2.1	Smart grid applications (adapted from [42])	29
2.2	Power-telecom architecture of a smart distribution grid	30
2.3	The smart grid as a cyber-physical system	31
2.4	Mixed graph for the smart distribution grid	33
2.5	Resulting zones due to failure propagation and grid fast response (before reconfiguration)	35
2.6	Snapshot from the french MV distribution grid (DSO Open Data)	36
2.7	Failure propagation in power distribution networks	37
2.8	Simplified representation of a MV-LV substation in networks with a series configuration	37
2.9	Layout of the extended simulation model	43
2.10	Battery model	46
2.11	Repair crew assignment	47
2.12	Grid configuration after fast response	48
2.13	Gantt chart for the schedule of intervention crews on damaged lines	48
2.14	Evolution of supplied power during distribution system restoration	49
3.1	Summarized interactions in the proposed model for the SDG	51
3.2	Layout of the proposed restoration model	53
3.3	Illustration of key steps in the distribution system restoration for full-overhead telecom-aware case	59
3.4	Evolution of supplied power during distribution system restoration	60
4.1	Gantt chart for the schedule of repair crews on damaged lines	62
4.2	MILP solution sensitivity to repair time	63
4.3	Performance comparison of the MILP solution	64
4.4	Repair sequence from MILP solution implementation by the simulation model	65

4.5	Layout of the hybrid optimization approach	66
5.1	Test case with 36 power nodes and 7 telecom points [5]	72
5.2	Evolution of restoration in terms of supplied power under different budgets	74
5.3	Steps of data processing for realistic use-case construction	75
5.4	Evolution of supplied power during DSR	77
5.5	A 141-bus system with 5 damages	80
5.6	Supplied power under different restoration conditions	81
5.7	Repair timeline of damaged lines	82
5.8	A 49 primary substations system with 156 damages	84
5.9	Used log-normal distribution of repair time (h), $\mu = 1.1$ and $\sigma = 0.5$	85
5.10	Simulation run with 3 repair crews at each depot	87
5.11	Objective evolution over simulation iterations	88
1	Crew schedule for the telecom-aware case in a 141-bus system	96

List of Tables

2.1	Description of considered agents	45
3.1	MILP solution time using warm-starting for a generic case (141-bus, 6 faults)	58
4.1	Parameter settings for DSR use-case	63
4.2	Repair time setting	63
5.1	Supplied power considering new-RCS deployment with varying budget B and number of telecom damages = 3	73
5.2	Parameter settings for DSR use-cases	76
5.3	Repair time setting	76
5.4	Average MV outage duration incentive-penalty calculation [113]	79
5.5	Case study parameters	86
5.6	Solution comparison for varied number of replications	88

Acronyms

LV : Low Voltage

MV : Medium Voltage

HV : High Voltage

MILP : Mixed-Integer Linear Programming

ABM : Agent-Based Modeling

FLISR : Fault Location, Isolation, and Service Restoration

DSR : Distribution System Restoration

ICT : Information and Communication Technologies

PF : Power Flow

CN : Complex Network

DE : Discrete-Events

TS : Telecom Service

CI : Critical Infrastructure

EPS : Electrical Power System

SDG : Smart Distribution Grid

CPS : Cyber Physical Systems

HILP : High Impact Low Probability

DG : Distributed Generators

OT : Operation Technology

GIS : Geographical Information System

IT : Information Technology

IED : Intelligent Electronic Device

SW : Switch

AggP : Aggregation Point

AP : Access Points

WAN : Wide-Area Network

U-AP : Utility-owned Access Point
F-AP : Fixed Access Point
W-AP : Wireless Access Point
SCF : Single Commodity Flow
DLF : Directed Local Flow
AC-OPF : AC Optimal Power Flow
CS-CT : Continuous-State Continuous-Time
DS-CT : Discrete-State Continuous-Time
CC : Control Center
OSM : OpenStreetMap
RC : Repair Crew
MC : Manual switching Crew
SLA : Service Level Agreement
SoC : State-of-Charge
GT : DG placement Time
ACR : Auto-recloser or automatic Circuit Recloser
MT : Manual switching Time
GC : DG Placement Crew

Nomenclature

Indices

c, e Index of communication, electric service, respectively

Parameters

GT_g DG placement time at bus g

M Large number

MT_l Manual switching time of damage l

r_{ij} Resistance of line (i, j)

Res^{dp} Repair resources available at depot dp

Res_l Demand of repair resources from faulted line l

RT_l Repair time of damage l

s_i Binary parameter. 1 if i is a SS, 0 otherwise

TT_{lm} Travel time from l to m (depot, line, or bus)

x_{ij} Reactance of line (i, j)

Sets

DP Set of depots

F Set of failed power lines

F^o Set of failed overhead lines

F^u Set of failed underground lines

GC Set of DG placement crews

L	Set of all lines
L^m	Set of manual switchable lines
L^r	Set of remote switchable lines
L^u	Set of underground lines
L^{ar}	Set of auto-reclosing lines
L^{cb}	Set of circuit-breaking lines
MC	Set of manual switching crews
N	Set of all power nodes (HV/MV SS, MV buses)
$n(j)$	Set of neighbor nodes of node j
$n_m(l)$	Set of neighbor manual lines of line l
RC	Set of repair crews
S	Set of HV/MV Substations (SS)
U	Set of utility-owned access points
W	Set of Wireless access points
X	Set of fiXed access points

Variables

$a_{i,t}^e$	1 if bus i is available at t , 0 otherwise
$a_{i,t}^{dg}$	1 if a DG is available at bus i at t , 0 otherwise
$a_{ij,t}$	1 if line $l = (i, j)$ is available at t , 0 otherwise
$b_{i,t}$	1 if AP battery i is not empty at t , 0 otherwise
$d_{ij,t}$	1 if power flows from i to j at t , 0 otherwise
$E_{i,t}$	Energy storage of the battery at node i at t
$gc_{n,t}^{dp,k}$	1 if bus n is under DG-placement by crew k of depot dp at time t , 0 otherwise
$mc_{l,t}^{dp,k}$	1 if line l is under manual switching by crew k of depot dp at time t , 0 otherwise

$p_{i,t}^{dg}, q_{i,t}^{dg}$ Active, reactive DG power at node i at t , resp.

$p_{i,t}^{ns}, q_{i,t}^{ns}$ Loss of active, reactive load at node i at t , resp.

$p_{ij,t}, q_{ij,t}$ Active, reactive power flow of line (i, j) at t , resp.

$rc_{l,t}^{dp,k}$ 1 if line l is under repair by crew k of depot dp at time t , 0 otherwise

$ss_{i,t}^c$ 1 if TS of a SS i is available at t , 0 otherwise

$sw_{ij,t}$ 1 if directed switch (i, j) is closed at t , else 0

$sw_{l,t}$ 1 if switch at $l = (i, j)$ is closed at t , else 0

$T_{i,t}^c$ 1 if TS from the operator access point i is available at t , 0 otherwise

$T_{i,t}^e$ 1 if electricity supply for the operator access point i is available at t , 0 otherwise

$u_{i,t}^c$ 1 if telecom service (TS) from utility-owned access point i is available at t , 0 otherwise

$v_{i,t}$ Voltage magnitude at node i

$y_{i,t}^e$ 1 if bus i is energized at t , 0 otherwise

$y_{i,t}^{dg}$ 1 if a DG is connected at bus i at t , 0 otherwise

Appended Papers

Journals

- Paper [1]: Youba Nait Belaid, Patrick Coudray, José Sanchez-Torres, Yiping Fang, Zhiguo Zeng, Anne Barros. “Resilience Quantification of Smart Distribution Networks—A Bird’s Eye View Perspective”. In: *Energies* 14.10, MDPI, Jan. 2021.
- Paper [2]: Youba Nait Belaid, Yiping Fang, Zhiguo Zeng, Anthony Legendre, Patrick Coudray, Anne Barros. “Resilience Optimization of Wide-Area Control in Smart Distribution Grids”. In: *IFAC-PapersOnLine*, 2405-8963, Jan. 2022.
- Paper [3]: Youba Nait Belaid, Yiping Fang, Zhiguo Zeng, Patrick Coudray, Anne Barros. “Optimal Allocation of Resilience Resources for Strategic Communication-aware Restoration of Smart Distribution Grids”. Under review at: *IEEE Journal of Modern Power Systems and Clean Energy*.
- Paper [4]: Youba Nait Belaid, Yiping Fang, Enrique Kremers, Zhiguo Zeng, Patrick Coudray, Anne Barros. “On the Implementation and Enhancement of Optimal Deterministic Crew Schedules during Smart Distribution Grid Restoration”. Under review at: *Elsevier Journal of Sustainable Energy, Grids, and Networks*.

International Conferences

- Paper [5]: Youba Nait Belaid, Anne Barros, Yiping Fang, Zhiguo Zeng, Anthony Legendre, Patrick Coudray. “Enhanced Power and Communication Modeling in Cyber-Physical Distribution Grids for Resilience-based Optimization”. In: *European Safety and Reliability Conference (ESREL)*, Dublin, Aug. 2022.
- Paper [6]: Youba Nait Belaid, Yiping Fang, Zhiguo Zeng, Patrick Coudray, Anne Barros. “Restoration Modeling and Optimization of Hybrid Overhead-Underground Power Distribution Systems”. In: *IEEE Innovative Smart Grid Technologies (ISGT)*, Washington, Jan. 2023.

Chapter 1

Introduction

Emergence of complex engineered systems crafted the relative welfare in modern society by providing essential services and ensuring the availability of vital resources. Such systems are commonly referred to as critical infrastructures (CIs). The electric power system (EPS) is a prominent example of a large-scale CI providing power supply services to residential, commercial, and industrial customers; as well as supporting the operation of other CIs like non-electric power systems, telecommunication networks, water systems, transportation systems, financial services, health facilities, etc. At the same time, the power grid is dependent on some CI systems, among which the telecom network is probably the most influential [7] given the intensive connectivity in the generation, transmission, and distribution levels, alongside many communication-dependent grid tasks such as monitoring, measurement, control, or even local and global decision-making.

Telecommunications are introduced in the grid as a major technological leap to unlock a whole new package of applications that render the grid flexible, cost-effective, more efficient, and highly reliable [8, 9, 10]. However, all these communication-brought advantages induce an unprecedented complexity that outrun the pace with which grid practitioners can analyze, seize, and manage the evolution of the smart grid. Then, despite that complexity-caused vulnerabilities can be misleadingly hidden at nominal operation, they clearly appear at episodes of extreme events (cyber-attacks, natural hazards, man-made errors, etc) [11, 12], compromising power supply and the entire grid reliability.

Interestingly, the legacy metrics for grid reliability are often set to ignore the impact of extreme events, urging the need for adequate extensions and more recently the introduction of the resilience paradigm [13, 14]. Resilience is “the ability to prepare and plan for, absorb, recover from, or more successfully adapt to actual or potential adverse events” [15]. The dynamics and resources of response, adaptability, and restoration are tracked in

resilience studies with recommended problem handling through system modeling. Thus, for the specific case of smart grid resilience, information and communication technologies (ICTs) need to be integrated in the modeling for resilience assessment and attendant tools [16].

The major challenge with smart grids is to guarantee a resilient telecom service in a context where this same telecom network is dependent on power supply, yielding a two-way interdependence. This is even more problematic at the distribution level of the grid, which integrates most of the new grid applications, while being inherently more vulnerable [17]. The work in this dissertation concentrates then on the smart distribution grid (SDG), which is very representative of the whole electric system and many industrial cyber physical systems (CPSs) in terms of power-telecom interdependencies.

1.1 Problem Statement and Research Questions

Distribution system operators (DSOs) invest in many communication technologies and architectures to better connect their assets, but still observe significant flaws in the provided telecom service. This is accentuated during high impact low probability (HILP) events where the power-telecom interdependencies are at the peak. More precisely, the grid needs the telecom service to operate remote switches from the control center, communicate with repair/isolation crews, guide the deployment of distributed generators, and above all coordinate the assignment of aforementioned restoration resources. Conversely, the telecom network depends on the grid for its power supply, despite some battery autonomy. **The first research question of this dissertation is consequently: How could we build a tractable model to include power-telecom interdependencies and represent the smart grid during a crisis management situation?**

Current DSO restoration strategies and tools do not integrate the availability of the telecom service and tend to separately plan the restoration resources at hand. Additionally, although some conceptual frameworks and implementable models are proposed for resilience-based co-optimization, very few tools claim the ability to handle the resilience of interdependent power-telecom systems. **The second research question is: What could be the benefit of strategically recovering power supply to telecom points during restoration?**

Moreover, for the distribution system restoration, some works proposed mathematical programming problems that yield in most cases some optimal solutions. The deterministic

nature of the formulated problems poses the question of knowing the extent to which the optimal solution can perform well in a more realistic system. **The third research question is: How could we improve a solution from a deterministic model to well perform in detailed, more complex, and probably stochastic systems ?**

1.2 Literature Review and Research Gap

Distribution grids have been around for many decades, never stopped gaining importance in the modern world, and are set to play a major role in the current and upcoming energy transition challenges [18]. A growing body of literature attempts to bring answers and guidelines for further investigation of the important research questions formulated in the previous section.

Paper [1] offers a detailed perspective on the quantification methods of the SDG resilience under harsh disruption conditions. A major insight pinpoints *system modeling* as the main enabler for resilience quantification [19, 20]. Only a modest number of models address the resilience of interdependent power-telecom smart grids [21, 22, 23], which calls for more efforts in this direction [11, 24]. The main sought benefits are to better understand and predict the behavior of the SDG, as well as integrate the contribution of ICTs to grid resilience during crisis situations [20].

Resilience quantification can be conducted at precise moments in time depending on the objective and targeted applications. Traditionally, as resilience deals with the post-event stage, reactive assessment is adopted taking into account the latest available information on the event for real-time response to support grid survivability and accelerate recovery operations [25]. As approaches evolved towards a broader application of resilience, opportunity was identified in including pre-event actions to proactively foresee possible threats and adapt the power grid planning to include resilience-enabling actions [26]. The two approaches are important and complementary, but it can be observed that anticipatively dealing with a multitude of uncertainties can be very challenging, and the expensive planning stage resources (e.g. hardening lines, new deployments, etc.) serve more the survivability component of resilience than the restoration component. In that regard, assessing resilience at real-time can benefit from some revealed uncertainties and leverage the under-exploited potential of relatively cheaper resources to boost the restoration [27]. Many works concentrated on the restoration process (as will be detailed in Chapter 3) by designing advanced models not only for resilience assessment but also

for resilience-based optimization [28, 29, 30, 31]. The lacking aspect is to include the power-telecom interdependencies as attempted by authors in [32, 33, 34].

Furthermore, developed resilience-based optimization models are mostly deterministic [35, 36]. This is in one hand justified by the realization of many uncertainties at the post-event stage, but also imposed by an increased computational burden of a restoration optimization under uncertainty [37]. Two interrogations can be raised from this observation: i) Some parameters of the restoration problem remain uncertain even at post-event stage, how does this affect the performance of the solution from the deterministic model? ; ii) If an optimal solution under uncertainty is computationally prohibitive (especially when introducing many telecom-related integer variables), is there a way to (at least) improve the performance of the deterministic solution?. No effort was conducted in the context of SDG restoration to tackle this problem.

1.3 General Contributions

The present work adds to the smart grid existing literature in many aspects that may be broadly classified into four contribution axes: system modeling, optimization, simulation, and resilience analysis.

1.3.1 System modeling

The conducted literature review in Paper [1] identifies many gaps in smart grid modeling with no or partial consideration of power-telecom interdependencies. The models presented in Chapter 2 tackle this issue by integrating purely power, purely telecom, and hybrid power-telecom components of the smart distribution grid. Common system details are kept with their standard formulation (power flow, switch operation) or revisited for better performance in the proposed model (failure propagation, conductor type, and radiality).

The demonstration of the integrated modeling is conducted throughout the thesis using the distribution system restoration (DSR) function, which has the characteristic of involving power-telecom interdependencies while often resorting to resilience analysis due to crisis management situations under extreme events. For that reason, restoration resources (denoted also as *resilience resources* in some parts) are captured and jointly optimized in Chapter 3. Considered resources involve remote switches, repair crews, mobile distributed generators (DGs), and novel introduction of manual switches (and their operation by specialized crews).

1.3.2 Optimization

The current work aims to be prescriptive in order to help decision makers during crisis management situations. This is achieved through an optimization formulation where power supply is opportunistically restored to telecom points, which contribute to the acceleration of the whole grid restoration process. The formulation is kept tractable for medium size distribution grids through appropriate modeling choices and linearization.

1.3.3 Simulation

The DSR optimization problem is recognized in this part not to be the deterministic optimization model, but rather the performance of the system evaluated using the real system (if available) or simulation [38, 39]. We put forward a simulation proposal for the DSR problem emphasizing in system details of interest to our study such as battery evolution, crew displacement in roads, and communication messages. The simulation is used to evaluate the solution of the deterministic optimization model in a more detailed description of the system.

One can argue that the simulation is just another modeling of the system and it could be meaningless to test a solution from one model in another one. The stand we take in this is that, as long as the performance measure calculations (e.g. supplied power) in the simulation model are proven to give consistent results with the deterministic model, the extended details in other parts of the model (battery, road, telecoms, etc.) do not invalidate the comparison. Indeed, if each model is set differently and evaluates the performance in different ways (and possibly different scales), it would be not interesting or even impossible to compare the performance of an optimization solution. However, if for a given baseline, the two models have equivalent performances, this guarantees that the simulation model will give meaningful performance of the considered optimization solution.

The investigation is pushed further by conducting sensitivity analysis on important parameters and designing a simulation-optimization methodology to enhance the performance of the initial solution in a more detailed system. Again, the simulation may not be the real system, but the developed approach is intended for use with the best system representation at disposal.

1.3.4 Resilience Analysis

The widely used performance-based resilience quantification [40, 41] is adopted, where the performance measure is grid-oriented following a distribution system operator perspective. This allows to construct the so-called *resilience curve* to track the evolution over time of the defined performance measure. Then, resilience metrics like the area under the curve, the degradation slope, restoration time, and rate of recovery can be computed [26]. Many phases are distinguished in the literature, which we synthesize in Figure 1.1 with four main phases and complementary prevention and learning.

Paper [1] highlights the relative maturity of resilience as a concept in power systems compared to telecom networks, where the power system research community builds upon well-established grid reliability analyses, with all associated methods, metrics, standards, and tools. The telecom networks have comparable history of reliability analysis, but evolve at a much faster pace since their massive adoption in late 20th century. In addition, a wide heterogeneity of technologies, architectures, and network layers add difficulty to reliability analysis because of different failure modes and dominantly non-linear dependencies. To catch up on this lag, the state of the telecom network contributes in our analysis to the construction of the resilience curve by serving grid assets connectivity and coordinating restoration operations. The resilience quantification is conducted at post-contingency stage with more focus on the restoration process where ICTs contribute the most.

1.4 Thesis Organization

The present dissertation is organized in two parts, where the association between the chapters in Part I and the appended papers in Part II is shown in Figure 1.1, according to resilience phases and application topics.

Part I

Contains six chapters that present the flow of the conducted research work from motivation, problem definition, methodology description, to results and insights;

Chapter 2, describes two integrated power-telecom model for the smart distribution grid. The former is based on complex network theory and power flow dynamics, while the later is an extension using agent-based modeling and discrete-events. A consistency check is conducted to prove the existing equivalence between the two model when the same parameters are used.

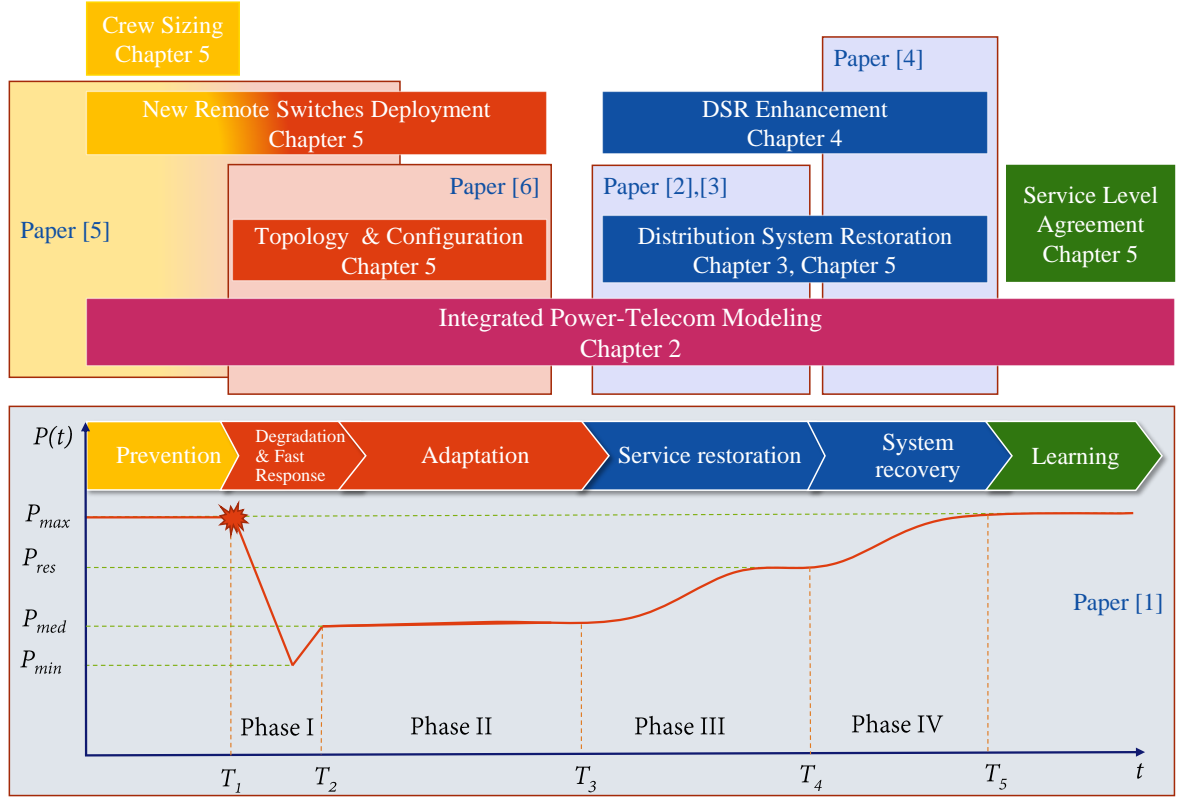


Figure 1.1: Summary of thesis contributions

Chapter 3, delves into the formulation of a MILP co-optimization problem for the allocation of resilience resources during the DSR. Telecom points are considered in order to check for strategic choices that allow restoring the grid faster. The model is linearized and solved by an out-of-the-shelf MILP solver (CPLEX).

Chapter 4, uses the second model from Chapter 4 to evaluate the solution from the previous deterministic MILP, then proposes a methodology to enhance the initial solution by means of exploiting a developed simulation.

Chapter 5, summarizes realistic applications of the developed approaches alongside some preliminary extensions.

Chapter 6, recapitulates the work conducted during this thesis and provides insights and perspectives for future research.

Part II

Gathers published, submitted for publication, and under submission papers that disseminate the results and serve here to provide more details for the reader;

Paper [1] presents a deep literature review on the quantification methods of the resilience in smart grids. The main research gap of poor interdependent power-telecom system

modeling is identified and all insights are used throughout the different proposal in this thesis Papers [2] and [3] give more details on the graph-based model in Section 2.2 and cover the entire matter of Chapter 3. Similarly, Paper [4] covers the model in Section 2.3 and simulation-based analyses of Chapter 4. Papers [5] and [6] treat new remote switches deployment and the different conductor configurations, respectively.

Chapter 2

Integrated Modeling of Smart Distribution Grids

Conducted literature review revealed many gaps in analyzing cyber-physically interdependent smart distribution grids. Mainly, the power and telecom layers are considered separately, making study outcomes limited to marginal cases with loose application in real world systems. In addition, the power system is often referred to as the physical layer and the telecom network regarded as the cyber layer; while in fact each system can be described as a cyber-physical system by itself. Integrated modeling is proposed in this chapter to incorporate the telecom layer in grid analysis and set the basis for a telecom-aware restoration enhancement. The operation of the distribution grid is briefly recalled with focus on failure propagation, interdependencies, and restoration operations. Radiality conditions are revisited for multi-feeder configurations with the integration of hybrid overhead and underground lines.

2.1 Distribution Grid Operation

Power distribution systems combine low and medium voltage levels and interface with HV transmission systems through HV/MV substations. Power supply is the primary function of the grid and at the core of an operator's strategy, who seeks the combination of electrical parameters that guarantees the best dispatching of power while reducing operational costs. Electro-technical components like substations, transformers, lines, and switch gears ensure the physical flow of electricity in the system and notify for intervention in case of outages or damages. The balance between power supply and demand as well as the protection of grid assets are monitored at real-time by keeping electrical quantities at desired ranges

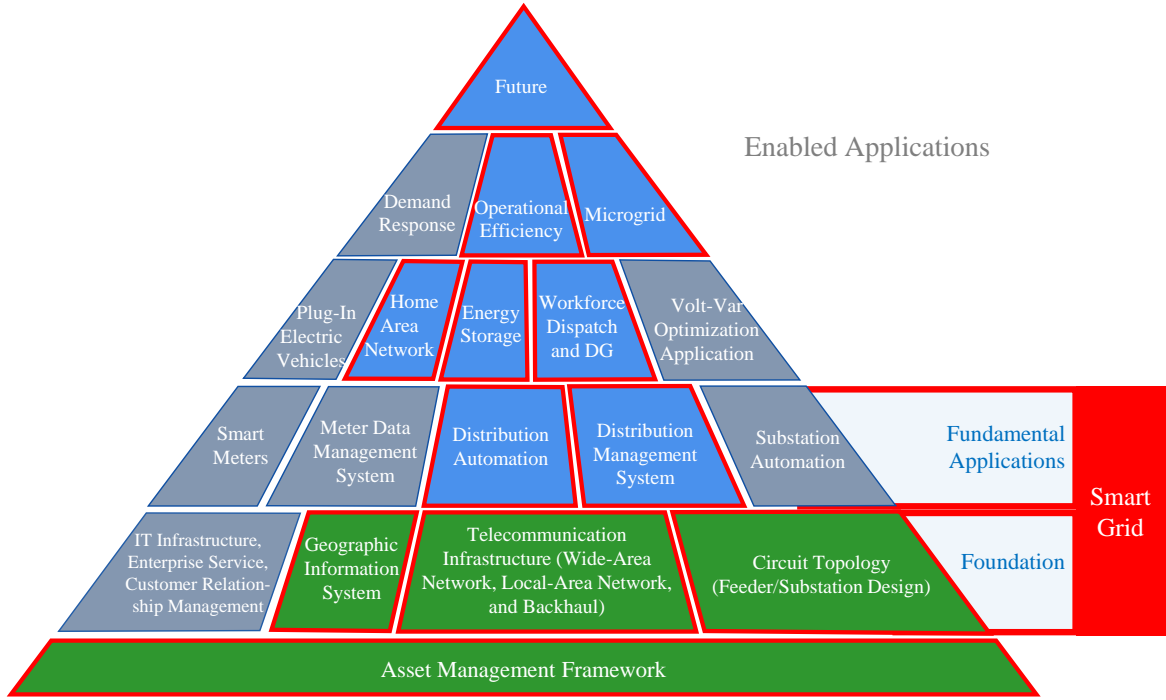


Figure 2.1: Smart grid applications (adapted from [42])

relying on a set of connected devices such as sensors, controllers and actuators.

The overall operation of the modern *smart grid* can be broken down to many interacting applications as shown in Figure 2.1. The proposed modeling for the DSR problem embodies the SG founding blocks of power and telecom infrastructures, with more focus on operation technology (OT), while only the geographical information system (GIS) is called up from information technology (IT). The model spans wider as the smart grid pyramid is swept bottom-up: the DSR includes the distribution automation and distribution management system as fundamental applications; then, energy storage (batteries), workforce dispatch and distributed generation (gensets) are represented; resulting in enabled applications of microgrid formation and operational efficiency. The selected applications at different levels sum up to be well representative of power-telecom interdependencies during a crisis management situation, used in Chapter 3 to develop a telecom-aware restoration optimization.

Figure 2.2 shows the configuration of a distribution grid and associated connections of field devices, crews, and substations to operator's main sites through the telecom network. The power supply of telecom points is also illustrated alongside their battery storage. Complex network theory and flow-based approaches are used to model the interdependent SDG of Figure 2.2 in the first part of this chapter. The model is extended in the second part to further describe the telecom layer, battery discharge, and crew interventions by introducing agent-based modeling and discrete events.

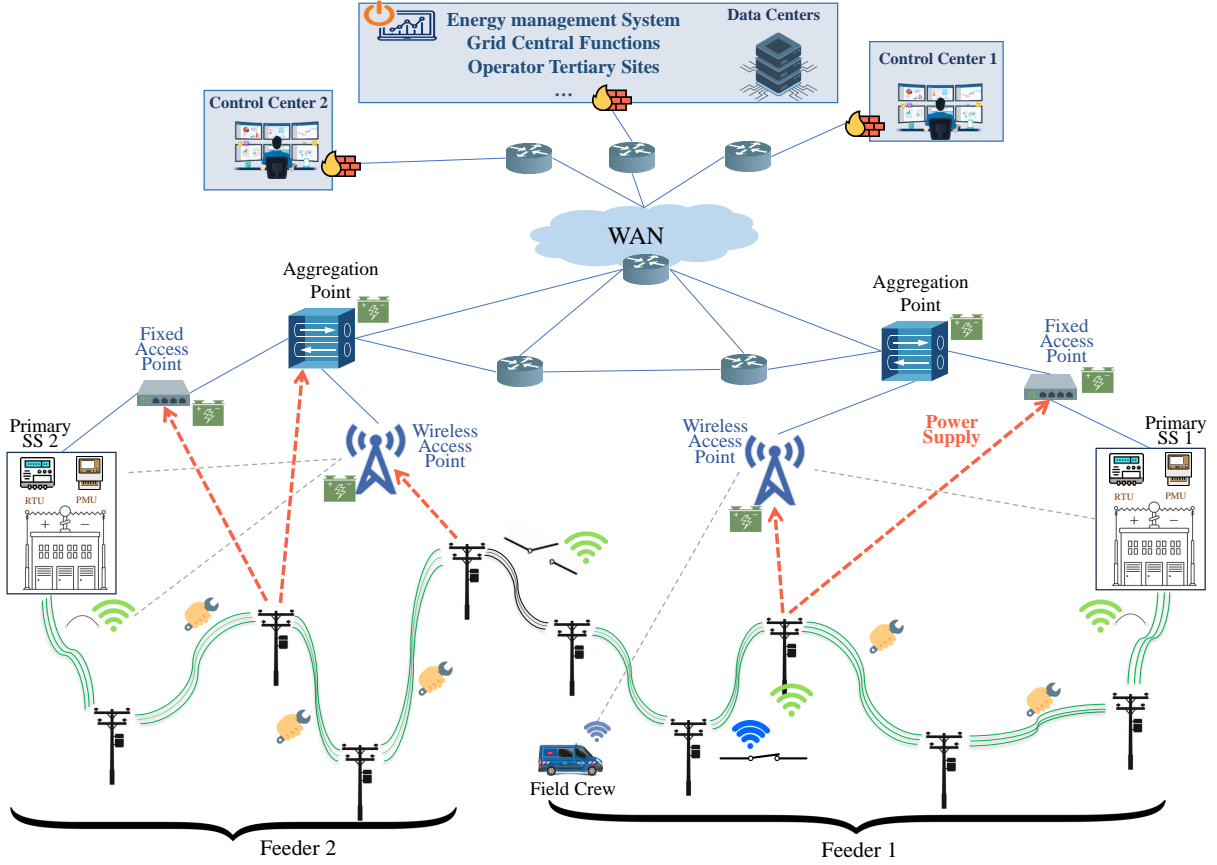


Figure 2.2: Power-telecom architecture of a smart distribution grid

2.2 Complex Network Theory and Flow-based Model

Large-scale networked systems, like power grids and telecom networks, fit nicely into a mathematical representation using graph theory tools. Notably, topology description with graphs offers a universal framework to understand living and complex engineered systems, where nodes capture important components (humans, substations, routers, etc.), and edges represent inter-component links (relationships, power lines, communication channels, etc.). This natural structure catalyzed efforts to develop the widely used *complex network theory*, where classical graph theory has seen its pioneering concept of randomness extended to handle real inter-connected systems, which are rather governed by generic organizing principles [43].

Further, the complex network theory attempts to include network dynamics like network growth, information spread, failure propagation, re-connection, and robustness by analyzing over time many nuanced predictors such as node centrality, edge weights, link direction, and network connectivity [44]. This succeeded to some extent on understanding complex behaviors and characteristics, but unlike topology, universally describing the panoply of dynamics in different systems is ever elusive. Flow-based methods help to

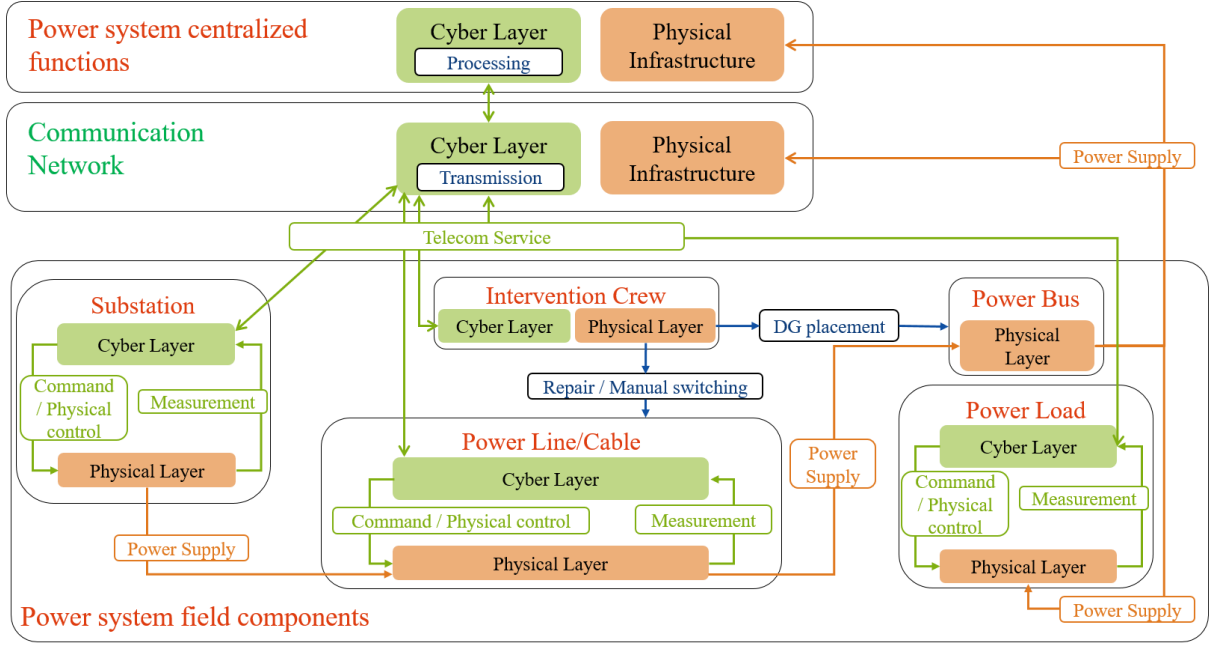


Figure 2.3: The smart grid as a cyber-physical system

stretch the description of dynamics in networks that are centered around the successive (usually continuous) delivery of a commodity, like power in the grid [45]. Physical laws are then leveraged to better depict ongoing processes. We hybridize the two approaches into an integrated model of the SDG benefiting from the straightforward application of complex network theory in the considered context and the increased detail brought by incorporating the power flow. More discussion on complex network theory and flow-based methods can be found in [46] and [47].

Algebraic equations are used to formalize the modeling contributions in this work, readily embraced as equality and inequality constraints for restoration optimization in the next chapters. This covers novel propositions for power-telecom interdependencies, failure propagation, and radiality.

2.2.1 Interdependence

Dedicated power system analysis enables a solid understanding of many grid problems, but looking into it exclusively neglects paramount related factors like power-telecom interdependencies. The DSR is a prominent example of a grid function where recent digitalization created a tight nexus between power system assets and the measurement, monitoring, and control through communication devices.

Many power grid components have cyber and physical characteristics, which result altogether in a cyber-physical system (CPS). In particular, substations, transformers, and

intelligent electronic devices (IEDs) handle physical quantities (power, voltage, current), while being able to outflow and deal with information. Likewise, control centers, intervention warehouses, and field crews involve physical processes under a relatively intensive information exchange and processing. The centralized and distributed constituents of the power system are connected via a telecommunication network, which is by itself a CPS coupled with the power grid. Figure 2.3 shows how cyber and physical layers of both power and telecom domains interact within the smart distribution grid. Clearly, the telecommunication network conveys information between centralized functions and localized system components, or even between localized components in a device-to-device setting that is not illustrated in Figure 2.3.

Overall, we alleviate the literature existing ambiguity between cyber-physical and telecom-power interdependencies in the context of smart grids [48, 49, 50], which applies also to other networked industrial systems. Each of the power and telecom systems is considered in this dissertation as a standalone CPS with two layers: cyber (C) and physical (P). The system C-P intra-coupling is defined as the cyber-physical interdependence. When P-P or C-C interactions take place between layers of the two systems, we evoke power-telecom interdependencies. This description is important to mark the distinction between embedded ICTs in power nodes and communication providing nodes from telecom operators. In addition, the physical layer of telecom networks is uncovered to make the analysis comprehensive compared to existing interdependence studies where telecoms are only described as a cyber layer.

A mixed graph is constructed as illustrated in Figure 2.4a, where *nodes* represent HV/MV substations (primary substations), MV buses¹(black disks), switches (SW), and telecom aggregation/access points (AggP/AP); whereas *edges* depict the power lines and ICT links. Edges can be directed or undirected depending on represented connections:

- **Power connections:** account for electrical lines that exist between two electrical buses or a substation and a bus. The power can flow in either direction depending on the feeding operational configuration. If a line switch is opened, the graph connection is deactivated (orange dashed-lines).
- **Power supply connections:** represent the unidirectional dependence of telecom points on power supply from electrical buses. Considering some extensions on interdependence studies [51, 24], the one-to-one relationship is not assumed as a

¹A bus refers to a specific location or point where grid components, such as substations and lines, are connected. A bus as a node may also include loads, transformer, generators, etc.

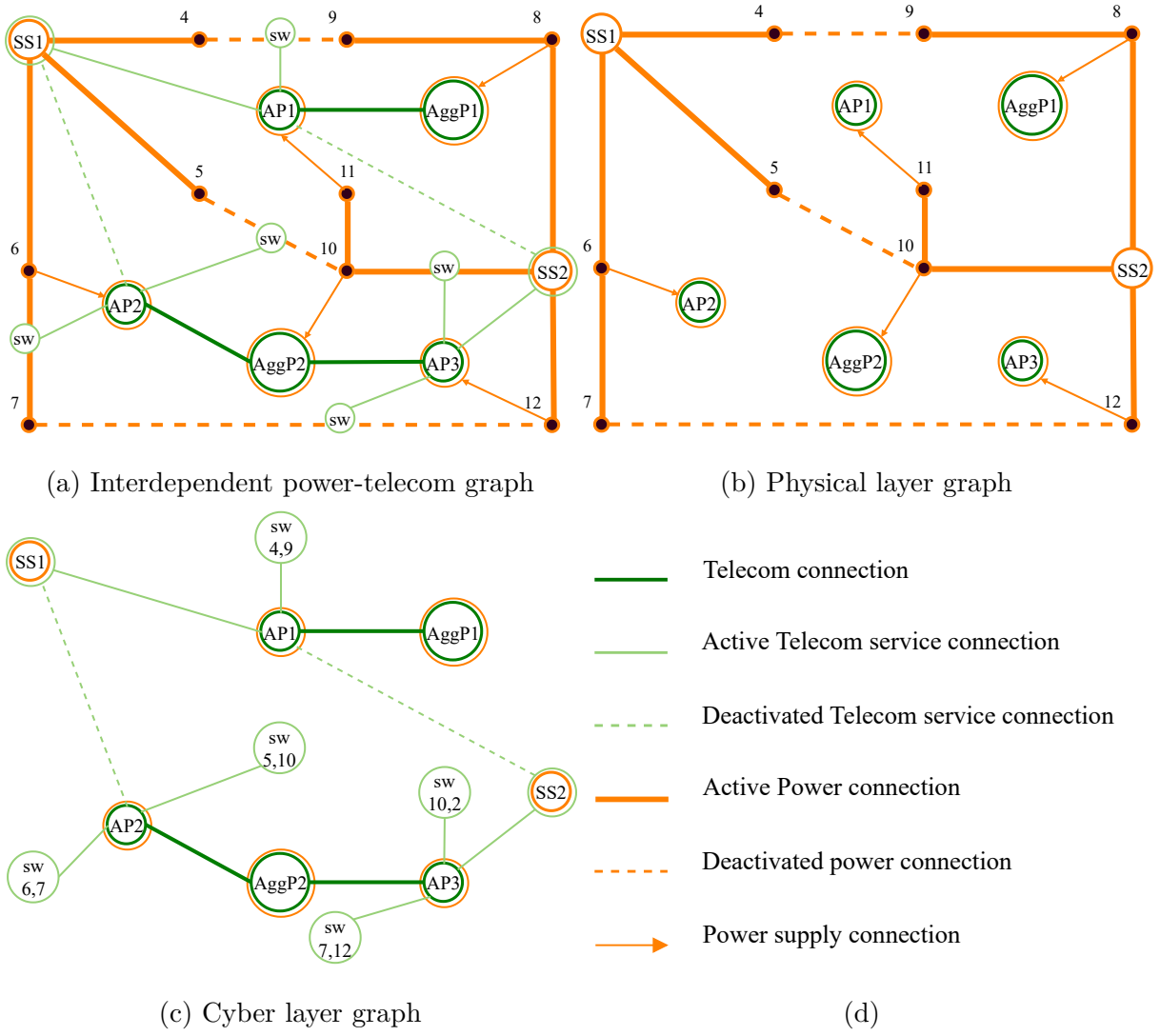


Figure 2.4: Mixed graph for the smart distribution grid

power bus can supply multiple telecom nodes, but each telecom node is realistically tied to only one supplying MV bus.

- **Telecom connections:** represent links between telecom points. Considering telecom dynamics in uplink and downlink channels, the connections can be seen as bi-directional, or broken down to two oppositely directed links. When the hierarchical structure of the telecom network is considered, the connections are unidirectional from the upper entity to the lower one.
- **Telecom service connections:** exhibit the same characteristics as previous telecom connections, at the difference of being at the service of grid components, which forms a power dependence on telecoms. In some cases, redundancies are planned for important nodes like HV/MV substations (green dashed-lines). One-to-multiple and multiple-to-one relationships are defined as: i) an access point can serve multiple

power components, ii) a given power component (depending on its criticality) can be served by more than one access point.

The representation is adaptive as some elements can be *edges* in one layer and referred to as *nodes* in the other, e.g. lines are edges in the physical layer, and could be seen as nodes in the cyber layer given their switching capabilities. At each section below, the most convenient graph from 2.4a, 2.4b, and 2.4c is selected.

2.2.2 Telecom Availability

Hierarchical relationships exist between communicating elements in the cyber graph (Figure 2.4a). Aggregation points (AggPs) are at the top of this hierarchy, conveying information to the control center through wide-area networks (WANs), while providing a telecom service for underlying access points (APs). Unless specified differently, AggPs are assumed in this work to have a permanent telecom service and do not suffer from power shortages. The analysis focus then on APs, which can be of different types:

- **Private or utility-owned access point (U-AP)** A DSO can possess private communication APs. These points may rely on the service from telecom operators, with a primary fixed link and a secondary wireless link. U-APs can provide RCSs and intervention crews with requested telecom services.
- **Telecom operator fixed access point (F-AP)** The F-AP serves DSO assets such as HV/MV substations, RCSs, and U-APs. The battery capacity is limited to some hours.
- **Telecom operator wireless access point (W-AP)** The W-AP serves also the DSO assets, and can be a secondary link in redundancy-enabled configurations. The battery capacity is limited to some hours.

The communication channel is neglected in this section where only the availability of nodes and hierarchical relationships are considered. The edges are directed from serving to connected nodes. The telecom service can be unavailable at any node due to a physical damage, a power shortage or no service from upper node. The damage has escalating effects on the cyber layer (top-down), but does not cascade necessarily to the physical layer (affected indirectly in some cases). Then, the unavailability of an upper node causes the disconnection of all its served nodes.

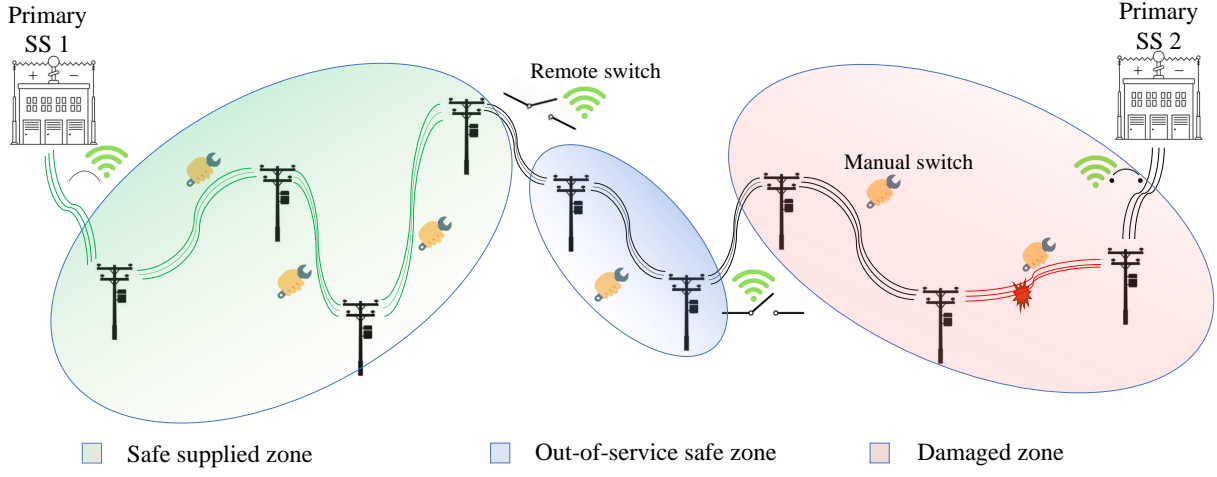


Figure 2.5: Resulting zones due to failure propagation and grid fast response (before reconfiguration)

2.2.3 Grid Failure Propagation

The term failure is used interchangeably with fault, damage, outage, and incident in this work to indicate an unavailability status of a component due to an exogenous event. Without loss of generality, failures are only considered in power lines, and can propagate to other components. Some faults are temporary, representing less danger to the grid as they fade away allowing return to normal grid operation after activation of the protection and reclosing mechanisms [52]. Thus, it goes without saying that the type of electrical failures considered here is what is called non-transient active and passive failures, which propagate through the network, have higher impact, are more frequent during extreme events, and need specialized interventions to be mitigated [53]. Examples of such failures include short circuits, over-currents, and physical breakdowns that cause damage in an initial impact point and threaten other parts. The electrical layer graph in Figure 2.4b is used, with HV/MV substations and MV buses as *nodes*, telecom points as *loads*, and power lines as *edges*.

Failure propagation and grid self-healing mechanisms conflict during an extreme event to result in three possible separate zones (shown in Figure 2.5):

- **Damaged zone:** contains grid segments where the initial damage is located alongside subsequent elements affected through failure propagation;
- **Out-of-Service safe zone:** contains parts of the grid, at first included in the damaged zone, but eventually isolated from the damage using switches. Buses in this zone can be re-connected by satisfying other conditions in the network;

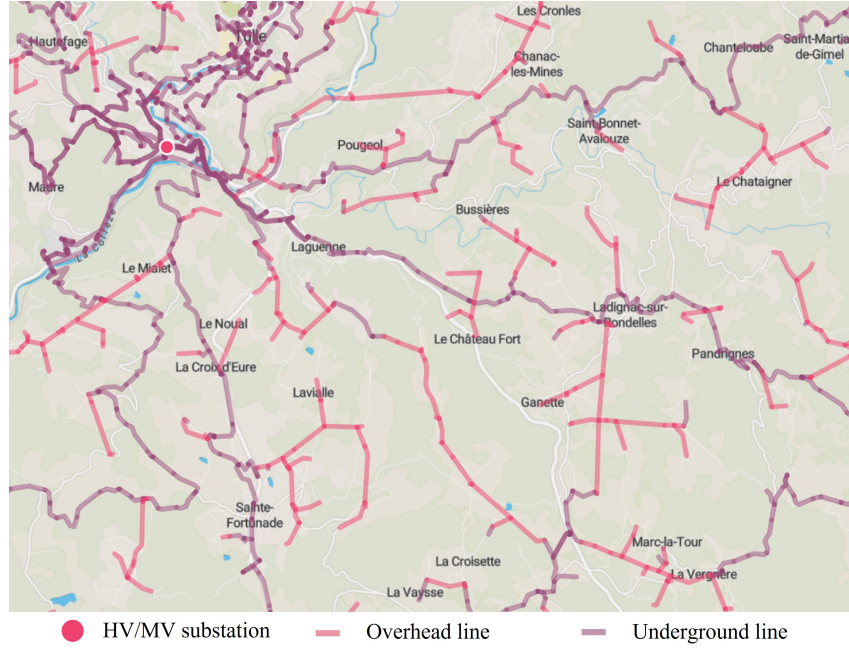


Figure 2.6: Snapshot from the french MV distribution grid (DSO Open Data)

- **Supplied safe zone:** includes segments of the grid that are safe from damages and energized.

Figure 2.6 shows a snapshot from the french MV distribution system with both overhead and underground lines. It can be noticed that in the specific case of France, lines are mostly underground near cities and urban areas, whereas ruralities are often served by overhead lines (may or may not apply to other countries). The main national DSO, managing 95% of the distribution system, displays in 2022 a mix of 52% underground and 48% overhead lines. The type of configuration affects the formation of aforementioned zones as line rollout rules differ in terms of switch placement and network topology. More precisely, underground networks are better equipped with switches in order to tighten failure isolation and minimize the dependence on expensive and time-consuming interventions. Also, MV/LV substations are closer to the mainstream feeder in underground networks or even aligned in series in most configurations, while many derivations from the mainstream are present in overhead networks².

Figures 2.7a and 2.7b illustrate two widely used configurations in overhead and underground grids, respectively. A damage in line (i, j) would be at best isolated by opening switches at lines (h, i) and (j, k) , leaving buses i and j in the damaged zone. For the underground case instead, a better isolation can be achieved by opening switches at both

²The overhead configuration is taken as default and throughout the thesis, while the underground is considered only in the part where it is explicitly mentioned.

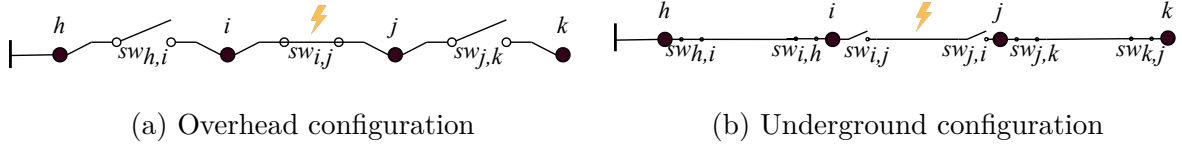


Figure 2.7: Failure propagation in power distribution networks

ends of line (i, j) , securing i and j in the safe zone. A bus corresponds to junction points of different overhead derivations, while for underground networks it represents physical busbars in a substation, or simply the substation. For modeling purposes we continue associating switches to lines in the underground case despite having the switches on the substation (the bus) as shown in Figure 2.8.

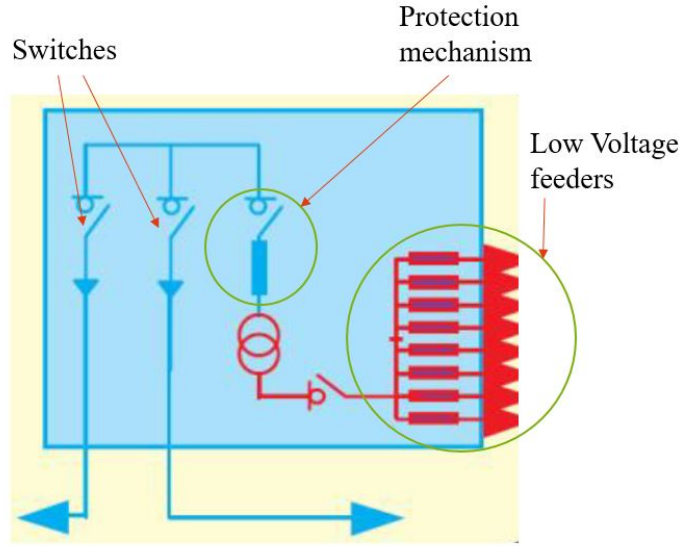


Figure 2.8: Simplified representation of a MV-LV substation in networks with a series configuration

We introduce in Papers [6] and [3] a binary variable sw_{ij}^u to model the status of the switch closest to i in line (i, j) and capture the difference with an equivalent overhead line containing only one switch sw_{ij} with no specific direction. Thus, we have the quadratic relationship in underground lines L^u ,

$$sw_{l,t} = sw_{ij,t} \cdot sw_{ji,t}, \forall l = (i, j) \in L^u, \forall t \quad (2.1)$$

which can be linearized as follows

$$sw_{l,t} \leq sw_{ij,t}, \forall l = (i, j) \in L^u, \forall t \quad (2.2)$$

$$sw_{l,t} \leq sw_{ji,t}, \forall l = (i, j) \in L^u, \forall t \quad (2.3)$$

$$sw_{ij,t} + sw_{ji,t} - 1 \leq sw_{l,t}, \forall l = (i, j) \in L^u, \forall t \quad (2.4)$$

Failures are initially assumed in electrical lines, with binary variable $a_{l,t}$ taking value 0 if line l is not available due to a damage, and 1 otherwise. Considering the behavior of electrical quantities, failures propagate in closed lines and only halted by open lines.

$$a_{i,t}^e + sw_{l,t} - 1 \leq a_{j,t}^e, \forall l = (i, j) \in L, \forall t \quad (2.5)$$

$$a_{i,t}^e \leq a_{i,t-1}^e + a_{l,t}, \forall l = (i, j) \in F^o, \forall t \quad (2.6)$$

$$a_{i,t}^e \leq a_{i,t-1}^e + a_{ij,t} + (1 - sw_{ij,t}), \forall (i, j) \in F^u, \forall t \quad (2.7)$$

According to equation (2.5), buses connected with a closed line will have the same availability status. Then, equations (2.6) and (2.7) express the propagation of a failure from lines to neighboring buses in overhead and underground lines, respectively. Variable $a_{i,t}^e$ will be carrying the damage information throughout the model, i.e. even failure of electrical buses can be considered by directly setting $a_{i,t}^e$ to 0.

2.2.4 Radiality

Distribution grids are meshed by design but operated radially to ensure efficient failure mitigation as damages on the grid cause abnormal states on electrical quantities, which propagate so fast that it is safer to have a pre-determined separation between feeders.

The spanning tree conditions of *connectivity* and $N - 1$ *branches* are adopted in many works to guarantee radiality [54, 55]. However, large-scale grids have multiple substations and exhibit a spanning forest topology, with many feeders interconnected through normally open switches (called also tie-switches). Then, each sub-graph needs to be a connected tree in the configuration, which must have $N - sg$ branches, where sg is the number of sub-graphs (or islands). A widely used implementation of these updated conditions is the single commodity flow (SCF) where a fictitious network is defined, with each node as either a source or a load of 1 unit commodity demand. Flow balance equations are then leveraged to satisfy the overall demand, establishing all corresponding source-load paths [56, 57]. The approach works well in normal and degradation stages as the supply configuration is stable or reducing by the loss of some connected nodes. However, when reconfigurations are executed in parallel with a deployment of DGs, the roots and composition of the tree-shaped sub-graphs are no longer known in advance. Consequently, the condition on the number of branches in the final configuration is updated to,

$$\sum_{\forall (i,j) \in L} sw_{ij,t} = N - \sum_i^N root_{i,t}, \forall t \in T \quad (2.8)$$

where $root_{i,t}$ indicates whether a bus at node i or a power source (substation or DG unit) is a root of an island at time t [58]. We ensure for our proposed formulation in Paper [6] the respect of this adaptive condition, while proposing the novel admission of out-of-service (safe and damaged) zones, missed in all state-of-the-art works. For instance, the formulation presented in [59] is flexible and has many applications for the distribution system optimization, but does not isolate faulted closed lines and overlooks the latent role of manual switches that are uncontrollable during the initial remote reconfiguration. Dangerous situations can result from such omission, as damages propagate in faulted closed lines and integrating them in the microgrid formation misleadingly infringes failure propagation rules. Also, the extension to consider manual switches requires additional constraints. The proposed directed local flow (DLF) radiality conditions tackle these issues and offer a simplified and effective remedy. Additional issues like the changing parent and child sets [60, 55] and the need for the spanning-tree polytope [59] are bypassed. The DLF was first demonstrated on fast remote reconfiguration in Paper [6], prior to extension for the distribution system restoration in Paper [3].

$$d_{ij,t} + d_{ji,t} \leq sw_{l,t}, \forall l = (i, j) \in L, \forall t \quad (2.9)$$

$$sw_{l,t} - (2 - y_{i,t}^e - y_{j,t}^e) \leq d_{ij,t} + d_{ji,t}, \forall l = (i, j) \in L, \forall t \quad (2.10)$$

$$d_{ij,t} + d_{ji,t} - (2 - y_{i,t}^e - y_{j,t}^e) \leq sw_{l,t}, \forall l = (i, j) \in L, \forall t \quad (2.11)$$

$$\sum_{\forall j \in n(i)} d_{ji,t} \leq a_{i,t}^e - s_i - y_{i,t}^{dg}, \forall i \in N, \forall t \quad (2.12)$$

$$\sum_{\forall j \in n(i)} d_{ij,t} \leq M \cdot \left(\sum_{\forall j \in n(i)} d_{ji,t} + s_i + y_{i,t}^{dg} \right), \forall i \in N, \forall t \quad (2.13)$$

Inequality (2.9) allows the presence of out-of-service closed lines and equations (2.10) – (2.11) incorporate the term $(2 - y_{i,t}^e - y_{j,t}^e)$ to only have co-occurrence of line closing and power flow when both nodes are connected. Radiality of the supplied sub-network at any given instant is verified through successive application of equations (2.9), (2.13), and (2.12).

2.2.5 Power Flow

The definition of electricity forwarding as a flow is owed to streams of electrical charges going from generating units to final loads. Laws of flow conservation apply to electric currents and voltages allowing for the well known *power flow* denomination. Power flow (PF) in the grid is governed by electrical (Kirchhoff's and Ohm's) laws on physical quantities

of voltage, current, impedance, and power. The objective, variables, and constraints are tweaked to fit various problems, like unit commitment, economic dispatch, grid stability, contingency response, volt/var control, etc [61]. Models for optimal power flow (OPF) are extensively studied in the literature, initially for transmission [62, 63] then for distribution [64, 65, 66]. The full AC optimal power flow (AC-OPF) is non-convex and NP-hard [63] due to inherent non-linearities and non-convexities in electrical quantities and multi-part pricing, as well as non-convexities including discrete and continuous variables and functions. Hence, many relaxations and approximations are developed to accelerate solving the OPF, mainly using semi-definite, second order conic, quadratic, and linear programming [67, 68, 61, 69].

Power grids are generally assumed as balanced networks, allowing for per-phase analysis [70], which consists of calculating electrical quantities (essentially current and voltage) in one phase and use the result to deduce the values in other phases by applying a $\pm 120^\circ$ phase shift. Load balancing occurs in three-phase systems when the loads are evenly spread across all phases. For distribution networks, the LinDistFlow model [71] is widely adapted to efficiently solve the PF problem, especially in resilience studies [29, 60]. The balance assumption is less obvious in distribution grids due to increasing DER penetration and radial structure [72], hence unbalanced extensions of LinDistFlow are introduced to cope with the distribution grid characteristics [73, 74, 75].

Still, the balanced LinDistFlow model is used in this dissertation based on the fact that MV grids serve MV/LV substations that are usually sized to meet an equi-partitioned LV load, that can be considered as balanced. The balance equations therein enforce the conservation of power at any node by equating the incoming and outgoing flows. The difference in node voltages is expressed in terms of power and impedance to account for line losses. Limits on active/reactive power line capacities, node voltages, and DG active/reactive power are also introduced.

2.2.6 Dispatch of Intervention Crews

Hardship in analyzing the DSR is not solely the consequence of power and telecom dynamics, but encloses as well the complexity of field operations like the dispatch of intervention crews to operate manual switches, repair damages, and install DGs. Many graph-based representations can be set to model the movement of crews from their depots to intervention sites. Mostly, depots and intervention sites are modeled as nodes, while edges obey various definitions and rules, e.g. representation of distances or travel times

between the nodes as edge weights, introduction of directed edges in case of specified travel directions, omission of edges between nodes of intervention sites for operations that impose returning to the depot after each task completion (DG placement), etc.

The aim is to determine for each intervention crew the sequence of sites to visit, while minimizing the restoration time and costs. The whole process reduces then to two interdependent sub-problems: routing and scheduling [76]. Routing involves selecting the best route for each crew to travel between depots and intervention sites. Scheduling, on the other hand, involves setting a timeline for the crews to carry out their travel and activities. The selected route for each crew affects the amount of time required to travel and complete tasks, which in turn impacts the scheduling of subsequent activities.

Recent contributions propose adaptations of the vehicle routing and traveling salesman problems to solve crew dispatch in grid restoration [31, 28, 30], based on variables in the form of $c_{m,n}^k$ indicating the travel of a crew k along the path between nodes m and n . The limitation of this representation is the implicit *visit* of a crew to a node, which can only be deduced from the solution. This information is important in the present study as the tasks (manual switching, repair, and DG placement) are conducted at damage sites and interdependencies of intervention crews with ICTs and switches arise at these same nodes. To cope with this, we opt for a node-centered variable $c_{n,t}^k$ that indicates the presence of a crew k at node n at time t . This allows to better manage the coupling between resilience resources [29], while capturing the newly considered power-telecom interdependencies.

$$c_{l,t+\tau}^k + c_{m,t}^k \leq 1, \quad \forall k, \forall l \neq m, \tau \leq TT_{l,m} \quad (2.14)$$

Our model is based on the scheduling rule in (2.14): each crew k can visit two different intervention sites l and m ($l \neq m$) only if a period at least equal to the traveling time $TT_{l,m}$ has elapsed. This rule is proven in [29] to produce feasible routes for the crew dispatch, and verified here to remain valid when integrated to the proposed contributions in our work.

2.3 Model Extension: Agent-based and Discrete-Events

Smart grid functions in general, and the DSR in particular, engage heterogeneous entities from different domains, each with specific behaviors and decision making capabilities. The intended application of the previous model for optimization purposes (as will be seen in Chapter 3) imposed many simplifications for computational tractability. Only the availability of telecom nodes is incorporated, while measurement and control messages

conveyed over communication channels are ignored. The movement of intervention crews is also restrained to the relationship with distance. In fact, event-driven communications and multi-derivation road networks introduce many non-linearities and complex behaviors, hardly describable by closed-form equations, let alone with linear terms. Therefore, other modeling paradigms are needed in order to capture this level of detail.

The ABM approach is well-suited for large-scale systems endowed with various interactions among heterogeneous entities, commonly referred to as *agents*. Many properties can be associated with agents, such as autonomy, interaction, mobility, intelligence, and adaptability [77, 78, 79]. ABMs³ are particularly useful in cases where individual behaviors are more accessible for modeling than the collective complex dynamics in a given system [80]. The system can be described at the microscopic level by modeling the simple interactions between single elements, then reconstruct the global system behavior. Furthermore, ABMs allow to represent emergent phenomena due to their bottom-up nature: an emergent phenomenon is an effect at the system level that cannot (directly) be inferred by the behavior of the individual parts, meaning that the system behavior is more than the (pure linear) sum of the parts [81]. Another advantage is the ability to incorporate other modeling approaches either by dedicated interfaces, or inside the agents themselves in a parallel or/and a hierarchical structure. This latter feature is precisely leveraged in this work, as the complex network theory approach from the previous section is adapted and reused, alongside the introduction of discrete-event (DE) simulation. DE is a powerful modeling technique that tracks the evolution of the system dynamics at key instants in time corresponding to the occurrence of events that bring change to the system [82]. A typical telecom point can then be modeled as an agent whose behavior include sending and receiving event-driven messages, while the main simulation can make a call for power flow calculation when needed.

The resulting model is a hybrid simulation that extends the previous graph-based model, serving in later chapters to compare the solution from analytical optimization, as well as monitor the deployment of a given restoration strategy. The built platform can be utilized to experiment with varying parameters and resources at real-time to emulate changing conditions during crisis management situations, relying on the microscopic bottom-up construction and adaptability of the hybrid simulation.

³When used on the plural, ABMs refers to Agent-Based Models

2.3.1 Model Layout

The extended model represents telecom points and intervention crews using ABM and discrete events in order to catch advanced details of information transfer, realistic battery discharge, and road-tailored displacement. From Figure 2.9, the ABM-DE module sends

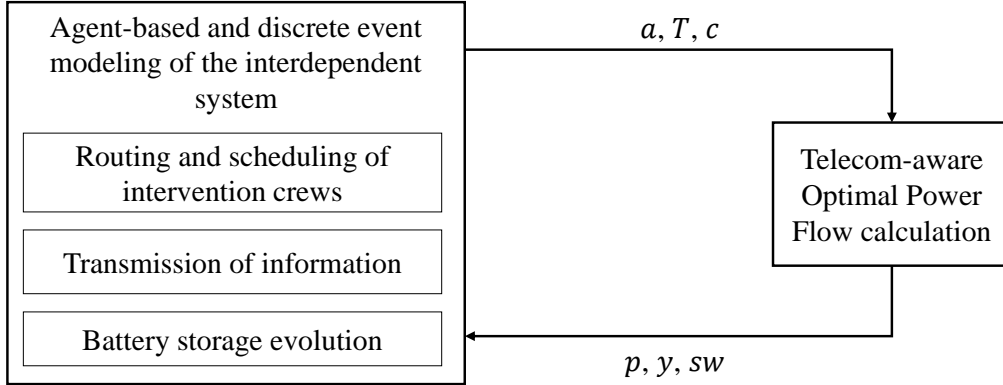


Figure 2.9: Layout of the extended simulation model

the availability of power components \mathbf{a} , state of telecom points \mathbf{T} , and the evolution of crew dispatch \mathbf{c} to the PF module. Then, the electro-technical quantities of active/reactive power and node voltage are calculated, alongside the state of switches \mathbf{sw} and connectivity of power buses \mathbf{y} .

Considering the DSR, when a restoration task is completed, a power flow verification before re-connection is performed by calling a one-shot PF computation using a modified instance of the model in Section 1. In this case, no periodic PF calculation is needed, and the traditional approach to PF of continuous-state continuous-time (CS-CT) is replaced by a discrete-state continuous-time (DS-CT) approach, referred to as *discrete-event* [83]. When combined with the previously mentioned event-driven telecom domain, the whole model is continuous-time, agent-based, and discrete-event. It is worth noting that the simulation of a continuous-time model always involves a discretization procedure with a relevant fixed time step.

As a result, beyond the improved description of system details, the main advantage of the proposed model is the seamless integration of the power and telecom domains. This is made possible through power-telecom component synchronization using combined time-stepped, event scheduling, and agent communication approaches [84, 77]. The simulation engine updates the state of the model components, such as agents, processes, and resources, according to their defined behaviors and interactions. At each time increment, events and processes are executed in a sequential order established based on dependencies and

triggers, while the user is able to define some priorities and preemption [85].

Agents with specific behaviors are defined to describe the main elements of interest during the DSR as summarized in table 2.1, where power-telecom interdependencies are considered by tying up the state of telecom agents and power flow calculations. Intervention crews are captured as mobile agents, capable of communicating with the control center over the telecom network.

2.3.2 Telecom Service

The availability of telecom access and aggregation points is considered in the hybrid model, with the possibility to define individual failure times or upload failure data from external sources. The hierarchical relationship steers then the telecom failure propagation as a damaged telecom point cuts service to its served entities. Further, the communication channels between telecom points (or telecom points and connected assets) are modeled as agents as well, allowing to incorporate information transfer failures and limitations of link delay and bandwidth.

Unlike previous considerations of the telecom service being either fully available or not at all, the current model integrates service degradation, generally caused by congestion and transmission channel disturbance [86]. Separate queues are established for download/upload transfer of data (messages to lower/higher entities), with a chosen default FIFO queuing system (unless specified, the other possible queuing options, like priority-based, agent comparison, and LIFO, are not used).

Smart grid messages are replicated to represent notifications from field devices to the control center (CC) and commands in the opposite direction, as illustrated in Table 2.1. These messages well represent the logical operation of the smart grid control and interactions therein, but make complete abstraction of the protocol, packet, and bit levels. Both agent-based and discrete-event modeling approaches intervene as messages are built as communication-shaped agents, which are exchanged between other agents following triggered events in the system.

³**Send()** is a built-in function in this work used to pass user-defined *Notify* messages between different agents as well as other messages, such as sending the targeted power line to a crew that does the repair.

Table 2.1: Description of considered agents

Agent	Description	Behavior	Out messages	In messages
PowerLine	A power line between two successive buses. The line availability is tracked based on line failure initial information and quantities from PF calculations .	Fail due to a damage, but recover after repair by field crews. Reconnection is conducted by operating switches based on PF results.	Notify (LINE_FAILURE)	Notify(WAIT_FOR_REPAIR)
			Notify (LINE_REPAIRED)	Notify(CREW_ARRIVED)
			Notify (LINE_ISOLATED)	Notify(LINE_RECONNECTION)
			Notify(CREW_FINISHED_TASK)	
Depot	The location from where intervention crews can depart towards damage sites.	Manage the number of resources and organize failed lines as repair requests to assign them to intervention crews	Send(failed PowerLine agents) to available crews	NA
AccessLink	Bi-directional telecom link between field elements and access points	Transmit information from/to access points and field elements (switches, intervention crews, substations)	Relay Notify and Send ⁴ messages	Relay Notify and Send messages
AccessPoint	Telecom point directly serving field elements	Send/receive messages to/from upper and lower layer entities	Relay Notify and Send messages	Relay Notify and Send messages
AggPoint	Telecom point directly serving access points. Control center processing is implemented here.	Send/receive messages to/from lower layer access points	Notify(WAIT_FOR_REPAIR) Notify(LINE_RECONNECTION)	Notify(LINE_FAILURE) Notify(LINE_REPAIRED) Notify(LINE_ISOLATED)
RepairCrew	Moving technicians sent through the road network to conduct repair	Conduct repair operations and operate manual switches	Notify(CREW_ARRIVED)	Send(failed PowerLine agent) Notify(CREW_FINISHED_TASK)
Manual-SwCrew	Moving technicians sent through the road network to operate switches	Perform manual switching	Notify(CREW_ARRIVED)	Send(failed PowerLine agent) Notify(CREW_FINISHED_TASK)
Notify	Template of exchanged messages between different agents	Convey information to notify task completion as well as commands from the control center.	NA	NA

2.3.3 Power Supply Analysis

Power quantities and grid failure propagation are comprehensively considered in the PF module, which assimilates also the updates from the ABM-DE module on the availability of lines (e.g. after repair) and the battery state of telecom points. Thus, the PF calculations maintain awareness of the power-telecom interdependencies and suggest optimal reconfiguration schemes. The battery model is taken from EnergyLogic library [87], containing essential battery settings regarding charge, discharge, loss, and battery degradation as illustrated in Figure 2.10. This model is continuous, meaning that the battery level can

battery - Battery_continuous

Name: ☒ Show name ☐ Ignore

☒ Single agent ☐ Population of agents

Battery control

Charge/discharge need (kW) (negative: charging; positive: discharge):

Battery parameters

Storage capacity(kWh):

Rated charge power(kW):

Rated discharge power(kW):

Self-discharge rate(kWh/h):

Transition loss in percentage of charging power:

Level at start(kWh):

Operational minimum level: 0 means empty, while 1 means full (soc):

Choice of Degradation table: ☒ Degradation ignored ☐ Choose the default degradation table ☐ Input a new degradation table

Figure 2.10: Battery model

change continuously over time, fitting the global time continuity of the hybrid model discussed earlier.

