Incorporating Distributed Generation into Distribution Network Planning: The Challenges and Opportunities for Distribution Network Operators

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I, David Wang, declare that the content of the thesis and the results presented in this thesis unless otherwise referenced are my own work for fulfilling the requirements of the PhD study.

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Victory favours neither the righteous nor the wicked.

It favours the prepared.

Abstract

Diversification of the energy mix is one of the main challenges in the energy agenda of governments worldwide. Technology advances together with environmental concerns have paved the way for the increasing integration of Distributed Generation (DG) seen over recent years. Combined heat and power and renewable technologies are being encouraged and their penetration in distribution networks is increasing. This scenario presents Distribution Network Operators (DNOs) with several technical challenges in order to properly accommodate DG developments. However, depending on various factors, such as location, size, technology and robustness of the network, DG might also be beneficial to DNOs.

In this thesis, the impact of DG on network planning is analysed and the implications for DNOs in incorporating DG within the network planning process are identified. In the first part, various impacts of DG to the network, such as network thermal capacity release, security of supply and on voltage, are quantified through network planning by using a modified successive elimination method and voltage sensitivity analysis. The results would potentially assist DNOs in assessing the possibilities and effort required to utilise privately-owned DG to improve network efficiency and save investment. The quantified values would also act as a fundamental element in deriving effective distribution network charging schemes. In the second part, a novel balanced genetic algorithm is introduced as an efficient means of tackling the problem of optimum network planning considering future uncertainties. The approach is used to analyse the possibilities, potential benefits and challenges to strategic network planning by considering the presence of DG in the future when the characteristics of DG are uncertain.

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Glossary and List of Acronyms

The definitions of the following terms are based on the explanations provided by the GB Security and Quality of Supply Standard (SQSS) [1] and Distribution Code [2].

Contingency – An accidental event which affects the normal network operating condition, such as loss of transmission lines, transformers or generation.

Cyclic Rating - The load carrying capability of an item of equipment in excess of its nominal rating which can be achieved given the expected daily load cycle of the equipment. Such additional capability will normally arise as a result of the thermal inertia of the equipment.

Demand - The demand of MW or MVar of electricity

Demand group - A site or group of sites which collectively take power from the remainder of the transmission system.

Distributed Generator - A generator whose generation sets are directly connected to the DNO's distribution system.

Distributed Generation Connection Charge – Cost paid by a distributed generator to a distribution network operator in order to connect the distributed generation to a distribution network operated and owned by the distribution network operator.

Distribution Network Operator (DNO) - The person or legal entity who owns and operates a part of distribution system.

Distribution System - The electrical network operated by a distribution network operator.

Distribution Use of System Charge – Cost paid by the customers to a distribution network operator for using the distribution system owned and operated by the distribution network operator.

Generator - A person who generates electricity.

Peak Demand - The highest level of demand recorded/forecast for a 12-month period.

Planned Outage - An outage of one or more items of primary transmission apparatus and/or generation plant, initiated by manually instructed action which has been subject to the recognised GB outage planning process.

Power Factor - The ratio of active power to apparent power.

Protection - The provisions for detecting abnormal conditions in a system and initiating fault clearance or actuating signals or indications.

Reactive Power - The product of voltage and current and the sine of the phase angle between them which is normally measured in kilovar (kVar) or megavar (MVar).

Real Power - The product of voltage and current and the cosine of the phase angle between them which is normally measured in kilowatt (kW) or megawatt (MW).

Secured event - A contingency which would be considered for the purposes of assessing system security and which must not result in the remaining power system being in breach of the security criteria.

Steady State - A condition of a power system in which all automatic and manual corrective actions have taken place and all of the operating quantities that characterise it can be considered constant for the purpose of analysis.

Voltage Step Change - The difference in voltage between that immediately before a secured event or operational switching and that at the end of the *transient time phase* after the event.

Transient Time Phase - The time within which fault clearance or initial system switching, the transient decay and recovery, auto switching schemes, generator inter-tripping, and fast, automatic responses of controls such as generator AVR and SVC take place. Load response may be assumed to have taken place. Typically 0 to 5 seconds after an initiating event.

Unplanned Outage - An outage of one or more items of primary transmission apparatus and/or generation plant, initiated by manually instructed action which has not been subject to the recognised GB outage planning process.

AVR – Automatic voltage regulator

BGA – Balanced genetic algorithm

BI – Benefit Index

CBGA – Chu-Beasley genetic algorithm

CCGT – Combined cycle gas turbines

CHP – Combined heat and power

DEA – Data envelopment analysis

DG – Distributed generation

DMU – decision-making unit

DNO – Distribution network operator

DPCR – Distribution price control review

DUoS – Distribution use of system

EHV – Extra high voltage

FACTS – Flexible AC transmission system

GA – Genetic algorithm

GSP – Grid supply point

IGA – Improved genetic algorithm

IIP – Information and incentives project

LP – Linear programming

MDEA – Modified data envelopment analysis

MV – Medium voltage

NBI – Net benefit index

PV – Present value

RI – Risk index

SE – successive elimination

S/S – Substation

SVC – Static Var compensator

CHAPTER 1 - Introduction

The beginning of the 21st Century sees a worldwide surge in installed capacity of distributed generation (DG). Generally speaking, there is no strict and universal definition of DG. However, according to a survey in the International Conference on Electricity Distribution (CIRED 1999) [3], some have defined DG based on the voltage level of the power network it is connected to, others see DG as generation which is placed near the customer load and directly supplying it, while DG could also be referred to as electricity generation utilising some specific energy conversion technologies. Nevertheless, the features of DG have one common characteristic: relatively small physical size and generation capacity.

Due to the smaller size of DG compared to conventional power plants, DG could be connected within distribution networks without major network upgrades. It could also be installed near customer loads where only limited space is provided. Finally, the advancement in some energy conversion technologies, such as fuel cells, gas micro-turbines, as well as renewables like wind turbines, etc., allows smaller amounts of energy to be harvested in a feasible and more economical way. As a result, the working group of CIGRE defined DG as "*the electricity generation which has the capacity less than 100MW and is not dispatched centrally"* [3]. Similar to this, another definition proposed by IEEE "as *the electricity generation which size is sufficiently smaller than central power plants as it could be connected at nearly any point in a power system"* [4].

Fig. 1.1 shows the growth of electricity generated from renewable resources in the main EU countries, Ireland and the UK as a percentage of gross electric energy consumption from 1997-2007 along with the prediction for 2010 [5]. It shows the UK in particular has been lagging behind in the utilisation of renewable resources for electricity generation. The renewable energy resources include hydro, wind, solar, geothermal and biomass/wastes. Apart from the establishment of large off-shore wind farms in very recent years, most of the electricity generated from the renewable resources can be considered from the contribution of DG.

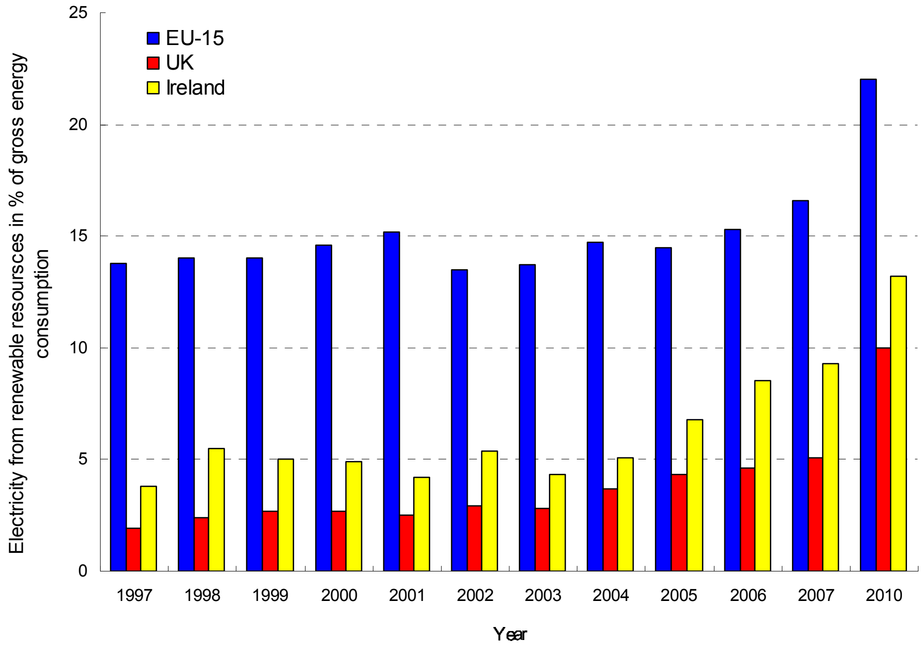


Fig. 1.1. Electricity generated from renewable resources in percentage of gross electric energy consumption.

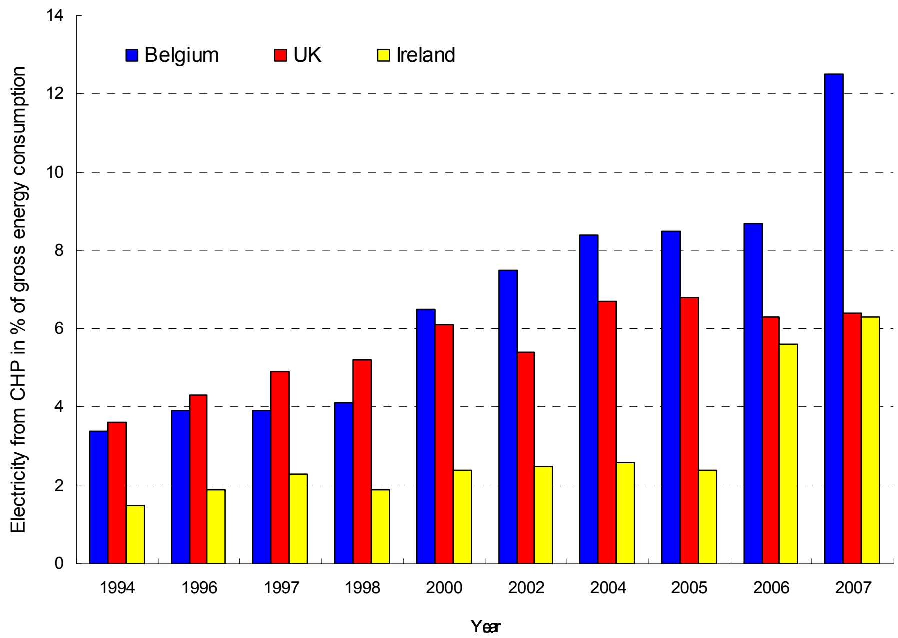


Fig. 1.2. Electricity generated from CHP in % of gross electric energy consumption.

The installed capacity of combined heat and power generation (CHP), which is classified as

DG due to its vicinity to the loads, has also increased considerably in many European countries. The electricity generated by CHP technology in Belgium, Ireland and the UK as a percentage of gross electric energy consumption from 1994-2007 is depicted in Fig.1.2 [6]. Again, the use of CHP in the UK has progressed relatively slowly compared with Belgium and Ireland.

The popularity of DG can be attributed to its economic feasibility as an alternative to conventional bulk power plants due to the following reasons [7]:

- Increasing cost-effectiveness due to the gradual maturation of some DG technologies;
- Smaller size leads to lower investment costs, shorter construction time and therefore higher payback rate;
- The incentives from governments for renewable DG and CHP due to perceived environmental benefits and the promise by governments to achieve target CO_2 reductions. The incentives include the Renewable Obligation (RO) in the UK, and the Erneuerbare Energien Gesetz (EEG) in Germany [8, 9]. The direction of the incentives is concentrated on minimizing the investment risks of DG.

1.1 Technical Impacts of DG

DG connections have caused profound impacts on distribution networks and brought many challenges for Distribution Network Operators (DNOs). Before the era of DG, the major function of distribution networks was to merely receive the electric energy from the transmission network at higher voltage level and transmit it efficiently to end-users connected within the distribution networks. Now, the long-established network configurations and control mechanisms are forced to evolve in order to maintain the energy transmission efficiency of the networks while accommodating the DG within the networks. The more unpredictable outputs from DG powered by variable resources (wind, solar, wave, etc.) have also resulted in the need for DNOs to frequently re-evaluate both the economic and technical effectiveness of their strategies of network planning and control.

The technical impacts from DG connections to the distribution network can be explained by the alterations of power flows in circuits in terms of either quantity, direction, or both. As a result, four major impacts that a DG connection could cause are listed in the following [10]:

- transmission and distribution capacity and losses;
- voltage variation;
- protection;
- system reliability.

Transmission and distribution capacity and losses

The load near to the DG would be directly supplied by the DG instead of by the distant centralised power plants. If part of the load is met by the DG output, the power required from the grid supply point would be decreased, releasing extra capacity on the conductors below their maximum thermal capacity. The decreased current flowing through the conductors between the grid supply point (GSP) and the load will also decrease the losses and increase the transmission efficiency. Under the circumstances when DG is able to meet all the demand and is starting to export its energy back to the network, the direction of power flow will be reversed leading to the rise of usage of the conductors and losses. Should the DG be large enough, the losses can rise above the original level.

The impact of DG on network loss reduction has been analysed thoroughly. Reference [11] analysed the changes of network losses according to different locations and capacities of DG as well as different DG technologies [12]. Other work [13-16] has adopted various optimisation methods to find the optimum placement and size of DG for minimising the network losses.

Voltage variation

DG could impose either voltage-rise or voltage-drop on the network. The severity of the voltage change caused by DG again depends on its location and relative output to the load demand. An example is shown in Fig. 1.3, where a load at bus 2 is supplied from the GSP via an overhead line with impedance of R+jX. The power travelling through the conductor (P, Q) in the direction towards the load would be the sum of the load demand (P_L, Q_L) and the losses, P_{loss} and Q_{loss}, incurred in the line. The graph in Fig. 1.3shows an approximate linear relationship assuming the length of the line connecting bus 1 and bus 2 is limited.

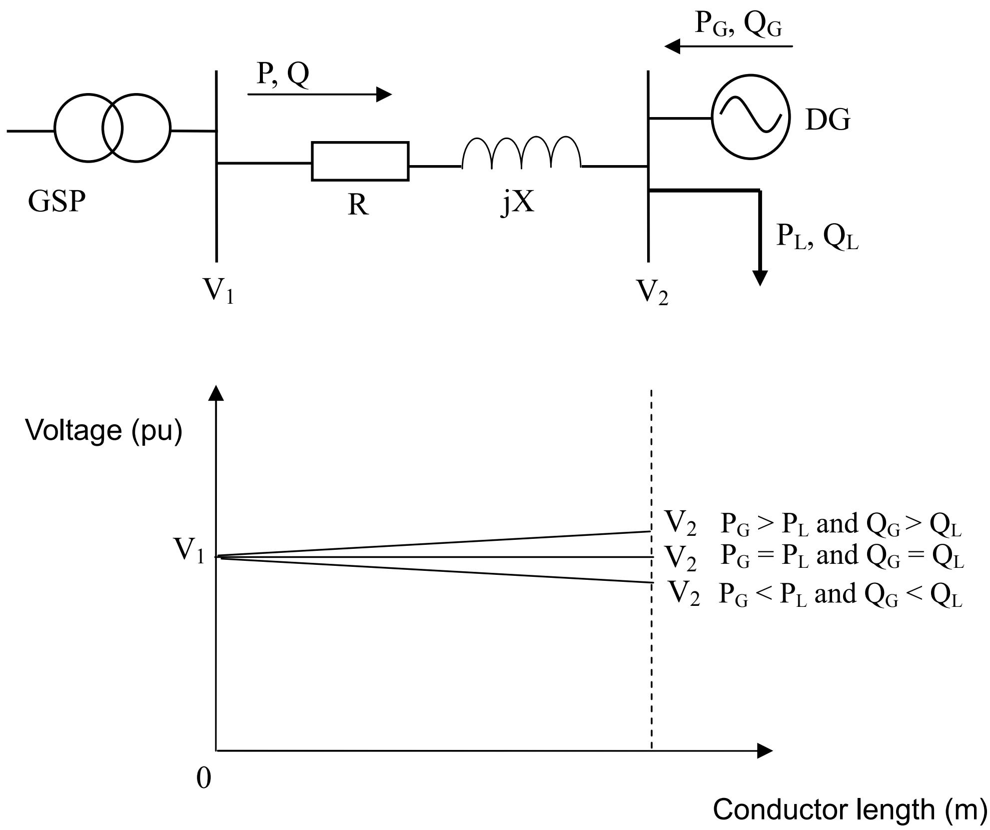


Fig. 1.3. Simple 2-bus network.

