



OPTIMAL DESIGN AND PLANNING OF AN INTELLIGENT DISTRIBUTION NETWORK

A Thesis submitted to The University of Manchester for The
Degree of
Doctor of Philosophy

in the Faculty of Science and Engineering

2019

ZHENGHUI ZHAO

School of Electrical and Electronic Engineering
Electrical Energy and Power Systems Group

List of contents

List of contents	1
List of Figures	5
List of Tables.....	9
List of Abbreviations	11
List of Publications	13
Abstract	15
Declaration	16
Dedication	19
Acknowledgment	21
Chapter 1 Introduction.....	23
1.1 Background.....	23
1.1.1 High penetration of renewable energy resources	25
1.1.2 Declined levelized cost of RESs	28
1.1.3 Demand-side participation.....	30
1.2 Introduction of distribution network design and planning	31
1.2.1 Distribution network design and planning.....	31
1.2.2 Challenges for current distribution network design and planning framework.....	32
1.2.3 Research Gaps	33
1.3 Research Aims and Objectives	36
1.4 Contributions of this thesis	38
1.5 Thesis Structure	43
Chapter 2 Distribution network design and planning: An Overview	45
2.1 Introduction	45
2.2 A review of distribution systems	49
2.2.1 Distribution system structure	49
2.2.2 Voltage regulation and protection strategy of the distribution network.	52
2.3 Distribution network design and planning	53
2.3.1 Load forecasting	54

2.3.2 Distribution network operation constraints	58
2.3.3 Investments in the distribution systems	58
2.4 Integration of Distributed Energy Resources	60
2.4.1 Photovoltaic	64
2.4.2 Wind generation	64
2.4.3 Application of DGs	68
2.5 Demand-side participation	70
2.5.1 Aims of demand-side participation	71
2.5.2 Methods of demand side-participation	73
2.6 Chapter summary	77
Chapter 3 Review of Electricity Market	79
3.1 Introduction	79
3.2 The Role of Economics in Power Systems	81
3.3 Components of electricity price	83
3.3.1 Electricity producing costs	83
3.3.2 Transmission and network operation costs	85
3.4 Fundamentals of the electricity market	89
3.4.1 Customer behaviours and producer behaviours	89
3.4.2 The law of supply and demand	92
3.4.3 Structure and competition of the electricity market	94
3.4.4 Dynamic electricity pricing	97
3.5 Policy for renewable generation in the UK	98
3.6 Chapter summary	101
Chapter 4 Network reconfiguration in the distribution system	103
4.1 Introduction	103
4.2 Definition of distribution network reconfiguration technologies	105
4.3 Optimum distribution network reconfiguration methodology	107
4.4 Numerical results	112
4.4.1 Data preparation	112
4.4.2 case study	114
4.5 Chapter summary	117
Chapter 5 Optimal conductor size selection problems in distribution networks	119
5.1 Introduction	119
5.2 Challenges for current conductor size selection problem	121
5.3 Algorithms developed for solving the current conductor size selection problems	125

5.2.1 Objective function	126
5.2.2 Hybrid CCS optimization	132
5.4 Numerical results	134
5.3.1 Case study of the 33-bus network	136
5.3.2 Case study of the 69-bus network	143
5.3.3 Summary and discuss	149
5.5 Chapter summary	150
Chapter 6 Dynamic Pricing Framework for Demand Response considering the thermal limitation	153
6.1 Introduction	153
6.2 Concept of Time-Varying Electricity Pricing Mechanism	155
6.3 Typical Frameworks of Time-Varying Pricing in the Existing Studies	160
6.4 Models for TUoS and DUoS allocation approach	162
6.5 Electricity pricing elasticity matrix	167
6.6 Numerical results	170
6.7 Chapter summary	178
Chapter 7 Investigation of the potential conflict between day-ahead distribution network use of system charges and renewable energy production	181
7.1 Introduction	181
7.2 Current challenges for the day ahead electricity pricing mechanism	184
7.3 Framework developed for the proposed day-ahead pricing mechanism	187
7.4 Case study	194
7.4.1 Case study 1 (neglecting network constraints)	198
7.4.2 Case study 2 (considering network constraints)	201
7.4.3 Discuss of the numerical results	204
7.5 Chapter summary	210
Chapter 8 Conclusions and Future Work	213
8.1 Main objectives accomplished	214
8.2 Main contributions	215
8.3 Future Work	218
References	221
Appendix	243
A. Power flow data and branch data for 37 bus distribution system	243
A.1 Branch data for 37 bus distribution system	243
A.2 Underground cable data used for 37 bus distribution system	244
A.3 Loads data for 37 bus distribution system	244

A.4 Predicted load profiles for 37 bus distribution system	245
A.5 Predicted PV and wind generation for 37 bus distribution system.....	246
B. Power flow data and branch data for 33 bus distribution system	247
B.1 Power flow data for 33 bus distribution system.....	247
B.2 Branch data for 33 bus distribution system.....	247
B.3 Baseload profiles	248
C. Power flow data and branch data for 69 bus distribution system	248
C.1 Power flow data for 69 bus distribution system.....	248
C.2 Branch data for 69 bus distribution system.....	250
D. Power flow data and branch data for 6 bus distribution system.....	252
D.1 Power flow data for 6 bus distribution system	252
D.2 Branch data for 6 bus distribution system	252

Word count: 60405

List of Figures

Figure 1-1 EU-28 renewables share (as percentage of gross electricity production) [41]	26
Figure 1-2 Generation mix in 2018 [41]	27
Figure 1-3 2030 projection of renewable electricity share in European Commission’s Long- Term Strategy [41]	27
Figure 1-4 Total power generation capacity in the European Union 2008-2018 [42]	28
Figure 1-5 Global levelized cost of electricity from utility-scale renewable power generation technologies [43]	29
Figure 2-1 The basic structure of a typical power system [89]	46
Figure 2-2 Typical structures of radial, loop and meshed network [89]	50
Figure 2-3 Typical structure of a distribution system [89]	51
Figure 2-4 Typical scheme of a distribution branch with voltage regulator [89]	52
Figure 2-5 Typical load profiles of different kind of customers	57
Figure 2-6 The typical generation output of solar photovoltaic [139]	64
Figure 2-7 The structure of wind turbine [140]	66
Figure 2-8 The typical wind turbine characteristic curve [140]	67
Figure 2-9 Typical load shape for different means of demand side management	74
Figure 3-1 Typical demand curve of electricity trading [160]	90
Figure 3-2 Typical supply curve of electricity trading [160]	91
Figure 3-3 Market equilibrium in the short term trading process [160]	93
Figure 3-4 The basic structure of the traditional monopoly electricity utility [172]	95
Figure 3-5 Electricity market structure with retailer competition [172]	97
Figure 4-1 Modified IEEE 37-bus test network	107
Figure 4-2 Process of proposed genetic algorithm based optimization approach	111
Figure 4-3 Typical household electricity demand in the UK (Source from CREST Domestic electricity demand model)	112
Figure 4-4 Typical output of PV generation (Source from CREST Integrated PV electricity demand model)	112
Figure 4-5 load profiles of each node in the network	113

Figure 4-6 Predicted PV generation in the test system	113
Figure 4-7 Predicted wind generation in the test system.....	114
Figure 5-1 Flow chart of the proposed hybrid CSS optimization algorithm	134
Figure 5-2 Single line diagram of the 33-bus distribution network.....	137
Figure 5-3 Overall results of the best fitness value and average fitness value	138
Figure 5-4 Adaptive mutation rate in each iteration	139
Figure 5-5 Conflict of the life cycle costs of conductors and energy losses costs (case 33-bus network)	141
Figure 5-6 Wind farm output at each iteration (case 33-bus network).....	141
Figure 5-7 Minimum voltage at each iteration (case 33-bus network)	142
Figure 5-8 Maximum voltage in each iteration (case 33-bus network).....	142
Figure 5-9 Single line diagram of the 69-bus distribution network.....	143
Figure 5-10 Overall results of the best fitness value and average fitness value (case 69-bus network)	145
Figure 5-11 Adaptive mutation rate in each iteration (case 69-bus network)	145
Figure 5-12 Conflict of the life cycle costs of conductors and energy losses costs (case 69-bus network)	146
Figure 5-13 Wind farm outputs at each iteration (case 69-bus network).....	147
Figure 5-14 Minimum voltage at each iteration (case 69-bus network)	147
Figure 5-15 Maximum voltage in each iteration (case 69-bus network).....	148
Figure 6-1 Sample of Time of Use Pricing (TOU).....	157
Figure 6-2 Sample of Real-Time Pricing (RTP).....	158
Figure 6-3 Sample of Variable Peak Pricing (VPP).....	159
Figure 6-4 Sample of Critical Peak Pricing (CPP)	159
Figure 6-5 Sample of Critical Peak Rebate Pricing	160
Figure 6-6 Proposed IEEE 6 bus test network	171
Figure 6-7 Demand curve in each load	172
Figure 6-8 Transmission usage in each line.....	173
Figure 6-9 Hourly transmission cost at each load point	173
Figure 6-10 Hourly nodal price at each load point and customers expected price.	174
Figure 6-11 Initial demand curve and adjusted demand curve at load 5	176
Figure 6-12 Comparison of electricity price signal and initial price at load 5.....	177

Figure 6-13 Initial demand curve and adjusted demand curve at load 6	177
Figure 6-14 Comparison of electricity price signal and initial price at load 6.....	178
Figure 7-1 Framework for the proposed day-ahead pricing mechanism	188
Figure 7-2 Modified IEEE-33 nodes distribution network.....	195
Figure 7-3 Average domestic electricity usage profiles in the UK	195
Figure 7-4 Predicted load profiles.....	197
Figure 7-5 The relationship between unit generation price and real-time usage rate of the wind turbine	198
Figure 7-6 Energy consume from two sources and the variation of load profile (scenario 1).....	199
Figure 7-7 Usage rate of each line by time-series in scenario 1.	200
Figure 7-8 DUoS charge of each node in scenario 1.	200
Figure 7-9 The performance of different price signal in scenario 1.	201
Figure 7-10 Energy consume from two sources and the variation of load profile (scenario 2).....	202
Figure 7-11 Usage rate of each line by time-series in scenario 2.	202
Figure 7-12 DUoS charge of each node in scenario 2.	203
Figure 7-13 The performance of different price signal in scenario 2.	203
Figure 7-14 Average daily DUoS charge at each node.....	204
Figure 7-15 Comparison of optimized price signal of two scenarios.....	205
Figure 7-16 Time varying usage rate at line 7	205
Figure 7-17 Time varying usage rate at line 19	206
Figure 7-18 Time varying usage rate at line 22	206
Figure 7-19 Time varying usage rate at line 29	207
Figure 7-20 Time varying price signal at node 7	208
Figure 7-21 Time varying price signal at node 17	208
Figure 7-22 Time varying price signal at node 22	209
Figure 7-23 Time varying price signal at node 29	209

List of Tables

Table 2-1 Voltage range of distribution system in different countries [93, 96, 97] ..51	51
Table 2-2 Summary of the characteristic and functions of different types of DGs ...63	63
Table 4-1 Definition of loops that used in proposed approach108	108
Table 4-2 Relationship between status of loops and bit value108	108
Table 4-3 distribution network reconfiguration status under certain chromosome string.....109	109
Table 4-4 Numeric results of binary traversal approach114	114
Table 4-5 Numeric result of the genetic algorithm approach115	115
Table 4-6 Elapsed time of two different approaches116	116
Table 5-1 Parameter of adaptive generic algorithm135	135
Table 5-2 Parameter of the standard generic algorithm135	135
Table 5-3 Specifications of proposed ACSR Conductors135	135
Table 5-4 Cost parameters of conductor investment [233]136	136
Table 5-5 Parameters of test network137	137
Table 5-6 Best conductor size selection for 33-bus distribution network.....139	139
Table 5-7 Parameters of the 69-bus network143	143
Table 5-8 Best conductor size selection for 69-bus distribution network.....148	148
Table 7-1 Investment and O&M cost list of the wind turbine196	196

List of Abbreviations

Abbreviations

AC-OPF

AGA

CBs

CHP

CPF

CfD

CSS

COM

ED

EMS

DERs

DNOs

DP

DGs

DR

DSM

DMS

DUoS

EPS

EPEM

EMR

ESS

EV

FCs

GA

IEDs

LCC

LCCC

Definition

AC Optimal Power Flow

Adaptive Genetic Algorithm

Circuit Breakers

Cogeneration Heats and Power

Carbon Price Floor

Contracts for Difference

Conductor Size Selection

Common Object Model

Economic Dispatch

Energy Management System

Distributed Energy Resources

Distribution Network Operators

Dynamic Pricing

Distributed Generations

Demand Response

Demand Side Management

Demand Management System

Distribution Use of System Charges

Emission Performance Standard

Electricity Price Elasticity Matrix

Electricity Market Reform

Electricity Storage System

Eclectic Vehicle

Fuel Cells

Genetic Algorithm

Intelligent Electronic Devices

Life Cycle Cost

Low Carbon Contracts Company

LCOE	Levelized Costs of Electricity
MGs	Microgrids
MMG	Multi-microgrid
NGs	Nanogrids
NETA	New Electricity Trading Arrangement
O&M	Operation and maintenance
PV	Photovoltaic
RES	Renewable Energy Resources
RO	Renewable Obligation
ROCs	Renewable Obligation Certificates
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
SSS	Smart Secondary Substation
V2G	Vehicle to Grid
VPP	Virtual Power Plants

List of Publications

Conference papers:

1. Zhao, Z.; Mutale, J. Simulation of automatic network reconfiguration technology in distribution system by OpenDss. In Proceedings of 2016 51st International Universities Power Engineering Conference (UPEC), 6-9 Sept. 2016; pp. 1-5.
2. Z. Zhao and J. Mutale, "Improved dynamic pricing framework for demand response considering transmission limits," 2018 13th IEEE Conference on Industrial Electronics and Applications (ICIEA), Wuhan, 2018, pp. 672-678.

Journal articles:

3. Zhao, Z.; Mutale, J. Optimal Conductor Size Selection in Distribution Networks with High Penetration of Distributed Generation Using Adaptive Genetic Algorithm. *Energies* 2019, 12, 2065.
4. Zhao, Z.; Mutale, J. 'Investigation of the potential conflict between day-ahead distribution network use of system charges and renewable energy production' to be submitted to the journal *IET Transmission, Distribution & Generation*.

Abstract

The University of Manchester

submitted by Zhenghui Zhao
for the degree of Doctor of Philosophy
and entitled Optimal Design and Planning of an Intelligent Distribution Network
June 2019

Climate change is currently a public concern. As a significant amount of electricity is still produced from fossil fuels, there is a lot of work focusing on the decarbonisation of the electric industry. By 2020, it is expected that 15% of the total electricity demand in the UK is required to be generated from renewable energy sources (RES) with a 20% reduction in greenhouse gas (GHG) emissions. A series of efforts have been made in distribution systems for achieving the above targets such as widespread utilisation of distributed generations (DGs) and the application of electricity tariff schemes. However, a high penetration of the DGs results in the potential mismatch between the generation and the demand profile since the generation of typical DGs such as wind turbines (WTs) and photovoltaic (PV) largely depend on the availability of natural resources.

The work reported in this thesis focused on the design of innovative network planning frameworks and investment models assuming the dynamic DUoS and variable RES generation pricing mechanisms. In particular, an optimum day-ahead pricing mechanism was developed for DGs and DNOs to manage their RES to achieve revenue reconciliation and connected more DGs. Based on the proposed DUoS charge approach and the principle of electricity price elasticity, an innovative dynamic-pricing framework was introduced to find out the optimum price signal with the consideration of wholesale market, benefits of power suppliers and customers' behaviours. Moreover, a hybrid optimization approach was introduced to solve the optimal conductor size selection (CSS) problem in the distribution systems planning process with the high penetration of DGs. Finally, a genetic algorithm based distribution network reconfiguration approach was designed to provide the optimum day-ahead network topologies considering the predicted data of load demand and available output of the distributed generations.

The numerical results demonstrated that the proposed day-ahead pricing mechanism efficiently reduce the mismatch between the RES generation and demand profiles and relieve the network congestion problems during both peak demand or peak generation periods. Moreover, DNOs can use the proposed framework to provide the optimized time-based electricity price to their customers for changing the time and amount that customers consume the electricity, thus avoiding the curtailment of RES or high DUoS charge. The numerical results also demonstrated that the proposed CSS approach can allocate the suitable conductor type from the given inventories to each branch in the network.

Declaration

No portion of the work referred to in the thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

Copyright Statement

i The author of this thesis (including any appendices and/or schedules to this thesis) owns certain copyright or related rights in it (the “Copyright”) and s/he has given The University of Manchester certain rights to use such Copyright, including for administrative purposes.

ii Copies of this thesis, either in full or in extracts and whether in hard or electronic copy, may be made **only** in accordance with the Copyright, Designs and Patents Act 1988 (as amended) and regulations issued under it or, where appropriate, in accordance with licensing agreements which the University has from time to time. This page must form part of any such copies made.

iii The ownership of certain Copyright, patents, designs, trade marks and other intellectual property (the “Intellectual Property”) and any reproductions of copyright works in the thesis, for example graphs and tables (“Reproductions”), which may be described in this thesis, may not be owned by the author and may be owned by third parties. Such Intellectual Property and Reproductions cannot and must not be made available for use without the prior written permission of the owner(s) of the relevant Intellectual Property and/or Reproductions.

iv Further information on the conditions under which disclosure, publication and commercialisation of this thesis, the Copyright and any Intellectual Property and/or Reproductions described in it may take place is available in the University IP Policy (see [http:// documents.manchester.ac.uk/ DocuInfo.aspx?DocID=487](http://documents.manchester.ac.uk/DocuInfo.aspx?DocID=487)), in any relevant Thesis restriction declarations deposited in the University Library, The University Library’s regulations (see <http://www.manchester.ac.uk/library/aboutus/regulations>) and in The University’s policy on Presentation of Theses

Dedication

To my dearest mum and dad, Song Li and Shoucheng Zhao
who encouraged and constantly supported me to take up this challenge of my life

Acknowledgment

I would like to express my deepest gratitude to all the people who help and support me for my PhD study and this thesis.

First and foremost, I would like to express my greatest gratitude to my supervisor, Professor Joseph Mutale. I am deeply grateful for his kindness, consideration, continuous guidance and support during the whole period of my PhD. He has provided great academic ideas, inspiring discussions and helpful comments, all of which have contributed to this achievement.

I wish to thank my friends and colleagues Mingyu Sun and Zhaoyang Jin for their kind help when I started my PhD study.

I also want to express my appreciation to my friends Buyang Qi, Yi Chen, YIngze Jia, and Gaoyuan Liu, whose support cannot be over-emphasized and others too numerous to mention. Thanks to you all and God bless you.

I would like to express my thanks to my special friends, Hui, Ocean and Miao for their company and pleasure sharing through my study.

At last, my deepest gratitude stays with my family, my mum and dad, and my girlfriend who have always been there to encourage me and support me and have been the best gift to my life.

Chapter 1

Introduction

1.1 Background

The first attempt to design and operate an electric power system was made by the Godalming Power Station, and the streets of Godalming were illuminated in 1881 [1]. Then, the electric industry became the cornerstone of modern society, and almost all manufacturing and life demands of modern society depend on reliable and secure electricity supplies. The fundamental objective of the current electrical power systems is the same as that of the first power system. The changing of the economic and social background considerably impacts the development of the electric power supply industry. Currently, global climate change is stimulating public concern, and conventional fossil fuel generators are responsible for the majority of carbon dioxide emissions. Thus, concerns about global environmental problems are facilitating the decarbonization of the electric industry. In the UK, for instance, distribution network operators (DNOs) are making significant changes due to UK energy targets for 2050. By 2020, it is expected that 15% of the total energy consumption in the UK will be

generated from renewable energy sources (RESs), with a 20% reduction in greenhouse gas (GHG) emissions. Further, a target reduction of 80% of GHG emissions should be achieved by 2050 [2, 3]. In addition to actions in the UK, it is expected that RESs such as wind and solar sources can provide approximately half of the electricity requirements in the EU by the end of 2050 [4].

A series of efforts have been made in distribution systems to achieve the above targets. These include the widespread utilization of distributed generators (DGs) [5-11], application of demand-side participation tools [12-16] and application of innovative electricity tariff schemes [17-26]. All these efforts significantly change the background of current electrical power sectors. Ultimately, the overall background of this thesis can be summarized as follows.

1. High penetration of renewable energy resources

Concerns about global climate change are motivating current electric sectors to become more environmentally friendly and sustainable. Therefore, one of the objectives among power systems is to increase electricity generation from renewable energy resources (RESs) and thereby reduce GHG emissions. Thus, electrical power systems, specifically distribution systems, are currently encountering a significantly increased penetration of DERs that is driven predominantly by growing consumer commitments to environmentally friendly generation, government incentives, increasing electricity prices, and reductions in the cost of DER technologies.

2. Declined levelized cost of renewable generation

The cost of renewable energy is now falling so fast that it is expected to be a consistently cheaper source of electricity generation than traditional fossil fuels within just a few years, according to a new report from the International Renewable Energy Agency (IRENA) [27, 28]. The declined levelized cost of renewable generation and the beneficial policies designed to support an increase in RESs make renewable generation competitive in the electricity market. The owner of a renewable generator may charge their generation output with a relatively low rate during wind blowing or sunshine periods. Thus, in the future,

electricity users are encouraged to consume more electricity during the low-tariffs period when the power suppliers apply the hourly dynamic pricing mechanism, which has the capability to reflect the real-time wholesale price [17, 29, 30].

3. Demand-side participation

Demand-side participation provides an opportunity for electricity customers to actively participate in the currently competitive electricity market by offering different options for them to manage their electricity consumption. Larger electricity users may install distributed generators, and small customers may undertake activities such as 1) increasing energy efficiency by reducing standby power [31], 2) peak demand shifting [32] [33], 3) reducing consumption [34, 35], and 4) generating their own electricity by roof PV panels or small turbines [36-40]. In general, the actions of demand-side participation mentioned above provide DNOs and power suppliers with opportunities to affect the energy consumption behaviour of electricity users, thus increasing the average capacity factor of renewable generation and efficiently relieving network congestion problems during both peak demand and peak renewable generation periods. In the near future, hourly dynamic electricity retail pricing and hourly day-ahead pricing frameworks are expected to replace the current economic incentive framework (fixed two-rate or three-rate tariffs) and become important demand-side participation tools. Thus, DNOs and power suppliers require an innovative optimization framework to determine the optimal price signals and optimal design and operation of distribution systems with considerations for the new mechanisms of demand-side participation.

The following sections provide further insights into the above backgrounds for this research work.

1.1.1 High penetration of renewable energy resources

Due to environmental concerns, RESs have been regarded as an efficient approach to relieving the concerns of global warming and carbon dioxide emissions. Based on the deregulation process of the European energy market, the unbundled energy

sector is now in transition to more competition in electricity generation, distribution and trading. With free access to the electrical distribution grids and suitable energy wheeling conditions, new players will arrive in the competitive market, further supporting the already existing trend towards more distributed generators (DGs) of power. This trend has mainly been induced by the increasing integration of RESs. In general, more and more power is generated by renewable resources such as wind, solar and hydro in European countries. Figure 1-1 indicates that renewables generated 32% of the electricity consumed by EU electricity users in 2018. In particular, wind had the largest share in the renewables mix, contributing 12% of Europe’s electricity. Solar contributed 4%, which was less than biomass and a third of wind generation.

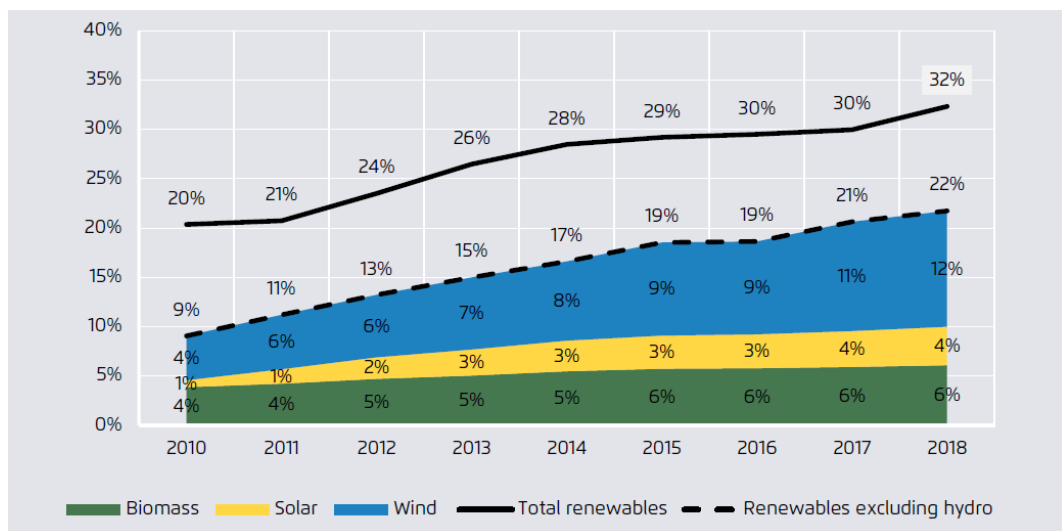


Figure 1-1 EU-28 renewables share (as percentage of gross electricity production) [41]

The increasing share of electricity generated from RESs results in a significant decrease of generation from hard coal and gas generators. Figure 1-1 indicates that RESs had the largest share (32.3%) in total electricity generation in 2018. Generators fuelled by hard coal and gas only had the second largest share (28.9%) in total electricity generation.

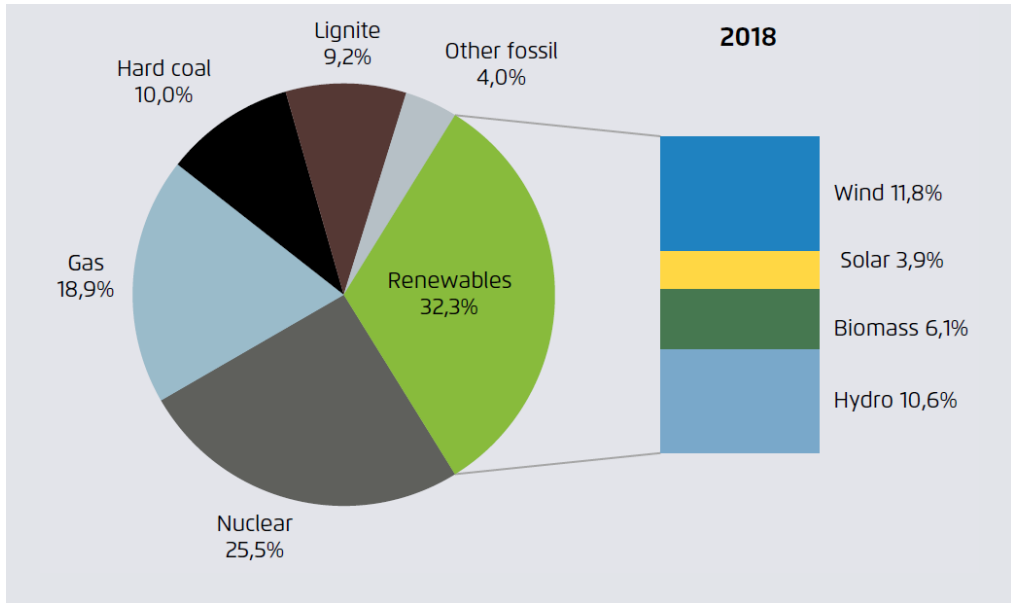


Figure 1-2 Generation mix in 2018 [41]

However, a more ambitious strategy was released in 2018 by the European Commission to achieve decarbonisation of the European economy. The objective of this strategy is to increase the share of RESs among total electricity generation to 57% from the current level of 32% by the end of 2030. In particular, Figure 1-3 shows the detailed targets expected for different RESs in 2030. For example, wind more than doubles from 12% in 2018 to 26% 2030, and solar almost triples from 4% to 11%.

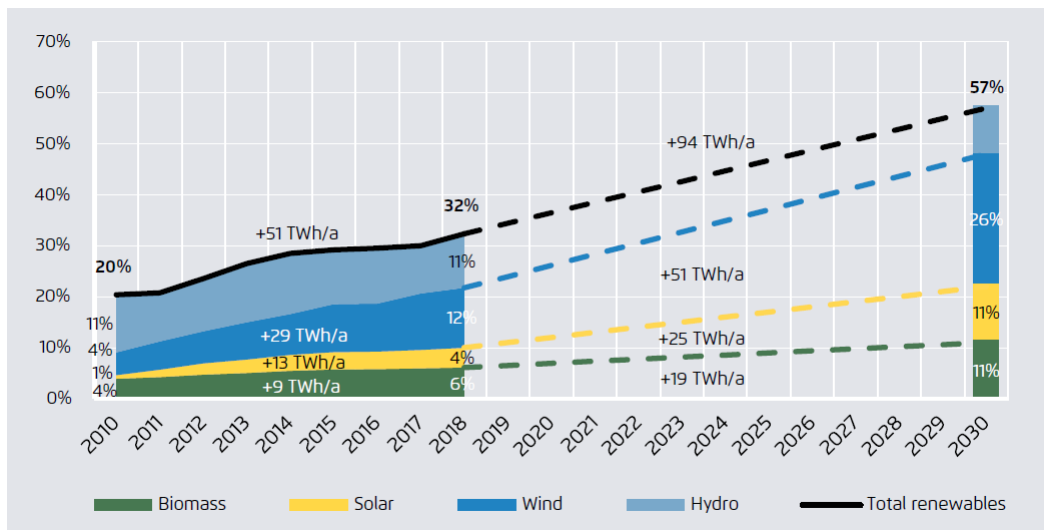


Figure 1-3 2030 projection of renewable electricity share in European Commission's Long-Term Strategy [41]

On the other hand, the newly installed capacity of RESs indicates that the power sector in EU countries is becoming cleaner and more sustainable. In 2018, 11.7 GW

of new wind generators were installed in the EU. So far, wind generators have a total installed capacity of 178.8 GW in the EU. They are the second largest form of power generation capacity in the EU-28 and are likely to overtake natural gas installations in 2019. Figure 1-4 show the installed capacity of wind generators.

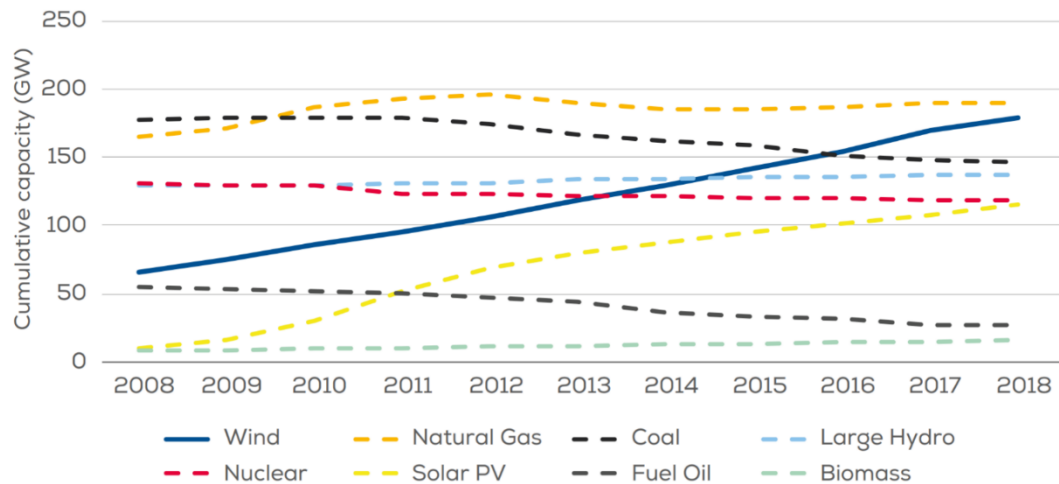


Figure 1-4 Total power generation capacity in the European Union 2008-2018 [42]

Ultimately, all the above materials and studies indicate that the electrical power system is currently encountering a significantly increased penetration of DERs driven predominantly by growing consumer commitments to environmentally friendly generation, government incentives, increasing electricity prices, and a reduction in the cost of DER technologies. However, the widespread application of different kinds of renewable generation significantly affects the design and operation of modern power systems. The characteristics of renewable generation such as poor predictability and variability of output result in an imbalance between the supply and the demand for electricity. Electricity storage system (ESSs) can partially relieve the mismatch between renewable power generation and power consumption. However, the relatively high investment and maintenance costs of ESSs undermine the advantages of this solution. Therefore, the increasing capacity of DER provides both opportunities and challenges for the operation and management of current power systems.

1.1.2 Declined levelized cost of RESs

The cost of renewable energy is now falling so fast that it should be a consistently cheaper source of electricity generation than traditional fossil fuels within just a few

years, according to a new report from the International Renewable Energy Agency (IRENA). The report also claimed that the cost of generating power from onshore wind has fallen by approximately 23% since 2010, while the cost of solar photovoltaic (PV) electricity has fallen by 73% in that time. With further price decreases expected for these and other green energy options, the report proposed that all renewable energy technologies should be competitive in price with fossil fuels by 2020. In particular, Figure 1-5 indicates that the majority of the levelized cost of electricity from utility-scale renewable power generation technologies has significantly decreased since 2010 and fallen into the range of fossil fuel costs. The fossil fuel-based generation cost range in 2017 was assessed to range from a low of USD 0.05 per kilowatt-hour (kWh) to a high USD 0.17/kWh and this cost range is shown in the Figure 1-5 as the green rectangle area. Historical data from the German wholesale electricity market also indicate that renewable energy technologies have become more and more competitive in price with conventional coal and gas plant operation costs. The intermittent nature of renewable production and the relatively low capacity factor of renewable generation are two major barriers to establish an electrical power sector dominated by RESs. Distribution network operators (DNOs) are currently developing innovative network operation and management approaches to host more renewable generation.

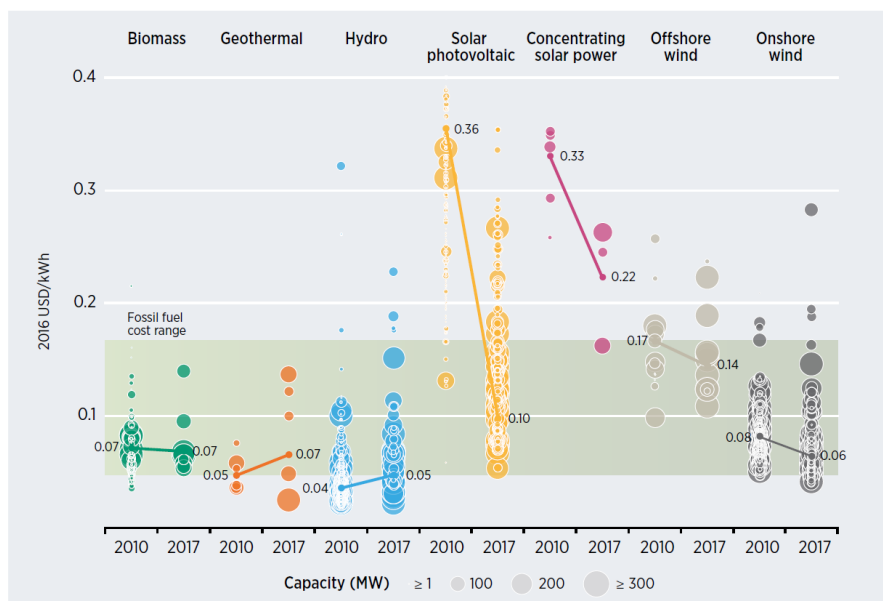


Figure 1-5 Global levelized cost of electricity from utility-scale renewable power generation technologies [43]

1.1.3 Demand-side participation

Demand-side participation provides opportunities for electricity users to actively participate in the currently competitive electricity market by offering different options for them to manage their electricity consumption. These techniques of demand-side participation are available to customers depending on their size and capacity. For example, larger commercial or industrial users may install their own energy generation supplies, undertake energy efficiency activities or negotiate arrangements to curtail their demand at peak usage times for incentives or energy cost benefits. On the other hand, small or individual electricity users such as normal households or small commercial customers may undertake activities such as energy efficiency (e.g., replacing light bulbs and reducing standby power), peak demand shifting (e.g., moving energy use to off-peak and cheaper time periods), reducing consumption, and generating their own electricity (e.g., installing solar PVs). Information to customers on the availability and impact of such actions is critical in supporting effective customer energy management. In the view of DNOs, demand-side participation can be considered as an auxiliary approach to network expansion or the network design process. In particular, distribution networks are required to meet the maximum demand on the network, for example, the electricity demand on the hottest or coldest day of the year. Demand-side participation options such as the integration of DGs and agreements with electricity customers to curtail energy use at peak demand times can defer investment on network expansion or decrease the investment of designing a new distribution network.

Demand-side participation options for DGs are currently supported by many policies in different countries. For example, Contracts-for-Difference (CfD) [44], Emission Performance Standard (EPS) [45] and Carbon Price Floor (CPF) [46] are the three newest policies to encourage the integration of RESs and secure the revenue or investment of DGs. Similar to feed-in tariff (FiTs) [47], these new policies are designed to guarantee that the DG owners can receive sufficient payments to cover their investment and O&M costs. However, the declined levelized costs of DGs allow their owners to provide low and competitive electricity tariffs during wind blowing or sunshine periods due to the low marginal costs (near to zero). However, it is difficult

to identify the relationship between the generation output of DGs and the required tariffs to cover the investment and O&M costs.

Demand-side participation options for customers are often formed as variable electricity price schemes such as peak/off-peak pricing lists [48]. Day-ahead and intraday real-time wholesale electricity pricing mechanisms enable an efficient electricity trading process [49, 50]. Hourly dynamic retailer electricity prices and hourly day-ahead retailer electricity prices [17, 29, 30] can be regarded as more efficient pricing mechanisms compared to the current fixed two-rate or three-rate pricing schemes [51]. These two innovative pricing mechanisms have the ability to not only efficiently reflect fluctuating wholesale electricity prices but also encourage the consumption of RESs during peak generation periods. However, the wide application of the hourly retailer electricity pricing mechanism requires DNOs to have precise and robust optimization approaches to deal with load forecasting and DER generation forecasting, thus determining the optimal dispatch information of DGs and optimal price signals in real time.

In the future, it is expected that all the innovative demand-side participation tools mentioned above will arrive in the electricity retailer market. Thus, the future framework of distribution network design and planning cannot neglect the consideration of these challenges and opportunities.

1.2 Introduction of distribution network design and planning

1.2.1 Distribution network design and planning

Distribution network design and planning can be regarded as one of the most significant steps to build and operate a distribution system. On the one hand, the aim of distribution network design is to ensure that distribution systems are able to meet demand growth in the most time sensitive, economical, reliable, and safe manner possible. Typically, a distribution network needs to be designed more than 10 years ahead of construction. Two significant principles considered in the design of a distribution system are 1) predicting the growth in demand of electricity users and planning system upgrades and extensions in advance and 2) choosing the optimal facilities and equipment for replacing the assets that have reached their maximum

lifespan [52]. This classical network design framework is widely applied in traditional one-way distribution systems, for which the energy delivery path is only from a high-voltage transmission system to low-voltage distribution feeders [53-55].

On the other hand, conventional distribution planning can be considered as a network operation strategy to provide a reliable and economical electricity supply with a minimum cost. In particular, DNOs predict peak load demands within the expected planning horizon and explore optimal network planning schemes to satisfy the predicted peak demands.

1.2.2 Challenges for current distribution network design and planning framework

Traditional distribution systems are predominantly designed to carry power unidirectionally from substations to consumers in a radial scheme, and they pay little attention to the participation of electricity users. The increasing penetration of DERs that are integrated into distribution systems, the declined levelized costs of renewable generation and the application of innovative demand-side participation tools have resulted in substantial changes in the conventional role of distribution systems. In general, distribution systems are slowly transferring from current passive systems to future active systems. This evaluation of distribution systems ensures that future networks have the capability to decrease the impact of connecting large-scale DGs and integrating DERs, thus allowing a high level of integration of DERs and a high penetration of RES-based DGs.

However, current methods of distribution network design and planning cannot efficiently deal with the challenges mentioned above. In particular, the high penetration of DGs results in a potential mismatch between generation and demand profiles because typical DGs such as wind turbines (WTs) and photovoltaic (PV) panels largely depend on the availability of natural resources. Moreover, the declined levelized cost of renewable generation prompts a significant increase in electricity usage during wind blowing or sunshine periods by providing low tariffs. Thus, future frameworks of distribution network design and planning are expected to counter the challenges mentioned above to achieve the maximum potential benefits of DGs with minimum costs.

1.2.3 Research Gaps

Distributed renewable generation will play an important role in future power systems due to concerns about environment impacts and limited fossil fuels resources. Thus, the potential of applying innovative optimization approaches to increase the penetration and average capacity factor of DERs in distribution networks have attracted a considerable amount of research effort. Much of the existing literature has focused on affecting the consumption behaviour of electricity customers by using relevant economic incentives, such as different tariff schemes, so that the economic benefits to both utilities and customers can be optimized. However, the DUoS charges have often been neglected in previous studies. This is partly because 1) most current distribution networks have a sufficient capacity to provide secure service to end customers, 2) the development of demand-side participation tools is currently in the early stages, and 3) the real-time pricing mechanism has only been tested in small-scale applications and no specific framework has been designed to achieve the function of dynamic DUoS charging. Further, most studies that have been devoted to designing innovative electricity tariff schemes have also paid attention to the large-scale integration of renewable generation. However, few studies have considered the O&M and investment costs of DERs in their optimization frameworks. This is partly because assuming the costs of DERs to be a fixed amount or zero can simplify optimization models.

On the other hand, considerable effort has been devoted to designing optimal electricity retail pricing mechanisms to allow a high level of integration of DERs and a high penetration of RES-based DGs [17, 18, 23, 24, 26, 56-63]. Most of this work has focused on changing the usage behaviour of customers in response to economic incentives such as time-of-use (ToU) electricity pricing approach or optimal day-ahead electricity pricing approach. In particular, TOU pricing can be regarded as an appropriate approach to apply demand-side management (DSM), where electricity retailers can use ToU pricing mechanism to affect behaviour of electricity users. By allocating different electricity prices during the daytime, the retailers can encourage electricity users to adjust their demand from peak periods to off-peak periods [23, 64]. On the other hand, day-ahead electricity markets are considered as a significant

trading process under de-regulated electricity market. A day-ahead electricity market is a short-term hedge market that operates a day in advance of the actual physical delivery of power. The optimal day-ahead scheduling approaches [65-67] and optimal day-ahead bidding strategies [68-70] for various energy systems have been intensively studied. However, few studies related to the ToU pricing mechanism or optimal day-ahead electricity pricing mechanism have noticed the problems arising from the current pricing mechanism of distribution services when designing electricity tariff schemes. In particular, they did not consider distribution use of system (DUoS) charges as a price signal in the day-ahead market, thus failing to establish a trade-off between DUoS charges and energy procurement costs. DUoS charges are levied by the UK's regional Distribution Network Operators (DNOs) and go towards the operation, maintenance and development of the UK's electricity distribution networks. The current mechanism of DUoS charging is less efficient for dealing with the high penetration of DERs in distribution networks. For example, customers who consume substantial amounts of electricity during low tariff periods only need to assume responsibility for the use of the system by the current pricing mechanism. However, the costs of network operation and future investment will be significantly increased due to the increasing consumption of DERs caused by lower tariffs during wind blowing or sunshine periods. Thus, the customers who consume less electricity still need to pay increased DUoS charges. In general, the current apportionment of DUoS charges between fixed, off-peak and peak use of system charges needs to be more cost-reflective. Thus, the current pricing mechanism in the electricity retailer market has failed to precisely reflect real-time pricing fluctuations in the wholesale market or to efficiently relieve network congestion during peak demand periods.

Moreover, other work [22, 25, 71-75] on the optimal day-ahead pricing optimization problem have considered the effect of RESs (e.g., wind generation and solar energy) and network constraints thought various mathematical algorithms such as robust optimization approach [76, 77], mixed-integer nonlinear bilevel program [78] and mixed-integer linear programming [79-81]. However, no specific studies have been devoted to designing a dynamic charging model for pricing the output of distributed

renewable generation. The declined levelized cost of renewable generation and related beneficial policies significantly increase the price competitiveness of RESs in the electricity market. Current fixed-price models or zero-cost models of DERs that have been widely applied in previous studies cannot reflect this trend and have failed to ensure revenue from DERs.

Furthermore, the significantly increased application of DERs and the rapid demand growth due to urbanization and industrialization have resulted in new challenges for the design of new distribution networks or the upgrading of existing networks. Power losses minimization is often considered as one of the most important key issues during network planning [52, 82-86]. Specifically, the conductor size selection problem can be regarded as an important process of distribution network design. A judicious selection of the conductor set can not only significantly decrease investment costs but also ensure that the network capacity can satisfy the load growth during the expected operation years. Several current frameworks designed to deal with the CSS problem have considered the integration of DERs and load growth. However, minimizing power losses and investment costs are two major targets that have been achieved in previous studies. In particular, no specific framework has been designed to investigate the potential economic conflict between the life-cycle costs of conductors and the costs of renewable resource curtailment (DNOs power suppliers need to purchase energy from the wholesale market when a selected conductor cannot provide sufficient capacity to deliver all renewable generation during wind blowing or sunshine periods). In particular, the relatively low resistance of conductors and cables, the reduced voltage levels and the high currents in distribution networks result in significant power losses. Network designers are expected to select an optimal combination of conductors to achieve the economic balance between capital investments and life cycle power loss costs. However, the large-scale installation of DERs and the declined levelized costs of renewable generation challenge the traditional optimal CSS strategy. Installed DERs in distribution systems are often considered as zero marginal cost energy resources in power operation analysis.

1.3 Research Aims and Objectives

In terms of the specific research gaps mentioned above, there are no specific optimization frameworks, dynamic pricing mechanisms or day-ahead pricing mechanisms in the literature that systematically address the impact of a high penetration of DERs and network congestion problems by considering dynamic DUoS charges and dynamic renewable prices. Moreover, no specific optimization framework has been proposed in the literature to deal with optimal CSS problem among the distribution network design process by systematically addressing the impact of a high penetration of DERs and dealing with network congestion problems. Thus, the aims and objectives of this thesis can be summarized as two main aspects in response to these research gaps. First, innovative dynamic pricing mechanisms and day-ahead pricing mechanisms are proposed to help distribution networks host more RESs and increase the average capacity factor of DERs by introducing a dynamic DUoS charging mechanism and a dynamic renewable pricing mechanism. Second, an innovative CSS framework is proposed to deal with problems among future distribution network design and planning projects. The potential cost conflict between the conductor life-cycle costs and the costs of renewable resource curtailment is a key optimization target considered in this framework.

Based on the above premises, the research presented in this thesis aims to 1) develop an innovative dynamic pricing/day-ahead pricing optimization framework and 2) develop an innovative optimization framework to deal with the optimal CSS problem. To design these two frameworks, the following objectives are required: 1) to develop a dynamic DUoS charging mechanism, 2) to develop a dynamic charging model for pricing the output of distributed renewable generation and 3) to develop an innovative optimization algorithm to deal with the CSS problem. The detailed aims of this thesis are listed as follows.

1. To develop a novel usage-based DUoS charging mechanism

As discussed earlier, most previous efforts devoted to designing the optimal electricity pricing mechanism have not considered the DUoS charges as a price signal in the day-ahead market, thus failing to establish a trade-off between DUoS charges and energy procurement costs. In general, the current

apportionment of DUoS charges between fixed, off-peak and peak use of system charges needs to be more cost-reflective. Therefore, the first objective of this thesis is to develop a new DUoS charging mechanism, highlighting the role of this price signal for efficiently relieving network congestion problems during both the peak demand and peak RES generation periods. In particular, the proposed DUoS charging mechanism is expected to provide a precise price signal based on the real-time power flow in distribution lines and ensure that the corresponding charges can completely cover the network investment and O&M costs.

2. *To develop a dynamic charging model for pricing the output of distributed renewable generation*

As mentioned earlier, most previous studies have not considered the practical economic characteristics of DERs. Indeed, the marginal cost of DERs can be considered to be zero because no fuel is consumed during operation. However, a zero marginal cost model cannot reflect the actual investment and O&M costs of DERs, thus failing to secure revenue for the owners. To fill this research gap, a dynamic charging model for pricing the output of DERs is required. The proposed model is expected to provide the competitive day-ahead price signal in the market, thereby not only encouraging suppliers to voluntarily consume more renewable energy but also ensuring that the owner of DERs' revenue can cover the investment and operation costs of DERs.

3. *To develop an optimization algorithm to deal with the CSS problems in distribution systems with a high penetration of distributed generation.*

One of the major targets of this thesis is to develop an optimization approach to determine the optimal CSS when designing a new distribution network or upgrading an existing network. The proposed optimization framework is expected to consider the dynamic pricing model of DERs mentioned above. Thus, the potential cost conflict between conductor life-cycle costs and the costs of renewable resource curtailment must be considered first. In general,

there are two optimization targets that need to be achieved: 1) minimizing the total costs of conductor life-cycle costs and the costs of generators' operation for each potential conductor selection solution (the lower optimization target) and 2) determining the optimal conductor selection for the objective network (the upper optimization target). However, most optimization approaches designed to solve the relevant problem in previous studies are not compatible with this two-level optimization issue. Therefore, it is worth developing an innovative optimization algorithm to deal with the CSS problem in distribution systems with a high penetration of distributed generation.

4. *To develop an innovative day-ahead pricing mechanism that considers dynamic DUoS charges and dynamic renewable generation prices*

Based on the research gaps introduced in section 1.2, one of the major targets of this thesis is to design an optimal day-ahead pricing mechanism to address the impact of a high penetration of DERs and network congestion problems by considering dynamic DUoS charges and dynamic renewable prices. The mechanism should have the capability to help DNOs manage their renewable resources to achieve revenue reconciliation and maximize generation output. Moreover, DNOs can optimally manage the controllable appliances installed by customers and balance energy consumption from the main grid and DERs to minimize the electricity price by applying this innovative day-ahead pricing mechanism.

1.4 Contributions of this thesis

The wide deployment of DERs challenges conventional distribution network design and planning strategies. The intermittent nature of renewable production and demand-side participation require DNOs to have the capability to immediately respond to varying renewable generation conditions and electricity consumption behaviours of customers. Moreover, the current pricing mechanism in the electricity retailer market has failed to precisely reflect real-time pricing fluctuations in the wholesale market or to efficiently relieve network congestion during peak demand

periods. Thus, it is necessary to develop innovative pricing models and optimization algorithms to fill the research gaps mentioned above. In addition, it is essential for power system designers to comprehensively incorporate the impact of high DER penetration into the distribution network design process. This thesis makes substantial contributions and innovations, such as developing an innovative dynamic DUoS charging mechanism, implementing a hybrid optimization approach to deal with the CCS problem, proposing a novel dynamic pricing framework for DR considering thermal limitations, and developing a day-ahead pricing mechanism for managing distribution network congestion caused by the increasing application of renewable generation. Ultimately, this thesis has established several innovative models and optimization frameworks for decreasing the impact of integrating DERs and increasing the operation efficiency of distribution systems.

More specifically, the main contributions of this thesis are summarized as follows:

1. *The development of an innovative network configuration technology for distribution networks*

To explore the performance and benefits of network configuration technologies in distribution systems, a genetic algorithm (GA) is applied in MATLAB and OpenDSS to determine the status of switches each hour to achieve minimum power losses. To verify the accuracy of the GA approach, a binary traversal approach was tested in the network first to provide a standard result. Then, the GA approach was tested in the same network with the same load and distributed generation profiles. The results indicated that the GA approach provided the same solution for network reconfiguration, but the elapsed simulation time dramatically decreased. Benefited by the decrease of the elapsed time, the methodology is expected to be applied in real distribution networks. The approach has the capability to arrange the optimal topology in advance at each hour by analysing the predicted data of load demand and distributed generation.

The relevant research and study are presented in Chapter 4. This research has been summarized as a conference paper titled 'Simulation of the automatic

network reconfiguration technology in the distribution system by OpenDss', which has been presented orally and included in the database IEEE Xplore.

2. The development of the conductor size selection problem in distribution network design and planning

To explore the optimal distribution network design problems, we consider the conductor size selection problem in distribution networks with renewable resources. The large-scale installation of distributed generators (DGs) and the declined levelized cost of renewable generation challenge the traditional optimal CSS strategy. Installed DGs in a distribution system is often considered as a zero marginal cost energy resource in power operation analysis. In distribution systems with a high penetration of renewable generation, DNOs need to allocate suitable conductors at different branches to consume the available output of DGs, thus maximizing the economic benefits from renewable resources. Therefore, the selected conductors are expected to have enough current carrying capacity to satisfy the peak output of the installed DGs. In addition, the conductor investment cost is also an important economic factor that needs to be considered. Therefore, DNOs have difficulty identifying the optimal conductor arrangement for a distribution system with a high penetration of DGs. During the CSS process, DNOs often face two opposite results: 1) an excessive investment in conductor selection and 2) an insufficient capacity in the selected conductors to consume available renewable resources, thus increasing the total energy procurement costs. A hybrid optimization approach is introduced to solve the optimal conductor size selection problem in distribution networks with a high penetration of DGs. An adaptive genetic algorithm (AGA) is employed as the primary optimization strategy to find the optimal conductor combination for networks. The aim is to minimize the sum of the life-cycle costs (LCCs) of the selected conductors and the total energy procurement cost. AC optimal power flow (AC-OPF) analysis is applied as the secondary optimization strategy to secure the economic dispatch (ED) and return the optimal energy procurement results to the primary optimization process when a certain

conductor arrangement is assigned by the AGA. The effectiveness of the proposed algorithm for optimal conductor size selection is validated by testing it on modified IEEE 33-bus and IEEE 69-bus distribution systems, for which several DGs are installed on selected buses.

The relevant research and study are present in Chapter 5. This research has been summarized as a journal article titled 'Optimal conductor size selection in distribution networks using adaptive genetic algorithm considering large-scale distributed generations', which has been accepted and published in the journal MDPI: energies.

3. The development of a dynamic pricing framework for demand response considering thermal limitations

To explore the performance of the active demand-side management of modern distribution networks, we proposed a dynamic pricing framework, allowing the wholesale market, power suppliers and electricity customers to participate in the electricity market intensively. The comprehensive factors, including the wholesale electricity price, transmission cost allocation and the response of customers to electricity price variations, that act on the price signal are integrated into the framework. Therefore, the wholesale price will no longer be the dominant factor affecting and guiding variations of the price signal completely. In the simple time-varying electricity price structures, the relatively low wholesale price may directly result in a sharp increase of energy utilization during the corresponding period. Consequently, the increasing energy requirement during the low-price signal period leads to potential network congestion. Conversely, part of the transmission system may take the risk of reaching the capacity limitation. In the proposed framework, the problems can be solved by the participation of DNOs. More specifically, transmission costs increase when transmission facilities face congestion problems, thus countering the economic incentive of the low wholesale price. The main target of the proposed framework is to determine the optimal price signal at each time slot given the global considerations of the wholesale market, the benefits of power suppliers and the behaviours of customers.

The relevant research and study are present in Chapter 6. This research has been summarized as a conference paper titled 'Improved Dynamic Pricing Framework for Demand Response considering Transmission Limits', which has been presented orally and included in the database IEEE Xplore.

4. *The development of a day-ahead pricing mechanism for managing distribution network congestion caused by the increasing application of renewable generations*

To explore the optimal distribution network planning and operation problems, we proposed a day-ahead pricing mechanism for managing distribution network congestion caused by renewable generation. The proposed concept of day-ahead pricing is designed to minimize customer electricity bills by taking account of line thermal constraints resulting from the increased penetration of renewable generation. It is assumed that each user is equipped with controllable appliances and a smart meter enabling two-way communications between suppliers and their customers. Suppliers employ an hourly demand-side management strategy that considers the price signal from DNOs, DGs and the wholesale market. A weighted average DUoS charge approach is applied in this mechanism, allowing DNOs to send a cost-reflective DUoS charge to electricity users in different locations based on their hourly predicted day-ahead power consumption. An optimal day-ahead pricing mechanism has been developed for DGs to manage their renewable resources to achieve revenue reconciliation and maximize generation output. Finally, power suppliers can optimally manage the controllable appliances installed by each end user and balance the energy consumption from the main grid and DGs to minimize the electricity price. Several case studies were conducted with the modified IEEE-33 bus distribution network, for which a large-scale nonlinear optimization programming algorithm was applied to solve the problem.

The relevant research and study are presented in Chapter 7. This research has been summarized as a journal article titled 'Investigation of the potential conflict between day-ahead distribution network use of system charges and

renewable energy production', which has been submitted to the journal IET transmission, distribution and generation.

1.5 Thesis Structure

The thesis is organised as follows:

Chapter 2 introduces the basic participators and components in the distribution network. The comprehensive literature review of existing technologies of distribution network design and planning are also presented in this part. In particular, the principle of demand response, active demand management, network reconfiguration, dynamic pricing and day-ahead pricing are introduced. Finally, the gap between the current distribution network design and planning technologies and the optimal network design and planning approaches in this thesis is presented.

Chapter 3 introduces the fundamental principles of the electricity market and power system economics. And, the current policy for supporting the development of renewable energy resources in the UK is also indicated in this Chapter. The economic incentives are regarded as one of the best approaches to affect the purchasing behaviour of electricity customers. The literature reviews of the power system economics in this Chapter summarize the principles and policy that are used in the following Chapters due to the renewable energy resources and various electricity pricing mechanisms are considered as the major research aspects in this thesis.

Chapter 4 proposes a genetic algorithm which is applied in MATLAB and OpenDSS for implementing automatic reconfiguration technology in distribution networks. The objective of the approach is to explore the optimum topology in advance at each hour by analysing the predicted data of load demand and distributed generation. The algorithm is tested in IEEE 37-bus feeder network with the consideration of DG.

Chapter 5 propose a hybrid optimization algorithm to solve the CSS problems in distribution systems with high penetration DGs. AGA and AC-OPF are employed

together to find the optimal sizing of conductors to minimize the sum of the life-cycle cost of selected cables and the total generation costs from traditional fossil fuels.

Chapter 6 proposes a dynamic pricing framework which allows the wholesale market, power suppliers and electricity customers to participate in the electricity market intensively. The comprehensive factors (including wholesale electricity price, transmission cost allocation and customers' response to the electricity price variation) that act on the price signal are integrated into the framework.

Chapter 7 presents a new approach to the optimal design of a day-ahead pricing mechanism for managing distribution network congestion caused by renewable generation. The proposed concept of day-ahead pricing is designed to minimize customer electricity bills taking account of line thermal constraints resulting from increased penetration of renewable generation.

Chapter 8 summarizes the main achievements and results of this thesis.

Chapter 2

Distribution network design and planning: An Overview

This chapter provides an overview of distribution network design and planning. First, the fundamental structure of current distribution systems and the basic process of distribution network design and planning are introduced. Then, the underlying issues related to the problems of future distribution network design and planning such as the large-scale integration of RESs and demand-side participation are discussed. Finally, both the opportunities and challenges faced by current distribution network design and planning frameworks are summarized, and the research gaps are identified.

2.1 Introduction

The primary purpose of the electric power system is to satisfy the energy requirements of users. The major components of a typical power system include power generation, transmission systems and distribution systems. Generators are responsible for producing the required energy from different resources such as fossil fuels, nuclear and sustainable resources. The transmission systems are designed to deliver large amounts of energy from the concentrated generation stations to the

major energy consumption locations. Then, the distribution systems are responsible for carrying the energy to every single electricity customer in the system with the proper voltage level and power frequency. The transmission systems and the distribution systems are operated at different voltage levels, thus requiring the relevant transformers to adjust the voltage to the appropriate level. Figure 2-1 illustrates the basic structure of a typical power system that includes the major subsystems. In the conventional design of a power system, the majority of the electricity is generated by concentrated fossil-fuel-based power plants, large hydroelectric plants or nuclear plants. These large-scale generation facilities are normally constructed in areas far away from the electricity users, thus long-range power transmission systems are required to bridge power generation sites and customers [87].

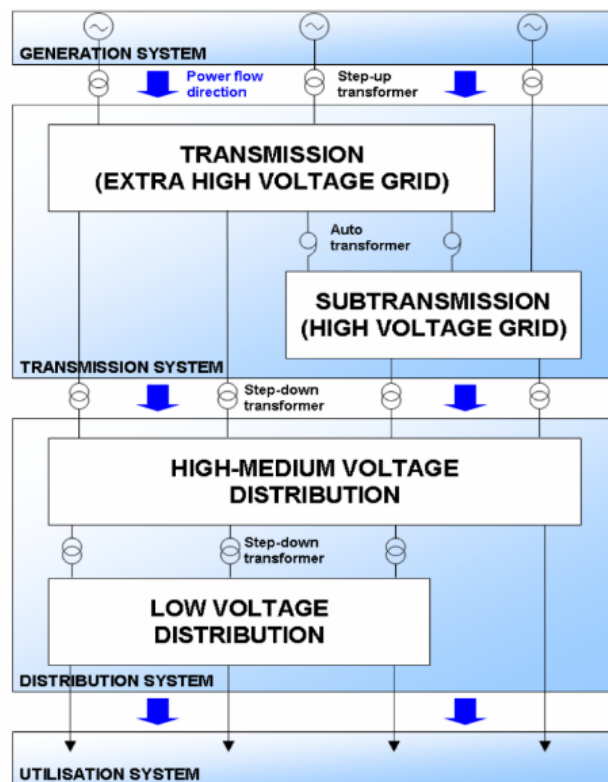


Figure 2-1 The basic structure of a typical power system [88]

With social and economic development, the availability and efficiency of current power system are expected to be improved due to the requirements of electricity customers. In addition, the large-scale application of renewable resources and the liberalisation of the electricity market are prompting power systems to undergo

some significant and useful changes in operation and planning at the system level in the near future. In particular, the competitiveness of the electricity market and ongoing government supports are encouraging electricity market participants to pay more attention to the economics of system operation and energy procurement costs. Concerns about increased environmental problems caused by carbon dioxide emissions are also encouraging the power industry to provide more efficient and clean energy. The continual increase in electricity demand in Europe countries reveals the power of addressing congestion problems and optimal power dispatch problems. To address these problems, the conventional approach is to add new large fossil-fuel-based power generation units and enhance transmission facilities. Before the electricity linearization process and the development of renewable energy, vertically integrated power companies shouldered the responsibility constructing new bulk generators and new transmission systems [8]. However, more efficient and environmentally friendly power generation technologies such as combined heat and power (CHP) and renewable energy sources (RESs) provide the power system with another choice to deal with the problems of increasing electricity demand and power delivery congestion [89, 90]. In particular, the increasing application of RESs is primarily a result of distributed generators such as photovoltaic and wind plants or small-scale wind farms. Distributed generation systems are typically connected to distribution systems directly by static conversion facilities. The share of electricity generation from steam-turbine-based thermoelectric power generators will decrease in the near future, and these kinds of generators are typically connected to transmission systems directly by the appropriate transformers. From the view of the entire power system, the decreasing of conventional synchronous generators affects the capability of essential ancillary services such as real-time power balancing. The development and reinforcement of transmission systems can be deferred because the increasing electricity demand can be fulfilled by DGs, thus allowing investments in long-range power delivering facilities to be postponed [91]. However, from the view of distribution systems, the increasing penetration of DGs urges distribution system operators (DSOs) to upgrade distribution networks and improve the operation efficiency [92]. In particular, the high penetration of photovoltaic and wind plants that connect to the distribution systems affects the certainty of the operation

status of the power system due to the potential bi-directional power flow and the uncertainty of the power output from DGs. Integrated DGs also challenge existing distribution network protection strategies because the DGs may improve the short-circuit current and voltage at the connection points. Meanwhile, distribution network operators are required to adopt innovative information and communication technologies. Specifically, the liberalization of the electricity market provides innovation to the energy trading process in which electricity users and the power generation sector can make deals in a relatively short time frame with the real-time market pricing clear mechanism.