2.3.4 Crew Interventions

Model initialization clusters recorded damaged lines to their closest depot. The depots are defined as agents encapsulating crew agents as restoration resources that are hosted and managed. An assignment routine is implemented at each depot for the various crew types using discrete-event blocks as exemplified in Figure 2.11 for repair crews. The figure shows an entry block *repairResources* that takes repair crews from the defined population of agents *repairCrews* to put them in a task-ready queue named *repairQueue*. As of the setting of the queue, the first arriving crew will access the *working* block first, where the

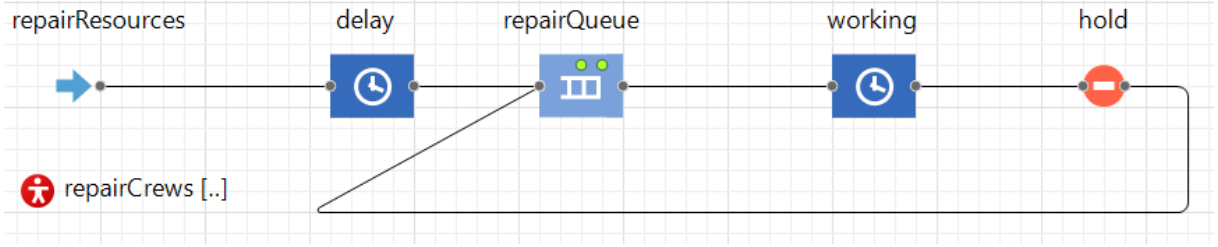


Figure 2.11: Repair crew assignment

nearest damaged line (nearest by route) is picked, based on road data requested from the OpenStreetMap (OSM) server [88]. The *hold* block assures that a crew completing its task releases the handled line before repositioning at *repairQueue* to handle another task. The assignment behavior is modulated in later sections to fit the exact application. For example, when the hybrid model executes an already existing schedule, the action at the *working* block consists of taking the planned repair task and not necessarily the nearest one.

Intervention crews notify the task completion to the control center through the telecom infrastructure before re-connection. Such events occur sporadically, justifying the relevance of an event-driven modeling approach for a better representation.

2.3.5 Model Consistency

The hybrid model is introduced to improve the description of the system by including more details. However, an important step is to check the consistency of its results when set to the level of detail contained in the graph-based model. We conduct this analysis in the case of a DSR process using resources of repair and manual/remote switching. We consider a multi-feeder 141-bus distribution grid with 150 power lines, among which 6 lines are damaged. All possible remote isolation and reconfiguration are conducted to yield the configuration in Figure 2.12. Generic values are chosen for different parameters: line impedances, load demand, voltage limits, etc. The graph-based model is implemented first to restore the grid given a random initial restoration sequence $\{1,2,3,4,5,6\}$. Two depots are considered with depot 1 having two repair crew (RC) and one manual switching crew (MC), whereas depot 2 has one RC and one MC (MCs move twice faster than RCs). For simplicity, the repair time and manual switching time are set for all damages to 2 and 1 time steps, respectively; and the manual switching time is associated directly with the damaged line, instead of considering the operation of each manual switchable neighboring line as considered in other parts of this work. The resulting schedule for model 2.2 is

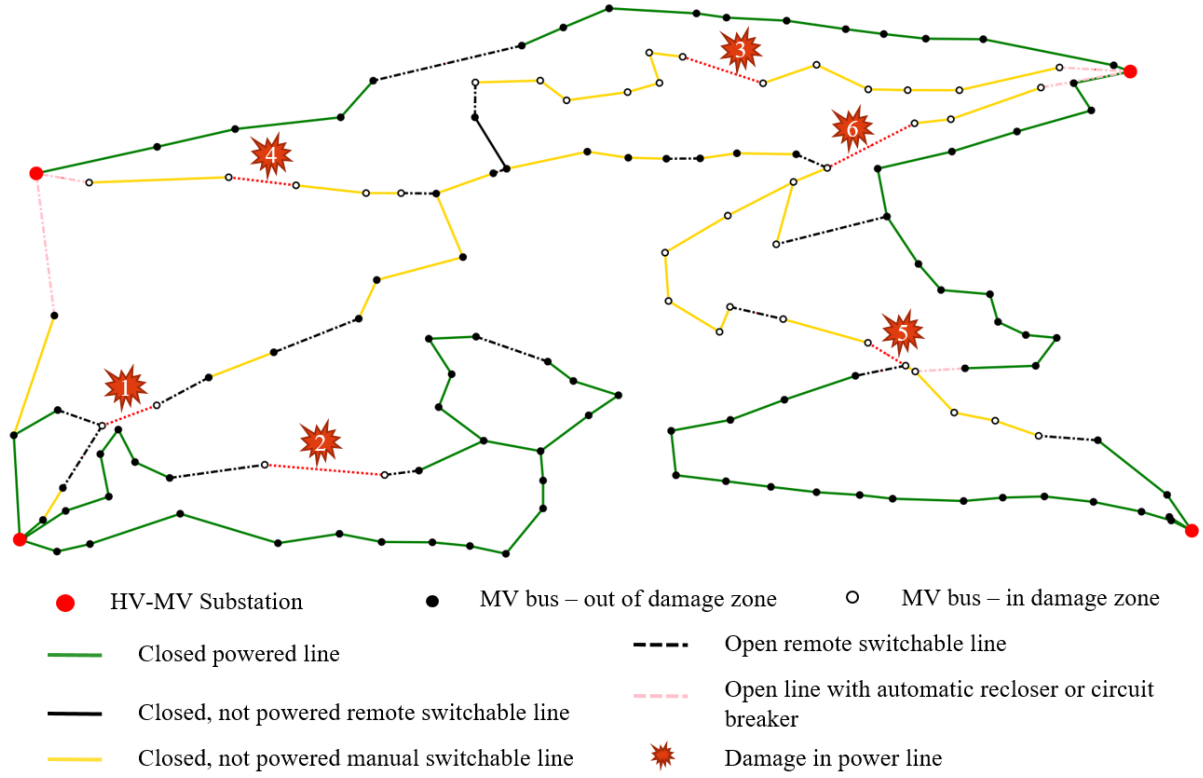


Figure 2.12: Grid configuration after fast response

depicted in Figure 2.13.

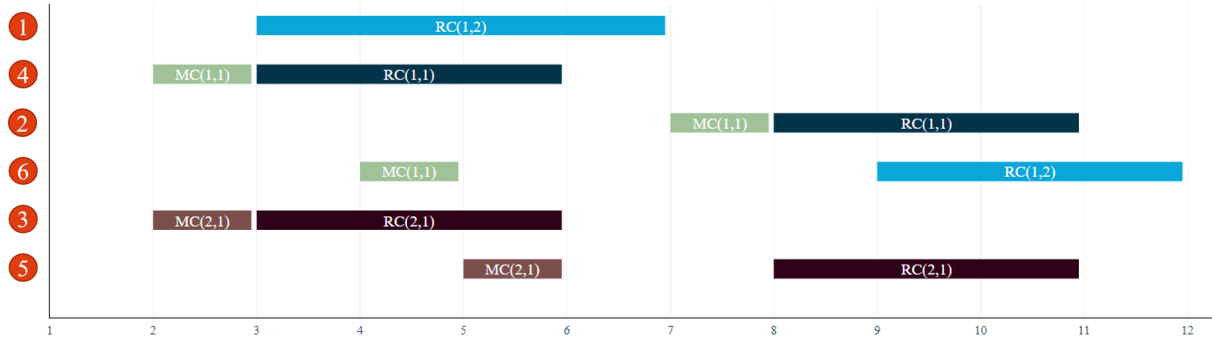


Figure 2.13: Gantt chart for the schedule of intervention crews on damaged lines

The schedule is applied next to the hybrid model considering the same settings above. The supplied power and the time to complete recovery are chosen as measures of performance to be compared between the two models. Figure 2.14 shows the evolution of supplied power during restoration following the considered schedule. A complete match is seen between the performance curves of the two models and the time of recovery completion at $t = 10$. This verification confirms the claim that a given problem can be modeled equivalently using different modeling methods [89], and it is up to the modeler to choose the most relevant technique. In our specific case, the two models are used jointly in different applications to make each model benefit from the advantages of the other.

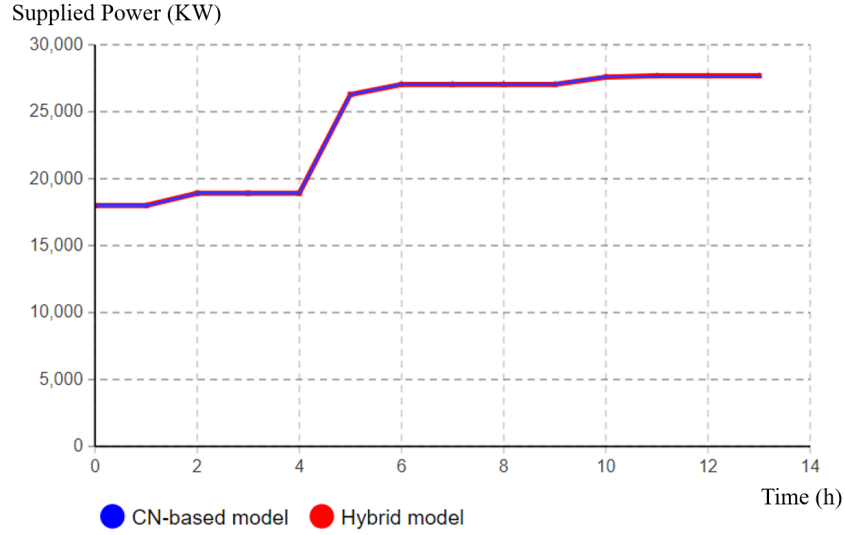


Figure 2.14: Evolution of supplied power during distribution system restoration

2.4 Summary

This chapter introduced two models for the distribution system. The first model uses complex network theory to capture the topology, connections, and power-telecom interdependencies between the smart distribution grid components. The flow of power is also considered to represent failure propagation and the main grid functionality of supplying power, while highlighting the novelty of this work on tracking the availability of supply to telecom points-of-interest. The second model captures an extension of the first model towards a hybrid representation to seize advanced telecom, battery discharge, and crew displacement details using ABM and discrete-events. The practical contribution of using the CN-based and hybrid models is associated in next chapters to applications of telecom-aware DSR, solution enhancement, resource sizing and the definition of service level agreements (SLAs) based on *proven harm*.

Chapter 3

Telecom-aware Optimization of Distribution System Restoration

Communication networks resolved poor observability issues in grid operation and paved the way for advanced applications like distribution automation, automatic metering, distribution system management, and outage management. The emergent challenge is then to guarantee the perfect functioning of the ICTs as the smart grid is increasingly connectivity-dependent. Unfortunately, communication networks fail to permanently provide the grid required connectivity service, causing episodes of blind operation and inability to perform desired remote actions. The relationship gets more intricate when power shortage at the distribution level is recognized as the main cause of telecom nodes unavailability (thus telecom service interruption). This is simply a two-way power-telecom interdependence that is neglected so far by distribution operators in the planning and daily operation of the grid due to believed limitation of the impact. Yet, the need for rapid restoration reveals the criticality of this interdependence during contingencies. This chapter proposes a telecom-aware optimization of the distribution system restoration by tracking the availability state of telecom points and strategically prioritizing the recovery of electrical buses that supply telecom points, which eventually contribute to the acceleration of the overall recovery process.

3.1 Optimization of Distribution System Restoration

DSOs work continuously to improve the technical, economic, environmental, and regulatory performance of the grid by thoroughly evaluating investment options through expansion planning [90, 91]. A complimentary, less expensive [60, 27], and effective action is to

investigate the resilience potential of the grid under contingency planning, which turns out to be arduous as many uncertainties are involved regarding initial events and component failures [92, 93]. Partially revealed uncertainties after the burst of a disruption event push forward the post-contingency resilience analysis in order to better integrate the newly collected information and track the recovery process [94]. Beyond the analysis, DSOs seek to limit the degradation and accelerate the restoration by deploying various resources such as repair crews, mobile distribution generators, batteries, etc. Unfortunately, resource management and allocation is dominantly left to the appreciation of field operators, who make the best out of their experience and system knowledge despite the lack of decision aid systems.

Recent literature addresses this gap by adopting optimization methods for single and multi-resource deployments during grid restoration [60, 28, 29, 31]. The aim is to cost-effectively utilize available resources towards the acceleration of system recovery, where the coordinated deployment of the intertwined resources through co-optimization is shown to yield the best performing restoration strategies. A closer look into DSR co-optimization reveals the critical role of the telecom network on conveying all relevant information, while being dependent on the power supply from the grid or batteries. This two-way power-telecom interdependence is missed out on the few works that consider DSR communications, as analyses are mostly limited to the cyber layer of the telecom network [95, 96, 32].

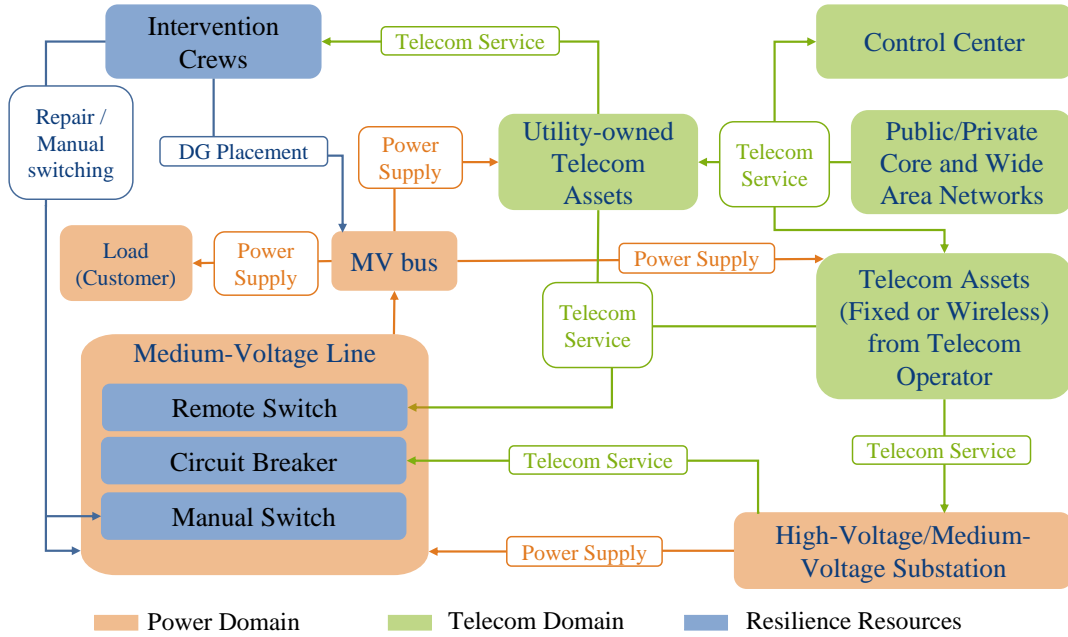


Figure 3.1: Summarized interactions in the proposed model for the SDG

We propose in papers [2] and [3] to co-optimize the allocation of restoration resources,

while considering the evolution of telecom availability. Figure 3.1 shows the captured interdependencies in the developed model. The distribution grid is represented with power lines, substations, buses and loads (orange elements). The telecom service to grid assets is provided by private and public telecom points (green elements), which allow communication to the control center. The telecom service is also used by investigated resources of remote switches, circuit breakers, intervention crews, and mobile distributed generators. The weighting between the amount and cost of committed resources is settled based on risk-aversion and tolerance to the loss of grid services.

3.1.1 Resilience-based Objective

The response of the grid against extreme events involves the two main resilience components of survivability and restoration. We set a preliminary optimization that captures failure propagation and fast remote actions, isolates segments on the system to limit the damage, and makes the first reconfigurations to recover some load; corresponding to *Phase I* in Figure 1.1.

We choose the supplied power as the measure of performance in this work, and integrate it to the objective function by using the variable $p_{i,t}^{ns}$, the instantaneous non-supplied power at a given node i .

$$\min_{\mathbf{p}, \mathbf{d}, \mathbf{sw}, \mathbf{a}, \mathbf{y}, \mathbf{w}} \sum_{\forall t \in \{T_1, T_2\}} \left[\alpha \left(\sum_{\forall i \in N} C_i^{ns} \cdot p_{i,t}^{ns} - \sum_{\forall i \in N} C_i^e \cdot a_{i,t}^e \right) + \beta \sum_{\forall l \in L} C^{sw} \cdot w_{l,t} \right] \quad (3.1)$$

The fast reconfiguration objective function is given in (3.1) with \mathbf{p} a vector of electrical quantities (line active/reactive power, node voltages, non-supplied load); \mathbf{d} the directions of power flow in power lines; \mathbf{sw} the statuses of line switches; \mathbf{a} the availability of power buses, lines, or DGs, and \mathbf{y} the connectivity of power buses or DGs. The first double summation term represents the total cost of not supplying a portion of the system load during Phase I, where each load has its associated criticality-based cost C_i^{ns} . The next term expresses the cumulative cost induced by the extent of the damaged zone, where C_i^e is the cost of an electrical node being in a damaged zone. The final term is designed to include the cost of switching, as no change on the configuration is desired unless there is a gain in restored power. C^{sw} is considered the same for all operated switches, and variable $w_{ij,t}$ results from the linearization of the absolute value of $sw_{l,t} - sw_{l,t-1}$.

$$sw_{l,t} - sw_{l,t-1} \leq w_{l,t}, \forall l \in L, \forall t \quad (3.2)$$

$$sw_{l,t-1} - sw_{l,t} \leq w_{l,t}, \forall l \in L, \forall t \quad (3.3)$$

From (3.2) and (3.3), $|sw_{l,t} - sw_{l,t-1}|$ equals 1 if the switch at line l is toggled at t , and 0 otherwise.

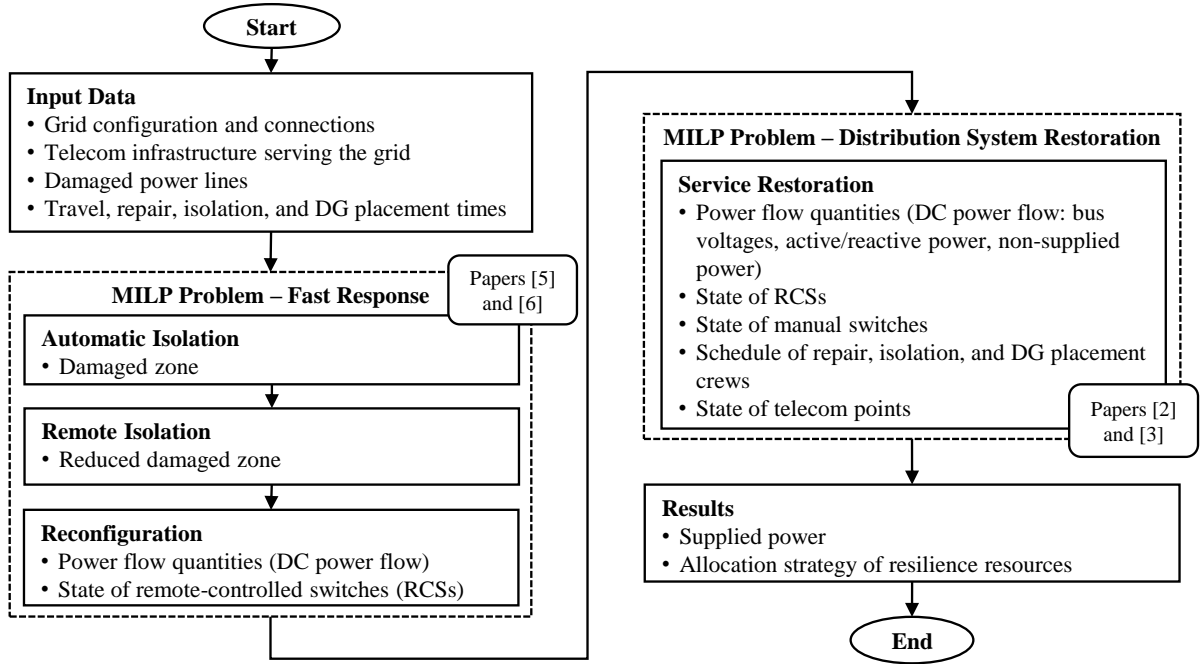


Figure 3.2: Layout of the proposed restoration model

Appended papers [5, 6] give more details on the fast response model, while [2, 3] treat the DSR stage where the result from the fast response stage is used. Figure 3.2 summarizes the input data to the proposed model and the successive phases with associated variables. In *Phase I*, the telecom network is confronted with physical damages only as the period $[T_1, T_2]$ lasts at most some minutes, causing no problem in terms of power shortage to telecom points that possess back-up storage. Therefore, we focus more on the lengthy restoration (*Phases II, III, and IV*) to deeply investigate the power-telecom interdependencies as ICTs are affected by long outages and battery depletion.

$$\begin{aligned}
 \min_{\mathbf{p}, \mathbf{d}, \mathbf{sw}, \mathbf{c}, \mathbf{a}, \mathbf{y}, \mathbf{T}, \mathbf{E}, \mathbf{w}} \sum_{\forall t \in \{T_2, T_5\}} & \left[\alpha \sum_{\forall i \in N \setminus S} C_i^{ms} \cdot p_{i,t}^{ns} + \beta \sum_{\forall l \in L} C^{sw} \cdot w_{l,t} \right. \\
 & \left. + \gamma \left(\sum_{\forall (dp, k, l, t)} C_i^{rc} \cdot rc_{l,t}^{dp, k} + \sum_{\forall (dp, k, l, t)} C_i^{mc} \cdot mc_{l,t}^{dp, k} + \sum_{\forall (dp, k, n, t)} C_i^{gc} \cdot gc_{n,t}^{dp, k} \right) \right]
 \end{aligned} \tag{3.4}$$

Equation (3.4) poses the post-*Phase I* restoration objective function with additional vectors of variables: \mathbf{c} the vector of intervention crews placement; \mathbf{T} the vector of electric and telecom statuses of public and private access points; \mathbf{E} the state-of-charge (SoC) and $b_{i,t}$ the depletion status of batteries. C_i^{ns} , C_i^{rc} , C_i^{mc} , and C_i^{gc} refer to non-supplied load, repair, MS, and DG placement costs, respectively. DSOs integrate institutional and

public satisfaction to restoration efforts, making resource costs only relevant in case of equi-performing restoration strategies, thus $\alpha \gg \beta$ and $\alpha \gg \gamma$.

The contribution of deployed resources lifts the performance curve in Figure 1.1 towards the nominal performance P_{max} . Once all loads are energized, equation (3.4) will no longer encourage sending resources to the field even that some lines are not repaired yet. This assumes the DSR to not impose complete repair of the system during the event, allowing to temporarily prioritize service recovery in early hours (or days), and let complete recovery for later steps. If desired, full recovery can be plugged into (3.4) by adding $(-\sum_{l \in F^l} C_l^e \cdot a_{l,t})$ to the term weighted by α , where F^l is the set of failed lines, C_l^e the cost of a non-repaired line ($\ll C_i^{ns}$), and $a_{l,t}$ equals 1 when a line l is available at time t (0 otherwise). Note that telecoms are not included in the objective function as the standpoint of a power operator is adopted, and only DSO-used telecom points are of interest.

3.1.2 Key Constraints

The main characteristics of the distribution system are introduced in Chapter 2, with emphasis on the studied application of distribution restoration. The equations from the CN-based model in Section 2.2 as well as additional details and assumptions are integrated to the constraints of the DSR optimization formulation:

1) We concentrate on the MV level of the distribution system. Each power line is equipped with a switch that can be remote or manual, represented with a binary variable $sw_{l,t}$ that takes value 1 for the *close* status and value 0 for the *open* status. Manual switches can be operated either by repair crews (RCs) or manual switching crews (MCs). These two crew types are motivated by the fast movement of MCs compared to heavily equipped RCs, allowing to conduct damage isolation to enable rapid restoration in the grid.

2) Without loss of generality, components that can be damaged (and repaired) are the distribution lines, with the possibility of damage propagation to power buses. Damages on telecom points are also considered but not repaired as this falls within the competence of a telecom operator. Variables $a_{l,t}$ and $a_{i,t}^e$ give the availability of a power line l and a bus i , respectively; whereas $T_{i,t}^e$ and $T_{i,t}^c$ represent the electrical (e) and communication (c) availability of a telecom point i , respectively.

3) The telecom service is provided by a pre-defined access point for each connecting grid asset. Between telecom points, the hierarchical structure is followed as the upper entities provide the telecom service to lower entities.

4) The telecom network depends on the power grid through the energization of access points. A value 1 of the binary variable $y_{i,t}^e$ tells the ability of bus i to supply power at time t . Each access point has a back-up battery for use in case of defects in the primary power supply from the grid. The battery can secure supply for a period from some minutes to few hours, depending on chosen capacity and operation conditions.

$$T_{i,t}^c \leq T_{i,t}^e, \forall i \in W \cup X, \forall t \quad (3.5)$$

$$\frac{1}{M} \cdot (1 - f_i) \cdot (E_{i,t} + y_{i,t}^e) \leq T_{i,t}^e \leq M \cdot (1 - f_i) \cdot (E_{i,t} + y_{i,t}^e), \forall i \in W \cup X, \forall t \quad (3.6)$$

$$E_{i,t} = E_{i,t-1} - p_i^{disc} \cdot (1 - y_{i,t-1}^e) \cdot b_{i,t-1}, \forall i \in W \cup X, \forall t \quad (3.7)$$

Constraint (3.5) formalizes the availability of the telecom service at a safe AP ($f_i = 0$) only when power supply is available, either from the grid or the back-up battery (3.6). We adopt the simple discharge model in (3.7) to track the evolution of the battery state-of-charge (SoC) $E_{i,t}$. No battery degradation or losses are considered.

5) The power system depends on the telecom network to: i) notify the completion of manual switching, line repair, DG placement by intervention crews; ii) command circuit-breakers and remote switches from the control center.

$$a_{l,t} \leq u_{k,t}, \forall (k, l) \in U \times F, \forall t \quad (3.8)$$

$$sw_{l,t-1} - u_{k,t}^c (2 - a_{i,t}^e - a_{j,t}^e) \leq sw_{l,t} \leq sw_{l,t-1} + u_{k,t}^c \cdot a_{i,t}^e \quad (3.9)$$

$$\forall l = (i, j) \in L^r \cup L^{ar}, (k, (i, j)) \in U \times L, \forall t$$

Constraint (3.8) makes a repaired line seen available from the control center only when conveying this information is possible via an available AP (also applies for an installed DG). Equivalently, from (3.9) operating a remote switch (or a circuit-breaker) needs the availability of the telecom service.

6) For the dispatch of intervention crews, the form $c_{l,t}^k$ from [29] is extended here to $c_{l,t}^{dp,k}$, explicitly capturing that each crew k (visiting node l at time t) is linked to a given depot dp ; as well as integrate the widely used problem reduction techniques of pre-assigning damages and DG candidates to depots [28, 30, 29]. A depot is in charge of dispatching crews and DGs, whereas the clustering of damages and candidates is performed at the control center, which has access to the location of damaged components, the list of candidates for DG placement, and the estimation of traveling/repair times from diagnosis tools and technicians.

Pre-assignment of damaged lines to depots is based on the depot-damage distance [28, 30, 29]. We extend this approach by considering the distances between damages as well,

because a repair or MS crew will pass by many damages in its intervention plan before going back to the depot. Let a binary variable f_l^{dp} taking value 1 to assign a damaged line l to a depot dp , and 0 otherwise. A parameter $dist$ is used to hold the distances between depot-damage and damage-damage pairs.

$$\min_f \sum_{\forall dp} \sum_{\forall l \in F} \sum_{\substack{\forall m \in F \\ m \neq l}} \left(dist_{dp,l} \cdot f_l^{dp} + dist_{l,m} \cdot f_l^{dp} \cdot f_m^{dp} - K \cdot f_l^{dp} \right) \quad (3.10)$$

$$\sum_{\forall dp} f_l^{dp} \leq 1, \forall l \in F \quad (3.11)$$

$$\sum_{\forall l} f_l^{dp} \cdot Res_l^r \leq Res_{dp}^r, \forall dp \in DP \quad (3.12)$$

The small quadratic program in (3.10)–(3.12) minimizes the total travel distance of crews, while imposing in (3.11) damaged line l assignment to at most one depot, depending on the availability of repair resources Res_{dp}^r at each depot as indicated in (3.12). The term $(-K \cdot f_l^{dp})$, where K is a large positive number, is added to (3.10) to avoid the solution of not assigning any damage, which provides a minimal total distance of zero.

Candidate nodes are identified as not all nodes can receive DGs, especially that we consider truck-mounted DGs, which need considerable space. We identify the candidate nodes for receiving DGs based on pre-established criteria, which we choose here as: criticality of the connected load (hospitals, patients with high vital risk, etc.), accessibility through the road network, and adequacy of the node surroundings for DG installation. Inclusion in an affected zone from the damages in the grid is another criterion that can be added from the latest diagnosis information. These candidates are assigned to depots to improve the computational efficiency of the model.

$$\min_f \sum_{\forall dp} \left(\sum_{\forall g \in CD} dist_{dp,g} \cdot f_g^{dp} - K \cdot f_g^{dp} \right) \quad (3.13)$$

$$\sum_{\forall dp} f_g^{dp} \leq 1, \forall g \in CD \quad (3.14)$$

$$\sum_{\forall g} f_g^{dp} \cdot Res_g^{dg} \leq Res_{dp}^{dg}, \forall dp \in DP \quad (3.15)$$

The problem formulation (3.13)–(3.15) is assigning each candidate g to the closest depot dp with available DG resources Res_{dp}^{dg} , while minimizing the total traveled depot-candidate distance.

7) The scheduling rule in (2.14) is revisited here using the form $c_{l,t}^{dp,k}$ of variables rc , mc , and gc . The number of constraints is reduced in (3.16) and (3.17) by summing over the period $[t, t + \min(TT_{l,m}, T - t)]$, where T is the number of time periods.

$$\sum_{\tau=0}^{\min(TT_{l,m}^c, T-t)} \left(c_{l,t+\tau}^{dp,k} + c_{m,t}^{dp,k} - 1 \right) \leq 0, \quad \forall l \neq m, \forall (dp, k, l, m), \forall t \quad (3.16)$$

$$\min_{\tau=0}^{(TT_{g,1}^{gc}+TT_{n,1}^{gc}, T-t)} \left(gc_{g,t+\tau}^{dp,k} + gc_{n,t}^{dp,k} - 1 \right) \leq 0, \quad \forall n \neq m, \forall (dp, k, g, n), \forall t \quad (3.17)$$

Additional constraints in [3] limit the number of repair crews to 1 for any intervention site and impose differed arrival of MS/repair crews, where MS crews can conduct isolation before repair crews perform their task, or repair crews take charge of isolation and repair.

8) Each task among MS, repair, and DG placement is achieved when the specialized crew has spent at the intervention site the sufficient manual-switching time (MT), repair time (RT), and placement time (GT), respectively.

3.1.3 Solution Methodology

The DSR procedure takes damage information and the latest grid configuration from the output of the fast response stage. Clustering formulations in (3.10)–(3.12) and (3.13)–(3.15) are executed first to assign damages and DG candidates to depots considering the available restoration resources at each depot.

The proposed model involves constraints with some integer quadratic terms $x_1 * x_2$, such as equation (3.9), which are easily linearized by introducing an integer variable z as follows

$$z \leq x_1 \quad (3.18)$$

$$z \leq x_2 \quad (3.19)$$

$$x_1 + x_2 - 1 \leq z \quad (3.20)$$

Before solving the resulting MILP optimization, a simulation run of the hybrid model is used to generate a feasible schedule for use as a warm-start¹ for the branch-and-cut algorithm of the MILP solver. To demonstrate the effectiveness of this approach, we conduct warm-starting using: i) An infeasible, but meaningful solution: for instance, all switch status variables are set to 1 $sw_{l,t} = 1$, which cannot be the case in practice, but as most of the switches will be closed, this solution would differ in only some sw values with any feasible or optimal solution; ii) A feasible solution from the hybrid model; iii) A previous optimal solution. Solution times are summarized in Table 3.1 (each value is the average over 5 runs). The lowest computation time is obtained when a previous optimal solution is provided, which is not possible in practice, but shows that the solver indeed takes into account the warm-start input and use it to accelerate the solution procedure. Cases i) and ii) show an improvement compared to not considering warm-starting, and are both included in all implementations.

¹A warm-start in optimization is the procedure of using initial values for the variables to provide a

Table 3.1: MILP solution time using warm-starting for a generic case (141-bus, 6 faults)

	No warm-start	Infeasible solution	Feasible solution from the hybrid model	Optimal solution
Solution time (S)	184.6	70.5	72.89	34.97

The MILP is implemented in Python programming language utilizing the Pyomo package [97], which calls the IBM ILOG-Cplex solver with an optimality gap of 0.01% in an Intel Core i7 (2.5 GHz) and 32 GB RAM computer. Cplex uses an enhanced branch-and-cut algorithm where LP instances are solved using the simplex algorithm.

3.2 Example Case Study

3.2.1 System Setting

Detailed application of the model is reported in appended Papers [2] and [3]. The approach is demonstrated in a multi-feeder 36-bus MV distribution grid with a scenario of 8 damages (7 damaged power lines and one telecom access point). The illustration of restoration of the SDG to such event is summarized in Figure 3.3.

3.2.2 Results and Discussion

Paper [3] compares three strategy cases under two conductor configurations of *full-overhead* and *hybrid overhead-underground*. The considered strategies are: i) Perfect telecom-based: where all telecom points are assumed operating at all periods. This is an ideal case considered for comparison purposes. ii) telecom-agnostic: refers to the strategy adopted currently by DSO that conduct restoration operations, undergoing in the way any issue in the telecom service. iii) telecom-aware (proposed approach): restoration operations in this case are conducted while considering the prioritization of some telecom points (not necessarily all) that will contribute later to accelerate the restoration.

Figure 3.4 show that the perfect telecom case outperforms the other two case in both full overhead and hybrid configurations. Then, we see a clear improvement in the cumulative supplied power (supplied energy) with the telecom-aware case as the restoration strategy is able to steer intervention crew to sites where power supply can be restored

first guess towards solving the problem under investigation

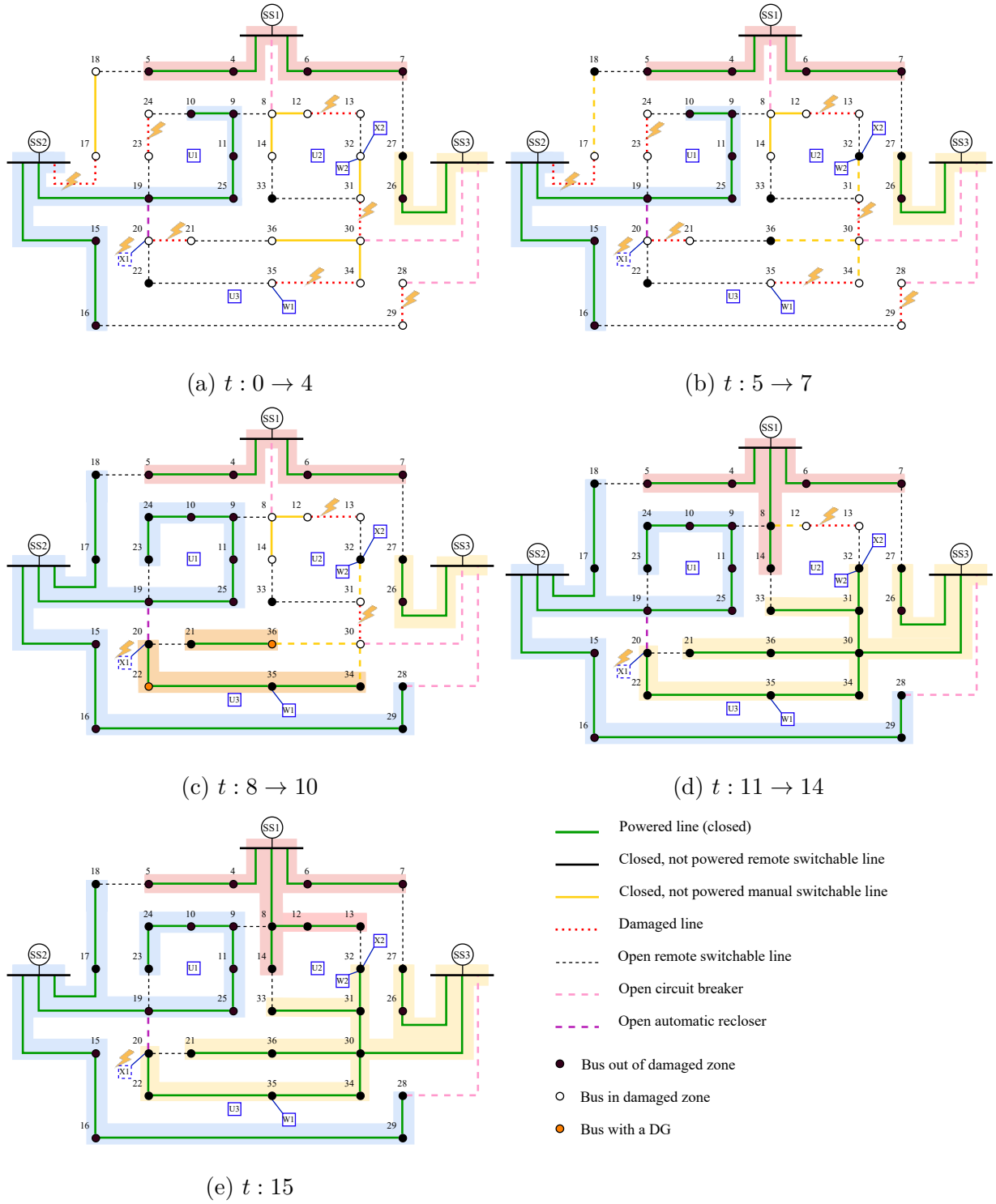


Figure 3.3: Illustration of key steps in the distribution system restoration for full-overhead telecom-aware case

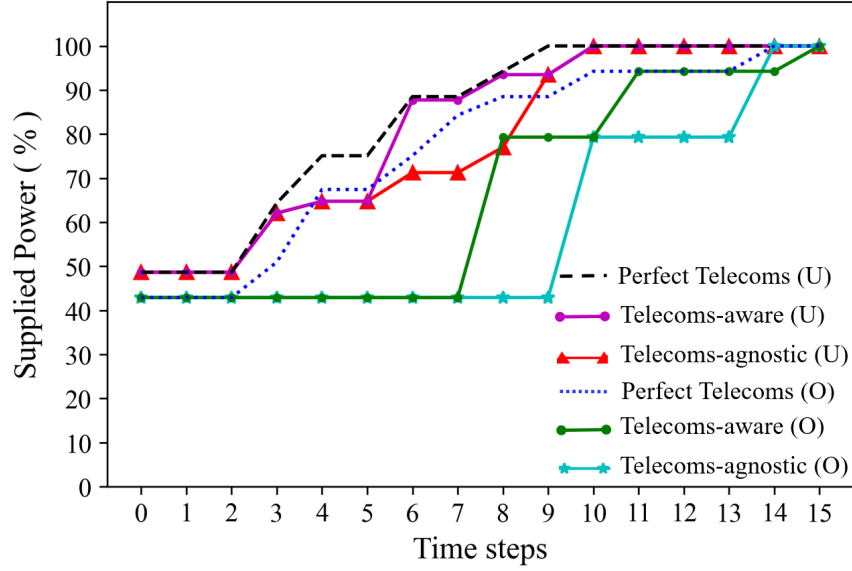


Figure 3.4: Evolution of supplied power during distribution system restoration

first to some communication points that use it accelerate the whole process. Again, the hybrid configuration beats the full-overhead one as the former is able to isolate better early into the event. Another interesting point is highlighted in the appended Paper [3] concerning the demonstrated benefit of introducing a fast moving manual-switching crew that succeeds to isolate some areas rapidly, allowing to recover a part of the grid.

3.3 Summary

The restoration process in distribution grids is modeled integrating power-telecom interdependencies and considering multi-resources. Reconfiguration switches, repair/MS crews, and DGs are coordinated by a telecom-aware MILP co-optimization yielding improved resilience strategies. The general cases of underground and overhead electrical networks are explored, revealing advantages of tight damage isolation. The proposed approach incorporates both the contribution of communication networks to DSR (by connecting remote switches and field crews to grid central functions) and power supply of telecom assets, for a comprehensive analysis of two-way power-telecom interdependencies. Results in Paper [3] show that co-optimization of resource allocation and telecom-aware strategic interventions improve the DSR, enhancing the overall resilience of the grid. The model is applicable to a medium size use case reported in Chapter 5 applicability of the model.

Chapter 4

Improved Distribution System Restoration using Hybrid Modeling

System modeling is a powerful and very flexible approach to deeply investigate complex phenomena by focusing on the most relevant features to gain valuable insights. The process of running a system model to represent the involved behaviors is referred to as *simulation*, where the model is executed over dynamic parameters (usually time) to observe the evolving operational conditions. Simulation can have a broader definition of modeling the system to the finest detail and computationally execute the model. Hence, we can safely call the detail-enhanced model in Section 2.3 a simulation in the sense of having advanced description of the system behavior.

After a model is run and solved, the obtained quantities may be interpreted and translated into general conclusions or even immediate actions. In the exact case of distribution restoration, types of actions that are sought include the execution sequence of switch maneuvers and crew dispatch. Given a problem formulation similar to Chapter 3, the output result can be implemented in different ways, for example: i) Execute the precise schedule of sending crews and operating switches at times specified in the solution; ii) Infer the sequence of actions from the solution and execute them in-the-fly considering the actual state of the grid at real-time. Option ii) is generally preferred as it is more robust and adaptive to field conditions, while conceding by construction that the predicted performance from the deterministic model may be altered regardless if the optimal solution is thoroughly executed. This chapter investigates to which extent the solution from the deterministic model is effective, then studies the parameters which affect the most the solution performance. An attempt to enhance the initial solution towards a new optimum is formulated using a hybrid optimization paradigm. Note in what follows the use of

optimal solution for the ideal solution taken from the deterministic model, and *optimum solution* for the targeted best solution under real system conditions.

4.1 Sensitivity Analysis

Deterministic analytical models help to find a solution that can be considered as a coarse schedule during operations [98]. The power system is known to be very complex and stochastic, meaning that in any case, no matter how good is the solution from a deterministic model, it may turn out to be sub-optimum as the conditions on the system change. The challenge then is more to, at least, have a solution that does not move away too far from its initial predicted performance and be as close as possible to the true, unknown, new optimum.

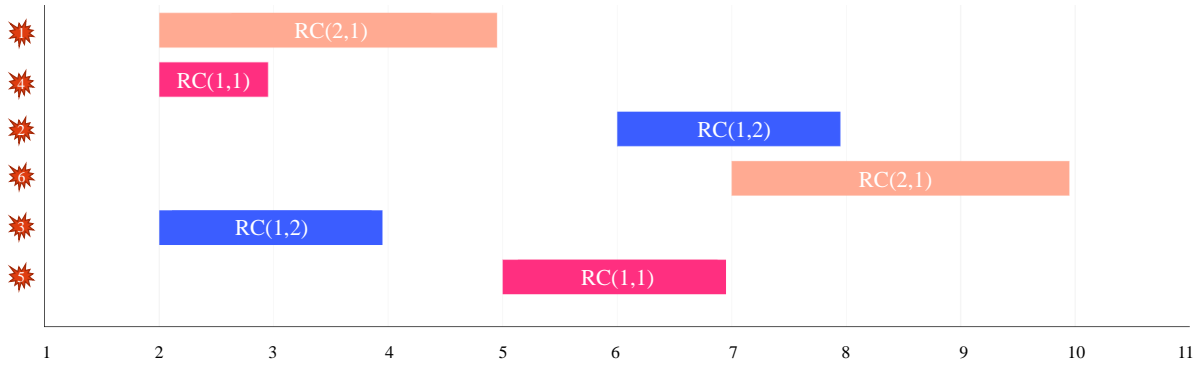


Figure 4.1: Gantt chart for the schedule of repair crews on damaged lines

Without loss of generality, a reduced version of the DSR problem in Chapter 3 is considered in this section (no DGs and isolation crews, only resources of repair and reconfiguration), but no pre-assignment of damages is assumed, meaning that any crew can repair a given line. The problem is solved for a 141-bus case study under a scenario of 6 damaged lines. From the timeline of repair in Figure 4.1, the sequence of repairing lines is to be taken for implementation in the simulation model. The resulting sequence is $\{4, 3, 1, 5, 2, 6\}$. A sensitivity analysis is conducted on repair time and its effect on the performance of the solution.

Figure 4.2 illustrates the evolution of supplied power in terms of repair time in the range $[0.5, 6]$ hours. The performance of the solution is not heavily affected and remains within 10% of the MILP obtained performance under a considerable change in repair time, which corroborates the effectiveness of the MILP model, despite many abstractions and simplifications. However, when dealing with extreme events, the small percentage can be

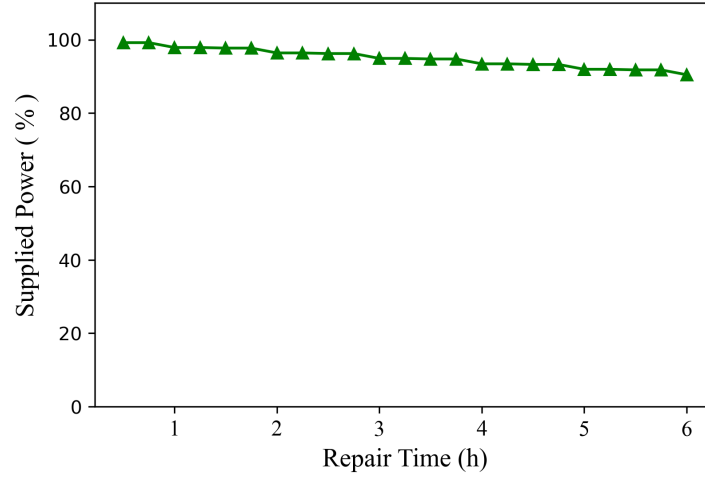


Figure 4.2: MILP solution sensitivity to repair time

Table 4.1: Parameter settings for DSR use-case

Depot	Repair Crews (RC)	Travel Time (TT)
DP 1	RC(1,1), RC(1,2)	2h
DP 2	RC(2,1)	2h
Telecom Point	Battery Duration	
Aggregation Point	AggP1	15h
Fixed Access Point (X)	X1, X2	3h
Wireless Access Point (W)	W1, W2	1h

vital, and many recent works consider uncertainties in repair and even travel times [99, 100]. Note that the cases of long repair time did not cause a high performance drop, especially that telecom points consume all their battery storage. The reason is that the effect of the availability of telecom points by keeping crews longer at damage sites represents an endogenous uncertainty to the repair time, which is out of the scope of this study. Only the random component of the uncertainty in repair time is considered, not including the waiting time for re-connection where above endogenous uncertainty arises. Finally, The repair time is selected here for further analysis as the travel time is relatively well modeled by proportionality with distance and the linkage to road networks. Tables 4.1 and 4.2 give the default parameters of the case study used in this section and later in the chapter.

Table 4.2: Repair time setting

Line	1	2	3	4	5	6
Repair Time (h)	3	2	2	1	2	3

4.2 Solution Evaluation Under Uncertain Repair Time

A strong assumption is adopted in this chapter by considering that the simulation model is close to the real system and an optimal solution evaluation can be conducted therein. This is motivated by the utmost focus of the study on the methodology to enhance the performance of an optimal solution when confronted with non-deterministic (quasi-) real conditions. Having that in mind, the proposed approach surely depends on the validity and quality of the simulation, but still gives important insights.

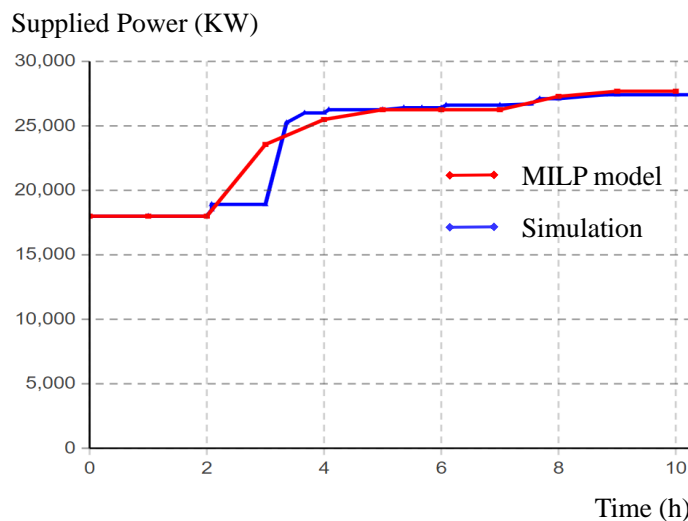


Figure 4.3: Performance comparison of the MILP solution

The simulation is set to run the DSR process including the uncertainty in repair time, which is not captured in the MILP model of Chapter 3. A Weibull distributed repair time [35] is introduced with a shape parameter $k = 7$ and a scale parameter $\gamma = 2.3$, which produces values around the repair times used in the MILP, reported in Table 4.2. The repair sequence from the MILP is injected into the simulation that runs it and collects the performance in terms of supplied power and time of line repair. Figure 4.3 shows the comparison between the performance given by the MILP and the obtained results from the simulation. The MILP solution underperforms in the simulation model due to different repair times, despite the values being on average equivalent to the repair time values in Table 4.2. The repair sequence from the simulation $\{4, 1, 3, 2, 6, 5\}$ (Figure 4.4) differs from the specified one from the MILP.

The simulation test of the solution shows the reduction in performance, but does not provide information on whether the MILP solution is still optimal. Consequently, we try to check if there is a solution that achieves a better performance in the simulation

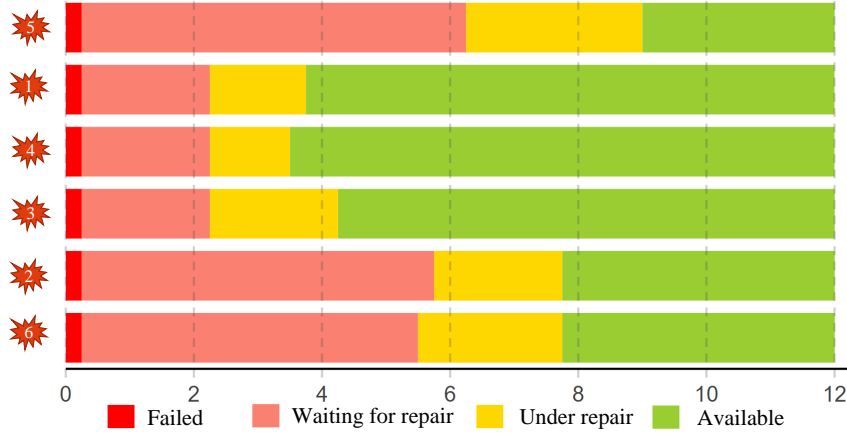


Figure 4.4: Repair sequence from MILP solution implementation by the simulation model

model, then work on a proposal to generalize the methodology of finding new solutions that outperform the initial MILP solution in a more realistic setting.

4.3 Solution Enhancement

The simulation is used in this section to help improve the obtained solution from the MILP model. Simulation is generally used to conduct *what-if* studies, analyze sensitivity, and evaluate the system performance under various scenarios. Although used also in decision-making, simulation does not provide action recommendations, as it is completely up to the user to retrieve the adequate information for a given decision-making task [101]. As such, a growing interest is seen to extend simulation using optimization techniques in order to improve its applicability to decision-making, while keeping the advantages of a good system description [102].

Simulation-based optimization is the most popular of such applications, where the simulation model evaluates the objective function by iterative calls from an optimization procedure [103]. The role of the optimization is to efficiently guide the exploration of the solution space, while the simulation is providing an evaluation of each proposed solution from the optimization [104]. A different approach is adopted in this work as the simulation is not used just for objective evaluation, but the feedback from the simulation is leveraged to update the optimization model itself [39, 105, 102] at the cost factors of the optimization objective. Figure 4.5 shows the general layout of the proposed *simulation-optimization* or *hybrid optimization* approach, where the optimization model sends a repair sequence for execution at the simulation model, and collects the resulting performance (supplied power). This feedback updates the MILP to prepare the next run in the iterative process.

The vector \mathbf{a} of the availability of lines conveys the information on the repair sequence, whereas \mathbf{p} contains the supplied power on the grid after implementing a given sequence in the simulation.

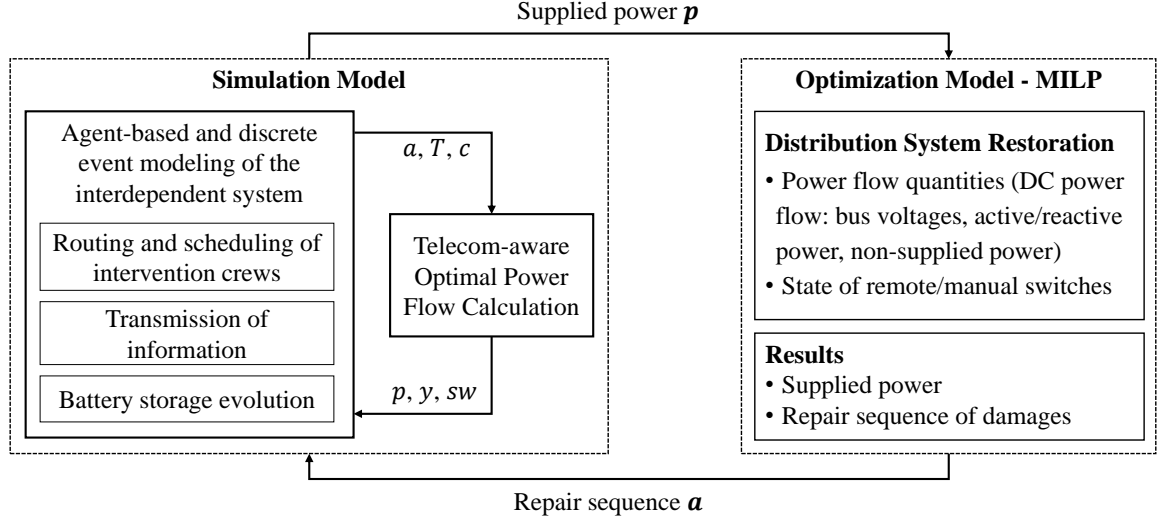


Figure 4.5: Layout of the hybrid optimization approach

4.3.1 Simulation Model

The hybrid model from Section 2.3 is used as a simulation model in the proposed approach. The simulation takes a sequence of repairs as an input and executes it to collect performance indicators. The sequence of damages is put in a repair queue shared by all depots. Any idle crew queries the repair queue to get the next damage to repair by choosing the closest damaged line. The access to the queue is managed by a first-arrived first-served rule, imposing a random tie-break if two crews attempt to access the queue simultaneously. The constraints on the co-location of crews and exclusivity of repair tasks are inherently satisfied.

The telecom points are also represented in the simulation and their state tracked by monitoring the supply from the grid and the battery level. The choice of constraints to evacuate to the simulation model is really dependent on the desired level of tractability in the new MILP. The approach even allows to have some important system constraints represented in both the simulation and the optimization model, which is the case with PF constraints here.

4.3.2 Optimization Model

A simple MILP optimization model is constructed to interact with the above presented simulation model. The new MILP is set to solve for the optimal repair sequence that guarantees the best restoration considering topology and PF constraints only. The routing, scheduling, and telecom complicating constraints in the comprehensive DSR problem of Chapter 3 are implemented in the simulation, resulting in a smaller MILP to solve. The interaction with the simulation helps to incorporate all aspects of the problem and adjust the solution.

$$\min_{p,d,sw,a,y,w} \sum_{\forall t} \left[\alpha \sum_{\forall i \in N} C_i^{ns} \cdot p_{i,t}^{ns} + \beta \sum_{\forall l \in F} C_l^{rc} \cdot a_{l,t} + \gamma \sum_{\forall l \in L} C_l^{sw} \cdot w_{l,t} \right] \quad (4.1)$$

Equation (4.1) gives the objective function of the optimization problem, which seeks to minimize the cost of non-supplied power, and consider secondary objectives of reducing repair and switching costs ($\alpha \gg \beta, \alpha \gg \gamma$). Parameters C_i^{ns} and C_l^{rc} represent cost factors for the non-supplied power and line repair, respectively. Both can be updated from the simulation result at each iteration, bridging the simulation and the optimization. We omit for now the update of C_l^{rc} in order to understand the individual effect of each cost, where C_i^{ns} is surely more influential given the setting of the objective.

$$\sum_{\forall l \in F} a_{l,t} = 1, \forall t \quad (4.2)$$

Constraint (4.2) fixes to 1 the number of repaired lines at each step, enforcing an order in the restoration of the damaged lines. This is used in addition to failure propagation, radiality, and PF constraints from previous chapters. Note that a number of time steps equal to the number of damaged lines is sufficient to solve the problem.

4.3.3 Iterative Algorithm

The proposed approach is based on the observation that whatever is the solution from the MILP for the DSR (or any other applied type of optimization), the implementation will generally not follow the exact schedule but rather infer a sequence of tasks. The idea then is to directly solve the MILP for the sequence, which is an easier problem compared to finding all the crew schedules. The implementation of the complicating constraints (routing, scheduling, and telecom) in the simulation makes the optimization problem tractable in most cases. The MILP provides a "believed" optimal sequence to the simulation, which runs it and returns statistics on the performance of the solution in

terms of supplied power. This information is used to update the MILP, which takes it into consideration for the next proposed solution. In that sense, the MILP seeks optimality by exploring the solution space, while the simulation is helping to guide the search by providing feedback on the performance of feasible solutions [106].

The iterative process is stopped when a solution is proposed K consecutive times to the simulation (we let $K = 3$). The proposed methodology is outlined in Algorithm 1.

Algorithm 1 Algorithm of the hybrid optimization methodology

Initialize the cost of non-supplied load $C_i^{ns}, \forall i \in N$

Run initial optimization (MILP) with initial C_i^{ns}

$Seq \leftarrow \text{MILP}(C^{ns})$

while Repair sequence Seq did not converge **do**

 Run a simulation $\text{Sim}(Seq)$ using the repair sequence from MILP

 Update the MILP objective function cost factors: $C_i^{ns} \leftarrow \text{Sim}(Seq)$

 Run an MILP optimization using the results from the simulation

 Get the repair sequence: $Seq \leftarrow \text{MILP}(C_i^{ns})$

end while

The algorithm converged and the best performing repair sequence Seq selected

The approach is successfully demonstrated in Paper [4] for a 141-bus configuration considering a scenario of 6 damaged lines.

4.4 Summary

This chapter proposes a methodology to leverage the developed hybrid model in Chapter 2 for solution evaluation and enhancement under repair time uncertainty. The MILP solution for the DSR problem is implemented in the simulation to evaluate its performance and identify some parameters that influence it. The simulation is used next iteratively to assist a MILP in the solution procedure, by only keeping switching and PF constraints in the MILP and implementing the remaining complex constraints in the simulation. The MILP is solved for the sequence of line repairs that are translated into crew interventions in the simulation to assess the solution performance. A feedback on the achieved supplied power is returned from the simulation and used to update the objective cost factors of the MILP. Simulation results show that the converged sequence (which is taken as the final solution) performs better than the initial solution from the MILP. Moreover, the obtained solution is expected to be computed in a shorter time and perform close to the optimum solution (can

be checked if the optimum is known from other methods, like stochastic programming). The enhancement would be even higher in case of more stochastic environments, which is left for future work.

Chapter 5

Applications

The models and approaches developed in this thesis have been carried into various applications around the resilience of SDGs. This Chapter presents the main results and insights with reference to appended papers for further details.

5.1 Telecom-aware Optimal Planning and Restoration

5.1.1 Planning new RCS Deployments for Faster Response

Chapter 3 briefly discussed the role of fast response in reacting to damages in the distribution grid and preparing later intervention through advanced restoration operations (the DSR). The fast response occurs within some minutes of the event to remotely isolate damages and restore a portion of the lost load, mainly using remote switches [60, 93]. Three phases can be taken from Paper [5] to describe fast response: i) Automatic isolation: involves automatic opening of circuit breakers to protect primary substations, as well as the opening of auto-reclosers¹ when available in overhead lines; ii) Remote isolation: uses RCSs to reduce the wide automatically isolated zone. RCSs are opened wherever they allow to isolate some nodes from damaged zones; iii) Reconfiguration: successful isolation in previous phases allows to restore some loads. Topological, PF, and zone isolation conditions are verified before any reconfiguration in the network.

Through necessary use of RCSs, the fast response stage depends on the availability of telecom networks. At this stage, damages due to shortage of power supply are excluded for telecom points given their battery storage, but physical (or even cyber) contingencies can occur. As a result, DSOs are continuously faced with the problem of choosing the

¹Auto-reclosers or automatic circuit reclosers (ACRs) are electrical components very similar to circuit breakers in having voltage and current sensors and protection relays to mitigate transient faults [107]

right telecom technology and architecture to resiliently connect their legacy assets and new deployed components. Paper [5] considers the case of a new RCS deployments (upgrading manual switches to RCSs), where switches can be connected to one of two generic wireless technologies: i) Technology T: more redundancy of telecom access points, but less coverage and battery storage; ii) Technology R: less redundancy, but more coverage and battery storage. The objective is set to maximize the supplied power during fast response to damages in the telecom points and power lines, as given in (5.1)

$$\max_{p, sw, y, Tel, w} \sum_{\forall SC} p_{sc} \left[\left(\alpha \sum_{\forall i \in N} p_{i,t,sc}^{load} + \beta \sum_{\forall k \in Tel} \sum_{\forall l \in L} a_{k,l} \cdot batt_k \right) - \gamma \sum_{\forall l \in L} C^{sw} \cdot w_{l,t,sc} \right] \quad (5.1)$$

with $p_{i,t,sc}^{load}$ the supplied power to node i at phase t ; $a_{k,l}$ the decision variable indicating if line l is connected to telecom point k ; $batt_k$ the battery capacity of telecom point k ; y the vector of connection state of loads; p the vector of electrical quantities; Tel the vector of telecom points states; and sw the vector representing the statuses of switches. Index $t \in \{0, 1, 2, 3\}$ indicates the different phases². The constants α and β allow to tune the trade-off between restoring the maximum immediate load, and making best anticipative choices in terms of telecom points redundancy and battery storage, which will be advantageous for service restoration. Coverage is processed as an input to the model where a telecom point considers serving line switches within its coverage area only.

$$\sum_{\forall k \in Tel} \sum_{\forall l \in L} a_{k,l} \leq B \quad (5.2)$$

Inevitably, the deployment has a restricted budget B , expressed in (5.2) as the number of possible new RCSs that connect to adequate telecom points. The remaining constraints of fast response are based on the the failure propagation, radiality, PF, and telecom constraints introduced in Section 2.2. Unlike reconfiguration ($t = 3$) that should be optimized, the isolation (automatic and remote) follows deterministic rules characterizing CBs, ACRs, and RCSs. These are embedded to the MILP as linear constraints reported in Paper [6], which is giving more details on the modeling of fast response throughout the whole dissertation work.

A computational experiment is conducted in a modified 36-bus distribution system (Figure 5.1, possibly served by 7 telecom points. All telecom failure scenarios are enumerated and included with a given probability p_{sc} , forming the MILP deterministic equivalent

²Unlike the DSR model where evaluation steps correspond to instants in the homogeneous time, the small time-scale (seconds to minutes) in the fast response makes it more convenient to have a correspondence between each phase and a step index: initial phase $t = 0$, automatic isolation $t = 1$, remote isolation $t = 2$, and reconfiguration $t = 3$.

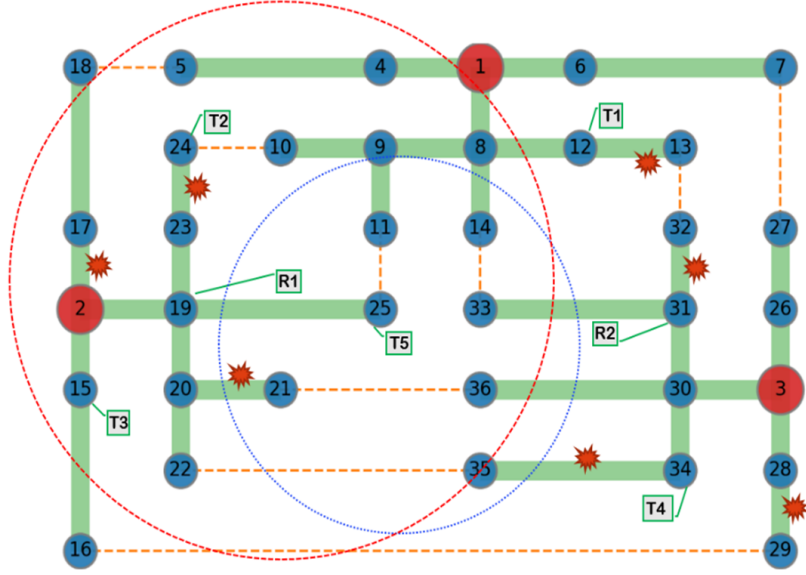


Figure 5.1: Test case with 36 power nodes and 7 telecom points [5]

of a stochastic problem. Only one power line failure scenario is considered in Paper [5] to focus on the impact of telecom failures.

Results and Discussion

The deployment budget was first fixed to $B = 3$ and failure scenarios classified based on the number of failed telecom points. Evaluating the fast response under each class of failure scenarios confirms that the restored power at this stage is limited (even with no telecom failures), while reducing when the number of telecom failures increases. In the other hand, fixing the number of failures and increasing the budget B shows an improvement in supplied power. Interestingly, beyond a given budget, power restoration saturates, indicating that there is a minimum number of new RCS beyond which no restoration is possible. This is an important insight for DSOs that want to achieve the best restoration, while reducing their deployment costs.

Table 5.1: Supplied power considering new-RCS deployment with varying budget B and number of telecom damages = 3

	Initial setup (B=0)	B=1	B=2	B=3	B=4	B=5	B=6	B=13
Circuit Breakers	1-4, 16, 1-8, 2-15, 2-17, 2-19, 3-26, 3-28, 3-30							
Remote Controlled Switches (RCS)	22-35, 14-33, 15-16, 31-33, 10-24, 5-18, 21-36, 11-25, 26-27, 13-32, 7-27, 16-29, 9-11, 4-5	17-18 {R1}	8-12 {T1,T4}	19-23 {T2,T3,T4}	30-31 {T1,T5}, 30-34 {R2}, 19-23	19-23 {T2,T3,T4}	8-9 {T1,T3,T4}	All lines are RCS
Manual Switches	8-9, 20-22, 12-13, 20-21, 30-31, 6-7, 31-32, 19-23, 9-10, 30-34, 30-36, 23-24, 19-20, 17-18, 28-29, 8-12, 8-14, 34-35, 19-25	17-18	8-12	19-23	30-31, 30-34, 19-23	19-23	8-9	
Supplied Power (%)	29.5	30.16	30.63	30.79	30.94	31.1	31.1	31.1

As shown in Table 5.1, by closely inspecting the setup of the network, the lines which can possibly be served by one T point and one R point (17 – 18, 30 – 34), tend to choose the R point as it has more resilience in terms of battery storage. At the same time, lines which are in the covered vicinity of one R point and multiple T points, choose rather the T technology for the offered redundancy of access.

To test the contribution of fast response to the overall restoration, the result from this stage for different budgets is fed to a restoration process where repair crews intervene. Figure 5.2 shows the restoration curves, where the increasing budget in RCS deployment not only improve fast restoration ($t = 1$ in Figure 5.2), but also contributes to the whole restoration process.

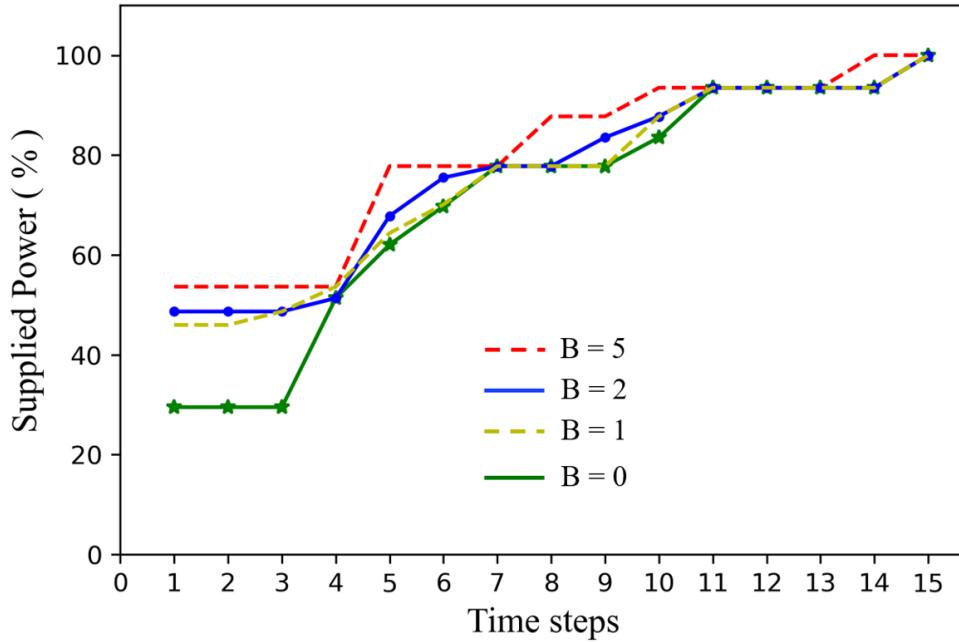


Figure 5.2: Evolution of restoration in terms of supplied power under different budgets

5.1.2 Restoration in Larger-Scale Distribution Grids

The proposed DSR optimization in Chapter 3 model and papers [2, 3] was demonstrated in the modified 36-bus system. This section shows the application of the model to a medium (to large) distribution grids. A realistic 315-bus system is constructed from the open data of the french main distribution operator *Enedis* [108]. An initial network of 4 primary substations (HV/MV substations) is selected, containing 25 feeders and thousands of MV line segments. As the targeted size was in the order of hundred buses, we chose to reduce the detailed network by: i) simplifying the lines: the considered data represent a power line as a collection of line segments that significantly increase the number of lines. We

bring these data to the standard definition of a line as one segment connecting two power buses. We pay attention to keep the information on the presence of remote switches. ii) Aggregating MV loads: even with line simplification, the number of buses was still high. A valid approach is to aggregate MV loads into the feeder's mainstream. iii) Aggregating by neighborhood: a smaller use-case is designed by a random successive removal of one of each two buses spaced with less than a given threshold, set to 1Km. Step ii) yields a 14-feeder use-case with 4 primary substations, 311 MV buses, and 324 MV lines (among which 64 are remotely switchable), while step iii) returns a 12-feeder use-case containing 4 primary substations, 141 MV buses, and 150 MV lines (among which 34 are remotely switchable). Applied processing allows to keep the overall network structure as shown in Figure 5.3, which include in figures 5.3c and 5.3d the 10-line damage scenario considered in this section. A damage in one fixed access point is considered (X1). Simulations are

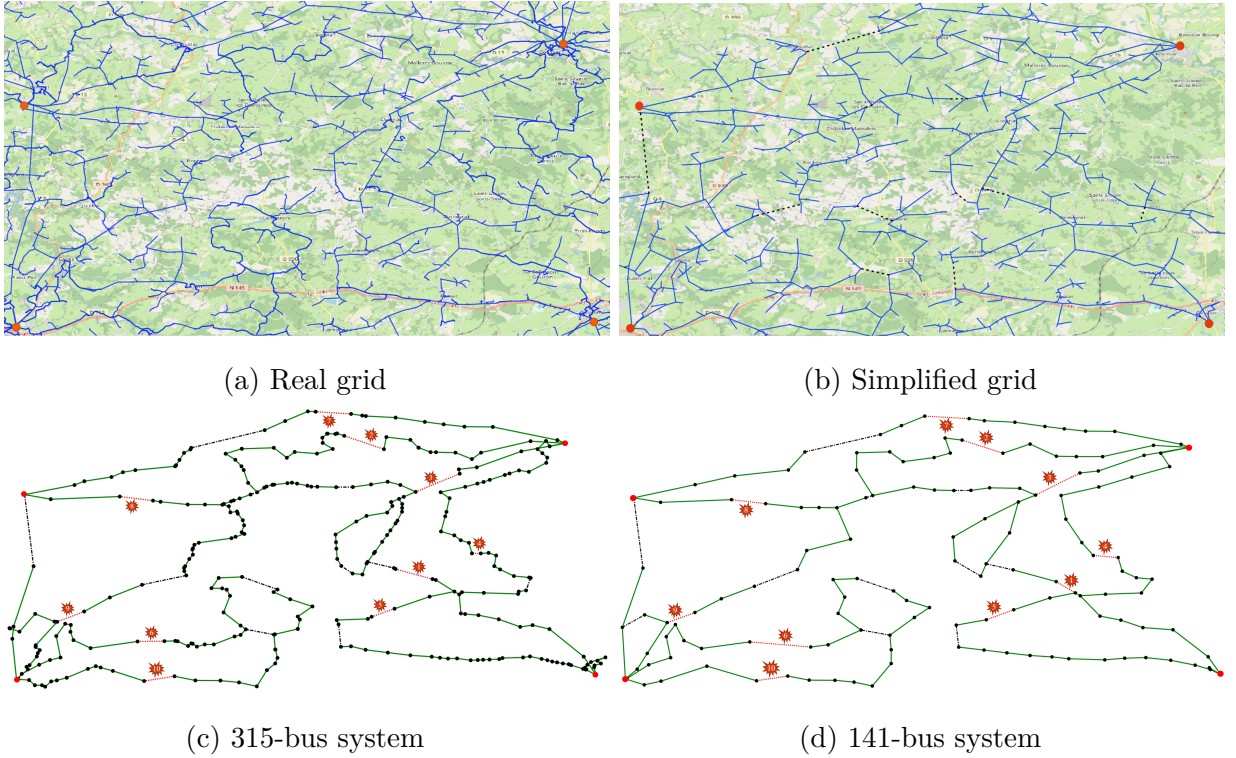


Figure 5.3: Steps of data processing for realistic use-case construction

conducted in both configurations to evaluate the computational complexity of the model and confirm the insights from the 36-bus use-case. Tables 5.2 and 5.3 summarize the parameters used. In addition, the manual switching time (MT) is set to $1h$, and the travel times of intervention crews are proportional to the distance, where manual-switching crews are the fastest, then DG placement crews, then repair crews. Four candidate nodes $\{CD1, CD2, CD3, CD4\}$ are identified for possibly receiving a DG with placement times GT of $1h$, $2h$, $1h$, and $1h$, respectively. The restoration model is run with a time step of $1h$ for

Table 5.2: Parameter settings for DSR use-cases

Depot	Repair Crews (RC)	Manual-switching Crews (MC)	DG Placement Crews (GC)
DP 1	RC(1,1), RC(1,2)	MC(1,1)	GC(1,1)
DP 2	RC(2,1), RC(2,2)	MC(2,1)	-
DP 3	RC(3,1)	MC(3,1)	GC(3,1)

Telecom Point	Battery Duration	
Aggregation Point	AggP1	15h
Fixed Access Point (X)	X1, X2	3h
Wireless Access Point (W)	W1, W2	1h

Table 5.3: Repair time setting

Line	1	2	3	4	5	6	7	8	9	10
Repair Time (h)	3	2	2	2	2	2	1	1	3	3

a 10h horizon, which is a realistic window given the work shifts of different crews and the updates from data collection within this period. The MILP is implemented in Python Pyomo, which calls the IBM ILOG-Cplex solver with an optimality gap of 0.01% in an Intel Core i7 (2.5 GHz) and 32 GB RAM computer.