The voltage drop between bus 1 and bus 2 can be approximated according to the following equation [17]:

$$V_1 - V_2 = \Delta V \approx R \cdot P + X \cdot Q \tag{1.1}$$

Suppose now DG injects P_G and Q_G into the network. The voltage changes can be classified into three scenarios based on the relative quantity between the outputs from DG and the load demand.

Scenario 1: $P_G < P_L$ and $Q_G < Q_L$. In this case the load is partially supplied by the DG. This requires less power transferred from the GSP to the load than in the case without DG.

Therefore according to (1.1), the voltage-drop from bus 1 to bus 2 shrinks, which implies the rise of V_2 as V_1 is regulated by the transformer and can be assumed as constant.

Scenario 2: $P_G = P_L$ and $Q_G = Q_L$. At the instant when the load is fully supplied by the entire output of DG, there are no power flows through the conductor, i.e. P and Q = 0. Therefore, there is no voltage difference between bus 1 and bus 2.

Scenario 3: $P_G > P_L$ and $Q_G > Q_L$. As the DG output surpasses the amount required for the demand, the excess power flows back to bus 1 from bus 2. Therefore, the directions of P and Q are changed, turning ΔV of the equation into negative. The negative ΔV indicates now V_2 rises above V_1.

One obligation for DNOs is to maintain the network voltage within regulatory limits during both transient and steady-state to prevent damaging the equipments; therefore it is important to ensure DG connections will not cause serious voltage issues throughout the network under any circumstances. DG had been utilised to mitigate the voltage dips within the distribution system in [18-20] and proved to be effective. The impacts of different DG voltage control mechanisms and co-ordination with other voltage control devices in the network have been analysed in [17, 21-24].

Protection

The purpose of network protection is to isolate the part of network which has been affected by faults, while ensuring the normal operation of the unaffected part. The protection devices therefore need to be able to sense the abnormal network condition and activate to 'cut off' the malfunctioned network only. However, DG could contribute to the fault-current, change its direction or quantity and affect the settings of the protection devices such as over-current/voltage and under-voltage/current relays [10, 25], as well as automatic reclosing breakers [26, 27]. As voltage might be raised at the connection boundary when DG is producing large output, one solution for DNOs to limit the voltage rise is to switch in an additional line to change the network configuration from radial to ring. However, the change in network configuration change could shorten the critical clearing time of DG if a fault occurs, making protection devices only activate after DG has become instable [28]. As a result the configuration change could necessitate re-adjustment of protection settings. Furthermore, if DG should remain connected during a fault (ride-through), network islanding could occur after the fault implying that a part of the network which is supposed to be disconnected from the main grid still remains energized due to the connection of the DG. The danger related to public safety would arise if the network operator is not aware of this phenomenon. The co-ordination of protection devices due to loss of mains or for islanding protection has proven to be the most challenging task for UK DNOs [29].

There are various methods proposed to improve the co-ordination of protection devices in the presence of DG. An adaptive protection scheme was developed by Brahma and Girgis [30] under high penetration of DG. In their approach, a network is divided into multiple smaller networks, while in each divided section the load demand can be more or less balanced by the DG connected within the same section. The fault location can be detected by measuring the fault current contributed by each DG. Another adaptive protection scheme was developed for automatic reclosing and voltage sag under the presence of DG [31]. In [32], a new protection method for detecting islanding operation was proposed.

Reliability

A reliable network is able to satisfy large part of the demand connected to the system, even under contingencies, such as loss of transmission lines or transformers. Conversely, under critical contingencies when it is impossible to deliver the power to meet the whole demand, load shedding has to take place to mitigate pressure on the network and prevent wide network instability. This results directly in economic losses due to the demand unsupplied. The unsupplied demand would need to be reconnected as soon as possible to minimise such economic losses. There are incentives given from electricity regulators to DNOs to develop and design a more reliable network, such as Information and Incentives Project (IIP) [33] and Distribution Price Control Review (DPCR) [34] in UK.

The impacts of DG on system reliability, in terms of measuring the expected energy not supplied (EENS) or amount of load shedding or reliability indices such as System Annual

Interruption Frequency Index (SAIFI) etc., have been investigated [35-38]. In [39] and [40], DG was utilised along with intentional islanding to improve the system reliability. In [41], an algorithm has been developed to strategically place DG to minimise the costs incurred during load shedding.

Multi-impact Analysis

It is however clear that DG simultaneously imposes different impacts on the system to which it is connected, while the impacts could be either beneficial or adverse to the network, depending on the DG characteristics, such as location, output, technologies etc., as well as the load demand. Therefore, substantial research has also concentrated on evaluating the DG performance in a multi-objective manner. A multi-objective index has been introduced by Ochoa *et al.* [42, 43] by aggregating sub-indices used for measuring the impacts of DG on system real and reactive power losses, voltage, thermal capacity of conductors and fault currents. A higher value of the multi-objective index given to DG implies that it would have more positive impacts on the distribution network. Later in [44], the multi-objective index was used as the objective function of an evolutionary algorithm to find the optimum placement and allocation of distributed wind power generation throughout a test distribution network to maximise the DG penetration level while satisfying the technical constraints. The use of an aggregated multi-objective index however will require deep knowledge from the decision maker to provide sensible weighting factors for each sub-index for yielding objective final results. In [45] and [46], approaches were developed to place DG strategically for network loss minimization and meanwhile to enhance the voltage profile. Singh and Verm*a* [47] analyzed the impacts of different load models on the optimum siting and sizing of DG to improve the voltage profile and thermal capability of the network as well as minimize the network losses. The results showed that different load models would affect the final strategy of siting and sizing DG considerably. In [48], the allocation of DG was optimised for the purpose of network voltage drop mitigation, increase of short circuit capacity and loss minimisation. In [49], the search of multi-objective solutions for sizing and siting stochastic and controllable DG (CHP, photovoltaic panels, wind turbines) was conducted by a specialized strength Pareto evolutionary algorithm (SPEA2). SPEA2 effectively generates non-dominated solutions which do not have superior performance related to one objective than another. The objectives such as minimization of network losses, annual energy curtailment from the DG, amounts of CO_2 emissions, etc., are taken into account. Comparing with the methods mentioned, instead of selecting the best solution based on a singe index, the approach allows the decision maker to analyse the impact of trade-offs between the objectives on the competitiveness of the solutions obtained, despite the computational burden of conducting the approach could increase substantially.

1.2 Economic Impact of DG on Network Planning

One major concern for DNOs, which are capital-intensive entities, about DG connection is its impact on network development. The technical impacts imposed by DG on distribution networks tends to promote changes in network planning, in terms of what types of reinforcements are required and when to connect them; therefore they could have significant influence on the planning costs.

As DG could bring many potential benefits to the connecting distribution network, it has been acknowledged as a feasible and economically attractive alternative to expensive traditional network upgrades, such as overhead lines and transformers. It is of great importance and interest for DNOs to consider DG within distribution network planning. Many approaches have been proposed to incorporate DG into distribution network planning. Soroudi and Ehsan [50] adopted the particle swarm optimisation technique to find the optimum DG allocation while minimizing the DG installation and operation costs, costs of purchasing power from the grid, and the environmental costs. Brown *et al.* [51] used the successive elimination method to work out the optimum network planning with and without the consideration of DG as a reinforcement option. The objective was to minimize the installation costs of the reinforcements while effectively reducing the network losses. The results showed that the cost of the network expansion planning considering DG was significantly less than the costs of the network planning without DG. In [52], multi-objective meta-heuristic algorithm was developed to tackle the problem of network planning considering DG. The objective function included the minimisation of installation costs, network losses and the enhancement of power quality. Instead of using one single multi-objective index, the algorithm was able to produce a set of Pareto solutions, which allowed the planner to understand the trade-off relationship between the objectives. Celli *et al.* [53] developed a multi-objective genetic algorithm to optimise the sizing and siting of DG in order to minimise the cost of network upgrades, losses, energy not supplied and the cost of purchasing energy. In [54], a novel heuristic approach was presented to analyse the economic benefits for distribution network companies of optimal siting and sizing of DG capacity. The objective was to maximise the profits by maximising the revenue from selling electricity from DG while minimising the costs of DG investment and operation, payments of buying energy from the grid, costs of network losses as well the costs of unserved power in the hourly basis.

However, the attitude of DNOs towards utilising DG to provide potential benefits to the distribution networks can be very different according to the eligibility of DG ownership by DNOs. In the countries, such as in USA, where DNOs are allowed to invest and own DG themselves, the location, capacity and the operation of DG would be completely based on the decisions of DNOs. Under this circumstance, DG can directly be used as an option for network expansion and can provide any services desired by DNOs, while its revenue from selling electricity would also contribute to the profits of DNOs. In other countries, such as the ones in the European Union (EU), in a deregulated electricity market one of the primary functions of DNOs is to promote the competition in the electricity market. As a result, DNOs in the EU are not allowed to have DG on their own accord. Under such circumstances, the fast growth of DG penetration has brought challenges to the DNOs. The location, capacity and operation of DG would depend on the interest of DG owners to maximise their own profits, despite the fact that such decisions made about the DG characteristics could degrade the distribution network efficiency and require additional reinforcements. The conflicts between DNOs and DG owners in terms of the agreement of final DG capacity and connection point has been perceived and addressed [55]. Such conflicts have tended to hinder the progress of DG connections and slow the pace to achieve the target of CO_2-reductions [56].

As a consequence, the only solution for DNOs in the EU to either mitigate the adverse impacts brought by DG or utilise it to provide system support services is to incentivise DG owners through the electricity market pricing system, e.g. DG connection charges and distribution use of system charges. At present, the benefits for DNOs in promoting DG connections in the UK arise from incentives offered by the regulator Ofgem, which include the reduction of network losses due to DG connections as DG incentive would offer modest reward based on per kW of DG capacity [57]. However, there is an argument that in the deregulated unbundled market, the market signal for DG connection has to be established also based on the real impacts of DG on the network [58]. Such impacts, which could be either positive or negative, would be recovered or compensated by DNOs over time through connection charges and the distribution use of system (DUoS) charging schemes [59].

Despite DG potentially imposing technical impacts on the system, the economic impact of DG can be assessed by DNOs by analysing the impact of DG on network planning, i.e., how DG affects the investment plan of network upgrades in terms of costs and the schedule in the future. Indeed, as shown in the results of [55], properly sharing the investment deferral benefits between DNOs and DG owners would tend to minimise the conflicts that arise due to the presence of DG. This leads to the importance of the quantification of the investment deferral of reinforcements caused by DG as the preliminary step towards establishing reflective market signals for DG connection. According to Jenkins *et al.* [60], quantifying the positive impact that DG brings to the network in reducing investment costs is a pre-requisite for establishing cost-reflective charging schemes for effective increases in DG penetration and achieving the target CO_2-reductions. Although the impact of DG on deferring new network upgrades is well acknowledged, there is relatively little research that quantifies the investment deferral impacts of DG [58, 61], which are not without drawbacks and will be discussed in later chapters.

1.3 Contribution of the Thesis

The contribution from the research concentrates on developing algorithms and models which not only able to analyse different technical impacts of DG on a distribution network, but also to convert those impacts into resultant economic impact of the DG from the point view of

DNOs. A flow chart of incentives to increase DG penetration effectively can be drawn and is shown in Fig.1.4, the resultant economic assessment of a DG connection together with other financial factors, such as real-time monitoring the usages of the network conductors by DG, would be essential factors to establish a cost-reflective network charging system to assist in increasing DG penetration effectively.

The different impacts of DG on distribution networks (thermal, voltage, security of supply, losses) are quantified through a range of optimal network planning methods developed for the purpose. The methods adopted depend on the problem contemplated. It is assumed here that the conditions prevailing in the UK apply so that under all circumstances DNOs can not own DG by regulation. The change in the resultant impacts of DG due to different DG characteristics, such as its location, installed capacity, penetration, technology and reliability etc., will be analysed. Furthermore, the impact of DG on network planning will also depend on how DNOs would utilise DG in network planning, i.e. whether DG would be treated as a temporary solution which merely causes the schedule changes of the reinforcements originally planned (investment deferral), or DNOs would regard DG as a new reinforcement option which could replace some traditional reinforcements permanently to derive a new network planning strategy.

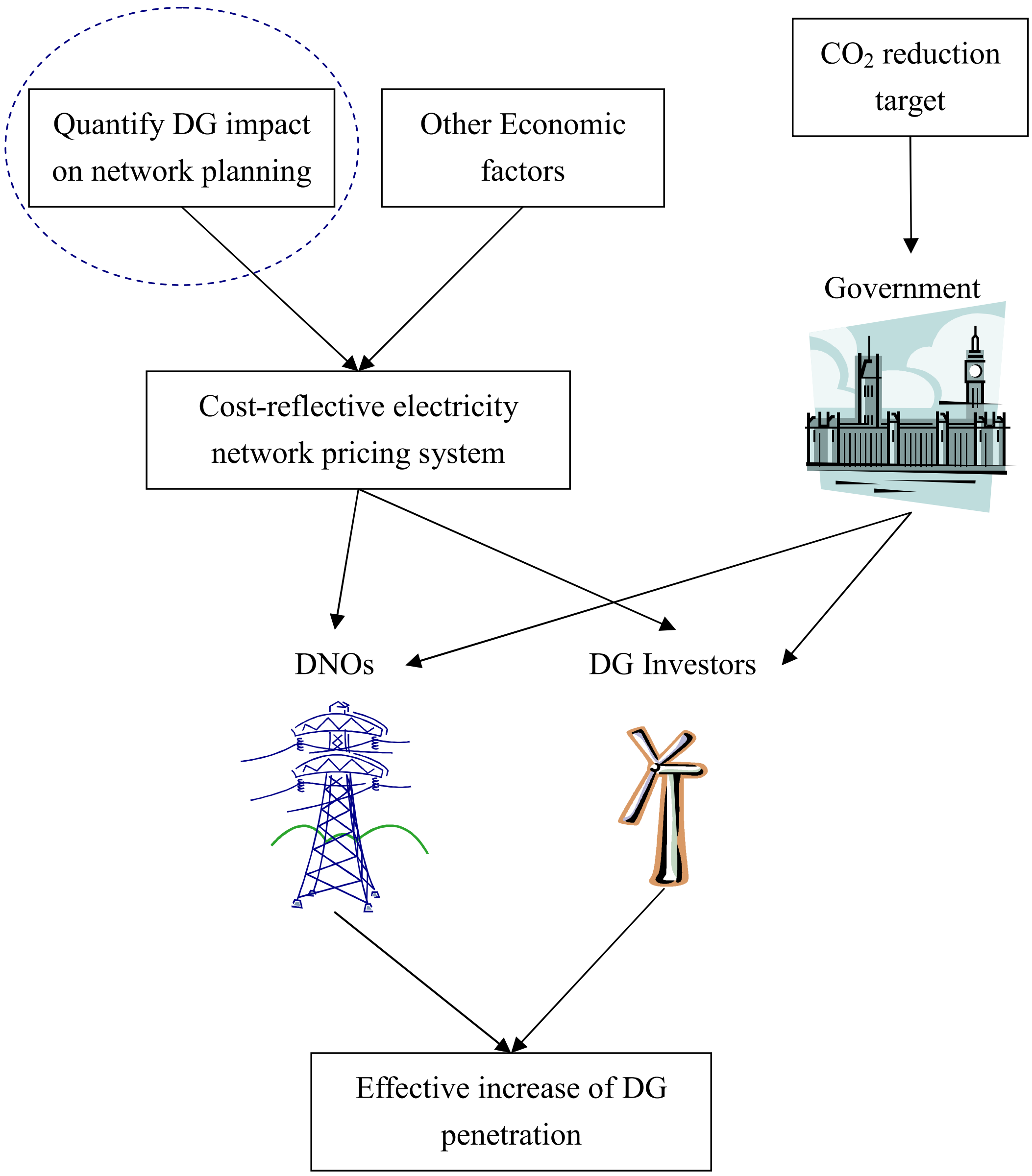


Fig. 1.4. A flow chart of incentives for effective increase of DG penetration.