In general, the task of conventional DNOs or power suppliers is to supply electricity to their customers by a clear and univocal one-way direction of power flow and to charge the customer a fixed rate regardless of the power usage period. However, in the near future, DNOs are expected to be able to optimally design and plan their distribution networks to satisfy new challenges such as the integration of distributed energy resources, real-time network estimation and management, voltage and two-way power flow management, the optimal dispatch of distributed generation, constraint and congestion management and the integration of common customers to the competitive electricity market. In this thesis, we study potential approaches to drive distribution network design and planning towards future smart distribution systems. Therefore, in this chapter, the relevant knowledge of traditional distribution systems and related operation mechanisms are introduced first [93, 94]. Then, the state-of-the-art technologies that have been widely researched and studied are illustrated. Because distributed energy resources are one of the most important facilities that significantly affect the operation and design of current distribution systems, the typical technological characteristics of DERs are also introduced in this chapter.

The remainder of this chapter is organized as follows: Section 2.2 introduces the definition and structure of distribution systems, and section 2.3 introduces current distribution network planning technologies. Distributed generators and relevant applications are introduced in 2.4. Section 2.5 illustrates popular demand-side

participation approaches that are applied in current distribution networks. In the end, section 2.6 summarizes the chapter.

2.2 A review of distribution systems

Before the large-scale installation and application of renewable energy resources, which significantly change the operation and design of the entire power system, researchers and the industry in general paid little attention to the design and planning of distribution networks when compared to the other parts of power systems such as generation and power transmission. This phenomenon can be partly attributed to the traditional vertically integrated power system management strategy, which is supported by the single energy supply approach and one-way power delivery direction. In particular, the planning, operation and management of transmission systems have been comprehensively researched and investigated in the past few decades because transmission systems are designed to actively manage major power flows and control the energy exchange balance. Different from transmission systems, distribution networks are designed to be passive systems in traditional planning and operation philosophies. For instance, the main task of conventional distribution systems is to receive the unidirectional power flow from upstream transmission systems and pass it to downstream low voltage distribution networks or end users.

2.2.1 Distribution system structure

To introduce the essential characteristics of distribution systems, it is necessary to first identify the major differences between distribution and transmission systems. The majority of distribution networks in European countries are designed with a radial structure. In some circumstances, a distribution network may be designed as a loop structure but operated as a radial structure. However, most transmission systems are designed and operated as meshed structures. Figure 2-2 shows the typical radial, loop and meshed network structures. The meshed structure can provide redundant and secure power delivery services due to its tough and complicated topology, and the default power delivery path can be redirected to other transmission lines to supply upstream networks when an unexpected fault occurs. However, providing the same power delivery security services with traditional

distribution systems with radial structures is difficult. The common strategy for dealing with unexpected distribution systems faults is to isolate or disconnect the faulted part of the network and resupply the electricity after a successful repair action. This major difference between the two systems requires distribution network operators to pay more attention to network operation.

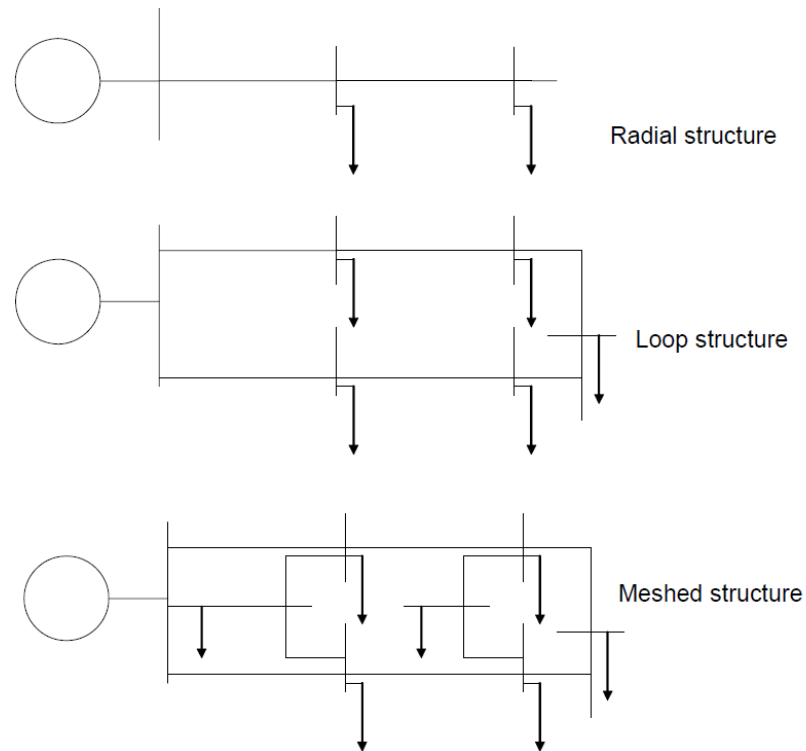


Figure 2-2 Typical structures of radial, loop and meshed network [88].

Another important characteristic of distribution networks is that the conductors used in the distribution systems have a relatively higher resistance compared to the transmission systems. This feature of high resistance results in a higher network loss in the distribution systems, which is a major problem that DNOs need to plan for to achieve optimal network operation. In general, distribution networks have two major subsystems: the primary circuits and the secondary circuits. The primary circuits, which are also described as feeders, operate with a higher voltage and typically directly supply large electricity users such as industrial and commercial customers. The secondary circuits receive electricity from primary feeders, where transformers step down the voltage to relatively lower levels that can be used by household

electricity customers. Figure 2-3 illustrates the typical structure of distribution systems and their major components including primary circuits, circuit breakers, distribution transformers and secondary circuits.

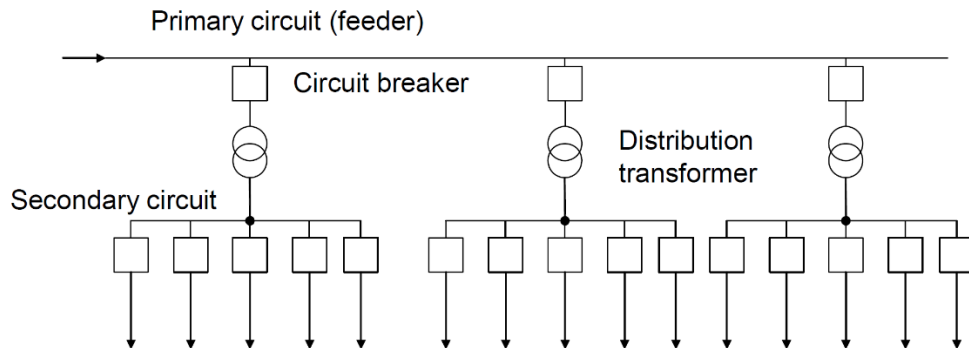


Figure 2-3 Typical structure of a distribution system [88]

The typical voltage of primary circuits in European countries is normally within the range from 10 kV to 110 kV, and the voltage of secondary circuits is normally designed to be 220 V, 380 V or 440 V. However, the values of the voltages operating in the distribution levels vary by country. The typical values of the voltages used in the distribution systems in the US, UK and China are shown in Table 2-1.

Table 2-1 Voltage range of distribution system in different countries [92, 95, 96]

	US	Germany	UK	Australia	China
High-voltage distribution systems	69 kV	110 kV	132 kV	66 kV	110 kV-35 kV
Medium-voltage primary circuit	600 V-35 kV	6 kV-60 kV	11 kV- 33 kV	11 kV	6kV- 20 kV
Low-voltage secondary circuit	120/240V	230/400 V	230/400 V	415 V	220/380V

Distribution systems are required to deliver energy not only to modern cities with high population densities but also to remote areas such as rural regions and villages. It is noted that electricity facilities may only have less than 10 metres of distribution circuits in urban areas with a high population density, while the length of secondary distribution circuits may extend to over 300 metres to transport electricity to each electricity user in a rural area. Therefore, the secondary circuits of distribution

systems in rural areas are often designed as overhead line structures based on their economic investment and simplified design. In urban areas, underground cables are considered as the primary solution in the process of designing and planning distribution systems due to the high population density and the overall city design requirements. A mixed design framework with overhead lines and underground cables is often used in the design of distribution systems in suburban areas. The configurations and circuit lengths of the distribution networks are different in urban areas and rural areas because of the disparate population densities and construction requirements.

2.2.2 Voltage regulation and protection strategy of the distribution network

The voltage of the primary feeder on the distribution network decrease when a heavy load demand occurs. In order to maintain the voltage of the primary feeder can continually satisfy the minimum requirement of the regulation (0.94 p.u. in the United Kingdom), the voltage regulators are normally allocated on the primary feeder. In particular, the function of the voltage regulator is similar to a small transformer with a variable ratio. Specifically, the voltage regulator has the capability to automatically adapt the variable incoming voltage and maintain the outgoing voltage within the predetermined value. The typical scheme of a distribution feeder with the voltage regulator is shown in Figure 2.4 below.

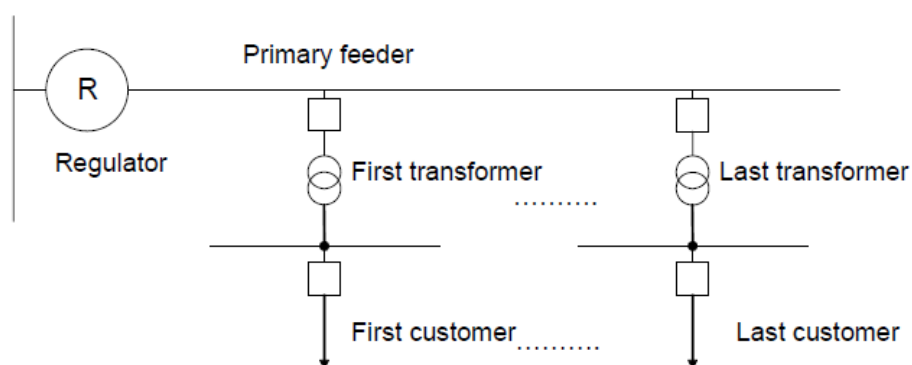


Figure 2-4 Typical scheme of a distribution branch with voltage regulator [88]

Recently, an increasing number of distributed generation technologies such as solar photovoltaic and wind generation which have been installed since those new generation methods can dramatically reduce the emission of carbon dioxide and meet the EU renewable energy targets. Distributed generation is connected to the distribution network directly. Hence, there is no doubt that distribution network plays a significant role in the power system.

2.3 Distribution network design and planning

Typically, a distribution network needs to be designed and planned more than 10 years ahead of construction [97]. Two significant principles are considered in the design and planning of a distribution system: 1) predicting growth in the demand of electricity users and planning system upgrades and extensions in advance and 2) choosing the optimal facilities and equipment for replacing the assets that have reached their maximum lifespan [97-99]. This classical network design and planning framework is widely applied in traditionally one-way distribution systems, for which the energy delivery path is only from a high-voltage transmission system to low-voltage distribution feeders[100, 101].

Distribution system design and planning are complicated and complex tasks with several major steps. The first target is to predict the load demands and relevant growth rate in a design area and establish the asset management and condition monitoring systems [102]. The second step is to identify the system capacity with load forecasting technologies, thus allowing distribution system planners to model the structure and loading levels of the system. The system inadequacies and network constraints are also identified in this step [103]. The third step is to explore and list all the potential solutions of network design and planning and assess the corresponding investment costs of each potential solution. Particular and detailed economic assessments and technical evaluations of each feasible solution are conducted in the fourth step [104, 105]. The next step is to optimally select the best solution based on relevant standards and requirements. Indeed, there are several additional processes, such as government approval and official authorization, that

need to be confirmed before infrastructure construction. These four main steps are normally considered by distribution network planners.

In general, there are several factors that need to be considered during the distribution network design and planning process, and they are listed as the following aspects:

- Satisfying the load demand during the fully designed life cycle with the consideration of expected load growth
- Providing reliable and efficient electricity supply
- Optimally allocating the system components of the distribution network
- Optimally selecting the most economical solution of distribution network planning
- Minimizing the electricity price
- Maximizing the profits of distribution network operators and power supplier

Thus, the major objectives and targets of the distribution network design and planning process can be summarized as 1) load forecasting, 2) power quality, 3) compliance with standards, 4) investments and 5) power losses. These five objectives of the distribution network design and planning process are introduced in the remaining part of this section [91, 106, 107].

2.3.1 Load forecasting

Distribution systems are designed to supply different types of electricity users including industry customers, commercial customers and common household customers. In particular, household customers have a broad energy requirement range, with rural areas having load densities of 10 kVA per square metre and modern city areas having load densities up to 300 MVA per square metre. A feeder in a distribution system is required to satisfy the peak load demands of each individual connected to the same circuits at the same time. Each customer's load requirements and behaviour are difficult to predict precisely. However, the district level load demands have some common characteristics and can be predicted with an accepted accuracy rate. In general, the load demand changes through the daytime and normally reaches a peak in the afternoon and early evening. Load forecasting is one

of the major steps of the distribution system planning and design process because the predicted demand and load growth rate can significantly affect the conductor size selection and the relevant utilities capacity selection during the planning and design process. There are several common definitions of the load characteristics widely used in load forecasting [89, 108].

- Demand

Demand is used to describe the average load during a certain time period, where the time period is typically 15 mins, 20 mins or 30 mins. And the demand can not only characterize the total power but also can present real power, reactive power or current. The predicted peak demand over a certain period of time is widely used by distribution network planner to quantify the required capacity of a circuit or feeder. However, current demand is often used to characterize the capacity of the substations.

- Load factor

Load factor characterizes the ratio between the peak demand and the average demand, where the value of the load factor is, therefore between zero and one. The constant or stable load demand results in a high load factor value, which is close to one. And the low load factor value represents a significantly varying load demand. The distribution network operators or the power suppliers have expected a relatively high load factor due to the consideration of sustainable network operation. Specifically, the load factor can be illustrated by the equation 2-1 [109, 110].

$$LF = \frac{kWh}{pd_{kw} \times t} \quad (2 - 1)$$

where,

LF represents the load factor of a chosen customer

kWh represents the total energy usage in kilowatt-hour

pd_{kw} represents the peak load demand in kilowatt-hour

t represents the time periods of hours

- Coincident factor

Coincident factor characterizes the ratio of the peak demand of the whole system to the sum of all individuals' peak demand belongs to this system. In particular, the peak load demand of the whole system is normally described as peak diversified demand or coincident demand. And the electricity demand of individual customer is named as noncoincident demand. The value of the coincident factor is normally between zero and one due to the individual load demands are barely reach their peak values at the same time.

- Diversity factor

Diversity factor characterizes the ratio of the sum of all individuals' peak demand belongs to this system to the peak demand of the whole system. The value of diversity factor is normally larger than one.

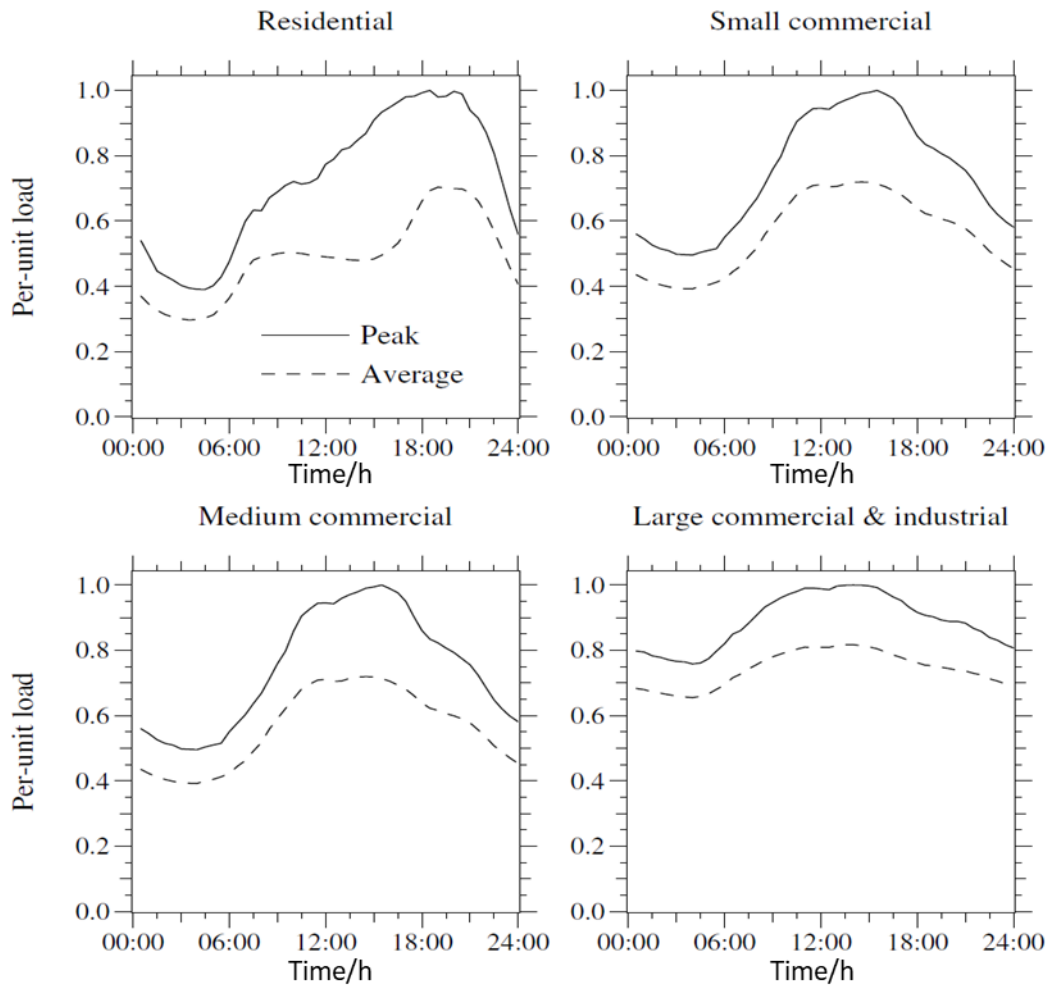


Figure 2-5 Typical load profiles of different kind of customers

In general, the load demand patterns of various types of customers are significant differences. However, the customers that in the same classification have similar characteristics of electricity usage. Specifically, the commercial electricity customers normally have a peak demand from 8 AM to 6 PM of the daytime. And household customers or residential loads have the highest demand during the evening. On the other hand, the diversity of temperature or the weather may change the loading levels in both commercial areas and residential areas due to the intensive application of air conditional or the heating systems. The typical load profiles of different kind of customers including: residential, small commercial, medium commercial and large commercial or industrial are presented in the Figure2-5 [111, 112].

2.3.2 Distribution network operation constraints

The primary target of distribution network planning is to satisfy the electricity demands of all customers. However, electricity suppliers are also required to provide customers with a reliable and uninterrupted supply of electricity. As a consequence, supplying electricity with the required level of continuity and availability is the fundamental goal in the design and planning of distribution networks. Power quality has a broad definition; however, it can be generally determined by the following aspects: voltage, power factor, harmonic content in the network and supply frequency [113].

2.3.3 Investments in the distribution systems

One of the most important processes in distribution network planning is to assess the investment costs of the required system infrastructure and predict the relevant operation and management costs during the expected lifespan. In particular, designers and planners are required not only to satisfy the fundamental regulations and standards of power system operation, such as the voltage constraints and frequency constraints but also to establish a financial analysis that includes the life-cycle costs of the systems during the distribution network design and planning process. Therefore, the efficient reliability, power quality and investment costs all significantly affect the process of network planning, and an optimal solution will be achieved by the relevant optimization models based on the required principles and target [114].

The investment strategy of a power system has two main categories: new investments and replacement investments. New investments are applied to expand the existing network or to build a completely new power network in a required district. Replacement investments are used to replace or upgrade major components in an existing network, and this action is normally done for ordinary maintenance purposes due to component ageing and malfunction problems. The main targets of distribution network investment are to minimize the overall costs of the infrastructure and to follow the O&M costs during the expected lifespan of a system, and the boundaries and constraints of power system operation must be satisfied at the same time. Three major components are considered in distribution network

investment: 1) capital costs, 2) operational costs and 3) interruption costs. In particular, capital costs include the infrastructure material procurement costs, labour costs and other necessary costs during network construction. Operation costs include the power loss costs, inspection and maintenance costs, reconditioning costs and other necessary costs. Interruption costs include failure costs and discard costs. The formulation 2-2 indicates the total costs of distribution network investment [114-116].

$$C_{total} = CC + \sum_{t=1}^T (OC_t + IC_t) \quad (2 - 2)$$

where

C_{total} represents the total network investment costs

CC represents the capital cost costs

OC_t represents the operation costs in operation year t

IC_t represents the interruption costs in operation year t

T represents the expected life span of the designed distribution network

The minimization of the total network investment is achieved when the formulation reaches the minimized value. Increasing the investment on the costs of infrastructures and materials and providing a high-quality network operation and management service is able to reduce the interruption costs. In particular, selecting the conductors or cables with the high capacity defer the network upgrading and reinforcement since high capacity power delivering facilities can improve the capability of the network to satisfy the load growth of the electricity customers. And the increasing investment on the auxiliary and protection facilities in the networks is able to decrease the costs due to the system fault.

However, the increasing penetration of distributed energy resources and the deregulation of the electricity market require the distribution network planner to design and plan the network by a new framework. Currently, distribution networks

become more and more complicated and are difficult to plan and management. On the one hand, lots of innovated and smart applicant and units have been connected to the distribution network such as Micro-grids, Nano-girds and electric energy storage systems. These new units challenge the traditionally integrated vertically design and planning approach, where each unit or cell is expected to be optimally and appropriately allocated in the system. On the other hand, the distributed generations result in the two-way power flows in the distribution network, thus the new design and planning strategy are required to deal with the short-circuit protection and conductor size selection problems in this new circumstance. The deregulation and decentralization of the electricity market encourage the normal electricity users to participate in the market trading programme for the reason of high-efficiency active demand response. As a consequence, the information and communication technologies such as smart meter are required to be equipped to each customer to monitor and collect the useful data, thus allowing a real-time distribution network management.

2.4 Integration of Distributed Energy Resources

At the beginning of 1990, power companies around the world were challenged by significant increases in electricity consumption, which were partly attributed to population growth and industrialization [117]. This situation resulted in a huge investment in electricity transmission systems and the relevant auxiliary or protection facilities. Thus, high voltage and high capacity transmission facilities were widely developed and constructed during that period [118]. Environmentalist noticed the potential pollution issues caused by the increasing amounts of fossil fuels generators [119]. In particular, conventional generation systems are powered by different fossil fuel sources such as coal and gas. The average operation efficiency of conventional coal plants is approximately 35% and significantly depends on the operation conditions [120]. These traditional resources are stable and concentrated

and have shouldered the most responsibility for power supply until now. However, the common problem of all traditional generation technologies is that they produce carbon dioxide during the combustion process. Increasing concerns about the climate and the environment of our planet have been raised regarding the significant challenges as a result of carbon dioxide pollution. On the other hand, carbon dioxide is not the only pollutant produced by fossil fuel generation systems; there are many other more severe types of pollution produced by traditional generation processes, such as nitrogen and sulphur oxides, which may result in acid rain and significantly affect the health of human beings [121, 122]. Thus, environmental considerations became a major concern for humanity, with more than 70% of all electrical energy produced coming from fossil fuels. Climate change and the greenhouse effect caused by non-sustainable electricity generation have alarmed governments and the energy sector and forced them to consider alternative ways of providing electricity using low-carbon generation strategies.

A conventionally structured power system delivers electricity through a broad network of interconnected transmission systems at different voltage levels. From the electrical perspective, electrical energy losses occur from production centres to places of consumption. High-voltage and new materials have the ability to reduce power losses during long-range power transmission. However, reducing power losses to a relatively low range in the majority of distribution networks is difficult due to economic considerations in network design and planning. Thus, approximately 4%-5% of the energy produced in power plants is lost by transmission systems, and 10-15% of the energy produced in power plants is lost by distribution systems [123, 124]. In addition, increases in electricity consumption result in financial burdens on the investment of new transmission facilities. For instance, it is assumed that a new transmission line has a capacity of 100 MW and is used to support a maximum load demand of 50 MW. If the load has an average annual growth of 5 MW, the transmission network operators are required to upgrade the transmission line after only 10 years [125].

Therefore, it is expected that new electricity generation approaches can not only deal with environmental concerns but also defer investments in power transmission

systems. Renewable generation is considered to be one of the best solutions to counter environmental problems, and it has the ability to postpone transmission lines development projects [126, 127]. Because renewable resources such as wind power and solar energy are normally distributed in remote areas, consuming renewable energy by connecting these sources to nearby load-consuming areas through distribution systems is considered to be the optimal method [128, 129]. Thus, distribution networks participate in this challenge and are required to deal with the potential problems of the integration of non-dispatchable renewable resources. Among the various sustainable resources, wind generation and photovoltaics are regarded as the most important generation approaches, and they have been widely deployed in various countries. In particular, large-scale wind farms or PV panel stations are typically connected to transmission systems due to their enormous capacity [130, 131]. However, small-scale solar PV panels can be roof-mounted on commercial or residential buildings or ground-mounted close to load demands in the proximity of commercial and industrial areas, while small wind generators are quite common in rural areas [132].

Small-scale solar PV panels, such as roof-mounted units and small wind turbines, are concluded to be the sources of distributed generation or decentralized production based on their technical aspects. The evolution of the use of these words indicates that DG has gradually eliminated the term decentralized production in almost all relevant scientific literature. In addition to these terms, embedded generation is common in some texts [133]. Additionally, the term distributed resource is sometimes used for the concept of DG. Specifically, distributed generators (DGs) are defined as small-scale generation units that are connected to the main grid and are located close to the demand side. DGs are designed to operate in an isolated way to support local demands independently or to connect to the main grid to deliver energy to the remainder of the power system. Renewable energy such as wind power and solar energy are the main resources of distributed generation. The typically installed capacity of DG units ranges in size from less than 1 kW to 10 MW. However, apart from the criteria presented above, on the basis of production capacity, DGs are divided into four categories: micro (1 W to 50 kW), small (5 kW to 5 MW), medium

(5 to 50 MW), and large (more than 50 MW). Installed DGs have the capability to fulfil the basic requirements of the electricity demand of the owners during ideal conditions such as wind blowing periods. The location of the generation devices and the capacity of installed generation are two major characteristics that define DG technologies. In general, terms, DGs are allocated close to the electricity customers and connected to the distribution systems rather than the high voltage systems [134, 135].

The majority of DGs used in current power systems are based on renewable resources such as wind power, solar energy and hydropower. However, there are two types of distributed generation technologies, and another relatively new type is the fuel-based DG technologies. The typical generation methods of this type of DG include combustion energies, microturbines, fuel cells, diesel generators and biomass generators. A comparison of the characteristic and functions of different types of DGs is summarized in Table 2-2 [9, 136-139].

Table 2-2 Summary of the characteristic and functions of different types of DGs

Technologies	Gas turbine	microturbines	Fuel cell	Wind turbines	Solar cell
Typical power rates	15 kW-30 MW	25 kW-500 kW	15 kW-30 MW	1 kW-20 MW	300 kW-2 MW
Electrical efficiency (%)	25-30	20-30	30-60	20-40	5-15
Installation cost(\$/kW)	400-1200	1200-1700	1000-5000	1000-5000	6000-10000
O&M cost (\$/MWh)	3-8	5-10	5-10	1-4	10
CO ₂ emission (kg/MWh)	580-680	720	430-490	0	0
NO _x emission (kg/MWh)	0.3-0.5	0.1	0.005-0.01	0	0

Because wind turbines and photovoltaics are the primary types of DGs applied and discussed in this thesis, typical models for photovoltaic generation and wind generation are introduced in the following parts [136-139].

2.4.1 Photovoltaic

The amount of energy that can be produced in a PV system is directly dependent on irradiance and the angle at which the solar PV cells are radiated. Irradiance and production depend on meteorological conditions. The power output of PV generators can be assumed to be linearly dependent on the global solar irradiance. The typical generation output of solar photovoltaics is shown in Figure 2-6.

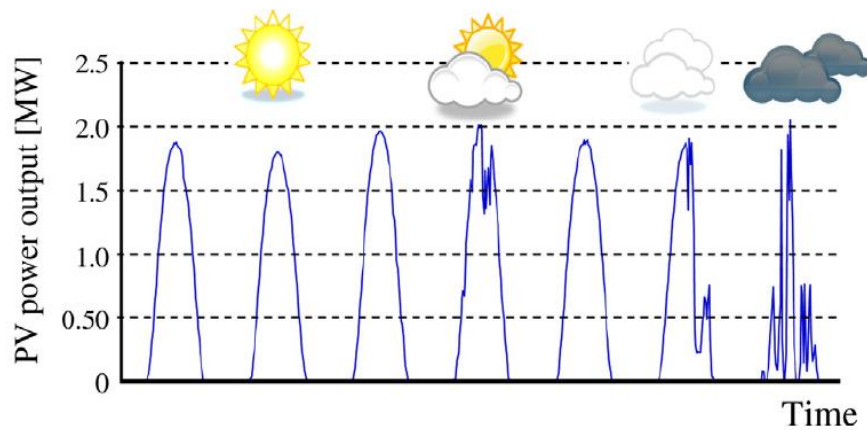


Figure 2-6 The typical generation output of solar photovoltaic [40]

2.4.2 Wind generation

It is assumed that the air has a mass m and the corresponding wind speed is v . Therefore, the kinetic energy ke can be evaluated by the air mass and the relevant wind speed [140], where the formulation 2-3 is given by

$$ke = \frac{1}{2} \times m \times v^2 \quad (2 - 3)$$

And, the mass of air can be evaluated in terms of the corresponding air density and the amount of air that pass the wind turbine [140]. The formulation 2-4 that used to calculate the mass of air is given by

$$m = \rho \times A \times x \quad (2 - 4)$$

where

ρ represents the air density.

x represents the thickness of the certain blade (in particular, this index indicates the distance crossed by the air from the first point of the hub to the point where the air leaves the turbine blade).

A represents the swept area.

It is noted that the swept area A can be assessed by the blade length L , where the formulation that used to calculated swept area A is given by. Thus, the equation can be extended as express 2-5 and 2-6 below [140].

$$A = \pi L^2 \quad (2 - 5)$$

$$ke = \frac{1}{2} \rho \pi L^2 v^2 x \quad (2 - 6)$$

Therefore, the potential power that storage in the air can be assessed by the differential of kinetic energy with time. Thus, the total power stored in the wind P_w can be calculated by equation 2-7.

$$P_w = \frac{1}{2} \rho \pi L^2 v^2 \frac{dx}{dt} = \frac{1}{2} \rho \pi L^2 v^3 \quad (2 - 7)$$

However, it is difficult to extract all potential power stored in the air. This ideal situation occurs when the air flow velocity is uniform across the blades and the air is considered as incompressible. In practical, the air velocity decrease after the air flow passing the blades and the air pressure increase after the air flow passing the blades. Thus, only part of the power can be captured by the wind turbine and the fraction of the power largely based on the power coefficient C_p . Based on the Betz limit, C_p is equal to 0.59 theoretically but in reality C_p varies from 0.2 to 0.5. Therefore, the power that can be captured by the wind turbine can be calculated by modifying equation 2-8 in terms of C_p as shown in formulation 2-8 [140].

$$P_a = \frac{1}{2} \rho \pi L^2 v^3 C_p \quad (2 - 8)$$

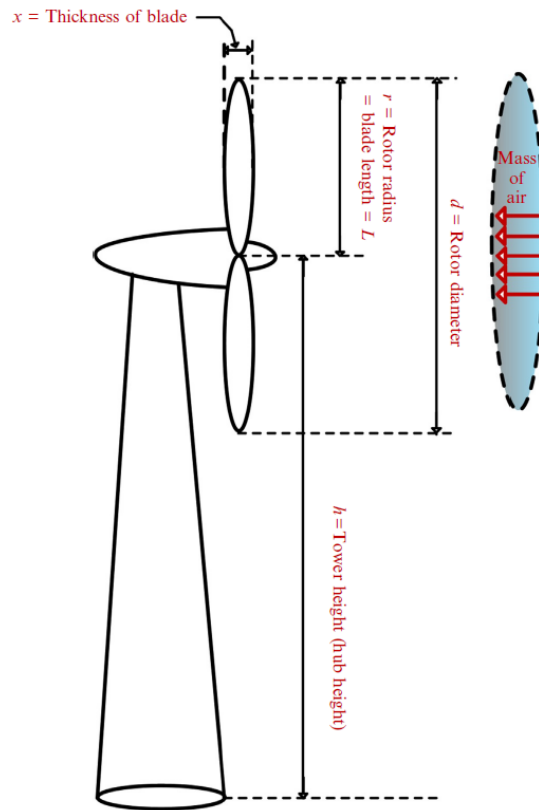


Figure 2-7 The structure of wind turbine [140]

The equation 2-8 indicates that the actual power generation of the wind turbine largely depends on the wind speed, blade length, and power coefficient (C_p). Apparently, the wind speed frequently varies during the daytime and significantly affected by the weather and seasons. Thus, the power generation of the wind turbine varies due to these external nature characteristics. In the practical engineering areas, the wind turbines are designed with upper and lower output constraints to ensure secure operation. Therefore, the power characteristic curve of a certain wind turbine is often introduced to indicate the special relationship between the mechanical power developed by this wind turbine and the wind speed variation.

The typical wind turbine characteristic curve is shown in Figure 2-8. And, the figure indicates that there are two classic operating modes of wind turbines: 1) parking mode and 2) operating mode. These two operation modes depend on determining or defining of three values of wind speed: cut-in, rated, and cut-out wind speed.

- Cut-in speed

Cut-in speed represents the lowest value of wind speed that enables the wind turbine to operate. Under this value the wind turbine is stopped and enters the parking mode.

- Cut-out speed

Cut-out speed represents the highest value of wind speed that the wind turbine can operate at without damage. Over this value the wind turbine has to be stopped and enters the parking mode.

- Rated speed

Rated speed represents the value of wind speed that the wind turbine operates at and produces its nominal power. After this value the output power of a wind turbine is fixed with any increase in wind speed till the cut-out speed.

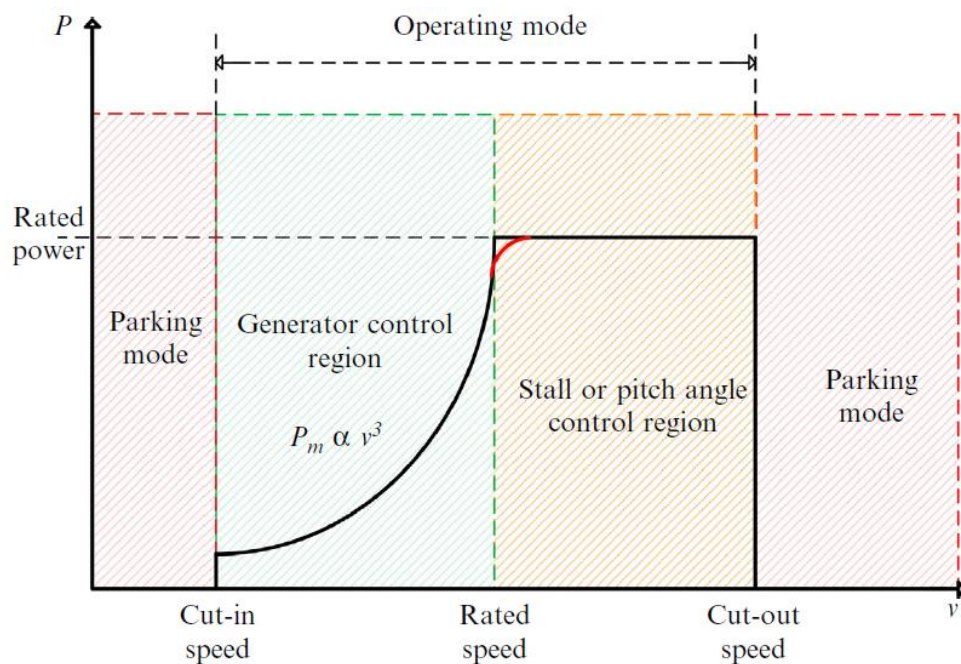


Figure 2-8 The typical wind turbine characteristic curve [140]

Based on the previously mentioned definitions, the operation states of the wind turbine can be defined as two major categories: parking and operating mode. In particular, the operating mode can be divided into two different regions: 1) generator control region, and 2) stall or pitch angle control region [141].

Generator control region starts from the cut-in wind speed to the rated wind speed. The main advantage of this region is that mechanical power is proportional to the

cubic of wind speed v^3 . Stall or pitch angle control region starts from the rated wind speed to the cut-out wind speed. In this region, the mechanical power is no longer proportional to the cubic of wind speed v^3 . The red line on the curve represents the actual power characteristic curve of the wind turbines found in the market but the sharp black portion represents the theoretical power characteristic curve of the wind turbines. It has to be fixed with the increase of wind speed to prevent wind turbines from any damage. There are two types of control that can be issued or applied to the wind turbine to achieve the mission stall or pitch angle control. Stall or pitch angle control is known as an aerodynamics control system [141-143].

2.4.3 Application of DGs

Distributed generation units are designed and constructed with different sizes, fuel types and efficiencies. As mentioned in the previous section, DGs fall into two major categories: conventional fuel-based generation technologies and technologies based on renewable resources. DG technologies that use conventional energy resources can be controlled and regarded as dispatchable generators. In contrast, DG technologies that use renewable energy resources are based on different forms of natural resources such as sunlight from the sun, the force of the wind, and the combustion value of organic matter. Because the typical renewable resources that are widely used as fuel in DGs are wind energy and photovoltaics, the advantages and disadvantages of wind energy and PVs are listed in Table 2-3 to identify potential problems [144].

The main difference between renewable and conventional resources is that the output of renewable resources depends on variable inputs such as wind or solar energy. The power produced by renewable resources may fluctuate more, making it difficult to forecast. In the case in which a DG is connected to a local load to supply the load during interruptions and enable operation in islanded operational mode, the demand and supply may not match, especially if the DG is renewable. In this case, the DG is either disconnected due to the activation of the frequency or voltage protection devices or the system will shed some loads and only supply critical loads.

Table 2-3 The advantages and disadvantages of wind energy and PVs

	Wind turbines	Photovoltaic
Advantages	Easy design and installation process	Easy design and installation process
	No emissions during electricity generation	No emissions during electricity generation
	Different installation sizes	No moving parts or noise
	Low O&M costs	Low O&M costs
Disadvantages	Wind force is highly variable	High capital costs
	Low availability during high demand periods	Low availability during high demand periods
	Audible and visual noise	Large areas required
	Limited resource sites	Low efficiency and capacity factor

There are many potential applications for DG technologies. They can be classified as backup DGs or baseload DGs. DGs can be used as backup generators to replace normal sources when they fail to supply a load, thereby allowing customer facilities to continue to operate satisfactorily during power outages. Most backup generators are diesel engines because of their low cost, fuel availability, and quick start time [145].

A backup DG is connected to the local load, and a manual or automatic switch is installed on the feeder side of the DG local load. During faults on the main feeder or its laterals, the circuit breaker on the substation side will trip to clear the fault, causing the entire feeder to be interrupted. Then, the DG switch can be closed, and the DG unit can start supplying its local load.

A baseload DG is used by some customers to provide a portion or all of their electricity needs in parallel with the electric power system. It can also be used as an independent stand-alone source of power. The technologies used for these

applications include renewable DGs such as wind turbines, PVs, fuel cells (FCs), and combined heat and power (CHP) systems.

The presence of DGs in a distribution system may improve system reliability as a result of supplying loads in islanded operation. Islanded operation implies that loads are disconnected from the substation and supplied from the DG until the utility restores power from the main supply. A DG may not be able to supply the demand completely during islanded mode due to the availability and capacity of the DG, especially when it depends on a renewable resource. Note that power balancing must occur between the DG, the main supply, and any energy storage capability [146].

2.5 Demand-side participation

Traditional electrical power systems are required to provide a continuous energy supply to the demand side in real-time due to their characteristics of non-economical and non-efficient storage. However, the widespread utilization of renewable energies and electric vehicle (EV) charging systems has affected the stability of the current electricity grid [147, 148]. To deal with the problem of increasing the penetration of RESs and increasing the implementation of EVs, it is important to alter previous positive management strategies to active schemes. Therefore, demand-side management (DSM) was introduced as a new approach to actively manage the power system. The concept of DSM was originated in the 1970's in response to the impacts of energy shocks to the electricity utility industry [149]. In particular, DSM is based on the purpose of the planning, implementation and monitoring of the activities of electric power companies focused on altering customer electricity consumption patterns to produce desired changes in the load shape of the distribution system.

To achieve a successful DSM scheme, the extent of participation by electricity consumers is considered to be one of the most important indexes. The electricity usage of concentrative industrial consumers or business consumers can easily be managed and optimized by the corresponding distribution network aggregators. However, the electricity usage behaviours of residential consumers cause a negative effect on the operation of DSM schemes because the change of using electricity may

significantly influence the comfortable rate of part of them. Financial incentives based on the theories of economics can be treated as an efficient and effective approach to adjust the electricity usage of residential users [12, 16].

Typically, there are four main methods for DSM, including the administrative approach, the economical method, the legal process and the environment method. With the increasing consideration of emissions reduction targets and renewable energy integration problems, both governments and network operators tend to implement DSM in distribution networks [150, 151]. The security and reliability of distribution networks can be enhanced by applying DSM technologies. Meanwhile, DSM has the capability to shoulder the responsibility of peak load shifting. Moreover, DSM has the advantage of promoting sustainable economic and social development by increasing the utilization of renewable resources. With the increasing penetration of low-carbon technologies in distribution networks, more economic benefits can be received by network operators. Providing part of the economic benefits to customers is an appropriate method for both the management side and the utilization side. Hence, it is recognized that a well-designed DSM strategy can offer various benefits to both the operation side and the customer side [152, 153].

2.5.1 Aims of demand-side participation

Demand-side participation is designed to encourage or influence the electricity usage behaviour of customers. Electricity customers may modify their electricity consumption by shifting their usage at a certain time (demand (kW) modified) or by changing the total amount of usage during a particular time period (energy (kWh) modified). The application of demand-side participation is based on the planning, implementation and evaluation of distribution network operators or relevant unities. Two major categories of demand-side participation tools are usually considered by system operators: 1) energy saving programmes and 2) load management programmes.

- **Energy saving programmes**

Electricity customers who have low-efficiency home appliances are encouraged to change their devices to high-efficiency models. Power suppliers or network operators

are required to notify their customers that new home appliance models are able to provide the same service (quality and quantity) and reduce energy use, thus contributing to low energy bills. In general, this kind of program increases the overall electricity usage efficiency at the system level and can partly decrease peak demands. However, it is difficult for power suppliers and network operators to take economic benefits from energy saving programmes.

- **Load management programmes**

Load management programmes are the major tools by which power suppliers or network operators modify the electricity usage behaviours of their customers. The programmes are particularly designed by utilities to reduce overall energy consumption during peak periods. The key targets of load management programmes are 1) to encourage electricity customers to consume energy at relatively low electricity unit rates when the system has sufficient available resources, such as renewable energy resources during wind blowing periods, and 2) to decrease peak demands using high electricity unit rates to relieve potential network congestion problems. In general, load management programmes 1) reduce the energy bills of customers, 2) reduce renewable energy resource curtailment, 3) deal with potential network congestion issues and 4) provide power suppliers and network operators with potential economic benefits because they receive more revenue when providing the service with the same quality [154].

Demand-side participation programmes use several typical approaches to achieve the expected targets. Economic measures or financial means are one of the common methods that have been researched intensively in the area of DSM. A detailed introduction and discussion of DSM price incentive mechanisms are illustrated in Chapter 3.5, where a literature review of the deregulation and decentralization of the electricity market is presented. The direct load control approach is also used in DSM programmes. In this approach, distribution network operators or power suppliers have the authority to control all or part of the appliances of individual customers. In particular, the loads of customers who have preassigned contracts with

the power suppliers are partially shut down during extreme peak demand periods [155].

2.5.2 Methods of demand side-participation

In this section, six common approaches that are applied to establish demand-side participation and affect the electricity usage behaviours of customers are introduced.

- **Peak clipping**

Peak clipping is applied by distribution network operators to reduce a load of customers directly during peak demand periods. This action can efficiently reduce demand and match demand to available generation when a system reaches its maximum generation capacity or a distribution network reaches its maximum power delivery capacity. Peak clipping is normally applied by the direct load control approach, in which some or all customer appliances or devices can be controlled by distribution network operators or power suppliers. However, this type of DSM program is difficult to widely apply to normal household customers due to considerations of privacy and inconvenience. Figure 2-9 (a) indicates a typical load change pattern for the peak clipping approach [14, 15].

- **Valley filling**

During off-peak demand periods, it is desirable that the sum of the long-run incremental cost of generators and the relevant operation costs is less than the average price of electricity. Therefore, attempting to consume electricity during off-peak periods can decrease energy bills. In addition, it is desirable for some RESs to have sufficient available generation output such as wind blowing at midnight. Under this circumstance, a power system can achieve a more efficient operation state if the available RES generation output can be consumed sufficiently. The valley filling approach is applied by distribution network operators or power suppliers to encourage electricity customers to consume more energy during off-peak periods. However, off-peak demand periods often occur in the night or before dawn. Thus, it is difficult to increase the typical electricity usage of households and commercial users during these special periods. One of the proposed methods is to encourage EVs to process the

charging service during these off-peak periods. Industrial automation and fully automatic factories can also consume energy during off-peak hours. Figure 2-9 (b) shows a typical load change pattern for the valley filling approach.

In general, both the peak clipping approach and the valley filling approach focus on decreasing the difference between the maximum and minimum power demands. At a certain time, an interval peak load can be directly clipped, and load shifting is based on load shifting from peak to off-peak times [156].

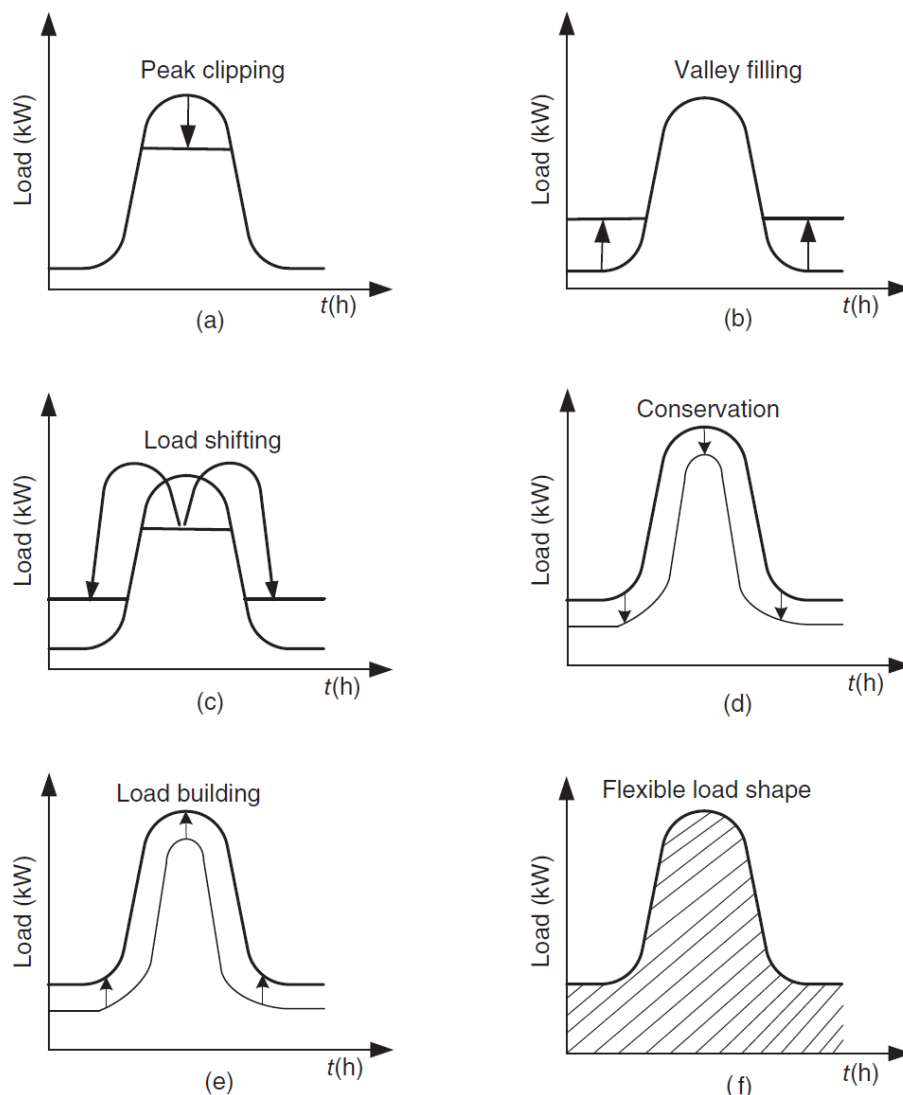


Figure 2-9 Typical load shape for different means of demand side management

- Load shifting

The target of the load shifting approach is to move the load demand from peak periods to off-peak periods. The approach also attempts to maintain the total

energy consumption at the same amount during the day time. One of the tools used to apply load shifting is the time-of-use rate. This economic incentive approach can encourage customers to change the timing of their energy consumption from peak periods to off-peak periods, thus avoiding the high costs of energy bills. Off-peak electricity rates peak is typically lower than average rates. Therefore, price-sensitive customers tend to consume more energy during the low-rate periods. However, predicting and forecasting the behaviours of human beings are complicated tasks, and achieving high-accuracy results is difficult. Distribution network operators and power suppliers cannot guarantee that a predicted power demand pattern will exactly match the actual power demand pattern, and thus, reserved generators and potential congestion solutions are required to deal with unexpected circumstances. However, the application of appliances with an energy storage function can shift the timing of their operation. This is another efficient tool that can be used for load shifting. For example, hot water tanks can initiate the water heating process and washing machines can operate during off-peak periods. Figure 2-9 (c) shows a typical load change pattern of the load shifting approach [13].

- Strategic conservation

The target of the strategic conservation approach is to reduce the overall energy consumption of customers to a particular level. This action is essentially achieved by using some efficiency techniques to decrease energy consumption in both off-peak and peak demand periods, thus reducing the total energy consumption. The typical means of strategic conservation include weatherization programmes and appliance efficiency improvement programmes. Figure 2-9 (d) shows a typical load change pattern of the strategic conservation strategy.

- Strategic load growth

The target of the strategic conservation approach is to increase the overall energy consumption of customers to a particular level. In the event of an increase in new consumers or the energy intensity, the overall sales are increased. This action is essentially achieved by using efficiency techniques to increase energy

consumption in both off-peak and peak demand periods, thus increasing the total energy consumption. Figure 2-9 (e) shows a typical load change pattern of the strategic load growth strategy.

- Flexible load shape

The flexible load shape approach can be described as load management optimization by comprehensively considering the power system reliability, operation constraints and overall economic benefits beyond the load shifting approach introduced previously. In particular, power suppliers are required to study the optimal electricity supply solution by applying different means, including economic incentive-based load control and direct load control. The flexible load shape approach attempts to optimally solve the load management and economic generation dispatch problems in advance, normally one day ahead. Figure 2-9 (f) shows a typical load pattern of the flexible load shape approach. Currently, efficiently consuming the high penetration of renewable energy resources and increasing the capacity of EV charging systems pose new challenges to DSM. More efficient optimization approaches and load management strategies are required to deal with these potential challenges [157].

In conclusion, all the means of demand side management is to affect and change the timing or level of customers' electricity usage, thus achieving the expected load objectives. Distribution network operators or power suppliers apply the proper approach to deal with the different load management requirements. For instance, the valley filling approach can be used in the situation that the system has underutilized capacity during the off-peak periods. However, peak clipping approach and strategic conservation approach are applied to deal with the situation that the system experience an unexpected load demand increasing. In particular, these two approaches are able to provide several potential benefits including 1) defer the investment on the network upgrading due to the rapidly growing load demand, 2) secure the power quality and improve customer service, 3) defer the negative effect to the environment, and 4) maximize the overall benefits of the social welfare. It is noted that peak clipping, load shifting, flexible load shapes and strategic conservation

are typically applied by distribution network operators as the useful tools to manage the increasing load demand of electricity customers, thus securing the efficient system operation. However, strategic load growth and valley filling approach are considered as the major tools to deal with the long-term expectations of surplus power.

2.6 Chapter summary

As mentioned in Chapter 1, the increasing penetration of DERs in distribution systems, the declined levelized costs of renewable generation and the application of innovative demand-side participation tools result in substantial changes in the conventional role of distribution systems. The aims and objectives of this thesis seek to design an innovative optimization algorithm and mechanisms to transition current passive power systems to future active systems. Therefore, the relevant knowledge of conventional distribution systems and their related operation mechanisms were first reviewed. Then, current challenges to the conventional distribution network design and planning process, such as the high penetration of distributed generation and demand-side participation, were discussed. Because DERs are one of the most important facilities that can significantly affect the operation and design of current distribution systems, the typical technological characteristics of DERs were introduced. In addition, the typical tools of demand-side participation were introduced to identify current DR programmes that can be widely applied in the electric power sector.

Chapter 3

Review of Electricity Market

3.1 Introduction

In the last century, the electricity industry in the UK was operated centrally by a single organization called the system operator (SO). Both the dispatch of power generation and the delivery of electricity are managed and controlled by the SO. However, the UK government launched the electricity industry liberalization plan in 1990 by establishing an obligatory day-ahead spot market, and this framework was designed to reform the electricity market in England and Wales [158]. After this successful attempt, the initial mechanism was upgraded to a new market structure in 2001—the New Electricity Trading Arrangement (NETA) [159]. The NETA framework first introduced a real-time wholesale electricity market, in which the power suppliers, generators, traders and electricity users participate intensively in this competitive electricity market mechanism. In 2005, the British Electricity Trading and Transmission Arrangements (BETTA) framework eventually replaced the NETA framework and extended the service to cover Scotland [160]. The BETTA framework

enabled integration of the electricity markets in England, Wales and Scotland. A free and efficient electricity trading system for all of Great Britain was thereby established. Along with deregulation of the electricity market, the domestic electricity retail market in the UK was first opened to competition in 1999, and the regulation of electricity pricing controls was removed in 2002.

As a thorough trading schedule, the current UK electricity wholesale market provides both bilateral trading or contract serving for energy production over different time spans, such as years ahead contracts, day-ahead trading or intraday business. Moreover, the trading service can be extended to other European countries. Currently, electricity can be imported from France, the Netherlands and Ireland or exported to those countries through international power connection facilities. Electricity is considered to be a special product that cannot be stored efficiently and economically based on current technologies. The power generation and electricity demand in a system must be matched and balanced during all operation periods. The accidental failure of generators in the trading process may lead to an imbalance in the electricity supply, which is considered to be one of the major drawbacks in the deregulation and marketisation of the electricity industry. Therefore, punishment mechanisms and auxiliary balancing mechanism have been designed for the current electricity market framework to deal with differences between contracted energy consumption and generation.

In general, the framework of the trading system encourages participants in the electricity wholesale market to treat electricity as a normal product or commodity while still ensuring that the power system can operate within its natural physical constraints [161].

The remainder of this chapter is organized as follow: Section 3.2 introduces the role of economics in power systems and Section 3.3 introduces the major components that existed in the electricity price. Fundamentals of the electricity market are introduced in 3.4. And, section 3.5 introduces the policies in the United Kingdom for encouraging the application of renewable generations. In the end, section 3.6 summaries the contents in this Chapter.

3.2 The Role of Economics in Power Systems

Economics can be regarded as the research areas that optimally solve the allocation of insufficient resources to meet the requirements of human beings. In the electricity industry, the power system economics of the resources in question address the costs of power generation and the costs of energy delivery and distribution. In particular, the costs include 1) the capital investment of generators, transmission systems, distribution systems and auxiliary facilities, 2) labour costs, 3) system operation and maintenance costs, 4) operation costs of electricity trading system and 5) fuel costs. Indeed, RESs, such as small-scale rooftop solar PV panels and wind turbines, can provide electricity without consuming fossil fuels. Thus, these technologies are normally considered to be zero marginal cost generation methods in most studies and economic models. However, operators still need to make large investments to procure the required materials and equipment [162].

The requirements of human beings, in this case, can be regarded as the supply of electricity. However, electricity cannot be considered as a uniform commodity due to the scale of its production and the difficulty of economically storing it. Further, electricity requirements vary largely depending on the time period of consumption and the quality of the electricity provided to customers. Thus, the value of electricity can be divided into the following general categories: baseload electricity, peak-hour electricity, high-quality electricity, low-quality electricity. In addition, supplying electricity to different types of customers requires various power delivery systems. For instance, concentrated industry customers are connected to transmission systems directly or are sited near generators. Industry customers actually avoid distribution network charges, thus decreasing the costs of purchasing electricity. Household customers in remote areas connect to the main grid by relatively long distribution lines or cables. Thus, customers in rural areas must pay high use of distribution system charges. In practice, household customers in different locations are charged different electricity prices for the same time period. However, this price differential is very low for the consideration of a fair pricing mechanism.

Similar to other commodities sold in the market, electricity can be regarded as a common good, as portrayed in economic manuals. However, electricity trading has

two characteristics that significantly differ from normal commodity trading: 1) the constraints and regulations of power systems restrict the use of electricity because the reliable and safe operation of a system is considered to be the primary target of operators and 2) electricity is currently considered to be a non-storable resource, and thus, fluctuations in wholesale market pricing significantly affect real-time electricity prices for retailers. In particular, short-term power generation must match the demand at all times and have the ability to instantaneously respond to any variations in the demand. Indeed, these characteristics are not exclusive to electricity; the modern high-speed internet shopping experience is similar in these respects. The majority of the commodities in the market can be distributed and delivered by different logistics approaches, such as road transport and air transport. However, delivering and distributing electricity require more accurate real-time analysis and the observance of complex regulations and constraints, thus allowing customer to receive quality energy service instantaneously. System operators have the responsibility of providing quality energy service to their customers because electricity is considered to be fundamental to modern life and a basic human right, similar to the water supply. However, power delivery systems, which are similar to highways, have a maximum transporting capacity. Thus, large amounts of money are required to construct sufficient power transmission and distribution systems to meet the increasing electricity demands of customers, especially during peak demands. System operators are expected to consider potential future investments in the use of transmission or distribution charges based on the operation conditions of a network (network congestion, peak or off-peak periods) and when electricity is consumed.

Furthermore, the utility derived from electricity changes with the time, quality and type of use (or user), giving rise to different services rather than a single uniform service. These types cannot be freely interchanged; however, flexibility in this regard is limited.

Thus, demands for electricity are not all the same, and they vary for each type of electricity. The willingness to pay and the elasticity of demand (i.e., the variation in electricity consumption when prices change) differ for these services. Another

feature of electricity is that it is generally considered, at least in developed countries, as a basic service that must be provided universally, reliably and affordably to facilitate on-going development. In fact, the supply of electricity is considered to be one of the key factors for enhancing welfare, and it can be argued that access to electricity should be considered a basic human right [162].

3.3 Components of electricity price

Investigating the costs of electricity production and the relevant transmission and distribution costs is fundamental to establishing an efficient electricity market. Section 3.1 indicated that the costs of producing electricity and the costs of power delivery vary depending on influences such as fuel types, the time of generation, network constraints and relevant regulations [163]. Thus, the general cost types and the relevant definitions of each cost type are described in this section.

3.3.1 Electricity producing costs

Electricity generation costs can be generally summarized by three major aspects: 1) the construction costs of power plants, 2) operation and maintenance costs, and 3) fuel costs.

- Construction costs

The construction costs of power plants or generators are the combination of capital costs, labour costs, land acquisition costs and construction material procurement costs. These costs are also regarded as the investment costs incurred during the full construction time period. The construction time of a power plant largely depends on the size of the generators and the technologies of the generators, such as conventional fossil fuel generators, nuclear generators or wind turbines. Thus, the time required to construct a power plant ranges from a few days (small-scale micro turbines or roof-mounted photovoltaics) to a few months (normal generators), even up to a few years (large-scale generation facilities or nuclear generation stations) [164].

- Operation and maintenance (O&M) costs

Operation and maintenance costs of the generation sector include the labour costs of plant operation and maintenance and relevant material costs during the repair process. Indeed, fuel is also significant in power plant operation. These particular costs are discussed separately later due to the various types of fuel consumed in current generation facilities. Two approaches are typically used to assess the O&M costs of certain power plants. The first approach is to consider the O&M costs as a fixed amount during the period of one year. Thus, the costs are constant regardless of the amount of electricity generated during this period. Another approach is to assess the O&M costs based on the exact amount of electricity produced. For instance, the operation hours and the frequency of start-ups are considered in this assessment method. Therefore, fixed O&M costs are measured in monetary units per year, and dynamic O&M costs are measured in monetary units per kWh [164].

- Fuel costs

Fuel costs are regarded as one of the most important elements of the total electricity generation costs for fossil fuel based generators. However, the fuel costs are much less for sustainable generations such as nuclear plants. And, zero fuel cost is considered for the renewable generations such as wind, solar and hydro generators. Fuel costs can be assessed by two major approaches: 1) measuring before the generation process, and 2) measuring as a fraction of the cost of electricity. In the first approach, the costs can be calculated by the unit price of different types of fuel and the amount used to produce the electricity. And, in the second approach, the costs can be assessed by the actual electricity generation by the units per kWh with the consideration of the energy transferring efficiency rate. Fuel costs are neither necessarily constant nor linear with output: in thermal power plants, for example, they start from a certain output level (the technical minimum, below which the plant cannot function) and then evolve nonlinearly with the level of output.

Thus, the costs of electricity production are consisted of different aspects and factors. And, the costs are largely depending on the selected generation technologies, the size of the power plants and particular fuel used for electricity generation. Quadratic formulation 3-1 is normally used to describe the unit electricity generation costs of the thermal generators [165].

$$GC_g = \alpha_g \times PG_g^2 + \beta_g \times PG_g + \gamma_g \quad (3 - 1)$$

where, α_g , β_g and γ_g are cost coefficients for generator g . GC_g and PG_g are generator cost and corresponding power output of generator g .

Some technologies require very large investments per installed kW, whereas others do not. Some rely on expensive fuels, whereas in other fuel is cost-free (solar or wind). Future electricity generation costs are, moreover, highly uncertain, since they depend on the variation in fuel prices as well as on technological developments. This explains the wide variations sometimes observed in future cost estimates. Thus, the principle of the levelized costs of electricity (LCOE) is introduced to indicate the minimum unit electricity generation costs for different kind of generators to cover the investment costs and the O&M costs during the lifetime of the project. The calculation of levelized costs of electricity is based on the economic assessment of the life-cycle costs of the certain generators includes the initial investment and labour costs, operations and maintenance costs, costs of fuel and cost of capital. Indeed, this assessment highly depends on the assumption of predicted electricity generation in the total lifetime and the frequency of the generator maintenance. LCOEs which calculated over 20 to 40 year lifetimes of the generators, however, can be regarded one of the most useful approaches to identify and distinguish different generation technologies regard of the unit generation costs [27, 28].

3.3.2 Transmission and network operation costs

In the electricity market, transmission costs and network operation costs are already a critical part of electricity bills. The costs of these services include fixed construction fees and future maintenance requirements. It is expected that electricity consumers

can be charged transmission and network operation fees based on their usage. However, the current charging approach for transmission and distribution network services relies on fixed tariffs, which fail to reflect actual potential congestion and thermal limitations.

It is expected that all users of transmission facilities will pay for the network usage of the system using an efficient transmission pricing mechanism that can recover transmission costs and allocate them to network users in a fair way to provide signals for the right placement of new generation and transmission facilities [166, 167]. The priority target of transmission and network operation costs is to cover all transmission assets and common operation requirements. However, the components of wheeling costs are complicated and are required for calculations. Usually, the wheeling party includes assets costs, maintenance and operation costs and potential congestion charging.

