An Optimised Reactive Power Ancillary Service in Wind Power Integrated Systems

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Yichen Liu

Department of Electrical and Electronic Engineering

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Abstract

Due to legally binding decarbonisation targets and emerging technologies, the power system is undergoing unprecedented changes. Traditional generators are being replaced by renewable generators. Among them, wind power is considered to be one of the most important renewable energy resources. However, the reactive power capabilities of wind turbines are usually limited. Then, this replacement of traditional generators leads to insufficient reactive power compensation, which may cause voltage instability in the power systems. In this case, any contingency or outage will pose a more serious threat to the stable operation of the power systems. In addition, the reliability of existing power system optimisation schemes may be affected by wind power integration. It is deemed necessary to formulate a new scheme for the reactive power optimisation strategy in the wind power integrated systems.

This thesis presents a coordinated reactive power ancillary service strategy for the power systems with integrated wind farms. The strategy considers a day-ahead reactive power procurement (RPP) strategy and a day-ahead optimised reactive power dispatch (ORPD) strategy with hourly modifications.

The purpose of the proposed RPP strategy is to reduce total reactive power cost. Based on a chance-constrained stochastic optimisation, the strategy employs day-ahead predicted wind energy and load demand data considering uncertainties and contingencies to set reserved capacities for all reactive power providers. Using this strategy, both the unit commitment and economic dispatch of reactive power are achieved. In addition, the stochastic optimisation of the RPP strategy is achieved by a decision tree framework with an improved genetic algorithm.

As for the ORPD strategy, the objectives are to minimise voltage deviations, active power losses, wind turbine harmonics emission, and the number of switching operations of on-load tap changers (OLTCs). In this ORPD strategy, the deterministic optimisation has been solved using an improved genetic algorithm based on the elitist non-dominated sorting genetic algorithm with inheritance (i-NSGA-II) and a roulette wheel selection.

The proposed optimal reactive power ancillary service strategy can be applied to both transmission and distribution systems and has been rigorously tested by using IEEE 33-bus test system, PG&E 69-bus test system and modified real GB network. Results obtained confirmed the efficacy and applicability of the proposed strategy.

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

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List of publications

Journal publication

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Technical reports

Work Package 5, ‘D5.1 Literature review of dynamic voltage control in transmission networks,’ *MIGRATE Project Report*, 2021.

Work Package 5, ‘D5.2 Recommendations for future dynamic voltage control in the GB network,’ *MIGRATE Project Report*, 2021.

1 Introduction

Over the past decades, due to the worldwide target of reducing carbon emissions, renewable energy power generation technology has developed rapidly. Wind power, solar power, hydropower, biomass and other renewable energy resources are considered as alternative energy sources which have the trend to become the major form of energy supply [1]. At the same time, because of the increasing awareness of environmental protection throughout the world, renewable energy is widely believed to be able to alleviate climate change, especially through clean energy power generation to reduce greenhouse gas emissions in the atmosphere [2]. Furthermore, combining conventional resources with renewable energy sources significantly improves the power system reliability, especially under voltage fluctuations. This combined integration also reduces some of the limitations of renewable energy sources [1], [3].

However, the increasing penetration level of renewable energy generation systems may still cause a substantial impact on the stability issues of power systems owing to their uncertainties and intermittency. This may adversely affect the voltage stability level of the renewable energy integrated systems [4]. At present, wind power becomes one of the most important renewable energy resources around the world. Most of the wind power generations are based on extensively use of power electronics. Typical examples are Type-3 (doubly-fed induction generator, DFIG) and Type-4 (full convertor wind turbine, FCWT) wind turbines. The reactive power output capabilities of these kinds of wind turbines are usually limited. Then the integration of these kinds of generations may lead to reduced reactive power supply and power system inertia [5]. On the one hand, reduced reactive power support and increasingly complex system topologies have brought considerable challenges to stable and secure system operations. On the other hand, it is also necessary to operate the power system under more stressful conditions that are closer to the stability limits than ever before, considering economic issues and deregulation of the power system [5]-[8]. To operate power systems in a secure, economic and stable manner, reactive power control becomes more important than before. Nevertheless, some special optimised designs can be used to overcome these challenges such as optimised reactive power procurement plan and reactive power dispatch optimisation [1]. In this thesis, an optimal reactive power procurement plan and an optimal reactive power dispatch strategy are presented and considered simultaneously as a whole reactive power ancillary service strategy.

The rest of the chapter is organised as follows: Section 1.1 outlines the background behind the research presented in the thesis. In Section 1.2 the objectives and motivations of this research are presented. Then the main methodologies of this research have been provided in Section 1.3. Section 1.4 and Section 1.5 provide the contributions of the thesis and a list of publications, respectively. Finally, Section 1.6 outlines the rest of the chapters in the thesis.

1.1 Background

1.1.1 Wind power generations development

The majority of electric power in conventional power systems is supplied by fossil fuel generation plants. However, due to the depletion of fossil resources worldwide and the increasing awareness of environmental protection in most countries, renewable energy sources have developed rapidly in recent years. The United Kingdom (UK) has set a legal binding decarbonisation target to net zero by 2050 compared to 1990 [9]. To achieve its ambitious carbon neutrality goal, the UK will have to build another 120 GW of renewable energy generation capacity [10].

Among all kinds of renewable energy resources, wind power generation technology is becoming gradually mature. Its power generation costs reduce gradually and its economic benefits are getting higher accordingly. Wind energy has many advantages: cost effective; clean power generation process; sustainable; inexhaustible and so on [11]. It has progressively become one of the fastest growing and largest forms of renewable power generation. In recent years, countries around the world continue to increase investment in the wind power industry and research on related technologies [12]. At the same time, governments around the world have formulated preferential policies to encourage and promote the development of the wind power industry [13]. As shown in Figure 1-1, wind power global capacity has increased sharply in the past 10 years.

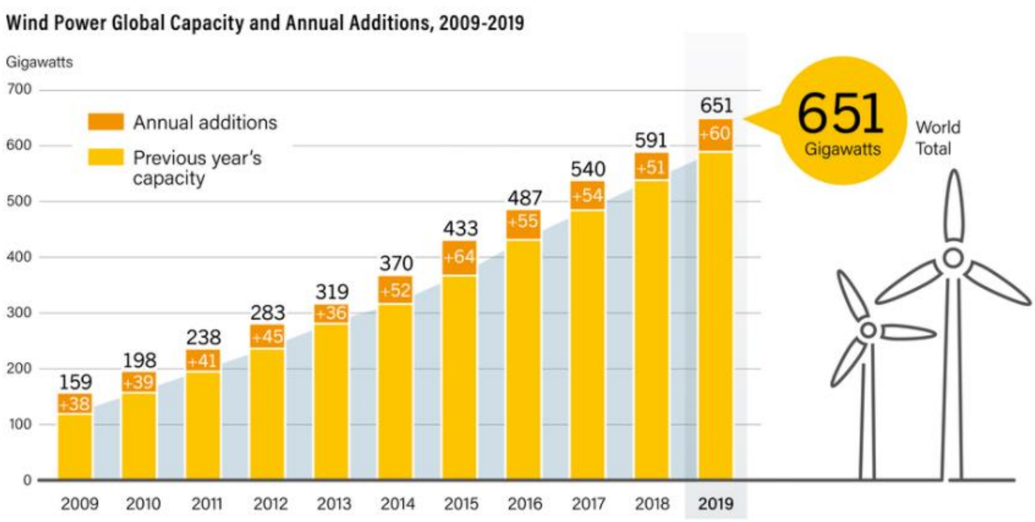


Figure 1-1 Wind power global capacity and annual additions, 2009-2019 [12]

With a large number of wind power integration, the research on power system stability issues of the wind power integrated systems becomes a significant important topic. Two major differences between conventional generators and wind turbines are that most wind turbines do not contribute to power system inertia and fault level and normally most of them are considered as can only contribute a very limited amount of reactive power [4]. Based on these characteristics, wind power integrated networks deserve more attention from energy management systems and system operators.

1.1.2 **Electrical energy management system (EMS)**

Energy management system (EMS) is a computer-aided tool used in control rooms by power system operators to monitor, control and perform optimised energy management and operational planning, which consists both hardware and software parts. The hardware part of EMS includes remote terminal units (RTU), intelligent electronic devices (IED), protection, computer network, etc. As for the software part of EMS, it consists of application programs for power system metering, monitoring and network analysis. One of the purposes of an EMS is to determine power generation or power demand at each node and to achieve specific objectives such as minimising power generation costs, minimising power loss, or reducing environmental impact [14]. RTU is an integral part of the supervisory control and data acquisition (SCADA) to EMS or the energy control centre (ECC). Inside SCADA, based on the information measured through RTU, a monitoring function is applied which can collect voltage magnitudes, power flow data etc. [15], [16]. The main task of SCADA and EMS combined system is to constantly measure and monitor the parameters of the power system and to ensure reliable, stable and optimal operation of the controlled system [16].

Nowadays, there are mainly two kinds of control and operation systems. One is the SCADA / EMS / GMS (Supervision Control and Data Acquisition / Energy Management System / Generation Management System) which is used for supervision, control, optimisation and management in generation and transmission systems. The other one is SCADA / DMS (Supervision Control and Data Acquisition / Distribution Management System) which performs the same function as the previous one, but in distribution networks [17].

Both systems can help generation companies to collect, store and analyse data in country or regional networks, implement network modelling, simulate power operations, detect faults, or power delivery interruptions, or provide different types of other services, e.g. participation in power bidding market [17].

In EMS, applications are running in real-time and extended real-time environments to operate the geographically dispersed transmission and generation assets. In different countries and networks, EMS has various required functions. Nowadays, the main functions of EMS include generation dispatch and control, energy scheduling and accounting, transmission security management and etc. [16]. These functions are described below.

- Generation dispatch and control-(GDC) provides the functions required for multiple generators dispatching and closed-loop control simultaneously in an optimal manner. This should take into account the exchange plan, dynamic plan, time error correction, reservation requirements and security constraints of the network under a certain system operation guide.
- Energy scheduling and accounting-(ESA) provides applications to monitor the network reported standards, production costs, interchange scheduling, weather-adaptive demand forecasting and so on.
- Transmission security management-(TSM) provides applications to monitor and control the security constraints of power generation and transmission. Transmission security management system applications use real-time data to evaluate and improve system safety performance.

Therefore, an EMS is a computerized control centre of a power system consisting of several applications. The application is executed by the system operator to maintain power system in a secure and stable operation. As stated, EMS consists of several programs of specific interconnections to get solutions in real time. As one of the commonly used methods to ensure power system stability, reactive power ancillary service management is also applied in EMS. Consequently, the proposed optimal reactive power ancillary service strategy in this thesis can be applied to these functions to replace the conventional optimal reactive power dispatch manner and reservation plans to achieve a more reliable, secure and economic system operation. The implementation of the reactive power ancillary service optimisation strategy, presented in this Thesis, into EMS is shown in Figure **1-2**.

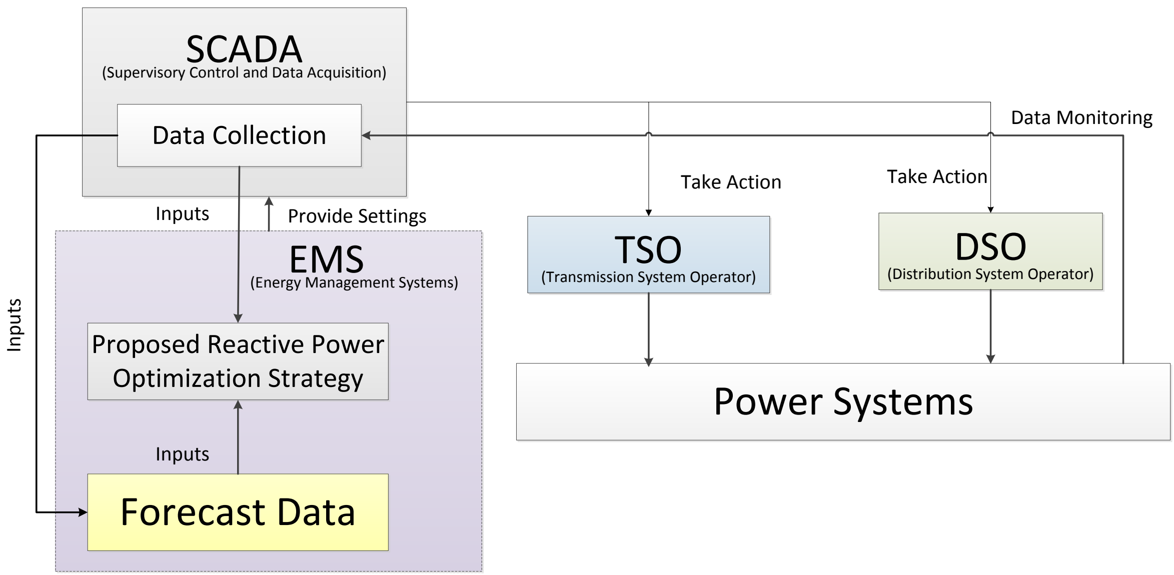


Figure 1-2 Implementation of the proposed reactive power optimisation strategy

As shown in the figure above, EMS and SCADA are both important entities for power systems. SCADA helps EMS to perform operational control of the power system through real-time monitoring. Power system data, both continuous and discrete are selectively transmitted to EMS by SCADA. The power and information flow between SCADA, EMS and system operators (SOs) can be observed in Figure 1-2. The monitored data from power systems to SCADA include both power flow data and information data. But the data from EMS to TSO/DSO then be fed back to the power system are only control actions and information data. So it can be concluded that the electrical data flow from the power system through SCADA to EMS is in single direction while information data flow form an interface of SCADA between power systems and EMS is bi-directional [15].

1.1.3 **Ancillary service**

In recent years, with the rapid development of economy, science and technology, the electricity industry is undergoing a major transformation. The electricity industry is a traditional industry with a long history, and it plays a very important role in the development of the national economy [8]. Due to the particularity electricity, it has been monopolized for a long time, implementing an integrated system of power generation, transmission, and distribution. This system effectively promoted the development of the electricity industry in its early stage. However, with the continuous expansion of the scale of the power system, especially the development of the modern market economy, the traditional power system was becoming increasingly unsuitable for economic development, and there was an urgent need to deregulate the power system and introduce a competition mechanism [6], [18].

Since the 1980s, UK has first explored the power system deregulation, and then the United States, Norway, Australia, Argentina and other countries have successively implemented power system deregulation including separation of generation companies and bidding mechanisms [19]. Although the specific mechanisms of various countries are not the same, the similar purpose was to eliminate monopoly, promote competition, and promote the development of electricity industry [7]. Consequently, the gradual implementations of electricity market and power system deregulation have brought a series of related issues that require further in-depth study.

In order to meet the needs of users and to adapt competition among the generation companies, the power system must be able to produce, transmit and distribute high-quality, low-cost electrical energy. Due to the particularity of power production, to ensure that users can receive high-quality and low-cost electrical power, it must rely on grid-related ancillary services to ensure the economic and stable operation of the power systems [19]. As for the term ancillary service, it is used to refer to a variety of operations beyond generation and transmission that are required to support the basic services of generating capacity, energy supply and power delivery but to maintain power system stability [18].

These services generally include frequency control, reliability backup, reactive power reserve and voltage control, re-schedule/ re-dispatch, restoration service and so on [1]. The listed ancillary services are briefly explained below.

- Frequency control ancillary service is responsible for dealing with the mismatch between demand and power generation, to maintain the system frequency. Consequently, deviations between demand and power generation in the control area and the deviation between the actual value of the exchange power between the control areas and the planned value can be minimised. This service is run in real time.
- Reliability backup: Due to power generation or power transmission system fault, when the load and generation have a large deviation, the urgently needed capacity can be provided in a short time to restore the level of load tracking service. This load tracking service is to track the changes in load peaks and valleys in real-time.
- Reactive power reserve and voltage control: It is designed to inject or absorb reactive power into the system through generators or other reactive power providers to maintain the system reactive power balance and voltage stability.
- Re-schedule/ re-dispatch: When there is large power generation and load imbalance, the system operators must re-schedule the output of each generation.
- Restoration service: It is also called black start which is a process used to restore power when the national transmission system is completely or partially shut down.

Previously, due to the implementation of unified power dispatch and unified power management under the traditional power production mode, these functional services can be easily guaranteed so as to the reliability of power production. However, under the conditions of power system deregulation, the autonomy of generation companies has been enhanced but it has also brought huge challenges to the stable and reliable operation of the power system [20]. As a result, there will be various problems like power angle stability, voltage stability, overload and even collapse of the power system [21]-[23]. This has made the power system ancillary services being widely recognized as critical functions for stable and reliable power system operation. However, in the modern electricity market, generation companies cannot be required to provide ancillary services unconditionally [24]. Therefore, a series of problems must be solved, that are the costs associated with each ancillary service and the contribution of each ancillary service provider.

In deregulated power systems and competitive power markets, pricing ancillary services is normally based on contracts between Independent System Operator (ISO) who coordinates, controls, and monitors the grid and generation companies (GENCOs) who provide services to the grid for a specific period of time to provide the required ancillary services [18], [19]. Therefore, ancillary services are divided into different parts. Some of the ancillary services provided by the GENCOs are obtained by the ISO through compulsory services. For example, ISO may require the GENCOs to provide a certain value of reactive power services as obligatory service as a prerequisite for its integration. However, with the hyper growth of modern power system, the GENCOs may be required to provide more ancillary services under deregulated electricity market scheme. These part of the ancillary services with more commercial value can be obtained through electricity market so there will be more GENCOs aimed to participate in the ancillary service market for additional revenue [8].

If more ancillary services are required, the contracts of different ancillary services in transmission systems are usually processed in bidding procedure. As for distribution systems, there is not yet a bidding procedure for ancillary services; however, this procedure should also be used in the near future to ensure a stable and economic operation and also the profit of GENCOs. In modern electricity markets, not only traditional generations like synchronous generators (SGs) but also distributed generators (DGs) like renewable energy resources can contribute to the ancillary service market [25]-[38]. However, according to the current operation rules of the UK's electricity market, the providers of ancillary services still have to obey the dispatch schedule from system operator, which means it is essentially unified scheduled by the system operation centre and unified implemented dispatch on the basis of pre-agreed contract or bidding process [8].

With the continuous deepening of research and practice in the electricity market, ancillary service issues have attracted the interest of a number of researchers and generation companies due to their importance and technical complexity. Therefore, the research on ancillary services and their pricing methods has very important theoretical and practical significance in the deregulated power systems, especially for reactive power ancillary services. There is an urgent need for in-depth research on reactive power ancillary services in the electricity market.

1.2 Objective and motivation

Motivated by the high penetration of renewable energy sources, including wind farms (WFs) in both transmission and distribution networks, this thesis aims to provide an optimisation strategy for reactive power ancillary services management, to operate power system in a more stable, reliable and economic manner in different time scales.

The scope of power system optimisation is broad. The research presented in this thesis mainly focuses on reactive power ancillary service optimisation in both distribution and transmission systems by using day-ahead reactive power procurement plans and day-ahead reactive power dispatch plans with hourly modifications.

Reactive power procurement (RPP) is basically a reservation planning issue between independent system operator (ISO) and generation companies based on a bidding procedure. The optimal set of RPP should cover the reactive power requirements in planned time period even when some outages, contingencies or uncertainties happen in a certain system. Considering the unpredictability of wind power, load demand and potential contingencies, stochastic optimisation of planed procurement in deregulated power system plays a vital role in the wind power integrated systems. The proposed RPP stochastic optimisation strategy in this thesis is based on the reactive power pricing procedure with the objective to minimise total reactive power ancillary service cost to ensure system economic operations which should be considered as a precondition for optimal reactive power dispatch. To use the stochastic optimisation is to consider all the possible scenarios to ensure the sufficient reactive power reservation should be made. Within this procurement procedure, both the unit commitment and economic dispatch of reactive power are achieved. Unit commitment is the process to decide when and which reactive power providers to use and the economic dispatch is the process to decide the output of each reactive power provider in time. The output of this procurement procedure is the reactive power reservation planning for the other day.

Optimal reactive power dispatch (ORPD) is one of the key ancillary services based on which the system stability is ensured. The proposed day-ahead ORPD strategy considers the following aspects relevant for optimal power system operation: a) power losses, b) voltage deviations, c) number of switching of OLTCs and d) harmonic emissions. They are a part of multi-objective optimisation problem. Considering the possible forecast errors of wind power and load demand, an hourly modification is also considered in the proposed ORPD strategy. Additionally, the reactive power reservation results obtained from RPP optimisation are considered as limits for ORPD. The whole process of the proposed reactive power ancillary service optimisation strategy is shown in Figure 1-3.

Figure 1-3 Reactive power ancillary service optimisation process

The main objectives of the research project can be summarised as follows:

- To propose a new reactive power ancillary service planning strategy for both transmission and distribution networks. This strategy should include both a stochastic reactive power procurement (RPP) strategy and a deterministic optimal reactive power dispatch (ORPD) strategy.
- To ensure system economic operations and schedule reservation plans for all reactive power providers, a comprehensive cost function based RPP strategy should be designed including all reactive power providers considering forecast errors, outages and contingencies. (Chapter 4)
- To provide precise settings for system operators to take operations for multiple generators, reactive power compensations and OLTCs, the ORPD strategy considering power loss, voltage deviations, operation times of vulnerable devices and harmonic distortions should be presented. With considering the forecast errors in day-ahead time scale, hourly modifications should also be included when the received forecast errors are above threshold value. (Chapter 5)
- To solve the formulated constrained objective functions, a proper solver should be applied to increase convergence speed at the same time not to jeopardise the calculation accuracy when the proposed strategies are applied to complex mesh networks. (Chapters 4 and 5).

1.3 Research methodology

The research work presented in this thesis is carried out through software simulations on a computer with 3.4 GHz processor and 16 GB RAM.

The simulation software used includes MATLAB [28] and MATPOWER [29] software packages, which enable power flow calculations and objective function solving process. Test systems include systems from literatures, e.g. IEEE 33-bus, PG&E 69-bus test system and real-life network i.e. GB 29-zone test system [30].

As mentioned before, considering uncertainties, contingencies and outages, a constrained stochastic objective function has been proposed to ensure both sufficient reserve and economic operation in reactive power procurement procedure. As for optimal reactive power dispatch problem, a constrained multi-objective function has been established to solve both day-ahead and hourly optimisations.

To solve the stochastic reactive power procurement objective function, a chance constrained decision tree framework has been used to address the potential scenarios the other day. Then for each scenario, an improved genetic algorithm (GA) is used to calculate the reserved reactive power from all reactive power providers. As for the optimal reactive power dispatch strategy, this improved genetic algorithm is also used to solve the proposed multi-objective function.

GA is one of the traditionally used solvers of non-convex mixed integer optimisation problems like the one formulated in this research. But in the multi-objective optimisation problem, the biggest problem is how to determine the importance of each objective. Multi-objective optimisation also known as Pareto optimisation involves the optimisation of multi-objective functions. The NSGA-II algorithm was proposed by [31] on the basis of GA which is ideal for constrained multi-objective optimisation problems like power system optimisation. Furthermore, it has been significantly improved and made more computationally efficient by involving parent inheritance in [32]. In this thesis, an improved genetic algorithm based on the elitist non-dominated sorting genetic algorithm with inheritance (i-NSGA-II) [32] and incorporating a roulette adaption selection algorithm [33] is used as an effective solver for proposed objective functions to optimise the reactive power ancillary service of power systems with integrated wind farms.

The proposed methodologies have been rigorously tested in both distribution and transmission networks. Results obtained confirmed the efficacy and applicability of the proposed strategy. More detailed information on the specific use of these strategies will be given in the appropriate chapters below.

1.4 **Main contributions**

The main contributions of this thesis can be summarized as follows:

- A new strategy of the reactive power ancillary service planning problem has been presented, including a day-ahead reactive power procurement (RPP) strategy considering minimising the total reactive power cost and a day-ahead optimal reactive power dispatch (ORPD) strategy with hourly modifications. This is the first time considering RPP and ORPD simultaneously as RPP should be seen as a precondition of ORPD to ensure both economic and stable operations. Novelties of the proposed RPP and ORPD strategies are:

- ❖ Considering outages, contingencies and uncertainties of day-ahead forecast data, the proposed reactive power procurement planning strategy is a stochastic optimisation strategy based on reactive power bidding procedures. All the reactive power providers e.g. grid connection point or synchronous generators (SGs), DGs, shunt reactors or compensators (SRCs) and flexible demand i.e. VAr reduction have been considered in this procedure. In this thesis, the cost function for each reactive power provider is formulated in a more comprehensive way when compared with the previous literatures. (Chapter 4)
- ❖ For optimising the operation of power systems with integrated wind farms, the presented coordinated optimal reactive power dispatch strategy has a more comprehensive multi-objective function. It considers a day-ahead reactive power dispatch with hourly modifications owing to the input data forecast errors. The objective function of this strategy consists: 1) reduce network voltage deviations, 2) minimise active power losses, 3) mitigate wind turbine harmonics emission, and 4) decrease the number of switching operations of on-load tap changers (OLTCs). With the comparison study, superior performances compared to previously published approaches have been shown. (Chapter 5)

- An improved GA approach, solving faster the formulated constrained optimisation problem, has been applied so that the proposed strategy can be applied into both day-ahead time scale and hourly modifications. As a meta-heuristic algorithm, it can also be used in both radial networks and mesh networks without introducing approximation errors. (Chapters 4 and 5)
- Both the proposed RPP and ORPD have been applied and tested into both transmission and distribution networks. (Chapters 4 and 5).

1.5 Thesis outline

The rest of the thesis is organised as follows.

Chapter 2 – Existing reactive power ancillary service in power system

This Chapter gives a brief introduction to existing reactive power ancillary services in power systems. First, the role and importance of providing reactive power as an ancillary service have been presented. Then the commonly used reactive power providers in the system have been introduced. After that, the potential reactive power loss in the power systems is also discussed.

Chapter 3 – Optimal reactive power ancillary service planning strategies in modern power systems

This Chapter describes the existing optimal reactive power ancillary service strategies in modern power systems. Firstly, the modern power system deregulation process has been introduced. Then, the commonly used reactive power pricing and procurement mechanisms have also been presented. After that, the existing modern optimal reactive power procurement and dispatch strategies are introduced. Technical motivation and control variables of optimal reactive power ancillary services have been discussed in detail when facing new challenges and opportunities. The main drawbacks of existing strategies have also been stated based on a thorough literature review. Last but not least, the commonly used solvers for constrained optimisation problems are categorized and introduced.

Chapter 4 – Reactive power procurement planning strategy considering contingencies in deregulated systems

In this Chapter, motivated by minimising reactive power ancillary service cost, a reactive power procurement strategy is proposed considering all available reactive power providers limitations, potential uncertainties, outages and contingencies. Every limitation and cost function of different reactive power provider has been detailed in this Chapter. After that, an improved genetic algorithm is introduced to solve the proposed cost function. This proposed reactive power procurement strategy has been simulated and tested using IEEE 33-bus system, PG&E 69-bus system and the modified real GB network. The outputs of this proposed strategy are all reserved reactive power capacities from different reactive power providers the other day.

Chapter 5 – Proposed optimised reactive power dispatch strategy in wind power integrated systems

A novel day-ahead optimised reactive power dispatch strategy with hourly modifications is proposed in this Chapter. The proposed strategy considers a comprehensive objective function including minimising power losses, voltage deviations, operation times of OLTCs and wind farms harmonic emissions. They are a part of constrained multi-objective mixed-integer optimisation problem. Every single objective and its satisfaction function have been detailed. In addition, the system constraints and control variables are defined. After that, the proposed ORPD strategy has been rigorously tested in IEEE 33-bus system, PG&E 69-bus system and the modified real GB network.

Chapter 6 – Conclusion and future work

This Chapter summarises the research work carried out in this thesis. In addition, some potential future work stemming from the thesis is presented.

2 Existing reactive power ancillary services in power systems

2.1 Introduction

The research work presented in this thesis is to provide optimisation plans for day-ahead reactive power ancillary service. So, firstly, it is important to understand the basic knowledge of existing reactive power ancillary services in power systems.

In order to maintain reliable and stable operation of power systems and to ensure power quality, other than active power production and transmission, multiple generation companies (GENCOs) and system operators (SOs) usually have to provide extra ancillary services as well. It normally includes frequency regulation, automatic power generation control, peak load regulation, reactive power adjustment, reserve, blackout restart, etc. [8].

As for reactive power ancillary services, they are critically important as the power system operations need sufficient reactive support to maintain both the power flow stability and bus voltage stability [19]. This chapter gives a brief introduction of existing reactive power ancillary services in power systems. Then, before optimising the reactive power ancillary services, it is important to clarify all the reactive power providers in the system. So the rest of the chapter is organized as follows. Section 2.2 details the role and importance of providing reactive power as an ancillary service. Section 2.3 specifics the commonly used reactive power providers in power systems. Section 2.4 presents the potential reactive power loss in systems. And Section 2.5 concludes the chapter.

2.2 Reactive power ancillary service

Most electrical equipment is operating according to electromagnetic induction, such as transformers, generators, etc., which rely on the establishment of an alternating magnetic field to convert and transfer power. The electrical power required to establish the alternating magnetic field and induced magnetic flux is called reactive power. Consequently, other than the widely known active power supply, reactive power is also required in the power supply system, both of which are indispensable. Reactive power is essential for the stable operation of the power system. It facilitates active power flow from generation sources to load centres [34]-[36] and maintains bus voltages within prescribed limits [37]. Especially the modern networks with integrated high penetration level of renewable energy, their reactive power insufficiency issues are more severe [38].

Most of the loads in the power system are inductive which should consume reactive power. In addition, the reactive power demand of a power system is related to the load conditions of transmission lines, transformers and cables. Reactive power service providers need to ensure that under heavily loaded conditions, they should still have the ability to provide enough reactive power to meet the needs of consumers and the system, while absorbing excessive system residual reactive power under light loaded conditions.

In addition, as shown in Figure 2-1, since the reactance of transmission lines are normally much larger than their resistance, i.e. $X >> R$, the load voltage magnitude is highly related to reactive power.

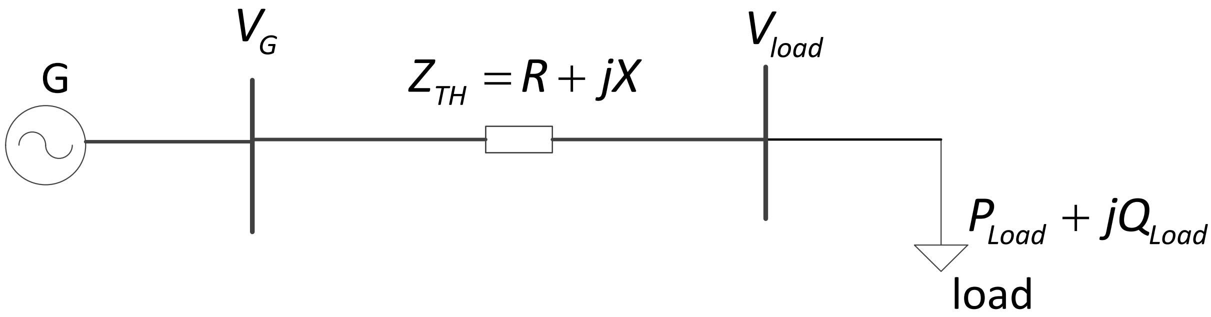


Figure 2-1 Power system Thevenin equivalent circuit

$$V_{load} \approx V_G - \Delta V = V_G - \frac{P_{load} R + Q_{load} X}{V_{load}} \tag{1}$$

Unlike the system-wide uniform characteristics of frequency, the bus voltage is highly associated with the local reactive power supply and demand. So having sufficient reactive power support on the major buses or heavily loaded buses can ensure these bus voltage to be better controlled, so that the voltage level of the entire system can be maintained in a safety range. Then the stable operation of the entire system can be ensured.

Also, reactive power optimisation is an effective measure to reduce network loss. A sensibly optimised reactive power supply and bus voltage level can reduce the active power loss in the network, thereby improving the operating efficiency of the entire system. Consequently, reactive power ancillary service is a necessary function for the economic and stable operations in all the networks, especially under heavily loaded conditions. As aforementioned, reactive power optimisation and control become extremely important [39]. The balance of reactive power and also reasonable reactive power reserve in the system must be ensured [40].

To conclude, the role of reactive power ancillary services in the electricity market mainly include: 1) supply of non-functional sources, 2) reactive power reserve, 3) voltage regulation and 4) reactive power optimisation [19], [39]-[43]:

- To supply the non-functional sources. The supply of reactive power must meet the needs of the reactive load demand which may vary according to the size and characteristics of the active load demand.
- To provide reactive power reserve. In order to maintain the on-site balance of reactive power supply and demand, there must be sufficient reactive power reserve, including capacitive reactive power reserve capacity and inductive reactive power reserve, to meet the system requirements when an outage or contingency occurs.
- To ensure the voltage level of the system. As aforementioned, bus voltage is highly related to reactive power. There must be a reasonable supply of reactive power to ensure voltage stability in the system so as to ensure both short and long-term voltage stability.
- Reactive power optimisation. Reactive power optimisation uses multiple generators or other reactive power providers in the power system to inject or absorb reactive power from the network to ensure the stable and economical operation of the power system.

Compared with active power production, reactive power ancillary service has its particularities:

- Diversity of reactive power providers. Most generators are required to provide a certain amount of reactive power according to the requirements of the system. However, different from active power, in addition to multiple generators, reactive power providers in power systems also include capacitors, static VAr compensators (SVCs), and so on.
- The regional supply. Since the long-distance transmission of reactive power requires a large voltage difference between the generating terminal and the receiving terminal, the reactive power supply needs to be optimised by considering network topology [40].
- Related to voltage control. Similar to frequency control requiring active power balance, voltage control also requires reactive power balance. However, the frequency

is uniform throughout the entire power network and depends on the active power balance of the entire network, while the voltage is different for each node, and must rely on the reactive power compensation of the certain bus or nearby buses.

- The complexity of analysis. The cost of active power is mainly the cost of power generation, while the operating cost of reactive power is relatively small but the investment cost is large. The production of reactive power does not consume fuel and is integrated with the synchronous operation of the unit [44], [27]. Therefore, it is necessary to separate the related cost of reactive power from the total cost and to set a proper reactive power pricing mechanism.

All in all, reactive power ancillary services in the electricity market would have to be planned and scheduled separately in the power generation, transmission and distribution levels based on the controllable reactive power providers in different levels.

2.2.1 **Problems caused by the lack of reactive power**

As discussed in the previous section, with the higher penetration level of renewable energy resources, the modern power systems may be operated under a weak system condition. In this situation, voltage instability imposes a severe threat to modern networks especially the area where a large number of distributed generator (DG) units, like wind turbines (WTs), are being integrated. Voltage stability is one of the most important indicators of power system stability. The problems caused by voltage fluctuations are very wide. Hence, reactive power, which has a strong correlation with voltage stability, has begun to attract more attention. To ensure the system voltage level and the power quality of the entire system, reactive power dispatch must be optimised. It not only directly affects the performance of electrical equipment, but also brings difficulties to the stable and economic operation of the system, and even may cause the collapse of the system voltage stability, resulting in a large-scale blackout.

For example, the New York blackout in 1977 was confirmed to be caused by insufficient reactive power. The Tokyo blackout in July 1987 is also believed to be caused by a lack of reactive power and voltage collapse during the summer peak period [80]. The blackouts happened in Italy in 2003 and 2004 are also believed to be caused by reactive power insufficiency [81]. Through reactive power optimisation dispatching, the distribution of reactive power flow in the power systems can be optimised. By doing so, the active power loss and voltage deviation of the power system can be reduced, thereby improving voltage stability and ensuring the stable operation of electrical equipment. In terms of guaranteeing the stability and economy of modern power systems, the importance of optimal reactive power dispatch has received global attention.

2.3 **Reactive power supports in power systems**

As stated in the previous section, a stable operation of power systems requires the availability of sufficient reactive generations [45]. So it is critically important to choose suitable reactive power support methods to contribute to the power system reactive power adjustment operations. And then the power system stability can be ensured.

Generally, reactive power providers can be divided into static and dynamic reactive power sources. Both static and dynamic reactive power sources play an important role in power system stability [25], [46]. Static reactive power sources refer to the reactive power providers that do not provide active voltage control. Their outputs do not change with the square of the bus voltage such as capacitors. As for dynamic reactive power providers, they usually refer to generators, synchronous condensers, static VAr compensators (SVC) and etc.

Usually, the reactive power demand of loads close to the major generation area is provided by generators and combined with cheaper static reactive power devices, such as shunt capacitor banks and reactors. However, in the load area where is far from the major generators, capacitor banks are usually installed in combination with dynamic devices such as static VAr compensators to increase the effective reactive power adjustment range.

The reactive power ancillary service should be scheduled based on the characteristics and limits of the installed reactive power providers. This means before optimising reactive power ancillary services, it is also essential to understand the control principle of these commonly used reactive power providers. They can be divided into reactive power compensations and VAr reduction.

2.3.1 **Reactive power compensation**

In general, the effect of compensation means injecting more reactive power to improve power system voltage control and contribute to stability enhancement. In most cases, the compensation is provided by the synchronous generators and other reactive power compensators, which offset the main inductive nature of the transmission system or load. It may also include a reactor that requires consideration of reactive power absorption.

Furthermore, in recent years, distributed generators are also expected to generate reactive power for compensation under certain grid codes [47], [48].

As stated in the previous section, these controllable reactive power providers are usually classified as static components or dynamic components. Static components are usually adjusted in fixed discrete steps and the operations should be with some time delay such as shunt capacitors or reactors [49]. On the other hand, dynamic compensation devices can achieve quick and continuous control, such as synchronous generators, synchronous condensers, distributed generators and static VAr compensators (SVCs). However, it is typically more expensive per MVar than static compensation. To conclude, dynamic reactive power compensation devices like synchronous generators, distributed generators and static VAr compensators, are usually required when fast voltage fluctuations happen. As for the static reactive power compensation devices, they cannot be used to improve system response to short-term phenomena. But they are very reliable and cost-effective for reactive compensation in the long term.

In this section, we will focus on these most important sources and sinks of reactive power in power systems.

2.3.1.1 **Synchronous generator and synchronous condenser**

All synchronous generators (SGs) covered by the requirements of the grid code are required to have the capability to provide reactive power. At any given output of the synchronous generators, they are normally required to produce or absorb a certain value of reactive power to manage bus voltages close to its point of common coupling (PCC) [49].

Normally, synchronous generators are running with a lagging power factor to provide reactive power to the system. However, when necessary, the excitation current can also be reduced to achieve a leading power factor to absorb the redundant reactive power in the system. When the excitation current is increased from a certain under-excitation state, the leading reactive power output of the generator begins to decrease, and the reactive component in the armature current also begins to decrease. Once reach the normal excitation state, the reactive power becomes zero and the reactive component in the armature current also becomes zero. Conversely, if the excitation current continues to increase, the generator will produce lagging reactive power, and the reactive component in the armature current begins to increase again. Consequently, it can be achieved by adjusting the excitation current to adjust the output reactive power of the synchronous generator.

- Reactive capability limit of synchronous generators

Synchronous generators are usually rated in terms of their maximum apparent power output at a certain terminal voltage and certain power factors that to ensure a stable and continuous operation without damaging the devices. The active power output limit of a SG is related to the capability of its prime mover. As for the reactive power output limit, it is related to three things: armature current limit, field current limit and end region heating limit [49].

Both the armature current and field current will cause power losses and then result in a temperature increase. So there are armature current limit and field current limit to avoid overheating. And the localized heating in the end region of the armature introduces another limit of synchronous generator operation. This is because the eddy current in laminations will cause localized heating in the end region. Again to avoid overheating, this eddy current should also be limited. The above-mentioned limits should be considered together to decide the operation range of a certain synchronous generator. This should vary based on the design of different machines. The general reactive power output capability curve is shown in Figure 2-2.

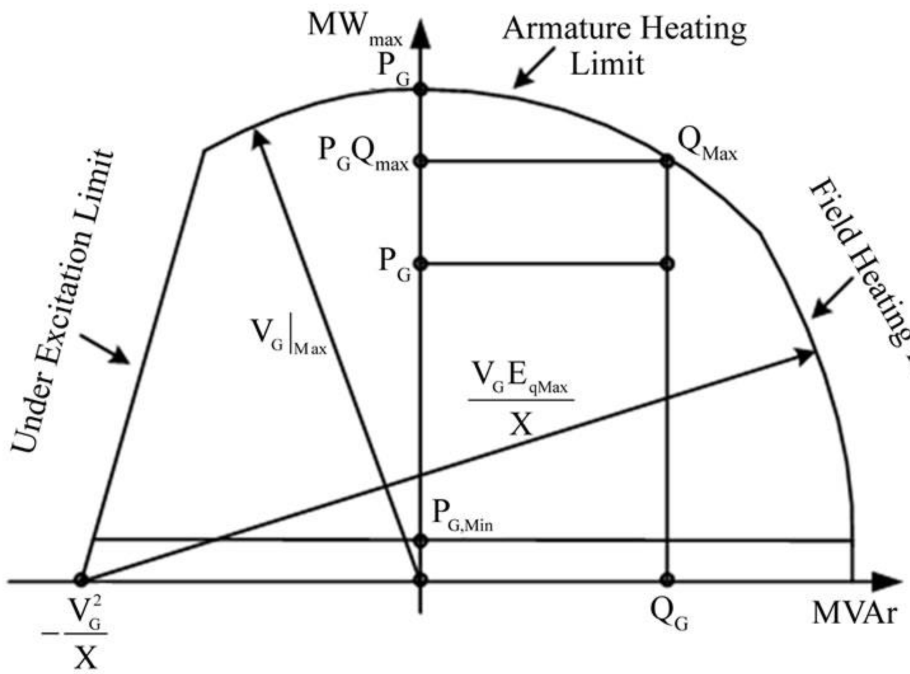


Figure 2-2 reactive power capability curve of a synchronous generator [50]

Additionally, when the synchronous generator is connected to the network, there is another limit which is power system stability limit which means its output should consider grid code set by system operators [49]. When doing the reactive power ancillary service optimisation like the RPP and ORPD strategies proposed in this thesis, the reactive power output limits of synchronous generators are considered as constraints.

- Synchronous condensers

Additionally, there is a special operation state of SGs which is synchronous condensers. Synchronous condensers are idle running synchronous generator. Under these circumstances, there is no output of active power, which is zero, and reactive power is specifically provided or absorbed to adjust the power factor of the system in the case of under excitation or over excitation operations. Synchronous condensers equipped with self-excitation device can smoothly adjust the input or output reactive power according to the voltage, which is their advantage. However, the active power loss is large, and their operation and maintenance cost is large.

For some low-efficiency generators, although they are not competitive in the active power generation market, they can be converted to synchronous condensers operation mode to provide reactive power ancillary services so as to obtain additional benefits. The purpose is to ensure the transmission capacity of the network under different load conditions and to ensure the voltage stability of the system. The typical maximum value of reactive power generated from synchronous condensers connected to the grid is in the range of 20 to 200 MVAr [49].

Synchronous generators and synchronous condensers can be controlled to regulate the voltage of a bus and then generate or absorb reactive power depending on the need of the surrounding network dynamically. Due to their short response time, they can be used to improve both the short-term and long-term response of the power system.

2.3.1.2 **Distributed generators**

For a long time, the output reactive power capability of distributed generators (DGs) has usually been ignored in most literatures to ensure sufficient active power output. Actually, distributed generators can also be used as reactive power providers to make contributions to the system voltage stability. Nowadays, most types of renewable energy resources are connected to the system via converters or inverters that can realize active/reactive decoupling control, like doubly fed induction generators (DFIGs). The reactive characteristics of this kind of renewable energy resources based on DGs depend on the control loop of certain DGs [38].

Generally, the high penetration level of renewable energy has been seen as a threat to the system voltage stability. However, reference [35] shows that distributed generator units also have the ability to generate reactive power. The power electronics (PE) controllers in a certain distributed generator make it a fast-acting dynamic reactive power source, thereby achieving the reactive power dispatch and voltage control capabilities. This means, upon a change in active power, the generation unit could provide the required reactive power according to the system voltage stability requirements, which can be achieved by adjusting the power electronic controllers. Furthermore, in recent years, the reactive output capability of distributed generators has been further expanded to generate more reactive power into the system to help with voltage control. In a very up-to-date literature [51], the output reactive power capability of a certain type of distributed generator, i.e. DFIG, is shown in Figure 2-3. Under different level of active power output, the reactive power output capability can be further extended to the red line with proper adjustments.

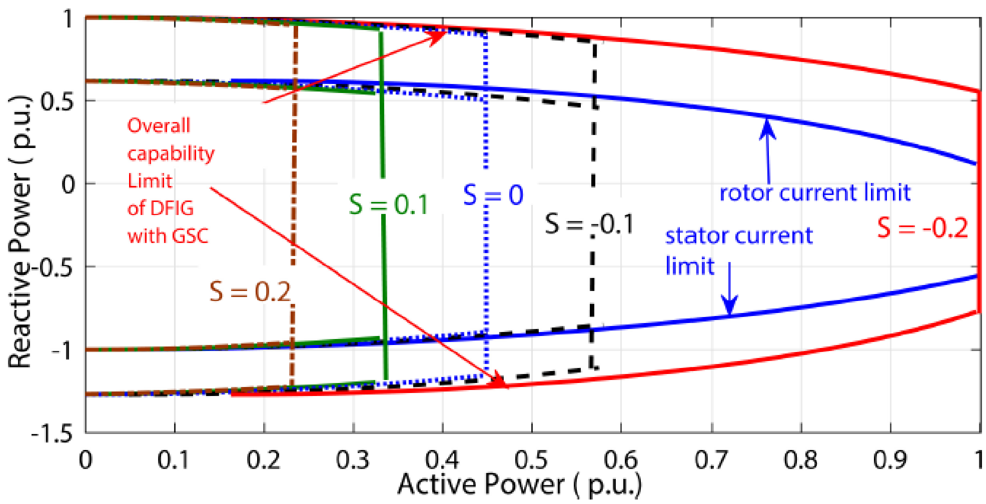


Figure 2-3 Active and reactive power output capability curves of DFIG [51]

Therefore, when achieving the full operation range of the DG units, some extra available reactive power can be used to compensate other parts of the network and possibly reduce system costs. If implemented with a DG voltage controller, this extended function also allows for improved voltage recovery after grid disturbances [35].

In the perspective of network voltage stability, when large-scale renewable energy units are connected to networks, they should be capable to provide reactive power compensation by continuously operating at a range of capacitive/inductive power factors under a certain country’s grid code.

Figure 2-4 shows the typical requirements on the reactive power and power factor control of a wind farm, enforced by the Danish Grid Code [52]. It requires DGs to operate with a power factor interval of 0.95 capacitive to 0.95 inductive when the DG production is more than 20% of the rated power. Besides that, DGs must be designed in such a way that the operating point can be anywhere within the hatched area in Figure 2-4 to assist steady-state or after fault voltage regulation [52].

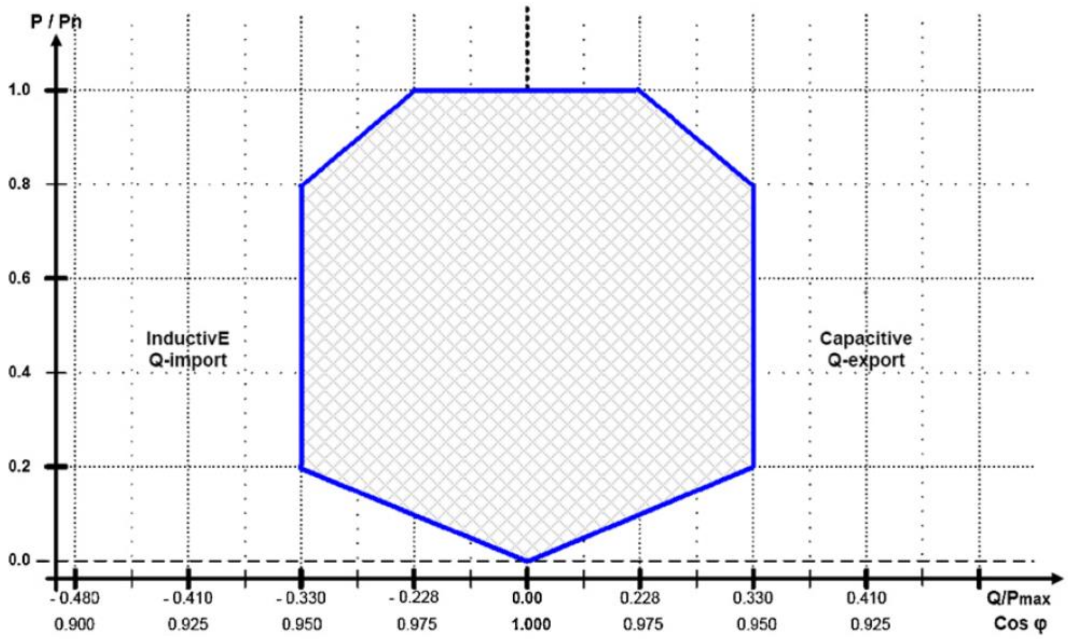


Figure 2-4 Active–Reactive power response curve requested by Danish grid code [52]

In addition, British and Irish grid codes require from DGs to provide reactive power support according to the characteristics shown below:

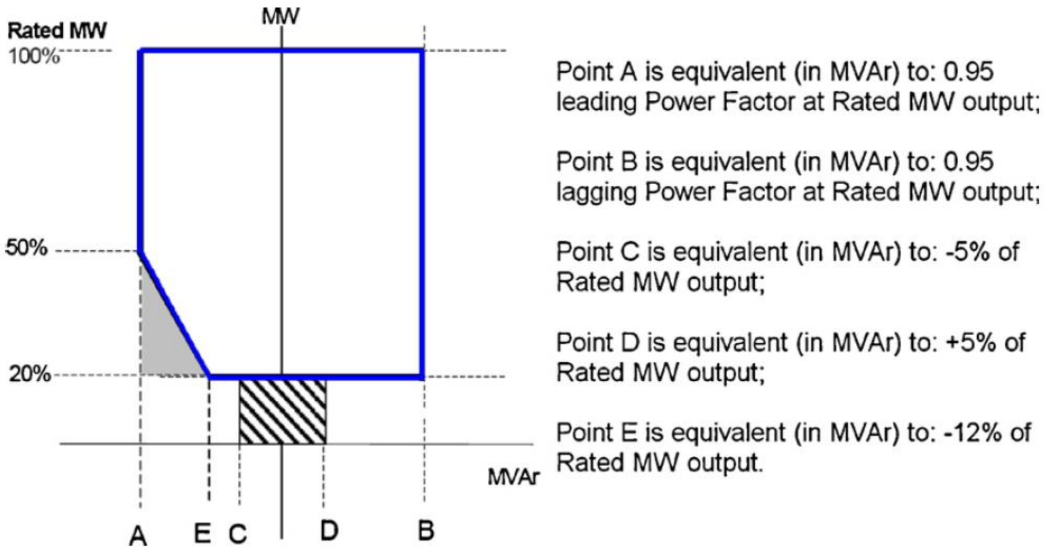


Figure 2-5 Reactive power control requirement enforced by British grid code [52]

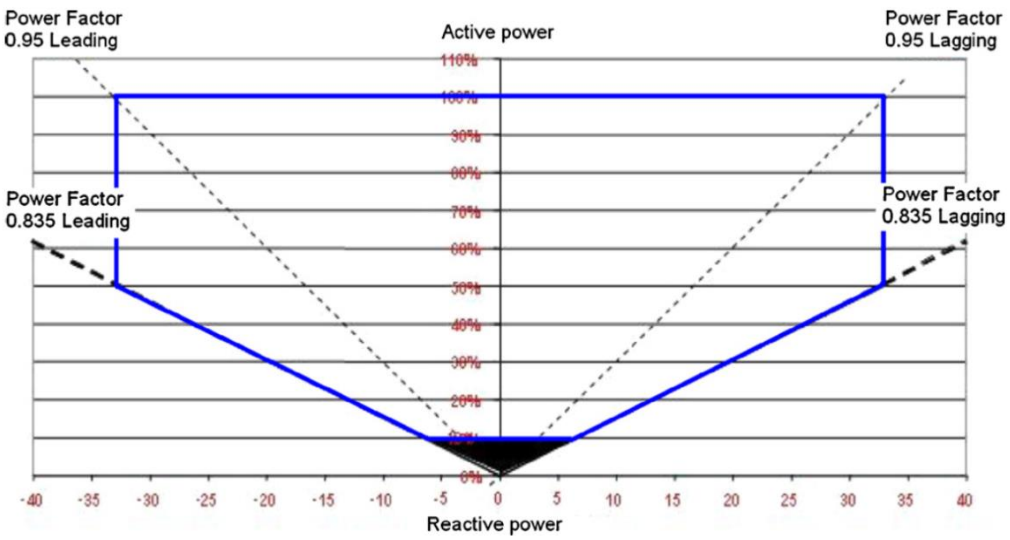


Figure 2-6 Power factor control requirement enforced by Irish grid code [52]

Additionally, as “the world's first major renewable energy economy [53]”, Germany uses a wider grid code described in [54] as ‘Within this voltage stability range, DG units that deliver at least 20% of their rated power are allowed to freely change their power factor within the shaded area represented in Figure 2-7’. The proposed characteristic requires inverter-based distributed generation units, such as WT or photovoltaic systems. The German grid code also mentions that depending upon different aspects, that is, grid configuration, load, and feed-in power, the system operators (SOs) may also need to extend the output reactive power limits different from the standard curve under different situations to the whole area circle in Figure 2-7 [54].