<u>Thesis Hypothesis and Publications</u>

The main achievement of the thesis is to show that a DG connection could bring significant benefits to a distribution network not just a challenge. Despite DG characteristics (location, installed capacity etc.) are uncontrollable by DNOs, while through thorough analysis of DG technical impacts on the network and by converting the impacts into economic assessment the DNOs will be able to gain benefits by incorporating DG into network planning. Cost-reflective network charging mechanisms can be then developed by the DNOs and

Ofgem based on the quantified results. The novelty in the thesis hence lies in the methods developed for quantifying the impacts of DG and working out best network planning strategies considering such impacts. As a result, several papers are published or under preparation shown as follows:

Journal:

[1] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "DG Impact on Investment Deferral: Network Planning and Security of Supply", IEEE Trans. on Power Systems, May, 2010, in Press.

[2] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Modified GA and Data Envelopment Analysis for Multistage Power Systems Network Expansion Planning Under DG Uncertainties", IEEE Trans. on Power Systems, submitted.

Conference Proceedings

[1] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison, C.J. Dent, A.R. Wallace; "Evaluating investment deferral by incorporating distributed generation in distribution network planning", PSCC'08, 7pp, 14-18 July 2008.

[2] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Assessing the economic impact of distributed generation on voltage regulation in distribution networks", AUPEC'08, 6pp, 14-17 December 2008.

[3] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Distributed generation and security of supply: Assessing the investment deferral", IEEE/PES PowerTech 2009, 28 June-2 July 2009.

[4] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Expansion planning of distribution networks considering uncertainties", UPEC 2009, 1-4 September 2009.

1.4 Structure of the Thesis

The main content of thesis can be visualised in Fig. 1.5. Chapters 2 and 3 contemplate the impact of DG on the deferral of network reinforcements originally planned, while Chapters 4 to 6 lead on from these and concentrate on developing approaches to quantify the change in the optimal network planning strategies if DG is incorporated. The thesis is structured as follows:

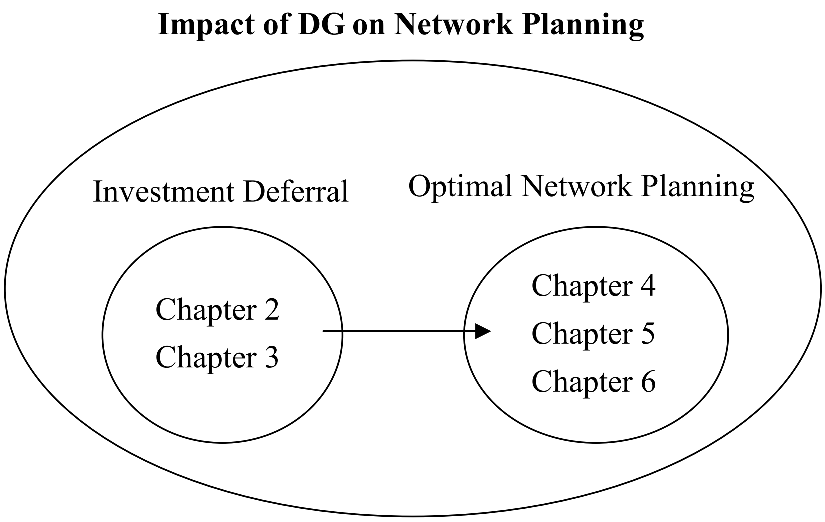


Fig. 1.5. Content flow of the thesis classified by different purposes.

Chapter 2 first explores the theory behind the impact of DG on reinforcement deferral. The successive elimination method is adopted to quantify the impact of DG on the investment deferral of load-related reinforcements required to solve the thermal and voltage problem in a radial distribution network.

In Chapter 3, the successive elimination method is substantially modified and is applied to a large meshed network. A real constraint of security of supply in the UK is added to conduct the experiment. The impact of additional different DG characteristics, such as technology, security contribution etc., on the investment deferral of the thermal- and security-driven reinforcements will also be analysed.

DNOs could utilise DG to solve different problems existing within the networks, while in the previous chapters voltage variation has not been a remarkable problem, which could cause the DNOs significant amounts of investments on voltage support devices. In Chapter 4, the ability of supporting network voltages with SVCs and DG are compared. The economic assessment is on the ability of DG as a substitute for SVCs to provide voltage services to prevent the violation of steady-state voltage and voltage step-change constraints. A modified voltage sensitivity method is developed to analyse the change in optimal allocation of SVCs caused by DG and is applied to a network which suffers from voltage problems. In the chapter the DNOs attitude towards considering DG into planning changes from passive toactive, from merely utilizing DG to defer the originally-planned reinforcements, to use DG as a reinforcement option in strategic network planning for take the full advantages of DG.

Chapter 5 considers the wider issue of network planning and in particular the issue of uncertainties as there will be uncertainties associated to DG. The novel balanced genetic algorithm is introduced and specialised for tackling network planning problems under uncertainties. The algorithm is applied to a green-field network planning problem considering the uncertainties of future load locations. The results are compared with the results obtained by conventional genetic algorithm. Improved data envelopment analysis is adopted to rank the optimum network planning strategies and determine the best one to adopt.

Chapter 6 concentrates on identifying the possibilities, the risks and benefits for network operators to incorporating intermittent DG into network planning. The balanced genetic algorithm introduced in the previous chapter along with a decision theory are prepared for solving the problem of optimum network planning considering the uncertainties about DG outputs and locations.

In Chapter 7 conclusions are drawn for the thesis, discussing the importance of the results as well as the advantages and limitations of using the approaches developed. The potential future directions of the work are also stated.

CHAPTER 2 – Quantifying Investment Deferral

2.1 Introduction

Chapter 1 outlined that depending on its location, technology, penetration and robustness of the system, integration of Distributed Generation (DG) may bring about various challenges for Distribution Network Operators (DNOs), and regulators [10, 60]. On the contrary, potential benefits can also be offered by DG in reducing carbon dioxide emissions. However, to establish proper market signals and therefore encourage DG developers it must be understood that other benefits brought about by these technologies should be assessed and quantified.

The potential for DG to alleviate network power flows and reduce power losses is a direct technical benefit for the DNO. However, its economic impact will be only seen depending on the corresponding regulatory agency's strategy for improving DNO efficiency. A more tangible economic benefit for DNOs can be through decongesting network assets, wherein DG has the ability to help avoid or defer reinforcements otherwise necessitated by demand growth in a given time.

Although the reinforcement deferral impact of DG has already been discussed by researchers and industry and UK DNOs are currently consulting on distribution charging methodologies that recognise the ability of DG to delay load-related investments [59, 62], this research aims to fully quantify it. In this work, the deferment will be considered as that which occurs when investments that are required to enable further capacity are postponed as a result of connecting non-intermittent DG (e.g., CHP, CCGT). Moreover, given the multistage nature of network upgrades, i.e., investments are performed throughout the planning horizon, the impact of siting DG in different stages will be also analysed.

The chapter is structured as follows: In Section 2.2 the methods to quantify the investment deferral impact brought about by DG are examined. Section 2.3 advocates the concept of measuring the investment deferral impact used in this chapter, followed by an overview of optimisation methods for network planning. The detailed descriptions of the approach developed here are shown in Section 2.5. Section 2.6 shows the application and results of the method and conclusions are drawn in Section 2.7.

2.2 Methods of Measuring Investment Deferral Impact of DG

The distinct approaches to define investment deferral were proposed in some literatures. These are revised in detail.

Method by Mendez et al

Mendez et al. [61] studied the impact of DG and different annual load growth rates on the probability of overload in a radial distribution network. The likelihood of overload reduced after DG was connected. Therefore, the time of investment deferral caused by DG can be measured by comparing the annual load growth rates which give the same level of overload probability of the network due to the connection of DG. The overload probability was obtained by using Monte Carlo simulation, which take the probability curves of load and generation variations, under different scenarios such as different load growth rates, DG technologies, DG penetration and concentrations. The maximum transfer capacity (MTC) of the network is determined by the capacity of the feeder which would be the first one to be overloaded as the load demand continuously increases. The distribution network was then modelled as a single branch with the capacity equivalent to the MTC. The simplified network is considered overloaded if the net demand (total demand – total generation from DG) is greater than the constant MTC.

Despite the results produced by Mendez *et al.* clearly showing the impact of DG on the capability of the network to accommodate higher annual demand growth and therefore defer the investment, the constant MTC is not a credible assumption if a meshed network is used and the location of DG is varied. Under such situations the location of the overload will change according to different load and generation patterns, resulting in different MTC values. Furthermore, the results only gave one investment deferral time and the impact of

DG on the cost of investment deferral of each reinforcement is not evaluated.

Method by Gil and Joos

Gil and Joos [58] developed a simple approach to quantifying network capacity investment deferral of DG by observing the change of currents within the network caused by DG across different locations. The impact of DG on the investment deferral can be visualised in Fig. 2.1, where the connection of DG decreases the power flowing through conductor *k*.

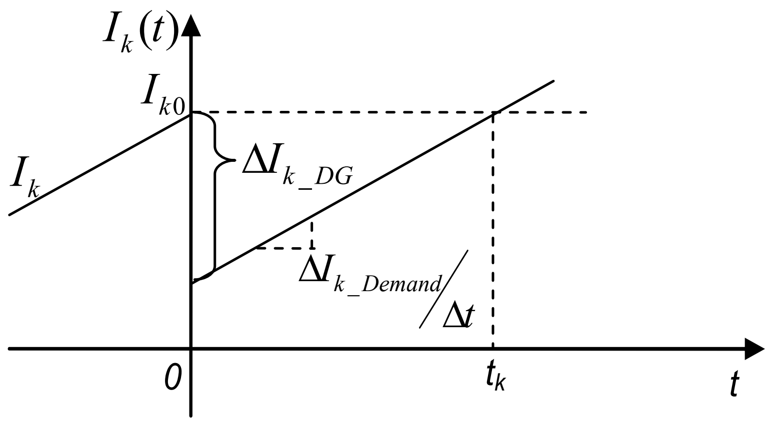


Fig. 2.1. Delay of investment t_k due to connection of DG.

As the demand grows, the current I_k flowing through the conductor increases and reaches I_{k0} at the instant before DG is connected. The connection of DG at $t = 0$ reduces the amount of current flow in the conductor by ΔI_{k_DG}. Continued demand growth will see current I_k take time t_k to recover back to I_{k0}. Time t_k depends on the increase of power flow ΔI_{k_Demand} in the conductor. The benefits from deferring the investment in new capacity caused by the DG would be measured by the cost difference in present value (PV) terms between the investments at $t = 0$ and $t = t_k$ using the exponential function:

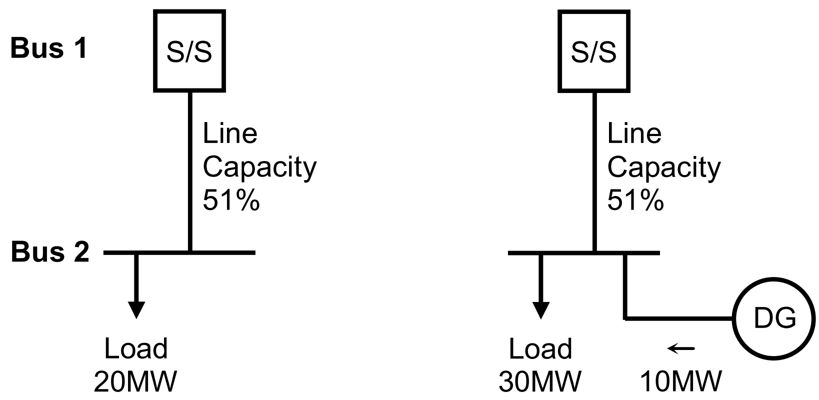
$$Investment \quad deferral \quad benefit = \frac{C_{k\_t=0}}{e^{\rho * 0}} - \frac{C_{k\_t=t_k}}{e^{\rho * t_k}} \tag{2.1}$$

where $C_{k\_t=0}$ and $C_{k\_t=t_k}$ are the investment costs of the new line at $t = 0$ and $t = t_k$, while ρ

is the annual interest rate.

Since the measured time of investment deferral t_k in this approach refers to the time required for the power flows in the conductor after DG connection to return to the level prior to the connection of DG, it is not, in fact, equivalent to the time interval when the real investment costs are deferred due to the DG. Therefore, the method proposed by Gil and Joos could lead to inaccurate results as described and illustrated below.

A simple example is shown in Fig. 2.2(a). A load of 20MW is supplied by the grid supply point through a substation and conductor, which is currently loaded up to 51% of its maximum capacity at the instant before the DG connection ($t = 0$). If the method of *Gil and Joos* is applied, to quantify the investment impact brought by a 10 MW DG connected at bus 2, then the time t_k is obtained when the network is at the operating condition shown in Fig. 2.2(b). In Fig. 2.2(b) the load at bus 2 has increased to 30MW until the conductor has used up its 51% of maximum capacity (the same level as in Fig. 2.2(a)).



(a) (b)

Fig. 2.2. Two-bus test system (a) Base year, no DG; (b) Load increase required to achieve the non-DG line capacity.

Assuming the annual load growth for this example is 3%, the time t_k for which the load is increased from 20MW to 30MW can be calculated:

$$Time\,Def. = \frac{\ln\left(\dfrac{Load^f}{Load^0}\right)}{\ln(1+i)} = \frac{\ln\left(\dfrac{30}{20}\right)}{\ln(1+0.03)} = 13.7 \text{ years}$$

where $Load^f$ is the future demand at $t = t_k$, $Load^0$ is the demand at the instant before $t = 0$, and i is the annual load growth.