Results and Discussion

Three cases are defined in Paper [3] to evaluate the contribution of telecoms: i) Perfect telecom (Case 1): an ideal case, serving as a baseline, where communications are neither affected by a direct damage nor a power supply shortage; ii) Telecom-agnostic (Case 2): a case corresponding to current DSO practices, where telecoms can fail due to a damage of power shortage, but are not taken into account in the organization of restoration operations; iii) Telecom-aware (Case 3): the case implementing the proposed approach of strategically restoring buses to recover telecom points that help accelerate the restoration. Note that results of Case 2 are obtained by first solving the DSR problem under *perfect* communications (Case 1), then the obtained solution for crew allocation (the sequence of dispatching crews) is used to solve for the remaining variables of telecom and switch states as well as power quantities.

The performance of the restoration is evaluated in terms of the supplied power as shown in Figure 5.4. In both configurations, the perfect telecom case achieves the best performance and serves as an upper bound for the considered restoration. For the 315-bus

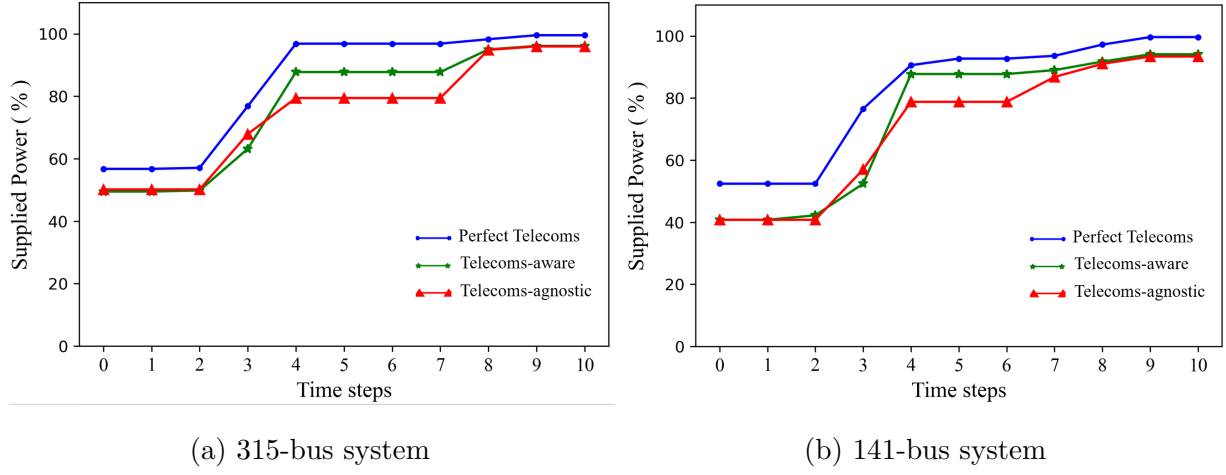


Figure 5.4: Evolution of supplied power during DSR

system, Case 1 is above cases 2 and 3 by 13.27% and 9.65% of total supplied power over the considered period, respectively. Similarly, for the 141-bus system, the difference between the perfect case and cases 2 and 3 is 14.6% and 10.4%, respectively. This indicates a considerable over-estimation of the restoration capacity of the grid that applies when telecom assets are not considered. Interestingly, Case 1 has more supplied power even at initial and very early steps of the restoration. After inspection, the improvement could be achieved during the fast response stage, as the perfect availability of telecoms allowed to maneuver some critical switches. Previous Figure 3.4 did not show such a behavior, as in that configuration there was no retained fast (remote) reconfiguration due to the unavailability of the telecom service. It is worth mentioning that in Chapter 3, the telecom service redundancy is ensured for line switches, which is not considered here for the sake of inspecting a different telecom layout, and to avoid heavy computation; as a test was conducted for the 315-bus system, yielding no optimal solution after 30 mn (with 19% gap).

In addition to demonstrating the impact of communications, the telecom-aware proposed approach is notably able to propose a restoration strategy that outperforms Case 2 in the two configurations. This relies on a strategic restoration of specific buses that help recover the telecom service, which contributes to the overall restoration operations.

The model is reasonably tractable for the considered cases. The bigger 315-bus system was solved in 225.3 seconds and 267.4 seconds for the perfect and telecom-aware cases, respectively (average over 10 simulation runs); while for 141-bus system the solution times were lower as 55.96 seconds and 58.66 seconds for the perfect and telecom-aware cases, respectively. The perfect case does not include telecom considerations as in the telecom-aware case, suggesting that associated constraints do not highly impact the computational

performance of the model. However, it has been observed that the solution time explodes when important parameters (like: battery duration, repair time, manual-switching time, DG placement time, travel times) are reduced or the number of resources is increased, suggesting that the variation of these parameters calls for more tasks to be conducted in the defined optimization horizon, which highly increases the search space. In the other hand, if the parameters are worsened (e.g. increase of times, reduction of resources), the model would require a larger window to solve for complete restoration, which render the computation challenging. Hence, the combinatorial nature of the problem at hand can be limiting for large and very large grids, but application to medium-size grids is efficiently achieved, which allows to reveal essential SDG characteristics.

5.2 Grid-scale Simulation

A novel valuation of the power-telecom resilience quantification is presented in this section by linking resilience assessment to the service level agreement (SLA) between a telecom and a power operator. Next, the simulation is demonstrated to provide a benefit in running *what if?* analyses to support grid operators during crisis management.

5.2.1 Service Level Agreement Definition

A power operator owns a part of the ICT infrastructure in the grid, but relies on tier parties, typically telecom operators, to provide and manage substantially or entirely some communication services [109]. An agreement binds the telecom operator to provide a service with pre-defined metrics such as availability, maximum service interruption duration, guaranteed time to repair, latency, etc [110]. Levels of penalty are also defined to guarantee adequate compensation for the power operator. This is very similar to the regulation from national energy authorities³that compel energy operators (including electric power operators) to well defined targets in terms of security and quality of power supply [111]. Precisely, a link is established in this section between the penalty that a DSO may incur from the regulator due to a failure in securing supply to customers, and the penalty applied to a telecom operator. This relies on thoroughly identifying the part of supply loss that can be imputed to a telecom service deficiency.

As such, the penalty is calculated in this work based on the *public grid usage tariff*⁴

³In France, this corresponds to the energy regulation commission – in french Commission de régulation de l'énergie (CRE) [112].

Table 5.4: Average MV outage duration incentive-penalty calculation [113]

Computation	The average MV outage duration of year n D_n^{MV} , also called criterion-M, is defined as the average time of long outages (over 3 minutes) for MV customers, weighted by the subscribed power of these same customers on December 31 st of year n .
Scope	D_n^{MV} is determined excluding incidents resulting from exceptional events (more than 100,000 customer loss) and excluding causes related to the public transmission grid (or load shedding).
Follow-up	<ul style="list-style-type: none"> - Calculation frequency: monthly - Frequency of feedback to the regulator: quarterly - Publication frequency: quarterly - Frequency of calculation of incentives: annual
Objective	Reference objective D_n^{ref} <ul style="list-style-type: none"> - 2021 : 42.1 mn - 2022 : 41.8 mn - 2023 : 41.5 mn - 2024 : 41.2 mn
Incentive	Bonus (or penalty for negative values) = 5.9 M€ * ($D_n^{ref} - D_n^{MV}$)

regulation in France [113]. A financial incentive-penalty (bonus-malus) is defined therein for service continuity at the MV level as summarized in table 5.4

Equation (5.3) calculates D_n^{MV} over a whole year for all MV loads (customers). The contribution of each customer to the total yearly cost is deduced in (5.4), where p_i represents the subscribed load by a MV customer i .

$$D_n^{MV} = \frac{\sum_{year\ n} \text{duration of long outages for MV customers weighted by their demand}}{\text{Total subscribed power at the MV level on December 31st of year } n} \quad (5.3)$$

$$C_i = \frac{p_i}{\sum_{\forall i} p_i} \cdot 5.9 \quad (5.4)$$

The cost C_i (in k€) is used thereafter as a marginal cost for an outage at node i . This is obtained by applying a factor of 1/1000, given the considered case study below that represents (with its total 27MW) approximately 1/1000 of the national electricity load in France. Particularly, when an outage at a node or the inability to restore it is caused by the telecom service, the cost C_i applies for the given duration Δt . The quantity $C_i \cdot \Delta t$ represents a compensation that a DSO can request from the telecom operator for undergone costs (or loss in bonus-gaining performance indicators).

The approach can be applied in real-time using supervisory tools that track telecom-based incapacities and save the duration for later cost calculation. Another possibility, is to proceed at post-event by using saved equipment traces and logs, as well as the timeline

⁴Produced by the french energy regulator to settle the level at which grid operators are remunerated and well specify performance targets (In french tarif d'utilisation du réseau public d'électricité –TURPE).

of restoration operations, which help identify the situations where the penalty applies. We opt for the second approach, as possibly lacking or not shared information from the telecom operator (like the availability status of telecom points during an event) can be simulated based on known data (e.g. battery storage) to demonstrate the proposal.

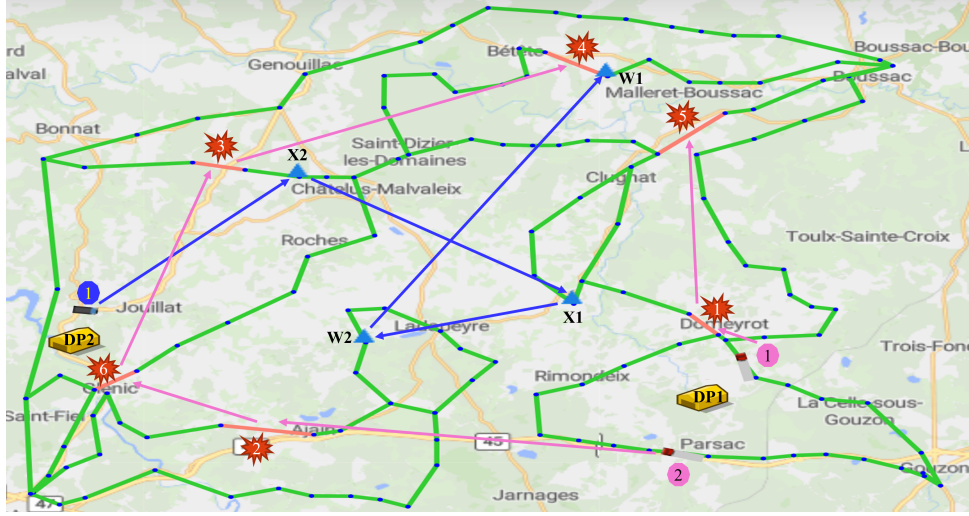


Figure 5.5: A 141-bus system with 5 damages

A configuration and system settings similar to the 141-bus seen before are considered, with 6 damaged lines, colored red in Figure 5.5. Depots and moving intervention crews are also depicted. Depot 2 (DP2) is assumed to belong to a telecom operator, where crews are sent to conduct tasks at access points without any particular attention to the connectivity of grid assets, as this is not a requirement and the telecom operator conducts the repairs that suit its own strategy. A telecom crew adds another option of power supply recovery at the access point (alongside grid power and battery storage) by installing portable mobile DGs. For simplicity, two grid intervention crews and 1 telecom crew are considered, alongside 4 access points (W1, W2 wireless with 1h battery duration, and X1, X2 wired with 3h battery duration). The repair timelines of grid intervention crews are reconstructed as shown for repair crews 1 and 2. The telecom crew is set to visit the closest site to its location (closest by route), yielding a valid strategy that may not suit the needs of the grid. Note that it could be simpler to just consider the battery storage of access points as no precise knowledge is detained concerning the restoration strategy of a telecom operator. The choice here is to try to find a reasonable and fair compensation basis to include in the SLA, which the addition of scenarios with telecom repair will avoid overestimating.

The telecom crew is assumed to move slower than grid crews to represent the fact that DSOs are urged by authorities, industries, and the public to react rapidly given the vital

role of electricity, while as important as communications are in the modern world, there is still some tolerance for connection loss.

Results and Discussion

From the considered crew timelines shown in Figure 5.5, the situations where the restoration of the grid was slowed down by the unavailability of telecom points can be identified by replaying the restoration process in the simulation, while adding the telecom dynamics of battery discharge and telecom restoration. The performance of the restoration is evaluated in four cases: I) Perfect telecoms; II) Telecom repair considered and grid crews staying at the repaired node if no connection; III) Telecom repair considered and grid crews setting the repaired line as normally-open (can be restored remotely later), while going to another location; IV) No telecom crew intervention.

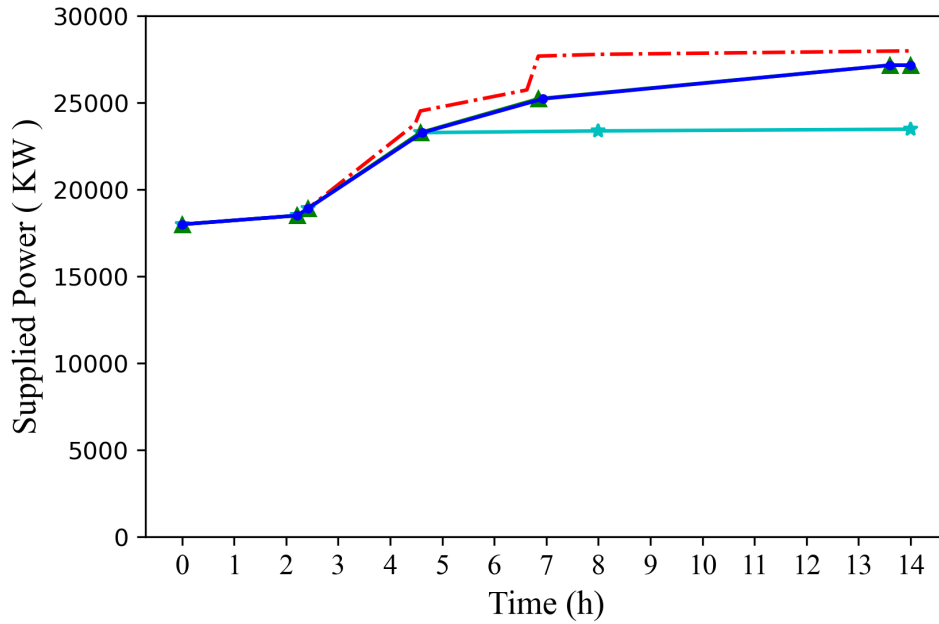


Figure 5.6: Supplied power under different restoration conditions

Figure 5.6 assembles the supplied power results for the four cases. The baseline case of having the telecoms running during the whole restoration achieves the best performance; while Case IV is the worse as telecom points could sustain the event at the beginning, but finally had the batteries emptied, which halted the whole restoration process. The grid repair crews cannot communicate with the control center, causing no reconnection of repaired lines. Cases II and III exhibit similar performance despite the difference between repair crew behavior. Figure 5.7 shows the detailed instants of line repair for the two cases, which reveal that lines could be visited faster by more rapidly freed crews in Case III (for

instance damaged line 4), but the instant of reconnection still depends on the availability of an access point, similar to Case II. Repairs in lines 1, 2, 3, and 6 are followed by direct reconnection, whereas lines 4 and 5 can only be restored if the telecom crew installs a DG at their associated access point(s). Consequently, to calculate the cost of losing connection, the cost of non-restored load should be considered for both cases, in addition to the cost of repair crews staying at the site in Case II. The former is computed using equation (5.4) and Figure 5.6 to compare to what a perfect case would have yielded, and the later can be deduced from Figure 5.7 for case II.

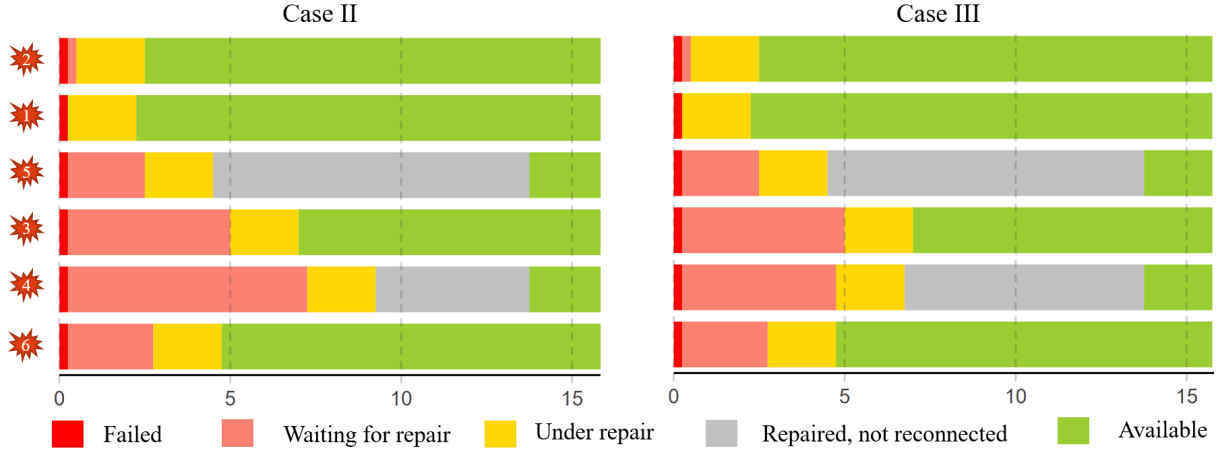


Figure 5.7: Repair timeline of damaged lines

- Case II: a load of $P_5 = 4860$ kW at $t = 4.5h$ and $P_4 = 1210$ kW at $t = 6.6h$ is restored in Case I after repairing line 5 and line 4, respectively. This could not be done in Case II till $t = 13.6h$ for both lines due to no telecom service, despite finished repair at $t = 4.5h$ for line 5 and $t = 9.2h$ for line 4. The cost of this telecom unavailability is computed as

$$C^{II} = (t_4^{reconnected} - t_4^{repaired}) \cdot (C_4 + C^{rc}) + (t_5^{reconnect} - t_5^{repaired}) \cdot (C_5 + C^{rc})$$

- Case III: Similarly, the same load from above is not restored in Case III after repairing line 5 at $t = 4.5h$ and line 4 at $t = 6.6h$, respectively. The cost of this telecom unavailability is computed as

$$C^{III} = (t_4^{reconnected} - t_4^{repaired}) \cdot C_4 + (t_5^{reconnected} - t_5^{repaired}) \cdot C_5$$

where C^{rc} the hourly cost of a repair crew (set to 750 €), and C_4 and C_5 are calculated from equation (5.4) using P_4 and P_5 , respectively.

$$C^{II} = (13.6 - 9.2) \cdot \left(\frac{1210}{27690} \cdot 5.9 + 0.75\right) + (13.6 - 4.5) \cdot \left(\frac{4860}{27690} \cdot 5.9 + 0.75\right) = 20.7 \text{ k€}$$

$$C^{III} = (13.6 - 6.6) \cdot \left(\frac{1210}{27690} \cdot 5.9\right) + (13.6 - 4.5) \cdot \left(\frac{4860}{27690} \cdot 5.9\right) = 11.2 \text{ k€}$$

This quantifies the real cost supported by the DSO due to the unavailability of the telecom service, computed for the two possible cases in the grid. Case III achieved a lower cost as the crews were not retained at the damage sites and could complete their tasks rapidly. Generally, a wide deployment of RCSs permits passing from cases of crews leaving after reconnection, to cases of leaving directly after repair. Note that case IV was introduced to show the wide difference between considering that telecom operators react in some way to the event (which that they actually do, i.e. cases II and III) and the case of no intervention, that may halt the restoration.

This approach aims to set a transparent and cooperative exchange about the delivered service between power and telecom operators. In some cases, calls for tenders from power operators for telecom services include highly demanding metrics and penalties, leading to few (or no) tenders or a scale down of the requirements. Introducing explainable metrics and penalties as proposed in this section allows a better positioning of the different stakeholders.

5.2.2 Grid Monitoring and Resource Sizing

The modeling approaches developed in this dissertation are implemented into a prototype platform for distribution system simulation and analysis. The focus is kept on the study of restoration operations, while representing the power-telecom interdependencies. Specifically, the hybrid model is endowed with suitable interfaces and modules to load and process geographical information system (GIS) data. The Anylogic software [87] is used for the implementation and visualization of use-cases in the simulation platform.

Prior to restoration operations, pre-positioning and sizing of resources rises as an important preparation procedure, where the amount of required resources is estimated to avoid shortages and unnecessary costs [114]. Mobile energy generation and storage concentrate most of the research work on the subject in both distribution grid [114, 115, 116] and microgrid [117, 118] settings. Mobile energy sources are generally carried by intervention crews, which may conduct other tasks of damage assessment, manual switching, and asset repair [117].

Sizing is less applied to intervention crews as DSOs are generally aware of their staffing capacities in advance, although this becomes less obvious during situations of disaster relief, where crews from different areas (regions or even countries) join the damage epicenter zone to accelerate the restoration efforts. Operators need then to well distribute the arriving crews among the depots considering restoration needs and depots hosting capacities. This

can be decomposed to a phase of assigning the first wave of arriving crews, then a second phase of dealing with the belated arbitrary arrivals. We consider a simulation-based optimization approach to find the number of repair crews at each depot that guarantees the fastest repair of all damages under minimal costs, while leveraging the flexibility of the adopted modeling to integrate new arriving crews.

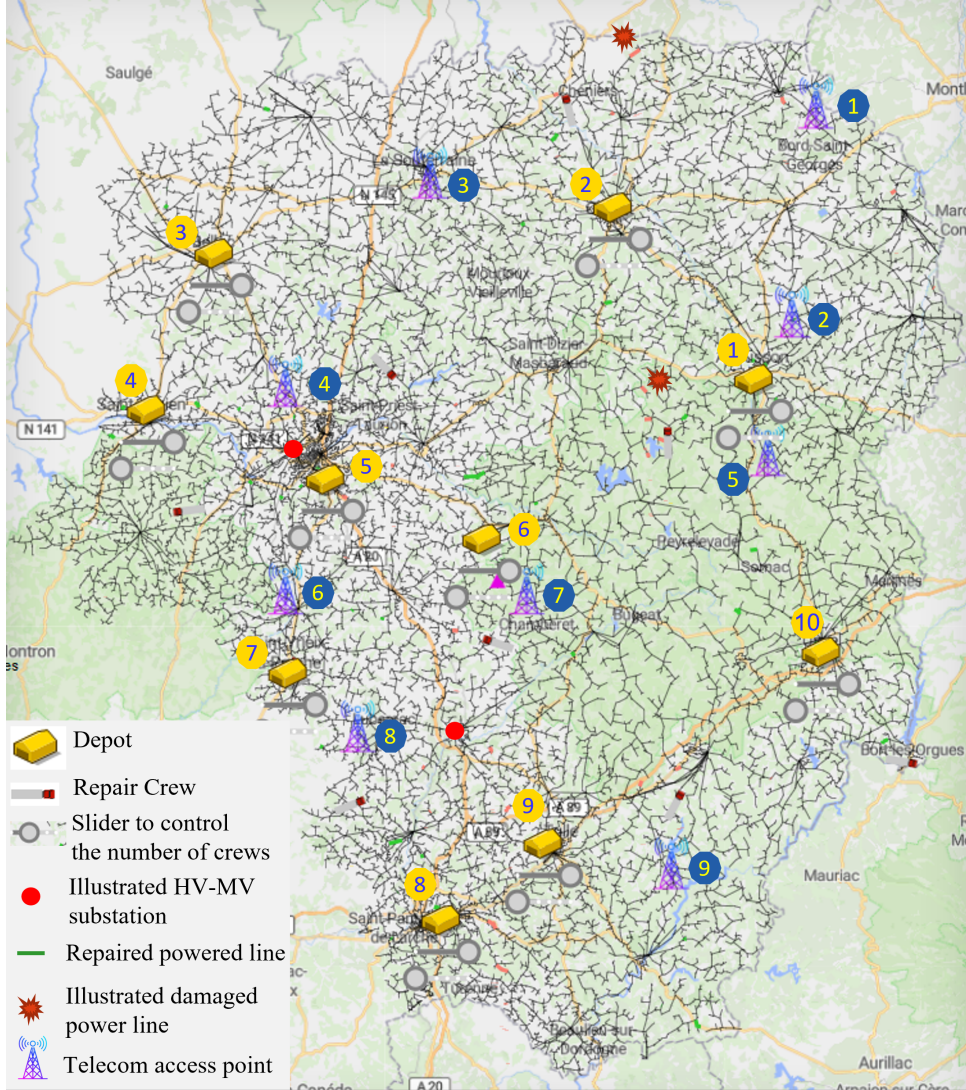


Figure 5.8: A 49 primary substations system with 156 damages

A real (anonymized) grid of 49 primary substations, 10 depots, and 9 telecom access points is considered as shown in Figure 5.8. The serving telecom points are generic and could not be obtained along the grid data. Without loss of generality, we opt for reducing the number of the possible access points in such a large area (17,000 km²) and increase their collective coverage to the whole region. This allows to closely monitor the state of access points, which can be affected by power outages in their neighborhoods and would be lost if the associated battery is emptied before the grid supply is restored (battery duration is set between 30 mn and 6h). No redundancy is assumed in telecom service or

power supply to access points. A single scenario of 156 damaged lines is considered as the present approach is intended for use after a preliminary assessment on grid damages. This is well justified below with a practical calculation time of some minutes.

An off-the-shelf optimizer is chosen to solve the problem by considering the simulation as the objective evaluator. Hence, the optimizer iteratively proposes solutions to the simulation, which runs them and returns an evaluation in terms of considered performance measures. An off-the-shelf solver is used as the focus more on the application of the developed simulation with no solver-specific requirements.

$$\max_{N_k} \sum_{\forall t} \left(\sum_{\forall l \in L} V_l \cdot a_{l,t} - \sum_{\forall k \in DP} C_{k,t}(N_k) \right) \quad (5.5)$$

$$C_{k,t}(N_k) = \sum_{i=0}^{N_k} C_i \cdot c_{i,t}^k + \sum_{l \in L^{dp}} C_l \cdot a_{l,t}^k \quad (5.6)$$

Equations (5.5) and (5.6) define the objective function used by the optimizer as evaluated from the simulation. Decision variables $\{N_k\}$ represent the sought number of crews at each depot k , while $a_{l,t}$ and $c_{i,t}$ are binary state variables indicating at each time t the availability of a line l and the work state of crew i , respectively. Variables a and c are not included in the solution from the optimizer but change accordingly. Parameter V_l expresses the value brought by restoring a line l , directly linked to the amount of enabled load recovery. Parameter $C_{k,t}$ gives the instantaneous cost associated to each depot, which depends on the number of crews as given by (5.6), where C_i is the cost of crew intervention in a unit of time. The second term shows the summation of intervention costs specific to a line C_l (e.g. needed materials), accounted for if l is handled by depot dp (where the superscript k for a).

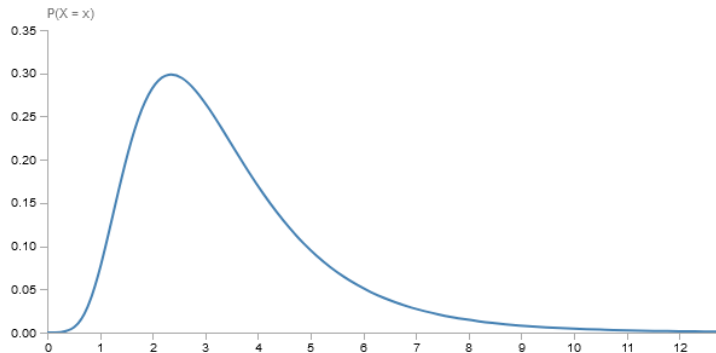


Figure 5.9: Used log-normal distribution of repair time (h), $\mu = 1.1$ and $\sigma = 0.5$

Only repair crews are considered for the numerical case study, with a travel speed of 50 km/h along roads retrieved from OpenStreetMap [88], and a log-normal distribution of

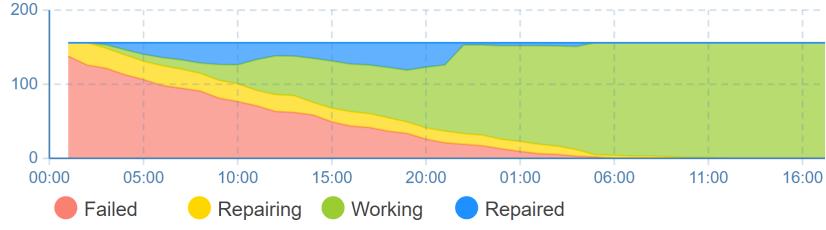
Table 5.5: Case study parameters

Parameter	Value
Access points battery duration (h)	{ 2, 1, 5, 2, 3, 2, 1.5, 0.5, 6 }
Self Discharge Rate of batteries (kWh/h)	0.02
Line repair cost C_l (€)	600
Crew hourly cost C_i (€)	750
Line Value V_l (€)	5000
Optimization ranges for the number of crews	{[0, 8], [0, 5], [0, 2], [0, 2], [0,3], [0, 2], [0, 5], [0, 4], [0, 3], [0, 3]}

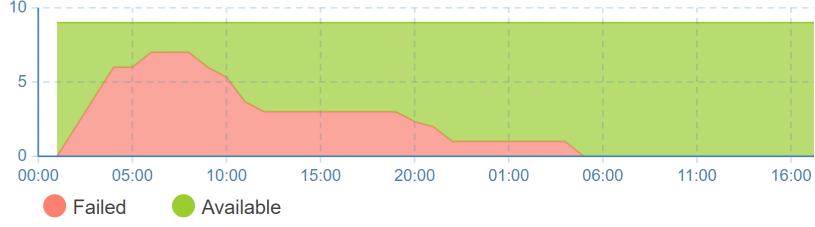
repair time [36] ($\mu = 1.1$ and $\sigma = 0.5$ as shown in Figure 5.9). Simulations are therefore replicated 5 times for each solution proposed from the optimizer, before returning the mean performance of the 5 runs. Simulation parameters are summarized in table 5.5.

Results and Discussion

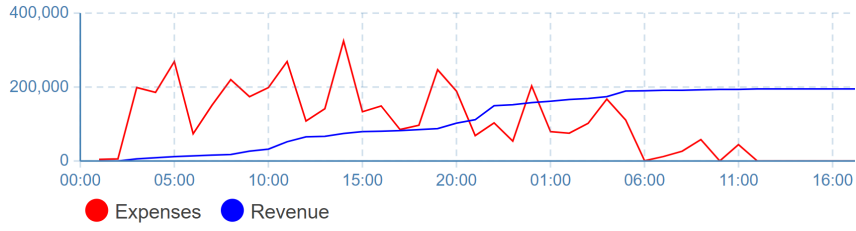
We launch a simulation run with all depots having 3 repair crews. The damages are pre-assigned to depots based on distance by route, and any idle crew requests the damage queue of its depot for the closest line to repair (closest by route). The evolution of repair operations is shown in Figure 5.10a where a band for the number of lines under repair is shown to shrink as the operations are conducted, and the number of failed lines reduces almost linearly during the 48h simulation window. This can be attributed partially to the homogeneous number of crews across all depots and the pre-assignment of damages, which are well spread all over the area. However, the repair curve could have been steeper if not for the portion of lines that is repaired but not restored due to a lack of the telecom service, as access points fail successively following the depletion of their batteries as illustrated in Figure 5.10b. Eventually, as the repair evolves, the power supply is restored to telecom points, helping to accelerate the restoration, particularly at $t = 11h$ and $t = 22h$. Figure 5.10c depicts the variations in repair expenses that exhibit a cyclic-like trend due to the additional repair cost at the damage site, the cost of a repair crew being valid even when the crew is driving. This behavior is checked to not be due to the log-normally distributed repair time as a run is performed using a uniform distribution $u(0.5, 5)$ (Figure 5.10d).



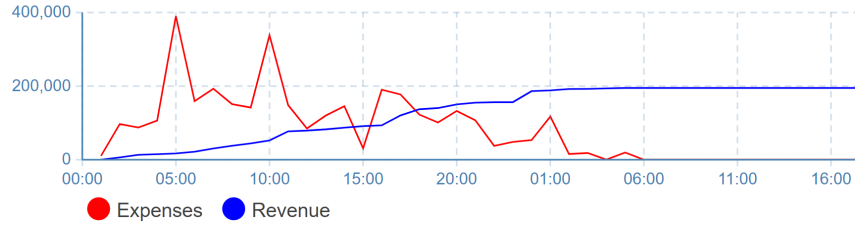
(a) Evolution of line repair



(b) State of telecom access points



(c) Repair expenses and the revenue from restored lines



(d) Repair expenses and the revenue from restored lines

Figure 5.10: Simulation run with 3 repair crews at each depot

The unavailability of some telecom points is shown to affect the revenue in Figure 5.10c, where the revenue is not increasing linearly despite the assumption of a fixed V_l and the repair trend in Figure 5.10c. In this case, the revenue starts to overtake the expenses when more than a half of damaged lines are repaired.

Next, The optimization is run to solve for the number of repair crews at each depot that guarantees the best restoration of lines under minimal costs. Realistic ranges of the optimization variables are provided as in table 5.5, which helps to accelerate the convergence. The evolution of the objective function over a total of 273 iterations is displayed in Figure 5.11, showing that a good solution is rapidly found (green curve) but the optimization continues to explore other solutions for the remaining iterations (blue dots). The returned best solution is $\{6, 5, 2, 2, 3, 2, 4, 4, 3, 1\}$ for the 10 depots,

Table 5.6: Solution comparison for varied number of replications

Number of replications	Best Objective	Solution time (s)	Number of iterations	Iterations to solution <3% from the best found	Solution
5	$1.421 \cdot 10^7$	873	273	9	{ 6, 5, 2, 2, 3, 2, 4, 4, 3, 1 }
10	$1.434 \cdot 10^7$	1989	315	13	{ 6, 5, 2, 2, 3, 2, 5, 4, 2, 2 }
15	$1.402 \cdot 10^7$	1779	264	8	{ 7, 5, 2, 2, 3, 2, 3, 4, 3, 2 }

respectively; with an objective value of $1.421 \cdot 10^7$.

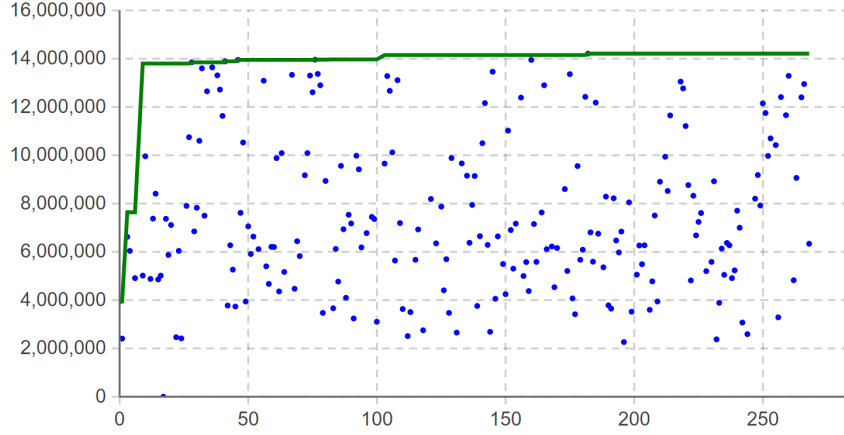


Figure 5.11: Objective evolution over simulation iterations

The 273 iterations were computed over 873 s (14 mn 33 s), which is satisfactory given the targeted application. Tests using more simulation replications of 10 and 15 achieved slightly different solutions with objectives within 1% (Table 5.6).

The present method does not guarantee optimality as the used off-the-shelf optimizer implements meta-heuristics for solving the problem. We implement an equivalent mathematical programming formulation of this problem as a deterministic MIP by simplifying the non-linear objective function in (5.5) using the assumption that crews are operating at all considered time periods ($c_{i,t}^k = 1, \forall i$).

$$\max_{N_k} \sum_{\forall t} \sum_{\forall l \in L} V_l \cdot a_{l,t} - \sum_{\forall k \in DP} \left(C_{k,t} \cdot N_k + \sum_{\forall t} \sum_{l \in L^{dp}} C_l \cdot a_{l,t}^k \right) \quad (5.7)$$

Routing and scheduling constraints and variables are taken from the developed model in Chapter 3, in particular the scheduling rule (3.16). Attempt to solve this problem on the same large grid using IBM ILOG-Cplex solver was still at 63.47% optimality gap after 2265.58 s (37 mn 45 s). The use of simulation as an objective evaluator reveals consequently a great potential when dealing with very large complex problems when a good solution is needed in a relatively short time. The developed simulation model proves to be very effective for this technique by spending on average less than 5 s for each iteration.

The power flow calculations were not considered given the computation burden that would be added. Yet, considering that operators of large distribution grids do not calculate the PF quantities at real-time during reconfiguration, but rather use the pre-calculated results from heavy, conservative, scenario-based studies; the rules taken from these studies can be easily implemented in our model.

5.3 Summary

various applications of the developed methods and tools during this thesis are applied in realistic case studies. The insights from previous chapters on power-telecom interdependencies at the restoration stage are enforced by results for the planning and resource-sizing stages. A novel approach for the SDG telecom service SLA evaluation is also proposed.

Chapter 6

Conclusion

Electric power grids sailed remarkably through the twentieth century with a massive societal impact by enabling almost all modern life services, while evolving to a masterpiece of engineering by integrating so many innovations and technical advancements. This continues nowadays through numerous new grid applications and an increasing connectivity through information and communication technologies. This dissertation investigates the interdependencies between telecom networks and the grid, particularly at the vulnerable distribution level, and puts forward proposals for interdependence modeling, optimization, simulation, and resilience analysis.

The DSR application in the grid is strategically chosen to feed and demonstrate the conducted work. Many domains of action intervene within the DSR, from technical processes (e.g. FLISR, PF calculation, etc.) to logistics (e.g. crew dispatch, mobile DGs, etc.) and institutional regulations and response protocols. This is orchestrated by a wide presence of telecoms at multiple levels, serving remote switches, control centers, substations, and intervention crews. In addition, from an economic perspective, it is fairly affordable and convincing for system operators to implement actions for a telecom-aware restoration than altering long-term expensive investments, which can be a follow-up enhancement if telecoms prove their criticality, as claimed in the output of this work. Finally, Restoration is inherently about contingency analysis and management where the power-telecom interdependencies are most impactful, setting a natural candidate when the resilience of a the grid is to be assessed.

An intensive modeling effort is conducted to well represent the interactions within the smart distribution grid and extend the existing literature. Failure propagation is improved to incorporate the action of automatic and manual switches, while radiality conditions are revisited to suit the multi-feeder configurations considered throughout the thesis. Both

overhead and underground lines are examined and their differences highlighted. A special attention is allocated to the power-telecom coupling, which is represented as a two-way interdependence: a telecom network that depends on power supply from the grid, and the grid that uses telecom services to conduct multiple operations. The hierarchical architecture of telecom networks is embraced in private and public communications. Restoration re Eventually, a CN theory-based model is constructed including all above aspects, which is extended using ABM and discrete-events to a more detailed hybrid model, through advanced description of battery discharge, communication messages and crew movement.

The developed models are leveraged to tackle the optimization of restoration operations. The perspective of a DSO is adopted by targeting a minimized non-supplied power and considering costs only when equally performing strategies are found. A proposed deterministic MILP, embedding the CN-based model, quantified the advantage of considering telecom availability during restoration, while proposing a co-optimization of different resources (reconfiguration switches, intervention crews, and DGs). The hybrid model is then used to challenge the optimal solution from the deterministic MILP by considering an uncertain repair time. Given the drop in performance, a procedure is introduced to find a better performing solution under the system conditions by combining both mathematical programming and hybrid model simulation. The resulting iterative simulation-optimization exhibits a potential for handling advanced uncertainty and processing large scale problems.

The flagship contribution of the thesis of quantifying the impact of telecom awareness on the grid restoration is transposed to other distribution system applications in close connection to the DSR. New deployments of remote switches and crew sizing are conducted at the pre-event stage, taking into account the power-telecom interdependencies. A novel SLA definition method is also designed based on post-recovery evaluation of the true impact of communication services from a telecom operator on grid restoration. Telecoms are therefore to be considered at all stages of resilience assessment all over the grid. This insight can be extended to any industrial cyber-physical system where the core system functionality need to be modeled, analyzed, and optimized jointly with the ubiquitous ICTs to achieve an enhanced resilience.

Future Work

Identified extensions, limitations, and raised questions from this dissertation can be a subject for a prospective research work. First, applying the developed methods at the

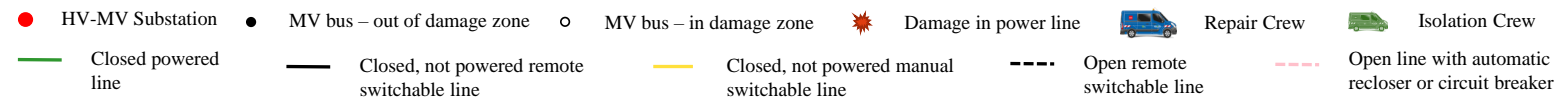
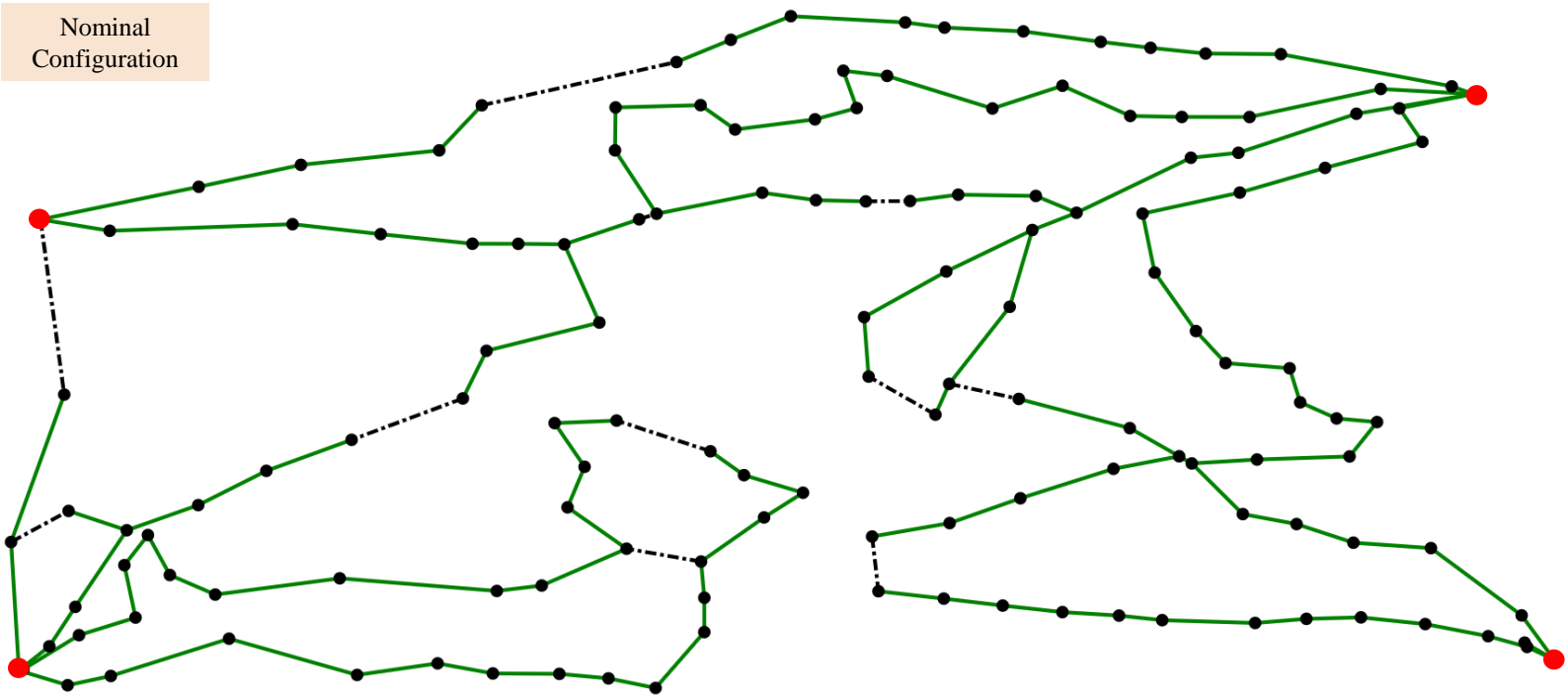
planning phase is a natural continuation as the benefit of telecom-aware restoration is demonstrated at event time and different resources are available at the pre-event stage. Next, most of the considered models are deterministic and uncertainty is only introduced in one application for repair time to show the potential of developed methods to cope with uncertainty; thus further inspection is needed to consolidate the results and investigate other parameters like the traveling time, the damage scenario, and available resources. This is to be looked at closely considering the computation burden that may be added, where the need for advanced algorithms and decomposition techniques to solve the to-be-formulated restoration problems under uncertainty.

Further, despite the improvement in capturing the telecom network, many characteristics are overlooked, like latency, packet loss, re-transmission, congestion, and hand-over. A proposal is to work on a standard formulation of information flow that can be integrated with the PF in the context of smart grids [95], although the final formulation can be intractable for practical use cases. Simulation can readily integrate aforementioned system characteristics, but would probably render the proposed simulation-optimization time-consuming and impractical. Still, simulation models are a strong enabler for state-of-the-art artificial intelligence techniques that can process a good system description and even resolve the uncertainty issues stated before. For instance, many recent contributions concentrated on the use of reinforcement learning to cope with the large state and action spaces of restoration problems, conducting an off-line learning using an environment (system description, usually simulation), before application in real-time. Consequently, the developed simulation model can act as a partially observable state space of a distribution grid under disruption, and used to train an intelligent agent for optimal resilience-based decision-making.

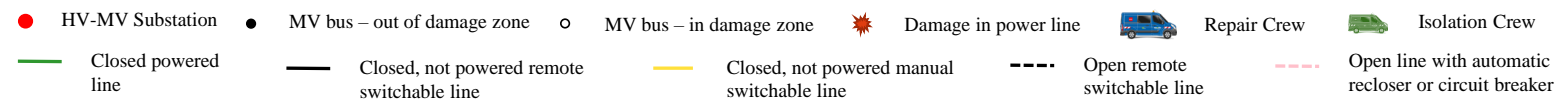
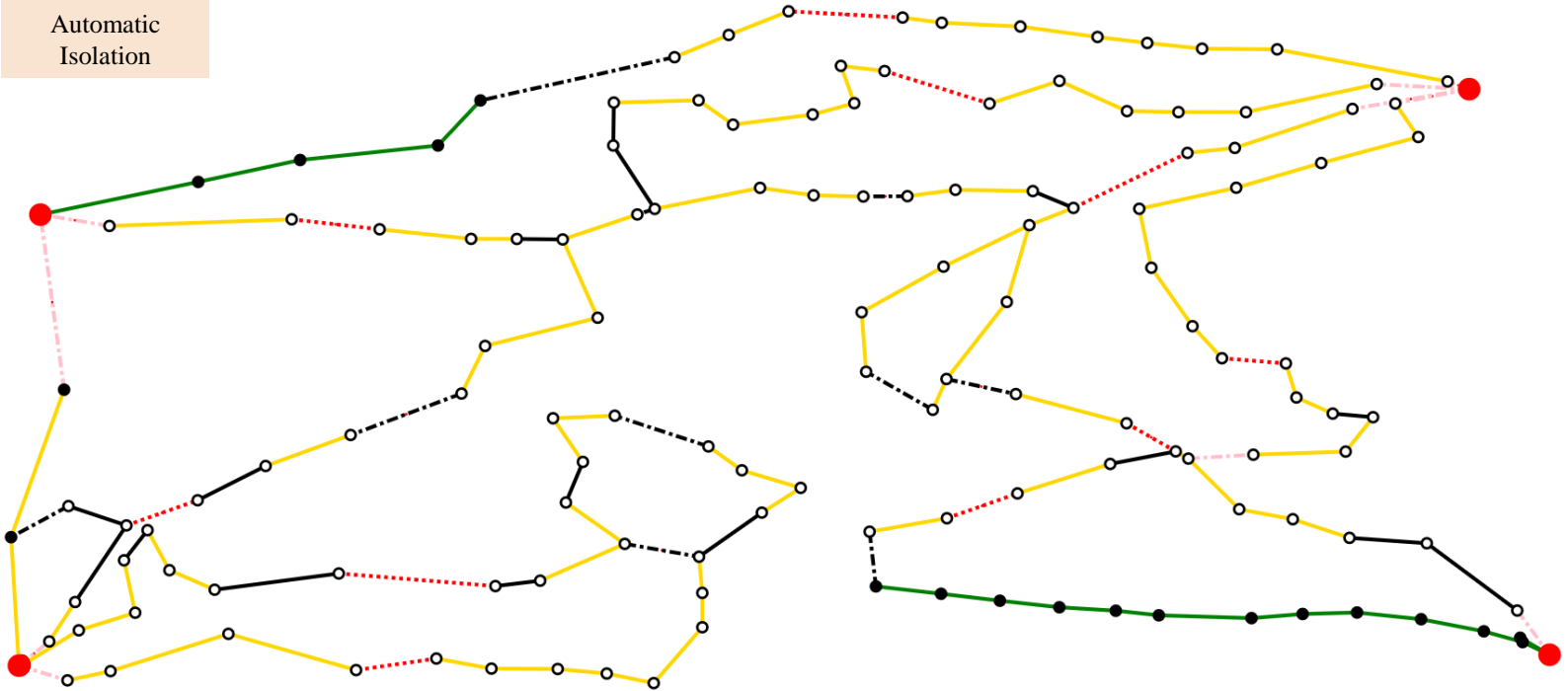
Appendix A: Fast Response

The steps involved in a fast response are shown for the 141-bus case study seen in Chapter 5. This corresponds to the FLISR function, except for the fault location, which is out of the scope of this work. The first figure shows the nominal layout of the distribution grid. Followin the event, automatic isolation, remote isolation, then fast reconfiguration intervene successively to limit the damage in the grid and restore as much load as possible.

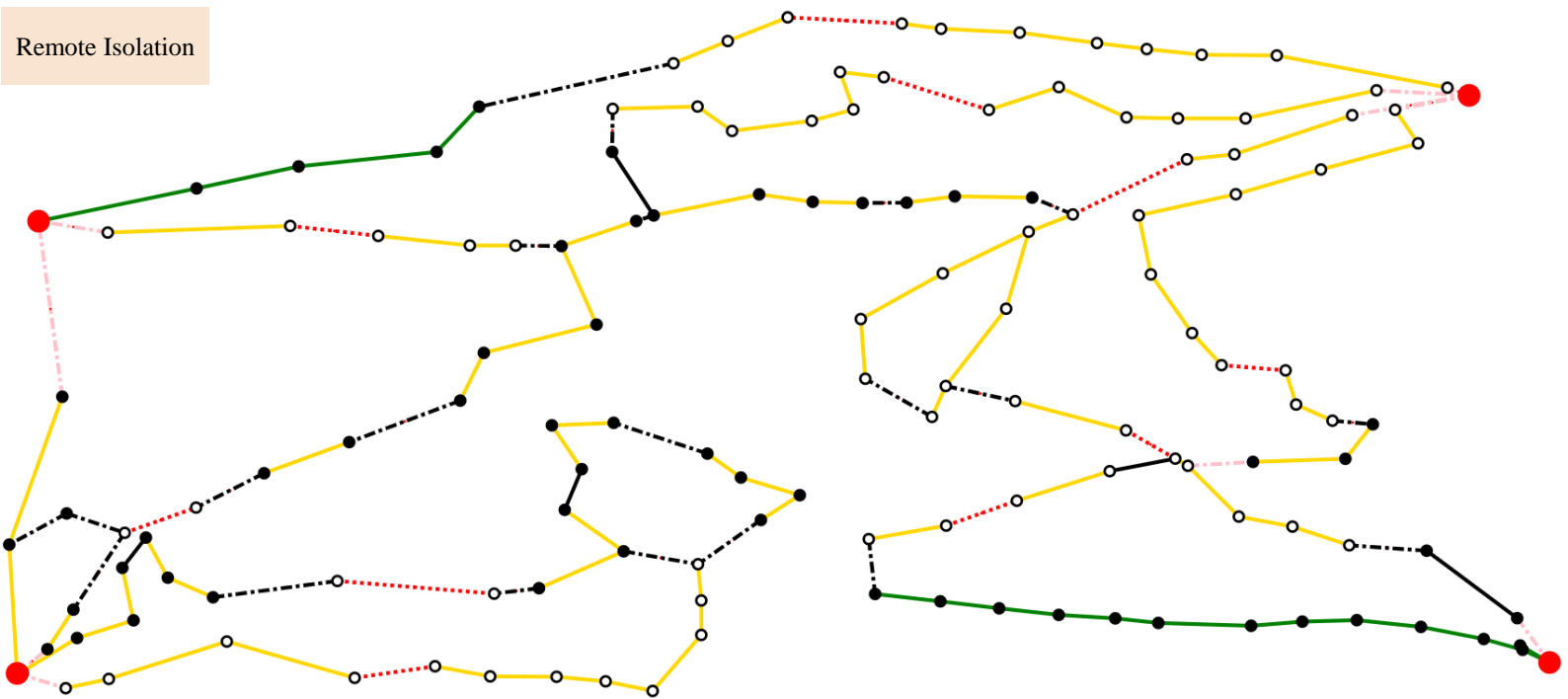
Nominal Configuration



Automatic Isolation

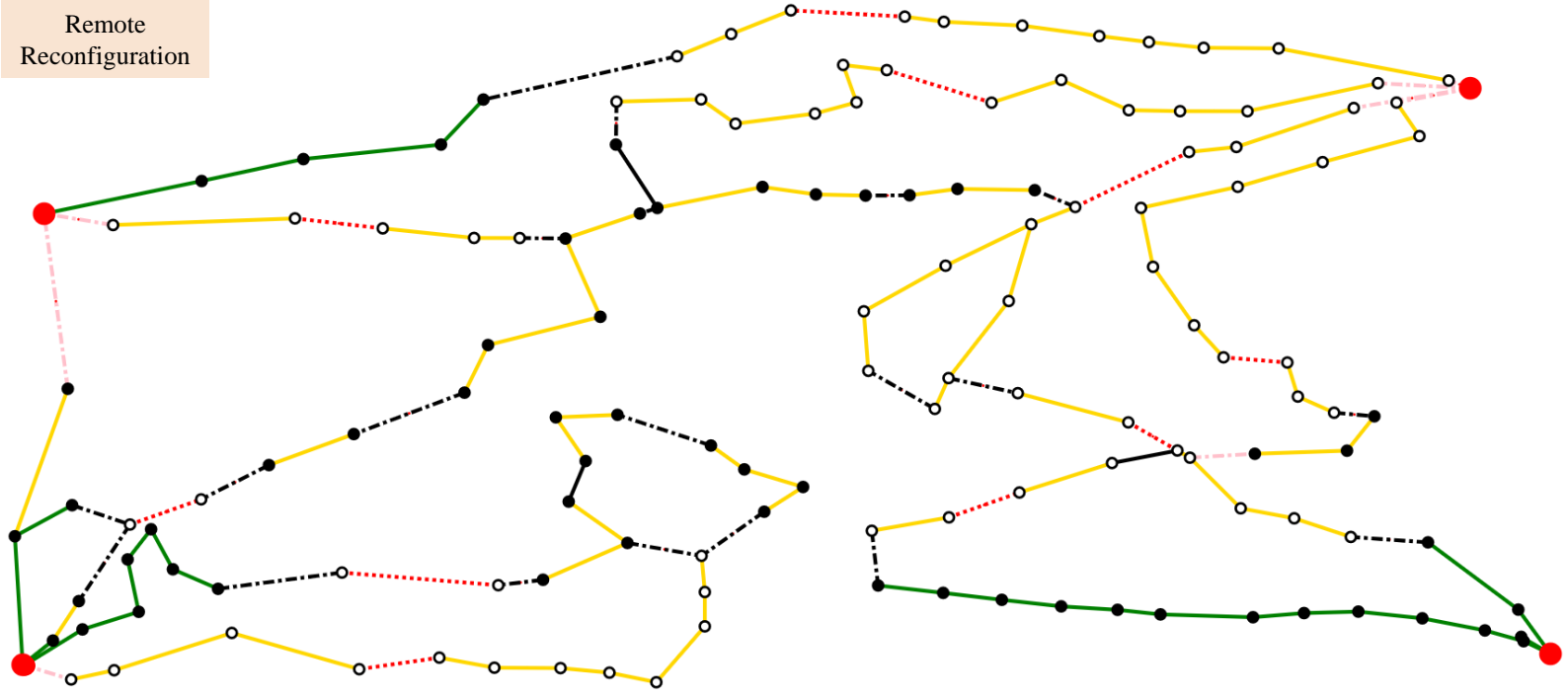


Remote Isolation



- HV-MV Substation
- MV bus – out of damage zone
- MV bus – in damage zone
- Damage in power line
- Repair Crew
- Isolation Crew
- Closed powered line
- Closed, not powered remote switchable line
- Closed, not powered manual switchable line
- Open remote switchable line
- Open line with automatic recloser or circuit breaker

Remote Reconfiguration



- HV-MV Substation
- MV bus – out of damage zone
- MV bus – in damage zone
- Damage in power line
- Repair Crew
- Isolation Crew
- Closed powered line
- Closed, not powered remote switchable line
- Closed, not powered manual switchable line
- Open remote switchable line
- Open line with automatic recloser or circuit breaker

Appendix B: Distribution System Restoration

The schedule resulting from the telecom-aware case in the 141-bus case study of Chapter 5 is illustrated in Figure 1. Next, the restoration operations are depicted at each time step.

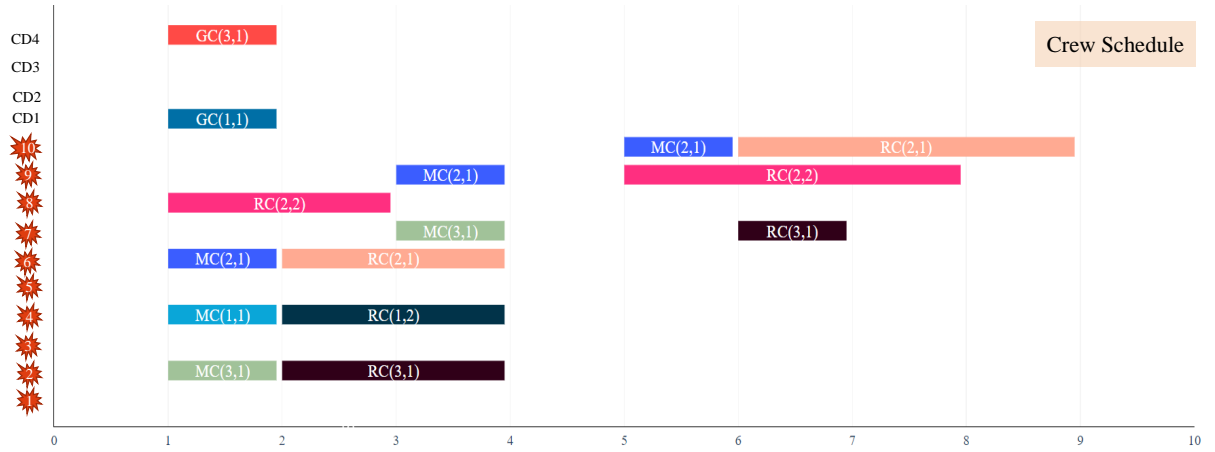
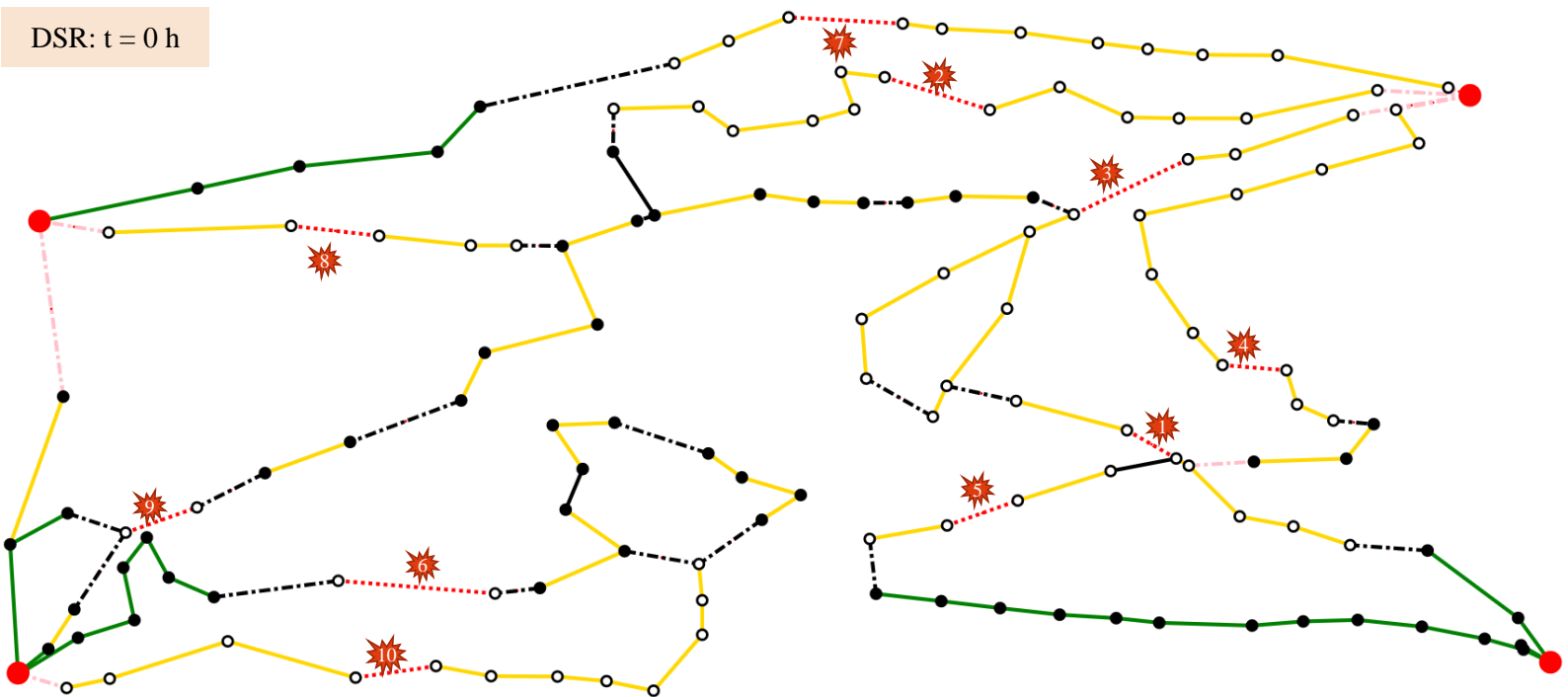
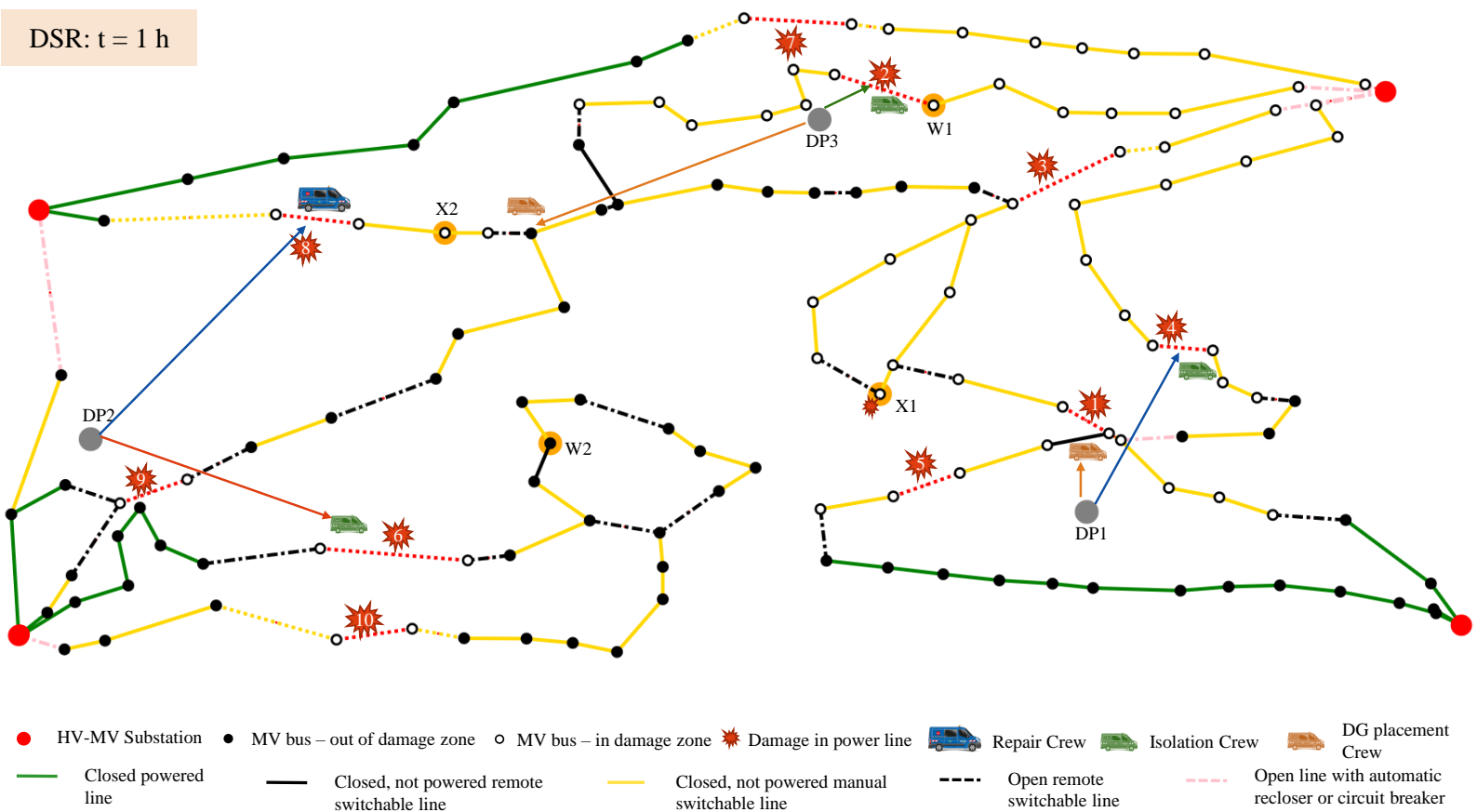