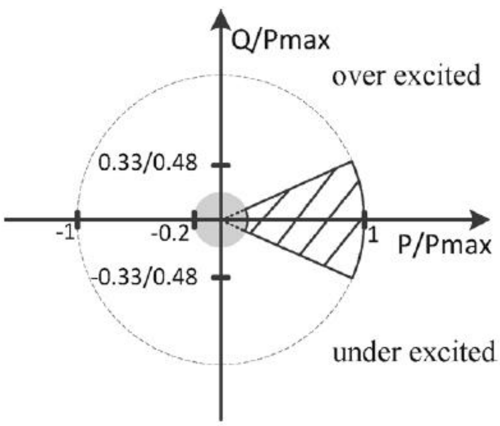


Figure 2-7 Germen grid code [54]

Again when doing the reactive power ancillary service optimisation like the RPP and ORPD strategies proposed in this thesis, both the reactive power output limits and grid codes of distributed generators are considered as constraints.

2.3.1.3 Reactive power compensators

Other than generators, reactive power compensators can also be used to improve the operation of the power system stability by injecting reactive power. This kind of device plays an important role in keeping the bus voltage close to its nominal value, reducing the line current to reduce network losses, and helping to improve system stability.

In most cases, reactive power compensation is provided by capacitor-based devices, which will offset the main inductive characteristics of the transmission system or load. However, it may also include reactor-based devices to accomplish reactive power absorption under certain circumstances. In this section, we will include capacitors installed in series with the transmission lines and shunt components connected to the system buses.

- Line series compensation

Because of the electrical distance between power generation and the load centre, to avoid voltage instability, series compensation can be installed to reduce the impedance of long-distance transmission lines, as shown in the simple equivalent of Figure 2-8. Series capacitors are usually located at the midpoint, 1/3 or 1/4 point of the transmission lines [55].

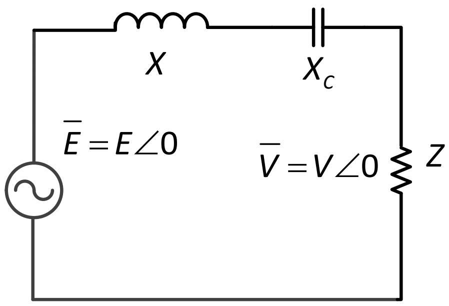


Figure 2-8 Equivalent of line series compensation

Series capacitors are usually connected in series at heavily loaded lines and thereby to reduce their reactive losses.

- Shunt compensation

The connection of shunt capacitors (or reactors) is the simplest and most widely used form of reactive power compensation. Shunt compensators are usually added in order to provide extra reactive power so that to keep the bus voltage within its limits. Nowadays, as the load grows increasingly, more shunt compensation is used to keep the bus voltages within their normal operating range. By doing so, the network operating point will be ensured to be within a safety range. A simple equivalent system of shunt capacitor is shown in Figure 2-9, which combines the effect of offline charging (susceptance B_L) with an adjustable shunt compensation (susceptance B_C).

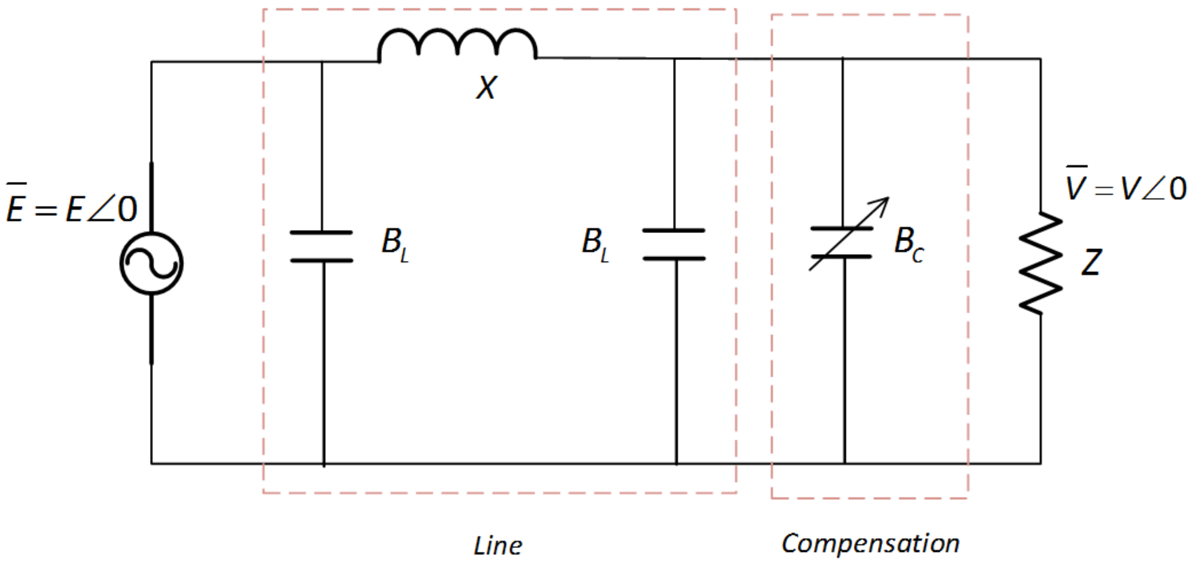


Figure 2-9 Network capacitance and shunt compensation

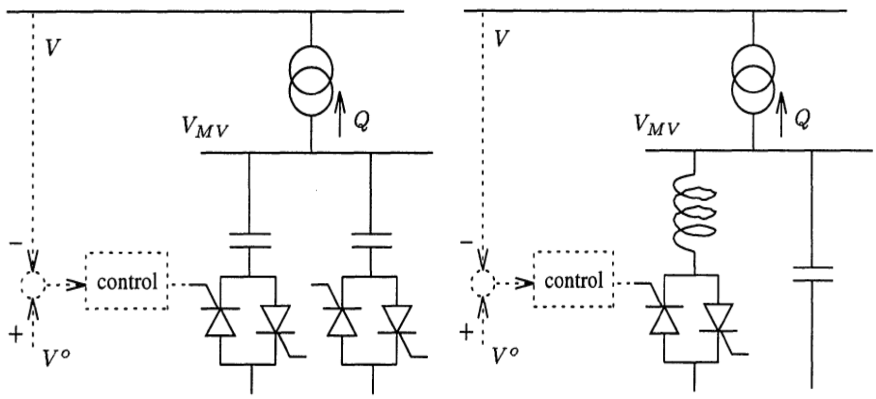
Similarly, in systems with large capacitance effects, shunt reactors ($B_C < 0$) should be connected under light load conditions to avoid overvoltage. In extra-high voltage (EHV) systems, due to the stability considerations, long-distance power transmission is below surge impedance loading, which often occurs. This requires shunt reactors to absorb the excess reactive power generated.

- Static VAr compensators (SVCs)

The static VAr compensator (SVC) is a voltage-controlled shunt compensation device that normally consists of a fixed capacitor and a variable capacitor or reactor. SVC is a dynamic reactive power compensation device that usually being controlled in real-time. Nowadays, with the increasing of system stability requirements and the control action speed, it is reasonable to apply such kind of dynamic compensation devices like SVCs although they may increase the grid operation cost. This usually occurs in the case of power angle instability and short-term voltage instability situations.

The following are two major techniques used to obtain variable susceptance:

- ❖ In the Thyristor Switched Capacitor (TSC) (Figure 2-10.a), a variable number of shunt capacitor units are connected to the system through thyristor used as switches to achieve a variable value grid connect compensators;
- ❖ In the thyristor-controlled reactor (TCR) (Figure 2-10.b), the fundamental frequency component of the current flowing into the reactor can be changed by adjusting the thyristor connected in series with the reactor. At the same time, various technologies are used to eliminate harmonics. This is equivalent to having a variable shunt reactor with a fixed capacitor [56].



(a) Thyristor Switched Capacitor (TSC) **(b) Thyristor Controlled Reactor (TCR)**

Figure 2-10 Schematic representation of SVCs [56]

When doing the reactive power ancillary service optimisation like the RPP and ORPD strategies proposed in this thesis, the reactive power output limits of reactive power compensators are considered as constraints.

- Static synchronous compensators (STACOMs)

Static synchronous compensators (STATCOMs) are fast-acting devices that can supply or absorb reactive current to regulate the voltage at the point where it is connected to the grid. It is a flexible AC transmission system (FACTS) device. The technology is based on the voltage source converters with semiconductor valves in a modular multi-stage configuration.

Furthermore, STATCOM is also known as an advanced SVC. A typical application of a STATCOM is for rapid voltage support in wind farms during fault which can regulate the voltage at the point of common coupling into a stable range and enhance the reactive power output capability of the wind farm. The principle diagram of STATCOM is shown in Figure 2-11.

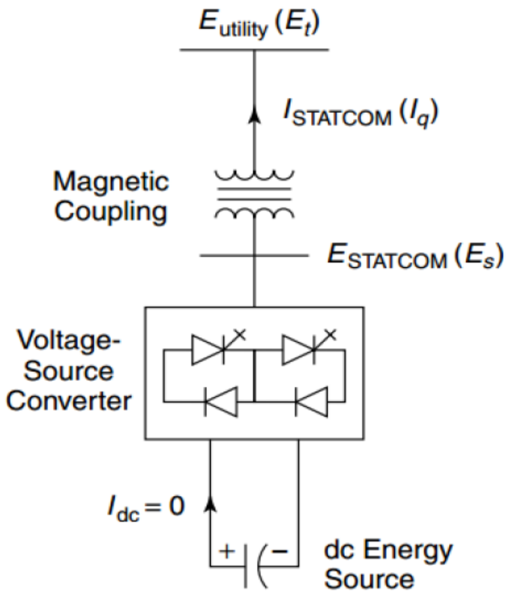


Figure 2-11 Principle diagram of STATCOM [57]

2.3.2 **Undervoltage Q reduction**

As previously stated, generators' reactive power controls and reactive compensation elements have no negative impact on consumers and are relatively low-cost actions. However, the voltage level at the receiving end is still highly dependent on the absorption or injection of reactive power by the load. So, reactive power reduction and emergency load shedding are also efficient means to prevent voltage instability and ensure power system stable operations.

Under the operation of the system operator (SO) and load management system, the characteristics and locations of the load that should be used as the flexible demand to accomplish reactive load reduction or to be used as emergency load shedding are also very important for preventing system instability. Consequently, the flexible demand should also obey a bidding procedure with SO before it can be applied. This section focuses on the design and implementation of flexible demand and emergency load shedding.

2.3.2.1 **Flexible demand**

With the increasing popularity of electric vehicles and demand-side response appliances, the role of power consumers has gradually changed from passive power consumption to actively participating in the energy management of the power systems. These loads are flexible demand which contain both active and reactive part. Therefore, on the distribution network side, in order to meet the increase of load demanding, scheduling flexible demand, i.e. pre-scheduled load reduction, is another way to provide reactive power ancillary service. This part of loads will also need to be planned and reserved before it can be used when there is a lack of reactive power compensation by system operators and load management systems via the bidding process. The load management should be user-oriented. With the help of various economic and technical considerations, while ensuring the stability of the power network, it aims to change the shape of the system’s typical load curve to achieve different load management goals, thereby serving the reliable and economic operation of the power system. There are generally six correction goals: i) Peak Clipping, ii) Valley Filling, ii) Load Shifting, iv) Strategic Load Increment, v) Strategic Conservation and vi) Flexible Load. The scheduled flexible demand normally contains both active load reduction and reactive load reduction.

In the context of deregulation of the electricity market and in the view of renewable energy supply and load demand, a strategy for the instruction of intelligent power equipment groups based on the reservation of flexible demand resources should be proposed. As shown in Figure 2-12, normally, the peak load demand does not come along with a peak renewable output. So in order to meet the consumption requirement of renewable energy resources such as wind power, some planned flexible demand should be reserved for a better time period. And when there is a need to consume more renewable energy generated power, the reserved loads can be used to absorb this part of renewable energy, thereby improving the utilization rate of renewable energy.

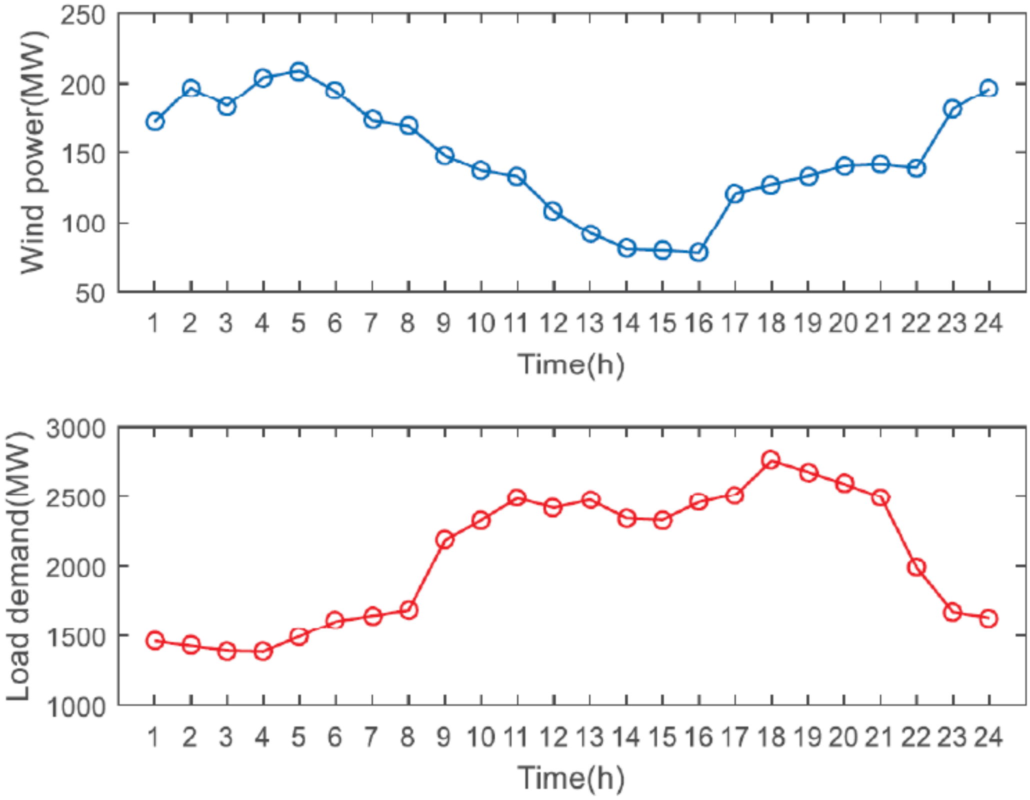


Figure 2-12 Time distribution characteristics of load demand and wind turbine output [56]

Therefore, the response mode of the flexible demand is mainly the interactive response of joint power generation and the power supply side. In conclusion, this interaction is mainly reflected in two aspects: Firstly, users change their own energy consumption habits, reducing energy demand or shifting energy demand within a certain period of time in order to achieve the reduction or transfer of peak time load demand, improve the system load characteristics, and reduce the system power supply cost. Secondly, some consumers with renewable energy resources integrated may also have a certain degree of self-sufficiency, reducing the power distribution capacity and the main network power supply demand, which even has the ability to deliver energy to other systems (heat energy, air-conditioning and other energy forms).

With the gradual diversification of residents' electric load type and the automatic control of household appliances has been continuously improved, the system management centre should consider generating a class of flexible demand when system operators provide certain economic stimulus. It can achieve economic benefits by intelligently controlling a kind of electrical equipment or equipment group, changing the operation time to match the demand response strategy of power system operators. With the support of some corresponding energy storage equipment, this kind of load can be completely disconnected from the grid in certain time periods or even generate some power to the grid. This is the benefit of optimally managing flexible demand.

When doing the reactive power ancillary service optimisation like the RPP and ORPD strategies proposed in this thesis, the maximum installed or available flexible demand is considered as constraints.

2.3.2.2 **Emergency load shedding**

Reactive power ancillary service optimisation has usually been seen as a preventive voltage control strategy. When designing these preventive control actions, contingency ranking should be considered and the very low occurrence contingencies might be neglected. So it is economically unwise to reserve preventive control actions when the probability of some severe contingencies occurrence is low.

However, when there is a large amount of inductive machine loads in a power system, once the excitation current of the generator supporting the transmission voltage is limited, long-term voltage instability may lead to a sharp drop in voltage magnitude. In addition, after a failure, inductive machines may not be able to accelerate again, and their stalling will cause short-term voltage instability. Under this circumstance, some emergency actions to adjust bus voltage will be needed such as load shedding [58].

This section investigates the ability of the emergency load shedding other than the aforementioned predesigned flexible demand scheme [59]-[61], to deal with mainly short-term voltage instabilities. This scheme has to be achieved with real-time information exchange. And the selectivity of this protection scheme can be increased by optimising various controllers in time.

Emergency load shedding should be the last-resort control measure against voltage instability triggered by large disturbances in modern power systems [59]-[61]. Or when the initial voltage drop is too obvious to be corrected by other means, emergency control actions need to be taken, such as unscheduled emergency load shedding. For this reason, some event-based [62] and response-based [63] protection schemes have already been successfully developed and tested. Among them, the event-driven emergency load shedding is expected to be executed immediately after the receiving end fails to prevent loss of power angle stability or unpredictable cascading failures. And the response-based scheme adjusts corrective measures according to the severity and location of the disturbance and this scheme runs in a closed-loop to obtain higher robustness. So here it has to be emphasized again that unscheduled load shedding is the emergency measure to save a system from blackout. It should be the last resort when there is no other choice to prevent the system collapse.

- Shedding time

It is obvious from the previous statement that the available time period for load shedding is limited because of emergencies. In order to avoid a severe blackout, this situation may appear in the form of generator losing synchronization or motor stalling. There is very limited time in this situation when a sudden voltage drop after large disturbances happens.

There are several severe outcomes that may be caused when a sharp voltage drop happens: i). power system degradation caused by undervoltage tripping of the field current-limiting generator or open circuit operation of transmission lines; ii). if the disturbance is large enough, this may cause damage induced by continuous low voltage in the case of long-term voltage instability.

So in terms of long-term voltage stability, if the delay of emergency load shedding action is too long then more load shedding may be required. This will bring new problems for the system to regain its long-term stability [64]. However, there still should be some delay to activate other controls operations and so as to decrease the amount of emergency load shedding. As stated in [64], it indicates that the best shedding time is 15 to 20 seconds after the disturbance. This time delay allows the automatic devices to switch shunt compensators or other reactive power compensations, thereby providing more reactive power and improving network transmission capacity. The amount of load that needs to be shed will be reduced under this circumstance.

- Shedding location and shedding amount

In view of voltage instability, the emergency shedding location is very important, because when shedding at an unsuitable location may require more load shedding. In practice, due to some structural problems and also the different system strengths of each area, the areas prone to have voltage instability issues are known in advance. However, in such an area, the optimal location to have load shedding may still vary with different disturbances (and also related to instability mode) [64].

It has been proven sensitivity analysis techniques to determine which load positions to shed are most effective to avoid long-term voltage instability. More recently, sensitivity analysis of load shedding ranking can also be combined with real-time simulation to find the best corrective measures in the case of instability after a large disturbance [65].

Once the load shedding ranking has been set, the location of the load to shed and the minimum amount of shedding can be accordingly determined. This will need to consider a large amount of system information in the research work of the pre-designed load shedding schemes [64].

A possible suboptimal but simpler and more reliable solution is to first apply load shedding at the node with the largest voltage drop. Even though this may result in more emergency load reduction, this standard is still meaningful since the long-term low voltage will cause damage to customers [66].

Based on the previous statement, it can be drawn that load shedding schemes are usually rule-based and highly depend on the measured voltages used in these rules as shown below [67]:

$$if\ \ V < V^{th}\ \ during\ \ \tau\ \ \text{sec}onds,\ shed\ \Delta Q\ MVAr \tag{2}$$

where V is the measured bus voltage, V^{th} is the threshold value, τ is the aforementioned time delay before load shedding action and ΔQ is the load shedding amount.

Consequently, the threshold V^{th} must be low enough so that there is no load shedding after an acceptable small disturbance. This value can be set by contingency ranking which usually involves all *N-1* accidents and can also be extended to *N-k* accidents. But it should also be high enough so that the load shedding will not be too late.

In the same way, in terms of long-term instability, the delay τ must be long enough to avoid the reaction to nearby faults and allow reasonable action time for protection operations so that voltage can return to normal values. However, it must also be short enough for avoiding further instability as already mentioned.

The post-disturbance voltage is a suitable input signal for the above-mentioned purpose. Nevertheless, in fact, the voltage has practically no inertia, and the effect on certain components is almost instantaneously, at least in the neighbourhood, which may cause inappropriate emergency load shedding.

By this detailed study of emergency load shedding, it is clear that this emergency voltage control action may lead to some unexpected system operations. So it is critically important to avoid using this last resort to prevent power system instability in real networks. This also shows the importance of pre-designed preventive voltage control strategies including the proposed reactive power ancillary service optimisation strategies in this research.

2.4 Reactive power losses

In the power systems, the reactive power needs to be transmitted from the generator or reactive power provider side to the point in the grid where the reactive power is required. Therefore, there will be a voltage difference between the start point and the end point of the reactive power transmission. In the middle of the transmission process, there will be transformers and some transmission lines, so that the reactive power that is received is not as much as it has been generated. Transmission lines and transformers will consume some of them as reactive power losses. Therefore, the reactive power losses can be mainly divided into: i) the reactive power losses in power transformers and ii) the reactive power losses on transmission lines [56].

2.4.1 Reactive power losses in power transformers

The reactive power losses in the transformer can be divided into two parts, namely the loss in the excitation circuit and the winding circuit. Among them, the percentage of excitation circuit loss is basically equal to the percentage of no-load current, about 1% to 2%. When the loss in the winding leakage reactance is at the full load of the transformer, it is basically equal to the percentage of the short-circuit voltage, which is about 10%. Therefore, for a one-transformer network, the reactive power losses in the transformer are not large, which is about 10% of its rated capacity in the full load situation. However, when referring to a multi-voltage level network, the reactive power losses in the transformers are considerable. The results of typical calculations show that the reactive power losses of the transformer in the system accounts for a considerable proportion, which may be much larger than the active power losses [49].

2.4.2 Reactive power losses on the transmission lines

The reactive power losses on the transmission lines can be also divided into two parts: the reactive power losses in parallel susceptance and series reactance. The loss in parallel susceptance is proportional to the square of the line voltage and is capacitive. The loss in series reactance is proportional to the square of the load current and is inductive. Therefore, it is not sure whether the transmission line as a component of the power system consumes capacitive or inductive reactive power. Therefore, natural transmission power is defined.

Natural transmission power is a characteristic parameter that represents the transmission characteristics of a transmission line and is used to estimate the operating characteristics of this transmission line. When the active power transmitted by the transmission line reaches a certain value, the transmission line reactive power consumption and the reactive power generation at this time are balanced, and the power transmitted at this time is called the natural transmission power [56].

According to the concept of natural power, when the active power transmitted through the transmission line is larger than the natural transmission power, the transmission line will consume capacitive reactive power. Otherwise, it will consume inductive reactive power. Generally, the power transmitted by 110kV and below transmission lines is often larger than the natural transmission power. The power transmitted by the 500kV line is roughly equal to the natural transmission power. So other than some extremely high voltage systems, for the transmission lines, the transmitted power is normally larger than natural transmission power which should consume capacitive reactive power [49].

2.5 Chapter summary

This Chapter gives an introduction to the existing reactive power ancillary services in power systems, which is the cornerstone of the research presented in this thesis. After that, the major reactive power providers in power systems are presented. Both static reactive power compensation devices and dynamic reactive power devices are introduced as reactive power providers in detail. After that, both pre-scheduled flexible demand and emergency load shedding are introduced as two major VAr reduction strategies in power systems. Consequently, the importance of sufficient reactive power reserve and optimal reactive power planning can be drawn by knowing the major disadvantages of emergency load shedding. In addition, potential reactive power losses are also introduced for the purpose to make sufficient reactive power reservation plans. The conclusion is that reactive power ancillary services optimisation and emergency operations should be combined together to prevent system collapse.

3 Optimal reactive power ancillary service planning strategies in modern power systems

3.1 Introduction

In modern power systems, many countries are gradually developing new technologies into power systems such as renewable energy resources, energy storage, flexible demand, etc. So, recently, the penetration level of distributed generation integration in both transmission networks (TNs) and distribution networks (DNs) is increasing. Their output can be intermittent and random, which may easily cause the problem of system voltage instability. In transmission systems, the threats to have voltage fluctuation and cascading tripping have significantly increased. As for distribution systems, much higher voltage rise and poor power quality may happen because of fluctuations [68]. Faced with these challenges, current voltage control methods may not be sufficient to maintain the bus voltage only within an acceptable voltage stability range. As aforementioned, voltage control is highly related to reactive power. Therefore, appropriate transmission and distribution system reactive power optimisation strategies should be applied to transmission system operators (TSO) and distribution system operators (DSO).

Under the circumstance of power system deregulation, reactive power should not be only considered as obligatory services from generation companies anymore [1]. So an appropriate reactive power procurement (RPP) plan should be designed to minimise the total reactive power cost. Then each generation company will be able to reserve sufficient reactive power to provide ancillary services according to the procurement plan with the system operator. In addition, within this reserved reactive power limits, as a preventive control strategy, optimal reactive power dispatch (ORPD) works as a coordinated control that can set the optimal values for all necessary operational devices within their operational ranges to mitigate voltage violations and hence to operate power systems in an economic and stable manner. Consequently, a proper ORPD strategy that can be applied to both TNs and DNs is necessary. The challenge is that both RPP and ORPD problem is usually formulated as mixed-integer non-linear non-convex problems. To solve this kind of problem, a considerable number of works have been carried out on this topic which could be generally divided into two categories: heuristic algorithms and analytical method [69]-[71].

This Chapter describes the current optimal reactive power ancillary service strategies in modern power systems. The rest of the chapter is organised as follows. Firstly, the modern power system deregulation process has been introduced as the cornerstone of reactive power pricing and procurement mechanism in Section 3.2. In this section, the commonly used reactive power pricing and procurement mechanisms have also been presented. After that, the modern optimal reactive power optimisation strategies are introduced in Section 3.3. Then, the main drawbacks of existing reactive power optimisation strategies and also the new challenges have been stated based on a thorough literature review in Section 3.4. In Section 3.5, the commonly used solver for power system constrained optimisation problems have been detailed. Finally, the chapter is concluded in Section 3.6.

3.2 Power system deregulation

In the past few decades, the global power market has undergone major changes. Among them, power system deregulation is one of the most important milestones. In many countries, such as United States, United Kingdom, Northern Europe, Australia, New Zealand and some South American countries, the power industry has already accomplished the change from a monopoly structure to a deregulated market structure [1].

The main motivations for power system deregulation are: 1) to improve generation and transmission efficiency; 2) to improve services received from generation companies; 3) to reduce service prices; 4) to provide more choices for consumers; 5) to encourage innovation; 6) to ensure competition; 7) to promote an open market and participation opportunities.

With the deregulation, the construction of the power market has two tasks: i) to ensure stable operation and ii) to achieve economic operations.

At present, the power systems of many countries in the world are still in a transitional period, and a complete power market mechanism has not yet been established. The full transition of power systems around the world from regulation to complete deregulation will still take some time.

3.2.1 Regulated and deregulated power systems

Among power systems, the market mechanism ensures resource allocation, production efficiency and technological innovation to achieve an optimal level. However, market mechanisms in power systems are not perfect. It may also have some shortcomings. In this case, regulation becomes very important in power systems. The so-called regulation refers to the behaviour of restricting the activities of individuals who constitute a certain society and economic entities according to certain rules. This can also be regarded as a superior method to achieve more economical benefits. The purpose of regulation is to limit the monopolist's ability at the same time to increase the welfare of the whole society while preserving an efficient monopoly [8].

Under this circumstance, according to the regulation levels in different power systems of different countries, the power systems can be divided into two categories: regulated power systems and deregulated power systems. Both mechanisms are discussed with their advantages and disadvantages separately.

3.2.1.1 **Regulated power systems**

The traditional power system is an independent industry that forms a monopoly in its service area. It is usually owned and operated by the government, running as a private enterprise. As the only public utility company providing electrical services in the service area, it is responsible for providing electricity to all users in the service area on its own.

With the establishment of the monopoly of power suppliers, the management agency has established electricity price standards in order to earn a reasonable profit rate on investment and to earn back their operating expenses. In this regulated environment, the generation company's maximum rate of profit is restricted by the regulatory agency. In addition, because the price is set by the management agency, the cost expense is transferred to the consumer, and various risks are taken into account, so that the power system has no motivation to reduce cost expense. Therefore, consumers have no opportunity to choose electricity suppliers or to choose electricity prices.

3.2.1.2 **Deregulated power systems**

Compared with a monopoly market, there are different service providers and many consumers in an ideal competitive market. Competition makes the market price tend to the latest production unit cost. This is a cost-effective solution. The task of the deregulated mechanism is to build a competitive market so that it has enough competition to distribute market domination.

With the deregulated mechanism, the traditional independent power system can be decomposed into power generation, transmission and distribution service providers. Thereby, a deregulated power system can be divided into three main segments: generation companies

(GENCOs), transmission companies (TRANSCOs) and distribution companies (DISCOs) to establish a competitive electricity market. Therefore, the decision-making mechanism of electricity market operation has also been changed.

In the deregulated power system, the economic decision-making mechanism responds to the process of decentralization. Every participator is aiming to get the most benefit. Unlike in a regulated environment, the deregulated mechanism cannot guarantee that a new procurement plan could cover the cost of investment. Therefore, risk management has become a major part of the power industry in the market economy. In addition, a major change in the electricity market is the introduction of more uncertainties into the power industry, which increases the complexity of the power system analysis and drives the demand for new optimisation strategies.

In the deregulated electricity market, normally a bid structure is used in the context of an electricity market [19]. Both buyers and sellers bid in the market to obtain the amount of electricity they want to trade in the market. Power generation companies (GENCOs) in this electricity market will compete for providing power to the grid. If the price of the power generation company is too high, it may not be able to make the sale. There is an independent system operator (ISO) in the market who can decide and perform economic dispatch. In an ideal competitive market, if power generation companies bid to the ISO at their settled price, the market will force the unit price to reach a competitive level, which is equivalent to the settled price of the most efficient bidders. In such an ideal market, low-cost producers usually benefit from ISO scheduling. An ideal market is a competitive market where generation companies bid at their marginal prices. However, when market domination exists, the generation companies that dominate the market may not need to bid at their marginal price to make the sale.

Other than to decide the electricity price, in a deregulated power system, the responsibility of ISO is also to maintain the reliability and stability of the system by providing ancillary services such as reactive power support, spinning reserve, energy balance, and frequency regulation [19]. So the reactive power procurement process in deregulated power systems also becomes increasingly important. In order to manage voltage levels, proper reactive power procurement procedures should be decided by ISO also based on the bided reactive power support offers from GENCOs.

3.2.2 Reactive power procurement procedure in deregulated power system

Current power system may not have a proper reactive power market yet, however, it is of great importance to generate an appropriate reactive power procurement procedure for future power systems when the deregulation process will be more mature. The reactive power procurement procedure in ideal deregulated power systems should also obey the bidding mechanism and a cost-effective reactive power procurement strategy for deregulated power systems. Before optimising this procurement strategy, it should be critically important to first address the characteristics, limitations and cost functions for all available reactive power providers in systems. In this section, the reactive power pricing and bidding procedures of each kind of reactive power provider are introduced.

3.2.2.1 Reactive power pricing and bidding procedure for traditional reactive power providers

Traditional reactive power providers refer to the devices that are expected to provide reactive power support which means they are required to provide some obligatory reactive power services. This kind of reactive power providers mainly include synchronous generators, shunt reactors, static VAr compensators etc. For a long time, the reactive power bidding procedure for the traditional reactive power providers has been formulated as a multi-leader-follower game [18]. The system operators will invite generation companies to bid for providing reactive power services. To balance the supply function between the generation companies (GENCOs), that each GENCO should have a conjecture about the supply function of its competitors.

The bidding process allows the Generation companies to request

- an Available Capability Price (£/MVarh), and/or a Synchronised Capability Price (£/MVarh), and/or a Utilisation Price (£/MVarh)
- the choice of a term with a minimum period.

These reactive power pricing procedures for traditional reactive power providers used in the bidding process have been widely discussed in previous literatures [18], [27], [43], [44]. In [43], a five-zone reactive power cost curve of synchronous generators based on the extra reactive capacity beyond obligation and the lost opportunity costs has been proposed for the first time. The opportunity cost describes the benefit loss that may be caused by engaging in the activity relative to engaging in an alternative activity that provides higher value or returns.

This is a market-based solution to manage reactive power services of transmission operators. In addition, the fair distribution of the reactive power ancillary service cost has been discussed in [44]. Moreover, this cost curve has been further modified in [27] by including capital cost. Both seasonal and hourly reactive power procurement have been considered for the first time in the proposed two-level reactive power service framework in [27], based on maximizing the total system revenue generated from reactive power services minus system operator (SO)'s expected payment.

By considering the previously published literatures and the real-life GB reactive power market, the reactive power service pricing procedure for traditional reactive power providers used in this thesis includes mainly two parts, i.e. obligatory reactive power service (ORPS) and enhanced reactive power service (ERPS) [72]:

1. Obligatory Reactive Power Service (ORPS)
   - The Obligatory Reactive Power Service (ORPS) is the provision of mandatory varying reactive power output.
   - At any given output of the synchronous generators, they may be required to produce or absorb a certain value of reactive power to help manage system voltages close to its point of connection. All generators covered by the requirements of the grid code are required to have the capability to provide reactive power.
   - Generally, most transmission connected generators over 50MW are required to have the capability to provide this part of reactive power service, i.e. it is mandatory for large generators. However, some distributed generators may be under different grid codes in some countries.
   - Commonly, the synchronous generators in the GB network must:
     - ❖ Be capable to supply their rated power output (MW) at any point between the certain power factor limits
     - ❖ Keep the reactive power output under steady state conditions fully available within the pre-defined voltage stability range
     - ❖ Have a continuously acting automatic excitation control system to provide constant terminal voltage control without instability over the entire operating range

    - ❖ Generators are generally instructed to reach a target MVAr level within two minutes. This target will be within the reactive performance capability of the generator, outlined in their performance chart.
    - ❖ Generators will be advised during their connection compliance process what is required from them and the process to set up and put in place a mandatory services agreement (MSA).
  - The contractual form of this service is captured in the Mandatory Services Agreement (MSA). GB National Grid (NG) pays all synchronous generators for utilisation in £/MVArh. This Utilisation payment is updated monthly in line with market indicators. The generation companies will be paid from the date that the Mandatory Service Agreement (MSA) is signed. This is regardless of whether or not they are instructed for reactive power, as the provider will naturally drift between leading or lagging rather than constantly staying at zero MVAr.

2. Enhanced Reactive Power Service (ERPS)
  - The enhanced reactive power service (ERPS) is suitable for reactive power providers who can provide reactive power over and above the Grid Code and obligatory reactive power service (ORPS) requirements. It is the provision of voltage support that exceeds the minimum technical requirement of ORPS.
  - ERPS can be provided alongside other ancillary services.
  - The reactive power providers are generally instructed to provide a target megavar (MVAr) level which must be reached within two minutes.
  - The Enhanced Reactive Power Service is procured via a market bidding process
  - The service providers will need to be in line with the commercial services agreement awarded in the bidding process.
  - If the generator is successful following the tender assessment, then a market agreement is entered into.
  - The price is assumed to be based on generators being compensated for availability, energy losses, and opportunity costs associated with active power output reductions due to the required reactive power provision and generator capability limits [27].

Based on the listed pricing mechanisms, the commonly used reactive power offers curve is listed as:

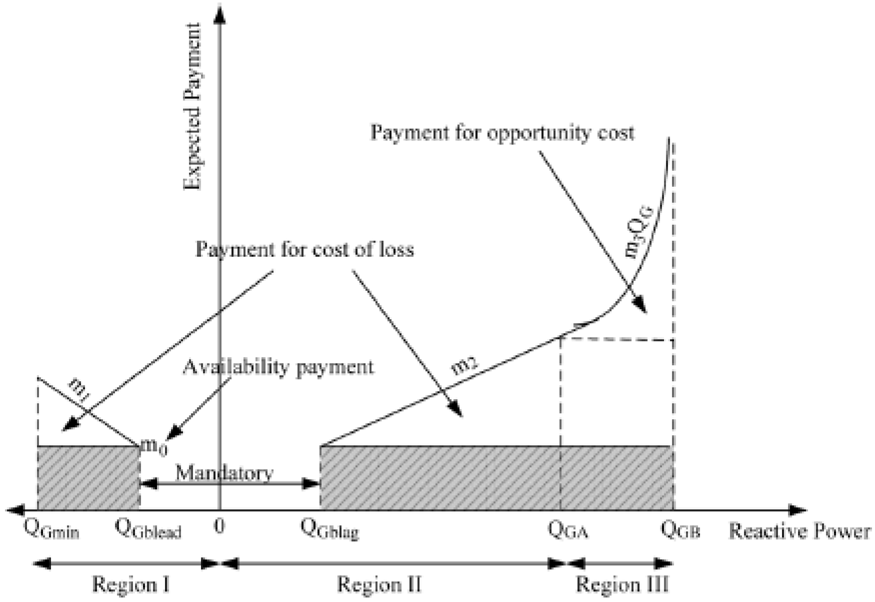


Figure 3-1 Normal reactive power offers from generation companies [27]

Additionally, the price in Figure 3-1 for different regions should be set based on:

Availability payment ($): A fixed component used to explain the supplier's capital cost attributable to reactive power production.

Cost of loss payment ($/Mvar): A hypothetical linear change component used to describe the winding loss that increases with the increase in reactive power output, in the range of under excitation and over excitation, respectively.

Opportunity payment ($/Mvar/Mvar): When a supplier is restricted from producing its predetermined active power to increase its reactive power production, it is used to account for the quadratic component of opportunity cost loss [27].

3.2.2.2 **Reactive power procurement procedure for distributed generators**

Motivated by the international climate targets, the use of sustainable and renewable energy technologies has been promoted in all economic sectors for several years [48]. Furthermore, renewable energy generation has a potential that has not yet been exhausted, which means that a further increase is to be expected.

As aforementioned, currently, wind power is the most important renewable energy resource worldwide. At present, wind turbines (WTs) have commonly adopted variable speed constant frequency control technology to achieve grid-connected operation. And among all the wind farms, doubly fed inductive generator (DFIG) based wind turbines (WTs), have been widely applied.

Rather than being considered as the threat of reactive power optimisation, recently, a number of grid codes using DGs to provide more reactive power support have been proposed by some researchers. The proposed strategies are both technically and economically viable solutions for improving the voltage stability in power systems with high penetration levels of DGs but also need to be planned with ISO.

Some researchers assume that DG inverters are able to inject reactive power at no cost [46], [47], there are trade-offs involved in producing reactive power through the inverter. The first trade-off is the additional losses in the inverter because of the reactive power usage [48], which either reduces the active power output of the DG or has to be compensated by the grid [49]. However, there is another trade-off in providing reactive power using inverters, the increase in wear and tear of the inverter components [51]. The increased wear and tear has been analysed by power electronics researchers and shown to reduce the lifetime of the inverter. The additional losses from reactive power injection cause temperature rise in the inverter components, especially during the time when DG is not generating any active power. Consequently, an increase in thermal stress has adverse impacts on the lifetime of inverter components. Based on these circumstances, literature [51] has proposed a cost suggestion of reactive power for PV at different penetration levels.

From the previous section, it can be concluded, the three obvious features of reactive power pricing proposals are: 1) Obligatory power generation facilities to provide and absorb reactive power services in proportion to their active power output; 2) Generations should also have the capabilities to provide enhanced reactive power support if needed with a higher price based on their lost opportunity costs; 3) Optimising and integrating the lowest cost solution for reactive procurement and market operations.

As for the reactive power cost of DGs, the cost of generators to provide reactive power services mainly includes the built-in cost of the generator units and the opportunity cost of potential losses due to derating of active power capacity. In addition, a small amount of cost can be attributed to transmission loss and the wear and tear cost of the automatic voltage regulator (AVR). However, they are usually not quantifiable and ignored. The method of recovering the built-in cost of generators from reactive power services has always been heuristic, because the main purpose of generator sets is to provide active power, and there is no clear distinction between reactive and active costs. Although the lost opportunity cost of generators (if they occur) should be covered from reactive power services, the calculation method is often affected by the specific circumstances of market arrangements and assumptions related to generator profits [43]. In this thesis, a similar pricing procedure with the traditional reactive power providers is used which will be detailed in the following Chapter.

3.3 Reactive power optimisation in modern power systems

Based on the bidding and pricing procedures introduced in the previous section, the reactive power services can be further optimised in two aspects. The first one is to minimise the total reactive power ancillary services cost. And the other one is to optimise the reactive power dispatch so that the voltage stability will be ensured and the power systems will be operated in an economic and stable manner. In this section, the motivations of reactive power optimisation strategies and the problems caused by the lack of reactive power in model power systems have been discussed.

3.3.1 Technical motivation of optimal reactive power planning in modern power networks

Under the power system deregulation environment, power system operators are looking for a cost-effective way to have sufficient reactive power support from all the reactive power providers. Normally, the reactive power from static reactive power providers like shunt capacitors is cheaper. In addition, renewable energy resources are believed to have lower power generation costs. The use of sustainable and renewable energy technologies has been promoted in all economic sectors for several years. However, as most of the renewable energy sources are concentrated in more remote areas, long-distance power transmission is adopted as an economical and efficient transmission method which means long-distance transmission lines and many transformers will be used. The application of these distributed generations, long-distance transmission lines and a large number of transformers introduce a large amount of line impedance to the grid, i.e. the impedance of transmission lines and the leakage inductance of the transformers cannot be ignored. According to the configuration of the power system, the size of the system impedance is usually determined by the power transformer and the long-distance transmission line [73].

At the same time, most of the renewable energy resources are connected to the main system with converters or inverters. For these distributed generators, which are decoupled from the main system, they cannot provide contributions to system inertia. In the power system, inertia is a term that refers to the kinetic energy found by the rotating mass of a traditional generator, which rotates synchronously with each other and is coupled to the power system, thereby providing a stable system frequency [73], [74]. Consequently, when the penetration level of DGs in a certain system increases, the system inertia will accordingly decrease.

In [49], a weak system is defined in the following way: “it can be considered as a weak system in two aspects: 1) System impedance is high; 2) System inertia is low”. With this definition, it can be concluded that the increase in the penetration level of DGs will make the power grid becoming weaker.

To define if a system is a weak system, system strength is a commonly used term which is to describe how strong the power system is in response to disturbances such as changes in load or switching of equipment [75]. Then system strength is defined as a measure of the power system stability under all reasonably possible operating conditions [76]. Based on this, power systems can then be categorised into two categories: 1) strong systems and 2) weak systems [77].

In a certain system, if there are some disturbances but the system frequency and the bus voltage at the location where these disturbances happened do not have large changes, then the system can be described as a strong system [75]. Otherwise, the system is a weak system. The strength of a system is associated with the sensitivity of the bus voltage to disturbances. Its bus voltage normally has a high robustness to disturbances in a strong system while the voltage can be distorted easily in a weak system.

In traditional power systems, in most cases, it is not necessary to explicitly consider the system strength to ensure the stability of the power system, because there are many synchronous generators connected to the grid, which will inherently contribute to the system inertia and normally have large capacities.

However, when it comes to assessing system strength in an area where DGs are integrated, the system strength calculation is normally applied in a way called short circuit ratio (SCR). The initial stage is to perform a classical three-phase short circuit fault analysis at the point of common coupling (PCC) of DGs, the SCR metric is computed as follows [78]:

$$SCR_{PCC} = \frac{SCMVA_{PCC}}{MW_{CIG}} \tag{3}$$

Where $SCMVA_{PCC}$ is the short circuit MVA level at the point of common coupling (PCC) without the current contribution of the DGs, and MW_{DG} is the rated output power of the DGs [79].

High SCR systems have low sensitivity to voltage disturbances and are predominantly not affected by changes in active power or reactive power injection or absorption. In the DGs integrated systems, a low SCR value indicates the system strength in this certain system is small which means the DG is connected to a weak system. With the increasing penetration level of distributed generations in modern networks, short circuit capacity and inertia are gradually decreased. So in a certain part of the system with a higher penetration level of DGs, the voltage of PCC will have lower robustness to disturbance or changes in load. In addition, there will be many related stability problems encountered in areas where the penetration level of DGs is high, especially in terms of voltage and frequency stability.

Recently, with the hyper growth of renewable energy resources, the penetration level of DGs is increasingly growing in modern power systems. With this increase, the power system will become weaker which brings both voltage stability and frequency stability issues to modern power systems.

Furthermore, in weak system areas, it is mandatory to mitigate the adverse impacts of low system strength on the voltage stability using the operation of existing conventional units, DGs and axillary devices adopting different available solutions. There are several solutions to reduce the adverse impacts of the low system strength on voltage stability, such as transmission reinforcement, synchronous condensers, reactive power and voltage support delivered by DGs and utilization of flexible AC transmission systems (FACTS) devices, especially static VAr compensator (SVC) and static synchronous compensator (STATCOM) [76]. These solutions should be applied to the systems according to the corresponding reactive power planning strategies to ensure the system is operating in an optimal manner against potential disturbances.

3.4 **Existing optimal reactive power ancillary service strategies**

Recently, as aforementioned, large-scale renewable energy resources based generations are integrated into both transmission and distribution networks. In [68], challenges under such a situation have been described as significantly increased risks of voltage fluctuation and cascading tripping in transmission networks, as well as much higher voltage rise and drop fluctuation leading to poor power quality in distribution networks. Facing these challenges, some optimal reactive power ancillary service strategies have been proposed in recent years. To operate power systems in a reliable, economic and stable manner with large-scale wind farm integration, both reactive power procurement (RPP) strategies and optimised reactive power dispatch (ORPD) are the key measures to mitigate the risks of voltage fluctuations.

Both of these two strategies are in the category of power system optimisation problems.

Usually to finalize an optimisation problem in a power system is to firstly establish a mathematical model of the proposed problem, and then to select a suitable algorithm for solving the proposed problem. The process of optimisation mathematical model establishment is normally based on the constrained objective function [82]-[86]. This constrained objective function typically includes two core issues, one is to determine the optimisation objectives and each objective function; the other is to provide different kinds of constraints for the objective functions.

Both establishing a suitable objective function and selecting a set of suitable constraints should help to obtain better optimisation results.

The aforementioned constrained objective function can be formulated as:

$$\begin{aligned} &\min_{x \in X} f(\mathbf{x}) \\ &s.t. \begin{cases} \mathbf{h}(\mathbf{x}) = 0 \\ \mathbf{g}(\mathbf{x}) \le 0 \end{cases} \end{aligned} \tag{4}$$

where $\mathbf{x}$ represents the control variables, $f(\mathbf{x})$ represents the objective function, $\mathbf{h}(\mathbf{x})$ represents the equality constraints and $\mathbf{g}(\mathbf{x}) \le 0$ represents the inequality constraints in power systems.

Firstly, the control variables in the reactive power optimisation problems mainly include different kinds of reactive power providers. There are continuous control variables such as the reactive power output of the synchronous or distributed generators and SVCs, and also discrete control variables such as transformer tap positions, the output of reactive power compensation equipment such as, shunt reactors and capacitors. This should be different for each certain system based on the installed reactive power providers. Especially in modern networks with more complicated components, control variables should be paid more attention to [84].

Secondly, as for the proposed objective functions, there are many selections for the objectives of power system reactive power optimisation. Among them, reducing the total reactive power cost, minimising system voltage deviations, minimising the network active power losses and the best equipment adjustment economy are usually selected objectives. It can be both a single objective function and a multi-objective function based on the purpose of system operators.