However, as discussed previously, the argument is that since the investment deferral impact should be an economic evaluation, the time deferral must be based on when the reinforcements are needed. In other words, the interval should be measured between the instants when the actual expenditure for a reinforcement is made, not between $t = 0$ and $t = t_k$. The concept is shown in Fig. 2.3. Without the presence of DG, additional reinforcement is required when the thermal capacity of the existing conductor is reached, as shown in Fig. 2.3(a), an upgrade would occur when the load is increased to 39.2MW assuming the load is 20MW at base year $t = 0$. Assuming annual load growth is 3%, the time the investment is made t_1 would be a:

$$t_1 = \log\left(39.2/20\right) / \log(1+0.03) = 22.8 \quad \text{years.}$$

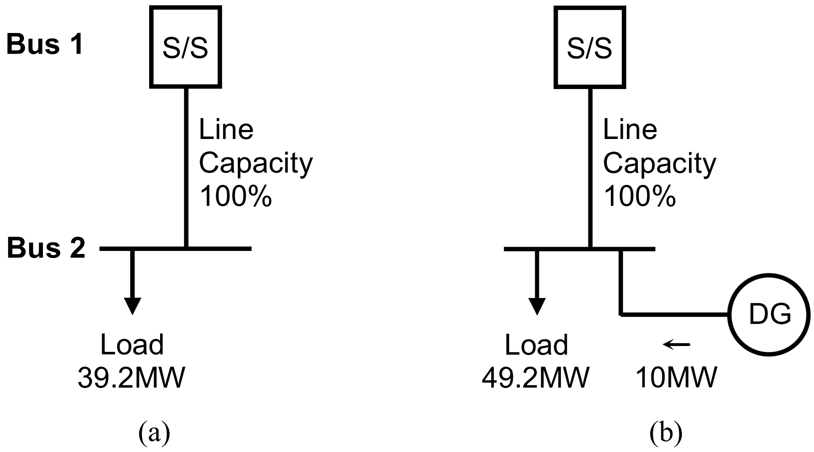


Fig. 2.3. Two-bus test system using maximum line capacity (a) Load scenario without DG; (b) Load scenario with DG.

Now consider the connection of a 10MW DG. As depicted in Fig. 2.3(b), the new reinforcement will now be required only when the load is increased to 49.2MW. The time for investment t_2 because of the DG connection is at:

$$t_2 = \log\left(49.2 \big/ 20\right) \big/ \log\left(1 + 0.03\right) = 30.5 \quad \text{years.}$$

The example shows that, the investment is deferred by 30.5 – 22.8 = 7.7 years, comparing with 13.7 years from the example in Fig. 2.2. This is the first point where the method developed by Gil and Joos would lead to the over-estimation of the investment deferral impact brought by DG.

The over-estimation is further magnified as Gil and Joos assumed DG would cause investment deferral immediately after it is connected, i.e. at $t = 0$. Supposing, the reinforcement would cost \$1m and the discount rate is 3%, according to the PV method, the investment deferral impact in the first example (Fig. 2.2) would be:

$$1 \big/ e^{0.03 \cdot 0} - 1 \big/ e^{0.03 \cdot 13.7} = 1 - 0.663 = \$0.337m \,.$$

Since the impact starts at $t = 0$, this amount is, in fact, the maximum one could get among all the cases where DG can postpone the investment by 13.7 years. If the investment is incurred at $t > 0$, then the amount will shrink due to the decreased present value. For instance, if $t_1 = 5$ and $t_2 = 5+13.7 = 18.7$, then the investment deferral impact would be:

$$1 \big/ e^{0.03 \cdot 5} - 1 \big/ e^{0.03 \cdot 18.7} = 0.8607 - 0.5706 = \$0.29m \,.$$

In the previous example, as the investment in a new conductor does not really occur at $t = 0$, the method by Gil and Joo*s* would further over-estimate the benefit through the PV method. The investment deferral impact yielded in the second example (Fig. 2.3) would be \$0.104m, which is only 30% of the amount estimated in Fig. 2.2.

2.3 Robust Quantification on Investment Deferral Impact

To draw a conclusion from the last section, to quantify the investment deferral impact of DG would require the following information:

1. The costs of the reinforcements.
2. The time period by which the investments are deferred by DG
3. The connection schedules of the reinforcements in both cases with and without the presence of DG.

The accuracy of the variables above would affect the quantified values. The values of all the variables can be obtained from the results of a power systems planning exercise. Therefore, by observing how DG could affect the results of the network planning within a specified time frame, its investment deferral impact can be properly evaluated.

The approach proposed here for quantifying the investment deferral impact consists of two stages. Firstly, a network planning method is adopted to determine the essential reinforcements for a distribution network at the end of specified planning horizon. Secondly, in the stage of multi-stage planning, the schedule of each reinforcement will be determined. Then the total cost of the investment plan is calculated using the PV method. By comparing the costs of the reinforcement plans between the scenarios with and without the presence of a DG, the investment deferral impact of DG on the connected distribution network can be quantified.

2.4 Overview of Network Planning Optimisation Methods

The preliminary element required for finding an optimal network planning strategy is to decide which optimisation method to adopt. The optimisation methods which have been used for tackling the problems in the context of electric power systems are explained here.

2.4.1 Mathematical Optimisation Methods

Optimisation methods can be classified into two categories: mathematical optimisation and evolutionary algorithms. In mathematical optimisation methods, the problem is modelled as strict mathematical equations including an objective function which is subjected to several constraints. Linear programming, non-linear programming, integer and mixed-integer programming and dynamic programming belong to this class. One major difference between the methods is the way the problem is formulated.

Linear Programming

In linear programming (LP), all the objective functions along with constraints are formulated as linear equations. The major advantage of LP is its relative simple way of describing the problem which leads to a high computational efficiency. While LP can be used to solve DC power flow comfortably, difficulties arise for LP in formulating a problem involving AC power flow that is non-linear in nature. Under this situation LP would not be able to formulate the problem accurately and the computational burden would increase significantly. Nonetheless, LP has been applied to solve optimal power flow [63], reactive power planning [64], and active and reactive power dispatch [65, 66].

Non-Linear Programming

Contrary to LP, non-linear programming (NLP) uses non-linear equations to model problems that are not linear in nature, including objective functions and constraints. The general approach in NLP is to first guess a feasible solution and then work out a direction towards which the objective function can be optimized, example includes Newton-raphson method and interior point etc. A common problem of using NLP methods is that with an inappropriate initial guess may result in a solution divergence. Therefore, normally a flat start is used, i.e. the first guess will include all the same variable states set to a sensible and fixed value. Optimal power flow typically is solved as NLP [67]. Following the direction the variables are continuously updated through iterations. Examples of using NLP to power systems applications can be found in [68], such as economic dispatch and to minimise network losses.

Integer and Mixed-Integer Programming

The mathematical formulation of a problem in integer programming (IP) is similar to that of LP with the additional constraint that all the variables have to take integer values. In mixed-integer programming (MIP) only the variables specified in the constraint are bound to be integers. A popular approach used in IP and MIP is called 'Branch-and-Bound' technique. The concept of Branch-and-Bound technique is first dividing the whole set of feasible solutions into smaller subsets, and then to examine how good the solutions in each subset are. A subset is abandoned if it is found that it is very unlikely the subset would contain the optimum solution in respect of the whole problem [69]. Both IP and MIP have been applied successfully to many power systems problems, such as power systems planning [70, 71], unit commitment [72, 73], and generation scheduling [74].

Dynamic Programming

Dynamic Programming is a technique to make a sequence of decisions which are inter-related. Different decisions would lead to different states between the origin and the optimal point. The concept is based on the idea that the optimal point would be achieved if the path which consists of all optimal decisions towards the optimality is chosen. DP is powerful but suffers from large dimensionality in the decisions identified in the problem [75]. DP had been applied to areas such as voltage control [76], planning [77] and unit commitment [78].

Benefits and Costs of Mathematical Optimisation Methods

The optimisation methods described above are all well-defined and mature techniques which are ready to apply to large-scale power systems. Under strict mathematical formulation the optimal solution is normally guaranteed if the problem tackled can be accurately described mathematically. However, power systems problems are usually complicated, non-linear and non-convex, which leads to significant difficulties for the mathematical optimisation methods to accurately formulate the problems into mathematical equations. As a consequence, adopting mathematical optimization methods to solve power systems problems have been observed to have frequent convergence problems and the final solution is often a mere local optimum [79].

2.4.2 Evolutionary Algorithms

This class of optimisation methods relies on the ability of computers to search for the optimum point on the vast solution space while binding to some searching rules. Since the 1990s the optimisation methods, which utilise artificial intelligence (AI), have become very common in academic literature for solving various problems in the power systems. Apart from genetic algorithms, which will be explained in detail in Chapter 5, Tabu search, simulated annealing, and particle swarm optimisation will be explained in the following paragraphs.

Tabu Search

Starting from one initial solution, the Tabu Search (TS) improves the solution iteratively until the solution reaches the optimum point. The improvement of the solution is guided by the *aspiration level*, *tabu list* and *moves* [80]. The *aspiration level* which is similar to the objective function, defines what makes a better solution. The solution intends to improve itself by changing the value of one variable in a small step each time and evaluating the performance resulting from the change. After all the possible changes are experienced, the solution then permanently changes to the state which yields the best performance (*move*) among all the changes examined. The tabu list stores the *moves* which the solution has previously made in order to prevent the solution repeating the same *moves* and avoiding an infinite loop in the algorithm. To prevent the search being trapped into local optima, the algorithm offers a random chance of accepting the *moves* which actually guide the solution into another having worse performance. Power systems examples where TS had been utilized to yield optimal network planning and can be found in [80, 81].

Simulated Annealing

Simulated annealing (SA) imitates the process of cooling a solid material in order to form a crystalline structure [82]. Slower cooling processes result in a more perfect (defect free) crystal, which in SA implies a more detailed searching in the solution space. Starting from an initial solution, a stochastic mechanism is used, such as add-swap-remove or remove-swap-add [82], to generate another new solution by changing some variables in the current one slightly and randomly. If the new solution has a better objective function value than the old solution, then it would replace the old solution. Otherwise, it can still substitute the old one by random changes for the purpose of preventing the search being trapped into local optima. The search continues to find new solutions whose values of objective function are within the currently defined range ('temperature' range). A smaller temperature range would result in a more detailed search for the solutions but increases the computational burden. After some requirements have been met, the search will be directed into the area in which the solutions would have their objective values lying within the next defined temperature range. Power systems applications of SA such as optimal network planning and unit commitment can be found in [82-84].

Particle Swarm Optimisation

Particle swarm optimisation (PSO) is another evolutionary algorithm that has attracted attention. The concept of PSO is from the observation that information is shared within a swarm of individuals, e.g. a flock of birds, in order to achieve the same objective (e.g. finding food), while the behaviour of each individual would be affected by the experiences (information) and the behaviour of others in the group. The PSO starts with a population of individuals and each is currently occupying one single solution space within the whole solution dimension. The direction of searching the next solution space for each individual depends on its current searching direction and the direction towards where the best solution is in the population with an addition of some random attributes. As a consequence, the searching points usually get closer to the optimal point after each iteration. PSO is at its best in tackling problems containing continuous variables rather than the problems of network planning. More detailed explanation of PSO and its power systems applications such as optimal reactive power planning and loss minimisation can be found in [85-87].

Benefits and Costs of Evolutionary Algorithms

The common advantage of the evolutionary algorithms is that they do not require strict mathematical formulations (unlike the mathematical optimisation methods) and therefore are suitable for tackling combinatorial optimisation problems. They have shown their capability to obtain optimal or sub-optimal solutions instead of the local optimum [88]. The disadvantages are that stochastic mechanisms are involved in the evolutionary algorithms, which make methods in this class prone to stochastic errors. For example, it is possible that due to the random process inserted in an evolutionary algorithm, a solution is selected which is not actually the best one among all the available options. As a result premature convergence is common in the algorithms that are not well-designed. It remains the case that evolutionary algorithms also cannot guarantee to find an optimal solution.

2.5 Quantifying Reinforcement Deferral Impact of DG: The Applied Approach

The approach proposed here to quantify the investment deferral impact of DG on network reinforcements includes three major phases. A successive elimination (SE) method is adopted to find the optimal network reinforcement plan at the end of the specified planning year in the cases with or without DG. Then a multistage planning method is used to determine the timing of the reinforcements along the planning horizon. Finally, the costs in present value of the essential reinforcements are calculated using the present value (PV) method.

2.5.1 Successive Elimination Network Planning Method

Brown *et al* [51] proposed a SE algorithm for distribution network expansion considering DG as a reinforcement option. The results showed that a network expansion plan which uses DG is cheaper than the optimum expansion plan that does not consider DG as a reinforcement option, as DG can be a very effective source to improve network efficiency. The SE method proposed is a simple planning technique making it possible to calculate the investments required by the non-DG and DG scenarios, thus obtaining the corresponding economic benefit.

It is important for all the related parties, such as DNOs, the regulator and DG customers, to understand how benefits or charges are derived for DG connections. Therefore, a method needs to be transparent and easily understandable. However, the mathematical optimisation methods and evolutionary algorithms mentioned in the previous sections can not fully meet this requirement. The mathematical methods are often too complicated while the evolutionary algorithms usually do not produce the same results between each execution. On the contrary, the successive elimination (SE) method applied here, which is a so-called greedy heuristic (examine all reinforcement options before making the best choice), is straightforward and rule-based, making the process easily understandable by the planner and other market participants due to the use of a cost-effectiveness index, especially when the results will be integrated into some economic process such as DG connection and DUoS charging schemes.

The SE method starts by initially overbuilding the network with all possible reinforcement candidates including transformers and lines. Then, the least cost-effective option is removed until the further removal of any remaining candidate would cause system constraint violations during the planning horizon.

Strictly speaking, SE method is a meta-heuristic optimisation method but does not belong to either mathematical or evolutionary algorithm. While the optimisation-based planning strategies for distribution networks shown in the previous section are commonly found in the literature and could give a better solution than so-called greedy heuristics like SE, the latter will still produce a satisfactory solution [89]. Fig. 2.4 shows the flow chart for the SE technique, while the steps of the methodology are as follows:

Step 1. Consider the load demands corresponding to the year at the end of the planning horizon.

Step 2. Identify all the required network capacity expansion options (lines, transformers etc.) and connect them to the network. Verify that the overbuilt network has no constraint violations (thermal and voltage).

Step 3. Disconnect each expansion candidate in turn and verify there are no constraints violated or load not being supplied. If so, calculate its cost-effectiveness using the following equation:

$$CE_a = \frac{P - P_a}{Cost_a} \tag{2.2}$$

where CE_a is the cost-effectiveness measurement of option a in MW/$, P is the total MW flow of the network before option a is disconnected, P_a is the total MW flow of the network without option a, and $Cost_a$ is the cost of option a. The candidate is then put into an elimination list. Step 3 is repeated until all expansion candidates have been examined.

Step 4. Compare the cost-effectiveness of all the options in the elimination list. Find the least cost-effective candidate and remove it from the network. If the list is not empty, go to Step 3, otherwise go to Step 5.

Step 5. The final expansion plan has been determined. Save the remaining candidates for the multistage planning analysis.

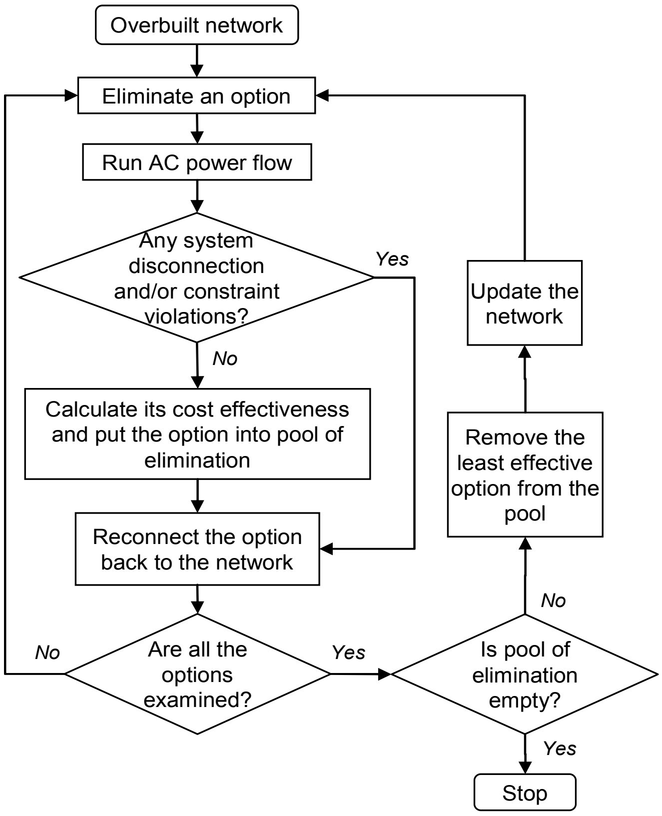


Fig. 2.4. Flow chart of the successive elimination method.