Figure 1: Crew schedule for the telecom-aware case in a 141-bus system

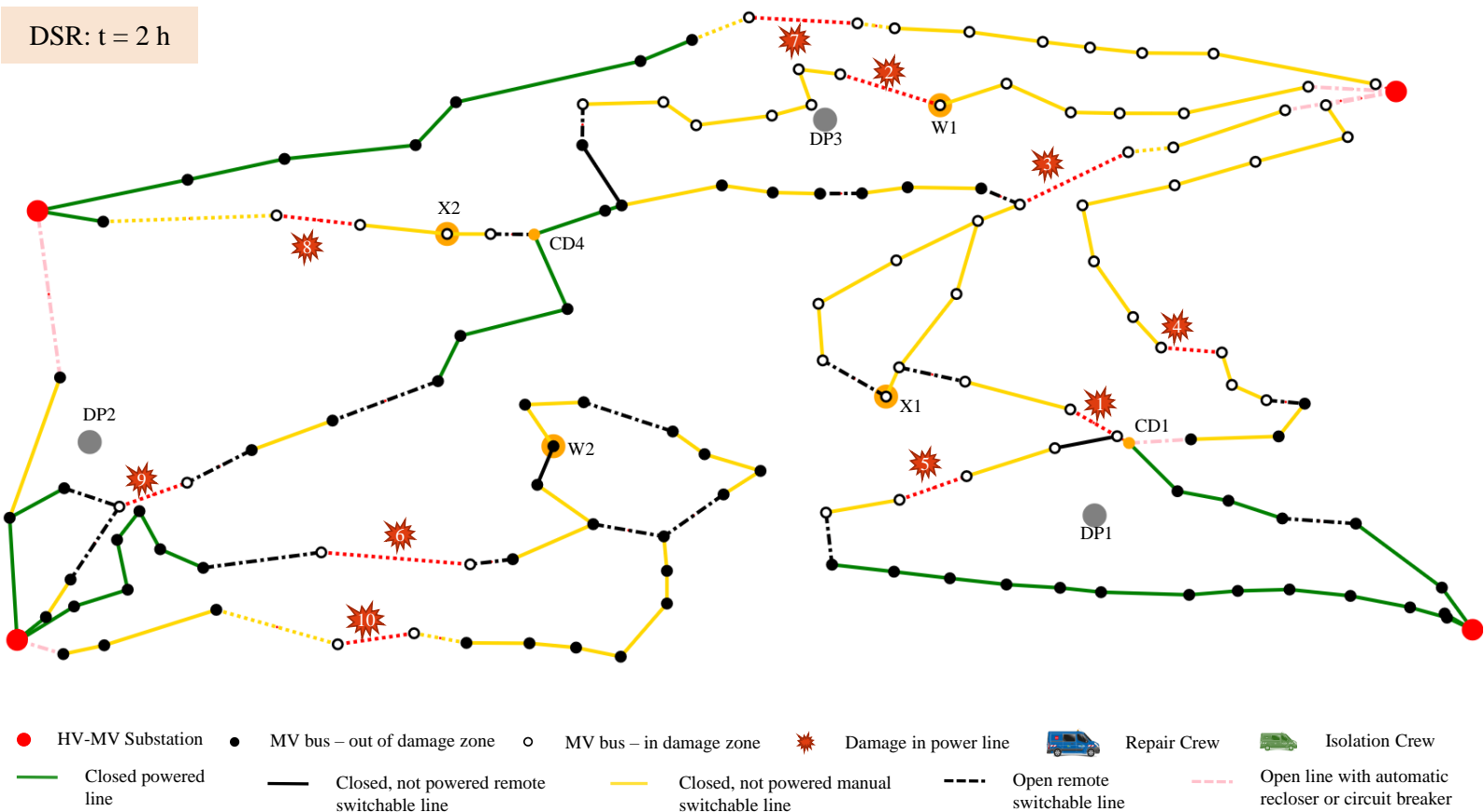
DSR: $t = 0$ h



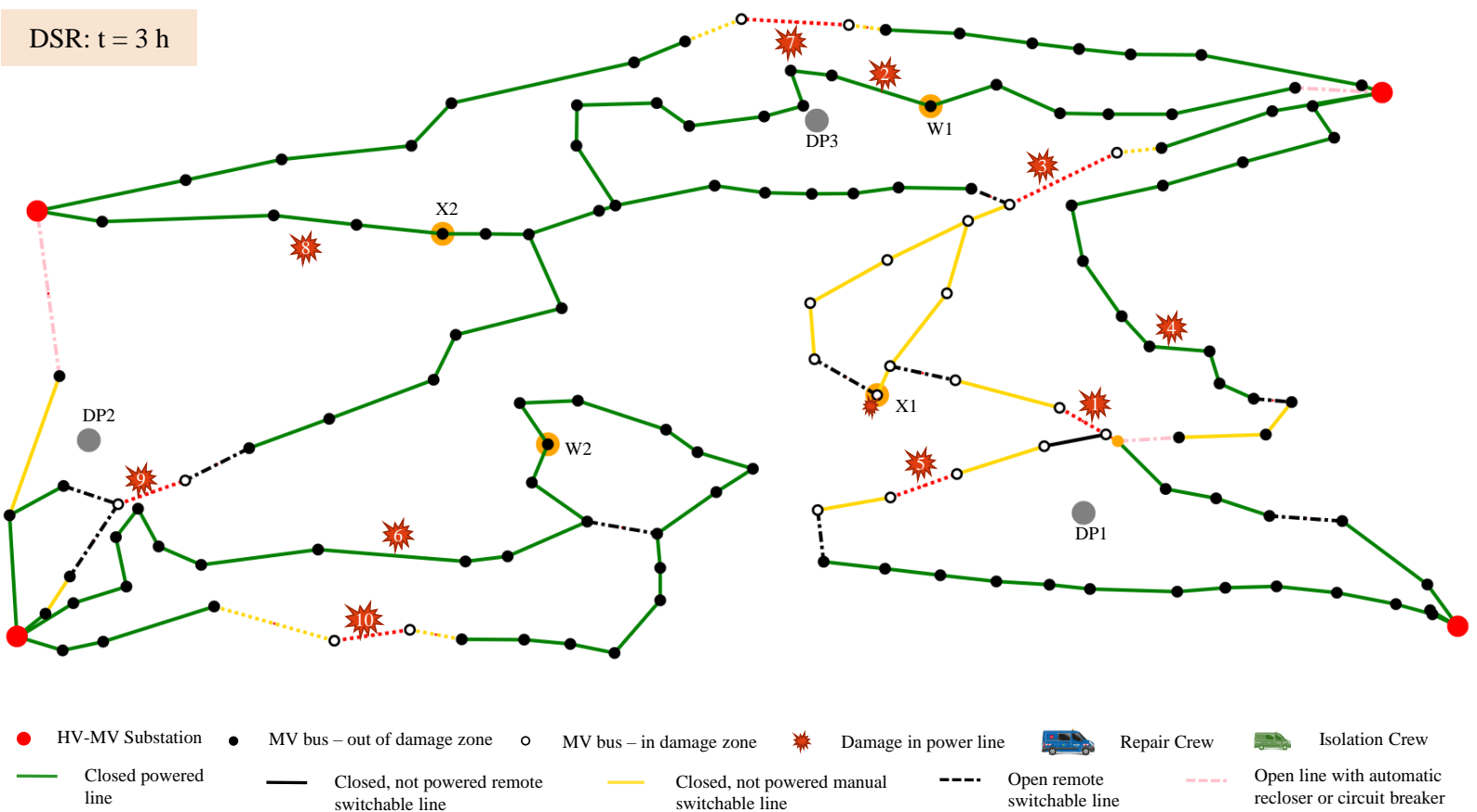
DSR: $t = 1$ h



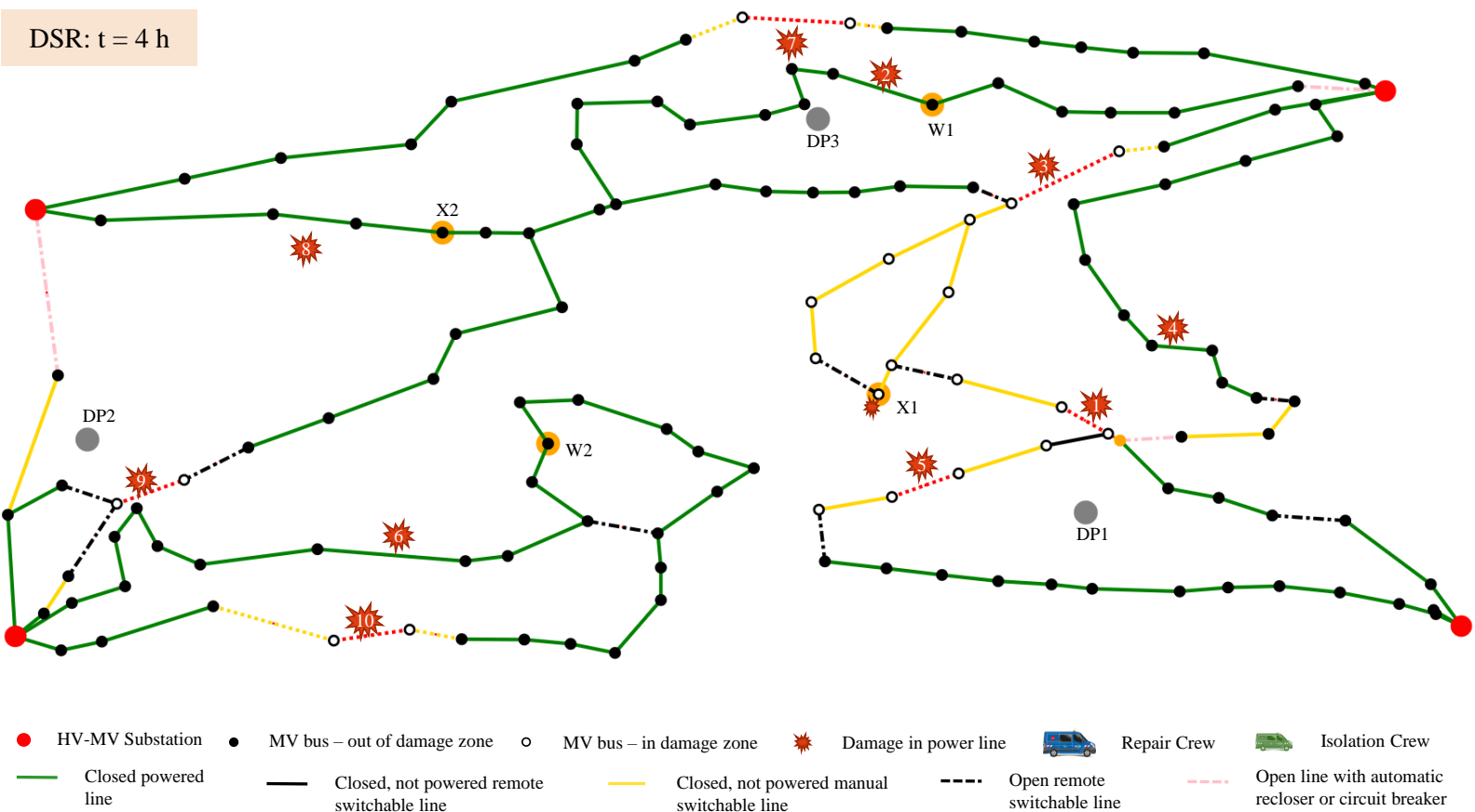
DSR: t = 2 h



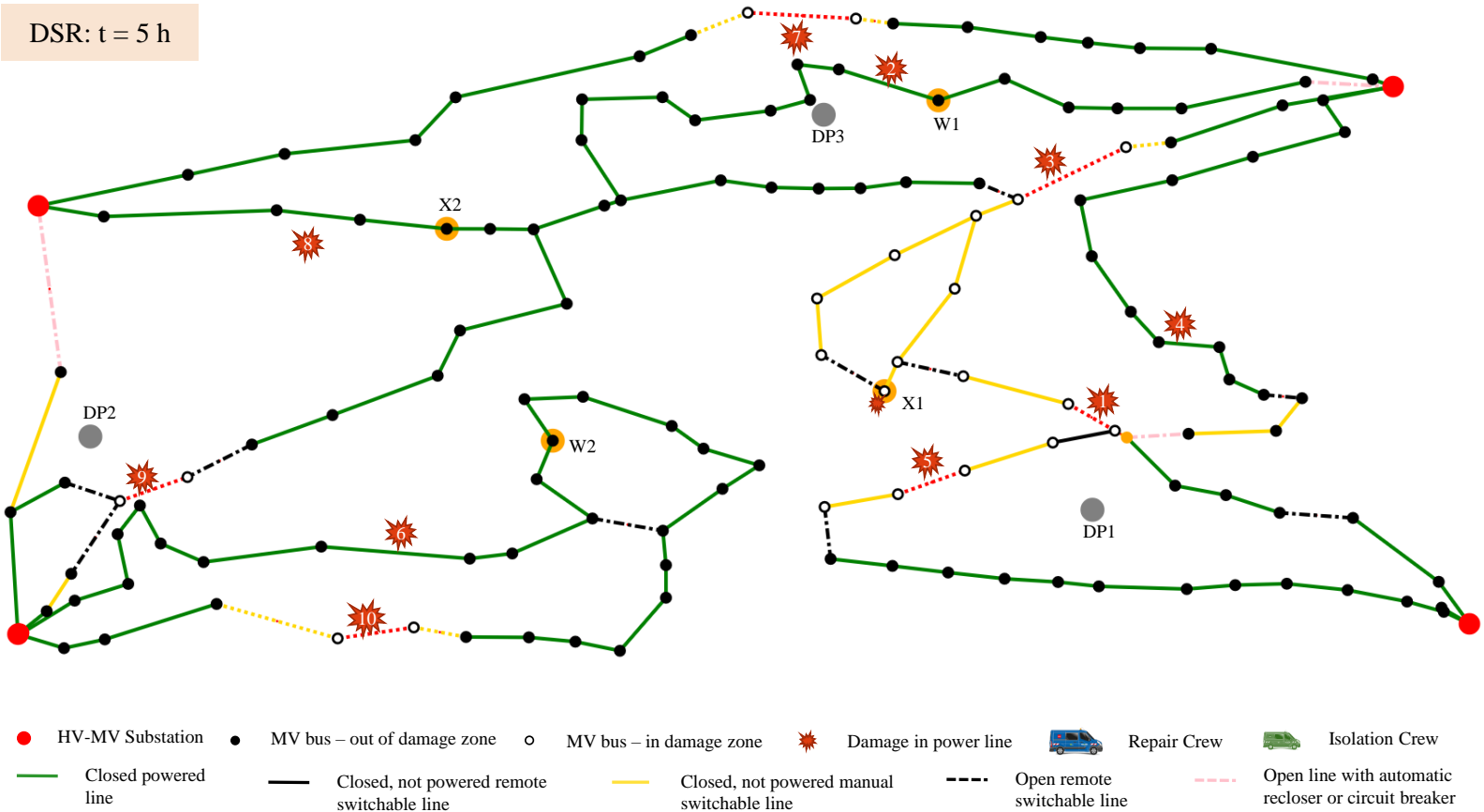
DSR: t = 3 h



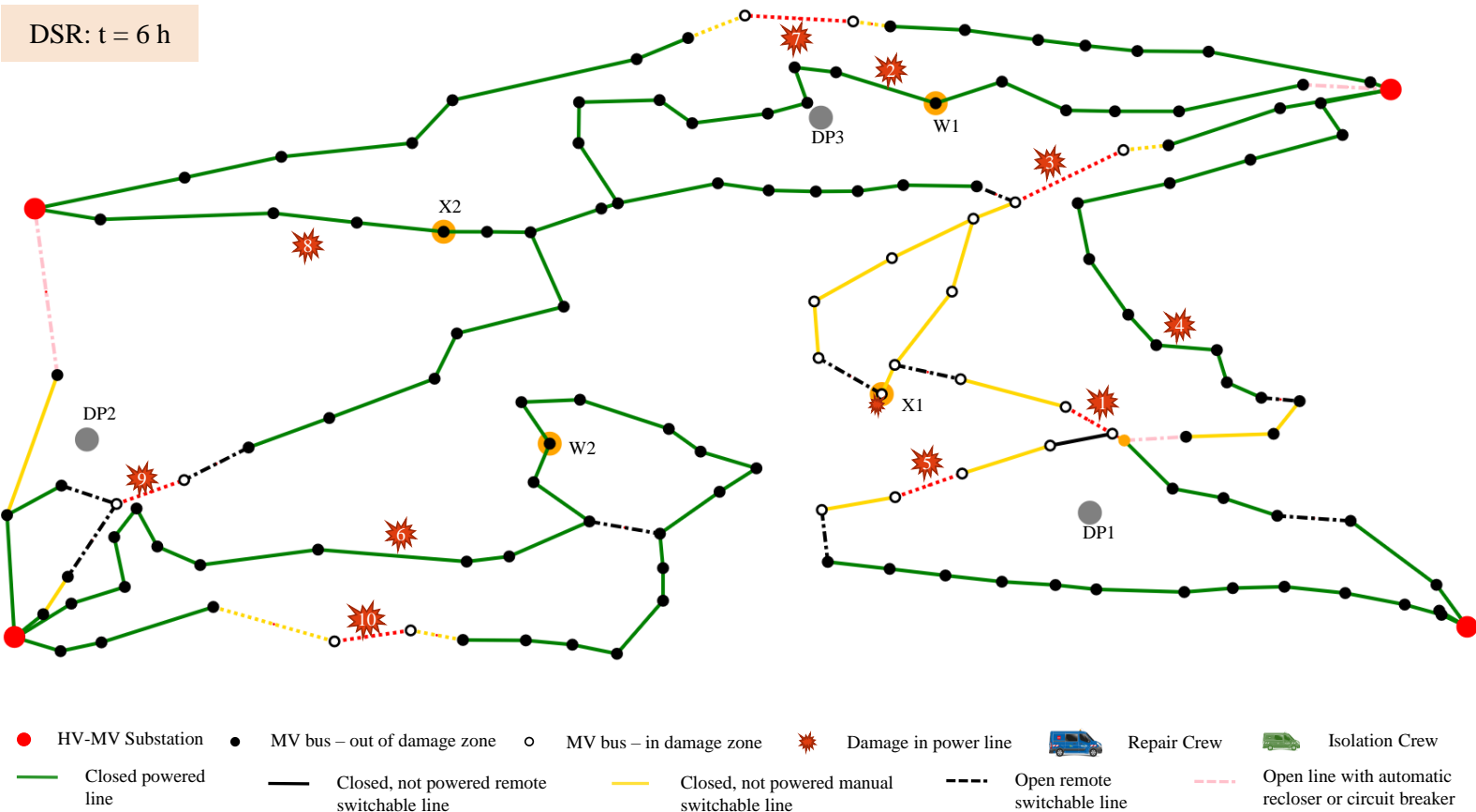
DSR: t = 4 h



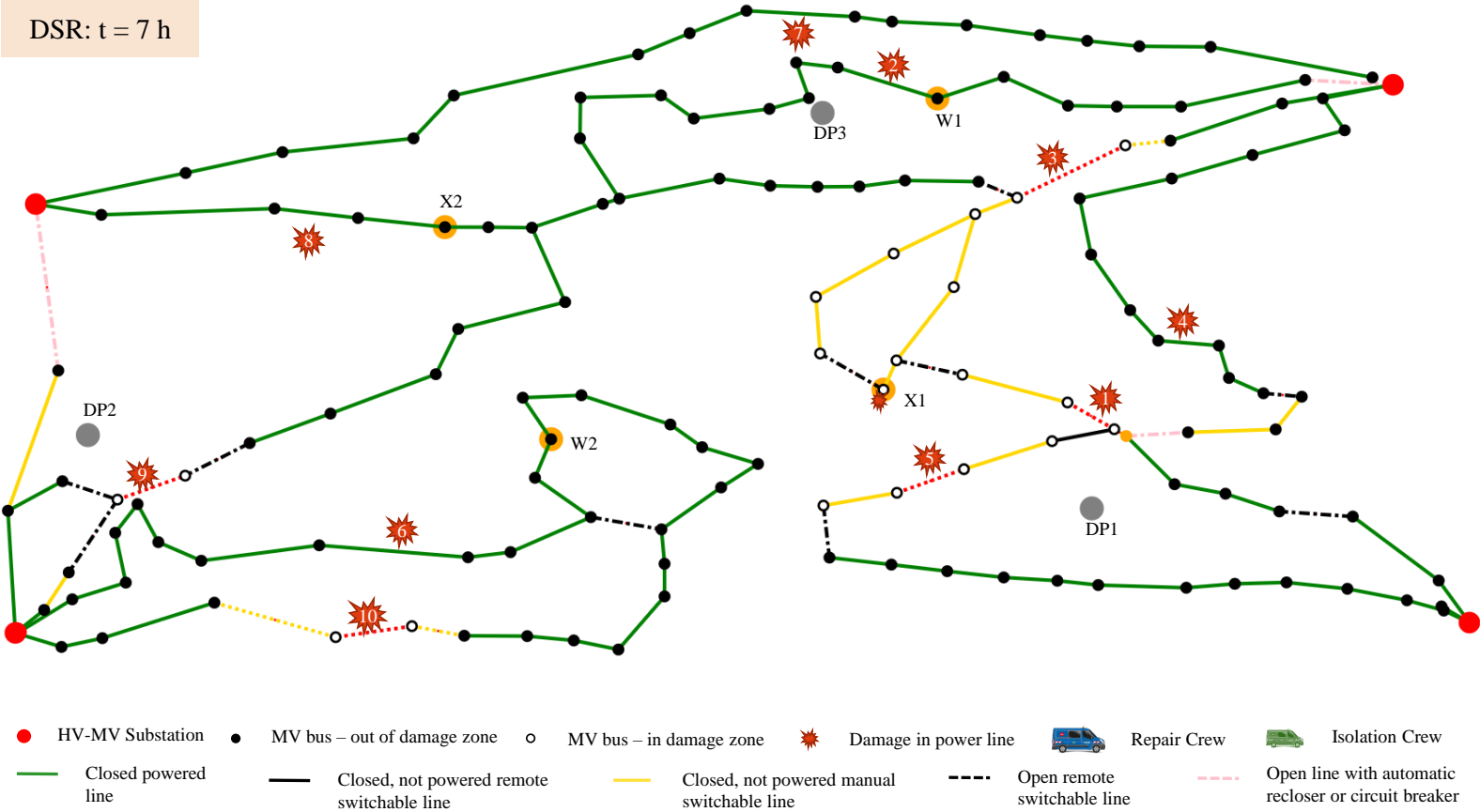
DSR: t = 5 h



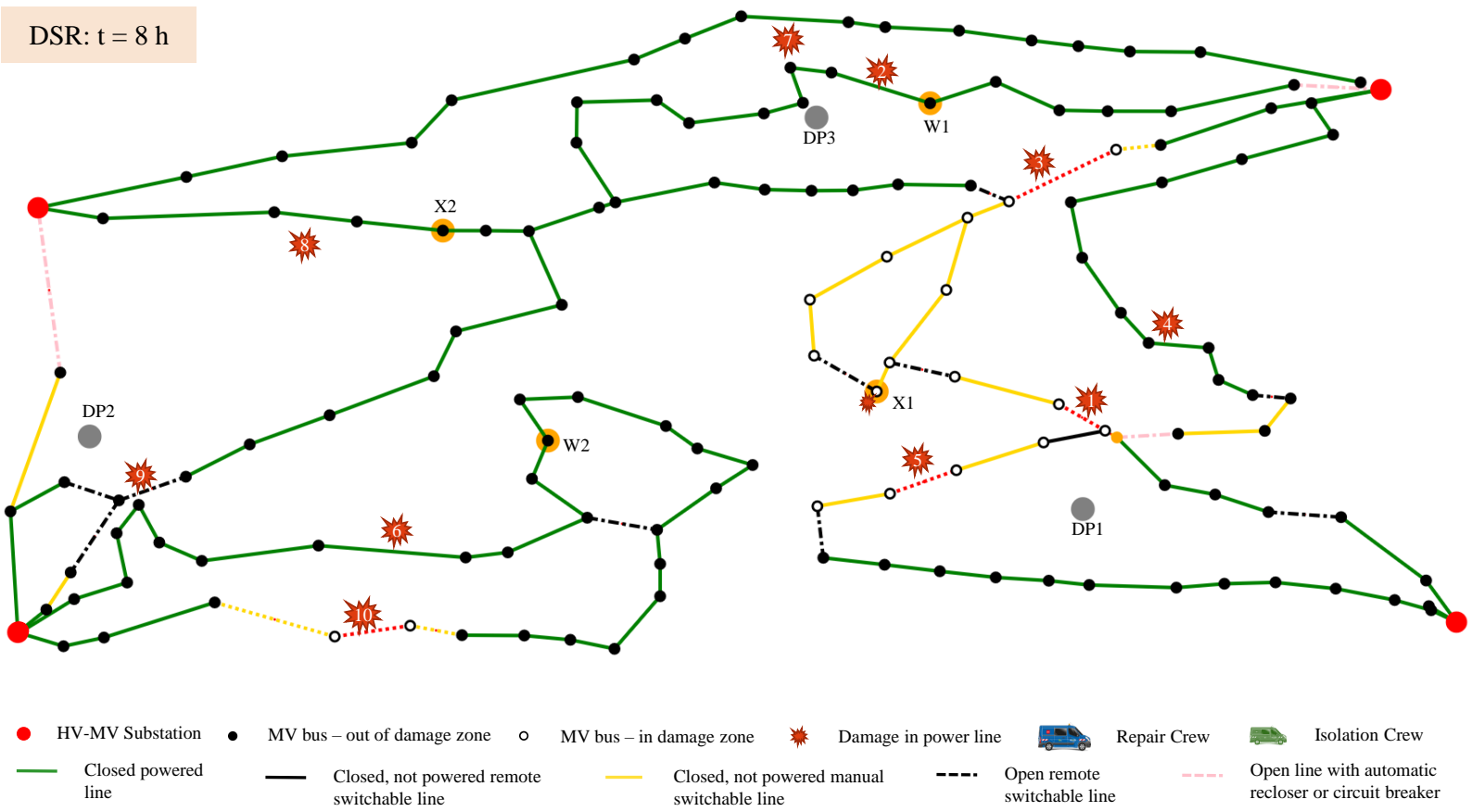
DSR: t = 6 h



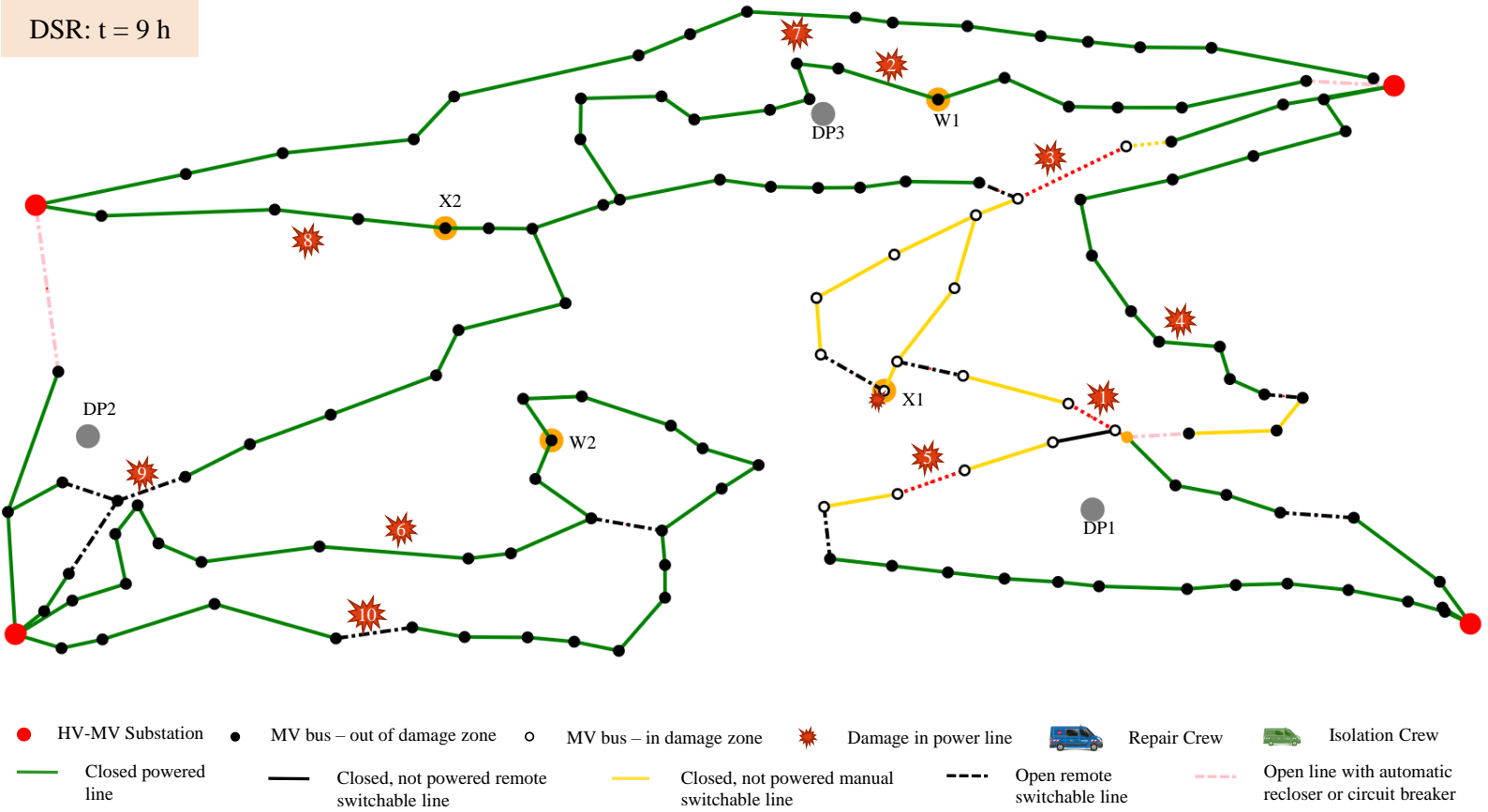
DSR: t = 7 h



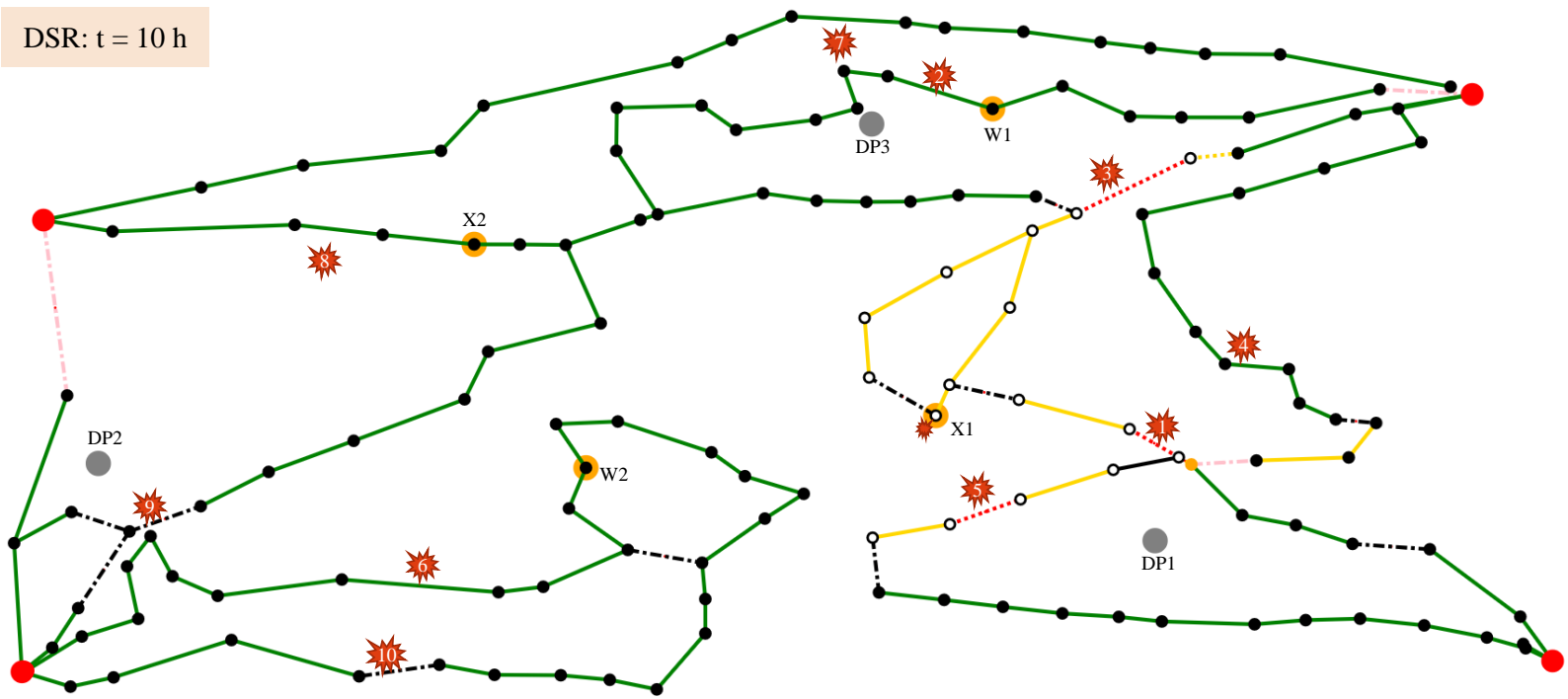
DSR: t = 8 h







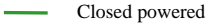
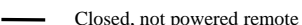
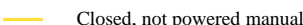




DSR: t = 9 h



DSR: t = 10 h



- | | | | | | | | | | | | |
|--|---------------------|---|--|---|--|---|-----------------------------|---|--|--|----------------|
|  | HV-MV Substation |  | MV bus – out of damage zone |  | MV bus – in damage zone |  | Damage in power line |  | Repair Crew |  | Isolation Crew |
|  | Closed powered line |  | Closed, not powered remote switchable line |  | Closed, not powered manual switchable line |  | Open remote switchable line |  | Open line with automatic recloser or circuit breaker | | |

Bibliography

- [1] Youba Nait Belaid et al. “Resilience Quantification of Smart Distribution Networks—A Bird’s Eye View Perspective”. en. In: *Energies* 14.10 (Jan. 2021). Number: 10 Publisher: Multidisciplinary Digital Publishing Institute, p. 2888. ISSN: 1996-1073. DOI: [10.3390/en14102888](https://doi.org/10.3390/en14102888). URL: <https://www.mdpi.com/1996-1073/14/10/2888> (visited on 08/11/2022).
- [2] Youba Nait Belaid et al. “Resilience Optimization of Wide-Area Control in Smart Distribution Grids”. In: *IFAC-PapersOnLine*. 18th IFAC Workshop on Control Applications of Optimization CAO 2022 55.16 (Jan. 2022), pp. 136–141. ISSN: 2405-8963. DOI: [10.1016/j.ifacol.2022.09.013](https://doi.org/10.1016/j.ifacol.2022.09.013). URL: <https://www.sciencedirect.com/science/article/pii/S2405896322011843> (visited on 10/01/2022).
- [3] Youba Nait Belaid et al. “Optimal Allocation of Resilience Resources for Strategic Communication-aware Restoration of Smart Distribution Grids”. en. In: *IEEE Transactions on Industrial Informatics* (2023).
- [4] Youba Nait Belaid et al. “On the Implementation of Optimal Deterministic Crew Schedules for Distribution System Restoration”. In: *International Journal of Electrical Power & Energy Systems* (Aug. 2023).
- [5] Youba Nait Belaid et al. “Enhanced Power and Communication Modeling in Cyber-Physical Distribution Grids for Resilience-based Optimization”. en. In: Aug. 2022, p. 289. URL: <https://hal-centralesupelec.archives-ouvertes.fr/hal-03898749> (visited on 05/16/2023).
- [6] Youba Nait Belaid et al. “Restoration Modeling and Optimization of Hybrid Overhead-Underground Power Distribution Systems”. en. In: *IEEE Innovative Smart Grid Technologies*. IEEE, 2023. URL: <https://hal-centralesupelec.archives-ouvertes.fr/hal-03961376> (visited on 01/29/2023).
- [7] The White House and Office of the Press Secretary. *Presidential Policy Directive – Critical Infrastructure Security and Resilience*. en. Feb. 2013. URL: <https://www.whitehouse.gov/presidential-policy-directive-critical-infrastructure-security-and-resilience/>

- obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil (visited on 06/30/2023).
- [8] V. C. Gungor et al. “Smart Grid Technologies: Communication Technologies and Standards”. In: *IEEE Transactions on Industrial Informatics* 7.4 (Nov. 2011). 31, pp. 529–539. ISSN: 1941-0050. DOI: [10.1109/TII.2011.2166794](https://doi.org/10.1109/TII.2011.2166794).
 - [9] X. Fang et al. “Smart Grid — The New and Improved Power Grid: A Survey”. In: *IEEE Communications Surveys Tutorials* 14.4 (2012). Conference Name: IEEE Communications Surveys Tutorials, pp. 944–980. ISSN: 1553-877X. DOI: [10.1109/SURV.2011.101911.00087](https://doi.org/10.1109/SURV.2011.101911.00087).
 - [10] Murat Kuzlu, Manisa Pipattanasomporn, and Saifur Rahman. “Communication network requirements for major smart grid applications in HAN, NAN and WAN”. en. In: *Computer Networks* 67 (July 2014), pp. 74–88. ISSN: 13891286. DOI: [10.1016/j.comnet.2014.03.029](https://doi.org/10.1016/j.comnet.2014.03.029). URL: <https://linkinghub.elsevier.com/retrieve/pii/S1389128614001431> (visited on 08/15/2022).
 - [11] Dorothy Reed et al. “Systems-Based Approach to Interdependent Electric Power Delivery and Telecommunications Infrastructure Resilience Subject to Weather-Related Hazards”. en. In: *Journal of Structural Engineering* 142.8 (Aug. 2016). ISSN: 0733-9445, 1943-541X. DOI: [10.1061/\(ASCE\)ST.1943-541X.0001395](https://doi.org/10.1061/(ASCE)ST.1943-541X.0001395). URL: <http://ascelibrary.org/doi/10.1061/%28ASCE%29ST.1943-541X.0001395> (visited on 03/08/2021).
 - [12] European Commission. Joint Research Centre. *Power grid recovery after natural hazard impact*. en. LU: Publications Office, 2017. URL: <https://data.europa.eu/doi/10.2760/87402> (visited on 03/29/2021).
 - [13] Dorothy A. Reed. “Electric utility distribution analysis for extreme winds”. en. In: *Journal of Wind Engineering and Industrial Aerodynamics* 96.1 (Jan. 2008), pp. 123–140. ISSN: 0167-6105. DOI: [10.1016/j.jweia.2007.04.002](https://doi.org/10.1016/j.jweia.2007.04.002). URL: <http://www.sciencedirect.com/science/article/pii/S0167610507000955> (visited on 12/12/2020).
 - [14] C. Ji, Y. Wei, and H. V. Poor. “Resilience of Energy Infrastructure and Services: Modeling, Data Analytics, and Metrics”. In: *Proceedings of the IEEE* 105.7 (July 2017). Conference Name: Proceedings of the IEEE, pp. 1354–1366. ISSN: 1558-2256. DOI: [10.1109/JPROC.2017.2698262](https://doi.org/10.1109/JPROC.2017.2698262).

- [15] National Research Council. *Disaster Resilience: A National Imperative*. en. Aug. 2012. ISBN: 978-0-309-26150-0. DOI: [10.17226/13457](https://doi.org/10.17226/13457). URL: <https://www.nap.edu/catalog/13457/disaster-resilience-a-national-imperative> (visited on 12/12/2020).
- [16] K. Moslehi and R. Kumar. “A Reliability Perspective of the Smart Grid”. In: *IEEE Transactions on Smart Grid* 1.1 (June 2010). 37 Conference Name: IEEE Transactions on Smart Grid, pp. 57–64. ISSN: 1949-3061. DOI: [10.1109/TSG.2010.2046346](https://doi.org/10.1109/TSG.2010.2046346).
- [17] A. Ipakchi and F. Albuyeh. “Grid of the future”. In: *IEEE Power and Energy Magazine* 7.2 (Mar. 2009). 32, pp. 52–62. ISSN: 1558-4216. DOI: [10.1109/MPE.2008.931384](https://doi.org/10.1109/MPE.2008.931384).
- [18] Pavlos S. Georgilakis and Nikos D. Hatziargyriou. “A review of power distribution planning in the modern power systems era: Models, methods and future research”. en. In: *Electric Power Systems Research* 121 (Apr. 2015), pp. 89–100. ISSN: 03787796. DOI: [10.1016/j.epsr.2014.12.010](https://doi.org/10.1016/j.epsr.2014.12.010). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0378779614004490> (visited on 07/01/2023).
- [19] Irene Eusgeld, D. Henzi, and W. Kröger. *Comparative Evaluation of Modeling and Simulation Techniques for Interdependent Critical Infrastructures*. en. Tech. rep. 2008.
- [20] Jing Wang et al. “Literature review on modeling and simulation of energy infrastructures from a resilience perspective”. en. In: *Reliability Engineering & System Safety* 183 (Mar. 2019), pp. 360–373. ISSN: 09518320. DOI: [10.1016/j.res.2018.11.029](https://doi.org/10.1016/j.res.2018.11.029). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0951832017313972> (visited on 12/15/2020).
- [21] W. K. Chai et al. “Resilience of interdependent communication and power distribution networks against cascading failures”. In: *2016 IFIP Networking Conference (IFIP Networking) and Workshops*. May 2016, pp. 37–45. DOI: [10.1109/IFIPNetworking.2016.7497224](https://doi.org/10.1109/IFIPNetworking.2016.7497224).
- [22] Alexis Kwasinski. “Modeling of Cyber-Physical Intra-Dependencies in Electric Power Grids and Their Effect on Resilience”. en. In: *2020 8th Workshop on Modeling and Simulation of Cyber-Physical Energy Systems*. Sydney, Australia: IEEE, Apr. 2020, pp. 1–6. ISBN: 978-1-72818-721-1. DOI: [10.1109/MSCPES49613.2020.9133702](https://doi.org/10.1109/MSCPES49613.2020.9133702). URL: <https://ieeexplore.ieee.org/document/9133702/> (visited on 03/08/2021).

- [23] Stine Fleischer Myhre et al. “Modeling Interdependencies with Complex Network Theory in a Combined Electrical Power and ICT System”. en. In: *2020 International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*. Liege, Belgium: IEEE, Aug. 2020, pp. 1–6. ISBN: 978-1-72812-822-1. DOI: [10.1109/PMAPS47429.2020.9183667](https://doi.org/10.1109/PMAPS47429.2020.9183667). URL: <https://ieeexplore.ieee.org/document/9183667/> (visited on 03/08/2021).
- [24] X. Liu et al. “Electric power grid resilience with interdependencies between power and communication networks – a review”. In: *IET Smart Grid* 3.2 (2020). Conference Name: IET Smart Grid, pp. 182–193. ISSN: 2515-2947. DOI: [10.1049/iet-stg.2019.0202](https://doi.org/10.1049/iet-stg.2019.0202).
- [25] Pouya Jamborsalamati, Seyedfoad Taghizadeh, and Moein Manbachi. “Enhancing Power Grid Resilience Through an IEC61850-Based EV-Assisted Load Restoration”. en. In: *IEEE TRANSACTIONS ON INDUSTRIAL INFORMATICS* 16.3 (2020). 18, p. 12.
- [26] Mathaios Panteli et al. “Power Systems Resilience Assessment: Hardening and Smart Operational Enhancement Strategies”. In: *Proceedings of the IEEE* 105.7 (July 2017). Conference Name: Proceedings of the IEEE, pp. 1202–1213. ISSN: 1558-2256. DOI: [10.1109/JPROC.2017.2691357](https://doi.org/10.1109/JPROC.2017.2691357).
- [27] Zhaohong Bie et al. “Battling the Extreme: A Study on the Power System Resilience”. In: *Proceedings of the IEEE* 105.7 (July 2017). Conference Name: Proceedings of the IEEE, pp. 1253–1266. ISSN: 1558-2256. DOI: [10.1109/JPROC.2017.2679040](https://doi.org/10.1109/JPROC.2017.2679040).
- [28] Anmar Arif et al. “Power Distribution System Outage Management With Co-Optimization of Repairs, Reconfiguration, and DG Dispatch”. en. In: *IEEE Transactions on Smart Grid* 9.5 (Sept. 2018), pp. 4109–4118. ISSN: 1949-3053, 1949-3061. DOI: [10.1109/TSG.2017.2650917](https://doi.org/10.1109/TSG.2017.2650917). URL: <https://ieeexplore.ieee.org/document/7812566/> (visited on 04/21/2021).
- [29] Shunbo Lei et al. “Resilient Disaster Recovery Logistics of Distribution Systems: Co-Optimize Service Restoration With Repair Crew and Mobile Power Source Dispatch”. en. In: *IEEE Transactions on Smart Grid* 10.6 (Nov. 2019), pp. 6187–6202. ISSN: 1949-3053, 1949-3061. DOI: [10.1109/TSG.2019.2899353](https://doi.org/10.1109/TSG.2019.2899353). URL: <https://ieeexplore.ieee.org/document/8642442/> (visited on 04/21/2021).

- [30] Yanling Lin et al. “A Combined Repair Crew Dispatch Problem for Resilient Electric and Natural Gas System Considering Reconfiguration and DG Islanding”. In: *IEEE Transactions on Power Systems* 34.4 (July 2019). Conference Name: IEEE Transactions on Power Systems, pp. 2755–2767. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2019.2895198](https://doi.org/10.1109/TPWRS.2019.2895198).
- [31] Yiheng Bian et al. “Service Restoration for Resilient Distribution Systems Coordinated with Damage Assessment”. en. In: *IEEE Transactions on Power Systems* (2021), pp. 1–1. ISSN: 0885-8950, 1558-0679. DOI: [10.1109/TPWRS.2021.3137257](https://doi.org/10.1109/TPWRS.2021.3137257). URL: <https://ieeexplore.ieee.org/document/9658141/> (visited on 08/16/2022).
- [32] Zhigang Ye et al. “Boost Distribution System Restoration with Emergency Communication Vehicles Considering Cyber-Physical Interdependence”. In: *IEEE Transactions on Smart Grid* (2022). Conference Name: IEEE Transactions on Smart Grid, pp. 1–1. ISSN: 1949-3061. DOI: [10.1109/TSG.2022.3205039](https://doi.org/10.1109/TSG.2022.3205039).
- [33] Xin Liu et al. “Towards Optimal and Executable Distribution Grid Restoration Planning With a Fine-Grained Power-Communication Interdependency Model”. In: *IEEE Transactions on Smart Grid* 13.3 (May 2022). Conference Name: IEEE Transactions on Smart Grid, pp. 1911–1922. ISSN: 1949-3061. DOI: [10.1109/TSG.2022.3149973](https://doi.org/10.1109/TSG.2022.3149973).
- [34] Gongyu Wu, Meiyan Li, and Zhaojun Steven Li. “Resilience-Based Optimal Recovery Strategy for Cyber-Physical Power Systems Considering Component Multistate Failures”. In: *IEEE Transactions on Reliability* 70.4 (Dec. 2021). Conference Name: IEEE Transactions on Reliability, pp. 1510–1524. ISSN: 1558-1721. DOI: [10.1109/TR.2020.3025179](https://doi.org/10.1109/TR.2020.3025179).
- [35] Yi-Ping Fang and Giovanni Sansavini. “Optimum post-disruption restoration under uncertainty for enhancing critical infrastructure resilience”. en. In: *Reliability Engineering & System Safety* 185 (May 2019), pp. 1–11. ISSN: 09518320. DOI: [10.1016/j.ress.2018.12.002](https://doi.org/10.1016/j.ress.2018.12.002). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0951832017310062> (visited on 08/25/2022).
- [36] Anmar Arif et al. “Optimizing Service Restoration in Distribution Systems With Uncertain Repair Time and Demand”. In: *IEEE Transactions on Power Systems* 33.6 (Nov. 2018). Conference Name: IEEE Transactions on Power Systems, pp. 6828–6838. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2018.2855102](https://doi.org/10.1109/TPWRS.2018.2855102).

- [37] Line A. Roald et al. “Power systems optimization under uncertainty: A review of methods and applications”. en. In: *Electric Power Systems Research* 214 (Jan. 2023), p. 108725. ISSN: 03787796. DOI: [10.1016/j.epsr.2022.108725](https://doi.org/10.1016/j.epsr.2022.108725). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0378779622007842> (visited on 07/01/2023).
- [38] W.B. Powell. “The optimizing-simulator: merging simulation and optimization using approximate dynamic programming”. In: *Proceedings of the Winter Simulation Conference, 2005*. ISSN: 1558-4305. Dec. 2005, 14 pp.—. DOI: [10.1109/WSC.2005.1574243](https://doi.org/10.1109/WSC.2005.1574243).
- [39] Christian Almeder, Margaretha Preusser, and Richard F. Hartl. “Simulation and optimization of supply chains: alternative or complementary approaches?” en. In: *OR Spectrum* 31.1 (Jan. 2009), pp. 95–119. ISSN: 1436-6304. DOI: [10.1007/s00291-007-0118-z](https://doi.org/10.1007/s00291-007-0118-z). URL: <https://doi.org/10.1007/s00291-007-0118-z> (visited on 06/30/2023).
- [40] IEEE PES Task Force et al. “Methods for Analysis and Quantification of Power System Resilience”. In: *IEEE Transactions on Power Systems* (2022). Conference Name: IEEE Transactions on Power Systems, pp. 1–14. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2022.3212688](https://doi.org/10.1109/TPWRS.2022.3212688).
- [41] Seyedmohsen Hosseini, Kash Barker, and Jose E. Ramirez-Marquez. “A review of definitions and measures of system resilience”. en. In: *Reliability Engineering & System Safety* 145 (Jan. 2016). 50, pp. 47–61. ISSN: 09518320. DOI: [10.1016/j.res.2015.08.006](https://doi.org/10.1016/j.res.2015.08.006). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0951832015002483> (visited on 12/03/2020).
- [42] Hassan Farhangi. “The path of the smart grid”. In: *IEEE Power and Energy Magazine* 8.1 (Jan. 2010). Conference Name: IEEE Power and Energy Magazine, pp. 18–28. ISSN: 1558-4216. DOI: [10.1109/MPE.2009.934876](https://doi.org/10.1109/MPE.2009.934876).
- [43] Reka Albert and Albert-Laszlo Barabasi. “Statistical mechanics of complex networks”. In: *Reviews of Modern Physics* 74.1 (Jan. 2002). arXiv:cond-mat/0106096, pp. 47–97. ISSN: 0034-6861, 1539-0756. DOI: [10.1103/RevModPhys.74.47](https://doi.org/10.1103/RevModPhys.74.47). URL: <http://arxiv.org/abs/cond-mat/0106096> (visited on 03/06/2023).
- [44] Albert-Laszlo Barabasi. *Network Science by Albert-László Barabási*. 2016. URL: <http://networksciencebook.com/> (visited on 03/08/2023).

- [45] S. Boccaletti et al. “Complex networks: Structure and dynamics”. en. In: *Physics Reports* 424.4 (Feb. 2006), pp. 175–308. ISSN: 0370-1573. DOI: [10.1016/j.physrep.2005.10.009](https://doi.org/10.1016/j.physrep.2005.10.009). URL: <https://www.sciencedirect.com/science/article/pii/S037015730500462X> (visited on 03/08/2023).
- [46] M. E. J. Newman. *Networks: an introduction*. en. OCLC: ocn456837194. Oxford ; New York: Oxford University Press, 2010. ISBN: 978-0-19-920665-0.
- [47] Ravindra K. Ahuja, Thomas L. Magnanti, and James B. Orlin. *Network Flows: Theory, Algorithms, and Applications*. en. 1993. URL: <https://mitgmtfaculty.mit.edu/jorlin/network-flows/> (visited on 03/09/2023).
- [48] Reza Arghandeh et al. “On the definition of cyber-physical resilience in power systems”. en. In: *Renewable and Sustainable Energy Reviews* 58 (May 2016), pp. 1060–1069. ISSN: 1364-0321. DOI: [10.1016/j.rser.2015.12.193](https://doi.org/10.1016/j.rser.2015.12.193). URL: <https://www.sciencedirect.com/science/article/pii/S1364032115015762> (visited on 03/17/2023).
- [49] Haibo He and Jun Yan. “Cyber-physical attacks and defences in the smart grid: a survey”. en. In: *IET Cyber-Physical Systems: Theory & Applications* 1.1 (2016). eprint: <https://onlinelibrary.wiley.com/doi/pdf/10.1049/iet-cps.2016.0019>, pp. 13–27. ISSN: 2398-3396. DOI: [10.1049/iet-cps.2016.0019](https://doi.org/10.1049/iet-cps.2016.0019). URL: <https://onlinelibrary.wiley.com/doi/abs/10.1049/iet-cps.2016.0019> (visited on 03/17/2023).
- [50] Inger Anne Tøndel et al. “Interdependencies and reliability in the combined ICT and power system: An overview of current research”. en. In: *Applied Computing and Informatics* 14.1 (Jan. 2018), pp. 17–27. ISSN: 2210-8327. DOI: [10.1016/j.aci.2017.01.001](https://doi.org/10.1016/j.aci.2017.01.001). URL: <https://www.sciencedirect.com/science/article/pii/S2210832716300552> (visited on 03/17/2023).
- [51] Sergey V. Buldyrev et al. “Catastrophic cascade of failures in interdependent networks”. en. In: *Nature* 464.7291 (Apr. 2010), pp. 1025–1028. ISSN: 0028-0836, 1476-4687. DOI: [10.1038/nature08932](https://doi.org/10.1038/nature08932). URL: <https://www.nature.com/articles/nature08932> (visited on 05/19/2023).
- [52] Surachai Chaitusaney and Akihiko Yokoyama. “Prevention of Reliability Degradation from Recloser–Fuse Miscoordination Due To Distributed Generation”. In: *IEEE Transactions on Power Delivery* 23.4 (Oct. 2008). Conference Name: IEEE Transactions on Power Delivery, pp. 2545–2554. ISSN: 1937-4208. DOI: [10.1109/TPWRD.2007.915899](https://doi.org/10.1109/TPWRD.2007.915899).

- [53] R.N. Allan and J.R. Ochoa. “Modeling and assessment of station originated outages for composite systems reliability evaluation”. In: *IEEE Transactions on Power Systems* 3.1 (Feb. 1988). Conference Name: IEEE Transactions on Power Systems, pp. 158–165. ISSN: 1558-0679. DOI: [10.1109/59.43193](https://doi.org/10.1109/59.43193).
- [54] Marina Lavorato et al. “Imposing Radiality Constraints in Distribution System Optimization Problems”. In: *IEEE Transactions on Power Systems* 27.1 (Feb. 2012). Conference Name: IEEE Transactions on Power Systems, pp. 172–180. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2011.2161349](https://doi.org/10.1109/TPWRS.2011.2161349).
- [55] Rabih A. Jabr, Ravindra Singh, and Bikash C. Pal. “Minimum Loss Network Reconfiguration Using Mixed-Integer Convex Programming”. In: *IEEE Transactions on Power Systems* 27.2 (May 2012). Conference Name: IEEE Transactions on Power Systems, pp. 1106–1115. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2011.2180406](https://doi.org/10.1109/TPWRS.2011.2180406).
- [56] Ying Wang et al. “On the Radiality Constraints for Distribution System Restoration and Reconfiguration Problems”. In: *IEEE Transactions on Power Systems* 35.4 (July 2020). Conference Name: IEEE Transactions on Power Systems, pp. 3294–3296. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2020.2991356](https://doi.org/10.1109/TPWRS.2020.2991356).
- [57] Tao Ding et al. “A New Model for Resilient Distribution Systems by Microgrids Formation”. In: *IEEE Transactions on Power Systems* 32.5 (Sept. 2017). Conference Name: IEEE Transactions on Power Systems, pp. 4145–4147. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2017.2650779](https://doi.org/10.1109/TPWRS.2017.2650779).
- [58] Yanling Lin. “Tri-level optimal hardening plan for a resilient distribution system considering reconfiguration and DG islanding”. en. In: *Applied Energy* (2018), p. 14.
- [59] Shunbo Lei et al. “Radiality Constraints for Resilient Reconfiguration of Distribution Systems: Formulation and Application to Microgrid Formation”. In: *IEEE Transactions on Smart Grid* 11.5 (Sept. 2020). Conference Name: IEEE Transactions on Smart Grid, pp. 3944–3956. ISSN: 1949-3061. DOI: [10.1109/TSG.2020.2985087](https://doi.org/10.1109/TSG.2020.2985087).
- [60] Jiancun Liu, Yixin Yu, and Chao Qin. “A Unified Two-Stage Reconfiguration Method for Resilience Enhancement of Distribution Systems”. In: *IET Generation, Transmission & Distribution* 13 (May 2019). DOI: [10.1049/iet-gtd.2018.6680](https://doi.org/10.1049/iet-gtd.2018.6680).
- [61] Steven H. Low. “Convex Relaxation of Optimal Power Flow, Part II: Exactness”. In: *IEEE Transactions on Control of Network Systems* 1.2 (June 2014). arXiv:1405.0814 [cs, math], pp. 177–189. ISSN: 2325-5870. DOI: [10.1109/TCNS.2014.2323634](https://doi.org/10.1109/TCNS.2014.2323634). URL: <http://arxiv.org/abs/1405.0814> (visited on 08/09/2022).

- [62] J Carpentier. “Optimal power flows”. en. In: *International Journal of Electrical Power & Energy Systems* 1.1 (Apr. 1979), pp. 3–15. ISSN: 0142-0615. DOI: [10.1016/0142-0615\(79\)90026-7](https://doi.org/10.1016/0142-0615(79)90026-7). URL: <https://www.sciencedirect.com/science/article/pii/0142061579900267> (visited on 08/09/2022).
- [63] Mary B. Cain, Richard P. O’neill, and Anya Castillo. *History of Optimal Power Flow and Formulations Optimal Power Flow Paper 1*. 2012.
- [64] Alejandro Garces. “A quadratic approximation for the optimal power flow in power distribution systems”. en. In: *Electric Power Systems Research* 130 (Jan. 2016), pp. 222–229. ISSN: 0378-7796. DOI: [10.1016/j.epsr.2015.09.006](https://doi.org/10.1016/j.epsr.2015.09.006). URL: <https://www.sciencedirect.com/science/article/pii/S037877961500276X> (visited on 08/09/2022).
- [65] M H Haque. “Load flow solution of distribution systems with voltage dependent load models”. en. In: (), p. 6.
- [66] Andrey Bernstein and Emiliano Dall’Anese. “Linear power-flow models in multi-phase distribution networks”. In: *2017 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe)*. Sept. 2017, pp. 1–6. DOI: [10.1109/ISGTEurope.2017.8260205](https://doi.org/10.1109/ISGTEurope.2017.8260205).
- [67] M. Huneault and F.D. Galiana. “A survey of the optimal power flow literature”. In: *IEEE Transactions on Power Systems* 6.2 (May 1991). Conference Name: IEEE Transactions on Power Systems, pp. 762–770. ISSN: 1558-0679. DOI: [10.1109/59.76723](https://doi.org/10.1109/59.76723).
- [68] Stephen Frank, Ingrida Steponavice, and Steffen Rebennack. “Optimal power flow: a bibliographic survey I: Formulations and deterministic methods”. en. In: *Energy Systems* 3.3 (Sept. 2012), pp. 221–258. ISSN: 1868-3967, 1868-3975. DOI: [10.1007/s12667-012-0056-y](https://doi.org/10.1007/s12667-012-0056-y). URL: <http://link.springer.com/10.1007/s12667-012-0056-y> (visited on 08/09/2022).
- [69] Fariba Zohrizadeh et al. “A survey on conic relaxations of optimal power flow problem”. en. In: *European Journal of Operational Research* 287.2 (Dec. 2020), pp. 391–409. ISSN: 0377-2217. DOI: [10.1016/j.ejor.2020.01.034](https://doi.org/10.1016/j.ejor.2020.01.034). URL: <https://www.sciencedirect.com/science/article/pii/S0377221720300552> (visited on 08/09/2022).

- [70] A.P. Sakis Meliopoulos and Fan Zhang. “Multiphase power flow and state estimation for power distribution systems”. In: *IEEE Transactions on Power Systems* 11.2 (May 1996). Conference Name: IEEE Transactions on Power Systems, pp. 939–946. ISSN: 1558-0679. DOI: [10.1109/59.496178](https://doi.org/10.1109/59.496178).
- [71] M.E. Baran and F.F. Wu. “Network reconfiguration in distribution systems for loss reduction and load balancing”. In: *IEEE Transactions on Power Delivery* 4.2 (Apr. 1989). Conference Name: IEEE Transactions on Power Delivery, pp. 1401–1407. ISSN: 1937-4208. DOI: [10.1109/61.25627](https://doi.org/10.1109/61.25627).
- [72] K. Balamurugan and Dipti Srinivasan. “Review of power flow studies on distribution network with distributed generation”. In: *2011 IEEE Ninth International Conference on Power Electronics and Drive Systems*. ISSN: 2164-5264. Dec. 2011, pp. 411–417. DOI: [10.1109/PEDS.2011.6147281](https://doi.org/10.1109/PEDS.2011.6147281).
- [73] Michael Sankur et al. “A Linearized Power Flow Model for Optimization in Unbalanced Distribution Systems”. In: (June 2016).
- [74] Daniel B. Arnold et al. “Optimal dispatch of reactive power for voltage regulation and balancing in unbalanced distribution systems”. In: *2016 IEEE Power and Energy Society General Meeting (PESGM)*. ISSN: 1944-9933. July 2016, pp. 1–5. DOI: [10.1109/PESGM.2016.7741261](https://doi.org/10.1109/PESGM.2016.7741261).
- [75] Saverio Bolognani and Florian Dörfler. “Fast power system analysis via implicit linearization of the power flow manifold”. In: *2015 53rd Annual Allerton Conference on Communication, Control, and Computing (Allerton)*. Sept. 2015, pp. 402–409. DOI: [10.1109/ALLERTON.2015.7447032](https://doi.org/10.1109/ALLERTON.2015.7447032).
- [76] Dimitris C. Paraskevopoulos et al. “Resource constrained routing and scheduling: Review and research prospects”. en. In: *European Journal of Operational Research* 263.3 (Dec. 2017), pp. 737–754. ISSN: 03772217. DOI: [10.1016/j.ejor.2017.05.035](https://doi.org/10.1016/j.ejor.2017.05.035). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0377221717304824> (visited on 08/16/2022).
- [77] K. Hopkinson et al. “EPOCHS: a platform for agent-based electric power and communication simulation built from commercial off-the-shelf components”. In: *IEEE Transactions on Power Systems* 21.2 (May 2006). Conference Name: IEEE Transactions on Power Systems, pp. 548–558. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2006.873129](https://doi.org/10.1109/TPWRS.2006.873129).

- [78] C.M. Macal and M.J. North. “Tutorial on agent-based modeling and simulation”. In: *Proceedings of the Winter Simulation Conference, 2005*. ISSN: 1558-4305. Dec. 2005, 14 pp.—. DOI: [10.1109/WSC.2005.1574234](https://doi.org/10.1109/WSC.2005.1574234).
- [79] Michael Wooldridge. *An Introduction to MultiAgent Systems*. 2nd. Wiley Publishing, 2009. ISBN: 978-0-470-51946-2.
- [80] Van Parunak, Robert Savit, and Rick Riolo. “Agent-Based Modeling vs. Equation-Based Modeling: A Case Study and Users’ Guide”. In: July 2000. ISBN: 978-3-540-65476-6. DOI: [10.1007/10692956_2](https://doi.org/10.1007/10692956_2).
- [81] Enrique Kremers. “Modelling and Simulation of Electrical Energy Systems through a Complex Systems Approach using Agent-Based Models”. Journal Abbreviation: Modelling and Simulation of Electrical Energy Systems Through a Complex Systems Approach using Agent-Based Models Publication Title: Modelling and Simulation of Electrical Energy Systems Through a Complex Systems Approach using Agent-Based Models. PhD thesis. July 2012. DOI: [10.5445/KSP/1000031133](https://doi.org/10.5445/KSP/1000031133).
- [82] Bernard P. Zeigler, Herbert Praehofer, and Tag Gon Kim. *Theory of Modeling and Simulation*. en. Google-Books-ID: REzmYOQmHuQC. Academic Press, Jan. 2000. ISBN: 978-0-12-778455-7.
- [83] Michele Garau et al. “Co-simulation and Discrete Event Simulation for Reliability Assessment of Power System and ICT: A Comparison”. In: *2021 5th International Conference on System Reliability and Safety (ICSRS)*. Nov. 2021, pp. 66–73. DOI: [10.1109/ICSRS53853.2021.9660630](https://doi.org/10.1109/ICSRS53853.2021.9660630).
- [84] Kevin Mets, Juan Aparicio Ojea, and Chris Develder. “Combining Power and Communication Network Simulation for Cost-Effective Smart Grid Analysis”. In: *IEEE Communications Surveys & Tutorials* 16.3 (2014). Conference Name: IEEE Communications Surveys & Tutorials, pp. 1771–1796. ISSN: 1553-877X. DOI: [10.1109/SURV.2014.021414.00116](https://doi.org/10.1109/SURV.2014.021414.00116).
- [85] Anylogic. *Agent synchronization — AnyLogic Help*. en. 2023. URL: <https://anylogic.help/anylogic/agentbased/synchronization.html#agent-synchronization> (visited on 06/24/2023).
- [86] T. Gomes et al. “A survey of strategies for communication networks to protect against large-scale natural disasters”. In: *2016 8th International Workshop on Resilient Networks Design and Modeling (RNDM)*. Sept. 2016, pp. 11–22. DOI: [10.1109/RNDM.2016.7608263](https://doi.org/10.1109/RNDM.2016.7608263).

- [87] Anylogic. *Optimizing Energy Systems with AnyLogic Simulation Modeling*. en. 2010. URL: <https://www.anylogic.com/resources/case-studies/optimizing-energy-systems-with-anylogic-simulation-modeling/> (visited on 06/23/2023).
- [88] Muki Haklay and Patrick Weber. “OpenStreetMap: User-Generated Street Maps”. In: *Haklay, M. and Weber, P. (2008) OpenStreetMap: user-generated street maps. IEEE Pervasive Computing*, 7 (4). pp. 12-18. ISSN 15361268 7 (Oct. 2008). DOI: [10.1109/MPRV.2008.80](https://doi.org/10.1109/MPRV.2008.80).
- [89] Andrei Borshchev and Alexei Filippov. “From System Dynamics and Discrete Event to Practical Agent Based Modeling: Reasons, Techniques, Tools”. en. In: (2004), p. 22.
- [90] Gregorio Muñoz-Delgado, Javier Contreras, and José M. Arroyo. “Multistage Generation and Network Expansion Planning in Distribution Systems Considering Uncertainty and Reliability”. In: *IEEE Transactions on Power Systems* 31.5 (Sept. 2016). Conference Name: IEEE Transactions on Power Systems, pp. 3715–3728. ISSN: 1558-0679. DOI: [10.1109/TPWRS.2015.2503604](https://doi.org/10.1109/TPWRS.2015.2503604).
- [91] Miguel Asensio et al. “Joint Distribution Network and Renewable Energy Expansion Planning Considering Demand Response and Energy Storage—Part I: Stochastic Programming Model”. In: *IEEE Transactions on Smart Grid* 9.2 (Mar. 2018). Conference Name: IEEE Transactions on Smart Grid, pp. 655–666. ISSN: 1949-3061. DOI: [10.1109/TSG.2016.2560339](https://doi.org/10.1109/TSG.2016.2560339).
- [92] Cameron A. MacKenzie and Christopher W. Zobel. “Allocating Resources to Enhance Resilience, with Application to Superstorm Sandy and an Electric Utility: Allocating Resources to Enhance Resilience”. en. In: *Risk Analysis* 36.4 (Apr. 2016). 13, pp. 847–862. ISSN: 02724332. DOI: [10.1111/risa.12479](https://doi.org/10.1111/risa.12479). URL: <http://doi.wiley.com/10.1111/risa.12479> (visited on 12/01/2020).
- [93] Shiva Poudel, Anamika Dubey, and Anjan Bose. “Risk-Based Probabilistic Quantification of Power Distribution System Operational Resilience”. en. In: *IEEE Systems Journal* 14.3 (Sept. 2020). 4, pp. 3506–3517. ISSN: 1932-8184, 1937-9234, 2373-7816. DOI: [10.1109/JSYST.2019.2940939](https://doi.org/10.1109/JSYST.2019.2940939). URL: <https://ieeexplore.ieee.org/document/8848458/> (visited on 12/01/2020).
- [94] Zhiwen Wang et al. “Risk-Limiting Load Restoration for Resilience Enhancement With Intermittent Energy Resources”. In: *IEEE Transactions on Smart Grid* 10.3

- (May 2019). Conference Name: IEEE Transactions on Smart Grid, pp. 2507–2522. ISSN: 1949-3061. DOI: [10.1109/TSG.2018.2803141](https://doi.org/10.1109/TSG.2018.2803141).
- [95] Shujun Xin et al. “Information-Energy Flow Computation and Cyber-Physical Sensitivity Analysis for Power Systems”. In: *IEEE Journal on Emerging and Selected Topics in Circuits and Systems* 7.2 (June 2017). Conference Name: IEEE Journal on Emerging and Selected Topics in Circuits and Systems, pp. 329–341. ISSN: 2156-3365. DOI: [10.1109/JETCAS.2017.2700618](https://doi.org/10.1109/JETCAS.2017.2700618).
 - [96] Gang Huang et al. “Cyber-Constrained Optimal Power Flow Model for Smart Grid Resilience Enhancement”. In: *IEEE Transactions on Smart Grid* 10.5 (Sept. 2019). Conference Name: IEEE Transactions on Smart Grid, pp. 5547–5555. ISSN: 1949-3061. DOI: [10.1109/TSG.2018.2885025](https://doi.org/10.1109/TSG.2018.2885025).
 - [97] William E. Hart, Jean-Paul Watson, and David L. Woodruff. “Pyomo: modeling and solving mathematical programs in Python”. en. In: *Mathematical Programming Computation* 3.3 (Sept. 2011), pp. 219–260. ISSN: 1867-2957. DOI: [10.1007/s12532-011-0026-8](https://doi.org/10.1007/s12532-011-0026-8). URL: <https://doi.org/10.1007/s12532-011-0026-8> (visited on 06/26/2023).
 - [98] A.S. Jain and S. Meeran. “Deterministic job-shop scheduling: Past, present and future”. en. In: *European Journal of Operational Research* 113.2 (Mar. 1999), pp. 390–434. ISSN: 03772217. DOI: [10.1016/S0377-2217\(98\)00113-1](https://doi.org/10.1016/S0377-2217(98)00113-1). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0377221798001131> (visited on 07/24/2023).
 - [99] Qingxin Shi et al. “Enhancing distribution system resilience against extreme weather events: Concept review, algorithm summary, and future vision”. en. In: *International Journal of Electrical Power & Energy Systems* 138 (June 2022), p. 107860. ISSN: 01420615. DOI: [10.1016/j.ijepes.2021.107860](https://doi.org/10.1016/j.ijepes.2021.107860). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0142061521010759> (visited on 07/20/2023).
 - [100] Jiayong Li, Mohammad E. Khodayar, and Mohammad Ramin Feizi. “Hybrid Modeling Based Co-Optimization of Crew Dispatch and Distribution System Restoration Considering Multiple Uncertainties”. In: *IEEE Systems Journal* 16.1 (Mar. 2022). Conference Name: IEEE Systems Journal, pp. 1278–1288. ISSN: 1937-9234. DOI: [10.1109/JSYST.2020.3048817](https://doi.org/10.1109/JSYST.2020.3048817).

- [101] M. Barbati, G. Bruno, and A. Genovese. “Applications of agent-based models for optimization problems: A literature review”. en. In: *Expert Systems with Applications* 39.5 (Apr. 2012), pp. 6020–6028. ISSN: 0957-4174. DOI: [10.1016/j.eswa.2011.12.015](https://doi.org/10.1016/j.eswa.2011.12.015). URL: <https://www.sciencedirect.com/science/article/pii/S0957417411016861> (visited on 01/19/2022).
- [102] Shaghaygh Akhtari and Taraneh Sowlati. “Hybrid optimization-simulation for integrated planning of bioenergy and biofuel supply chains”. en. In: *Applied Energy* 259 (Feb. 2020), p. 114124. ISSN: 03062619. DOI: [10.1016/j.apenergy.2019.114124](https://doi.org/10.1016/j.apenergy.2019.114124). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0306261919318112> (visited on 07/09/2023).
- [103] Satyajith Amaran et al. “Simulation optimization: A review of algorithms and applications”. In: *Annals of Operations Research* 240.1 (May 2016). arXiv:1706.08591 [cs, math], pp. 351–380. ISSN: 0254-5330, 1572-9338. DOI: [10.1007/s10479-015-2019-x](https://doi.org/10.1007/s10479-015-2019-x). URL: <http://arxiv.org/abs/1706.08591> (visited on 07/21/2023).
- [104] Andreas Klemmt et al. “Simulation-based optimization vs. mathematical programming: A hybrid approach for optimizing scheduling problems”. en. In: *Robotics and Computer-Integrated Manufacturing* 25.6 (Dec. 2009), pp. 917–925. ISSN: 07365845. DOI: [10.1016/j.rcim.2009.04.012](https://doi.org/10.1016/j.rcim.2009.04.012). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0736584509000362> (visited on 07/21/2023).
- [105] Yavuz Acar, Sukran N. Kadipasaoglu, and Jamison M. Day. “Incorporating uncertainty in optimal decision making: Integrating mixed integer programming and simulation to solve combinatorial problems”. en. In: *Computers & Industrial Engineering* 56.1 (Feb. 2009), pp. 106–112. ISSN: 03608352. DOI: [10.1016/j.cie.2008.04.003](https://doi.org/10.1016/j.cie.2008.04.003). URL: <https://linkinghub.elsevier.com/retrieve/pii/S036083520800082X> (visited on 07/09/2023).
- [106] K Kulkarni and J Venkateswaran. “Hybrid approach using simulation-based optimisation for job shop scheduling problems”. en. In: *Journal of Simulation* 9.4 (Nov. 2015), pp. 312–324. ISSN: 1747-7778, 1747-7786. DOI: [10.1057/jos.2014.40](https://doi.org/10.1057/jos.2014.40). URL: <https://www.tandfonline.com/doi/full/10.1057/jos.2014.40> (visited on 07/02/2023).
- [107] IEEE Power Systems Relaying Committee. “Automatic Reclosing of Transmission Lines”. In: *IEEE Transactions on Power Apparatus and Systems* PAS-103.2 (Feb.