Thirdly, about the constraints for the objective function, they usually contain equality and inequality constraints. The equality constraints normally refer to the power flow constraints which mean the distribution branch power flow and transmission network power flow. As for the inequality constraints, they mainly include logical constraints like operation times of vulnerable devices, capacity constraints for transmission lines and all equipment and other constraints like grid codes for renewable energy integrations [87]. Again the constraints should be different for each selected system.

3.4.1 **Existing optimal reactive power procurement planning strategies**

Reactive power procurement planning problems can be designed in both short term and long term. The long-term planning strategies are mainly the construction and installation problems of reactive power providers in modern networks [87]. And the short-term planning strategies are mainly the reactive power reserve problems [88]. Both of them have been widely formulated as constrained single or multi-objective optimisation problems as aforementioned.

This process is generally optimised based on the total cost or the voltage profile. Literature [21] has proposed an interactive fuzzy norm (FN) satisfaction method for multi-objective long-term reactive power planning problems by considering the fuzzy objective of the decision-maker (DM) for each objective function. The new reactive power sources will be built on weak buses and then a global planning problem has been formulated to minimise power loss and voltage deviation. Moreover, a theoretical voltage profile management and reactive power reserve strategy has been proposed in [23] considering competitive pool-based generation markets. This work has decided the space difference of the marginal pricing of each electrical area depends on its specific voltage safety characteristics. Similarly, a long-term reactive power procurement problem (RPP) has been formulated in [24] for deregulated power systems, with an optimal solution that voltage stability improves as well as the reactive power cost. A strategy based on a stochastic solution then has been used to solve this optimisation problem. Based on the partitions Y-bus matrix, the strategy in [44] can identify the reactive source and calculate the amount of reactive power consumed on each load bus. Both seasonal reactive power procurement and hourly reactive dispatch have been considered in the proposed two-level reactive power service framework in [27], based on maximizing the total system revenue generated from reactive power services minus ISO's expected payment.

In addition, as aforementioned, with the increase of DG penetration level in modern power systems, long-term reactive power planning in DG integrated systems has extensively drawn researchers' attention and in some literatures, DGs have also been considered as important reactive power providers [89]. In [26], by detailed considering the WF capability curve, the possibility of including WFs as reactive power providers has been discussed under different grid codes [90]-[92]. An optimisation strategy to minimise total cost and voltage deviations for WFs integrated systems has been proposed also considering wind speed prediction errors. Additionally, [38] has proposed a procedure for DGs to be involved into reactive power ancillary services. The Monte Carlo method has been used to run this multi-objective optimisation algorithm with the aims to minimise power loss, voltage deviation and payment. Voltage control has been formulated as a mandatory service for devices that could contribute with reactive power ancillary services including DGs in [38]. Then within this mandatory margin, an optimisation problem to maximize the active production has been solved delivering a set point for each control device. Based on the convex relaxation of potential problems and the online convex optimisation, a novel stochastic scheme is developed for reactive power management in DGs integrated microgrids (MGs) with the objective to minimise the total reactive power cost [40]. Furthermore, in [41] MGs have been even considered as active and reactive power ancillary service providers to minimise the total power loss of the main grid.

While maintaining the stable operation of the system, [93] has managed to minimise the cost of reactive power, as well as the annual operating cost of conventional generators corresponding to curtailed wind energy. The result has shown that with this planning optimisation, the installation cost of transmission lines would be reduced.

Some papers have also tried to use reactive power ancillary service for dynamic reserves in DGs integrated systems in order to successfully ride through voltage sags and swells [94]-[96].

Other than using DGs or reactive power compensators, literature [42] has provided a novel alternative method using existing parallel transformers to absorb temporary excess reactive power. This research has established a new reactive auxiliary service that allows the distribution network to use its existing parallel transformers to achieve an economic voltage control.

3.4.1.1 **Main drawbacks of the existing optimal reactive power procurement planning strategies**

However, the proposed strategies in previous papers have never considered the outage of reactive power providers for the short-term planning and most of them without considering the stochastic characteristics of load demand and wind power. This is important even in the day-ahead planning to ensure sufficient reactive power reserve. And their cost function for each device is very simple without considering all kinds of costs. This may lead to miscalculation compared with the realistic electricity market. Also, most of them did not consider the contributions of OLTCs and flexible demand which are also very important in modern power systemsIn the reactive power procurement strategy proposed in the next Chapter, these main shortcomings will be addressed.

3.4.2 **Existing optimal reactive power dispatch strategies**

Optimal reactive power dispatch is another power system reactive power optimisation method and preventive voltage control method. This kind of problem in the power system usually refers to thoroughly adjusting the generator terminal voltage, transformer tap ratio, the output of the reactive power compensation device and other control variables when the power system has sufficient reactive power. Objectives such as the bus voltage reaching the qualified value and the active power loss of the whole network are normally considered. With different operating objects and constraints, ORPD becomes a constrained mixed-integer, multi-objective problem with conflicting objectives [97]-[100].

The system optimal reactive power dispatch problem is very complicated. Such a problem is a branch of the well-known optimal power flow (OPF) problem of the power system. The mathematical model of the system optimal power flow can be described as: when the system structural parameters and load conditions are given, the control variables should be adjusted to find the power flow dispatch that should satisfy all the specified constraints and make a certain performance index or multi-objective function of the system reach its optimum.

Also with the increase of distributed generation (DG) penetration level in modern power systems, DGs have also been considered as reactive power providers in recent literatures as aforementioned. Under this situation, there should be more controllable variables in modern networks when doing optimal reactive power dispatch calculations. However, by involving these distributed generators as extra control variables, various problems will also be introduced like wind power uncertainties and harmonic emissions. Consequently, in modern networks, to ensure voltage stability level and reactive power ancillary service requirements, ORPD in a relatively short time period or even real-time considering multi objectives and uncertainties should be addressed wisely. To achieve this goal with different optimisation aims, various strategies have been proposed in the past. The existing ORPD strategies usually consider two optimisation objectives, namely active power losses and voltage deviations which are formulated into well-established objective functions under various constraints including network power flow, devices limitations and logical constraints, etc. And the control variables usually include adjusting the generator VAr output, transformer tap staggers and capacitors/reactors or reactive power compensators. Other than the most widely used two objectives, minimising power loss and voltage deviation, to reduce maintenance costs and the operation times of OLTCs have also been considered in [99], [100]. In [99], a multi-objective function based strategy is proposed to reduce network power losses and the number of switching operations of OLTCs. In [101] an approach for improving day-ahead reactive power dispatch using two-stage Heuristic search-based correction is presented. By this, voltage deviations and power losses are considered. In [102], a robust ORPD problem in transmission and distribution networks is designed. However, the same objective

function which is only to minimise the power loss is used and the calculation time of their proposed algorithm is not provided but the authors mentioned to improve their current algorithm's convergence effectiveness as a future task.

3.4.2.1 Main drawbacks of the existing optimal reactive power dispatch strategies

There are four main shortcomings of existing ORPD strategies available in the open literatures: i) because of the algorithm limitations, most ORPD strategies are implemented only in distribution networks ii) wind farm harmonic emissions, i.e. power quality, have not been considered after including the reactive power injected from WTs iii) existing ORPD solvers are usually very complex requiring extensive calculations, while convergence rate is relatively low, which may lead to local optima when being applied to high-dimensional space iv) usually, power system constraints are checked only with the final calculation results without being included into the iteration calculation process. In addition, from all these literatures, most of them are mainly considered the high penetration level of WTs concerns only happened in distribution networks. However, the major challenge for high wind power penetration in transmission networks has also been raised as significantly increased risks of voltage fluctuation and cascading tripping in [68]. So it is suggested that a proper voltage control in both transmission and distribution systems or even a coordination control in transmission network operators (TSO) and distribution system operators (DSO) is needed.

3.4.3 **Challenges of reactive power optimisation in modern power systems**

During recent decades, after considering more control variables and conflict objectives, the reactive power optimisation problem becomes more complicated in modern power systems. For example, after considering DGs as reactive power providers, harmonic emissions are a known power quality concern in modern wind turbines (WTs) [103] and are consequently regulated by the relevant network operator codes [104]. Harmonics are traditionally quantified through the total harmonics distortion (THD) factor and are directly linked to increased costs and other problems, e.g. accelerated aging of network operation assets. In this context, minimisation of system average THD of voltages and currents at wind farms is an equally important objective of an optimal operation of networks with integrated wind farms. As such, it is directly related to the reactive power optimisation strategy design.

This means a more comprehensive objective function for reactive power optimisation is necessary when considering the situation in modern power systems. However, when including more objectives in one objective function, the importance of every single objective should be sorted based on the system operation priority by system operators.

Furthermore, existing reactive power optimisation strategies available in the open literatures never consider the optimal reactive power procurement strategy and optimal reactive power dispatch strategy simultaneously.

When considering a whole process of reactive power optimisation, both optimal reactive power planning like reactive power procurement and optimal reactive power dispatch should be combined together to ensure both the economic reactive power reserve and a stable and secure system operation.

In addition, as a preventive control strategy, reactive power optimisation works as a coordinated control that can set the optimal values for all necessary operational devices to mitigate voltage fluctuations. Instead of considering the high penetration level of DGs only happened in distribution systems, reactive power optimisation in both distribution and transmission systems needs more attention. Consequently, a proper reactive power optimisation strategy that can be applied to both TNs and DNs is necessary.

3.5 Solvers for the constrained objective function based power system optimisation problems

Power system reactive power optimisation includes complex multi-dimensional planning problems with multiple variables and multiple constraints. As aforementioned, control variables include both discrete variables such as OLTC taps and continuous variables such as generator reactive power output. To efficiently solve the optimisation problem is also a challenging task because of the non-convex characteristics or even the discrete variables involved in the operation stage [70]. It is difficult to accurately achieve the optimal solution so the mathematical model is often simplified in previous reactive power optimisation research. Many optimisation solvers adopt the method of treating discrete variables as continuous variables and vice versa. The optimal solution obtained in this way may be the "sub-optimal solution" of the original problem, and there is a certain deviation from the original optimisation problem solution. Therefore, how to solve the optimisation model, improve the intelligence of optimisation, and achieve a rapid solution, has always been the focus of academic research. With the development of computer technology, mathematical theory and modern optimisation theory, to address these challenges, a considerable number of works have been carried out on this topic which could be generally divided into two categories: conventional method and heuristic algorithms [70].

Nowadays there are some researchers focusing on exploring the conventional methods [105]-[107]. These kinds of methods are mainly based on accurate convex or cone relaxation, bus injection model (BIM) and the branch flow model (BFM). However, the relative tightness of the relaxations depends on the network topology [106]. After formulating several relaxations of optimal power flow (OPF), the IEEE tutorial [108] provides algorithmic recommendations for different types of networks as: for radial networks, conventional methods are recommended as the approximation error can still be neglected by using the bus injection model (BIM) or the branch flow model (BFM). However, for mesh networks, especially large networks with higher level complexity, a heuristic search algorithm can be worth exploring for finding feasible solutions within a limited time. Furthermore, literature [109] characterizes the dispatch approximation errors between the original non-convex economic dispatch problem and the solutions of three commonly used approximated convex relaxation analytical methods showing that this type of approximation error is problematic in realistic transmission systems. Consequently, conventional methods are mainly applied in distribution systems. To apply the reactive power optimisation strategy to both distribution and transmission systems, a heuristic algorithm should be used.

In this case, intelligent algorithms such as genetic algorithm (GA), particle swarm optimisation (PSO), etc can be applied [110]. These heuristic algorithms are easy to use and very straightforward, but sometimes they can be time-consuming or lead to local solutions instead of global optima [108]. In [99], a GA based strategy is proposed to reduce network power losses and the number of switching operations of OLTCs. In [111], a risk-based robust optimisation strategy for long-term VAr planning is proposed with minimising system operating costs. In [101] an approach for improving day-ahead reactive power dispatch using two-stage heuristic search-based correction is presented. A data-driven modelling strategy was used in [112] to deal with transmission expansion planning and reactive power optimisation with the objectives of minimising network losses and operating times of adjustment equipment. A similar strategy is also used in [113] to address the energy and reserve dispatch problem in renewable energy integrated systems to minimise system generation costs. There are also various heuristic search algorithms, such as grey wolf optimisation [114], PSOGSA [115], chaotic bat algorithm[116], differential evolution algorithm [117], cuckoo search algorithm [118], jellyfish search algorithm [119], and salp swarm algorithm [120] have been considered to solve single-objective reactive power optimisation problems. However, for a complex multi-objective optimisation problem, they may easily lead to local optimal solutions due to the non-convexity of the power system optimisation problem and different directional or conflicting objectives of the objective functions [20]. To address multiple objective optimising problem challenges, various methods, such as an improved heap-based optimiser [121], teaching learning based optimisation [123] firefly algorithm [124], oppositional krill herd algorithm [125], particle swarm optimisation [126], artificial bee colony [101], genetic algorithm considering dynamic crowding distance [127] or genetic algorithm incorporating fuzzy for both radial network reconfigurations and losses [128], multi-objective evolutionary algorithm [129] and adaptive immune algorithm [130] have been proposed and considered to solve the multi-objective reactive power optimisation problems.

However, as aforementioned, most intelligent algorithms can be time-consuming or be trapped in local optima especially when there are many control variables or the network topology is complicated. Owing to this, these previous strategies are only applied ito day-ahead time and in distribution networks. So, an improved GA, based on i-NSGA-II and roulette selection, is proposed in this thesis to solve the multi-objective problem both in distribution and transmission networks. The inclusion of the inheritance operator and roulette concept improves the speed of convergence to global Pareto-optimal significantly with a minimum number of generations over the conventional NSGA-II [110] and several jumping gene (JG) based NSGA-II algorithms [111]. Such an improved genetic algorithm will be presented in the next Chapter. It has been used as the main solver in this thesis to solve the proposed RPP and ORPD strategies.

In later sections, both classical methods and intelligent methods are introduced in detail.

3.5.1 **Classical methods for solving optimisation problems**

Classical optimisation methods are a group of precise algorithms that are suitable for simple optimisation problems, mainly including linear programming method, nonlinear programming method, branch and bound method, interior point method and etc. In recent years, the development of classical methods has already been mature and their effect on optimisation models with low complexity is obvious. But classical methods have limitations when processing mixed-integer optimisation problems and they will introduce large approximation errors when applying to large complex systems.

3.5.1.1 **Linear programming method**

The linear programming method linearizes all the objective functions and constraints in the power system optimisation problem by ignoring the higher-order terms. Then the nonlinear programming problem will be transferred into a linear programming problem at the initial point. Since the 1970s, researchers have conducted a lot of research on the optimal power flow algorithm based on the linear programming method. The linear programming method is widely used in active power optimisation and reactive power optimisation planning problems

[131]. The mathematical model of the linear programming method is simple and straight. Additionally, as the physical concept is clear, the calculation speed can be fast. Due to the completeness and maturity of the method, it has been widely used in the power system optimisation area. But at the same time, the linear approximation of the model inevitably will bring large calculation errors.

3.5.1.2 **Non-linear programming method**

The nonlinear programming method can directly deal with non-linear objective functions. The widely used nonlinear programming methods mainly include the simplified gradient method, Newton method and quadratic programming method. It usually uses a simplified model to express the objective function and linearizes the constraint conditions. Compared with linear programming, the accuracy of non-linear programming is higher [132].

Literature [133] uses the basic nonlinear programming model of the power system to solve the optimal power flow problem. Literature [134] proposed a reactive power optimisation model and used a sequential nonlinear programming method to solve it. Literature [135] proposed a dual sequential quadratic programming method to solve the economic dispatch problem with constraints. The form of nonlinear programming is relatively simple and can approximately reflect the physical characteristics of the power system. However, it will also introduce approximation errors to the original optimisation problem [136].

3.5.1.3 **Branch and bound method**

The branch and bound method is a kind of classical solution for constrained optimisation problems with a finite number of feasible solutions. Branching refers to the division of the feasible solution space of the original problem repeatedly by introducing relaxation to make it become a smaller sub-problem feasible solution domain. Delimitation is to set a bound for the solution value of each sub-problem: set the upper bound for the maximum programming problem, and set the lower bound for the minimum programming problem.

The branch and bound method divides the feasible region repeatedly and continuously transforms the original problem into several sub-problems. By continuously cutting the sub-problems according to the cutting criterion, until all the sub-problems are processed, the optimal solution of the original problem can be found in the integer feasible solutions. It can be seen from this, that the essence of the branch and bound method is to continuously divide or decompose the feasible solution set of the original problem on the basis of "relaxation", "branch", "delimitation", and "cutting" to transform the original problem into multiple sub-problem and to solve these sub-problems separately. The general ideas of this method and algorithm flow of the branch and bound method for solving the minimum programming problem are introduced as a branch and bound tree.

The branch and bound tree is also called the enumeration tree, which fully embodies the well-known divide and conquers strategy. That is, when it is too difficult to solve the problem directly within the original feasible solution domain, the original problem can be divided into smaller sets. Then the obtained result in each set should be compared to find the optimal solution to the original problem. The details are shown in Figure 3-2.

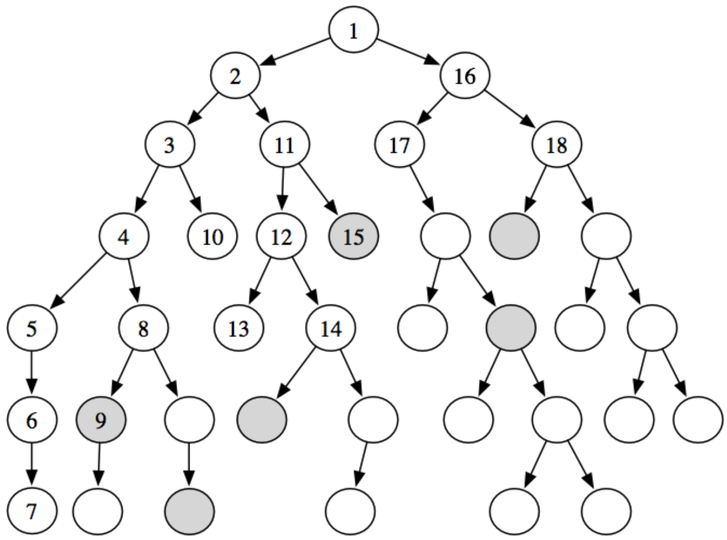


Figure 3-2 Branch and bound tree graph [137]

Among all the classical methods, the branch and bound method is the most widely used method nowadays. It solves the problem by enumerating all feasible solutions of integer programming problems indirectly. However, it is in exponential complexity. For example, if n is the number of binary variables, i.e. {0, 1}, then in the worst case, the branch and bound method needs to solve 2^n sub programs to get the global optimal solution [137]. Consequently, the establishment of effective branching criteria and the construction of relaxation conditions also have a great influence on the efficiency of the solving process. The branch and bound method can be used not only to solve pure integer programming problems but also to solve mixed-integer programming problems by approximation and relaxation [138].

3.5.1.4 **Two stage optimisation method**

Nowadays, practical problems are also solved in two stages optimisation method. In the first stage, an approximation algorithm should be used to quickly obtain a feasible solution for solving the master problem (MP). The general idea is to ignore some variables first, and construct a model that uses only part of the variables (the rest of the variables are first set to 0) so that a solution can be quickly found. Then variables outside the model should be searched to find the variable that can make the solution better, and add it to the objective function to solve it again. This process should repeat until it cannot find a better solution [137].

In the second stage, after obtaining this feasible solution as an initial solution, it will be used into the optimal solver of branch and bound method in the sup problem (SP), as the upper or lower bound. Then, a search tree is dynamically generated by the branching process. Finally, the bounding process shrinks the upper and lower bound of the primary model according to the optimal solution of the relaxed model at all leaf nodes until the optimal solution is achieved [139].

The gap between the upper and lower bounds can be used as a test standard for the quality of the initial solution. In the second stage, as the sup problem (SP) of the branch and bound method proceeds, the optimisation solver is likely to find a better solution than the first stage solution (better upper or lower bound), thereby reducing the gap. When upper bound equals lower bound, GAP=0, that is, the global optimal solution has been found [139].

In power system reactive power optimisation problems, researchers commonly use discrete reactive power compensators as control variables in the first stage as the “here and now” decisions while continuous reactive power compensators are used in the second stage as the “wait and see” decisions.

However, the two-stage strategy has limitation as it cannot find the global optimal solution in only one stage with both discrete and continuous variables. Also because of the limitation of the relaxation process requested in this method, it can only be applied to radial networks to neglect approximation errors. So most of the papers using this kind of method are focus on distribution networks. In literature [105], [112] this kind of algorithm is used.

3.5.1.5 **Interior point method**

The basic idea of the interior point method is to start from an initial point inside the feasible region and to find a new interior point that reduces the objective function along a feasible direction. After that, starting from this new interior point, the subsequent interior point that makes the objective function drop in a feasible direction should be found iteratively. The iteration process should be repeated to get a sequence composed of interior points so that the solution will gradually tend to the optimal value.

In order to find the optimal solution, the enumeration method needs to traverse most or all the possible points within the feasible region. It will consume too much time to find the optimal solution when dealing with large-scale problems. However, the calculation time of the interior point method is not sensitive to the problem scale. It has polynomial time and is more suitable for large-scale system optimisation. There are currently three main types of interior point methods: projection method [140], affine scaling method [141] and primal-dual method [142]. With the continuous development, the application field of the interior point method has also been extended from linear programming to linear complementary problems, quadratic programming problems, and nonlinear programming problems.

Although the interior point algorithm has been widely used in the field of mathematical optimisation with its excellent convergence and robustness, recent studies have found that the interior-point algorithm still needs to be improved. The interior point algorithm may cause the problem to converge to an infeasible point when solving the nonlinear programming with more than two equality constraints and the total number of constraints is greater than the total dimension of the variables. In addition, the global convergence of the interior point algorithm is still questionable.

3.5.2 Artificial intelligence-based algorithms

Although the conventional methods have gradually overcome the difficulties in inequality constraint processing, calculation speed and convergence, there is still no suitable solution for the processing of mixed continuous and discrete variables and to avoid approximation errors. In recent years, with the development of technologies such as computers and artificial intelligence, artificial intelligence (AI) methods have been used successively for reactive power optimisation problems in power systems.

The intelligent methods include heuristic and meta-heuristic search algorithms that can overcome the problems conventional methods have and have the capabilities to process mixed-integer optimisation models. Commonly used intelligent algorithms include: genetic algorithm (GA), particle swarm optimisation algorithm (PSO), simulated annealing algorithm, tabu search algorithm, ant colony algorithm and etc. In order to further improve the performance of artificial intelligence (AI) optimisation methods and deal with more complex optimisation models, a variety of improved intelligent algorithms are widely used in power system optimisation and related fields. However, due to the random nature of intelligent optimisation methods, there will be a trade-off between increasing the number of samples or the number of iterations to achieve higher accuracy and the speed of convergence. It is also difficult to process complex multi-objective optimisation problems. They may easily lead to local optimal solutions due to the non-convexity of the optimisation models and different directional or conflicting objectives of the objective functions.

As artificial intelligence-based solvers, they can provide optimal solutions for multi-objective problems by heuristic search and iteration within all control variables’ feasible region. Additionally, by setting the corresponding precisions, some modern AI algorithms can set certain control variables to integer or not, like the improved i-NSGA-II, which is especially suitable for solving mixed-integer optimisations [32].

As for meta-heuristic search algorithms, the biggest difference between them and heuristic algorithms is that heuristic algorithms usually seek more local optimality but meta-heuristic algorithms can overcome local optimisation which is more suitable for seeking global optimality. For example, the genetic algorithm (GA) has a mutation mechanism to overcome convergence to local optima. Secondly, the design of the heuristic algorithm is more dependent on the problem, and the meta-heuristic algorithm is independent of the problem. It can be operated as a black box and has wide applicability. But it still needs to adjust various parameters of the algorithm according to the practical problem like crossover and mutation rate in GA. So after carefully setting these parameters, mixed-integer multi-objective optimisation problems can be directly solved by meta-heuristic algorithms.

However, when there are too many objectives, some meta-heuristic algorithms may have shortcomings like low efficiency or low reliability. So in practical problems, some researchers also trying to further improve the existing meta-heuristic algorithms to improve computational efficiency and produces high-quality results [31]-[33].

3.6 Chapter summary

In this Chapter, firstly, deregulated power system scheme has been introduced which has been widely applied in modern societies. Then the pricing mechanism and procurement procedure in deregulated systems have been discussed. This chapter also gives an introduction to existing reactive power optimisation strategies in modern power systems. The technical motivation of reactive power optimisation in modern power systems after introducing many new technologies has been presented. Both existing optimal reactive power procurement strategies and optimal reactive power dispatch strategies have been introduced.

After that, major drawbacks of the existing reactive power optimisation strategies have been described. Consequently, the importance of proposing a new reactive power planning strategy that includes a more comprehensive objective function with more control variables that can be applied to both TNs and DNs can be drawn. The conclusion is that both optimal reactive power procurement strategy and optimal reactive power dispatch strategy should be combined together to maintain a stable and economic operation in modern power systems. After that, in this Chapter, the feasible solvers for multi-objective optimisation problems have also been reviewed. So, a heuristic search algorithm based solver for reactive power optimisation problems with fast convergence speed and high accuracy is needed when considering applying the reactive power optimisation strategy into both distribution and transmission networks. This is particularly important for efficient and timely hourly modifications of control variables, i.e. wind generators' and reactive power compensators' power injections, as well as positions of taps at OLTCs. A novel optimal RPP and ORPD strategies will be proposed, simulated and tested in the later chapters.

4 Reactive power procurement planning strategy considering contingencies in deregulated systems

4.1 Introduction

With the process of power system deregulation all over the world, system operators are aiming at minimising the total cost of the power production and system operation. As mentioned in Chapter 2.2, reactive power control as an ancillary service in deregulated power systems plays a vital role especially in the wind power integrated systems. However, other than the obligatory reactive power support, more available reactive power ancillary service should cost extra money from the system operator side. On the one hand, the system operator company desires to economically purchase the reactive power ancillary service from all available reactive power providers. In addition, the power system stability level highly depends on the availability and distribution of reactive power. It is very important to ensure a sufficient amount of reactive power in the network at any moment to make sure a stable and reliable operation of the power system. The independent system operator must also ensure that under certain contingencies or sudden load changes should not cause any voltage instability that may lead the system to collapse. Then there will be a trade-off between preparing adequate reactive power for better system stability level and saving reactive power ancillary service cost for economic purposes. Therefore, a wise procurement of reactive power has become a very important issue in the operation of modern power systems which should consider both the unit commitment and economic dispatch of reactive power.

To operate power systems in a secure, economic and stable manner, sufficient but not redundant reactive power reserve is one of the key measures. And this reactive power reserve plan should be considered via a reactive power procurement plan in which the proper reactive power compensation devices should be selected. Their sizes, ratings and locations must be decided based on a detailed planning analysis. Then after optimally addressing the reactive power procurement problems, the calculated reserved amount of reactive power can be applied as all control variables' limits when doing reactive power dispatch calculations.

So far, reactive power procurement mechanisms are depending on the policies of different countries. In many deregulated markets, as aforementioned, they have not yet established a financial compensation mechanism for reactive power ancillary services while there are also some electricity markets that do have plans to pay for reactive power support services. In the United Kingdom, the National Grid (NG), which performs ISO functions, should invite GENCOs to bid for reactive power ancillary services. GENCOs can achieve this through bids consisting of capacity components (price per MVAr and quantity provided) and utilization components (MVArh price curve). The selected bidder signs a bilateral contract with the national grid and receives part of the remuneration for ability and utilization. Then GENCOs will be able to operate within their reserved capacity limits to produce or absorb reactive power [19]. As aforementioned, in modern power systems, renewable energy resources also have the capabilities to provide reactive power support. So, targeting at the wind power integrated systems, the reactive power output capabilities from wind farms are presented firstly in Section 4.2.

In this Chapter, motivated by ensuring power system voltage stability and minimising reactive power ancillary service cost, a novel reactive power procurement strategy is proposed in Section 4.3 considering all available reactive power providers limitations, potential uncertainties, outages and contingencies. For a more economical solution, the total reactive power cost of the other day has been chosen as the objective function.

In addition, in order to minimise the reactive power loss, it is not desirable to transmit too much reactive power through the network. Therefore, reactive power should be purchased at different locations in the system based on the predicted demand conditions, load type, and the availability of the potential reactive power support equipment. However, these devices have different characteristics. For example, generators are fast response reactive power support devices with high opportunity costs, while capacitors are slow devices but with lower installation and operating costs. So, each constrain and cost function of different reactive power providers will be detailed in Section 4.3.1. After that, the constraints for the proposed objective function will be presented as well as considered uncertainties and contingencies are stated in Section 4.3.3 and 4.3.4. This proposed reactive power procurement strategy then has been simulated and tested in Section 4.3.7.

4.2 **Reactive power support from wind farms**

Motivated by the net zero targets by 2050, sustainable and renewable energy technologies have been promoted in all economic sectors for several years. In recent years, considering economic and stable system operations, the implementation of reactive power support in the renewable energy integrated power system is attracting a higher level of attention, especially because of the increase of wind power penetration level. At present, wind energy is the most important renewable energy in the world. Highly permeable intermittent renewable resources such as wind turbine (WT) systems may cause problems in voltage stability, for example, bus voltage limits may be exceeded due to insufficient reactive power support. In order to ensure the economic and stable operation of the wind power integrated systems, wind farms are also expected to provide reactive power support which is considered as a necessary basis. On this basis, the voltage level and other system performances can be guaranteed.

In all wind farms, wind turbines (WT) based on doubly fed induction generators (DFIG) are widely used due to their favourable performance and economic prospects [90]. So in this section, the wind farm with installed DFIGs will be taken as an example to investigate the reactive power support in renewable energy integrated systems.

4.2.1.1 **Wind farm reactive power control**

To further increase the reactive power output capability from wind farms and to protect the power electronic devices installed in each wind turbine unit during voltage drop, there are usually some axillary reactive power compensation devices in the wind farms. By adding other devices like static VAr compensator (SVC), static synchronous compensator (STATCOM) [90], dynamic voltage restorer (DVR) [91] and series grid side converter (SGSC) [92] to enhance the reactive power compensation capability of wind farms have been presented in previous literatures. Among these, as both static VAr compensator (SVC) and static synchronous compensator (STATCOM) can perform continuous reactive power regulation, they have become the most commonly used reactive power compensation devices for wind farms. However, since they are using power electronic converters and controllers, such reactive power compensation methods are expensive. The economics of wind farm operation is also an issue that must be considered. In addition, the installed reactive power compensation capacity should also be optimised. If the designed compensation capacity is too large, it will cause a waste of resources and increase the investment of the wind farm. In addition, in order to reduce the installation cost of the reactive power compensation devices, the reactive power compensation capability of the wind turbine itself should also be considered and fully utilized.

Therefore, the reactive power control strategy of a wind farm can be generally divided into two levels:

1. The reactive power coordination between the wind farm and the grid, including the reactive power output by the axillary reactive power compensation devices.
2. After the wind farm obtains the reactive power demand from the power system, this demand will be uniformly dispatched and distributed among the axillary devices and wind turbines in the wind farm.

As for a single wind turbine, the reactive power limit is normally determined by the following factors [91], [92]:

1. Capacitive reactive power generation is usually limited by the rotor current;
2. Inductive reactive power generation is usually limited by the stator current;
3. Rotor voltage, slip and P/Q priority modes may also limit DFIG reactive power capability.

Consequently, by combining both the axillary reactive power compensators installed into wind farms and the wind turbine reactive power output capability, renewable energy resources based generation units can also contribute a certain amount to the reactive power ancillary services in power systems.

4.2.1.2 **Reactive power capability of Type-III wind generators**

As mentioned, most types of renewable energy resources like the doubly-fed induction generator (DFIG) can realize active and reactive decoupling control. The reactive characteristics of this kind of wind turbine depend on the inner control loop of the DFIGs. The major three kinds of operational modes of DFIGs can be divided into [47]:

- Constant Power Factor Operation (Mode-A)

In this mode of operation, in order to maintain constant reactive power exchange at point of common coupling (PCC), the wind turbine is operating with a certain power factor. This is a more traditional operation mode of controlling wind turbines. As the wind farms are normally integrated at the remote end of the network with a long electric distance to the main grid, the wind farm may have to absorb or generate some of the reactive power to keep the power factor at the PCC point to be constant.

- Voltage Control Mode Operation (Mode-B)

In this control mode, to control the voltage at PCC to be a predefined constant value, the operation of the wind turbine has been modified from the traditional control mode. So the reactive power exchanged with the grid can be changed corresponding to the voltage magnitude. When the voltage deviates from this predefined value, the required reactive power will be calculated and injected or absorbed with a small time constant (normally within 50 ms). But this should consider the capacity of the converters. The PCC voltage predefined value is normally calculated by steady-state analysis, e.g. optimal power flow (OPF) or ORPD. In addition, if the wind farm has additional static reactive power compensator (STATCOM) or other reactive power compensation devices integrated, their reactive power generation capacity will also be included in the wind farm control.

- Transient Stability Enhancement Mode Operation (Mode-C)

In this control mode, the wind farm will operate according to the converter's control principle which is normally vector control. When a fault or disturbance happened, that is, when the PCC voltage drops below a threshold value, the wind farm will enter this control mode. This mode is usually used in the wind turbine low voltage ride through (LVRT) process. When there is no voltage disturbance, the wind farm should be operated in the voltage control mode described in the Mode B.

Nowadays, with the increase of wind power integrated penetration level, wind farms are normally expected to be operated as the voltage control mode during steady-state with optimally set the PCC voltage and to enter the transient stability enhancement mode to provide extra reactive power support during fault or voltage fluctuations for the power system to maintain stable voltage level and to ride through low voltage period. To accomplish the steady-state optimisation proposed in this thesis, both the control mode-A and control mode-B of wind farms are considered as constraints in the proposed strategies.

4.3 The proposed reactive power procurement (RPP) strategy in deregulated power systems

In deregulated power systems, reactive power procurement (RPP) strategies have long been discussed in hourly daily, seasonally and yearly time scales. It is normally designed based on minimising the total system reactive power ancillary services cost. According to the pricing and procurement procedure described in Chapter 3, in this section, a new day-ahead reactive power procurement strategy based on forecasted data and the bidding procedure has been proposed. The reactive power procurement process has been formulated as a constrained single-objective optimisation problem. Compared with the proposed strategies in previous literatures, they have never considered the outage of reactive power providers for the other day and most of them without considering the stochastic characteristics of load demand and wind power. In addition, their cost function for each device is very simple without considering all kinds of costs such as fixed cost and opportunity of loss cost. Also, most of them did not consider the contributions of flexible demand, i.e. MVAr reduction. In the reactive power procurement, the SO should consider bid prices from all the reactive power providers e.g. grid connection point or synchronous generators (SGs), DGs, shunt reactors or compensators (SRCs) and MVAr reduction. This thesis has addressed all these issues in the proposed day-ahead reactive power procurement strategy. This procurement strategy is designed in day-ahead time scale is to ensure accuracy of the forecast inputs when compared with monthly and yearly plans.

This proposed strategy should be applied in EMS or DMS combining with the bidding process between generation companies and independent system operators. The outputs are the total reserved reactive power of each reactive power provider in the system the other day. Then these reserved capacities should be used as limits for optimal power flow or optimal reactive power flow calculations.

In Figure 4-1, the time scale for implementing the proposed RPP strategy is given.

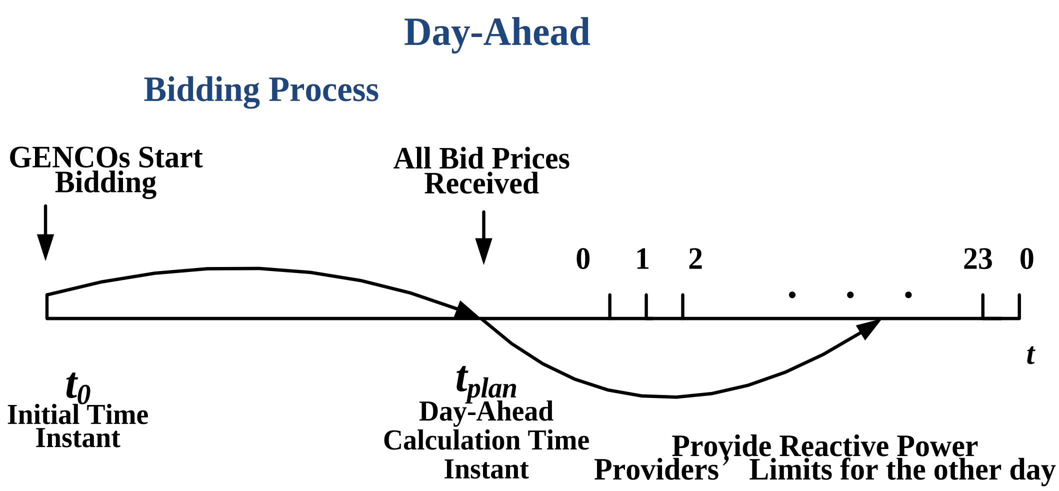


Figure 4-1 Time scale of the proposed reactive power procurement strategy

It is assumed at the initial time instant t_0, independent system operator companies such as the national grid in the UK should invite tenders to bid for reactive power support services based on day-ahead forecast data. All generation companies (GENCOs) then can start bidding for reactive power support through price per MVAr·h and quantity to offer. Based on their offers, the proposed reactive power procurement strategy should be applied at the day-ahead calculation time instant t_{plan}. With the total reactive power cost function as the objective function, all procured reactive power from each provider for the other day will be settled. After that, the selected GENCOs and ISO will get their daily bilateral contracts for the capacities of the paid reactive power ancillary services for the other day [19].

The optimal day-ahead reactive power procurement solution is obtained using an improved genetic algorithm described later in this Chapter. The detailed new RPP strategy is described in the section below.

4.3.1 Cost functions

As mentioned, the role of the day-ahead RPP strategy is to optimally set the output limits for all reactive power providers installed in the system and consequently to ensure sufficient margins for reactive power dispatch plans. The proposed constrained optimisation strategy considers a) synchronous generators or grid connection points, b) distributed generators c) capacitances of SCs and SVCs and d) flexible demand. They are belonging to the set of control variables, dominating the day-ahead optimisation of the RPP strategy. The optimisation is based on the criteria to minimise the total reactive power ancillary services cost. Considering the possible contingencies, uncertainties and forecast errors in day-ahead time, a stochastic optimisation model is designed with security constraints as listed below:

$$\begin{aligned} \min_{x \in X} \quad & f(\mathbf{x}) \\ s.t. \quad & \Pr\left\{\mathbf{P}(\mathbf{x},\xi) \le 0\right\} \ge 1-\varepsilon \\ & \mathbf{h}(\mathbf{x},\xi) = 0 \\ & \mathbf{g}(\mathbf{x},\xi) \le 0 \end{aligned} \tag{5}$$

where $\mathbf{x}$ represents the control variables, $f(\mathbf{x})$ is the objective function of the proposed RPP strategy, $\mathbf{P}(\mathbf{x},\xi) \le 0$ refers to the security constraints in power systems, ε is the acceptable failure rate, $\mathbf{h}(\mathbf{x},\xi) = 0$ is the equality constraints and $\mathbf{g}(\mathbf{x},\xi) = 0$ is the inequality constraints.

In this section, the proposed reactive power procurement optimisation is with the objects to minimise total reactive power cost. And the system security constraints mainly include load demand and wind power day-ahead forecast errors rate. Then the optimisation model is listed below:

$$
\begin{aligned}
\min \quad & C(Q)=\sum_{t=1}^{24} C(Q^{t})=\sum\nolimits_{t\in\Omega_t}\sum\nolimits_{k\in\Omega_k}\pi_k\cdot C(Q^{t,k}) \\
s.t. \quad & \Pr\left\{\begin{array}{l} P_{D,i\_\min}^{t}<P_{D,i}^{t,k}(\xi_1)<P_{D,i\_\max}^{t} \\ W_{i\_\min}^{t}<W_{i}^{t,k}(\xi_2)<W_{w\_\max}^{t} \end{array}\right\}\geq 1-\varepsilon \\
& oc_{ij}^{t,k}\cdot x_{ij}^{k}\cdot\left[I_{ij}^{t,k}\right]^2\leq\left(\overline{I}_{ij}^{t}\right)^2 \\
& U_{i\_\min}^{k}<U_{i}^{t,k}<U_{i\_\min}^{k} \\
& \mathbf{h}^{t,k}(\mathbf{x}^{t,k},\xi_1,\xi_2)=\mathbf{0} \\
& \mathbf{g}^{t,k}(\mathbf{x}^{t,k},\xi_1,\xi_2)\leq\mathbf{0} \qquad t\in\Omega_t\ ;k\in\Omega_k\ ;i\in\Omega_b\ ;ij\in\Omega_l
\end{aligned}
\tag{6}
$$

where $C(Q)$ is the total cost function of reactive power schedule for the other day. Here t is the calculation time window which will last one hour, $t\in\Omega_t(t=1,2,...,24)$ and security states $k\in\Omega_k(k=0,1,2,3...)$ where *k=0* is base-case (N-0) and *k>0* is single outages (N-1); $P_{D,i}^{t,k}(\xi_1)$ is the forecast load demand with probability; $W_i^{t}(\xi_2)$ is the forecast wind speed with probability; $U_i^{(t,k)}$ is the bus voltage of bus *i,* at time *t,* regime *k; oc_{ij}^{t}* is the binary operation variable for branch *ij* at time *t,* regime *k,* equal 1 for closed branches and 0 for open branches; x_{ij}^{k} is input parameter that specifies which branch is on outage for security case k (for k=0, all $x_{ij}^{k}=1$).

**Note that x_{ij}^{k} is not dependent on time because in preventive control, it is assumed unchangeable for the entire period*

As the reactive power providers considered in this stage include: a) synchronous generators or grid connection points, b) distributed generators c) capacitances of SCs and SVCs and d) flexible demand, the total reactive power cost function should consider costs from all these reactive sources as listed below:

$$
C\left(Q^{t,k}\right)=C\left(Q_G^{t,k}\right)+C\left(Q_{DG}^{t,k}\right)+C\left(Q_{SRC}^{t,k}\right)+C\left(Q_{SVC}^{t,k}\right)+C\left(Q_{QR}^{t,k}\right) \tag{7}
$$

where $C(Q_G^{t,k})$ is the total expected cost of the reactive power from synchronous generator or grid support point at time *t,* regime *k,* $C(Q_{DG}^{t,k})$ is the total expected cost of reactive power from distributed generations (DGs) at time *t,* regime *k,* $C(Q_{SRC}^{t,k})$ is the total expected cost of reactive power from reactive power shunt compensator or reactor at time *t*, regime *k*, $C(Q_{SVC}^{t,k})$ is cost for static VAr compensator, and $C(Q_{QR}^{t,k})$ is the total expected cost of reactive power from flexible demand i.e. MVAr reduction, at time *t*, regime *k*.

Each reactive power provider's cost function is presented in detail in the following subsections.

4.3.1.1 **Cost function for synchronous generators (SGs) or grid connection point**

In this section, the cost function of grid connection point and synchronous generators is given. In distribution networks, the grid connection point refers to the connection point between this distribution network and the transmission network, generator or any other distribution network. Through this point, power is injected into the distribution network. It should be the most important reactive power provider in a distribution network. The grid connection point is assumed to have similar reactive power regional offers as synchronous generators. As for the synchronous generators in both distribution and transmission networks, they should be able to provide a certain amount of obligatory reactive power support with a fixed cost to ensure the availability of the other day. Other than that, SGs should also have the capability to provide more reactive power with linear or quadratic price offers as shown in Figure 3-1. So the cost function for grid connection point and synchronous generators is listed below:

$$C(Q_G^{t,k}) = \sum_{i=1}^{N_G} \left\{ se_{G,i}^{t,k} \left[\begin{array}{l} C_{G-F}^{t} + cr_{G,i,1}^{t,k} \cdot cost_{MVAr-G,i,1}^{t} \cdot q_{G,i,1}^{t,k} + cr_{G,i,2}^{t,k} \cdot C_{MVAr-G,i,2}^{t} \cdot \left(q_{G,i,2}^{t,k}\right)^2 \\ + cr_{G,i,3}^{t,k} \cdot C_{MVAr-G,i,3}^{t} \cdot q_{G,i,3}^{t,k} \end{array} \right] \right\} \quad (8)$$

where $se_{G,i}^{t,k}$ is the binary decision variable on unit *gi* MVAR availability window at interval *t*, case $k, C_{G-F}^{t}\left(£/h\right)$ is the fixed cost of the other day using power from SG or grid support point, $cr_{G,i,1}^{t,k}$ is the binary decision variable for a certain SG *i* to use linear price offer service at time *t*, regime *k*, $cr_{G,i,2}^{t,k}$ is the binary decision variable for a certain SG *i* to use quadratic price offer service at time *t*, regime *k*, $cr_{G,i,3}^{t,k}$ is the binary decision variable for a certain SG *i* to use MVAr absorption linear price offer service at time *t*, regime *k*, $C_{MVAr-G,i,1}^{t}\left(£/MVAr/h\right)$ is the linear offer region reactive power price of each MVar per hour, $C_{MVAr-G,i,2}^{t}\left(£/MVAr/h\right)$ is the quadratic offer region reactive power price of each MVar per hour, $C_{MVAr-G,i,3}^{t}\left(£/MVAr/h\right)$ is the linear price offer for using MVAr absorption service per hour, $q_{G,i,1}^{t,k}$ is the reactive power needed from SG or grid support point at time *t*, regime *k* within linear price offer region, $q_{G,i,2}^{t,k}$ is the reactive power needed from SG or grid support point at time *t*, regime *k* within quadratic price offer region, $q_{G,i,3}^{t,k}$ is the MVAr reactive power absorption service from SG or grid support point at time *t*, regime *k* within linear price offer region.

4.3.1.2 Cost function for distributed generators

In this section, the cost function of the distributed generators is given. As aforementioned, the distributed generators are also expected to provide reactive power support in modern power systems. The cost function of distributed generators is similar with the one of synchronous generators. Generally, they can be divided into two types based on their capabilities to reschedule active power. If the certain distributed generators are not able to rearrange their scheduled real power in order to increase their reactive power production, there will not be quadratic component in the cost function. In this thesis, the distributed generators refer to wind turbine based generations.

- For distributed generators that do not have capability to reschedule active power-no opportunity costs

$$C(Q_{DG}^{t,k})=\sum_{n=1}^{N_{DG}}\left\{se_{DG,i}^{t,k}\left[C_{DG-F}^{t}+cr_{DG,i,1}^{t,k}\cdot C_{MVAr-DG,i,1}^{t}\cdot q_{DG,i,1}^{t,k}+cr_{DG,i,2}^{t,k}\cdot C_{MVAr-DG,i,2}^{t}\cdot q_{DG,i,2}^{t,k}\right]\right\} \quad (9)$$

Otherwise, if the distributed generators have the capability to rearrange their scheduled real power, then the quadratic component which represents the lost opportunity cost will be added into cost function.

- For distributed generators with possibility to reschedule active power

$$C(Q_{DG}^{t,k})=\sum_{n=1}^{N_{DG}}\left\{se_{DG,i}^{t,k}\begin{bmatrix}C_{DG-F}^{t}+cr_{DG,i,1}^{t,k}\cdot C_{MVAr\text{-}DG,i,1}^{t}\times q_{DG,i,1}^{t,k}+cr_{DG,i,2}^{t,k}\times C_{MVAr\text{-}DG,i,2}^{t}\times q_{DG,i,2}^{t,k}\\+cr_{DG,i,3}^{t,k}\times C_{MVAr\text{-}DG,i,3}^{t}\times(q_{DG,i,3}^{t,k})^{2}\end{bmatrix}\right\} \quad (10)$$

where $se_{DG,i}^{t,k}$ is the binary decision variable on unit *DGi* MVAr availability window at interval *t*, regime *k*, $cost_{DG-F}^{t}\left(£/h\right)$ is the fixed cost of the other day using power from DG, $cr_{DG,i,1}^{t,k}$ is the binary decision variable for a certain DG *i* to use linear price offer service at time *t*, regime *k*, $cr_{DG,i,2}^{t,k}$ is the binary decision variable for a certain DG *i* to use MVAr absorption linear price offer service at time t, $cr_{DG,i,3}^{t,k}$ isthe binary decision variable for a certain DG i to use quadratic price offer service at time t, regime k, $C_{MVAr-DG,i,1}^{t}(£/MVAr/h)$ is the linear offer region reactive power price of each MVar per hour, $C_{MVAr-DG,i,2}^{t}(£/MVAr/h)$ is the linear price offer for using MVAr absorption service per hour , $C_{MVAr-DG,i,3}^{t}(£/MVAr/h)$ is the quadratic offer region reactive power price of each MVar per hour, $q_{DG,i,1}^{t,k}$ is the reactive power needed from DG at time t, regime k within linear price offer region, $q_{DG,i,2}^{t,k}$ is the MVAr reactive power absorption service from DG at time t, regime k within linear price offer region, $q_{DG,i,3}^{t,k}$ is the reactive power needed from DG at time t, regime k within quadratic price offer region.

4.3.1.3 **Cost function for shunt capacitor or reactor**

In this section, the cost function for shunt capacitor or reactor is given. Here it is assumed by set certain value to $B_{type,i}^{t,k}$, either a shunt capacitor or shunt reactor will be selected, i.e. for reactor $B_{type,i}^{t,k}<0$ and for capacitor $B_{type,i}^{t,k}>0$. In the following cost function, the first summation is for selected shunt reactors (SR) and the second is for the selected shunt capacitors (SC).

$$\begin{aligned}C(Q_{SRC}^{t}) &= \sum_{n=1}^{N_{SR}}\left[se_{SR,i}^{t,k}\cdot C_{SR\text{-}F}^{t}+C_{MVAr-SR,i}^{t}\cdot(U_{i}^{t,k})^{2}\cdot\sum\nolimits_{type}cr_{SR-type,i}^{t,k}\cdot|B_{type,i}^{t,k}|\right]\\ &+\sum_{n=1}^{N_{SC}}\left[se_{SC,i}^{t,k}\cdot C_{SC\text{-}F}+C_{MVAr-SC,i}^{t}\cdot(U_{i}^{t,k})^{2}\cdot\sum\nolimits_{type}cr_{SC-type,i}^{t,k}\cdot B_{type,i}^{t,k}\right]\end{aligned} \quad (11)$$

where $se_{SR,i}^{t,k}$ is the binary decision variable on unit *SRi* MVAr availability window at time t, regime k, $se_{SC,i}^{t,k}$ is the binary decision variable on unit *SCi* MVAr availability window at time t, case k, $C_{SR-F}^{t}(£/h)$ is the fixed cost of the other day using power from SR, $C_{SC-F}^{t}(£/h)$ is the fixed cost of the other day using power from SC, $cr_{SR-type,i}^{t,k}$ is the binary decision variable for a certain shunt reactor *step*, at time t, regime k, if this step is chosen, $cr_{SR-type,i}^{t,k}=1$ otherwise $cr_{SR-type,i}^{t,k}=0$, $cr_{SC-type,i}^{t,k}$ is the binary decision variable for a certain shunt capacitor *step*, at time t, regime k, if this step is chosen, $cr_{SC-type,i}^{t,k}=1$ otherwise, $cr_{SC-type,i}^{t,k}=0$, $C_{MVAr-SR,i}^{t}(£/MVAr/h)$ is the reactive power price of each MVar per hour from a certain SR,

$C^{t}_{MVAr-SC,i}\left(£/MVAr/h\right)$ is the reactive power price of each MVar per hour from a certain SC, $B^{t,k}_{type-i}$ is optional step susceptance for a certain SR/SC at time *t*, regime *k*, $U^{t,k}_{i}$ is the terminal voltage at bus *i*, time *t*, regime *k*.