- Capital costs

Capital costs represent the common instalment costs related to corresponding distribution and transmission networks and usually include the costs of required equipment and related service costs. To cover the entire investment with assets and retain consistent revenues, current wheeling cost charging approaches provide a fixed tariff to each electricity consumer, in which the tariffs depend on the calculation results of annualised asset costs, associated service costs and required revenues. For distribution network operators, this charging mechanism can ensure a balanced trade-off relationship with consumers. However, the operation conditions and potential associated congestion problems cannot be considered under this charging approach.

- Operation and maintenance costs

Unlike capital costs, which have a confirmed amount, operation and maintenance costs cannot be calculated precisely. However, distribution network operators can readily recover their operation and maintenance costs by permitting charges in the

range of 2-5% of the calculation results of annualised asset costs Costs of network losses [168, 169].

Energy losses are an unavoidable result of the delivery of energy through power networks. In Great Britain, an average of 1.7% of the electricity transported through the transmission network and 5-8% of the electricity transported through local distribution networks are indicated as power losses [170, 171].

Similar to capital costs and operation costs, the costs of network losses can be added to wheeling charges. However, the problem of allocating the costs of network losses should be considered carefully. Distribution network operators are expected to identify the specific route and path that each consumer uses to obtain electricity. Consequently, the costs of power losses can be covered by arranging the entire expansion of losses from all consumers or by indicating the costs occurring from increasing losses under the influence of precise transmissions in the power system.

- Congestion costs

Transmission and distribution network congestion is defined as a situation in which transmission systems have no sufficient capacity to deliver all of the electricity requested by consumers. Therefore, to ensure the stability and reliability of power systems, transmission network and distribution network operators are expected to rearrange power transmission and generation based on considerations of thermal limitations and potential congestion. As a result, some of the requests may be denied or delayed. However, it is important to design a smart and reasonable strategy to manage each electricity request denial or delay. Currently, various approaches and regulatory strategies have been applied for congestion management. However, most of them are based on an active management method, which is not efficient and effective. As a consequence, economic incentives, whereby a congestion fee is added to the final electricity price, have been introduced in congestion management [172, 173].

Various congestion charging frameworks have been intensively researched recently, and the widely applied approaches are introduced below

- Postage Stamp Method (transaction / non-transaction)
- Contract Path Method (transaction based)
- Distance-Based MW-Mile Method (transaction based)
- Power Flow Based MW-Mile Method (transaction based)
- Power flow tracing based on proportionate sharing principle (non-transaction)
- Equivalent bilateral exchange (EBE) method (non-transaction)
- Zbus based method (non-transaction)
- Postage stamp method

Under this charging system, all electricity consumers are expected to pay a use of system charge to their local distribution network operator. The amount of the charge is usually based on the electricity usage of each user. Due to this charging approach cannot correctly reflect the path of power flow, the charge to electricity users simply represent their average usage of whole local distribution and transmission facilities. To make sure a guaranteed revenue to cover all construction investment and annual service cost, distribution network operators usually announce a relatively high charge of transmission cost. Therefore, it is unable to manage the congestion of the transmission system by the economic incentive and unfair to part of electricity users who use their appliance during an off-peak period.

- Contract path method

In the charging approach of contract path method, a specific route named as contract path is defined firstly. This route is between the electricity delivery starting point and energy receive a point, which is chosen by both distribution network operators and electricity consumers. The asset costs of the transmission system associated with certain contract path will be allocated to the wheeling consumers in corresponding to their electricity usage.

Due to the approach will charge the transmission cost by a fixed rate on a chosen path, the actual network operation situation is neglected. Therefore, the transacted power may be carried by the transmission facilities which are not included in the contract path. Consequently, the inappropriate price signal may be sent to customers, which may result in inefficient and ineffective system operation and management.

- MW-Mile method

The MW-mile method is introduced to overcome the disadvantage and limitations of the contract path method and postage stamp method, where the approach is implemented by actual power flow analysis. The wheeling charging in the approach is calculated by the extent of transmission facilities' usage and geographical distance between the power supply point and customers. Usage of the power delivery can be extracted by the power system analysis. However, the geographical distance cannot fully reflect the actual meshed network. Consequently, the price tariffs are still a failure to provide the appropriate congestion signal in most circumstances.

3.4 Fundamentals of the electricity market

In the previous section, it was mentioned that electricity is must be regarded as a special good in the electricity trading system and electricity market. However, the operation of the electricity market still follows the concepts of market fundamentals, particularly those of microeconomics. Therefore, the basic concepts of microeconomics and market fundamentals are introduced in this section. Based on the literature, the mechanisms and operation of the electricity market will be introduced in the next section. Demand curves and supply curves are two essential tools used to indicate the operation of microeconomics and the principles of market fundamentals. In particular, the relationship between demand and supply indicates that the demand for a given good or service is based on the performance of customers and the supply costs. These fundamental principles of economics can also be applied in the trading of electricity.

3.4.1 Customer behaviours and producer behaviours

In general, customers decide to purchase a good if they assume that possession of a product will afford greater satisfaction than the price paid for it. Therefore, the basic criterion that most customers would like to follow is to purchase products only if their price is equal to or less than their expected utility, where utility can be regarded as the degree of satisfaction or the profits that the customers can obtain. Increases in the level of satisfaction are measured in terms of marginal utility, where marginal

means the additional utility obtained by consuming one additional unit of a given product or service. Customers would like to capture the maximum benefits from the difference between the satisfaction received by purchasing a certain number of products and the total cost paid for the products. Therefore, customers are expected to purchase a certain product continually when the marginal utility of the product is higher than the price of the product. Customers stop or refrain from purchasing a product when its marginal utility is lower than its price.

Based on the previous introduction to customer behaviour, a typical demand curve can be described by aggregating the amounts that all consumers would like to purchase at each single electricity price. Such a curve, which indicates the relationship between electricity price and demand, is shown in Figure 3-1.

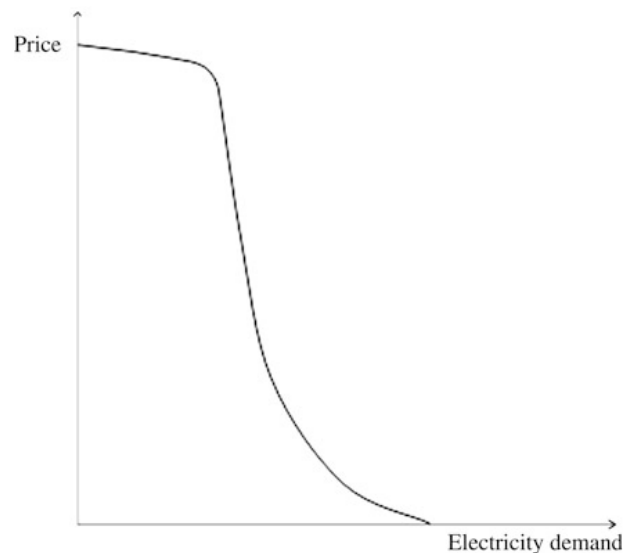


Figure 3-1 Typical demand curve of electricity trading [162]

Figure 3-1 shows that the demand for electricity experiences a significant increase when the unit price of electricity decreases. Conversely, electricity users tend to reduce their usage if the electricity price increases.

Similar to the demand curve introduced above, Figure 3-2 is applied to indicate the market behaviour of electricity suppliers. In particular, the curve in Figure 3-2 indicates the relationship between the quantities of the energy that power generators are willing to supply and the market trading price.

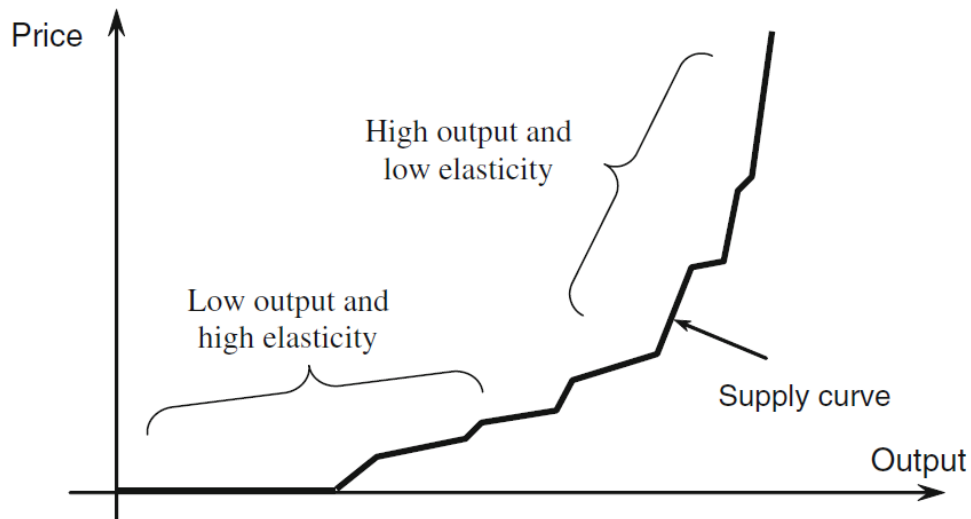


Figure 3-2 Typical supply curve of electricity trading [162]

Producer behaviour and the supply curve depend heavily on two factors: production costs and the number and size of companies competing in the same market. An understanding of the supply curve calls for an analysis of optimal producer behaviour. When companies offer their products on the market, they seek the highest possible profit, which means that they must compare the cost of producing one additional unit to the revenues from the sale of that unit.

However, the electricity supply curve is usually not continuous due to the simultaneous existence of various generation technologies. In particular, must-run power generators have to provide a minimum generation output when they are operated in working condition. This kind of generator is difficult to shut down for short intervals because controllable thermal plants are expected to maintain their operation status. These behaviours can be partly attributed to security reasons such as a minimum level of generation reserve, which is requested by network operators, or the provision of generation reserves by renewable energy resources (the output uncertainty of wind generation or solar photovoltaics). Typically, this kind of generator, which is normally regarded as a baseload generator, includes hydro generation, fossil-fuel-based generation and nuclear plants. These baseload power plants supply electricity with relatively low variable costs. The supply curve in this area shows significant elasticity. In particular, these generators tend to respond to increases in electricity demand with small changes in the electricity price.

CCGTs and low-efficiency coal generators can be considered as power plants with middle price elasticity. These generators contribute to the middle shape of the supply curve.

The last shape of the supply curve is formed by various peaking plants. These generators supply energy with a relatively low price elasticity. Single-cycle gas turbines, oil-based generators and hydro storage plants are normally regarded as typical peak demand reserved generators with the highest electricity price. However, electricity customers only consider purchasing electricity from low elasticity generators during peak hours.

3.4.2 The law of supply and demand

The trading of electricity is operating in the competitive market after the electricity market deregulation process. The principle of demand and supply can be partly applied to analyse the relationship between electricity suppliers and the customers. Based on the supply curve and demand curve that discussed in section 3.3.1, the market equilibrium is reached at the point of intersection by these two curves. The price balance is achieved only at this point since electricity customers purchase all the energy with the price that is lower than their expectation and refuses to purchase the energy with the price higher than their expectation. The similar explanation can be applied to the electricity supplier at the same time.

Figure 3-3 indicates the typical market equilibrium in the short-term trading process. This equilibrium can be used to identify the surplus of electricity users. The customers surplus here is defined as the difference value between the total utility and the total electricity purchase costs. And, the precise customer surplus is located in the areas between the demand curve and the equilibrium price. On the other hand, the area to the right of the equilibrium point underneath the demand curve is the aggregate consumer utility that is not satisfied because the marginal utility is lower than the equilibrium price. The area under the supply curve represents producer costs, and therefore producer surplus is the area to the left of the equilibrium point above the supply curve.

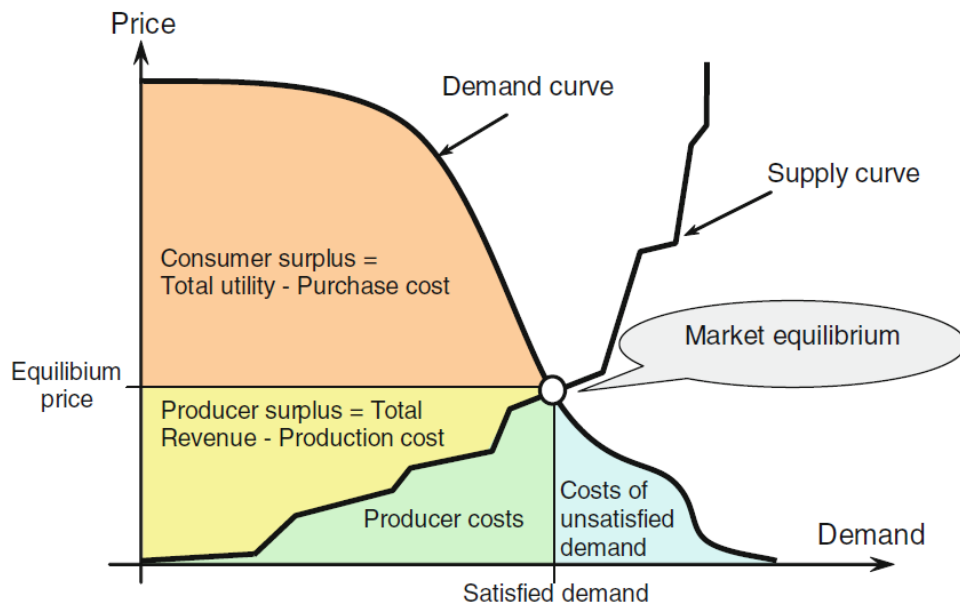


Figure 3-3 Market equilibrium in the short term trading process [162]

The current electricity trading is normally operated in electricity pools or power exchange companies in their business areas. And, the electricity can be traded ranging from a small amount to a large amount on the short-term markets. However, most of the electricity trading between the power supplier and the power generators are finished typically one day-ahead. Thus, both suppliers and generators are required to precisely predict the electricity demand in the following day by half-hour time slot (or a 20 mins slot in several countries). And, the market equilibrium point can be theoretically achieved by the optimization algorithm and bidding process of the trading agents in the electricity pools. Then, the negotiated day ahead hourly electricity price is provided to the suppliers and generators with a different rate due to the commission fee and other required costs. Indeed, the actual demand is different from the predicted demand in most of the circumstances. The intraday trading process is applied to deal with the mismatch between the actual demand and predicted demand in the operation day.

The actual trading process and the optimization algorithm of the bidding process are complicated. however, the general rule of the electricity trading can be concluded as that all bids from the electricity purchase side with the price higher than the equilibrium prices are accepted and the selling price from the generator side is also accepted when this price is lower than the equilibrium price. On the contrary, the

electricity purchase bids are declined when the price of bids is lower than the clearing price and the selling price from the generator side are rejected when this price is higher than the clearing price [162].

3.4.3 Structure and competition of the electricity market

The electricity sector used to be designed as the monopolized industry. Thus, the electricity customers have to purchase the electrical energy from the unique sector or company. And, a utility that has the right to supply the electricity to certain areas is normally vertically integrated. Specifically, the utility owns the entire industry process of the electricity supply which includes the power generation, transmission, distribution and retail market of electricity trading. Indeed, the monopoly structure of the electricity industry encourages the application of electric energy since governments have sufficient financial and political resources. After the rapid development of the electricity industry in the last few decades, most countries in the world have established a tough and reliable power system. And, the electricity customers in those countries have access to the high-quality electricity service regardless of the remote areas or the urban areas. In particular, the development of the electricity industry significantly improved the reliability of the electricity supply to the end users, where the average time that consumer losses the power supply reduced to two minutes per year.

However, the electricity market lack of economic incentive when the power systems operate in the monopoly mechanism. Thus, electric utilities are difficult to operate efficiently with the help of the competitive market and may results in unnecessary investments in some circumstances. Relevant research and study indicated that the average electricity price could be lower when the electricity sector can be reformed to the competitive market. Thus, the electricity supply can follow economic principles rather than monopoly regulation. Under this background, the UK launched electricity deregulation in the early 1990s. And, the electricity market reform (EMR) is still ongoing in the UK.

In the rest part of this section, two typical structures of the electricity market that widely applied in the world are introduced to identify the difference between the competitive electricity market and traditional monopoly electricity utility [174].

- Monopoly

The basic structure of the traditional monopoly utility is shown in Figure 3-4. And, there are two typical models of the monopoly structure. In the first model (shown in Figure 3-4 (a)), the electricity utilities completely integrated whole power supply sectors includes the electricity generation, transmission and distribution. Thus, this unique utility responsible for electricity producing, power delivering and the retailer market. On the other hand, a half monopoly structure is shown in Figure 3-4 (b). Under this structure, the major monopoly utility owns the electricity sectors of generation and transmission. The electricity is sold to the local monopoly distribution companies and these local electricity sectors shoulder the responsibility to sell the electricity to the end users.

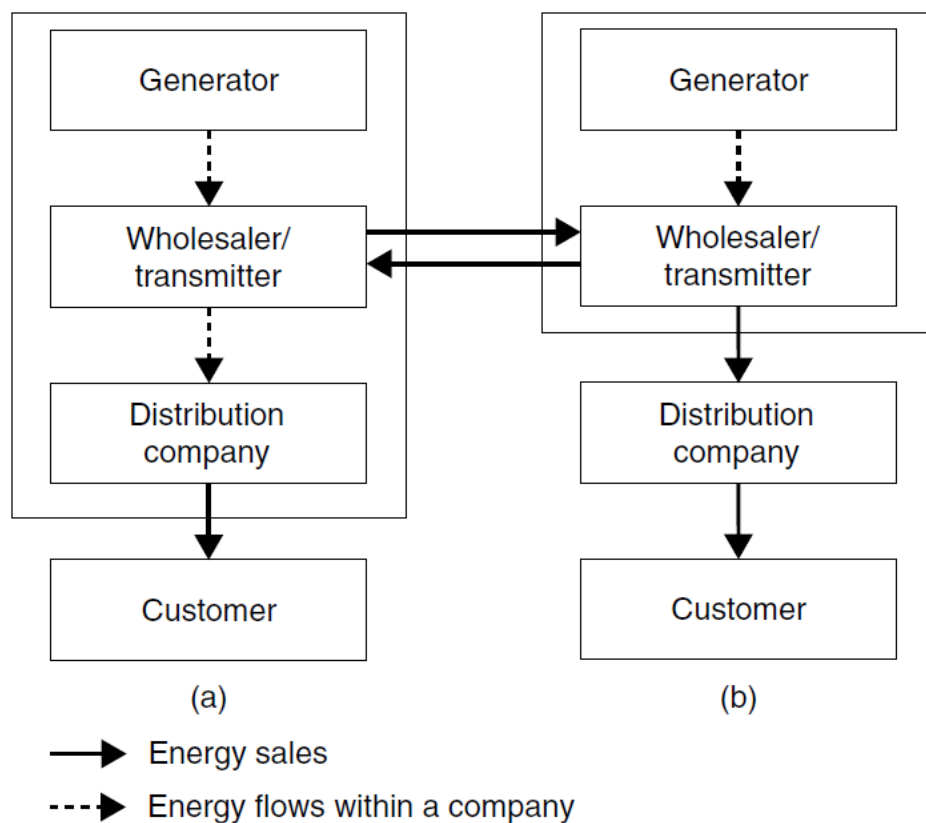


Figure 3-4 The basic structure of the traditional monopoly electricity utility [174]

- Retail competition

The electricity market finally reaches the fully competitive form in this stage, where all customers have the right their favour electricity suppliers. In this model,

the large consumers purchase the energy directly from the wholesale market and the medium or normal household customers purchase the energy from the retailers they prefer. More importantly, the function of electricity selling in the retailer market is separated from the distribution companies in this model. Thus, distribution companies no longer have a local monopoly for the supply of electrical energy in the area covered by their network. And, the function of distribution network operation and maintenance is succeeded by the local distribution network operators (DNOs). For example, there are 14 licensed distribution network operators (DNOs) in Britain and each is responsible for a regional distribution services area. And, these DNOs shoulder the responsibility to carry electricity from the high voltage transmission grid to industrial, commercial and domestic users.

In this model, the only remaining monopoly functions are thus the provision and operation of the transmission and distribution networks. However, governments in different countries will establish some independent departments to supervise the operation of the monopoly electricity utilities. For example, the UK government established the Office of Gas and Electricity Markets (Ofgem) which is a non-ministerial government department and an independent National Regulatory Authority, recognised by EU Directives. The principal objective of the Ofgem is to protect the interests of existing and future electricity and gas consumers.

On the other hand, sufficiently competitive markets are established in this model. There are no monopoly electricity utilities to set the fixed electricity retail price and the end consumers such as the household customers and the small commercial customer can easily change retailer. And, the electricity users are usually price sensitive customers and tend to choose the retailers who can provide the lower electricity price. Thus, the electricity retailers have to improve their operation efficiency to decrease the electricity price they provide to their customers. Therefore, the overall electricity market can achieve the optimum operation condition. However, the cost of the transmission and distribution

networks is still charged to all their users. This is done on a regulated basis because these networks remain monopolies.

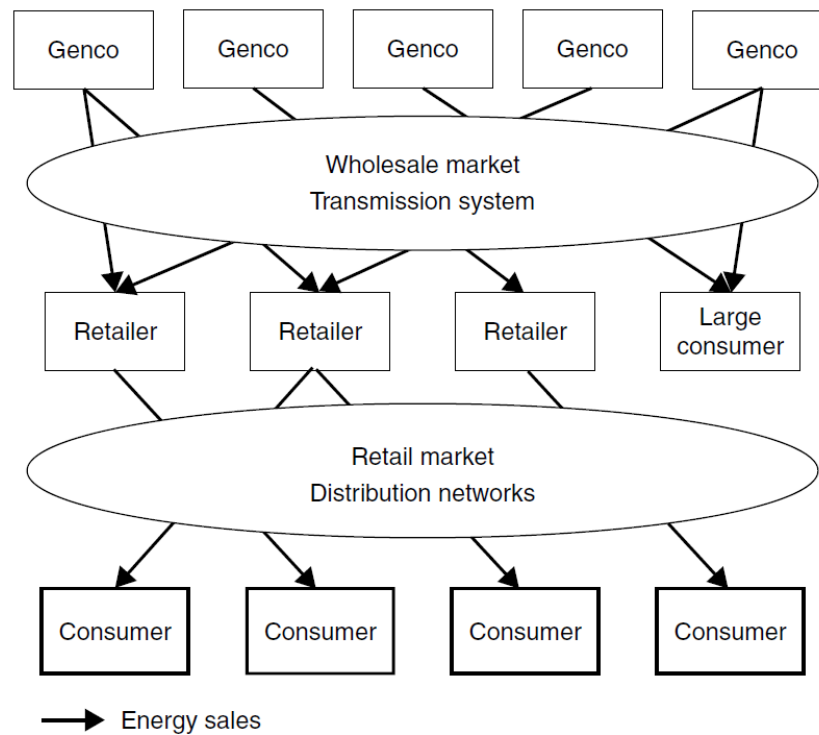


Figure 3-5 Electricity market structure with retailer competition [174]

3.4.4 Dynamic electricity pricing

The optimal scheduling of loads in the demand side has gained considerable research interest with the introduction of dynamic pricing (DP) in the electricity sector. In particular, DP is being considered as a vital approach of demand side management (DSM) which could be crucial for connecting more renewable energy sources (RES) into the electric industry [175]. On the other hand, DP has the capability to reduce peak load by providing different electricity retailer prices at different times based on the relationship between energy supply and load demand. Peak demand in the load profiles results in the potential network congestion problem during the peak periods. Moreover, additional power transmission or distribution capacity are required to satisfy the peak load demand [176]. This reserved network capacity stays idle during off-peak periods resulting in a loss of opportunity cost and system efficiency. The application of DP has the capability to affect the electricity usage behaviours of customers by economic incentives, thus shifting the demand from peak to off-peak periods and defer large capital investments in power delivering facilities [177].

Electricity retailers in UK normally offer flat pricing or two/three rates pricing to their customers. In the charging approach of flat pricing, the electricity prices remain unchanged irrespective of demand. On the other hand, there are two or three fixed per unit rates of electricity can be provided to customers based on the time they consume the energy (peak or off-peak periods) [178]. However, the costs of generation to meet peak demands are high as compared to those for off-peak demand, since most peak time generating units have higher operating costs than base load units. The wide application of RES also decreases the generation costs during the off-peak periods due to the its characteristics of low O&M costs [179]. Thus, the above-mentioned electricity prices cannot reflect the true costs of generation and distribution. Although fixed electricity rates provide certainty and simple electricity bills to customers, this pricing mechanism results in costly capacity additions and cannot provide cost-reflective electricity rate to users. In addition to the function of reduction in peak demand, DP also offer individual electricity user with an opportunity to reduce his/her electricity bill at a constant consumption level, just by changing the consumption pattern by shifting their load demand [180].

3.5 Policy for renewable generation in the UK

The UK can be regarded as the pioneer of the electricity deregulation in the world, where it launched this revolution in the early 1990s. Several efforts have been made in the electricity deregulation such as the disintegration of the traditional monopoly electricity utilities and the permission of private electricity retailers. However, the UK renewables policy also play a vital role in the process of electricity deregulation due to the wide application of distributed generations and the environmental concerns in the last decade.

The governments in the world widely accept that climate change should be considered as one of the major threats to human beings. The first action that the UK government tried to encourage the application of renewable energies was launched

in 2002, where Renewable obligation certificates (ROCs) announced as a new policy by the government. In particular,

Electricity retailers were responsible for source the increasing share of their sales from the renewable energies. And, the retailers have to fill up the insufficient obligation by purchasing the renewable obligation certificates or paying a fixed buy-out charge of £30 per MWh. The renewable generators received all buy-out charges as part of the revenue to encourage the investment on renewable energies. However, the renewable generators undertake the responsibility to sell their available output in the electricity market and fill up the imbalance by themselves [181]. Thus, operators of the renewable generations were required to predict the wholesale prices, imbalance payments and renewable obligation certificates at the same time to ensure sufficient revenue can be captured. After the first attempt of the renewable policy, the UK government launched a wide range of new policies to encourage the development of renewable energies. The most recent action launched by the UK government to support the renewable resources are Contracts-for-Difference (CfD), Emission Performance Standard (EPS) and Carbon Price Floor (CPF). These three actions are parts of the package of electricity market reform (EMR) which was introduced by the UK government in 2013. The basic introduction of these three measures is indicated below [19, 46, 181-185].

- Contracts-for-Difference (CfD)

Contracts for Difference (CfD) was an innovated regulation that launched in 2014 by the UK government to replace the previous Renewable Obligation strategy. The large-scale renewable energy resources (typically more than 5 MW) are the major target that is supporting the CfD scheme. In particular, the electricity price in the power market and the predesigned strike price are two major components in the CfD project. Under this regulation, the owner of renewable generators can confidently participate in the electricity trading process. If the strike price is higher than a market price, the CfD counterparty must pay renewable generator the difference between the strike price and the market price. If the market price is higher than the agreed strike price, the renewable generator must pay back the

CfD Counterparty the difference between the market price and the strike price. UK government established an independent company named Low Carbon Contracts Company (LCCC) to shoulder the responsibility of making contracts to the owner of renewable generators. It is noted that the LCCC has to follow the regulations which are designed by the government to ensure the development of renewable energy resources. The typical CfD contracts between the LCCC and the renewable generators are awarded for 15 years. And, the renewable technologies that have the right to participate in this project can be summarized as follow: wind generation, solar photovoltaic, hydropower generation, ocean power generation and the biomass or gas based generations [19, 182, 183].

However, the UK is currently the only county that launch the CfD scheme and the regulators are expected to use this new project to replace the renewable obligation scheme which has been widely applied for almost two decades. Thus, the CfD scheme still requires a relatively long operation time to identify its advantages.

- The carbon price floor (CPF)

The Carbon Price Floor (CPF) was proposed by UK government in 2013 to provide a sufficient carbon price to the generators in the UK, thus encouraging the investment to the renewable energy resources (no carbon emission charge is required for RES). The carbon price in the EU emission trading system reduced to a relatively low rate since the oversupply in the market and other relevant reasons. The conventional carbon price strategy in the EU cannot restrict the fossil fuel based generator efficiently. Thus, the CPF scheme suggests an additional top-up tax to the generators that release the carbon emission. Based on the combination of this tax and EU ETS allowance prices, generators should always pay the minimum carbon price for their carbon emissions. Thus, the target of the CPF scheme is to underpin the price of carbon at a level that drives low carbon investment, which the EU ETS has not as yet achieved [46, 184, 185].

- Emissions Performance Standard (EPS)

The Emissions Performance Standard (EPS) is a regulatory limit on the amount of carbon a fossil fuel plant is permitted to emit. Whilst carbon pricing and other incentives will encourage a switch to cleaner forms of electricity generation, the EPS aims to provide an ultimate backstop limit which will prevent coal-fired power generation without carbon capture and storage (CCS). In particular, the EPS has been set at a level equivalent to emissions of 450gCO₂/kWh for a plant operating at baseload. This is equivalent to around half the level of emissions of unabated coal generation and is fixed until end 2044. The EPS provides a regulatory reinforcement of the existing planning requirement that any new coal-fired power station can only be built if it is equipped with CSS. The EPS also applies to new gas plant, but the Emissions Limit is not expected to impact on the operation of modern gas plant. The EPS is the first of its kind to be introduced by any country in the European Union.

3.6 Chapter summary

This chapter reviewed the fundamentals of power economics and electricity market deregulation in the UK. Section 3.2 introduced the role of economics in power systems, and section 3.3 introduced the major components of electricity price. The fundamentals of the electricity market were introduced in section 3.4. Section 3.5 introduced the policies in the United Kingdom that encourage the application of renewable generation.

Innovative frameworks and approaches, such as the optimal day-ahead pricing mechanism and the selection of optimal conductor sizes in distribution network planning, are related to the economics and relevant principles of the electricity market. Thus, it is important to clarify and identify their basic principles. Distributed generation was considered and applied in this thesis, and thus, the relevant policies launched by the UK government to encourage the application of renewable energy resources were also introduced in this chapter. In particular, various economic incentives, such as the previous Renewable Obligation and the current Contract of Difference, were discussed as typical policies that have been applied to secure the economic benefits of distributed generation operators.

Chapter 4

Network reconfiguration in the distribution system

4.1 Introduction

Due to environmental concerns, renewable energy resources (RES) have been regarded as an efficient approach to relieving the concerns of global warming and carbon dioxide emissions that caused by conventional fossil fuel power plants [186]. . In particular, the wide application of renewable DG units is considered as an appropriate alternative to conventional power plants. The total installed capacity from RES, globally, has increased from around 2000 GW in 2016 to 2167 GW in 2017 (i.e., 8.3% increase in one year) [187]. However, the specific characters of distributed generation sources such as poor predictability and variability of output affect the stability and efficiency of the distribution system. On the other hand, power losses on transmission and sub-transmission lines made up 30% of the total power losses, while losses in a distribution network system accounted for 70% of the total losses in power system network. Power loss directly affects the operational cost of a power system. In order to minimize the power losses among the distribution system, various approaches are considered and applied by network operators and designers. In particular, these approaches include re-conducting, capacitor bank installation,

network voltage raising and distribution network reconfiguration [188, 189]. Among the mentioned approaches above, the distribution network reconfiguration is considered as the one that requires less investment for the distribution network operators, since this technology can be applied by existed infrastructures in the networks. However, the distribution network reconfiguration and the wide application of DGs are usually studied separately. Thus, the integration of these two sub-problems together can bring more benefits to the whole distribution system.[190].

The majority of distribution networks operate with a radial topology and design with loop structure, thus the topological of those distribution network is convertible [191]. The topological structure of the distribution network is, therefore, reconfigured to improve the efficiency of the network operate or reduce the active power losses based on the requirement. The network reconfiguration is achieved by changing the on/off status of the sectionalizing and tie line switches [192]. In particular, the distribution network reconfiguration can be defined as a process that handles the open/close status of sectionalizing switches and tie-switches in order to find the best network configuration that optimizes different criteria while satisfying operational constraints [193].

It is mentioned above that the increasing application of the distributed generations challenges the common algorithm of the distribution network reconfiguration approach [193-195]. Thus, it is important to explore new methodologies for achieving the balance between network multiple objectives and constraints (including load balance, voltage performance, system losses) when applying the network reconfiguration technologies and considering the high penetration of the distributed generation. A genetic algorithm based network reconfiguration technology was introduced in this Chapter. The objective of the approach is to explore the optimum topology in advance at each hour by analysing the predicted data of load demand and distributed generation. The algorithm is tested in IEEE 37-bus feeder network with distributed generations.

The rest of the Chapter is organized as follows: the definition of distribution network reconfiguration technologies is introduced in section 4.2. A Genetic algorithm based

optimum distribution network reconfiguration technology is introduced in section 4.3. And, the numerical results are summarized in section 4.4. in the end, the main conclusions of the study are discussed in Section 4.5.

4.2 Definition of distribution network reconfiguration technologies

Network reconfiguration technologies for the reduction of power losses were initially suggested by Merlin and Back [196]. The first attempt to implement a simple algorithm for the network reconfiguration was proposed by Civanlar et al. [197], where, the benefits of network reconfiguration for power losses reduction has been proven in the paper. Branch exchange technology was firstly developed by Baran et al. [193] for feeder reconfiguration and validating that network reconfiguration also has the capability to enhance the load balance. A heuristic search approach has been claimed by Morelato and Monticelli [198], where, the methodology was tested in a real distribution network with analytical operation status for calculating the optimal reconfiguration structure. Meanwhile, heuristic algorithms have been a core research area in the network reconfiguration, Goswami et al. [199] and Chin et al. [200] proposed different kinds of heuristic algorithms which were verified as the efficient approach to solving certain reconfiguration problems. Since network reconfiguration is a typical optimisation question, plenty of optimisation algorithms such as artificial algorithm [201] and fuzzy controlled evolutionary programming [202] have been implemented by various researchers. Considering the increasing number of distributed generations (DGs) which have been allocated in the distribution network, a new analysis approach that evaluates the impact of DGs with the network reconfiguration technology has been firstly suggested by Oliveira and Ochoa [203].

The methods mentioned above have significantly developed the theory of network reconfiguration technology. As an engineering approach the theory is expected to be implemented in practice. Hao et al. [204] taken time-varying load and distribution generation into consideration for establishing a dynamic network reconfiguration approach based on optimal economic benefits in the network. Song et al. [205] have combined reconfiguration technology into a design of a smart distribution

management system, where network reconfiguration was successfully integrated into the actual network.

Genetic algorithm (GA) was presented by Holland [206] and has been widely used in various research subjects. Choi et al. [207] have firstly applied GA technology into network reconfiguration and Radha et al. [208] has successfully implemented GA into an actual network.

The above literature has deeply explored network reconfiguration and related algorithms, however, most of them implemented the approach and algorithms by the conventional mathematic mechanisms which are operated by pure mathematic software C++ or MATLAB. In this paper, GA technology will be implemented into the simulation process by applying Common Object Model (COM) abilities of OpenDSS which is a typical distribution simulation software. MATLAB shoulders the responsibility of implementing GA technology and coordinates the algorithm with the simulation results which are conducted by OpenDSS. GA technology has the capability to dramatically improve simulation speed. As a consequence, a time-series optimal reconfiguration strategy for a certain network can be provided based on the predicted data of the load demand and the output of DGs. In the method, a daily load profile with 1hour time resolution is defined as the predicted data. The data are imported in genetic algorithms with the sequence of time series, then the simulation result provides the optimal reconfiguration strategy for each hour. When the approach is applied in a real distribution network, system operators can change the topology of the network by the real-time emulation output. The conventional binary traversal search approach is implemented first to provide a reference to compare the results of the genetic algorithms approach.

4.3 Optimum distribution network reconfiguration methodology

A real distribution network is an acceptable choice for testing the approach since the proposed technology will be applied to the practical networks. However, before implementing the method to the real network, conducting the investigation by a standard simulation network is able to provide a chance to compare the simulation result with other approaches. Distribution IEEE Test Feeder Working Group develops several standard networks for researchers to test their approaches or methodologies. In this paper, IEEE 37-bus test network is chosen as the analysis platform.

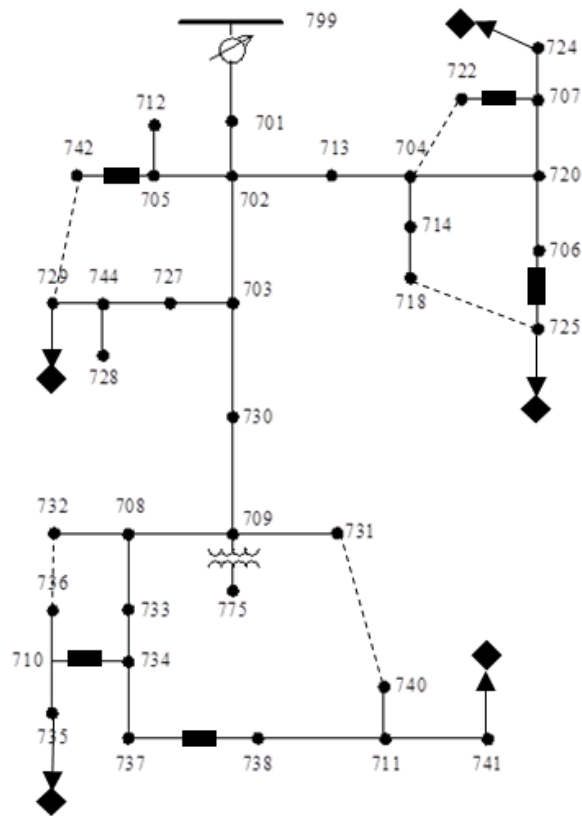


Figure 4-1 Modified IEEE 37-bus test network

The operating voltage of this distribution network is arranged as 4.8KV and the full power load is 2521 kW with an average power factor of 0.9. In order to test the performance of the approach for a network operating under high penetration of renewable resources, three PV distributed generation systems and two wind farms

are installed in the network, which is represented by a diamond shape in the Figure 4-1. Three PV generators are rated at 50kW are located in node 725, 731 and 729 respectively. Three wind generators also rated at 50kW and are placed at node 724, 735 and 741 respectively. Five normally open tie-switches points (NOP) are established at line 742-729, 704-722, 718-725, 732-736 and 731-740 which are represented by dashed lines the Figure 4-1. It is expected that the distribution network can still operate radially after reconfiguration, a corresponding normally closed point (NCP) is arranged for each NOPs. In a certain time, only one of them can be activated as a connection state in order to keep the radial structure of the distribution network. The detailed power flow and branch data of IEEE- 37 bus network are given in Appendix A.1 and Appendix A.2.

The initial task of applying GA technology is to define the key elements of the algorithm and determine the corresponding relation between the phenotype and genotype. The definition of a phenotype depends on its corresponding chromosome, while in this approach it represents the certain network structure. Five loops (each loop contains one NOP and one NCP) are defined and the detained dispatch arrangement is indicated in Table 4-1.

Table 4-1 Definition of loops that used in proposed approach

	contained nodes
Loop 1	742-729-744-727-703-702-705-742
Loop 2	704-722-707-720
Loop 3	704-714-718-725-706-720
Loop 4	732-736-710-734-733-708
Loop 5	708-709-731-740-711-738-737-734-733

Table 4-2 Relationship between status of loops and bit value

	Loop 1	Loop2	Loop3	Loop4	Loop5
NOP closed	1	1	1	1	1
NCP closed	0	0	0	0	0

The binary encoding method is applied in the method, where each single bit in the binary string represents a particular status of its related loop. The relationship between the connection situation of each loop and the bit value in the string is listed

in Table 4-2. For instance, the distribution network connection status in a certain time which is represented by chromosome string **11011** is shown in Table 4-3.

Table 4-3 distribution network reconfiguration status under certain chromosome string

Loop 1	disable line 742-705	Enable line 742-729
Loop 2	disable line 722-707	Enable line 722-704
Loop 3	disable line 706-725	Enable line 725-718
Loop 4	disable line 710-734	Enable line 732-736
Loop 5	disable line 737-738	Enable line 731-740

The genetic algorithm process which is applied in this paper consists of the following steps: encoding the chromosome string, randomly creating an initial population, breeding and mutation. The fitness value of each chromosome is calculated in equation 4-1. The following step is to define the probability of each corresponding calculated fitness value as formulated in equation 4-2. The next object is to decide the breed status of each chromosome (string) by calculating the expected count as formulated in equation 4-3.

Fitness value:

$$\mathbf{fitness\ value = power\ losses} \quad (4 - 1)$$

where, power losses are the simulation result from OpenDSS as percentage.

$$Probability = \frac{f(x)_i}{\sum_{i=1}^n f(x)_i} \quad (4 - 2)$$

where, n is the number of chromosomes in the population

$$Expected\ count = \frac{\frac{f(x)_i}{\sum_{i=1}^n f(x)_i}}{n} \quad (4 - 3)$$

where, n is the number of chromosomes in the population.

Expected count appears as the capability of breeding for each chromosome:

1, If the expected count of a certain chromosome is calculated as 0, this chromosome has no chance to breed.

2, If the expected count of a certain chromosome is calculated as 1, this chromosome has one chance to breed.

3, If the expected count of a certain chromosome is calculated as 2, this chromosome has two chances to breed.

The main process of implementing the algorithm for network reconfiguration is illustrated in Figure 4-2 below. The first step is to randomly create the initial chromosomes, then the algorithm chooses optimal parents and eliminates the poor ones based on the basic principle of nature selection- 'survival of the fittest'. The next step is to process the breeding and mutation, then choosing the optimal child.

Two possible cases may occur at this stage:

1, If the optimal child reaches the simulation destination, the result which corresponds to the child is defined as the optimal result and the simulation ends.

2, if the optimal child cannot reach the requirement, four children who have higher probability to breed are chosen for the next generation and the simulation loop will start again until the requirement is achieved.

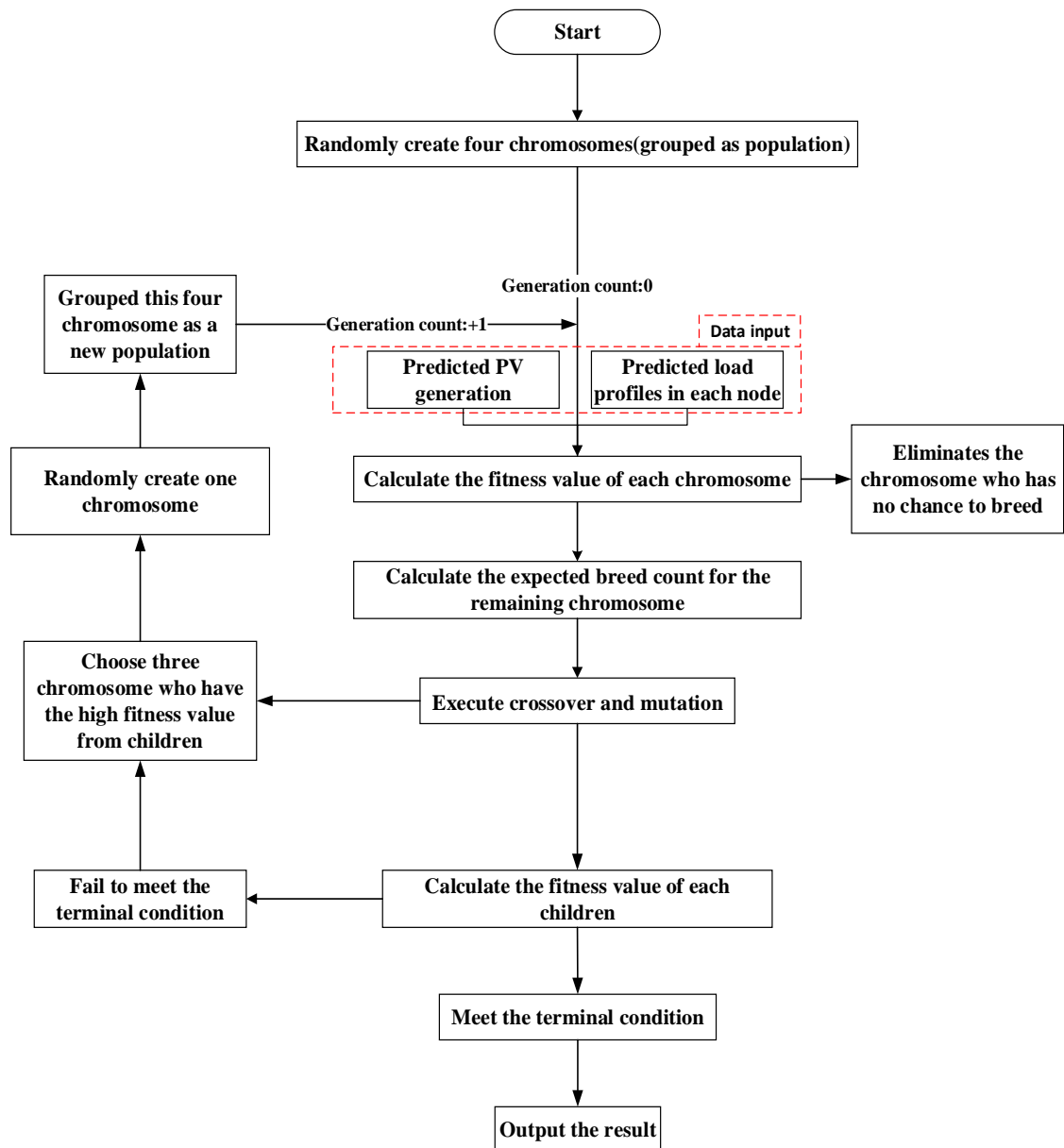


Figure 4-2 Process of proposed genetic algorithm based optimization approach

In the early investigation stage of network reconfiguration, researchers prefer to explore the methodology based on the single load model due to computation limitations of computers. However, to apply the dynamic load profile in the simulation process can provide a more credible result. CREST Domestic electricity demand model which is designed by Loughborough University [18] can be utilized for simulating the normal electricity demand in the UK. The load profile applied in this paper is extracted from CREST demand model directly and reschedule to the needed time resolution.

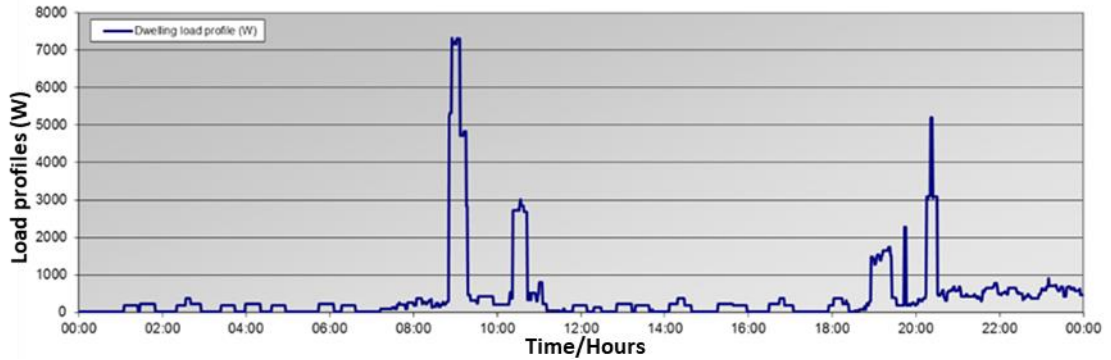


Figure 4-3 Typical household electricity demand in the UK (Source from CREST Domestic electricity demand model)

The data of photovoltaic (PV) generation is obtained from another demand model which is also created by Loughborough University.

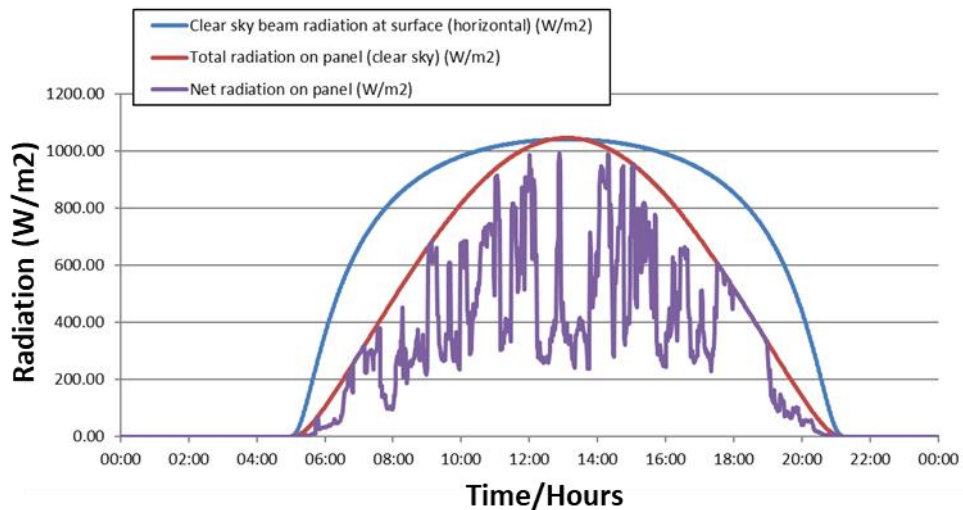


Figure 4-4 Typical output of PV generation (Source from CREST Integrated PV electricity demand model)

4.4 Numerical results

4.4.1 Data preparation

The proposed framework is tested on a modified IEEE-37 bus network. The detailed branch data and cable data that used in IEEE-37 bus network are given in Appendix A.1 and Appendix A.2 respectively. The hourly predicted load profiles of each node in the network is shown in Figure 4-5 and the detailed data is given in Appendix A.4.

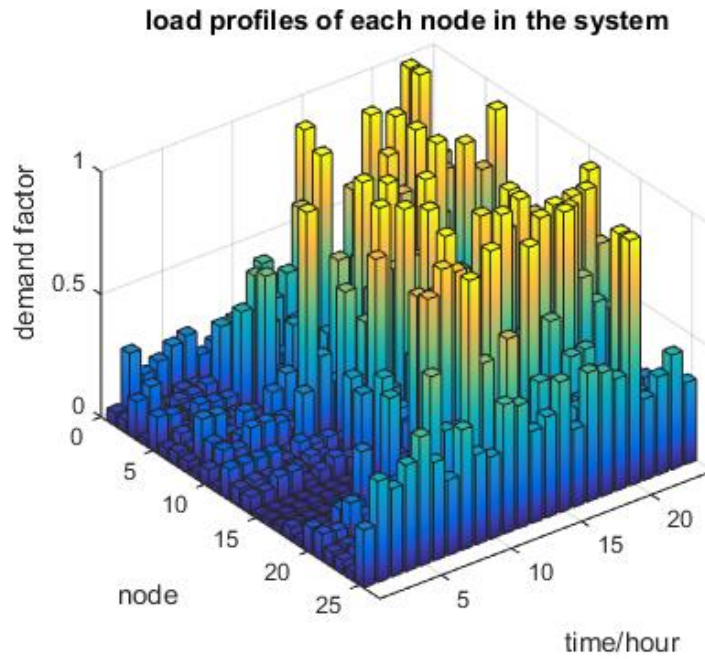


Figure 4-5 load profiles of each node in the network

The input data of renewable generation including PV and wind farm are shown in the Figure 4-6 and Figure 4-7. The data are extracted from the CREST Domestic electricity demand model which has been described in the section 4.3. The detailed data of PV generation and wind generation are given in Appendix A.5.

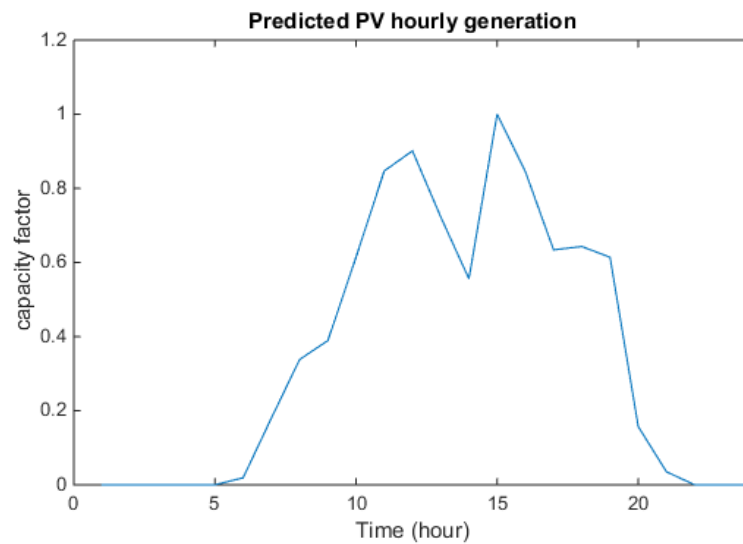


Figure 4-6 Predicted PV generation in the test system

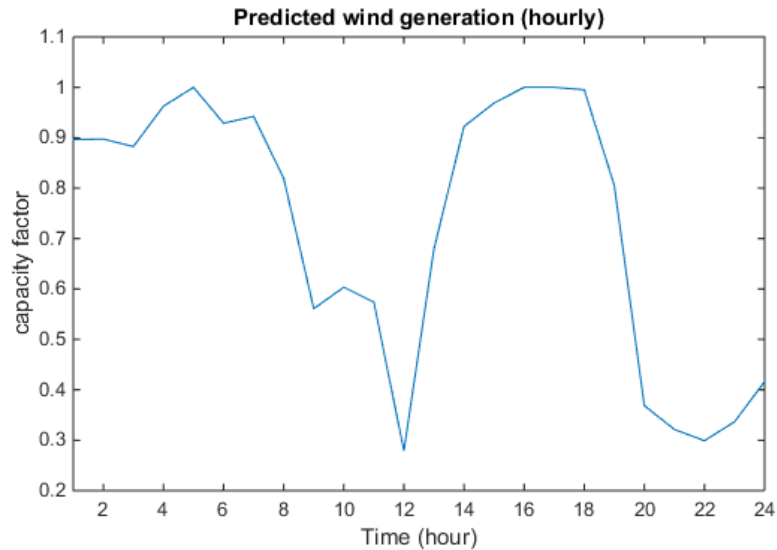


Figure 4-7 Predicted wind generation in the test system

4.4.2 case study

Binary traversal approach can search all the possible reconfiguration topologies in a certain time and calculates all the corresponding power losses. The results of the approach can provide key information such as the elapsed time of simulations and the optimal reconfiguration method for each simulation. The same load profiles and binary encoding methods applied in the following genetic algorithms are firstly implemented in binary traversal approach to keep the comparability. The simulation output is shown in Table 4-4. It is shown that network reconfiguration technology is able to reduce the power losses at each time point. The power losses reducing is between 0.1% and 0.2% (based on corresponding power delivery) in the daytime.

Table 4-4 Numeric results of binary traversal approach

Time series	Optimal string	Optimal power losses (MW)	Original power losses (MW)
1h	10000	0.094	0.096
2h	01111	0.068	0.070
3h	10000	0.073	0.075
4h	01111	0.071	0.073
5h	01111	0.072	0.074
6h	10000	0.061	0.063

7h	10000	0.050	0.051
8h	10000	0.033	0.034
9h	10000	0.038	0.039
10h	10000	0.027	0.028
11h	10000	0.026	0.027
12h	01111	0.026	0.027
13h	10000	0.025	0.026
14h	10000	0.033	0.034
15h	10000	0.028	0.029
16h	01100	0.027	0.028
17h	10000	0.026	0.027
18h	01011	0.024	0.025
19h	10000	0.026	0.027
20h	01111	0.030	0.031
21h	01111	0.031	0.032
22h	01111	0.030	0.031
23h	10000	0.032	0.033
24h	10000	0.044	0.045

The proposed genetic algorithm was implemented by MATLAB and OpenDSS for the simulation of network reconfiguration. The search termination in the simulation is limited by maximum generations. To make sure a sufficient time of breeding, the genetic algorithm is ended when the generation reached 5 times. The simulation result is shown in Table 4-5.

Table 4-5 Numeric result of the genetic algorithm approach

Time series	Optimal string	Optimal power losses (MW)	Original power losses (MW)
1h	01110	0.094	0.096
2h	01111	0.068	0.070
3h	01110	0.073	0.075
4h	01111	0.071	0.073
5h	01111	0.072	0.074

6h	01111	0.061	0.063
7h	00110	0.050	0.051
8h	01111	0.033	0.034
9h	01110	0.038	0.039
10h	10000	0.027	0.028
11h	01111	0.026	0.027
12h	00110	0.026	0.027
13h	00110	0.025	0.026
14h	10110	0.033	0.034
15h	11101	0.028	0.029
16h	01011	0.027	0.028
17h	01111	0.026	0.027
18h	01010	0.024	0.025
19h	00111	0.026	0.027
20h	01111	0.030	0.031
21h	00111	0.031	0.032
22h	01101	0.030	0.031
23h	01100	0.032	0.033
24h	10110	0.044	0.045

It is seen from Table 5 that the genetic algorithm approach can provide the same optimal result comparing with the conventional binary traversal approach. However, the optimal string is not completely the same since the power losses in the network can reach the minimum value by the similar network topology. Elapsed time of two kinds of approaches listed in Table 4-6, were shown that the GA approach is faster than binary traversal approach with a 41% time-saving.

Table 4-6 Elapsed time of two different approaches

Approach	Elapsed time
Binary traversal approach	26.23s
Genetic algorithm approach	15.54s (time-saving 41%)

Computer information:

CPU: Intel Core i7-4710MQ 2.5GHz

Memory: DDL3L 8G

4.5 Chapter summary

In this Chapter, a genetic algorithm based distribution network reconfiguration approach was introduced to explore the optimum topology in advance at each hour considering the predicted data of load demand and available output of the distributed generations. In particular, the definition of distribution network reconfiguration technologies is introduced in section 4.2 to clarify the feasibility of the proposed approach. Then, the proposed optimum distribution network reconfiguration approach is indicated in section 4.3. The genetic algorithm was applied in MATLAB and OpenDSS for determining the status of switches in each hour to achieve the minimum power losses. To verify the accuracy of the GA approach, numeric results are summarized in section 4.4. Binary traversal approach was tested in the network firstly to provide a standard result. Then the GA approach was tested in the same network with the same load profile and distributed generation profile. The numeric results indicated that GA approach provided the same solution for the network reconfiguration, where simulation elapsed time is dramatically decreased. Benefited by the decrease of the elapsed time, the methodology is expected to apply in the real distribution network.

Chapter 5

Optimal conductor size selection problems in distribution networks

5.1 Introduction

One of the most important processes in the distribution network planning is to assess the investment costs of the required system infrastructure and predict the relevant operation and management costs during the expected life span. In particular, the designers and planners are required not only to satisfy the fundamental regulation and standards of the power system operation such as the voltage constraints and frequency constraints, but also need to establish a financial analysis inducing the life-cycle costs of the systems during the distribution network design and planning process. Therefore, the efficient reliability, power quality and the investment costs are all significantly affect the process of the network planning and an optimum solution will be achieved by the relevant optimization models based on the required principles and targets [209]. Traditionally, the distribution networks are designed and

planned more than 10 years ahead of the construction. And, two significant principles are considered in the design and planning of a distribution system: 1) predicting the growth of the electricity users' demand and planning the system upgrade and extension in advance; 2) choosing the optimum facilities and equipment for replacing the assets that have reached the maximum operation years. This conventional network design and planning framework is widely applied in the traditionally one-way distribution system, where the energy delivering path is only from a high-voltage transmission system to the low-voltage distribution feeders. However, the large-scale application of the distributed generation challenges the classic distribution network design and planning approaches [210]. In particular, the distributed generations that installed in the demand side results in the two-way power flows in the distribution network. Under this circumstance, the conductors and cables that selected based on the previous one-way power flow framework are difficult to satisfy the high penetration of distributed generations. Thus, many countries are currently preparing and planning to consider the distribution network reinforcement or upgrading issues due to the increasing penetration of the distributed generation. The report 'The Cost of Distribution System Upgrades to Accommodate Increasing Penetrations of Distributed Photovoltaic Systems on Real Feeders in the United States' which was published by the National Renewable Energy Laboratory (NREL) at 2018 indicates that the distribution network operators in the United State have initiated the plan for upgrading their networks. In this report, the NREL suggested that the distribution system was originally designed for one-way power flow from centralized generators to distributed loads, this increasing deployment of distributed generation can impact operations at the distribution level. In order to deal with these problems, the distribution system upgrades are required to mitigate them and maintain voltage, reliability, power quality. And the network upgrading incurs the relevant costs. One of the key insights from this report is:

"There is significant variability in hosting capacity and distribution upgrade costs versus penetration level depending on the feeder, spatial distribution of distributed photovoltaic systems (DPV), and the size of the DPV systems. While we have selected a set of feeders and analysis scenarios intended to capture a range of representative

cases, additional work is required to validate the extendibility of our results to other systems.”

Therefore, it is important to explore and investigate the potential conflict between distribution upgrade costs (life-cycle costs of the upgraded conductors are our major concern in this paper) and the costs of renewable resources curtailment when dealing with the distribution network reinforcement or upgrading problem. In this chapter, we would like to focus on the optimum conductor size selection (CSS) problem in the distribution network design and planning or upgrading process. Conductors or cables and the relevant auxiliary equipment are an important part of the design and planning of a certain distribution network. And, this problem has more and more difficult and challenging due to the deregulation of the electricity market and the increasing installation of renewable resources [211].

In this Chapter, the challenges for the current conductor size selection problem are introduced firstly in section 5.2. In order to comprehensively study the CCS problems, a new pricing approach is proposed for assessing the conductor life-cycle cost. The approach is applied to ensure a precise and practice numerical study results, where the approach is introduced in section 5.3. And, the hybrid optimization approach is also introduced in section 5.3 to deal with the current conductor size selection problem. The numerical results are summarized in section 5.4 and the main conclusions of the study are discussed in Section 5.5.

5.2 Challenges for current conductor size selection problem

The significantly increased the application of distributed generations and the rapid demand growth due to the urbanization and industrialization results in the new challenges for the design and planning of the distribution networks or the network upgrading projects. Power losses minimization is often considered as one of the most important key issues during network planning. Specifically, the relatively low resistance of the conductors and cable, reduced voltage levels and the high currents in the distribution network results in the significant power losses. Network designers are expected to select the optimum combination of the conductors to achieve the

economic balance between the capital investments and the life cycle power losses costs.

Indeed, the optimum distribution network planning problem has been studied for decades, where the main aim of this optimization is to minimize the total investments or energy losses. Traditionally, the distribution network operators concern the energy losses, power quality and voltage constraints when considering a short-term network expansion planning. Capacitor banks and voltage regulators are considered as the normal and economical way to deal with the problem. However, in a long-term perspective, replacing the conductors is an alternative solution to solve the network planning. More importantly, the large-scale installation of distribution generations (DGs) including wind farm and photovoltaic has significantly impacted the operation and planning of the low voltage networks. The international renewable energy agency (IRENA) reported that global renewable energy prices would be decreased to the cost range of traditional fossil fuels generation [212]. And most of the developed countries have launched their plans to support the development of renewable energies due to the consideration of environmental benefits. In the UK, for instance, a Contract for Difference (CfD) mechanism is introduced to improve the economic competitiveness of renewable resources in the electricity market [213]. Therefore, increasing investment on DGs provides the new challenge to the distribution network operators (DNOs) due to the natural characteristic of renewable resources such as poor predictability and variability of output. Power losses, voltage profiles and frequency of the power system are often considered as the major impacts and factors in the researches of distribution networks with high penetration DGs [214, 215]. But, the decrease in the cost of renewable technologies promoted the rapid integration of DGs at the distribution level. The maximum current carrying capacity of conductors are expected to satisfy the potential output of installed DGs and the increasing load demands. Meanwhile, the life-cycle cost of the chosen conductors is also a significant factor that needs to be assessed since the objective of the DNOs is to provide a cost-effective service in the competitive market. Therefore, a judicious choice is that the selected conductors can satisfy the long-term load growth in the networks and achieve the optimal economic balance between the infrastructure investment and

the energy procurement saving from consuming the installed DGs (the DGs are commonly considered as the zero marginal cost generation plants).