- 1984). Conference Name: IEEE Transactions on Power Apparatus and Systems, pp. 234–245. ISSN: 0018-9510. DOI: [10.1109/TPAS.1984.318222](https://doi.org/10.1109/TPAS.1984.318222).
- [108] Enedis. *Cartographie des réseaux exploités par Enedis - Enedis Open Data — Enedis Open Data*. 2023. URL: <https://data.enedis.fr/pages/cartographie-des-reseaux-contenu/> (visited on 07/10/2023).
- [109] Emilio Ancillotti, Raffaele Bruno, and Marco Conti. “The role of communication systems in smart grids: Architectures, technical solutions and research challenges”. en. In: *Computer Communications* 36.17-18 (Nov. 2013), pp. 1665–1697. ISSN: 01403664. DOI: [10.1016/j.comcom.2013.09.004](https://doi.org/10.1016/j.comcom.2013.09.004). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0140366413002090> (visited on 08/14/2022).
- [110] ETSI. *Part 3: Template for Service Level Agreements (SLA), User Group; Quality of telecom services*; tech. rep. 2017. URL: https://www.etsi.org/deliver/etsi_eg/202000_202099/20200903/01.02.01_50/eg_20200903v010201m.pdf (visited on 07/12/2023).
- [111] A. Bobbio et al. “Unavailability of critical SCADA communication links inter-connecting a power grid and a Telco network”. en. In: *Reliability Engineering & System Safety* 95.12 (Dec. 2010), pp. 1345–1357. ISSN: 09518320. DOI: [10.1016/j.ress.2010.06.011](https://doi.org/10.1016/j.ress.2010.06.011). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0951832010001456> (visited on 07/12/2023).
- [112] CRE. *Energy regulation commission*. fr-FR. 2023. URL: <https://www.cre.fr/> (visited on 07/12/2023).
- [113] CRE. *Délibération de la Commission de régulation de l’énergie du 21 janvier 2021 portant décision sur le tarif d’utilisation des réseaux publics de distribution d’électricité (TURPE 6 HTA-BT)*. 2021. URL: https://www.cre.fr/content/download/23338/file/210121_2021-13_TURPE_6_HTA-BT.pdf.
- [114] Shunbo Lei et al. “Mobile Emergency Generator Pre-Positioning and Real-Time Allocation for Resilient Response to Natural Disasters”. In: *IEEE Transactions on Smart Grid* 9.3 (May 2018). Conference Name: IEEE Transactions on Smart Grid, pp. 2030–2041. ISSN: 1949-3061. DOI: [10.1109/TSG.2016.2605692](https://doi.org/10.1109/TSG.2016.2605692).
- [115] Jip Kim and Yury Dvorkin. “Enhancing Distribution System Resilience With Mobile Energy Storage and Microgrids”. en. In: *IEEE Transactions on Smart Grid* 10.5 (Sept. 2019), pp. 4996–5006. ISSN: 1949-3053, 1949-3061. DOI: [10.1109/TSG.2018.](https://doi.org/10.1109/TSG.2018.)

2872521. URL: <https://ieeexplore.ieee.org/document/8476200/> (visited on 07/15/2023).
- [116] Babak Taheri et al. “Distribution System Resilience Enhancement via Mobile Emergency Generators”. In: *IEEE Transactions on Power Delivery* 36.4 (Aug. 2021). Conference Name: IEEE Transactions on Power Delivery, pp. 2308–2319. ISSN: 1937-4208. DOI: [10.1109/TPWRD.2020.3007762](https://doi.org/10.1109/TPWRD.2020.3007762).
 - [117] Seyed Amir Mansouri et al. “A hierarchical scheduling framework for resilience enhancement of decentralized renewable-based microgrids considering proactive actions and mobile units”. en. In: *Renewable and Sustainable Energy Reviews* 168 (Oct. 2022), p. 112854. ISSN: 13640321. DOI: [10.1016/j.rser.2022.112854](https://doi.org/10.1016/j.rser.2022.112854). URL: <https://linkinghub.elsevier.com/retrieve/pii/S1364032122007365> (visited on 07/15/2023).
 - [118] Y. Wang, A. Oulis Rousis, and G. Strbac. “Resilience-driven optimal sizing and pre-positioning of mobile energy storage systems in decentralized networked microgrids”. en. In: *Applied Energy* 305 (Jan. 2022), p. 117921. ISSN: 03062619. DOI: [10.1016/j.apenergy.2021.117921](https://doi.org/10.1016/j.apenergy.2021.117921). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0306261921012319> (visited on 07/15/2023).

Part II

Appended Papers

Paper [\[1\]](#)

Youba Nait Belaid, Patrick Coudray, José Sanchez-Torres, Yiping Fang, Zhiguo Zeng, Anne Barros. “Resilience Quantification of Smart Distribution Networks—A Bird’s Eye View Perspective”. In: *Energies* 14.10, MDPI, Jan. 2021.

Review

Resilience Quantification of Smart Distribution Networks—A Bird's Eye View Perspective

Youba Nait Belaid ^{1,2}, Patrick Coudray ¹, José Sanchez-Torres ¹ , Yi-Ping Fang ^{2,*} , Zhiguo Zeng ² and Anne Barros ²

¹ Electricité de France R&D, 7 Boulevard Gaspard Monge, 91120 Palaiseau, France;

youba.nait-belaid@edf.fr (Y.N.B.); patrick.coudray@edf.fr (P.C.); jose.sanchez-torres@edf.fr (J.S.-T.)

² Risk and Resilience of Complex Systems, Laboratoire Génie Industriel, CentraleSupélec, Université Paris-Saclay, 3 Rue Joliot Curie, 91190 Gif-sur-Yvette, France; zhiguo.zeng@centralesupelec.fr (Z.Z.); anne.barros@centralesupelec.fr (A.B.)

* Correspondence: yiping.fang@centralesupelec.fr

Abstract: The introduction of pervasive telecommunication devices, in the scope of smart grids (SGs), has accentuated interest in the distribution network, which integrates a huge portion of new grid applications. High impact low probability (HILP) events, such as natural hazards, manmade errors, and cyber-attacks, as well as the inherent fragility of the distribution grid have propelled the development of effective resilience tools and methods for the power distribution network (PDN) to avoid catastrophic infrastructural and economical losses. Multiple resilience evaluation frameworks are proposed in the literature in order to assist distribution system operators (DSOs) in managing their networks when faced with exogenous threats. We conduct detailed analysis of existing quantitative resilience studies in both electric and telecommunication domains of a PDN, focusing on event type, metrics, temporal phases, uncertainty, and critical load. Our work adopts the standpoint of a DSO, whose target is to identify feasible resilience assessment frameworks, which apply to pre-defined requirements in terms of resilience evaluation objectives (planning, reactive response, or simple assessment), time of evaluation, and available enhancement strategies. Finally, results and observations on selected works are presented, followed by discussion of identified challenges and opportunities.

Keywords: resilience; quantification; smart grids; power networks; information and communication networks



Citation: Nait Belaid, Y.; Coudray, P.; Sanchez-Torres, J.; Fang, Y.-P.; Zeng, Z.; Barros, A. Resilience Quantification of Smart Distribution Networks—A Bird's Eye View Perspective. *Energies* **2021**, *14*, 2888. <https://doi.org/10.3390/en14102888>

Academic Editor: Marco Pasetti

Received: 15 April 2021

Accepted: 13 May 2021

Published: 17 May 2021

Publisher's Note: MDPI stays neutral with regard to jurisdictional claims in published maps and institutional affiliations.



Copyright: © 2021 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<https://creativecommons.org/licenses/by/4.0/>).

1. Introduction

Current information and communication technologies (ICTs) have achieved a high degree of penetration in all critical infrastructure (CI) systems, owing to the ever-increasing capabilities of their services in terms of coverage, throughput capacity, latency, scalability, and privacy [1–4]. In power systems, the massive introduction of telecommunication devices accelerated the shift toward smart grids (SGs) [5] that come with a whole new package of functionalities such as automated control, smart sensing and metering, high-power converters, and modern energy management techniques based on the optimization of demand, energy, and network availability [6]. The high-performance smart grid allows thereby for the insertion of new applications in the network like distributed generation, Industrial Internet of Things (IIOT), and electrical vehicles [7]. This comes, however at the expense of increased complexity, which brings new vulnerabilities and broadens the attack surface [8]. Recent extreme events of natural disasters, cyber-attacks, and man-made errors which we refer to as HILP events, have shown that SGs are susceptible to strong disruptions given the large-scale networks they represent, and the attendant interdependencies [9]. Some recent examples are the power disruptions in the US in 2017, caused by hurricanes and wildfires [10], which caused a cumulative damage of \$306.2 billion, affecting a total of

47 million people—nearly 15 percent of the nation’s population. For instance, at the peak of hurricane Irma, more than 6.7 million electrical customers were without power [11], and hurricane Maria severely damaged the Puerto Rico power grid leaving 1.5 million people out of power [12]. China’s severe ice storm in 2008 resulted in the service disruption of 2000 power substations and 8500 towers leading to power interruptions in 13 provinces and 170 cities [13], and over 4 million customers went on power outage for over seven days during the Great East Japan Earthquake in 2011 [14]. During the Ukraine power grid cyber-attack in 2015, 30 power substations were turned off, and hundreds of thousands of people were without electricity for a period from 1 to 6 h [15,16].

Events like these reveal the need for strategies that are able to cope with such harsh impacts, especially given that the capacity to operate resiliently against attacks and natural disasters is one of the multiple smart grid attributes [17]. Resilience is defined as the ability to “anticipate, absorb, adapt to and/or rapidly recover from a disruptive event” [18]. In line with this definition, the U.S. Presidential Policy Directives-21(PPD-21) introduces resilience as “the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions” [19]. This same directive involves the “fail safe” paradigm in system engineering through recommendations for cyber-physical security, while highlighting the shift toward “safe-to-fail” paradigm brought by cyber-physical resilience. Many conceptual frameworks are proposed for understanding and evaluating resilience, where the time dimension is very important, as various facets (anticipation, absorption, robustness, survivability, mitigation, flexibility, adaptability, restoration, and recovery) are linked to different temporal phases that describe system performance during an extreme event [20–25]. Resilience moves from traditional risk assessment, which relies on probabilistic analysis of likely failures, toward dealing with unexpected events, requiring mitigation and healing strategies. The main difference is that risk assessment aims to achieve situational awareness and diagnosis, while resilience moves one step further by incorporating reactive actions against the contingency and launching restoration operations, which maintain the functionality of most critical loads and/or make them rapidly recoverable [26].

Within the growing literature on power system resilience [27–31], utilities are particularly interesting in quantitative assessments of resilience, which propose relevant indicators to guide cost-benefit studies before planning investments. In this context, multi-dimensional characteristics of resilience are a considerable challenge [32–34]. Ouyang and Dueñas-Osorio [35] tackled technical, organizational, and social dimensions of resilience, while providing an alternative to evaluate the economic dimension by estimation of economic losses. Only the technical dimension of the power network is widely investigated in the literature [36], which reveals the need to examine all other dimensions for a comprehensive analysis of resilience [33,37,38]. Technical and organizational dimensions are the most suitable in the case of power grids as they can be applicable at individual system levels, while social and economic dimensions are better suited for community level (interdependent systems), to which resilience studies should converge in the future [38]. Temporal multi-phase resilience quantification is a well-adopted technique that can embed other dimensions by linking them to technical and organizational dimensions through the implementation of enhancement strategies. Unlike [35], most proposed metrics in literature exclude pre-event and post-recovery phases, suggesting that quantification is conducted for a single scenario and not for a sequence of disruptive events, which corroborates the relevance of resilience for HILP disruptions. Work in [39] introduced resilience-based component importance measures centered in the recovery phase; on the one hand by establishing a ranking for load restoration using optimal repair time, and on the other hand, by quantifying the potential loss in optimal system resilience due to a delay in component repair process (computed through resilience reduction worth metric). Likewise, [40] focuses on the recovery stage of resilience, with the goal of comparing different restoration strategies and selecting an appropriate performance measure. Authors in [41] proposed a multi-phase framework to assess the resilience of the UK power transmis-

sion network under a windstorm. The framework considered both infrastructural and operational aspects, introducing four simple metrics to describe the degree and speed of degradation, duration of the disruption, and recovery speed. Grid connectivity and operational metrics can jointly describe the whole span of post-event analysis, and be used for planning short-term mitigation and recovery, or long-term hardening [42]. Resilience strategies to minimize system performance loss can be further analyzed under budget constraint by a tri-level planner-attacker-defender model [43], where a planner optimizes long-term transmission network expansion before an attack hits the system. Short-term switching operations are then applied in reaction. Resilience is quantified using customer demand not supplied, which includes both mitigation and recovery capabilities in the system. Many other optimization models and performance measures are adopted in related studies [44,45].

Given widely stretched power networks, resilience studied at the system level for generation and transmission, does not (or negligibly) include distribution grid components [35,39–43]. In 2010, only 15% to 20% of feeders implement distribution automation in the North American grid, one of the most advanced electrical systems [46]. This illustrates that the PDN is the most fragile level of electrical systems due to legacy “blindness” and manual operations along with electromechanical components [47], especially with the fact that an estimated 90% of customer outages in the US are related to this part of the system [48].

The advent of smart grids renewed interest in enhancing the PDN performance [49] as nearly all SG provided abilities of self-healing, high reliability, energy management, and real-time pricing are empowered by technologies introduced at the distribution level such as advanced metering, automation, distributed generation, and distributed storage [50]. ICTs are the main enabler of this new portfolio of applications [7], by transforming a traditionally one-way, limited-control, and radial PDN into a two-way power flow, intelligent, and mesh-networked grid capable of guaranteeing improved service for all connected loads [51]. In this regard, expected high-performance capabilities of smart distribution grid can succeed in coping with most failures in the system [49,50]. The smart PDN remains susceptible to HILP events, or even more prone in some cases, due to increased uncertainty (in events, load, distributed generation, market prices) [52–54] and strong dependency on telecommunications that widen the attack surface [55] and may cause undesirable cascade effects [56]. Consequently, the resilience of smart PDN becomes a concern from both electric and communication domain perspectives, as a failure in the telecommunication service may affect the electric service [57] and vice-versa [58]. Recent publications recommend a joint handling of smart PDN resilience quantification as the robustness and adaptation ability of a coupled system are even lower than a single system [56,59–61]. However, such an approach needs to build upon a solid understanding of resilience assessment of electric and communication domains when considered distinctly.

The present paper aims to set the ground for future joint evaluation of PDN resilience by reviewing relevant works, centered thus far on electric service, and to a lesser extent on ICT service. Essentially, the type of HILP event is identified from each selected contribution with details in the method used for contingency characterization. Also, the measure of performance, recognized as an enabler for resilience quantification [62], is tracked through this work to explain how it is defined and computed, relying usually on system modeling, or empirical and surrogate models in some cases. In addition, a classification based on the temporal phase where resilience evaluation takes place is proposed, which allows for addressing practical requirements of utility companies. The resilience phase-based approach was linked with different objectives of the assessment, from simple metrics evaluation, to either planning or response for survivability and recovery, achieved through a variety of improvement strategies for which allocation is optimized under the constraint of a limited budget. This bridges resilience studies and economic considerations in order to help stakeholders in investment plan elaboration and crisis decision-making. Aspects of cost, critical load, microgrids, and uncertainty of hazards, load, and distributed generation are

discussed to show their high importance, and available tools to date for their involvement in the study.

We extend by this work the wide spectrum of subjects associated with resilience quantification in power networks (modeling and simulation, enhancement strategies, metrics, and extreme events), covered in recent reviews [28,36,44,45,63–65]. The main contributions and novelty of this paper can be summarized as follows: (a) focus on resilience assessment of both electric and telecommunications domains of smart power distribution networks. (b) Detailed analysis and classification of performance calculation techniques. (c) Fine-grained categorization of quantitative resilience works based on time of evaluation and target objective.

Finally, despite the considerable number of works analyzed and relatively deep examination of reviewed methods for resilience quantification in smart PDNs, this paper does not claim to be comprehensive in the issues addressed (and related references), but remains complete enough to give a good overall perspective of the research trends and understanding of challenges and opportunities.

This paper is organized into five sections. Section 1 is the introduction. Section 2 introduces the link between resilience and both reliability and Quality of Service (QoS). Section 3 expands on the taxonomy of resilience evaluation methods and proposes a classification of associated models. Section 4 treats the relationship between the objective of resilience study and time of evaluation. Section 5 presents reviewed papers with all pertaining characteristics, observations, and discussions. Concluding notes are given in Section 6.

2. Resilience in Smart Grids

Amid desired functionalities for smart grids lays the need for capabilities like: self-healing, high reliability, power quality, and resistance against various disasters and attacks [50]. Resilience represents a promising approach to meet such requirements, by being able to address network circumstances not handled by widely adopted principles of reliability and quality of service.

2.1. From Reliability to Resilience

Reliability is the ability of an item (component or system) to operate under designated operating conditions for a designated period of time or number of cycles, where this ability can be formulated through a probability [66]. In electrical networks, this is equivalent to maintaining the delivery of electric services to customers in the face of routine uncertainty under operating conditions [67]. Metrics like Energy Not Supplied (ENS), Average Customer Curtailment Index (ACCI), System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI) are widely used to describe PDN reliability [68,69]. System operators use such indicators to track and enhance the performance of their networks. These indices are further used by system regulators and system operators in service level agreements (SLAs), in order to define penalty thresholds and ensure that the right compensation is paid based on the experienced outages. Reliability metrics are relevant to assess the impact of recurrent events with available historical records, over which maintenance actions are applicable; excluding major hazards such as severe weather events [70]. Some of these metrics were extended to capture more severe events, where metrics like STorm Average Interruption Frequency Index (STAIFI) and STorm Average Interruption Duration Index (STAIDI) are proposed [71]. However, a demonstration was made that these two metrics are not relevant for resilience evaluation because, when used during a storm, they show large deviation that can be even greater than the values of STAIDI and STAIFI [62].

Resilience is “the ability to prepare and plan for, absorb, recover from, or more successfully adapt to actual or potential adverse events” [72]. Unlike reliability, which focuses on the frequency and duration of failures “event-agnostically,” resilience seeks to further track the dynamics and resources of response, adaptability, and ability to restore.

This is relevant to HILP hazards where consequences in the system need to be studied with respect to specific events, as each disruption has its distinguishing characteristics [73]. Thus, the fundamental difference resides in the scale, scope, and duration of events handled: resilience targets events with strong impact in a wide geographical area with long duration of outages, while reliability handles local impact in short duration outages [74].

Despite this difference between the two concepts, mainly due to events each of them tackles, they remain closely related because enhancing resilience or reliability may require the same strategies, with resilience being more general, confirming that being resilient typically encompasses being reliable, but not vice versa [75].

2.2. Resilience and QoS in ICT Networks

ICT networks traditionally rely on QoS metrics to define SLAs [76]. These metrics consisting of delay, jitter, bandwidth, packet loss, bit error rate, and traffic load are performance measures that do not give a comprehensive view of network state. Therefore, other complementary metrics are adopted in SLAs in order to better quantify the system state, namely availability metrics.

In the initial introduction of Quality of Resilience (QoR) in [77], QoS is divided into short-term quality parameters referred to by availability, and long-term quality parameters grouped under QoR. In other words, resilience is considered as an aspect of QoS, as latency or packet loss. However, QoR is presented in [78] as a concept-treating quality at different levels of the Open Systems Interconnection model (OSI-model), including the network level which corresponds to traditional QoS. Figure 1 shows how QoR extends QoS to include other types of quality: Quality of Experience (QoE), Quality of Delivery (QoD), and Quality of Protection (QoP). This is done by considering the additional metrics from each level. QoR is used as a transverse evaluation for all aforementioned qualities. This is done by considering the metrics that describe different resilience stages. From a high-level perspective, we can say that QoR is a shift from client-centric evaluation, conducted using QoS, toward a more general framework that includes the system potential in terms of resources, organizational processes, and humans.

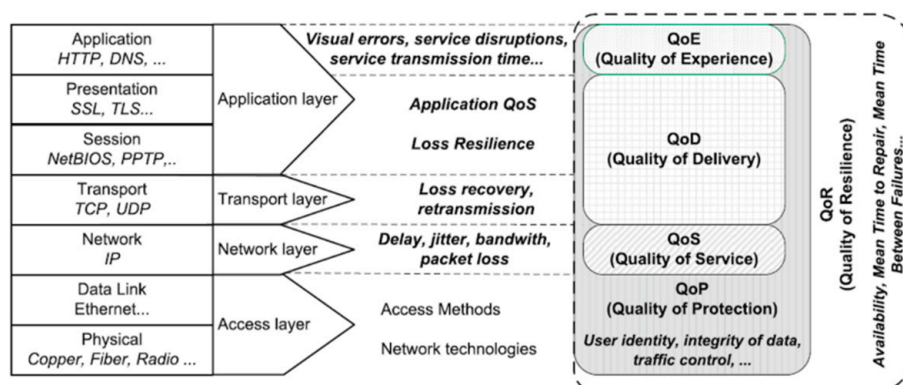


Figure 1. OSI-based classification of quality in relation with resilience [78].

Once again, in both cases above, the need for resilience stems from harsh large-scale events imposing consideration of stress in the system and recovery strategies. Then, despite the slight divergence in terminology that is still the case today, the two concepts go beyond the traditional QoS evaluation, to capture both requirements of customers and enhancement strategies of operators. Nevertheless, the idea that resilience takes in QoS is gaining more attention [75], suggesting that a system cannot be resilient if it does not offer acceptable QoS, but providing acceptable QoS is not the only requirement for a network to be resilient.

3. Taxonomy of Resilience Evaluation Methods

The panoply of methods proposed for qualitative evaluation of resilience in electric power networks [20–25] is not enough to convince critical infrastructure operators in general, and utilities in particular, to adopt the resilience-based design. They are unable to systematically discover hidden vulnerabilities and critical elements [79]. To overcome this, stakeholders need to have a closer, more tangible grasp of resilience, using quantitative analyses which gained huge momentum in recent years. Most of these analyses are performance-based, where performance is defined in various ways in order to fit different participants and study objectives [80]. The fact that almost all works selected in this paper happen to belong to this high-level method of quantification comes to stress the consensus in progress toward the adaptation of this method as a tool for resilience quantification.

In Figure 2, we propose four aspects based on which the state-of-the-art papers on resilience metrics for smart power distribution network could be classified, evaluated, and compared. Some of these aspects will be further elaborated in the later sections. For instance, in Section V we classify the papers based on extreme event handled, performance calculation method, and both type and computational method of resilience metrics. Each of these four aspects is explained in detail below.

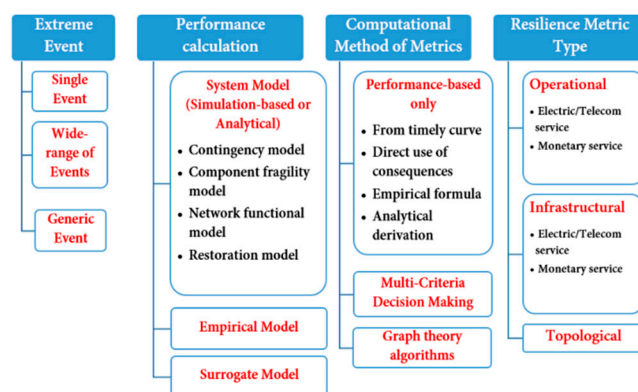


Figure 2. Proposed classification for resilience evaluation frameworks.

3.1. Extreme Event

Given that resilience takes all its meaning when a high-impact hazard occurs [72], it is paramount to classify the works on resilience based on the extreme event(s) they target.

3.1.1. Single Event

Generally, resilience evaluation frameworks are by definition designed to cope with a single (type of) event (like a natural hazard, a cyber-attack, or a physical manmade attack) [67]. Disruptions studied are strong, have large geographic extents, and cause high impacts on the network, that no sequence of events is considered. However, a single event is considered capable to strike at different points in the network simultaneously.

3.1.2. Wide-Range of Events

There are attempts to address multiple events, in order to make developed methods more attractive to use by network operators as they sweep a wide spectrum of failure scenarios [81–83]. However, addressing multiple types of hazards is challenging, partially due to the various nature and properties of the hazards. It is often very hard to use a single modeling framework for different hazards (e.g., natural hazards vs. cyber-attacks). Also, the inherent trade-offs between resilience strategies make multi-event studies more challenging, as some enhancement operations can be profitable for a set of events but not for others [84]. Therefore, choosing the set of contingencies to be handled jointly turns out to be challenging and careful attention needs to be allotted.

3.1.3. Generic Event

The focus of some studies is limited to metric design, then authors prefer to render generic the choice of failure that hit the network by directly observing the impact [85,86]. In that case, the system model when considered, no longer needs to cover contingency and component fragility. Indeed, this is a straightforward way to skip the difficulties inherent to disaster impact modeling, but it does leave the designer with a large set of possible scenarios from which a selection of the most relevant ones is not easily made. A well-defined event helps to narrow down the number of possible system failure modes.

3.2. Performance Calculation

Performance, or Figure of Merit (FoM) [87], is a quantity that describes how good the system is at providing services, system operation cost-effectiveness, and the behavior of the system when confronted with internal or external stress. These issues are addressed with different indicators, each of which is relevant to system operator objectives, and can be adopted as a performance measure [35,41,78,88].

Evaluating performance is a key element toward the end goal of resilience quantification. This performance information necessary for resilience metrics computation is not readily available, and designers resort to modeling in order to calculate performance measures. We classify works based on the modeling method that permits obtaining performance indicators. Mention was given earlier to the dominance of performance-based studies in the field of resilience quantification. Even rare works, which consider other aspects of quantification as main enablers [89], resort to the use of performance within their frameworks.

Modeling methods adopted by the scientific community to evaluate performance are described below.

3.2.1. System Model Method

The study of power distribution or telecommunication networks requires, as with other critical infrastructure, modeling the system with all its internal and external characteristics [79,90]. Two broad families of modeling are usually embraced for performance evaluation: analytical models, and simulation-based models [61]. Analytical models rely on mathematical concepts like graph theory, percolation theory, worst-case analysis, Markov chains (or processes), and statistics [91–94] to represent the structure and behavior in any network and interactions therein. Theoretical analyzes can also be used for the threat, fragility, and recovery characterization process. Then, rigorous formulation is conducted using multiple mathematical tools.

Simulation-based models basically have the same objective of system representation analytical models, but with the intent to have less abstraction and more fidelity to real networks. To do so, simulators are developed [95–97], based on the analytical approaches, however with many practical considerations which are usually too complex and not tractable by mathematical formulation. Thus, it is quite common to use simulation-based models as a validation method for the solution obtained by analytical analysis [79].

A deeper look at the modeling techniques explained above shows that both are comprised of four distinguishable sub-models [35]. Note that this further granularity allows, in some cases, hybrid analytical-simulation models, as each sub-model is constructed analytically or by simulation, independently from the others. These sub-models are:

- Contingency model: describes hazard profile, which is expressed in terms of characterizing parameters. An example would be to have a statistical profile that gives the probability distribution of wind intensities [41] or meteorological data to calculate the amount of ice accreted on conductors and overhead lines during an ice disaster [91]. Another widely considered example is cyber (or cyber/physical) attack scenarios [98,99]. In some cases, there is deep uncertainty about the threat, then worst-case analysis [100,101] and less conservative approaches like robust optimization [43] are the most suitable to model such events.

- Component fragility model: represents the sensitivity of system components to a threat. This goes hand in hand with the contingency models, as fragility curves or other ways of representation are developed with respect to event profiles [41,91].
- Restoration model: complements previous contingency and fragility models in order to yield threat impact quantification [102]. Focus is in recovery times which can be estimated using mathematical programming, fuzzy logic, statistical methods, specialist expertise, random distributions, or even heuristic approaches in some cases [28,103].
- Network functional model: functional models in use range in complexity from pure topological approaches to physics-based models of AC power flows [104]. They describe system infrastructure, topology, services, and all related dynamic interactions. This is present in all system models and constitutes their core element, because it replicates the structure and all functions found in real networks as much as possible. Examples include percolation theory and complex networks [92], graph theory analysis [21,105], power flow [14,41], agent-based information traffic flow [106], and many simulation software that emulate network behavior [82,96].

3.2.2. Empirical Model Method

Post-recovery surveys are conducted by network operators, government agencies, and market regulators to assess the impact of extreme events in the system and efficiency of implemented enhancement strategies, saving results as historical records [14]. Collected field data are so informative that it can be used to construct models by which performance is calculated [31,107,108]. Note that other sources of information for such models are network management systems, like outage management system (OMS), distribution management system (DMS) in electric network, core network in telecommunications, as well as expert judgements [94]. This kind of models serve as baseline for previous analytical and simulation-based representations [61].

3.2.3. Surrogate Model Method

A relatively new approach to performance evaluation in smart grids is the introduction of surrogate models, borrowed from the evolutionary computation community [109]. Surrogate models aim to reduce runtime and complexity of analytical and simulation-based models while maintaining a high degree of fidelity. The idea is to bypass conventional system modeling (where the name “surrogate” or “meta-model”) using techniques such as neural networks [110,111], and kriging methods [112]. A simple example is a machine learning (ML) agent taking as input system topology parameters, hazard characteristics, area climate, and topography; and outputs performance measures. The system model is replaced by an implicit non-linear multi-variate function implemented by the ML agent. The biggest challenge is to choose the right inputs (predictors). A Polynomial Chaos Expansion-based method is proposed in [113] to conduct risk analysis for rare events, which is projected by the authors to have an extension to resilience assessment.

3.3. Resilience Metric Computational Method

Once the performance is calculated using one of the methods described before, it will be used to compute resilience metrics. The goal is to provide the decision-maker with resilience information in the most instructive way.

3.3.1. Service and Assets Performance Only

Resilience computation is solely based on performance measures obtained from the operational services and infrastructural assets of the network. Metrics can be calculated from a curve describing the evolution of performance with time [41], using a justified empirical formula [114], following an analytical derivation, or taken directly as the consequences observed from the event [80].

3.3.2. Multi-Criteria

This method combines various parameters (such as service performance, topology, topography, and event characteristics) to output resilience metrics. Different analytical tools are used to aggregate all these parameters into final metrics [67,92,115].

3.3.3. Graph Theory Algorithms

Resilience computation is uniquely based on performance measures obtained from network topology and calculated using graph theory algorithms [116].

3.4. Resilience Metric Type

There are many possible angles to categorize and classify metrics based on their types [45,63]. The choice is made in our classification to select simple categories, which link intuitively to metric computational methods presented above.

3.4.1. Operational Metrics

Metrics that use performance as described in terms of functional service (electric, telecoms) and associated monetary costs. Expected lost load [24], supplied energy [117], and recovery duration [14] are examples of performance measures used by this type of resilience metrics.

3.4.2. Infrastructural Metrics

Metrics that use performance as described in terms of network infrastructure (electric, telecoms) and associated monetary costs. The number of affected components [41,101] (and associated costs) is an example of a performance measure used by this type of resilience metrics.

3.4.3. Topological Metrics

Metrics that use performance as described in terms of network topology and static connections between different elements such as measures of connectivity, betweenness, and redundancy [116].

4. Resilience Quantification Objectives

Four broad classes of resilience metrics are generally adopted: (i) average performance metrics, (ii) integrated multi-phase metrics, (iii) time-dependent metrics, and (iv) probability-based metrics [118]. In the case of a HILP event, probability distributions are often not available, whereas the other three classes depend on the measure of performance in the network. Thus, a reasonable statement is that an ideal evaluation of resilience may consist of a complete tracking of the time-dependent performance function $P(t)$. This way, network operators can have the value of performance at any instant for the complete event duration. However, despite the apparent dependence of $P(t)$ in time, performance function does not necessarily change with time if it is not for the extreme event which hits the system. In other words, performance function depends on many parameters including hazard intensity, system preparedness, resilience strategies in hand, and priority decisions made, all of which cause network state to change. This sends back the problem of resilience multi-dimensionality, which makes developing closed form derivation for resilience function challenging and hitherto out of reach. Performance-based methods try to include all previously mentioned parameters and additional ones into a temporal curve describing the performance evolution of the network. It can be said that many resilience features are embedded in a performance curve as shown in Figure 3, because the construction of such a graph takes into consideration all factors intervening during a catastrophic contingency.

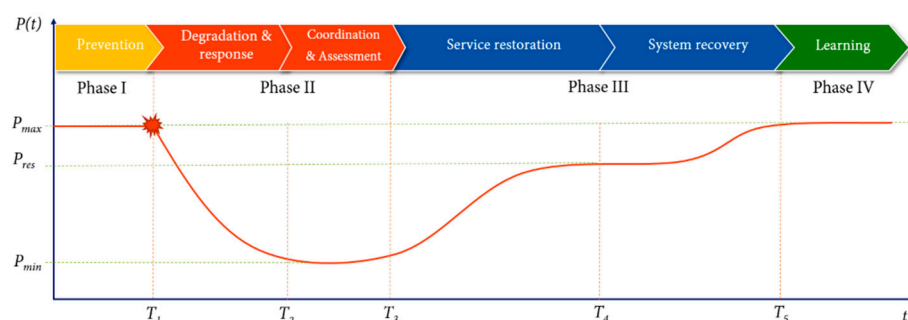


Figure 3. Performance curve for resilience quantification.

A salient advantage of such an approach is to have the temporal follow-up of network state which allows decision-makers to be in a best-informed posture. Four main phases can be distinguished, among which some can be further detailed into sub-phases:

- **Anticipation phase (phase I):** Represents the time period before the event occurrence, when performance is at its nominal level. Monitoring information, impact projections, and historical data when available are used for prediction studies, and all possible defensive measures are implemented. This serves particularly in the case of multi-hazard management where risks and vulnerabilities to each event are investigated. For single hazard resilience analysis which is the most relevant in the case of HILP event, this phase is not considered and a post-event resilience study is adopted. However, this also refers to the period of normal operation where reliability and risk management for recurrent failures can be conducted, which participates in system resilience, because a resilient system needs to be first as reliable and low-risk as possible. In addition, security measures for protecting the system and preparing it to withstand malicious behaviors are implemented at this stage [96].
- **Mitigation phase (phase II):** Once an extreme event hits the network, reliance is on system robustness, reactivity, and absorption to minimize the effect on services and infrastructure. Adding to some preparation policies that could be anticipated, many dynamic actions can be implemented to reduce the aftermath, like distribution automation actions, load shedding, and monitoring actions in power distribution networks or customer prioritization in telecom networks. These actions can withstand performance degradation that is in place, or serve to coordinate between entities in order to achieve an accurate assessment of consequences and prepare next crisis management steps.
- **Recovery phase (phase III):** Unlike short-timed low impact incidents where maintenance actions are achieved relatively fast, in major events, recovery actions can require anywhere between several weeks to months [119]. The main reason is that, given the safety of emergency crews and logistic constraints, restoration is conducted carefully and waits for the reduction in hazard intensity, or more generally identification of restoration windows. Priority is first given to service restoration where all alternative (even temporary) ways to provide services are explored and deployed allowing to regain an intermediate level of performance. Complete recovery will take more time and effort as it involves mostly infrastructure catering which turns out to be very challenging.
- **Learning phase (phase IV):** This phase is less considered than the two previous phases in quantitative resilience frameworks, generally with the argument that resilience is best examined in face of exogenous threats [120]. The post-recovery phase should still be looked at closely in order to draw conclusions about damages experienced by the network and how various implemented policies helped to alleviate consequences. Data collection through field surveys and supervisory management tools enable improvement in system performance and enhancement in preparation for upcoming extreme events backing the vision for a sustainable network.

Many works [13,27,45,63] explore each of these phases with slightly different denominations. Here a generalizing description is adopted where the four above-mentioned phases are considered, with mitigation and recovery divided each into two sub-phases in order to better explain all involved mechanisms. Resilience quantitative frameworks can be assessed based on phases they handle [64]. The more phases taken into consideration, the better the insight into system operation during extreme events. Furthermore, the layout can be used to seek answers for the following questions: When is resilience evaluation conducted and for which reason?

Figure 4 distinguishes time instants at which resilience quantification can be conducted, and objectives of this evaluation. The former here orients/guides/steers the latter, because for example, an operator who aims to plan investments for his network will most likely opt for pre-event evaluation, while another who only wants to see the impact induced by a contingency in his network may adopt post-recovery damage evaluation. Knowing “why” resilience is to be evaluated serves as a guideline to choose “when” it should be done. Without loss of generality, resilience evaluation can be induced from the performance curve in Figure 3; so it is important to know when system operators can get such a representation. Three options are available:

- **Proactive evaluation:** The procedure in this case is to drive pre-event studies with the goal of obtaining resilience indicators before contingency happens. The outbuilding is in prediction data, recommendations of experts, supervision alerts, and historical records. However, for HILP anomalies, little information is available, then designing preventive measures appeals for simulation tools, emulation, and analytical models which help to make projections for the impact that will be borne by the network in face of uncertain events.

Once metrics are computed, they can be used to make informed decisions about resilience strategies to implement in order to minimize the impact and speed up recovery. In other words, the output of this phase is planning schemes which enhance robustness, survivability, restoration, and recovery of the system that can be summarized in the concept of resilience. The prominent advantage of a proactive evaluation is the ability to look-forward that allows foreseeing what is coming. On the other hand, the large number of possible contingency scenarios and little relevant data cause low-confidence results.

- **Reactive evaluation:** Quantification is carried out as the event happens, meaning that resilience metrics are computed on-the-fly, and policies adopted to cope with severe hazards are taken from the inherent reaction capacity of the system without support from pre-event recommendations. Metrics are calculated as the event goes for the two broad phases of robustness and recovery. In such real-time setup, information that can be gathered is realistic and narrows down failure modes space. However, the flexibility margin can be very tight because the HILP event hits the network by surprise while no anticipative actions are in place. There are no good or bad choices between proactive and reactive evaluation, they are both suitable for resilience analysis and can be complementary. The goal is to find a balanced fit for a given use case [121].
- **Deductive evaluation:** When resilience metrics are computed at the end of a HILP disturbance, they mainly serve to draw conclusions about how the system handled an external event [81,107,108]. Results of this are intended to point out axes of improvement for future reference in similar extreme situations, and can also be considered as performance evolvement baseline. Further, the output of such post-recovery evaluation can be fed to the pre-event phase for hazards in the future, closing a kind of a cycle with the evaluations presented above.

Proactive approaches are dominant in resilience engineering, especially when considering the fact that in some cases the reactive approach is subsumed therein. The combination of the two is simply referred to as proactive approaches.

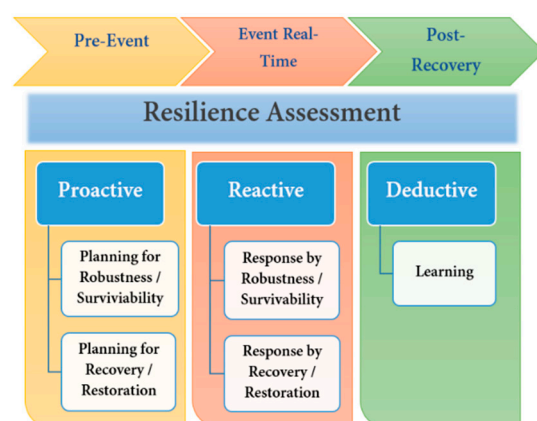


Figure 4. Options for resilience evaluation timing and associated objectives.

5. Literature Review

The present work, on state-of-the-art resilience quantification of smart grids at the distribution level, is conducted with three main objectives:

- Understanding architectures and models involved in resilience quantification methodologies;
- Identifying all considered objectives behind resilience quantification;
- Explaining implementation specifics that directly relate to the practical application of the proposed methods.

The selection process of reviewed papers is briefly introduced in the following section, then a detailed discussion and results are presented.

5.1. Paper Selection Process

With the aim of being as comprehensive as possible, a wide swipe of various digital libraries was carried out: IEEE Xplore, Science Direct, Scopus, Elsevier, Google Scholar. The review is limited to the last six years (2015 to 2020 included), and search expressions comprised various combinations of specific words: resilience, quantification, evaluation, assessment, metrics, indicators, measures, smart grid, distribution network, ICT network, (tele)communication network.

A first selection step consisted of reviewing abstracts of all found papers (in the order of several hundreds), and shortlisting works which:

- Analyze the power network at the distribution level, or the ICT network of power network, and;
- Present quantitative analysis of resilience, with the proposed metrics.

This resulted in a total of 34 pre-selected papers, 10 of which were excluded from this survey as they were recognized after deep analysis to not entirely satisfy the two selection criteria. Thus, the final selection included 24 papers, 18 of them targeting distribution power network [122–139], and 6 for grid ICT network [140–145]. This set of works was evaluated based on proposed categorizations in Sections 3 and 4.

5.2. Power Distribution Network

The set of 18 papers that analyze resilience quantification from the perspective of PDN electrical service is summarized in Table 1. In addition to the provided implementation details, the references are assessed based on extreme events and methods adopted for performance calculation. Metrics type and computational method are not shown in Table 1 for convenience considerations.

Table 1. Review of handled extreme event and performance calculation method—electric service.

Paper	Extreme Event			Performance Calculation					
	Single Event	Wide-Range of Events	Generic Event	Contingency Model	System Model Fragility Model	Restoration Model	Functional Model	Empirical Model	Surrogate Model
[122]	Earthquake			Range of Peak Ground Acceleration		Discretized restoration functions	Matpower AC load flow analysis		
[123]	Weather Event			Possibilistic-Scenario model					
[124]	Wind storm			Probabilistic profile	Probabilistic component fragility	Fixed restoration time Included in OPF constraints	AC Power Flow Analysis		
[125]						Restoration problem as a MILP	Power Flow (not explicitly mentioned)		
[126]	Typhoon weather			Batts model for wind speed		Proposed fixed repair time			
[127]			Generic Storm				Matpower load flow analysis		
[128]	Hurricane			Stochastic Spatio-Temporal Hurricane Impact Analysis tool (STHIA)		Ranges of Localization, Switching, and Repair times	Simulated Power Flow Analysis		
[129]									Machine Learning based
[130]								Collected Field Data	
[131]		Natural disasters e.g. Hurricane, Tropical cyclone, Earthquake, Tsunami		Worst N-k contingencies determined by knapsack problem		Restoration rate-based optimization	Power Flow + Graph Theory		
[132]				Extended N-k Network Interdiction Model					
[133]	Cyber-Physical Attack			Min-cardinality Disruption problem		Restoration problem as a multi-period MIP	Linear Distribution Power Flow Analysis		
[134]	Storm Sandy							ConEdison Data	
[135]			Generic Faults in the distribution network			Proposed MILP model for pre-event, degradation, isolation, and restoration phases with topological & operational constraints			
[136]		Generic events: duration from 1 to 10 ⁶ S							
[137]			Generic Contingency Scenarios	MATLAB/Simulink simulation-based model including Power Flow					
[138]			Generic emergency				Robust counterpart of deterministic model		
[139]			Generic fault in a feeder				Real-Time Digital Simulator		

By steering interest toward when resilience metrics are obtained, the concentration of resilience quantification in the pre-event phase can be pointed out, corroborating the preventive nature of such studies and their contribution to planning for unseen events. However, real-time evaluation gained some interest [133,136–139] and offers valuable information used on-the-fly to monitor and enhance the distribution network resilience. Next, after recovery from a HILP hazard, works in [127] and [130] survey the network for lessons, with [127] offering more learning opportunities as empirical advanced experiments are done for moderate and heavy damage scenarios.

Natural hazards catch most of the attention in present PDN resilience research due to various recent catastrophic events which raised awareness among the government agencies, regulators, and network operators about the damage that a distribution system may incur. Generally, a resilience study handles a single event, which makes the setting dependent on considered specific characteristics. Table 1 shows that some resilience frameworks are designed for a wider scope so as to tackle a set of these natural events [130–132,136]. This renders anomaly modeling challenging, albeit feasible through a knapsack problem [131] or extended N-k network interdiction model [132]. Even so, the model should be readjusted whenever applied to a specific contingency. To handle multiple events simultaneously, [136] derives a code-based metric by computing network resilience several times for all possible natural hazards. Even though the approach is based on an empirical formula and more work should be done to justify the choice, it is an easy-to-understand measure and introduces an interesting concept of the “service potential” of the network.

With the exception of [133], cyber or cyber-physical (CP) attacks are put aside in this portion of the literature despite increasing damage induced even in physical electrical infrastructure, but this apparent neglect remains understandable due to the focus of this section on electric service.

5.2.3. Uncertainty

Uncertainties in HILP events, intermittent power generation (with DER), load, and energy markets are a major concern for resilience assessment [52–54]. In [123], the spatio-temporal uncertainty of a harsh weather event and wind turbine generation is managed through a probabilistic approach. Authors in [134] assume a probability distribution for uncertain parameters in their resource allocation optimization problem (event parameters and resource allocation effectiveness parameters), by modifying the objective to the expected value of resilience. Likewise, in [135] a stochastic scenario-based optimization is adopted to cope with event uncertainties. However, for deep uncertain events, little to no data are available, turning interest toward robust optimization in both [132] for multi-stage and multi-zone natural hazard, and [138] for load and renewable generation. Also, simulation tools in [128,139] take into consideration the uncertainties in HILP events and intermittent power sources, respectively. Uncertainty is sometimes handled implicitly as it is inherent to HILP events without clear and well-defined formulation, like in [125].

5.2.4. Critical Load

An essential distinguishing feature of resilience is the ability to establish a differentiation between loads. For instance, in electrical networks, groups of customers are prioritized during emergencies, and will be spared from load shedding strategies due to their relative importance compared to other loads. Analyses in [128,135] assign weights to loads based on the priority they have during the load-shedding procedure or the restoration phase in case of a strong event which affects even critical nodes. Resilience evaluation is however done on impact over the entire network. Works such as [124,127,131] take it a step further by evaluating the resilience metrics for the whole system on the one hand, then on the other hand only for critical loads, giving a deeper insight into the network dynamics during the event. Finally, frameworks in [126,136–138] focus mainly on the critical load, as priority rankings are considered during curtailment and recovery stages, and resilience metrics quantify the impact in critical units.

5.2.5. Metrics Computation

As said before, performance assessment is an enabler for resilience quantification. Performance can include network topological characteristics and human factors, but it is mostly associated with service operational aspects defined in various ways: number of disconnected users [122,127,129,134], probability of lines failure [123], power from the main grid [123], power from distribution generation [123], supplied/connected load [124,126,128,130,131,135,136] (or equivalently load shedding [122,123,126,127,132,133]), critical supplied load [124,131], total customer-hours of outages [127], total customer energy not served [122,125,127], outage duration [129,130,134], number of outages [129], loss of voltage and frequency regulation [133], load control and islanding [133], probability of source availability and penalty [137], total forecasted load [138], and current flow [139].

A straightforward approach suggests considering displayed performance indicators as resilience metrics [122,123,127–129,132] or proposes a justified empirical formula [136] that concocts performance into resilience. The dominant technique is to build a representation of performance (e.g., time curve) and use it to extract indicators, as in [122] where an index of resilience is proposed by tracking the number of LV customers not served. This results in a time-dependent index which can be used in different phases illustrated in Figure 3. With the same dynamic, [138] introduces an index calculated periodically as the ratio between the level of priority (or critical) load and total load. Moreover, authors in [124] propose to compute multiple phase-specific indices for vulnerability, degradation, and restoration efficiency, all from a timely curve of supplied load. This is then supplemented with a resilience index, which covers the whole event horizon. The same tendency is observed in [128] where the load expected maximum loss, interruption rate, restoration rate, and the recovery rate are evaluated. In relation to this, works in [131,139] present fewer details on phase, but still offer the possibility to distinguish, in a broad sense, between survivability and restoration. A novel approach is highlighted in [135], where the percentage of loss load is proposed as a resilience metric, explicitly distinguishing in its terms loss of load in each single resilience phase.

However, unlike the above phases fine-grained analyses of resilience, studies in [126,130,133,134] opt for embedding the entire resilience information in a single metric, based on the inverse of power loss during an extreme typhoon event in [126], the ratio between up-time and event time in [130], loss percentage in [133], and combination of average loss and recovery time in [134]. This offers the advantage to be more attractive for DSOs as the framework is simple and less cumbersome, but it should be handled carefully to not miss tradeoffs that exist in resilience assessment. A good example is illustrated in [130], where resilience is calculated as the ratio between up-time and total event time. Attention was given to emphasize that this measure is defined for a single node, embodying another kind of granularity different from the one offered by multiple metrics for different phases.

Poudel et al. [125], extend a risk-based metric, value-at-risk (VaR) which calculates the maximum loss expected over a given time period and give a specified degree of confidence. The proposal is conditional VaR (CVaR), defined to calculate the expected resilience loss due to probabilistic threat events, conditioned on the events being HILP. This bridges traditional risk management and all-phases resilience study.

Topological characteristics are considered in [131] in the form of node degree. Bajpai et al. [137] make advanced use of the modeling graph, by proposing a multi-criteria decision-making (MCDA) approach which takes a set of inputs, among which performance and topology parameters, and aggregates them into a single resilience metric using Choquet Integral.

5.2.6. Resilience Strategies

Table 3 summarizes the different implemented measures to enhance PDN resilience. Infrastructure hardening, energy storage, and distributed generation resources are intensively explored owing to their wide deployment and availability. In addition, both distribution automation and network reconfiguration (which can be manual or automatic)

contribute to enhancing the robustness and adaptability of the network, and enable very efficient recovery. It can be seen thereby that all works from Table 2 that handle recovery either in pre-event, or event real-time, implement one or both of these two strategies. Contribution in [128] develops a set of probabilistic metrics that capture features and a detailed process of automatically locating, isolating faults, and restoring the service to customers in distribution systems. More precisely, the proposed algorithm devises a switching sequence and calculates load interruption when dealing with a large number of switches in large-scale distribution networks. Despite promising results to boost resilience, attention should be paid to the level of automation to be introduced in the network, because it can produce the inverse effect in rare events [146].

Table 3. Resilience enhancement strategies.

	[122]	[123]	[124]	[125]	[126]	[127]	[128]	[129]	[130]	[131]	[132]	[133]	[134]	[135]	[136]	[137]	[138]	[139]	[140]	[141]	[142]	[144]	[145]
Hardening	x	x	x	x	x		x	x			x		x										
Defensive Islanding														x			x						
Fuel genset dispatch									x														x
Energy storage						x			x	x			x		x		x						x
Repair crews							x		x				x			x							x
Distributed generation		x		x		x				x	x	x	x		x	x	x	x					
Network re- configuration		x								x			x			x							
Distribution automation				x	x		x						x	x									
Vegetation removal								x					x										
Load control		x										x											
Vehicle-to-grid power																		x					
New deployment																			x	x			
Data replication																					x		
Random behavior																					x		
SDN and virtualization																							x

Various smart grid functions of improved safety, self-healing, high DER penetration, and active load control can be enhanced using microgrids [147]. Microgrids (MGs) are in some cases operated in parallel with the main distribution grid, where the possibility to have their separate resilience analysis [30,148,149], meaning that MGs can be taken as a testbed to illustrate the applicability of the proposed resilience quantification [124,136,137]. In another approach, MGs are adopted as a resilience strategy that can be enabled in case of a disaster through islanding technique [150,151], thus the need to schedule the formation of MGs and associated DER dispatch and remote switches operation [133,138]. Further resilience benefit is achieved when multiple MGs are interconnected, given a better situational awareness conveyed between networked grids and eventually sharing of distributed resources [30,127]. Contributions in [124,127,133,136–138] are only a small part of the increased interest in MGs for distribution grid resilience enhancement [65]. In a general sense, resilience strategies are in some cases adapted only to certain disruption, and can be even a shortcoming during different circumstances [30]; thus, network planner needs to conduct a general study which includes all possible anomalies and try to manage all the tradeoffs therein when it comes to implementing resilience enhancement strategies.

5.3. Grid ICT Network

The resilience of PDN communication service is analyzed in [140–145] and a summary is given in Table 4. Again, classifications are used as in Sections 3 and 4 to review these works.

Table 4. Review of handled extreme event and performance calculation method—telecom service.

Paper	Extreme Event			Performance Calculation				Empirical Model
	Single Event	Wide-Range of Events	Generic Event	Contingency Model	Fragility Model	Restoration Model	Functional Model	
[140]			Scenarios with different network conditions				Graph theory + Clustering	
[141]			Generic HILP event				WAMS dependency graphs analysis	
[142]	Selective Forwarding attacks			k% randomly designated compromised nodes among all network nodes			WSN simulator	
[143]	Hurricane Sandy			Spatio-temporal non-Stationary random process				Real data from 4 DSOs
[144]			Generic failure			DayLight SDN controller interfaced with Mininet-based testing framework integrated with ns-3 network simulator		
[145]		Natural disasters						Real data from various scenarios

5.3.1. Performance Calculation, Resilience Metrics, and Extreme Event

Figures of performance (FoP) defined for ICT system in distribution grid are different from the ones presented before for electric service. Both [142,144] adopt simulation-based modeling to set the ground for resilience quantification. The former builds upon the ad-hoc nature of wireless sensor networks (WSNs) technology that can be used to support metering infrastructure for redundancy and replication, therefore the use of a WSN simulator to evaluate various routing protocols (assumed 300 nodes) based on five performance measures: average delivery ratio, energy efficiency, delivery fairness, average throughput, and delay efficiency. Then, all these are normalized and provided as an equiangular polygon where each performance metric is presented by an axis. Resilience metric is taken as the area of that polygon, so the wider it is, the more resilient is the routing protocol against selective forwarding attacks. Authors in [144] consider a simpler configuration with one software defined networking (SDN) controller, and three substations each having a connected field device; with the goal to show that SDN is a viable technology with negligible switching delay to backup wireless communication and a minimum number of packet loss, which are taken as resilience metrics.

A graph-based analytical model is adopted in [140] to determine the needed transmission power and required number of gateways for wireless-enabled mesh architectures in the context of smart metering. A proposed methodology involves clustering to assign each smart meter to a gateway, then the average number of hops and the number of independent paths to reach the gateway are calculated as intra-cluster resilience metrics, while node capability to connect to other gateways in case of a primary gateway failure is addressed by inter-cluster resilience. A different graph approach is used by [141] to consider dependencies between ICT and measurement layers which, seen from a higher perspective, are no more than the entire communication infrastructure used in a smart grid. The degree of centrality is used to find the importance of each communication link and measurement unit,

then resilience metric is defined as the deviation from ideal importance values, knowing that the main goal is to reduce the importance of critical nodes that increases the robustness of the network.

At this point, one can notice the absence of resilience phases notion from the presented works so far, which is a major drawback. This can be seen also from the relatively low importance given to disruption modeling and characterization, considered very important in resilience studies. On the contrary, [143,145] introduce temporal phases; though with fewer details than electric service cases, but sufficiently to convey all relevant information about resilience. Both works rely on empirical data from post-recovery assessments by DSOs. In the case of [143], the proposed resilience metric is calculated for the infrastructure and the service using expected cost from customer and system sides (4 considered DSOs) during hurricane sandy (2012). Obtained curves show the effectiveness of coupled non-stationary random processes modeling for failures, recoveries, and costs to customers.

As suggested in [130], the same author defines power supply resilience of an ICT site in [145] as the ratio between up-time and event duration, and uses real field data from different natural disasters to calculate this quantity. This illustrates how the same metric can be applied to quantify the resilience of electric and telecommunication services in a smart grid.

5.3.2. Time of Evaluation

Attention was drawn above to the absence of temporal analysis in most ICT network reviewed works, and when present, empirical models are used for resilience frameworks. This renders knowing when performance measures should be calculated and for which objective without detailed exploration. In other words, analysis is still at an initial level of uniquely obtaining the metrics and, except for [141], no planning or response is based on these metrics. For instance, [141] proposes to optimize the wide area monitoring system (WAMS) design through the optimal resilient deployment of phasor measurement units (PMUs) and new optical ground wires, formulated as an optimization problem based on performance measures used to calculate the resilience metric. Thus, almost all evaluations are conducted after the event as illustrated in the telecommunications part of Table 2 which entails no further use in planning or response.

5.3.3. Resilience Strategies

Proposing resilience enhancement is tightly connected to the type of conducted evaluation. So, due to the limitation here to post-recovery metric calculation, improvement strategies are shown to have a positive impact on the network but only one optimized implementation [141] is achieved to exploit the whole potential of these measures (Table 3).

Data-related strategies of replication and redundancy are completely adapted to multi-hop routing mechanisms in WSN networks, and need to be explored considering the associated cost for either the initial investment or subsequent maintainability [142]. SDN and virtualization technologies represent an attractive option for SG resilience under different architectures (e.g., substation automation, utility Machine-to-Machine (M2M) applications, cloud and IoT applications . . .) which can address SG-related issues of security, privacy, granularity, vendor-specific components, and network management [152]. This wide penetration of SDN opens the opportunity to leverage it also to improve the resilience of the network.

Furthermore, measures seen for electric service [130] are suggested for ICT case [145] highlighting interdependence between the two networks, and the possibility to develop promising joint evaluation frameworks treated in the recent literature [61], out of the scope of present work.

5.4. Results and Insights

This section builds on presented observations and analysis of the reviewed literature to explain challenges and priority perspectives for resilience quantification in modern distribution grids.

5.4.1. Moving from Qualitative to Quantitative Resilience Assessments of the ICT Domain

From a qualitative perspective, resilience studies are very well established and succeed to demonstrate the shift of paradigm they incarnate in terms of preventing a given infrastructure from catastrophic failures and orchestrating restoration of nominal services. However, when it comes to quantitative assessments, general tendency heads toward restraining resilience capacity to one of its components such as robustness, survivability, adaptability, restoration, and recovery [153].

Power network resilience analyses in general, and PDN in particular, are managed in recent years to develop quantitative frameworks that describe and harness all capabilities of resilience. This is not limited to proposing metrics for all temporal phases, but includes also using developed indicators to optimize enhancement strategies like done in [125,131,133–135,137]. Certainly, more works should be carried out in this sense and even more to mutualize visions through standardization to yield consensus in evaluation methodologies and metrics; but the right research direction is indeed being explored in electric distribution networks. Parallel to this, the same dynamic should be adopted also for telecommunication services involved in smart grids which so far, as shown through this review, stick to partial definitions of resilience adopted even in studies targeting communication networks outside the scope of smart grids. Differently said, ICT resilience studies are a step behind compared to what is done in power networks in terms of adopted definitions and proposed frameworks. Awareness then increases that smart grid comprehensive resilience analysis goes hand in hand with both electric and telecommunication services evaluation at comparable levels of advancement, meaning that ICT layer in distribution grid has a considerable margin for improvement that can mimic electric service analyzes and be guided by recent works in general purpose resilient communication networks [75,78].

One can argue that tracking electric service performance subsumes the telecommunication aspect, because the latter contributes to the degradation of power supply to customers which is after all the main concern. This is a client-centric approach that resilience contains, but also complements with operator (or network) centric view, where a fine-grained analysis of all system mechanisms is needed, involving among others a separate and deep look at ICT functions.

5.4.2. Need to Specify Time of Evaluation

Emphasis is put throughout previous sections on the importance of “when” resilience evaluation is conducted (Table 2), which is not to be confused with the time of the event occurrence [36]. The difference is easily seen in an example of proactive approaches, where the entire event time horizon is studied in the pre-event phase of real-time scale. This means that event time is taken as the virtual quantity, which in case of data availability or use of modeling can be observed before it happens, while the real-time scale describes the moment of resilience quantification. Therefore, the concern of event time is to know if the resilience framework treats all phases (the more phases the better), but time of evaluation wants to know when resilience assessment metrics will be available, probably for use in optimization by enhancement strategies.

Obviously, DSOs are more interested in the look-forward method, which allows them to anticipate major disruptions and prepare the network. However, HILP events are so unpredictable that fidelity of assumed models and projections is reduced, supporting the need for real-time resilience analyzes that will have more knowledge into the impact of an event, and could complement initial proactive measures. Thereby, effort should be put to explore the possibility of a framework with both proactive and reactive resilience

quantification in order to seize the advantages of the two approaches. At last, post-recovery evaluation can back both previous alternatives by collecting valuable field data after hazards.

5.4.3. Topology and Service Performance Metrics

Only a few reviewed papers consider topological parameters in metrics computation [127,131,140,141] due to the high level of abstraction in graph-based methods and static features therein. Still, it is important to include them in resilience studies because they capture network architecture and internal dependencies between different elements that complement service performance measures. As discussed in Section 5, a noteworthy multi-criteria approach was suggested in [137] to combine topological and operational characteristics in the same metric. Although more inclined toward topological features, this proposal illustrates how multiple weighted parameters can be aggregated into a single representative indicator. In addition, interdependence modeling widely adopts topological approach [154,155], so it is unavoidable to embrace it in power systems, because in the long run, smart grids resilience must be analyzed taking into account the interactions between electric and ICT layers; and with other infrastructure networks (gas, heat, cooling, transports, etc.).

Like transmission power networks [29], multiple metrics are proposed for resilience quantification in [124,128,131,135,142]. A single resilience metric, even in the case where it embeds a maximum number of resilience features, can represent a drawback if it offers less information for enhancement strategies implementation. The reason is apparent in some strategies that only target one facet of resilience, let us say for example robustness; hence, when the metric combines many features it dilutes the information about robustness in the general index. This is why multiple metrics, each handling an aspect or phase of resilience, can help to build better knowledge and guide more specific actions.

5.4.4. Spatial Scale

Resilience frameworks need to combine qualitative and quantitative analyses at various temporal and spatial scales [156]. The temporal aspect is treated widely through monitoring of performance evolution with time, however, more effort should be put into considering time horizons of different events which directly relate to the system resilience and the efficiency of quantification methods [136]. For a small service area, the same failure probability of each component is considered when the distribution system suffers from natural disasters [131]. In the case of larger areas, it becomes very important to consider the spatial distribution of an event, in order to better estimate the hazard impact and recovery duration [105]. This can be achieved by defining multiple impact zones and use of failure probability or N-k contingency constraint [123,132]. Other methods use a model for event path [128], the spatial distribution of the number of outages [129], and spatio-temporal random processes [143]. Since post-disruption electric grid performance is highly sensitive to event spatial characteristics [105], the spatial dimension should be explicitly incorporated into performance function, unlike most related works.

5.4.5. Critical Load

Different levels of prioritization exist between loads in an electric distribution network. Resilience involves the tolerance to curtail less important customers while keeping supply to more critical ones (hospitals, emergency services, banking, government facilities ...). When the outage is general, critical loads are to be restored first. This behavior needs to be captured by resilience metrics where the difference between normal and crucial loads can be explicitly seen.

In the telecommunication layer of distribution networks, the concept of critical elements is less applied (not found at all in reviewed articles) due to the fact that communicating devices are mostly used in protection, monitoring, management, and control functions which are all very important to the whole network operation. However, within

the telecommunication architecture used by grid functions, hierarchies exist, and entities can be prioritized. For example, a regional control center can have the highest criticality in a given region, compared to remote terminal units (RTUs) at substations, or field devices. With the advent of smart grids, there is an ever-increasing number of distribution-connected items that can be seen as loads more than controlling devices such as smart meters, industry 4.0 robots, and industrial IoT. Thereby, even more hierarchy can be put in place based on which elements are most important, or even achieve cross-importance rankings with electric infrastructure and loads in the system.

5.4.6. Uncertainty Quantification

The main sources of uncertainty in smart grids are HILP events, load demand, distributed generation, and market prices. Among these, HILP hazards have the characteristic to severely damage the network, thus like seen in [123,132,134,135], different methods are proposed to cope with its uncertainties. Again, this topic necessitates being investigated for the grid telecommunication layer because it is also vulnerable to extreme event uncertainties, especially as it is in the front line against cyber-attacks.

5.4.7. Economical Cost

DSOs do not just scrutiny costs due to phenomenal disasters and attacks, but also audit their investment strategies to find the best balance between resilience and minimal spending. Cost is inserted in resilience studies at different levels, most of the time directly on the metric [123,127,128,133,143], but can also be incorporated in objective functions of cost-benefit analyzes [131,134,138,141] that search the optimal tradeoff between resilience and associated investment costs.

5.4.8. Resilience Potential

Performance-based evaluation of resilience is widely adopted to conduct an assessment from event eruption until the final recovery. It is always reported to the nominal performance of the system before a contingency. Authors in [136] introduced “service potential” which describes how able is the network to deliver its service under given the unfavorable conditions. This allows comparing two grid systems or architectures under different orders of event durations. We can extend this into resilience potential, which is no more than a quantity that gives resilience of a network, considering all possible redundancies and resources, very similar to risk assessment empowered with consideration for enhancement strategies. Concisely, expand on the idea that the same nominal level of performance does not mean the same level of resilience.

5.4.9. Interdependencies

Separate analysis of electric and ICT services in distribution grids is deemed to converge into a joint layout due to multiple existent interdependencies, wherein the continuation of this work, the study should be steered by a resilience perspective [90]. Contribution in [61] summarizes research in interdependent power-ICT research on system modeling, failure, and resilience enhancement strategies. From the fact that mutualized resilience evaluation is the best approach to deal with interdependency which makes the coupled network more vulnerable to disruptions through cascading and escalating effects [155], many recent works conduct resilience studies jointly for both communication (or cyber) and electric domains of the grid [56,157–159].

Dependencies of electric network with other infrastructures are also handled jointly in case of gas network [102], buildings [160], urban transportation [161], integrated energy system [88], water network [162]; allowing for the possibility to adapt some prominent ideas and principles for application in the specific case of smart grids. Further discussion of interdependencies is out of the scope of this article, but it should be emphasized that this topic is the natural follow-up of the work presented here.

6. Conclusions

In this paper, state-of-the-art studies on resilience quantification of smart distribution grids are summed up with the perspective to analyze all involved tools and point out assessment objectives. Performance calculation is identified as the main enabler of resilience evaluation, as almost all reviewed metrics rely either exclusively on operational performance measures, or as a mix of operational and topological parameters. Many models are proposed in the literature to compute performance, among which system modeling is the most dominant with a focus on four main aspects: contingency, fragility, restoration, and functional dynamics. Empirical models serve as baseline and data feeder for system models, whereas surrogate models try to bypass network modeling by the harness of advanced machine learning techniques to directly infer performance measures from various topological, topographic, and operational parameters.

Distribution grid resilience is defined in reviewed research in the face of HILP events which need to be foreseen using forecast data, historical records, estimation tools, and contingency models. Accentuation is made on the difficulty to design resilience for multiple events, especially with the fact that enhancement strategies can be very specific as they are advantageous in some cases and not in others. In addition, we propose a classification based on the time of resilience evaluation, which allows projecting real case applicability of presented assessment frameworks. The resilience phases-based approach was linked with different objectives of the assessment, from simple metrics evaluation, to either planning or response for survivability and recovery; achieved through a variety of improvement strategies for which allocation is optimized under the constraint of a limited budget. This bridges resilience studies and economic considerations in order to help stakeholders in investment plans elaboration and crisis management decision-making.

Aspects of critical load, microgrids, and uncertainty of hazards, load, and distributed generation are discussed to show their high importance, and explain available tools so far for their involvement in the study. Finally, a demonstration was made on ahead steps that resilience studies in the electric domain have compared to telecommunication domain, and an urgent need to level up the two for complete joint resilience analysis of smart grids, unlike current separate works that neglect several pertaining interdependencies. Therefore, future works need to focus on coupled electric-ICT networks with joint quantification frameworks, which not only consider the resilience of the coupled system, but seek further granularity by investigating constituent applications and functions such as distribution automation, automatic metering, and grid management.