4.3.1.4 **Cost function for SVCs**

In this section, the cost function of SVCs is given. SVCs are considered as an adjustable shunt capacitor and should have the similar cost function with SCs only with $B^{t,k}_{SVC,i}$ as a continuous variable. It is believed by adjusting values for $B^{t,k}_{SVC,i}$, SVCs can achieve both functions to produce and absorb reactive power to the grid. When $B^{t,k}_{SVC,i}<0$, it will absorb reactive power and when $B^{t,k}_{SVC,i}>0$, it will produce reactive power. So its cost function is listed below:

$$C\left(Q^{t,k}_{SVC}\right)=\sum_{i=1}^{N_{SVC}} se^{t,k}_{SVC,i}\cdot\left[C^{t}_{SVC-F}+cr^{t,k}_{SVC,i}\cdot C^{t}_{MVAr-SVC,i}\cdot B^{t,k}_{SVC,i}\cdot(U^{t,k}_{i})^{2}\right] \tag{12}$$

where $se^{t,k}_{SVC,i}$ is the binary decision variable on unit SVC_i MVAr availability window at interval *t*, case *k*, $C^{t}_{SVC-F}\left(£/h\right)$ is the fixed cost of the other day using power from SVC, $cr^{t,k}_{SVC,i}$ is the binary decision variable for a certain SVC, at each hour t, if this SVC is chosen, $cr^{t,k}_{SVC,i}=1$, otherwise $cr^{t,k}_{SVC,i}=0$, $B^{t,k}_{SVC,i}$ is optional step for a certain SVC, $U^{t,k}_{i}$ is the terminal voltage.

4.3.1.5 **Cost function for flexible demand, i.e. MVAr reduction:**

Flexible demand is known as scheduled MVAr reduction. Its cost function is given in this section. As aforementioned, it is believed with pre-schedule, reactive load curtailment can also be considered as reactive power provider in a certain power system. Its cost function should contain a fixed cost part and a linear cost of loss price which is shown below:

$$C(Q^{t,k}_{QR})=\sum_{n=1}^{N_L} se^{t,k}_{QR,i}\cdot\left[C^{t}_{QR-F}+cr^{t,k}_{QR,i}\cdot C^{t}_{MVAr-QR,i}\cdot q^{t,k}_{QR,i}\right] \tag{13}$$

where $se^{t,k}_{QR,i}$ is the binary decision variable on unit QR_i MVAr availability window at interval *t*, regime *k*, $cr^{t,k}_{QR,i}$ is the binary decision variable for a certain QR *i* to use service at time *t*, regime k, $C^{t}_{QR-F}\,(£/h)$ is the fixed cost of the other day using power from QR, $q^{t,k}_{QR,i}$ is the reactive power needed from QR at time t, regime k.

4.3.2 **Operation time window**

As aforementioned, all reactive power providers should take part in the bidding procedure with the independent system operator. In this procedure, some generation companies have their minimum engagement operation time window for participating in reactive power ancillary services. In this thesis, considering the real operation situation in the GB networks, for synchronous generators, distributed generators, shunt capacitors, stative VAr compensators and flexible demand, the operation time window of these devices to provide reactive power as ancillary services (beyond obligatory part) are set as at least 3 hours to monitor the real situation in modern networks. This means in the reactive power procurement stage, there should be one more coupling constraint that once the ancillary service has been required from such providers, the procurement planning time window should be at least 3 hours. The operation time window for SGs, DGs, SRCs, SVCs and QRs is shown in Figure **4-2**. This has been achieved in this thesis by calculating the optimal output reactive power for these reactive power providers hourly. After that, if the reactive power ancillary service has been used for a certain provider, a manual adjustment should be added to fit the pre-agreed minimum ancillary service time window.

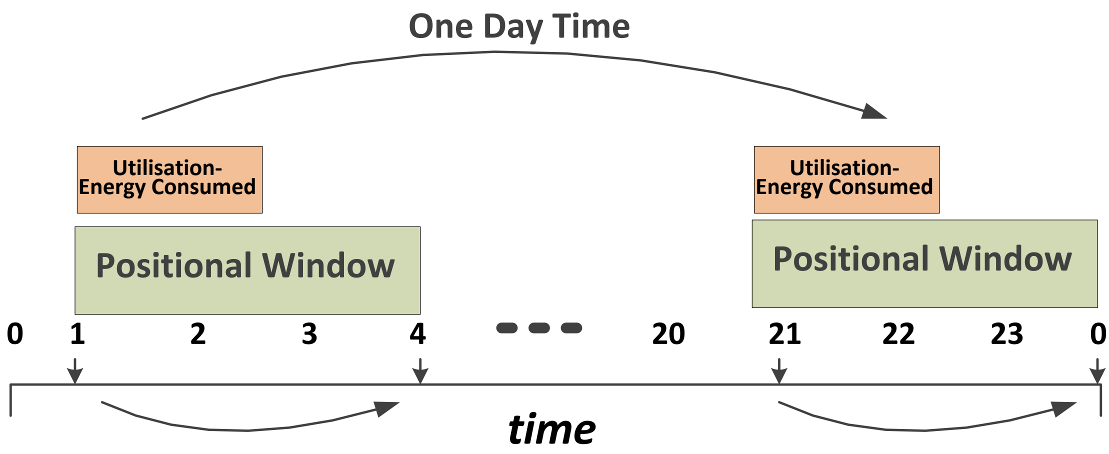


Figure 4-2 Ancillary service operational time window for SGs, DGs and QRs

4.3.3 **Constraints:**

The proposed reactive power procurement cost function and all control variables should meet several constraints including stochastic optimisation constraint, power flow constraints, logical constraints and other constraints.

4.3.3.1 **Stochastic optimisation constraint**

Considering the forecast errors in day-ahead planning stage, forecasted load demand and wind speed should be limited within a confidence range. So the stochastic optimisation constraints are listed as follow:

$$\Pr\left\{\begin{matrix} P_{D,i\_\min}^{t} < P_{D,i}^{t,k}(\xi_1) < P_{D,i\_\max}^{t} \\ W_{i\_\min}^{t} < W_{i}^{t,k}(\xi_2) < W_{w\_\max}^{t} \end{matrix}\right\} \ge 1-\varepsilon \tag{14}$$

4.3.3.2 **Power flow constraints**

All control variables and criteria should meet power flow constraints so that the active power balance in each node, each hour and each security case is listed below:

$$\begin{aligned} & m_i^{t,k}\cdot p_{SS,i}^{t,k} + \left(p_{G,i}^{t} - cr_{G,i,3}^{t,k}\cdot \Delta p_{G,i}^{t,k}\right) + \left\{p_{DG,i}^{t}\left[w_i^t\left(\xi_2\right)\right] - cr_{DG,i,3}^{t,k}\cdot \Delta p_{DG,i}^{t,k}\right\} \\ & -p_{Di}^{t}\left(\xi\right) - \sum\nolimits_{ij\in\Omega_l}\left[x_{ij}^{k}\cdot oc_{ij}^{t,k}\cdot p_{ij}^{t,k}\left(\cdot\right)\right] = 0\ ; \\ & \forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\ \forall i\in\Omega_b \end{aligned} \tag{15}$$

And the reactive power balance in each node, each hour and each security case is:

$$\begin{aligned} & m_i^{t,k}\cdot q_{SS,i}^{t,k} + \left\{cr_{G,i,1}^{t,k}\cdot q_{G,i,1}^{t,k} + cr_{G,i,2}^{t,k}\cdot q_{G,i,2}^{t,k} - cr_{G,i,3}^{t,k}\cdot q_{G,i,3}^{t,k}\right\} + \left\{cr_{DG,i,1}^{t,k}\cdot q_{DG,i,1}^{t,k} + cr_{DG,i,2}^{t,k}\cdot q_{DG,i,2}^{t,k} - cr_{DG,i,3}^{t,k}\cdot q_{G,i,3}^{t,k}\right\} \\ & +(U_i^{t,k})^2\cdot\left[\sum\nolimits_{type} cr_{SC-type,i}^{t,k}\cdot B_{type,i}^{t,k} - \sum\nolimits_{type} cr_{SR-type,i}^{t,k}\cdot |\, B_{type,i}^{t,k}\,|\right] + cr_{SVC,i}^{t,k}\cdot B_{SVC,i}^{t,k}\cdot (U_i^{t,k})^2 \\ & +B_{Shunt,i}^{k}\cdot (U_i^{t,k})^2 - \left[q_{D,i}^{t}\left(\xi_1\right) - cr_{QR,i}^{t,k}\cdot q_{QR,i}^{t,k}\right] - \sum\nolimits_{ij\in\Omega_l}\left[x_{ij}^{k}\cdot oc_{ij}^{t,k}\cdot q_{ij}^{t,k}\left(\cdot\right)\right] = 0\ ; \\ & \forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\ \forall i\in\Omega_b \qquad \left\{\forall i,j\in\Omega_b\right\} \end{aligned}$$

(16)

Branch power flow:

$$\begin{aligned} & p_{ij}^{t,k}\left(\cdot\right) = (U_i^{t,k})^2 g_{ij}^{k} - U_i^{t,k}\cdot U_j^{t,k}\cdot\left(g_{ij}^{k} cos\theta_{ij}^{t,k} + b_{ij}^{k} sin\theta_{ij}^{t,k}\right) \qquad \left\{\forall i,j\in\Omega_b\right\} \\ & q_{ij}^{t,k}\left(\cdot\right) = -(U_i^{t,k})^2 b_{ij}^{k} + U_i^{t,k}\cdot U_j^{t,k}\cdot\left(b_{ij}^{k} cos\theta_{ij}^{t,k} - g_{ij}^{k} sin\theta_{ij}^{t,k}\right) \qquad \left\{\forall i,j\in\Omega_b\right\} \end{aligned} \tag{17}$$

And the security constraints for transmission line thermal constraints and voltage stability range constraints are also used in this proposed day-ahead reactive power procurement strategy.

$$oc_{ij}^{t,k} \cdot x_{ij}^{k} \cdot \left[I_{ij}^{t,k} \right]^2 \le \left(\overline{I}_{ij}^{t} \right)^2 \\ U_{i\_\min}^{k} < U_{i}^{t,k} < U_{i\_\min}^{k} \tag{18}$$

For the systems including OLTCs, there should be one more constraint for OLTC ratio:

$$tap_{\min,ij} \le tap_{ij}^{t,k} \le tap_{\max,ij} \;;\forall t \in \Omega_t \;;\forall k \in \Omega_k ;\forall ij \in \Omega_l \tag{19}$$

where m_i^t is the binary variable denoting circuit connection to primary substation at node *i* at each hour *t*, p_{Gi}^t, q_{Gi}^t is the active & reactive power at time *t* from SG or grid support point at node *i*, p_{DGi}^t, q_{DGi}^t is the active & reactive power at time *t* from DG at node *i*, p_{Di}^t, q_{Di}^t is the active & reactive demand at time *t* at node *i*, q_{SCi}^t reactive power at time *t* from reactive power compensator at node *i*, oc_{ij}^t is the binary operation variable for branch *ij* at time *k*, equal 1 for closed branches and 0 for open branches, p_{ij}^t, q_{ij}^t is active & reactive power flows in branch *ij* at time , y_i^t is the OLTC ratio in p.u. at bus *i* of time *t*.

where $m_i^{t,k}$ is the binary variable denoting circuit connection to primary substation at node *i* at time *t*, regime *k*, p_{Gi}^t, q_{Gi}^t is the active & reactive power at time *t* from SG or grid support point at node *i*, p_{DGi}^t, q_{DGi}^t is the active & reactive power at time *t* from DG at node *i*, p_{Di}^t, q_{Di}^t is the active & reactive demand at time *t* at node *i*, q_{SCi}^t reactive power at time *t* from reactive power compensator at node *i*, $oc_{ij}^{t,k}$ is the binary operation variable for branch *ij* at time *k*, equal 1 for closed branches and 0 for open branches, $p_{ij}^{t,k}, q_{ij}^{t,k}$ is active & reactive power flows in branch *ij* at time , $tap_{ij}^{t,k}$ is the OLTC tap position between bus *ij* of time *t*, regime *k*. $W_i^t\left(\xi_2\right)$ is the forecast wind speed with probability; x_{ij}^k is the fault parameter for branch *ij*:0 for outage;1 otherwise; $B_{Shunt,i}^k \cdot (U_i^{t,k})^2$ is sum of shunt susceptances of all lines and transformers which originate from node *i*.

4.3.3.3 **Logical constraints**

In the proposed RPP strategy, there are also some logical constraints to cooperate control variables and criteria.

In distribution networks, for normally open points, considering network reconfiguration, maximum number of back feeding points for distribution network outages k) should be limited:

$$\sum_{ij \in \Omega_{NOP}} oc_{ij}^{t,k} \leq N_{NOP} \;\; ;\forall t \in \Omega_t \; ;\forall k \in \Omega_k \setminus 0 \tag{20}$$

Where N_{NOP} is the maximum number of NOPs used during outages.

For operation coupling constraints for switches, the number of branch switching in one day should be limited:

$$\sum_{t \in \Omega_t} oc_{ij}^{t,k} \leq N_{SW} \;\; ; \; \forall k \in \Omega_k \tag{21}$$

N_{SW} is the number of switching in one hour (control room capability), N_{BS} is the maximum number of subs used during outages.

**Note: base case k=0 and each contingency last for 24 hours*

Additionally, the number of switching at one time should also be limited considering control room capability:

$$\sum_{ij \in \Omega_l} oc_{ij}^{t,k} \leq N_{SW} \;\; ; \; \forall t \in \Omega_t \; ; \;\; \forall k \in \Omega_k \tag{22}$$

Again, for distribution networks, the maximum number of back-feed feeders connected to primary substations during outages is also specified in the UK utilities [143]:

$$\sum_{i \in \Omega_{BS}} m_i^{t,k} \leq N_{BS} \;\; ; \; \forall t \in \Omega_t \; ;\forall k \in \Omega_k \setminus 0 \tag{23}$$

As for the grid connection point or the synchronous generators with regional cost function, there are logical constraints for the binary decision variables. First, these kind of reactive power providers have the capability either to absorb or produce reactive power. But they cannot absorb and produce reactive power at the same time. So the binary decision variable for absorbing reactive power and the binary decision variable for producing reactive power should have the following logical constraint:

$$cr_{G,i,1}^{t,k}+cr_{G,i,3}^{t,k}\le 1\ ;\ \forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{24}$$

Second, the quadratic price offer will only be applied when the required reactive power is more than the limit of linear component. So the binary decision variable for these two regions should have the following constraint:

$$cr_{G,i,2}^{t,k}\le cr_{G,i,1}^{t,k}\ ;\forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{25}$$

As aforementioned, the ancillary service of reactive power from some synchronous generators or grid connection point should have a minimum operation window. Based on the UK power system, this time window has been set as 3 hours in this thesis. Then there will be constraints for minimum operation time window:

$$se_{G,i}^{t,k}\le se_{G,i}^{t+1,k}\le se_{G,i}^{t+2,k}\ ;\forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{26}$$

$$\sum\nolimits_{t\in\Omega_t}\left|se_{G,i}^{t+1,k}-se_{G,i}^{t,k}\right|\le 2\cdot NW_G\ ;\forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{27}$$

Similar to SGs, distributed generator also have similar logical constraints:

$$cr_{DG,i,1}^{t,k}+cr_{DG,i,2}^{t,k}\le 1\ ;\forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{28}$$

$$cr_{DG,2,i}^{t,k}\le cr_{DG,1,i}^{t,k}\ ;\forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{29}$$

$$se_{DG,i}^{t,k}\le se_{DG,i}^{t+1,k}\le se_{DG,i}^{t+2,k}\ ;\forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{30}$$

$$\sum\nolimits_{t\in\Omega_t}\left|se_{DG,i}^{t+1,k}-se_{DG,i}^{t,k}\right|\le 2\cdot NW_{DG}\ ;\forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{31}$$

where NW_G and NW_{DG} are the pre-set maximum number of time window for synchronous generators/grid connection point and distributed generators separately.

As for shunt reactors and shunt capacitors, they have different *steps* which represent certain amount of susceptance. Only one *step* can be selected at a time, so there are constraints:

$$\sum\nolimits_{type}cr_{SR-type,i}^{t,k}\le 1\ ;\ \forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{32}$$

$$\sum\nolimits_{type}cr_{SC-type,i}^{t,k}\le 1\ ;\ \forall t\in\Omega_t\ ;\ \forall k\in\Omega_k\ ;\forall i\in\Omega_b \tag{33}$$

Similarly, shunt reactor/capacitor and flexible demand also have the minimum operation window when providing reactive power ancillary services.

$$se_{SR,i}^{t,k} \le se_{SR,i}^{t+1,k} \le se_{SR,i}^{t+2,k} \;;\forall t \in \Omega_t \;;\; \forall k \in \Omega_k ;\forall i \in \Omega_b \tag{34}$$

$$se_{SC,i}^{t,k} \le se_{SC,i}^{t+1,k} \le se_{SC,i}^{t+2,k} \;;\forall t \in \Omega_t \;;\; \forall k \in \Omega_k ;\forall i \in \Omega_b \tag{35}$$

$$\sum\nolimits_{t\in\Omega_t} \left| se_{SR,i}^{t+1,k} - se_{SR,i}^{t,k} \right| \le 2 \cdot NW_{SR} \;;\forall k \in \Omega_k ;\forall i \in \Omega_b \tag{36}$$

$$\sum\nolimits_{t\in\Omega_t} \left| se_{SC,i}^{t+1,k} - se_{SC,i}^{t,k} \right| \le 2 \cdot NW_{SC} \;;\forall k \in \Omega_k ;\forall i \in \Omega_b \tag{37}$$

$$se_{QR,i}^{t,k} \le se_{QR,i}^{t+1,k} \le se_{QR,i}^{t+2,k} \;;\forall t \in \Omega_t \;;\; \forall k \in \Omega_k ;\forall i \in \Omega_b \tag{38}$$

$$\sum\nolimits_{t\in\Omega_t} \left| se_{QR,i}^{t+1,k} - se_{QR,i}^{t,k} \right| \le 2 \cdot NW_{QR} \;;\forall k \in \Omega_k ;\forall i \in \Omega_b \tag{39}$$

where NW_{SR}, NW_{SC} and NW_{QR} are the pre-set maximum number of time window for shunt reactors/capacitors and flexible demand separately.

4.3.3.4 **Other constraints**

Other than the power flow constraints and logical constraints, there are also some other constraints.

Firstly, as described in the regional reactive power price offer, the synchronous generators and distributed generators may have the capability to rearrange their scheduled active power. But they still have the apparent power limitations and maximum active power reduction limitations as listed below:

$$cr_{G,i,2}^{t,k} \cdot Q_{G2-\min,i}^{t} \le q_{G,i,2}^{t,k} \le cr_{G,i,2}^{t,k} \cdot \sqrt{(S_{G2-\max,i}^{t})^2 - [p_{G,i}^{t}(\zeta_1) - \Delta p_{G,i}^{t,k}]^2} \tag{40}$$

$$0 \le \Delta p_{G,i}^{t,k} \le cr_{G,i,2}^{t,k} \cdot \Delta p_{G-\max,i}^{t,k} \tag{41}$$

$$cr_{DG,i,3}^{t,k} \cdot Q_{DG3-\min,i}^{t} \le q_{DG,i,3}^{t,k} \le cr_{DG,i,3}^{t,k} \cdot \sqrt{(S_{DG3-\max,i}^{t})^2 - [p_{DG,i}^{t}(\zeta_1,\zeta_2) - \Delta p_{DG,i}^{t,k}]^2} \tag{42}$$

$$0 \le \Delta p_{DG,i}^{t,k} \le cr_{DG,i,3}^{t,k} \cdot \Delta p_{DG-\max,i}^{t,k} \tag{43}$$

where $\Delta p_{G,i}^{t,k}$ is possible reduction of generation due to excessive MVAr production; $p_{G,i}^{t}$ is known active power generation. It was assumed if $cr_{(G,i,3)}^{(t,k)} = 1$ then there is possibility to reduce power.

where $\Delta p_{DG,i}^{t,k}$ is reduction of active power; $p_{DG,i}^{t}$ is known active power generation. It was assumed if $cr_{DG,i,3}^{t,k}=1$ then there is possibility to reduce power

Additionally, all control variables should be within their reactive power capacities. Reactive limits for SGs or grid connection point:

$$cr_G^t \cdot P_{G_{\min}} \le p_{Gn}^t \le cr_G^t \cdot P_{G_{\max}}, \quad cr_G^t \cdot Q_{G\_\min} \le q_{Gn}^k \le cr_G^t \cdot Q_{G\_\max} \tag{44}$$

$$cr_{G,1,i,}^{t,k} \cdot q_{G-\min,1,i}^{k} \le q_{G,1,i}^{t,k} \le cr_{G,1,i,}^{t,k} \cdot q_{G-\max,1,i}^{k} \;;\forall t \in \Omega_t \;\;;\forall k \in \Omega_k \;\;;\forall i \in \Omega_b \tag{45}$$

$$cr_{G,2,i,}^{t,k} \cdot q_{G-\min,2,i}^{k} \le q_{G,2,i}^{t,k} \le cr_{G,2,i,}^{t,k} \cdot q_{G-\max,2,i}^{k} \;;\forall t \in \Omega_t \;\;;\forall k \in \Omega_k \;\;;\forall i \in \Omega_b \tag{46}$$

$$cr_{G,3,i,}^{t,k} \cdot q_{G-\min,3,i}^{k} \le q_{G,3,i}^{t,k} \le cr_{G,3,i,}^{t,k} \cdot q_{G-\max,3,i}^{k} \;;\forall t \in \Omega_t \;\;;\forall k \in \Omega_k \;\;;\forall i \in \Omega_b \tag{47}$$

Reactive limits for DG:

$$cr_{DG,1,i,}^{t,k} \cdot q_{DG-\min,1,i}^{k} \le q_{DG,1,i}^{t,k} \le cr_{DG,1,i,}^{t,k} \cdot q_{DG-\max,1,i}^{k} \;;\forall t \in \Omega_t \;\;;\forall k \in \Omega_k \;\;;\forall i \in \Omega_b \tag{48}$$

$$cr_{DG,2,i,}^{t,k} \cdot q_{DG-\min,2,i}^{k} \le q_{DG,2,i}^{t,k} \le cr_{DG,2,i,}^{t,k} \cdot q_{DG-\max,2,i}^{k} \;;\forall t \in \Omega_t \;\;;\forall k \in \Omega_k \;\;;\forall i \in \Omega_b \tag{49}$$

$$cr_{DG,3,i,}^{t,k} \cdot q_{DG-\min,3,i}^{k} \le q_{DG,3,i}^{t,k} \le cr_{DG,3,i,}^{t,k} \cdot q_{DG-\max,3,i}^{k} \;;\forall t \in \Omega_t \;\;;\forall k \in \Omega_k \;\;;\forall i \in \Omega_b \tag{50}$$

Flexible demand reduction MVAr limits:

$$0 \le q_{QR,i}^{t,k} \le q_{QR-\max,i}^{t,k} \;;\forall t \in \Omega_t \;\;;\forall k \in \Omega_k \;\;;\forall i \in \Omega_b \tag{51}$$

$$cr_{QR,i}^{t,k} \cdot p_{D,i}^{t,k}\left(\zeta_1\right) \cdot \tan\left(\varphi_{new,i}\right) \le q_{QR,i}^{t,k} \le cr_{QR,i}^{t,k} \cdot p_{D,i}^{t,k}\left(\zeta_1\right) \cdot \tan\left(\varphi_{old,i}\right) \tag{52}$$

For DGs integrated into power systems, there are also grid codes from the grid side that should be considered as constraints. Two different grid codes has been used in this thesis:

$$Q_{DG\_\max}^{k} = (P_{DG\_\max}^{k} - cr_{DG,i,3}^{t,k} \cdot \Delta p_{DG,i}^{t,k}) \cdot \tan\left(\cos^{-1}\left(0.95\right)\right) \tag{53}$$

$$Q_{DG\_\max}^{k} = \sqrt{\left(S_{DG\_\max}^{k}\right)^2 - \left(P_{DG\_\max}^{k} - cr_{DG,i,3}^{t,k} \cdot \Delta p_{DG,i}^{t,k}\right)^2} \tag{54}$$

$S_{DG\_\max}^{k}$ is the apparent power limit of DG which is decided by the capacity of converters.

For shunt reactor or capacitors:

$$
\begin{aligned}
X_{type\_\min} \le X_{type}^{t} \le X_{type\_\max} \\
B_{type\_\min} \le B_{type}^{t} \le B_{type\_\max}
\end{aligned} \tag{55}
$$

$$
pf_{\min} \le pf_{new} \le pf_{\max} \tag{56}
$$

Last, when there are distributed generators connecting to networks, there is a possibility that the optimal results include islanding conditions in which loads are supplied only by DGs. To prevent islanding conditions, 'fictitious power flows' has been presented in [143]. The main purpose is to define fictitious loads at buses connected to DGs, which would generate fictitious power flows and then islanding conditions should be prevented. Fictitious power balance equations (55) are specified for each node and they are restricted by constraint (56).

**Note: the virtual power flow has nothing to do with the actual power flow. They are actually part of the radial configuration requirements of the entire feeder in each regime k. Therefore, relations (57) and (58) are expressed by constructing and manipulating decision variables.*

$$
\sum_{ij \in \Omega_l} oc_{ij}^{t,k} \cdot x_{ij}^{k} \cdot f_{ij}^{t,k} = K_i \;\; ; \; \forall t \in \Omega_t \;\; ; \forall k \in \Omega_k \;\; ; \forall i \in \Omega_b \tag{57}
$$

$$
\left| f_{ij}^{t,k} \right| \le N_{DG} \cdot oc_{ij}^{k} \cdot x_{ij}^{k} \; ; \; \forall t \in \Omega_t \;\; ; \forall k \in \Omega_k \, ; \; \forall ij \in \Omega_l \tag{58}
$$

Considering system reconfiguration, for each regime k, the radial configuration of the optimal solution in distribution networks must be ensured. This is expressed by a set of constraints related to the complete network (57) and to the contingent configurations (58).

Radial configuration of the optimal solution has to be ensured for each regime *k*; this is expressed through a set of constraints related to intact network (59), as well as to contingent configurations (60).

$$
\sum_{ij \in \Omega_l} oc_{ij}^{t,k} = n_b^k - 1 \, ; \forall t \in \Omega_t \;\; ; k = 0 \tag{59}
$$

$$
\sum_{ij \in \Omega_l} oc_{ij}^{t,k} \cdot x_{ij}^{k} = n_b^k - \sum_{i \in \Omega_{BS}} m_i^{t,k} \;\; ; \; \forall t \in \Omega_t \;\; ; k > 0 \tag{60}
$$

where n_b^k is the total number of nodes in regime *k;* $f_{ij}^{t,k}$ is the fictitious power flow in branch *ij*, regime *k* due to DG; K_i is the fictitious load equal 1 at DG node i;0 otherwise.

4.3.4 **Contingency and outage analysis**

During the day-ahead reactive power procurement planning stage, system planners usually perform contingency analysis to identify severe contingencies to make sure that a sufficient reactive power reservation will be made to maintain power system stability level when there are contingencies or outages happen.

It would increase the system stability level if as much as possible contingencies and outages have been considered and to prepare more available reactive power. However, there is a trade-off between economic reactive power reserve and secure reactive power reserve.

In previous literature, to consider the economic situation, loads were set to fifty percent of the peak demand in [144] and eighty percent in [145]. But to ensure sufficient reserves during contingencies, the worst condition of a power system under different uncertainties has been tackled in previous literature mostly to settle the system operation margin and installed capacities. Usually, the largest required capacities of all generators during the most serve contingencies are selected as preserved reactive power limits [144]-[151]. To meet the requirement of worst contingency scenarios is an essential task in these papers. And in [152], a certain scenario failure rate (SFR) is set to guarantee the robustness of the proposed chance constrained solution, which means a small fraction of total scenarios are allowed to have exceeded constraints.

Other than this, there are also two popular methods to further obtain risk assessment by doing contingencies and outages ranking from the reliability evaluation: the Analytic Method (AM) and Monte Carlo Simulation (MCS) [151].

- Analytic method

In [145], it has used past experience of the probability of occurrence of different contingencies for proper planning criteria to keep a balance between cost and performance. The combined customer interruption cost and utility cost is calculated and as shown in Figure 4-3, the minimised point should be taken as the system future plan. Some papers also did sensitivity studies between base case and contingencies to compare the cost differences [143], [152].

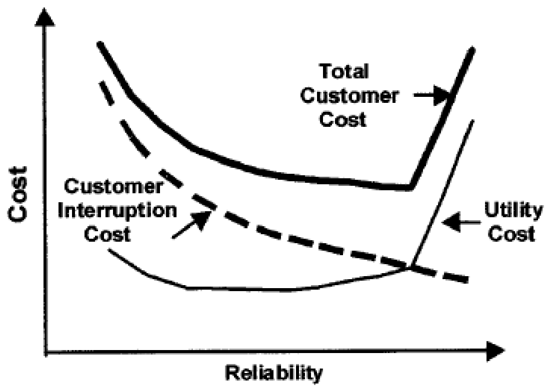


Figure 4-3 Total customer cost [145]

In [153], to against voltage collapse, all possible contingencies are simulated and their corresponding voltage collapse locations are calculated. Then the weak contingencies which have less effect on voltage stability have been screened out and only the severe ones are kept. Similarly, based on the effect on small-signal stability, different contingencies have been simulated in [154]. The most critical generator in the new England 39-bus system has been selected. This kind of framework has also been used in [156], all the contingencies are ranked and selected by precisely calculating circuit load margin, bus voltage margin and reactive power limits of generators. Furthermore, also by using numerical pre-simulations, [155] has clustered all contingencies into 1) contingencies require preventive actions; 2) one only need corrective actions and 3) no actions. To reduce the simulation time, this paper is based on simplifying large power systems. And in [157], after analysing all scenarios, a certain scenario failure rate (SFR) is set to guarantee the robustness of the proposed chance constrained solution, which means a small fraction of total scenarios are allowed to have exceeded constraints.

- Monte Carlo simulation

Unlike analytic methods need to enumerate all the contingencies and then to calculate the risks of them, only some samples of contingencies are calculated. Then heuristic rules based on probabilities of contingencies will be set. And then the contingencies with small probabilities will be eliminated [157]. An approach based on fuzzy set theory is established for contingency ranking of Taiwan power system in [158]. A heuristic rule based index value is set to different kinds of contingencies by the system operators based on their past experience to meet the human judgments. After that, an evidence combined fuzzy reasoning ranking list will be performed. The intelligent contingency ranking has also been used [159], from selected samples, the so-called high-impact outages are predicted based on operation costs and then sufficient reserves are delivered to cover the high-impact contingency.

In the proposed RPP strategy in this thesis, firstly based on [156], to ensure the system voltage stability, contingencies are ranked by system voltage deviation drop. The contingency which will cause the highest system voltage deviation has been analysed and used as the *N-1* security simulation. As for the outages, in distributed networks, outages have been considered as possible to happen of all reactive power providers. This means, in distribution networks, it is assumed each provider may have the chance to be cut off. The scenario of losing any of the reactive power providers will be calculated.

But in transmission networks, it is assumed that outages for reactive power providers on the other day are not allowed. After the contingencies and outages analysis, the method from [157] and [158] has been used that is to set the forecast data scenario failure rate. Forecast errors with very small probabilities should not be considered to make the economic recommendation.

In this thesis, to ensure sufficient reactive power reserve and to operate the system in a more stable manner, the largest required capacities for each hour the other day of all generators are chosen as the procured reactive power reserve for all providers.

4.3.5 **Model solution**

To address the uncertainties, outages and contingencies considered in the proposed reactive power procurement strategy, a stochastic optimisation solver has to be used. In this thesis, the probability decision tree and sample average approximation (SAA) have been used to generate a cost probability distribution function (pdf) for each scenario. Additionally, an improved genetic algorithm has been used to find the best solution for each scenario. Then based on the final pdf, a confidence level of the chance constrained optimisation can be decided and the stochastic optimisation will be solved in this confidence level. In this section, the mentioned solvers have been presented in detail.

4.3.5.1 **Decision tree**

The probabilistic decision tree approach is used to model uncertainties and to do stochastic optimisation for different time t and regime k. This means the overall problem is set in the form of a decision tree, where the nodes denote different regimes in certain time periods. In the RPP problem proposed in this thesis, the decision tree is created using the following concept that the planning starts from the first hour of the next day and looks into 24 hours ahead. It is driven by the regulatory requirement to provide procured reactive power reserve for all reactive power providers with minimum cost plans at all time periods [143]. The base case and starting point is the last hour of the current day. As predefined, for the base case: $k=0$; and each contingency last for 24 hours. So the decision tree for the day-ahead RPP stage should have the following structure：

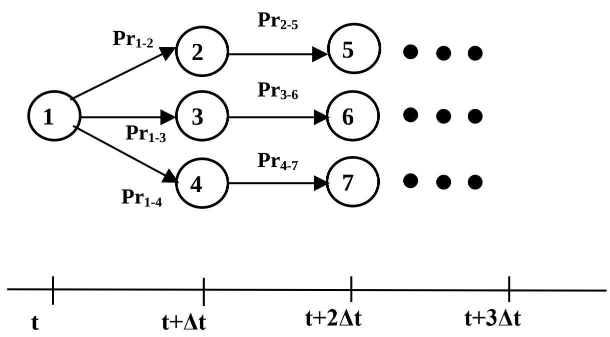


Figure 4-4 Illustrative example of a decision tree

Probabilities of each scenario $Pr_{x\text{-}y}$ are associated with each branch between two configurations which equals to the sum of probabilities of all paths that lead to that tree node. And the total 'cost of each node' is equal the path cost in the case of a single path cost. Every single path's minimum cost is calculated using the improved genetic algorithm (GA), i.e. improved i-NSGA-II, under a certain regime. The end result is a discrete probability distribution function (pdf) of the required reactive power and its cost from all providers in each time interval studied. Then the planned preserve reactive power capacities need to be specified with the ability to cover different scenarios to achieve minimum values for the proposed objective function in the next day [143].

4.3.5.2 **Sample average approximation (SAA)**

To solve the probability with wind speed and load demand, SAA will be used. In order to solve this kind of stochastic optimisation problem, [157] uses Monte Carlo to generate scenarios and calculate the entire scenarios failure rate which should waste too much time. Additionally, the SAA method is usually applied for converting the stochastic problem into deterministic [160], [161]. The basic idea of the SAA method is to approximate its true distribution with the empirical distribution of the random data and to generate samples about the random data through the Monte Carlo sampling method. Then use sample statistics to replace the random quantities involved in the model. The sample statistic is calculated as:

$$S^{-1}\sum_{n=1}^{S} F(x,\xi^n) \tag{61}$$

where S is the sample size, F is the objective function value of a certain sample and n is a certain sample.

The sample average is used to approximate the mathematical expectation, and the method of the constraint index function is used to describe the opportunity constraint. The original problem is transformed into the corresponding deterministic SAA problem to replace, and the solution of the SAA problem is used as the approximate optimal solution of the original problem. Some literatures also tried to improve SAA by increasing the Monte Carlo sample size [162]. In this thesis, the forecast errors for both wind speed and load demand are assumed should obey normal distribution [163], [164]. In this thesis, to improve the SAA accuracy, an iteration process has been added to the randomly generated Monte Carlo data within the initial generation's $[\mu-3\sigma, \mu+3\sigma]$. Based on the iteration results shown in later simulation suction, in this thesis, the final generation's $\mu-3\sigma, \mu, \mu+3\sigma$ are chosen as three final samples to formulate uncertainties of load demand and the final generation's $\mu-3\sigma, \mu, \mu+3\sigma$ are chosen as three final samples to formulate uncertainties of wind speed. The probability that the day-ahead forecast data are out of this range is considered as the acceptable failure rate

Finally, the outputs of reactive power procurement plans for the next day should consider the maximum required capacities under all scenarios. Such a framework, resulting in the security constraints being met for the realizations of a certain confidence level of outages, wind speed and load demand forecast errors [157]. Consequently, the outputs of the day-ahead RPP optimisation are the RPP plans of all reactive power providers for the other day. And then, in the ORPD optimisation, the deterministic optimisation will be calculated using the improved genetic algorithm. And the output will be the settings for all control devices.

4.3.5.3 **Improved genetic algorithm**

As described in Chapter 3, to solve a constrained objective function, there are usually two kinds of solvers, i.e. traditional methods and artificial intelligence algorithms. Genetic algorithm is an artificial intelligence algorithm for solving complex non-convex problems by simulating the natural evolution processes. When applying different types of solvers for constrained objective function based optimisation problems, like the one described in this

Chapter, it is important to consider the trade-off between expected accuracy and algorithm speed. When it comes to the proposed RPP strategy, the accuracy is critically important, but from the perspective of generating all solutions for different scenarios, the computational speed of the algorithm is essential, particularly if the size of the considered network is large. When creating the solver of the formulated optimisation problem, the starting point was the conventional genetic algorithm.

- Conventional genetic algorithm

Genetic algorithm (GA) was firstly proposed by John Holland in the 1980s [165]. It is designed and proposed according to the evolutionary laws in nature. It is a computational model that simulates the biological evolutionary process of natural selection and the genetic mechanism by simulating the natural evolution process. The algorithm transforms the problem-solving process into a process similar to selection, crossover, and mutation of chromosomal genes in biological evolution by means of mathematics and computer simulation operations. When solving complex combinatorial optimisation problems, it can usually obtain better optimisation results and be faster than some conventional optimisation algorithms. In recent years, genetic algorithm has been widely used in the field of power system optimisation like the ones proposed in this thesis.

Normally, available control variables in power systems are used as individuals for GA based strategy. A number of individuals were randomly taken within the pre-set constraints of a certain independent variable. These individuals will take three basic genetic operators: selection, crossover and mutation.

The operation of selecting superior individuals from the group and eliminating inferior individuals is called selection. The purpose of selection is to inherit the optimised individuals directly to the next generation or to generate new individuals through pairing and crossover and then inherit them to the next generation. In the selection part, individuals will be transferred to multiple binary codes that can represent the attributes of those individuals. Individual binary codes with the same attributes are the same. In each cycle of population update, a crossover and mutation are then performed.

Crossover refers to the operation of replacing and combining the partial structures of two parent individuals to generate new individuals. The crossover of biological genetic genes plays a critical role in the evolution of natural organisms. Similarly, the crossover operator is also a key role in genetic algorithms. In the crossover part, according to the probability of crossover, a random individual and another random individual will have a random disconnection of a certain part and then the broken gene fragment will be exchanged and combined into new segments. Through crossover, the global search ability of genetic algorithm can be greatly improved.

In the mutation part, according to the probability of mutation, a random gene in a random individual will be reversed to obtain a new gene. The genetic algorithm introduces mutations for two purposes: i) to make the genetic algorithm have a local random search capability; ii) to accelerate random search capability to convergence to the optimal solution through the crossover operator when the genetic algorithm is close to the optimal solution neighbourhood.

The termination condition of the genetic algorithm can be generally divided into three categories: i) the fitness value of the optimal solution reach a given threshold, ii) the fitness value of the optimal solution no longer change, iii) the number of iterations reaches a pre-set number of generations. When meeting either termination condition, the algorithm will terminate accordingly. This process has been shown below:

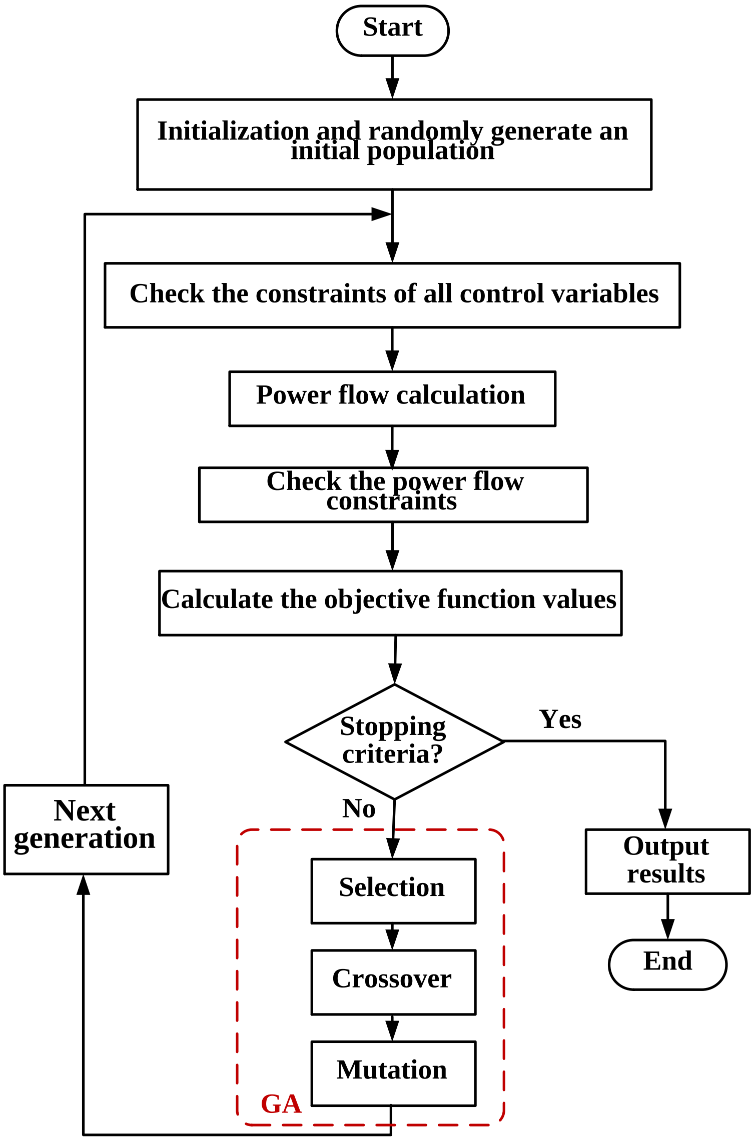


Figure 4-5 Schematic of the calculation process for the proposed objective functions

When applying this algorithm, a number of so-called *individuals* have to be defined. In this thesis, each individual refers to a combination of control variables i.e. outputs of reactive power providers. Individuals are firstly randomly selected from in advance specified feasible space, determined by the constraints adopted for all control variables. They are then processed by selection, crossover, and mutation procedures.

In this solver, to ensure that each selected individual has only the control variables within power system constraints, the power flow calculation is included in each of the improved GA cycles. This will make the out-of-limit individuals will be sifted out immediately and consequently achieve a better result for the objective function.

The RPP strategy proposed in this Chapter is a single-objective optimisation problem. However, the ORPD strategy proposed in the next Chapter is a multi-objective optimisation problem. To adapt this solver for both strategies, the application of this improved GA to multi-objective optimisation problems also has to be considered. For single-objective optimisation problems, conventional GA shows its superiority. But in the multi-objective optimisation problem, the biggest problem is how to determine the fitness of each individual. Multi-objective optimisation also known as Pareto optimisation involves the optimisation of multi-objective functions. In this kind of optimisation problem, there is usually no feasible solution to minimise all objective functions at the same time. Therefore, the so-called Pareto optimal solution is a solution that cannot be improved in any goal without compromising at least one goal [166].

- Elitist non-dominated sorting genetic algorithm with inheritance (i-NSGA-II)

The NSGA-II algorithm was proposed by [31] on the basis of conventional GA which is ideal for constraint multi-objective optimisation problems.

In the NSGA-II calculation process, firstly, each population will be divided into a set of Pareto non-dominated sets. Individuals in a non-dominated set are not dominated by any individuals in the current or subsequent non-dominated set. This is achieved by selecting all non-dominated individuals that are not dominated by any other individuals each time. Then these individuals are deleted from the population and established as a non-dominated set. Then repeat the process for the rest of the population until all individuals are finished. After that, all the obtained non-dominated sets are set according to the crowd distance. Crowd distance is the sum of the distances of adjacent individuals in each dimension. When doing the selection procedure in genetic algorithm, these non-dominated sets are taken from the front to the back according to their order.

Furthermore, it has been significantly improved and made more computationally efficient by involving parent inheritance in [32]. It is believed that the best quality initial parental chromosomes may produce the best chromosome pool, which will help to converge to the global Pareto optimal at a faster speed. The improved quality of the initial parent population is based on selecting the best chromosome with the largest fitness value for the objective function of a given multi-objective optimisation problem. In this process, a random number of individuals are firstly used to generate initial populations, and the chromosomes are compared with each other according to the fitness value of the objective function. The chromosome with the largest fitness value is allocated and copied to the new improved parent population box. For multi-objective optimisation problems involving more than one objective function, multiple chromosomes will be selected at a time from the initial random population. Then the individuals are also sorted out according to the fitness values of every single objective in the initial population. All individuals with a higher fitness value for a single objective will be also selected as the initial parents. They also have a chance to generate children population, even though they might not be the best result for the whole multi-objective function. But they also have the possibility to generate the global optimal children population when having crossover. As such, for the first generation, inherently selected parents develop a better pool of parent chromosomes, called inheritance, which will produce a better pool of the child’s chromosomes.

- Roulette selection algorithm

To further improve the calculation speed, when making selections, the *roulette selection algorithm* [33] is applied. Individuals in each new generation are eliminated like a slot on the roulette wheel. The probabilities of these individuals to be selected are equal to the probabilities of the stop point dropping into the slot when spinning the roulette wheel. For each individual, its slot size is decided according to the objective function result for this individual, which is calculated as:

$$P_m = F(m) \Big/ \sum_{m=1}^{N_P} F(m) \tag{62}$$

where P_m is the area size of a certain individual m on roulette which is also the selection probability of m, $F(m)$ is the multi-objective function adaptive value of m and N_P is the size of each population.

By doing all these improvements, essentially smaller number of generations with a minimum number of function evaluations converging to the global optimal result is required. As it will be demonstrated in the next section, using conventional GA some 100 generations are needed to reach the optimal solutions, whereas the improved GA converges to the optimal solution within only 15 generations, delivered practically the same level of accuracy.

These improvements contributed to the efficacy of the entire optimisation, what is particularly important in a real-time application, in which a large number of variables have to be simultaneously processed. However, the question to be answered was if the increased algorithm speed will jeopardise the algorithm accuracy. In the next section, the new solver is tested.

4.3.6 RPP strategy block diagram

Based on these selected optimisation solvers, the proposed RPP strategy will be solved and the entire diagram of RPP is drawn in

Figure 4-6.

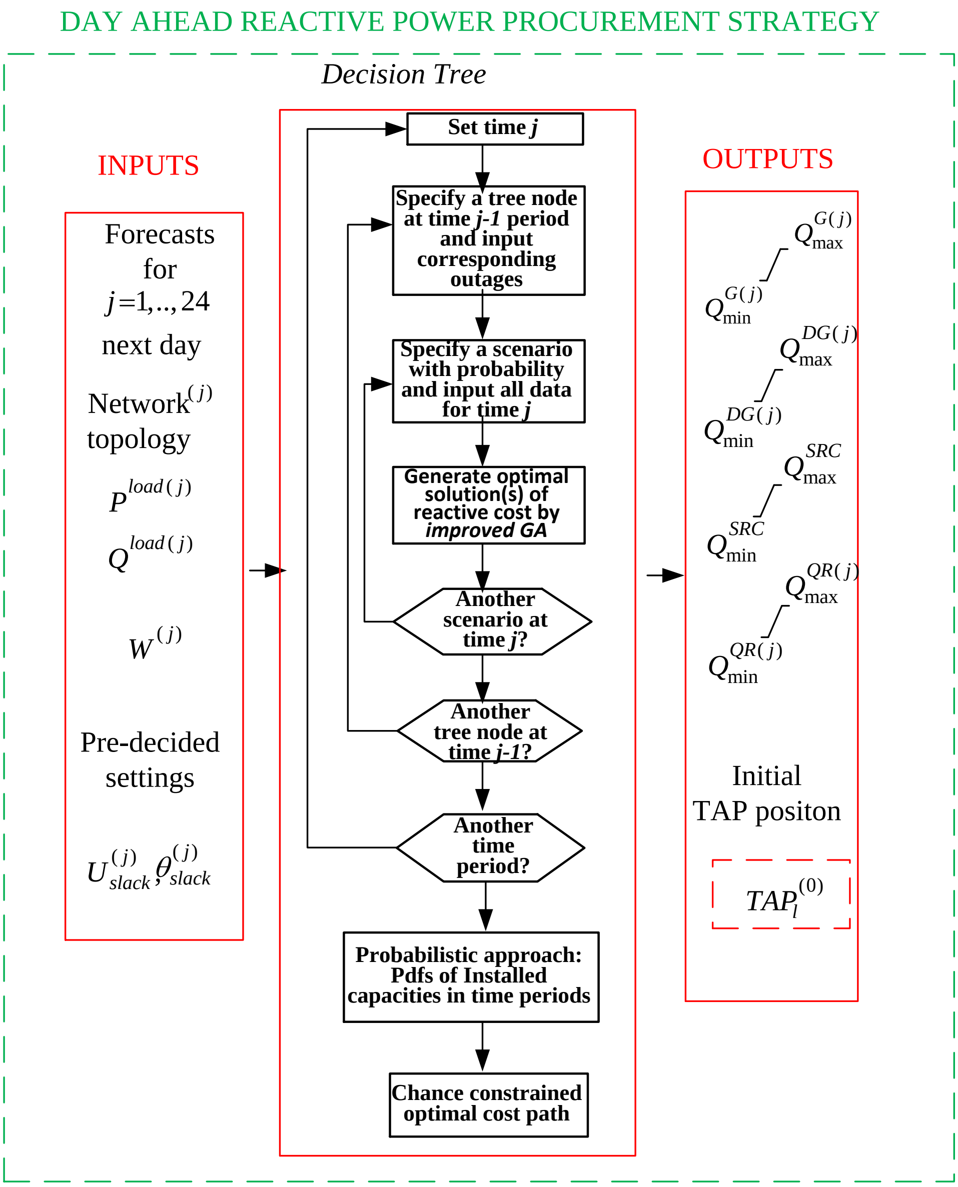


Figure 4-6 Stochastic optimisation diagram of RPP strategy

4.3.7 **Simulations**

To test the proposed reactive power procurement strategies, two distribution systems, the IEEE 33-bus and the PG&E 69-bus systems, as well as one transmission system, the modified GB network, are used.