The common conductor size selection (CSS) problems have been widely researched and investigated in the past decades. Funkhouser and Huber [216] firstly introduced the approach for determining economical conductor sizes for distribution networks. The approach found the minimized investment of the conductor combination in a 13-kV distribution network and considered the voltage regulation and short-circuit current safety requirement. The economic model of conductors was carefully established in the approach, where the labour cost, material cost and installation cost were fully considered in the paper. However, most of the costs such as the annual costs of energy losses and energy price applied in the papers were fixed, which was failing to reflect the practice scenario in the real power system. In [209], a practical approach to the conductor size selection was proposed for utility engineers. The approach considered the maximum allowable voltage drop and load growth as the objective in the cable selection and can achieve the optimal results quickly by a heuristic method. However, the method ignored the economic objective and can only be applied in pure radial distribution networks due to the simplified power flow analysis strategy. In [217], the authors maximized the total financial saving in conductor material and energy losses. However, the proposed approach used the same conductor type for each branch in the networks. The judicious conductor size selection approach is expected to allocate the optimal conductor type to different branches in the networks since the various load profiles at each feeder results in different burdens to each branch. A Mixed-Integer LP Approach was applied to solve the CSS problems in [210] by Franco et al. The approach used a linearization method to simplify the optimization process and guaranteed the accuracy and conversancy speed. Recently, several studies [9-16] used heuristic and evolutive algorithm to solve the CSS problems. In [218, 219], particle swarm optimization (PSO) was introduced to minimize the overall cost of power losses and the investment of selected conductors and reference [220-223] applied Genetic Algorithm (GA). In [222], a novel approach based on crow search algorithm (CSA) was proposed for optimal CSS problems in low voltage networks. The harmony search algorithm with

a differential operator was applied in [224] to solve the optimal CSS problems and minimize the total capital investment on conductors and the energy losses cost.

However, the large-scale installation of DGs and the declined levelized cost of renewable generation challenge the traditional optimal CSS strategy. Installed DGs in the distribution systems are often considered as a zero marginal cost energy resources in the power operation analysis. In the distribution systems with high penetration renewable generations, DNOs need to allocate suitable conductor at different branches to consume the available output of DGs, thus maximizing the economic benefits from renewable resources. Therefore, the selected conductors are expected to have enough current carrying capacity to satisfy the peak output of the installed DGs. On the other hand, the investment of conductors is also an important economic factor need to be considered. Therefore, DNOs are difficult to identify the optimal conductor arrangement for the distribution system with high penetration DGs.

Thus, we explore an innovated conductor size selection framework which can be used to deal with the future distribution network design and planning projects. The proposed framework for the first time considers the potential cost conflict between the conductor life-cycle costs and the costs of renewable resources curtailment when dealing with the CSS problems at the distribution level, by using an improved adaptive genetic algorithm that specifically designs for the CSS problem. Moreover, a precise conductor investment and the O&M cost model is introduced in this framework to ensure the accuracy of the proposed framework. In particular, the following targets are addressed in this chapter to achieve an optimum conductor size selection problem in the distribution systems.

- 1) Comprehensive conductor investment and O&M cost model.
- 2) Instead of the fixed renewable generation output, the output of the renewable generations in this paper is based on the available output and system level economics at the same time.

- 3) The potential cost conflict between the conductor life-cycle costs and the costs of renewable resources curtailment are considered in the paper for the first time.
- 4) Major network constraints and power quality indexes such as maximum or minimal voltage, power balance and conductor thermal limitation are considered in the paper.
- 5) Propose an improved adaptive genetic algorithm that specifically designs for the conductor size selection problem.

5.3 Algorithms developed for solving the current conductor size selection problems

The major concerns of the current conductor size selection problems in the distribution networks are the high penetration of distributed generations and its competitive marginal cost. The distribution network operators or power suppliers have an increasing interest in purchasing the energy from renewable resources since the consideration of global environment concern and economic concern. However, the distribution generations are normally connected to the demand side of the power systems. And the reserve of wind power or the valid amount of sunlight significantly affects the installation location of the new renewable infrastructures. Therefore, the distribution system operator cannot guarantee that connecting all renewable resources to the distribution feeders with sufficient reserved capacity. The distribution network operators have two potential solutions to deal with this problem: 1) replace the low capacity underground cable or overhead line to high capacity power delivery infrastructures, thus fully satisfying the requirement of absorbing all available renewable resources by the connected distributed e generations. 2) maintain the current network configuration and distribution circuits and curtail the capacity of the planned renewable generation to secure the network

stability and power quality. However, distribution network operators may receive two opposite results: 1) excessive investment on the conductor selection and, 2) the selected conductors have insufficient capacity to consume available renewable resources, thus increasing the total energy procurement cost.

In this section, a hybrid optimization algorithm is proposed to solve the problems of current conductor size selection in distribution networks.

5.2.1 Objective function

The aim of the optimal conductor size selection problem is to allocate the suitable conductor type from the given inventories to each branch in the network, thus minimizing the sum of all conductor's life-cycle costs, power losses costs and the total energy procurement costs during the expected operation years of the conductors. The optimal process is subject to common power system operation constraints such as voltage limits, thermal limits and power balance. Life-cycle cost of a certain conductor LCC_l includes the investment cost, operation cost and maintenance cost. In particular, the investment cost includes the purchasing costs of fixed assets, purchasing costs of accessories (such as towers, wood poles and insulators), design and installation costs and other costs (such as land acquisition fee). The operation cost of a certain distribution line in this paper is considered as the total power losses costs of this feeder during its whole life cycle. The maintenance cost of a certain distribution line in this paper includes inspection cost and recondition cost.

In this paper, we propose a lump sum payment of total asset purchasing costs to simplify the formulation, where the annual discount rate is not applied in the objective function. The investment costs IC_l , operation cost OC_l and maintenance cost MC_l of a certain conductor l can be expressed by (5-1) to (5-3), then the life-cycle cost of this conductor can be expressed by (5-4).

$$IC_l = AP_l + AC_l + IN_l \quad (5 - 1)$$

$$OC_l = \sum_t^T PL_l^t \times EP_t \quad (5 - 2)$$

$$MC_l = (ISP_l \times IST + REC_l \times RET) \times T \quad (5 - 3)$$

$$LCC_l = AP_l + AC_l + IN_l + \sum_t^T PL_l^t \times EP_t + (ISP_l \times IST + REC_l \times RET) \times T \quad (5 - 4)$$

where AP_l is the asset purchasing cost of the conductor l , AC_l is the accessories purchasing cost of the conductor l , IN_l is the installation cost of the conductor l , PL_l^t is the total power losses of the conductor l in the operation year t , OC_l is the operation cost of the conductor l , PL_l^t is the power losses of the conductor l in the operation year t , EP_t is the average energy procurement costs in operation year t and T is the expected life span of the conductor. MC_l represents the life-cycle maintenance cost of the conductor l , ISP_l is the inspection cost of the conductor l , ISP (*times/year*) is per year inspection times of the conductor l , REC_l is the recondition cost of the conductor l , RET (*times/year*) is the per year recondition times of the conductor l .

Since we consider the full life span economic performance of the conductors, the existing loads in the networks are expected to have an accepted load growth rate lg . Instead of the fixed energy price that applied in the majority of earlier research, we use a quadratic cost function to establish a dynamic energy price curve. The load at each bus i with load growth lg and the generator cost function are expressed by equation (5-5) to (5-7).

$$P_{Di}^t = P_{Di} \times (1 + lg)^{(t-1)} \quad (5 - 5)$$

$$Q_{Di}^t = Q_{Di} \times (1 + lg)^{(t-1)} \quad (5 - 6)$$

$$GC_{gi} = \alpha_{gi} \times PG_{gi}^2 + \beta_{gi} \times PG_{gi} + \gamma_{gi} \quad (5 - 7)$$

where P_{Di}^t and Q_{Di}^t are active and reactive load at feeder i in the operation year t . P_i and Q_i are active and reactive load at bus i in the first operation year. α_{gi} , β_{gi} and γ_{gi} are cost coefficients for generator gi . GC_{gi} and PG_{gi} are generator cost and corresponding power output of generator gi .

AC optimal power flow analysis can be employed to obtain the energy procurement costs and confirm the precise power losses when each branch of the network is allocated with a particular type of conductor. Therefore, the objective function of the proposed CSS problems can be expressed by equation (5-8).

$$\begin{aligned} \min \quad & \sum_t^T \sum_g^G GC_g^t \\ & + \sum_l^L \left(AP_l + AC_l + IN_l + \sum_t^T PL_l^t \times EP_t + (ISP_l \times IST \right. \\ & \left. + REC_l \times RET) \right. \\ & \left. \times T \right) \end{aligned} \quad (5-8)$$

subject to:

$$P_i^t = V_i^t \sum_{j=1}^n V_j^t Y_{ij} \cos(\theta_{ij}^t + \delta_j^t - \delta_i^t) \quad (5-9)$$

$$Q_i^t = V_i^t \sum_{j=1}^n V_j^t Y_{ij} \sin(\theta_{ij}^t + \delta_j^t - \delta_i^t) \quad (5-10)$$

$$P_{gi}^t - P_{Di}^t = P_i^t \quad (5-11)$$

$$Q_{gi}^t - Q_{Di}^t = Q_i^t \quad (5-12)$$

$$\sum_i P_{gi}^t - \sum_i P_{Di}^t = P_{loss}^t \quad (5-13)$$

$$\sum_i Q_{gi}^t - \sum_i Q_{Di}^t = Q_{loss}^t \quad (5 - 14)$$

$$V_{min} \leq V_i^t \leq V_{max} \quad (5 - 15)$$

$$P_{gi,min} \leq P_{gi}^t \leq P_{gi,max} \quad (5 - 16)$$

$$Q_{gi,min} \leq Q_{gi}^t \leq Q_{gi,max} \quad (5 - 17)$$

$$|\delta_i - \delta_j| \leq |\delta_i - \delta_j|_{max} \quad (5 - 18)$$

where, P_i^t and Q_i^t are the active and reactive power injected at bus i at operation year t , Y_{ij} is the admittance parameter of the distribution line between bus i and bus j . θ_{ij}^t , δ_j^t and δ_i^t are relevant phase angles. Expressions (5-15) to (5-18) indicate that voltage at each bus, power generation and phase angles are constrained by relevant limitations.

Genetic algorithms (GAs) is one of the most popular optimization algorithms that are applied to solve complex optimization and adaptation problems. The basic principles of the GA technique are based on nature selection and were initially introduced by Holland in [225]. Traditional GA approach includes the process of creating initial population, selection, crossover and mutation. The best fitness value and its corresponding individual are obtained when the maximum number of iterations is reached, or the convergence criterion is satisfied. However, the performance of GA largely depends on presupposed control parameters such as crossover rate and mutation rate, where a poor choice of parameters may result in a premature convergence solution or low convergence speed [226-228]. The adaptive genetic algorithm (AGA) with self-controlled parameters is widely researched and proved as one of the best solutions to deal with the problem of falling into the local optimum result or low convergence speed in common GA approach [208, 229, 230]. The proposed adaptive genetic algorithm in this paper is specifically designed for the aim of optimal conductor size selection in the distribution power systems. Similar to the

standard GA approach, a set of the initial population with N_p chromosomes are created at the beginning of the approach. Each chromosome can be represented as $C_i = [c_1, c_2, c_3 \dots, c_D]$, where D is the number of genes in the chromosome C_i . In this study, we assume the number of branches in the network is N_b and the available types of conductors in the inventory is N_c . In the proposed AGA approach, $c_i \in [1, N_c]$ and the value of c_i represents the conductor size selection of branch i . Therefore, each chromosome represents one solution of conductor size selection in the network, where each gene of chromosome related to the selection of its corresponding branch. For example, in a CSS problem, it is assumed that the system has ten branches and four different available types of conductors in the inventory. Then, based on the previous definitions, the number of branches N_b equals to 10 and the number of available conductor types N_c equals to 4. For a random individual, it will have the chromosome like this '3 1 2 2 4 2 4 4 3 2 1'. And each gene in the chromosome represents a choice of conductor type for the corresponding branch. In particular, the first gene in this chromosome indicates that the branch c_1 will be allocated as the type 3 conductor.

Double adaptive crossover rates, hybrid fitness value and self-adaptive mutation operator are innovatively introduced in this approach. Instead of the normal single fitness value structure in the standard GA approach, a hybrid fitness value is designed for the SSC problems since the individual who has the optimal fitness value is also required to satisfy the network constraints at the same time. We assume $f(C_i)$ is the fitness value of individual C_i and $V(C_i)$ is the auxiliary fitness value of individual C_i . If the individual C_i can satisfy the network constraints such as the voltage constraints and thermal constraints in the optimal power flow analysis, then $V(C_i) = 1$ otherwise $V(C_i) = 0$. The individuals that cannot survive in the network constraints test will be replaced by a new random individual that can satisfy the network constraints test. In the crossover operator, we assume two crossover rates: elite crossover rate cr_{elite} and standard crossover rate cr_{sta} . The individual who has the best fitness value in the iteration t is marked as $C_{bf}(t)$, where this individual can generate offspring with other individuals in the population with the probability PC_{elite} prior. Then, the rest of the individuals will generate offspring following the

standard GA crossover process with the probability PC_{sta} . In self-adaptive mutation operator, two adaptive factors σ_n and σ_m are introduced to achieve the function of self-adaptive GA, and the factors are expressed by equation (5-19) to (5-22).

$$\sigma_n(t) = \rho \times (1 - 10^{\left(\frac{-1}{\mu(t)}\right)}) \quad (5 - 19)$$

$$\mu(t) = \left| \frac{avefitness(t) - avefitness(t - 1)}{avefitness(t - 1) - avefitness(t - 2)} \right| \quad (5 - 20)$$

$$\sigma_m(t) = \varepsilon \times 10^{\left(\frac{\omega}{N_{tole}(t)}\right)} \quad (5 - 21)$$

$$\begin{cases} N_{tole}(t) = N_{tole}(t - 1) + 1; & \text{if objective function maintain the same} \\ & \text{best fitness value at iteration } t + 1 \\ N_{tole}(t) = 0; & \text{if objective function obtain better fitness value} \\ & \text{at iteration } t + 1 \end{cases} \quad (5 - 22)$$

where, $avefitness(t)$ is the average fitness value of all population at iteration t , N_{tole} is the count number of iterations above which the GA process cannot achieve a better fitness value and $\omega, \varepsilon, \rho$ are auxiliary factors supporting the adaptive factors. $\sigma_n(t)$ represents the stability of overall population and the is applied to the adapt the number of genes that need to be mutated in next iteration. $\sigma_m(t)$ is used here to help the proposed GA approach to escape the local optimum point, where this factor is related to the mutation rate in next iteration. The genes that are required to mutated in iteration t and the mutation rate in iteration t are expressed by equation (5-23) and (5-24).

$$N_{mut}(t) = N_b \times \sigma_n(t) \quad (5 - 23)$$

$$P_{mut}(t) = \sigma_m(t) \quad (5 - 24)$$

The formulation (5-21) and (5-22) indicate that the mutation rate will continually increase when the proposed GA approach falls into a local optimum point and cannot generate better fitness value. However, the increased mutation rate will reach the presupposed auxiliary index ε ($\varepsilon \in (0,1)$) to maintain the stability of the mutation operator. And, the index ω in the formulation (5-21) is designed as a presupposed index to control the variation speed of the mutation rate. Based on the formulation

(5-22), it is noted that the mutation rate will reset to the initial value when a better fitness value is captured. This function can efficiently secure the new best fitness value and allow the corresponding chromosome or genes to fully integrate to the population through the elite crossover process.

5.2.2 Hybrid CCS optimization

The proposed hybrid CSS optimization approach contains two main mechanisms: AC optimal power flow study and adaptive genetic algorithm. AGA is applied as the primary optimization mechanism which is responsible for collecting the simulation results from the AC-OPF, exploring the best individual and updating the evolution strategy of the approach. AC-OPF is responsible for accessing the minimum energy costs of each individual in the population of every iteration. The detailed flow chart of the approach is shown in Figure 5-1. In particular, the framework follows the steps below:

- 1) AGA module generates the initial population with the required number of the individuals.
- 2) AGA module decodes the individuals and applies the decoded information to allocate the conductor size selection. It is noted that each individual represents a unique conductor size selection plan for the chosen distribution network.
- 3) The conductor size selection of each individual is captured and loaded to the AC-OPF optimization module and the life-cycle cost assessment module.
- 4) The AC-OPF optimization module processes the power flow study of each individual by the relevant conductor size selection plan. In order to capture the change of power losses due to the increasing load demand, the power flow study is operated N times for each individual, where N represents the expected operation years of the conductors. It is noted that the individuals that cannot survive in the requirement of minimal voltage constraints or thermal constraints are eliminated immediately and replaced by the one who can satisfy the relevant constraints. This process is prior to the fitness value calculation. Finally, for each survived individual in

the current iteration, the sum of the power losses and the energy procurement costs during the expected operation years are obtained.

5) For each individual in the current iteration, the life-cycle cost assessment module evaluates the life-cycle cost of each conductor and provides a system level life-cycle costs data. The system level conductor life-cycle costs here represent the sum of each conductor's life cycle cost in the network.

6) After the power flow analysis and calculation in the AC-OPF module and the life-cycle cost assessment module, the fitness value of each individual (sum of the system level conductor life-cycle cost, the total energy procurement costs and energy losses costs) is confirmed.

7) After all individuals in the current iteration are assessed, the selection module is expected to find the best fitness value in this iteration and compare it with the present best fitness value.

8) AGA module generates the adaptive crossover factor and adaptive mutation factor for the next iteration, where the factors are evaluated and decided by all individuals' fitness value of current and last iteration (explained in section 2.2 already).

9) Move to the next iteration or stop the process since the maximum number of iterations is reached or the convergence criterion is satisfied

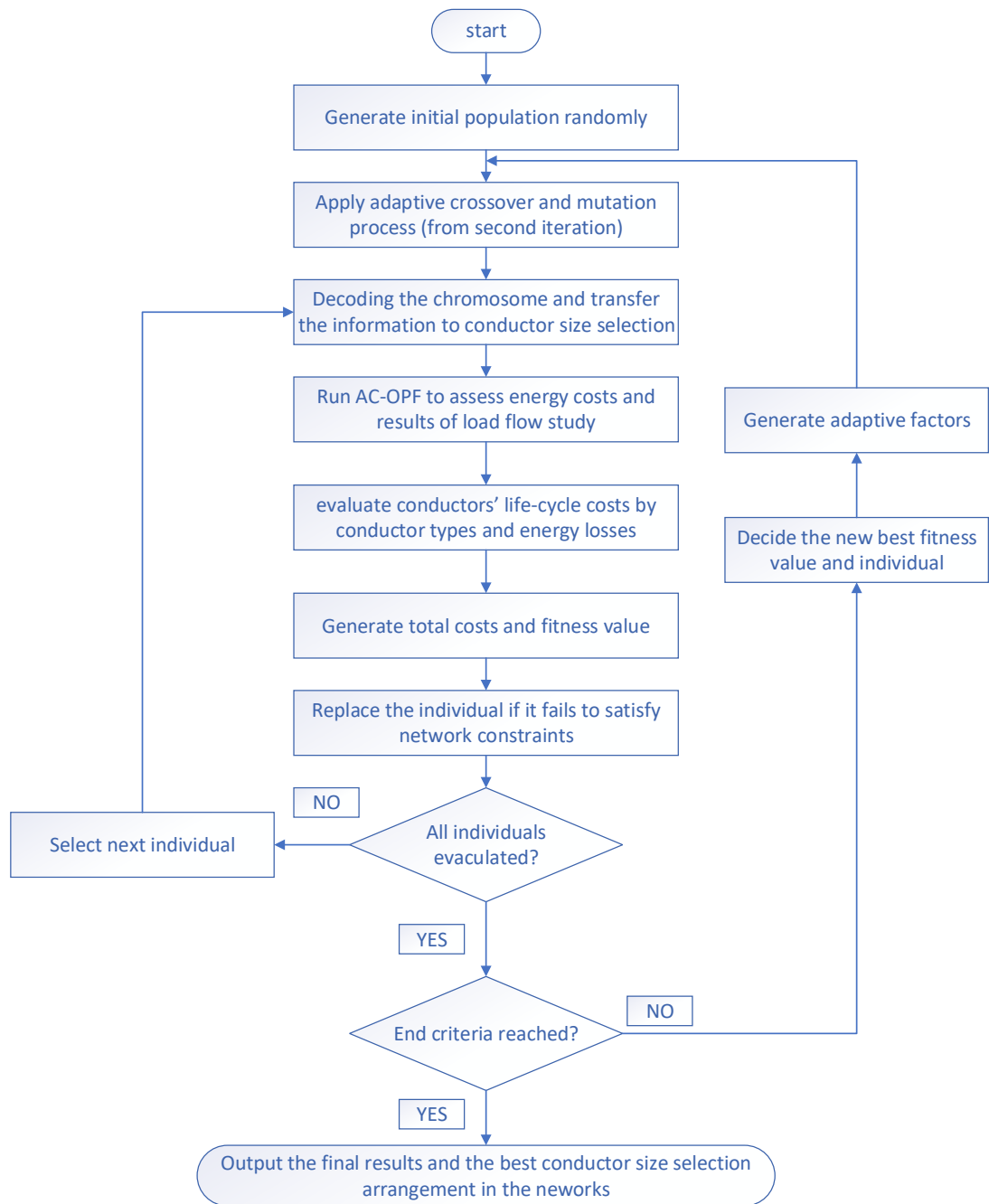


Figure 5-1 Flow chart of the proposed hybrid CSS optimization algorithm

5.4 Numerical results

The proposed hybrid optimal CSS approach is tested on the 33-bus distribution network and a 69-bus distribution network in the numerical tests. In each test network, three distributed wind turbines with different available outputs are

allocated at selected branches. The relevant parameters of the adaptive genetic algorithm used in this numerical test are summarized in Table 5-1.

Table 5-1 Parameter of adaptive generic algorithm

Parameter	Value
Initial population	100
Length of chromosome	32
Initial elite crossover rate	3%
Initial standard crossover rate	85%
Initial mutation rate	5%
Initial mutation genes	1
Auxiliary factor ρ	6
Auxiliary factor ε	0.5
Auxiliary factor ω	2.2
Maximum iterations	300

In order to identify the efficiency and the performance of the proposed AGA, the standard generic algorithm [231, 232] is applied in this paper for the aim of comparison. And the parameters used for the standard genetic algorithm are shown in Table 5-2.

Table 5-2 Parameter of the standard generic algorithm

Parameter	Value
Crossover rate	80%
Mutation rate	5%
Mutation genes	1
Maximum iterations	300

The available conductor types in the inventory and the relevant specifications are listed in Table 5-3. It is noted that the data of the conductors are different between manufactories and the unit price of the conductors vary between different markets. We refer to several papers [217, 218, 224] to provide this data.

Table 5-3 Specifications of proposed ACSR Conductors

Conductor type	R(Ω /km)	X(Ω /km)	I_{max} (A)	UP(\$/km)
Mole	2.718	0.3740	70	90
Squirrel	1.376	0.3896	115	170
Gopher	1.098	0.3100	138	210
Weasel	0.9108	0.3797	150	260
Ferret	0.6795	0.2980	180	340
Rabbit	0.5441	0.3973	208	420

Mink	0.4546	0.2850	226	500
Beaver	0.3841	0.2795	250	590
Raccoon	0.3675	0.3579	260	630
Otter	0.3434	0.3280	270	770

The assumed parameters that used to evaluate the life-cycle cost of the conductors are shown in Table 5-4. The relevant researches normally considered the life span horizon of the cable or conductor as 20 or 30 years [231-233]. Thus, we assumed that the expected operation year of the selected conductor is 20 years in the case study. It is difficult to identify the precise installation and accessories costs of each conductor. However, we link those relevant costs with the unit wire purchase cost of conductors with different sizes. In the case study, we assumed that the accessories cost is 4.5 times as compared with corresponding conductor purchase costs. It is assumed that the design and installation costs is equal to the corresponding conductor purchase costs. Moreover, the inspection cost and recondition costs are considered as 75% and 8% of the corresponding conductor purchase costs. Finally, it is assumed that the annual operation costs are equal to 5% of total project investment in this case study. The detailed evaluation approach has been explained in section 2.1. For example, if one of the branches in the network is allocated by the conductor with type Gopher, the life-cycle cost can be evaluated by express: $210(\$/km) \times length\ of\ conductor(km) \times (450\% + 100\% + 50\%) \times [1 + (75\% + 8\% \times 12 + 5\%) \times operation\ year]$.

Table 5-4 Cost parameters of conductor investment [234]

Parameter	Value
Planning operation period	20 years
Accessories cost	450% wire cost
Design and Installation cost	100% wire cost
Inspection cost	75% wire costs (per year)
Recondition costs	8% wire cost (per month)
Annual operation cost	5% of total investment

5.3.1 Case study of the 33-bus network

The proposed hybrid optimal CSS approach is tested on a 33-bus distribution network and there are three distributed wind turbines located at node 10, 18 and 26

respectively. The single line diagram of this 33-bus distribution network is shown in Figure 5-2. And the relevant operation data and network constraints are listed in Table 5-5. The detailed power flow and branch data of IEEE- 33 bus network are given in Appendix B.1 and Appendix B.2.

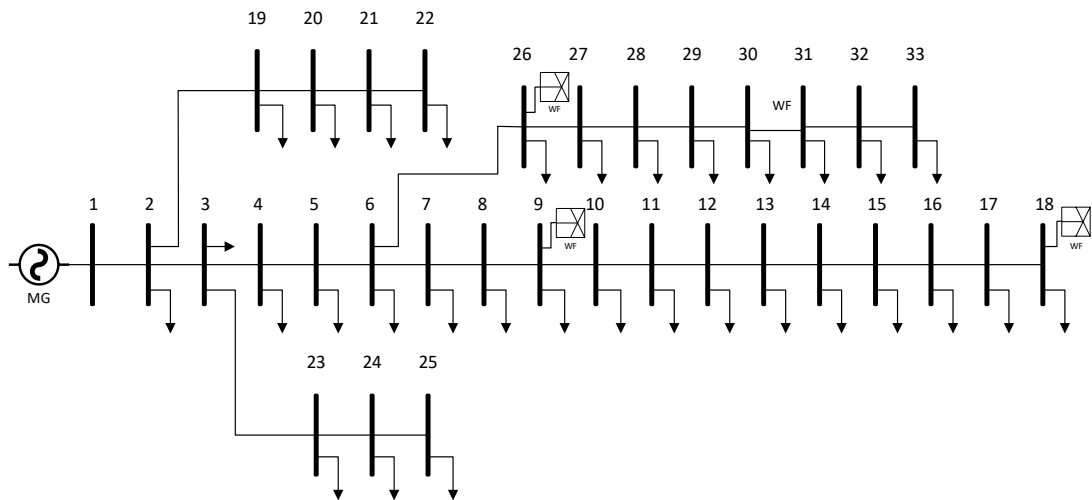


Figure 5-2 Single line diagram of the 33-bus distribution network

Table 5-5 Parameters of test network

Parameter	Value
Maximum voltage	1.1 (p.u.)
Minimum voltage	0.94 (p.u.)
Initial total active demand	3.72 MW
Initial total reactive demand	1.16 MW
Load growth rate	5%/year
Operation year	20 years
Total branches	32
Maximum available output of the wind farm at node 9	1.2 MW
Maximum available output of the wind farm at node 18	1.0 MW
Maximum available output of the wind farm at node 26	0.6 MW

The quadratic generation cost function of the main generator connected at node 1 is expressed in equation (5-21) and it is noted that we consider the wind farm as a zero marginal cost generator in this approach.

$$Gen_{cost}(\$/MWh) = 0.78 \times PG^2 - 2.1 \times PG + 10.4 \quad (5 - 21)$$

where, PG is the power output of this generator and is within the limitation of its generation output ($0 \leq PG \leq 10MW$).

The overall results of the proposed AGA optimal conductor size selection for the selected 33-bus distribution network are shown in Figure 5-3. It is observed that the best fitness can be achieved after approximately 150 iterations. The mutation rate is self-adaptive during the process of the AGA which is shown in Figure 5-4. It can be observed that the mutation rate is increased when the AGA cannot provide better fitness value and resets to zero when a better fitness value is achieved.

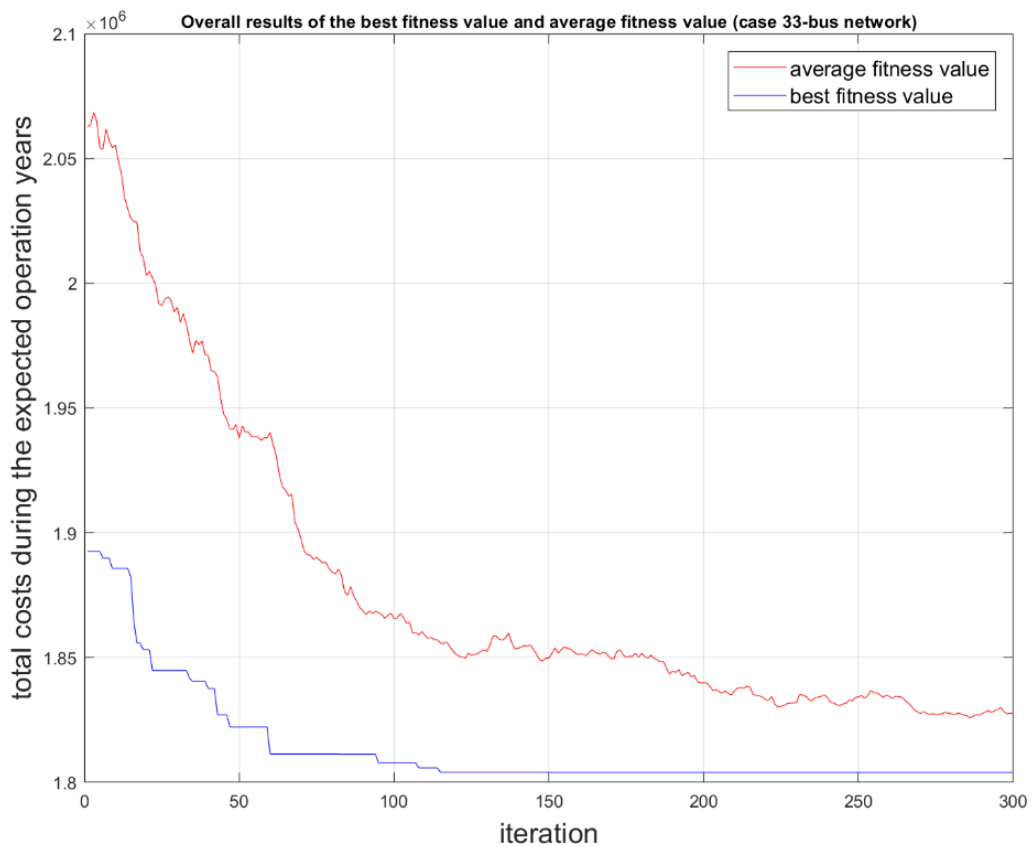


Figure 5-3 Overall results of the best fitness value and average fitness value

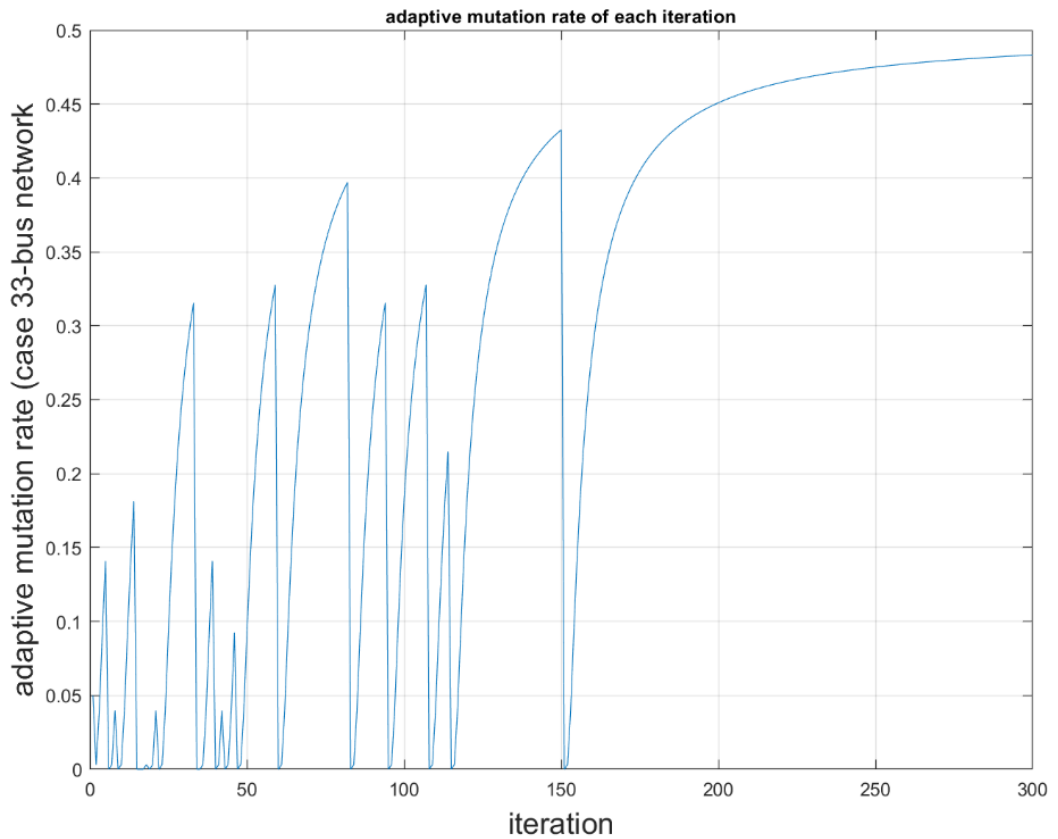


Figure 5-4 Adaptive mutation rate in each iteration

The detailed optimum results of conductor size selection by two different approaches are shown in Table 5-6. After the decoding process, the best conductor type of each branch in the 33-bus networks can be checked in this table.

Table 5-6 Best conductor size selection for 33-bus distribution network

branch	From node	To node	Initial demand at branch ending node (kW)		Selected conductor type via standard GA	Selected conductor type via AGA
			P	Q		
1	1	2	100	30	Rabbit	Raccoon
2	2	3	90	20	Mole	Mole
3	3	4	120	30	Ferret	Ferret
4	4	5	60	30	Mink	Raccoon
5	5	6	60	20	Gopher	Mole
6	6	7	200	50	Otter	Weasel
7	7	8	200	50	Otter	Gopher
8	8	9	60	20	Weasel	Mole
9	9	10	60	20	Weasel	Gopher
10	10	11	45	30	Otter	Gopher
11	11	12	60	35	Mole	Mole
12	12	13	60	35	Mole	Mole
13	13	14	120	30	Ferret	Gopher

14	14	15	60	20	Ferret	Weasel
15	15	16	60	20	Mole	Weasel
16	16	17	60	20	Squirrel	Rabbit
17	17	18	90	40	Mole	Rabbit
18	2	19	90	40	Mole	Mole
19	19	20	90	40	Squirrel	Mole
20	20	21	90	40	Gopher	Mole
21	21	22	90	40	Weasel	Beaver
22	3	23	90	50	Squirrel	Ferret
23	23	24	420	100	Mole	Mole
24	24	25	420	100	Mole	Squirrel
25	6	26	60	25	Mole	Mole
26	26	27	60	25	Mink	Gopher
27	27	28	60	20	Gopher	Gopher
28	28	29	200	50	Beaver	Mole
29	29	30	200	50	Mole	Mole
30	30	31	150	50	Mole	Mole
31	31	32	210	50	Mole	Squirrel
32	32	33	60	20	Weasel	Mole
Total life cycle costs					\$ 2404475.17	\$ 1804009.74
Net cost saving						\$ 600465.43
Cost saving percentage						25%

Table 5-6 indicates that the expensive conductor has a relatively lower value of resistance, thus allowing lower energy losses when the system has the same load condition. Therefore, there is a potential conflict between the total life span energy losses costs and the total life-cycle costs of all conductors in the network. Figure 5-5 reveals this conflict and prove the proposed algorithm can successfully achieve the balance between these two contrary costs. On the other hand, even though the wind farm generation in the network is considered as a zero marginal cost generator, attempting to fully consume all available output of the renewable resources in the demand side may result in high conductor investment costs or the high energy losses costs. Figure 5-6 shows that the optimum power consumption of the wind farm generations in each iteration. From the results in Figure 5-6, it is observed that parts of the available capacity are curtailed for achieving the minimum total costs (including total energy losses costs, energy purchase costs and conductor's investment costs). Based on the proposed approach, the conductor sizes that cannot satisfy the minimum and maximum voltage constraints are eliminated and replaced

by the new ones that can satisfy the constraints. Figures 5-7 and 5-8 illustrate that the minimum and maximum voltage occur in each iteration and proves that the proposed approach can successfully ensure that all the conductors satisfy the voltage constraints (0.94 to 1.1 p.u.).

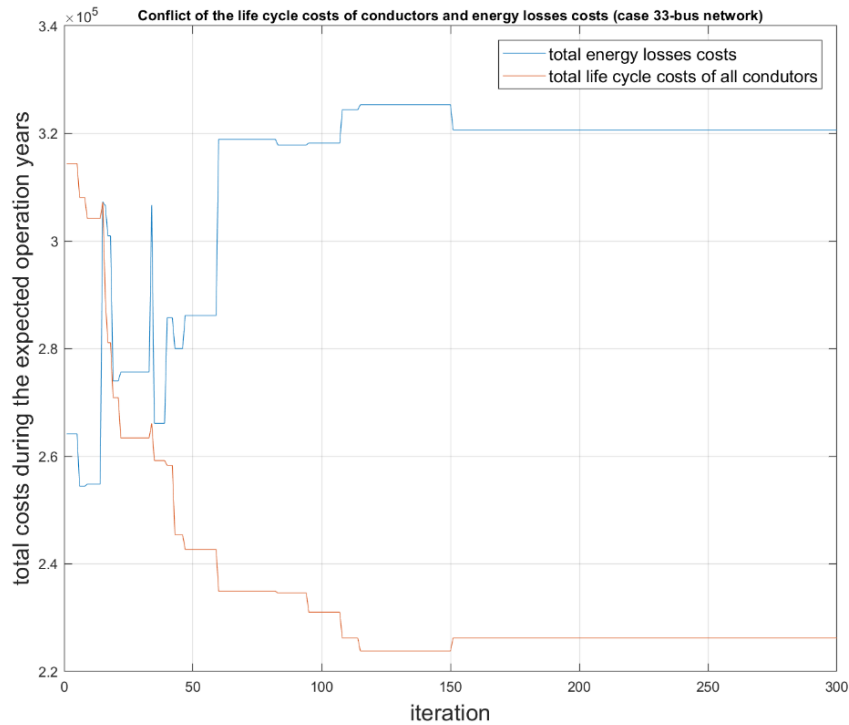


Figure 5-5 Conflict of the life cycle costs of conductors and energy losses costs (case 33-bus network)

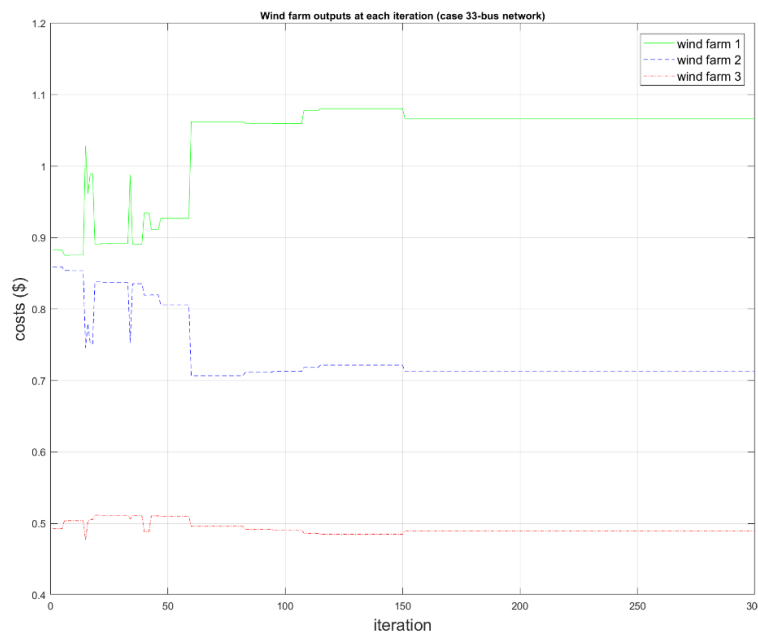


Figure 5-6 Wind farm output at each iteration (case 33-bus network)

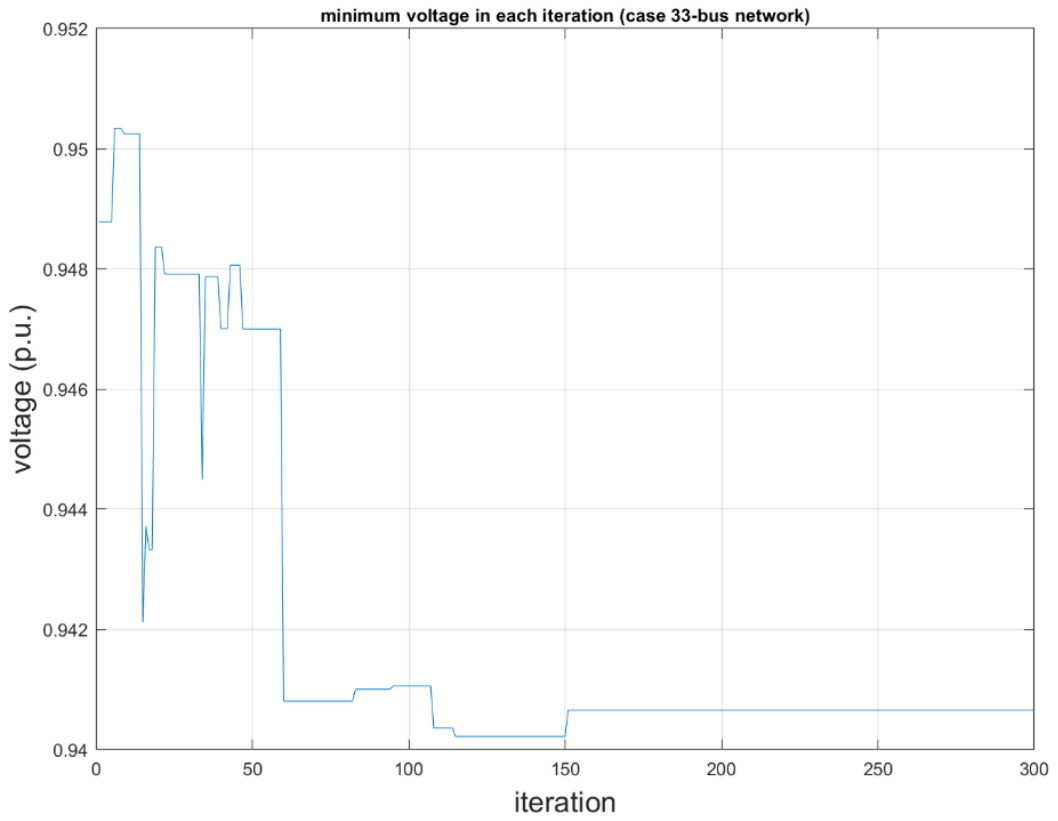


Figure 5-7 Minimum voltage at each iteration (case 33-bus network)

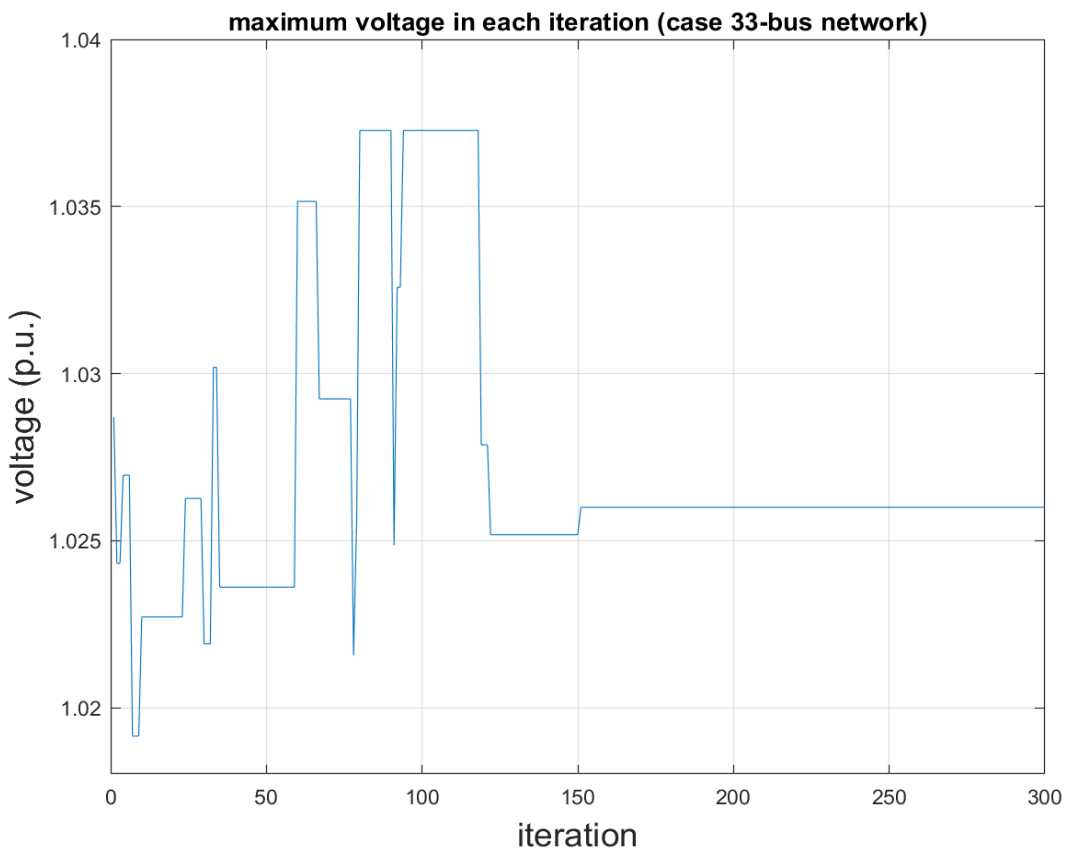


Figure 5-8 Maximum voltage in each iteration (case 33-bus network).

5.3.2 Case study of the 69-bus network

The proposed CCS optimization approach is tested on a 69-bus network in this section, where three wind generators are connected to the network at branch 6, branch 36 and branch 53. The single line diagram of this 69-bus distribution network is shown in Figure 5-9. And the relevant operation data and network constraints are listed in Table 5-7.

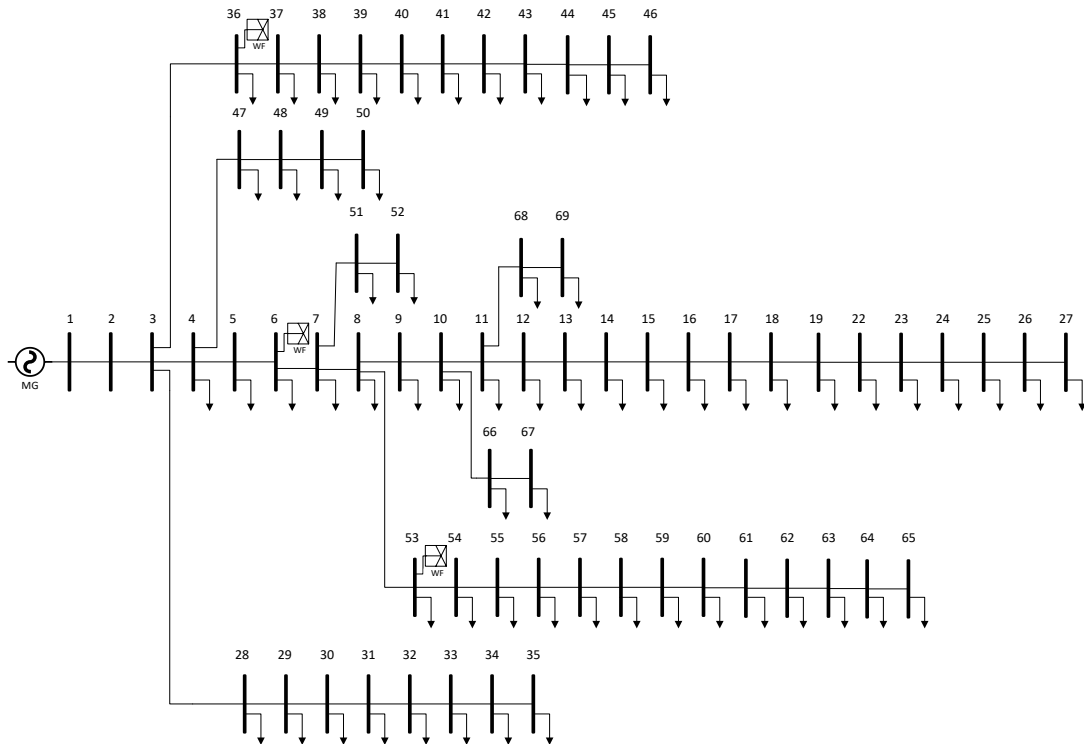


Figure 5-9 Single line diagram of the 69-bus distribution network

Table 5-7 Parameters of the 69-bus network

Parameter	Value
Maximum voltage	1.1 (p.u.)
Minimum voltage	0.94 (p.u.)
Initial total active demand	3.22 MW
Initial total reactive demand	1.78 MW
Load growth rate	3%/year
Operation year	20 years
Total branches	68
Maximum available output of wind farm at node 6	1.2 MW
Maximum available output of wind farm at node 36	1.0 MW
Maximum available output of wind farm at node 53	0.6 MW

The detailed power flow and branch data of IEEE- 69 bus network are given in Appendix B.1 and Appendix B.2. Same as the case of 33-bus network, the quadratic generation cost function of the main generator connected at node 1 is expressed in equation (5-21) and the wind farm is also considered as a zero marginal cost generator in the case of the 69-bus network.

The overall results of the proposed AGA optimal conductor size selection for the selected 69-bus distribution network are shown in Figure 5-10. It is observed that the best fitness can be achieved after approximately 160 iterations. The mutation rate is self-adaptive during the process of the AGA which is shown in Figure 5-11. It can be observed that the mutation rate is increased when the AGA cannot provide better fitness value and resets to zero when a better fitness value is achieved. And, it is noted that the best fitness value is captured after 250 iterations since the 69-bus system is more complicated than the 33-bus system.

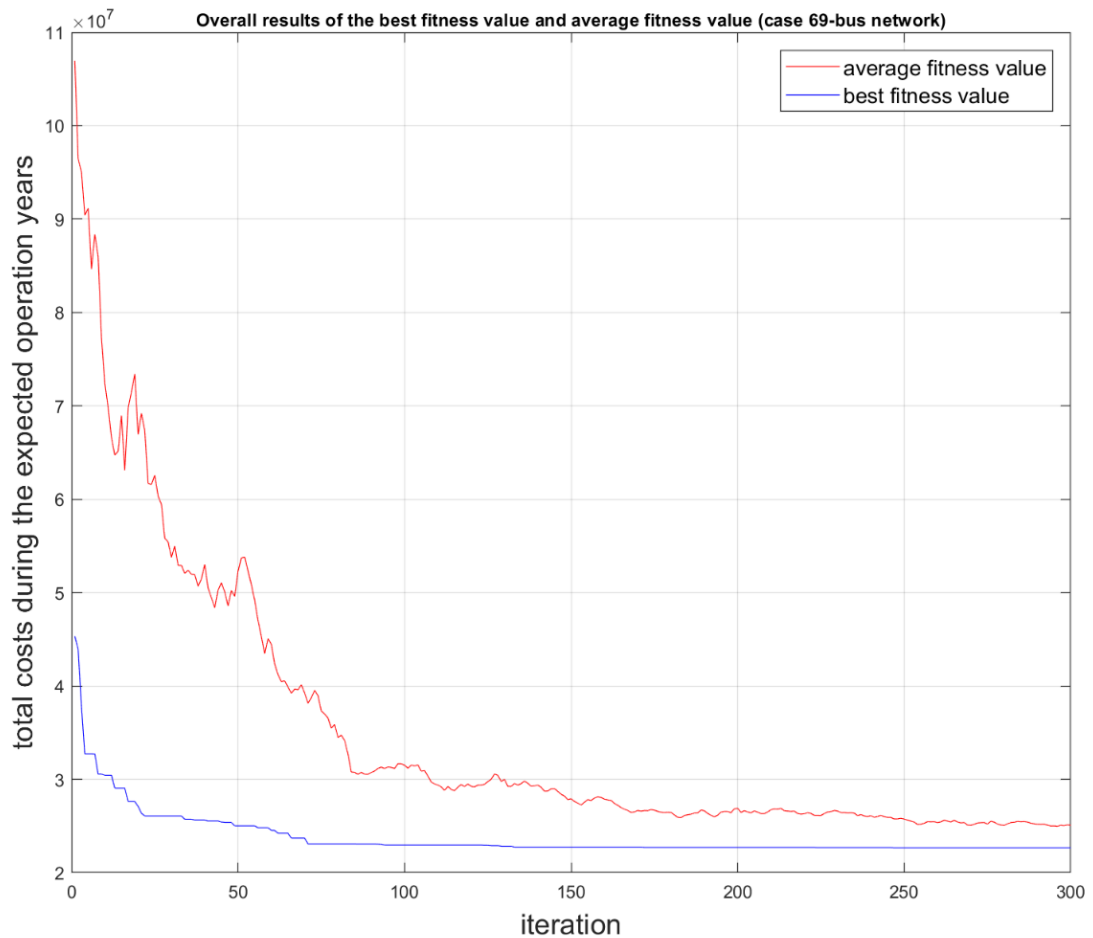


Figure 5-10 Overall results of the best fitness value and average fitness value (case 69-bus network)

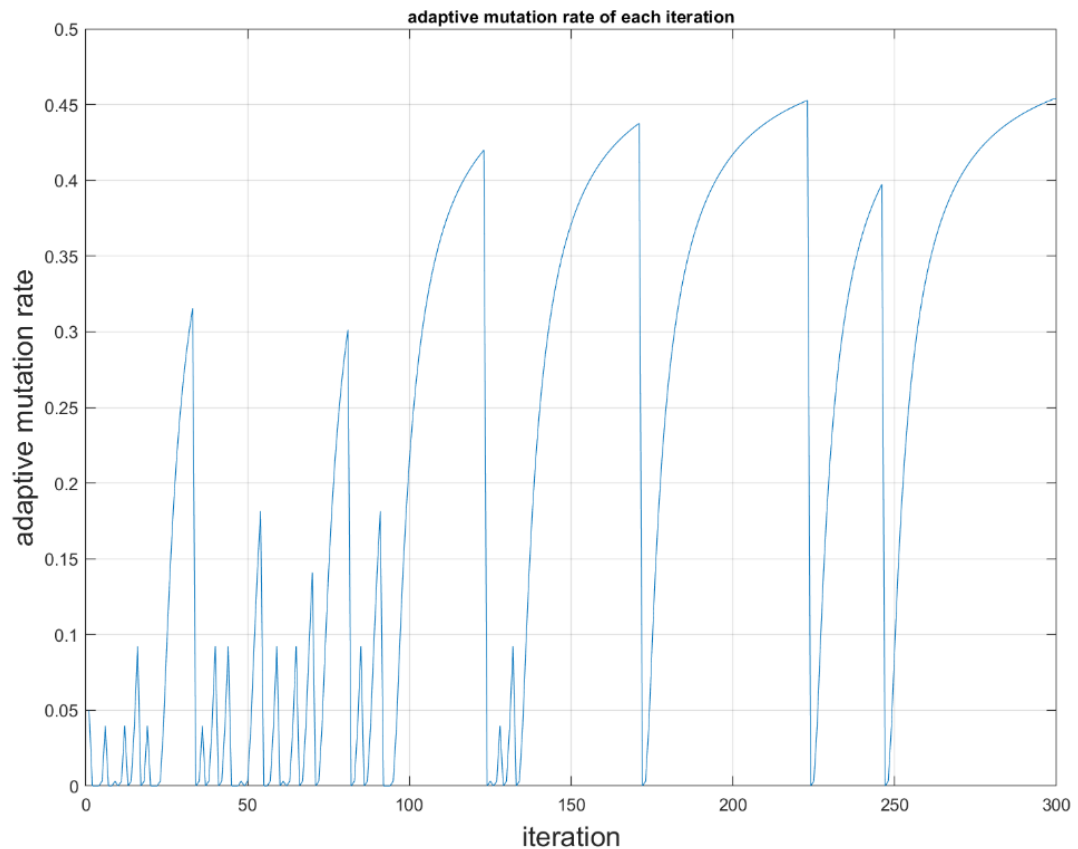


Figure 5-11 Adaptive mutation rate in each iteration (case 69-bus network)

Similar to the results of the 33-bus system, Figure 5-12 reveals the conflict between total energy losses and the life cycle costs of all conductors in the 69-bus network, thus proving the proposed algorithm can successfully achieve the balance between these two contrary costs. And, Figure 5-13 indicates that the optimum power consumption of the wind farm generations in each iteration in the case of the 69-bus system. Similar to the results in the 33-bus system, parts of the available capacity are curtailed for achieving the minimum total costs (including total energy losses costs, energy purchase costs and conductor's investment costs).

Similar to the results in the case study of the 33-bus network, the individuals that cannot satisfy the minimum and maximum voltage constraints are eliminated and replaced by the new individuals that can satisfy the constraints. Figures 5-14 and 5-15 illustrate that the minimum and maximum voltage occur in each iteration and

proves that the proposed approach can successfully ensure all the individuals satisfy the voltage constraints (0.94 to 1.1 p.u.).

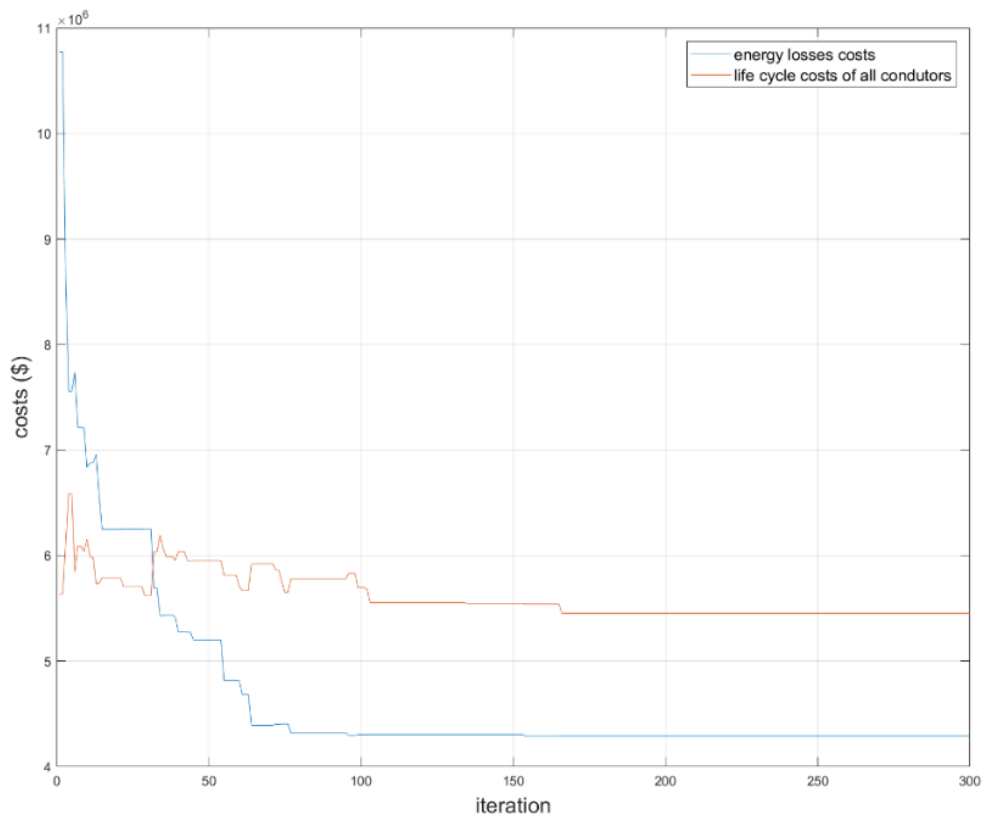


Figure 5-12 Conflict of the life cycle costs of conductors and energy losses costs (case 69-bus network)

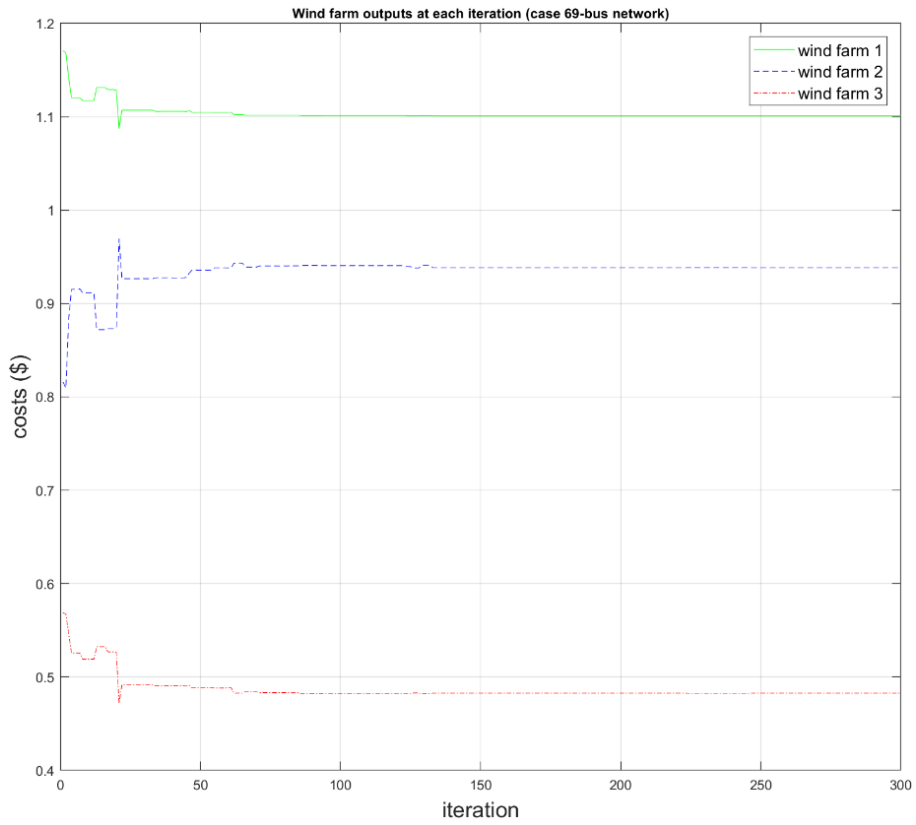


Figure 5-13 Wind farm outputs at each iteration (case 69-bus network)

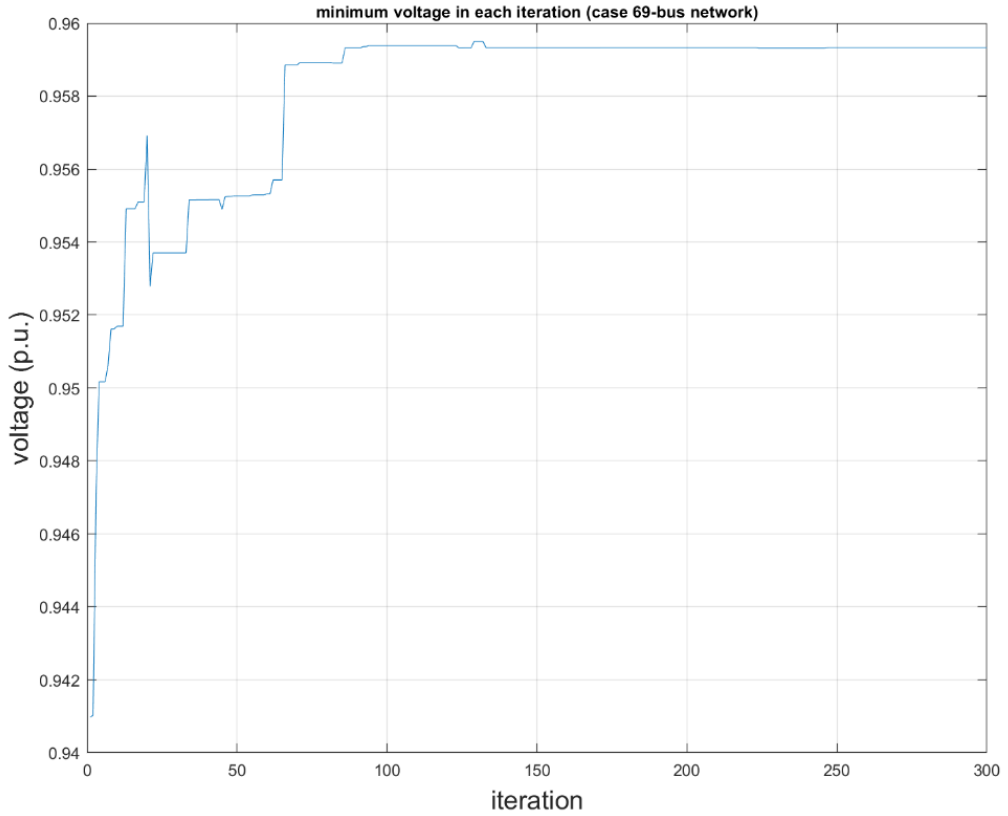


Figure 5-14 Minimum voltage at each iteration (case 69-bus network)

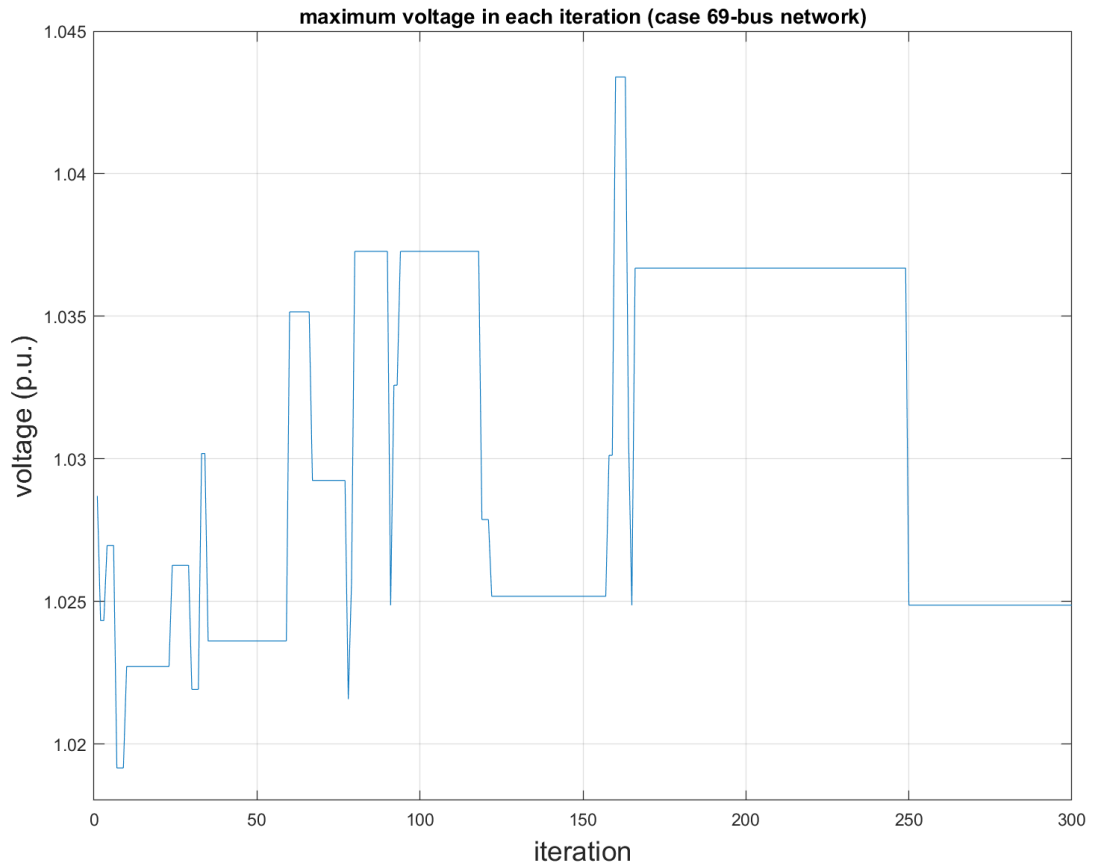


Figure 5-15 Maximum voltage in each iteration (case 69-bus network).