2.5.2 Multistage Planning Analysis

The purpose of the multistage planning analysis is to schedule the implementation of the essential reinforcements obtained from the SE method along the planning horizon. Thus, by scheduling the reinforcements according to the demand growth it is possible to calculate the PV and therefore evaluate the investment deferral produced by the connection of DG at different stages.

Starting at the base year of the planning horizon and, with the expansion options identified by the SE method, the multistage analysis requires the following steps. Fig. 2.5 shows the flow chart for this analysis.

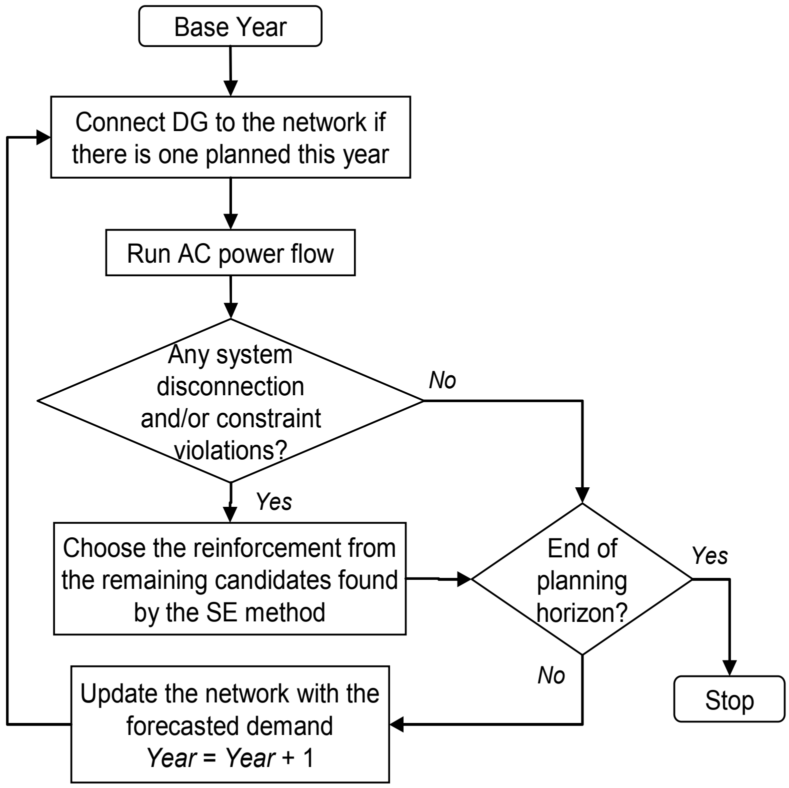


Fig. 2.5. Flow chart of the Multistage Planning.

Step 1. Forecast the demand for the base year (year 0).

Step 2. Connect any scheduled DG. Verify whether there are system disconnections (isolated sections) or constraint violations. If no, go to Step 3, otherwise connect one remaining reinforcement found by SE method in turn from the most cost-effective to the least one. Disconnect the reinforcement if it does not solve any constraint violations and connect the next one in the list until all the constraints are met for this year.

Step 3. Stop if the planning horizon has been achieved. Otherwise, forecast the demand for the next year and return to Step 2.

2.5.3 Calculation of Investment Deferral

From the previous two subsections, the capacity upgrades for the network expansion and the corresponding scheduling of investments can be determined. To obtain the total investment incurred by each planning scenario studied, the present value of each upgraded asset should be calculated. In this way, the total present value (PV) cost of the plan is given by:

$$\mathrm{PV} = \sum_{t=1}^{h} \sum_{i=1}^{n} \frac{C_{i,t}}{e^{\rho \cdot t}} \tag{2.3}$$

where h is the number of years in the planning horizon, n is the number of reinforcements required for year t, $C_{i,t}$ is the cost of asset i required for year t, and ρ is the continuously compounded discount rate (%).

The investment deferral, as a benefit brought about by the connection of new DG, is then calculated by subtracting the PV of the total investment required by a given DG planning scenario from that of the original (no new generation) planning scenario:
Investment Deferral

$$\text{Investment Deferral} = \left.\sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{e^{\rho \cdot t}}\right|_{no\ DG} - \left.\sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{e^{\rho \cdot t}}\right|_{DG} \tag{2.4}$$

2.6 Application and Results

2.6.1 Applied Network and Assumptions

The successive elimination method and multistage planning analysis were implemented in the commercially available PSS/E power systems modelling environment using the Python programming interface, as shown in Fig. 2.6. The algorithm of SE planning is programmed in Python including the built-in functions to command PSS/E to run AC power flows and check the network constraints.

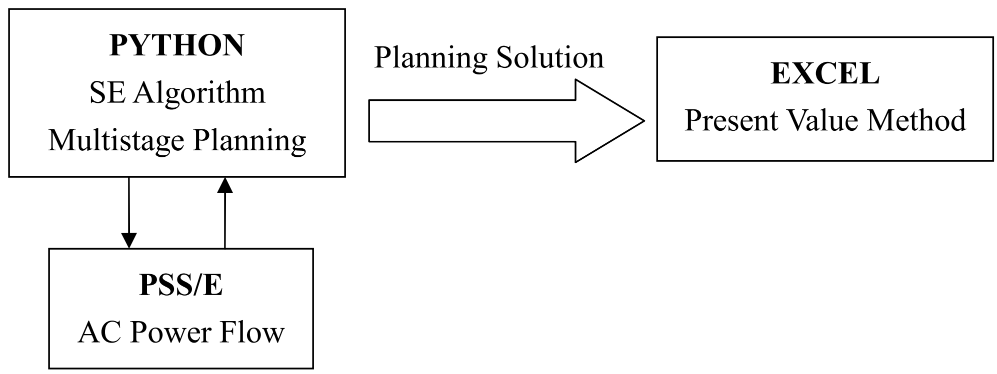


Fig. 2.6. Interaction between the tools used in the approach.

The methodology is applied to a 20-bus distribution network, as depicted in Fig. 2.7. It is a simplified circuit from the UK Generic Distribution System (UK GDS) – EHV Network 6 [90]. The network topology is highly radial while the major branches are supplied by the 275kV grid supply point via 275kV/132kV transformers. Energy is delivered though 132kV lines and step down to 33kV when entering the major load zones with high customer density. All loads are connected at 11kV and total 173.4 MW. It is shown in the diagram that some of the transformers are already heavily loaded at the base year. The MVA rating and the current loading of each line and transformer in the base year are also shown in the diagram.

First, the traditional planning analysis, i.e., excluding DG, is applied to the distribution network. Then, in order to evaluate the locational deferral benefit throughout the circuit, a single DG unit is placed at each load node in turn. Finally, the investment deferral when DG is connected at different stages of the planning horizon (15 years) is studied. A load growth of 2% and a real discount rate of 6% were adopted. Voltage limits were set to ±6% of the nominal voltage UK standard as required by Engineering Recommendation P28 [91]. The generation capacities analysed here will be small relative to the load, therefore, DG-led reinforcements will not be considered in the planning costs. It is possible that DG could postpone an investment of a new reinforcement to beyond the specified planning period; in order to prevent over-estimating the results by ignoring the investment, it is assumed in such cases the reinforcement is connected at the final year of the planning period.

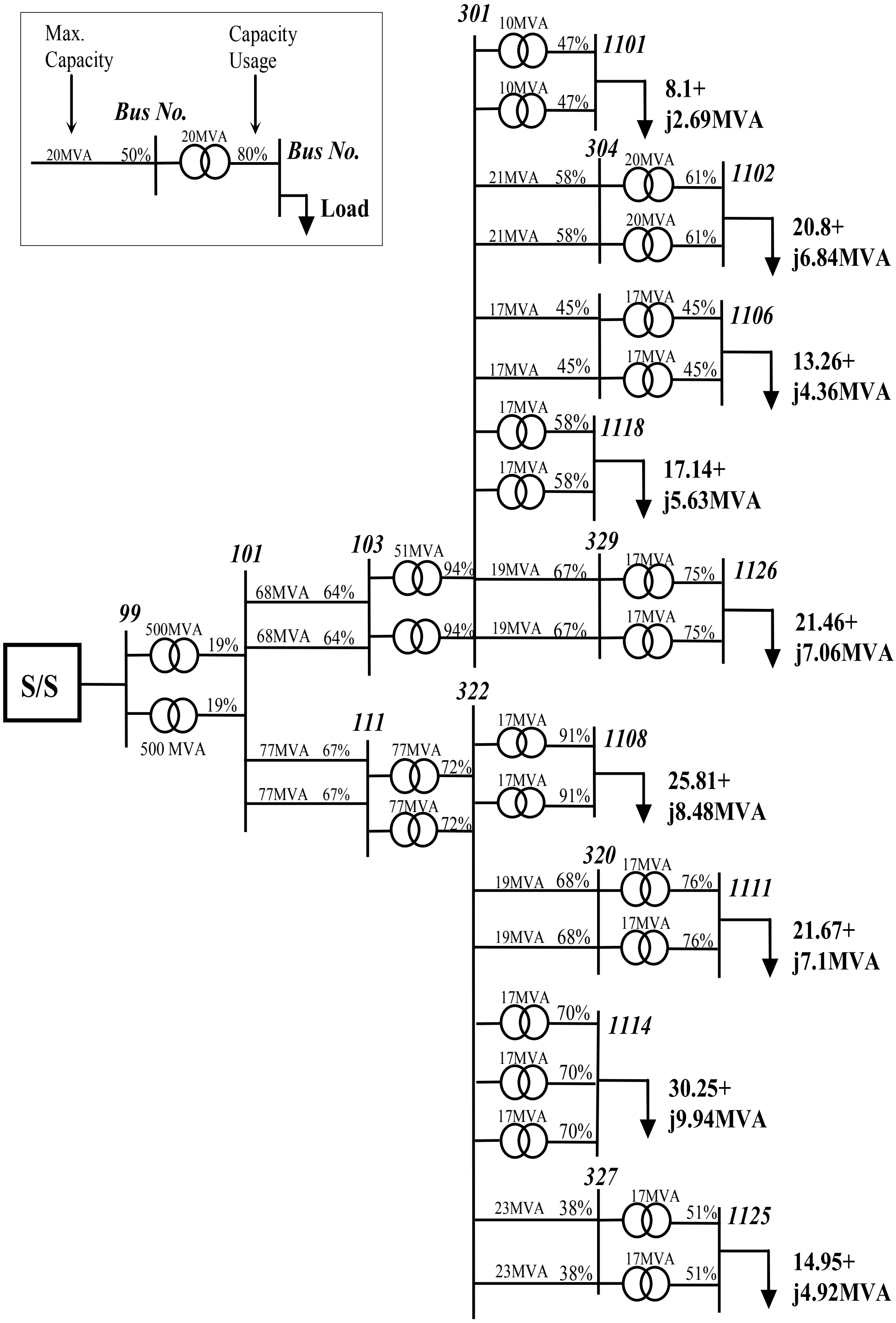


Fig. 2.7. Simplified 20-bus network from the United Kingdom Generic Distribution System.

2.6.2 Traditional Planning Analysis

Table 2.1 indicates the cost of reinforcement options for building an overbuilt (dummy) network, while after applying the successive elimination method and the corresponding multistage analysis for the case without DG, Table 2.2 presents the scheduling of the investments required along the 15-year planning horizon. The cost data is from [92] and the costs are indicative only. The present value of the total planning investment accounts for approximately US$ 1.91 million. The most expensive reinforcement is the parallel 132/33kV transformer connected between bus 103-301 (in the upper branch), which is also the most urgent one and required to be connected at year 3. Despite the cost of the transformer connecting bus 111 and 332 being as expensive as the one at location 103-301, its cost in present value is much less due to its connection at the end of the planning horizon.

Overhead line

Voltage (kV)	Capacity (MVA)	Cost/km (10^3 US$)
33	30	100
33	50	130
132	90	145
132	100	155

Transformer

Voltage (kV/kV)	Capacity (MVA)	Cost (10^3 US$)
132/33	68	1212
132/33	78	1350
33/11	23	248
33/11	30	310

Table 2.1. Cost of reinforcement options considered to build a dummy network.

Location	**Feeder**	**Capacity (MVA)**	**Cost (10^3 US$)**	**Year of Execution**	**Present Value (10^3 US$)**
103-301	103	1 x 68	1212	3	1012.10
322-1108	111	1 x 23	248	5	183.80
320-1111	111	1 x 23	248	13	113.74
329-1126	103	1 x 23	248	14	107.11
111-322	111	1 x 68	1212	15	492.64
				Total Investment Required	*1909.39*

Table 2.2. Scheduling of new transformers required along a 15-year planning horizon, without considering DG connection.

From Fig. 2.7 it can be seen that the capacity usage of the lines is relatively low compared to that of the transformers. Indeed, given the initial characteristics of the network assets, the 132:33kV transformers located at 103-301 (2x51MVA; 6% capacity headroom) need to be upgraded sooner than those at 111-322 (2x77MVA; 28% headroom). Also due to the capacity usage, reinforcements are also required for those transformers corresponding to the loads at 1108, 1111, 1126, which are the 2nd, 3rd and 4th largest loads of the systems. The most heavily loaded bus (1114) is served by three transformers (3x17MVA) guaranteeing enough spare capacity. No line needs reinforcement.

2.6.3 DG Analysis – Base Year Connection

The initial analysis considered the connection of a single generator (unity power factor) at the 11kV bus 1126 commissioned in the base year, i.e., at the beginning of the planning horizon. By applying the methodology presented in the previous section it is possible to compute the new total investment required and the corresponding schedule of new equipment for different capacities of DG. Results shown in Table 2.3 clearly indicate the impact of the generator on displacing the need for further network capacity, creating a new scheduling for those transformers required for the non-DG planning scenario (Table 2.2) and, therefore, deferring the investment.

Year of Execution	no DG	DG Capacity (MW)					
		1	2 - 3	4 - 5	6 - 7	8 - 9	10
3	**103-301**	**103-301**					
4			**103-301**				
5	322-1108	322-1108	322-1108	**103-301** 322-1108	322-1108	322-1108	322-1108
6					**103-301**		
7						**103-301**	
8							**103-301**
13	320-1111	320-1111	320-1111	320-1111	320-1111	320-1111	320-1111
14	**329-1126**						
15	111-322	111-322 **329-1126**	111-322	111-322	111-322	111-322	111-322
>15			**329-1126**	**329-1126**	**329-1126**	**329-1126**	**329-1126**
Present Value (US$)	1909.39	1903.15	1838.34	1782.83	1730.55	1681.32	1634.96
Investment Deferral		0.33%	3.72%	6.63%	9.37%	11.94%	14.37%

Table 2.3. Scheduling of new transformers required along a 15-year planning horizon with various DG capacities connected at bus 1126.

It can be verified that while the schedule of those transformers located in the feeder below bus 103 (in bold) was affected, the connection of the DG had no influence on the capacity upgrades required for the feeder below bus 111. Moreover, in this particular case, it can be seen that the larger the power output, the larger the investment deferral.