Each test system has been extended with OLTCs (with a switchable range from 0.9 to 1.1) and DFIG based WTs (penetration level up to 50%). Reactive power compensators exist in all test systems. And flexible demand exists in both distribution networks. When applying the improved GA, the crossover and mutation probability were respectively 0.8 and 0.3 [128], [129].

4.3.7.1 **Input data**

When considering day-ahead forecast data, a typical load demand curve and WT active power prediction curve [164] are used in this simulation. The predicted inputs of each hour, used in this study, are shown in Figure 4-7.

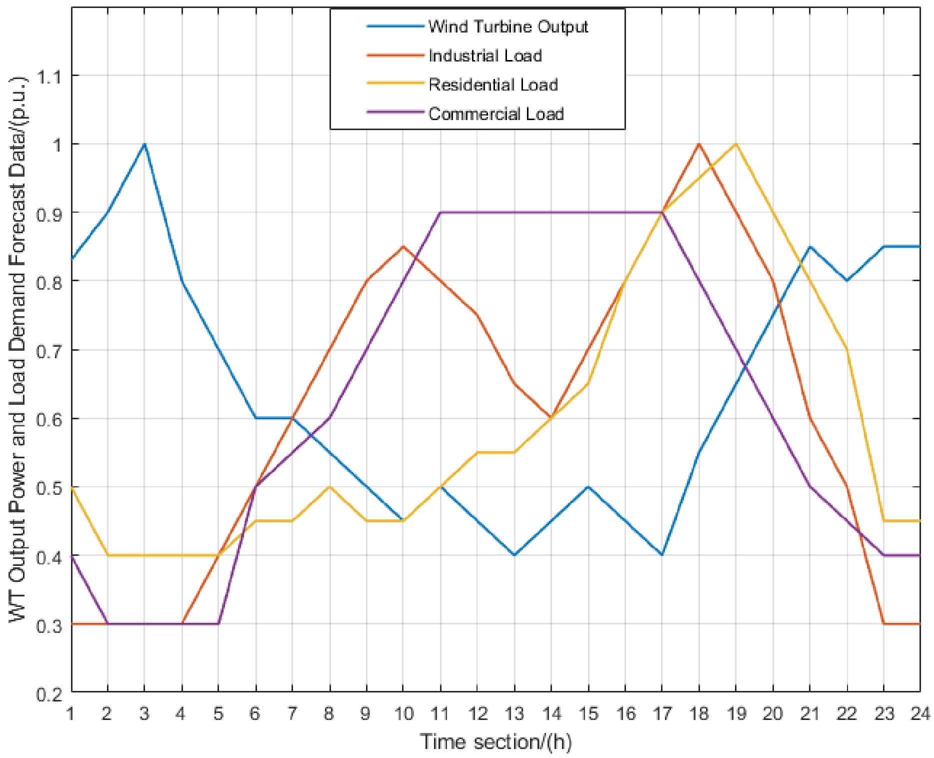


Figure 4-7 Typical load demand and WT active power prediction curves [164]

However, the day-ahead forecast data may introduce forecast errors. In this thesis, it is assumed that these forecast errors should obey normal distribution as shown in Figure 4-8. In the reactive power procurement optimisation, the Monte Carlo method is used to generate random forecast errors with the range of [-20%, 20%]. After interactions, the randomly generated data's forecast error will converge. The initial samples' mean and deviation values and the final converged samples' mean and deviation values are shown in Figure 4-9.

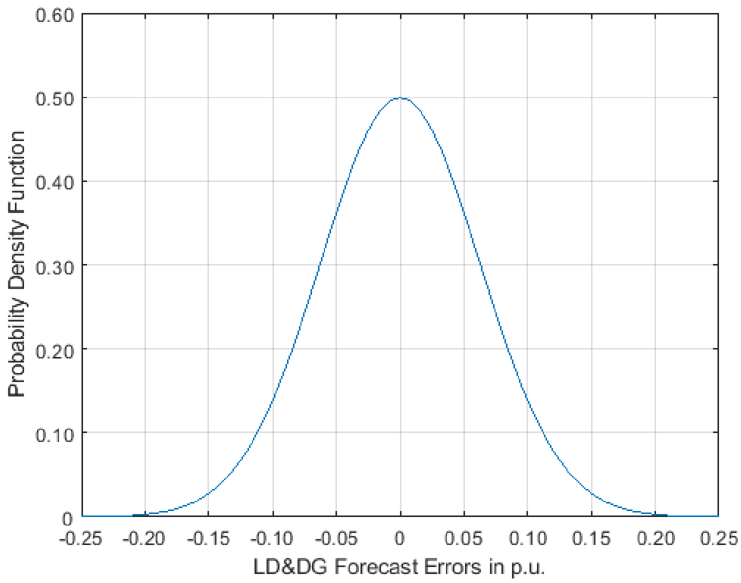


Figure 4-8 Probabilistic Distribution of DGs and Load Demand Forecast Errors from Day Ahead

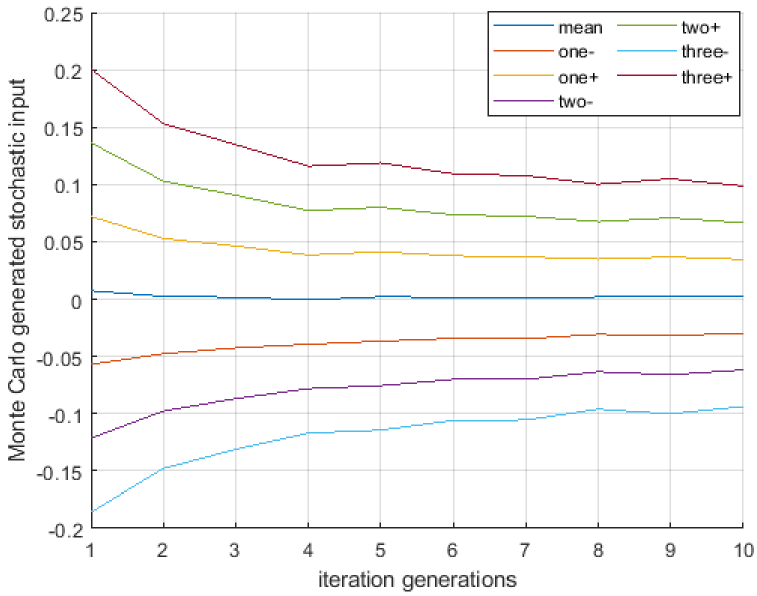


Figure 4-9 Monte Carlo generated samples' mean and deviation VAr of LD&DG forecast errors

It can be seen that the converged samples' mean value is 0 and their $[\mu-3\sigma, \mu+3\sigma]$ range is [-10%, 10%]. Using the sample average approximation method, -10%, 0, 10% are chosen as the final samples for day-ahead forecast load demand and distributed generator output data. Therefore, in the proposed reactive power procurement optimisation strategy, to ensure sufficient reactive power reserve, the final samples of load demand and distributed generator output are assumed as -10%, 0, 10% with the probabilities 20%, 60%, 20% respectively; and for load demand uncertainties are -10%, 0, 10% with the probabilities 20%, 60%, 20% respectively.

Furthermore, as aforementioned, in the reactive power procurement planning, redundancy should be carefully considered for both distribution and transmission networks to ensure system security level at the same time minimising total reactive power cost. In the day-ahead RPP planning, considering both stability and reliability requirements, *N-1* security is the optimal degree of network redundancy [168]. This means in the simulations, only one contingency or outage is allowed in each scenario. And this contingency or outage should last for 24 hours which means the whole day. So as for the forecast errors, it is assumed the forecast error ranges do not change hourly but last for 24 hours.

4.3.7.2 **Reactive power zonal price and limitations**

To provide procurement plans for the other day and their cost values, the reactive power price offers, data referred from [22] and [168] are used and listed below. It is assumed reactive power price offers for the selected two distribution systems and one transmission system are the same which have been shown in Chapter 8.1 Appendix A - Table 8-1. Due to the lack of information, the reactive power price is calculated in US dollars in this thesis. The currency selection will not affect the calculation and absolute simulation results.

The zonal reactive power limits for different reactive power providers in distribution systems referred from [22] are listed in Chapter 8.2 Appendix B - Table 8-2.

As for the zonal reactive power limits for different reactive power providers in transmission systems i.e. 29 zone GB network used in this thesis, data referred from [30] are shown in Chapter 8.3 Appendix C - Table 8-3.

Based on these zonal prices and limitations, the simulations will be done to provide suggested reactive power procurement plans for different systems.

4.3.7.3 **Test on IEEE 33-bus system**

In this section, a modified IEEE 33-bus system [167] is shown in Figure 4-10. The initial network includes 33 nodes, 35 branches (consists of 32 section switches and 3 tie switches) and the total load demands of the networks is set as 37.15MW and 23.00MVAr. The base capacity is set as 100MVA and the base voltage is 12.66kV. This test system is firstly used to test feasibility of the proposed improved GA and secondly to provide hourly optimisation results for reactive power procurement plans. The wind turbine's Q-control strategy is assumed as *Q-control strategy 2*. Here the system modification is referred to the inclusion of WTs, shunt capacitors (SC) and flexible demand (QR). As a note, in the proposed RPP strategy, system power flow is used for obtaining electrical quantities needed for objective functions.

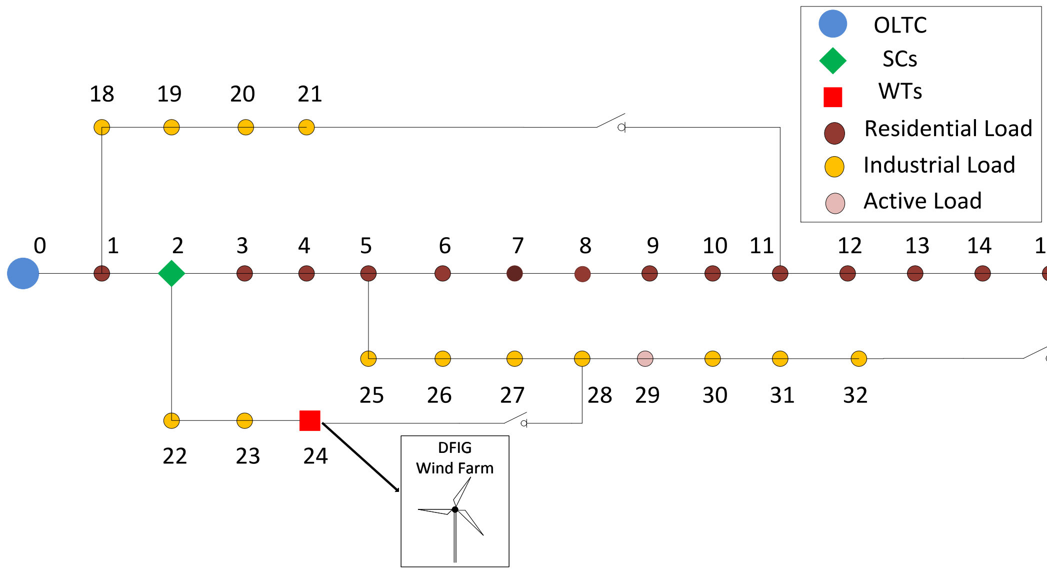


Figure 4-10 Single line diagram of the modified IEEE 33-bus distribution system

- Comparison between improved GA and conventional GA

To test the ability for different solvers to achieve optimal results of constrained objective function, the proposed RPP objective function has been used to do the comparison studies. Firstly, accuracy and convergence of the proposed improved GA are compared with accuracy and convergence of the traditional GA. In Figure 4-11 the convergence characteristic curves for both conventional and improved GA are given. As a heuristic search algorithm, GA may have different contingency route in each run. Therefore, randomly selected 5 curves out of 100 different tests, in which the population size, N_P, was 50, are presented in Figure 4-11 to demonstrate the improved GA family of curves. The forecasted WT output active power limit and the load demand are both assumed to be 1 p.u. The WT reactive output power limit was calculated according to the *Q-control strategy 2*.

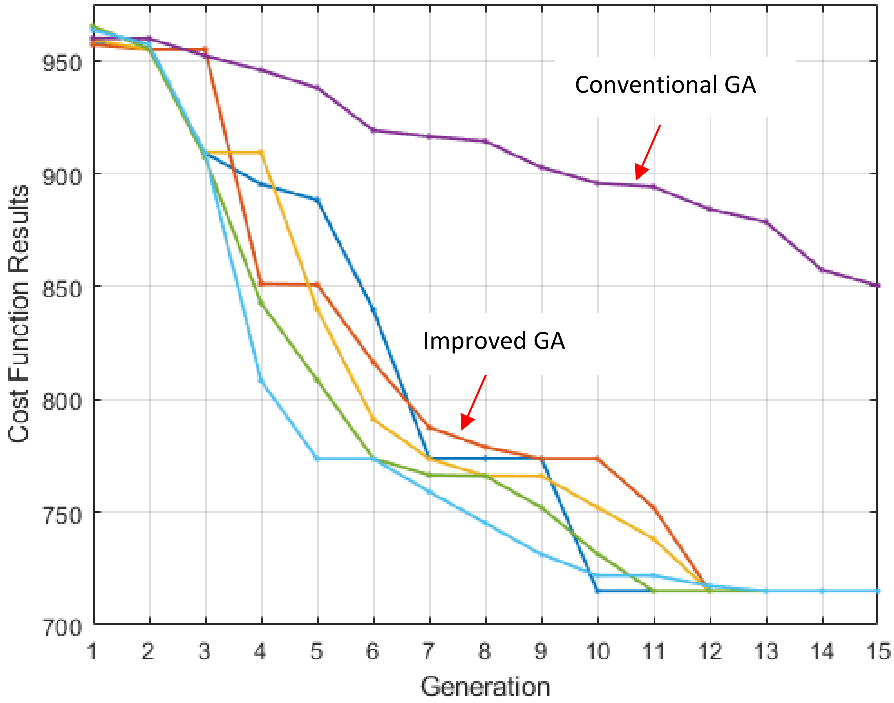


Figure 4-11 Adaptive convergence characteristic curves

As can be seen in Figure 4-11, the proposed improved strategy: i) always converges to the same optimal point for which adaptive value of objective function equals to $715, ii) always converges in less than 15 generations. Under the same situation, the conventional GA requires much more generations to achieve the optimal point. In Table 4-1 the outputs obtained by both improved and conventional GA are shown and compared.

Table 4-1 Comparison between improved GA and conventional GA

Results	Improved GA	Conventional GA	Difference
Q_G	18.9399MVAr	18.9320MVAr	0.04%
Q_{DG}	3.9197MVAr	3.9231MVAr	0.01%
Q_{SC}	0.2139MVAr	0.2140MVAr	0.01%
Q_{QR}	0.3871MVAr	0.3872MVAr	0.01%

Total Q	23.4606MVAr	23.4563MVAr	0.02%
$F(x)$	\$715.3233	\$715.3216	0.01%
Calculation Time	110.594s	292.134s	181.54s

From the results, all settings are within the system limits and pre-listed constraints. As can be seen, the differences in results obtained by both methods are very small. However, the conventional GA requires much more time than the improved GA. It can be concluded that for a faster speed the accuracy after involving the proposed improvements of GA has not been compromised for the proposed constrained objective function.

As the genetic algorithm is one of the meta-heuristic search algorithms, to further prove the feasibility of these kinds of algorithms, the proposed solver has been also compared with one of the classical method, i.e. branch and bound method.

Table 4-2 Comparison between the proposed solver and branch and bound method

Results	Improved GA	Branch and Bound Method	Difference
Q_G	18.9399MVAr	18.9320MVAr	0.04%
Q_{DG}	3.9197MVAr	3.9231MVAr	0.01%
Q_{SC}	0.2139MVAr	0.2140MVAr	0.01%
Q_{QR}	0.3871MVAr	0.3868MVAr	0.01%
Total Q	23.4606MVAr	23.4559MVAr	0.02%
$F(x)$	\$715.3233	\$715.2942	0.01%
Calculation Time	110.594s	522.134s	411.54s

As can be seen, both solvers can achieve similar level of optima. The differences between the two meta-heuristic search algorithms and the classical solver are small which means in an acceptable level. Since the branch and bound method is one of the classical solvers of optimisation problems, by searching all possible solutions directly or indirectly, it ensures the results obtained by this solver are the global optima. However, this kind of enumerate method requires much more time than the heuristic search algorithm especially the proposed improved GA with essentially short calculation time. From the comparison studies, it can be concluded that both the conventional GA and the proposed improved GA as meta-heuristic search algorithms can save much more time than the classical solvers while they can still obtaining similar results. This is critically important when obtaining hourly optimal results for all scenarios in complex systems. Moreover, with the combination of the elitist non-dominated sorting genetic algorithm with inheritance (i-NSGA-II) and a roulette wheel selection, the proposed algorithm has further improved the calculation speed comparing to the conventional GA. Then, the conclusion that the improved GA can achieve a faster convergence without affecting accuracy can be drawn. So that this proposed solver will be used into later simulations for the other selected power systems.

- Reactive power procurement optimisation hourly results for IEEE 33-bus system

As the pre-condition of short-term or real-time optimisation, the proposed reactive power procurement strategy has been simulated in this section to provide limitations for the other day. In the reactive power procurement stage, it is assumed the base case at the end of current day is $k=0$, which means no contingencies or no outage for reactive power providers. And for the next day, only one contingency or outage (N-1) is considered at one time and this contingency or outage should last for 24 hours. In this test system, as branch 1-2 is the highest loading one which also could cause the highest voltage deviation, it is selected as the simulated contingency in the N-1 case. In this test system, outages of WT, SC and AL are also simulated. Each contingency or outage is assumed to have a probability of 5% to happen [145]. But the outage of grid support point is not considered. By also considering the uncertainties of wind speed and load demand, for each hour, there will be 9 tree nodes under one regime. And in total, there are 5 regimes in each hour. Considering all the scenarios, the first-stage outputs should be the preserved capacities for all reactive power providers in the test system per hour. Associated probabilities of all scenarios are shown in Figure 4-12:

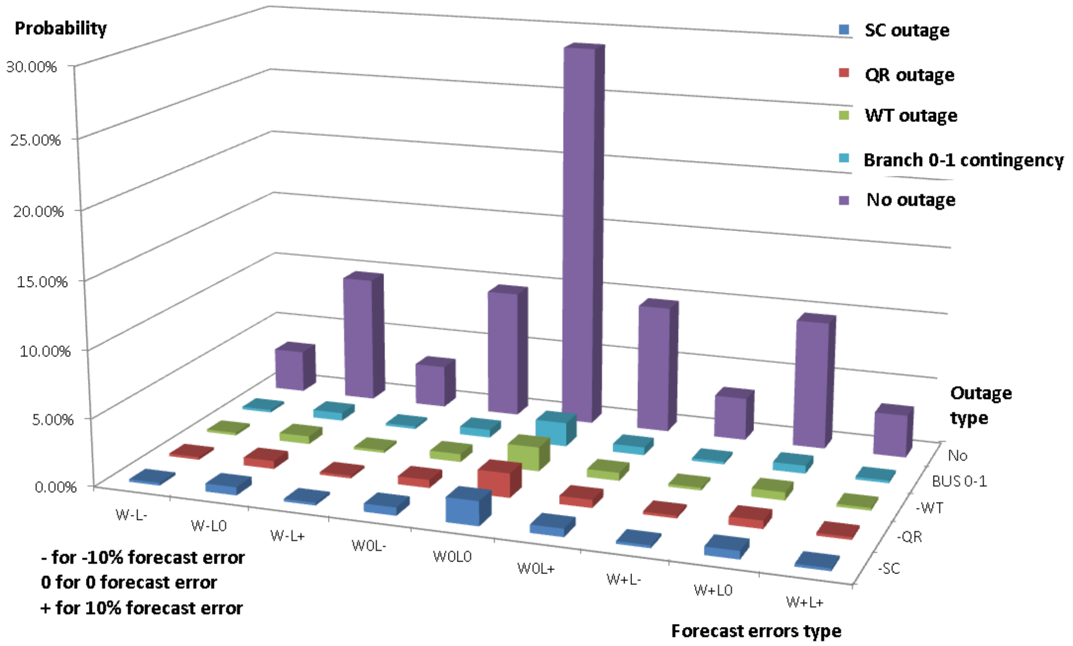


Figure 4-12 Associated probabilities for each scenario

Firstly, when assuming the installed wind turbine is under *Q control strategy 1*, all the cases are simulated. The no outage scenarios in 24 hours are simulated and the optimised results are listed in Chapter 8.5 Appendix – E Table 8-5. The required reactive power from each provider is selected as the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the total daily required reactive power to make first-stage objective function having a minimum cost is shown in Figure 4-13:

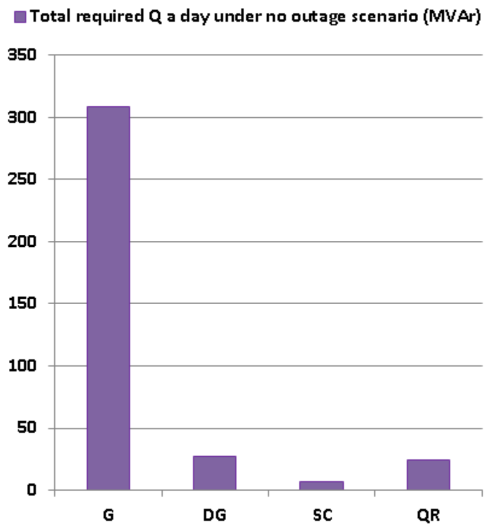


Figure 4-13 Daily total required reactive power from all providers under no outage scenario

From the results, under no outage or contingency scenario with WT in *Q control strategy 1*, the total required reactive power from all installed providers is 367.162MVAr in which the reactive power as ancillary service part is 129.4908MVAr. Then the total cost of reactive power ancillary service is $4988.502.

The Branch 0-1 contingency scenarios in 24 hours are simulated and the optimised results are listed in Chapter 8.5 Appendix – E Table 8-6. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the total daily required reactive power to make first-stage objective function having a minimum cost from each kind of reactive power provider is shown in Figure 4-14:

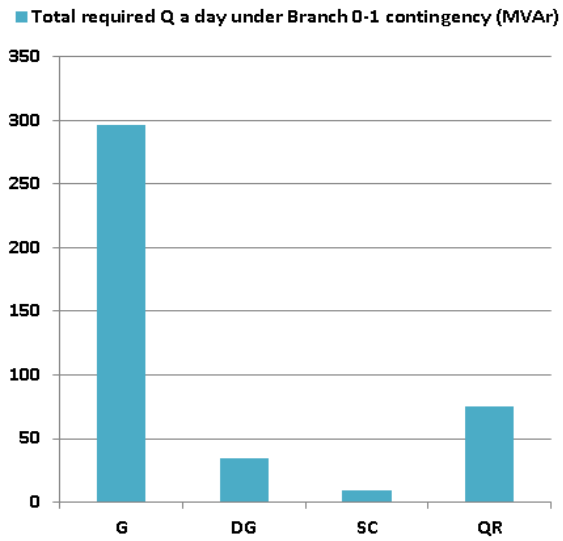


Figure 4-14 Daily total required reactive power from all providers under Branch 0-1 contingency

From the results, under N-1 contingency scenario, the total required reactive power from all installed providers is 414.8224MVAr in which the reactive power as ancillary service part is 185.6209MVAr. Then the total cost of reactive power ancillary service is $7125.18.

The shunt reactor/capacitor outage scenarios in 24 hours are simulated and the optimised results are listed in Chapter 8.5 Appendix – E Table 8-7. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the daily total required reactive power from each kind of reactive power provider to make first-stage objective function having a minimum cost is shown in Figure 4-15:

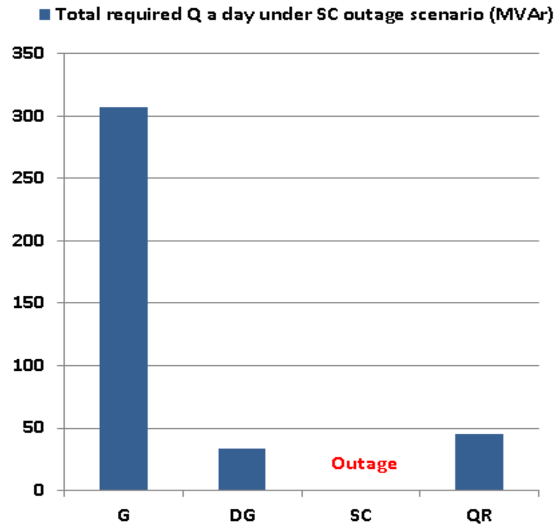


Figure 4-15 Daily total required reactive power from all providers under SC outage scenario

From the results, under SC outage scenario, the total required reactive power from all installed providers is 385.3305MVAr in which the reactive power as ancillary service part is 146.1092MVAr. Then the total cost of reactive power ancillary service is $5733.907.

The flexible demand i.e. MVAr reduction outage scenarios in 24 hours are simulated and the optimised results are listed in Chapter 8.5 Appendix – E Table 8-8. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the daily total required reactive power from each reactive power provider to make first-stage objective function having a minimum cost is shown in Figure 4-16:

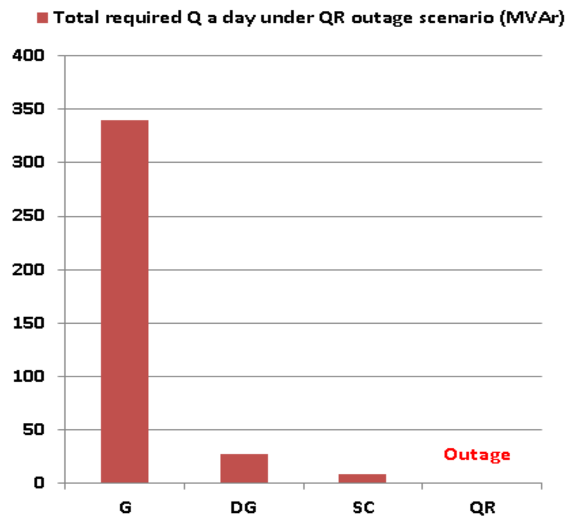


Figure 4-16 Daily total required reactive power from all providers under QR outage scenario

From the results, under QR outage scenario, the total required reactive power from all installed providers is 375.5739MVAr in which the reactive power as ancillary service part is 135.6153MVAr. Then the total cost of reactive power ancillary service is $5208.912.

The wind farm outage scenarios in 24 hours are simulated and the optimised results are listed in Chapter 8.5 Appendix – E Table 8-9. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the daily total required reactive power from each reactive power provider to make first-stage objective function having a minimum cost is shown in Figure 4-17:

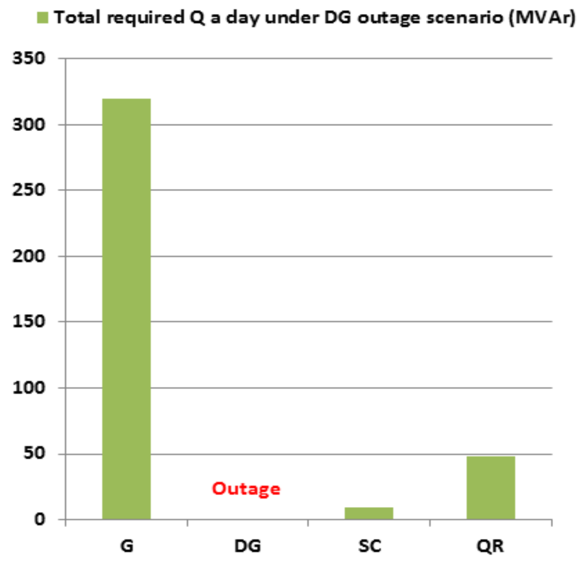


Figure 4-17 Daily total required reactive power from all providers under WT outage scenario

From the results, under DG outage scenario, the total required reactive power from all installed providers is 377.5263MVAr in which the reactive power as ancillary service part is 137.5263MVAr. Then the total cost of reactive power ancillary service is $5543.488.

As can been seen from the probabilistic decision tree concept (Figure 4-4 and Figure 4-5), by simulating all the tree nodes, the final results of the proposed reactive power procurement strategy is listed in Table 4-3. These results are the required reactive power procurement planes of all reactive power providers for the other day to cover all considered possible scenarios.

Table 4-3 Optimised maximum required value at each hour for each reactive power provider during a day (WT with *Q-control strategy 1*)

t	$q_{Gi,\max}$	$q_{DGi,\max}$	$q_{SR/SCi,\max}$	$q_{QRi,\max}$
1.00	11.2339 MVAr	1.7225 MVAr	0.4695 MVAr	2.9617 MVAr
2.00	10.9772 MVAr	2.2938 MVAr	0.4769 MVAr	3.8186 MVAr
3.00	10.3909 MVAr	2.5156 MVAr	0.4957 MVAr	3.9694 MVAr
4.00	10.7497 MVAr	1.7929 MVAr	0.3715 MVAr	3.0275 MVAr
5.00	10.7420 MVAr	2.1227 MVAr	0.4905 MVAr	2.3090 MVAr
6.00	11.5133 MVAr	1.1633 MVAr	0.4300 MVAr	3.2436 MVAr
7.00	13.6574 MVAr	1.9700 MVAr	0.4539 MVAr	3.2114 MVAr
8.00	13.3695 MVAr	1.8130 MVAr	0.4882 MVAr	3.0566 MVAr
9.00	14.5685 MVAr	0.9427 MVAr	0.4869 MVAr	2.7114 MVAr
10.00	16.3982 MVAr	1.4238 MVAr	0.3426 MVAr	3.0394 MVAr
11.00	15.6694 MVAr	0.9454 MVAr	0.4625 MVAr	3.2222 MVAr
12.00	15.7177 MVAr	0.9952 MVAr	0.4830 MVAr	3.3688 MVAr
13.00	15.4850 MVAr	0.9830 MVAr	0.4943 MVAr	3.2953 MVAr
14.00	15.2275 MVAr	0.8997 MVAr	0.3999 MVAr	3.0026 MVAr
15.00	14.5592 MVAr	0.9035 MVAr	0.4947 MVAr	3.1939 MVAr
16.00	16.9379 MVAr	2.2275 MVAr	0.4845 MVAr	3.8622 MVAr
17.00	16.6456 MVAr	1.8590 MVAr	0.4896 MVAr	3.8502 MVAr
18.00	18.3558 MVAr	2.7225 MVAr	0.4654 MVAr	3.0007 MVAr
19.00	19.7363 MVAr	2.0021 MVAr	0.4407 MVAr	3.0608 MVAr
20.00	17.6230 MVAr	2.6459 MVAr	0.4578 MVAr	3.0002 MVAr
21.00	16.5990 MVAr	2.9594 MVAr	0.4767 MVAr	3.0000 MVAr
22.00	13.4999 MVAr	1.8323 MVAr	0.4873 MVAr	3.6753 MVAr

23.00	12.7417 MVAr	2.7399 MVAr	0.4288 MVAr	2.7183 MVAr
24.00	12.5307 MVAr	1.6621 MVAr	0.4255 MVAr	2.4575 MVAr
Total	344.9293 MVAr	45.3378 MVAr	10.9964 MVAr	76.8566 MVAr

To ensure each scenario will be successfully implemented, the maximum required reactive power from all providers should be chosen as their preserved procurement capacities for the other day. From the calculation results listed in Table 4-3, the total generated reactive power for this test system the other day is 478.1201MVAr in which the ancillary service is 238.1201MVAr and the total cost of reactive power is $9076.498.

As can be seen from the comparison between different scenarios, in the *N-1* contingency case, the required reactive power output from grid connection point has reduced while the required output from flexible demand has significant increased. In this case, the total required reactive power has also increased sharply which makes this scenario as the one requires the most amount of reactive power and the highest cost. This indicates when the Branch 0-1 is under contingency, the importance of grid connection point in the reactive power ancillary service has reduced while the flexible demand becomes more essential. In addition, among all the device outage scenarios, the flexible demand outage scenario requires the smallest amount of reactive power and the least cost. This is because when one of the reactive power providers is not available, the others should be forced to provide more reactive power contributions. Although the flexible demand plays significant role during *N-1* contingency scenario, it is more expensive than wind farm or shunt capacitor. So when it is in outage, the final plan should be the cheapest one among outage scenarios.

Similarly, the simulations have also been done when assuming the WT is under *Q-control strategy 2*. The simulation results are shown in Table 4-4.

Table 4-4 Optimised maximum required value at each hour for each reactive power provider during a day (WT with *Q-control strategy 2*)

t	$q_{Gi,\max}$	$q_{DGi,\max}$	$q_{SR/SCi,\max}$	$q_{QRi,\max}$
1.00	11.2339 MVAr	1.7225 MVAr	0.4695 MVAr	2.9617 MVAr
2.00	10.9772 MVAr	2.2938 MVAr	0.4769 MVAr	3.8186 MVAr
3.00	10.3909 MVAr	2.9160 MVAr	0.4957 MVAr	3.6691 MVAr

4.00	10.7497 MVAr	1.7929 MVAr	0.3715 MVAr	3.0275 MVAr
5.00	10.7420 MVAr	2.1227 MVAr	0.4905 MVAr	2.3090 MVAr
6.00	11.5133 MVAr	1.1633 MVAr	0.4300 MVAr	3.2436 MVAr
7.00	13.6574 MVAr	1.9700 MVAr	0.4539 MVAr	3.2114 MVAr
8.00	13.3695 MVAr	1.8130 MVAr	0.4882 MVAr	3.0566 MVAr
9.00	14.5685 MVAr	0.9427 MVAr	0.4869 MVAr	2.7114 MVAr
10.00	16.3982 MVAr	1.4238 MVAr	0.3426 MVAr	3.0394 MVAr
11.00	15.6694 MVAr	0.9454 MVAr	0.4625 MVAr	3.2222 MVAr
12.00	15.7177 MVAr	0.9952 MVAr	0.4830 MVAr	3.3688 MVAr
13.00	15.4850 MVAr	0.9830 MVAr	0.4943 MVAr	3.2953 MVAr
14.00	15.2275 MVAr	0.8997 MVAr	0.3999 MVAr	3.0026 MVAr
15.00	14.5592 MVAr	0.9035 MVAr	0.4947 MVAr	3.1939 MVAr
16.00	16.9379 MVAr	2.2275 MVAr	0.4845 MVAr	3.8622 MVAr
17.00	16.6456 MVAr	1.8590 MVAr	0.4896 MVAr	3.8502 MVAr
18.00	18.3558 MVAr	2.7225 MVAr	0.4654 MVAr	3.0007 MVAr
19.00	19.7363 MVAr	2.0021 MVAr	0.4407 MVAr	3.0608 MVAr
20.00	17.6230 MVAr	2.6459 MVAr	0.4578 MVAr	3.0002 MVAr
21.00	16.2431 MVAr	3.1594 MVAr	0.4767 MVAr	2.9768 MVAr
22.00	13.4999 MVAr	1.8323 MVAr	0.4873 MVAr	3.6753 MVAr
23.00	12.4177 MVAr	3.1399 MVAr	0.4288 MVAr	2.6566 MVAr
24.00	12.5307 MVAr	1.6621 MVAr	0.4255 MVAr	2.4575 MVAr
Total	344.2494 MVAr	43.7378 MVAr	10.9964 MVAr	75.9717 MVAr

In the calculation results listed in Table 4-4, the total required reactive power to be reserved for this test system the other day is 474.9553MVAr in which the ancillary service is 234.9553MVAr and the total cost of reactive power is $8965.906.

From the comparison between the results under different Q control strategies, it can be seen that the total cost of reactive power will be further reduced when using *Q-control strategy 2* at hours when the wind speed is high.

Based on these calculated reactive power reserve, then the short-term optimisations can be applied within these limits to calculate the exact outputs for all reactive power providers using real-time data.

4.3.7.4 **Test on IEEE 69-bus system**

To test the proposed reactive power procurement strategy with more complex test system and more control variables, a modified PG&E 69-bus system has been used in this subsection. Here the system modification is referred to the inclusion of WTs, shunt capacitors (SC) and flexible demand (QR). The PG&E 69-bus test system has 69 nodes and 73 branches. Its base capacity is 100 MVA and reference voltage is 12.66 kV. The initial network includes 69 nodes, 73 branches (consists of 68 section switches and 5 tie switches) and the total load demands of the networks is set as 37.9189MW and 26.941MVAr.

Among them, the OLTC in the substation accesses to the grid connection point i.e. bus 0 and its step is [0.9, 1.1].

Firstly, each hour optimisation is performed using typical load demand and WT active power prediction curves (Figure 4-7). In addition, the day-ahead reactive power procurement plans have been calculated under two different Q control strategies. The topology of modified PG&E 69-bus system is shown in

Figure **4-18**. Four DFIGs connected to the test system are assumed with *Q-control strategy 2*.

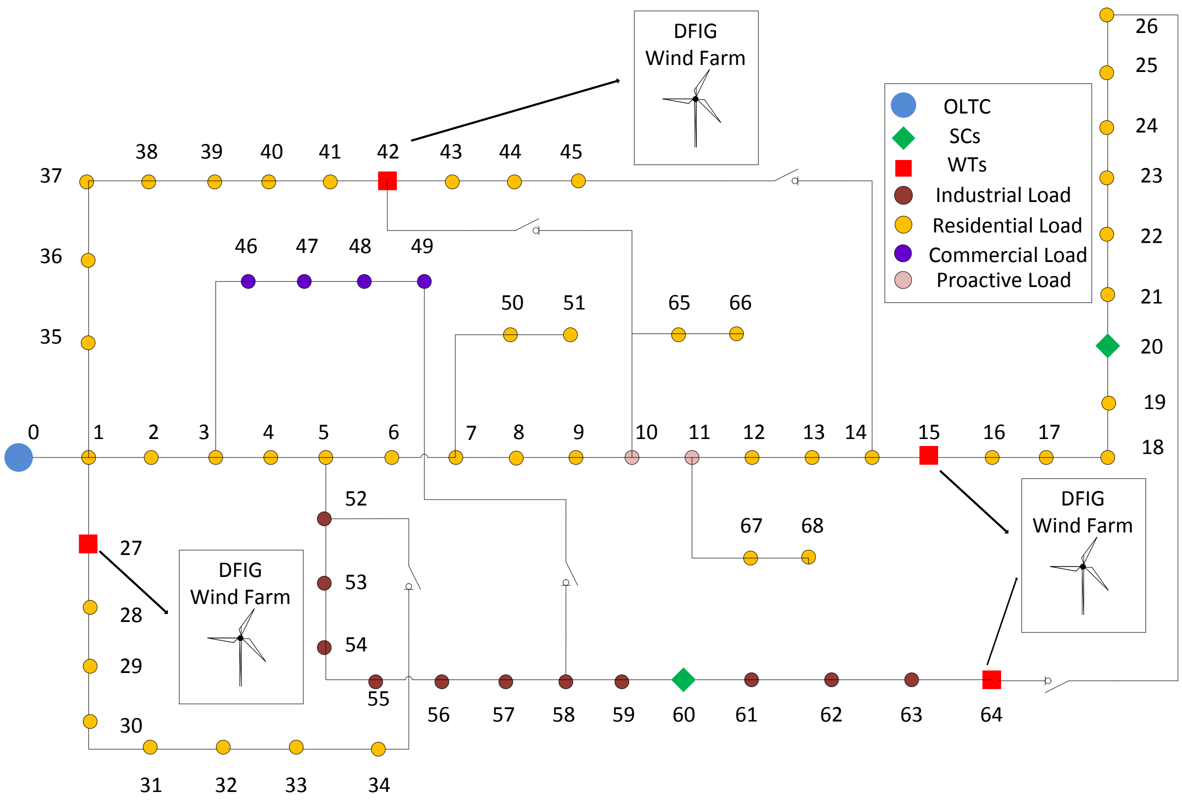


Figure 4-18 Topology of modified PG&E 69-bus distribution system

In this reactive power procurement stage, it is assumed the base case at the end of current day is *k=0*, which means no contingencies or outage for reactive power providers. And for the next day, only one outage (*N-1*) is allowed in one regime and this contingency should last for 24 hours. In this test system, Branch 0-1 is the highest loading one which also could cause the highest voltage deviation, so it has been chosen to calculate *N-1* regime. And outages of all WTs, SCs and ALs are also considered as a contingency. But the outage for grid support point is not considered. So in total there are 10 regimes. By also considering the uncertainties of wind speed and load demand, for each regime in each hour, there will be 9 tree nodes. Considering all the scenarios, the first-stage output should be the reactive power procurement plans of each hour for all reactive power providers in the test system. Associated probabilities are shown in Figure 4-19.

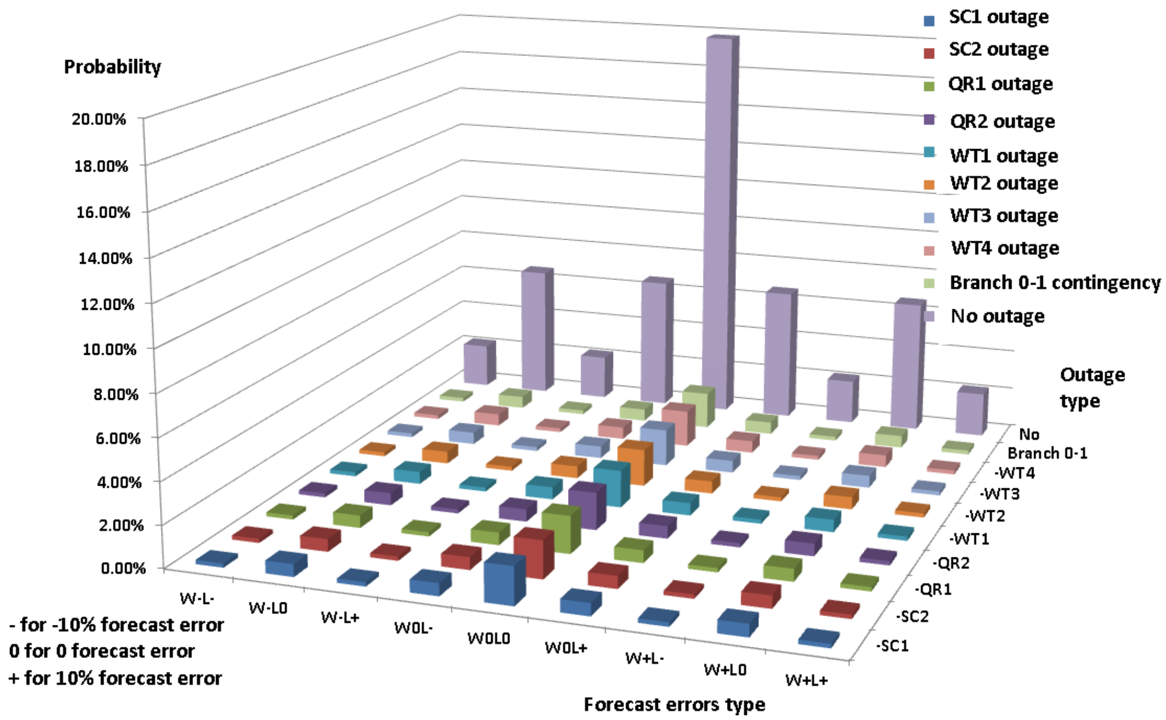


Figure 4-19 Associated table probabilities for each scenario in 69-bus system

All scenarios are simulated using the decision tree concept considering all possible contingencies, outages and forecast errors. To ensure each scenario will be successfully implemented, the maximum required reactive power from all providers should be chosen as their preserved procurement capacities for the other day. So firstly, the optimised maximum required reactive power of each hour from all providers when assuming the WTs are under *Q-control strategy 1* is listed in Table 4-5:

Table 4-5 Optimised required value of each hour for each reactive power provider during a day (WTs under *Q-control strategy 1*)

t	$q_{Gi,\max}$ MVAr	$q_{DG1,\max}$ MVAr	$q_{DG2,\max}$ MVAr	$q_{DG3,\max}$ MVAr	$q_{DG4,\max}$ MVAr	$q_{SRC1,\max}$ MVAr	$q_{SRC2,\max}$ MVAr	$q_{QR1,\max}$ MVAr	$q_{QR2,\max}$ MVAr
$1.^{00}$	10.398	1.0608	0.3802	1.1804	0.6969	0.4940	0.3326	0.6293	0.4259
$2.^{00}$	10.132	1.0788	1.0469	0.8701	0.9980	0.2614	0.4663	0.2088	0.5170
$3.^{00}$	10.994	1.1152	1.0352	0.9870	0.6563	0.1517	0.4158	0.5885	0.4086
$4.^{00}$	10.569	0.8309	1.0433	0.9716	0.6956	0.2415	0.2707	0.7025	0.5524
$5.^{00}$	10.419	1.0758	1.1934	1.0987	0.8952	0.4247	0.1508	0.5035	0.8105

$6.^{00}$	11.179	1.0235	1.0560	0.7726	0.8614	0.4734	0.4567	0.7020	0.7131
$7.^{00}$	13.396	1.0342	1.0421	1.0638	1.0547	0.4010	0.3991	0.8281	0.8377
$8.^{00}$	14.415	1.0427	1.0558	1.0920	0.7551	0.4673	0.4883	0.7506	0.9114
$9.^{00}$	14.941	1.0770	1.0697	0.9231	0.7051	0.4109	0.4779	0.7409	0.9188
$10.^{00}$	14.942	1.1767	1.1150	0.8095	1.0414	0.4635	0.4299	0.8381	0.9117
$11.^{00}$	15.941	0.7735	0.7251	0.8150	0.8121	0.4575	0.3256	0.4585	0.5025
$12.^{00}$	15.471	1.0485	0.8246	0.9336	1.0485	0.4887	0.3304	0.4461	0.6261
$13.^{00}$	14.848	1.0373	0.9117	0.8772	0.6469	0.4628	0.4296	0.3727	0.5167
$14.^{00}$	14.953	0.7439	0.8287	0.7681	0.7527	0.3263	0.4703	0.5861	0.3380
$15.^{00}$	15.748	1.0913	0.8972	1.6406	1.0478	0.4876	0.3540	0.6494	0.9452
$16.^{00}$	16.785	0.8072	0.8985	0.8842	1.2822	0.4700	0.4708	0.6249	0.7095
$17.^{00}$	17.649	0.9518	0.9147	1.1255	0.6165	0.4815	0.4517	0.9997	0.8128
$18.^{00}$	18.862	1.4398	0.9435	1.0369	1.6918	0.4051	0.3901	0.9086	0.9094
$19.^{00}$	18.941	1.2627	1.4902	1.4539	1.5360	0.4864	0.3368	0.8229	0.8300
$20.^{00}$	18.114	1.1925	0.9906	1.0884	1.0878	0.4153	0.4161	0.4013	0.5052
$21.^{00}$	16.448	1.3601	0.8157	1.1749	0.7765	0.4137	0.4126	0.7619	0.8919
$22.^{00}$	13.978	1.2575	1.0366	0.8315	1.0639	0.4215	0.3949	0.2697	0.2477
$23.^{00}$	13.154	0.9617	0.9513	0.9059	1.0742	0.3142	0.4545	0.2854	0.3776
$24.^{00}$	11.267	0.8465	0.9544	0.6703	0.7723	0.3975	0.4784	0.1262	0.3752
Total	343.54	25.29	23.220	23.975	22.569	9.818	9.604	14.206	15.595

From the calculation results listed in Table 4-5, the total generated reactive power for this test system the other day is 487.8187MVAr in which the ancillary service is 247.8187MVAr and the total cost of reactive power is $9068.78.

Then the optimised maximum required reactive power of each hour from all providers when assuming the WTs are under *Q-control strategy 2* is listed in Table 4-6:

Table 4-6 Optimised required value of each hour for each reactive power provider during a day (WTs under *Q-control strategy 2*)

t	$q_{Gi,\max}$ MVAr	$q_{DG1,\max}$ MVAr	$q_{DG2,\max}$ MVAr	$q_{DG3,\max}$ MVAr	$q_{DG4,\max}$ MVAr	$q_{SRC1,\max}$ MVAr	$q_{SRC2,\max}$ MVAr	$q_{QR1,\max}$ MVAr	$q_{QR2,\max}$ MVAr
$1.^{00}$	10.398	1.6008	0.3802	1.1804	0.6969	0.4940	0.3326	0.2933	0.3289
$2.^{00}$	10.132	1.7880	1.4690	1.8701	0.9980	0.2614	0.4663	0.2088	0.4517
$3.^{00}$	10.994	1.1152	1.0352	1.9870	0.6563	0.1517	0.4158	0.5885	0.4086
$4.^{00}$	10.569	0.8309	1.0433	0.9716	0.6956	0.2415	0.2707	0.7025	0.5524
$5.^{00}$	10.419	1.7582	1.1934	1.0987	0.8952	0.4247	0.1508	0.3035	0.2646
$6.^{00}$	11.179	1.2325	1.0560	0.7726	0.8614	0.4734	0.4567	0.5020	0.3131
$7.^{00}$	13.396	1.3742	1.0421	1.0638	1.0547	0.4010	0.3991	0.8281	0.8377
$8.^{00}$	14.415	1.0427	1.0558	1.0920	0.7551	0.4673	0.4883	0.7506	0.9114
$9.^{00}$	14.941	1.0770	1.0697	0.9231	0.7051	0.4109	0.4779	0.7409	0.9188
$10.^{00}$	14.942	1.1767	1.1150	0.8095	1.0414	0.4635	0.4299	0.8381	0.9117
$11.^{00}$	15.941	0.7735	0.7251	0.8150	0.8121	0.4575	0.3256	0.4585	0.5025
$12.^{00}$	15.471	1.0485	0.8246	0.9336	1.0485	0.4887	0.3304	0.4461	0.6261
$13.^{00}$	14.848	1.0373	0.9117	0.8772	0.6469	0.4628	0.4296	0.3727	0.5167
$14.^{00}$	14.953	0.7439	0.8287	0.7681	0.7527	0.3263	0.4703	0.5861	0.3380
$15.^{00}$	15.748	1.0913	0.8972	1.6406	1.0478	0.4876	0.3540	0.6494	0.9452
$16.^{00}$	16.785	0.8072	0.8985	0.8842	1.2822	0.4700	0.4708	0.6249	0.7095
$17.^{00}$	17.649	0.9518	0.9147	1.1255	0.6165	0.4815	0.4517	0.6643	0.6758
$18.^{00}$	16.876	1.7698	1.6935	1.2369	1.8818	0.4051	0.3901	0.5674	0.6745
$19.^{00}$	17.897	1.6273	1.4902	1.4539	1.5360	0.4864	0.3368	0.7629	0.6543

$20.^{00}$	16.676	1.9253	1.4993	1.3864	1.6878	0.4153	0.4161	0.3013	0.2052
$21.^{00}$	14.346	1.9544	1.5145	1.3746	1.2776	0.4137	0.4126	0.4619	0.4986
$22.^{00}$	13.978	1.2575	1.0366	0.8315	1.0639	0.4215	0.3949	0.2697	0.2477
$23.^{00}$	13.154	0.9617	0.9513	0.9059	1.0742	0.3142	0.4545	0.2854	0.3776
$24.^{00}$	11.267	0.8465	0.9544	0.6703	0.7723	0.3975	0.4784	0.1262	0.3752
Total	336.97	29.792	25.600	26.673	23.860	9.8175	9.6039	12.333	13.246

From the calculation results listed in Table 4-6, the total required reactive power to be reserved for this test system the other day is 487.8977MVAr in which the ancillary service is 247.8977MVAr and the total cost of reactive power is $8963.233.