The detailed optimum results of conductor size selection by two different approaches are shown in Table 5-8. After the decoding process, the best conductor type of each branch in the 69-bus network can be checked in this table.

Table 5-8 Best conductor size selection for 69-bus distribution network

Branch	from	to	Selected conductor type via standard GA	Selected conductor type via A GA	Branch	from	to	Selected conductor type via standard GA	Selected conductor type via A GA
1	1	2	Gopher	Mink	35	3	36	Squirrel	Squirrel
2	2	3	Weasel	Ferret	36	36	37	Squirrel	Otter
3	3	4	Mole	Otter	37	37	38	Gopher	Ferret
4	4	5	Ferret	Otter	38	38	39	Mole	Gopher
5	5	6	Gopher	Ferret	39	39	40	Beaver	Raccoon
6	6	7	Mole	Beaver	40	40	41	Gopher	Mole
7	7	8	Rabbit	Beaver	41	41	42	Squirrel	Ferret
8	8	9	Gopher	Otter	42	42	43	Ferret	Rabbit
9	9	10	Weasel	Mink	43	43	44	Rabbit	Mink
10	10	11	Mink	Otter	44	44	45	Gopher	Weasel
11	11	12	Gopher	Rabbit	45	45	46	Mink	Gopher
12	12	13	Mole	Beaver	46	4	47	Ferret	Ferret

13	13	14	Rabbit	Rabbit	47	47	48	Rabbit	Beaver
14	14	15	Squirrel	Mink	48	48	49	Weasel	Mink
15	15	16	Gopher	Beaver	49	49	50	Gopher	Gopher
16	16	17	Mole	Raccoon	50	8	81	Gopher	Rabbit
17	17	18	Gopher	Rabbit	51	51	52	Beaver	Squirrel
18	18	19	Squirrel	Mole	52	9	53	Gopher	Raccoon
19	19	20	Squirrel	Squirrel	53	53	54	Mink	Beaver
20	20	21	Squirrel	Weasel	54	54	55	Mole	Mink
21	21	22	Mink	Raccoon	55	55	56	Squirrel	Raccoon
22	22	23	Mole	Mink	56	56	57	Mole	Beaver
23	23	24	Gopher	Weasel	57	57	58	Rabbit	Otter
24	24	25	Beaver	Mole	58	58	59	Mole	Otter
25	25	26	Rabbit	Squirrel	59	59	60	Rabbit	Raccoon
26	26	27	Weasel	Weasel	60	60	61	Weasel	Otter
27	3	28	Weasel	Mole	61	61	62	Mole	Ferret
28	28	29	Beaver	Ferret	62	62	63	Weasel	Otter
29	29	30	Mole	Rabbit	63	63	64	Gopher	Otter
30	30	31	Ferret	Ferret	64	64	53	Mole	Rabbit
31	31	32	Mole	Mole	65	53	54	Squirrel	Gopher
32	32	33	Otter	Squirrel	66	66	67	Gopher	Squirrel
33	33	34	Weasel	Squirrel	67	12	68	Mole	Mole
34	34	35	Mole	Weasel	68	68	69	Mole	Squirrel
Total life-cycle costs of two approaches					Standard GA			\$ 39054123.9	
					Proposed AGA			\$ 27617228.5	
Net cost saving								\$11436895.4	
Cost saving percentage								29%	

5.3.3 Summary and discuss

The study results of the 33-bus network and the 69-bus network indicate that the proposed adaptive genetic algorithm has the capability to provide a more efficient and effective way to solve the new challenge in the CSS problem than the standard genetic algorithm. In particular, 25% and 29% total costs saving are achieved separately by the proposed approach in two different distribution networks. More important, the potential economic conflict between the investment of conductors and the renewable resources curtailment costs is firstly considered in the CCS problem. On the other hand, the proposed approach employs a comprehensive conductor investment and O&M pricing model to provide precise and practical study results.

5.5 Chapter summary

In this chapter, the challenges of the future distribution network design and planning are introduced in section 5.1 firstly. In the next part, the previous and relevant researches and studies which are focused on CCS problem are indicated in section 5.2. In the traditional CCS framework, the power losses and the demand growth are considered as the two major factors that affect the conductor selection during the network design and planning projects.

Thus, the large-scale installation of DGs and the declined levelized cost of renewable generation are generally not considered in the previous studies about the CCS problems. Installed DGs in the distribution systems are often considered as a zero marginal cost energy resources in the power operation analysis. In the distribution systems with high penetration renewable generations, DNOs need to allocate suitable conductor at different branches to consume the available output of DGs, thus maximizing the economic benefits from renewable resources. Therefore, the selected conductors are expected to have enough current carrying capacity to satisfy the peak output of the installed DGs. On the other hand, the investment of conductors is also an important economic factor need to be considered. Therefore, DNOs are difficult to identify the optimal conductor arrangement for the distribution system with high penetration DGs.

In order to deal with the potential conflict during the distribution network design and planning, a hybrid optimization algorithm is designed in this chapter to deal with the CSS problems in distribution systems with high penetration DGs. In particular, an adaptive genetic algorithm that has a dynamic mutation rate and a dynamic number of mutated genes are introduced as the main optimization mechanism. The proposed AGA mechanism is responsible for finding the optimal conductor size selection for the chosen network and the objective function is to minimize the sum of the life-cycle cost of selected conductors, the total energy procurement costs and energy losses costs. It is noted that the total energy procurement costs and energy losses costs of each individual are provided by the AC-OPF which is employed as the auxiliary optimization tool in the approach.

To test the efficiency and feasibility of the proposed framework, the proposed hybrid optimal CSS approach is tested on the 33-bus distribution network and a 69-bus distribution network in section 5.3. The numerical results have demonstrated an ability to provide accurate and feasible solutions for solving the optimal conductor size selection problem and ensured the results satisfy the network constraints. Different from the majority previous researches of the CSS problem, this approach comprehensively considers the economic dispatch problems of the traditional fossil fuel generator and the renewable resources. Instead of the objective function of minimum energy losses costs, the minimum system level costs are considered as the main target in this approach.

Although most of the important influence factors that may affect the conductor size selection have been considered in the proposed framework. There are still several potential influence factors are required to be addressed during the conductor size selection and distribution network planning. For instance, the high penetration of DGs will significantly change the short-circuit currents through the system. Indeed, this feature may affect the selection of conductors when the distribution network operators consider a network upgrading plan. But, there are still several approaches able to deal with this potential problem when the DNOs design or upgrade their distribution networks such as application of the superconducting fault current limiter (SFCL) or installing the second circuit break (CBs) at the right place. From the view of network protection, the potential conflict between the costs of second circuit break or superconducting fault current limiter and the costs of conductors upgrading needs to be investigated carefully. Indeed, the practical distribution network planning or upgrading is complicated and required to consider different influence factors and potential economic conflicts. The final design and planning of a distribution network should incorporate different economic benefits and satisfy the required power quality at the same time. The distribution network operators (DNOs) are expected to consider different aspects of comprehensively. Our research aims to provide the advice that focuses on the potential cost conflict between the conductor life-cycle costs and the costs of renewable resources curtailment with the consideration of detailed conductor investment and O&M costs model. The potential conflict

between the costs of second circuit break or superconducting fault current limiter and the costs of conductors upgrading can be considered as a new research area and worth to investigate. The DNOs can comprehensively consider the advice from 1) the research that focuses on the costs of protection devices and conductor upgrading costs and 2) our research that focus on the costs of DGs curtailment and conductor life-cycle costs, and finally decide the optimum design and planning by the relevant experts.

On the other hand, the development of the high capacity electric vehicle charging stations and electrical storage system also affect the planning of the distribution networks. In particular, several countries have launched the plan to eliminate the usage of fossil fuel-based vehicles and encourage citizens to purchase electricity vehicles. Under these circumstances, the normal household electricity demand will have a significant increase (especially during the peak demand periods such as 7:00 PM-12:00 PM) when electric vehicles dominate the market. The conductor size selection problem is expected to consider those technologies. Thus, the modern smart grid technologies and protection problems caused by the integration of distributed generations are considered in the future research regard of the conductor size selection and the distribution network planning.

Chapter 6

Dynamic Pricing Framework for Demand Response considering the thermal limitation

6.1 Introduction

Dynamic pricing framework or day-ahead pricing approach plays a key role in the revolution of the demand response (DR) programme. Plenty of frameworks and mechanism related to economic incentive and price response have been developed in earlier publications to improve the stability and efficiency of the entire power system by managing the power consumption at the demand side. On the other hand, the increasing installation of distributed generations has significantly affected the price structure of the current electricity bill. These new types of generations are mostly connected to the demand side, thus avoiding the application of long-range power transmission facilities. And, the international renewable energy agency (IRENA) reported that global renewable energy prices would be decreased to the cost range of traditional fossil fuels generation. Based on the background of the electricity market and breakdown of the energy bill that is introduced in Chapter 3, the use of transmission system charge and energy wholesale price are two major parts of the

total energy cost. Therefore, the customers are expected to pay less unit electricity price when they consume the energy from the renewable generations that have geographic advantages. However, the output of the renewable energy resources (DER) vary depending on the time of day and is difficult to have a precise prediction. Thus, only when the electricity customers match the energy consumption to the output of DER can the unit electricity price reaches the optimum number. Under such circumstances, common flat electricity rates that used widely in current electricity retail market undermine the application of DERs and affect the optimum results of the economic dispatch of different generations. Current flat rates also provide the misleading information to the transmission system operators (TSO) and distribution network operators (DSO) since they continually receive the use of transmission system charge and use of distribution system charge respectively regardless of the actual power delivery route.

The new generation technologies and the concern of the global environmental problems have driven the revolution of the electricity pricing mechanism. Thanks to the development of the information communication technologies, power suppliers and their electricity consumers can achieve the real-time interaction, thus allowing the real-time demand-side management, day-ahead demand prediction, day-ahead electricity pricing predication and dynamic pricing. Based on these innovative pricing mechanisms, the dynamic electricity rates can reflect the time-varying output of DERs and the costs of electricity delivering. Plenty of current publications have identities that applying the flexible rates of electricity have wide benefits such as decreasing the retail electricity prices, reduce wholesale prices, decreasing the curtailment of DERs, avoiding or deferring the investment of transmission and distribution infrastructures. There are several different ways to allow the electricity prices to reflect the variation in energy procurement costs and electricity delivering costs. The common approaches include real-time pricing (PTR), time-of-use pricing (ToU), variable peak pricing (VPP), critical peak pricing (CPP) and critical peak rebate (CPR).

The different types of time-varying electricity mechanism can indeed affect the electricity users' behaviours to some extent. However, majority of power suppliers

only provide several simple flexible electricity rates such as 1) two rates model: peak and off-peak price, 2) three-rates model: off-peak rate, peak rate and overnight rate. indeed, plenty of publications have intensively researched the potential solution to launch the complicated time-varying electricity pricing mechanisms. It is noted that few efforts made to investigate the potential network constraints such as the thermal limitation of the electricity delivering facilities or the voltage limitation during the system operation. Even though almost all earlier researches have considered these constraints in their objectives or case studies, few of them applied the constraints as an economic incentive factor to participate in the electricity market bidding system. In this chapter, the distribution use of system charge (DUoS) and transmission use of system charge (TUoS) allocation approach are introduced firstly. And, electricity customers' actual usage of each power delivering facilities will be identified through the proposed approach, thus allowing a precise and real usage based TUoS or DUoS charge.

The rest of the chapter is organised as follow, the definition of different time-varying electricity pricing mechanisms is reviewed in section 6.2. Typical Frameworks of time-varying pricing in the existing studies is illustrated in section 6.3. And, the motivation and target of the research in this chapter are also presented in this section. Then, the proposed models, which are designed for assessing the transmission and distribution use of system charges, are introduced in section 6.4. The framework of the electricity pricing elasticity matrix, which is designed to predict the customer's response to the provided signals, are presented in section 6.5. several case studies are addressed in section 6.6 and the numerical results verify the efficiency and feasibility of the proposed day-ahead pricing mechanism. In the end, the conclusion of this chapter is presented in section 6.7.

6.2 Concept of Time-Varying Electricity Pricing Mechanism

Traditionally, electricity customers include industry, commercial and residential electricity users are required to pay the fixed price for a single unit of the electricity service regardless of the time of the day or the seasons when they consume the

energy. The actual costs of system operation and maintenance which change depending on the geographical locations and the time of the day cannot be reflected by the common fixed electricity rates. Therefore, time-varying pricing mechanisms are designed and planning for providing the fluctuating and dynamic electricity pricing to the customers, thus achieving a more economical electricity market and efficient operation of power systems.

There is no clear and agreed definition for time-variant pricing mechanism. However, it usually has several typical forms such as time-of-use pricing (TOU), real-time pricing (PTR), variable peak pricing (VPP), critical peak pricing (CPP) and critical peak rebate (CPR).

In comparison with the conventional flat rate pricing strategy, TOU pricing scheme is designed to divide a day into two or three interval time periods with different electricity rate. Normally, the electricity rates are recognized as peak prices, interim prices and off-peak prices. However, each rate is still remaining fixed for each day during a certain season. This simple pricing mechanism is introduced and applied in plenty of countries already. The aim of the TOU pricing approach is to encourage electricity users to decrease their electricity usage during the peak demand time to avoid a relatively high rate and consume the energy during the off-peak period to enjoy a lower electricity price. Indeed, TOU pricing mechanism is a useful and simple method that can be widely applied in the current electricity market easily and have the potential capability to reduce the peak demand. But, TOU pricing approach cannot provide a response to the variable wholesale prices and the output of renewable energy resources since it remains the fixed rates for each interval day-to-day [18, 56]. Figure 6-1 illustrates the typical form of Time of Use Pricing.

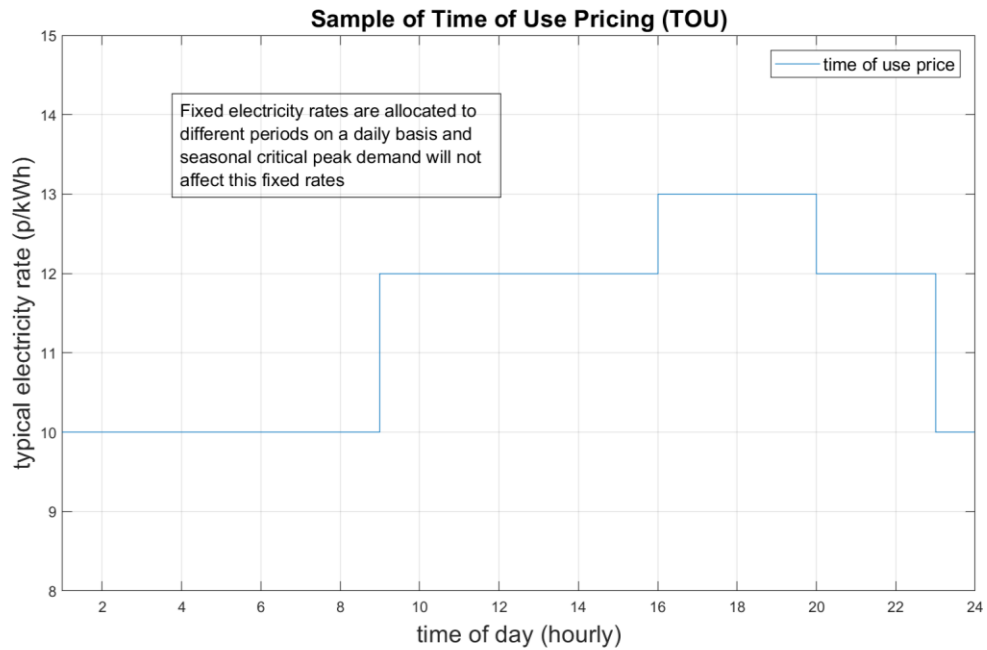


Figure 6-1 Sample of Time of Use Pricing (TOU)

Real-time pricing (RTP) mechanism is another useful approach designed to affect electricity customers' behaviours of power consumption by economic incentive. Different to the TOU mechanism, electricity rate in PTR mechanism is changed frequently during the daytime. The daytime is divided into 24 or 48 intervals and electricity customers will be charged different rate at each interval. As a consequence, the real-time electricity pricing that provide to the end customers can reflect the variation of wholesale electricity price and the output of renewable energy resources. Normally, the price signal of PTR that delivers to consumers will be released one day ahead as an hourly or half hourly form. Indeed, RTP mechanism has the potential to improve the efficiency of the electricity trading system and can respond to the wholesale market prices quickly due to its high rate varying frequency. The application of sufficient and intensive information communication infrastructures is one of the key barriers for widely applying this pricing mechanism. On the other hand, each customer has its own behaviour to respond to the provided price signal and human behaviours are difficult to predict. Therefore, the PTR mechanism is currently widely applied for large industrial and commercial customers that have the capability to respond to the price signal by planned orders. Figure 6-2 illustrates the typical form of Real-Time Pricing.

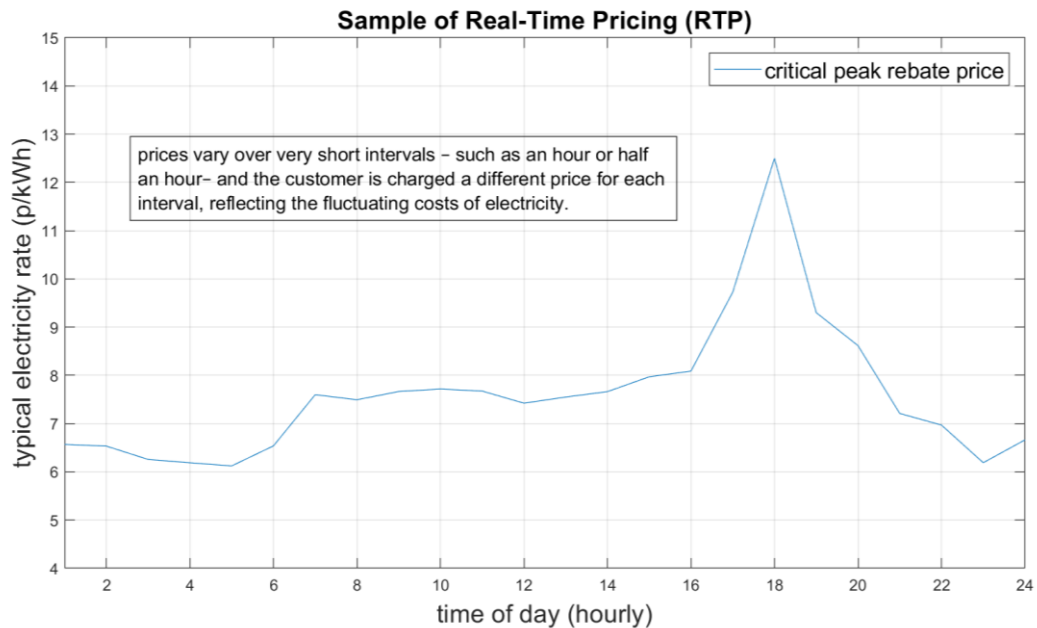


Figure 6-2 Sample of Real-Time Pricing (RTP)

Variable peak pricing (VPP) mechanism is a particular form of time-of-use pricing framework, where the peak electricity rate varies depending on the real-time system operation statuses. However, the variable peak prices and the corresponding trigger conditions are still pre-determined, thus the performance of this mechanism largely depends on the planning and schedule made by the power suppliers. Indeed, the VPP mechanism is similar to the TOU mechanism that encouraging the customers to reduce the energy consumption during the peak periods by responding to the price signal. But, a higher peak electricity rate is applied by VPP mechanism during some extremely system operation conditions. Figure 6-3 illustrates the typical form of Variable Peak Pricing.

Critical peak pricing (CPP) mechanism provides electricity customers with a relatively high rate during selected days of the year. The selected days are normally identified based on some particular situations such as the extremely hot days of the year or cold days of the year. The price sensitive customers can avoid the high electricity rate during the critical peak periods of the year. Typically, the maximum price in the CPP tariffs may reach ten times as much as the standard rate, which results in an efficient load shape during the peak load time. Like the previous two schemes, However, the proposed method in their paper did not implement in a real power system. Moreover,

fully bidding electricity market will significantly raise the electricity price extremely in peak load period, which may affect some essential power usage. Figure 6-4 illustrates the typical form of Critical Peak Pricing.

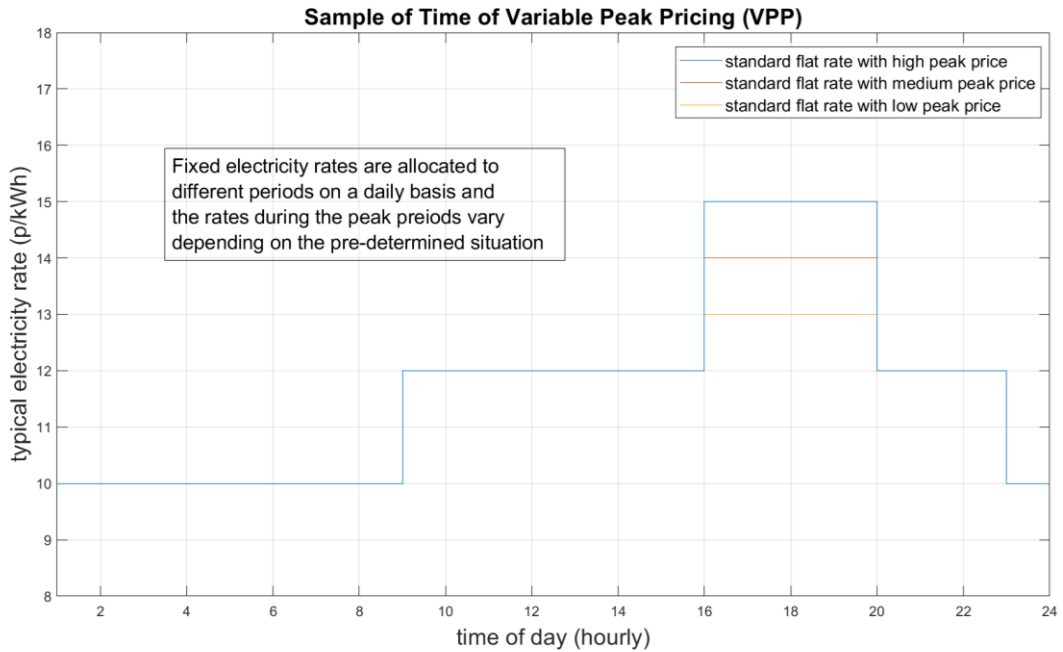


Figure 6-3 Sample of Variable Peak Pricing (VPP)

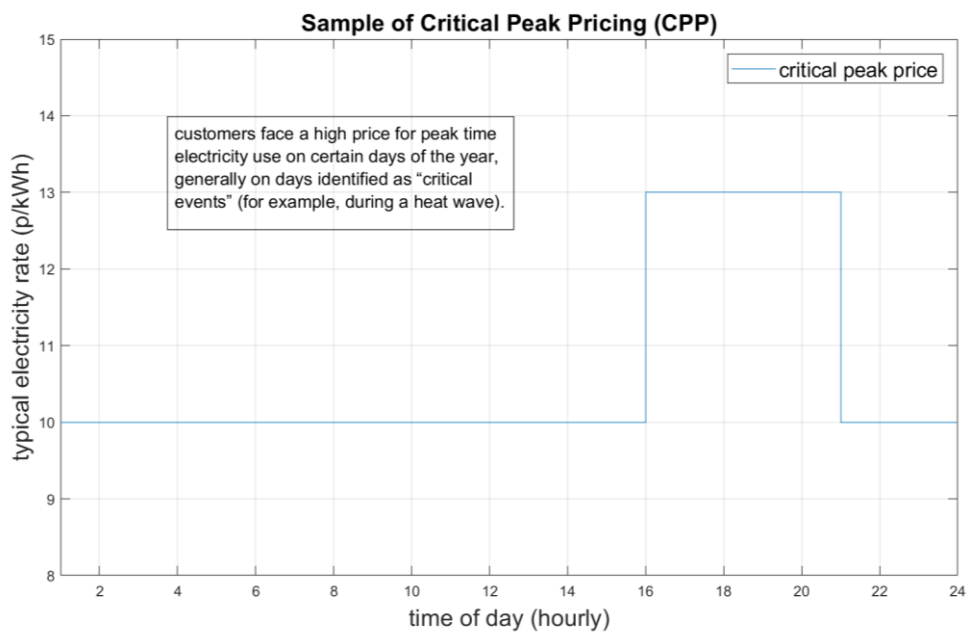


Figure 6-4 Sample of Critical Peak Pricing (CPP)

With critical peak rebate (CPR) mechanism, electricity customers receive financial support for reducing the electricity usage during the peak periods of the year. Baseline amounts of electricity usage are allocated to different types of customers. Figure 6-5 illustrates the typical form of Critical Peak Rebate Pricing.

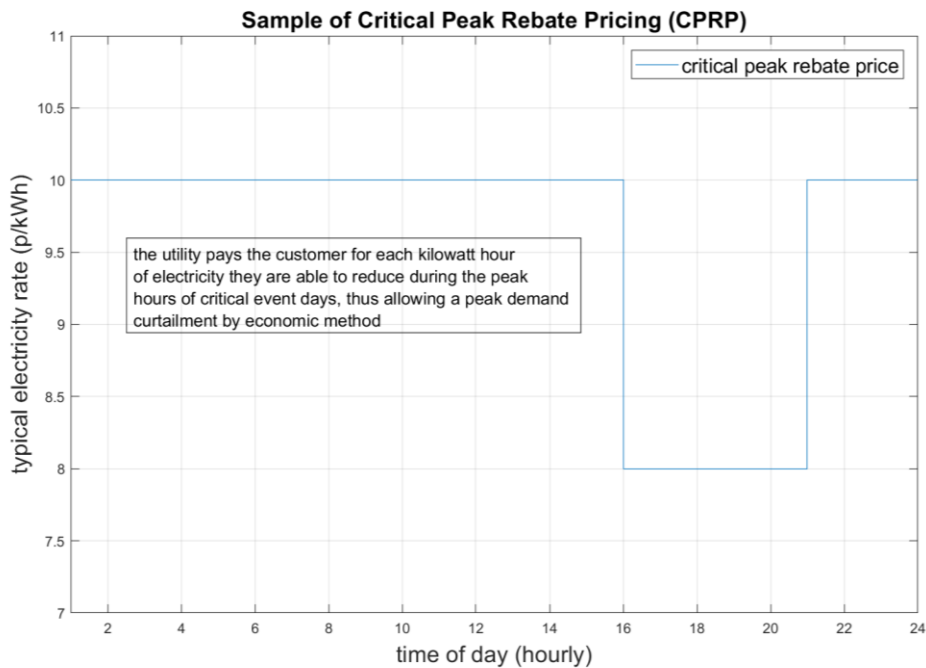


Figure 6-5 Sample of Critical Peak Rebate Pricing

6.3 Typical Frameworks of Time-Varying Pricing in the Existing Studies

Considerable efforts have been made for developing optimal and efficient time-varying pricing models. Majority of earlier researches have paid attention to improve the efficiency of the electricity trading process and provide economic benefit to both customers and power suppliers or other power system relevant utilities by using appropriate economic incentive tool. A day-ahead hourly pricing (DAHP) framework was proposed by Jia and Tong, where the framework is designed to adjust real-time consumptions of electricity customers and increase the economic benefits of each consumer. The framework also establishes a trade-off relationship between the

demand side and supply side by a Stackelberg game model, which can properly reflect the human behaviour and price elasticity [58]. Nguyen and Le presented an improved price-decision approach [60] that the power demand is subjectively divided as a flexible and inflexible load. In their research, a relatively low and stable electricity price is arranged to consumers' basic requirement and a dynamic price tariff is provided to inflexible requirement. However, several market side factors such as wholesale price are not considered in their action models. A new centralised complex-bid market-clearing mechanism based on dynamic pricing schemes was introduced by Su and Kirschen, which consider different categories of market participants. The proposed mechanism accepts bids from both demand and supply sides with the consideration of network constraints to achieve maximum social welfare [235]. To simplify the simulation progress, the potential congestion problem and thermal limitation of the transmission network is neglected. In sum, most of the analysis and results in existing literature related to the design of dynamic pricing framework only consider the interactions between power retailer and its customers. Unfortunately, the profits and benefits of distribution network operators (DNOs) or transmission utilities are neglected in most of the related literature. Since the transmission prices account for approximately 40% of the retail prices in the UK, DNOs are encouraged to participate in the electricity pricing mechanism.

The proposed dynamic pricing framework allows the wholesale market, power suppliers and electricity customers to participate in the electricity market intensively. The comprehensive factors (including wholesale electricity price, transmission cost allocation and customers' response to the electricity price variation) that act on the price signal are integrated into the framework. Therefore, the wholesale price will no longer be the dominant factor to affect and guide the variation of the price signal completely. In the simple time-varying electricity price structures, the relatively low wholesale price may directly result in a sharply increasing of energy utilisation during the corresponding period. Consequently, the increasing energy requirement during the low-price signal period leads to potential network congestion. On the other hand, part of the transmission system may take the risk of reaching the capacity limitation. In the proposed framework, the problems can be solved by the participation of DNOs.

More specific, transmission cost experiences an increase when transmission facilities face the congestion problems, thus countering the economic incentive of the low wholesale price. The main target of the proposed framework is to find out the optimum price signal at each time slot with the global consideration of wholesale market, benefits of power suppliers and customers' behaviours.

In this chapter, a novel transmission cost allocation approach is designed to support the proposed dynamic pricing framework, where it persuades the efficient usage of the distribution network and postpone the further investment of distribution facilities, thus improving the performance of the operation in distribution systems. The approach is expected to consider the electricity users' contributions to actual usage in each transmission facilities. The appropriate price signal reflects the usage of the transmission system can be achieved by the contributions of two independent pricing mechanisms: 1) cost allocation mechanism supported by power sensitivity analysis; 2) incremental transmission cost mechanism based on the asset of each transmission facility. On the other hand, the user's response to the provided price signal is a matter of considerable concern since it significantly affects the performance of each dynamic pricing framework. In the proposed modelling, the electricity price elasticity matrix (EPEM) is intended to capture the system-level impact of demand response, rather than local effects on a single consumer. The value of elasticity in the matrix can be adjusted to simulate different kinds of energy consumers' response behaviours.

6.4 Models for TUoS and DUoS allocation approach

A reasonable and well-designed transmission cost allocation (TCA) approach is expected to appropriately reflect the electricity customers' contribution to the actual usage of corresponding transmission facilities. Proposed transmission cost allocation approach is designed to generate a relatively fair price signal to the customer side, which covers the investment of transmission assets and the operation cost. Therefore, to satisfy the benefits of both customers and power supplies, the proposed TCA scheme should have following characteristics: 1) the real-time usage

of each transmission line and the value of its assets should be considered in the final price signal that delivers to the customers; 2) the price signal that each customer received should be appropriately allocated by the user's actual contribution to the power flow in each transmission facility. Several approaches have been proposed to calculate and allocate transmission cost in previous researches. The postage stamp and the simple contract-path methods were firstly introduced to implement the transmission cost allocation. However, both these two pricing approaches are unsuccessful to appropriately reflect the actual usage of transmission facilities [236]. MW-Miles and other power flow tracing based transmission cost allocation methodologies were applied to take into consideration of electricity customers' contribution to the transmission systems. However, geographical distance cannot fully reflect the actual meshed network [21]. Consequently, current price tariffs are still unable to provide the appropriate congestion signal in most circumstances. The previous studies have proposed many transmission cost allocation methods, a more proper and suitable pricing approach is still required to be explored to reflect actual usage of each transmission facility and allocate the price signal to different customers appropriately.

The proposed transmission cost allocation approach is a combined application of the incremental transmission pricing model (ITP) and power flow tracing algorithm (PFT). The original methodology of incremental transmission pricing approach was firstly introduced by Li to predict optimum future investment in the transmission system based on the previous data of transmission facilities' usage rate [61, 62, 237, 238]. In this paper, the real-time charging of each transmission line can be calculated by advanced ITP approach and the final price signal of transmission usage can be allocated by power transfer distribution factors (PTDFs) based power flow tracing algorithm. The incremental transmission pricing model is defined as a component in the network that is affected by a nodal injection, there will be a cost associated with it if the investment is accelerated or credit if it is deferred. Calculating the present value of the investment is one of the most important parts of the incremental transmission pricing approach. This value can be affected by the total investment, related discount rate and the lifespan of the project.

For a given load growth rate r , the current transmission usage D of a single circuit will reach its maximum capacity C by using an expected period Y . Therefore, the equation that represents the relationship above can be formulated in (6-1).

$$C_l = D_l \times (1 + r)^{Y_l} \quad (6 - 1)$$

The equation can be rearranged to:

$$(1 + r)^{Y_l} = \frac{C_l}{D_l} \quad (6 - 2)$$

Then taking the logarithm to two sides:

$$Y_l \times \log(1 + r) = \log C_l - \log D_l \quad (6 - 3)$$

Therefore, the equation can be transferred to the form as equation (6-4).

$$Y_l = \frac{\log C_l - \log D_l}{\log(1 + r)} \quad (6 - 4)$$

The investment on transmission assets can be calculated to its present value by the equation (6-5).

$$PV_l = \frac{Asset_l}{(1 + d)^{Y_l}} \quad (6 - 5)$$

Based on the mechanism of incremental transmission pricing, the increasing power transaction request will raise the unit charging of power delivery. Therefore, it is necessary to explore the pricing response due to the variation of the power transaction.

The additional power flow ΔP_l is arranged in line l will result in a new year index Y_{lnew} which can be reflected in the new equation (6-6).

$$C_l = (D_l + \Delta P_l) \times (1 + r)^{Y_{lnew}} \quad (6 - 6)$$

Based on the similar equation rearrange method, we will receive the equations (6-7) to (6-10).

$$(1 + r)^{Y_{lnew}} = \frac{C_l}{(D_l + \Delta P_l)} \quad (6 - 7)$$

$$Y_{lnew} \times \log(1 + r) = \log C_l - \log(D_l + \Delta P_l) \quad (6 - 8)$$

$$Y_{lnew} = \frac{\log C_l - \log(D_l + \Delta P_l)}{\log(1 + r)} \quad (6 - 9)$$

$$PV_{lnew} = \frac{Asset_l}{(1 + d)^{Y_{lnew}}} \quad (6 - 10)$$

Therefore, the variation of the present value due to the change of power flow through the line l can be formed in equation (6-11), where this variation also represents the marginal cost of the transmission line l .

$$\Delta PV_l = PV_{lnew} - PV_l = \frac{Asset_l}{(1 + d)^{Y_{lnew}}} - \frac{Asset_l}{(1 + d)^{Y_l}} \quad (6 - 11)$$

With the sensitivity method, the equation (6-11) can be transferred to the form in equation (6-12) to reflect the sensitive relationship between transmission facility's usage rate u and the transmission marginal cost TC .

$$\begin{aligned} TC &= \frac{\partial PV_l}{\partial D_l} = \frac{\partial PV_l}{\partial Y_l} \cdot \frac{\partial Y_l}{\partial D_l} \\ &= (-Asset_l \cdot \frac{\log(1 + d)}{(1 + d)^{Y_l}}) \cdot (-\frac{1}{P_l \times \log(1 + r)}) \\ &= \frac{Asset_l}{P_l} \cdot \frac{\log(1 + d)}{\log(1 + r)} \cdot u^{\left(\frac{d}{r} - 1\right)} \end{aligned} \quad (6 - 12)$$

Based on the equation (6-12), the marginal cost TC_l of a given transmission line l can be calculated by its corresponding asset value, discount rate d , load growth rate r and real-time usage rate u .

$$TC_l^t(\text{hourly}) = \frac{Asset_l}{P_l} \cdot \frac{\log(1 + d)}{\log(1 + r)} \cdot u^{\left(\frac{d}{r} - 1\right)} \cdot \mu \cdot \eta \quad (6 - 13)$$

In the equation (6-13) the annuity factor μ can be calculated by the equation (6-14) and hourly factor η equals to 1/8760.

$$\mu = \frac{(1 - (1 + r)^{(-n)})}{r} \quad (6 - 14)$$

where,

r represents the rate per period

n represents the number of periods

The real-time cost of transmission usage for each line can be calculated by the equation (6-13). However, the cost is still expected to be allocated to each final customer appropriately. To explore the variation of real power flows based on the change of power injection in a specific node, it is important to conduct the sensitivity analysis in power system. Therefore, Power transfer distribution factors (PTDFs) is employed to apply the power tracing approach in the transmission cost allocation process. PTDFs provide the sensitivity of the active power flow through line n with respect to an additional power injection in node i and withdrawal at node j ,where the definition of power transfer distribution factors is shown in equation (6-15).

$$PTDF_{i,j,l} = \frac{\text{change in power flow through line } l \text{ due to the power transaction between node } i \text{ and } j}{\text{power transaction between node } i \text{ and } j} \quad (6 - 15)$$

PTDFs can be conventionally calculated by the nodal matrix of selected power network via the equation (6-16) to (6-17).

$$PTDF_{i,j,l} = \frac{\Delta P_{i,j,l}}{\Delta P_{i,j}} \quad (6 - 16)$$

$$PTDF_{i,j,l(m,n)} = \frac{(X_{mi} - X_{mj}) - (X_{ni} - X_{nj})}{X_l} \quad (6 - 17)$$

Therefore, the final price signal that DNOs provide to customers at load point j in time slot t can be formulated in equation (18) by adding the wholesale price in time slot t (denoted as WP_t) and the integration of all cost charged by each transmission line based on the actual contribution of the consumers in load point j .

$$\begin{aligned}
 PS_j^t &= WP_t + \sum TC_l^t \\
 &= WP_t + \sum_{l=1}^L \sum_{i=1}^I \frac{Asset_l}{P_l} \cdot \frac{\log(1+d)}{\log(1+r)} \cdot u^{\left(\frac{d}{r}-1\right)} \cdot \mu \cdot \eta \\
 &\quad \cdot \frac{(X_{mi} - X_{mj}) - (X_{ni} - X_{nj})}{X_l} \quad (6 - 18)
 \end{aligned}$$

6.5 Electricity pricing elasticity matrix

Optimum time-varying electricity pricing signal can be generated by the proposed transmission cost allocation approach which has been introduced in the last section. The user's response to the provided price signal is also a matter of considerable concern since it significantly affects the performance of the proposed dynamic pricing framework. However, most of the analysis and results in existing literature related to customers' behaviours only consider the single optimization solution between the power supplier and the aggregated demand group. The elasticity of the demand in electricity price, which shows how elasticities can simulate the customers' response to the price signal, has been introduced by Daniel S. Kirschen [235]. In the proposed modelling, the EPEMs are modified from Daniel's achievement and intended to capture the system-level impact of demand response, rather than local effects on a single consumer. On the other hand, the value of elasticity in the matrix can be adjusted to simulate different kinds of energy consumers' response behaviours.

Proposed dynamic pricing framework assumes that the demand of customers is fully elastic, where the users will adjust their power usage in response to the variation of electricity price. Due to the price sensitivity of the demand side, a tiny amount of price increases by the supply side may result in a decrease in demand. However, it is important to understand the extent of the decrease of the demand when the price increases. Typically, the price response of the demand side is not a fixed number

corresponding to the change of supply. Therefore, the price elasticity is introduced, where it is defined as the ratio of the corresponding variation in demand amount to the relevant variation of price [239, 240].

$$\epsilon = \frac{\Delta q/q}{\Delta \pi/\pi} = \frac{\pi \Delta q}{q \Delta \pi} \quad (6 - 19)$$

The definition of electricity price elasticity (EPE) has been mentioned in equation 6-19. However, to introduce the electricity price elasticity matrix, the time index is expected to add in the idea of EPE. For a day-ahead market of designed time intervals, each unit in the EPEM indicates the consumption deviation from its scheduled amount at certain interval t as a reaction to price change either at the same interval t or another interval τ . Thus, the formulation of electricity price elasticity can be enhanced to equation (6-20).

$$\epsilon_{t\tau} = \frac{\Delta P_t}{\Delta p_\tau} \quad (6 - 20)$$

On the other hand, it is assumed that all the electricity prices and power demand can be normalised with respect to a chosen reference point (π_0 and q_0) to simplify the calculation and formulation of price elasticity in the electricity price elasticity matrix, Therefore, the typical elasticity expression can be transferred to the equation (6-21).

$$\epsilon = \frac{\pi_0}{q_0} \times \frac{\Delta q}{\Delta \pi} \quad (6 - 21)$$

Based on the idea of standard price elasticity above, the elasticity in the matrix can be transferred to the expression (6-22).

$$\text{standard } \epsilon_{t\tau} = \frac{\frac{\Delta P_t}{p_{t,ref}}}{\frac{\Delta p_\tau}{p_{\tau,ref}}} \times 100\% = \frac{P_{t,act} - P_{t,ref}}{p_{\tau,act} - p_{\tau,exp}} \times \frac{p_{\tau,exp}}{P_{t,ref}} \quad (6 - 22)$$

where:

$$\Delta P_t = P_{t,act} - P_{t,ref} \quad (6 - 23)$$

$$\Delta p_\tau = p_{\tau,act} - p_{\tau,exp} \quad (6 - 24)$$

Thus, the fundamental element $\epsilon_{t\tau}$ can be calculated by equation (6-25).

$$\epsilon_{t\tau} = \text{standard } \epsilon_{t\tau} \times \frac{P_{t,ref}}{p_{\tau,exp}} = \frac{P_{t,act} - P_{t,ref}}{p_{\tau,act} - p_{\tau,exp}} \quad (6 - 25)$$

A typical illustration of the electricity price elasticity matrix is shown in the form below. In the matrix, each element represents the elasticity that the demand variation at a time slot t when the electricity price changes at corresponding time interval τ .

$$\begin{pmatrix} \epsilon_{11} & \epsilon_{12} & \epsilon_{13} & \dots & \epsilon_{1\tau} \\ \epsilon_{21} & \epsilon_{22} & \epsilon_{23} & \dots & \epsilon_{2\tau} \\ \epsilon_{31} & \epsilon_{32} & \epsilon_{33} & \dots & \epsilon_{3\tau} \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ \epsilon_{t1} & \epsilon_{t2} & \epsilon_{t3} & \dots & \epsilon_{t\tau} \end{pmatrix}$$

The function of each element in the matrix is based on its corresponding location. The main diagonal elements (when $t=\tau$) represent the self-elasticity, where this type of elasticity indicates the demand variation which is depended on price change at the same time interval. The other elements in the matrix are named as cross-elasticity which are the off-diagonal (where $t \neq \tau$) elements in the matrix. Those elements represent the demand variation at time slot t by the influence of the price change in another time slot τ . It is indicated that the important index T in the electricity price elasticity matrix can be calculated by the formulation (6-26). Moreover, both t and τ in the matrix vary in their value within T .

$$T = t = \tau = \frac{24}{\text{Interval}} \quad (6 - 26)$$

Due to the increase of electricity price at time slot t will result in a confirmed demand decrease at its time interval, the value of on-diagonal units in the electricity price elasticity matrix must be negative or zero (inelasticity model). By contrast, the value of off-diagonal elements must be positive or zero since the price growth in time slot τ will lead a confirmed increased demand at interval t [241]. It is assumed that the proposed EPEM are operated in a lossless feature to ensure the total energy usage of each customer maintains in the same amount. More specific, a lossless shifting of any interval's scheduled consumption happens when customers curtail some of their consumption at that interval but redistribute the exact amount of such curtailed

consumption over all or some other intervals. If the overall consumption throughout the day is to stay lossless (i.e., EPEM is lossless), the previous statement should hold for all intervals throughout the day describe the mathematical condition for a lossless EPEM as equation (6-27).

$$\sum_{\tau=1}^T \text{standard } \epsilon_{t\tau} = 0 \quad \forall t \quad (6 - 27)$$

Thus, the demand response of each customer at every time slot can be calculated by EPEM with the different value between customers' expected price and the price signal that provided by DNOs. Each row in the electricity price elasticity matrix indicates the variation of power demand at a selected time slot t based on the change of the price at the same time slot t or any other time slot τ . Each value of elasticity in the row is required to multiply the differential between current price signal and the expected price to calculate the modified power demand [242]. In the proposed framework, it is assumed that the customer's expected electricity price is affected by the real-time wholesale price via a sensitive factor θ , where this factor can be experimentally calculated by the historical data of the electricity retailer price and the wholesale price. Therefore, the customers' demand response (denoted as the shifted demand at time slot t : P_{sd}^t) can be carried out by the equation (6-28) to (6-31).

$$[\Delta P] = [EPEM][\Delta p] \quad (6 - 28)$$

$$\Delta p = PS_t - \theta \cdot WP_t \quad (6 - 29)$$

$$\Delta P = P_{sd}^t - P_{act}^t \quad (6 - 30)$$

$$[P_{sd}^t] = [EPEM][PS_t - \theta \cdot WP_t] + [P_{act}^t] \quad (6 - 31)$$

6.6 Numerical results

In this section, the numerical results are presented to verify the proposed dynamic pricing framework on the IEEE 6 bus test system. The operating voltage of this distribution network is arranged as 11KV, and the full power load is 6000 kW with an average power factor of 0.9. Three loads which are rated at 2000kW are located at bus2, bus5 and bus6 respectively. The detailed power flow and branch data of IEEE-

6 bus network are given in Appendix D.1 and Appendix D.2. It is assumed that the load demand and generation buses are considered to be separate. Thus, the simulation results of load demand and the usage of transmission facilities are all positive number.

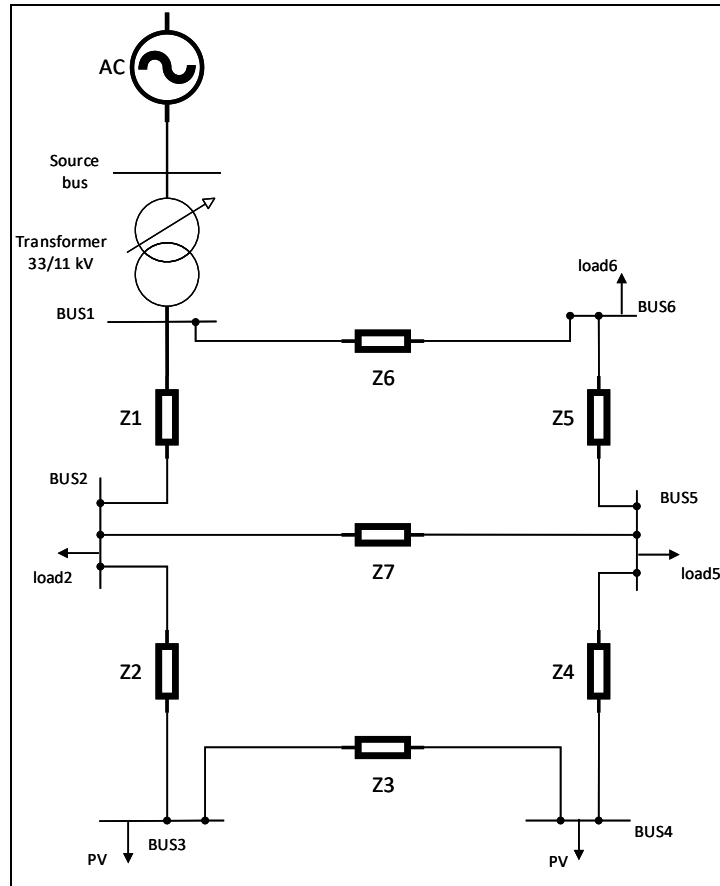


Figure 6-6 Proposed IEEE 6 bus test network

In the proposed framework, the actual demand data of consumers is applied in the simulation process to ensure the high accuracy and precision of the numerical results. To reflect the real electricity demand in the UK, data from National Grid has been employed to represent the normal daily demand curve. Data on January 1, January 2 and January 3 in 2017 from National Grid is applied and has been rescheduled to the expected time resolution. Figure 6-7 shows the demand curve based on each load in the test network. Since the proposed transmission cost allocation approach requires the detailed power flow analysis results, the Newton-Raphson method is applied here for obtaining the required data. After the power flow analysis, the result of the usage rate of each transmission line in the 24 hours' time slot is illustrated in Figure

6-8. Then, the transmission cost can be carried out by its corresponding real-time usage rate via equation (6-12). It is assumed that the capacity of transmission lines in the test system equal to 2000kW. There is no specific data to provide an exact and precise number about the cost of transmission network investment. However, based on the experiential data, the value of the assets is assumed as £2,000,000. Meanwhile, the discount rate is assumed as 6.9% per annual and the expected lifespan of the transmission line is assumed as 35 years. After applying the index to the formulation (12), the transmission cost at each load point can be obtained by the corresponding usage rate and shows in Figure 6-9.

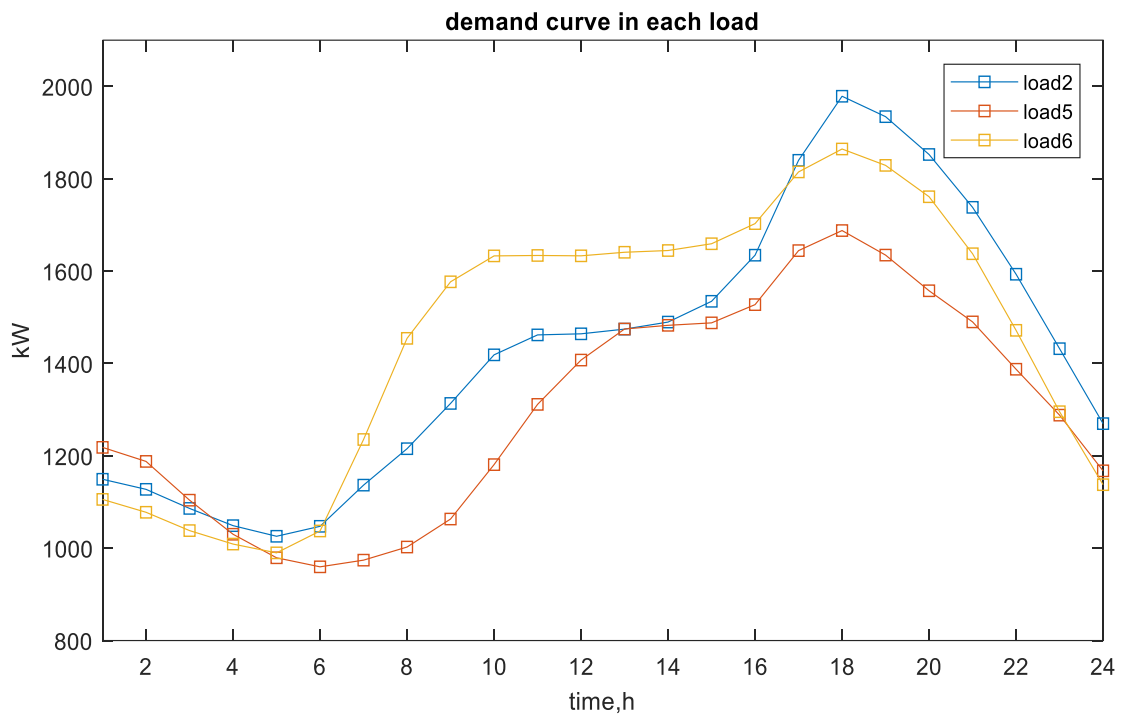


Figure 6-7 Demand curve in each load

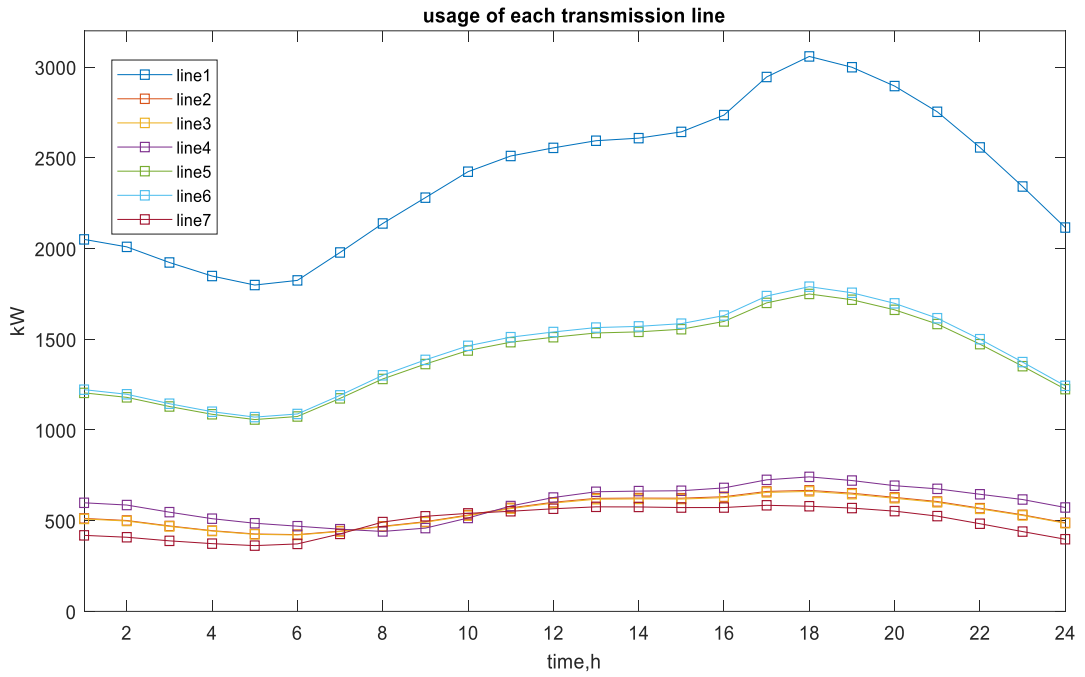


Figure 6-8 Transmission usage in each line

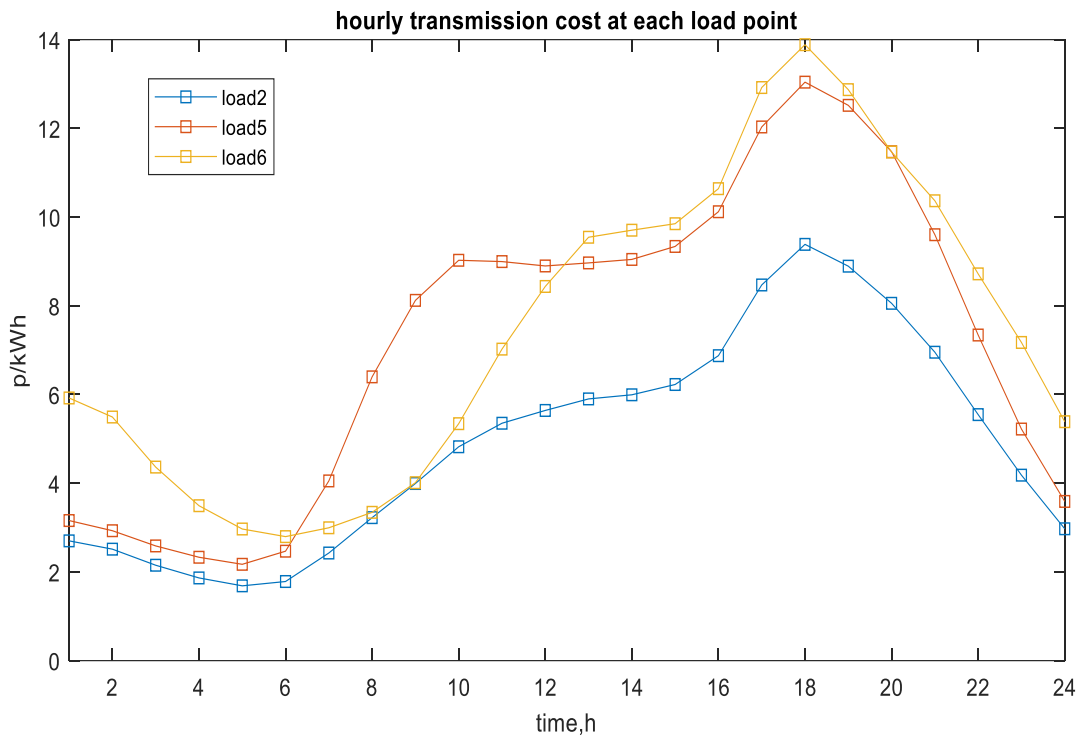


Figure 6-9 Hourly transmission cost at each load point

So far, we have obtained the result of cost at each transmission line. Therefore, the final electricity price signal can be carried out by equation (6-18) by the participation

of real wholesale price (shown in Figure 6-10) and the proposed transmission cost allocation. Based on equation (6-29), to carry out the shifted demand of consumers at different load point, the customer's expected price should be obtained. In equation (6-29), the expected electricity price can be carried out by the real-time wholesale price via a sensitive factor θ , where this factor equals to 0.4 which is calculated by the historical data of the electricity retailer price and the wholesale price. Now, the final price signal that DNO provides to the consumers at each load point and users' expected electricity price can be obtained and illustrated in Figure 6-10.

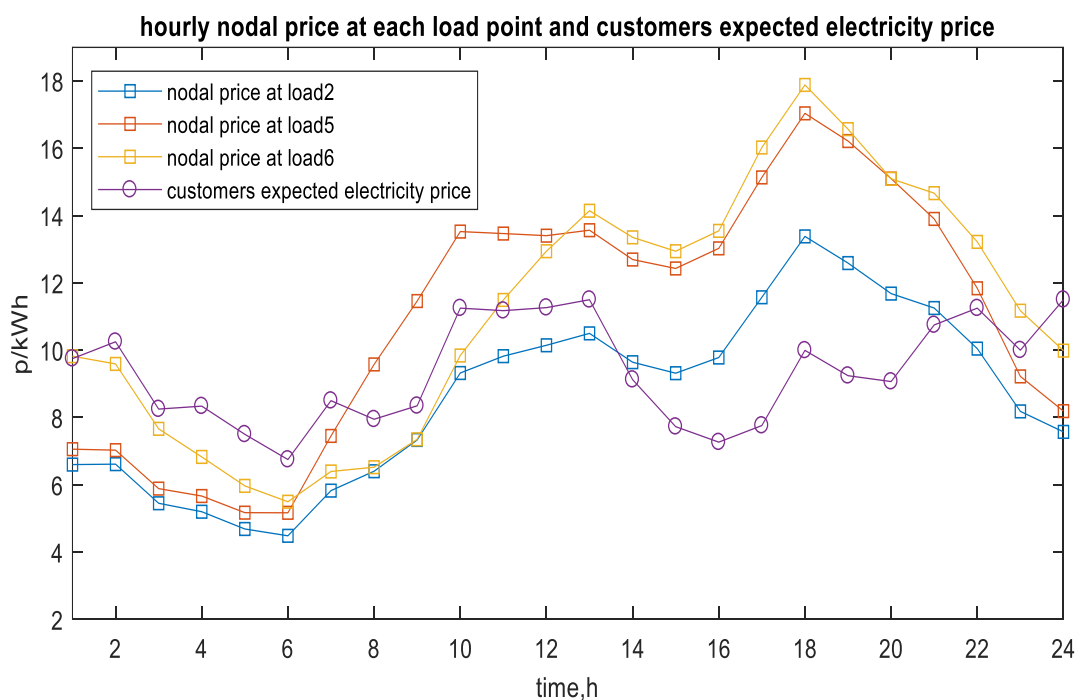


Figure 6-10 Hourly nodal price at each load point and customers expected price

The customer's response to the provided price signal is another important study in this paper, where the response can be carried out by previous numerical result via equation (6-28).

Firstly, we need to prepare the electricity price elasticity matrix which is required to simulate the demand response. In the proposed framework, the value of main diagonal elements in the matrix is assumed as -0.2 and the value of off-diagonal elements in the matrix are assumed as 0.033. The electricity price elasticity matrix

applied in the framework is considered as a lossless matrix since the total energy requirement of customers is expected to maintain in the same amount.