Author Contributions: Methodology, formal analysis, investigation, writing—original draft preparation, Y.N.B.; methodology, visualization, supervision, writing—review and editing, P.C., J.S.-T., Y.-P.F., Z.Z., A.B. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Acknowledgments: Authors would like to thank the reviewers for their insightful comments and constructive suggestions.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. Soldani, D.; Manzalini, A. Horizon 2020 and Beyond: On the 5G Operating System for a True Digital Society. *IEEE Veh. Technol. Mag.* **2015**, *10*, 32–42. [\[CrossRef\]](#)
2. Yu, W.; Liang, F.; He, X.; Hatcher, W.G.; Lu, C.; Lin, J.; Yang, X. A Survey on the Edge Computing for the Internet of Things. *IEEE Access* **2018**, *6*, 6900–6919. [\[CrossRef\]](#)
3. O'Mahony, M.J.; Politi, C.; Klonidis, D.; Nejabati, R.; Simeonidou, D. Future Optical Networks. *J. Light. Technol.* **2006**, *24*, 4684–4696. [\[CrossRef\]](#)
4. Galli, S.; Scaglione, A.; Wang, Z. For the Grid and Through the Grid: The Role of Power Line Communications in the Smart Grid. *Proc. IEEE* **2011**, *99*, 998–1027. [\[CrossRef\]](#)
5. Fang, X.; Misra, S.; Xue, G.; Yang, D. Smart Grid—The New and Improved Power Grid: A Survey. *IEEE Commun. Surv. Tutor.* **2012**, *14*, 944–980. [\[CrossRef\]](#)

6. Gungor, V.C.; Sahin, D.; Kocak, T.; Ergut, S.; Buccella, C.; Cecati, C.; Hancke, G.P. Smart Grid Technologies: Communication Technologies and Standards. *IEEE Trans. Ind. Inform.* **2011**, *7*, 529–539. [CrossRef]
7. Gungor, V.C.; Sahin, D.; Kocak, T.; Ergut, S.; Buccella, C.; Cecati, C.; Hancke, G.P. A Survey on Smart Grid Potential Applications and Communication Requirements. *IEEE Trans. Ind. Inform.* **2013**, *9*, 28–42. [CrossRef]
8. Moslehi, K.; Kumar, R. A Reliability Perspective of the Smart Grid. *IEEE Trans. Smart Grid* **2010**, *1*, 57–64. [CrossRef]
9. Momoh, J.A. Smart grid design for efficient and flexible power networks operation and control. In Proceedings of the 2009 IEEE/PES Power Systems Conference and Exposition, Seattle, WA, USA, 15–18 March 2009; pp. 1–8.
10. The President’s National Infrastructure Advisory Council. Surviving a Catastrophic Power Outage—How to Strengthen the Capabilities of the Nation. Available online: https://www.cisa.gov/sites/default/files/publications/NIAC%20Catastrophic%20Power%20Outage%20Study_FINAL.pdf (accessed on 7 December 2020).
11. U.S. Department of Energy. Infrastructure Security and Energy Restoration. Hurricane Irma & Hurricane Harvey Event Summary (Report #28). September 2017. Available online: <https://www.energy.gov/sites/prod/files/2017/10/f37/Hurricanes%20Irma%20and%20Harvey%20Event%20Summary%20%2328.pdf> (accessed on 7 December 2020).
12. Román, M.O.; Stokes, E.C.; Shrestha, R.; Wang, Z.; Schultz, L.; Carlo, E.A.S.; Sun, Q.; Bell, J.; Molthan, A.; Kalb, V.; et al. Satellite-based assessment of electricity restoration efforts in Puerto Rico after Hurricane Maria. *PLoS ONE* **2019**, *14*, e0218883. [CrossRef]
13. Panteli, M.; Mancarella, P. The Grid: Stronger, Bigger, Smarter? Presenting a Conceptual Framework of Power System Resilience. *IEEE Power Energy Mag.* **2015**, *13*, 58–66. [CrossRef]
14. Bie, Z.; Lin, Y.; Li, G.; Li, F. Battling the Extreme: A Study on the Power System Resilience. *Proc. IEEE* **2017**, *105*, 1253–1266. [CrossRef]
15. Liang, G.; Weller, S.R.; Zhao, J.; Luo, F.; Dong, Z.Y. The 2015 Ukraine Blackout: Implications for False Data Injection Attacks. *IEEE Trans. Power Syst.* **2017**, *32*, 3317–3318. [CrossRef]
16. Sullivan, J.E.; Kamensky, D. How cyber-attacks in Ukraine show the vulnerability of the U.S. power grid. *Electr. J.* **2017**, *30*, 30–35. [CrossRef]
17. The Smart Grid Implementation Strategy Team; National Energy Technology Laboratory. What is the Smart Grid? March 2009. Available online: <https://www.power-grid.com/smart-grid/smart-grid-implementation-strategies-for-success/#gref> (accessed on 7 December 2020).
18. Civil Contingencies, Cabinet Office. Keeping the Country Running: Natural Hazards and Infrastructure. October 2011. Available online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/61342/natural-hazards-infrastructure.pdf (accessed on 7 December 2020).
19. Obama, B.; Presidential Policy. Directive 21: Critical Infrastructure Security and Resilience. Homeland Security Digital Library. 12 February 2013. Available online: <https://www.hsdl.org/?abstract&did=> (accessed on 7 December 2020).
20. Cimellaro, G.P.; Reinhorn, A.M.; Bruneau, M. Seismic resilience of a hospital system. *Struct. Infrastruct. Eng.* **2010**, *6*, 127–144. [CrossRef]
21. Ganin, A.A.; Massaro, E.; Gutfraind, A.; Steen, N.; Keisler, J.M.; Kott, A.; Mangoubi, R.; Linkov, I. Operational resilience: Concepts, design and analysis. *Sci. Rep.* **2016**, *6*, 19540. [CrossRef] [PubMed]
22. Henry, D.; Ramirez-Marquez, J.E. Generic metrics and quantitative approaches for system resilience as a function of time. *Reliab. Eng. Syst. Saf.* **2012**, *99*, 114–122. [CrossRef]
23. Madni, A.M.; Jackson, S. Towards a Conceptual Framework for Resilience Engineering. *IEEE Syst. J.* **2009**, *3*, 181–191. [CrossRef]
24. Panteli, M.; Mancarella, P. Modeling and Evaluating the Resilience of Critical Electrical Power Infrastructure to Extreme Weather Events. *IEEE Syst. J.* **2017**, *11*, 1733–1742. [CrossRef]
25. Smith, P.; Hutchison, D.; Sterbenz, J.P.; Schöller, M.; Fessi, A.; Karaliopoulos, M.; Lac, C.; Plattner, B. Network resilience: A systematic approach. *IEEE Commun. Mag.* **2011**, *49*, 88–97. [CrossRef]
26. Arghandeh, R.; von Meier, A.; Mehrmanesh, L.; Mili, L. On the definition of cyber-physical resilience in power systems. *Renew. Sustain. Energy Rev.* **2016**, *58*, 1060–1069. [CrossRef]
27. Gholami, A.; Shekari, T.; Amirioun, M.H.; Aminifar, F.; Amini, M.H.; Sargolzaei, A. Toward a Consensus on the Definition and Taxonomy of Power System Resilience. *IEEE Access* **2018**, *6*, 32035–32053. [CrossRef]
28. Wang, Y.; Chen, C.; Wang, J.; Baldick, R. Research on Resilience of Power Systems under Natural Disasters—A Review. *IEEE Trans. Power Syst.* **2015**, *31*, 1604–1613. [CrossRef]
29. Espinoza, S.; Panteli, M.; Mancarella, P.; Rudnick, H. Multi-phase assessment and adaptation of power systems resilience to natural hazards. *Electr. Power Syst. Res.* **2016**, *136*, 352–361. [CrossRef]
30. Li, Z.; Shahidehpour, M.; Aminifar, F.; AlAbdulwahab, A.; Al-Turki, Y. Networked Microgrids for Enhancing the Power System Resilience. *Proc. IEEE* **2017**, *105*, 1289–1310. [CrossRef]
31. Reed, D.A.; Kapur, K.C.; Christie, R.D. Methodology for Assessing the Resilience of Networked Infrastructure. *IEEE Syst. J.* **2009**, *3*, 174–180. [CrossRef]
32. Zhao, X.; Chen, Z.; Gong, H. Effects Comparison of Different Resilience Enhancing Strategies for Municipal Water Distribution Network: A Multidimensional Approach. *Math. Probl. Eng.* **2015**, *2015*, 1–16. [CrossRef]
33. Cutter, S.L. The landscape of disaster resilience indicators in the USA. *Nat. Hazards* **2016**, *80*, 741–758. [CrossRef]

34. Dessavre, D.G.; Ramirez-Marquez, J.E.; Barker, K. Multidimensional approach to complex system resilience analysis. *Reliab. Eng. Syst. Saf.* **2016**, *149*, 34–43. [\[CrossRef\]](#)
35. Ouyang, M.; Dueñas-Osorio, L. Multi-dimensional hurricane resilience assessment of electric power systems. *Struct. Saf.* **2014**, *48*, 15–24. [\[CrossRef\]](#)
36. Mahzarnia, M.; Moghaddam, M.P.; Baboli, P.T.; Siano, P. A Review of the Measures to Enhance Power Systems Resilience. *IEEE Syst. J.* **2020**, *14*, 4059–4070. [\[CrossRef\]](#)
37. Kontokosta, C.E.; Malik, A. The Resilience to Emergencies and Disasters Index: Applying big data to benchmark and validate neighborhood resilience capacity. *Sustain. Cities Soc.* **2018**, *36*, 272–285. [\[CrossRef\]](#)
38. Chang, S.E.; Shinozuka, M. Measuring Improvements in the Disaster Resilience of Communities. *Earthq. Spectra* **2004**, *20*, 739–755. [\[CrossRef\]](#)
39. Fang, Y.-P.; Pedroni, N.; Zio, E. Resilience-Based Component Importance Measures for Critical Infrastructure Network Systems. *IEEE Trans. Reliab.* **2016**, *65*, 502–512. [\[CrossRef\]](#)
40. Albasrawi, M.N.; Jarus, N.; Joshi, K.A.; Sarvestani, S.S. Analysis of reliability and resilience for smart grids. In Proceedings of the 2014 IEEE 38th Annual International Computer Software and Applications Conference, Vasteras, Sweden, 21–25 July 2014. [\[CrossRef\]](#)
41. Panteli, M.; Mancarella, P.; Trakas, D.N.; Kyriakides, E.; Hatziargyriou, N.D. Metrics and Quantification of Operational and Infrastructure Resilience in Power Systems. *IEEE Trans. Power Syst.* **2017**, *32*, 4732–4742. [\[CrossRef\]](#)
42. Dehghanian, P.; Aslan, S.; Dehghanian, P. Maintaining Electric System Safety through an Enhanced Network Resilience. *IEEE Trans. Ind. Appl.* **2018**, *54*, 4927–4937. [\[CrossRef\]](#)
43. Fang, Y.; Sansavini, G. Optimizing power system investments and resilience against attacks. *Reliab. Eng. Syst. Saf.* **2017**, *159*, 161–173. [\[CrossRef\]](#)
44. Jufri, F.H.; Widiputra, V.; Jung, J. State-of-the-art review on power grid resilience to extreme weather events: Definitions, frameworks, quantitative assessment methodologies, and enhancement strategies. *Appl. Energy* **2019**, *239*, 1049–1065. [\[CrossRef\]](#)
45. Das, L.; Munikoti, S.; Natarajan, B.; Srinivasan, B. Measuring smart grid resilience: Methods, challenges and opportunities. *Renew. Sustain. Energy Rev.* **2020**, *130*, 109918. [\[CrossRef\]](#)
46. Farhangi, H. The path of the smart grid. *IEEE Power Energy Mag.* **2010**, *8*, 18–28. [\[CrossRef\]](#)
47. Ipakchi, A.; Albuyeh, F. Grid of the future. *IEEE Power Energy Mag.* **2009**, *7*, 52–62. [\[CrossRef\]](#)
48. Beaty, H.W. *Electric Power Distribution Systems: A Nontechnical Guide*; PennWell Books: Tulsa, OK, USA, 1998.
49. Heydt, G.T. The Next Generation of Power Distribution Systems. *IEEE Trans. Smart Grid* **2010**, *1*, 225–235. [\[CrossRef\]](#)
50. Brown, R.E. Impact of Smart Grid on distribution system design. In Proceedings of the 2008 IEEE Power and Energy Society General Meeting—Conversion and Delivery of Electrical Energy in the 21st Century, Pittsburgh, PA, USA, 20–24 July 2008; pp. 1–4.
51. Amin, S.M.; Wollenberg, B. Toward a smart grid: Power delivery for the 21st century. *IEEE Power Energy Mag.* **2005**, *3*, 34–41. [\[CrossRef\]](#)
52. Ma, S.; Chen, B.; Wang, Z. Resilience Enhancement Strategy for Distribution Systems under Extreme Weather Events. *IEEE Trans. Smart Grid* **2018**, *9*, 1442–1451. [\[CrossRef\]](#)
53. Bertsimas, D.; Litvinov, E.; Sun, X.A.; Zhao, J.; Zheng, T. Adaptive Robust Optimization for the Security Constrained Unit Commitment Problem. *IEEE Trans. Power Syst.* **2013**, *28*, 52–63. [\[CrossRef\]](#)
54. Soroudi, A.; Ehsan, M. IGDT Based Robust Decision Making Tool for DNOs in Load Procurement Under Severe Uncertainty. *IEEE Trans. Smart Grid* **2012**, *4*, 886–895. [\[CrossRef\]](#)
55. Chen, P.-Y.; Cheng, S.-M.; Chen, K.-C. Smart attacks in smart grid communication networks. *IEEE Commun. Mag.* **2012**, *50*, 24–29. [\[CrossRef\]](#)
56. Chai, W.K.; Kyritsis, V.; Katsaros, K.V.; Pavlou, G. Resilience of interdependent communication and power distribution networks against cascading failures. In Proceedings of the 2016 IFIP Networking Conference (IFIP Networking) and Workshops, Vienna, Austria, 17–19 May 2016; pp. 37–45.
57. Zio, E.; Sansavini, G. Modeling Interdependent Network Systems for Identifying Cascade-Safe Operating Margins. *IEEE Trans. Reliab.* **2011**, *60*, 94–101. [\[CrossRef\]](#)
58. Kwasinski, A. Effects of Notable Natural Disasters of 2017 on Information and Communication Networks Infrastructure. In Proceedings of the 2018 IEEE International Telecommunications Energy Conference (INTELEC), Torino, Italy, 7–11 October 2018; pp. 1–8.
59. Martins, D.L.; Girão-Silva, R.; Gomes, Á.; Jorge, L.M.G.; Musumeci, D.F.; Rak, D.J. Interdependence between Power Grids and Communication Networks: A Resilience Perspective. In Proceedings of the DRCN 2017—Design of Reliable Communication Networks, 13th International Conference, Munich, Germany, 8–10 March 2017; p. 9.
60. Yang, Z.; Chen, Y.; Marti, J. Modelling cascading failure of a CPS for topological resilience enhancement. *IET Smart Grid* **2020**, *3*, 207–215. [\[CrossRef\]](#)
61. Liu, X.; Chen, B.; Chen, C.; Jin, D. Electric power grid resilience with interdependencies between power and communication networks—A review. *IET Smart Grid* **2020**, *3*, 182–193. [\[CrossRef\]](#)
62. Ji, C.; Wei, Y.; Poor, H.V. Resilience of Energy Infrastructure and Services: Modeling, Data Analytics, and Metrics. *Proc. IEEE* **2017**. [\[CrossRef\]](#)

63. Kandaperumal, G.; Srivastava, A.K. Resilience of the electric distribution systems: Concepts, classification, assessment, challenges, and research needs. *IET Smart Grid* **2020**, *3*, 133–143. [CrossRef]
64. Chi, Y.; Xu, Y.; Hu, C.; Feng, S. A State-of-the-Art Literature Survey of Power Distribution System Resilience Assessment. In Proceedings of the 2018 IEEE Power & Energy Society General Meeting (PESGM), Portland, OR, USA, 5–9 August 2018; pp. 1–5.
65. Chi, Y.; Xu, Y. Resilience-oriented microgrids: A comprehensive literature review. In Proceedings of the 2017 IEEE Innovative Smart Grid Technologies—Asia (ISGT-Asia), Auckland, New Zealand, 4–7 December 2017; pp. 1–6.
66. Kafka, P. Reliability and Safety. CERN. February 2002. Available online: https://indico.cern.ch/event/412169/attachments/841055/1169721/AT_Kafka.pdf (accessed on 13 December 2020).
67. Grid Modernization Laboratory Consortium. Grid Modernization: Metrics Analysis (GMLC1.1)—Resilience. April. Available online: https://gmlc.doe.gov/sites/default/files/resources/GMLC1.1_Vol3_Resilience.pdf (accessed on 13 December 2020).
68. IEEE Guide for Electric Power Distribution Reliability Indices. In *IEEE Std 1366–2003 (Revision of IEEE Std 1366–1998)*; Institute of Electrical and Electronics Engineers (IEEE): Piscataway, NJ, USA, 2008; pp. 1–50.
69. Billinton, R.; Allan, R.N. Distribution systems—Basic techniques and radial networks. In *Reliability Evaluation of Power Systems*; Springer US: Boston, MA, USA, 1996; pp. 220–248.
70. IEEE. *IEEE Draft Guide for Electric Power Distribution Reliability Indices*; IEEE P1366/D6; November 2011; IEEE: Piscataway, NJ, USA, 2011; pp. 1–40.
71. Reed, D.A. Electric utility distribution analysis for extreme winds. *J. Wind. Eng. Ind. Aerodyn.* **2008**, *96*, 123–140. [CrossRef]
72. Council, N.R. *Disaster Resilience: A National Imperative*; The National Academies Press: Washington, DC, USA, 2012.
73. Elliot, R.; National Rural Elec Association; Organization of MISO States; Aaronson, S.; Edison Electric Institute; National Associatio Advocates. *Utility Investments in Resilience of Electricity Systems*. 2019. Available online: <https://escholarship.org/content/qt9928v9jb/qt9928v9jb.pdf> (accessed on 13 December 2020).
74. DeMartini, P. Integrated, Resilient Distribution Planning. May 2020. Available online: <https://pubs.naruc.org/pub/D3D1CE12-155D-0A36-3130-1E8E4E51F582> (accessed on 13 December 2020).
75. European Network and Information Security Agency (ENISA). Enabling and Managing End-to-End Resilience. Report/Study. Available online: <https://www.enisa.europa.eu/publications/end-to-end-resilience> (accessed on 13 December 2020).
76. Chana, I.; Gill, S.S. Quality of Service and Service Level Agreements for Cloud Environments: Issues and Challenges. In *Cloud Computing. Computer Communications and Networks*; Springer: Cham, Switzerland, 2014; pp. 51–72.
77. Tapolcai, J.; Cholda, P.; Cinkler, T.; Wajda, K.O.; Jajszczyk, A.; Verchere, D. Joint Quantification of Resilience and Quality of Service. In Proceedings of the 2006 IEEE International Conference on Communications, Istanbul, Turkey, 11–15 June 2006; Volume 2, pp. 477–482.
78. Rak, J.; Hutchison, D. (Eds.) *Guide to Disaster-Resilient Communication Networks*; Springer International Publishing: New York, NY, USA, 2020.
79. Eusgeld, I.; Henzi, D.; Kröger, W. *Comparative Evaluation of Modeling and Simulation Techniques for Interdependent Critical Infrastructures*; Laboratorium für Sicherheitsanalytik, ETH: Zürich, Switzerland, 2008.
80. Vugrin, E.D.; Castillo, A.R.; Silva-Monroy, C.A. *Resilience Metrics for the Electric Power System: A Performance-Based Approach*; SAND2017-1493, 1367499; Sandia National Lab. (SNL-NM): Albuquerque, NM, USA, 2017.
81. Zobel, C.W.; Khansa, L. Characterizing multi-event disaster resilience. *Comput. Oper. Res.* **2014**, *42*, 83–94. [CrossRef]
82. Friginal, J.; De Andrés, D.; Ruiz, J.C.; Martínez, M. REFRAHN: A Resilience Evaluation Framework for Ad Hoc Routing Protocols. *Comput. Netw.* **2015**, *82*, 114–134. [CrossRef]
83. Mukherjee, S.; Nateghi, R.; Hastak, M. A multi-hazard approach to assess severe weather-induced major power outage risks in the U.S. *Reliab. Eng. Syst. Saf.* **2018**, *175*, 283–305. [CrossRef]
84. Keogh, M.; Cody, C. Resilience in Regulated Utilities. National Association of Regulatory Utility Commissioners (NARUC). November 2013. Available online: <https://pubs.naruc.org/pub/536f07e4-2354-d714-5153-7a80198a436d> (accessed on 15 December 2020).
85. Chen, G.; Dong, Z.Y.; Hill, D.J.; Zhang, G.H. An improved model for structural vulnerability analysis of power networks. *Phys. A Stat. Mech. Its Appl.* **2009**, *388*, 4259–4266. [CrossRef]
86. Hines, P.; Cotilla-Sanchez, E.; Blumsack, S. Do topological models provide good information about electricity infrastructure vulnerability? *Chaos Interdiscip. J. Nonlinear Sci.* **2010**, *20*, 033122. [CrossRef]
87. Janić, M. Modelling the resilience of rail passenger transport networks affected by large-scale disruptive events: The case of HSR (high speed rail). *Transportation* **2018**, *45*, 1101–1137. [CrossRef]
88. Moslehi, S.; Reddy, T.A. Sustainability of integrated energy systems: A performance-based resilience assessment methodology. *Appl. Energy* **2018**, *228*, 487–498. [CrossRef]
89. Gasser, P.; Suter, J.; Cinelli, M.; Spada, M.; Burgherr, P.; Hirschberg, S.; Kadziński, M.; Stojadinović, B. Comprehensive resilience assessment of electricity supply security for 140 countries. *Ecol. Indic.* **2020**, *110*, 105731. [CrossRef]
90. Wang, J.; Zuo, W.; Rhode-Barbarigos, L.; Lu, X.; Wang, J.; Lin, Y. Literature review on modeling and simulation of energy infrastructures from a resilience perspective. *Reliab. Eng. Syst. Saf.* **2019**, *183*, 360–373. [CrossRef]
91. Lu, J.; Guo, J.; Jian, Z.; Yang, Y.; Tang, W. Dynamic Assessment of Resilience of Power Transmission Systems in Ice Disasters. In Proceedings of the 2018 International Conference on Power System Technology (POWERCON), Guangzhou, China, 6–9 November 2018; pp. 7–13.

92. Chanda, S.; Srivastava, A.K. Defining and Enabling Resiliency of Electric Distribution Systems with Multiple Microgrids. *IEEE Trans. Smart Grid* **2016**, *7*, 2859–2868. [\[CrossRef\]](#)
93. Zhao, S.; Liu, X.; Zhuo, Y. Hybrid Hidden Markov Models for resilience metrics in a dynamic infrastructure system. *Reliab. Eng. Syst. Saf.* **2017**, *164*, 84–97. [\[CrossRef\]](#)
94. Ouyang, M. Review on modeling and simulation of interdependent critical infrastructure systems. *Reliab. Eng. Syst. Saf.* **2014**, *121*, 43–60. [\[CrossRef\]](#)
95. Smith, C. Representing Common-Cause Failures in the SAPHIRE Software. In Proceedings of the ASME International Mechanical Engineering Congress and Exposition, Boston, MA, USA, 31 October–6 November 2008; Volume 16, pp. 155–162.
96. European Commission; Joint Research Centre. Institute for the Protection and the Security of the Citizen. In *Risk Assessment Methodologies for Critical Infrastructure Protection. Part I: A State of the Art*; Publications Office of the European Union, Grand Duchy of Luxembourg: Luxembourg, 2012.
97. Broadwater, R.; Anderson, R. Distribution Engineering Workstation from EDD 2005. April 2006. Available online: https://www.researchgate.net/publication/332705760_DISTRIBUTION_ENGINEERING_WORKSTATION_FROM_EDD_2005 (accessed on 15 December 2020).
98. Ashok, A.; Govindarasu, M.; Wang, J. Cyber-Physical Attack-Resilient Wide-Area Monitoring, Protection, and Control for the Power Grid. *Proc. IEEE* **2017**, *105*, 1389–1407. [\[CrossRef\]](#)
99. Farraj, A.; Hammas, E.; Al Daoud, A.; Kundur, D. A Game-Theoretic Analysis of Cyber Switching Attacks and Mitigation in Smart Grid Systems. *IEEE Trans. Smart Grid* **2015**, *7*, 1846–1855. [\[CrossRef\]](#)
100. Yuan, W.; Zhao, L.; Zeng, B. Optimal power grid protection through a defender–attacker–defender model. *Reliab. Eng. Syst. Saf.* **2014**, *121*, 83–89. [\[CrossRef\]](#)
101. Alguacil, N.; Delgadillo, A.; Arroyo, J.M. A trilevel programming approach for electric grid defense planning. *Comput. Oper. Res.* **2014**, *41*, 282–290. [\[CrossRef\]](#)
102. Fang, Y.; Zio, E. An adaptive robust framework for the optimization of the resilience of interdependent infrastructures under natural hazards. *Eur. J. Oper. Res.* **2019**, *276*, 1119–1136. [\[CrossRef\]](#)
103. Arab, A.; Khodaei, A.; Han, Z.; Khator, S.K. Proactive Recovery of Electric Power Assets for Resiliency Enhancement. *IEEE Access* **2015**, *3*, 99–109. [\[CrossRef\]](#)
104. LaRocca, S.; Johansson, J.; Hassel, H.; Guikema, S. Topological Performance Measures as Surrogates for Physical Flow Models for Risk and Vulnerability Analysis for Electric Power Systems. *Risk Anal.* **2014**, *35*, 608–623. [\[CrossRef\]](#) [\[PubMed\]](#)
105. Rachunok, B.; Nateghi, R. The sensitivity of electric power infrastructure resilience to the spatial distribution of disaster impacts. *Reliab. Eng. Syst. Saf.* **2020**, *193*, 106658. [\[CrossRef\]](#)
106. Zhabelova, G.; Vyatkin, V. Multiagent Smart Grid Automation Architecture Based on IEC 61850/61499 Intelligent Logical Nodes. *IEEE Trans. Ind. Electron.* **2011**, *59*, 2351–2362. [\[CrossRef\]](#)
107. Maliszewski, P.J.; Perrings, C. Factors in the resilience of electrical power distribution infrastructures. *Appl. Geogr.* **2012**, *32*, 668–679. [\[CrossRef\]](#)
108. Kelly-Gorham, M.R.; Hines, P.; Dobson, I. Using historical utility outage data to compute overall transmission grid resilience. *arXiv* **2019**, arXiv:1906.06811.
109. Jin, Y. Surrogate-assisted evolutionary computation: Recent advances and future challenges. *Swarm Evol. Comput.* **2011**, *1*, 61–70. [\[CrossRef\]](#)
110. Cao, Z.; Wang, Y.; Chu, C.-C.; Gadh, R. Scalable Distribution Systems State Estimation Using Long Short-Term Memory Networks as Surrogates. *IEEE Access* **2020**, *8*, 23359–23368. [\[CrossRef\]](#)
111. Liu, Y.; Zhang, X.; Gao, H.; Zhu, C.; Yao, Y. Data-driven Heuristic Optimization to Manage Congestion of Urban Power Grid. In Proceedings of the 2019 IEEE Innovative Smart Grid Technologies—Asia (ISGT Asia), Chengdu, China, 21–24 May 2019; pp. 580–586.
112. Pan, I.; Das, S. Kriging Based Surrogate Modeling for Fractional Order Control of Microgrids. *IEEE Trans. Smart Grid* **2015**, *6*, 36–44. [\[CrossRef\]](#)
113. Xu, Y.; Korkali, M.; Mili, L.; Chen, X.; Min, L. Risk Assessment of Rare Events in Probabilistic Power Flow via Hybrid Multi-Surrogate Method. *IEEE Trans. Smart Grid* **2020**, *11*, 1593–1603. [\[CrossRef\]](#)
114. Cai, B.; Xie, M.; Liu, Y.; Liu, Y.; Feng, Q. Availability-based engineering resilience metric and its corresponding evaluation methodology. *Reliab. Eng. Syst. Saf.* **2018**, *172*, 216–224. [\[CrossRef\]](#)
115. Moslehi, S.; Reddy, T.A. Sustainability Index of Community Energy Systems for Benchmarking and Multi-Criteria Decision Analysis. In Proceedings of the ASME 2016 International Mechanical Engineering Congress and Exposition, IMECE 2016, Phoenix, AZ, USA, 11–17 November 2016.
116. Alenazi, M.J.; Sterbenz, J.P. Comprehensive comparison and accuracy of graph metrics in predicting network resilience. In Proceedings of the 2015 11th International Conference on the Design of Reliable Communication Networks (DRCN), Kansas City, MO, USA, 24–27 March 2015; pp. 157–164.
117. Gao, H.; Chen, Y.; Mei, S.; Huang, S.; Xu, Y. Resilience-Oriented Pre-Hurricane Resource Allocation in Distribution Systems Considering Electric Buses. *Proc. IEEE* **2017**, *105*, 1214–1233. [\[CrossRef\]](#)
118. Rodriguez, D.R. Physical and Social Systems Resilience Assessment and Optimization. Ph.D. Thesis, University of South Florida, Tampa, FL, USA, 2018.

119. Kwasinski, A. Effects of Hurricane Maria on Renewable Energy Systems in Puerto Rico. In Proceedings of the 2018 7th International Conference on Renewable Energy Research and Applications (ICRERA), Paris, France, 14–17 October 2018; pp. 383–390.
120. Huang, G.; Wang, J.; Chen, C.; Guo, C.; Zhu, B. System resilience enhancement: Smart grid and beyond. *Front. Eng. Manag.* **2017**, *4*, 271–282. [\[CrossRef\]](#)
121. Jackson, S.; Ferris, T. Proactive and Reactive Resilience: A Comparison of Perspectives. *INCOSE Insight* **2015**, *18*, 7.
122. Sordo, S.; Domaneschi, M.; Cimellaro, G.; Mahin, S. Seismic Resilience of Electric Power Networks in Urban Areas. In Proceedings of the IAMBAS 2018 International Conference on Bridge Maintenance, Safety and Management, Melbourne, Australia, 9–13 July 2018; pp. 1911–1919.
123. Nikkhah, S.; Jalilpoor, K.; Kianmehr, E.; Gharehpetian, G.B. Optimal wind turbine allocation and network reconfiguration for enhancing resiliency of system after major faults caused by natural disaster considering uncertainty. *IET Renew. Power Gener.* **2018**, *12*, 1413–1423. [\[CrossRef\]](#)
124. Amirioun, M.; Aminifar, F.; Lesani, H.; Shahidehpour, M. Metrics and quantitative framework for assessing microgrid resilience against windstorms. *Int. J. Electr. Power Energy Syst.* **2019**, *104*, 716–723. [\[CrossRef\]](#)
125. Poudel, S.; Dubey, A.; Bose, A. Risk-Based Probabilistic Quantification of Power Distribution System Operational Resilience. *IEEE Syst. J.* **2019**, *14*, 3506–3517. [\[CrossRef\]](#)
126. Luo, D.; Xia, Y.; Zeng, Y.; Li, C.; Zhou, B.; Yu, H.; Wu, Q. Evaluation Method of Distribution Network Resilience Focusing on Critical Loads. *IEEE Access* **2018**, *6*, 61633–61639. [\[CrossRef\]](#)
127. Galvan, E.; Mandal, P.; Sang, Y. Networked microgrids with roof-top solar PV and battery energy storage to improve distribution grids resilience to natural disasters. *Int. J. Electr. Power Energy Syst.* **2020**, *123*, 106239. [\[CrossRef\]](#)
128. Hosseini, M.M.; Parvania, M. Quantifying impacts of automation on resilience of distribution systems. *IET Smart Grid* **2020**, *3*, 144–152. [\[CrossRef\]](#)
129. Nateghi, R. Multi-Dimensional Infrastructure Resilience Modeling: An Application to Hurricane-Prone Electric Power Distribution Systems. *IEEE Access* **2018**, *6*, 13478–13489. [\[CrossRef\]](#)
130. Kwasinski, A. Quantitative Model and Metrics of Electrical Grids’ Resilience Evaluated at a Power Distribution Level. *Energies* **2016**, *9*, 93. [\[CrossRef\]](#)
131. Wang, H.; Wang, S.; Yu, L.; Hu, P. A novel planning-attack-reconfiguration method for enhancing resilience of distribution systems considering the whole process of resiliency. *Int. Trans. Electr. Energy Syst.* **2020**, *30*, 12199. [\[CrossRef\]](#)
132. Yuan, W.; Wang, J.; Qiu, F.; Chen, C.; Kang, C.; Zeng, B. Robust Optimization-Based Resilient Distribution Network Planning Against Natural Disasters. *IEEE Trans. Smart Grid* **2016**, *7*, 2817–2826. [\[CrossRef\]](#)
133. Shelar, D.; Amin, S.; Hiskens, I. Resilience of Electricity Distribution Networks—Part II: Leveraging Microgrids. *IEEE Transactions on Control Network Systems*. May 2019. Available online: <http://arxiv.org/abs/1812.01745> (accessed on 1 December 2020).
134. MacKenzie, C.A.; Zobel, C.W. Allocating Resources to Enhance Resilience, with Application to Superstorm Sandy and an Electric Utility: Allocating Resources to Enhance Resilience. *Risk Anal.* **2015**, *36*, 847–862. [\[CrossRef\]](#) [\[PubMed\]](#)
135. Liu, J.; Qin, C.; Yu, Y. Enhancing Distribution System Resilience with Proactive Islanding and RCS-Based Fast Fault Isolation and Service Restoration. *IEEE Trans. Smart Grid* **2020**, *11*, 2381–2395. [\[CrossRef\]](#)
136. Chanda, S.; Srivastava, A.K.; Mohanpurkar, M.U.; Hovsopian, R. Quantifying Power Distribution System Resiliency Using Code-Based Metric. *IEEE Trans. Ind. Appl.* **2018**, *54*, 3676–3686. [\[CrossRef\]](#)
137. Bajpai, P.; Chanda, S.; Srivastava, A.K. A Novel Metric to Quantify and Enable Resilient Distribution System Using Graph Theory and Choquet Integral. *IEEE Trans. Smart Grid* **2018**, *9*, 2918–2929. [\[CrossRef\]](#)
138. Hussain, A.; Bui, V.-H.; Kim, H.-M. Resilience-Oriented Optimal Operation of Networked Hybrid Microgrids. *IEEE Trans. Smart Grid* **2017**, *10*, 204–215. [\[CrossRef\]](#)
139. Jamborsalamati, P.; Hossain, J.; Taghizadeh, S.; Konstantinou, G.; Manbachi, M.; Dehghanian, P. Enhancing Power Grid Resilience Through an IEC61850-Based EV-Assisted Load Restoration. *IEEE Trans. Ind. Inform.* **2019**, *16*, 1799–1810. [\[CrossRef\]](#)
140. Renofio, J.R.R.; Pellenz, M.E.; Santin, A.; Jamhour, E.; Penna, M.C.; Souza, R.D. Insights on the resilience and capacity of AMI wireless networks. In Proceedings of the 2016 IEEE Symposium on Computers and Communication (ISCC), Messina, Italy, 27–30 June 2016; pp. 610–615.
141. Shahraeini, M.; Kotzanikolaou, P. A Dependency Analysis Model for Resilient Wide Area Measurement Systems in Smart Grid. *IEEE J. Sel. Areas Commun.* **2019**, *38*, 156–168. [\[CrossRef\]](#)
142. Erdene-Ochir, O.; Abdallah, M.; Qaraqe, K.; Minier, M.; Valois, F. Routing resilience evaluation for smart metering: Definition, metric and techniques. In Proceedings of the 2014 IEEE 25th Annual International Symposium on Personal, Indoor, and Mobile Radio Communication (PIMRC), Washington, DC, USA, 2–5 September 2014; pp. 1867–1871.
143. Ji, C.; Wei, Y. Dynamic resilience for power distribution and customers. In Proceedings of the 2015 IEEE International Conference on Smart Grid Communications (SmartGridComm), Miami, FL, USA, 2–5 November 2015; pp. 822–827.
144. Aydeger, A.; Akkaya, K.; Cintuglu, M.H.; Uluagac, A.S.; Mohammed, O. Software defined networking for resilient communications in Smart Grid active distribution networks. In Proceedings of the 2016 IEEE International Conference on Communications (ICC), Kuala Lumpur, Malaysia, 23–27 May 2016; pp. 1–6.

145. Kwasinski, A. Realistic assessment of building power supply resilience for information and communications technologies systems. In Proceedings of the 2016 IEEE International Telecommunications Energy Conference (INTELEC), Austin, TX, USA, 23–27 October 2016; pp. 1–8.
146. Wafler, J.; Heegaard, P.E. Interdependency in smart grid recovery. In Proceedings of the 2015 7th International Workshop on Reliable Networks Design and Modeling (RNDM), Munich, Germany, 5–7 October 2015; pp. 201–207.
147. Lasseter, R.H. Smart Distribution: Coupled Microgrids. *Proc. IEEE* **2011**, *99*, 1074–1082. [[CrossRef](#)]
148. Farzin, H.; Fotuhi-Firuzabad, M.; Moeini-Aghaie, M. Enhancing Power System Resilience through Hierarchical Outage Management in Multi-Microgrids. *IEEE Trans. Smart Grid* **2016**, *7*, 2869–2879. [[CrossRef](#)]
149. Gholami, A.; Shekari, T.; Aminifar, F.; Shahidehpour, M. Microgrid Scheduling with Uncertainty: The Quest for Resilience. *IEEE Trans. Smart Grid* **2016**, *7*, 2849–2858. [[CrossRef](#)]
150. Gao, H.; Chen, Y.; Xu, Y.; Liu, C.-C. Resilience-Oriented Critical Load Restoration Using Microgrids in Distribution Systems. *IEEE Trans. Smart Grid* **2016**, *7*, 2837–2848. [[CrossRef](#)]
151. Chen, C.; Wang, J.; Qiu, F.; Zhao, D. Resilient Distribution System by Microgrids Formation after Natural Disasters. *IEEE Trans. Smart Grid* **2016**, *7*, 958–966. [[CrossRef](#)]
152. Rehmani, M.H.; Davy, A.; Jennings, B.; Assi, C. Software Defined Networks-Based Smart Grid Communication: A Comprehensive Survey. *IEEE Commun. Surv. Tutorials* **2019**, *21*, 2637–2670. [[CrossRef](#)]
153. Zeng, Z.; Fang, Y.-P.; Zhai, Q.; Du, S. A Markov reward process-based framework for resilience analysis of multistate energy systems under the threat of extreme events. *Reliab. Eng. Syst. Saf.* **2021**, *209*, 107443. [[CrossRef](#)]
154. Donges, J.F.; Schultz, H.C.H.; Marwan, N.; Zou, Y.; Kurths, J. Investigating the topology of interacting networks. *Eur. Phys. J. B* **2011**, *84*, 635–651. [[CrossRef](#)]
155. Buldyrev, S.V.; Parshani, R.; Paul, G.; Stanley, H.E.; Havlin, S. Catastrophic cascade of failures in interdependent networks. *Nat. Cell Biol.* **2010**, *464*, 1025–1028. [[CrossRef](#)]
156. Renschler, C.S.; Frazier, A.E.; Arendt, L.A.; Cimellaro, G.P.; Reinhorn, A.M.; Bruneau, M. A Framework for Defining and Measuring Resilience at the Community Scale: The PEOPLES Resilience Framework. 2010. Available online: https://www.researchgate.net/profile/Amy-Frazier-3/publication/284507306_Framework_for_defining_and_measuring_resilience_at_the_community_scale_The_PEOPLES_resilience_framework/links/565e082408ae1ef92983a0ea/Framework-for-defining-and-measuring-resilience-at-the-community-scale-The-PEOPLES-resilience-framework.pdf (accessed on 18 December 2020).
157. Clark, A.; Zonouz, S. Cyber-Physical Resilience: Definition and Assessment Metric. *IEEE Trans. Smart Grid* **2019**, *10*, 1671–1684. [[CrossRef](#)]
158. Reed, D.; Wang, S.; Kapur, K.C.; Zheng, C. Systems-Based Approach to Interdependent Electric Power Delivery and Telecommunications Infrastructure Resilience Subject to Weather-Related Hazards. *J. Struct. Eng.* **2016**, *142*, 4015011. [[CrossRef](#)]
159. Huang, G.; Wang, J.; Chen, C.; Guo, C. Cyber-Constrained Optimal Power Flow Model for Smart Grid Resilience Enhancement. *IEEE Trans. Smart Grid* **2019**, *10*, 5547–5555. [[CrossRef](#)]
160. Cardoni, A.; Cimellaro, G.; Domaneschi, M.; Sordo, S.; Mazza, A. Modeling the interdependency between buildings and the electrical distribution system for seismic resilience assessment. *Int. J. Disaster Risk Reduct.* **2020**, *42*, 101315. [[CrossRef](#)]
161. Wang, X.; Shahidehpour, M.; Jiang, C.; Li, Z. Resilience Enhancement Strategies for Power Distribution Network Coupled with Urban Transportation System. *IEEE Trans. Smart Grid* **2019**, *10*, 4068–4079. [[CrossRef](#)]
162. Najafi, J.; Peiravi, A.; Anvari-Moghaddam, A.; Guerrero, J. An efficient interactive framework for improving resilience of power-water distribution systems with multiple privately-owned microgrids. *Int. J. Electr. Power Energy Syst.* **2020**, *116*, 105550. [[CrossRef](#)]

Paper [\[2\]](#)

Youba Nait Belaid, Yiping Fang, Zhiguo Zeng, Anthony Legendre, Patrick Coudray, Anne Barros. “Resilience Optimization of Wide-Area Control in Smart Distribution Grids”. In: IFAC-PapersOnLine, 2405-8963, Jan. 2022.

Resilience Optimization of Wide-Area Control in Smart Distribution Grids

Youba Nait Belaid*, Yi-Ping Fang**, Zhiguo Zeng**, Anthony Legendre*, Patrick Coudray*, Anne Barros**

*Electricité de France R&D, 7 Boulevard Gaspard Monge, 91120 Palaiseau, France
(e-mail: youba.nait-belaid@edf.fr).

**Risk and Resilience of Complex Systems, Laboratoire Génie Industriel, CentraleSupélec, Université Paris-Saclay, 3 Rue Joliot Curie, 91190 Gif-sur-Yvette, France
(e-mail: youba.nait-belaid@centralesupelec.fr)

Abstract: Large-scale power distribution networks rely on the wide-area control (WAC) function to conduct daily grid operations. Grid control is even more critical during extreme events as the WAC function is required to orchestrate the response to contingencies and enhance the power system resilience through failure localization, isolation, and service restoration. Both power and telecommunication domains are involved in control applications, giving rise to multiple cyber-physical interdependencies. This paper proposes a resilience-based optimization of the distribution service restoration (DSR) by coordinating strategies of crew dispatch and manual/remote switches operation. The telecommunication service and underlying infrastructure are identified as main enablers of the co-optimization as all considered resilience strategies communicate with the control center that collects crisis management information. Therefore, the availability of telecom points in terms of power supply is examined in this work. Failure propagation in the coupled power-telecom network is highlighted, and differences in failure propagation between overhead and underground power lines are explored. The proposed approach is formulated as a mixed-integer linear programming (MILP) model, evaluated under a multi-feeder interdependent power-telecom test network. Results show that combined scheduling of resilience strategies as well as prioritization of power supply to telecom points-of-interest, yield an enhanced recovery strategy.

Copyright © 2022 The Authors. This is an open access article under the CC BY-NC-ND license (<https://creativecommons.org/licenses/by-nc-nd/4.0/>)

Keywords: Wide Area Control, Resilience, Distribution Service Restoration, Extreme Event, MILP.

NOMENCLATURE

Sets

N	All power nodes (HV/MV SS, MV buses)
SS	HV/MV Substations
Fx, W	Fixed, Wireless Telecom operator access points
RR	Utility-owned radio relays
$n(j)$	Neighbor nodes of node j
$n_M(l)$	Neighbor manual lines of line l
L, SW	All power lines, switches in lines
L^M	Manually switchable lines
F	Failures of power lines
DP	Depots
RC, MC	Repair crews, manual switching crews
Parameters	
M	Large number
r_{ij}, x_{ij}	Resistance, Reactance of line (i, j)
p^{max}	Total active power demand
Q^{max}	Total reactive power demand
f_{ij}	1 if failure in line (i, j) , 0 otherwise
f_i	1 if failure at telecom access point i , 0 otherwise
Res^l	Demand of repair resources from faulted line l
Res^{dp}	Repair resources available at depot dp
RT_l, MT_l	Repair, manual switching time of damage l , $RT_l \geq 1$
TT_{lm}	Travel time between l and m (depot or failed line)
	Manual switching/isolation time of line l

p_i^{disc}	Active battery discharge power of node i
s_i	Binary parameter. 1 if i is HV/MV SS, 0 otherwise
Variables	
$sw_{ij,t}$	1 if switch at $l = (i, j)$ is closed at t , 0 otherwise
$p_{ij,t}, q_{ij,t}$	Active, Reactive power flow of line (i, j) at time t
p_i^d, q_i^d	Active, Reactive power demand of node i
$p_{i,t}^{sd}, q_{i,t}^{sd}$	Loss of active/Reactive load at node i at time t
$v_{i,t}$	Voltage magnitude at node i
$d_{ij,t}$	1 if power flows from i to j at t , 0 otherwise
$a_{ij,t}$	1 if line $l = (i, j)$ is available at time t , 0 otherwise
$a_{i,t}^e, y_{i,t}^e$	1 if bus i is available, energized at time t , 0 otherwise
$rr_{i,t}^c$	1 if telecom service (TS) from utility-owned radio relay i is available at t , 0 otherwise
$ss_{i,t}^c$	1 if TS of HV/MV SS i is available at t , 0 otherwise
$T_{i,t}^c$	1 if communication service from the telecom operator access point i is available at t , 0 otherwise
$T_{i,t}^e$	1 if electricity supply for the telecom operator access point i is available at t , 0 otherwise
E_i^{max}	Maximum energy storage of the battery of node i
$E_{i,t}$	Energy storage of the battery at node i at t
$b_{i,t}$	1 if the battery of node i is not empty at t , 0 otherwise
$rc_{i,t}^{dp,k}$	1 if line l is being repaired by repair crew, manual switching crew k of depot dp at time t , 0 otherwise
$mc_{i,t}^{dp,k}$	

1. INTRODUCTION

Generalized deployment of wide-area measurement systems (WAMS) boosted WAC applications of monitoring, oscillation damping, voltage control, wide-area protection, and disturbance localization, isolation and mitigation (Chakraborty and Khargonekar, 2013). In case of extreme events, the WAC contributes to the DSR by maintaining essential system functions and coordinating the recovery process. Resilience-based optimization gained interest in recent years at distribution grid level, where operators seek fastest DSR strategies with minimal costs. (Arif *et al.*, 2018) proposed co-optimization resilience strategies of repair crew dispatch, distributed generators (DGs) placement, and switches-enabled reconfiguration. A MILP is formulated based on LinDistFlow model (Baran and Wu, 1989) and solved with the aim to maximize served load and minimize restoration time. Similarly, (Lei *et al.*, 2019) constructed a MILP to co-optimize equivalent resilience strategies, while proposing a novel vertex-wise formulation of the crew routing problem, breaking with the widely adopted edge-wise formulation derived from the well-known travel salesman problem (TSP) (Miller, Tucker and Zemlin, 1960). The co-optimization approach is applied to interdependent electric and natural gas systems (Lin *et al.*, 2019) to improve the combined restoration of both infrastructures. At this point, despite explicitly involving WAC during the DSR through remote switches manipulation, these works do not investigate the impact of WAC impairment, or unavailability of information and communication technologies (ICTs) that convey miscellaneous data and act as virtual hands for decision-making entities in the power system. The growing dependency on ICTs renders grid applications, especially WAC, very sensitive to data quality, interoperability, and security (Zhu, Chenine and Nordstrom, 2011). The grid is challenged by emerging coupling effects between the ICT and energy domains, which can be captured by extending the relatively mature modeling of power flow to include information flow as proposed in (Xin *et al.*, 2017). The resulting integrated model is highly non-linear due to dominantly event-driven communications. In line with this, (Huang *et al.*, 2019) developed a cyber-constrained power flow model to evaluate and enhance power system resilience. The model is once again highly non-linear, and authors proposed an exact bi-level linear programming reformulation to solve the problem. To the best knowledge of the authors, only (Ye, Chen and Wu, 2021) investigates the state of telecommunication service (TS) in an integrated distribution system restoration framework, by considering the cooperation and coordination of the repair crews, the distribution system and emergency communication. The present work addresses the identified literature gap of not considering the state of ICT service during DSR optimization. Contributions of this work are:

- Demonstrate the need for TS awareness during DSR
- Quantify the benefit of co-optimizing reconfiguration and crew dispatch
- Present a more realistic model for modern smart distribution grids

The remaining of the paper presents in Section 2 the optimization model formulation. Simulations and numerical

results are provided in Section 3, and the conclusion is drawn in Section 4.

2. MODEL FORMULATION

The primary response to damages on the network is not considered in this work, where we assume that all possible automatic protection and remote reconfigurations were made within some minutes after event occurrence (Liu, Qin and Yu, 2020). The resultant remote reconfiguration of the power distribution network (PDN) and received diagnoses, based on information from either field components (electrical sensors, drones, and connected smart devices) or inspection crews, are feeded to the model as a record of identified damages, an estimation of repair time, and an indication of damaged sites accessibility. Scenarios of events in the current work consist of damages in power lines, complemented with possible direct damage on a telecom access point due to the event or an indirect failure caused by shortage in the power supply.

Switches of different types exist in the network. They can be at two states: open or closed. A binary variable is used to model this behavior. Human intervention in the field is necessary to operate manual switches but optional for remote controllable switches (RCSs) that can be toggled from the control center via communication links. RCSs are most of the time fully controlled by the control center (CC) but can in some cases open automatically. This feature is generally implemented at the head of feeders as a safety measure for power ingress nodes, and sometimes across long-distance feeders to enable better initial isolation.

For the power domain, a graph theoretic approach is adopted representing power substations (HV/MV SS and MV buses) as nodes and lines as edges. The same approach is applied to the cyber domain as telecom points are considered as nodes, and communication links as edges. The interdependence between the two domains is captured by telecom points being loads from the grid perspective, while power substations and switches are clients from the telecom perspective (Figure 1).

2.1. Zone separation and PDN topology constraints

During the process of service restoration, three zones can be sorted out: 1) Damage zone: part of the network affected by the propagation of the damage; 2) Unserved zone: part of the network, at first included in the damage zone, but eventually isolated using manual switches when operated by intervention crews, then wait for restoration 3) Served zone: segments of the PDN that are energized and safe from damages.

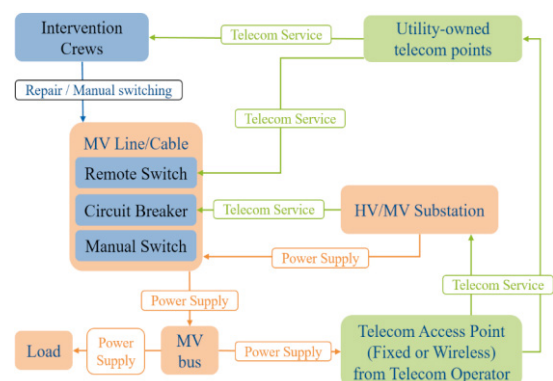


Figure 1. Summarized interactions in the proposed model

Unservd and served zones are both safe from failures.

We focus in this paper on overhead lines as the underground case can be handled by a simplification of the overhead case.

$$a_{i,t}^e + sw_{ij,t} - 1 \leq a_{j,t}^e, \quad \forall (i,j) \in L, \forall t \quad (1.a)$$

$$a_{j,t}^e + sw_{ij,t} - 1 \leq a_{i,t}^e, \quad \forall (i,j) \in L, \forall t \quad (1.b)$$

Constraints (1. a) and (1. b) ensure that damage zones are not connected to served zones or reconnected to unserved zones. This is guaranteed by requiring open lines between safe and damage zones. Connection between safe (served and unserved) zones is possible.

At the distribution level, radiality should be ensured at normal operation and always verified.

$$d_{ij,t} + d_{ji,t} \leq sw_{ij,t}, \forall (i,j) \in L, \forall t \quad (2.a)$$

$$sw_{ij,t} - (2 - a_{i,t}^e - a_{j,t}^e) \leq d_{ij,t} + d_{ji,t}, \forall (i,j) \in L, \forall t \quad (2.b)$$

$$d_{ij,t} + d_{ji,t} - (2 - a_{i,t}^e - a_{j,t}^e) \leq sw_{ij,t}, \forall (i,j) \in L, \forall t \quad (2.c)$$

$$a_{i,t}^e + a_{j,t}^e - 1 \leq sw_{ij,t}, \forall (i,j) \in L^M, \forall t \quad (3)$$

$$\sum_{i \in n(j)} d_{ij,t} \leq 1 - s_j, \forall i, j \in N, \forall t \quad (4)$$

$$y_{j,t}^e = \sum_{i \in n(j)} d_{ij,t}, \forall j \in N, \forall t \quad (5.a)$$

$$y_{i,t}^e \leq a_{i,t}^e, \quad \forall i \in N, \forall t \quad (5.b)$$

$$a_{i,t}^e \leq a_{i,t-1}^e + a_{ij,t}, \forall (i,j) \in F, \forall t \quad (6)$$

$$sw_{ij,t-1} \leq sw_{ij,t}, \forall (i,j) \in L^M \setminus L^{F \times M} \quad (7.a)$$

$$a_{ij,t-1} \leq a_{ij,t}, \forall (i,j) \in L \quad (7.b)$$

$$a_{i,t-1}^e \leq a_{i,t}^e, \quad \forall i \in N, \forall t \quad (7.c)$$

$$y_{i,t-1}^e \leq y_{i,t}^e, \quad \forall i \in N, \forall t \quad (7.d)$$

Constraints (2. a), (2. b), and (2. c) impose that when a line (i, j) is in a safe zone ($a_{i,t}^e = 1$ and $a_{j,t}^e = 1$), power will flow unidirectionally in any closed line. However, in a damage zone, power does not flow in closed lines. (3) states that manual lines are closed after repair or isolation from damage zones and will not be used as tie-switches. Constraint (4) prohibits power from flowing into HV/MV substations while indicating that power arrives to any bus from a single direction. Constraint (5. a) says that a load can be energized if power flows into the corresponding bus, and from (5. b) only available buses (not in damage zone) can supply power to their loads. In (6), individual buses need to wait for the availability of the linked line to become also available. Constraints (7. a), (7. b), (7. c), and (7. d) indicate respectively that: manual lines not directly adjacent to damages are not opened, lines are being repaired during all the time horizon, buses are recovered, and loads are restored to the network.

2.2. Power flow constraints

The operation of the PDN can be described in terms of power flow from substations to aggregated loads connected at the MV buses. The LinDistFlow model (Baran and Wu, 1989) is used as described below for the active power ($\forall (i,j) \in L, \forall t$)

$$\sum_{k:(j,k) \in L} p_{jk,t} + p_j^d = \sum_{i:(i,j) \in L} p_{ij,t} + p_{j,t}^{sd}, \forall i, j, k \in N \quad (8)$$

$$v_{i,t} - v_{j,t} - 2(r_{ij}p_{ij,t} + x_{ij}q_{ij,t}) \leq (1 - d_{ij,t})M \quad (9)$$

$$v_{i,t} - v_{j,t} - 2(r_{ij}p_{ij,t} + x_{ij}q_{ij,t}) \geq -(1 - d_{ij,t})M \quad (10)$$

$$0 \leq p_{ij,t} \leq S^{max} d_{ij,t}, \forall (i,j) \in L, \forall t \quad (11)$$

$$v_i^{min} \leq v_{i,t} \leq v_i^{max}, \forall i \in N, \forall t \quad (12)$$

$$(1 - y_{i,t}^e)p_i^d \leq p_{i,t}^{sd} \leq p_i^d, \quad \forall i \in N, \forall t \quad (13)$$

Constraint (8) is the power balance equation. (9) and (10) represent the node voltages difference in terms of power and impedance quantities. (11) limits the capacity of closed lines. (12) bounds the bus voltages. (13) sets the limits for the active shed power.

2.3. Telecom constraints

Telecom or ICTs used in distribution grids can be managed by the distribution system operator (DSO) itself or subcontracted to telecom operators. Figure 1 shows captured interactions between DSO or utility-owned ICT infrastructure and telecom operator services in the case of WAC. Besides RCSs and substations, which are electric components with communication capabilities, other components are involved:

- Utility-owned Radio Relays (RRs): Assumed to not fail due to the event given a large battery storage. Each RR has a primary fixed (wired) and a secondary wireless link. Serves RCSs and intervention crews

- Telecom operator fixed access points (FAP): The FAP serves the DSO assets as a primary link (HV/MV SS, RR).

- Telecom operator wireless access points (WAP): The WAP Serves DSO assets as a secondary link (HV/MV SS, RR).

FAPs and WAPs Can fail due to an event and rely on batteries to keep operation. In that case, HV/MV SS and RR will not necessarily fail, but will operate in a degraded (blind!) mode.

Constraint (14) indicates that the TS is available at a RR when one of its serving FAP or WAPs is operating. A given RR can be served by just one FAP, but with one or more WAPs. Likewise, (15) describes the availability of the telecom service to substations. (16. a) and (16. b) emphasize that the TS is at disposal only when power supply is guaranteed. More precisely, from (17. a) and (17. b) power is drawn from either the grid or the battery storage. (18) sets the bounds for the batteries, quantified here as the number of time steps before depletion. A simple piecewise-linear discharge model is taken in (19). (20) checks whether the battery is empty.

$$\frac{1}{M} \left(T_{k,t}^c + \sum_{j:(j,i) \in W \times RR} T_{j,t}^c \right) \leq rr_{i,t}^c \leq T_{k,t}^c + \sum_{j:(j,i) \in W \times RR} T_{j,t}^c, \forall (k,i) \in Fx \times RR, \forall t \quad (14)$$

$$\frac{1}{M} \left(T_{k,t}^c + \sum_{j:(j,i) \in W \times SS} T_{j,t}^c \right) \leq ss_{i,t}^c \leq T_{k,t}^c + \sum_{j:(j,i) \in W \times SS} T_{j,t}^c, \forall (k,i) \in Fx \times SS, \forall t \quad (15)$$

$$T_{i,t}^c \leq T_{i,t}^e, \forall i \in W \cup Fx, \forall t \quad (16)$$

$$\frac{1}{M}(1-f_i)(E_{i,t} + y_{i,t}^e) \leq T_{i,t}^e \leq M(1-f_i)(E_{i,t} + y_{i,t}^e), \quad \forall i \in W \cup Fx, \forall t \quad (17)$$

$$0 \leq E_{i,t} \leq E_i^{max}, \forall i \in W \cup Fx, \forall t \quad (18)$$

$$E_{i,t} = E_{i,t-1} - p_i^{disc}(1 - y_{i,t-1}^e)b_{i,t-1}, \forall i \in W \cup Fx, \forall t \quad (19)$$

$$\frac{E_{i,t}}{M} \leq b_{i,t} \leq E_{i,t}, \forall i \in W \cup Fx, \forall t \quad (20)$$

(19) contains a non-linear quadratic component. As the involved variables are integers, this can be easily linearized

$$z_{i,t} = (1 - y_{i,t}^e)b_{i,t}, \forall i \in N_T, \forall t$$

$$E_{i,t} = E_{i,t-1} - p_i^{disc}z_{i,t-1}, \forall i \in N_T, \forall t \quad (19.a)$$

$$z_{i,t} \leq (1 - y_{i,t}^e), \forall i \in N_T, \forall t \quad (19.b)$$

$$z_{i,t} \leq b_{i,t}, \forall i \in N_T, \forall t \quad (19.c)$$

$$(1 - y_{i,t}^e) + b_{i,t} - 1 \leq z_{i,t}, \forall i \in N_T, \forall t \quad (19.d)$$

Constraints (19.a) – (19.d) replace constraint (19). An equivalent procedure is conducted for (28) and (29) later.

2.4. Routing and scheduling constraints

Early collected data from field devices and diagnosis crews help to estimate important quantities (such as the repair time) and ultimately provide an intervention timeline. In practice, instructions about the paths towards damage sites are also specified. This combines into handling a routing and scheduling problem. Most available literature adapts through generalization the formulation of the traveling salesman problem (TSP) to tackle specific problems. The TSP defines routing variables on paths between each city pairs. This is less convenient when considering the distribution service restoration problem where tasks are to be conducted at damage sites. In such a problem, depots and damage sites are nodes connected with road paths seen as edges, and the aim is to find the sequence of locations each crew visited while minimizing the overall restoration time. This node-centered approach (unlike the TSP edge-centered approach) bypasses the issues of transportation–grid coupling and their different timescales. We adopt in this work the formulation proposed and demonstrated in (Lei et al., 2019) where routing variables have a time subscript to utterly characterize the node visited by each crew at any given time. We define then variables $rc_{l,t}^{dp,k}/mc_{l,t}^{dp,k}$ as repair/manual switching crew k , from depot dp , being at site l (damage site or depot), at time step t . We use variable $c_{l,t}^{dp,k}$ when the same constraint applies to both. the notation using the cross sign between different sets is used in this paper to represent indexed sets, where only meaningful elements are evaluated. In other words, $DP \times RC \times F^{dp} \times F^{dp}$ does not contain all possible four-dimensional (dp, k, l, m) combinations formed by the four sets, but includes only the valid (l, m) pairs assigned to crew, which is associated to depot dp . For example, in case of two depots 1 and 2 each having one repair crew k , forming the pairs (dp, rc) : (1,1), (2,1). Let us say that damages m and l were assigned to depot 1, and damages r and s to depot 2. Valid combinations would be (1,1, l , m) and (2,1, r , s) and an example of a non-valid combination is (1,1, r , s).

$$\sum_{\tau=0}^{\min(TT_{l,m}^{rc}, T-t)} (c_{l,t+\tau}^{dp,k} + c_{m,t}^{dp,k} - 1) \leq 0, \quad \forall (dp, k, l, m) \in DP \times RC \times F^{dp} \times F^{dp}, \forall l \neq m, \forall t \quad (21)$$

$$\sum_{\tau=t}^T \sum_{\forall (dp,k,l) \in DP \times MC \times F} mc_{l,\tau}^{dp,k} \leq M \left(1 - \sum_{\forall (dp,k,l) \in DP \times RC \times F} rc_{l,\tau}^{dp,k} \right), \forall l \in F, \forall t \quad (22)$$

$$\sum_{\tau=t}^T \sum_{\forall (dp,k',l) \in DP \times RC \times F; k' \neq k} c_{l,\tau}^{dp,k'} \leq M(1 - c_{l,t}^{dp,k}), \quad \forall (dp, k, l) \in DP \times RC \times F, \forall t \quad (23)$$

$$\sum_{\tau=t+\sum_{m \in n_M(l)} MT_m}^T mc_{l,\tau}^{dp,k} \leq M(1 - mc_{l,t}^{dp,k}), \quad \forall (dp, k, l) \in DP \times MC \times F, \forall t \quad (24)$$

$$\sum_{\tau=t}^T \sum_{\forall (dp,k,l) \in DP \times MC \times F} mc_{l,\tau}^{dp,k} \leq \sum_{\forall m \in n_M(l)} MT_m, \quad \forall l \in F, \forall t \quad (25)$$

$$\sum_{\forall (dp,k,l) \in DP \times RC \times F} rc_{l,\tau}^{dp,k} + \sum_{\forall (dp,k,l) \in DP \times MC \times F} mc_{l,\tau}^{dp,k} + a_{l,t} \leq 1, \quad \forall l \in F, \forall t \quad (26)$$

$$\sum_{\forall l \in F} a_{l,t} Res^l \leq Res^{dp}, \forall (dp, l) \in DP \times F \quad (27)$$

Constraint (21) enforces any repair or manual switching crew to be present at a maximum of one node (damage site or depot) at any given time. Moreover, moving between two nodes is restricted with the travel time $(TT_{l,m}^{rc}, TT_{l,m}^{mc})$. (22) indicates that no Isolation crew can visit an incident after a previous visit from a repair crew to that incident. In (23), if a crew visits a damage, no other crew with the same function visits that incident in subsequent periods. (24) sets isolation crews to intervene in contiguous periods, and (25) forces isolation crews to be at an incident for the isolation duration only. According to (26), at any time step, the damage is in one of the following states: not visited yet, under isolation, under repair, or resolved. (27) limits the number of incidents in depot.

2.5. Interdependence constraints

Power and telecom domains of the smart PDN are interdependent as the telecom points require power supply from the grid, and RCSs as well as intervention crews need the telecom service to exchange information and commands with the control center. Constraints (16), stated before for convenience, show one side of this relationship, and the following constraints illustrate the other side.

$$sw_{ij,t-1} \leq sw_{ij,t} \leq sw_{ij,t-1} + ss_{k,t}^c a_{i,t}^e, \quad \forall (k, (i, j)) \in L^{SS \times CB}, \forall t \quad (28)$$

$$sw_{ij,t-1} - rr_{k,t}^c (2 - a_{i,t}^e - a_{j,t}^e) \leq sw_{ij,t} \leq sw_{ij,t-1} + rr_{k,t}^c a_{i,t}^e, \forall (k, (i, j)) \in L^{RR \times SW}, \forall t \quad (29)$$

$$a_{l,t} \leq rr_{k,t}^c, \forall (k, l) \in L^{RR \times F}, \forall t \quad (30)$$

(28) indicates that circuit breakers can be operated only when the telecom service from substations is up, and (29) implies the same condition for other RCSs for which communications transit by the RR. A given line is available for reconnection if the communication link is available (30).

$$a_{l,t} \leq \frac{\sum_{\tau=0}^t (\sum_{(dp,k) \in DP \times RC} r c_{l,\tau}^{dp,k} + \sum_{(dp,k) \in DP \times MC} m c_{l,\tau}^{dp,k})}{RT_l + 2 \sum_{m \in n_M(l)} MT_m} \quad \forall l \in F, \forall t \quad (31)$$

$$sw_{m,t} \leq a_{l,t} + 2 - \varepsilon -$$

$$\frac{1 + \sum_{\tau=h}^{t-1} (\sum_{(dp,k) \in DP \times RC} r c_{l,\tau}^{dp,k} + \sum_{(dp,k) \in DP \times MC} m c_{l,\tau}^{dp,k})}{1 + \sum_{m \in n_M(l)} MT_m}, \quad \forall l \in F, \forall t \quad (32.a)$$

$$sw_{m,t-1} - \varepsilon -$$

$$\frac{1 + \sum_{\tau=h}^{t-1} (\sum_{(dp,k) \in DP \times RC} r c_{l,\tau}^{dp,k} + \sum_{(dp,k) \in DP \times MC} m c_{l,\tau}^{dp,k})}{1 + \sum_{m \in n_M(l)} MT_m} \leq sw_{m,t}, \quad \forall l \in F, \forall t \quad (32.b)$$

With $h = \max(0, t - 1 - \sum_{m \in n_M(l)} MT_m)$.

A second major type of interdependence resides between resilience strategies of intervention crews and reconfiguration. A line is not operable unless repair is finished (31). Also, opening manual switches directly adjacent to damages achieves best isolation. This is done according to (32.a) and (32.b) after isolation and repair crews spent required time to finish their tasks.

2.6. Objective function

The standpoint of a DSO is adopted in this work as the main objective is supplied power, while the cost of resilience strategies is considered to settle cases where many restoration policies minimize to the same level non-supplied load (or equivalently maximize supplied load).

$$\min_{P, sw, d, a, y, rc, mc, b, z, T, E} \alpha \sum_{\forall t} \sum_{\forall l \in N} w_l p_{l,t}^{sd} + \gamma \sum_{\forall t} \sum_{\forall l \in F} C_l (1 - a_{l,t}) \quad (33)$$

The objective function is given in (33) with P as a vector of all electrical quantities (p, q, v) and T representing all telecom-related variables. The remaining vectors assemble all variables with the corresponding name. C_l is the cost of repairing a damaged line l . Note that for the constants α and γ : $\alpha \gg \gamma$ as from the standpoint of a DSO during crisis management, restoring power to clients is of utter most importance and costs are only considered when equivalently performing strategies are compared. As adopted in most of the literature (Panteli et al., 2017; Fang and Zio, 2019), the resilience of the system can be calculated based on the temporal evaluation of a performance measure, which we choose here as supplied load.

3. SIMULATION AND RESULTS

A case study is designed based on the layout of the IEEE 12-node test feeder to demonstrate the effectiveness of the proposed approach. Figure 2.a shows the buses served by each feeder, and the interconnections between feeders using tie-switches (or normally-open switches). We set: $\alpha = 10$, $\gamma =$

0.01, $C_l = 100$, and $Res^l = 1$ for all failed lines. The MILP is implemented in Pyomo (Hart et al., 2017) and solved using CPLEX on a personal computer with Intel Core i7 Processor (1.8 GHz) and 8 GB RAM. A time step of 30 mn is used.

Nodes 1, 2, and 3 in Figure 2.a represent the HV/MV substations, while the remaining nodes are the MV buses, which not only supply power to electrical loads, but also energize telecom operator Fx and W access points. A scenario of 8 physical damages is considered, with 7 affected power lines and 1 telecom access point (Figure 2.a). Damages 23-24, 2-17, 20-21 are pre-assigned to DP1, and the remaining to DP2. The used (widely adopted) technique pre-allocates damages to depots based on their distances to the depots as (Lin et al., 2019) Repair crews (RC) and manual switching crews (MC) are initially located at depots. DP1 is set to have 1 RC ($Res^1 = 1$) and 1 MC, whereas DP2 has 2 RCs ($Res^2 = 2$) and 1 MC. The travel time is proportional to the distance between a depot and a damage or between two damages, whilst MCs are twice faster than RCs. Without loss of generality, repair and operation of manual switches by crews are chosen for all lines to last 2 and 1 time steps respectively. The damage in the telecom access point is not repaired as the repair process is limited to grid assets, and this task should be handled by the telecom operator. Unlike utility-owned radio relays that are assumed to have power storage of one to two days, telecom operator access points have only limited battery storage, set for a duration of 1.5h (3 time steps). Remote switches and intervention crews get TS from the closest RR, and substations provide TS to circuit breakers. RRs and substations connect to the closest WAP and FAP.

A preliminary simulation is conducted to confirm the intuitive (and literature well-verified) statement that co-optimization achieves better performance than non-cooperative approaches. Considering perfect communications, we obtain a gain of 12% in total supplied load using the proposed co-optimization, compared to a case where we solve first an optimization problem for crew schedules, then take the result as an input to switch reconfiguration stage under power flow constraints (Arif et al., 2018).

Next, to quantify the criticality of TS in smart distribution grids, a telecom agnostic case is constructed. The co-optimization is solved within 8 sec for telecom agnostic case (Case I), and 75 sec for telecom aware case (Case II). Figure 2.b depicts the evolution of supplied power during the event scenario. TS agnostic case satisfies 79% of the power demand during the simulation horizon compared to 71% in the more realistic TS aware case. Case I clearly dominates Case II between $t = 2$ and $t = 9$, meaning that the difference in total supplied power is experienced in a limited time window, towards the beginning of the event, which corresponds to the

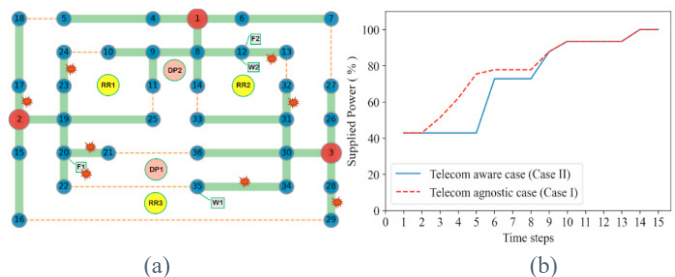


Fig 2. (a) Multi-feeder network (b) Evolution of supplied power

most critical period for contingency mitigation. Thus, Case I magnifies the restoration potential by not considering the availability of telecom points, and better insight can be taken from Case II as the telecom domain is modeled. Figures 3 and 4 display the timelines of all intervention crews in both cases. MC1 of DP2 (MC(2,1)) isolated buses 8 and 14 from damaged 12-13 by opening 8-12, but branches 8-14-33 could not be restored till $t = 6$ due to unavailability of the TS. Likewise, Line 20-21 was repaired by RC1 of DP1 (RC(1,1)) at $t = 4$ but could not be reconnected till $t = 6$ that corresponds to the completion of repair at 12-13, which enabled the TS provided by W2 and F2. These two waived reconnections contributed considerably to the gap in supplied power between I and II. Damages 12-13 and 34-35 are visited by MC(2,1) and MC(1,1) respectively, many time periods before repair is conducted (Figure 3). Figure 2.b unveils the gain in terms of supplied power (curve of Case I) as loads connected to 8, 14, 31, 30, and 36 could be restored as soon as isolated from the propagating incidents. Hence, it is important to have fast moving crews, which can perform such operations and not always wait for heavily equipped repair crews to launch the restoration. Still, repair crews operate manual switches after finishing their task as they are already on site, in accordance with the control center instructions. Figures 3 and 4 depict the post-repair manual switching by retaining repair crews at the handled damage longer than the repair time, set here to 2 time steps. From Figure 4, the obtained solution prioritizes repair of line segments directly affecting the availability of TS. Lines 20-21 and 12-13 that supply power to telecom access points are repaired during first time steps. 12-13 contributes indeed to boost the restoration process, however, as F1 is damaged, the TS intended benefit from this repair could not be leveraged. This reveals the drawback of situational blindness about repair operations conducted by telecom operators. In better observable cases, the optimization is able to use knowledge about battery discharging of telecom access points, to delay sending MC(2,1) to 34-35, because in any case the possible profitable reconfigurations allowed by manual isolation cannot be carried till restoration of a portion of the TS at $t = 6$. This delay can allow to assign another task to the crew and avoid the cost of waiting at the site until the TS is restored.

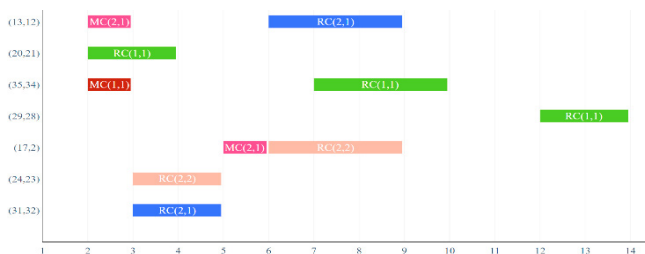


Figure 3. Schedule of intervention crews for Case I

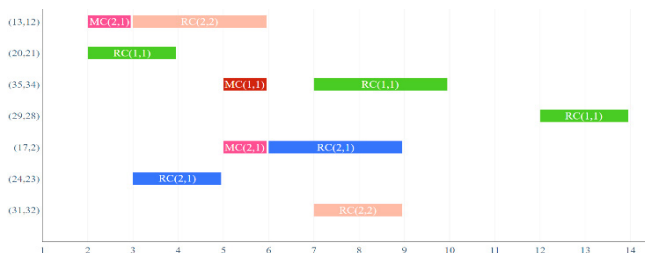


Figure 4. Schedule of intervention crews for Case II

4. CONCLUSION

This paper proposes a resilience-based optimization of intervention crews dispatch and manual/remote switches operation. The objective is to maximize the total supplied power during an outage scenario, while minimizing the intervention cost in case two strategies achieve the same performance. In addition to repair crews, fast moving isolation crews are introduced to allow highly flexible recovery. A more realistic model of the distribution grid is considered, where ICT points are supplied from electrical buses and have limited battery storage. RCSs and intervention crews get their TS from utility-owned RR and substations, which are served from the telecom operator access points.

ACKNOWLEDGEMENT

This work is funded by EDF/Orange/SNCF in the framework of the Chair on Risk and Resilience of Complex Systems (CentraleSupélec, EDF, Orange, SNCF).

REFERENCES

- Arif, A. et al. (2018) 'Power Distribution System Outage Management With Co-Optimization of Repairs, Reconfiguration, and DG Dispatch', *IEEE Transactions on Smart Grid*, 9(5), pp. 4109–4118. doi:10.1109/TSG.2017.2650917.
- Baran, M.E. and Wu, F.F. (1989) 'Network reconfiguration in distribution systems for loss reduction and load balancing', *IEEE Transactions on Power Delivery*, 4(2), pp. 1401–1407. doi:10.1109/61.25627.
- Chakraborty, A. and Khargonekar, P.P. (2013) 'Introduction to wide-area control of power systems', in *2013 American Control Conference*, 2013 American Control Conference, pp. 6758–6770. doi:10.1109/ACC.2013.6580901.
- Fang, Y.-P. and Zio, E. (2019) 'An adaptive robust framework for the optimization of the resilience of interdependent infrastructures under natural hazards', *European Journal of Operational Research*, 276(3), pp. 1119–1136. doi:10.1016/j.ejor.2019.01.052.
- Hart, W.E. et al. (2017) 'The Pyomo Command', in Hart, W.E. et al. (eds) *Pyomo — Optimization Modeling in Python*. Cham: Springer International Publishing (Springer Optimization and Its Applications), pp. 79–96. doi:10.1007/978-3-319-58821-6_5.
- Huang, G. et al. (2019) 'Cyber-Constrained Optimal Power Flow Model for Smart Grid Resilience Enhancement', *IEEE Transactions on Smart Grid*, 10(5), pp. 5547–5555. doi:10.1109/TSG.2018.2885025.
- Lei, S. et al. (2019) 'Resilient Disaster Recovery Logistics of Distribution Systems: Co-Optimize Service Restoration With Repair Crew and Mobile Power Source Dispatch', *IEEE Transactions on Smart Grid*, 10(6), pp. 6187–6202. doi:10.1109/TSG.2019.2899353.
- Lin, Y. et al. (2019) 'A Combined Repair Crew Dispatch Problem for Resilient Electric and Natural Gas System Considering Reconfiguration and DG Islanding', *IEEE Transactions on Power Systems*, 34(4), pp. 2755–2767. doi:10.1109/TPWRS.2019.2895198.
- Liu, J., Qin, C. and Yu, Y. (2020) 'Enhancing Distribution System Resilience With Proactive Islanding and RCS-Based Fast Fault Isolation and Service Restoration', *IEEE Transactions on Smart Grid*, 11(3), pp. 2381–2395. doi:10.1109/TSG.2019.2953716.
- Miller, C.E., Tucker, A.W. and Zemlin, R.A. (1960) 'Integer Programming Formulation of Traveling Salesman Problems', *Journal of the ACM*, 7(2), pp. 330–355.
- Panteli, M. et al. (2017) 'Metrics and Quantification of Operational and Infrastructure Resilience in Power Systems', *IEEE Transactions on Power Systems*, 32(6), pp. 4732–4742. doi:10.1109/TPWRS.2017.2664141.
- Xin, S. et al. (2017) 'Information-Energy Flow Computation and Cyber-Physical Sensitivity Analysis for Power Systems', *IEEE Journal on Emerging and Selected Topics in Circuits and Systems*, 7(2), pp. 150–161.
- Ye, Z., Chen, C. and Wu, K. (2021) 'Boost Distribution System Restoration with Emergency Communication Vehicles Considering Cyber-Physical Interdependence', p. 8.
- Zhu, K., Chenine, M. and Nordstrom, L. (2011) 'ICT Architecture Impact on Wide Area Monitoring and Control Systems' Reliability', *IEEE Transactions on Power Delivery*, 26(4), pp. 2801–2808. doi:10.1109/TPWRD.2011.2160879.