The same analysis was applied to each of the load buses in turn. The planning investments required for the planning horizon were calculated for different DG capacities at unity power factor. Fig. 2.8 shows the investment deferred as a percentage of the total expansion cost without DG (Table 2.2), for the most and least sensitive buses for each of the two main feeders. Due to the high cost of a new transformer at 103-301 and, given the need for its near-term replacement, placing a generator with significant capacity at any of its downstream load buses results in larger savings than siting the DG unit within feeder 111. However, as illustrated in Fig. 2.8, within the same feeder the location of the generator also influences its ability to defer investments. Since it is the headroom of the transformers upstream from the loads that also determines how soon reinforcements will be needed, proper siting of DG is able to bring about the largest benefits. Consequently, a larger penetration of DG does not necessarily mean a larger investment deferral benefit.

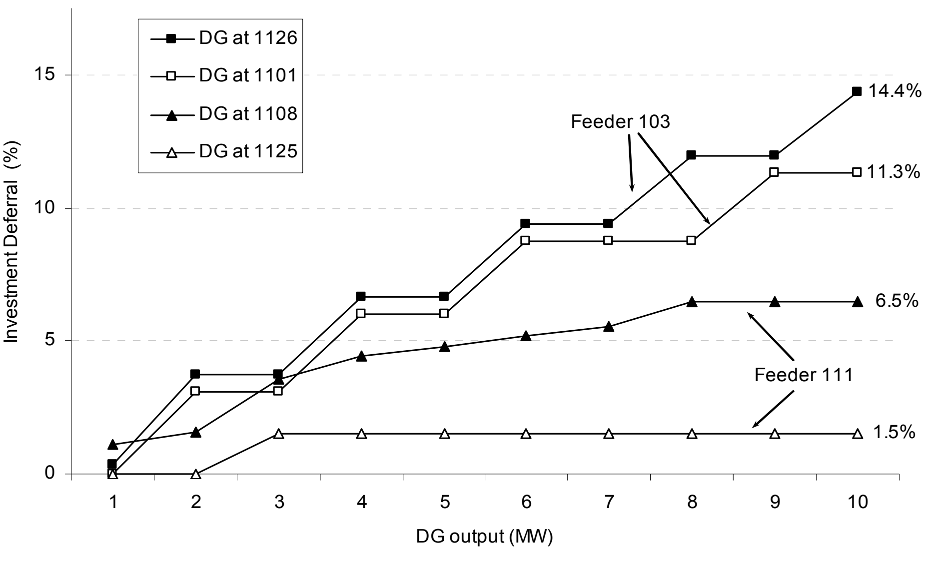


Fig. 2.8. Investment deferral benefit with single DG unit of different capacity at several locations.

Another parameter that influences how the DG connection impacts on the total expansion cost is its power factor. Fig. 2.9 shows the results corresponding to the connection of a DG unit at bus 1126, varying its power output and considering 0.9 lagging (injecting reactive power), unity and 0.9 leading (absorbing reactive power) power factors. As expected, the lagging power factor scenario improves the network voltage profile, increasing also the capacity headroom, and therefore postponing investments. On the other hand, leading power factor forces earlier circuit reinforcement and, above a capacity of 7MW, the need for capacitors to support feeder voltage.

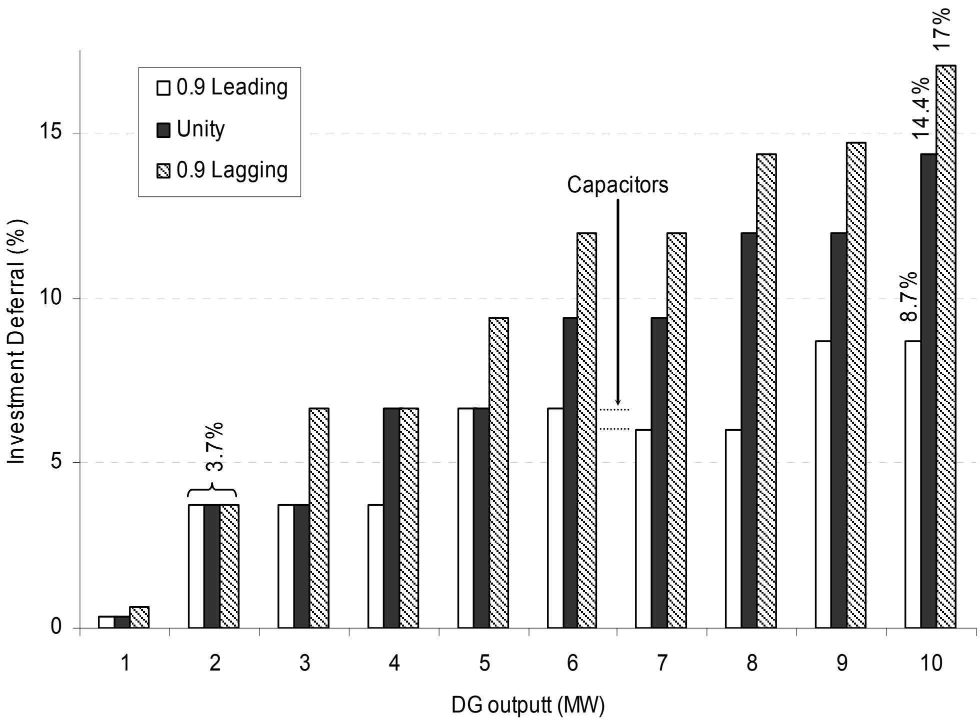


Fig. 2.9. Investment deferral benefit of different DG capacities and power factors at bus 1126.

By analysing the DG impact on the total expansion planning cost, as shown in Fig. 2.8 and Fig. 2.9, it is possible to obtain the average investment deferral per MW of a single DG unit connected to each of the studied load buses. These values are shown in Fig. 2.10. As expected, siting a generator at bus 1126 leads to the largest benefits per MW, suggesting that, from the DNO point of view, a DG of any size would be better located there than at any other point of the network in order to defer the most investment. It can also be verified, as observed in Fig. 2.10, that larger benefits are achieved when a lagging power factor is adopted by the generator.

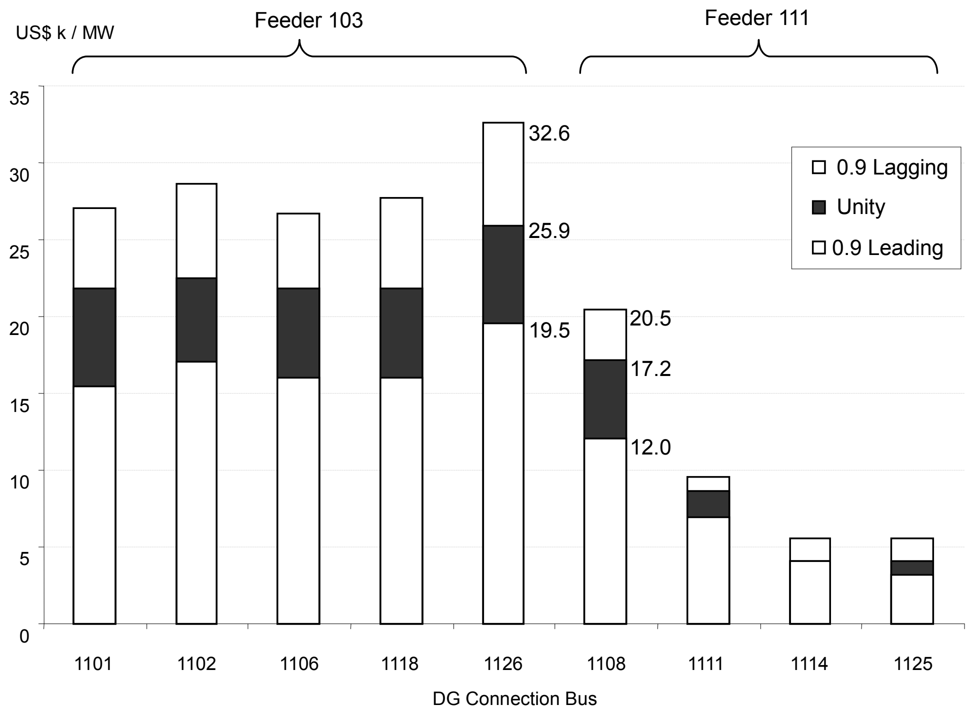


Fig. 2.10. Investment deferral per MW of a single DG unit.

2.6.4 DG Analysis – Scheduling Connection

In the previous subsection the commissioning of the DG unit was considered to take place at the base year of the planning horizon. As the proposed methodology highlights the scheduling of the required investments, the effect of different commissioning times of DG can be evaluated. Table 2.4 presents the investment deferrals produced by connecting a 5MW generator (unity power factor) at bus 1126, considering three different commissioning times: base year, year 3 and year 4. The load growth requires the feeder 103 to be reinforced at year 3 with the installation of an extra 68MVA transformer (non-DG case, Table 2.2). Therefore, the placement of a DG unit during that period will reduce the local load, alleviating the power transfer and defer part of the investment. On the other hand, Table 2.4 shows that commissioning the generator at year 4 will only delay the installation of the

23MVA transformer (329-1126) directly upstream from the DG, resulting in few savings.

The effect of two 5 MW, unity power factor, DG units located at buses 1126 and 1108, which presented the largest sensitivities for each feeder (Fig. 2.8 and Fig. 2.10) are shown in Table 2.5. The investment deferral benefit of both generators was found to equal the sum of their individual benefits (Fig. 2.8). This is explained by the fact that DG sited in one feeder does not affect the loads or the planning process of the other (although protection schemes in neighbouring feeders might need to be reinforced; this scenario was not considered). Additionally, the effect on the investment deferral produced by the late commissioning of the generators can also be verified in this case.

Year of Execution	no DG	Comissioning of DG at bus 1126 (Year)		
		0	3	4
3	**103-301**			**103-301**
5	322-1108	**103-301** 322-1108	**103-301** 322-1108	322-1108
13	320-1111	320-1111	320-1111	320-1111
14	**329-1126**			
15	111-322	111-322	111-322	111-322
>15		**329-1126**	**329-1126**	**329-1126**
Present Value (US$)	1909.39	1782.83	1782.83	1897.28
Investment Deferral		6.63%	6.63%	0.63%

Table 2.4. Scheduling of new transformers required with different commissioning times for a 5MW DG at bus 1126.

Year of Execution	no DG	Comissioning of DG at buses 1126 & 1108 (Year & Year)		
		0 & 0	3 & 5	4 & 6
3	**103-301**			**103-301**
5	322-1108	**103-301**	**103-301**	322-1108
12		322-1108	322-1108	
13	320-1111	320-1111	320-1111	320-1111
14	**329-1126**			
15	111-322			
>15		111-322 **329-1126**	111-322 **329-1126**	111-322 **329-1126**
Present Value (US$)	1909.39	1691.10	1691.10	1868.59
Investment Deferral		11.43%	11.43%	2.14%

Table 2.5. Scheduling of new transformers required with different commissioning times for two 5MW DG connected at buses 1126 and 1108.

In this network, it is relatively straightforward to work out which reinforcement schedule would be affected by the DG at a certain location. However, the necessary upgrades are not obvious in meshed networks where changing the impedance of a line changes flow patterns in the network, making it difficult to predict the rate of current change in the conductors due to increase of a load demand without load flow analysis. This is also the case in any network (meshed or radial) where voltage constraints are important or where a wider range of upgrades such as VAr support is available.

2.7 Chapter Summary

An approach for quantifying the impacts that DG may have on the deferment of demand-related network reinforcements was developed, taking into account the effects of the generator's capacity, location and commissioning time. A successive elimination technique along with a multistage planning analysis was adopted in order to determine the required investments and their corresponding scheduling. Knowledge of the required assets and their commissioning time along the planning horizon enables identification of those assets affected by the connection of DG, making it possible to obtain the corresponding new total investment cost. DG-led reinforcements were not considered in the analysis due to the relatively small DG penetration studied, however a procedure to take into account such investments can be incorporated into the proposed methodology.

Results showed that the investment deferral varies significantly with the location, size and even the control strategy (power factor) of the generator. Furthermore, the calculation of the investment deferral per MW of DG appears to be a useful index for DNOs to identify the connection points that are most beneficial, recognising at the same time the extra value of DG. While Fig. 2.8 is useful in identifying the investment deferral trends with DG capacity, it is with Fig. 2.10 that a better comparison of the benefits brought about per MW of DG can be made.

In the EU, DNOs are usually not able to own generation or decide the commissioning time of new developments. However, the second analysis clearly shows the impact that DG have when considered as an option in the planning process in order to defer demand-related investments. While regulations are unlikely to change in certain countries and uncertainties surround the actual commissioning of new developments, it would be of great value for DNOs to incorporate DG into the planning process.

However, the approach is not without limitations. The algorithm is designed for quantifying the DG impacts on investment deferral of the reinforcements driven by the demand growth under the circumstance without the presence of DG. Therefore, it will not consider any reinforcements required for integrating DG into the network. The approach developed in this chapter is suitable under the condition of low DG penetration, which is the case that a DG connection is less likely to require any network upgrades. As shown in the results, the approach is however already capable of quantifying the impacts of DG depending on its locations, power factor controls and connection schedules. To accommodate high penetration of DG leading to additional network upgrade, DG is required to be connected to the overbuilt (dummy) network when running SE method since the DG could require extra reinforcements compared to the case without DG. SE method needs to be executed each time when there is any change in the DG characteristics.

In this chapter, the network constraints such as thermal, voltage, connectivity were considered. However, one critical element which will affect the network planning significantly was missing. It is DNOs' obligation to ensure the demand can still be satisfied under various contingencies. Therefore, in the next chapter security-related reinforcements will be introduced. Moreover, the impact of the technology-dependent security contribution of DG on the network planning will also be taken into account.

CHAPTER 3 – Security-Driven Network Reinforcements

3.1 Introduction

In Chapter 2 an approach to quantity the investment deferral impact of connecting DG was introduced and successfully applied to a radial distribution system. However, the application missed some significant factors which would lead to results with less practical value.

The first concern was the omission of incorporating the network security of supply constraints into the planning. It is known from the experience of DNOs that under many conditions, the problems of failing to secure the supply to the demand would trigger before the point when the maximum thermal capacity of a part of network is fully used. Poor security of supply would result in more frequent load shedding to prevent system collapse after critical contingent events [93]. Therefore, investment in security led-reinforcements are one major part of network operators' spending. As DG's ability to enhance network reliability and decrease both the frequency variations and amount of load shedding has been well-recognised and several approaches have been proposed to utilise such DG capability [41, 94], it will be of great value to quantify the DG's impact on deferring reinforcements driven by security of supply. In the last chapter, the availability of DG was not considered in the approach. To assume DG can produce the output at its full installed capacity, when it is required, could over-estimate the benefit of DG to the distribution system, and would lead DNOs into making false decisions in planning if the DG is incorporated into the process. The availability of DG would depend on the technology and the nature of energy resources used (intermittent or non-intermittent). Therefore, incorporating DG availability based on these features into the approach would further allow DNOs to distinguish the impacts between different DG technologies.

In this chapter, the successive elimination method and the multi-stage planning analysis are substantially modified to take these concerns into account. The security of supply constraint is applied based on the N-1 analysis and the guidelines provided by Engineering Recommendation (ER) P2/6 "Security of Supply" [95]. The approach is applied to a meshed distribution network, where it is more difficult to identify the reinforcements affected by DG without power flow simulation. DG-led reinforcements are also possible. A simple sensitivity analysis is also conducted to investigate the potential of maximising the investment deferral impact through strategic placement of DG at multiple locations.

Section 3.2 extracts the important relevant information from ER P2/6 through explanation and examples. In Section 3.3 the modifications to the SE method, multistage planning analysis and the present value method are explained. Section 3.4 describes an example application and the results are discussed in Section 3.5. Finally, the content in this chapter is summarized in Chapter 3.6.