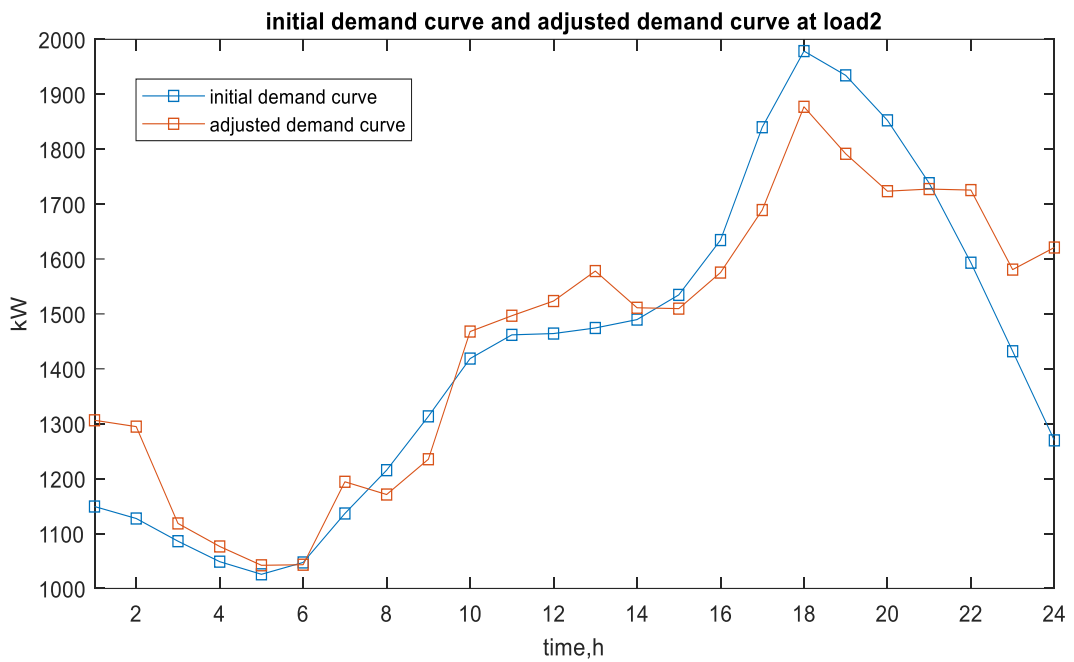


Fig. 6. Initial demand curve and adjusted demand curve at load 2

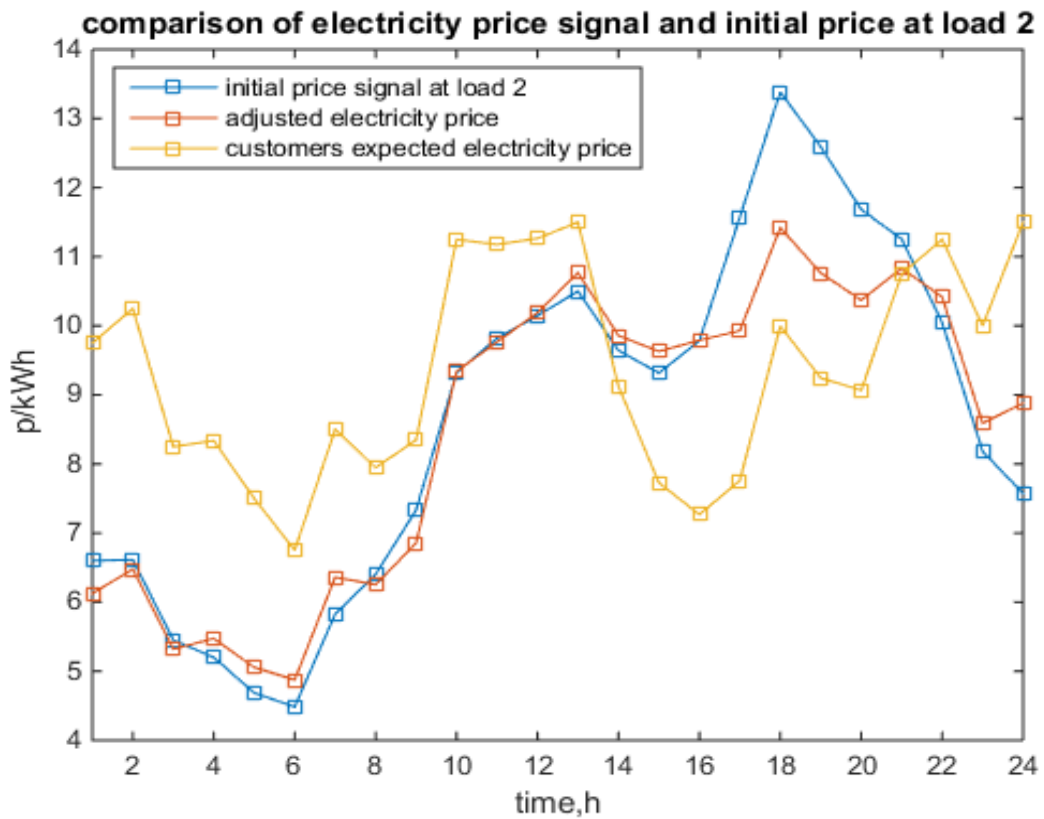


Fig. 7. Comparison of electricity price signal and initial price at load 2

The following numerical results indicate that the proposed dynamic price signal can successfully curtail the load demand in the peak period. In the demand side, the economic benefits are obtained by the customers who participate in the load reshape process. Figure 6-11 shows the adjusted demand curve and the initial demand curve at load 2. It is indicated that the peak load (around 6 pm) experiences a significant decrease due to the corresponding high electricity price. Due to the lossless characteristic of the electricity price elasticity matrix, the decreased demand will rebound to other off-peak time periods such as 1 pm and 0 am to maintain the total daily energy requirement. Meanwhile, the adjusted electricity price which is illustrated in Fig.7 has significantly decreased in several peak load periods such as 17:00 to 20:00(drops 1.645p/kWh, 1.964 p/kWh, 1.827 p/kWh and 1.311 p/kWh respectively).

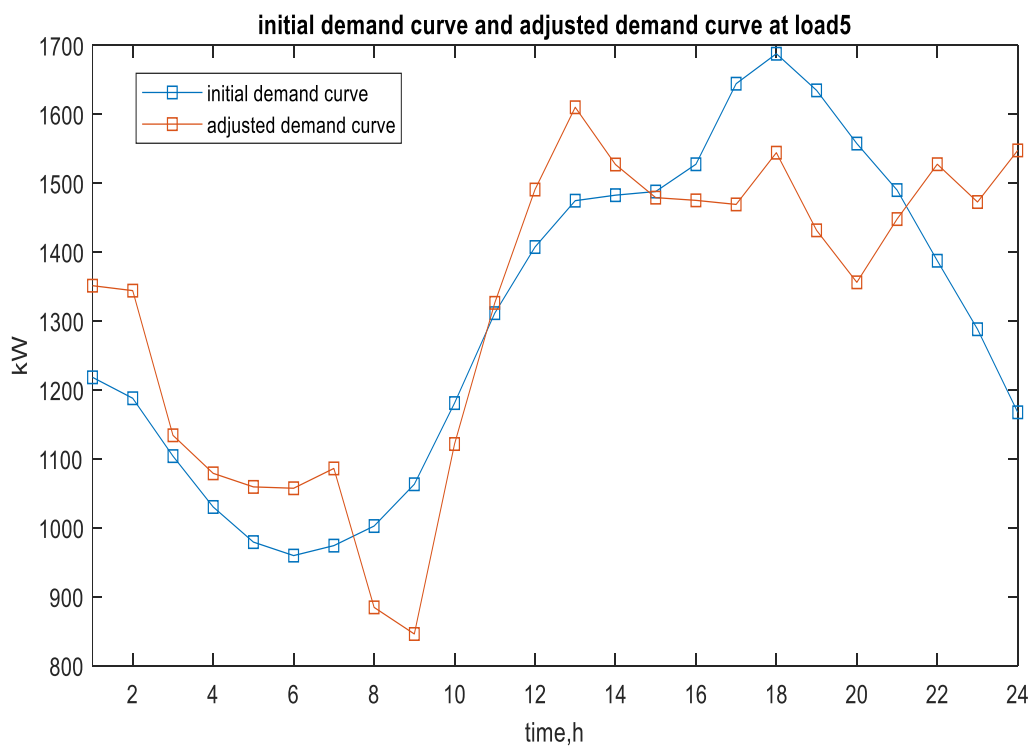


Figure 6-11 Initial demand curve and adjusted demand curve at load 5

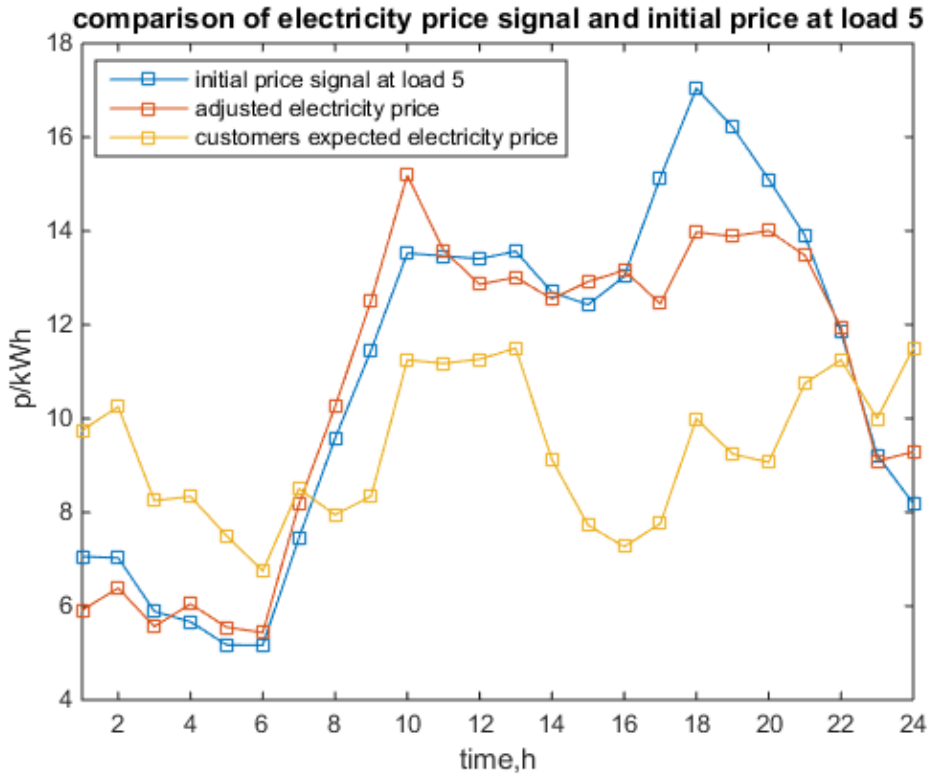


Figure 6-12 Comparison of electricity price signal and initial price at load 5

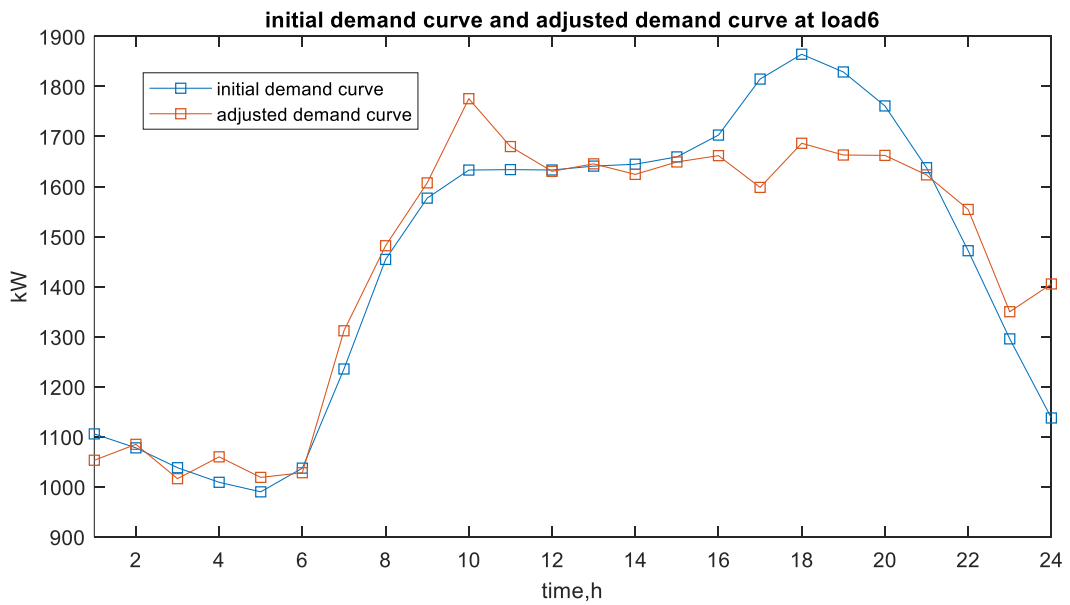


Figure 6-13 Initial demand curve and adjusted demand curve at load 6

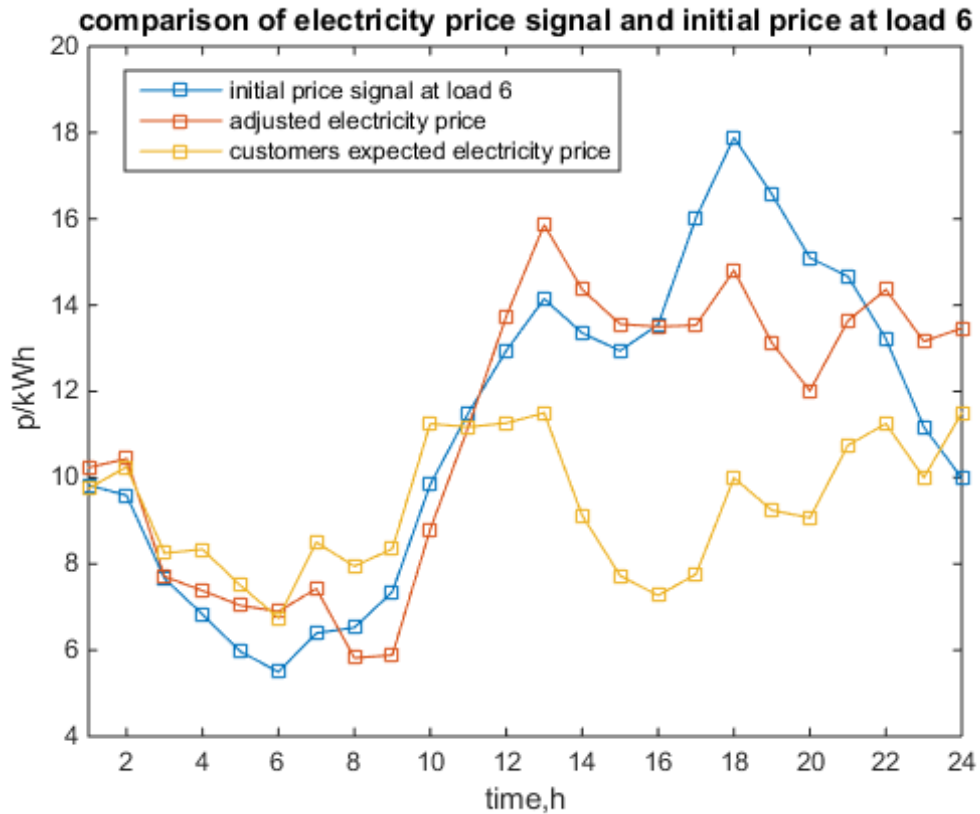


Figure 6-14 Comparison of electricity price signal and initial price at load 6

Like the numerical result in load point 2, Figure 6-12 shows the adjusted demand curve and the initial demand curve at load point 5. The adjusted electricity price which is illustrated in Figure 6-13 has significantly decreased in several peak load periods such as 17:00 to 20:00 (drops 2.684p/kWh, 3.069 p/kWh, 2.331 p/kWh and 1.097 p/kWh respectively). Meanwhile, Figure 6-14 shows the adjusted demand curve and the initial demand curve at load point 6. The adjusted electricity price which is illustrated in Figure 6-15 has significantly decreased in several peak load periods such as 17:00 to 20:00 (drops 2.490/kWh, 3.078 p/kWh, 3.456 p/kWh and 3.079 p/kWh respectively).

6.7 Chapter summary

In this chapter, an innovative dynamic-pricing framework is introduced to find out the optimum price signal at each time slot with the global consideration of wholesale market, benefits of power suppliers and customers' behaviours. Specifically, the definition of different time-vary pricing mechanisms is introduced in section 6.2 to indicate the motivation of the study in this chapter. In the next part, the typical

frameworks of time-varying pricing approach that widely applied in the current electricity market are introduced in section 6.3. The electricity pricing elasticity matrix is introduced in section 6.4 to simulate customers response to the pricing signals by applying the mathematic approach. The methodology and formulation that used to develop the proposed day-ahead pricing mechanism are indicated in section 6.5. Then, the numerical results extracted from the case study are presented in section 6.6 to verify the efficiency and feasibility of the proposed framework.

Specifically, an innovated use of system charge allocation approach is designed to support the proposed dynamic pricing framework. The approach persuades the efficient usage of the transmission network and postpones the further investment of transmission facilities, thus improving the performance of the operation in distribution systems. The approach is expected to consider the electricity users' contributions of actual usage in each transmission facilities. The appropriate price signal reflects the usage of the transmission system can be achieved by the contributions of two independent pricing mechanisms: 1) cost allocation mechanism supported by power sensitivity analysis; 2) incremental transmission cost mechanism based on the asset of each transmission facility. On the other hand, the user's response to the provided price signal is a matter of considerable concern since it significantly affects the performance of each dynamic pricing framework. In the proposed modelling, the electricity price elasticity matrix (EPEM) is intended to capture the system-level impact of demand response, rather than local effects on a single consumer. The value of elasticity in the matrix can be adjusted to simulate different kinds of energy consumers' response behaviours. In the end, the numerical results successfully verify the proposed dynamic price framework has the capability to rearrange the daily load shape by providing the appropriate price signal to their customers. The numerical results also indicate that the electricity price signal obtained in the paper satisfies the real electricity price (around 0.12GBP/kWh) in current UK market.

Chapter 7

Investigation of the potential conflict between day-ahead distribution network use of system charges and renewable energy production

7.1 Introduction

In the light of the introduction in chapter 3, the traditional electricity retail market is criticized for its low efficiency of demand-side management, especially in improving the penetration of renewable resources and encouraging customers to change their electricity usage behaviour. The primary role of power suppliers in the UK is bridging the gap between the end customers and wholesale electricity markets. More specifically, suppliers purchase power in the wholesale electricity market with variable prices and selling it to their customers at a relatively fixed price [243]. In the UK electricity retail market, power suppliers usually provide their customers with fixed tariffs one or two years in advance. With the consideration of the electricity procurement price in the wholesale market and volatile power demand, the electricity bills of some customers who consume energy during the off-peak period could be significantly higher than the actual procurement price [244]. It is evident

that electricity bill minimization can not only encourage power suppliers to attract more potential customers in the competitive market, but also improve the trade efficiency of the retail electricity market. Many reports have already indicated sustainable power generation costs are already very competitive and fall into the price range of current fossil fuels generation technologies [245]. The European Council has launched the EU's 2030 projects for reducing the production of greenhouse gases and increasing the penetration of sustainable resources in total energy production. In the UK electricity market, an ambitious environment target also has been initiated to achieve its 2020 renewable energy supply projections through several renewable obligation policies [246]. On the other hand, the development of information technologies triggers the wide application of controllable appliances at the electricity end-user level [24].

However, electricity customers specifically household users are required to pay the fixed price for a single unit of the electricity service regardless of the time of the day or the seasons when they consume the energy. Indeed, several countries have prepared to launch the simple time-varying electricity pricing mechanism in their electricity market. But, the most popular electricity charging models in the market can be generally concluded as two fixed or three fixed-price framework. For instance, the electricity price for a certain customer can be divided by the peak periods rate and off-peak periods rate. The increasing of the peak demand can be decelerated by this variable electricity rates, thus deferring the investment of the new generators and the investment on the network capacity upgrading. It is noted that simple variable electricity rates can be regarded as an efficient approach to affect the customer's behaviours and achieve an optimum network operation condition when majority electricity consumed in the network is generated by the conventional fossil fuel generators. Due to the environment concerns and the economic incentive from the government policies, renewable energy resources (particular small-scale distributed generations) experience a significant increase in the last decade. The feature characteristic of the renewable energies is difficult to dispatch and predict the output, thus cannot response the varying demand. On the other hand, full capacity generation periods of wind farms or photovoltaics cannot be guaranteed to

match the peak demand of the electricity customers. Under this circumstance, the pre-designed electricity price (such as fixed two rates or three rates) structure cannot fully reflect the real-time relationship between the electricity demand and the generation, particularly from the renewable resources. Therefore, real-time pricing mechanisms are designed and planning for providing the fluctuating and dynamic electricity pricing to the customers, thus achieving a more economic electricity market and efficient operation of power systems. The detailed introduction of a different kind of varying-time pricing mechanism including real-time pricing has been presented in section 6.1 of Chapter 6.

In Chapter 6, the customer response to the day-ahead dynamic pricing scheme is investigated when considering the thermal limitation of the conductors in the distribution networks. In particular, the thermal limitation in chapter 6 is transferred and presented as the dynamic transmission or distribution network usage charges. For example, the high usage of electricity delivering facilities during a certain period incur the relatively high use of system charges at the same time. But, these charges are assessed by each independent transmission or distribution lines. Thus, they are still required to be allocated to each final customer appropriately. To explore the variation of real power flows based on the change of power injection in a specific node, it is important to conduct the sensitivity analysis in power system. Therefore, power transfer distribution factors (PTDFs) is employed in the chapter 6 to apply the power tracing approach in the transmission cost allocation process.

However, the use of system charges is assessed by the expected day ahead customer demand and customer response to the provided price signal is assessed by the fixed electricity price elasticity. Thus, the final trading electricity pricing cannot guarantee system level optimization. In this chapter, a new day-ahead pricing approach is introduced to the optimal design of a day-ahead pricing mechanism for managing distribution network congestion caused by renewable generation. The proposed framework of the day-ahead pricing is designed to minimize customer electricity bills taking account of line thermal constraints resulting from increased penetration of renewable generation. It is assumed that each user is equipped with controllable appliances and a smart meter enabling two-way communications between suppliers

and their customers. Suppliers employ an hourly demand-side management strategy which considers the price signal from distribution network operators (DNOs), distributed generations (DGs) and wholesale market. A weighted average DUoS charge approach is applied in this framework, allowing DNOs to send a cost reflective use of system charge to electricity users in different locations based on their hourly predicted day-ahead power consumption. An optimum day-ahead pricing mechanism has been developed for DGs to manage their renewable resources to achieve revenue reconciliation and maximize generation output. Finally, power suppliers can optimally manage the controllable appliances installed in each end user and balance the energy consumption from the main grid and DGs to minimize the electricity price. Several case studies have been conducted with a modified IEEE-33 bus distribution network, where a large-scale nonlinear optimization programming algorithm is applied to solve the problem.

The remainder of this chapter is organized as follow: Section 7.2 introduces the current challenges for day ahead electricity pricing mechanism and highlight the targets and objectives of the proposed framework. Then, a framework developed for the proposed day-ahead pricing mechanism is presented in 7.3. And, section 7.4 illustrates the numeric results of the proposed day-ahead pricing mechanism. In the end, section 7.5 summaries the chapter.

7.2 Current challenges for the day ahead electricity pricing mechanism

In the current electricity market, different incentive-based demand response frameworks are considered as the popular approaches to achieve the target of peak load reduction and increasing the load factor of renewable resources. These frameworks rely on day-ahead pricing scheme which includes for example time of use pricing (ToU), critical peak time pricing (CPP), real-time pricing (RTP). However, those schemes are classified as active demand management method that has failed to meet the new challenges of the increasing application of sustainable energies and customers' satisfaction [17, 57, 247]. In response to the technology gap, a wide range of literature is dedicated to the implementation of the novel day-ahead tariffs or

dynamic pricing scheme to accomplish the target of customer participating in demand-side management and improve the economic performance of the power system. In [24], the trading relationship between customer surplus and supplier revenue is considered in day-ahead hourly pricing. The proposed mechanism allows the suppliers to achieve global optimization of their benefits and relieve the effects of incorporated sustainable variable output sources. A short-term planning framework was introduced in [248] to provide the optimum bidding strategies for maximizing the benefits of electricity suppliers. In [249] a two-stage based robust optimization method to determine the optimum bidding strategy for power suppliers is proposed. An economic bidding optimization strategy was also addressed in [250] to achieve the optimum price signal in both day-ahead and real-time markets. Many authors [23, 24, 248-250] all focused on the optimum electricity price optimization in the day ahead or intraday market. The effect of different renewable sources and the application of demand deferral or controllable appliances are also included in these publications. However, they only considered the economic performance in a simplified power system and electricity market model. Transmission and distribution network constraints (e.g. thermal constraints and voltage constraints) and procurement cost are also expected to be considered in the current deregulated and complex electricity market. In contrast, a pool-based day ahead pricing mechanism aims to maximise social welfare as reported in [251]. Power flow constraints and security constraints are considered in this mechanism, thus the assumption in the paper is close to the practical situations of real power systems. In [63], the author focused on the day-ahead electricity clearing market in distribution networks level since the increasing installation of distributed generations. A distribution locational marginal pricing (DLMP) was designed in this paper to encourage renewable resources to participate in the congestion management by the system Volt/VAR control. Comprehensive research and numerical analysis of the day-ahead market clearing problem was solved by a two-paper series [252] and [26]. Both producer revenues and network constraint were considered in a practical day-ahead auction model established in these papers. IEEE-118 bus and IEEE-300 bus system were applied to prove the proposed approach can operate in relatively large networks. In [253], a congestion fund that is received from the electricity customers and used to

compensate for the basic financial transmission right. Similar to [253], a distribution congestion price (DCP) was built in [254] to reflect the real congestion cost and affect the demand response program in the power networks. Many previous works on the day-ahead pricing optimization problem have considered the effect of renewable energy resources (e.g. wind generation and solar energy), demand responses and network constraints through various mathematical algorithms (e.g. robust optimization approach, mixed-integer nonlinear bilevel program and mixed-integer linear programming). However, few papers consider the distribution network use of system charges as a price signal in the day ahead-market, thus failing to establish a trade-off between the DUoS charge and the energy procurement costs. In addition, the network operation and management costs account for approximately 40% of the retail prices in the current UK electricity market [158]. Therefore, distribution network operators are encouraged to participate in the electricity trading market through a day-ahead network use pricing approach.

Thus, an innovated day-ahead pricing mechanism is presented in this chapter to deal with the mentioned challenges for the day-ahead pricing strategy. The proposed mechanism considers the distribution network use of system (DUoS) charges as a price signal in the day ahead-market, thus establishing a trade-off between the DUoS charges and the energy procurement costs. The proposed concept of day-ahead pricing is designed to minimize customer electricity bills taking account of line thermal constraints resulting from increased penetration of renewable generation.

In particular, the main objectives and aims of this chapter are summarised as follows:

- 1) A novel usage-based charging mechanism which is designed to account for the day-ahead DUoS charges at each node in the distribution networks is proposed. The approach recognizes the detailed distribution facilities usage information at each node to establish an economically efficient DUoS charge allocation.

- 2) A day-ahead pricing mechanism for the small size distributed generations is introduced. In the UK, policies such as renewable obligation (RO) and non-competitive contracts of differences (CfDs) protect the economic benefits of low carbon electricity generators by determining the strike prices [158]. However, it is

noticed that the strike price of renewable generations is still higher than the wholesale price in most of the trading period. In response to this problem, a day-ahead charge model for pricing the output of distributed renewable generations is introduced. The proposed model is designed to provide the competitive day-ahead price signal in the market, thus not only encouraging the suppliers to voluntarily consume more renewable energy but also ensuring their revenue can cover the investment and operation cost of DGs.

3) It is proposed, for the first time, to consider both feeder thermal constraints and renewable generation as the economic variable factors in the optimization programming by the proposed models which are mentioned in 1) and 2). On the other hand, the electricity usage of all the end-users will be attributed as the generic aggregated domestic load profiles to simplify the simulation.

7.3 Framework developed for the proposed day-ahead pricing mechanism

In the future power system, it is expected that many DGs will be installed in the distribution networks. IRENA reported that the renewable power generation would fall into the price range of current fossil fuel concentrated generations by 2020. Therefore, we can expect that the suppliers voluntarily consume more renewable energy when renewable energy becomes cheaper than fossil fuels in the electricity market. However, the generation of renewable resources is naturally non-shifted due to their special characteristics.

It is difficult to entirely allocate all available capacity of renewable resources in the distribution networks to match the predicted load profiles. The relatively low capacity factor (around 30% in the UK) operation status of DGs results in high procurement cost of renewable resources since the requirement of investment recovery [255]. In this paper, we introduce a novel day-ahead pricing mechanism to consider the benefits of four major participants in the electricity market including the wholesale market, distributed generations, distribution network operators and aggregated demand response of the domestic customers. In the framework, the potential problem of network congestion and distributed generation pricing strategy

are both formulated mathematically. The detailed framework of the proposed mechanism is shown in Figure 7-1. The load profiles and wind speed are extracted from UK historical data taking account of uncertainty and all the data are prepared in the data input module. The proposed day-ahead pricing is formulated within a constrained DC power flow framework. Even though the formulation of DC power flow analysis is linear, both the DUoS charges and renewable energy procurement cost are formulated by nonlinear expressions in this paper. Therefore, nonlinear optimization programming is applied in the framework to achieve the minimized total cost of the combination of DUoS charge and energy procurement costs.

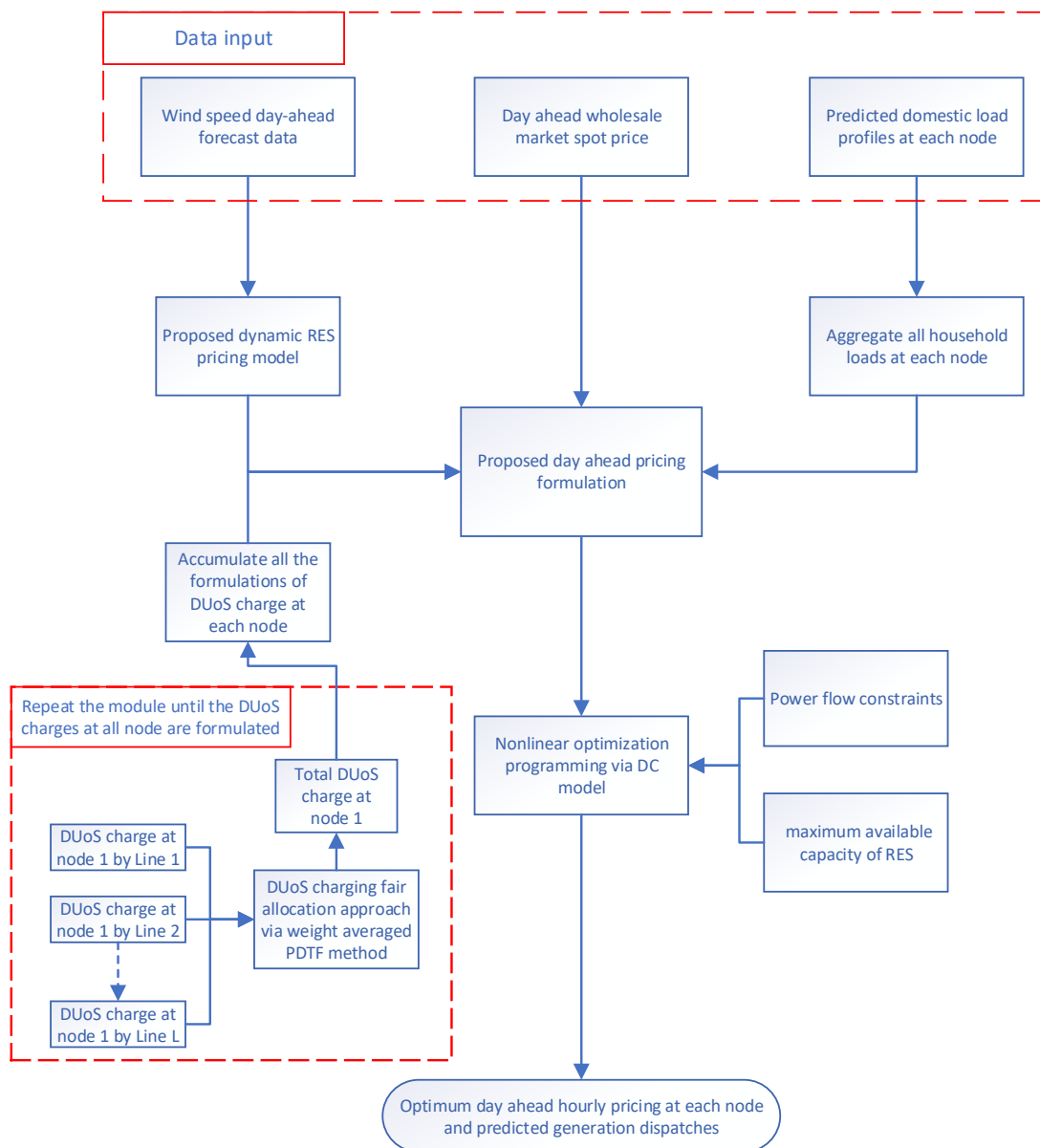


Figure 7-1 Framework for the proposed day-ahead pricing mechanism

Based on the proposed day-ahead DGs pricing mechanism, the low unit procurement cost of power generation from renewable energy sources is achieved when a large amount of the available capacity can be consumed. In response to this situation, we assume that part of the domestic loads such as electric vehicle charging, wash machines and air conditioners are combined as aggregated controllable demand. This allows the suppliers to automatically and optimally reschedule part of the customers' daily load to match the predicated renewable generation, thus achieving the target of energy procurement cost minimization. To do so, the concept of Levelized Cost of Electricity (LOCE) is employed in the mathematical formulation of the problem [256]. We assume that a generation asset requires the total investment expenditures of I_0 , where it is designed to functionally operate with T^l years. The main components of investment expenditures are pre-development cost c^p , construction cost c^t and infrastructure cost c^i , where all three components are described in unit £/kW to adopt the generation asset with different capacity cp . In the operation year $t \in T^l$, the total annual operation and management cost is expressed as A^t . And $M_{t,lf}$ represents the produced quantity of electricity in the respective year t in kWh with an average load factor lf^t . Then, the function of I_0 , $M_{t,lf}$ and LOCE can be expressed as show in equation (7-1) to (7-3).

$$I_0 = (the\ c^p + c^t) \times cp + c^i \quad (7 - 1)$$

$$M_{t,lf} = lf^t \times cp \quad (7 - 2)$$

$$LOCE = \frac{I_0 + \sum_{t=1}^n \frac{A_t}{(1+d)^t}}{\sum_{t=1}^n \frac{M_{t,lf}}{(1+d)^t}} \quad (7 - 3)$$

It is indicated in (3) that, for a given generation facility g , the real-time price of this renewable generator $LCOE_g$ has a linear relationship with the corresponding usage rate ur_g which is the ratio of real-time generation to its maximum capacity. This relationship is summarised as equation (7-4) for the reason of simplified expression and capacity factor are expressed by (7-5).

$$LCOE_g = f_{LCOE}(ur_g) \quad (7-4)$$

$$ur_g(\%) = \left(\frac{p_g}{CP_g} \right) \times 100\% \quad (7-5)$$

The detailed DUoS charges, for the first time, are considered as the economic variables affecting the mechanism of the optimum day-ahead electricity pricing. Firstly, the day-ahead DUoS charging approach which is based on the principle of the incremental transmission pricing model is introduced [61, 62, 237, 238]. The investment cost IC and the use of system charge are linked by the present value PV of the certain assets by two economic participants: lifespan of the project Y and discount rate d . It is assumed that, for a given load growth rate r , the usage of a certain distribution facility l is D and the usage rate will reach its maximum capacity C by the period Y_l . Then we will have the equation (7-6) to represent the relationship between them.

$$C_l = D_l \times (1 + r)^{Y_l} \quad (7-6)$$

Since the capacity of the distribution line and the power flow at a given time are both provided in the scenario, we transfer the formulation to equation (7-7) for future analysis.

$$Y_l = \frac{\log C_l - \log D_l}{\log(1 + r)} \quad (7-7)$$

The day-ahead DUoS charge is formulated by the variation of the present value of the distribution line l . We assume the benchmark value of current power flow is $D_{l,B}$, maximum thermal capacity of line l is C_l and investment cost of line l is IC_l . Therefore, the benchmark present value $PV_{l,B}$ of the facility can be addressed by equation (7-8) and (7-9), then leading to (7-10).

$$Y_{l,B} = \frac{\log C_l - \log D_{l,B}}{\log(1 + r)} \quad (7-8)$$

$$PV_{l,B} = \frac{IC_l}{(1 + d)^{Y_{l,B}}} \quad (7-9)$$

$$PV_{l,B} = \frac{IC_l}{(1+d)^{\frac{\log C_l - \log D_{l,B}}{\log(1+r)}}} \quad (7-10)$$

However, the actual present value $PV_{l,A}$ determined by the real-time usage of the distribution system in a certain time slot t is normally different from the benchmark present value $PV_{l,B}$. Like the equation (7-8) to (7-10), the actual usage based present value can be addressed by (7-11).

$$PV_{l,A} = \frac{IC_l}{(1+d)^{\frac{\log C_l - \log D_{l,A}}{\log(1+r)}}} \quad (7-11)$$

Then, the difference between the actual present value $PV_{l,A}$ and benchmark present value $PV_{l,B}$ can be formulated in (7-12) to represents the additional charge that is incurred by the network congestion or unexpected heavy load.

$$\Delta PV_l = PV_{l,A} - PV_{l,B} \quad (7-12)$$

To formulate the proposed day-ahead DUoS charge mechanism, annuity factor and hour factor are considered to covert the ΔPV_l to the hourly day-ahead price signal. Therefore, the hourly distribution use of system charge of the distribution line l at time-slot t can be expressed in the equation (7-13). We introduce $UR_l^t(\%)$ in the equation (7-14) to represent the ratio of real-time (t) usage of distribution line l to its maximum capacity cp_l . Apparently, the $DUoS_l^t$ will be only affected by the variation of the usage rate of the chosen distribution line. Therefore, we summarize the mathematical relationship between the day-ahead DUoS charge and its related usage rate by (7-15).

$$\begin{aligned} DUoS_l^t &= \Delta PV_l \times annuity_{factor} \times hour_{factor} \\ &= IC_l \times \left(\frac{1}{(1+d)^{\frac{\log C_l - \log D_{l,A}}{\log(1+r)}}} - \frac{1}{(1+d)^{\frac{\log C_l - \log D_{l,B}}{\log(1+r)}}} \right) \\ &\quad \times annuity_{factor} \times hour_{factor} \end{aligned} \quad (7-13)$$

$$UR_i^t(\%) = (D_{l,A}/cp_l) \times 100\% \quad (7 - 14)$$

$$DUoS_i^t = f_{DUoS}(UR_i^t) \quad (7 - 15)$$

$$annuity_{factor} = \frac{(1 - (1 + d)^{-Y_{l,B}})}{d} \quad (7 - 16)$$

where annuity factor can be calculated by the corresponding data by (7-16). Since the benchmark time slot in this paper is suggested as one hour, the annuitized DUoS charge will be reduced to the hourly value through multiplying it by hourly factor. The proposed day-ahead DUoS charge approach can provide an accurate price signal by the real-time power flow in the distribution lines and ensure the corresponding charge can fairly cover the investment cost. However, each distribution line in the power system will provide its unique price signal determined by its real-time usage rate. And, each aggregated load point only needs to pay the DUoS charges for the distribution lines that are used to deliver energies. Therefore, each price signal of the DUoS charge is only allocated to the related load points for cost-reflective pricing. The power flow tracing algorithm (PFT) and power transfer distribution factors (PTDFs) are employed to achieve the proposed fair DUoS charge allocation approach. PTDFs provide the sensitivity of the active power flow through line l with respect to an additional power injection in node i and withdrawal at node j , where the definition of PTDFs is shown in (7-17).

$$PTDF_{i-j}^l = \frac{\Delta P_{i,j}^l}{\Delta P_{i,j}} \quad (7 - 17)$$

In (17), $\Delta P_{i,j}^l$ represents the change in power flow through line l due to the power transaction between node i and j and $\Delta P_{i,j}$ represents power transaction between node i and j . Therefore, the power flow of a chosen distribution line k can be expressed by (7-18) through the PTF and PTDFs respectively.

$$L_k = \sum_g^G \sum_n^N PTDF_{g-n}^k \times (P_g - D_n) \quad (7-18)$$

where P_g represents the power generation from the main grid or DGs and D_n represents the demand in node n .

$$DUoS_n^t = \sum_t^T \sum_n^N f_{DUoS} \left(\frac{PTDF_{g-n}^l \times (P_g - D_n)}{\sum_g^G \sum_l^L PTDF_{g-n}^k \times (P_g - D_n)} \right) \quad (7-19)$$

The objective of this work is to minimize the global electricity bills of all customers. Therefore, the target of the power suppliers is to minimize the total energy procurement cost and distribution network use of system charge. The objective function is expressed in (7-20).

$$\text{Minimize } TC = \sum_{t=1}^T [(P_{wg}^t \times c_{wg}^t) + \sum_{rg}^{RG} (P_{rg}^t \times p_{rg}^t) + \sum_{n=1}^N DUoS_n^t] \quad (7-20)$$

In (7-20), P_{wg}^t represents the amount of energy purchased from the wholesale market with the corresponding price c_{wg}^t and P_{rg}^t represents the amount of energy purchased from DGs with the corresponding price p_{rg}^t . Then, the (7-13) to (7-20) can be reorganized together and expressed as (21) of the proposed objective.

$$\begin{aligned} \text{Minimize } TC &= \sum_{t=1}^T [(P_{wg}^t \times c_{wg}^t) + \sum_{rg}^{RG} (P_{rg}^t \times p_{rg}^t) + \sum_{n=1}^N DUoS_n^t] \\ &= \sum_{t=1}^T (P_{wg}^t \times c_{wg}^t) \\ &\quad + \sum_g^G \left(P_{rg}^t \times f_{LCOE} \left(\frac{P_{rg}^t}{C P_{rg}^t} \right) \right) \\ &\quad + \sum_{n=1}^N \sum_{t=1}^T \sum_{i=1}^{l_n} f_{DUoS} \left(\frac{PTDF_{wg-i}^l \times (P_{wg}^t - D_n^t)}{\sum_{wg}^{WG} \sum_{l=1}^L PTDF_{wg-i}^k \times (P_{wg}^t - D_n^t)} \right) \\ &\quad + \varepsilon_{rg}^t \frac{PTDF_{rg-i}^l \times (P_{rg}^t - D_n^t)}{\sum_{rg}^{RG} \sum_{l=1}^L PTDF_{rg-i}^k \times (P_{rg}^t - D_n^t)} \end{aligned} \quad (7-22)$$

s. g.

$$\sum_g^G \sum_{n=1}^N PTDF_{g-n}^k \times (P_g - D_n) < Limit_k \quad (7-21a)$$

$$\mu \times D_{n,exp}^t \leq D_n^t \leq D_{n,exp}^t \quad (7-21b)$$

$$P_{rg}^t \leq CP_{rg}^t \quad (7-21c)$$

$$\sum_{t=1}^T D_n^t = \sum_{t=1}^T D_{n,exp}^t \quad (7-21d)$$

$$\sum_{n=1}^N D_n^t = \sum_{wg}^{WG} P_{wg}^t + \sum_{rg}^{RG} P_{rg}^t ; \quad t \in \forall T \quad (7-21e)$$

Since we assume the benchmark power flow direction refers to the main grid, a correction factor ε_{rg}^t is introduced in (7-21) to revise the potential opposite direction issues. In the constraints (7-21b) μ represents the ratio of the aggregated controllable demand to the total predicted load demand.

7.4 Case study

The single line diagram of the IEEE 33-node distribution network shown Figure 7-2 is used in the case study. An 8 MW wind turbine is connected to the distribution network at node 30. The detailed power flow and branch data of IEEE-33 bus distribution system are given in Appendix B.1 and Appendix B.2.

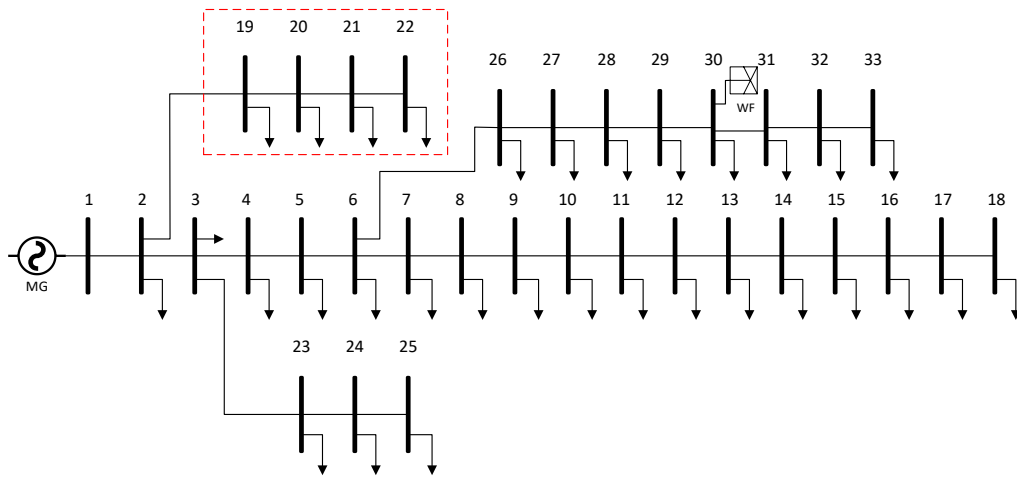


Figure 7-2 Modified IEEE-33 nodes distribution network

We consider two types of domestic customers in the case study to implement sensitive load analysis. The first type of customers is dual bill customers who consume gas to support their heating appliance. The second type customers are electricity bill only, who use electricity for space heating and located in nodes 19 to 22. Both types of customers will have a baseload profile which is suggested by the average electricity usage profiles from the UK [257-259]. The baseload profile is shown in Figure 7-3. The detailed baseload profile is given in Appendix B.3.

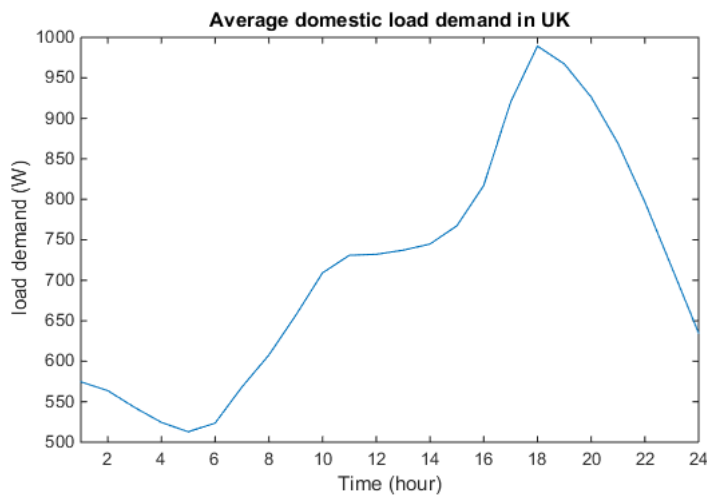


Figure 7-3 Average domestic electricity usage profiles in the UK

A random factor σ is introduced to implement the uncertainty of load profiles and random factor ω , an integer, is used to reflect the energy requirement for heating. The household electricity survey report in also indicates that the electricity usage

fluctuation of different customers is within 40% and the averaged electricity usage for supplement heating requirement by a typical household is within 2.5 kW. Therefore, for a certain customer c , the σ_c is randomly chosen from -0.2 to 0.2 and assigned to corresponding customer c . Like σ_c , ω_c is randomly chosen from 0 to 5 and base heating level hl is assumed as 0.5kW. Mathematical formulation of two types customer are expressed in (7-23) and (7-24).

$$load (type 1) = \sum_{c=1}^c baseload \times (1 + \sigma_c) \quad (7 - 23)$$

$$load (type 2) = \sum_{c=1}^c baseload \times (1 + \sigma_c) + hl \times \omega_c \quad (7 - 24)$$

We assume each node has 1000 domestic customers and each customer has its unique load profiles that can be sequentially produced by (23) and (24). Therefore, the predicted load profile of each node can be accumulated and shown in Figure 7-4. To take account of the investment and related O&M costs in the proposed day-ahead renewable generation pricing mechanism, the data sourced from the UK government is applied to ensure accuracy and precision.

Table 7-1 Investment and O&M cost list of the wind turbine

Investment and O&M cost list of wind turbine	
Maximum capacity	5 MW
Infrastructure cost	£ 3,300,000.00
Unit pre-development cost	£ 190.00/kW
Unit construction cost	£ 1500.00/kW
Fixed O&M cost	£232,000.00/MW/year
Variable O&M cost	£ 5.00/MW/year
Discount rate	10%
Expected operation year	24 years

The department for business, energy & industrial Strategy (BEIS) published the electricity generation costs reported and divided the levelized cost of generation into different kinds of renewable resources. And each resource has three potential installation cost levels. The data referred to in this paper is for onshore wind farm model with the medium installation cost level. The detailed numbers are shown in Table 7-1.

The proposed function $f_{LCOE}(ur_g)$ can be obtained by inserting detailed economic data of the wind turbine that is described above into (1) to (5). The relationship between the real-time usage rate of the wind turbine and the corresponding price signal is shown in Figure 7-5.

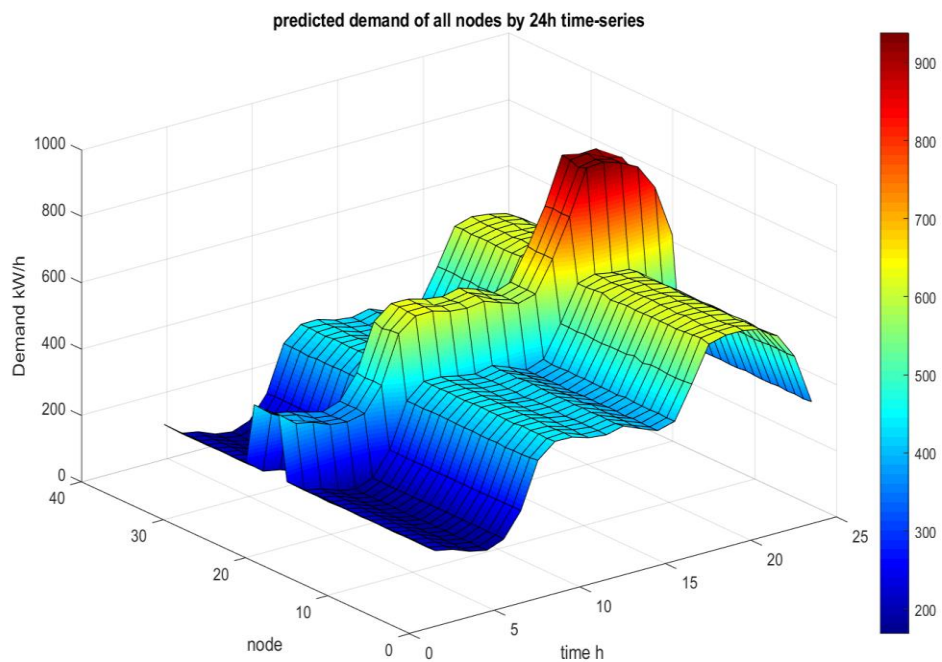


Figure 7-4 Predicted load profiles

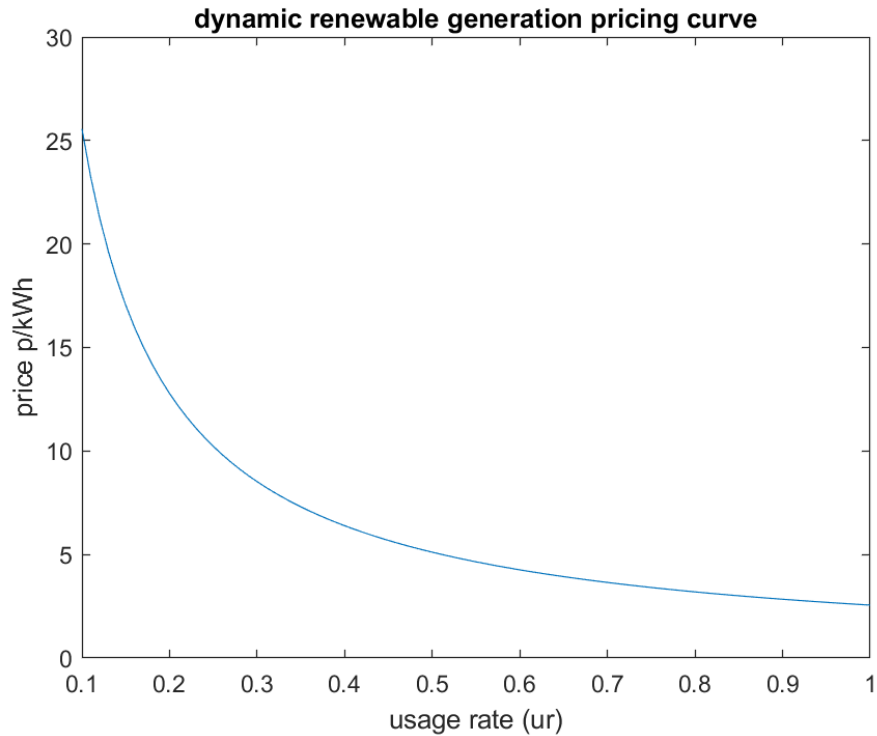


Figure 7-5 The relationship between unit generation price and real-time usage rate of the wind turbine

Non-linear optimization programming is applied to process the proposed simulation in MATLAB. Two different scenarios are considered in the simulation: 1) neglecting the network constraints and the DUoS charge in the day-ahead electricity market and 2) considering the proposed day-ahead DUoS charge in the day-ahead electricity market. The first scenario can provide information of the potential network congestion problems since network constraints and day-ahead DUoS are neglected in this case. However, in scenario 2, both factors are considered to prove high price signal of DUoS produced by the proposed mechanism to relieve and manage the congestion issues in scenario 1.

7.4.1 Case study 1 (neglecting network constraints)

In this scenario, the system performance neglecting network constraints is investigated. Figure 7-6 indicates that the peak demand which occurs between 18:00 and 22:00 is successfully shifted to the off-peak period. Due to the low wholesale price and low base load during the period from 2:00 to 6:00, the shifted loads are concentrated in this period.

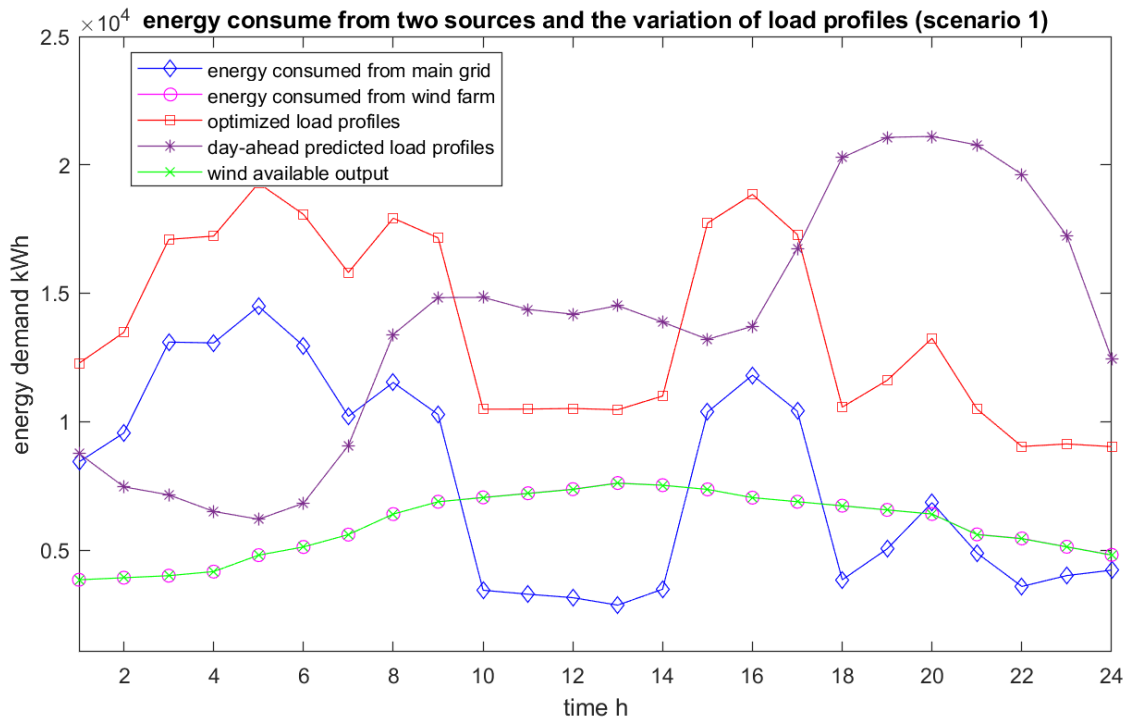


Figure 7-6 Energy consume from two sources and the variation of load profile (scenario 1)

Suppliers choose to consume all available renewable energy since no high DUoS charge will be triggered during this scenario and a relatively low unit generation price signal will be provided by DGs when they implement the proposed day-ahead renewable generation pricing approach. However, the full consumption of the available renewable resources results in a high line usage rate in some circumstances. Figure 7-7 demonstrates the potential network congestion issues in scenario 1. It is indicated that some distribution facilities including line 5 to line 15, line 23 and line 29 exceed or reach their thermal limit.

The optimization programme in scenario 1 neglects network constraints and DUoS charge. In this scenario the nodal DUoS charges are calculated using the proposed economically efficient DUoS allocation approach. It can be observed from Figure 7-8 that domestic customers in several nodes suffer relatively high DUoS charges. In some extreme circumstances the unit DUoS charge will exceed 10p/kWh.

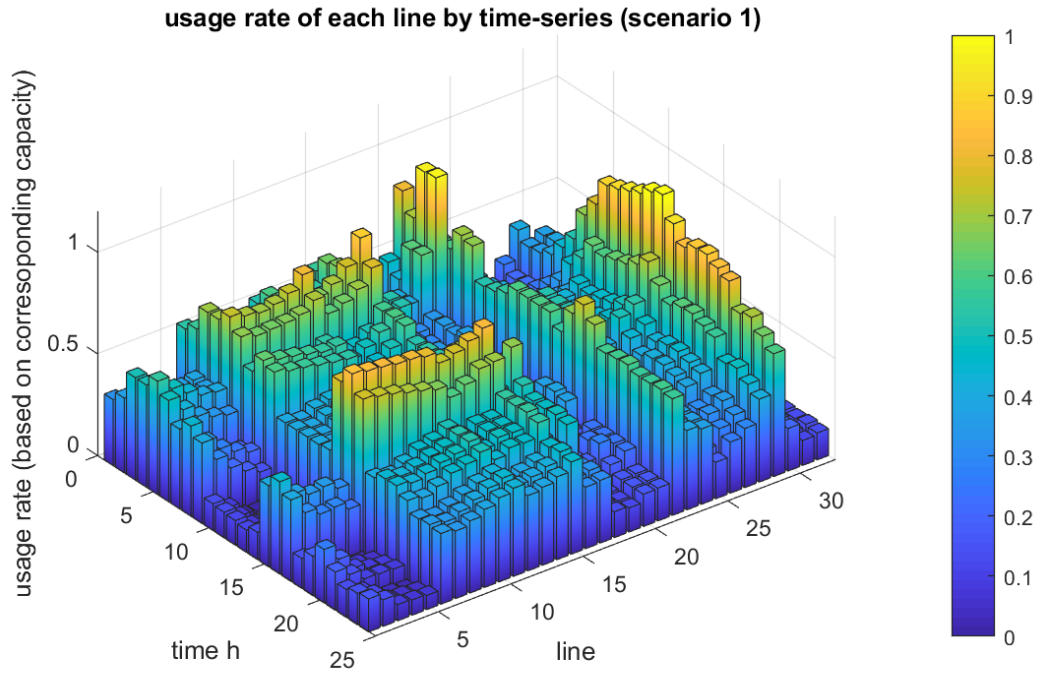


Figure 7-7 Usage rate of each line by time-series in scenario 1.

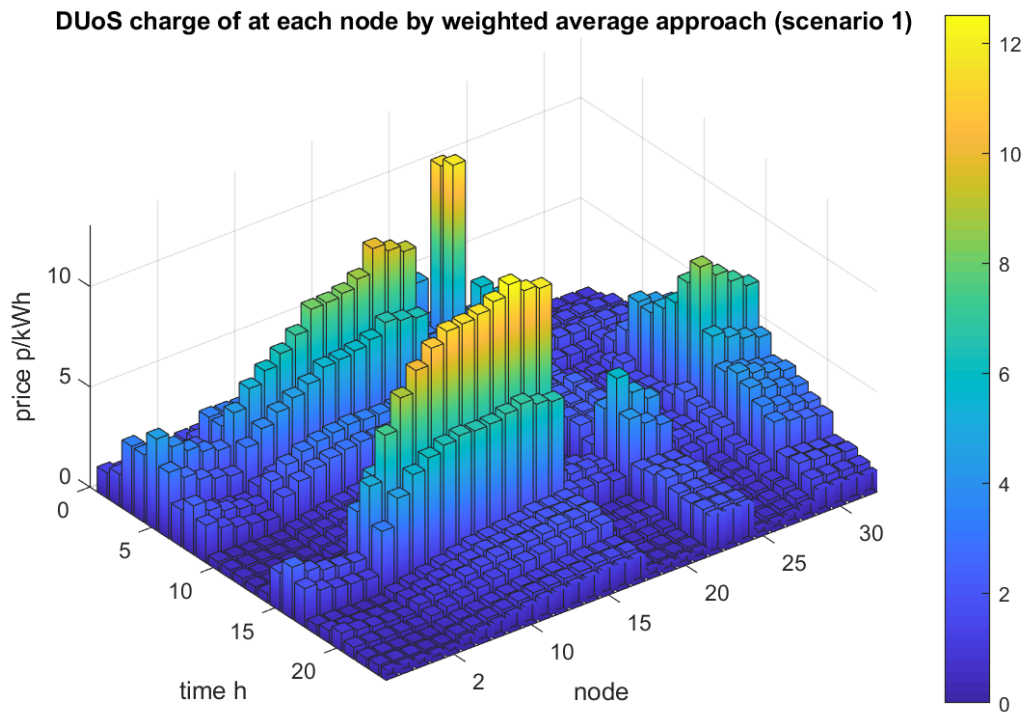


Figure 7-8 DUoS charge of each node in scenario 1.

From Figure 7-9 it is noted that the unit electricity generation price of the wind farm (line with cross) is lower than the wholesale electricity price (line with circle) when it

operates on full capacity. However, the high usage rate of lines in the distribution network leads to high DUoS charge (line with asterisk).