Paper [3]

Youba Nait Belaid, Yiping Fang, Zhiguo Zeng, Patrick Coudray, Anne Barros. “Optimal Allocation of Resilience Resources for Strategic Communication-aware Restoration of Smart Distribution Grids”. Under review at: IEEE Journal of Modern Power Systems and Clean Energy

Optimal Allocation of Resilience Resources for Strategic Communication-aware Restoration of Smart Distribution Grids

Youba Nait Belaid^{*†}, Yiping Fang^{*}, Zhiguo Zeng^{*}, Patrick Coudray[‡], Anne Barros^{*}

^{*} University Paris Saclay - CentraleSupélec, Paris, France [‡] Electricité de France (EDF) R&D, Paris, France

Abstract—Albeit power grids evolve to be smarter, major extreme events still pose reliability and resilience challenges, mainly at the distribution level due to increased vulnerabilities and limited recovery resources. Information and communication technologies (ICTs) introduce a new set of vulnerabilities, widely examined in the literature, like remote device failures, communication channel disturbances, and cyber attacks. However, very few studies explored the opportunity offered by communications to improve the resilience of power systems and move away from viewing power-telecom interdependencies as a threat only. This paper proposes a communication-aware distribution system restoration (DSR) methodology, which leverages power-telecom interdependencies to find optimal restoration strategies. The state of the grid-energized telecom points is tracked to inform the best restoration actions, which are enabled via resilience resources of repair, manual switching (MS), remote reconfiguration, and distributed generators (DGs). As the telecommunication network coordinates the allocation of those resilience resources due to their coupling, different telecom architectures are introduced to investigate the contribution of private and public ICTs to grid management and restoration operations. The system restoration takes as input the configuration after the remote fast-response to formulate the problem as a mixed integer linear program (MILP). Results from numerical simulations highlight the enhancement in the DSR process brought by telecom-aware recovery and co-optimization of resilience resources, while quantifying the existent disparity between overhead and underground power line configurations.

Index Terms—Smart Grid, Distribution System Restoration, Cyber-Physical Systems, Resilience, Co-optimization, MILP

NOMENCLATURE

Indices and Sets

c, e	Index of communication, electric service, resp.
N	Set of all power nodes (HV/MV SS, MV buses)
S	Set of HV/MV Substations (SS)
X, W	Set of fiXed, Wireless access points, resp.
U	Set of utility-owned access points
$n(j)$	Set of neighbor nodes of node j
$n_m(l)$	Set of neighbor manual lines of line l
L, L^u	Set of all lines and underground lines, resp.
L^m, L^r	Set of manual, remote switchable lines, resp.
L^{ar}, L^{cb}	Set of auto-reclosing, circuit-breaking lines, resp.
F	Set of failed power lines
F^o, F^u	Set of failed overhead, underground lines, resp.
DP	Set of depots
RC, MC	Set of repair, manual switching crews, resp.
GC	Set of DG placement crews

Parameters

M	Large number
r_{ij}, x_{ij}	Resistance, Reactance of line (i, j)
Res_l	Demand of repair resources from faulted line l
Res^{dp}	Repair resources available at depot dp
RT_l, MT_l	Repair, manual switching time of damage l , resp.
GT_g	DG placement time at bus g
TT_{lm}	Travel time from l to m (depot, line, or bus)
s_i	Binary parameter. 1 if i is a SS, 0 otherwise

Variables

$sw_{l,t}$	1 if switch at $l = (i, j)$ is closed at t , else 0
$sw_{ij,t}$	1 if directed switch (i, j) is closed at t , else 0
$p_{ij,t}, q_{ij,t}$	Active, reactive power flow of line (i, j) at t , resp.
$p_{i,t}^{ns}, q_{i,t}^{ns}$	Loss of active, reactive load at node i at t , resp.
$p_{i,t}^{dg}, q_{i,t}^{dg}$	Active, reactive DG power at node i at t , resp.
$v_{i,t}$	Voltage magnitude at node i
$d_{ij,t}$	1 if power flows from i to j at t , 0 otherwise
$a_{ij,t}$	1 if line $l = (i, j)$ is available at t , 0 otherwise
$a_{i,t}^e$	1 if bus i is available at t , 0 otherwise
$y_{i,t}^e$	1 if bus i is energized at t , 0 otherwise
$y_{i,t}^{dg}$	1 if a DG is connected at bus i at t , 0 otherwise
$a_{i,t}^{dg}$	1 if a DG is available at bus i at t , 0 otherwise
$u_{i,t}^c$	1 if telecom service (TS) from utility-owned access point i is available at t , 0 otherwise
$ss_{i,t}^c$	1 if TS of a SS i is available at t , 0 otherwise
$T_{i,t}^c$	1 if TS from the operator access point i is available at t , 0 otherwise
$T_{i,t}^e$	1 if electricity supply for the operator access point i is available at t , 0 otherwise
$E_{i,t}$	Energy storage of the battery at node i at t
$b_{i,t}$	1 if AP battery i is not empty at t , 0 otherwise
$rc_{l,t}^{dp,k}$	1 if line l is under repair by crew k of depot dp at time t , 0 otherwise
$mc_{l,t}^{dp,k}$	1 if line l is under manual switching by crew k of depot dp at time t , 0 otherwise
$gc_{n,t}^{dp,k}$	1 if bus n is under DG-placement by crew k of depot dp at time t , 0 otherwise

I. INTRODUCTION

SMART grids abide by high standards of quality-of-supply and service continuity despite being challenged by extreme events such as natural hazards, cyber-physical

attacks, and human errors. Consequently, all involved stakeholders strive for increased grid reliability and resilience [1]. Resilience commonly encompasses proactive planning, robustness, damage assessment, and restoration [2, 3]. For resilience improvement, operational measures at the restoration stage are identified as a high opportunity compared to the expensive hardening measures [4, 1]. Smart grids restoration aims to get the system back to an acceptable level of performance as fast as possible, with minimized adverse impacts on society. Methods to achieve this objective evolved from rule-based expert systems to heuristics like genetic algorithms and fuzzy logic, then mathematical optimization and AI-based methods [3, 5]. Resilience-based optimization is introduced in many recent literature for grid restoration. The transmission network has drawn many efforts in this area given its high criticality by acting as the backbone of the electric system [6, 7]. Yet, increasing grid applications (renewables, electrical vehicles, smart-meters, etc.), pervasive ICTs, and inherent vulnerabilities in the smart distribution grid (SDG) prompted deep analysis of restoration optimization at this level [8]. Thereby, even if the insights from the present work apply well to transmission grids and other industrial cyber-physical systems, the model focuses on distribution grids as advanced operational aspects of radiality, switching, and power balancing are discussed.

For distribution grid restoration, literature-proposed approaches range from *single-resource optimization in the power grid* to *multi-resource co-optimization in interdependent systems*. Investigated resources include mainly reconfiguration switches, intervention crews, and mobile power storage. Authors in [4] focused on the fast response of the grid using remote-controlled switches (RCSs). A unified two-stage optimization model was constructed starting from proactive RCS allocation, followed by remote reconfiguration. A two-stage remote and manual switching is considered in [9], where an initial MILP formulation describes feeder reconfigurations with DG-assisted grid-forming, before seeking with a similar optimization method the optimal sequence of switching operations. For multi-resource DSR optimization, Ref. [10] models the routing and scheduling of crews to disrupted components by two MILPs that correspond to the cases of full-repair requirement before reconnection and possible partial operation, respectively. Some works discussed dynamic programming [11], markov decision processes [12], and reinforcement learning [13] as promising methods to overtake computation and scalability concerns related to models of large-scale real world systems. However, mixed integer programming (MIP) methods are this far dominant in co-optimization of multiple resilience resources for faster crew interventions with microgrid formation capabilities. The work in [14] coordinates resilience strategies of repair crew dispatch, DG placement, and reconfiguration. A MILP is formulated based on power flow, routing, and scheduling constraints to optimize the served load and the restoration time. With similar objectives and resources, but using vertex-wise routing instead of the edge-wise approach, [15] constructed a MIP to optimally recover the distribution system in minimum time. The problem was convexified

and linearized equivalently, then reduced by pre-assigning damages and DG candidates to depots. The co-optimization approach is extended by the authors in [16] to encompass damage assessment for comprehensive system restoration analysis. The designed framework brings forward crew schedules and reconfiguration to the damage assessment stage, resulting in a dynamic update of restoration schedules as failures are revealed. All these recent contributions to DSR analysis are comprehensive and already address many aspects related to restoration modeling for single-resource and multi-resources problems with various constraints, as well as scalability issues. However, none of them consider the omni-present power-telecom interdependencies.

The DSR invoke many power-telecom interdependent functions from outage management and wide-area monitoring, protection and control systems, e.g. volt/VAR control, fault location, isolation, and service restoration (FLISR), and intervention workforce management [17, 18, 4]. According to [19], this power-telecom coupling can be seized by extending the optimal power flow model to include information flow. The resulting integrated model is non-convex and highly non-linear due to prevailing event-driven communications. Alike complexity is observed in [20] that developed a cyber-constrained power flow model to evaluate and enhance the power system resilience, then used a bi-level linear programming exact reformulation to solve the problem. An attempt was conducted in [21] to investigate the status of the telecommunication service (TS) by coordinating repair and reconfiguration alongside the deployment of emergency communications. However, this work considers power supply effect on feeder terminal units (FTUs) only till the batteries are depleted, and does not look into prioritizing the recovery of nodes from which FTUs are initially supplied. An emergency deployment is conducted, looping back to only considering telecom impacts on the grid, missing the impact of the grid on communications. Authors in [22] present a fine-grained description of the power-telecom interdependence with a discrete-event evaluation methodology. However, back-up power supplies such as batteries in communication devices are not modeled, making the study of the impact on the restoration process incomplete.

Hence, reviewed state-of-the-art works consider no- or one-way power dependence on the telecom service. This reduces the telecom network to its cyber layer, whereas practical evidence strongly demonstrates the importance of telecoms' physical layer that can be affected either by a physical damage or a shortage in power supply [23]. In addition, no previous DSR contribution considered underground lines, which differ from overhead lines in terms of failure isolation [24]. To bridge these gaps, the present work considers both cyber and physical layers of the telecom network, allowing to capture two-way power-telecom interdependencies: the power distribution system depends on telecoms to control switches and communicate with intervention crews, while telecom assets depend on the power supply from the grid or back-up batteries to operate. A telecom-aware co-optimization is proposed to solve the DSR problem, with novel contributions outlined as follows:

- The model captures the two-way power-telecom interdependencies, as well as the coupling among restoration resources and within public-private telecoms;
- A DSR co-optimization is formulated to seek optimal restoration strategies by leveraging information on the availability of telecom assets and their power supply;
- Various grid architectures are accounted for by the two broad families of overhead and underground lines, demonstrating minimal model changes for configuration evolution;
- A simplified formulation is used for radiality conditions, and a realistic multi-feeder network is constructed to validate the proposed approach.

Section II introduces the system model and the proposed restoration approach; Section III presents simulations and numerical results; and the conclusion is drawn in Section IV.

II. SYSTEM MODEL

Distribution grids are meshed by design but operated radially to limit the propagation of faults by opening some switches in normal operation (called tie-switches). The term *failure* is used here interchangeably with fault, damage, outage, and incident to indicate an unavailability status of a component due to an exogenous event. Fig. 1 summarizes interactions among intra- and inter-domain components, with four main actions: power supply, telecom service, repair/isolation and DG placement (each arrow originates from an entity providing the action/service and ends at a targeted entity). After the outbreak of an extreme event, the fast response reconfigures the network by maneuvering RCSs, relying on prior knowledge about the structure and operation of the grid, as well as monitoring information. The whole process is conducted within few minutes of the surge and usually allows for a partial restoration. Topological, power flow, and zone isolation conditions are verified before any reconfiguration in the network. Interested readers can refer to [4, 9] for more details about the fast remote reconfiguration.

Following the initial response, the SDG attains a limited recovery that needs to be carried on by means of multiple resources: remote/manual switching, repair/MS crews, and DGs. A MILP formulation is proposed to co-optimize restoration resources, where the optimal combination of resilience resources is sought subject to topological, operational, and interdependence constraints. The co-optimization is motivated by tight coupling of considered resources. For instance, an intervention crew finishing a repair at a given line, would need to inform the control center that may execute some reconfiguration using switches, before commanding the crew to reconnect the repaired segment. Likewise, formed microgrids using DGs combine the tasks achieved by specialized intervention crews and reconfiguration in the network by manual and remote switches. There is also a complementarity between repairing and placing DGs, because zones that receive DGs are most likely to afford delayed repair, which allows prioritizing other zones, and vice versa. The inter-resource coupling is even more appealing when ICTs are acknowledged as the vector of coordination. Unlike

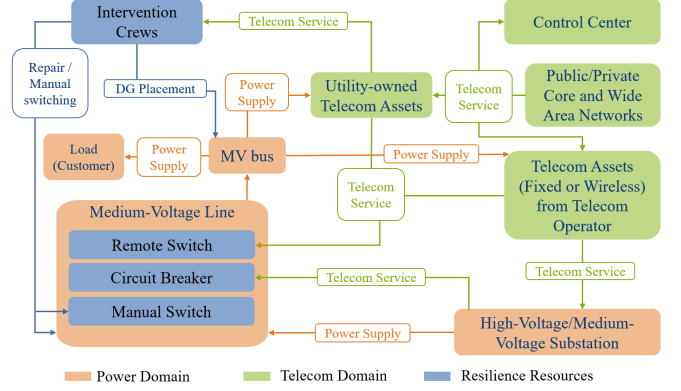


Fig. 1. Summarized interactions in the proposed model

the fast response, where telecom points are only affected by direct failures, power shortages affect important telecom points after depletion of their batteries. Therefrom, the DSR stage deals with the two-way power-telecom dependence, where ICTs are dependent on the grid for power supply, and the grid dependent on ICTs for both controlling field assets and coordinating restoration strategies. Information provided to the DSR stage ($t = 0$) includes remote reconfiguration from the first response and outage diagnoses. This is organized as a record of identified damages, an estimation of travel/repair time, and an indication of damaged sites' accessibility.

A. Zone Separation Constraints

Three zones can be distinguished during an event: i) *Damaged zone*: part of the grid containing the initial failure and subsequent damages due to failure propagation; ii) *Out-of-Service safe zone*: part of the network, at first included in the damaged zone, but could be isolated from the damage using switches. Elements in this zone wait for re-connection to the grid; iii) *Supplied safe zone*: parts that are safe from damages and energized. In overhead lines, only one switch is present at each line between two nodes (buses), then the tightest isolation could be made by opening switches of neighboring lines. However, in underground lines, a switch is often positioned at each side of a node, allowing for a better isolation by opening both sides for a damaged line.

$$a_{i,t}^e + sw_{l,t} - 1 \leq a_{j,t}^e, \forall l = (i, j) \in L, \forall t \quad (1)$$

$$a_{i,t}^e \leq a_{i,t-1}^e + a_{l,t}, \forall l = (i, j) \in F^o, \forall t \quad (2)$$

$$a_{i,t}^e \leq a_{i,t-1}^e + a_{ij,t} + (1 - sw_{ij,t}), \forall (i, j) \in F^u, \forall t \quad (3)$$

$$sw_{l,t} \leq sw_{ij,t}, \forall l = (i, j) \in L^u, \forall t \quad (4)$$

$$sw_{l,t} \leq sw_{ji,t}, \forall l = (i, j) \in L^u, \forall t \quad (5)$$

$$sw_{ij,t} + sw_{ji,t} - 1 \leq sw_{l,t}, \forall l = (i, j) \in L^u, \forall t \quad (6)$$

Constraint (1) ensures that damaged zones are not connected to safe (supplied or out-of-service) zones. This is guaranteed by requiring open lines between safe and damaged zones. Connection between supplied and out-of-service zones is possible. From (2)–(3), a power bus can be restored if no neighboring overhead or underground line is damaged ($a_{ij,t} = 0$), or isolated from neighboring underground line. The variable $sw_{ij,t}$ is directed, because it represents the switch

closest to node i and $sw_{ji,t}$ is the switch closest to node j in underground networks, while the undirected variable $sw_{l,t}$ is used when direction is not needed. Constraints (4)–(6) state that an underground line is closed only when both switches are closed, and open otherwise. Other than constraints (3)–(6), the undirected variable $sw_{l,t}$ is used throughout the model to represent the state of line $l = (i, j)$.

B. Radiality Constraints

A novel formulation is adopted to guarantee the radiality of the power grid

$$d_{ij,t} + d_{ji,t} \leq sw_{l,t}, \forall l = (i, j) \in L, \forall t \quad (7)$$

$$sw_{l,t} - (2 - y_{i,t}^e - y_{j,t}^e) \leq d_{ij,t} + d_{ji,t}, \forall l = (i, j) \in L, \forall t \quad (8)$$

$$d_{ij,t} + d_{ji,t} - (2 - y_{i,t}^e - y_{j,t}^e) \leq sw_{l,t}, \forall l = (i, j) \in L, \forall t \quad (9)$$

$$\sum_{\forall j \in n(i)} d_{ji,t} \leq a_{i,t}^e - s_i - y_{i,t}^{dg}, \forall i \in N, \forall t \quad (10)$$

$$\sum_{\forall j \in n(i)} d_{ij,t} \leq M \cdot \left(\sum_{\forall j \in n(i)} d_{ji,t} + s_i + y_{i,t}^{dg} \right), \forall i \in N, \forall t \quad (11)$$

Constraint (7) imposes unidirectional power flow, while capturing the existence of *unsupplied* closed lines in damaged zones. This fact is missed in all reviewed works as an equality sign in (7) would force energizing (de-energizing) a line to be equivalent to closing (opening) it. Then, (8) and (9) state that for all t , a line out of damaged zones is safely energized as soon as closed. Note that the damage in a line is represented by failing the direct connecting nodes, meaning that both *failed-open* and *failed-closed* events can be considered. Constraint (10) prohibits power flow into HV/MV substations or nodes with a DG source, while indicating that any other bus has at most one parent node. If this parent node is not supplying power to the considered node i , or i is neither a substation nor a DG, no downstream flow is possible from i as encoded in (11). The placement of DGs to form islanded zones (or microgrids) is anticipated by (10), and the resulting topology is a spanning forest similar to the case of multi-substation power system. This construction admits the formation of out-of-service islands.

C. Power Flow Constraints

The LinDistFlow model is used to represent the flow of power to all loads in the system.

$$\sum_{\forall j \in n(i)} p_{ij,t} + p_i^d = \sum_{\forall j \in n(i)} p_{ji,t} + p_{i,t}^{ns} + p_i^{dg}, \forall i \in N \setminus S, \forall t \quad (12)$$

$$\sum_{\forall j \in n(i)} q_{ij,t} + q_i^d = \sum_{\forall j \in n(i)} q_{ji,t} + q_{i,t}^{ns} + q_i^{dg}, \forall i \in N \setminus S, \forall t \quad (13)$$

$$\begin{aligned} -M \cdot (1 - d_{ij,t}) &\leq v_{i,t} - v_{j,t} - 2 \cdot (r_{ij} \cdot p_{ij,t} + x_{ij} \cdot q_{ij,t}) \\ &\leq M \cdot (1 - d_{ij,t}), \forall (i, j) \in L, \forall t \end{aligned} \quad (14)$$

$$0 \leq p_{ij,t} \leq S^{max} \cdot d_{ij,t}, \forall (i, j) \in L, \forall t \quad (15)$$

$$0 \leq q_{ij,t} \leq S^{max} \cdot d_{ij,t}, \forall (i, j) \in L, \forall t \quad (16)$$

$$v_i^{min} \leq v_{i,t} \leq v_i^{max}, \forall i \in N, \forall t \quad (17)$$

$$(1 - y_{i,t}^e) \cdot p_i^d \leq p_{i,t}^{ns} \leq p_i^d, \forall i \in N, \forall t \quad (18)$$

$$(1 - y_{i,t}^e) \cdot q_i^d \leq q_{i,t}^{ns} \leq q_i^d, \forall i \in N, \forall t \quad (19)$$

$$0 \leq p_{i,t}^{dg} \leq P^{dg,max} \cdot y_{i,t}^{dg}, \forall i \in D, \forall t \quad (20)$$

$$0 \leq q_{i,t}^{dg} \leq Q^{dg,max} \cdot y_{i,t}^{dg}, \forall i \in D, \forall t \quad (21)$$

Constraints (12)–(13) express the power balance at each bus. The difference in node voltages is given in (14) in terms of power and impedance quantities. Equations (15)–(16) limit the power capacity of closed lines, while (17) bounds the bus voltage. The non-supplied power is restrained by (18)–(19).

D. Telecom Constraints

The grid operators use public and/or private communications for DSR and other grid applications [25, 26, 27]. Public ICTs range from wired (fiber-optic, copper: PSTN, xDSL) to licensed (GSM, CDMA, LTE, 5G, etc.) and unlicensed (WiFi, LoRa, SigFox, etc.) wireless technologies [28]. DSOs subcontract telecom operators to provide and manage the access and core infrastructure that allows the connection of substations, field devices, and crews to the control center and other central functions (DSO datacenters, procurement centers, billing system, etc.). This has the advantages of reduced operational costs, wide coverage, and specialized support from experienced telecom teams. The alternative is to deploy a private network, managed by the DSO itself, to cope with privacy and congestion issues in public ICTs. Unfortunately, this imposes limitations like narrow bandwidth (i.e., reduced data rate), high OPEX, niche technology, and very restricted ecosystem. Such technologies encompass power line communications (PLC) for which the DSO already has the basic infrastructure, and private mobile radiocommunications (PMR), operated in a dedicated frequency band. A hybrid setting can offer a good compromise between the pros and cons of public and private communications, with great flexibility in selecting the technology that meets the requirements of a given grid application [25]. The constraints below show an example of a hybrid architecture that can be captured by the proposed DSR model combining utility-owned ICT infrastructure and telecom operator services. The hierarchical setup of telecom networks is illustrated by the wide area network (WAN) and core network that provide services to public and private access points (APs), which in turn serve grid assets. Therefore, in addition to connecting RCSs, crews, and substations, other communication components are modeled:

- Private or Utility-owned APs (U-APs): An important DSO asset equipped with large batteries. Each U-AP has a primary fixed (wired) and a secondary wireless link in case of a hybrid configuration. U-APs can provide RCSs and intervention crews with requested TS.
- Telecom operator fixed APs (F-APs): Serve the DSO assets (HV/MV SS and RCSs) in a public configuration, and can be a primary link for U-APs in a hybrid configuration. The battery can last some hours.
- Telecom operator wireless APs (W-APs): Serve the DSO assets (HV/MV SS and RCSs) in a public configuration,

and can be a secondary link for U-APs in a hybrid configuration. The battery can last some hours.

The upper layer that serves APs is called the *core network*, which collects, processes, and transmits data through technology-dependent aggregation points, location registers, gateways, etc. Some requests can be routed directly at the core level, while others resort to the grid's central functions, such as the control center in the case of the DSR. The core network connects to the WAN of the utility, which is a collection of routers, switches (communication switches), and various networking equipment granting access to grid functions and applications. The criticality associated with WANs pushed most power operators to deploy their own networks that may or may not be handed to a tier telecom operator for management [26]. The core network and WAN are admitted as perfectly operating in the present work to concentrate on the impact of the more vulnerable APs [29].

$$\frac{1}{M} \cdot \left(T_{k,t}^c + \sum_{\forall j:(j,i) \in W \times S} T_{j,t}^c \right) \leq ss_{i,t}^c \quad (22)$$

$$\leq T_{k,t}^c + \sum_{\forall j:(j,i) \in W \times S} T_{j,t}^c, \forall (k,i) \in X \times S, \forall t$$

$$\frac{1}{M} \cdot \left(T_{k,t}^c + \sum_{\forall j:(j,i) \in W} T_{j,t}^c \right) \leq u_{i,t}^c \quad (23)$$

$$\leq T_{k,t}^c + \sum_{\forall j:(j,i) \in W \times U} T_{j,t}^c, \forall (k,i) \in X \times U, \forall t$$

$$T_{i,t}^c \leq T_{i,t}^e, \forall i \in W \cup X, \forall t \quad (24)$$

$$\frac{1}{M} \cdot (1 - f_i) \cdot (E_{i,t} + y_{i,t}^e) \leq T_{i,t}^e \quad (25)$$

$$\leq M \cdot (1 - f_i) \cdot (E_{i,t} + y_{i,t}^e), \forall i \in W \cup X, \forall t$$

$$\frac{1}{M} \cdot E_{i,t} \leq b_{i,t} \leq E_{i,t}, \forall i \in W \cup X, \forall t \quad (26)$$

$$E_i^{min} \leq E_{i,t} \leq E_i^{max}, \forall i \in W \cup X, \forall t \quad (27)$$

$$E_{i,t} = E_{i,t-1} - p_i^{disc} \cdot (1 - y_{i,t-1}^e) \cdot b_{i,t-1}, \forall i \in W \cup X, \forall t \quad (28)$$

The notation using the cross sign between different sets is used to represent indexed sets, where only meaningful elements are evaluated. In other words, $W \times S$ does not contain all possible two-dimensional (j, i) combinations formed by elements of the two sets, but includes only the valid pairs formed by a substation $i \in S$ connecting to a W-AP $j \in W$. In (22), the summation over all W-APs associated to substation i shows the redundancy that can be offered by W-APs, obviously not found in fixed networks (dedicated wired link). The available TS to a HV/MV SS relies on the availability of either a F-AP or a secondary W-AP. Although quite common, this is a generic choice of connecting substations, and (22) is easily adaptable to other technologies. A hybrid public/private telecom architecture, where private assets are eventually sending and receiving data through public networks is stated in (23). Constraints (24) and (25) emphasize that the TS is at disposal only when power supply is guaranteed by the grid or back-up batteries. In that case, HV/MV SS and U-AP will not necessarily fail, but will operate in a blind mode. The binary variable $b_{i,t}$ is linked in (26) to the state-of-charge

(SoC) $E_{i,t}$ to indicate whether the battery of an AP i is empty ($b_{i,t} = 0$). Equation (27) bounds the SoC of the battery by min and max capacities. The discharge power is p_i^{disc} in (28) containing a quadratic component $y_{i,t}^e \cdot b_{i,t}$, which is easily linearized and replaced with a binary variable $w_{i,t}^1$.

E. Routing and Scheduling Constraints

Damage assessment is conducted by diagnosis crews, helicopter-transported teams, and airborne drones [8] to collect data and pinpoint damage locations, helping to estimate important parameters, e.g. repair time, travel time, and required resources. The DSO exploits gathered information to organize operations by allocating resources and providing a timeline and traveling paths. This is described by the well-known routing and scheduling problem [30]. For the DSR problem, depots and damaged lines are *nodes* connected with road paths seen as *edges*, and the aim is to find the sequence of locations for each crew to visit while minimizing the overall restoration time. The vehicle routing problem (VRP) is adopted in many recent works [16, 14] to model the dispatch of repair crews and/or DG placement. Since tasks (MS, repair, and DG placement) are conducted at damage sites and interdependencies of intervention crews with ICTs and switches arise at these same nodes, the edge-centred approach in VRP is less convenient for the DSR problem.

We adopt the node-centered approach proposed and demonstrated in [15] to bypass issues of transportation-grid coupling and their different timescales. Let c be a binary variable representing a crew k visiting node l at time t (a crew among repair (rc), manual switching (mc), and DG placement (gc) crews). Variable $c_{l,t}^k$ provides the same information in the present model as variables $c_{l,m}^k$, c_l^k , and AT_l^k used in [16, 14] to respectively represent crew k traveling the path (l, m) , crew k visiting node l , and the arrival time of k to damage l . Still, the number of variables is comparable between $c_{l,t}^k$ with $|C| \cdot |F^{dp}| \cdot |T|$ elements and the edge-centred approach necessitating $|C| \cdot |F^{dp}|^2 + |C| \cdot |F^{dp}|$ elements, where $|C|$ the number of crews, $|F^{dp}|$ the number of nodes (damaged lines + depots), and $|T|$ the number of DSR time steps. The square term indicates that the edge-centred approach grows fast with an increase in the handled failures, while the node-centred approach grows slower with the number of damages, and depends on the number of time steps that is usually limited from other parts of the global model. The form $c_{l,t}^k$ from [15] is extended here to $c_{l,t}^{dp,k}$ capturing the fact that each crew k is linked to a given depot dp , as well as integrating the widely used problem reduction techniques of pre-assigning damages and DG candidates to depots [14, 15].

$$\min(TT_{t,m}^c, T-t) \sum_{\tau=0} \left(c_{l,t+\tau}^{dp,k} + c_{m,t}^{dp,k} - 1 \right) \leq 0, \forall l \neq m, \quad (29)$$

$$\forall (dp, k, l, m) \in DP \times C \times F^{dp} \times F^{dp}, C = RC \cup MC, \forall t$$

$$\sum_{\tau=t}^T \sum_{\forall (dp,k) \in DP \times RC} mc_{l,\tau}^{dp,k} \leq M \cdot \left(1 - \sum_{\forall (dp,k) \in DP \times RC} rc_{l,t}^{dp,k} \right) \quad (30)$$

$$a_{l,t} \leq \frac{\sum_{\tau=0}^t h(\tau)^*}{RT_l + 2 \cdot \sum_{\forall m \in n_m(l)} MT_m}, \forall l \in F, \forall t \quad (31)$$

$$\sum_{l \in F} a_{l,T} \cdot \text{Res}_l \leq \text{Res}^{dp}, \forall (dp, l) \in DP \times F \quad (32)$$

$$h(t) + a_{l,t} \leq 1, \forall l \in F, \forall t \quad (33)$$

According to (29), a crew is at a maximum of one node (damaged line or depot) at any given t , and it would take at least the traveling time TT_{lm}^{rc} for a repair crew and TT_{lm}^{mc} for a MS crew to get from l to m . From (30), no isolation crew can visit an incident $l \in F$ at any t after having been visited by a repair crew. Constraint (31) shows that a line is repaired when repair and MS crews have spent sufficient time at the node, starting by MT_l to manually isolate the damage site, then RT_l for the repair, before taking MT_l to reconnect the restored line. Repair crews are able to perform the MS. A depot can handle a limited number of damages (32). In (33), the damaged line is in one of the following states at any time step: not visited yet, under isolation, under repair, or resolved.

$$\min(TT_{m,0}^{gc} + TT_{n,0}^{gc}, T-t) \sum_{\tau=0}^t (gc_{m,t+\tau}^{dp,k} + gc_{n,t}^{dp,k} - 1) \leq 0, \forall n \neq m, \quad (34)$$

$$\forall (dp, k, m, n) \in DP \times GC \times CD^{dp} \times CD^{dp}, \forall t$$

$$\sum_{\tau=0}^t \sum_{\forall n \in CD} gc_{n,t}^{dp,k} \leq \sum_{\tau=0}^t gc_{0,t}^{dp,k}, \forall (dp, k, n) \in DP \times GC \times CD \quad (35)$$

$$a_{n,t}^{dg} \leq \frac{\sum_{\tau=0}^t \left(\sum_{\forall (dp,k) \in DP \times GC} gc_{n,\tau}^{dp,k} \right)}{GT_n}, \forall n \in CD, \forall t \quad (36)$$

$$\sum_{\forall (dp,k) \in DP \times GC} gc_{n,t}^{dp,k} + a_{n,t}^{dg} \leq 1, \forall n \in CD, \forall t \quad (37)$$

Unlike the routing of repair and MS crews, DG placement crews need to get back to the depot after each task completion. This comes from the assumption that considered DGs are truck-mounted, which are bulky and require a whole team for transport and installation. In (34), a crew is at a maximum of one node (DG candidate or depot) at any given time t . At least a traveling time $TT_{n,0}^{gc}$ is required between a node n and its depot (0 is used to indicate that a crew is coming from/heading to its depot). (35) enforces that no direct paths between DG candidates are allowed. A DG is placed after a crew spends at least a placement time GT_n at a site n as indicated by (36). From (37), a candidate node is either not visited yet, undergoing a DG placement, or has the DG installed.

F. Interdependence Constraints

The first power-telecom dependence is unraveled in (24) as the power system energizes APs, making the TS only available when the physical equipment is up and running. Executing received commands by grid assets depicts another

power-telecom dependence, where the flow of power is regulated by applied controls.

$$a_{l,t} \leq u_{k,t}, \forall (k, l) \in U \times L, \forall t \quad (38)$$

$$sw_{l,t-1} - u_{k,t}^c (2 - a_{i,t}^e - a_{j,t}^e) \leq sw_{l,t} \leq sw_{l,t-1} + u_{k,t}^c \cdot a_{i,t}^e, \quad (39)$$

$$\forall l = (i, j) \in L^r \cup L^{ar}, (k, (i, j)) \in U \times L, \forall t$$

$$sw_{l,t-1} \leq sw_{l,t} \leq sw_{l,t-1} + ss_{k,t}^c \cdot a_{i,t}^e, \quad (40)$$

$$\forall l = (i, j) \in L^{cb}, (k, (i, j)) \in S \times L, \forall t$$

Before switching, a line needs to be available for connection, which is conditioned in (38) by the status of the communication AP. Constraint (39) implies the dependence of RCSs and ACRs on the TS from U-APs, and from (40) a CB is operated only when the TS from a substation is available. The non-linear square terms in (39)–(40) are easily linearized.

$$sw_{m,t-1} - \varepsilon - z^\dagger \leq sw_{m,t} \leq a_{l,t} + 2 - \varepsilon - z, \forall l \in F, \forall t \quad (41)$$

Interdependencies manifest also between resilience resources. Constraints (31) and (36) already expressed that a line and DG are not operable unless the missioned crews have finished their tasks. Also, closest manual lines are first opened for best isolation, then need to be closed after task completion (41). The dependence of U-APs on public ICTs is represented in (23), which can be built upon to model other dependencies based on chosen hybrid architectures.

G. Objective Function

During an extreme event, recovering power as fast as possible to the maximum number of clients is the utmost target of a utility. In this work, supplied power (or conversely non-supplied power) is adopted as a performance measure, and used in the objective function of the formulated MILP problem alongside costs related to deployed resilience resources.

$$\min_{p,d,sw,c,a,y,T,E,w} \left[\alpha \sum_{\forall t} \sum_{\forall i \in N \setminus S} C_i^{ns} \cdot p_{i,t}^{ns} + \beta \sum_{\forall t} \sum_{\forall l \in L} C^{sw} \cdot w_{l,t} + \gamma \left(\sum_{\forall (dp,k,l,t)} C_i^{rc} \cdot rc_{l,t}^{dp,k} + \sum_{\forall (dp,k,l,t)} C_i^{mc} \cdot mc_{l,t}^{dp,k} + \sum_{\forall (dp,k,n,t)} C_i^{gc} \cdot gc_{n,t}^{dp,k} \right) \right] \quad (42)$$

$$s.t. \quad (1) - (41), \quad (43) - (44)$$

Equation (42) poses the objective function with vectors of variables: c all intervention crews, a the availability of power buses, lines, or DGs, y the connectivity of buses to the grid or DGs, T the vector of electric and telecom status of public and private APs, E the SoC and $b_{i,t}$ the depletion status of batteries. C_i^{ns} , C_i^{sw} , C_i^{rc} , C_i^{mc} , and C_i^{gc} refer to non-supplied load, switching, repair, MS, and DG placement costs, respectively. DSOs do not spare efforts for restoration due to the pressure from governments, regulation bodies, and the public opinion, as well as the operator commitment.

$$^*h(t) = \sum_{\forall (dp,k) \in DP \times RC} rc_{l,t}^{dp,k} + \sum_{\forall (dp,k) \in DP \times MC} mc_{l,t}^{dp,k}$$

$$^\dagger z = (1 + \sum_{\tau=1}^{t-1} h(\tau)) / (1 + \sum_{\forall m \in n_M(l)} MT_m)$$

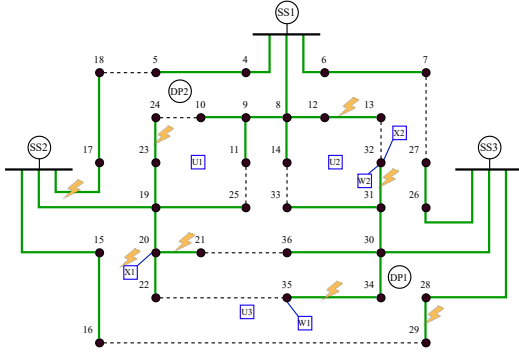


Fig. 2. Multi-feeder test network with serving telecom points

Thus, $\alpha \gg \beta$ and $\alpha \gg \gamma$, meaning that costs are only significant in cases of equivalently performing restoration strategies. The switching cost is introduced, as no change on the configuration is desired unless there is a gain in restored power or damage isolation. C^{sw} is considered the same for all operated switches, and variable $w_{ij,t}$ results from the linearization of $|sw_{l,t} - sw_{l,t-1}|$.

$$sw_{l,t} - sw_{l,t-1} \leq w_{l,t}, \forall l \in L, \forall t \quad (43)$$

$$sw_{l,t-1} - sw_{l,t} \leq w_{l,t}, \forall l \in L, \forall t \quad (44)$$

From (43) and (44), $|sw_{l,t} - sw_{l,t-1}|$ equals 1 if the switch at line l is toggled (opened or closed) at t , and 0 otherwise.

III. SIMULATIONS AND RESULTS

Multi-feeder systems are constructed to validate the proposed approach. Per-phase analysis is run in 20kV balanced grids. We set: $\alpha = 10, \beta = 0.1, \gamma = 0.1, C_i^{ns} = 0.5, C_i^e = 1, C_i^{sw} = 0.1, C_i^{rc} = 3, C_i^{mc} = 1, C_i^{gc} = 1.5$. The model is implemented in Pyomo and solved using CPLEX on a computer with Intel Core i7 (2.5 GHz) and 32 GB RAM.

A. Distribution System Restoration in 36-bus system

Fig. 2 shows a 36-bus system with a total 1305 kW demand. Supplied buses by each feeder have a supply path from the associated substation (through green lines) and tie-switches (dashed dark lines) make the interconnections between feeders. This is the nominal configuration, from the grid planning stage, which is out of the scope of this work. We consider two configurations: full-overhead (all lines are overhead) and hybrid overhead-underground (some lines are underground). Nodes SS1, SS2, and SS3 represent the HV/MV substations, while the remaining nodes are MV buses energizing power loads, F-APs (X1 and X2), and W-APs (W1 and W2). A scenario of 8 damages is considered, with 7 affected power lines and 1 telecom AP (X1 damaged for the whole period).

After events occurrence, the total supplied power drops from a 100% at the initial phase to 29.5% after degradation, before an increase owing to RCS-based reconfiguration. As expected, hybrid overhead-underground grids perform better than full-overhead grid with 48.66% against 42.91% of supplied power, respectively. Still, both cases are away from an

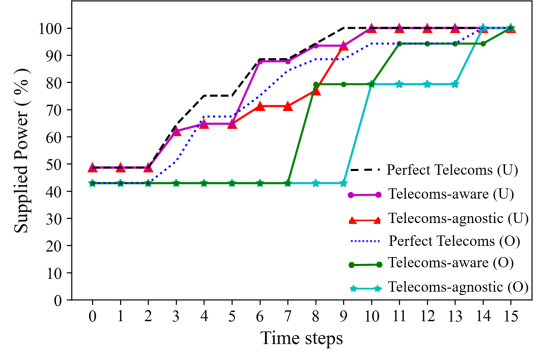


Fig. 3. Evolution of supplied power during the DSR stage

acceptable level of restoration due to the limited improvement brought by remote switches. Hence, distribution operators append other resources in next restoration steps.

The resulting grid configuration is taken as an initial state ($t = 0$) of the restoration process for which a time step of 1h is used. Damages 2 – 17, 20 – 21 and 23 – 24 are pre-assigned to depot 1 (DP1), whilst the remaining damages to depot 2 (DP2). Similarly, candidate buses for DG reception are set, for safety, to not be the directly connected buses to damaged lines, then, DP1: {36}; DP2: {14, 18, 22}. Repair crews (RC), MS crews (MC), and DG placement crews (GC) are initially located at depots. DP1 is set to have (RC,MC,GC)=(2,1,1), whereas DP2 has (RC,MC,GC)=(2,1,1). The travel time is proportional to the distance between a depot and a damage or between two damages, and MCs are twice faster as RCs and GCs. Repair, MS, and DG placement are chosen for all lines to last 2h, 1h, and 1h, respectively. All crews depart from depots. Without loss of generality, Utility-owned APs are assumed to possess large batteries, while possible supply shortage can be undergone by public communications despite the battery storage duration set here to 3h. The damage in the telecom AP should be handled by the telecom operator as the DSO repair strategy is limited to grid assets. RCSs and intervention crews connect to the closest U-AP, and CBs to their substations. U-APs and substations connect to the closest F-APs and W-APs.

A preliminary simulation is conducted to confirm the intuitive (and literature-well-verified) statement that co-optimization achieves better performance than non-cooperative approaches. Considering perfect communications (Case 1), we obtain gains of 12% and 9% in total supplied load using the proposed co-optimization, compared to a first case of separate optimization problems for reconfiguration and crew schedules [14], then a second case of co-optimization of reconfiguration and repair/MS crews (no DGs), respectively. Next, to quantify the criticality of TS in SDGs, a *telecom-agnostic* case is constructed (Case 2). This corresponds to the case where restoration decisions are made without special attention to the status of telecom points. To do so, the problem is solved first in case of *perfect* communications (Case 1), then the obtained solution of crew allocation (the sequence of dispatching crews) is used as a parameter to solve the formulated problem for

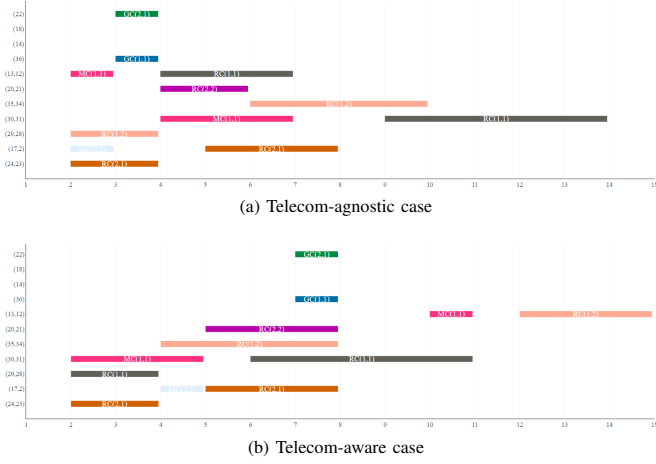


Fig. 4. Schedule of intervention crews for the overhead configuration

remaining variables of telecom and switch states as well as power quantities. Our approach that leverages the state of telecom points to find a restoration strategy is referred to as *telecom-aware* (Case 3).

The evolution of supplied power over restoration steps in the three cases is shown in Fig. 3 for both full-overhead (O) and hybrid overhead-underground (U) configurations. The co-optimization is solved within 1.25 seconds for Case 2, and 21 seconds for Case 3. Clearly, the hybrid configuration outperforms the purely overhead configuration in all three cases, due to advanced isolation capabilities in underground networks. This result should be taken carefully as the cost of MS and repair is assumed to be equal for underground and overhead networks in conducted simulations, which may not be valid given that underground interventions are complex and more time-consuming. Thus, a tight isolation surely helps to improve the level of restoration, but the cost of introducing enhanced isolation should be considered in the future. For the hybrid configuration, the ideal case of perfect communications achieves the best restoration compared to cases 2 and 3, but can be described as over-optimistic as the ICTs are not perfect and undergo many failures. Cases 2 and 3 are more realistic by including telecom failures, which are exploited in our proposed approach (Case 3) to orient restoration choices and attain a better recovery than Case 2, which does not link resource allocation to the state of telecom APs. A similar trend is observed in the overhead configuration as the curve associated with Case 1 dominates the telecom-aware and telecom-agnostic cases, while the importance of prioritizing supply restoration to some important telecom points (that will be useful for subsequent restoration) is demonstrated through Case 3, which outperforms Case 2.

Fig. 4 displays the schedules for all intervention crews in cases 2 and 3, exemplified in the overhead configuration. Unlike Case 2, interventions related to lines 30 – 31 and 34 – 35 are prioritized in Case 3, allowing earlier recovery of telecom points supplied by involved buses. For instance, although repair of lines 23 – 24 and 28 – 29 is finished at $t = 4$, their reconnection is delayed till $t = 8$ in 4b to be enabled by the recovered TS. MS crew MC1 of depot

TABLE I
TELECOM SERVICE AVAILABILITY FOR OVERHEAD CONFIGURATION

Telecom-agnostic				
	0 → 3	3 → 10	10 → 14	14 → 15
W1, U1, U3, SS2	TS	TS	TS down	TS up
X2, W2, U2, SS1, SS3	up	down	TS up	
Telecom-aware				
	0 → 3	3 → 5	5 → 8	8 → 15
W1, U1, U3, SS2	TS	TS	TS down	TS up
X2, W2, U2, SS1, SS3	up	down	TS up	

DP1 (MC(1,1)) isolated buses 32, 34, and 36 from damaged line 30 – 31 by opening 30 – 34, 30 – 36, and 31 – 32, allowing 34 and 36 to be restored at $t = 8$ after DG placement at 22 and 36, respectively. Hence, it is important to have fast-moving crews, which can better isolate damages prior to interventions from heavily equipped (and slow-moving) repair crews. The timelines show that repair crews operate manual switches after finishing their task as they are already on-site, in accordance with the control center instructions. The post-repair MS is depicted by retaining repair crews at the handled damage longer than the repair time, set here to 2 time steps. Further, knowledge about battery discharging of telecom APs is used in Case 3 to delay sending crews (GC(1,1), GC(2,1), RC(1,2), RC(2,2), RC(2,1), and MC(2,1)) to their respective tasks, because opportunities of reconfiguration are blocked by the absence of TS, and were carried out only following the restoration of a portion of the TS at $t = 8$. This intervention postponement can allow assigning another task to crews and avoid the cost of waiting at damaged sites until the TS recovery.

Table I summarizes the availability of the TS in both telecom-aware and agnostic cases for the full overhead configuration. The telecom-aware approach is able to restore supply to important telecom points faster, which accelerates later recovery operations.

B. Distribution System Restoration in 141-bus and 315-bus systems

Two case studies with 141 and 315 MV buses are constructed from a real MV grid to demonstrate the applicability of the proposed approach to larger networks (27 and 59 MW load power, respectively). A switch (remote or manual) is considered at each line, distinctive from most used bus systems where manual switches are ignored and very few remote switches are analyzed. A scenario of 10 failures is chosen, where 3 depots host restoration resources as follows: $DP_1 \rightarrow \{RC_{1,1}, RC_{1,2}, MC_{1,1}, GC_{1,1}\}$, $DP_2 \rightarrow \{RC_{2,1}, RC_{2,2}, MC_{2,1}\}$, $DP_3 \rightarrow \{RC_{3,1}, MC_{3,1}, GC_{3,1}\}$. For an overhead configuration, the DSR was solved in 225.3 and 267.4 seconds, respectively. Results from figures 5a and 5b confirm that the perfect telecom case achieves the best restoration in terms of cumulative supplied power. The telecom-aware approach succeeds in both usecases to outperform the telecom-agnostic case, following the same trend already observed in Fig. 3, where awareness about telecom points availability increases the restoration potential. The problem at hand is verified as *NP-Hard*, combining a

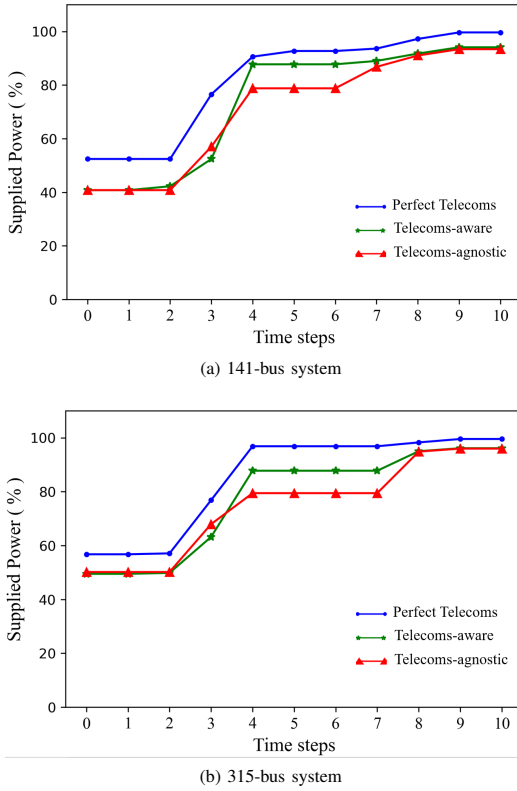


Fig. 5. Evolution of supplied power during DSR

routing combinatorial optimization problem (with exponential complexity) and SDG operation constraints. Obtained results remain important to confirm the validity of the proposed model, and allow to concentrate on a lower complexity solution in future works.

IV. CONCLUSION

The restoration process in distribution grids is modeled integrating power-telecom interdependencies and considering multi-resources. Reconfiguration switches, repair/MS crews, and DGs are coordinated by a telecom-aware MILP co-optimization yielding improved resilience strategies. The general cases of underground and overhead electrical networks are explored, revealing advantages of tight damage isolation. The proposed approach incorporates both the contribution of communication networks to DSR (by connecting remote switches and field crews to grid central functions) and power supply of telecom assets, for a comprehensive analysis of two-way power-telecom interdependencies. Results from case studies show that co-optimization of resource allocation and telecom-aware strategic interventions improve the DSR, enhancing the overall resilience of the grid. Results from the real distribution network, partially included due to space limit, validate the applicability of the model. The development of a lower complexity solution algorithm and extensions to capture telecom dynamics are identified for future works.

REFERENCES

[1] Z. Bie et al. "Battling the Extreme: A Study on the Power System Resilience". In: *Proceedings of the IEEE* (2017).

[2] Y. Wang et al. "Research on Resilience of Power Systems Under Natural Disasters—A Review". In: *IEEE Trans. PS* (2016).

[3] Y. Liu et al. "Power system restoration: a literature review from 2006 to 2016". en. In: *Journal of Modern Power Systems and Clean Energy* (2016).

[4] J. Liu et al. "A Unified Two-Stage Reconfiguration Method for Resilience Enhancement of Distribution Systems". In: *IET Gen. Trans. Dis., Transmission & Distribution* (2019).

[5] Q. Zhou et al. "Distribution feeder reconfiguration for service restoration and load balancing". In: *IEEE Trans. PS* (1997).

[6] P. Van Hentenryck et al. "Transmission system repair and restoration". en. In: *Mathematical Programming* (2015).

[7] Y.-P. Fang et al. "Optimum post-disruption restoration under uncertainty for enhancing critical infrastructure resilience". en. In: *Reliability Engineering & System Safety* (2019).

[8] G. Kandaperumal et al. "Resilience of the electric distribution systems: concepts, classification, assessment, challenges, and research needs". en. In: *IET Smart Grid* (2020).

[9] S. Poudel et al. "A two-stage service restoration method for electric power distribution systems". In: *IET SG* (2021).

[10] N. Morshedlou et al. "Work crew routing problem for infrastructure network restoration". en. In: *Transportation Research Part B: Methodological* (2018).

[11] R. Perez-Guerrero et al. "Optimal Restoration of Distribution Systems Using Dynamic Programming". en. In: *IEEE Trans. Pow. Del.* (2008).

[12] C. Wang et al. "Markov Decision Process-Based Resilience Enhancement for Distribution Systems: An Approximate Dynamic Programming Approach". en. In: *IEEE Trans. SG* (2020).

[13] M. M. Hosseini et al. "Resilient Operation of Distribution Grids Using Deep Reinforcement Learning". In: *IEEE Trans. Indus. Inf.* (2022).

[14] A. Arif et al. "Power Distribution System Outage Management With Co-Optimization of Repairs, Reconfiguration, and DG Dispatch". en. In: *IEEE Trans. SG* (2018).

[15] S. Lei et al. "Resilient Disaster Recovery Logistics of Distribution Systems: Co-Optimize Service Restoration With Repair Crew and Mobile Power Source Dispatch". en. In: *IEEE Trans. SG* (2019).

[16] Y. Bian et al. "Service Restoration for Resilient Distribution Systems Coordinated with Damage Assessment". en. In: *IEEE Trans. PS* (2021).

[17] W. Liu et al. "A wide area monitoring system based load restoration method". In: *IEEE Trans. PS* (2013).

[18] A. Ashok et al. "Cyber-Physical Attack-Resilient Wide-Area Monitoring, Protection, and Control for the Power Grid". In: *Proceedings of the IEEE* (2017).

[19] S. Xin et al. "Information-Energy Flow Computation and Cyber-Physical Sensitivity Analysis for Power Systems". In: *IEEE Journal on Emerging and Selected Topics in Circuits and Systems* (2017).

[20] G. Huang et al. "Cyber-Constrained Optimal Power Flow Model for Smart Grid Resilience Enhancement". In: *IEEE Trans. SG* (2019).

[21] Z. Ye et al. "Boost Distribution System Restoration with Emergency Communication Vehicles Considering Cyber-Physical Interdependence". In: *IEEE Trans. SG* (2022).

[22] X. Liu et al. "Towards Optimal and Executable Distribution Grid Restoration Planning With a Fine-Grained Power-Communication Interdependency Model". In: *IEEE Trans. SG* (2022).

[23] A. Kwasinski et al. "Telecommunications Power Plant Damage Assessment for Hurricane Katrina— Site Survey and Follow-Up Results". In: *IEEE Systems Journal* (2009).

[24] S. A. Fenrick et al. "Cost and reliability comparisons of underground and overhead power lines". In: *Utilities Policy* (2012).

[25] O. Al-Khatib et al. "Traffic Modeling and Optimization in Public and Private Wireless Access Networks for Smart Grids". In: *IEEE Trans. SG* (2014).

[26] E. Ancillotti et al. "The role of communication systems in smart grids: Architectures, technical solutions and research challenges". en. In: *Computer Communications* (2013).

[27] Q. Yang et al. "Communication Infrastructures for Distributed Control of Power Distribution Networks". In: *IEEE Trans. Indus. Inf.* (2011).

[28] V. C. Gungor et al. "Smart Grid Technologies: Communication Technologies and Standards". In: *IEEE Trans. Indus. Inf.* (2011).

[29] M. Kuzlu et al. "Communication network requirements for major smart grid applications in HAN, NAN and WAN". en. In: *Computer Networks* (2014).

[30] D. C. Paraskevopoulos et al. "Resource constrained routing and scheduling: Review and research prospects". en. In: *EJOR* (2017).

Paper [\[4\]](#)

Youba Nait Belaid, Yiping Fang, Enrique Kremers, Zhiguo Zeng, Patrick Coudray, Anne Barros. “On the Implementation and Enhancement of Optimal Deterministic Crew Schedules during Smart Distribution Grid Restoration”. Under review at: Elsevier Journal of Sustainable Energy, Grids, and Networks.

On the Implementation and Enhancement of Optimal Deterministic Crew Schedules during Smart Distribution Grid Restoration

Youba Nait Belaid^{*§}, Enrique Kremers[‡], Yiping Fang^{*}, Zhiguo Zeng^{*}, Patrick Coudray[§], Anne Barros^{*}

^{*} Risk and Resilience of Complex Systems, CentraleSupélec, Université Paris Saclay, France [§] Electricité de France (EDF) R&D, Paris-Saclay, France [‡] IABG Industrieanlagen-Betriebsgesellschaft mbH, Munich, Germany
E-mail: youba.nait-belaid@centralesupelec.fr

Abstract—The growing complexity in modern smart power grids calls for sophisticated modeling and simulation methods under various operation conditions. In particular, information and communication technologies (ICTs) bring a whole new set of difficulties given the event-driven nature of involved processes. This is intensified during episodes of extreme events as the electric power system undergoes maximum stress and exhibits multiple vulnerabilities, particularly at the distribution level. Many proposals push for the optimization of distribution system restoration (DSR) using deterministic mixed integer linear programming (MILP) models, which allow to obtain optimal solutions for small and medium-size configurations. The present work tackles the implementation of the solution from a MILP in a realistic setting, revealing the actual performance of the solution. A sensitivity analysis is conducted, identifying the repair time as an essential system parameter that can affect the performance of the solution. A simulation model with a Weibull distributed repair time is used to implement the MILP solution and evaluate its performance. A framework hybridizing simulation and MILP optimization is proposed to enhance the initial optimal solution for better performance in the realistic setting. Results show that the newly computed solution from the hybrid optimization is able to outperform the initial solution and present a potential for application in larger scale case studies.

Index Terms—Smart Distribution Grid, Optimization, Simulation, Resilience, Agent-Based Modeling, Discrete Events

I. INTRODUCTION

Power grids face an increasing number of disruptions from extreme events due to aging infrastructure and global climate change challenges [1, 2]. In that regard, the growing complexity in the distribution grid adds an unforeseen source of vulnerability where distribution power operators (DSOs) experience out-of-control situations due to lack of grid understanding [3]. Wide Digitization through ICTs, although enabling many grid applications and improving the general performance, is the vector introducing the most complexity to the grid in present days. As such, advanced analysis and modeling of the power-ICT coupling within smart grids is an active area of research [4, 5].

Many contributions focused on co-simulation to capture the two interacting layers, where a power simulator is interfaced with a telecom simulator to replicate the data exchange in real grids [6, 7]. The tractability and synchronization issues are recognized in those studies and solutions continuously explored [8]. Less detailed and more tractable modeling is achieved

through the application of complex network theory and flow-based approaches [9, 10, 11]. Additionally, approaches able to strike a balance between computational efficiency and system fidelity are proposed based on discrete event (DE) and agent-based modeling (ABM) [12, 13, 14]. DE or event-driven techniques are very suitable to queuing processes and match the sporadic sending of messages in the telecom network [15]. ABMs have the advantage of reduced modeling effort, high flexibility, and suitability for stochastic environments [16, 17].

Power-telecom interdependencies are even more critical during hazards and crisis situations, where additional vulnerabilities emerge, and DSOs need decision aid tools to better navigate through the events and achieve a faster restoration. Aforementioned techniques lack the decision support sought by system operators for crisis management [18, 19]. As a result, mathematical programming is identified as the suitable approach for optimizing the grid restoration under contingency considering power-telecom interdependencies [20, 21, 22], which is inline with the more explored DSR problem without power-telecom interdependencies [23, 24, 25, 26, 27]. When solved, these models are able to provide optimal solutions. Yet, some issues are still under investigation. First, the solution optimality is guaranteed within the proposed model, and most conducted works do not confront the obtained solution to real or realistic system settings to test their performance. This is even more appealing when recognizing the multitude of existing uncertainties on the damages, repair time, travel time, load, supply, etc. [28, 29, 30]. Second, the formulated models for the DSR are *NP-hard*, embedding combinatorial multi-resource routing and scheduling constraints with the PF, failure propagation, radiality, switching and any additional operational constraints. A high computational burden can be incurred for medium- to large- sized grids even in the deterministic case, let alone stochastic or robust formulations [31].

A novel approach is proposed in the present work to address the first issue on solution evaluation, and set the ground for future contributions on the second issue of computational complexity. The routing and scheduling of intervention crews, telecom points, and battery discharge are modeled using agents and discrete events. The PF calculations is kept into a callable module from defined agents. In summary, the major contributions in this work compile to:

- Propose a modeling approach to include more SDG

system details using ABM and DE, which is claimed as a *simulation model* of the system;

- Investigate the implementation of a solution from a DSR deterministic MILP model by evaluation in the proposed simulation model under an uncertain repair time;
- Provide an enhancement of the initial solution from the MILP by a new approach combining simulation and mathematical programming.

The remainder of the paper presents in Section II the proposed DSR model, before introducing the targeted applications of such modeling in Section III. Simulations and numerical results are reported in Section IV, while Section V draws conclusions and shares insights on future work.

II. DISTRIBUTION SYSTEM RESTORATION MODELING

Most state-of-the-art contributions to DSR modeling embed complex network theory and flow-based methods in optimization formulations (usually MILP) to seek the best restoration strategies [23, 24, 25]. Previous work from the authors adopted this approach to introduce telecom-aware DSR [32, 22], where a strategic restoration is conducted by identifying telecom points with a potential to accelerate the operations, and prioritizing them in terms of power supply recovery. For more system description, an extended model is proposed in this work, where the routing, scheduling, telecom, and battery constraints from the MILP-formulated DSR are implemented using ABM and DE techniques. Figure 1 shows the general layout of the proposed model, with the ABM-DE module having the ability to call a PF module whenever power calculations are needed. Unlike optimization, the decision-making capability is not inherent to the ABM and DE, which necessitates a new proposal to use the extended hybrid model for optimization tasks, as will be seen in Section III.B.

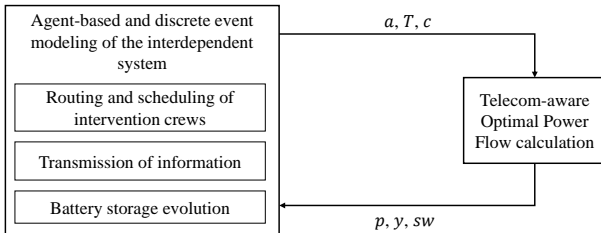


Fig. 1. Layout of the extended hybrid model

A. Crew Interventions

The crews are defined as agents with specific behaviors and characteristics. A Parent agent *Depot* is defined to contain crews of different types: repair (RC) crews, manual switching crews (MC), etc. The movement can be specified in different ways: i) Define the movement speed and either move in straight direction or rely on a routing engine (like OpenStreetMap [33]) to provide the itineraries through the road network; ii) Provide directly a travel duration between two points.

B. Telecom Infrastructure

Telecoms are represented as in [22] with a hierarchical architecture, where each element is considered as an agent with the ability to send/receive data uplink and downlink, while possessing a queuing system to handle messages:

- Aggregation point (AggP): allows to pass from the access part of the network to the core network where many processing and control decisions are taken. Without loss of generality, the aggregation point is considered to include the control center functions of a power system operator, which is in practice located in a separate entity.
- Access point (AP): is an entity lower than the aggregation point in the hierarchy of telecom points. APs offer a telecom service in a given area depending on the technology they use. We consider two types of APs: Fixed (or wired) points and wireless APs.
- Access link (AccL): The link from any grid asset (or other connecting components) and an AP is modeled by an agent *AccessLink*. This allows to capture failures in the communication channel as well as expressing characteristics of different access link technologies, e.g. wireless channel or fiber wires.

A queuing process guarantees that arriving messages are kept and treated when the agent is available. The power supply of any telecom point is tracked using an event starting the battery discharge as soon as power supply from the grid is out.

C. Power Flow

The LinDistFlow formulation is kept for the PF with the difference of launching only one-shot PF. In other words, the event-driven operation of the proposed hybrid model drives the calls to PF calculations, which are then only one-step look ahead.

D. Power-Telecom Interdependencies

The power-telecom interdependencies are seamlessly integrated in the modeling as telecom points react to events of power nodes failures or battery depletion, while grid operations and PF calculations depend on the transferred messages through the telecom infrastructure.

III. PROPOSED MODEL APPLICATIONS

The proposed model is steered towards a use in distribution restoration, while having the flexibility to capture other distribution grid functions. Two interesting applications are the implementation of MILP solutions to the DSR problem and the proposal of enhancements. Next sections will refer to *solution* or *MILP solution*, which is no other than the solution to the DSR problem obtained from the MILP formulation in [22].

A. Solution Implementation

As the hybrid model, also referred as simulation in this paper, is recognized to have an advanced description of the real system; it is proposed to run the MILP solution for the

DSR to test its performance. Although the simulation is not the real system, having more detailed modeling (in the absence of the real system) can help to identify the performance of the solution when applied out of the model it was computed in (the MILP).

An introduced uncertainty in the repair time as a weibull distribution [34] marks a simulation parameter that is not accounted for at the DSR, during MILP solution calculation. The values produced by the distribution are mostly around the deterministic values used by the MILP. This is achieved by adjusting the scale and shape parameters of the weibull distribution.

Generally, the solution from an optimization problem is not exactly the decision itself. For the DSR, this is seen when having the MILP solution displaying the exact crew schedules, with timely visits to precise locations. The decision maker will rather infer sequences of repair for each available crew, as meeting the exact schedule is just hardly achievable. It could be said then for the solution implementation and evaluation that a repair sequence from the MILP is injected into the simulation, that runs it, and collects the performance in terms of supplied power and end-of-repair time.

B. Solution Enhancement

In cases where the MILP solution underperforms in the simulation model, the aim is to find a solution with a better performance considering the simulation environment. In this section, the simulation is coupled with a mathematical programming formulation to enhance the solution to the DSR problem. This technique tries to leverage the simulation into an optimization task, while keeping the advantages of a good system description [35].

Fig. 2 shows the general layout of the proposed *hybrid-optimization* approach, where the optimization model sends a repair sequence for execution at the simulation model, and collects the resulting performance (supplied power). This feedback updates the MILP to prepare the next run in the iterative process. The vector \mathbf{a} of the availability of lines conveys the information on the repair sequence, whereas \mathbf{p} contains the supplied power on the grid after implementing a given sequence in the simulation.

1) *Simulation Model*: The hybrid model from Section II is used as a simulation model in the proposed approach. The simulation takes a sequence of repairs as an input and executes it to collect performance indicators. The sequence of damages is put in a repair queue shared by all depots. Any idle crew queries the repair queue to get the next damage to repair by choosing the closest damaged line. The access to the queue is managed by a first-arrived first-served rule, imposing a random tie-break if two crews attempt to access the queue simultaneously. The constraints on the co-location of crews and exclusivity of repair tasks are inherently satisfied.

The power supply and battery level of the telecom infrastructure is also monitored in order to apply adequate changes when particular event occur. The choice to not let only the PF constraints in the optimization and use the simulation to represent the other constraints is made to make the new MILP

fast solvable. There could be the possibility to have some constraints represented in the simulation and the optimization (like the PF constraints here). This helps for solution convergence, but it should be ensured that no big computation load is added. Also, a condition is added to stop any simulation run when all the loads are restored, as no additional information is needed, and no time is desirable to be spent in more steps where no operation is conducted.

2) *Optimization Model*: The simulation is interfaced with an optimization model formulated as a MILP. The new MILP is set to solve for the optimal repair sequence that guarantees the best restoration considering topology and PF constraints only. The routing, scheduling, and telecom complicating constraints in the comprehensive DSR problem of [22] are implemented in the simulation, resulting in a smaller MILP to solve. The feedback from the simulation is therefore important to incorporate the information in all system constraints in the proposed sequence.

$$\min_{\mathbf{p}, \mathbf{d}, \mathbf{sw}, \mathbf{a}, \mathbf{y}, \mathbf{w}} \sum_{\forall t} \left[\alpha \sum_{\forall i \in N} C_i^{ns} \cdot p_{i,t}^{ns} + \beta \sum_{\forall l \in F} C_l^{rc} \cdot a_{l,t} + \gamma \sum_{\forall l \in L} C^{sw} \cdot w_{l,t} \right] \quad (1)$$

Equation (1) gives the objective function of the optimization problem, which seeks to minimize the cost of non-supplied power, and consider secondary objectives of reducing repair and switching costs ($\alpha \gg \beta, \alpha \gg \gamma$); with \mathbf{p} the vector of power and voltage quantities, \mathbf{d} the vector of power flow directions in lines, \mathbf{sw} the vector of switch statuses, \mathbf{a} the vector of component (bus or line) availability, \mathbf{y} the connectivity of buses to the grid. Parameters C_i^{ns} and C_l^{rc} represent cost factors for the non-supplied power and line repair, respectively. Both can be updated from the simulation result at each iteration, bridging the simulation and the optimization. We omit for now the update of C_l^{rc} in order to understand the individual effect of each cost, where C_i^{ns} is surely more influential given how the objective is set. C^{sw} is the switching cost that is considered the same for all operated switches, and variable $w_{ij,t}$ results from the linearization of the absolute value of $sw_{l,t} - sw_{l,t-1}$.

$$\sum_{\forall l \in F} a_{l,t} = 1, \forall t \quad (2)$$

Constraint (2) fixes to 1 the number of repaired lines at each step, enforcing an order in the restoration of the damaged lines. This is used in addition to failure propagation, radiality, and PF constraints from The complete DSR problem. Setting the number of time steps to equal the number of damages is sufficient to properly solve the problem.

3) *Iterative Algorithm*: The MILP provides a "believed" optimal sequence to the simulation, which runs it and returns statistics on the performance of the solution in terms of supplied power. This information is used to update the MILP, which takes it into consideration for the next proposed solution. In that sense, the MILP seeks optimality by exploring the solution space, while the simulation is helping to guide the search by providing feedback on the performance of

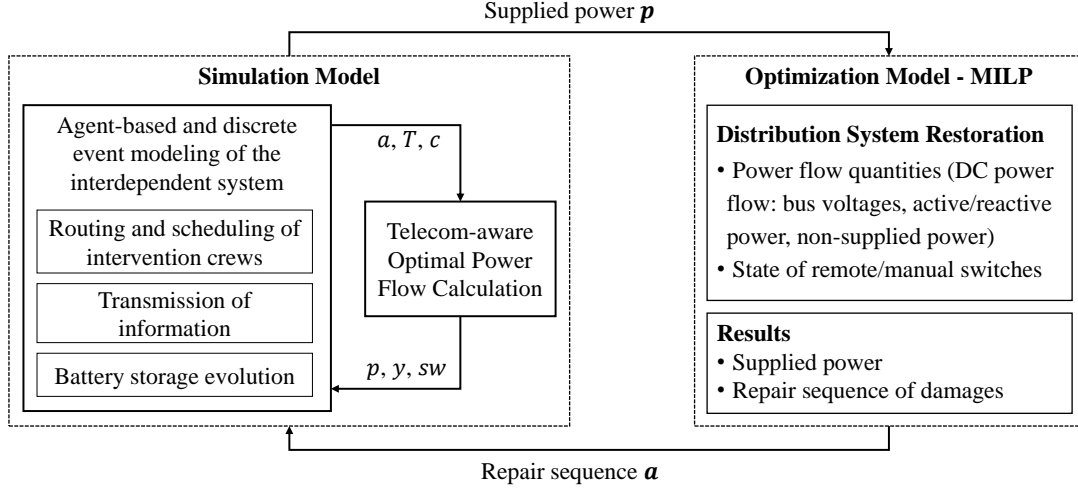


Fig. 2. Layout of the hybrid optimization approach

feasible solutions [36]. A procedure is set to iterate between the simulation and the optimization. Equation (3) states the considered update rule of the objective cost factors using the feedback from the simulation.

$$C_i^{ns,opt}(n+1) = E[C_i^{ns,sim}(n)], \forall i, \forall n \quad (3)$$

where i is the index of the bus, n the index for the current iteration, $C_i^{ns,sim}(n)$ is the total cost of the of losing power at node i during the simulation, and $C_i^{ns,opt}(n+1)$ the unitary (hourly) cost of losing power at node i at iteration $n+1$. By convention, the optimization is chosen to run first, so the update from the simulation corresponds to the end of an iteration. The proposed approach is based on the observation that whatever is the solution from the optimization for the DSR, the implementation will generally not follow the exact schedule but rather infer a sequence of tasks. The idea then is to directly solve the MILP for the repair sequence, which is an easier problem compared to finding all the crew schedules. The implementation of the complicating constraints (routing, scheduling, and telecom) in the simulation makes the optimization problem tractable in most cases.

The iterative process is stopped when a solution is proposed K consecutive times to the simulation (we let $K = 3$). The proposed methodology is given in Algorithm 1.