3.2 Acknowledging DG Contribution to Network Security of Supply – Challenges and Opportunities in the UK

Engineering Recommendation (ER) P2/5 was developed in the 1970s as a guideline for developing transmission and distribution networks with adequate security of supply. This was based on predefined outages under which there will be sufficient network capacity for the demand to be supplied or be restored within an acceptable time. Over many years investment in security-related reinforcements have been the major expenditure for the network operators [96].

In addition to detailed explanation, ER P2/5 comprised two tables: the first table (Table 1) suggests the minimum demand which should still be supplied after the predefined outages. As the size of the demand group increases, the minimum level of supply would be raised and would need still to be supplied even under multiple critical contingencies. The second table (Table 2) in the ER P2/5 states the contribution that generation could have towards network security if it is connected within a demand group.

ER P2/6 has now superceded ER P2/5 as the guide for network security of supply. ER P2/6 inherits the first table from ER P2/5 without significant modifications. However, due to the range of DG with various technologies introduced in the last decade, Table 2 has been updated considerably in ER P2/6. The contribution of generation from relatively new technologies is specified in the second table, which is shown in Section 3.2.1.

According to [96], the second table in P2/6 has not been widely utilised in network design and planning to date and its use would be limited in the short term. This is due to most of the DNOs still using the first table in P2/5 as the major security standard for network development. However, in the long term due to the pressure of load growth and asset ageing and replacements, the use of DG to meet the security supply standard will draw more attention as an economic option to defer any investment in security-related reinforcements.

To recognise and utilise the contribution of DG for improving network security is a vital step to increasing DG penetration. This recognition would give incentives to DNOs to encourage DG connection to support network security and defer the investment in security-related reinforcements.

3.2.1 ER P2/6 – Contribution of DG to System Security

ER P2/6 [95] provides the guidelines for transmission and distribution network operators to ensure their systems are operated above a certain standard of security of supply that meets demand even with disconnection of electrical equipment within the network, either due to contingency or for the purpose of maintenance.

The guidelines, which depend on the range of group demand, are briefly outlined in Table 3.1. A group demand is defined as “a site or group of sites which collectively take power from the remainder of transmission system.” It can be regarded that the larger a group demand, more customers would be affected in the demand group by a contingency. As a result not only would it yield greater economic losses for DNOs, but the loss of large demand by accident could also increase the risks of network instability. Therefore to minimise both economical and technical impacts, a stronger network is required for the part that transmits the energy to the larger demand group and to restore the affected customers within this load group as quickly as possible. According to the table, as the size of a group demand increases, a higher security level is required to supply to the group in turns of shortening the time interval required for restoring the full demand after the disconnection of a circuit (first circuit outage), as well as the expectation of meeting all or part of the demand if another circuit is also tripped (second circuit outage).

	Minimum demand to be met after	
Range of group demand	**First circuit outage**	**Second circuit outage**
Demand <= 1MW	In repair time: group demand	Nil
1MW < Demand <= 12MW	(a) Within 3 hours: group demand minus 1MW (b) Within 3 hours: group demand	Nil
12MW < Demand <= 60MW	(a) Within 15 minutes: smaller of (group demand minus 12MW); and 2/3 of group demand (b) Within 3 hours: Group Demand	Nil
60MW < Demand <= 300MW	(a) Immediately: group demand minus up to 20MW (b) Within 3 hours: group demand	(c) Within 3 hours; For group demand greater than 100MW: smaller of (group demand minus 100MW); and 1.3 group demand (d) Within time to restore arranged outage: group demand
300MW < Demand <=1500MW	Immediately: group demand	(b) Immediately: all consumers at 2/3 group demand (c) Within time to restore arranged outage: group demand
Demand > 1500MW	In accordance with the relevant transmission license security standard	

Table 3.1. Levels of security required from distribution networks [95].

DG connected to the distribution network might, to some extent, be able to contribute to system security, by maintaining supply to a defined level of demand under specified outage conditions. The ER P2/6 also specifies (indicative) contribution factors, known as ‘F-factors’, that determine the contribution from a given DG plant based on its declared net capacity (declared capability of the DG plant in MW less normal site power consumption). In other words, during a contingency, DNOs can have high confidence that a DG can still generate its output at least equal to its installed capacity times the corresponding F-factor. Table 3.2 presents the F-factors for different types of (a) firm (non-intermittent) and (b) intermittent generation, respectively. For DG powered by non-intermittent resources, F-factors are determined by calculating the probability of outage of a power plant with consideration of its generation technology and the number of generating units, while for DG utilising intermittent resources, the F-factors are calculated based on the following attributes [97]:

- Persistence (T_m) – the minimum duration expected for which intermittent DG will be continuously generating under certain conditions of switching or maintenance.
- Resolution of the intermittent generation data, i.e., the interval which the output is measured.
- Correlation between intermittent generation output and peak demand, especially in the winter season.

In reality, the F-factor would vary according to the different renewable characteristics at each site; therefore it is recommended to recalculate the F factor using the method for each location developed in [97].

	Number of units									
Type of generation	1	2	3	4	5	6	7	8	9	10+
Landfill gas	63	69	73	75	77	78	79	79	80	80
CCGT	63	69	73	75	77	78	79	79	80	80
CHP sewage	40	48	51	52	53	54	55	55	56	56
CHP sewage	53	61	65	67	69	70	71	71	72	73
Other CHP	53	61	65	67	69	70	71	71	72	73
Waste to energy	58	64	69	71	73	74	75	75	76	77

(a)

Type of generation	Persistence, T_m (hours)							
	1/2	2	3	18	24	120	360	>360
Wind farm	28	25	24	14	11	0	0	0
Small hydro	37	36	36	34	34	25	13	0

(b)

Table 3.2. F factors (%) for (a) non-intermittent and (b) intermittent DG

To illustrate the impact of the F-factors on investment planning, Fig. 3.1 presents an example system with DG plant. Two cases are analysed: (a) two identical 10MW CHP generation units or (b) a 20MW wind farm. The DG plant is connected to a bus with a 60MW load. The substation (S/S) supplies power via two 45MVA, 1.3 cyclic rating transformers through which the power flows with 0.95 power factor.

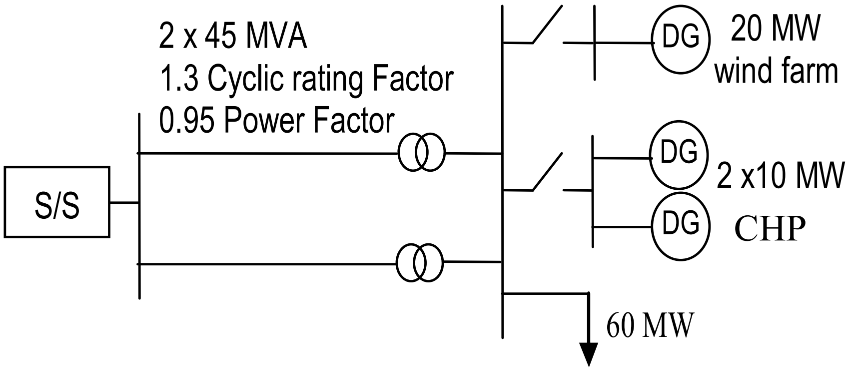


Fig. 3.1. Example system with DG.

ER P2/6 states that for a group demand up to 60MW, only the first circuit outage (FCO) of one of the transformers, needs to be considered [95]. The objective is to work out the maximum amount of demand, referred to as the 'Network Capability', which can be supplied without violating the rules in P2/6. Without DG, the Network Capability following the outage of the most crucial circuit would be:

$$1\times 45\times 1.3 \times 0.95 = 55.6\text{MW}$$

In this case, the full demand cannot be met and the circuit would need reinforcement, typically by adding a third transformer in parallel. If, however, DG is to be taken into account, the F-factor for the CHP plant with two generation units would be 61% (Table 3.2 (a)). It is assumed that a wind farm is required to continuously support a demand group for 3 hours (3 hours of persistence), implying that an F-factor is equal to 24% (Table 3.2(b)). The contribution of each DG plant is calculated as follows:

$$\text{Contribution}_{\text{CHP}} = 2\times 10\times 0.61 = 12.2\text{MW}$$

$$\text{Contribution}_{\text{WIND FARM}} = 0.24\times 20 = 4.8\text{MW}$$

This suggests that the final Network Capability after a first circuit outage considering the CHP plant is 67.8MW, while the contribution from the wind farm allows the demand up to 60.4MW to be carried under this condition. In both cases the security of supply requirement is fulfilled without further network investment.

3.3 Quantifying Investment Deferral – the Approach

3.3.1 Modified Successive Elimination Method

The SE method adopted in the last chapter allowed several different types of conductors to connect in parallel in a location. However, the network configuration has to be credible even if it is overbuilt. It would be not practical if several lines with various maximum thermal capacities and internal impedances are connected in parallel at the same location, which would result in unrealistic network operation and affect the judgement of the cost-effectiveness of each candidate. Therefore, here the SE method is further modified to take this consideration into account. The method here also considers the N-1 security of supply constraint. Therefore, initially from the overbuilt network, the cost-effectiveness evaluation of a given section of the network (overhead lines, cables or transformers) will consider either the upgrade of the assets or the addition of a parallel reinforcement (as illustrated in Fig. 3.2). If one of these two options is the least cost-effective of all options in the network, then the remaining one is adopted. The next cost-effectiveness evaluation is performed from that new configuration.

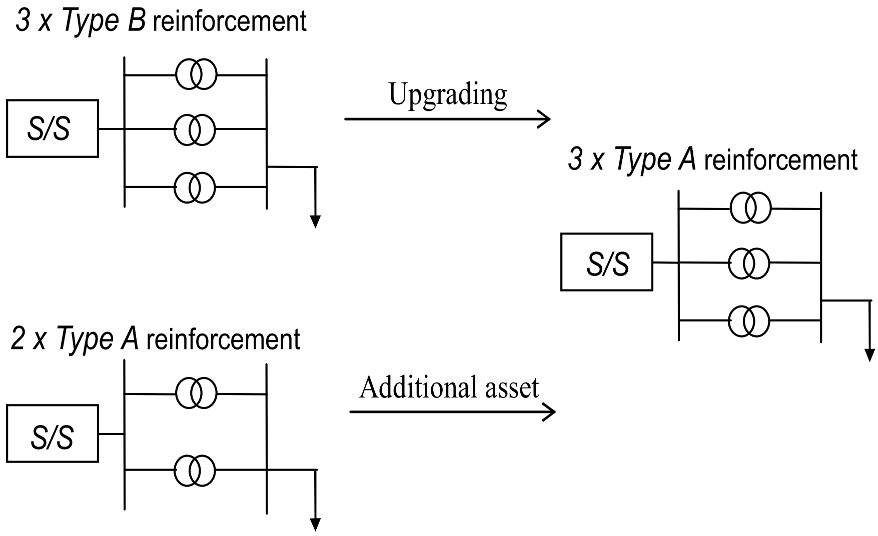


Fig. 3.2. Expansion planning options to ‘overbuild’ a given section of the network: upgrading of assets and addition of a parallel reinforcement.

Considering the load as that forecast at the end of the planning horizon, the network is initially overbuilt by connecting to each section the maximum possible number of those reinforcements with the largest capacity available. Then, the following steps are applied.

Step 1. Calculation of the cost-effectiveness (CE) of each expansion option identified in the network. If, for a given expansion option, constraint violations occur (voltage and thermal constraints are verified for both normal operation and N-1 security requirements considering the forecast demand), the cost-effectiveness of this option is set to a very large number, otherwise:

$$CE_a = \frac{\sum_{k \neq a} \left| P_{k\ \text{new}} - P_{k\ \text{original}} \right|}{Cost_a} \tag{3.1}$$

where CE_a is the cost-effectiveness measurement of option a in MW/\$, $P_{k\,original}$ is the MW flow on branch k before eliminating expansion option a, $P_{k\,new}$ is the MW flow on branch k after eliminating expansion option a, and $Cost_a$ is the cost of expansion option a.

Step 2. If all cost-effectiveness measures are set to a very large number, which implies that all the remaining options are required in order to prevent any constraint violations (thermal, voltage, connectivity and security of supply) in the network, then the final expansion plan has been determined. Otherwise, eliminate the expansion option with the lowest *CE* and go to Step 1.

3.3.2 Multistage Planning Analysis

Again the method here is slightly modified from the one in the last chapter. Instead of starting from the base year, the method begins at the final year of the specified planning period and works backwards, so the reinforcements obtained from the SE method would be eliminated gradually as the load decreases towards the base year. As a result the method would be more compatible with the SE method and slightly more efficient than the multistage planning analysis adopted previously.

Starting at the year at the end of the planning horizon and, with the expansion options identified found by the SE method, the multistage analysis requires the following steps:

Step 1. Assume the connection of DG unit(s) along the whole planning horizon and calculate the corresponding capacity contribution using the F-factors. In applying the multistage planning analysis for the no-DG scenario, Step 1 is ignored.

Step 2. Use the cost-effectiveness technique to identify those candidates that are not necessary this year, eliminating the least cost-effective expansion option. Repeat this until all the remaining options are essential to prevent any system violations for both normal operation and N-1 security requirements.

Step 3. Consider the demand forecast for the previous year (i.e., year = year–1). Stop if it is the base year, otherwise go to Step 2.

3.3.3 Investment Deferral

To obtain the total investment incurred by each planning scenario studied, the present value of each upgraded asset should be calculated. The total present value (PV) cost of a given expansion plan is calculated by:

$$PV = \sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{(1+\rho)^{t}} \tag{3.2}$$

where h is the number of years in the planning horizon, n is the number of reinforcements required for year t, C_i is the cost of asset i required for year t, and ρ is the discount rate.

The investment deferral, as a benefit brought about by the connection of new DG capacity, is then calculated by subtracting the PV of the total investment required by a given DG planning scenario from that of the original (no new generation) planning scenario:

$$Inv.\ Deferral = \left.\sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{(1+\rho)^{t}}\right|_{no\ DG} - \left.\sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{(1+\rho)^{t}}\right|_{DG} \tag{3.3}$$

While the PV method in the last chapter used an exponential function to determine discounting of future cash flows, the more well-known compound interest approach is applied. Nevertheless, the results from both methods are very similar, as indicated in Fig.3.3 which shows the PV of $1m spent in different years.

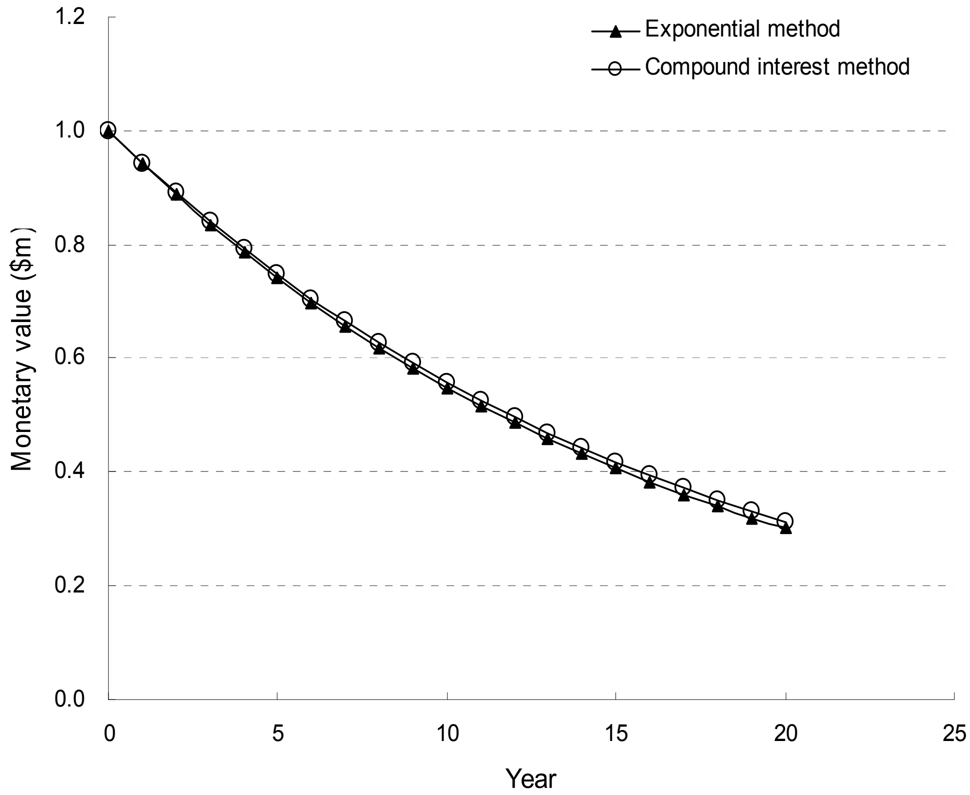


Fig. 3.3. Comparison between exponential and compound interest present value method.