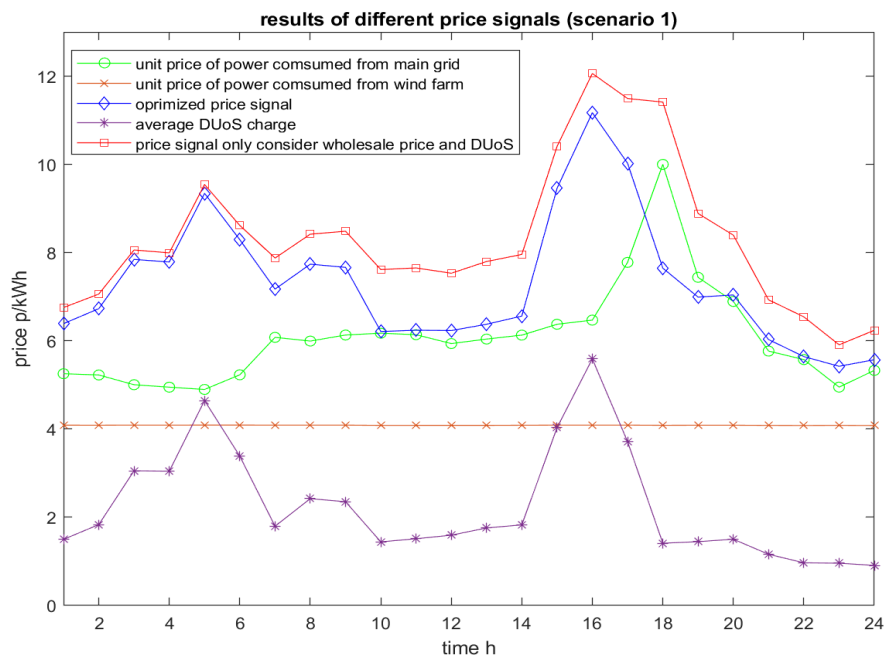


Figure 7-9 The performance of different price signal in scenario 1.

On the other hand, the blue line represents the sum of the weighted average energy procurement cost and DUoS charge and the red line represents the sum of wholesale market energy procurement cost and DUoS charge. From the comparison of these two lines, we can observe that the high DUoS charge counteracts the promotion of low renewable energy procurement cost and results in weak performance of electricity bill reduction.

7.4.2 Case study 2 (considering network constraints)

All proposed mechanisms and approaches are implemented in this scenario. It is clear that the day-ahead DUoS charge approach has successfully limited the consumption of renewable resources when high consumption leads to the high network congestion charge. Figure 7-10 demonstrates that the system still has the motivation to consume more renewable resources due to its low unit electricity price. However, the optimization result shows that the system is also encouraged to achieve a balance

between the high-price signal from the DUoS charge and the low-price signal from the renewable generations.

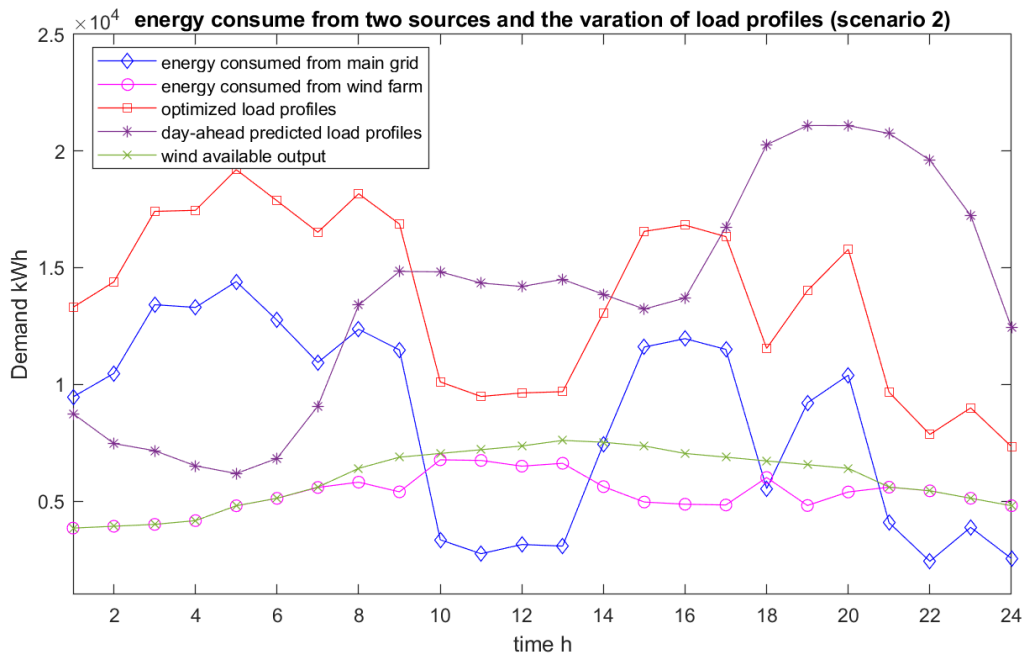


Figure 7-10 Energy consume from two sources and the variation of load profile (scenario 2)

In Figure 7-11 and Figure 7-12, it is observed that the usage rate of each distribution line and the weighted average DUoS charge at each node is relieved in this scenario.

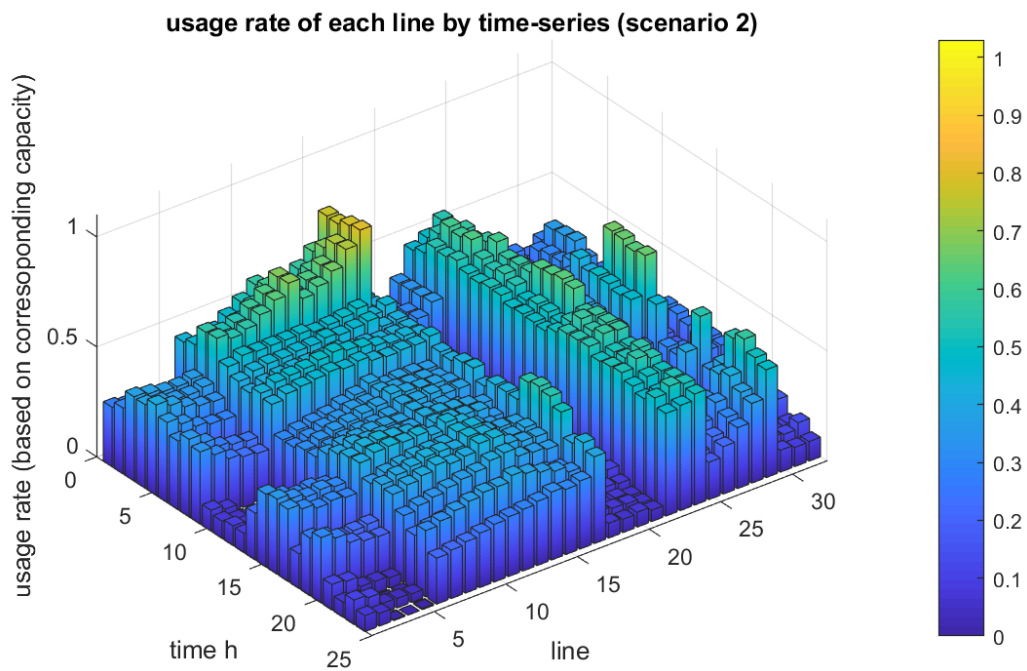


Figure 7-11 Usage rate of each line by time-series in scenario 2.

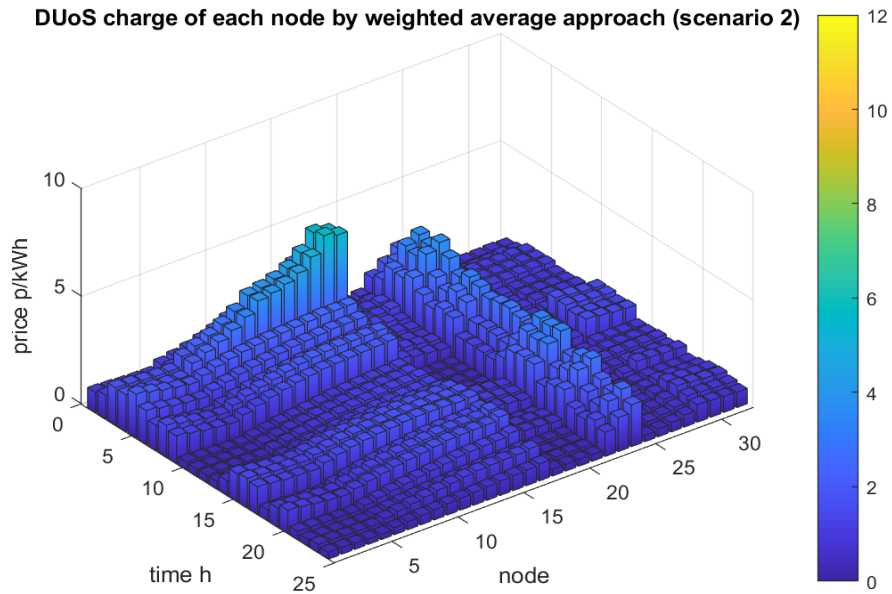


Figure 7-12 DUoS charge of each node in scenario 2.

The maximum usage rate reduces to 75% and most of the lines have a fair usage rate from 30% to 50%. On the other hand, the maximum DUoS charge reduces to 5p/kWh, and most of the DUoS charges at different nodes reduce to a relatively low number. In scenario 2, the proposed day ahead pricing mechanism has successfully optimized the load profiles.

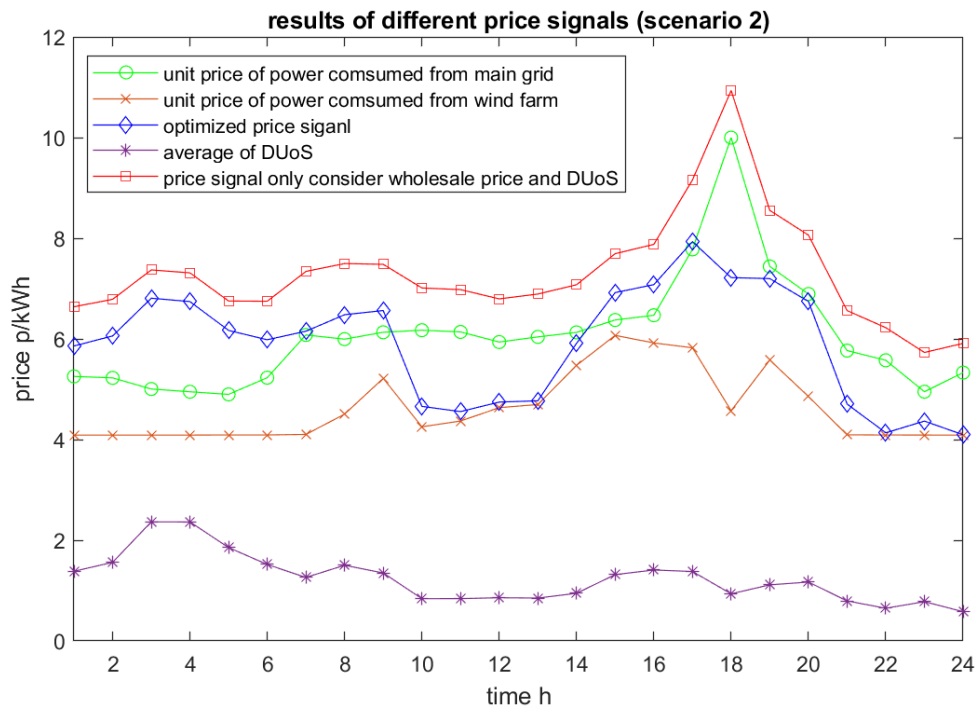


Figure 7-13 The performance of different price signal in scenario 2.

From Figure 7-13 it is noted that the average DUoS charges are limited to a low level. The optimized price signal (the sum of weighted average energy procurement cost and DUoS charge) is significantly lower than the sum of wholesale market energy procurement cost and the DUoS charge.

7.4.3 Discuss of the numerical results

In this section, both the system-level and local-level results comparison are demonstrated to highlight the benefits and achievements of the proposed day-ahead pricing mechanism.

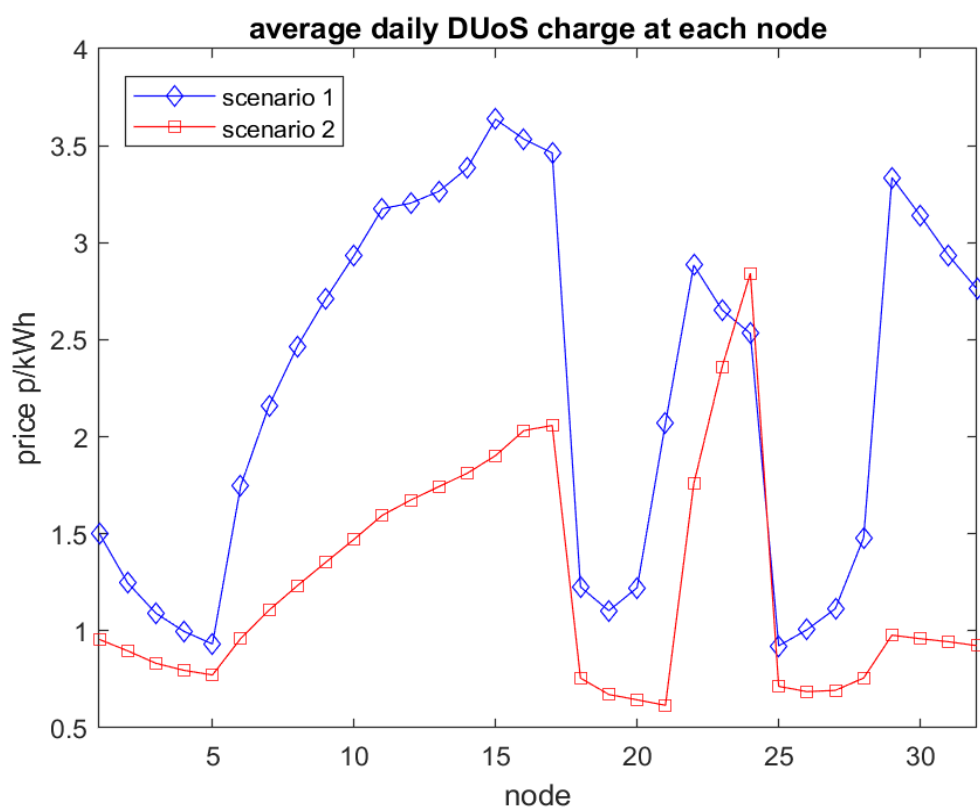


Figure 7-14 Average daily DUoS charge at each node

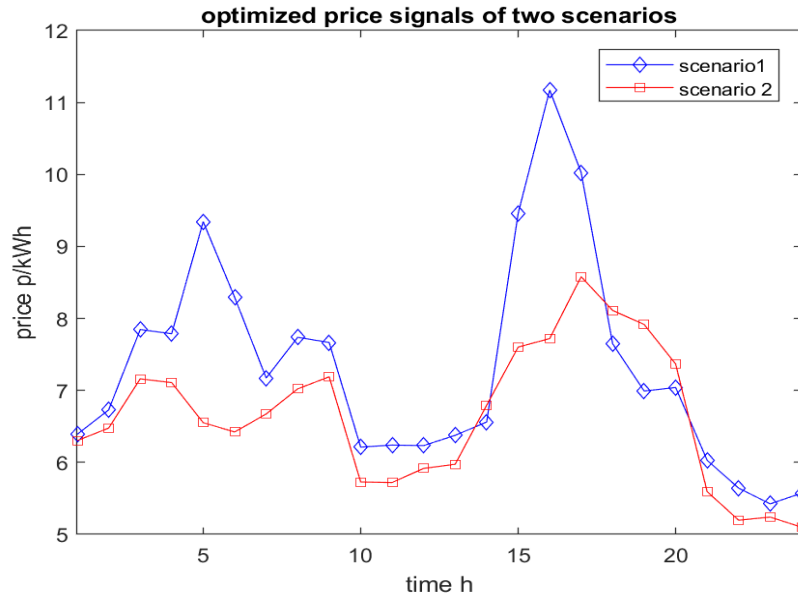


Figure 7-15 Comparison of optimized price signal of two scenarios

Firstly, the focus is on the system-level performance of the two scenarios, where the weighted average DUoS charge of all nodes in the system is calculated. In Figure 7-14, it is indicated that the average DUoS charges of each node are significantly reduced by the implementation of the proposed day-ahead day ahead pricing mechanism compared to scenario 1.

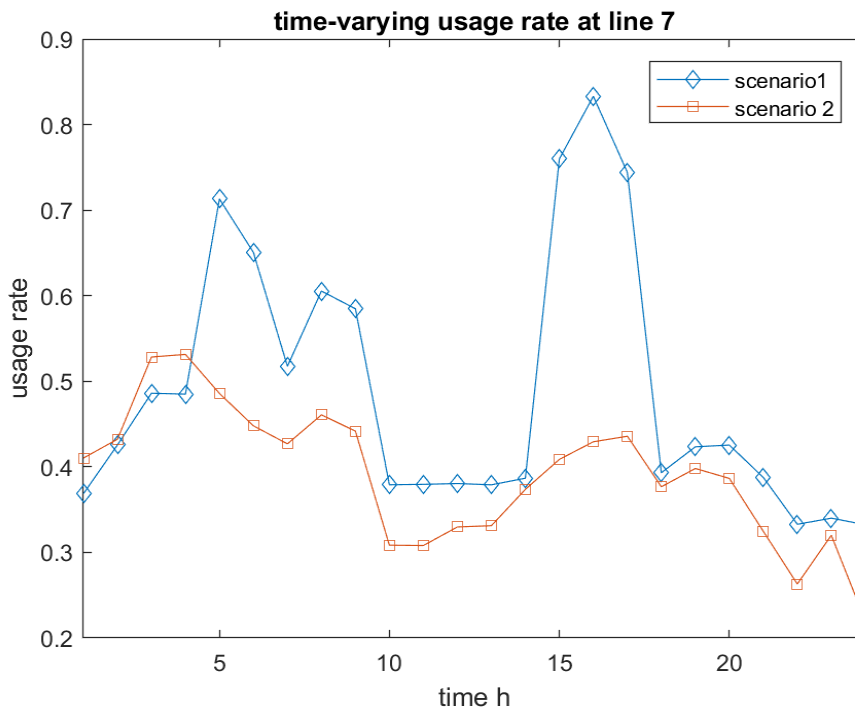


Figure 7-16 Time varying usage rate at line 7

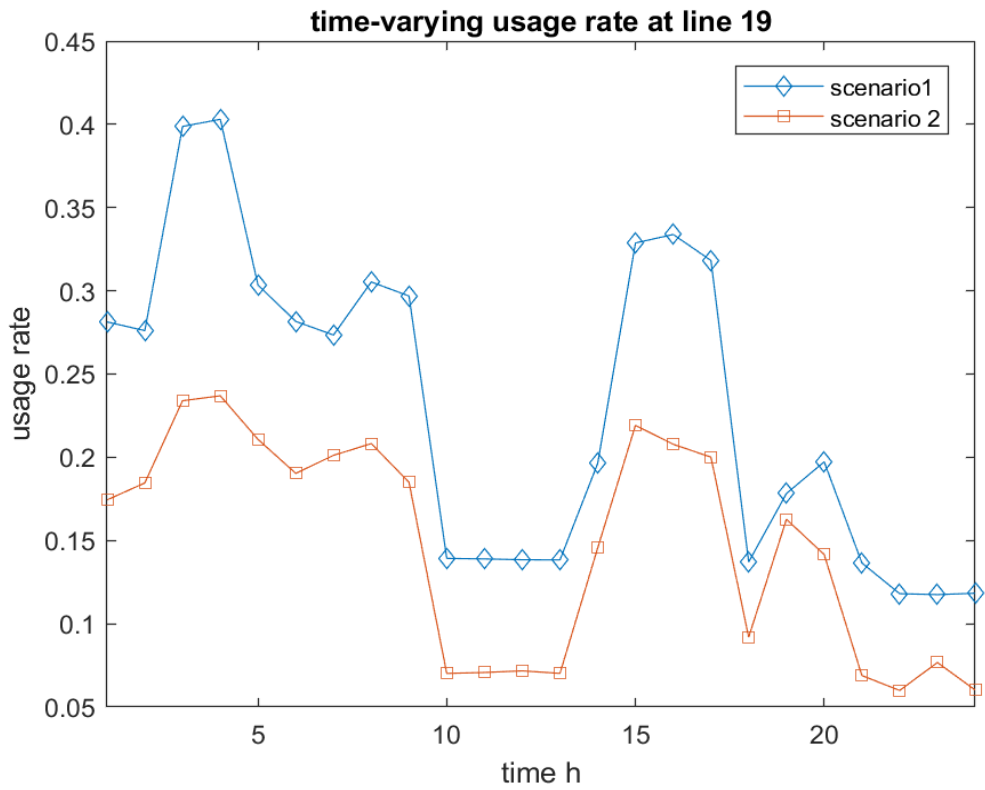


Figure 7-17 Time varying usage rate at line 19

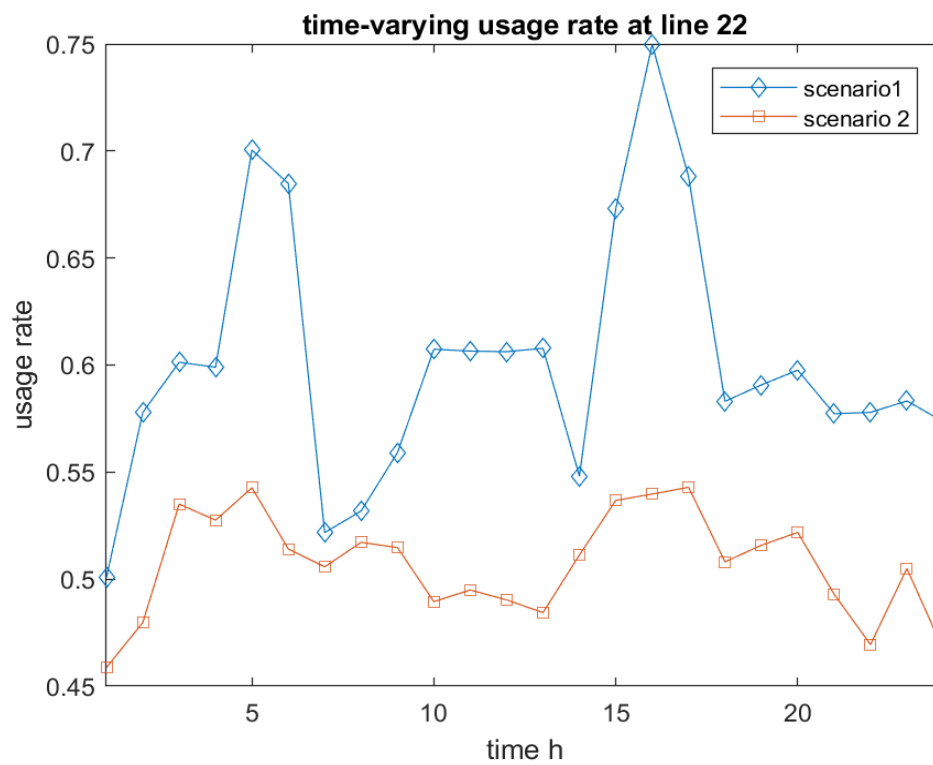


Figure 7-18 Time varying usage rate at line 22

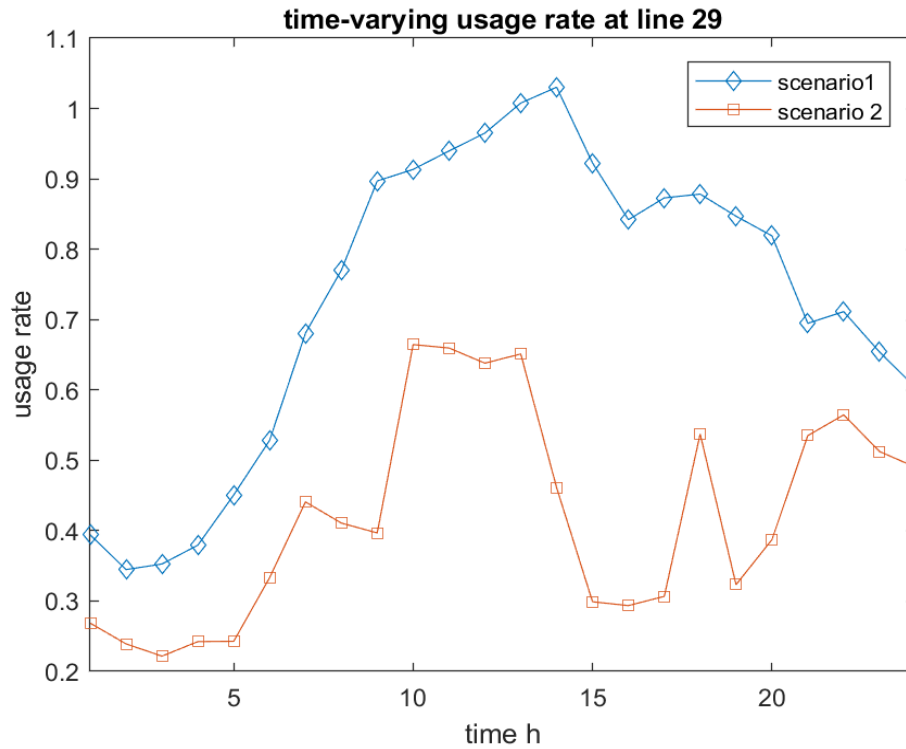


Figure 7-19 Time varying usage rate at line 29

On the other hand, Figure 7-15 shows that scenario 2 also provides a better performance of the final price signal that represents the sum of the energy procurement costs and the DUoS charges. The performance of the proposed approach at the local level is also investigated. Four nodes located in different areas in the system are selected to demonstrate the detailed performance at local level. Figure 7-16 to Figure 7-19 indicate that the line usage rates of these four nodes also experience a significant decrease by the implementation of the new approach. Figure 7-20 to Figure 7-23 indicate that domestic customers at nodes 7, 17, 22 and 29 all receive lower electricity signal compared to scenario 1.

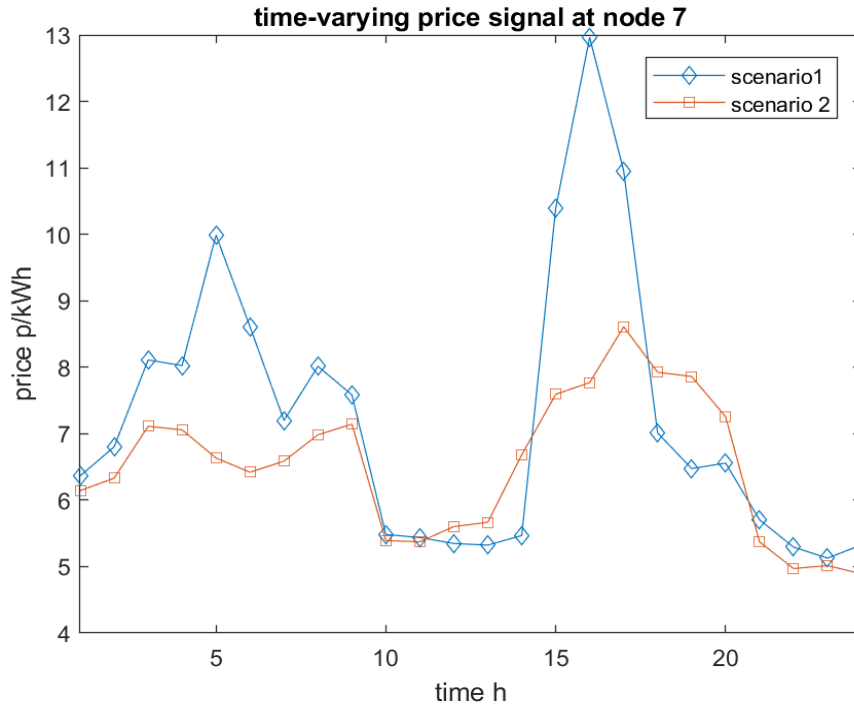


Figure 7-20 Time varying price signal at node 7

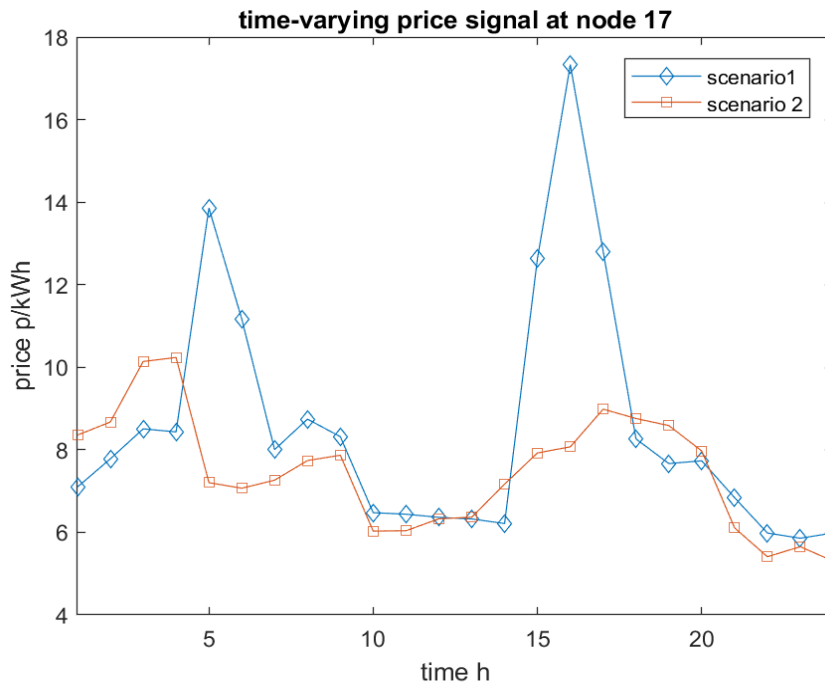


Figure 7-21 Time varying price signal at node 17

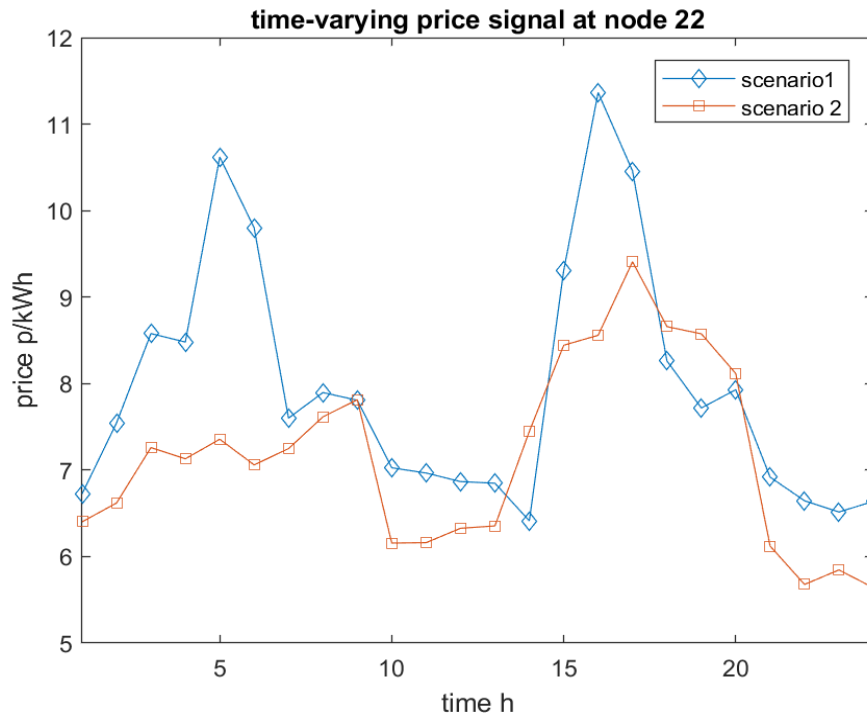


Figure 7-22 Time varying price signal at node 22

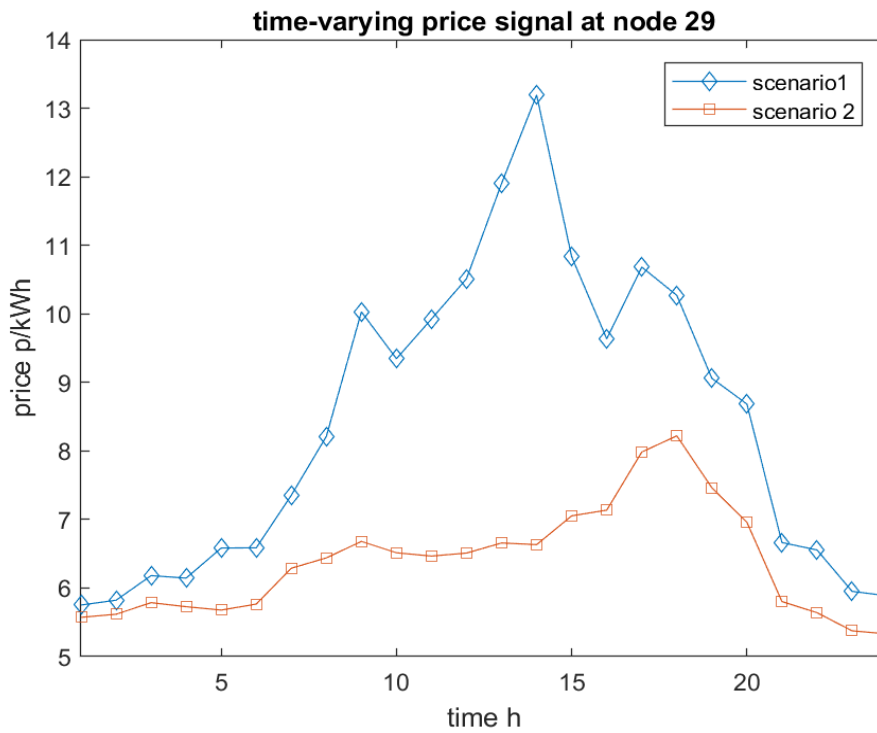


Figure 7-23 Time varying price signal at node 29

7.5 Chapter summary

In this chapter, an innovated day-ahead pricing mechanism is proposed to deal with the potential conflict between the distribution use of system charges and renewable energy production. Based on the study in Chapter 6, the proposed framework in this chapter is designed to minimize customer electricity bills taking account of line thermal constraints resulting from increased penetration of renewable generation. Specifically, the challenges of current day-ahead pricing mechanism are introduced in section 7.2 to highlight the motivation of the study in this chapter. In the next part, the methodology and formulation that used to develop the proposed day-ahead pricing mechanism are indicated in section 7.3. Then, the numerical results extracted from the case study are presented in section 7.4 to verify the efficiency and feasibility of the proposed framework.

The study in this chapter has investigated the potential conflict between the price signals provided by renewable resources and the DUoS charge. The problem has formulated as a large-scale nonlinear optimisation problem. The results of the case study prove that the proposed day-ahead pricing mechanism has the capability to relieve the peak demand and provide domestic customers with a lower electricity price signal. Also, the framework ensures each customer receives an economically efficient cost reflective price signal at each time slot. Specifically, for a given time, the utilisation of each facility in the distribution network can be determined by power flow analysis. Based on the proposed day-ahead DUoS charge approach, each facility will provide its unique price signal that is determined by its real-time usage rate. Since different nodes share the total usage of a given facility, the price signal will be assigned to each node based on their contribution to the utilisation of the facility. Finally, for each node, the various price signals provided by various facilities are combined to produce a single tariff by a weighted average approach. The proposed mechanism provides hourly a day-ahead use of system charge signal to each node based on predicted demand. The total revenue of the DUoS charges covers the infrastructure investment and operation cost of distribution networks. In contrast to fixed or two-rates (peak and off-peak) DUoS charge approaches which are applied in the current electricity market, the proposed day-ahead charging method could

provide more accurate and precise time-varying price signals of the network usage. On the other hand, the mechanism can also encourage the consumption of more renewable resources while taking account of the potential of exceeding thermal limits of distribution network facilities. Since voltage constraints in the distribution network are also a vital index that is should be considered in the system operation, this work will be expanded to explore this aspect using an AC model in the future research.

Chapter 8

Conclusions and Future Work

The aim of the research in this thesis is the optimal design and planning of distribution systems by using innovative mechanisms and technologies such as active demand-side participation tools, network reconfiguration technologies, dynamic pricing mechanisms and day-ahead pricing mechanisms.

This chapter provides an overview of the research work in this thesis, and a summary of the main objectives that achieved in this thesis is listed in section 8.1. Then, the main contributions of this thesis are summarized in section 8.2. In addition, the potential of research directions and future work are also suggested in section 8.3.

8.1 Main objectives accomplished

Two main targets have been addressed in the research work of this thesis. First, an innovative pricing mechanism and an innovative day-ahead pricing mechanism have been established to systematically address the impact of high penetration of DERs and network congestion problems by considering dynamic DUoS charges and dynamic renewable prices. Then, an optimization framework has been designed to deal with the optimal CSS problem. To this end, the following objectives have been accomplished in accordance with the aims and objectives of the research:

1. *Development of a dynamic DUoS charging mechanism*

The proposed DUoS charging mechanism has the capability to provide a precise price signal based on the real-time power flow in distribution lines and to ensure that the corresponding charges can completely cover the network investment and O&M costs. In particular, each distribution line or cable in a power system will provide its unique price signal based on its real-time usage rate. Customers located in the same feeder only need to pay the DUoS charges for the distribution lines that are used to provide their electricity delivery service. Therefore, each price signal of the DUoS charge is only allocated to the related load points, thus allowing cost-reflective pricing. The power flow tracing (PFT) algorithm and the power transfer distribution factors (PTDFs) are employed to achieve the proposed DUoS charging mechanism.

2. *Development of a dynamic charging model for pricing the output of distributed renewable generations*

A dynamic charging model for pricing the output of distributed renewable generators has been developed to provide dynamic tariffs for RESs based on their real-time generation output. Moreover, the tariffs provided by this model have the capability to cover the investment costs of the generators and the relevant O&M costs. In particular, the tariffs decrease when the distribution system can consume more available generation from the DERs, and the tariffs increase when the distribution system decides to curtail the

generation of DERs. Thus, based on this model, attempting to consume all available generation during a wind blowing or sunshine period can produce relative electricity tariffs for DERs.

3. *Development of an electricity price elasticity matrix to capture the system-level customer response to a provided price signal*

An electricity price elasticity matrix (EPEM) has been developed to capture the system-level impact of demand response rather than the local effects on a single consumer. The value of elasticity in the matrix can be adjusted to simulate different kinds of response behaviours by energy consumers. In the end, the numerical results successfully verify that the proposed dynamic price framework has the capability to rearrange the daily load shape by providing appropriate price signals to customers.

4. *Carried out general numerical studies.*

The above mechanisms, algorithms and frameworks have been applied to general scenarios and cases that were created based on the IEEE Test System, with considerations of the constraints of power system operation.

8.2 Main contributions

According to the aim and objectives proposed for the research work at the beginning of thesis, the main contributions are summarised and reiterated as follows. Together with the main objectives accomplished in the research work and the key conclusion inferred from the numerical analysis, this thesis has made some innovations and bridged certain research gaps. These include optimization algorithm to deal with the CSS problem in distribution systems with a high penetration of distributed generation, innovative dynamic pricing framework for demand response considering the thermal limitation, GA-based network reconfiguration technology to determine the optimal topology considering the integration of DERs, novel day-ahead pricing mechanism for managing distribution network congestion caused by the increasing application of renewable generation. In addition, the performance of the approaches and

mechanisms have been assessed and illustrated by thorough numerical case studies. Ultimately, this thesis has established a comprehensive framework for optimal designing and planning an intelligent distribution network. The main contributions of this thesis are listed below.

- ***Development of a GA-based network reconfiguration technology to determine the optimal topology considering the integration of DERs***

A genetic-algorithm-based distribution network reconfiguration approach has been developed to determine the optimal topology in advance at each hour considering the predicted data of load demand and available output of the distributed generators. The numeric results suggest that the developed GA approach has the capability to determine the optimal network topology to achieve the minimization of power losses while considering varying DER generation and demand-side participation.

- ***Development of an optimization algorithm to deal with the CSS problem in distribution systems with a high penetration of distributed generation***

A hybrid optimization algorithm has been developed to deal with the CSS problem in distribution systems with a high penetration of distributed generation. In particular, the proposed algorithm contains two main mechanisms: an AC optimal power flow study and an adaptive genetic algorithm (AGA). The AGA is applied as the primary optimization mechanism that is responsible for collecting the simulation results from the AC-OPF, exploring the best individual and updating the evolution strategy of the approach. Double adaptive crossover rates, hybrid fitness values and self-adaptive mutation operators are innovatively applied in the AGA. Instead of the normal single fitness value structure in the standard GA approach, a hybrid fitness value is designed for the SSC problem because the individual with the optimal fitness value also must satisfy the network constraints at the same time. In the end, the AC-OPF is responsible for accessing the minimum energy costs of each individual in the population of every iteration.

The numerical results demonstrated that the proposed optimum CSS approach has the capability to allocate the suitable conductor type from the given inventories to each branch in the network, thus minimizing the sum of all conductor life-cycle costs, power losses costs and the total energy procurement costs. In particular, the study results of the 33-bus network and the 69-bus network indicate that the proposed adaptive genetic algorithm has the capability to provide a more efficient and effective way to solve the new challenge in the CSS problem than the standard genetic algorithm. In particular, 25% and 29% total costs saving are achieved separately by the proposed approach in two different distribution networks. More important, the potential economic conflict between the investment of conductors and the renewable recourses curtailment costs is firstly considered in the CCS problem. On the other hand, the proposed approach employs a comprehensive conductor investment and O&M pricing model to provide precise and practical study results.

- ***Development of an innovative dynamic pricing framework for demand response considering the thermal limitation***

An innovative dynamic-pricing framework has been developed to determine the optimal price signal at each time slot with considerations of the wholesale market, the economic benefits of power suppliers and the behaviours of customers. Specifically, an innovative use of system charge allocation approach was introduced to support the proposed dynamic pricing framework. The electricity price elasticity matrix and the dynamic DUoS charging mechanism were incorporated into this framework to capture the response of customers to price signals and to provide the dynamic price signals caused by potential network congestion.

In the end, the numerical results successfully verify the proposed dynamic price framework has the capability to rearrange the daily load shape by providing the appropriate price signal to their customers. The numerical results also indicate that the electricity price signal obtained in the paper satisfies the real electricity price (around 0.12GBP/kWh) in current UK market.

- ***Development of an innovative day-ahead pricing mechanism for managing distribution network congestion caused by the increasing application of renewable generation***

An innovative day-ahead pricing mechanism has been applied to the optimal design of a day-ahead pricing mechanism for managing distribution network congestion caused by renewable generation. The proposed framework of day-ahead pricing has the capability to minimize the electricity bills of customers by considering line thermal constraints resulting from the increased penetration of renewable generation. The proposed optimum day-ahead pricing mechanism has been validated through the IEEE-33 bus Test System by a large-scale nonlinear optimization programming algorithm (sequential quadratic programming).

The numerical results demonstrated that the proposed optimum day-ahead pricing mechanism efficiently reduce the mismatch between the RES generation and demand profiles and relieve the network congestion problems during both peak demand or peak generation periods. Moreover, DNOs are able to use the proposed framework to provide the optimized time-based electricity price to their customers for changing the time and amount that customers consume the electricity, thus avoiding the curtailment of RES or high DUoS charge.

8.3 Future Work

In spite of the best efforts undertaken in this work to make innovations and bridge some research gaps through, an exhaustive exploration has not by any means been done for the constantly developing topic of this thesis. There is always great room for future work, such as improvements for the research work that has been done and

parallel projects on similar research topics that are inspired by the research work. Potential future work is therefore suggested as follows.

1. *To incorporate concerns about short-circuit currents into the proposed CSS framework*

The high penetration of DGs will significantly change the short-circuit currents through distribution systems. Thus, the potential cost conflict between conductor life-cycle costs and the costs of renewable resource curtailment is not the only optimization problem in the CSS process. From the view of network protection, the potential conflict between the costs of second circuit breaks and the costs of upgrading conductors is worth being investigated. Finally, DNOs can comprehensively consider the optimization results from 1) the research that focuses on the costs of protection devices and conductor upgrading costs and 2) our research that focus on the costs of DG curtailment and conductor life-cycle costs and decide on the optimal design and planning strategy for a distribution network.

2. *To incorporate EVs and ESSs into distribution network design and planning*

The development of high-capacity electric vehicle charging stations and electrical storage systems also affects the planning of distribution networks. In particular, several countries have launched plans to eliminate the usage of fossil-fuel-based vehicles and encourage citizens to purchase electric vehicles. If electric vehicles dominate the market, normal household electricity demands will significantly increase, especially during peak demand periods such as 7:00 PM-12:00 PM. The conductor size selection problem is expected to consider those technologies.

3. *To consider voltage constraints as a new price signal to relieve network congestion problems*

The dynamic DUoS charging mechanism designed in this thesis has the capability to provide precise price signals that reflect the real-time usage of distribution systems. Dynamic DUoS charges are determined by the actual

usage, with considerations of the network investment costs and the O&M costs. Thus, network thermal limitation concerns can be relieved by increasing the DUoS charge. Then, customers are expected to reduce energy consumption during peak demand periods due to the high DUoS charge. However, a high penetration of DERs in a distribution system may increase the voltage at the connection points during peak generation periods. Moreover, customers may increase their energy consumption during low electricity tariff periods, for example, by applying dynamic DER pricing mechanisms during periods of wind blowing or sunshine, thus resulting in a potential problem voltage drop among some feeders. Indeed, various voltage regulation tools and mechanisms can be applied to relieve the potential voltage increase and drop problem. Similar to the proposed dynamic DUoS charging mechanism, voltage constraints can also be developed as a price signal to affect the energy consumption behaviours of customers.

References

- [1] P. Breeze, "Chapter 1 - An Introduction to Electricity Generation," in *Power Generation Technologies (Second Edition)*, P. Breeze, Ed. Boston: Newnes, 2014, pp. 1-13.
- [2] D. Toke, "The UK offshore wind power programme: A sea-change in UK energy policy?," *Energy Policy*, vol. 39, no. 2, pp. 526-534, 2011.
- [3] G. Wood and S. Dow, "What lessons have been learned in reforming the Renewables Obligation? An analysis of internal and external failures in UK renewable energy policy," *Energy Policy*, vol. 39, no. 5, pp. 2228-2244, 2011.
- [4] A. Pye, "Great Britain's power struggle," *Engineering & Technology*, vol. 10, no. 6, pp. 68-71, 2015.
- [5] K. N. V. Matos, R. R. Londero, C. d. M. Affonso, and J. P. A. Vieira, "Secondary voltage control applied to DFIG-based wind park and its effect on long-term voltage stability," *Electric Power Systems Research*, vol. 175, p. 105878, 2019.
- [6] S. Ruggiero, V. Varho, and P. Rikkonen, "Transition to distributed energy generation in Finland: Prospects and barriers," *Energy Policy*, vol. 86, pp. 433-443, 2015.
- [7] L. Mehigan, J. P. Deane, B. P. Ó. Gallachóir, and V. Bertsch, "A review of the role of distributed generation (DG) in future electricity systems," *Energy*, vol. 163, pp. 822-836, 2018.

- [8] S. Zhang, H. Cheng, K. Li, N. Tai, D. Wang, and F. Li, "Multi-objective distributed generation planning in distribution network considering correlations among uncertainties," *Applied Energy*, vol. 226, pp. 743-755, 2018.
- [9] C. Roldán-Blay, G. Escrivá-Escrivá, and C. Roldán-Porta, "Improving the benefits of demand response participation in facilities with distributed energy resources," *Energy*, vol. 169, pp. 710-718, 2019.
- [10] G. Allan, I. Eromenko, M. Gilmartin, I. Kockar, and P. McGregor, "The economics of distributed energy generation: A literature review," *Renewable and Sustainable Energy Reviews*, vol. 42, pp. 543-556, 2015.
- [11] B. Li, C. Wan, K. Yuan, and Y. Song, "Demand Response for Integrating Distributed Energy Resources in Transactive Energy System," *Energy Procedia*, vol. 158, pp. 6645-6651, 2019.
- [12] E. Thomas, R. Sharma, and Y. Nazarathy, "Towards demand side management control using household specific Markovian models," *Automatica*, vol. 101, pp. 450-457, 2019.
- [13] C. G. Monyei and A. O. Adewumi, "Integration of demand side and supply side energy management resources for optimal scheduling of demand response loads – South Africa in focus," *Electric Power Systems Research*, vol. 158, pp. 92-104, 2018.
- [14] Z. Wu and X. Xia, "A Portfolio Approach of Demand Side Management," *IFAC-PapersOnLine*, vol. 50, no. 1, pp. 171-176, 2017.
- [15] M. Saffari, A. de Gracia, C. Fernández, M. Belusko, D. Boer, and L. F. Cabeza, "Optimized demand side management (DSM) of peak electricity demand by coupling low temperature thermal energy storage (TES) and solar PV," *Applied Energy*, vol. 211, pp. 604-616, 2018.
- [16] E. Guelpa *et al.*, "Demand side management in district heating networks: a real application," *Energy*, 2019.
- [17] M. Muratori and G. Rizzoni, "Residential Demand Response: Dynamic Energy Management and Time-Varying Electricity Pricing," *IEEE Transactions on Power Systems*, vol. 31, no. 2, pp. 1108-1117, 2016.
- [18] N. T. Mbungu, R. M. Naidoo, and R. C. Bansal, "Real-time Electricity Pricing: TOU-MPC Based Energy Management for Commercial Buildings," *Energy Procedia*, vol. 105, pp. 3419-3424, 2017.
- [19] T. Kristiansen, "Pricing of Contracts for Difference in the Nordic market," *Energy Policy*, vol. 32, no. 9, pp. 1075-1085, 2004.
- [20] C. Amountzias, H. Dagdeviren, and T. Patokos, "Pricing decisions and market power in the UK electricity market: A VECM approach," *Energy Policy*, vol. 108, pp. 467-473, 2017.
- [21] G. Duan, Z. Y. Dong, W. Bai, and X. F. Wang, "Power flow based monetary flow method for electricity transmission and wheeling pricing," *Electric Power Systems Research*, vol. 74, no. 2, pp. 293-305, 2005.

- [22] T.-C. Chiu, Y.-Y. Shih, A.-C. Pang, and C.-W. Pai, "Optimized day-ahead pricing with renewable energy demand-side management for smart grids," *IEEE Internet of Things Journal*, vol. 4, no. 2, pp. 374-383, 2016.
- [23] A. Mohsenian-Rad and A. Leon-Garcia, "Optimal Residential Load Control With Price Prediction in Real-Time Electricity Pricing Environments," *IEEE Transactions on Smart Grid*, vol. 1, no. 2, pp. 120-133, 2010.
- [24] N. G. Paterakis, O. Erdinç, A. G. Bakirtzis, and J. P. S. Catalão, "Optimal Household Appliances Scheduling Under Day-Ahead Pricing and Load-Shaping Demand Response Strategies," *IEEE Transactions on Industrial Informatics*, vol. 11, no. 6, pp. 1509-1519, 2015.
- [25] K. Zhu, N. Lu, J. Zheng, G. Sun, and F. Mei, "Optimal day-ahead scheduling for commercial building-level consumers under TOU and demand pricing plan," *Electric Power Systems Research*, vol. 173, pp. 240-250, 2019.
- [26] R. Fernández-Blanco, J. M. Arroyo, and N. Alguacil, "On the Solution of Revenue- and Network-Constrained Day-Ahead Market Clearing Under Marginal Pricing—Part II: Case Studies," *IEEE Transactions on Power Systems*, vol. 32, no. 1, pp. 220-227, 2017.
- [27] S. M. Rahman, R. Spalding-Fecher, E. Haïtes, and G. A. Kirkman, "The levelized costs of electricity generation by the CDM power projects," *Energy*, vol. 148, pp. 235-246, 2018.
- [28] M. Obi, S. M. Jensen, J. B. Ferris, and R. B. Bass, "Calculation of levelized costs of electricity for various electrical energy storage systems," *Renewable and Sustainable Energy Reviews*, vol. 67, pp. 908-920, 2017.
- [29] Z. Hu, J.-h. Kim, J. Wang, and J. Byrne, "Review of dynamic pricing programs in the U.S. and Europe: Status quo and policy recommendations," *Renewable and Sustainable Energy Reviews*, vol. 42, pp. 743-751, 2015.
- [30] Y. Lu, S. Wang, Y. Sun, and C. Yan, "Optimal scheduling of buildings with energy generation and thermal energy storage under dynamic electricity pricing using mixed-integer nonlinear programming," *Applied Energy*, vol. 147, pp. 49-58, 2015.
- [31] L. Tronchin, M. Manfren, and B. Nastasi, "Energy efficiency, demand side management and energy storage technologies – A critical analysis of possible paths of integration in the built environment," *Renewable and Sustainable Energy Reviews*, vol. 95, pp. 341-353, 2018.
- [32] S. Yilmaz, S. Weber, and M. K. Patel, "Who is sensitive to DSM? Understanding the determinants of the shape of electricity load curves and demand shifting: Socio-demographic characteristics, appliance use and attitudes," *Energy Policy*, vol. 133, p. 110909, 2019.
- [33] P. Palensky and D. Dietrich, "Demand Side Management: Demand Response, Intelligent Energy Systems, and Smart Loads," *IEEE Transactions on Industrial Informatics*, vol. 7, no. 3, pp. 381-388, 2011.

- [34] A. Mohsenian-Rad, V. W. S. Wong, J. Jatskevich, R. Schober, and A. Leon-Garcia, "Autonomous Demand-Side Management Based on Game-Theoretic Energy Consumption Scheduling for the Future Smart Grid," *IEEE Transactions on Smart Grid*, vol. 1, no. 3, pp. 320-331, 2010.
- [35] T. Logenthiran, D. Srinivasan, and T. Z. Shun, "Demand Side Management in Smart Grid Using Heuristic Optimization," *IEEE Transactions on Smart Grid*, vol. 3, no. 3, pp. 1244-1252, 2012.
- [36] P. S. Moura and A. T. de Almeida, "The role of demand-side management in the grid integration of wind power," *Applied Energy*, vol. 87, no. 8, pp. 2581-2588, 2010.
- [37] A. Pina, C. Silva, and P. Ferrão, "The impact of demand side management strategies in the penetration of renewable electricity," *Energy*, vol. 41, no. 1, pp. 128-137, 2012.
- [38] Z. Wu, H. Tazvinga, and X. Xia, "Demand side management of photovoltaic-battery hybrid system," *Applied Energy*, vol. 148, pp. 294-304, 2015.
- [39] R. J. Spiegel, J. E. C. Kern, and D. L. Greenberg, "Demonstration of the environmental and demand-side management benefits of grid-connected photovoltaic power systems," *Solar Energy*, vol. 62, no. 5, pp. 345-358, 1998.
- [40] A. Zahedi, "Maximizing solar PV energy penetration using energy storage technology," *Renewable and Sustainable Energy Reviews*, vol. 15, no. 1, pp. 866-870, 2011.
- [41] D. Jones, A. Sakhel, M. Buck, and P. Graichen, "The European Power Sector in 2017," *Agora Energiewende and Sandbag*, 2018.
- [42] Å. Lindman and P. Söderholm, "Wind energy and green economy in Europe: Measuring policy-induced innovation using patent data," *Applied energy*, vol. 179, pp. 1351-1359, 2016.
- [43] P. L. Joskow, "Comparing the costs of intermittent and dispatchable electricity generating technologies," *American Economic Review*, vol. 101, no. 3, pp. 238-41, 2011.
- [44] T. T. Onifade, "Hybrid renewable energy support policy in the power sector: The contracts for difference and capacity market case study," *Energy Policy*, vol. 95, pp. 390-401, 2016.
- [45] J. Teixidó, S. F. Verde, and F. Nicolli, "The impact of the EU Emissions Trading System on low-carbon technological change: The empirical evidence," *Ecological Economics*, vol. 164, p. 106347, 2019.
- [46] P. J. Wood and F. Jotzo, "Price floors for emissions trading," *Energy Policy*, vol. 39, no. 3, pp. 1746-1753, 2011.
- [47] A. Pyrgou, A. Kylili, and P. A. Fokaides, "The future of the Feed-in Tariff (FiT) scheme in Europe: The case of photovoltaics," *Energy Policy*, vol. 95, pp. 94-102, 2016.

- [48] W. Matar, "A household's power load response to a change in the electricity pricing scheme: An expanded microeconomic-physical approach," *The Electricity Journal*, vol. 32, no. 9, p. 106644, 2019.
- [49] D. Wozabal and G. Rameseder, "Optimal bidding of a virtual power plant on the Spanish day-ahead and intraday market for electricity," *European Journal of Operational Research*, vol. 280, no. 2, pp. 639-655, 2020.
- [50] G. Díaz, J. Coto, and J. Gómez-Aleixandre, "Prediction and explanation of the formation of the Spanish day-ahead electricity price through machine learning regression," *Applied Energy*, vol. 239, pp. 610-625, 2019.
- [51] F. Agyenim and N. Hewitt, "The development of a finned phase change material (PCM) storage system to take advantage of off-peak electricity tariff for improvement in cost of heat pump operation," *Energy and Buildings*, vol. 42, no. 9, pp. 1552-1560, 2010.
- [52] Z. Wang, B. Zhang, and Y. Wang, "Review of power distribution network planning," in *Electrical and Control Engineering & Materials Science and Manufacturing: The Proceedings of Joint Conferences of the 6th (ICECE2015) and the 4th (ICMSM2015)*, 2016, pp. 141-150: World Scientific.
- [53] M. H. S. Boloukat and A. A. Foroud, "Multiperiod Planning of Distribution Networks Under Competitive Electricity Market With Penetration of Several Microgrids, Part I: Modeling and Solution Methodology," *IEEE Transactions on Industrial Informatics*, vol. 14, no. 11, pp. 4884-4894, 2018.
- [54] A. Arefi, A. Abeygunawardana, and G. Ledwich, "A new risk-managed planning of electric distribution network incorporating customer engagement and temporary solutions," *IEEE Transactions on Sustainable Energy*, vol. 7, no. 4, pp. 1646-1661, 2016.
- [55] M. A. Alotaibi and M. M. Salama, "An Incentive-Based Multistage Expansion Planning Model for Smart Distribution Systems," *IEEE Transactions on Power Systems*, vol. 33, no. 5, pp. 5469-5485, 2018.
- [56] V. D. Cosmo and D. O'Hora, "Nudging electricity consumption using TOU pricing and feedback: evidence from Irish households," *Journal of Economic Psychology*, vol. 61, pp. 1-14, 2017.
- [57] K. M. Tsui and S. C. Chan, "Demand Response Optimization for Smart Home Scheduling Under Real-Time Pricing," *IEEE Transactions on Smart Grid*, vol. 3, no. 4, pp. 1812-1821, 2012.
- [58] L. Jia and L. Tong, "Dynamic Pricing and Distributed Energy Management for Demand Response," *IEEE Transactions on Smart Grid*, vol. 7, no. 2, pp. 1128-1136, 2016.
- [59] M. S. S. Rao and S. A. Soman, "Marginal Pricing of Transmission Services Using Min-Max Fairness Policy," *IEEE Transactions on Power Systems*, vol. 30, no. 2, pp. 573-584, 2015.

- [60] D. T. Nguyen, H. T. Nguyen, and L. B. Le, "Dynamic Pricing Design for Demand Response Integration in Power Distribution Networks," *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3457-3472, 2016.
- [61] F. Li, D. Tolley, N. P. Padhy, and J. Wang, "Framework for Assessing the Economic Efficiencies of Long-Run Network Pricing Models," *IEEE Transactions on Power Systems*, vol. 24, no. 4, pp. 1641-1648, 2009.
- [62] F. Li and C. Gu, "Long-Run Incremental Cost Pricing for Negative Growth Rates," *IEEE Transactions on Power Systems*, vol. 26, no. 4, pp. 2567-2568, 2011.
- [63] L. Bai, J. Wang, C. Wang, C. Chen, and F. Li, "Distribution Locational Marginal Pricing (DLMP) for Congestion Management and Voltage Support," *IEEE Transactions on Power Systems*, vol. 33, no. 4, pp. 4061-4073, 2018.
- [64] H. Khajeh, A. A. Foroud, and H. Firoozi, "Robust bidding strategies and scheduling of a price-maker microgrid aggregator participating in a pool-based electricity market," *IET Generation, Transmission & Distribution*, vol. 13, no. 4, pp. 468-477, 2019.
- [65] F. Farzan, M. A. Jafari, R. Masiello, and Y. Lu, "Toward Optimal Day-Ahead Scheduling and Operation Control of Microgrids Under Uncertainty," *IEEE Transactions on Smart Grid*, vol. 6, no. 2, pp. 499-507, 2015.
- [66] S. Golshannavaz, S. Afsharnia, and F. Aminifar, "Smart Distribution Grid: Optimal Day-Ahead Scheduling With Reconfigurable Topology," *IEEE Transactions on Smart Grid*, vol. 5, no. 5, pp. 2402-2411, 2014.
- [67] X. Jin, Y. Mu, H. Jia, J. Wu, X. Xu, and X. Yu, "Optimal day-ahead scheduling of integrated urban energy systems," *Applied Energy*, vol. 180, pp. 1-13, 2016.
- [68] R. H. Kwon and D. Frances, "Optimization-based bidding in day-ahead electricity auction markets: A review of models for power producers," in *Handbook of networks in power systems I*: Springer, 2012, pp. 41-59.
- [69] M. Peik-Herfeh, H. Seifi, and M. K. Sheikh-El-Eslami, "Decision making of a virtual power plant under uncertainties for bidding in a day-ahead market using point estimate method," *International Journal of Electrical Power & Energy Systems*, vol. 44, no. 1, pp. 88-98, 2013.
- [70] G. Steeger, L. A. Barroso, and S. Rebennack, "Optimal Bidding Strategies for Hydro-Electric Producers: A Literature Survey," *IEEE Transactions on Power Systems*, vol. 29, no. 4, pp. 1758-1766, 2014.
- [71] M. Mazidi, H. Monsef, and P. Siano, "Incorporating price-responsive customers in day-ahead scheduling of smart distribution networks," *Energy conversion and management*, vol. 115, pp. 103-116, 2016.
- [72] R. P. O'Neill, A. Castillo, B. Eldridge, and R. B. Hytowitz, "Dual pricing algorithm in ISO markets," *IEEE Transactions on Power Systems*, vol. 32, no. 4, pp. 3308-3310, 2016.

- [73] R. Fernández-Blanco, J. M. Arroyo, and N. Alguacil, "On the solution of revenue-and network-constrained day-ahead market clearing under marginal pricing—Part II: Case studies," *IEEE Transactions on Power Systems*, vol. 32, no. 1, pp. 220-227, 2016.
- [74] N. Javaid, A. Ahmed, S. Iqbal, and M. Ashraf, "Day ahead real time pricing and critical peak pricing based power scheduling for smart homes with different duty cycles," *Energies*, vol. 11, no. 6, p. 1464, 2018.
- [75] N. G. Paterakis, O. Erdinc, A. G. Bakirtzis, and J. P. Catalão, "Optimal household appliances scheduling under day-ahead pricing and load-shaping demand response strategies," *IEEE Transactions on Industrial Informatics*, vol. 11, no. 6, pp. 1509-1519, 2015.
- [76] G. Liu, Y. Xu, and K. Tomsovic, "Bidding Strategy for Microgrid in Day-Ahead Market Based on Hybrid Stochastic/Robust Optimization," *IEEE Transactions on Smart Grid*, vol. 7, no. 1, pp. 227-237, 2016.
- [77] S. Nojavan, K. Zare, and M. A. Ashpazi, "A hybrid approach based on IGDT–MPSO method for optimal bidding strategy of price-taker generation station in day-ahead electricity market," *International Journal of Electrical Power & Energy Systems*, vol. 69, pp. 335-343, 2015.
- [78] G. Kozanidis, E. Kostarelou, P. Andrianesis, and G. Liberopoulos, "Mixed integer parametric bilevel programming for optimal strategic bidding of energy producers in day-ahead electricity markets with indivisibilities," *Optimization*, vol. 62, no. 8, pp. 1045-1068, 2013.
- [79] M. P. Nowak, R. Schultz, and M. Westphalen, "A Stochastic Integer Programming Model for Incorporating Day-Ahead Trading of Electricity into Hydro-Thermal Unit Commitment," *Optimization and Engineering*, vol. 6, no. 2, pp. 163-176, 2005.
- [80] D. Streiffert, R. Philbrick, and A. Ott, "A mixed integer programming solution for market clearing and reliability analysis," in *IEEE Power Engineering Society General Meeting, 2005*, 2005, pp. 2724-2731 Vol. 3.
- [81] S. d. I. Torre, J. M. Arroyo, A. J. Conejo, and J. Contreras, "Price maker self-scheduling in a pool-based electricity market: a mixed-integer LP approach," *IEEE Transactions on Power Systems*, vol. 17, no. 4, pp. 1037-1042, 2002.
- [82] B. Sultana, M. Mustafa, U. Sultana, and A. R. Bhatti, "Review on reliability improvement and power loss reduction in distribution system via network reconfiguration," *Renewable and sustainable energy reviews*, vol. 66, pp. 297-310, 2016.
- [83] X. Shen, M. Shahidehpour, Y. Han, S. Zhu, and J. Zheng, "Expansion planning of active distribution networks with centralized and distributed energy storage systems," *IEEE Transactions on Sustainable Energy*, vol. 8, no. 1, pp. 126-134, 2016.