Based on these calculated reactive power reserve, the short-term ORPD will calculate the exact outputs for all reactive power providers using real-time data within these limits in next Chapter.

4.3.7.5 **Test on modified real GB network**

Both IEEE 33 and PG&E 69-bus systems are distributions networks. To demonstrate the feasibility of the proposed reactive power procurement strategy at transmission level, the modified GB network with extensive involvement of control devices is used. The topology of the modified GB network is shown in Figure 4-20 [30]. This network consists of 29 zones, 99 transmission lines and 65 generators. Its installed generation capacity is around 85GW consisting of non-renewable sources such as gas (around 31GW), coal (around 25GW), nuclear (around 10GW) and renewable generation (around 18GW). The total load demands of the network are 57.9633GW and 24.1855GVAr. Core control devices in this system are 5 OLTCs, 65 various types of generators and 8 SVCs. HVDC links are not considered as control devices owing to their time-consuming operation scheme. It is assumed flexible demand does not exist in transmission networks. The power flow for this test network is calculated using MATPOWER.

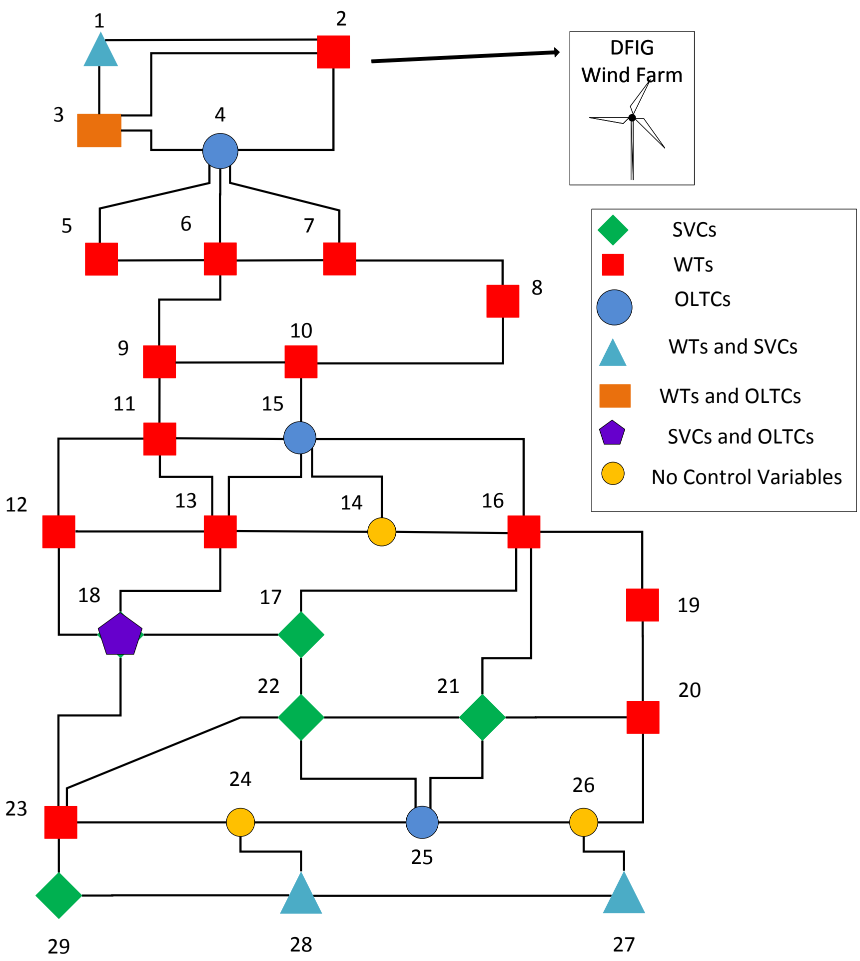


Figure 4-20 Topology of the reduced GB network

Based on data from National Grid ESO website [169], WT output and load demand hourly forecast with the estimated day-ahead forecast errors i.e. [-10%, 10%], have been shown in Figure 4-21.

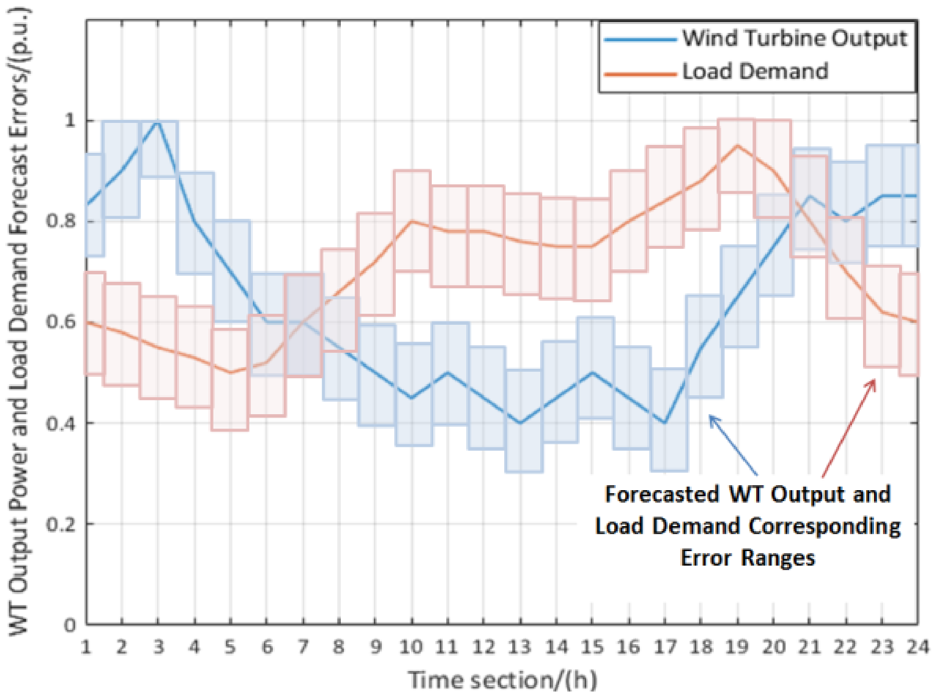


Figure 4-21 Forecasted WT output and load demand corresponding error ranges [169]

Based on the forecasted data and the corresponding error ranges, the reactive power procurement plans should be sorted out to settle the optimised day-ahead reactive power limits for all reactive power providers. Similar to distribution networks, the RPP plans should consider scenarios with contingencies and forecast errors. However, it is assumed in transmission networks, outages of reactive power providers are not allowed. As for the *N-1* contingencies, by calculating voltage deviations during different *N-1* contingencies, branch 6-7 is the one causing highest voltage deviation. It is also the highest loading one. Again, it is assumed there will be 5% probability to have this *N-1* contingency the other day. In addition, the uncertainties of wind speed and load demand are considered. Consequently, in each hour for each regime, there will be 18 tree nodes. Associated probabilities of all scenarios are shown in Figure 4-22:

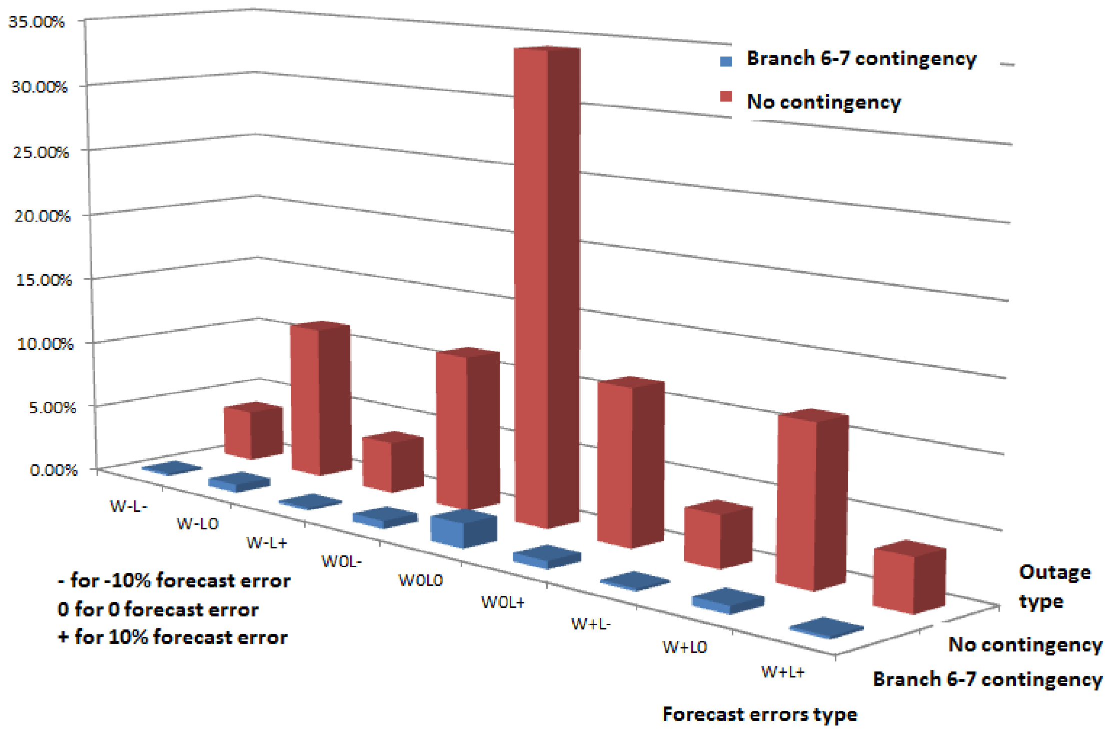


Figure 4-22 Associated probabilities for each scenario in GB network

In the reactive power procurement plans in GB network, for SGs, it is required to be capable of supplying reactive power at any point between a certain range as obligatory service and also with the capability to provide enhanced reactive power service as shown in Table 8-3. For DGs, there is no obligation to provide reactive capability but should be capable to supply at any point between 0.95 power factor lagging and leading [72]. Within these limits, the first-stage Q costs for each scenario are calculated. As the day-ahead RPP procedures should cover all scenarios, the maximum required reactive power output of each hour should be chosen as their limits for all reactive power providers. Also considering the 3 hour time window, total reactive power generations in 24 hours have been shown in Figure 4-23.

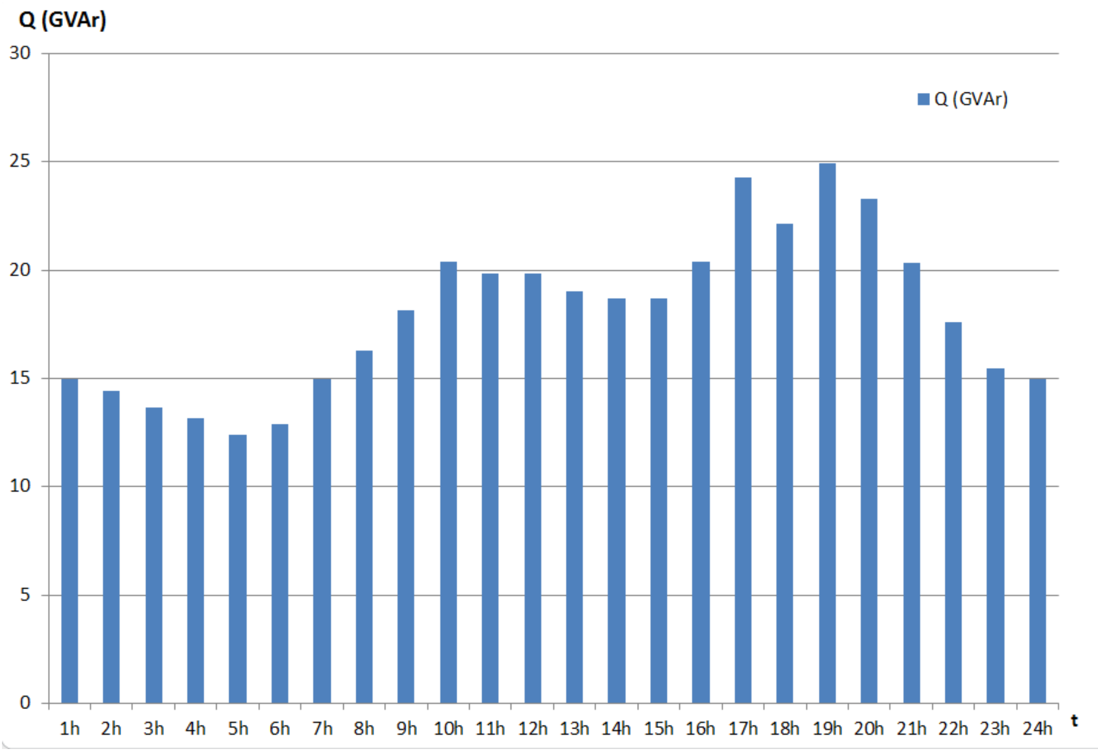


Figure 4-23 Q generation for each hour in GB network

Based on these required reactive power generation of each hour, the total reactive power costs in GB network of each hour are shown in Figure 4-24.

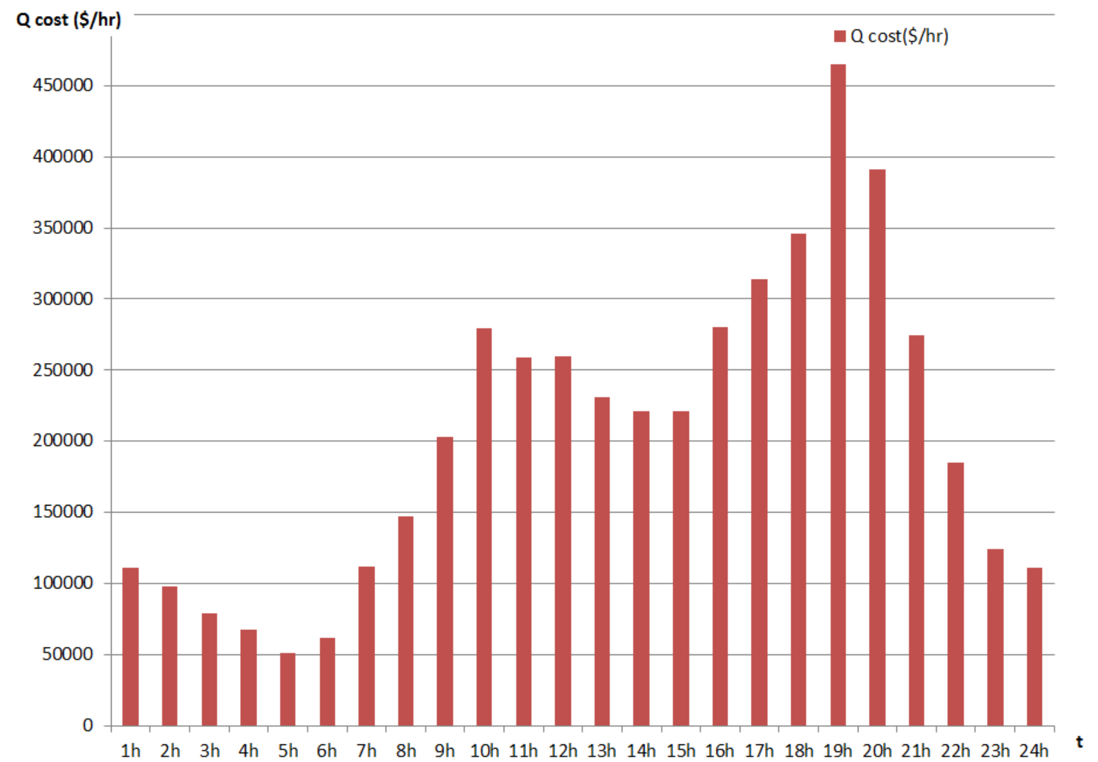


Figure 4-24 Q cost for each hour in GB network

Additionally, the total required reactive power and their cost are shown in Table 4-7 and Table 4-8:

Table 4-7 Optimised total required reactive power each hour and their cost

Time	1h	2h	3h	4h	5h	6h
Q (GVAr)	14.9396	14.4201	13.6501	13.1414	12.3833	12.889
Q cost($/hr)	110938.8	97779.84	79080.38	67506.24	50758.36	62031.61
Time	7h	8h	9h	10h	11h	12h
Q (GVAr)	14.9461	16.26846	18.1553	20.3919	19.8182	19.8256
Q cost($/hr)	111581.3	147029.7	203277.8	279354	258656.5	259398.2
Time	13h	14h	15h	16h	17h	18h
Q (GVAr)	18.9916	18.7089	18.7037	20.3971	24.2729	22.1445
Q cost($/hr)	231244.4	221446	220922.6	279898.4	313976.1	345630.7
Time	19h	20h	21h	22h	23h	24h
Q (GVAr)	24.9138	23.3112	20.3405	17.5907	15.4621	14.9396
Q cost($/hr)	464883.3	391375.2	274732.7	184543.1	124499.1	110938.8
Total Q: 430.606GVAr			Total Q cost: $4891483.12			

Table 4-8 Optimised required reactive power from each generator during a day

No.	1	2	3	4	5	6
Q_{max} (MVAr)	6219.936	15243.66	1489.644	1459.886	4568.352	2899.9104
Zone	1	1	1	2	2	3
Type	Hydro	WT	SVC	CCGT	WT	Hydro
No.	7	8	9	10	11	12
Q_{max} (MVAr)	0	3465.99	1966.378	12821.18	754.7712	4449.1776
Zone	3	5	5	6	7	7
Type	WT	Nuclear	WT	WT	CCGT	Nuclear
No.	13	14	15	16	17	18
Q_{max} (MVAr)	3674.544	824.29	2433.144	1559.198	4419.384	12910.56
Zone	7	8	9	10	10	10
Type	WT	WT	WT	CCGT	Nuclear	WT

No.	19	20	21	22	23	24
Q_{max} (MVAr)	566.08	21213.04	5352.917	5054.981	6316.243	10248.99
Zone	11	11	11	12	12	12
Type	CCGT	Nuclear	WT	CCGT	Hydro	Nuclear
No.	25	26	27	28	29	30
Q_{max} (MVAr)	5124.499	14211.54	824.2896	4687.526	12473.59	8034.341
Zone	12	13	13	14	15	15
Type	WT	CCGT	WT	CCGT	CCGT	Coal
No.	31	32	33	34	35	36
Q_{max} (MVAr)	30121.33	15164.94	8292.552	1489.68	10248.99	2979.36
Zone	16	16	17	17	18	18
Type	CCGT	WT	Coal	SVC	Nuclear	SVC
No.	37	38	39	40	41	42
Q_{max} (MVAr)	14579.01	5601.197	1479.749	16684.42	1092.432	28800.48
Zone	19	19	20	20	20	20
Type	CCGT	WT	CCGT	Nuclear	OCGT	WT
No.	43	44	45	46	47	48
Q_{max} (MVAr)	2979.36	2711.218	1489.68	18899.07	973.2576	1092.432
Zone	21	22	22	23	23	23
Type	SVC	CCGT	SVC	CCGT	Hydro	OCGT
No.	49	50	51	52	53	54
Q_{max} (MVAr)	734.9088	5680.646	11748.61	526.3536	13883.82	6117.619
Zone	23	24	25	25	26	26
Type	WT	CCGT	CCGT	OCGT	CCGT	Nuclear
No.	55	56	57	58	59	60
Q_{max} (MVAr)	3952.618	3029.016	6703.56	5412.504	367.4544	1191.744
Zone	27	27	27	28	28	28
Type	Nuclear	WT	SVC	CCGT	OCGT	WT
No.	61	62	63	64	65	

Q_{max} (MVAr)	3724.2	3317.021	15572.12	516.4224	8193.24	
Zone	28	29	29	29	29	
Type	SVC	CCGT	Nuclear	OCGT	SVC	

From the calculation results, the total required reactive power to be preserved for this test system the other day is 430.606GVAr in which the ancillary service is 167.649GVAr and the total cost of reactive power is $4891483.12.

Within these preserved capacities of each generator for the other day, the short-term optimisation will calculate the exact outputs for all reactive power providers using real-time data within these limits in next Chapter.

4.4 Chapter summary

In this chapter, the reactive power support from wind farms has been presented firstly. After that, a novel reactive power procurement (RPP) strategy for wind power integrated systems to provide day-ahead reactive power reservation plans has been presented. Based on the reactive power pricing and bidding procedures, the proposed RPP strategy considers a stochastic optimisation based day-ahead bidding process while reactive power cost has been considered as the objective function. In this objective function, all potential reactive power providers integrated into networks, i.e. the synchronous generators/grid connection point, distributed generators, reactive power compensators, static VAr compensators and flexible demand have been included and all their cost functions have been detailed presented. Furthermore, all kinds of constraints have been well thought out including power flow constraints, logical constraints and other constraints. This constrained stochastic optimisation objective function then has been solved by a decision tree framework considering uncertainties and outages. Each regime and hour solution has then been carried out by an improved genetic algorithm.

In the simulation part, IEEE 33-bus system, PG&E 69-bus system and modified GB network have been used to demonstrate the applicability of the proposed strategy. The results have shown the accuracy and efficiency of the proposed strategy.

5 Proposed optimised reactive power dispatch strategy in wind power integrated systems

5.1 Introduction

As stated in Chapter 3, so far, most ORPD strategies have been designed for distribution networks, considering only one or two goals, such as power loss and voltage deviation. For large-scale wind farm integrated systems with significant voltage changes, it may also be necessary to consider reducing OLTC switching operations and harmonic emissions. In addition, the hourly large-scale wind power generation and load demand changes need to be considered. These additional considerations with a large number of control variables will make the process of solving the objective function of the ORPD problem more complicated. Therefore, more efficient and faster optimal calculation algorithms are needed.

To resolve the aforementioned shortcomings, a novel optimised reactive power dispatch strategy is proposed in this Chapter. The proposed strategy considers a more comprehensive objective function including minimising power losses, voltage deviations, operation times of OLTCs and wind farms harmonic emissions. They are a part of constrained multi-objective mixed-integer optimisation problem. Every single objective and its satisfaction function have been detailed in Section 5.2. Depending on the power system involved, its priorities, assets, and planning and operating strategies, these objectives can have different levels of importance, then pre-selected weighting factors have been introduced. In addition, the system constraints and control variables are defined for the constrained multi-objective functions in Section 5.3.

After that, the proposed ORPD strategy has been rigorously tested in IEEE 33-bus system, PG&E 69-bus system and the real GB network. Results obtained confirmed the efficacy and applicability of the proposed strategy in both distribution and transmission networks.

5.2 Motivations and objectives

As aforementioned, the ORPD problem can be described in mathematics by objective functions with a set of constraints. It has the following characteristics: i) multi-objective; ii) a large number of constraints; iii) the nonlinearity of the objective function and constraints; iv) uncertainties of load; v) discreteness of control variables; vi) non-convexity of power flow; vii) objective function is difficult to be described explicitly by control variables.

Nowadays, with the continuous expansion of the power system scale, higher requirements on reactive power optimisation algorithms are urgent. The selection of optimisation objectives and constraints becomes even more important. So the motivations and objectives of the objective function selection in this research have been explained in this subsection.

5.2.1 **Active power loss**

Nowadays, with the hyper growth of modern society, the scale of electric energy production and consumption is huge. Modern power system covers a relatively wide area and is responsible for the task of power conversion and transmission providing industry, commercial and residential loads with clean and convenient energy. At the same time, the loss of the power system in the conversion, transmission and distribution process is also quite huge. Therefore, it is of great importance to minimise the loss of electric energy in the conversion, transmission and distribution process [49].

In the power system, due to a large number of induction motors and other inductive electrical equipment used by power users, in addition to the active power, the power system also needs to supply a large amount of reactive power. The transmission and conversion of reactive power through transmission lines and transformers will cause the loss of reactive power and reduce the power factor of the grid. This will reduce the output of the power generation equipment and increase the power loss. Therefore, in the power system, optimising reactive power dispatch is considered as one of the most effective ways to improve power transfer capacity and to reduce power loss.

In addition, the research works of system power loss in recent years have also focused on other power loss reduction measures, such as: distribution network reconfiguration [170]-[176], reactive power optimisation [101]-[114], positioning of compensation capacitors targeting network loss [174], [175] and distribution capacitor switching strategies [176] etc.

To minimise the system power loss in the aforementioned measures, the most important is to exactly calculate the actual system power loss. The calculation formula of network loss can be divided into two categories. The first one is based on the total net loss of the system which equals the total net injected power of each node in the entire network, normally calculated by the total generated power and load demand [101]:

$$\Delta P_{loss} = \sum P_i^{generation} - \sum P_i^{load} \tag{63}$$

where ΔP_{loss} is the total system power loss, $P_i^{generation}$ is the injected active power at node *i*, P_i^{load} is the connected load at node *i*.

The other one is based on the total network loss of the system which approximately equals the sum of the power losses of each branch in the system, normally calculated by the branch current formula [105]:

$$\Delta P_{loss} = \sum r_{ij} \cdot I_{ij}^2 \tag{64}$$

where r_{ij} is the resistance of branch (*i*, *j*), I_{ij} is the branch current of (*i*, *j*).

Since the network power flow is a large-scale non-linear non-convex problem, the system power loss is a non-linear non-convex function of the generators and the load. And the actual physical path of current is complicated, which makes it difficult to accurately calculate the power system loss through the branch current formula. Due to the non-convex nature of the power flow formula, it is impossible to accurately calculate the branch power flow. Therefore, this thesis chooses to calculate the system power loss through the net injected power of each node.

To ensure economic dispatch, minimising active power loss is always the priority of power system optimisation problems like the one proposed in this chapter. Consequently, it is included in the objective function used in this research to optimise reactive power dispatch.

5.2.2 **Voltage deviation**

In recent years, the implementation of voltage control in power systems especially the renewable energy sources integrated power systems is yelling for higher level of attention, especially for the increase in penetration contribution from wind power. In power systems throughout the world, voltage instability is considered as a major risk of a blackout, as important as thermal overloads and the associated risk of cascade line tripping. As these systems are forced by economic and environmental considerations to “walk closer to the edge”, the need for effective means to prevent an approaching critical condition, as well as to counteract an ongoing instability is becoming more evident every day.

The control of voltage is in fact closely related to the control of reactive power. An injection of reactive power at a bus will in general increase the voltage of that bus and its surrounding network. Additionally, voltage stability is not an isolation technique problem in the grid, needing to be observed from the whole power system. So to ensure the system voltage stability level, a system level reactive power optimisation strategy is needed. In the proposed optimal reactive power dispatch in this Chapter, system voltage deviation should also be chosen as one of the objectives based on the perspective of improving system stability level.

As the system operation mode and the load demand slowly changes all the time, the voltage at each bus of the system will also change. The difference between the actual voltage at each bus and the nominal voltage of the system is the voltage deviation. This system average voltage deviation is normally calculated as:

$$\Delta U_{ave} = \frac{\sum_{i=1}^{M} \left| U_i - U_{i\_nom} \right|}{M} \tag{65}$$

where ΔU_{ave} is the voltage deviation of M bus system, U_i is the voltage magnitude at bus i, U_{i_nom} is the nominal voltage at bus i of the M bus system.

To limit the bus voltage of the power system within the specified range, voltage regulation must be well carried out to ensure voltage stability. Commonly used methods to minimise the voltage deviation are:

- Adjusting tap changers of the transformer. The voltage level of each bus in the system is different and linked with the transformer tap ratio. A reasonable selection of the tap position of transformers can adjust the voltage level to limit the deviation between the actual voltage and the nominal voltage within a certain range.
- Reducing system impedance. Voltage deviation has a strong correlation with voltage loss. The larger the voltage loss, the more difficult it is to limit the voltage deviation. And the voltage loss of the power system is proportional to the system impedance. Therefore, reducing the system impedance can reduce the voltage loss and reduce voltage deviation.
- Optimising reactive power compensation. Optimising reactive power compensation can effectively reduce system voltage loss, thereby reducing voltage deviation to a certain extent.
- Balancing three-phase load. In the three-phase system, if the three-phase load is unevenly distributed, zero-sequence voltage will be generated. Similarly, the unbalanced load between the transmission lines will cause the unbalanced voltage

between the lines and increase the voltage deviation. Therefore, the three-phase balance should be achieved as much as possible.

As one of the reactive power optimisation methods, ORPD is one of the important methods to reduce system voltage deviation. So the ORPD strategy proposed in this Chapter also includes minimising voltage deviation as one of the objectives.

5.2.3 Operation times of vulnerable devices

In a power system optimisation problem, if do not consider the control equipment continuous adjustment, simply pursuing the reactive power optimisation of voltage level and network loss, it is called static reactive power optimisation scheduling. However, in the real-life reactive power optimisation process, the dynamic changes of the load are considered. Then the daily allowable operation times of discrete control variables should be considered and limited. This kind of reactive power optimisation is called dynamic reactive power optimisation. Because it needs to consider the correlation between various load levels of the power system and the scheduling results under operating conditions, it is more complicated than the static optimisation problem.

As aforementioned, the tap stagger of the transformer can be used to adjust voltage levels. It is one of the normally used discrete control devices to achieve voltage regulations. However, the total operation times of the transformer equipped on load tap changer (OLTC) are limited, which is generally determined by the mechanical and electrical limits of the tap staggers. If the limits are exceeded, both the fixed and moving contacts of the staggers will wear out. Generally, the power system standard stipulates that the electrical life of the on load tap changer is not less than 200,000 times, and the mechanical life is not less than 500,000 times. Generally, when the stagger is operated about 200,000 times, the system operator will request to replace the on load tap changer. The number of operation times of the on load tap changer is usually specified as no more than 10 times per day [49]. Consequently, it is of great importance to minimise the operation times of vulnerable devices such as OLTC within a day to reduce maintenance costs. The total tap step difference can be calculated as [99]:

$$N_{TAP} = \sum_{l=1}^{N} x_l \tag{66}$$

Where N_{TAP} is the total tap step difference from initial tap positions for all OLTCs existing in the system, x_l is the tap step difference from initial tap positions on OLTC at bus l and N is the total number of OLTCs in system.

And the maximum number of operation times, O_{l_max}, the tap position can be changed per day:

$$0 \le O_l \le O_{l\_\max} \text{ for } l = 1, \ldots, N \tag{67}$$

To optimise reactive power dispatch, the proposed strategy in this Chapter has included minimising operation times of OLTCs in the system as one of the objectives.

5.2.4 System harmonic distortion

Having high penetrated intermittent renewable resources such as wind turbines (WT), it might cause power quality problems, for example, total harmonic distortion (THD) may exceed. In order to run a stable operation of the power network, an optimised reactive power dispatch is one of the basic guarantees, based on which the power quality will be ensured. In order to improve the power quality criteria, THD should also be reduced to a proper level.

The harm of harmonics is very serious. Harmonics will reduce the efficiency of electric energy production, transmission and utilization will cause electrical equipment to overheat, generate vibration and noise and will cause insulation ageing problems. Additionally, harmonics will also cause local parallel resonance or series resonance in the power system, which will amplify the harmonic content, and cause the burning of capacitors and other equipment. Harmonics may also cause malfunctions of relay protection and automatic devices, causing confusion in electric energy measurement. For the outside of the power system, harmonics will cause serious interference to communication equipment and electronic equipment [177]-[179].

In order to solve the harmonic pollution problem of power electronic based devices and other harmonic sources, there are two basic strategies: one is to install a harmonic compensation device to compensate for harmonics, which is applicable to various harmonic sources. The other is to adjust the power electronic device itself so that it does not produce harmonics or produces fewer harmonics. However, both of the strategies will need axillary equipped devices and will increase the total cost of power generation.

When optimally reducing the total generated power from power electronic based devices like wind turbines, the system average total harmonic distortion (SATHD) can also be reduced.

So minimising the level of distortion of signals in the grid should be another objective in the ORPD strategy. SATHD can be calculated as [180], [181]:

$$SATHD = \frac{\sum_{k=1}^{M} S_k THD_k}{S_{total}} \tag{68}$$

where S_k is the generated or consumed apparent power at bus k, THD_k is the total harmonic distortion at bus k and S_{total} is the total apparent power generated by the system. The information about the distortion can be obtained using power quality meters, or other sensors capable of monitoring signal distortions. These data can be detected with the built-in harmonic ratio function of sensors or watt meters [178].

To ensure power quality, the SATHD has been included in the proposed ORPD strategy in this Chapter.

5.3 Constrained multi-objective optimisation strategy

With all the aforementioned objectives included, this section presents a coordinated reactive power dispatch preventive control strategy for optimising the operation of power systems with integrated wind farms. The strategy considers a day-ahead reactive power dispatch with hourly modifications owing to forecast errors. The purpose of this strategy is to i) reduce network voltage deviations, ii) minimise active power losses, iii) mitigate wind turbine harmonics emission, and iv) decrease the number of switching operations of on-load tap changers (OLTCs). In the day-ahead optimisations, the strategy employs day-ahead predicted wind energy and load demand data to precisely set the following variables: a) optimal tap positions of OLTCs, b) reactive power compensators injected reactive power and c) active and reactive power outputs of generators. However, the forecasting errors of day-ahead data are unavoidable. Considering uncertainties of wind energy and load demand, hourly modifications of the day-ahead optimisation results are undertaken on an hourly basis, resulting in optimally set real-time abovementioned optimised variables. Nevertheless, considering the operation time limitation of OLTCs, in the hourly modification part only SCs, SVCs and generators are used to achieve the adjustments.

In this section, a new ORPD strategy is presented with objective functions, system constraints and control variables defined for the created multi-objective optimisation problem. In Figure

5-1, time scales for implementing the proposed ORPD strategy in both day-ahead and hourly time are given.

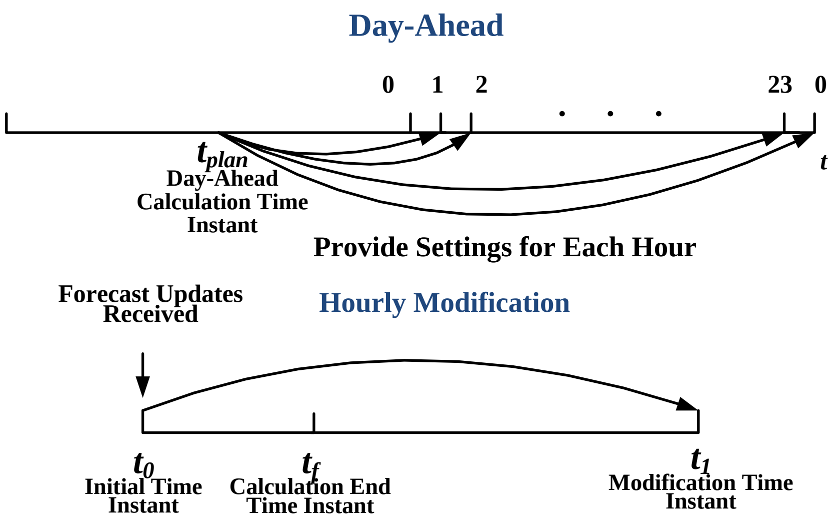


Figure 5-1 Time scale of the ORPD strategy for wind power integrated power system

Firstly, a day-ahead optimisation is assumed to be undertaken at the moment t_{plan}. In this time scale, control variables, i.e. output active and reactive power for generators, injected reactive power for SCs, SVCs and tap positions for OLTCs, are determined for each hour on the other day. When receiving forecast errors of load demand and WT power output, which may occur because of climate change or other reasons, the hourly modification section is done at the beginning of each hour. The day-ahead outputs are used as initial settings for the hourly modifications at t_0, in which the hourly real-time inputs are used, which are considered to be more reliable and less uncertain, compared to the forecasted inputs used for the day-ahead time. The proposed multi-objective ORPD strategy is described in the subsections below.

5.3.1 Day-ahead optimisation

The role of the day-ahead ORPD is to optimally adjust the control variables and consequently to ensure that the short-term and real-time dispatch has a sufficient safety margin. The proposed multi-objective constrained optimisation strategy considers the following four: a) the tap positions of OLTC, b) capacitance for SCs and SVCs, and c) active and reactive power output of generators will be used as the control variables for this optimised reactive power dispatch in day-ahead strategy. This optimisation is based on the following four main objects. The first object (J_1) is to minimise the network active power loss $\triangle P_{loss}$. The second object (J_2) is to minimise the voltage deviation across the network U_{ave}. The third object (J_3)

is to minimise the tap switching operation times caused by the tap stagger. The fourth object (J_4) is to minimise the total harmonic distortion *SATHD* injected by wind turbines. Depending on the power system in question, its priorities, assets, as well as planning and operation strategies, these objectives can have different levels of importance, what is modelled by introducing adequate, in advance selected weighting factors $\omega_1, \omega_2, \omega_3$ and ω_4, respectively. Therefore, considering these points, the day-ahead strategy system objective function can be presented as follows:

$$\min F = \omega_1 J_1 + \omega_2 J_2 + \omega_3 J_3 + \omega_4 J_4 \tag{69}$$

$$\min F = \omega_1 F_1(\Delta P_{loss}) + \omega_2 F_2(\Delta U_{ave}) + \omega_3 N_{TAP} + \omega_4 SATHD \tag{70}$$

where $F_1(\Delta P_{loss})$ and $F_2(\Delta U_{ave})$ are satisfaction functions related to active power losses and average system voltage deviation, N_{TAP} is the total tap step difference from their initial tap positions for all OLTCs existing in the system and *SATHD* is the system average *THD*. The first two objective functions are traditionally considered as the most important criteria. So, keeping them just within in advance prescribed limits would not lead to minimal losses and smallest voltage deviations. That is why for both mentioned criteria, adequate satisfaction functions have to be selected, what is described below.

Firstly, the power losses are calculated as follows:

$$\Delta P_{loss} = \sum P^{grid} + \sum P^{WT} - \sum P^{load} \tag{71}$$

where *S*-type membership function is used [101]:

$$F_1(\Delta P_{loss}) = \begin{cases} 0 & \text{if} \quad \Delta P_{loss} \le a \\ 2\left(\dfrac{\Delta P_{loss} - a}{b - a}\right)^2 & \text{if} \quad a \le \Delta P_{loss} \le \dfrac{a+b}{2} \\ 1 - 2\left(\dfrac{\Delta P_{loss} - b}{b - a}\right)^2 & \text{if} \quad \dfrac{a+b}{2} \le \Delta P_{loss} \le b \\ 1 & \text{if} \quad \Delta P_{loss} \ge b \end{cases} \tag{72}$$

where P^{grid} , P^{WT} and P^{load} are active powers of the traditional generators, WTs and load respectively; *a* and *b* are pre- calculated minimum and maximum power losses. The minimum power losses, *a*, are calculated when all reactive power demand is compensated locally and all transmission lines only transfer active power. The maximum power losses, *b*, is the maximum allowable system power losses, which is calculated assuming that Q is produced from synchronous generators only [101].

The S-type membership function is shown in Figure 5-2:

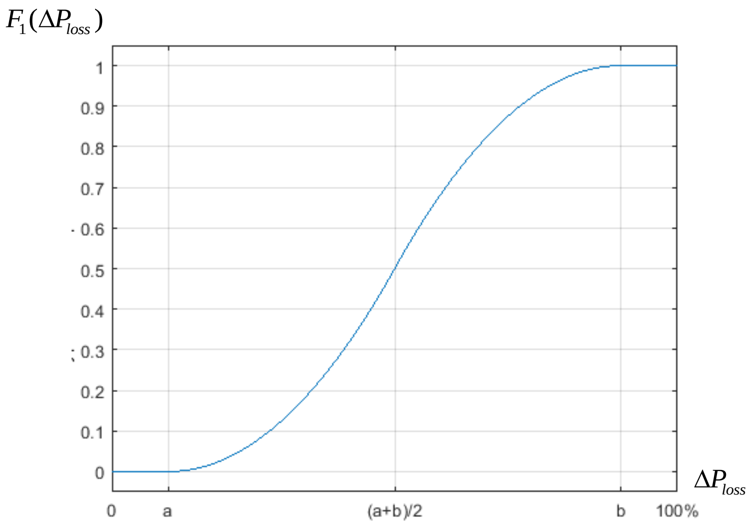


Figure 5-2 *S*-type membership function

For the second criterion, the Gauss-type function is used [101]:

$$\Delta U_{ave} = \frac{\sum_{i=1}^{M} \left| U_i - U_{i\_nom} \right|}{M} \tag{73}$$

$$F_2(\Delta U_{ave}) = e^{(\Delta U_{ave} - c)^2 / \sigma^2} \tag{74}$$

where U_{i_nom} is the nominal voltage at bus i of the M bus system, c and σ are the mean value and standard deviation of the voltage deviation set as 0 and 0.0425 pu, respectively.

The Gauss-type function is shown in Figure 5-3:

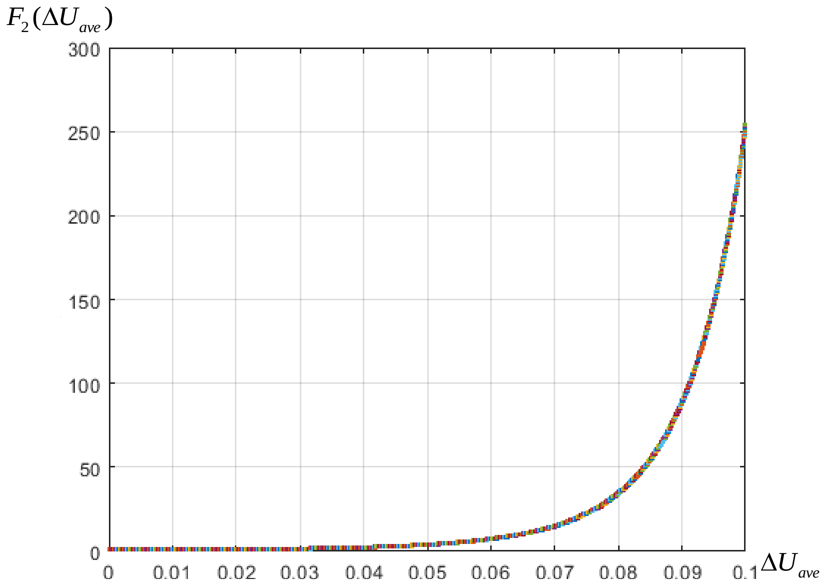


Figure 5-3 Gauss-type membership function

For the third criterion, the total tap step difference is calculated as [99]:

$$N_{TAP} = \sum_{l=1}^{N} x_l \tag{75}$$

where x_l is the tap step difference from initial tap positions on OLTC at bus l and N is the total number of OLTCs in system.

The level of distortion of signals in the grid is considered in the fourth criterion, in which *SATHD* is the system average THD, calculated as follows [179], [181]:

$$SATHD = \frac{\sum_{k=1}^{M} S_k THD_k}{S_{total}} \tag{76}$$

where S_k is the generated or consumed apparent power at bus k, THD_k is the total harmonic distortion at bus k and S_{total} is the total apparent power generated by the system. The information about the distortion can be obtained using power quality meters, or other sensors capable of monitoring signal distortions. These data can be detected with built-in harmonic ratio function of sensors or watt meters [182].

As for the advance selected weighting factors, they should be selected based on each related objective. However, the range of feasible values of all four objectives are different, requiring a shift to their *per unit* consideration. This challenge can be resolved by defining all four weighting factors as follows:

$$\begin{cases} \omega_1 = \mu_1 / F_{1\_\max}, 0 \le \mu_1 \le 1 \\ \omega_2 = \mu_2 / F_{2\_\max}, 0 \le \mu_2 \le 1 \\ \omega_3 = \mu_3 / N_{TAP\_\max}, 0 \le \mu_3 \le 1 \\ \omega_4 = \mu_4 / SATHD_{\_\max}, 0 \le \mu_4 \le 1 \end{cases} \tag{77}$$

where μ_1, μ_2, μ_3 and μ_4 are weighting coefficients representing the importance of each criterion, F_{1_max}, F_{2_max}, N_{TAP_max} and $SATHD_{\_max}$ are pre-calculated maximum values of each criterion. The weighting coefficients must meet the following condition:

$$\mu_1 + \mu_2 + \mu_3 + \mu_4 = 1 \tag{78}$$

The values of the weighting coefficients can be set through a sensitivity study, as described in the simulation section.

As aforementioned, the outputs of the day-ahead optimisation are optimal settings for all control variables, i.e. a) tap positions of OLTCs, b) capacitances of SCs and SVCs, and c) active and reactive power output of generators.

5.3.2 **Hourly modifications**

As the inputs of day-ahead optimisation are based on forecasted data, which might be significantly different than the actual inputs measured based on the hourly data of the other day. To deal with the forecast errors and to use more reliable real-time inputs, which as such would lead to more reliable optimal solutions valid for each new hour, an hourly modification is introduced. This could cause an excessive number of changes of the tap positions of the OLTCs, which would not be acceptable from the perspective of vulnerable ageing. In order to achieve a fast response modification for the initial setting values at the beginning of each hour, the OLTC will not be used in the second stage. That is why the hourly modification considers their positions delivered by the day-ahead optimisation as unchanged, leading to the conclusion that $\omega_3 = 0$. Consequently, the hourly modification multi-objective function and the weight coefficients of the hourly modification become:

$$\min F = \omega_1 J_1 + \omega_2 J_2 + \omega_4 J_4 \tag{79}$$

$$\min F = \omega_1 F_1(\Delta P_{loss}) + \omega_2 F_2(\Delta U_{ave}) + \omega_4 SATHD \tag{80}$$

Obviously, there are only 3 criteria and consequently only 3 weighting factors which have the same nature as the weighting factors from the day-ahead optimisation (equation (77)). However, they have different values, considering that:

$$\begin{cases} \omega_1 = \mu_1 / F_{1\_\max}, 0 \le \mu_1 \le 1 \\ \omega_2 = \mu_2 / F_{2\_\max}, 0 \le \mu_2 \le 1 \\ \omega_4 = \mu_4 / SATHD_{\_\max}, 0 \le \mu_4 \le 1 \end{cases} \tag{81}$$

$$\mu_1 + \mu_2 + \mu_4 = 1 \tag{82}$$

That is the reason, in general terms, why these weighting coefficients have different values compared to those in day-ahead optimisations.

5.3.3 **Constraints**

The proposed reactive power dispatch objective function and all control variables should meet several constraints including power flow constraints and logical constraints.

5.3.3.1 **Power flow constraints**

Firstly, all control variables and criteria should meet power system driven constraints, satisfying the power flow constraints:

$$\begin{cases} P_i = U_i \sum_{j=1}^{M} U_j (G_{ij} \cos\delta_{ij} + B_{ij} \sin\delta_{ij}) \\ Q_i = U_i \sum_{j=1}^{M} U_j (G_{ij} \sin\delta_{ij} - B_{ij} \cos\delta_{ij}) \end{cases} \tag{83}$$

where G_{ij} and B_{ij} are admittance matrix's real and imaginary part and δ_{ij} is voltage angle difference between buses *i* and *j*. Also, the following technical constraints must be satisfied:

$$\Delta P_{loss\_\min} \le \Delta P_{loss} \le \Delta P_{loss\_\max} \tag{84}$$

$$U_{i\_\min} \le U_i \le U_{i\_\max} \tag{85}$$

$$TAP_{l\_\min} \le TAP_l \le TAP_{l\_\max} \tag{86}$$

$$SATHD \le SATHD_{\_\max} \tag{87}$$

where $\Delta P_{loss\_\min}$ and $\Delta P_{loss\_\max}$ are the minimum and maximum system power losses, U_{i_min} and U_{i_max} are minimum and maximum permissible voltages at bus i, TAP_{l_min} and TAP_{l_max} are the minimum and maximum limits for tap position of the OLTC at bus l and $SATHD_{\_\max}$ is the permissible system average THD.

There is one more constraint, related to reactive power outputs of WTs, here Type 3, i.e. DFIG. According to [51], [183], [184], the following two reactive power limits have to be considered:

$$Q_{t,\max}^{WT} = P_{t,\max}^{WT} \tan(\cos^{-1}(0.95)) \tag{88}$$

$$Q_{t,\max}^{WT} = \sqrt{(S_{t,\max}^{WT})^2 - (P_{t,\max}^{WT})^2} \tag{89}$$

where $Q_{t,\max}^{WT}$ is the reactive power limit of WT, $P_{t,\max}^{WT}$ is the output active power limit of WT, and $S_{t,\max}^{WT}$ is the apparent power limit of WT. To distinct these two options, (29) is considered as *Q-control strategy 1* and (30) as *Q-control strategy 2*.

5.3.3.2 **Logical constraints**

In the day-ahead ORPD strategy there exists an additional constraint which is the maximum number of operation times, O_{l_max}, the tap position can be changed per day:

$$0 \le O_l \le O_{l\_\max} \text{ for } l = 1,\dots,N \tag{90}$$

In addition, the daily output reactive power capacities of all reactive power providers in the system should be considered within the calculated reactive power reserve limits from the proposed reactive power procurement strategy in Chapter 4.

With the all above constraints ((83)-(90)) and the multi-objective function defined, the ORPD becomes a constrained multi-objective optimisation problem, which can be solved using different solvers. An improved GA is proposed for solving the formulated problem.

5.3.4 **ORPD strategy block diagram**

In Figure 5-4, the block diagram of the proposed entire ORPD strategy is presented. Here, V_{slack} and θ_{slack} are voltage magnitude and angle for selected slack bus, W is the wind speed, $\dot{P}^G, \dot{Q}^G, \dot{Q}^{SC}, \dot{P}^{WT}, \dot{Q}^{WT}$, $\dot{x}_l$ are the calculated settings for all control variables as outputs from the day-ahead optimisation and $\ddot{P}^G, \ddot{Q}^G, \ddot{Q}^{SC}, \ddot{P}^{WT}, \ddot{Q}^{WT}$ are settings for control variables obtained as outputs from the hourly modifications. Note that the inputs for the day-ahead optimisation are based on forecast data, which can be less reliable. Also note that in the hourly modifications, the OLTC criterion is not considered considering wear and tear cost. The entire strategy has a routine, checking if the inputs for two optimisations are different. This is to check if the day-ahead forecast data is accurate or there are some forecast errors. If they are different, the hourly modifications should be performed. If they are not, the modifications for that particular hour should not be performed and the day-ahead outputs should be used. Based on a number of tests, a threshold value has been set to trigger hourly modifications. When the difference of the inputs is more than 5 %, it indicates that the hourly modifications have to be performed. Otherwise, modifications at the specific hour should not be necessary.