IV. SIMULATIONS AND RESULTS

A. Sensitivity Analysis

Deterministic models help to find a solution that can be considered as a coarse schedule during operations [37]. The power system is known to be very complex and stochastic, meaning that in any case, as good as the solution from a deterministic model may turn out to be not optimum as the conditions on the system change. The challenge then is more to, at least, have a solution that does not move away too far from its initial predicted performance and be as close as possible to the true, unknown, new optimum.

Only resources of repair and reconfiguration are considered in the DSR problem, and no pre-assignment of damages is

Algorithm 1 Proposed hybrid optimization methodology

Initialize the cost of non-supplied load $C_i^{ns,opt}, \forall i \in N$

Run initial optimization (MILP) with initial $C_i^{ns,opt}$

Get initial repair sequence: $Seq \leftarrow MILP(C_i^{ns,opt})$

while Repair sequence Seq did not converge **do**

1. Run a simulation $Sim(Seq)$ using the repair sequence from MILP

$C_i^{ns,sim} \leftarrow Sim(Seq)$

2. Update the MILP objective function cost factors:

$C_i^{ns,opt} \leftarrow E[C_i^{ns,sim}], \forall i$

$$\min_{p,d,sw,a,y,w} \sum_{\forall t} \left[\alpha \sum_{\forall i \in N} C_i^{ns,opt} \cdot p_{i,t}^{ns} + \beta \sum_{\forall l \in F} C_l^{rc} \cdot a_{l,t} + \gamma \sum_{\forall l \in L} C_l^{sw} \cdot w_{l,t} \right]$$

3. Run an MILP optimization using the results from the simulation

4. Get the repair sequence: $Seq \leftarrow MILP(C_i^{ns,opt})$

end while

The algorithm converged and the best performing repair sequence Seq^* selected

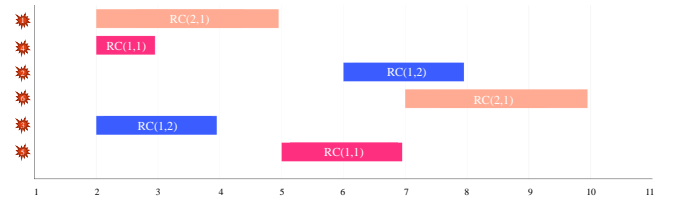


Fig. 3. Gantt chart for the schedule of repair crews on damaged lines

assumed, meaning that any crew can repair a given line. The problem is solved for a 141-bus case study under a scenario of 6 damaged lines. From the timeline of repair in Fig. 3, the sequence of repairing lines is to be taken for implementation in the simulation model. The resulting sequence is $\{4, 3, 1, 5, 2, 6\}$. A sensitivity analysis is conducted on repair time to track its effect on the performance of the solution.

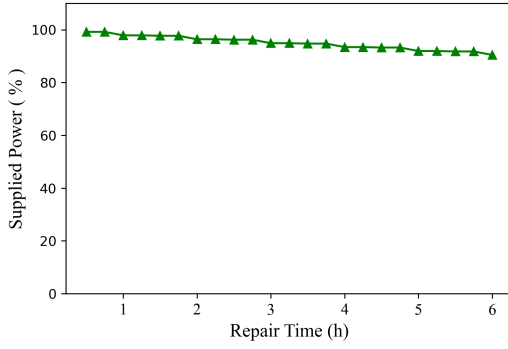


Fig. 4. MILP solution sensitivity to repair time

TABLE I
PARAMETER SETTINGS FOR DSR USE-CASE

Depot	Repair Crews (RC)	Travel Time (TT)
DP 1	RC(1,1), RC(1,2)	2h
DP 2	RC(2,1)	2h
Telecom Point		Battery Duration
Aggregation Point	AggP1	15h
Fixed Access Point (X)	X1, X2	3h
Wireless Access Point (W)	W1, W2	1h

Fig. 4 illustrates the evolution of supplied power in terms of repair time in the range [0.5, 6] hours. The performance of the solution is not heavily affected and remains within 10% of the MILP obtained performance under a considerable change in repair time, which corroborates the effectiveness of the MILP model, despite many abstractions and simplifications. However, when dealing with extreme events, the small percentage can be vital, and many recent works consider uncertainties in repair and even travel times [38, 39]. Note that the cases of long repair time did not cause a high performance drop, especially that telecom points consume all their battery storage. The reason is that the effect of the availability of telecom points by keeping crews longer at damage sites represents an endogenous uncertainty to the repair time, which is out of the scope of this study. Only the random component of the uncertainty in repair time is considered, not including the waiting time for re-connection where above endogenous uncertainty arises. Finally, The repair time is selected here for further analysis as the travel time is relatively well modeled by proportionality with distance and the linkage to road networks. Tables I and II give the default parameters of the case study used in this section and later in the chapter.

B. Solution Implementation

The MILP solution from the DSR use case is implemented in the simulation. Fig. 5 shows the comparison between the performance given by the MILP and the obtained results

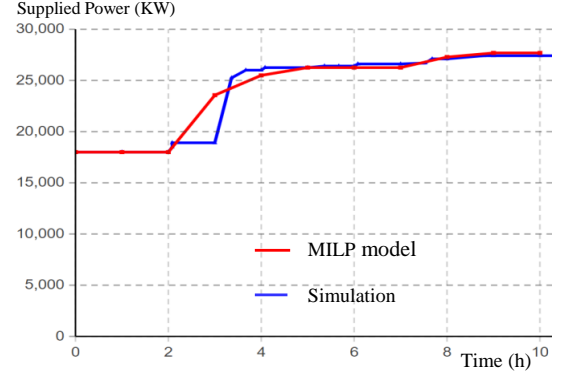


Fig. 5. Performance comparison of the MILP solution

from the simulation. The MILP solution underperforms in the simulation model due to different repair times, despite the values being on average equivalent to the repair time values in Table II. The repair sequence from the simulation {4, 1, 3, 2, 6, 5} (Fig. 6) differs from the specified one from the MILP.

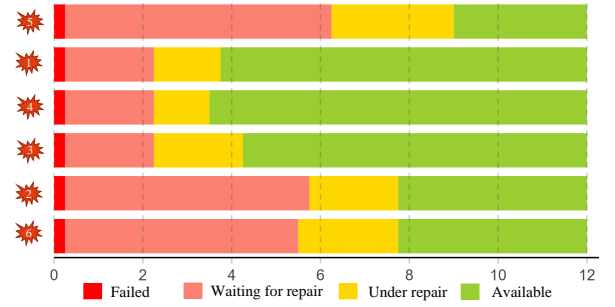


Fig. 6. Repair sequence from MILP solution implementation by the simulation model

The simulation test of the solution shows the reduction in performance, but does not provide information on whether the MILP solution is still optimal. Consequently, we try to check if there is a solution that achieves a better performance in the simulation model, then work on a proposal to generalize the methodology of finding new solutions that outperform the initial MILP solution in a more realistic setting.

C. Solution Enhancement

The 141-bus configuration is used to test the proposed approach, considering a scenario of 6 damaged lines (no telecom access point damage). Given the uncertainty in the repair time, each simulation is replicated 10 times during an iteration of the hybrid optimization. The solution to the DSR from the MILP is already known and its performance is evaluated in the simulation model. The hybrid optimization is run for 20 iterations (1 iteration \rightarrow solve MILP + 10 simulations of the MILP solution). The newly found sequence {4, 3, 1, 6, 5, 2}, portrayed in Fig. 7, and the previous MILP solution are tested in the simulation, and the average result of 10 runs is depicted in Figure 7. The proposed approach is able

TABLE II
REPAIR TIME SETTING

Line	1	2	3	4	5	6
Repair Time (h)	3	2	2	1	2	3

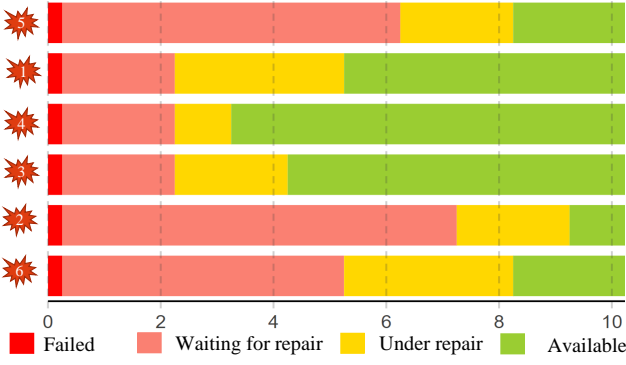


Fig. 7. Repair sequence from the hybrid optimization

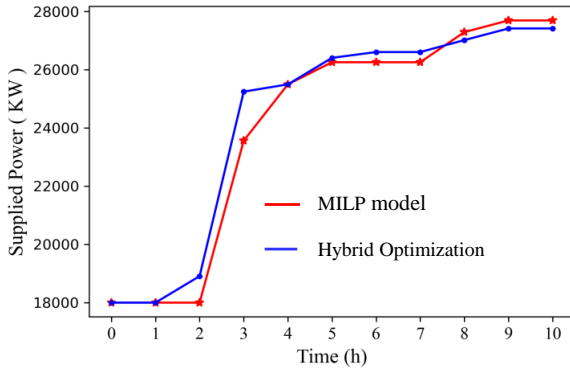


Fig. 8. Performance of the initial MILP solution and the hybrid optimization solution

to find a solution better than the considered MILP solution. No guarantee on the optimality of the new solution can be drawn at this point. Still, the result is interesting as the convergence could be attained in just some iterations (12 iterations). Having in mind the execution time of less than 5 seconds for the simulation model, achieved convergence opens the door to explore the hybrid optimization approach as an accelerator for MILP solution.

V. CONCLUSION

The DSR problem is modeled in this work using a multi-method approach. Routing, scheduling, data exchange, and battery storage characteristics are handled by DE and ABM techniques, which guarantee an increased level of description. The PF calculations are included using the traditional network and flow-based methods, with the subtlety to be calculated only on-demand by triggered events. An uncertain weibull distributed repair time is considered in the simulation, which is exploited in two main applications: i) Implementing the solution from a previous MILP solution of a DSR and evaluate its performance in terms of restoration key indicators of supplied power and time-to-repair; ii) Enhancing the MILP solution in case of a found performance drop from the evaluation. A hybrid simulation approach is proposed for the solution enhancement, which could be tested to give satisfying results of finding a better solution in a 141-bus system configuration.

This is enabled by an iterative process where the simulation runs a repair sequence from the optimization, collects the performance in terms of non-supplied power, and updates the optimization objective. The loop is run till the solution converges. Future works feature the use of the hybrid optimization approach to solve the DSR problem faster, as well as explore the reinforcement learning approach given the simulation at hand that can serve as a training environment.

VI. AUTHOR CONTRIBUTIONS

Youba Nait Belaid Conceptualization, Methodology, Investigation, Writing - original draft. **Enrique Kremers** Methodology, Supervision, Writing - review. **Yiping Fang, Zhiguo Zeng, Patrick Coudray, Anne Barros** Supervision, Writing - review.

VII. ACKNOWLEDGMENT

This work is funded by EDF/Orange/SNCF in the framework of the Chair on Risk and Resilience of Complex Systems (CentraleSupélec, EDF, Orange, SNCF). Youba Nait Belaid acknowledges the research grant (2022-57588366) from the Deutscher Akademischer Austauschdienst (DAAD).

REFERENCES

- [1] Hassan Farhangi. "The path of the smart grid". In: *IEEE Power and Energy Magazine* (2010).
- [2] Mathaios Panteli and Pierluigi Mancarella. "Influence of extreme weather and climate change on the resilience of power systems: Impacts and possible mitigation strategies". en. In: *Electric Power Systems Research* (2015). URL: <https://linkinghub.elsevier.com/retrieve/pii/S037877961500187X>.
- [3] Benjamin Schäfer et al. "Dynamically induced cascading failures in power grids". en. In: *Nature Communications* (2018). URL: <https://www.nature.com/articles/s41467-018-04287-5>.
- [4] Emilio Ancillotti, Raffaele Bruno, and Marco Conti. "The role of communication systems in smart grids: Architectures, technical solutions and research challenges". en. In: *Computer Communications* (2013). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0140366413002090>.
- [5] V. C. Gungor et al. "Smart Grid Technologies: Communication Technologies and Standards". In: *IEEE Transactions on Industrial Informatics* (2011).
- [6] Hua Lin et al. "Power system and communication network co-simulation for smart grid applications". In: *ISGT 2011*. 2011.
- [7] Tim Godfrey et al. "Modeling Smart Grid Applications with Co-Simulation". In: *2010 First IEEE International Conference on Smart Grid Communications*. 2010.
- [8] C. Steinbrink et al. "Simulation-Based Validation of Smart Grids – Status Quo and Future Research Trends". en. In: *Industrial Applications of Holonic and Multi-Agent Systems*. 2017.
- [9] José Sánchez, Raphaël Caire, and Nouredine Hadsaid. "ICT and power distribution modeling using complex networks". In: *2013 IEEE Grenoble Conference*. 2013.
- [10] Jonas Wafler and Poul E. Heegaard. "Interdependency in smart grid recovery". en. In: *2015 7th International Workshop on Reliable Networks Design and Modeling (RNDM)*. 2015. URL: <http://ieeexplore.ieee.org/document/7325230/>.
- [11] Jovica V. Milanović and Wentao Zhu. "Modeling of Interconnected Critical Infrastructure Systems Using Complex Network Theory". In: *IEEE Transactions on Smart Grid* (2018).
- [12] Inger Anne Tøndel et al. "Interdependencies and reliability in the combined ICT and power system: An overview of current research". en. In: *Applied Computing and Informatics* (2018). URL: <https://www.sciencedirect.com/science/article/pii/S2210832716300552>.
- [13] M. Amin. "Toward self-healing energy infrastructure systems". In: *IEEE Computer Applications in Power* (2001).
- [14] Cen Nan and Giovanni Sansavini. "A quantitative method for assessing resilience of interdependent infrastructures". en. In: *Reliability Engineering & System Safety* (2017). URL: <https://linkinghub.elsevier.com/retrieve/pii/S095183201630374X>.

- [15] Bernard P. Zeigler, Herbert Praehofer, and Tag Gon Kim. *Theory of Modeling and Simulation*. en. Academic Press, 2000.
- [16] C.M. Macal and M.J. North. "Tutorial on agent-based modeling and simulation". In: *Proceedings of the Winter Simulation Conference*, 2005. 2005.
- [17] Van Parunak, Robert Savit, and Rick Riolo. "Agent-Based Modeling vs. Equation-Based Modeling: A Case Study and Users' Guide". In: 2000.
- [18] M. Barbati, G. Bruno, and A. Genovese. "Applications of agent-based models for optimization problems: A literature review". en. In: *Expert Systems with Applications* (2012). URL: <https://www.sciencedirect.com/science/article/pii/S0957417411016861>.
- [19] Paul Davidsson, Jan Persson, and Johan Holmgren. "On the Integration of Agent-Based and Mathematical Optimization Techniques". In: 2007.
- [20] Zhigang Ye et al. "Boost Distribution System Restoration with Emergency Communication Vehicles Considering Cyber-Physical Interdependence". In: *IEEE Transactions on Smart Grid* (2022).
- [21] Xin Liu et al. "Towards Optimal and Executable Distribution Grid Restoration Planning With a Fine-Grained Power-Communication Interdependency Model". In: *IEEE Transactions on Smart Grid* (2022).
- [22] Youba Nait Belaid et al. *Optimal Allocation of Resilience Resources for Strategic Communication-aware Restoration of Smart Distribution Grids*. Preprint. 2023. URL: <https://centralesupelec.hal.science/hal-04437914>.
- [23] Anmar Arif et al. "Power Distribution System Outage Management With Co-Optimization of Repairs, Reconfiguration, and DG Dispatch". en. In: *IEEE Transactions on Smart Grid* (2018). URL: <https://ieeexplore.ieee.org/document/7812566/>.
- [24] Yanling Lin et al. "A Combined Repair Crew Dispatch Problem for Resilient Electric and Natural Gas System Considering Reconfiguration and DG Islanding". In: *IEEE Transactions on Power Systems* (2019).
- [25] Shunbo Lei et al. "Resilient Disaster Recovery Logistics of Distribution Systems: Co-Optimize Service Restoration With Repair Crew and Mobile Power Source Dispatch". en. In: *IEEE Transactions on Smart Grid* (2019). URL: <https://ieeexplore.ieee.org/document/8642442/>.
- [26] Yiheng Bian et al. "Service Restoration for Resilient Distribution Systems Coordinated with Damage Assessment". en. In: *IEEE Transactions on Power Systems* (2021). URL: <https://ieeexplore.ieee.org/document/9658141/>.
- [27] Chen Chen, Jianhui Wang, and Dan Ton. "Modernizing Distribution System Restoration to Achieve Grid Resiliency Against Extreme Weather Events: An Integrated Solution". In: *Proceedings of the IEEE* (2017).
- [28] Anmar Arif et al. "Optimizing Service Restoration in Distribution Systems With Uncertain Repair Time and Demand". In: *IEEE Transactions on Power Systems* (2018).
- [29] Aboelsood Zidan et al. "Fault Detection, Isolation, and Service Restoration in Distribution Systems: State-of-the-Art and Future Trends". In: *IEEE Transactions on Smart Grid* (2017).
- [30] Haixiang Gao et al. "Resilience-Oriented Critical Load Restoration Using Microgrids in Distribution Systems". In: *IEEE Transactions on Smart Grid* (2016).
- [31] Xin Chen, Wenchuan Wu, and Boming Zhang. "Robust Restoration Method for Active Distribution Networks". In: *IEEE Transactions on Power Systems* (2016).
- [32] Youba Nait Belaid et al. "Resilience Optimization of Wide-Area Control in Smart Distribution Grids". In: *IFAC-PapersOnLine* (2022). URL: <https://www.sciencedirect.com/science/article/pii/S2405896322011843>.
- [33] Muki Haklay and Patrick Weber. "OpenStreetMap: User-Generated Street Maps". In: *Haklay, M. and Weber, P. (2008) OpenStreetMap: user-generated street maps. IEEE Pervasive Computing*, 7 (4). pp. 12-18. ISSN 15361268 (2008).
- [34] Yi-Ping Fang and Giovanni Sansavini. "Optimum post-disruption restoration under uncertainty for enhancing critical infrastructure resilience". en. In: *Reliability Engineering & System Safety* (2019). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0951832017310062>.
- [35] Shaghaygh Akhtari and Taraneh Sowlati. "Hybrid optimization-simulation for integrated planning of bioenergy and biofuel supply chains". en. In: *Applied Energy* (2020). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0306261919318112>.
- [36] K Kulkarni and J Venkateswaran. "Hybrid approach using simulation-based optimisation for job shop scheduling problems". en. In: *Journal of Simulation* (2015). URL: <https://www.tandfonline.com/doi/full/10.1057/jos.2014.40>.
- [37] A.S. Jain and S. Meeran. "Deterministic job-shop scheduling: Past, present and future". en. In: *European Journal of Operational Research* (1999). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0377221798001131>.
- [38] Qingxin Shi et al. "Enhancing distribution system resilience against extreme weather events: Concept review, algorithm summary, and future vision". en. In: *International Journal of Electrical Power & Energy Systems* (2022). URL: <https://linkinghub.elsevier.com/retrieve/pii/S0142061521010759>.
- [39] Jiayong Li, Mohammad E. Khodayar, and Mohammad Ramin Feizi. "Hybrid Modeling Based Co-Optimization of Crew Dispatch and Distribution System Restoration Considering Multiple Uncertainties". In: *IEEE Systems Journal* (2022).

Paper [5]

Youba Nait Belaid, Anne Barros, Yiping Fang, Zhiguo Zeng, Anthony Legendre, Patrick Coudray. “Enhanced Power and Communication Modeling in Cyber-Physical Distribution Grids for Resilience-based Optimization”. In: European Safety and Reliability Conference (ESREL), Dublin, Aug. 2022.

Enhanced Power and Communication Modeling in Cyber-Physical Distribution Grids for Resilience-based Optimization

Youba Nait Belaid

Risk and Resilience of Complex Systems, CentraleSupélec, Université Paris-Saclay, France
Electricité de France R&D (EDF R&D), France, E-mail: youba.nait-belaid@centralesupelec.fr

Anne Barros

Risk and Resilience of Complex Systems, CentraleSupélec, Université Paris-Saclay, France

Yiping Fang

Risk and Resilience of Complex Systems, CentraleSupélec, Université Paris-Saclay, France

Zhiguo Zeng

Risk and Resilience of Complex Systems, CentraleSupélec, Université Paris-Saclay, France

Anthony Legendre

Electricité de France R&D (EDF R&D), France

Patrick Coudray

Electricité de France R&D (EDF R&D), France

Abstract

Evolving smart grid (SG) services for demand side applications, markets, and various stakeholders are well addressed leaning on Information and Communication Technologies (ICTs). Yet, this technological leap induced high complexity in the grid, due to various power-ICT interdependencies. Managing this complexity has been very challenging over the last decade as prototyping and tools to faithfully replicate SG dynamics and all involved interactions with ICTs are this far out-of-reach. Advanced attempts considered co-simulation of both power and ICT infrastructures using domain-specific software, resulting in a relatively good description but an additional outlay of synchronization and handling different time scales. For SG studies that require low level of details and adopt a systemic view, like resilience evaluation, modeling is better suited to shed the light on paramount features. Smart grid modeling is generally electric system oriented by wide dominance of power flow analysis, associated with very few considerations of ICTs. Availability of telecommunication points-of-interest is considered in this work to capture the interdependence between power and ICT domains of the distribution grid. The integrated modeling inherently omits extra inter-domain synchronization overhead. Different telecommunication settings are therefore compared for fault localization, isolation, and service restoration (FLISR) function. An application of the joint modeling is successfully illustrated in case of resilience-based power service restoration under extreme event failure scenarios.

Keywords: Cyber-Physical Systems, Smart Grids, Power Flow, Telecommunication, Resilience

1. Introduction

Nearly all modern power grid components have cyber and physical characteristics, which result in an overall cyber-physical system (Arghandeh et al. 2016; Yu and Xue 2016). In particular, substations, transformers and intelligent

electronic devices (IEDs) manage physical quantities (power, voltage, current), while being able to produce and process information. Similarly, control centers, intervention warehouses and field crews involve physical processes within the framework of a relatively intensive exchange and processing of

Proceedings of the 32nd European Safety and Reliability Conference

Edited by Maria Chiara Leva, Edoardo Patelli, Luca Podofillini, and Simon Wilson

Copyright ©2022 by ESREL2022 Organizers. *Published by Research Publishing, Singapore*

ISBN: 981-973-0000-00-0 :: doi: 10.3850/981-973-0000-00-0_esrel2022-paper

information. The centralized and distributed constituents of the electrical system are connected via a telecommunication network, which is itself a cyber-physical system (CPS) coupled to the electrical network (Wu, Kao, and Tseng 2011). Smart grids have a wide range of applications that use various communication technologies. The FLISR function in the distribution grid is chosen to investigate the power-telecom coupling during crisis management situations, where localizing and isolating faults then restoring power supply to customers is critical (Liu, Qin, and Yu 2020). The FLISR function intervenes when damages are identified as permanent after initial reclosing cycles involved in protection mechanisms. Fault detectors (FDs) and remote-controlled switches (RCSs) are the main enablers of the remote service restoration (Heidari Kapourchali, Sepehry, and Aravinthan 2018), as the FDs transmit all suitable fault-related measurements to the control center, and the RCSs are used as decision levers to execute the commands issued by the control center. RCSs can in some cases open automatically as a response for a fault, which is typically the case at the upstream of feeders where RCSs are called circuit breakers (CBs) because their opening shuts off the whole feeder. Manual switches are nonetheless more present in power lines and require field intervention crews to operate them on-site (Chen et al. 2019).

Placement of RCSs (Fang and Sansavini 2017) and distribution service restoration problems are extensively studied in the literature (Zidan et al. 2017; Carvalho, Ferreira, and da Silva 2005; Abiri-Jahromi et al. 2012). We extend these studies here to integrate the impact of ICTs. Thereby, the main contributions of this work sum up to:

- Include the automatic response in the grid service restoration model
- Consider the ICT availability
- Study the deployment of new RCSs based on the state of the telecom points and related characteristics of coverage, battery storage, and redundancy of access.

The remaining of the paper is structured as follows: Section 2 presents the system model for the interdependent power-ICT system. Section 3 describes the optimization problem formulation.

Simulations and results are shown in Section 4, and conclusion is given in Section 5.

2. System Model

The medium-voltage (MV) distribution level of the power grid is considered in this work. The distribution grid is represented as a graph, where edges are the power lines, and nodes comprise the high-voltage to medium-voltage (HV/MV) substations and the MV buses. A hierarchical graph captures the telecom domain of the grid, with edges representing communication links, while the control center is the top-level node, access points at the intermediate level, and connected grid assets (HV/MV substations, circuit breakers, RCSs) at the lowest level. FDs are considered perfect in this study as the focus is on the impact of ICTs and RCSs.

Interdependencies between the two domains are captured by considering ICT points as loads from the perspective of the electrical system, whilst electrical substations and switches are customers from the ICT perspective. Figure 1 summarizes the interactions between various components of the same domain or different domains, with three main actions: power supply, telecom service, and repair/manual switching.

Since RCSs can be operated both remotely and manually, they are more advantageous, and their proportion in the network is mostly determined by cost-benefit analyses due to increased expenses. The problem can be partitioned into four phases:

• **Pre-event phase (Anticipative new-RCS deployment):** In this phase, a new resilience-based deployment of RCSs is considered to determine proactively the manual switches to upgrade with the remote connection functionality, and which technology to use for that.

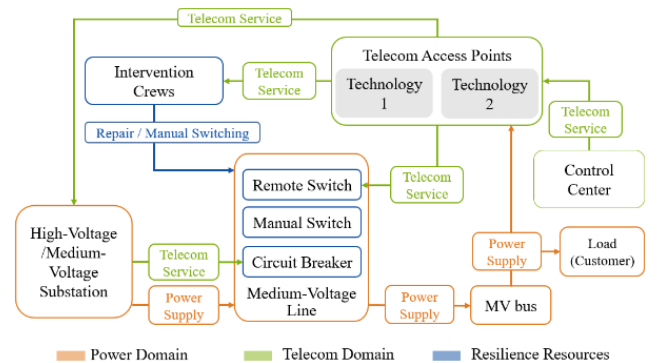


Figure 1. Interactions in the proposed model

• **Automatic isolation:** Scenarios of damages include in the current work faults in power lines and telecom points (TPs). The first response of the distribution grid is the automatic opening of circuit breakers of affected feeders to protect HV/MV substations. In underground networks, MV/LV substations are directly placed on the mainstream, and RCSs are commonly integrated into the substations. Overhead networks contain more derivations, and RCSs are placed on the lines.

• **Remote isolation:** The initial affected zone isolated by automatic devices is wide and can be reduced using RCSs. In this phase, RCSs are opened wherever they allow to isolate some nodes from faulted zones.

• **Fast service restoration:** Also called fast reconfiguration. At this point, some loads can be restored. An evaluation of the power flow conditions is conducted, and decisions on the state of switches are made. The output of this last phase of the fast reconfiguration stage will be taken by the operator during the deployment of latent restoration resources (e.g. repair crews, mobile distributed generators), which are not considered here.

The proposed model takes as input the electric-telecom configuration of the smart grid, as well as the available budget (B) expressed by the number of possible manual-to-remote upgrades. The scenario of damaged electrical segments is also assumed known. This is motivated by the fact that the distribution system operator (DSO) has a relatively good knowledge of the network vulnerability zones, and techniques out of the scope of this work are applied to estimate the impact on electrical lines. For the possible damages in TPs, the DSO has less insight as the TPs are usually managed by a telecom operator. To cope with this, scenario of damages in TPs are considered.

3. Optimization Formulation

The introduced four phases in Section 2 are assembled in Figure 2, alongside initial data and scenario settings, to construct the flowchart of the proposed approach.

3.1. Zone separation and topology

For the FLISR function, three zones can be distinguished: 1) Damage zone: affected by the propagation of the damage; 2) Unserved zone: initially affected by the damage but could be isolated using automatic and remote switches; 3) Served zone: completely safe zone, isolated from damages and supplied by power. Unserved and served zones are both safe from the failures.

We focus on the case of overhead lines as damages propagate wider under this scheme, and the model can be simplified to describe the underground case.

Associated constraints guarantee that damage zones are not connected to served zones or reconnected to unserved zones at any time step. In addition, radiality should be ensured at normal operation and remain verified in subsequent periods.

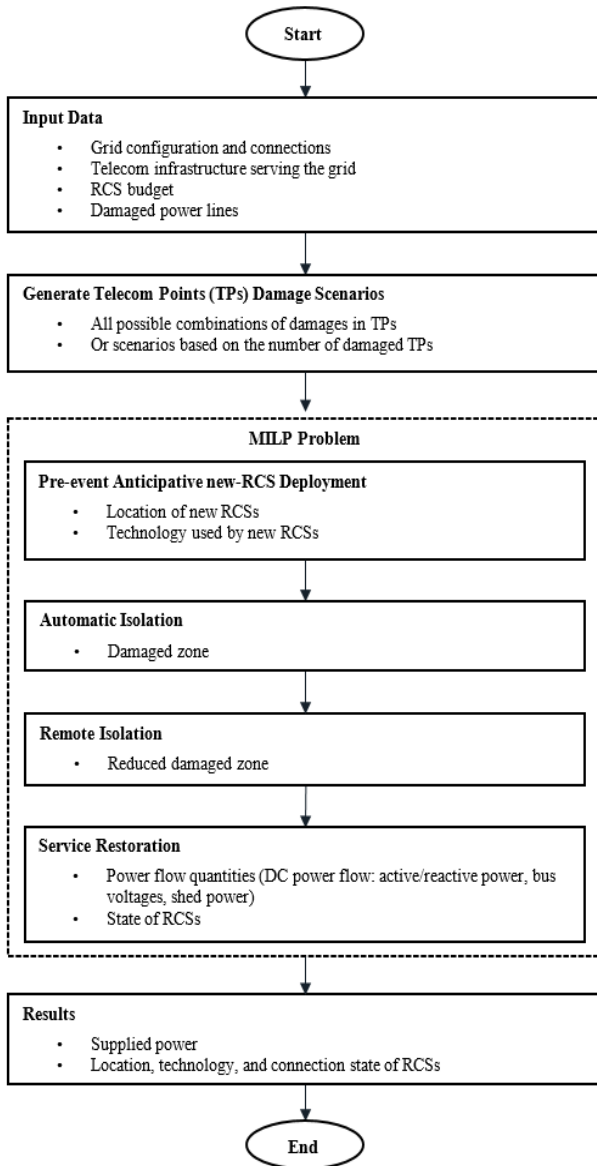


Fig. 2. Flowchart of the proposed approach

3.2. Power flow

The operation of the distribution grid can be described in terms of power flow from HV/MV substations to aggregated loads connected at the MV buses. The LinDistFlow model (Baran and Wu 1989).

3.3. Power-Telecom interdependence

Telecom points require power supply from the grid to deliver the communication service needed by RCSs. Despite this dependence, TPs have batteries that delay the impact of initial failures, and make the points-of-interest in the ICT infrastructure indirectly dependent on the grid. Likewise, the power network could suffer the consequences of a blind operation if ICTs are down. The two-way coupling is thus captured through linear constraints in the proposed MILP.

The telecom access points in Figure 1 enable connection to the control center that centralizes grid operations. This connection is assumed available in this work as long as the access points are operating.

3.4. Objective function

The main objective considered is maximizing supplied power, while introducing a term related to TPs battery capacity and redundancy.

$$\max_{p, y, T, sw, a} \sum_{\forall SC} p_{sc} \left(\alpha * \sum_{\forall i \in N} p_{i,t}^{load} + \beta * \sum_{\forall k \in T} \sum_{\forall l \in L} a_{k,l} batt(k) \right) \quad (1)$$

With p_{sc} the probability of TPs damage scenario sc ; $p_{i,t}^{load}$ the supplied power to node i at phase t ; $a_{k,l}$ the indication if line l is connected to telecom point k ; $batt(k)$ the battery capacity of TP k ; y the connection state of loads; p the vector of electrical quantities (active/reactive power, node voltages); T the vector representing the state of TPs; sw the state of the remote switches. $t \in \{0, 1, 2, 3\}$ indexes the different phases. Note that for convenience, the scenario specific subscript is omitted, as all variables are scenario specific.

The constants α and β allow to tune the tradeoff between restoring the maximum immediate load, and making best anticipative choices which will be advantageous for service restoration. The resilience of the system is calculated based on the temporal evaluation of the supplied load.

4. Simulation and Results

A case study of 36 power nodes is set based on the IEEE 12-node test feeder to demonstrate the effectiveness of the proposed approach. Capacitors, transformers, and regulators are simplified/ignored in compliance with the study objectives. A per-phase analysis is conducted in the constructed generic medium-size 20kV nominal voltage unbalanced distribution network of total 1305 kW demand. Figure 3 shows the buses served by each feeder, and the interconnections between feeders using tie-switches (dashed lines representing normally-open switches).

Each time step represents one phase in Figure 2. Nodes 1, 2, and 3 represent the HV/MV substations, and the blue nodes are the MV buses, which not only supply power to electrical loads, but also energize TPs of two wireless technologies: telecom operator-owned {T1, T2, T3, T4, and T5}, and utility-owned {R1 and R2}. Assets of technology T have coverage radius of 2.8 km and battery capacity of 3 hours, whereas for technology R the coverage radius is 3.5 km and battery capacity 5 hours. We can say that R has better coverage and battery storage, while T offers better options in terms of redundancy.

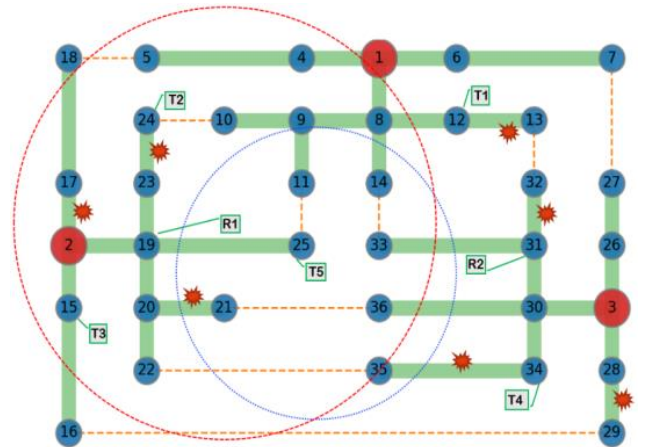


Fig. 3. Test case

Table 1. Percentage of supplied power at each phase with varying number of damages in telecom points; Budget B=3

Number of telecom damages	0	1	2	3	4	5	6	7
Pre-event phase	100%							
Automatic & Remote Isolation phases	29.5%							
Restoration Phase	50.96%	40.23%	33.77%	30.79%	29.91%	29.61%	29.5%	29.5%

Table 2 summarizes the initial type of switch in each power line. A line or a TP has a binary state, either damaged or safe. Then, a scenario of 7 physical damages in power lines is considered. All the possible 128 combinations of failures in TPs are inspected, constructing a scenario-based evaluation where each scenario is assigned with an equal probability of $1/128$. This straightforward stochastic optimization attempts to cope with the uncertainty around damaged TPs. The propagation of damages in overhead and underground lines is well described in the compact MILP formulation.

Result 1.

As we consider a single fault scenario in electrical lines as shown in Figure 3, the damage scenarios are categorized based on the number of affected TPs (Table 1). Damages in TPs clearly affect the ability to restore power supply to

customers. Table 1 also shows that if a given threshold of affected TPs is attained, no restoration would be possible even that some points are still available. In this case, the budget for new-RCS deployment was fixed to B=3, meaning only three manual switches could be upgraded to RCSs.

Result 2.

Table 2 illustrates that, when the number of damages is fixed to 3 and the budget (B) for new-RCS deployment is varied, the supplied power increases with increasing B from 0 to 5. However, when the budget is increased further, no gain is achieved in terms of supplied power. This suggests that beyond an optimal number of RCSs, restoration is no longer possible with RCSs, corroborating that most of the time only a limited recovery is carried out during fast reconfiguration.

Table 2. Supplied power considering new-RCS deployment with varying budget (B); Number of telecom damages = 3

	Initial setup (B=0)	B=1	B=2	B=3	B=4	B=5	B=6	B=13
Circuit Breakers	1-4, 1-6, 1-8, 2-15, 2-17, 2-19, 3-26, 3-28, 3-30							
Remote Controlled Switches (RCS)	22-35, 14-33, 15-16, 31-33, 10-24, 5-18, 21-36, 11-25, 26-27, 13-32, 7-27, 16-29, 9-11, 4-5	17-18 {R1}	8-12 {T1, T4}	19-23 {T2, T3, T4}	30-31 {T1, T5}, 30-34 {R2}, 19-23	19-23 {T2, T3, T4}	8-9 {T1, T3, T4}	All lines are RCS
Manual Switches	8-9, 20-22, 12-13, 20-21, 30-31, 6-7, 31-32, 19-23, 9-10, 30-34, 30-36, 23-24, 19-20, 17-18, 28-29, 8-12, 8-14, 34-35, 19-25	17-18	8-12	19-23	30-31, 30-34, 19-23	19-23	8-9	
Supplied Power (%)	29.5	30.16	30.63	30.79	30.94	31.1	31.1	

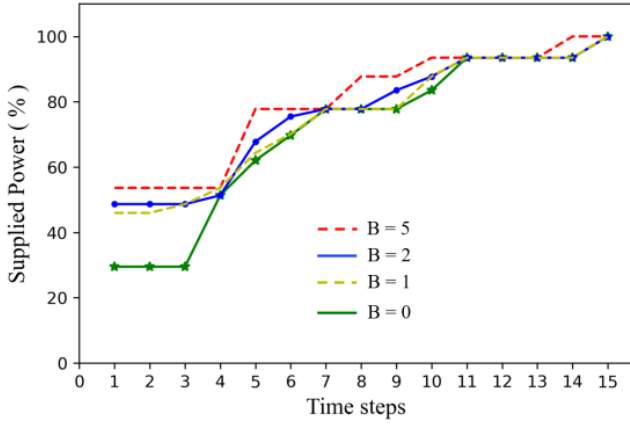


Figure 4. Evolution of restoration in terms of supplied power under different budgets

The supplied power values after fast restoration in Table 2 are close to the initial value, as the restored power is around 1% despite the spent budget. Still, a DSO would be willing to make this investment knowing that during a crisis the early actions target the critical load (hospitals, patients with high vital risks, government facilities, etc.), which represent a very small portion of the entire electrical load.

Result 3.

The newly equipped lines with RCS are shown in green (Table 2) for the different budgets. The present approach helps to establish a priority between the lines which should be upgraded. The telecom technology used is also specified, inside the curly brackets. By closely inspecting the setup of the network, the lines which can possibly be served by one T point and one R point (17-18, 30-34), tend to choose the R point as it has more resilience in terms of battery storage. At the same time, lines which are in the covered vicinity of one R point and multiple T points, choose rather the T technology for the offered redundancy of access.

Result 4.

Fast reconfiguration achieves a partial recovery as illustrated in tables 1 and 2. Yet, improving this first response can contribute to accelerate subsequent operations. Figure 4 shows the evolution of supplied power over time (Time steps in hours), in the case of assigning intervention crews to isolate faulted zones (by manoeuvres in manual switches) and repair damaged power lines. With identical crew resources for different budgets, the restoration is revealed to perform better, in terms of cumulative supplied power, as the budget is

increased. Interestingly, the lower budget curves ($B \in \{0, 1, 2\}$) can ultimately catch up the high budget one ($B = 5$), suggesting that deploying more RCSs will not necessarily accelerate attaining an advanced level of recovery. However, the impact of fast reconfiguration on the overall restoration is not limited to the first hours. When fast reconfiguration is improved through RCSs deployment, the restoration process exhibits enhancement during the whole crisis management.

5. Conclusion

This work provides a resilience-based optimization for fast restoration using remote controlled switches. The objective is to maximize the total power delivered during a failure event, while identifying the optimal scheme (location, technology) for new RCSs. The uncertainty around damages in TPs is partially accounted for through scenario-based optimization. The improvement to the overall restoration brought by fast reconfiguration is quantified.

Results suggest that fast restoration is stopped even when some TPs are still available, and there exists a threshold beyond which increasing the RCS deployment budget brings no more benefit. The chosen technology for each upgrade is linked to battery storage and connection redundancy. The fast reconfiguration is shown to improve the entire restoration process, not just during primary phases, but even well later. Many extensions are under exploration for this work, such as the adjustment of probabilities on different scenarios of TP failures and the investigation of more than just one power line failure scenario. In addition, the impact of the power supply failure to telecom points is considered by including the capacity of batteries into the objective function, but other options can be tested.

Acknowledgement

This work is funded by EDF/Orange/SNCF in the framework of the Chair on Risk and Resilience of Complex Systems (CentraleSupélec, EDF, Orange, SNCF).

References

Abiri-Jahromi, Amir, Mahmud Fotuhi-Firuzabad, Masood Parvania, and Mohsen Mosleh.

2012. "Optimized Sectionalizing Switch Placement Strategy in Distribution Systems." *IEEE Transactions on Power Delivery* 27 (1): 362–70. <https://doi.org/10.1109/TPWRD.2011.2171060>.
- Arghandeh, Reza, Alexandra von Meier, Laura Mehrmanesh, and Lamine Mili. 2016. "On the Definition of Cyber-Physical Resilience in Power Systems." *Renewable and Sustainable Energy Reviews* 58 (May): 1060–69. <https://doi.org/10.1016/j.rser.2015.12.193>.
- Baran, M. E., and F. F. Wu. 1989. "Network Reconfiguration in Distribution Systems for Loss Reduction and Load Balancing." *IEEE Transactions on Power Delivery* 4 (2): 1401–7. <https://doi.org/10.1109/61.25627>.
- Carvalho, P.M.S., L.A.F.M. Ferreira, and A.J.C. da Silva. 2005. "A Decomposition Approach to Optimal Remote Controlled Switch Allocation in Distribution Systems." *IEEE Transactions on Power Delivery* 20 (2): 1031–36. <https://doi.org/10.1109/TPWRD.2004.838470>.
- Chen, Bo, Zhigang Ye, Chen Chen, and Jianhui Wang. 2019. "Toward a MILP Modeling Framework for Distribution System Restoration." *IEEE Transactions on Power Systems* 34 (3): 1749–60. <https://doi.org/10.1109/TPWRS.2018.2885322>.
- Fang, Yiping, and Giovanni Sansavini. 2017. "Optimizing Power System Investments and Resilience against Attacks." *Reliability Engineering & System Safety* 159 (March): 161–73. <https://doi.org/10.1016/j.ress.2016.10.028>.
- Heidari Kapourchali, Mohammad, Mojtaba Sepehry, and Visvakumar Aravinthan. 2018. "Fault Detector and Switch Placement in Cyber-Enabled Power Distribution Network." *IEEE Transactions on Smart Grid* 9 (2): 980–92. <https://doi.org/10.1109/TSG.2016.2573261>.
- Liu, Jiancun, Chao Qin, and Yixin Yu. 2020. "Enhancing Distribution System Resilience With Proactive Islanding and RCS-Based Fast Fault Isolation and Service Restoration." *IEEE Transactions on Smart Grid* 11 (3): 2381–95. <https://doi.org/10.1109/TSG.2019.2953716>.
- Wu, Fang-Jing, Yu-Fen Kao, and Yu-Chee Tseng. 2011. "From Wireless Sensor Networks towards Cyber Physical Systems." *Pervasive and Mobile Computing* 7 (4): 397–413. <https://doi.org/10.1016/j.pmcj.2011.03.003>.
- Yu, Xinghuo, and Yusheng Xue. 2016. "Smart Grids: A Cyber-Physical Systems Perspective." *Proceedings of the IEEE* 104 (5): 1058–70. <https://doi.org/10.1109/JPROC.2015.2503119>.
- Zidan, Aboelsood, Mutaz Khairalla, Ahmed M. Abdrabou, Tarek Khalifa, Khaled Shaban, Atef Abdrabou, Ramadan El Shatshat, and Ahmed M. Gaouda. 2017. "Fault Detection, Isolation, and Service Restoration in Distribution Systems: State-of-the-Art and Future Trends." *IEEE Transactions on Smart Grid* 8 (5): 2170–85. <https://doi.org/10.1109/TSG.2016.2517620>.

Paper [6]

Youba Nait Belaid, Yiping Fang, Zhiguo Zeng, Patrick Coudray, Anne Barros. “Restoration Modeling and Optimization of Hybrid Overhead-Underground Power Distribution Systems”. In: IEEE Innovative Smart Grid Technologies (ISGT), Washington, Jan. 2023.

Restoration Modeling and Optimization of Hybrid Overhead-Underground Power Distribution Systems

Youba Nait Belaid^{*†}, Yiping Fang[‡], Zhiguo Zeng[‡], Patrick Coudray^{*}, Anne Barros[‡]

^{*} Electricité de France (EDF) R&D, Paris, France [‡] University Paris Saclay - CentraleSupélec, Paris, France

Abstract—Disaster awareness increased in recent years among power system stakeholders to face many natural, technical, and malicious adversities. The smart distribution grid (SDG) is thereby at the core of proposed system enhancements, due to its high fragility as well as being the interface to most newly introduced grid applications (distributed energy resources, electrical vehicles, industrial Internet-of-Things, etc.). The SDG can be characterized by the type of lines composing the feeders (overhead and/or underground) and deployed intelligent electronic devices (IED) that allow efficient monitoring, protection, and control of the system. This paper proposes an optimization formulation to enhance the resilience of overhead and underground networks, while considering the coupling between power grid operation and the communicating remote-controlled switches (RCS). Novel *radiality* constraints are introduced to guarantee the tree structure during operation. Results from testing the model in a real network show the validity of proposed radiality constraints and quantify the gap in terms of achieved resilience between full overhead and hybrid overhead-underground networks.

Index Terms—Smart Grid, Resilience, Overhead and Underground Networks, Radiality, Optimization, Communication

NOMENCLATURE

Sets

N	Set of all power nodes (HV/MV SS, MV buses)
S	Set of HV/MV Substations (SS)
L	Set of all power lines
L^o, L^u	Set of overhead (o), underground (u) lines
L^m, L^r	Set of manual, remote switchable lines, resp.
L^{ar}, L^{cb}	Set of auto-reclosing, circuit-breaking lines, resp.
F	Set of failures in power lines

Parameters

M	Large number
l_l^m, l_l^r	1 if line l is manual, remote (resp.), 0 otherwise
l_l^{ar}, l_l^{cb}	1 if l is a recloser, a circuit breaker, 0 otherwise
f_l	1 if failure in line l , 0 otherwise
s_i	Binary parameter. 1 if i is a SS, 0 otherwise

Variables

$sw_{l,t}$	1 if switch at $l = (i, j)$ is closed at t , 0 otherwise
$sw_{ij,t}$	1 if directed switch (i, j) is closed at t , 0 otherwise
$p_{i,t}^{ns}$	Loss of active load at node i at time t
$d_{ij,t}$	1 if power flows from i to j at t , 0 otherwise
$a_{i,t}$	1 if bus i is available at t , 0 otherwise
$y_{i,t}$	1 if bus i is energized at t , 0 otherwise
$y_{i,t}^{dg}$	1 if a DG is connected at bus i at t , 0 otherwise

I. INTRODUCTION

Power systems use different types of conductors to carry electricity from generating units to customers. Underground lines are mostly used in metropolitan cities and urban areas based on their reduced losses and adequacy to a restrained public and private space, shared with other critical infrastructure assets [1]. Underground networks exhibit better robustness to many natural events like windstorms, hurricanes, and heavy snowfall; but resist less to heatwaves, flooding, earthquakes, etc., and may reduce the speed of recovery compared to overhead lines [2]. This motivates thorough evaluation of hazard threats in any given area before making the choice of the suitable conductor type to adopt [3]. However, despite the considerable proportion of underground networks in power systems, overhead lines dominate planning, operation, and restoration studies [1]. This work aims to fill this gap by proposing a general purpose model for hybrid overhead-underground configurations, applied to the case of resilience assessment. Performance disparity between fully overhead and hybrid configurations is investigated, and introduced radiality formulation is validated in a real network case study.

II. RELATED WORKS

The radial operation remains the dominating configuration in distribution grids despite proposals, more than a decade ago, to use meshed configurations given the growing penetration of distributed energy resources [4, 5]. As such, many works consider spanning tree (ST) constraints to guarantee radiality, which facilitates coordination of protection mechanisms and reduces short-circuit currents. Ref. [6] produced two necessary conditions for tree-like networks; i) The solution must have $N - 1$ branches; ii) The solution must be connected. Authors in [7] specify detailed constraints for network radiality by introducing two binary variables corresponding to each line to indicate if the node at either end of the line is the parent of the other. However, typical distribution grids contain many feeders from one or multiple high-voltage/medium-voltage substations (HV/MV SS). Thus, ST constraints are not sufficient when there is more than one source, and the aforementioned radiality conditions update to; i) The solution must have $N - sg$ branches, where sg is the number of sub-graphs (or islands); ii) Each sub-graph in the solution is a connected tree.

The single commodity flow (SCF) model is widely adopted to extend the radiality conditions [8]. In such situation, two cases can be distinguished: Case 1 - The nominal configuration

is a spanning tree, and new distributed generators (DGs) are deployed later, enforcing a spanning forest configuration; Case 2 - A real network case with a spanning forest layout, which should be kept following any network reconfiguration. SCF defines a fictitious network, identical to the considered SDG, where each sub-graph has one power source, and the remaining nodes are taken as load buses with a unit demand. Balance equations of commodity (i.e. Power) flow are used to express how each load demand is satisfied in the network, implying the existence of a path from a demanding load to the source node in every single sub-graph [9].

The same approach is used in [10] to generalize the radiality conditions to multi-source situations, which works well for the phases of *normal operation* and *service degradation* as the connected portion of the grid is either stable or shrinking, and there is prior knowledge on the number/composition of sub-graphs (sub-networks, islands). Later, the DSO deals with a variable network as the restoration is conducted through the opening and closing of switches, meaning that the number/composition of the network is unknown and to be optimized. This leads to modify the updated condition i) to:

$$\sum_{\forall (i,j) \in L} sw_{ij,t} = N - \sum_i^N root_{i,t}, \forall t \in T \quad (1)$$

where $sw_{ij,t}$ is the connection status of line $(i, j) \in L$ at time t , and $root_{i,t}$ indicates whether a power source (substation or DG unit) or a bus at node i is a root of an island at time t . Authors in [11] propose an adapted formulation to cope with the changing configuration by restricting the feasible solution to a subset from the ST of a fictitious network (the same as the SDG but without damages). The use of this approach is motivated for multi-feeder/multi-substation networks as power sources can be merged into a single node for radiality constraints, but still treated separately in operational constraints of the system [12].

Networked systems, like smart grids, are inherently prone to failure propagation due to numerous connections between involved elements [13, 14, 15]. As a result, three zones can be distinguished during a contingency event: i) Damaged zone: containing the initial failure and subsequent damages due to failure propagation; ii) Out-of-Service safe zone: part of the network, at first included in the damaged zone, but could be isolated from the damage using switches. Components in this zone can be reconnected through reconfiguration in the power network; iii) Supplied safe zone: parts that are safe from damages and still energized. Formation of these zones may differ depending on the nature of the event and the type of the network. A reasonable assumption is made here about the ability of opened lines to interrupt the spread of failures, meaning that only propagation in closed lines is considered. Still, whether lines are overhead or underground affects the expanse of the respective zones. Underground grids have the advantage of reducing outage exposure, maintenance cost, and transmission losses [2], mainly at a cost of repair difficulty and increased expenses compared to overhead networks.

III. SYSTEM MODEL

The MV level of the SDG is modeled in this work. A graph representation is adopted, where *nodes* are the MV buses and the HV/MV SS, while *edges* are the power lines. Connected grid assets include HV/MV substations, circuit breakers, auto-reclosers, and RCSs. Fault detectors are considered perfect in this study as the focus is on the contribution of RCSs to service restoration. Without loss of generality, failures are only considered in power lines, and can propagate to buses and other lines. The operation of the distribution grid is captured by the LinDistFlow model, describing power flow from HV/MV substations to low voltage (LV) loads connected at MV buses.

A. Optimization Objective

The *supplied power* is used to evaluate the performance of restoration efforts, and set as the objective function of the formulated mixed integer linear programming (MILP) problem, alongside a second term to reduce switching cost.

$$\min_{\mathbf{p}, \mathbf{d}, \mathbf{sw}, \mathbf{a}, \mathbf{y}, \mathbf{w}} \left[\alpha \sum_{\forall t} \left(\sum_{\forall i \in N} C_i^{ns} \cdot p_{i,t}^{ns} + \sum_{\forall i \in N} C_i^e (1 - a_{i,t}) \right) + \beta \sum_{\forall t} \sum_{\forall l \in L} C^{sw} \cdot w_{l,t} \right] \quad (2)$$

Equation (2) is the objective function with \mathbf{p} a vector of electrical quantities (line active/reactive power, node voltages, non-supplied load), \mathbf{d} the directions of power flow in power lines, \mathbf{sw} the statuses of line switches, \mathbf{a} the availability of power buses, and \mathbf{y} the connectivity of power buses. The first double summation term represents the total cost of not supplying a portion of the system load, where each load has its associated criticality-based cost C_i^{ns} . The next term expresses the cumulative cost induced by the extent of the damaged zone, where C_i^e is the cost of losing each electrical node. The final term is designed to include the cost of switching, as no change on the configuration is desired unless there is a gain in restored power. C^{sw} is considered the same for all operated switches, and variable $w_{ij,t}$ results from the linearization of the absolute value of $sw_{l,t} - sw_{l,t-1}$. For the constants, $\alpha \gg \beta$ as from the standpoint of a DSO during an extreme event, restoring power to clients is given priority and costs are only considered when equivalently performing strategies are obtained.

B. Radiality Constraints

We propose in this work a simplified model that gets around the changing parent and child sets [16, 7], as well as bypasses both the need for the ST polytope [12] and identification of sub-network roots [10] as illustrated in equation (1).

$$d_{ij,t} + d_{ji,t} \leq sw_{l,t}, \forall l = (i, j) \in L, \forall t \quad (3)$$

$$sw_{l,t} - (2 - a_{i,t} - a_{j,t}) \leq d_{ij,t} + d_{ji,t}, \forall l = (i, j) \in L, t = 3 \quad (4)$$

$$d_{ij,t} + d_{ji,t} - (2 - a_{i,t} - a_{j,t}) \leq sw_{l,t}, \forall l = (i, j) \in L, t = 3 \quad (5)$$

TABLE I
COMPARISON OF VARIABLES AND CONSTRAINTS NUMBER

	[12]	[16]	Proposed DLF
Variables	$2 \cdot N \cdot L + L $	$ N + 3 \cdot L $	$2 \cdot N + 3 \cdot L $
Constraints	$ N ^2 + 2 \cdot N \cdot L - N - L + 1$	$ N + L $	$2 \cdot N + 3 \cdot L $

$$\sum_{\forall j \in n(i)} d_{ji,t} \leq a_{i,t} - s_i - y_{i,t}^{dg}, \forall i \in N, \forall t \quad (6)$$

$$\sum_{\forall j \in n(i)} d_{ij,t} \leq M \cdot \left(\sum_{\forall j \in n(i)} d_{ji,t} + s_i + y_{i,t}^{dg} \right), \forall i \in N, \forall t \quad (7)$$

Constraint (3) imposes unidirectional flow of power, while capturing the existence of *unsupplied* closed lines in damaged zones. This fact is missed in all reviewed works as an equality sign in (1) would force energizing (de-energizing) a line to be equivalent to closing (opening) it. Then, (4) and (5) state that for the reconfiguration phase ($t = 3$), a line out of damaged zones is safely energized as soon as closed. The damage in a line is represented by directly failing the two connected nodes, meaning that both *failed-open* and *failed-closed* events can be considered. Constraint (6) prohibits power from flowing into HV/MV substations or nodes with a DG source, while indicating that any other bus has at most one parent node. If this parent node is not supplying power to the considered node i , or i is neither a substation nor a DG, no downstream power supply is possible from i as encoded in (7). This construction admits the formation of out-of-service islands affected either by the failure event or a shortage of power supply. Our directed local flow (DLF) approach relies on basic local rules that ensure the systemic validity of the radiality requirement, without the need for *restricting* global constraints like (1).

Table I summarizes the number of variables and constraints in the proposed radiality formulation alongside two recent works [12] and [16]. The least number of constraints is presented in [16], where radiality conditions need the implicit contribution of power flow equations to avoid disconnected graphs with loops [6] (power flow constraints are not counted in Table I). This can be argued to be more compact (*compact* in the sense of less constraints to achieve the same goal), but when solving the MILP problem, infeasible configurations are considered due to insufficient radiality constraints, causing a larger number of iterations [17]. Besides, unlike DLF, out-of-service zones are not seized, imposing the energization of all nodes out of damaged zone.

The number of variables $a_{i,t}$ can be subtracted from our model when compared to [16] because the availability status of power nodes is defined anyway in the global distribution service restoration model, making the two models equivalent in terms of the number of variables. A tight construction is presented in [12] with the expense of an increased number of variables and constraints. The same level of tightness is achieved by applying constraints (3), (7), and (6) sequentially,

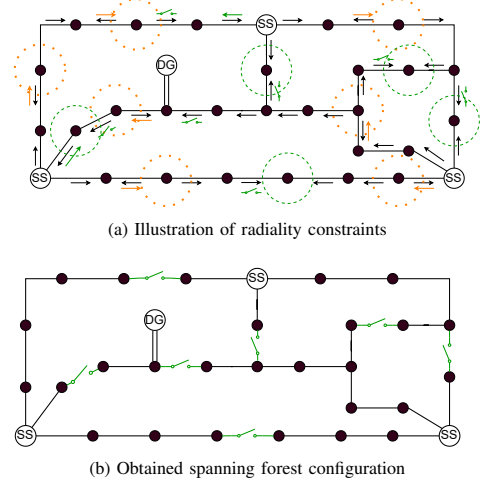


Fig. 1. Example of sequential application of the proposed DLF

to result in a directed spanning forest polytope as a solution set.

Figure 1a shows an example of applying constraints (3)–(7) in a multi-source distribution grid. The DG is assumed to be connected at the associated bus, and a general objective can be defined as maximizing the number of connected buses. First, only one power flow direction is allowed, and the dark arrows show a possible configuration that satisfies (3). Then, close inspection of this configuration reveals three issues: i) No power ingress to a bus that is supplying other buses (dotted orange circles); ii) More than one power ingress to a bus node (dashed green circles); iii) Power flow into substations or DGs. Constraint (7) solves issue i) by imposing the existence of a path from a source to any energized node, and the initial randomly-chosen configuration is updated with the orange arrows. Remaining issues are resolved using (6) (update with green arrows and opened switches) to yield a directed spanning forest with four tree-like islands interconnected with normally-open switches (Figure 1b).

C. Cascade Constraints

Figures 2a and 2b show two widely used topologies in overhead and underground SDGs, respectively. An electric bus in overhead lines allows downstream power flow to other buses, and supplies any load directly connected to it (e.g. MV/LV substation is the load in MV distribution grid). A single line in Figure 2a corresponds to many successive poles that join line segments in any large scale distribution grid. A switch is generally present in one of the poles, so it is fairly representative to model this by a switch for each line (that includes many poles and line segments). This representation is less valid in case of underground networks with less derivations as MV/LV substations are powered in series. A straightforward consequence of Figure 2b is that MV/LV SSs can be considered electrical buses with switches at any interface with a power line. Despite the expensive deployment of additional switches, the series configuration can achieve the

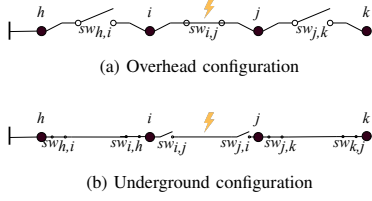


Fig. 2. Failure propagation in power distribution networks

narrowest isolation in case of a failure, which contributes to maintain more connected loads.

$$a_{i,t} + sw_{l,t-1} \cdot (1 - l_{ij}^{cb}) \cdot (1 - l_l^{ar}) - 1 \leq a_{j,t}, \quad \forall l = (i, j) \in L, t = 1 \quad (8)$$

$$a_{i,t} + sw_{l,t} - 1 \leq a_{j,t}, \forall l = (i, j) \in L, t \in \{2, 3\} \quad (9)$$

$$a_{i,t} \leq 1 - f_l \cdot sw_{l,0} + s_i, \forall l = (i, j) \in L^o, \forall t \quad (10)$$

$$a_{i,t} \leq 1 - f_l \cdot sw_{ij,t} + s_i, \forall l = (i, j) \in L^u, \forall t \quad (11)$$

$$sw_{l,t} = sw_{ij,t} \cdot sw_{ji,t}, \forall l = (i, j) \in L^u, \forall t \quad (12)$$

Constraint (8) represents the automatic response of the grid ($t = 1$), where the presence of a circuit breaker or an automatic recloser ($l_{ij}^{cb} = 1$ or $l_l^{ar} = 1$) at line (i, j) stops the propagation of the failure. Each line is visited twice in this expression, with $a_{i,t}$ and $a_{j,t}$ commuting positions, to yield an equality in case of an automatic response in the line. Constraint (9) ensures that damaged zones are not connected to safe (supplied or out-of-service) zones. This is guaranteed by requiring open lines between safe and damaged zones. Connecting out-of-service zones to supplied zones is possible.

Damages in power lines are fed to the model through parameter f_{ij} . Using (10), both connected nodes to an overhead line (i, j) become unavailable if the line was initially closed (failed-closed event). To include the failed-open case, (10) can be easily adapted by removing the operand $sw_{ij,0}$. Similarly, underground lines propagate the initial failure in (11), with the subtlety that $sw_{ij,t}$ is no longer indirected, because it represents the switch associated to node i and $sw_{ji,t}$ is the switch closest to node j . The underground case triples thereby the number of variables for switch states as the indirected variable $sw_{l,t}$ (switch status for line $l = (i, j)$) is kept. Constraint (12) determines that an underground line is closed only when both switches are closed. The non-linear quadratic component therein can be easily linearized to an equivalent set of constraints as the involved variables are integers.

$$sw_{l,t} \leq sw_{ij,t}, \forall l = (i, j) \in L^u, \forall t \quad (13)$$

$$sw_{l,t} \leq sw_{ji,t}, \forall l = (i, j) \in L^u, \forall t \quad (14)$$

$$sw_{ij,t} + sw_{ji,t} - 1 \leq sw_{l,t}, \forall l = (i, j) \in L^u, \forall t \quad (15)$$

The two variables $sw_{l,t}$ and $sw_{ij,t}$ are different. Other than constraints (11)–(15), the undirected variable $sw_{l,t}$ is used throughout the model to represent the state of line $l = (i, j)$.

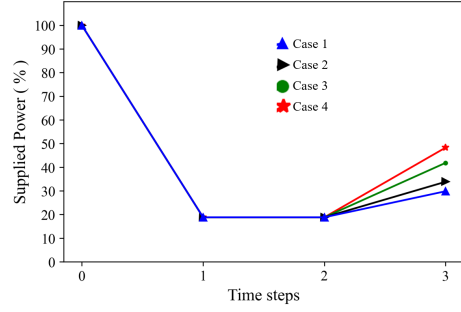


Fig. 3. Supplied power evolution during degradation, isolation, and reconfiguration

IV. CASE STUDY

A case study of 315 MV buses with 4 HV/MV substations (SS) is extracted from a french MV distribution network to demonstrate the effectiveness of the proposed approach. Capacitors, transformers, and regulators are ignored in compliance with the study objectives. The analysis is conducted in the real 20 kV nominal voltage unbalanced distribution network of total 58.935 MW demand. The model is implemented in Pyomo, and solved by Cplex solver. No optimality gap is specified to the solver as the model yields the optimal solution in all cases presented below. We choose: $\alpha = 10, \beta = 0.1, C_i^{ns} = 0.5, C_i^e = 1$, and $C_i^{sw} = 0.1$. Power lines contain either remote or manual switches, and a scenario of 15 damages is considered. We set:

- Case 1: all failed lines are overhead lines;
- Case 2: 5 out of 15 failed lines are remote and underground;
- Case 3: 10 out of 15 failed lines are remote and underground;
- Case 4: all failed lines are remote and underground.

Figure 3 depicts the evolution of the percentage of supplied power over degradation, isolation, and reconfiguration phases in the SDG. Performance is the same at degradation ($t = 1$) and isolation ($t = 2$) phases for different configurations, but the degree of isolation is different. This comes to light on the remote reconfiguration phase where Case 4, having the highest number of involved underground lines, achieves the best restoration strategy (47.84%). The other cases attain less recovery due to a broader isolation, which caused some buses to remain in faulted zones and not being able to reconnect.

The changing configuration of the SDG is tracked, in order of occurrence, by figures 4b–4d for automatic isolation, remote isolation, and remote reconfiguration. Examples of switch maneuvers are shown in 4b and 4c by an opened-switch symbol. The supplied buses are reached by green lines, while unserved manual and remote lines are shown in gold and violet, respectively. Opened lines for substation protection and isolation are shown in dashed lines (violet for remote switches, and light pink for circuit breakers). Radiality is respected as all damaged zones remain isolated from safe zones. Note that, for all considered cases, a simulation of

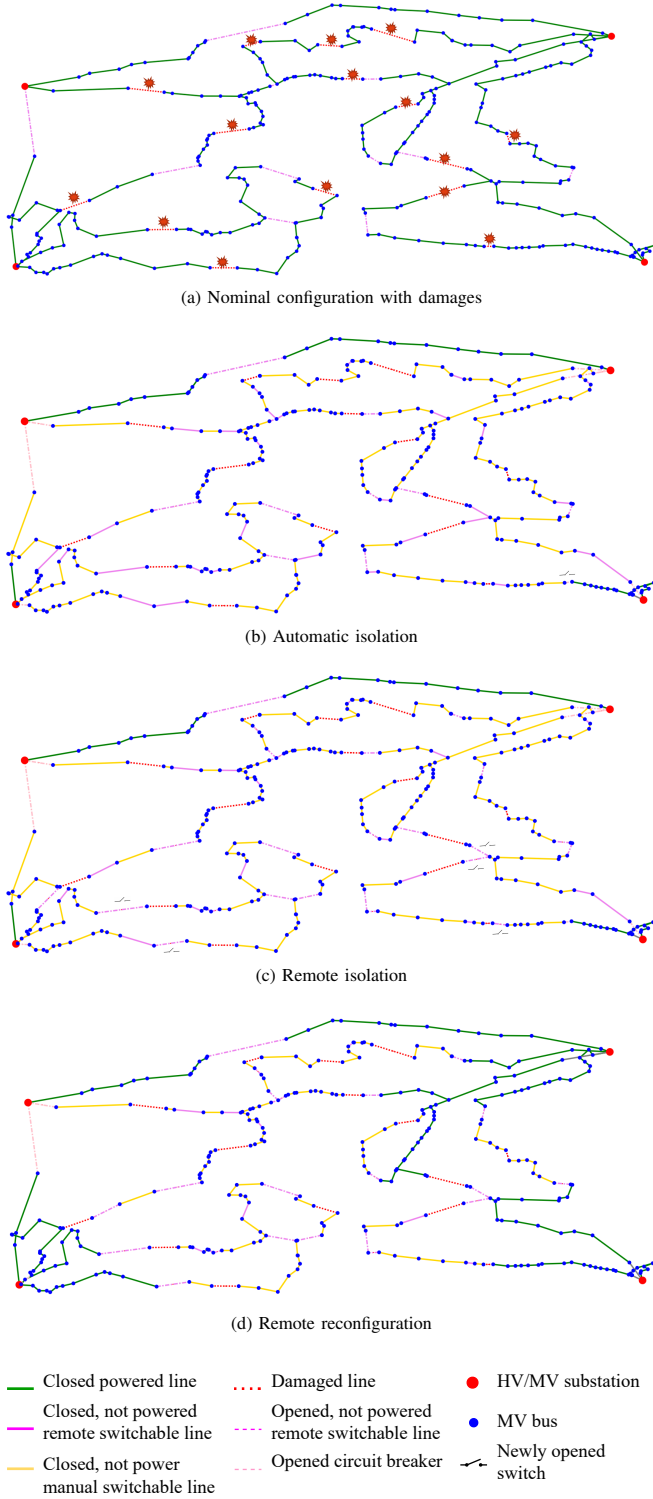


Fig. 4. Multi-feeder 315-bus distribution network in different phases

the model including data fetching, parameter initialization, solution, and result-retrieving takes 5 to 6 seconds, with less than 1 second for finding the solution by the optimizer (given the 34782 constraints and 14122 variables). This demonstrates

the computational efficiency of the proposed radiality model, designed for use during crisis management situations.

V. CONCLUSION

A modeling approach using a MILP is adopted in this work to represent the variety of configurations in SDGs in terms of conductor types. Thus, underground and overhead lines are well captured by proposed constraints, while radiality of the distribution system is guaranteed through a novel formulation. The model is applied to solve the remote reconfiguration problem that seeks a combination of switch states to maximize supplied load with minimal costs. Simulation results corroborate the effectiveness of the proposed approach. A single deterministic failure scenario is evaluated, based on the assumption of accurate damage assessment. This assumption need to be investigated in coming work by considering a damage impact model or a stochastic approach for damage scenario generation. Other future extensions feature the study of restoration operations after the first remote response. In such case, better performance of underground networks can be decreased due to associated long repair times.

REFERENCES

- [1] Andrej Trpovski and Thomas Hamacher. "A Comparative Analysis of Transmission System Planning for Overhead and Underground Power Systems using AC and DC Power Flow". In: *2019 IEEE PES Innovative Smart Grid Technologies Europe (ISGT-Europe)*. 2019.
- [2] Steve A. Fenrick and Lullit Getachew. "Cost and reliability comparisons of underground and overhead power lines". en. In: *Utilities Policy* (2012).
- [3] Johannes Reichl et al. "The importance of incorporating reliability of supply criteria in a regulatory system of electricity distribution: An empirical analysis for Austria". en. In: *Energy Policy* (2008).
- [4] G. Celli et al. "Meshed vs. radial MV distribution network in presence of large amount of DG". In: *IEEE PES Power Systems Conference and Exposition, 2004*. 2004.
- [5] Wanyu Cao et al. "Operating principle of Soft Open Points for electrical distribution network operation". en. In: *App. En.* (2016).
- [6] Marina Lavorato et al. "Imposing Radiality Constraints in Distribution System Optimization Problems". In: *IEEE Trans. PS* (2012).
- [7] Rabih A. Jabr, Ravindra Singh, and Bikash C. Pal. "Minimum Loss Network Reconfiguration Using Mixed-Integer Convex Programming". In: *IEEE Trans. PS* (2012).
- [8] Ying Wang et al. "On the Radiality Constraints for Distribution System Restoration and Reconfiguration Problems". In: *IEEE Trans. PS* (2020).
- [9] Tao Ding et al. "A New Model for Resilient Distribution Systems by Microgrids Formation". In: *IEEE Trans. PS* (2017).
- [10] Yanling Lin. "Tri-level optimal hardening plan for a resilient distribution system considering reconfiguration and DG islanding". en. In: *App. En.* (2018).
- [11] Shunbo Lei et al. "Resilient Disaster Recovery Logistics of Distribution Systems: Co-Optimize Service Restoration With Repair Crew and Mobile Power Source Dispatch". en. In: *IEEE Trans. SG* (2019).
- [12] Shunbo Lei et al. "Radiality Constraints for Resilient Reconfiguration of Distribution Systems: Formulation and Application to Microgrid Formation". In: *IEEE Trans. SG* (2020).
- [13] Ian Dobson. "Estimating the Propagation and Extent of Cascading Line Outages From Utility Data With a Branching Process". In: *IEEE Trans. PS* (2012).
- [14] Yiping Fang, Nicola Pedroni, and Enrico Zio. "Optimization of Cascade-Resilient Electrical Infrastructures and its Validation by Power Flow Modeling: Optimization and Validation of Cascade-Resilient Electrical Infrastructures". en. In: *Risk Analysis* (2015).
- [15] Zhen Huang et al. "Characterization of Cascading Failures in Interdependent Cyber-Physical Systems". In: *IEEE Transactions on Computers* (2015).

- [16] Jiancun Liu, Yixin Yu, and Chao Qin. "A Unified Two-Stage Reconfiguration Method for Resilience Enhancement of Distribution Systems". In: *IET Gen. Trans. Dis., Transmission & Distribution* (2019).
- [17] Hamed Ahmadi and José R. Martí. "Mathematical representation of radiality constraint in distribution system reconfiguration problem". en. In: *International Journal of Electrical Power & Energy Systems* (2015).