- [84] H. Arasteh, M. S. Sepasian, and V. Vahidinasab, "An aggregated model for coordinated planning and reconfiguration of electric distribution networks," *Energy*, vol. 94, pp. 786-798, 2016.
- [85] Ö. Özdemir, F. D. Munoz, J. L. Ho, and B. F. Hobbs, "Economic analysis of transmission expansion planning with price-responsive demand and quadratic losses by successive LP," *IEEE Transactions on Power Systems*, vol. 31, no. 2, pp. 1096-1107, 2015.
- [86] S. Shojaabadi, S. Abapour, M. Abapour, and A. Nahavandi, "Optimal planning of plug-in hybrid electric vehicle charging station in distribution network considering demand response programs and uncertainties," *IET Generation, Transmission & Distribution*, vol. 10, no. 13, pp. 3330-3340, 2016.
- [87] S. Wang, F. Luo, Z. Y. Dong, and G. Ranzi, "Joint planning of active distribution networks considering renewable power uncertainty," *International Journal of Electrical Power & Energy Systems*, vol. 110, pp. 696-704, 2019.
- [88] Z. Abdmouleh, A. Gastli, L. Ben-Brahim, M. Haouari, and N. A. Al-Emadi, "Review of optimization techniques applied for the integration of distributed generation from renewable energy sources," *Renewable Energy*, vol. 113, pp. 266-280, 2017.
- [89] M. Ul Hassan, M. H. Rehmani, R. Kotagiri, J. Zhang, and J. Chen, "Differential privacy for renewable energy resources based smart metering," *Journal of Parallel and Distributed Computing*, vol. 131, pp. 69-80, 2019.
- [90] H. Anand, N. Narang, and J. S. Dhillon, "Multi-objective combined heat and power unit commitment using particle swarm optimization," *Energy*, vol. 172, pp. 794-807, 2019.
- [91] A. Ehsan and Q. Yang, "State-of-the-art techniques for modelling of uncertainties in active distribution network planning: A review," *Applied Energy*, vol. 239, pp. 1509-1523, 2019.
- [92] C. K. Gan *et al.*, "Evaluation of alternative distribution network design strategies," in *CIREN 2009 - 20th International Conference and Exhibition on Electricity Distribution - Part 1*, 2009, pp. 1-4.
- [93] M. Attar, O. Homaei, H. Falaghi, and P. Siano, "A novel strategy for optimal placement of locally controlled voltage regulators in traditional distribution systems," *International Journal of Electrical Power & Energy Systems*, vol. 96, pp. 11-22, 2018.
- [94] M. J. Ghadi, S. Ghavidel, A. Rajabi, A. Azizivahed, L. Li, and J. Zhang, "A review on economic and technical operation of active distribution systems," *Renewable and Sustainable Energy Reviews*, vol. 104, pp. 38-53, 2019.
- [95] R. J. Alonzo, "Chapter 12 - Electrical Transmission and Distribution Systems," in *Electrical Codes, Standards, Recommended Practices and*

- Regulations*, R. J. Alonzo, Ed. Boston: William Andrew Publishing, 2010, pp. 405-467.
- [96] C. R. Bayliss and B. J. Hardy, "Chapter 18 - Overhead Line Conductor and Technical Specifications," in *Transmission and Distribution Electrical Engineering (Fourth Edition)*, C. R. Bayliss and B. J. Hardy, Eds. Oxford: Newnes, 2012, pp. 683-750.
- [97] E. Lakervi and E. J. Holmes, *Electricity Distribution Network Design*. Stevenage, UNITED KINGDOM: IET, 1987.
- [98] S. K. Khator and L. C. Leung, "Power distribution planning: a review of models and issues," *IEEE Transactions on Power Systems*, vol. 12, no. 3, pp. 1151-1159, 1997.
- [99] P. S. Georgilakis and N. D. Hatziargyriou, "A review of power distribution planning in the modern power systems era: Models, methods and future research," *Electric Power Systems Research*, vol. 121, pp. 89-100, 2015.
- [100] M. Asensio, P. M. d. Quevedo, G. Muñoz-Delgado, and J. Contreras, "Joint Distribution Network and Renewable Energy Expansion Planning Considering Demand Response and Energy Storage—Part I: Stochastic Programming Model," *IEEE Transactions on Smart Grid*, vol. 9, no. 2, pp. 655-666, 2018.
- [101] E. G. Carrano, R. T. N. Cardoso, R. H. C. Takahashi, C. M. Fonseca, and O. M. Neto, "Power distribution network expansion scheduling using dynamic programming genetic algorithm," *IET Generation, Transmission & Distribution*, vol. 2, no. 3, pp. 444-455, 2008.
- [102] I. Ziari, G. Ledwich, A. Ghosh, and G. Platt, "Integrated Distribution Systems Planning to Improve Reliability Under Load Growth," *IEEE Transactions on Power Delivery*, vol. 27, no. 2, pp. 757-765, 2012.
- [103] H. L. Willis, L. A. Finley, and M. J. Buri, "Forecasting electric demand of distribution system planning in rural and sparsely populated regions," *IEEE Transactions on Power Systems*, vol. 10, no. 4, pp. 2008-2013, 1995.
- [104] W. El-Khattam, Y. G. Hegazy, and M. M. A. Salama, "An integrated distributed generation optimization model for distribution system planning," *IEEE Transactions on Power Systems*, vol. 20, no. 2, pp. 1158-1165, 2005.
- [105] W. El-Khattam, K. Bhattacharya, Y. Hegazy, and M. M. A. Salama, "Optimal investment planning for distributed generation in a competitive electricity market," *IEEE Transactions on Power Systems*, vol. 19, no. 3, pp. 1674-1684, 2004.
- [106] H. Saboori, R. Hemmati, S. M. S. Ghiasi, and S. Dehghan, "Energy storage planning in electric power distribution networks – A state-of-the-art review," *Renewable and Sustainable Energy Reviews*, vol. 79, pp. 1108-1121, 2017.
- [107] L. Wang, G. Huang, X. Wang, and H. Zhu, "Risk-based electric power system planning for climate change mitigation through multi-stage joint-

- probabilistic left-hand-side chance-constrained fractional programming: A Canadian case study," *Renewable and Sustainable Energy Reviews*, vol. 82, pp. 1056-1067, 2018.
- [108] M. Grbić, D. Salamon, and J. Mikulović, "Analysis of influence of measuring voltage transformer ratio error on single-circuit overhead power line electric field calculation results," *Electric Power Systems Research*, vol. 166, pp. 232-240, 2019.
- [109] K. B. Lindberg, P. Seljom, H. Madsen, D. Fischer, and M. Korpås, "Long-term electricity load forecasting: Current and future trends," *Utilities Policy*, vol. 58, pp. 102-119, 2019.
- [110] J. Moral-Carcedo and J. Pérez-García, "Time of day effects of temperature and daylight on short term electricity load," *Energy*, vol. 174, pp. 169-183, 2019.
- [111] T. Y.-w. Wu and V. Rai, "Quantifying diversity of electricity generation in the U.S.," *The Electricity Journal*, vol. 30, no. 7, pp. 55-66, 2017.
- [112] B. Y. Schindler, L. Blaustein, R. Lotan, H. Shalom, G. J. Kadas, and M. Seifan, "Green roof and photovoltaic panel integration: Effects on plant and arthropod diversity and electricity production," *Journal of Environmental Management*, vol. 225, pp. 288-299, 2018.
- [113] J. Huang and Z. Jiang, "Power Quality Assessment of Different Load Categories," *Energy Procedia*, vol. 141, pp. 345-351, 2017.
- [114] Y. Liu, M. Wang, X. Liu, and Y. Xiang, "Evaluating investment strategies for distribution networks based on yardstick competition and DEA," *Electric Power Systems Research*, vol. 174, p. 105868, 2019.
- [115] Y. X. He, J. Jiao, R. J. Chen, and H. Shu, "The optimization of Chinese power grid investment based on transmission and distribution tariff policy: A system dynamics approach," *Energy Policy*, vol. 113, pp. 112-122, 2018.
- [116] L. Dunnan, X. Erfeng, Q. Guangyu, and H. Yingjing, "Research on Reasonable Grid Investment Scale Measurement under The Reform of Transmission and Distribution Electricity Price," *Energy Procedia*, vol. 156, pp. 412-416, 2019.
- [117] P.-Y. Chen, S.-T. Chen, C.-S. Hsu, and C.-C. Chen, "Modeling the global relationships among economic growth, energy consumption and CO2 emissions," *Renewable and Sustainable Energy Reviews*, vol. 65, pp. 420-431, 2016.
- [118] E. M. Carlini, R. Schroeder, J. M. Birkebæk, and F. Massaro, "EU transition in power sector: How RES affects the design and operations of transmission power systems," *Electric Power Systems Research*, vol. 169, pp. 74-91, 2019.
- [119] J. L. R. Proops, P. W. Gay, S. Speck, and T. Schröder, "The lifetime pollution implications of various types of electricity generation. An input-output analysis," *Energy Policy*, vol. 24, no. 3, pp. 229-237, 1996.

- [120] L. Meng, E. R. Sanseverino, A. Luna, T. Dragicevic, J. C. Vasquez, and J. M. Guerrero, "Microgrid supervisory controllers and energy management systems: A literature review," *Renewable and Sustainable Energy Reviews*, vol. 60, pp. 1263-1273, 2016.
- [121] R. E. H. Sims, H.-H. Rogner, and K. Gregory, "Carbon emission and mitigation cost comparisons between fossil fuel, nuclear and renewable energy resources for electricity generation," *Energy Policy*, vol. 31, no. 13, pp. 1315-1326, 2003.
- [122] R. J. Allam *et al.*, "High Efficiency and Low Cost of Electricity Generation from Fossil Fuels While Eliminating Atmospheric Emissions, Including Carbon Dioxide," *Energy Procedia*, vol. 37, pp. 1135-1149, 2013.
- [123] A. Bhuiya and N. Chowdhury, "Allocation of transmission losses in a deregulated power system network," in *Engineering Solutions for the Next Millennium. 1999 IEEE Canadian Conference on Electrical and Computer Engineering (Cat. No.99TH8411)*, 1999, vol. 2, pp. 1148-1152 vol.2.
- [124] G. Gross and S. Tao, "A physical-flow-based approach to allocating transmission losses in a transaction framework," *IEEE Transactions on Power Systems*, vol. 15, no. 2, pp. 631-637, 2000.
- [125] S. Howell, Y. Rezgui, J.-L. Hippolyte, B. Jayan, and H. Li, "Towards the next generation of smart grids: Semantic and holonic multi-agent management of distributed energy resources," *Renewable and Sustainable Energy Reviews*, vol. 77, pp. 193-214, 2017.
- [126] A. Rouhani, S. H. Hosseini, and M. Raoofat, "Composite generation and transmission expansion planning considering distributed generation," *International Journal of Electrical Power & Energy Systems*, vol. 62, pp. 792-805, 2014.
- [127] A. Ameli, S. Bahrami, F. Khazaeli, and M. Haghifam, "A Multiobjective Particle Swarm Optimization for Sizing and Placement of DGs from DG Owner's and Distribution Company's Viewpoints," *IEEE Transactions on Power Delivery*, vol. 29, no. 4, pp. 1831-1840, 2014.
- [128] W. Caisheng and M. H. Nehrir, "Analytical approaches for optimal placement of distributed generation sources in power systems," *IEEE Transactions on Power Systems*, vol. 19, no. 4, pp. 2068-2076, 2004.
- [129] P. Kayal and C. K. Chanda, "Placement of wind and solar based DGs in distribution system for power loss minimization and voltage stability improvement," *International Journal of Electrical Power & Energy Systems*, vol. 53, pp. 795-809, 2013.
- [130] S. Weicheng, Z. Wenxi, Z. Dong, and G. Yang, "Wind Power Peak Regulation Pricing Model Under Wind and Fire Alternative Trading Mechanism — A Case Study of Wind Power Integration, Gansu Province (Apr 2018)," in *2018 China International Conference on Electricity Distribution (CICED)*, 2018, pp. 2736-2741.

- [131] M. Liserre, R. Teodorescu, and F. Blaabjerg, "Stability of photovoltaic and wind turbine grid-connected inverters for a large set of grid impedance values," *IEEE Transactions on Power Electronics*, vol. 21, no. 1, pp. 263-272, 2006.
- [132] M. Thomson and D. G. Infield, "Impact of widespread photovoltaics generation on distribution systems," *IET Renewable Power Generation*, vol. 1, no. 1, pp. 33-40, 2007.
- [133] W. El-Khattam and M. M. A. Salama, "Distributed generation technologies, definitions and benefits," *Electric Power Systems Research*, vol. 71, no. 2, pp. 119-128, 2004.
- [134] E. Rokrok, M. Shafie-khah, and J. P. S. Catalão, "Review of primary voltage and frequency control methods for inverter-based islanded microgrids with distributed generation," *Renewable and Sustainable Energy Reviews*, vol. 82, pp. 3225-3235, 2018.
- [135] G. Pepermans, J. Driesen, D. Haeseldonckx, R. Belmans, and W. D'haeseleer, "Distributed generation: definition, benefits and issues," *Energy Policy*, vol. 33, no. 6, pp. 787-798, 2005.
- [136] R. Dorsey-Palmateer, "Effects of wind power intermittency on generation and emissions," *The Electricity Journal*, vol. 32, no. 3, pp. 25-30, 2019.
- [137] S. Dahlke, "Effects of wholesale electricity markets on wind generation in the midwestern United States," *Energy Policy*, vol. 122, pp. 358-368, 2018.
- [138] S. Tongsovit, S. Junlakarn, W. Wibulpolprasert, A. Chaianong, P. Kokchang, and N. V. Hoang, "The economics of solar PV self-consumption in Thailand," *Renewable Energy*, vol. 138, pp. 395-408, 2019.
- [139] R. Dogga and M. K. Pathak, "Recent trends in solar PV inverter topologies," *Solar Energy*, vol. 183, pp. 57-73, 2019.
- [140] M. Liu *et al.*, "Review on concentrating solar power plants and new developments in high temperature thermal energy storage technologies," *Renewable and Sustainable Energy Reviews*, vol. 53, pp. 1411-1432, 2016.
- [141] S. Ke, W. Yu, T. Wang, and Y. Ge, "Aerodynamic performance and wind-induced effect of large-scale wind turbine system under yaw and wind-rain combination action," *Renewable Energy*, vol. 136, pp. 235-253, 2019.
- [142] A. Rashad, S. Kamel, and F. Jurado, "Chapter 2 - The Basic Principles of Wind Farms," in *Distributed Generation Systems*, G. B. Gharehpetian and S. M. Mousavi Agah, Eds.: Butterworth-Heinemann, 2017, pp. 21-67.
- [143] S. Soula, J.-F. Georgis, and D. Salaün, "Quantifying the effect of wind turbines on lightning location and characteristics," *Atmospheric Research*, vol. 221, pp. 98-110, 2019.

- [144] S. Twaha and M. A. M. Ramli, "A review of optimization approaches for hybrid distributed energy generation systems: Off-grid and grid-connected systems," *Sustainable Cities and Society*, vol. 41, pp. 320-331, 2018.
- [145] B. Singh and J. Sharma, "A review on distributed generation planning," *Renewable and Sustainable Energy Reviews*, vol. 76, pp. 529-544, 2017.
- [146] S. N. Makhadmeh, A. T. Khader, M. A. Al-Betar, S. Naim, A. K. Abasi, and Z. A. A. Alyasseri, "Optimization methods for power scheduling problems in smart home: Survey," *Renewable and Sustainable Energy Reviews*, vol. 115, p. 109362, 2019.
- [147] C. King and B. Datta, "EV charging tariffs that work for EV owners, utilities and society," *The Electricity Journal*, vol. 31, no. 9, pp. 24-27, 2018.
- [148] M. A. Butturi, F. Lolli, M. A. Sellitto, E. Balugani, R. Gamberini, and B. Rimini, "Renewable energy in eco-industrial parks and urban-industrial symbiosis: A literature review and a conceptual synthesis," *Applied Energy*, vol. 255, p. 113825, 2019.
- [149] J. G. Roos and I. E. Lane, "Industrial power demand response analysis for one-part real-time pricing," *IEEE Transactions on Power Systems*, vol. 13, no. 1, pp. 159-164, 1998.
- [150] M. Behrangrad, "A review of demand side management business models in the electricity market," *Renewable and Sustainable Energy Reviews*, vol. 47, pp. 270-283, 2015.
- [151] F. Boshell and O. P. Veloza, "Review of developed demand side management programs including different concepts and their results," in *2008 IEEE/PES Transmission and Distribution Conference and Exposition: Latin America*, 2008, pp. 1-7.
- [152] P. Warren, "A review of demand-side management policy in the UK," *Renewable and Sustainable Energy Reviews*, vol. 29, pp. 941-951, 2014.
- [153] L. Gelazanskas and K. A. A. Gamage, "Demand side management in smart grid: A review and proposals for future direction," *Sustainable Cities and Society*, vol. 11, pp. 22-30, 2014.
- [154] K. Kostková, L. Omelina, P. Kyčina, and P. Jamrich, "An introduction to load management," *Electric Power Systems Research*, vol. 95, pp. 184-191, 2013.
- [155] R. Allasseri, A. Tripathi, T. Joji Rao, and K. J. Sreekanth, "A review on implementation strategies for demand side management (DSM) in Kuwait through incentive-based demand response programs," *Renewable and Sustainable Energy Reviews*, vol. 77, pp. 617-635, 2017.
- [156] Y. Wang, L. Liu, R. Wennersten, and Q. Sun, "Peak shaving and valley filling potential of energy management system in high-rise residential building," *Energy Procedia*, vol. 158, pp. 6201-6207, 2019.

- [157] M. Zachar and P. Daoutidis, "Scheduling and supervisory control for cost effective load shaping of microgrids with flexible demands," *Journal of Process Control*, vol. 74, pp. 202-214, 2019.
- [158] D. Toke, "UK Electricity Market Reform—revolution or much ado about nothing?," *Energy Policy*, vol. 39, no. 12, pp. 7609-7611, 2011.
- [159] R. E. A. Macatangay, "Market definition and dominant position abuse under the new electricity trading arrangements in England and Wales," *Energy Policy*, vol. 29, no. 5, pp. 337-340, 2001.
- [160] R. Green, "Are the British electricity trading and transmission arrangements future-proof?," *Utilities Policy*, vol. 18, no. 4, pp. 186-194, 2010.
- [161] G. Gürkan and R. Langestraat, "Modeling and analysis of renewable energy obligations and technology bandings in the UK electricity market," *Energy Policy*, vol. 70, pp. 85-95, 2014.
- [162] M. Ventosa, P. Linares, and I. J. Pérez-Arriaga, "Power System Economics," in *Regulation of the Power Sector*, I. J. Pérez-Arriaga, Ed. London: Springer London, 2013, pp. 47-123.
- [163] S. Dong, H. Li, F. Wallin, A. Avelin, Q. Zhang, and Z. Yu, "Volatility of electricity price in Denmark and Sweden," *Energy Procedia*, vol. 158, pp. 4331-4337, 2019.
- [164] H. W. Jeon, S. Lee, and C. Wang, "Estimating manufacturing electricity costs by simulating dependence between production parameters," *Robotics and Computer-Integrated Manufacturing*, vol. 55, pp. 129-140, 2019.
- [165] N. Gal, I. Milstein, A. Tishler, and C. K. Woo, "Investment in electricity capacity under fuel cost uncertainty: Dual-fuel and a mix of single-fuel technologies," *Energy Policy*, vol. 126, pp. 518-532, 2019.
- [166] P. F. S. Freitas, L. H. Macedo, and R. Romero, "A strategy for transmission network expansion planning considering multiple generation scenarios," *Electric Power Systems Research*, vol. 172, pp. 22-31, 2019.
- [167] Y. Lin, J. Zhang, B. Yang, H. Liu, and L. Zhao, "An optimal routing strategy for transport networks with minimal transmission cost and high network capacity," *Physica A: Statistical Mechanics and its Applications*, vol. 521, pp. 551-561, 2019.
- [168] I. Ziari, G. Ledwich, A. Ghosh, and G. Platt, "Optimal distribution network reinforcement considering load growth, line loss, and reliability," *IEEE Transactions on Power Systems*, vol. 28, no. 2, pp. 587-597, 2013.
- [169] V. F. Martins and C. L. T. Borges, "Active Distribution Network Integrated Planning Incorporating Distributed Generation and Load Response Uncertainties," *IEEE Transactions on Power Systems*, vol. 26, no. 4, pp. 2164-2172, 2011.

- [170] J. Crispim, J. Braz, R. Castro, and J. Esteves, "Smart Grids in the EU with smart regulation: Experiences from the UK, Italy and Portugal," *Utilities Policy*, vol. 31, pp. 85-93, 2014.
- [171] V. Hamidi, K. S. Smith, and R. C. Wilson, "Smart Grid technology review within the Transmission and Distribution sector," in *2010 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT Europe)*, 2010, pp. 1-8.
- [172] P. K. Tiwari, M. K. Mishra, and S. Dawn, "A two step approach for improvement of economic profit and emission with congestion management in hybrid competitive power market," *International Journal of Electrical Power & Energy Systems*, vol. 110, pp. 548-564, 2019.
- [173] M. A. Fotouhi Ghazvini *et al.*, "Congestion management in active distribution networks through demand response implementation," *Sustainable Energy, Grids and Networks*, vol. 17, p. 100185, 2019.
- [174] S. MacDonald and N. Eyre, "An international review of markets for voluntary green electricity tariffs," *Renewable and Sustainable Energy Reviews*, vol. 91, pp. 180-192, 2018.
- [175] S. Bu, F. R. Yu, and P. X. Liu, "Dynamic pricing for demand-side management in the smart grid," in *2011 IEEE Online Conference on Green Communications*, 2011, pp. 47-51.
- [176] D. Srinivasan, S. Rajgarhia, B. M. Radhakrishnan, A. Sharma, and H. P. Khincha, "Game-Theory based dynamic pricing strategies for demand side management in smart grids," *Energy*, vol. 126, pp. 132-143, 2017.
- [177] G. Dutta and K. Mitra, "A literature review on dynamic pricing of electricity," *Journal of the Operational Research Society*, vol. 68, no. 10, pp. 1131-1145, 2017.
- [178] M. G. Pollitt and A. Brophy Haney, "Dismantling a Competitive Retail Electricity Market: Residential Market Reforms in Great Britain," *The Electricity Journal*, vol. 27, no. 1, pp. 66-73, 2014.
- [179] B. Ćosić, N. Markovska, G. Krajačić, V. Taseska, and N. Duić, "Environmental and economic aspects of higher RES penetration into Macedonian power system," *Applied Thermal Engineering*, vol. 43, pp. 158-162, 2012.
- [180] C. Gu, X. Yan, Z. Yan, and F. Li, "Dynamic pricing for responsive demand to increase distribution network efficiency," *Applied Energy*, vol. 205, pp. 236-243, 2017.
- [181] P. Mirzania, A. Ford, D. Andrews, G. Ofori, and G. Maidment, "The impact of policy changes: The opportunities of Community Renewable Energy projects in the UK and the barriers they face," *Energy Policy*, vol. 129, pp. 1282-1296, 2019.
- [182] A. Tiwary, S. Spasova, and I. D. Williams, "A community-scale hybrid energy system integrating biomass for localised solid waste and

- renewable energy solution: Evaluations in UK and Bulgaria," *Renewable Energy*, vol. 139, pp. 960-967, 2019.
- [183] P. Wild, "Determining commercially viable two-way and one-way 'Contract-for-Difference' strike prices and revenue receipts," *Energy Policy*, vol. 110, pp. 191-201, 2017.
- [184] E. Tvinnereim and M. Mehling, "Carbon pricing and deep decarbonisation," *Energy Policy*, vol. 121, pp. 185-189, 2018.
- [185] C. Brink, H. R. J. Vollebergh, and E. van der Werf, "Carbon pricing in the EU: Evaluation of different EU ETS reform options," *Energy Policy*, vol. 97, pp. 603-617, 2016.
- [186] H. Lund, "Renewable energy strategies for sustainable development," *Energy*, vol. 32, no. 6, pp. 912-919, 2007.
- [187] J. O. Petinrin and M. Shaaban, "Impact of renewable generation on voltage control in distribution systems," *Renewable and Sustainable Energy Reviews*, vol. 65, pp. 770-783, 2016.
- [188] O. Badran, S. Mekhilef, H. Mokhlis, and W. Dahalan, "Optimal reconfiguration of distribution system connected with distributed generations: A review of different methodologies," *Renewable and Sustainable Energy Reviews*, vol. 73, pp. 854-867, 2017.
- [189] R. Pegado, Z. Ñaupari, Y. Molina, and C. Castillo, "Radial distribution network reconfiguration for power losses reduction based on improved selective BPSO," *Electric Power Systems Research*, vol. 169, pp. 206-213, 2019.
- [190] G. Eason, B. Noble, and I. N. Sneddon, "On Certain Integrals of Lipschitz-Hankel Type Involving Products of Bessel Functions," *Philosophical Transactions of the Royal Society of London. Series A, Mathematical and Physical Sciences*, vol. 247, no. 935, pp. 529-551, 1955.
- [191] B. Enacheanu, B. Raison, R. Caire, O. Devaux, W. Bienia, and N. HadjSaid, "Radial Network Reconfiguration Using Genetic Algorithm Based on the Matroid Theory," *IEEE Transactions on Power Systems*, vol. 23, no. 1, pp. 186-195, 2008.
- [192] N. C. Sahoo and K. Prasad, "A fuzzy genetic approach for network reconfiguration to enhance voltage stability in radial distribution systems," *Energy Conversion and Management*, vol. 47, no. 18, pp. 3288-3306, 2006.
- [193] M. E. Baran and F. F. Wu, "Network reconfiguration in distribution systems for loss reduction and load balancing," *IEEE Transactions on Power Delivery*, vol. 4, no. 2, pp. 1401-1407, 1989.
- [194] M. N. M. Nasir, N. M. Shahrin, Z. H. Bohari, M. F. Sulaima, and M. Y. Hassan, "A Distribution Network Reconfiguration based on PSO: Considering DGs sizing and allocation evaluation for voltage profile improvement," in *2014 IEEE Student Conference on Research and Development*, 2014, pp. 1-6.

- [195] T. T. Nguyen, A. V. Truong, and T. A. Phung, "A novel method based on adaptive cuckoo search for optimal network reconfiguration and distributed generation allocation in distribution network," *International Journal of Electrical Power & Energy Systems*, vol. 78, pp. 801-815, 2016.
- [196] A. Merlin, "Search for a Minimal-Loss Operating Spanning Tree Configuration for an Urban Power Distribution System," *Proc. of 5th PSCC, 1975*, vol. 1, pp. 1-18, 1975.
- [197] S. Civanlar, J. J. Grainger, H. Yin, and S. S. H. Lee, "Distribution feeder reconfiguration for loss reduction," *IEEE Transactions on Power Delivery*, vol. 3, no. 3, pp. 1217-1223, 1988.
- [198] A. L. Morelato and A. J. Monticelli, "Heuristic search approach to distribution system restoration," *IEEE Transactions on Power Delivery*, vol. 4, no. 4, pp. 2235-2241, 1989.
- [199] Z. Qin, D. Shirmohammadi, and W. E. Liu, "Distribution feeder reconfiguration for operation cost reduction," *IEEE Transactions on Power Systems*, vol. 12, no. 2, pp. 730-735, 1997.
- [200] W. Lin, F. Cheng, and M. Tsay, "Distribution feeder reconfiguration with refined genetic algorithm," *IEE Proceedings - Generation, Transmission and Distribution*, vol. 147, no. 6, pp. 349-354, 2000.
- [201] Y. Hsu and H. Huang, "Distribution system service restoration using the artificial neural network approach and pattern recognition method," *IEE Proceedings - Generation, Transmission and Distribution*, vol. 142, no. 3, pp. 251-256, 1995.
- [202] R. Syahputra, I. Robandi, and M. Ashari, "Reconfiguration of distribution network with DG using fuzzy multi-objective method," in *2012 International Conference on Innovation Management and Technology Research*, 2012, pp. 316-321.
- [203] M. E. d. Oliveira, L. F. Ochoa, A. Padilha-Feltrin, and J. R. S. Mantovani, "Network reconfiguration and loss allocation for distribution systems with distributed generation," in *2004 IEEE/PES Transmission and Distribution Conference and Exposition: Latin America (IEEE Cat. No. 04EX956)*, 2004, pp. 206-211.
- [204] T. Hao, L. Lin, and W. Yanhan, "Research of distribution network reconfiguration with renewable energy power generation unit," in *2014 International Conference on Power System Technology*, 2014, pp. 2680-2685.
- [205] I. Song, S. Yun, S. Kwon, and N. Kwak, "Design of Smart Distribution Management System for Obtaining Real-Time Security Analysis and Predictive Operation in Korea," *IEEE Transactions on Smart Grid*, vol. 4, no. 1, pp. 375-382, 2013.
- [206] J. H. Holland, *Adaptation in Natural and Artificial Systems: An Introductory Analysis with Applications to Biology, Control and Artificial Intelligence*. MIT Press, 1992, p. 228.

- [207] K. Prasad, R. Ranjan, N. C. Sahoo, and A. Chaturvedi, "Optimal reconfiguration of radial distribution systems using a fuzzy mutated genetic algorithm," *IEEE Transactions on Power Delivery*, vol. 20, no. 2, pp. 1211-1213, 2005.
- [208] L. M. O. Queiroz and C. Lyra, "Adaptive Hybrid Genetic Algorithm for Technical Loss Reduction in Distribution Networks Under Variable Demands," *IEEE Transactions on Power Systems*, vol. 24, no. 1, pp. 445-453, 2009.
- [209] W. Zhuding, L. Haijun, D. C. Yu, W. Xiaohui, and S. Hongquan, "A practical approach to the conductor size selection in planning radial distribution systems," *IEEE Transactions on Power Delivery*, vol. 15, no. 1, pp. 350-354, 2000.
- [210] J. F. Franco, M. J. Rider, M. Lavorato, and R. Romero, "Optimal Conductor Size Selection and Reconductoring in Radial Distribution Systems Using a Mixed-Integer LP Approach," *IEEE Transactions on Power Systems*, vol. 28, no. 1, pp. 10-20, 2013.
- [211] S. M. Ismael, S. H. E. A. Aleem, A. Y. Abdelaziz, and A. F. Zobaa, "Practical Considerations for Optimal Conductor Reinforcement and Hosting Capacity Enhancement in Radial Distribution Systems," *IEEE Access*, vol. 6, pp. 27268-27277, 2018.
- [212] D. Gielen, F. Boshell, D. Saygin, M. D. Bazilian, N. Wagner, and R. Gorini, "The role of renewable energy in the global energy transformation," *Energy Strategy Reviews*, vol. 24, pp. 38-50, 2019.
- [213] A. Fan, L. Huang, S. Lin, N. Chen, L. Zhu, and X. Wang, "Performance Comparison Between Renewable Obligation and Feed-in Tariff with Contract for Difference in UK," in *2018 China International Conference on Electricity Distribution (CICED)*, 2018, pp. 2761-2765.
- [214] M. Z. Degefa, M. Humayun, A. Safdarian, M. Koivisto, R. J. Millar, and M. Lehtonen, "Unlocking distribution network capacity through real-time thermal rating for high penetration of DGs," *Electric Power Systems Research*, vol. 117, pp. 36-46, 2014.
- [215] A. Y. Hatata, A. S. Ebeid, and M. M. El-Saadawi, "Application of resistive super conductor fault current limiter for protection of grid-connected DGs," *Alexandria Engineering Journal*, vol. 57, no. 4, pp. 4229-4241, 2018.
- [216] A. W. Funkhouser and R. P. Huber, "A Method for Determining Economical ACSR Conductor Sizes for Distribution Systems [includes discussion]," *Transactions of the American Institute of Electrical Engineers. Part III: Power Apparatus and Systems*, vol. 74, no. 3, pp. 479-484, 1955.
- [217] S. Sivanagaraju, N. Sreenivasulu, M. Vijayakumar, and T. Ramana, "Optimal conductor selection for radial distribution systems," *Electric Power Systems Research*, vol. 63, no. 2, pp. 95-103, 2002.

- [218] S. M. Ismael, S. H. E. Abdel Aleem, A. Y. Abdelaziz, and A. F. Zobaa, "Chapter 8 - Optimal Conductor Selection of Radial Distribution Feeders: An Overview and New Application Using Grasshopper Optimization Algorithm," in *Classical and Recent Aspects of Power System Optimization*, A. F. Zobaa, S. H. E. Abdel Aleem, and A. Y. Abdelaziz, Eds.: Academic Press, 2018, pp. 185-217.
- [219] N. C. Sahoo, S. Ganguly, and D. Das, "Simple heuristics-based selection of guides for multi-objective PSO with an application to electrical distribution system planning," *Engineering Applications of Artificial Intelligence*, vol. 24, no. 4, pp. 567-585, 2011.
- [220] M. Vahid, A. A. Hossein, and M. Kazem, "Maximum loss reduction applying combination of optimal conductor selection and capacitor placement in distribution systems with nonlinear loads," in *2008 43rd International Universities Power Engineering Conference*, 2008, pp. 1-5.
- [221] H. Keyhan, G. McClure, and W. G. Habashi, "Dynamic analysis of an overhead transmission line subject to gusty wind loading predicted by wind-conductor interaction," *Computers & Structures*, vol. 122, pp. 135-144, 2013.
- [222] A. Y. Abdelaziz and A. Fathy, "A novel approach based on crow search algorithm for optimal selection of conductor size in radial distribution networks," *Engineering Science and Technology, an International Journal*, vol. 20, no. 2, pp. 391-402, 2017.
- [223] D. Kaur and J. Sharma, "Optimal conductor sizing in radial distribution systems planning," *International Journal of Electrical Power & Energy Systems*, vol. 30, no. 4, pp. 261-271, 2008.
- [224] R. S. Rao, K. Satish, and S. V. L. Narasimham, "Optimal Conductor Size Selection in Distribution Systems Using the Harmony Search Algorithm with a Differential Operator," *Electric Power Components and Systems*, vol. 40, no. 1, pp. 41-56, 2011.
- [225] R. C. Correa, A. Ferreira, and P. Rebreyend, "Scheduling multiprocessor tasks with genetic algorithms," *IEEE Transactions on Parallel and Distributed Systems*, vol. 10, no. 8, pp. 825-837, 1999.
- [226] J. Liu, Z. Cai, and J. Liu, "Premature convergence in genetic algorithm: analysis and prevention based on chaos operator," in *Proceedings of the 3rd World Congress on Intelligent Control and Automation (Cat. No.00EX393)*, 2000, vol. 1, pp. 495-499 vol.1.
- [227] O. Hrstka and A. Kučerová, "Improvements of real coded genetic algorithms based on differential operators preventing premature convergence," *Advances in Engineering Software*, vol. 35, no. 3, pp. 237-246, 2004.
- [228] H. M. Pandey, A. Chaudhary, and D. Mehrotra, "A comparative review of approaches to prevent premature convergence in GA," *Applied Soft Computing*, vol. 24, pp. 1047-1077, 2014.

- [229] A. E. Eiben, R. Hinterding, and Z. Michalewicz, "Parameter control in evolutionary algorithms," *IEEE Transactions on Evolutionary Computation*, vol. 3, no. 2, pp. 124-141, 1999.
- [230] M. J. Mahmoodabadi and A. R. Nemati, "A novel adaptive genetic algorithm for global optimization of mathematical test functions and real-world problems," *Engineering Science and Technology, an International Journal*, vol. 19, no. 4, pp. 2002-2021, 2016.
- [231] A. Cichy, B. Sakowicz, and M. Kaminski, "Economic Optimization of an Underground Power Cable Installation," *IEEE Transactions on Power Delivery*, vol. 33, no. 3, pp. 1124-1133, 2018.
- [232] J. Andre, P. Siarry, and T. Dognon, "An improvement of the standard genetic algorithm fighting premature convergence in continuous optimization," *Advances in Engineering Software*, vol. 32, no. 1, pp. 49-60, 2001.
- [233] M. Zeng, S. Leng, Y. Zhang, and J. He, "QoE-Aware Power Management in Vehicle-to-Grid Networks: A Matching-Theoretic Approach," *IEEE Transactions on Smart Grid*, vol. 9, no. 4, pp. 2468-2477, 2018.
- [234] Z. Zhu, S. Lu, B. Gao, T. Yi, and B. Chen, "Life Cycle Cost Analysis of Three Types of Power Lines in 10 kV Distribution Network," *Inventions*, vol. 1, no. 4, 2016.
- [235] C. Su and D. Kirschen, "Quantifying the Effect of Demand Response on Electricity Markets," *IEEE Transactions on Power Systems*, vol. 24, no. 3, pp. 1199-1207, 2009.
- [236] A. G. Bakirtzis, Y.-H. Kim, and A. P. Sakis Meliopoulos, "Monte Carlo simulation for evaluating retail wheeling effects," *Electric Power Systems Research*, vol. 60, no. 3, pp. 137-144, 2002.
- [237] F. Li, "Long-Run Marginal Cost Pricing Based on Network Spare Capacity," *IEEE Transactions on Power Systems*, vol. 22, no. 2, pp. 885-886, 2007.
- [238] C. Gu and F. Li, "Long-Run Marginal Cost Pricing Based on Analytical Method for Revenue Reconciliation," *IEEE Transactions on Power Systems*, vol. 26, no. 1, pp. 103-110, 2011.
- [239] H. Ronellenfitsch, M. Timme, and D. Witthaut, "A Dual Method for Computing Power Transfer Distribution Factors," *IEEE Transactions on Power Systems*, vol. 32, no. 2, pp. 1007-1015, 2017.
- [240] K. L. Lo and S. P. Zhu, "Wheeling and marginal wheeling rates: Theory and case study results," *Electric Power Systems Research*, vol. 27, no. 1, pp. 11-26, 1993.
- [241] A. I. Aldaoudeyeh, R. G. Kavasseri, and I. T. Lima, "Characterization of Forward Electricity Market Price Variations and Price-Responsive Demands," in *2017 Ninth Annual IEEE Green Technologies Conference (GreenTech)*, 2017, pp. 211-218.

- [242] D. S. Kirschen, G. Strbac, P. Cumperayot, and D. d. P. Mendes, "Factoring the elasticity of demand in electricity prices," *IEEE Transactions on Power Systems*, vol. 15, no. 2, pp. 612-617, 2000.
- [243] I. A. G. Wilson, P. G. McGregor, D. G. Infield, and P. J. Hall, "Grid-connected renewables, storage and the UK electricity market," *Renewable Energy*, vol. 36, no. 8, pp. 2166-2170, 2011.
- [244] F. Zhao, P. B. Luh, J. H. Yan, G. A. Stern, and S. Chang, "Payment Cost Minimization Auction for Deregulated Electricity Markets With Transmission Capacity Constraints," *IEEE Transactions on Power Systems*, vol. 23, no. 2, pp. 532-544, 2008.
- [245] M. Ram, M. Child, A. Aghahosseini, D. Bogdanov, A. Lohrmann, and C. Breyer, "A comparative analysis of electricity generation costs from renewable, fossil fuel and nuclear sources in G20 countries for the period 2015-2030," *Journal of Cleaner Production*, vol. 199, pp. 687-704, 2018.
- [246] P. N. Biskas, D. I. Chatzigiannis, and A. G. Bakirtzis, "European Electricity Market Integration With Mixed Market Designs—Part I: Formulation," *IEEE Transactions on Power Systems*, vol. 29, no. 1, pp. 458-465, 2014.
- [247] N. O. Connell, P. Pinson, H. Madsen, and M. O. Malley, "Economic Dispatch of Demand Response Balancing Through Asymmetric Block Offers," *IEEE Transactions on Power Systems*, vol. 31, no. 4, pp. 2999-3007, 2016.
- [248] M. Song and M. Amelin, "Purchase Bidding Strategy for a Retailer With Flexible Demands in Day-Ahead Electricity Market," *IEEE Transactions on Power Systems*, vol. 32, no. 3, pp. 1839-1850, 2017.
- [249] M. Rahimiyan and L. Baringo, "Strategic Bidding for a Virtual Power Plant in the Day-Ahead and Real-Time Markets: A Price-Taker Robust Optimization Approach," *IEEE Transactions on Power Systems*, vol. 31, no. 4, pp. 2676-2687, 2016.
- [250] M. Kohansal and H. Mohsenian-Rad, "Price-Maker Economic Bidding in Two-Settlement Pool-Based Markets: The Case of Time-Shiftable Loads," *IEEE Transactions on Power Systems*, vol. 31, no. 1, pp. 695-705, 2016.
- [251] K. Singh, N. P. Padhy, and J. Sharma, "Influence of Price Responsive Demand Shifting Bidding on Congestion and LMP in Pool-Based Day-Ahead Electricity Markets," *IEEE Transactions on Power Systems*, vol. 26, no. 2, pp. 886-896, 2011.
- [252] R. Fernández-Blanco, J. M. Arroyo, and N. Alguacil, "On the Solution of Revenue- and Network-Constrained Day-Ahead Market Clearing Under Marginal Pricing—Part I: An Exact Bilevel Programming Approach," *IEEE Transactions on Power Systems*, vol. 32, no. 1, pp. 208-219, 2017.
- [253] H. Ye, Y. Ge, M. Shahidehpour, and Z. Li, "Uncertainty Marginal Price, Transmission Reserve, and Day-Ahead Market Clearing With Robust Unit

- Commitment," *IEEE Transactions on Power Systems*, vol. 32, no. 3, pp. 1782-1795, 2017.
- [254] W. Liu, Q. Wu, F. Wen, and J. Østergaard, "Day-Ahead Congestion Management in Distribution Systems Through Household Demand Response and Distribution Congestion Prices," *IEEE Transactions on Smart Grid*, vol. 5, no. 6, pp. 2739-2747, 2014.
- [255] A. Stephens and D. R. Walwyn, "Wind energy in the United Kingdom: modelling the effect of increases in installed capacity on generation efficiency," *Renewable Energy Focus*, vol. 27, pp. 44-58, 2018.
- [256] T. Georgitsioti, N. Pearsall, and I. Forbes, "Simplified levelised cost of the domestic photovoltaic energy in the UK: the importance of the feed-in tariff scheme," *IET Renewable Power Generation*, vol. 8, no. 5, pp. 451-458, 2014.
- [257] I. Richardson, M. Thomson, D. Infield, and C. Clifford, "Domestic electricity use: A high-resolution energy demand model," *Energy and Buildings*, vol. 42, no. 10, pp. 1878-1887, 2010.
- [258] Y. G. Yohanis, J. D. Mondol, A. Wright, and B. Norton, "Real-life energy use in the UK: How occupancy and dwelling characteristics affect domestic electricity use," *Energy and Buildings*, vol. 40, no. 6, pp. 1053-1059, 2008.
- [259] R. Yao and K. Steemers, "A method of formulating energy load profile for domestic buildings in the UK," *Energy and Buildings*, vol. 37, no. 6, pp. 663-671, 2005.

Appendix

A. Power flow data and branch data for 37 bus distribution system

A.1 Branch data for 37 bus distribution system

Node A	Node B	Length(ft.)	Config.
701	702	960	722
702	705	400	724
702	713	360	723
702	703	1320	722
703	727	240	724
703	730	600	723
704	714	80	724
704	720	800	723
705	742	320	724
705	712	240	724
706	725	280	724
707	724	760	724
707	722	120	724
708	733	320	723
708	732	320	724
709	731	600	723
709	708	320	723
710	735	200	724
710	736	1280	724
711	741	400	723
711	740	200	724
713	704	520	723
714	718	520	724
720	707	920	724
720	706	600	723
727	744	280	723
730	709	200	723
733	734	560	723
734	737	640	723
734	710	520	724
737	738	400	723
738	711	400	723
744	728	200	724
744	729	280	724
775	709	0	XFM-1
799	701	1850	721

A.2 Underground cable data used for 37 bus distribution system

Config.	Phasing	Cable	Spacing ID
721	A B C	1,000,000 AA, CN	515
722	A B C	500,000 AA, CN	515
723	A B C	2/0 AA, CN	515
724	A B C	#2 AA, CN	515

A.3 Loads data for 37 bus distribution system

Node	Load	Ph-1		Ph-2		Ph-3		Ph-4	
		kW	kVAr	kW	kVAr	kW	kVAr	kW	kVAr
701	D-PQ	140	70	140	70	350	175		
712	D-PQ	0	0	0	0	85	40		
713	D-PQ	0	0	0	0	85	40		
714	D-I	17	8	21	10	0	0		
718	D-Z	85	40	0	0	0	0		
720	D-PQ	0	0	0	0	85	40		
722	D-I	0	0	140	70	21	10		
724	D-Z	0	0	42	21	0	0		
725	D-PQ	0	0	42	21	0	0		
727	D-PQ	0	0	0	0	42	21		
728	D-PQ	42	21	42	21	42	21		
729	D-I	42	21	0	0	0	0		
730	D-Z	0	0	0	0	85	40		
731	D-Z	0	0	85	40	0	0		
732	D-PQ	0	0	0	0	42	21		
733	D-I	85	40	0	0	0	0		
734	D-PQ	0	0	0	0	42	21		
735	D-PQ	0	0	0	0	85	40		
736	D-Z	0	0	42	21	0	0		
737	D-I	140	70	0	0	0	0		
738	D-PQ	126	62	0	0	0	0		
740	D-PQ	0	0	0	0	85	40		
741	D-I	0	0	0	0	42	21		
742	D-Z	8	4	85	40	0	0		
744	D-PQ	42	21	0	0	0	0		
Total		727	357	639	314	1091	530		

A.4 Predicted load profiles for 37 bus distribution system

1) PART 1

Demand factor for each node of different time slot (demand factor/each hour)												
Node	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00
1	0.054	0.275	0.168	0.197	0.238	0.259	0.158	0.186	0.232	0.159	0.212	0.168
2	0.051	0.050	0.087	0.050	0.087	0.085	0.060	0.211	0.116	0.082	0.115	0.081
3	0.154	0.193	0.042	0.093	0.095	0.114	0.329	0.336	0.269	0.520	0.358	0.115
4	0.025	0.057	0.086	0.083	0.079	0.055	0.069	0.107	0.094	0.402	0.487	0.728
5	0.145	0.131	0.056	0.132	0.119	0.113	0.444	0.568	0.350	0.209	0.321	0.294
6	0.044	0.083	0.082	0.051	0.061	0.083	0.066	0.595	0.180	0.352	0.176	1.000
7	0.057	0.053	0.065	0.045	0.077	0.071	0.038	0.077	0.084	0.075	0.077	0.077
8	0.047	0.198	0.192	0.096	0.161	0.084	0.198	0.252	0.192	0.097	0.351	0.154
9	0.028	0.127	0.064	0.113	0.127	0.073	0.122	0.103	0.078	0.143	0.677	0.072
10	0.069	0.125	0.108	0.173	0.173	0.149	0.107	0.965	0.356	0.233	0.325	1.000
11	0.023	0.023	0.023	0.023	0.023	0.061	0.274	0.023	0.023	0.625	0.404	0.581
12	0.126	0.126	0.126	0.126	0.074	0.126	0.097	0.103	0.074	0.126	0.129	0.098
13	0.073	0.083	0.080	0.058	0.073	0.094	0.075	0.051	0.350	0.555	1.000	0.730
14	0.067	0.067	0.104	0.104	0.045	0.067	0.097	0.076	0.311	0.840	0.289	1.000
15	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.027	0.212	0.238	0.420
16	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.431	0.096	0.200	0.190
17	0.030	0.019	0.019	0.019	0.019	0.019	0.019	0.052	0.065	0.019	0.019	0.019
18	0.052	0.023	0.023	0.023	0.042	0.252	0.023	0.427	0.023	0.798	0.777	0.999
19	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.815	0.914	0.883
20	0.105	0.076	0.138	0.141	0.046	0.133	0.158	0.047	0.142	0.137	0.230	0.178
21	0.107	0.099	0.190	0.121	0.145	0.090	0.179	0.197	0.180	0.194	0.150	0.254
22	0.061	0.068	0.060	0.095	0.032	0.082	0.096	0.625	0.382	0.371	0.172	0.098
23	0.055	0.082	0.069	0.089	0.104	0.102	0.058	0.080	0.042	1.000	0.641	0.188
24	0.035	0.071	0.065	0.057	0.079	0.035	0.152	0.130	0.061	0.067	0.077	0.746
25	0.235	0.412	0.359	0.433	0.526	0.401	0.307	0.490	0.367	0.335	0.526	0.502

1) PART 2

Demand factor for each node of different time slot (demand factor/each hour)												
Node	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
1	0.275	0.233	0.095	0.275	0.168	0.264	0.186	0.282	0.592	1.000	0.269	0.116
2	0.256	0.188	0.075	0.097	0.189	0.112	0.087	0.087	0.171	1.000	0.214	0.212
3	1.000	0.409	0.133	0.113	0.110	0.082	0.072	0.149	0.111	0.478	0.281	0.192
4	0.137	0.079	0.049	0.136	1.000	0.132	0.626	0.663	0.684	0.730	0.243	0.077
5	0.152	0.147	0.766	0.306	0.617	1.000	0.394	0.310	0.380	0.418	0.125	0.087

6	0.131	0.068	0.083	0.083	0.116	0.177	0.203	0.173	0.180	0.149	0.083	0.083
7	0.049	0.558	0.097	0.938	0.762	1.000	0.685	0.793	0.635	0.151	0.313	0.157
8	0.162	0.230	0.395	0.281	0.301	0.292	0.658	0.263	0.503	0.780	1.000	0.321
9	0.100	0.232	0.338	0.098	0.202	1.000	0.317	0.954	0.255	0.383	0.218	0.091
10	0.796	0.504	0.762	0.128	0.454	0.260	0.351	0.186	0.357	0.288	0.306	0.173
11	1.000	0.123	0.166	0.146	0.126	0.191	0.125	0.172	0.367	0.176	0.190	0.153
12	0.323	0.277	1.000	0.529	0.580	0.169	0.197	0.316	0.202	0.194	0.130	0.123
13	0.546	0.735	0.054	0.094	0.094	0.046	0.076	0.088	0.099	0.736	0.597	0.347
14	0.381	0.324	0.268	0.110	0.183	0.336	0.393	0.312	0.289	0.495	0.430	0.116
15	1.000	0.152	0.365	0.476	0.356	0.763	0.128	0.175	0.020	0.020	0.063	0.020
16	0.184	0.151	0.140	0.940	0.767	1.000	0.814	0.334	0.029	0.029	0.084	0.029
17	0.019	0.019	0.064	0.454	0.888	0.990	0.767	0.286	0.755	0.780	1.000	0.197
18	0.836	0.127	0.147	1.000	0.427	0.216	0.894	0.877	0.964	0.969	0.729	0.473
19	0.778	0.071	0.128	0.058	0.523	0.970	1.000	0.968	0.661	0.540	0.493	0.026
20	0.152	0.127	0.119	0.432	0.241	0.577	1.000	0.243	0.163	0.236	0.325	0.229
21	1.000	0.169	0.148	0.099	0.158	0.130	0.265	0.210	0.266	0.295	0.252	0.244
22	0.191	0.174	1.000	0.168	0.264	0.487	0.495	0.216	0.236	0.190	0.073	0.102
23	0.110	0.108	0.476	0.075	0.206	0.342	0.275	0.064	0.204	0.283	0.132	0.116
24	0.150	0.167	0.062	0.181	0.354	0.473	0.215	1.000	0.218	0.183	0.196	0.087
25	0.375	0.411	0.532	0.317	0.526	0.504	0.457	1.000	0.331	0.399	0.467	0.332

A.5 Predicted PV and wind generation for 37 bus distribution system

Predicted hourly wind generation											
Time (h)	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00
Capacity factor	0.90	0.90	0.88	0.96	1.00	0.93	0.94	0.82	0.56	0.60	0.57
Time (h)	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
Capacity factor	0.68	0.92	0.97	1.00	1.00	1.00	0.81	0.37	0.32	0.30	0.34

Predicted hourly PV generation											
Time (h)	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00
Capacity factor	0.00	0.00	0.00	0.00	0.00	0.02	0.18	0.34	0.39	0.61	0.85
Time (h)	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
Capacity factor	0.72	0.56	1.00	0.84	0.63	0.64	0.61	0.16	0.03	0.00	0.00

B. Power flow data and branch data for 33 bus distribution system

B.1 Power flow data for 33 bus distribution system

Bus	Bus type	P_demand	Q_demand	baseKV	Vmax	Vmin
1	3	0	0	12.66	1	1
2	1	100	60	12.66	1.1	0.9
3	1	90	40	12.66	1.1	0.9
4	1	120	80	12.66	1.1	0.9
5	1	60	30	12.66	1.1	0.9
6	1	60	20	12.66	1.1	0.9
7	1	200	100	12.66	1.1	0.9
8	1	200	100	12.66	1.1	0.9
9	1	60	20	12.66	1.1	0.9
10	1	60	20	12.66	1.1	0.9
11	1	45	30	12.66	1.1	0.9
12	1	60	35	12.66	1.1	0.9
13	1	60	35	12.66	1.1	0.9
14	1	120	80	12.66	1.1	0.9
15	1	60	10	12.66	1.1	0.9
16	1	60	20	12.66	1.1	0.9
17	1	60	20	12.66	1.1	0.9
18	1	90	40	12.66	1.1	0.9
19	1	90	40	12.66	1.1	0.9
20	1	90	40	12.66	1.1	0.9
21	1	90	40	12.66	1.1	0.9
22	1	90	40	12.66	1.1	0.9
23	1	90	50	12.66	1.1	0.9
24	1	420	200	12.66	1.1	0.9
25	1	420	200	12.66	1.1	0.9
26	1	60	25	12.66	1.1	0.9
27	1	60	25	12.66	1.1	0.9
28	1	60	20	12.66	1.1	0.9
29	1	120	70	12.66	1.1	0.9
30	1	200	600	12.66	1.1	0.9
31	1	150	70	12.66	1.1	0.9
32	1	210	100	12.66	1.1	0.9
33	1	60	40	12.66	1.1	0.9

B.2 Branch data for 33 bus distribution system

Branch	From bus	To bus	R (Ω)	X (Ω)	angmin	angmax
1	1	2	0.0922	0.0470	-360	360
2	2	3	0.4930	0.2511	-360	360
3	3	4	0.3660	0.1864	-360	360
4	4	5	0.3811	0.1941	-360	360
5	5	6	0.8190	0.7070	-360	360
6	6	7	0.1872	0.6188	-360	360
7	7	8	0.7114	0.2351	-360	360
8	8	9	1.0300	0.7400	-360	360
9	9	10	1.0440	0.7400	-360	360
10	10	11	0.1966	0.0650	-360	360
11	11	12	0.3744	0.1238	-360	360

12	12	13	1.4680	1.1550	-360	360
13	13	14	0.5416	0.7129	-360	360
14	14	15	0.5910	0.5260	-360	360
15	15	16	0.7463	0.5450	-360	360
16	16	17	1.2890	1.7210	-360	360
17	17	18	0.7320	0.5740	-360	360
18	2	19	0.1640	0.1565	-360	360
19	19	20	1.5042	1.3554	-360	360
20	20	21	0.4095	0.4784	-360	360
21	21	22	0.7089	0.9373	-360	360
22	3	23	0.4512	0.3083	-360	360
23	23	24	0.8980	0.7091	-360	360
24	24	25	0.8960	0.7011	-360	360
25	6	26	0.2030	0.1034	-360	360
26	26	27	0.2842	0.1447	-360	360
27	27	28	1.0590	0.9337	-360	360
28	28	29	0.8042	0.7006	-360	360
29	29	30	0.5075	0.2585	-360	360
30	30	31	0.9744	0.9630	-360	360
31	31	32	0.3105	0.3619	-360	360
32	32	33	0.3410	0.5302	-360	360
33	21	8	2.0000	2.0000	-360	360

B.3 Baseload profiles

Based load profile											
Time (h)	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00
Load demand (W)	574.6	563.7	543	524.4	512.9	523.7	568.3	607.7	656.7	709.3	730.9
Time (h)	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
Load demand (W)	737.2	744.8	767.3	817.2	920	989.3	967.2	926.2	869	796.6	716

C. Power flow data and branch data for 69 bus distribution system

C.1 Power flow data for 69 bus distribution system

Bus	Type	Pd (kW)	Qd(kVar)	Base_KV	Vmax	Vmin
1	3	0	0	12.7	1.1	0.9
2	1	0	0	12.7	1.1	0.9
3	1	0	0	12.7	1.1	0.9
4	1	0	0	12.7	1.1	0.9
5	1	0	0	12.7	1.1	0.9
6	1	2.6	2.2	12.7	1.1	0.9
7	1	40.4	10	12.7	1.1	0.9
8	1	75	14	12.7	1.1	0.9

9	1	30	12	12.7	1.1	0.9
10	1	28	19	12.7	1.1	0.9
11	1	145	54	12.7	1.1	0.9
12	1	145	54	12.7	1.1	0.9
13	1	8	5.5	12.7	1.1	0.9
14	1	8	5.5	12.7	1.1	0.9
15	1	0	0	12.7	1.1	0.9
16	1	45.5	30	12.7	1.1	0.9
17	1	60	35	12.7	1.1	0.9
18	1	60	35	12.7	1.1	0.9
19	1	0	0	12.7	1.1	0.9
20	1	1	0.6	12.7	1.1	0.9
21	1	114	81	12.7	1.1	0.9
22	1	5.3	3.5	12.7	1.1	0.9
23	1	0	0	12.7	1.1	0.9
24	1	28	20	12.7	1.1	0.9
25	1	0	0	12.7	1.1	0.9
26	1	14	10	12.7	1.1	0.9
27	1	14	10	12.7	1.1	0.9
28	1	26	18.6	12.7	1.1	0.9
29	1	26	18.6	12.7	1.1	0.9
30	1	26	18.6	12.7	1.1	0.9
31	1	26	18.6	12.7	1.1	0.9
32	1	14	10	12.7	1.1	0.9
33	1	14	10	12.7	1.1	0.9
34	1	19.5	14	12.7	1.1	0.9
35	1	6	4	12.7	1.1	0.9
36	1	26	18.6	12.7	1.1	0.9
37	1	26	18.6	12.7	1.1	0.9
38	1	0	0	12.7	1.1	0.9
39	1	24	17	12.7	1.1	0.9
40	1	24	17	12.7	1.1	0.9
41	1	1.2	1	12.7	1.1	0.9
42	1	0	0	12.7	1.1	0.9
43	1	6	4.3	12.7	1.1	0.9
44	1	0	0	12.7	1.1	0.9
45	1	39.2	26.3	12.7	1.1	0.9
46	1	39.2	26.3	12.7	1.1	0.9
47	1	0	0	12.7	1.1	0.9
48	1	79	56.4	12.7	1.1	0.9
49	1	384.7	174.5	12.7	1.1	0.9
50	1	384.7	174.5	12.7	1.1	0.9
51	1	40.5	28.3	12.7	1.1	0.9
52	1	3.6	2.7	12.7	1.1	0.9
53	1	4.3	3.5	12.7	1.1	0.9
54	1	26.4	19	12.7	1.1	0.9

55	1	24	17.2	12.7	1.1	0.9
56	1	0	0	12.7	1.1	0.9
57	1	0	0	12.7	1.1	0.9
58	1	0	0	12.7	1.1	0.9
59	1	100	72	12.7	1.1	0.9
60	1	200	100	12.7	1.1	0.9
61	1	200	100	12.7	1.1	0.9
62	1	32	23	12.7	1.1	0.9
63	1	200	100	12.7	1.1	0.9
64	1	227	162	12.7	1.1	0.9
65	1	59	42	12.7	1.1	0.9
66	1	18	13	12.7	1.1	0.9
67	1	18	13	12.7	1.1	0.9
68	1	28	20	12.7	1.1	0.9
69	1	28	20	12.7	1.1	0.9

C.2 Branch data for 69 bus distribution system

Br. no. (i)	Send. end IS (i)	Recv. end IR (i)	R (Ω)	X (Ω)
1	1	2	0.0005	0.0012
2	2	3	0.0005	0.0012
3	3	4	0.0015	0.0036
4	4	5	0.0251	0.0294
5	5	6	0.366	0.1864
6	6	7	0.381	0.1941
7	7	8	0.0922	0.047
8	8	9	0.0493	0.0251
9	9	10	0.819	0.2707
10	10	11	0.1872	0.0619
11	11	12	0.7114	0.2351
12	12	13	1.03	0.34
13	13	14	1.044	0.34
14	14	15	1.058	0.3496
15	15	16	0.1966	0.065
16	16	17	0.3744	0.1238
17	17	18	0.0047	0.0016
18	18	19	0.3276	0.1083
19	19	20	0.2106	0.069
20	20	21	0.3416	0.1129
21	21	22	0.014	0.0046
22	22	23	0.1591	0.0526
23	23	24	0.3463	0.1145
24	24	25	0.7488	0.2475
25	25	26	0.3089	0.1021
26	26	27	0.1732	0.0572

27	3	28	0.0044	0.0108
28	28	29	0.064	0.1565
29	29	30	0.3978	0.1315
30	30	31	0.0702	0.0232
31	31	32	0.351	0.116
32	32	33	0.839	0.2816
33	33	34	1.708	0.5646
34	34	35	1.474	0.4873
35	3	36	0.0044	0.0108
36	36	37	0.064	0.1565
37	37	38	0.1053	0.123
38	38	39	0.0304	0.0355
39	39	40	0.0018	0.0021
40	40	41	0.7283	0.8509
41	41	42	0.31	0.3623
42	42	43	0.041	0.0478
43	43	44	0.0092	0.0116
44	44	45	0.1089	0.1373
45	45	46	0.0009	0.0012
46	4	47	0.0034	0.0084
47	47	48	0.0851	0.2083
48	48	49	0.2898	0.7091
49	49	50	0.0822	0.2011
50	8	51	0.0928	0.0473
51	51	52	0.3319	0.114
52	9	53	0.174	0.0886
53	53	54	0.203	0.1034
54	54	55	0.2842	0.1447
55	55	56	0.2813	0.1433
56	56	57	1.59	0.5337
57	57	58	0.7837	0.263
58	58	59	0.3042	0.1006
59	59	60	0.3861	0.1172
60	60	61	0.5075	0.2585
61	61	62	0.0974	0.0496
62	62	63	0.145	0.0738
63	63	64	0.7105	0.3619
64	64	65	1.041	0.5302
65	11	66	0.2012	0.0611
66	66	67	0.0047	0.0014
67	12	68	0.7394	0.2444
68	68	69	0.0047	0.0016

D. Power flow data and branch data for 6 bus distribution system

D.1 Power flow data for 6 bus distribution system

Buses No	Generation		Load	
	V p.u.	MVA	MW	MVAR
1	1	100		
2	1.04	15	20	10
3	1.04	40		
4	1.07	30		
5			40	15
6			30	10

D.2 Branch data for 6 bus distribution system

Lines	From bus	To bus	Resistance p.u.	Reactance p.u.
1	1	2	0.05	0.2
2	2	3	0.1	0.5
3	3	4	0.2	0.8
4	4	5	0.1	0.3
5	5	6	0.2	0.4
6	6	1	0.1	0.15
7	2	5	0.2	0.5