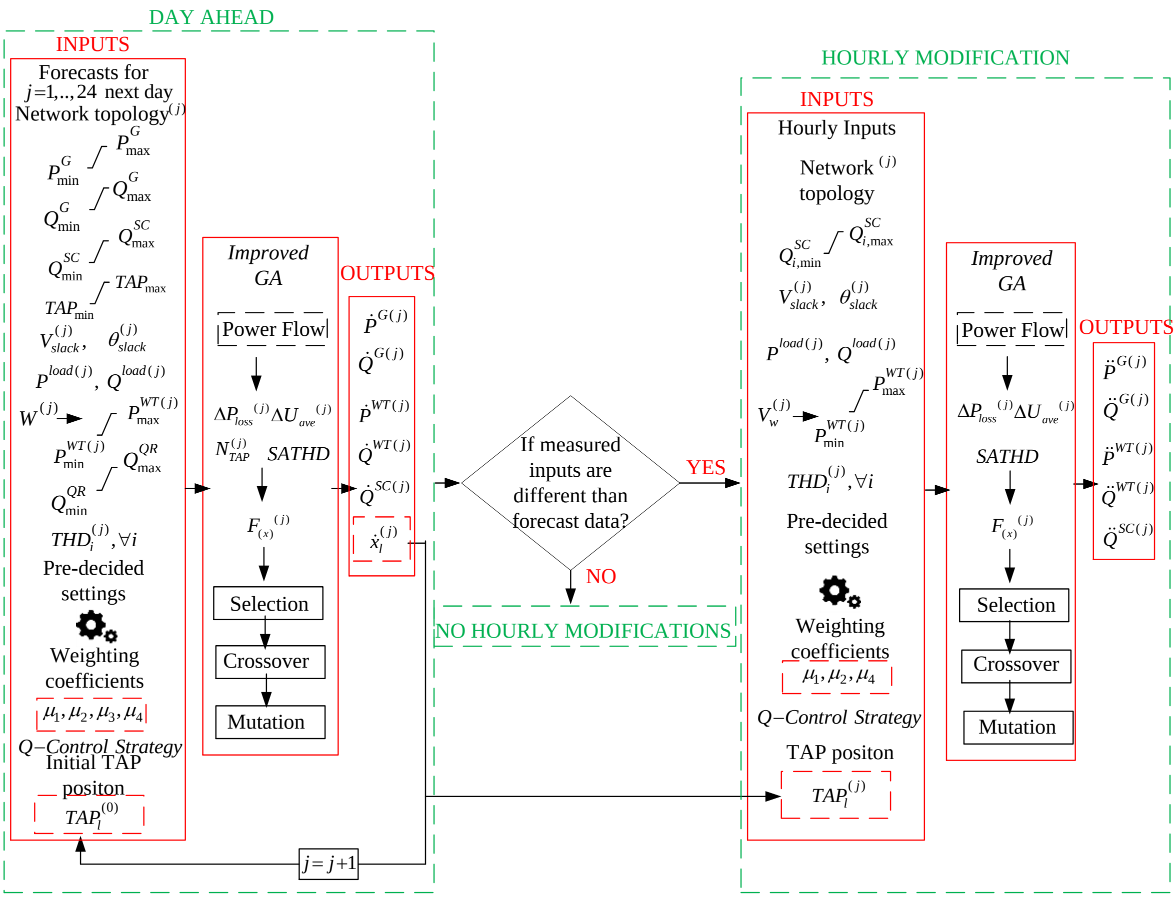


Figure 5-4 Block diagram of the proposed ORPD strategy

As aforementioned, the proposed new ORPD strategy has been formulated as a mixed-integer, multi-variable, multi-constraints, non-convex problem. To solve this multi-objective function of the ORPD problem, a considerable number of works have been carried out on this topic. About the available solvers, a brief introduction of both analytical methods and heuristic algorithms has been given in Chapter 3. The improved genetic algorithm used in the previous Chapter has already shown its superiority on single-objective problems. However, in the multi-objective optimisation problem, the biggest problem is how to determine the fitness of each individual. Multi-objective optimisation also known as Pareto optimisation involves multi-objective functions. The NSGA-II algorithm was proposed by [31] on the basis of GA which is ideal for constrained multi-objective optimisation problems like power system optimisation. Furthermore, it has been significantly improved and made more computationally efficient by involving parent inheritance in [32]. To further improve the GA speed, when making selections, the roulette selection algorithm [33] is applied. These two adjustments contributed to the efficacy of the entire optimisation, what is particularly important in real-time application i.e. hourly modifications, in which a large number of variables have to be simultaneously processed.

After applying this improved genetic algorithm to the proposed objective functions, the output of this new ORPD strategy will be settings for available control variables in the power system to achieve all objectives considered, i.e. minimising power losses, voltage deviations, operation times of OLTCs and total harmonic distortions. The proposed new strategy is tested using networks of different complexity and nature. Simulation results are given in the next section.

5.3.5 **Simulation**

To test the proposed ORPD strategy, two distribution systems (IEEE 33-bus and PG&E 69-bus systems) and one transmission system (modified GB network) are used. Each test system has been extended with OLTCs (with a switchable range from 0.9 to 1.1) and WTs (penetration level up to 50%). Reactive power compensation existed in all test systems. About the flexible demand, to ensure the profit of the customer side, it is assumed that the load demands in deterministic power system optimisation should be met as far as possible. So the comparison study has been done between scenarios of using flexible demand as one of the control variables or not.

When applying the improved GA, the crossover and mutation probability were respectively 0.8 and 0.3 [128]. It is also assumed that differences between inputs for both day-ahead and hourly optimisations obey Normal distribution [164], [185].

5.3.5.1 **Weighting coefficients settings**

In the optimal reactive power dispatch problem, the proposed multi-objective function required appropriate selection of weighting coefficients to sort four objectives. So there are three different groups of settings defined first (see Chapter 8.4 - Appendix D Table 8-4). Here setting 1 is used for testing of all test systems, while settings 2 and 3 are used for testing PG&E 69-bus system as comparison study.

5.3.5.2 **Test on IEEE 33-bus system**

In this Subsection, the modified IEEE 33-bus system shown in Figure 5-5 is again used to test feasibility of the proposed improved genetic algorithm for multi-objective function and to provide hourly optimised reactive power dispatch results. Then it is also used to demonstrate the application of the two different Q-control strategies based on equation (88) and (89) respectively. Here the system modification is referred to the inclusion of WT, flexible demand and shunt capacitors. Unlike the tests for reactive power procurement strategy proposed in Chapter 4, contingencies or outages are not considered in the proposed reactive power dispatch strategy. So the system topology is assumed as already known which means tie switches do not exist in the test systems. Then the single line diagram of the modified IEEE 33-bus system used in this section is shown in Figure 5-5.

As a note, in the proposed ORPD strategy, distribution system power flows are used for obtaining electrical quantities necessary for objective function and constraints.

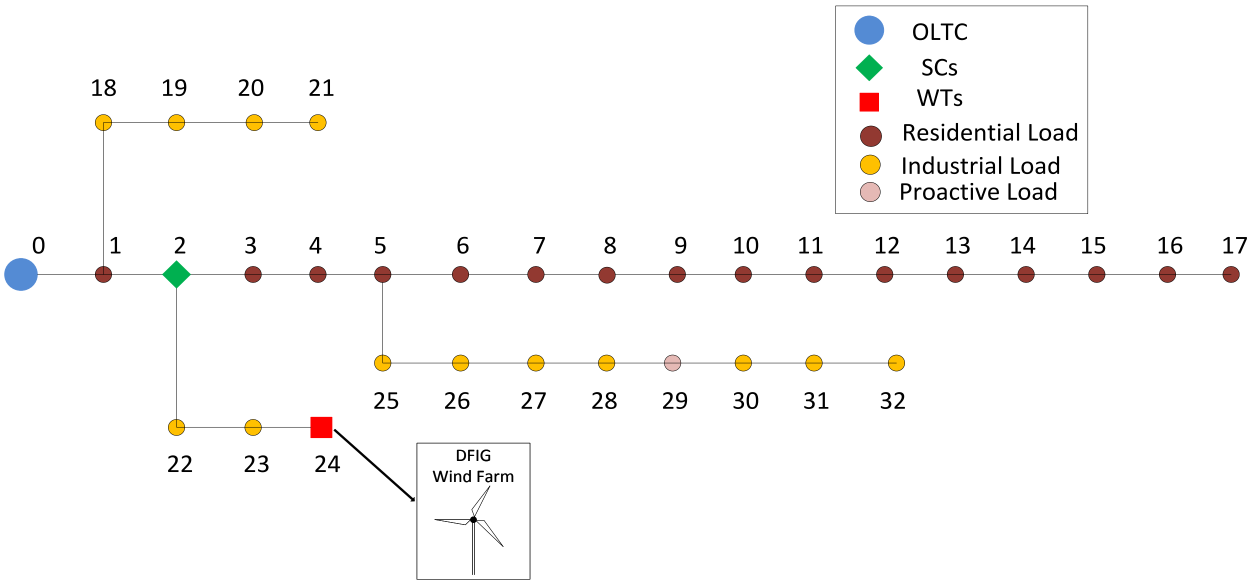


Figure 5-5 Single line diagram of the modified IEEE 33-bus distribution system for ORPD testing

- Comparison between improved GA and conventional GA

The proposed improved genetic algorithm has already shown its priority in solving single objective problem as shown in Chapter 4, however, its application to multi-objective problems still need to be approved. So to test the accuracy and convergence of the proposed improved GA to solve multi-objective problems, it is compared with the conventional GA and a classical solver, i.e. branch and bound algorithm. In Figure 5-6 the convergence characteristic curves for both conventional and improved genetic algorithms are given. *Setting 1* is used for weighting coefficients (see Table 8-4). As a heuristic search algorithm, genetic algorithm may have different contingency route in each run. Therefore, randomly selected 5 curves out of 100 times of different simulations, in which the population size, N_P, was 50, are presented in Figure 5-6 to demonstrate the improved GA family of curves. The forecasted WT output active power limit and the load demand are both assumed to be 1 p.u. The WT reactive output power limit was calculated according to the *Q-control strategy 2*. The reactive power capacities of grid connection point, wind farm and shunt capacitor are set to be within the calculated results from reactive power procurement strategy proposed in Chapter 4. Flexible demand is not used in this comparison study.

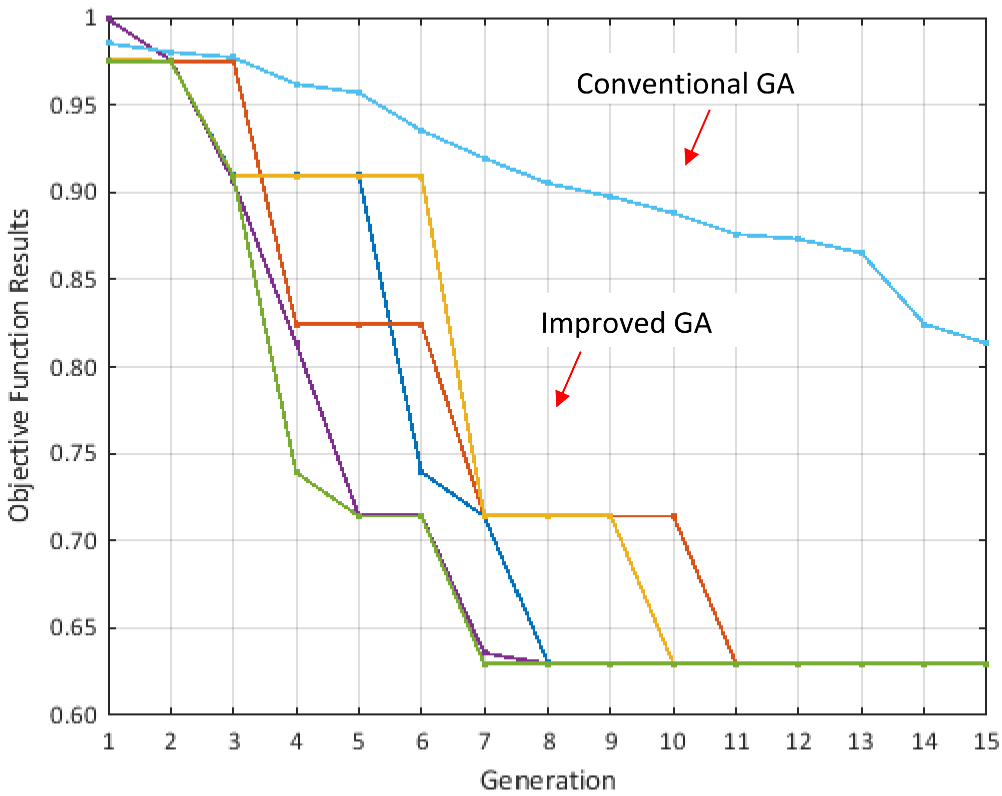


Figure 5-6 Adaptive convergence characteristic curves

As can be seen in Figure 5-6, the proposed improved genetic algorithm: i) always converges to the same optimal point for which the adaptive value of the proposed objective function equals to 0.62954, ii) always converges within less than 15 generations. Under the same situation, the conventional genetic algorithm requires much more generations to achieve the similar optimal results. When considering hourly modifications in real networks with higher complexity and more control variables, it is critical important to minimise calculation time in order to against forecast errors. So the improvements of the proposed solver are essentially necessary compared with conventional genetic algorithm.

In Table 5-1 the outputs obtained by both improved and conventional genetic algorithms are shown. All settings and objectives are within the system limits and the calculated reserved value from the proposed reactive power procurement plans. As can be seen, the differences in results obtained by both algorithms are very small. It can be concluded that for a faster speed the accuracy of improved genetic algorithm has not been compromised.

Table 5-1 Comparison between improved GA and conventional GA

Results	Improved GA	Conventional GA	Difference (%)
TAP	1.0024	1.0025	0.01%
Q^{SC}	0.4612MVAr	0.4619MVAr	0.01%
P^{WT}	3.6315MW	3.6312MW	0.02%
Q^{WT}	1.2735MVAr	1.2732MVAr	0.02%
ΔU_{ave}	0.0366p.u.	0.0363p.u.	0.8%
ΔP_{loss}	1.6137MW	1.6134MW	0.01%
SATHD	0.23965%	0.23961%	0.02%
$F(x)$	0.62954	0.62942	0.02%
Calculation Time	120.266s	302.134s	181.868s

Additionally, as both the conventional and improved genetic algorithms are meta-heuristic search algorithms, to further prove the feasibility of these kinds of algorithms, the proposed solver has also been compared with one of the classical method, i.e. branch and bound method.

Table 5-2 Comparison between the proposed solver and branch and bound method

Results	Improved GA	Branch and Bound Method	Difference
ΔU_{ave}	0.0366p.u.	0.0362p.u.	1%
ΔP_{loss}	1.6137MW	1.6131MW	0.01%
SATHD	0.23965%	0.23961%	0.02%
$F(x)$	0.62954	0.6294	0.02%
Calculation Time	120.266s	578.278s	458.012s

As can be seen from the calculation results shown in Table 5-2, all objectives are within the pre-set limits. From the comparison, the differences in results obtained by both genetic algorithm and branch and bound method are very small. It can be concluded that as one of the meta-heuristic search algorithms, the improved genetic algorithm will solve the multi-objective problem with a faster speed but the accuracy has not been compromised.

- **Optimisation results of each hour**

Optimisation results of each hour for the IEEE 33-bus test system under scenarios with or without flexible demand as one of the control variables are provided. Within each scenario, results are also provided under two different *Q-control strategies* based on (88) and (89) respectively.

As for the hourly modifications, considering the worst situation, the forecast errors are simulated in the case when load demand increases to the upper limit and WT output decreases to the lower limit which are ±10% respectively. So it is assumed hourly modifications have been performed for every hour.

Firstly, the scenario that flexible demand is not considered as one of the control variables has been simulated. Based on these inputs for both time scales, two *Q-control strategies* with different reactive power limits of DFIG are simulated. Weighting coefficients defined through *setting 1* (see Table 8-4) are used.

The *Q-control strategy 1* defines the output reactive power limits as ± 0.95 power factor set by FERC order 661-A, where the reactive limits are defined by the active power output in equation (88). By this, 24 hours histogram of calculated results is shown in Figure 5-7. The settings of each control variable in 24 hours have been shown separately.

The *Q-control strategy 2* uses DFIG's maximum output reactive power capability that can be extended based on (89). Under this constraint, the reactive power capability is limited by the total apparent power output. The calculation results histogram for *Q-control strategy 2* is shown in Figure 5-8. Again, the settings of each control variable in 24 hours have been shown separately.

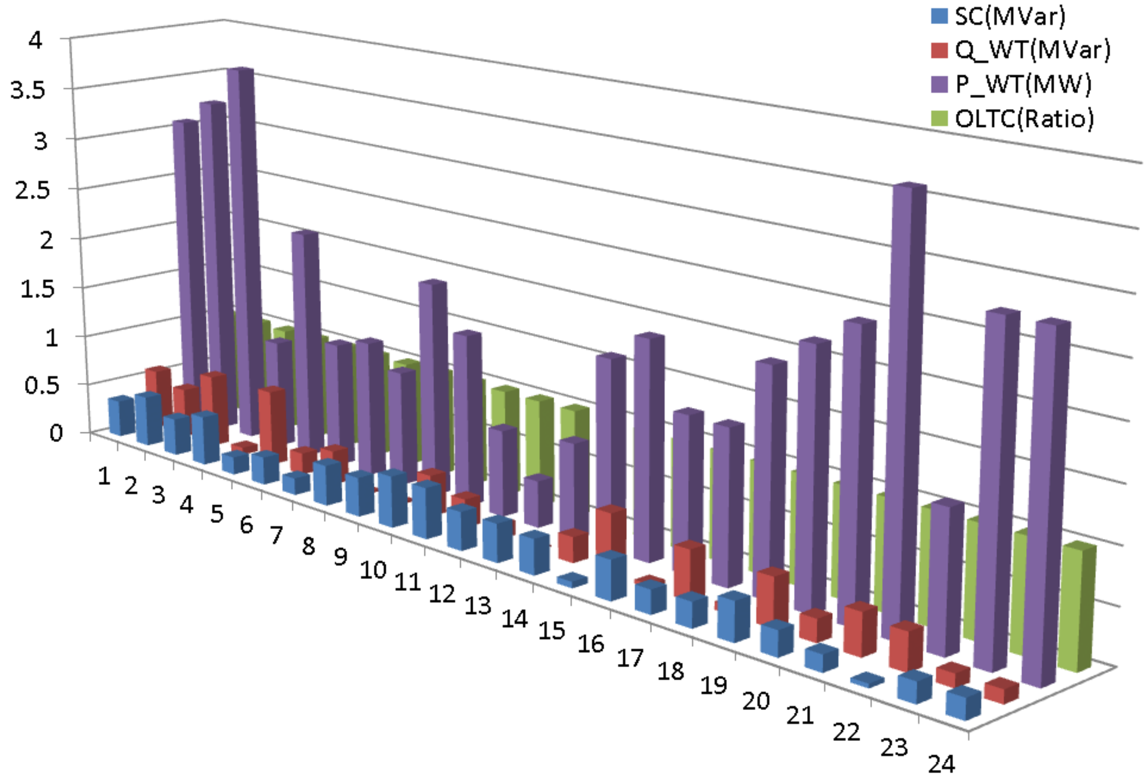


Figure 5-7 Result of ORPD obtained with *Q-control strategy 1* for IEEE 33-bus system without flexible demand

The exact optimal data with *Q-control strategy 1* for all control variables of 24 hours are shown in Table 5-3.

Table 5-3 Results of ORPD obtained with *Q-control strategy 1* for IEEE 33-bus system without considering flexible demand

Time	**1**	**2**	**3**	**4**	**5**	**6**
Q^{SC} (MVAr)	0.35815	0.48036	0.35815	0.47451	0.16915	0.26575
OLTC (Ratio)	1.0006	1.0003	1.0006	1.0002	1.0007	1.0005
P^{WT} (MW)	3.0711	3.3137	3.7001	1.043	2.2077	1.19
Q^{WT} (MVAr)	0.57913	0.47705	0.69774	0.071179	0.72563	0.20807

Time	**7**	**8**	**9**	**10**	**11**	**12**
Q^{SC} (MVAr)	0.16056	0.38392	0.36893	0.48298	0.47712	0.36048
OLTC (Ratio)	1.0005	1.0006	1.0001	1.0005	1.0002	1.0001
P^{WT} (MW)	1.2933	1.0898	2.0212	1.6184	0.81052	0.43637
Q^{WT} (MVAr)	0.32414	0.020716	0.028224	0.38792	0.26641	0.13702
Time	**13**	**14**	**15**	**16**	**17**	**18**
Q^{SC} (MVAr)	0.36016	0.32997	0.058968	0.36757	0.22147	0.23342
OLTC (Ratio)	1.0008	1.0008	1.0006	1.0005	1.0004	1.0001
P^{WT} (MW)	0.88576	1.7463	2.0108	1.4293	1.4163	2.0415
Q^{WT} (MVAr)	0.010984	0.23798	0.56038	0.034136	0.45668	0.073692
Time	**19**	**20**	**21**	**22**	**23**	**24**
Q^{SC} (MVAr)	0.35757	0.23169	0.15318	0.03933	0.18565	0.18565
OLTC (Ratio)	1.0004	1.0001	1.0016	1.0001	1.0006	1.0006
P^{WT} (MW)	2.3028	2.5477	3.7058	1.2464	2.8657	2.8657
Q^{WT} (MVAr)	0.44722	0.20724	0.38408	0.34161	0.12282	0.12282

In addition, the optimal settings of all control variables in histogram by utilizing *Q-control strategy 2* are shown in Figure 5-8.

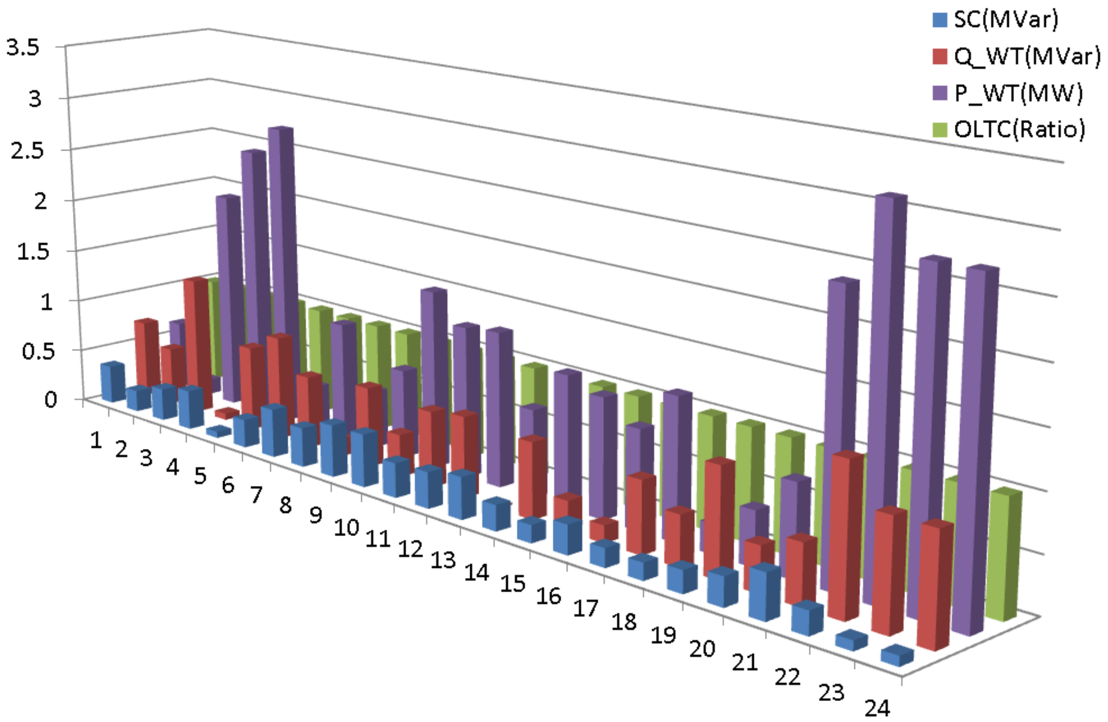


Figure 5-8 Result of ORPD obtained with *Q-control strategy 2* for IEEE 33-bus system without flexible demand

The optimal settings with *Q-control strategy 2* for WT for all control variables of 24 hours are shown in Table 5-4.

Table 5-4 Results of ORPD obtained with *Q-control strategy 2* for IEEE 33-bus system without considering flexible demand

Time	**1**	**2**	**3**	**4**	**5**	**6**
Q^{SC} (MVAr)	0.3637	0.20146	0.30221	0.36757	0.058968	0.26171
OLTC (Ratio)	1.0001	1.0004	1.0004	1.0005	1.0006	1.0001
P^{WT} (MW)	0.64098	0.14365	2.0429	2.5411	2.8151	0.41053
Q^{WT} (MVAr)	0.72559	0.5371	1.2908	0.060686	0.78454	0.95907
Time	**7**	**8**	**9**	**10**	**11**	**12**
Q^{SC} (MVAr)	0.44708	0.36048	0.47712	0.48298	0.31408	0.32864
OLTC (Ratio)	1.0005	1.0001	1.0002	1.0005	1.0006	1.0001
P^{WT} (MW)	1.0864	0.53334	0.81052	1.6184	1.368	1.4024
Q^{WT} (MVAr)	0.66807	0.16747	0.73377	0.38792	0.68829	0.73254
Time	**13**	**14**	**15**	**16**	**17**	**18**

Q^{SC} (MVAr)	0.38191	0.23326	0.16056	0.26575	0.16915	0.15372
OLTC (Ratio)	1.0006	1.0005	1.0005	1.0005	1.0007	1.0003
P^{WT} (MW)	0.79255	1.1876	1.0777	0.89248	1.2615	0.26474
Q^{WT} (MVAr)	0.015066	0.68727	0.27012	0.15606	0.64457	0.4518
Time	**19**	**20**	**21**	**22**	**23**	**24**
Q^{SC} (MVAr)	0.19883	0.25746	0.39812	0.20672	0.086847	0.086847
OLTC (Ratio)	1.0005	1.0003	1.0003	1.0001	1.0001	1.0001
P^{WT} (MW)	0.48664	0.81992	2.4863	3.2	2.7902	2.7902
Q^{WT} (MVAr)	0.95856	0.4019	0.53088	1.2899	0.95086	0.95086

In addition, the scenario that flexible demand is considered as one of the control variables has also been simulated. Based on the inputs for both day-ahead and hourly time scales, two *Q-control strategies* with different reactive power limits of DFIG are simulated. Weighting coefficients defined through *setting 1* (in Table 8-4) are used.

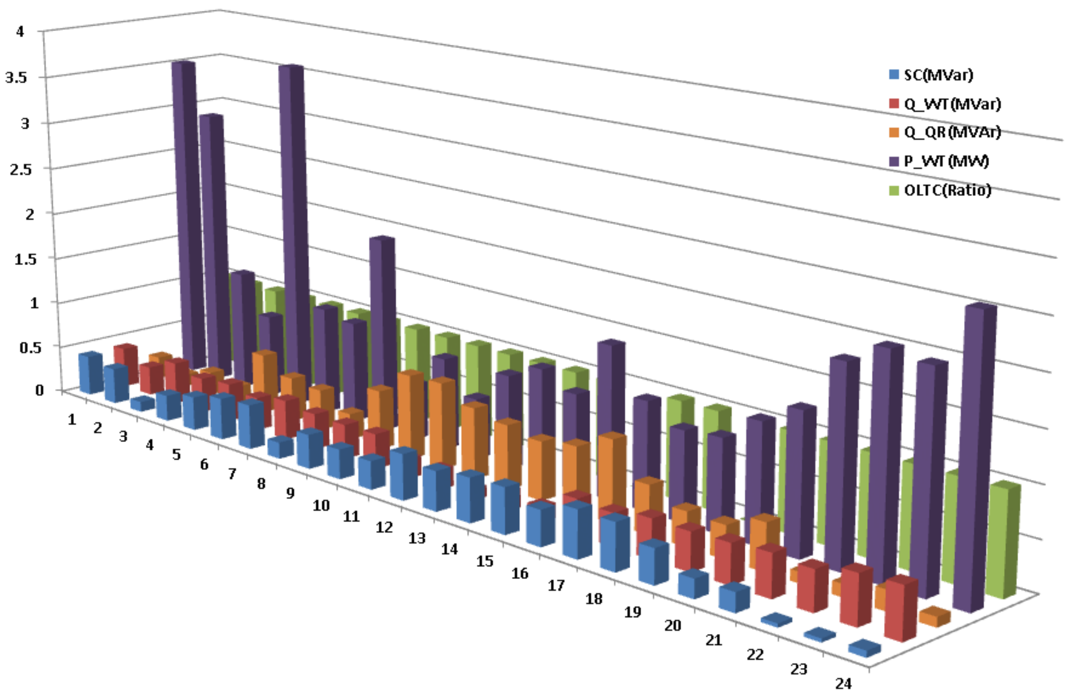


Figure 5-9 Result of ORPD obtained with *Q-control strategy 2* for IEEE 33-bus system with flexible demand

The optimal settings with *Q-control strategy 2* for WT for all control variables of 24 hours are shown in Table 5-5.

Table 5-5 Results of ORPD obtained with *Q-control strategy 2* for IEEE 33-bus system considering flexible demand

Time	**1**	**2**	**3**	**4**	**5**	**6**
Q^{SC} (MVAr)	0.4269	0.38027	0.10812	0.2733	0.35283	0.43438
Q^{WT} (MVAr)	0.4269	0.30721	0.4448	0.3662	0.3988	0.3469
OLTC (Ratio)	1.0003	1.0006	1.0005	1.0005	1.0001	1.0005
P^{WT} (MW)	3.5125	2.9754	1.2728	0.87544	3.6798	1.1309
Q^{QR} (MVAr)	0.2363	0.1292	0.24596	0.18491	0.62611	0.46453
Time	**7**	**8**	**9**	**10**	**11**	**12**
Q^{SC} (MVAr)	0.4646	0.17003	0.35451	0.30597	0.29221	0.470687
Q^{WT} (MVAr)	0.4122	0.3708	0.35751	0.3617	0.2077	0.2036
OLTC (Ratio)	1.0003	1.0001	1.0005	1.0003	1.0002	1.0002
P^{WT} (MW)	1.0623	2.0401	0.58807	0.9512	0.62454	0.9641
Q^{QR} (MVAr)	0.42889	0.27095	0.6128	0.87184	0.88876	0.72973
Time	**13**	**14**	**15**	**16**	**17**	**18**
Q^{SC} (MVAr)	0.40674	0.45087	0.46804	0.36094	0.4801	0.47532
Q^{WT} (MVAr)	0.1146	0.2001	0.1631	0.35624	0.3312	0.39382
OLTC (Ratio)	1.0007	1.0004	0.0001	1.0001	1.0003	0.0001
P^{WT} (MW)	1.1272	0.97	1.54917	1.0984	0.9123	0.9425
Q^{QR} (MVAr)	0.65837	0.59551	0.65068	0.825	0.49088	0.34597
Time	**19**	**20**	**21**	**22**	**23**	**24**
Q^{SC} (MVAr)	0.3493	0.19041	0.19203	0.03789	0.03665	0.062631
Q^{WT} (MVAr)	0.38591	0.3979	0.4259	0.3996	0.48663	0.5062
OLTC (Ratio)	1.0003	1.0001	1.0007	1.0004	1.0005	1.0001
P^{WT} (MW)	1.2021	1.4064	1.9487	2.1552	2.0984	2.6713
Q^{QR} (MVAr)	0.3307	0.4712	0.1093	0.1259	0.1994	0.0971

In addition, the optimal settings of all control variables in histogram by utilizing Q-control strategy 2 are shown in Figure 5-10.

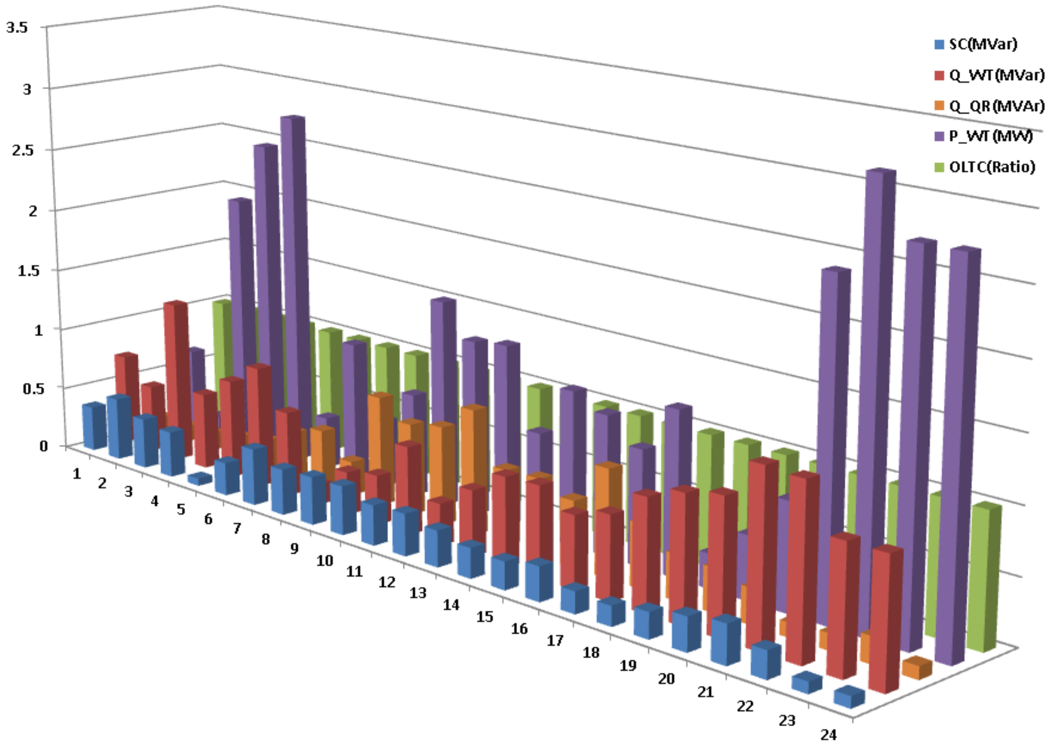


Figure 5-10 Result of ORPD obtained with *Q-control strategy 2* for IEEE 33-bus system with flexible demand

The optimal settings with Q-control strategy 2 for WT for all control variables of 24 hours are shown in Table 5-6.

Table 5-6 Results of ORPD obtained with *Q-control strategy 2* for IEEE 33-bus system considering flexible demand

Time	**1**	**2**	**3**	**4**	**5**	**6**
Q^{SC} (MVAr)	0.3637	0.50146	0.40221	0.36757	0.058968	0.26171
Q^{WT} (MVAr)	0.72559	0.5371	1.2908	0.60686	0.78454	0.95907
OLTC (Ratio)	1.0001	1.0004	1.0004	1.0005	1.0006	1.0001
P^{WT} (MW)	0.64098	0.14365	2.0429	2.5411	2.8151	0.41053
Q^{QR} (MVAr)	0.1363	0.1292	0.14596	0.18491	0.22611	0.36453
Time	**7**	**8**	**9**	**10**	**11**	**12**
Q^{SC} (MVAr)	0.44708	0.36048	0.37712	0.38298	0.31408	0.32864
Q^{WT} (MVAr)	0.66807	0.16747	0.3377	0.38792	0.68829	0.3254
OLTC (Ratio)	1.0005	1.0001	1.0002	1.0005	1.0006	1.0001
P^{WT} (MW)	1.0864	0.53334	0.81052	1.6184	1.368	1.4024

Q^{QR} (MVAr)	0.4489	0.27095	0.86128	0.7184	0.76876	0.9732
Time	**13**	**14**	**15**	**16**	**17**	**18**
Q^{SC} (MVAr)	0.28191	0.23326	0.216056	0.26575	0.16915	0.15372
Q^{WT} (MVAr)	0.5066	0.68727	0.7012	0.5606	0.64457	0.8518
OLTC (Ratio)	1.0006	1.0005	1.0005	1.0005	1.0007	1.0003
P^{WT} (MW)	0.79255	1.1876	1.0777	0.89248	1.2615	0.26474
Q^{QR} (MVAr)	0.5837	0.5951	0.5068	0.825	0.49088	0.34597
Time	**19**	**20**	**21**	**22**	**23**	**24**
Q^{SC} (MVAr)	0.19883	0.25746	0.29812	0.20672	0.086847	0.086847
Q^{WT} (MVAr)	0.95856	1.019	1.3088	1.2899	0.95086	0.95086
OLTC (Ratio)	1.0005	1.0003	1.0003	1.0001	1.0001	1.0001
P^{WT} (MW)	0.48664	0.81992	2.4863	3.2	2.7902	2.7902
Q^{QR} (MVAr)	0.3307	0.2712	0.1093	0.1259	0.1994	0.0971

From the results obtained, it can be concluded that: i) output results for all control variables and each of four criteria are within power system constraints; ii) comparing WT reactive power outputs in Figure 5-7 and Figure 5-8, it can be seen that more reactive power compensation will be made by WT when *Q-control strategy 2* is applied to DFIG; iii) for both *Q-control strategies*, the optimisation results of WT output active power are changing similarly to typical wind power prediction curve shown in Figure 4-7. For instance, at night, the forecasted WT output active power capability is higher and, in the optimisation results, the WT output active power is relatively high. Hence, the proposed ORPD strategy has made full use of the renewable energy resources and has provided reasonable results for each hour considering system operation nature.

As can be seen from the comparison study between the test with or without considering flexible demand as one of the control variables, by adding one extra reactive power provider, all four criteria have been further improved. And the outputs of other reactive power providers have accordingly reduced. This shows the

5.3.5.3 **Testing using PG&E 69-bus system**

In this Subsection, the modified PG&E 69-bus system is again used to test feasibility of the proposed improved genetic algorithm for multi-objective function and to provide hourly optimised reactive power dispatch results. Here the system modification is referred to the inclusion of WT, flexible demand and shunt capacitors. *Q-control strategy 2* based on (89) has been used as the reactive power limits of the wind turbines integrated into this test system. In addition, unlike the tests for reactive power procurement strategy proposed in Chapter 4, contingencies or outages are not considered in the proposed reactive power dispatch strategy. So the system topology is assumed as already known which means tie switches do not exist in the test systems. Then the single line diagram of the modified PG&E 69-bus system used in this section is shown in Figure 5-11.

As a note, in the proposed ORPD strategy, distribution system power flows are used for obtaining electrical quantities necessary for objective function and constraints.

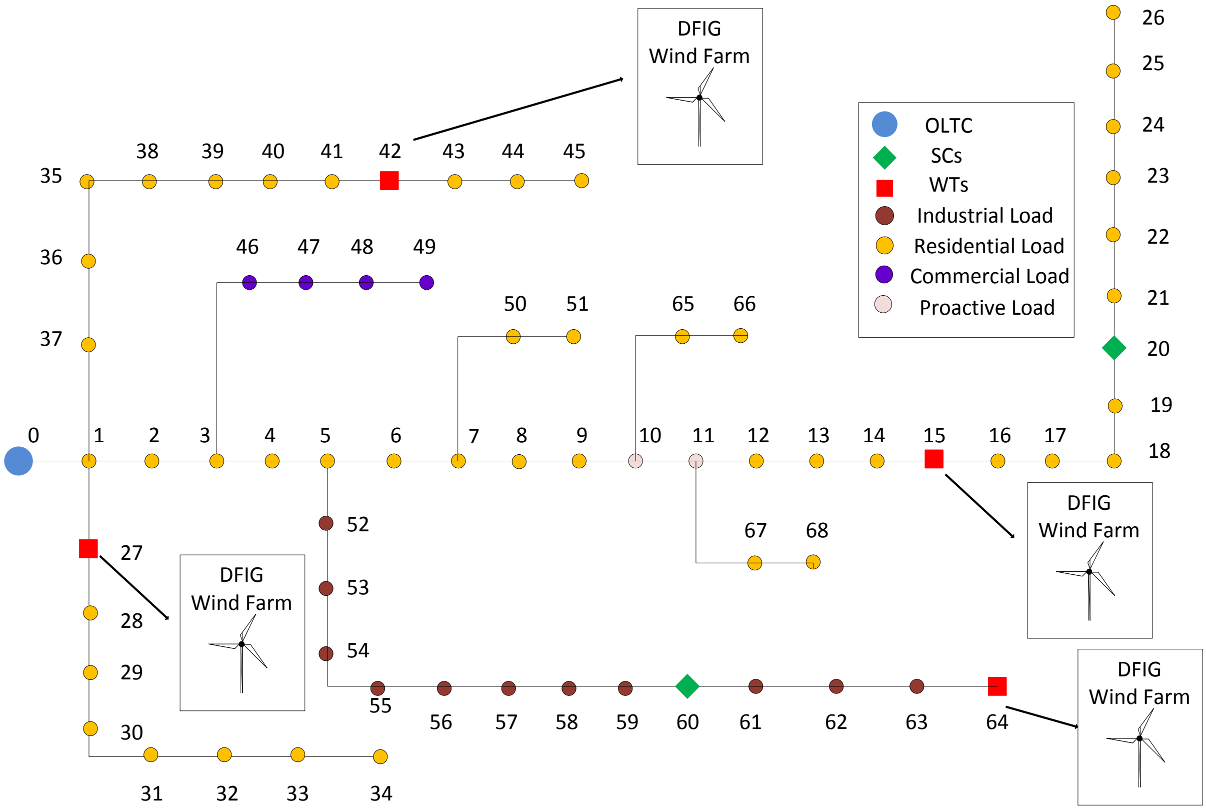


Figure 5-11 Topology of modified PG&E 69-bus distribution system

Firstly, weighting coefficients are varied to analyse the sensitivity of four criteria and objective function to changes in importance of each criterion. In addition, each hour optimisation is performed using typical load demand and WT active power prediction curves (Figure 4-7), followed by hourly modifications.

- Sensitivity study to the selection of weighting coefficients

To test the sensitivity of each criterion in the proposed ORPD strategy, different settings of weighting coefficients have been simulated separately (see Table 8-4). Data at 1AM are used for comparison between different scenarios. Additionally, the test results have been compared with results provided in [101]. All the results are summarized in Table 5-7.

Table 5-7 Optimisation results for PG&E 69-bus system with different weighting coefficients settings

Scenarios	$F(x)$	ΔP_{loss} (%)	ΔU_{ave} (p.u.)	N_{TAP}	$SATHD$ (%)
Setting 1	0.5776	2.62	0.06263	0	1.79
Setting 2	0.5829	2.63	0.06143	0.0005	1.81
Setting 3	0.5674	2.62	0.06076	0	3.42
Results [101]	NA	2.82	0.08880	0	NA

In case of the proposed ORPD strategy (first three rows), it can be seen that the optimal results for the multi-objective function are similar for different scenarios. However, with different settings of weighting coefficients, each single criterion has different optimisation result. With higher weighting coefficient, the criterion will be further optimised. In real system, this setting should be selected based on the system operation priority. In this paper, *setting 1* of weighting coefficients is chosen to do later simulations. The optimisation strategy given in [101] considers only two criteria which are power losses and voltage deviation. When comparing the ORPD strategy with the one given in [101], the proposed strategy achieves better results for both criteria. This shows the priority of the new strategy.

- Optimisation results of each hour

For each hour optimisation, both day-ahead and hourly modifications have been simulated. Firstly, the results are shown for every four hours in Table 5-8 without considering flexible demand as one of the control variables. From the simulation results, the calculation time is within 4 mins for each hour, which is faster than reference [99] that also uses GA based approach for solving their objective function. For day-ahead optimisation, typical load demand and WT active power prediction curves are used. For hourly modifications, considering the worst situation, they are simulated in the case when load demand increases to the upper limit and WT output decreases to the lower limit. Under this situation, the proposed strategy can still achieve hourly modifications with optimal results for all criteria by finishing calculations within 4 minutes. This shows the feasibility to apply the proposed ORPD strategy into real systems.

Table 5-8 Optimisation results for PG&E 69-bus system at different times of a day without considering flexible demand

Time		Adaptive Value	Network Loss (%)	Voltage Deviation (p.u.)	OLTC Ratio	*SATHD* (%)	Calculation Time (s)
1:00 AM	DA	0.5719	2.62	0.06147	1.0005	1.78	180.622
	HM	0.5776	2.62	0.06263	1.0005	1.79	180.262
2:00 AM	DA	0.59208	2.92	0.07033	1.0005	1.93	185.171s
	HM	0.5946	2.92	0.06998	1.0005	2.12	184.453
3:00 AM	DA	0.63303	3.11	0.06981	1.0005	2.15	182.262s
	HM	0.63614	3.11	0.07088	1.0005	2.18	181.899
4:00 AM	DA	0.55007	2.71	0.07023	1.0005	1.72	179.625s
	HM	0.57207	2.73	0.07023	1.0005	1.92	177.786
5:00 AM	DA	0.5948	2.40	0.07405	1.0005	1.50	184.673
	HM	0.6029	2.40	0.07843	1.0005	1.59	180.416
6:00 AM	DA	0.43945	2.03	0.07395	1.0005	1.29	186.691s
	HM	0.45099	2.03	0.06935	1.0005	1.41	184.352
7:00 AM	DA	0.42489	1.89	0.06843	1.0005	1.29	186.416s
	HM	0.44003	1.89	0.06978	1.0005	1.44	183.673
8:00 AM	DA	0.38845	1.64	0.06399	1.0005	1.18	192.651s
	HM	0.39854	1.63	0.06489	1.0005	1.29	188.672
9:00 AM	DA	0.4274	1.52	0.06253	1.0004	1.07	194.524
	HM	0.4287	1.58	0.06976	1.0004	1.09	189.36
10:00:AM	DA	0.34313	1.41	0.06078	1.0005	0.96	190.228s
	HM	0.35944	1.41	0.06393	1.0005	1.12	189.562
11:00:AM	DA	0.36113	1.48	0.06076	1.0005	1.07	189.360s
	HM	0.37119	1.48	0.06137	1.0005	1.17	187.672
12:00:PM	DA	0.34023	1.38	0.06179	1.0005	0.96	194.897s

	HM	0.35024	1.38	0.06188	1.0005	1.06	192.37
1:00 PM	DA	0.4264	1.30	0.07735	1.0004	0.81	190.86
	HM	0.4293	1.35	0.07919	1.0004	0.86	184.539
2:00 PM	DA	0.34213	1.39	0.0708	1.0005	0.96	192.552s
	HM	0.35019	1.41	0.07137	1.0005	1.02	190.672
3:00 PM	DA	0.35897	1.45	0.06919	1.0005	1.07	194.539s
	HM	0.37204	1.46	0.06992	1.0005	1.19	194.566
4:00 PM	DA	0.33505	1.32	0.06995	1.0005	0.96	190.398s
	HM	0.35506	1.32	0.07012	1.0005	1.16	192.452
5:00 PM	DA	0.4045	1.22	0.06318	1.0004	0.95	192.797
	HM	0.406	1.27	0.06358	1.0004	0.94	189.157
6:00 PM	DA	0.36788	1.44	0.06831	1.0005	1.17	200.510s
	HM	0.37397	1.46	0.06924	1.0005	1.21	189.263
7:00 PM	DA	0.40111	1.57	0.06058	1.0005	1.38	219.157s
	HM	0.4059	1.57	0.06849	1.0005	1.42	187.562
8:00 PM	DA	0.4421	1.76	0.07048	1.0005	1.59	188.662s
	HM	0.44931	1.76	0.07256	1.0005	1.66	178.243
9:00 PM	DA	0.5136	2.01	0.08236	1.0004	1.81	192.906
	HM	0.5487	2.05	0.08548	1.0004	1.82	184.773
10:00:PM	DA	0.48764	2.09	0.07588	1.0005	1.71	191.829s
	HM	0.50564	2.09	0.07593	1.0005	1.89	192.356
11:00:PM	DA	0.5389	2.50	0.06848	1.0005	1.82	184.773s
	HM	0.54796	2.52	0.06913	1.0005	1.89	185.256
12:00:AM	DA	0.54491	2.56	0.06862	1.0005	1.82	182.535s
	HM	0.55495	2.56	0.06899	1.0005	1.92	182.245

In addition, the scenario that flexible demand is considered as one of the control variables has also been simulated. Based on the inputs for both day-ahead and hourly time scales, different time optimisations with *Q-control strategy 2* as reactive power limits of DFIG are simulated.

Table 5-9 Optimisation results for PG&E 69-bus system at different times of a day considering flexible demand

Time		$F(x)$	ΔP_{loss} (%)	ΔU_{ave} (p.u.)	OLTC Ratio	*SATHD* (%)	Calculation Time (s)
1:00 AM	DA	0.5462	2.62	0.06191	1.0005	1.78	181.517
	HM	0.5463	2.62	0.06245	1.0005	1.78	180.789
2:00 AM	DA	0.5919	2.92	0.06826	1.0005	1.93	184.451
	HM	0.6110	2.92	0.06973	1.0005	2.12	186.758
3:00 AM	DA	0.6330	3.11	0.06984	1.0005	2.15	181.871
	HM	0.6341	3.11	0.07082	1.0005	2.16	182.356
4:00 AM	DA	0.5500	2.71	0.06967	1.0005	1.72	182.428
	HM	0.5710	2.72	0.06985	1.0005	1.92	179.554
5:00 AM	DA	0.4969	2.40	0.06812	1.0005	1.50	184.451
	HM	0.5031	2.40	0.07024	1.0005	1.56	185.672
6:00 AM	DA	0.4380	2.03	0.05984	1.0005	1.29	190.867
	HM	0.4501	2.03	0.06046	1.0005	1.41	190.782
7:00 AM	DA	0.4244	1.89	0.06395	1.0005	1.29	189.391
	HM	0.4375	1.89	0.06479	1.0005	1.42	175.562
8:00 AM	DA	0.3881	1.64	0.06087	1.0005	1.18	192.951
	HM	0.4042	1.69	0.06178	1.0005	1.29	188.672
9:00 AM	DA	0.3652	1.52	0.06195	1.0005	1.07	191.212
	HM	0.3679	1.52	0.06856	1.0005	1.09	178.726
10:00 AM	DA	0.3431	1.41	0.06042	1.0005	0.96	188.429
	HM	0.3572	1.41	0.06124	1.0005	1.10	186.782
11:00 AM	DA	0.3610	1.48	0.05908	1.0005	1.07	195.682
	HM	0.3701	1.48	0.06055	1.0005	1.16	189.892
12:00 PM	DA	0.3402	1.38	0.06156	1.0005	0.96	189.487
	HM	0.3502	1.38	0.06167	1.0005	1.06	189.887
1:00 PM	DA	0.3233	1.30	0.07231	1.0004	0.86	192.840
	HM	0.3299	1.36	0.07843	1.0004	0.86	190.897
2:00 PM	DA	0.3419	1.39	0.06818	1.0004	0.96	200.620
	HM	0.3490	1.41	0.06992	1.0004	1.01	196.245
3:00 PM	DA	0.3582	1.45	0.06196	1.0004	1.07	192.183

	HM	0.3688	1.46	0.06723	1.0004	1.16	189.672
4:00 PM	DA	0.3344	1.32	0.06321	1.0004	0.96	190.900
	HM	0.3476	1.32	0.06573	1.0004	1.09	190.967
5:00 PM	DA	0.3134	1.22	0.06387	1.0004	0.85	189.133
	HM	0.3264	1.26	0.06356	1.0004	0.94	187.356
6:00 PM	DA	0.3676	1.44	0.06598	1.0004	1.17	200.738
	HM	0.3728	1.46	0.06721	1.0004	1.20	198.672
7:00 PM	DA	0.4011	1.57	0.06015	1.0004	1.38	190.247
	HM	0.4028	1.57	0.06772	1.0004	1.39	187.654
8:00 PM	DA	0.4421	1.76	0.07041	1.0004	1.59	192.634
	HM	0.4432	1.76	0.07133	1.0004	1.60	189.342
9:00 PM	DA	0.4894	2.01	0.07381	1.0004	1.81	189.732
	HM	0.4936	2.04	0.07566	1.0004	1.82	186.563
10:00 PM	DA	0.4870	2.09	0.06934	1.0005	1.71	187.494
	HM	0.5061	2.09	0.07023	1.0005	1.90	177.563
11:00 PM	DA	0.5397	2.50	0.06693	1.0005	1.83	180.062
	HM	0.5449	2.52	0.06877	1.0005	1.86	180.892
12:00 PM	DA	0.5458	2.56	0.06707	1.0005	1.83	183.138
	HM	0.5518	2.56	0.06714	1.0005	1.89	182.235

All obtained results are within the limits and constraints. These simulation results have shown the feasibility to achieve the hourly modification considering forecast error within very short time. In addition, as can be seen from the comparison study between these two scenarios that with or without flexible demand as one of the control variables, with extra reactive power providers, the reactive power dispatch of the test system will be further optimised. This shows the feasibility of scheduled MVAr reduction in real power systems.

5.3.5.4 **Test on modified GB system**

Both IEEE 33 and PG&E 69-bus systems are distributions networks. To demonstrate the feasibility of the proposed ORPD strategy at the transmission level, the modified GB network with extensive involvement of control devices is used.

Considering of the WT output and load demand forecast errors, the presented hourly modification algorithm based on improved GA has been simulated in MATLAB and the power flow for this test network has been calculated using MATPOWER. Furthermore, the traditionally optimal power flow (OPF) calculation results are used as comparison to express the merits of this improved GA based solution. As for the basic settings of this GB network, the base capacity of is 10 MVA and there are 3 different reference voltages for different zones which are 132kV, 275kV and 400kV separately. The topology of the modified GB transmission network is shown in Figure 4-24.

Again, the day-ahead forecast data and hourly modifications are from National Grid ESO website [169]. The WT output and load demand hourly forecast with the estimated forecast errors have been shown in Figure 4-21. Considering the worst situation would happen, the WT output power will be set as the minimum value of the range and the load demand will be set as the maximum value of the range.

Within the limits calculated from reactive power procurement plans, the second-stage ORPD has been sorted out using weighting coefficients, *stetting 1* and *Q-control strategy 1* constraints for WTs. Simulated results of the optimisation objective function for 24 hours have been shown in Table 5-10.

Table 5-10 Optimisation objective function value results for GB modified network at three different times of a day

t	TRADITIONAL OPF		PROPOSED ORPD STRATEGY	
	Day Ahead	Hourly Modifications	Day Ahead	Hourly Modifications
1:00	0.182	0.1845	0.137	0.1375
2:00	0.182	0.18187	0.132	0.1323
3:00	0.182	0.18232	0.131	0.1324
4:00	0.181	0.18115	0.13	0.1315
5:00	0.179	0.18036	0.128	0.1287
6:00	0.179	0.17978	0.128	0.13
7:00	0.18	0.18017	0.131	0.1295
8:00	0.18	0.17946	0.13	0.1283

9:00	0.18	0.17894	0.128	0.1268
10:00	0.179	0.17928	0.127	0.1265
11:00	0.18	0.17895	0.128	0.1268
12:00	0.179	0.17919	0.127	0.1264
13:00	0.156	0.15611	0.133	0.133
14:00	0.179	0.179	0.127	0.1264
15:00	0.179	0.17928	0.128	0.1268
16:00	0.179	0.17936	0.127	0.1265
17:00	0.179	0.17899	0.126	0.1265
18:00	0.18	0.17975	0.128	0.1277
19:00	0.171	0.17238	0.131	0.1318
20:00	0.181	0.18072	0.129	0.1298
21:00	0.182	0.18163	0.13	0.1295
22:00	0.182	0.18123	0.131	0.1297
23:00	0.182	0.18175	0.132	0.1312
24:00	0.182	0.18177	0.132	0.1316

Comparing the traditional OPF simulation results and the proposed ORPD strategy simulation results for different hours of a day, it can be clearly concluded that the power system can be effectively optimised via the proposed ORPD strategy. Additionally, the calculation time for all hourly modification simulation cases is within 3 minutes. This means after using the day-ahead forecast data to set the initial settings for the involved control devices, hourly modifications based on real-time data can still be calculated within 3 minutes even the worst forecast errors happened. In addition, the detailed simulation results of all criteria and control variables are provided in Chapter 8.6 Appendix F – Table 8-10.

5.4 Chapter summary

In this Chapter, a new optimal reactive power dispatch (ORPD) strategy has been proposed in order to improve the steady state and long-term stability level in the wind power integrated systems. Pointing at a more comprehensive and better strategy compared with the existing strategies, i) a more comprehensive objective function is proposed to achieve multi-objective optimisation simultaneously and ii) more control variables are considered. Each of the considered objectives has been presented and formulated in Section 5.2. After that, the framework including two time scales i.e. day-ahead and hourly optimisations have been detailed. The objective functions and constraints for both day-ahead optimisation and hourly modifications have been presented in Section 5.3.

Then the proposed new ORPD strategy has been rigorously tested using IEEE 33-bus test system, PG&E 69-bus test system and modified real GB network. Results obtained confirmed the efficacy and applicability of the proposed strategy in both distribution and transmission networks.

6 Conclusion and future work

6.1 Thesis summary

With the hyper growth of renewable energy resources, the operation and optimization of the power systems are facing new challenges especially in the aspect of voltage stability and voltage control. As known, reactive power is highly related to voltage control. To operate power systems in a secure, economic and stable manner with large-scale renewable energy integration, reactive power optimization is one of the key measures to mitigate the risks of voltage fluctuations. Consequently, a proper and optimized reactive power ancillary service strategy considering unit commitment, economic and optimal reactive power dispatch in wind power integrated systems has been presented in this thesis. The simulation results have shown the accuracy and efficiency.

In this thesis, firstly, an overview of existing reactive power ancillary services and potential reactive power providers in modern power systems has been made. Additionally, in the case of power system deregulation, the pricing and procurement procedure of reactive power have been presented. After that, existing reactive power ancillary services optimization strategies have been discussed. A thorough literature review of the previous optimal reactive power procurement and dispatch strategies has been made.

Consequently, to address these aforementioned drawbacks and to ensure sufficient and optimized reactive power support, a proper optimal reactive power ancillary service strategy considering both a reactive power procurement plan and an optimal reactive power dispatch strategy has been proposed and thoroughly tested.

The reactive power procurement strategy has been considered as a day-ahead plan and the optimal reactive power dispatch strategy has two timescale, i.e. day-ahead and hourly modifications. The proposed reactive power procurement strategy has been considered as the pre-condition of the optimal reactive power dispatch strategy. The simulation results show that the whole reactive power ancillary service strategy can be applied to the energy management systems or distribution management systems cooperating with the data collection and data forecast systems to provide the optimal procurement plans and the optimal settings for all reactive power providers.

In the proposed reactive power procurement strategy, to minimize the total cost of reactive power ancillary services, a cost function conscientiously considering all potential reactive power providers has been established. In this planning stage, considering possible contingencies, outages and forecast errors of input data, a stochastic optimization framework has been used. To solve this stochastic optimization problem, a decision tree-structured solver has been employed. It includes all potential scenarios of the other day. For each scenario, it has been computed by an improved genetic algorithm. The output results of this reactive power procurement planning stage are the reserved reactive power amounts of all reactive power providers in the system, that is, the required reactive power to purchase from all the integrated synchronous generators, grid connection point, distributed generators, reactive power compositors and proactive loads in the other day. Compared with the previously published literatures, a more comprehensive and realistic cost function has been used for each reactive power provider. And all kinds of potential outages and contingencies have been considered to ensure secure and stable operations of power systems.

Then, the calculated results of reactive power procurement are used as calculation limits in the deterministic optimal reactive power dispatch strategy. In this reactive power dispatch strategy, a comprehensive multi-objective function has been established including a day-ahead optimization and its hourly modifications. In this stage, the active power loss, voltage deviation, operation times of OLTCs and wind farm harmonic distortion are considered to be minimized simultaneously in the day-ahead time scale. The objective function is more comprehensive compared with previously published literatures which normally only consider power loss or voltage deviations. In addition, considering the forecast errors of day-ahead input data, hourly modifications have also been carried out when the actual measured data are obviously different from the forecast data. There is a pre-set threshold value of forecast errors of wind power and load demand. If this threshold value is reached then the hourly modifications will be triggered. If not, then the outputs of the day-ahead optimization will be used directly on the other day without hourly modifications. Again, the proposed optimal reactive power dispatch problem has been solved by a proposed improved genetic algorithm.

This improved genetic algorithm is one of the meta-heuristic search algorithms which are a series of commonly used solvers for constrained mixed-integer, non-linear, non-convex, objective functions like the power system optimization problems. Compared with the conventional solvers of this kind of optimization problem, such as the branch and bound method, this kind of algorithm does not have the process of approximation or relaxation so that the approximation errors should not be introduced. In addition, the calculation time will be significantly reduced as the meta-heuristic search algorithms do not need to enumerate every possible solution. When selecting different kinds of solvers, it is important to consider the trade-off between the expected accuracy and the algorithm speed. However, the question to be answered was if the increased algorithm speed will jeopardise the algorithm accuracy. The proposed improved genetic algorithm by combining i-NSGA-II and roulette selection for solving the optimization problem significantly increases the convergence speed without compromising the algorithm accuracy. Using this meta-heuristic search algorithm to solve the proposed objective functions, this comprehensive optimal reactive power ancillary service strategy can be applied to both distribution and transmission networks in all complexity levels.

To prove the priority of the proposed strategy, both the optimal reactive power procurement plan and optimal reactive power dispatch strategy have been rigorously tested in both distribution and transmission networks, i.e. IEEE 33 bus system, PG&E 69 bus system and the modified GB network. After precisely testing using these two distribution networks and one transmission network, the proposed reactive power ancillary service strategy shows its superiority compared with the traditional reactive power optimization methods. In addition, the proposed improved genetic algorithm performs much better than conventional genetic algorithm and branch and bound method in convergence speed at the same time without reducing the calculation accuracy.

In conclusion, the main contributions of the proposed reactive power ancillary services strategy are listed as follow:

- It considers both the stochastic reactive power procurement strategy and the deterministic reactive power dispatch strategy simultaneously. Consequently, the reactive power ancillary service has been optimized from both economic and technical aspects.
- Both economic reactive power reserve and secure reactive power dispatch have been considered at the same time. This has ensured the final results of the proposed strategy is a more realistic plan for power system operators to take compared with previous literatures that only consider either economic or technical issue.

- Potential *N-1* security and forecast errors have been well thought out in making the reactive power procurement plans. This has ensured both economic and sufficient reactive power supply. In the previous literatures, outage of reactive power providers is not considered in day-ahead optimizations which will cause insufficient reactive power reserve for the other day.
- A more comprehensive objective function has been proposed for optimal reactive power dispatch aiming at minimizing i) active power losses, ii) voltage deviations, iii) operations of OLTCs and iv) system average total harmonic distortions. This has further ensured the power system to be operated in a stable manner compared with the previous strategies that only have one objective function.
- An improved genetic algorithm has been used as the solver for the proposed cost function and multi-objective function which has achieved a faster calculation speed at the same time without compromising the calculation accuracy. The comparison studies have been done which shows its priority compared with traditional methods.
- The simulation results have showed that the proposed reactive power ancillary services strategy can be applied in real distribution and transmission system energy management systems. This has been proved by the superior performances compared to previously published approaches in both distribution and transmission systems in the simulations sections.

6.2 **Future work**

The research work presented in this thesis has accomplished the majority of objectives defined for the research project. Nevertheless, there still exists space for improvements. In this section, further work stemming from this research project is proposed.

Both the proposed reactive power procurement plan and reactive power dispatch strategy have already been successfully applied to wind power integrated power systems. It can also be applied to other renewable energy resources integrated power systems such as photovoltaic. Energy storage system or even micro grid can also be considered as the research systems. The objective functions can be the same when applying these optimization strategies to other types of power systems. However, the power system constraints and logical constraints may need to be adjusted according to the potential reactive power providers in the research networks.

In addition, the proposed reactive power procurement plan is considered as a day-ahead plan. In real-life power systems, longer planning terms may also be needed for independent power system operators to design construction and establishment plans of new reactive power providers. However, when considering applying the proposed reactive power procurement plan to a longer time period, only *N-1* security may not be enough. Therefore, more contingency and outage scenarios should be considered. In addition, as currently there is actually no reactive power market in distribution networks, all the reactive power services are seen as obligatory in DSO at present. The proposed procurement strategy is designed for future electricity market. So if considering to apply the proposed procurement strategy in current distribution networks, the cost functions may need to be modified based on contracts between DSO and GENCOs.

And in the proposed reactive power dispatch strategy, only the operation times of OLTCs are considered to be minimized in this thesis. However, there are other vulnerable control devices in the power systems such as shunt reactors or capacitors. Although SRCs are much cheaper than OLTCs, their operation times may also need to be minimized. In addition, the ORPD can also be considered as a stochastic optimization problem because of the uncertainties of renewable energy and load demand. Additionally, to achieve a better voltage stability level, to minimise the system average voltage deviation has been considered as one criterion now. In the future, the voltage deviation on each bus bar could be also considered to ensure voltage stability level at each node of the system.

Therefore, it is worth proposing a reactive power procurement plan for a longer time period or for contract-based electricity market and an even more comprehensive optimal reactive power dispatch strategy that can be applied to wider situations.

7 Reference

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8 Appendices

8.1 Appendix A – Zonal price offers from reactive power providers

The zonal price offers from all reactive power providers used in the simulations of day-ahead reactive power procurement strategy are list below:

Table 8-1 Zonal price offers from reactive power providers

	$cost_F$	$cost_{MAr,1}$	$cost_{MAr,2}$	$cost_{MAr,3}$	$cost_{MAr,SR/SC}$	$cost_{MAr,QR}$
G	75$	40$/MVAr·h	40$/MVAr·h	20$/MVAr·h	NA	NA
DG	60$	30$/MVAr·h	15$/MVAr·h	30$/MVAr·h	NA	NA
SRC	50$	NA	NA	NA	20$/MVAr·h	NA
AL	40$	NA	NA	NA	NA	40$/MVAr·h

8.2 Appendix B - Reactive power zonal limits for each reactive power provider in distribution systems

The reactive power zonal limits for each reactive power provider in distribution systems i.e. IEEE 33-bus system and PG&E 69-bus system, used in the simulations of day-ahead reactive power procurement strategy are list below:

Table 8-2 Reactive power zonal limits for each reactive power provider in distribution systems

		$Q_{\min}$ (MVAr)	Q_M (MVAr)	Q_A (MVAr)	$Q_{\max}$ (MVAr)
G	33Bus	-20	[-10,10]	20	30
	69Bus	-200	[-10,10]	30	40
DG	33Bus	-10	0	$0.8\times Q_{DG,\max}(P_{\max})$	$Q_{DG,\max}(P_{\max})$
	69Bus	-15	0	$0.8\times Q_{DG,\max}(P_{\max})$	$Q_{DG,\max}(P_{\max})$
SRC	33Bus	-0.5	NA	NA	0.5
	69Bus	-0.5	NA	NA	0.5
AL	33Bus	0	NA	NA	6
	69Bus	0	NA	NA	1

8.3 Appendix C – Reactive power zonal limits for all reactive power providers in transmission systems

The reactive power zonal limits for each reactive power provider in transmission system i.e. modified GB network, used in the simulations of day-ahead reactive power procurement strategy are list below:

Table 8-3 Reactive power zonal limits for all reactive power providers in transmission systems

No.	**1**	**2**	**3**	**4**	**5**	**6**
$Q_{\min}$ (MVAr)	-626	0	-150	-147	0	-292
Q_M (MVAr)	0	0	NA	[-70,70]	0	0
Q_A (MVAr)	300	750	NA	110	220	150
$Q_{\max}$ (MVAr)	626	1535	150	147	460	292
Zone	1	1	1	2	2	3
Type	Hydro	WT	SVC	CCGT	WT	Hydro
No.	**7**	**8**	**9**	**10**	**11**	**12**

$Q_{\min}$ (MVAr)	0	-349	0	0	-76	-448
Q_M (MVAr)	0	[-170,170]	0	0	[-35,35]	[-220,220]
Q_A (MVAr)	0	250	90	600	50	350
$Q_{\max}$ (MVAr)	0	349	198	1291	76	448
Zone	3	5	5	6	7	7
Type	WT	Nuclear	WT	WT	CCGT	Nuclear
No.	**13**	**14**	**15**	**16**	**17**	**18**
$Q_{\min}$ (MVAr)	0	0	0	-157	-445	0
Q_M (MVAr)	0	0	0	[-75,75]	[-200,200]	0
Q_A (MVAr)	200	40	120	120	350	650
$Q_{\max}$ (MVAr)	370	83	245	157	445	1300
Zone	7	8	9	10	10	10
Type	WT	WT	WT	CCGT	Nuclear	WT
No.	**19**	**20**	**21**	**22**	**23**	**24**
$Q_{\min}$ (MVAr)	-57	-2136	0	-509	-636	-1032
Q_M (MVAr)	[-25,25]	[-1000, 1000]	0	[-250,250]	0	[-500,500]
Q_A (MVAr)	40	1600	260	420	300	750
$Q_{\max}$ (MVAr)	57	2136	539	509	636	1032
Zone	11	11	11	12	12	12
Type	CCGT	Nuclear	WT	CCGT	Hydro	Nuclear
No.	**25**	**26**	**27**	**28**	**29**	**30**

$Q_{\min}$ (MVAr)	0	-1431	0	-472	-1256	-809
Q_M (MVAr)	0	[-700,700]	0	[-230,230]	[-600,600]	[-400,400]
Q_A (MVAr)	250	1000	40	350	900	600
$Q_{\max}$ (MVAr)	516	1431	83	472	1256	809
Zone	12	13	13	14	15	15
Type	WT	CCGT	WT	CCGT	CCGT	Coal
No.	**31**	**32**	**33**	**34**	**35**	**36**
$Q_{\min}$ (MVAr)	-3033	0	-835	-75	-1032	-150
Q_M (MVAr)	[-1500, 1500]	0	[-400,400]	NA	[-500,500]	NA
Q_A (MVAr)	2400	800	600	NA	750	NA
$Q_{\max}$ (MVAr)	3033	1527	835	150	1032	300
Zone	16	16	17	17	18	18
Type	CCGT	WT	Coal	SVC	Nuclear	SVC
No.	**37**	**38**	**39**	**40**	**41**	**42**
$Q_{\min}$ (MVAr)	-1468	0	-149	-1680	-110	0
Q_M (MVAr)	[-700,700]	0	[-70,70]	[-840,840]	[-55,55]	0
Q_A (MVAr)	1100	280	120	1200	80	1500
$Q_{\max}$ (MVAr)	1468	564	149	1680	110	2900
Zone	19	19	20	20	20	20
Type	CCGT	WT	CCGT	Nuclear	OCGT	WT
No.	**43**	**44**	**45**	**46**	**47**	**48**

$Q_{\min}$ (MVAr)	-150	-273	-75	-1903	-98	-110
Q_M (MVAr)	NA	[-130,130]	NA	[-950,950]	0	[-55,55]
Q_A (MVAr)	NA	200	NA	1500	50	75
$Q_{\max}$ (MVAr)	300	273	150	1903	98	110
Zone	21	22	22	23	23	23
Type	SVC	CCGT	SVC	CCGT	Hydro	OCGT
No.	**49**	**50**	**51**	**52**	**53**	**54**
$Q_{\min}$ (MVAr)	0	-572	-1183	-53	-1398	-616
Q_M (MVAr)	0	[-280,280]	[550,550]	[-25,25]	[-650,650]	[-300,300]
Q_A (MVAr)	35	350	700	40	860	440
$Q_{\max}$ (MVAr)	74	572	1183	53	1398	616
Zone	23	24	25	25	26	26
Type	WT	CCGT	CCGT	OCGT	CCGT	Nuclear
No.	**55**	**56**	**57**	**58**	**59**	**60**
$Q_{\min}$ (MVAr)	-398	0	-675	-545	-37	0
Q_M (MVAr)	[-190,190]	0	NA	[-270,270]	[-18,18]	0
Q_A (MVAr)	280	150	NA	400	25	60
$Q_{\max}$ (MVAr)	398	305	675	545	37	120
Zone	27	27	27	28	28	28
Type	Nuclear	WT	SVC	CCGT	OCGT	WT
No.	**61**	**62**	**63**	**64**	**65**	

$Q_{\min}$ (MVAr)	-300	-334	-1568	-52	-525	
Q_M (MVAr)	NA	[-160,160]	[-750,750]	[-25,25]	NA	
Q_A (MVAr)	NA	200	1000	35	NA	
$Q_{\max}$ (MVAr)	375	334	1568	52	825	
Zone	28	29	29	29	29	
Type	SVC	CCGT	Nuclear	OCGT	SVC	

8.4 Appendix D – Weighting coefficients setting scenarios

The weighting coefficients setting scenarios used in the comparison study of the proposed optimal reactive power dispatch strategy is listed below:

Table 8-4 Weighting coefficients setting scenarios

	Day-ahead				Hourly Modification		
Scenario	μ_1	μ_2	μ_3	μ_4	μ_1	μ_2	μ_4
Setting 1	0.4	0.3	0.2	0.1	0.5	0.3	0.2
Setting 2	0.4	0.4	0.1	0.1	0.5	0.4	0.1
Setting 3	0.4	0.4	0.2	0	0.5	0.5	0

8.5 Appendix E – Detailed RPP simulation results for IEEE 33-bus system under *Q control strategy 1*

The no outage scenarios in 24 hours are simulated and the optimised results are listed in Table 8-5. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the results to make first-stage objective function having a minimum cost are:

**Note: the number in red colour indicates that is manually adjusted considering ancillary service operation time window*

Table 8-5 Hourly required reactive power from all providers under no outage scenario

t	$q_{Gi,\max}$	$q_{DGi,\max}$	$q_{SR/SCi,\max}$	$q_{QRi,\max}$
1.00	9.8077 MVAr	1.1273 MVAr	0.3008 MVAr	1.4508 MVAr
2.00	10.8137 MVAr	1.5822 MVAr	0.4030 MVAr	0.2351 MVAr
3.00	10.0904 MVAr	1.9294 MVAr	0.0937 MVAr	0.5009 MVAr
4.00	9.6099 (10.0904) MVAr	0.0891 MVAr	0.2807 MVAr	1.5107 MVAr
5.00	9.2360 MVAr	1.6052 MVAr	0.4493 MVAr	0.4875 MVAr
6.00	9.4339 MVAr	1.0213 MVAr	0.4196 MVAr	0.7011 MVAr
7.00	9.1936 MVAr	1.0930 MVAr	0.4529 MVAr	1.9219 MVAr
8.00	10.0901 MVAr	1.3880 MVAr	0.3353 MVAr	0.5112 MVAr
9.00	13.9727 MVAr	0.8792 MVAr	0.4536 MVAr	0.4069 MVAr
10.00	14.6338 MVAr	1.1876 MVAr	0.2355 MVAr	1.6961 MVAr
11.00	14.2201 MVAr	0.9340 MVAr	0.3428 MVAr	0.9476 MVAr
12.00	15.1225 MVAr	0.9536 MVAr	0.1641 MVAr	0.0652 MVAr
13.00	13.2077 MVAr	0.7212 MVAr	0.1313 MVAr	1.4851 MVAr
14.00	13.3372 MVAr	0.3948 MVAr	0.0472 MVAr	1.6458 MVAr
15.00	14.5508 MVAr	0.7122 MVAr	0.4437 MVAr	0.9439 MVAr
16.00	13.9764 MVAr	1.7832 MVAr	0.0760 MVAr	1.6590 MVAr
17.00	15.6629 MVAr	0.7930 MVAr	0.1384 MVAr	1.4985 MVAr
18.00	16.6053 MVAr	1.7225 MVAr	0.3272 MVAr	1.1247 MVAr
19.00	18.5064 MVAr	0.4939 MVAr	0.1580 MVAr	0.3163 MVAr
20.00	16.9413 MVAr	1.0769 MVAr	0.3613 MVAr	1.5020 MVAr

21.00	14.9105 MVAr	1.8903 MVAr	0.3869 MVAr	1.1377 MVAr
22.00	12.7287 MVAr	1.1178 MVAr	0.1857 MVAr	0.7565 MVAr
23.00	10.2937 MVAr	1.9366 MVAr	0.4277 MVAr	0.9572 MVAr
24.00	10.7512 MVAr	1.1853 MVAr	0.3830 MVAr	0.9080 MVAr
Total	308.1770 MVAr	27.6176 MVAr	6.9977 MVAr	24.3697 MVAr

The Branch 0-1 contingency scenarios in 24 hours are simulated and the optimised results are listed in Table 8-6. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the results to make first-stage objective function having a minimum cost are:

Table 8-6 Hourly required reactive power from all providers under Branch 0-1 contingency

t	$q_{Gi,\max}$	$q_{DGi,\max}$	$q_{SR/SCi,\max}$	$q_{QRi,\max}$
1.00	8.6184 MVAr	1.5217 MVAr	0.4434 MVAr	2.9617 MVAr
2.00	8.1960 MVAr	2.2938 MVAr	0.2562 MVAr	3.8186 MVAr
3.00	7.6887 MVAr	2.5156 MVAr	0.4581 MVAr	3.9694 MVAr
4.00	8.2899 MVAr	1.1935 MVAr	0.3715 MVAr	3.0275 MVAr
5.00	8.1233 MVAr	1.5736 MVAr	0.4905 MVAr	2.3090 MVAr
6.00	8.4743 MVAr	0.4898 MVAr	0.2068 MVAr	3.2436 MVAr
7.00	9.8109 MVAr	0.6820 MVAr	0.1724 MVAr	3.2114 MVAr
8.00	10.4006 MVAr	1.8130 MVAr	0.4198 MVAr	3.0566 MVAr
9.00	12.1328 MVAr	0.9427 MVAr	0.3718 MVAr	2.7114 MVAr
10.00	14.0355 MVAr	1.1019 MVAr	0.3426 MVAr	3.0394 MVAr
11.00	14.2751 MVAr	0.9699 MVAr	0.4199 MVAr	3.2222 MVAr

12.00	12.9773 MVAr	0.9952 MVAr	0.3823 MVAr	3.3688 MVAr
13.00	12.9818 MVAr	0.9830 MVAr	0.3797 MVAr	3.2953 MVAr
14.00	13.9424 MVAr	0.6351 MVAr	0.2978 MVAr	3.0026 MVAr
15.00	12.6969 MVAr	0.9035 MVAr	0.4947 MVAr	3.1939 MVAr
16.00	13.2147 MVAr	1.1261 MVAr	0.4256 MVAr	3.8622 MVAr
17.00	13.8874 MVAr	0.9240 MVAr	0.4848 MVAr	3.8502 MVAr
18.00	16.3296 MVAr	0.9027 MVAr	0.2706 MVAr	3.0007 MVAr
19.00	17.8625 MVAr	2.0021 MVAr	0.2851 MVAr	3.0608 MVAr
20.00	17.5737 MVAr	2.6459 MVAr	0.4144 MVAr	3.0002 MVAr
21.00	16.5990 MVAr	2.9594 MVAr	0.4767 MVAr	3.0000 MVAr
22.00	13.4999 MVAr	1.1282 MVAr	0.4873 MVAr	3.6753 MVAr
23.00	12.6073 MVAr	2.7399 MVAr	0.3906 MVAr	2.7183 MVAr
24.00	11.7078 MVAr	1.0868 MVAr	0.4255 MVAr	2.0000 MVAr
Total	295.9258 MVAr	34.1294 MVAr	9.1681 MVAr	75.5991 MVAr

The shunt reactor/capacitor outage scenarios in 24 hours are simulated and the optimised results are listed in Table 8-7. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the results to make first-stage objective function having a minimum cost are:

Table 8-7 Hourly required reactive power from all providers under SC outage scenario

t	$q_{Gi,\max}$	$q_{DGi,\max}$	$q_{SR/SCi,\max}$	$q_{QRi,\max}$
1.00	9.2213 MVAr	1.4131 MVAr	0 MVAr	2.8135 MVAr

2.00	10.1684 MVAr	1.2657 MVAr	0 MVAr	2.6802 MVAr
3.00	10.2727 MVAr	2.3015 MVAr	0 MVAr	2.0955 MVAr
4.00	10.0084 MVAr	1.7929 MVAr	0 MVAr	2.1848 MVAr
5.00	10.7420 MVAr	2.1227 MVAr	0 MVAr	1.1966 MVAr
6.00	10.7176 MVAr	1.1633 MVAr	0 MVAr	1.6619 MVAr
7.00	11.9104 MVAr	0.7389 MVAr	0 MVAr	1.3941 MVAr
8.00	12.0977 MVAr	0.9226 MVAr	0 MVAr	1.2293 MVAr
9.00	13.1066 MVAr	0.5809 MVAr	0 MVAr	1.2677 MVAr
10.00	13.7014 MVAr	1.4238 MVAr	0 MVAr	2.0139 MVAr
11.00	13.5470 MVAr	0.9906 MVAr	0 MVAr	2.6151 MVAr
12.00	13.6574 MVAr	0.6134 MVAr	0 MVAr	1.8077 MVAr
13.00	12.2901 MVAr	0.8401 MVAr	0 MVAr	2.4999 MVAr
14.00	12.0251 MVAr	0.8997 MVAr	0 MVAr	2.2275 MVAr
15.00	13.5777 MVAr	0.6892 MVAr	0 MVAr	2.4750 MVAr
16.00	15.2139 MVAr	2.2275 MVAr	0 MVAr	1.1406 MVAr
17.00	14.1148 MVAr	1.8590 MVAr	0 MVAr	1.7564 MVAr
18.00	16.1190 MVAr	2.7225 MVAr	0 MVAr	1.3226 MVAr
19.00	16.3507 MVAr	0.8028 MVAr	0 MVAr	2.3690 MVAr
20.00	15.1058 MVAr	1.6890 MVAr	0 MVAr	2.7253 MVAr
21.00	15.4075 MVAr	1.9624 MVAr	0 MVAr	1.2750 MVAr
22.00	12.3095 MVAr	1.8323 MVAr	0 MVAr	1.8408 MVAr
23.00	12.7417 MVAr	1.1411 MVAr	0 MVAr	1.2750 MVAr
24.00	12.5307 MVAr	1.5511 MVAr	0 MVAr	0.9796 MVAr

Total	306.9374 MVAr	33.5461 MVAr	0 MVAr	44.8470 MVAr

The flexible demand i.e. MVAr reduction outage scenarios in 24 hours are simulated and the optimised results are listed in Table 8-8. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the results to make first-stage objective function having a minimum cost are:

Table 8-8 Hourly required reactive power from all providers under QR outage scenario

t	$q_{Gi,\max}$	$q_{DGi,\max}$	$q_{SR/SCi,\max}$	$q_{QRi,\max}$
1.00	11.2339 MVAr	1.7225 MVAr	0.2868 MVAr	0 MVAr
2.00	10.9772 MVAr	1.6999 MVAr	0.4769 MVAr	0 MVAr
3.00	10.3909 MVAr	1.6309 MVAr	0.4401 MVAr	0 MVAr
4.00	10.7497 MVAr	1.4487 MVAr	0.1535 MVAr	0 MVAr
5.00	9.9586 MVAr	1.2951 MVAr	0.4076 MVAr	0 MVAr
6.00	11.5133 MVAr	1.1424 MVAr	0.4300 MVAr	0 MVAr
7.00	12.0851 MVAr	1.9700 MVAr	0.3384 MVAr	0 MVAr
8.00	13.3695 MVAr	0.7950 MVAr	0.4367 MVAr	0 MVAr
9.00	14.5685 MVAr	0.7658 MVAr	0.4869 MVAr	0 MVAr
10.00	16.3982 MVAr	0.8317 MVAr	0.2851 MVAr	0 MVAr
11.00	15.6694 MVAr	0.9454 MVAr	0.4625 MVAr	0 MVAr
12.00	15.7177 MVAr	0.8896 MVAr	0.4830 MVAr	0 MVAr
13.00	15.4850 MVAr	0.8198 MVAr	0.4755 MVAr	0 MVAr
14.00	15.2275 MVAr	0.8136 MVAr	0.3928 MVAr	0 MVAr
15.00	14.5592 MVAr	0.6104 MVAr	0.2983 MVAr	0 MVAr

16.00	16.9379 MVAr	0.9701 MVAr	0.4845 MVAr	0 MVAr
17.00	16.6456 MVAr	0.5815 MVAr	0.4896 MVAr	0 MVAr
18.00	18.3558 MVAr	1.3888 MVAr	0.4186 MVAr	0 MVAr
19.00	19.7363 MVAr	0.4017 MVAr	0.2003 MVAr	0 MVAr
20.00	17.6230 MVAr	0.2325 MVAr	0.3662 MVAr	0 MVAr
21.00	15.4509 MVAr	1.7069 MVAr	0.2150 MVAr	0 MVAr
22.00	13.2596 MVAr	1.2147 MVAr	0.0786 MVAr	0 MVAr
23.00	12.6431 MVAr	1.3223 MVAr	0.1011 MVAr	0 MVAr
24.00	11.5523 MVAr	1.6621 MVAr	0.3963 MVAr	0 MVAr
Total	340.1082 MVAr	26.8614 MVAr	8.6043 MVAr	0 MVAr

The wind farm outage scenarios in 24 hours are simulated and the optimised results are listed in Table 8-9. The required reactive power from each provider listed in the table is the maximum value under all the combinations of load demand and wind speed forecast errors. This is to ensure power system should have sufficient reactive power to overcome possible day-ahead forecast errors. Under this circumstance, the results to make first-stage objective function having a minimum cost are:

**Note: the number in red colour indicates that is manually adjusted considering ancillary service operation time window*

Table 8-9 Hourly required reactive power from all providers under WT outage scenario

t	$q_{Gi,\max}$	$q_{DGi,\max}$	$q_{SR/SCi,\max}$	$q_{QRi,\max}$
1.00	10.9468 MVAr	0 MVAr	0.4695 MVAr	1.3995 MVAr
2.00	10.9085 MVAr	0 MVAr	0.4656 MVAr	0.9417 MVAr
3.00	9.8791 (10.4085) MVAr	0 MVAr	0.4957 MVAr	1.6919 MVAr
4.00	10.0887 MVAr	0 MVAr	0.2011 MVAr	2.7170 MVAr

5.00	10.6171 MVAr	0 MVAr	0.3665 MVAr	2.0288 MVAr
6.00	11.0931 MVAr	0 MVAr	0.3602 MVAr	2.5589 MVAr
7.00	12.1241 MVAr	0 MVAr	0.4539 MVAr	1.0374 MVAr
8.00	12.6841 MVAr	0 MVAr	0.4882 MVAr	0.9409 MVAr
9.00	13.8904 MVAr	0 MVAr	0.4874 MVAr	1.6387 MVAr
10.00	15.0239 MVAr	0 MVAr	0.2377 MVAr	1.7464 MVAr
11.00	15.3284 MVAr	0 MVAr	0.3579 MVAr	1.7558 MVAr
12.00	15.0480 MVAr	0 MVAr	0.1974 MVAr	2.3613 MVAr
13.00	14.3333 MVAr	0 MVAr	0.4943 MVAr	1.5890 MVAr
14.00	13.1151 MVAr	0 MVAr	0.3999 MVAr	2.2485 MVAr
15.00	12.9870 MVAr	0 MVAr	0.1871 MVAr	2.8323 MVAr
16.00	13.4535 MVAr	0 MVAr	0.3943 MVAr	3.1655 MVAr
17.00	15.8276 MVAr	0 MVAr	0.3268 MVAr	2.7066 MVAr
18.00	16.8055 MVAr	0 MVAr	0.4654 MVAr	2.2249 MVAr
19.00	16.9835 MVAr	0 MVAr	0.4407 MVAr	2.5907 MVAr
20.00	16.3568 MVAr	0 MVAr	0.4578 MVAr	2.1011 MVAr
21.00	15.8000 MVAr	0 MVAr	0.4109 MVAr	1.9843 MVAr
22.00	12.7950 MVAr	0 MVAr	0.3024 MVAr	1.9129 MVAr
23.00	12.4177 MVAr	0 MVAr	0.4288 MVAr	1.8181 MVAr
24.00	10.9118 MVAr	0 MVAr	0.2387 MVAr	2.4575 MVAr
Total	319.9484 MVAr	0 MVAr	9.1282 MVAr	48.4497 MVAr

8.6 Appendix F – Detailed ORPD simulation results for GB network

Simulated results of important control variables and criteria for 24 hours have been shown in Table 8-10.

Table 8-10 Optimisation results for GB modified network at three different times of a day

t	RESULTS	TRADITIONAL OPF		PROPOSED ORPD STRATEGY	
		Day Ahead	Hourly Modifications	Day Ahead	Hourly Modifications
1:00	$F(x)$	0.182	0.1845	0.137	0.1375
	P^{WT} (MW)	16708	15961.3	11167	9914.7
	Q^{WT} (MVAr)	171.2	160.3	2565	2426.5
	Q^{SC} (MVAr)	712.6	719.274	525.8	540.46
	ΔP_{loss} (%)	1.82	1.82	1.05	1.06
	ΔU_{ave} (p.u.)	0.017	0.01803	0.015	0.0167
	N_{TAP}	0.004	NA	0.002	NA
	$SATHD$ (%)	1.15	1.14	0.66	0.64
2:00	$F(x)$	0.182	0.18187	0.132	0.1323
	P^{WT} (MW)	9505	9978.41	9539	10032
	Q^{WT} (MVAr)	340.5	320.052	1974	2336.7
	Q^{SC} (MVAr)	753.2	832.538	661.8	750.3
	ΔP_{loss} (%)	1.891	1.90229	0.952	0.9814
	ΔU_{ave} (p.u.)	0.012	0.01195	0.012	0.0119

	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.677	0.65415	0.679	0.6572
3:00	$F(x)$	0.182	0.18232	0.131	0.1324
	P^{WT} (MW)	9136	9797.27	9174	9842.5
	Q^{WT} (MVAr)	355.9	343.458	1766	2127.2
	Q^{SC} (MVAr)	693.3	792.202	606.8	695.95
	ΔP_{loss} (%)	1.881	1.89428	0.933	0.9618
	ΔU_{ave} (p.u.)	0.012	0.01197	0.011	0.0118
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.686	0.67458	0.689	0.6773
4:00	$F(x)$	0.181	0.18115	0.13	0.1315
	P^{WT} (MW)	8631	9106.77	8959	9407.2
	Q^{WT} (MVAr)	298.9	284.078	1709	2081.2
	Q^{SC} (MVAr)	656.4	755.232	612.7	702.3
	ΔP_{loss} (%)	1.879	1.8962	0.937	0.9705
	ΔU_{ave} (p.u.)	0.012	0.01171	0.011	0.0117
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.673	0.64847	0.673	0.647
5:00	$F(x)$	0.179	0.18036	0.128	0.1287
	P^{WT} (MW)	8040	8491.02	8064	8524.6
	Q^{WT} (MVAr)	253.8	251.449	1301	1666.1

	Q^{SC} (MVAr)	599.1	697.152	532.6	617.62
	ΔP_{loss} (%)	1.872	1.8909	0.908	0.9467
	ΔU_{ave} (p.u.)	0.011	0.01148	0.01	0.0106
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.664	0.63757	0.666	0.6397
6:00	$F(x)$	0.179	0.17978	0.128	0.13
	P^{WT} (MW)	7776	8254.34	8446	8908.9
	Q^{WT} (MVAr)	233	219.481	1659	1981.1
	Q^{SC} (MVAr)	599.9	698.044	618.5	713.17
	ΔP_{loss} (%)	1.876	1.894	0.948	0.9774
	ΔU_{ave} (p.u.)	0.011	0.01139	0.011	0.0114
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.642	0.61967	0.634	0.6125
7:00	$F(x)$	0.18	0.18017	0.131	0.1295
	P^{WT} (MW)	9045	9606.34	9094	9666.4
	Q^{WT} (MVAr)	241.7	219.624	2016	2403
	Q^{SC} (MVAr)	795.7	863.315	709.6	817.32
	ΔP_{loss} (%)	1.904	1.9236	0.976	1.0164
	ΔU_{ave} (p.u.)	0.012	0.01166	0.011	0.0112
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.622	0.60068	0.625	0.6039

8:00	$F(x)$	0.18	0.17946	0.13	0.1283
	P^{WT} (MW)	9547	9900.55	9586	9997.6
	Q^{WT} (MVAr)	223.3	206.066	2336	2689.5
	Q^{SC} (MVAr)	853.7	914.904	800.5	873.28
	ΔP_{loss} (%)	1.916	1.966	1.008	1.0728
	ΔU_{ave} (p.u.)	0.012	0.01157	0.011	0.0107
	N_{TAP}	0.001	NA	0	NA
	$SATHD$ (%)	0.606	0.56705	0.608	0.572
9:00	$F(x)$	0.18	0.17894	0.128	0.1268
	P^{WT} (MW)	9701	9985.79	10099	10459
	Q^{WT} (MVAr)	205.2	189.544	2740	2959.7
	Q^{SC} (MVAr)	897.5	961.2	881.7	950.97
	ΔP_{loss} (%)	1.955	1.9948	1.08	1.1039
	ΔU_{ave} (p.u.)	0.012	0.01157	0.011	0.0104
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.572	0.53447	0.57	0.5316
10:00	$F(x)$	0.179	0.17928	0.127	0.1265
	P^{WT} (MW)	10287	10662.7	10354	10862
	Q^{WT} (MVAr)	190.9	173.239	2928	3091.8
	Q^{SC} (MVAr)	985.9	1040.09	942	1000.9
	ΔP_{loss} (%)	2.008	2.0265	1.107	1.0655

	ΔU_{ave} (p.u.)	0.012	0.01196	0.01	0.0105
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.53	0.49903	0.533	0.5082
11:00	$F(x)$	0.18	0.17895	0.128	0.1268
	P^{WT} (MW)	10523	9405.39	10589	10993
	Q^{WT} (MVAr)	208.8	186.71	2974	3121.1
	Q^{SC} (MVAr)	971.8	905.405	923.2	987.99
	ΔP_{loss} (%)	1.999	1.9653	1.111	1.08
	ΔU_{ave} (p.u.)	0.012	0.01154	0.01	0.0105
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.556	0.54617	0.559	0.5263
12:00	$F(x)$	0.179	0.17919	0.127	0.1264
	P^{WT} (MW)	10086	10454.8	10145	10531
	Q^{WT} (MVAr)	189.9	173.059	2855	2995.9
	Q^{SC} (MVAr)	971.1	1025.39	925.5	984.31
	ΔP_{loss} (%)	1.999	2.0272	1.108	1.0889
	ΔU_{ave} (p.u.)	0.012	0.0119	0.01	0.0104
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.533	0.50068	0.535	0.51
13:00	$F(x)$	0.156	0.15611	0.133	0.133
	P^{WT} (MW)	14433	11383.6	9774	9517.5

	Q^{WT} (MVAr)	143.2	90.8	2799	2341.6
	Q^{SC} (MVAr)	918	942.135	900.6	925.29
	ΔP_{loss} (%)	1.54	1.53	1.025	1.028
	ΔU_{ave} (p.u.)	0.016	0.01729	0.016	0.0168
	N_{TAP}	0.002	NA	0.001	NA
	$SATHD$ (%)	0.78	0.74	0.45	0.43
14:00	$F(x)$	0.179	0.179	0.127	0.1264
	P^{WT} (MW)	9787	10233.4	9843	10531
	Q^{WT} (MVAr)	188.6	176.704	2715	2995.9
	Q^{SC} (MVAr)	941.6	1005.7	900.8	984.31
	ΔP_{loss} (%)	1.985	2.0188	1.089	1.0889
	ΔU_{ave} (p.u.)	0.012	0.01178	0.011	0.0104
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.538	0.50787	0.54	0.51
15:00	$F(x)$	0.179	0.17928	0.128	0.1268
	P^{WT} (MW)	10206	10487.3	10290	10565
	Q^{WT} (MVAr)	207.5	191.502	2835	2991.8
	Q^{SC} (MVAr)	942.3	999.21	898.3	960.01
	ΔP_{loss} (%)	1.983	2.0156	1.092	1.101
	ΔU_{ave} (p.u.)	0.012	0.01174	0.011	0.0104
	N_{TAP}	0	NA	0	NA

	$SATHD$ (%)	0.561	0.52694	0.565	0.5304
16:00	$F(x)$	0.179	0.17936	0.127	0.1265
	P^{WT} (MW)	10287	10750.4	10354	10862
	Q^{WT} (MVAr)	190.9	177.075	2928	3091.8
	Q^{SC} (MVAr)	985.9	1040.04	942	1000.9
	ΔP_{loss} (%)	2.008	2.0258	1.107	1.0655
	ΔU_{ave} (p.u.)	0.012	0.01195	0.01	0.0105
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.53	0.50315	0.533	0.5082
17:00	$F(x)$	0.179	0.17899	0.126	0.1265
	P^{WT} (MW)	10145	10667.5	10443	10981
	Q^{WT} (MVAr)	172.9	158.003	2972	3040.1
	Q^{SC} (MVAr)	1006	1062.43	984.7	1032.4
	ΔP_{loss} (%)	2.019	2.0065	1.088	1.0287
	ΔU_{ave} (p.u.)	0.012	0.01201	0.01	0.0109
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.503	0.48281	0.506	0.4862
18:00	$F(x)$	0.18	0.17975	0.128	0.1277
	P^{WT} (MW)	11980	12564.4	12091	12563
	Q^{WT} (MVAr)	230.9	212.552	3422	3548.1
	Q^{SC} (MVAr)	1040	1068.2	994.1	1035.1

	ΔP_{loss} (%)	2.008	1.9608	1.061	1.0084
	ΔU_{ave} (p.u.)	0.012	0.01193	0.011	0.0109
	N_{TAP}	0.003	NA	0.001	NA
	$SATHD$ (%)	0.561	0.5396	0.566	0.545
19:00	$F(x)$	0.171	0.17238	0.131	0.1318
	P^{WT} (MW)	21656	19394.2	14153	14118
	Q^{WT} (MVAr)	219.3	138.9	4312	4870
	Q^{SC} (MVAr)	1080	1233.25	1082	1297.7
	ΔP_{loss} (%)	1.55	1.53	1.17	1.15
	ΔU_{ave} (p.u.)	0.014	0.01491	0.013	0.0133
	N_{TAP}	0.004	NA	0.002	NA
	$SATHD$ (%)	0.84	0.8	0.58	0.57
20:00	$F(x)$	0.181	0.18072	0.129	0.1298
	P^{WT} (MW)	13701	14354.6	13779	14551
	Q^{WT} (MVAr)	308	277.236	3960	4137.3
	Q^{SC} (MVAr)	1055	1067.51	995.3	1043.8
	ΔP_{loss} (%)	1.966	1.9438	1.054	0.9884
	ΔU_{ave} (p.u.)	0.012	0.01187	0.011	0.0113
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.628	0.59825	0.631	0.6062
21:00	$F(x)$	0.182	0.18163	0.13	0.1295

	P^{WT} (MW)	12681	13606.9	12787	13683
	Q^{WT} (MVAr)	341.2	318.271	3679	3965.4
	Q^{SC} (MVAr)	986.3	1041.08	919.3	982.78
	ΔP_{loss} (%)	1.978	1.9726	1.103	1.0753
	ΔU_{ave} (p.u.)	0.012	0.01184	0.011	0.0107
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.654	0.63805	0.659	0.641
22:00	$F(x)$	0.182	0.18123	0.131	0.1297
	P^{WT} (MW)	10971	11879.6	11034	11963
	Q^{WT} (MVAr)	317.6	291.021	2854	3340.8
	Q^{SC} (MVAr)	896.5	964.381	841.3	902.03
	ΔP_{loss} (%)	1.934	1.9711	1.035	1.0888
	ΔU_{ave} (p.u.)	0.012	0.01169	0.011	0.0107
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.647	0.63663	0.65	0.6404
23:00	$F(x)$	0.182	0.18175	0.132	0.1312
	P^{WT} (MW)	9952	10612.9	10006	10667
	Q^{WT} (MVAr)	331	309.524	2268	2683.3
	Q^{SC} (MVAr)	823.1	879.036	732	826.26
	ΔP_{loss} (%)	1.9	1.9233	0.975	1.0198
	ΔU_{ave} (p.u.)	0.012	0.01194	0.012	0.0115

	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.663	0.64439	0.666	0.6471
24:00	$F(x)$	0.182	0.18177	0.132	0.1316
	P^{WT} (MW)	9696	10315.5	9746	10371
	Q^{WT} (MVAr)	327.7	309.078	2114	2534.4
	Q^{SC} (MVAr)	793.3	861.367	698	803.51
	ΔP_{loss} (%)	1.897	1.9122	0.964	1.0034
	ΔU_{ave} (p.u.)	0.012	0.01196	0.012	0.0117
	N_{TAP}	0	NA	0	NA
	$SATHD$ (%)	0.668	0.64539	0.671	0.6483