3.4 Application – Investment Deferral Impact on a Meshed Distribution Network

In this section the investment deferral produced by the connection of DG units is investigated on a generic distribution network. Different DG locations and two different technologies (CHP and wind power), with their corresponding security contributions, are considered. Finally, the deferred investment is also evaluated according to the contribution factor (F-factor) applied to DG units.

3.4.1 Network Characteristics and Assumptions

The proposed methodology is applied to the 81-bus meshed suburban distribution network depicted in Fig. 3.4. The full specification of the EHV Network 4 can be obtained in [90]. Power is supplied to the meshed network from a single grid supply point and two interconnectors linking neighbouring networks at 132kV. There are 32 loads scattered throughout the network of different voltage levels (33, 11 and 6.6kV). Total peak load in the base year is 151MW, with an annual load growth of 2% and a 10 year planning horizon assumed. Any reinforcement postponed beyond the horizon is assumed to be enacted at year 10 instead of complete avoidance of the reinforcement. This is relatively conservative as it will understate the true deferment. A cyclic rating of 1.1 is assumed for transformers and the discount rate is 6%.

System security standard ER P2/6 specifies that a group demand of less than 12MW is not required to be restored immediately. The only load bus exceeding such a limit is bus 1112. However, given the meshed characteristics of EHV Network 4, the adopted N-1 security constraint affects those lines and transformers that transfer capacity to more than one demand group. The lines between the interconnectors and the main network are excluded from the N-1 analysis.

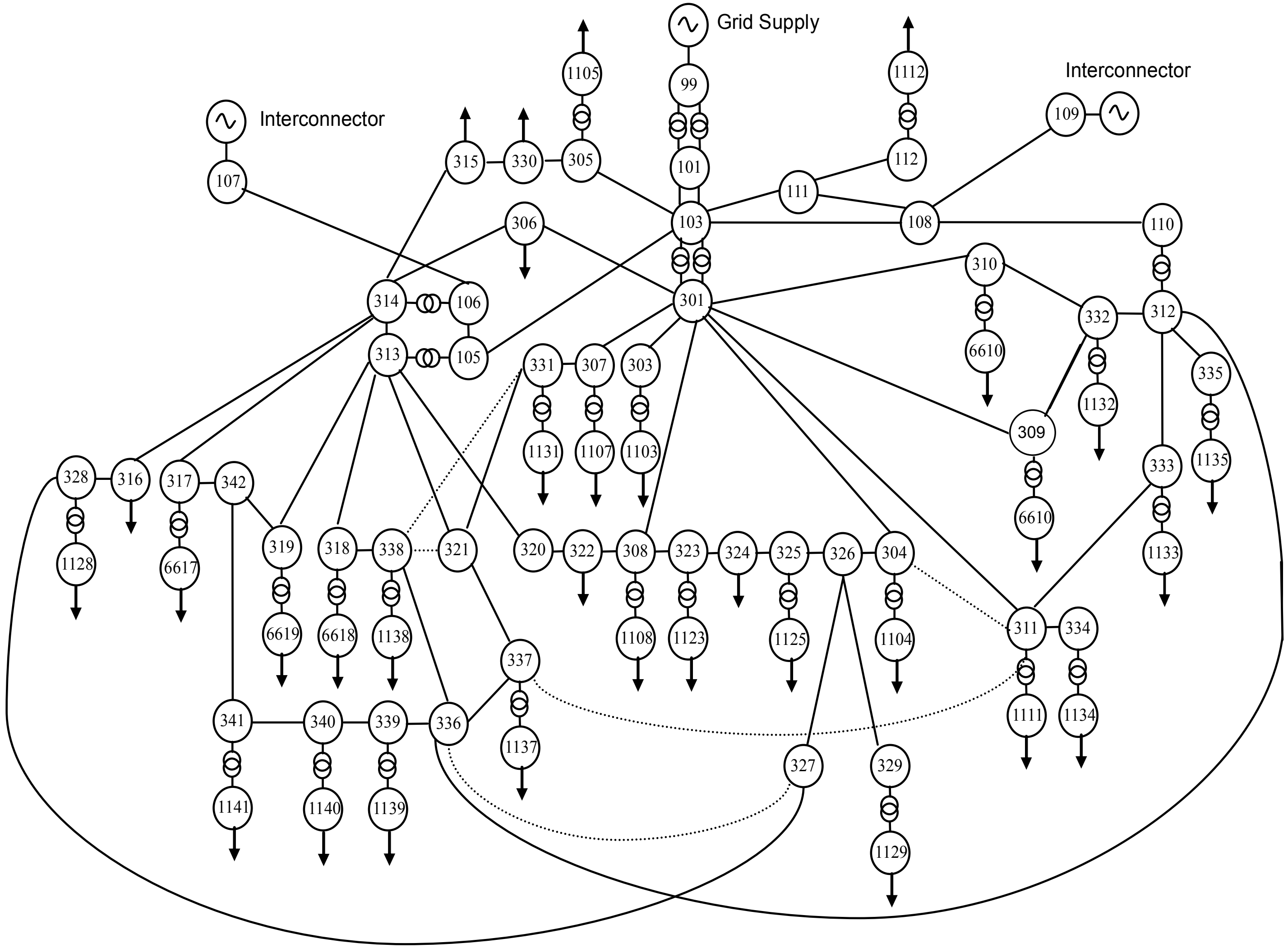


Fig. 3.4. UK GDS EHV Network 4 - Meshed suburban network [90].

3.4.2 Expansion plan without DG

Table 3.3 indicates the assumed costs of the reinforcement options for overbuilding the distribution network. These are the indicative costs from [92] as the UK DNOs were not willing to release detailed cost information.

Overhead line		
Voltage (kV)	Capacity (MVA)	Cost/km (US$k)
132	100	180
132	120	200
33	30	120
33	50	150
Transformer		
Voltage (kV/kV)	Capacity (MVA)	Cost (US$k)
132/33	80	1500
132/33	100	1700
132/11	30	500
33/11	23	350
33/11	30	420

Table 3.3. Costs of reinforcement options.

In the case without DG, the reinforcements required along with the commissioning schedules and PV costs are shown in Table 3.4. The term 'upgrade' refers to the replacement of existing lines, whereas 'parallel' indicates that the reinforcements are connected in parallel with the existing ones.

Name	Type	Capacity (MVA)	Cost(US$k/km)	Length (km)	Year	P.V. cost (US$k)
L101-103	upgrade	2 x 120	400	4.2	7	1117.30
L103-105	parallel	1 x 120	200	3.5	8	439.19
L301-304	parallel	1 x 30	120	1.1	1	124.53
L304-326	parallel	1 x 30	120	0.9	2	96.12
L311-337	parallel	1 x 30	120	0.5	0	60.00
L313-318	parallel	1 x 30	120	0.5	2	53.40
L313-319	parallel	1 x 30	120	1.6	0	192.00
L319-342	parallel	1 x 30	120	0.2	8	15.06
L341-342	parallel	1 x 30	120	1.7	0	204.00
L111-112	parallel	1 x 120	200	0.6	0	120.00
T112-1112	parallel	1 x 30	500	-	0	500.00
					Total	2921.59

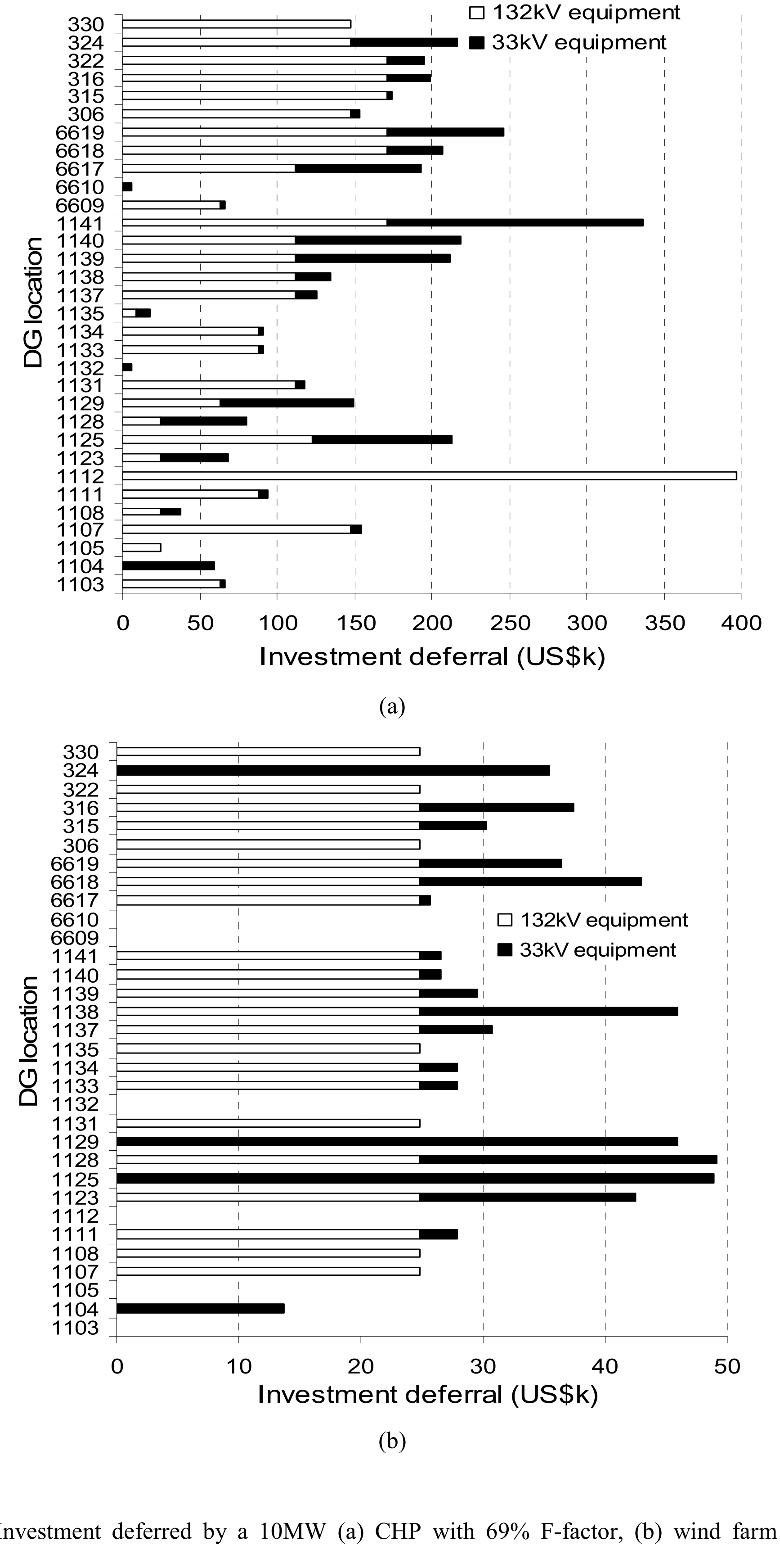
Table 3.4. Reinforcements required and their cost in present value within the planning horizon.

The total planning cost in present value is US$2.9m. Most of the reinforcements will be required within the first two years. With the load at bus 1112 greater than 12MW an extra transformer (T112-1112) is needed to meet the security requirements. In fact, if the security constraints were not applied, the only reinforcement required would be that of line L101-103. The majority of the upgrades specified are for parallel lines. In the UK, where additional wayleave requires planning permission this could be a challenge; therefore where DG is able to defer such upgrades it would be regarded as especially beneficial.

3.4.3 Locational Impact of DG

The ability of DG to defer investment depends on its location relative to the load and highly utilised assets. To illustrate this, consider the impact of a single 10MW installation connected in turn to all load nodes of the network. Two alternative generation types are considered: a five-unit CHP plant with an F-factor of 69% or a wind farm. Assuming the wind resource is equally available across the network and the persistence T_m required for the wind farm is 3 hours, the F-factor is 24% (Table 3.2). For the security analyses, the CHP plant and the wind farm would contribute 6.9MW and 2.4MW of capacity, respectively. Fig. 3.5 presents the corresponding results, differentiating the reinforcements required at 33 and 132kV.

As expected, a given DG plant of the same size and technology connected to different locations resulted in significant variations of the potential investment deferral. When assuming a CHP plant (Fig. 3.5a), the values vary between US$5.9k (buses 1132 and 6610) to US$396.7k (bus 1112). For the wind farm (Fig. 3.5b) no benefit was obtained in some cases, with the maximum deferment (US$49.1k) found when locating at bus 1128. It is interesting to see that the most beneficial location of connect DG has changed due to different DG technologies and F-factors, as the most beneficial location is at bus 1112 if the DG is a CHP, while if DG is a wind farm, the location is changed to bus 1128. Clearly, more investment is postponed when a higher capacity contribution of CHP leads to larger firm capacity being taken into account.



(a)

(b)

Fig. 3.5. Investment deferred by a 10MW (a) CHP with 69% F-factor, (b) wind farm with 24% F-factor across different locations.

In addition to the 33kV reinforcements affected by the reductions in power flows provided by the CHP plant (as seen for bus 1112), the cumulative impact defers 132kV asset reinforcements. Since the wind farm can only have its security contribution equivalent to 2.4MW in this case, the only impact of the wind farm on the 132kV reinforcements, if there is any, is to defer the connection of the line 101-103 by 1 year and result in additional $24k saving as indicated in Fig. 3.5b. The connection of the wind farm to buses 324, 1125 and 1129, however, even offers no deferment of 132kV reinforcements.

3.4.4 Impact of the F-Factor

The level of security contribution provided by a DG plant has a major impact on the investment that could be deferred. It is possible, however, that for a given (nominal) DG capacity, a smaller F-factor produces greater benefit. This is the case when larger DG capacities lead to network constraints during first circuit outages, suggesting the need for DG-driven upgrades. Fig. 3.6 shows the results for a 10MW DG plant connected at bus 1135 (far right of Fig. 3.4), considering separately CHP and wind power. Here, the CHP plant deferred US$17.5k, whereas with the wind farm almost US$25k worth of reinforcements was postponed.

During the loss of 132kV line 108-110, extra power flows through 33kV lines 313-318 and from 336-312 to support the loads on the right hand side area of the network. This contingency results in an overload of line 313-318. Therefore, any capacity contribution from the DG unit at bus 1135 alleviates the power flows, deferring the investment schedule of an extra line 313-318. However, under the outage of line 103-105, power will flow from bus 312 to bus 336. If the capacity contribution of the DG at bus 1135 is greater than its local load (4.5MW), then additional power will also flow through line 312-336. As a consequence, due to this contingency, the CHP plant requires an additional line 103-105 to be commissioned earlier than the case without DG.

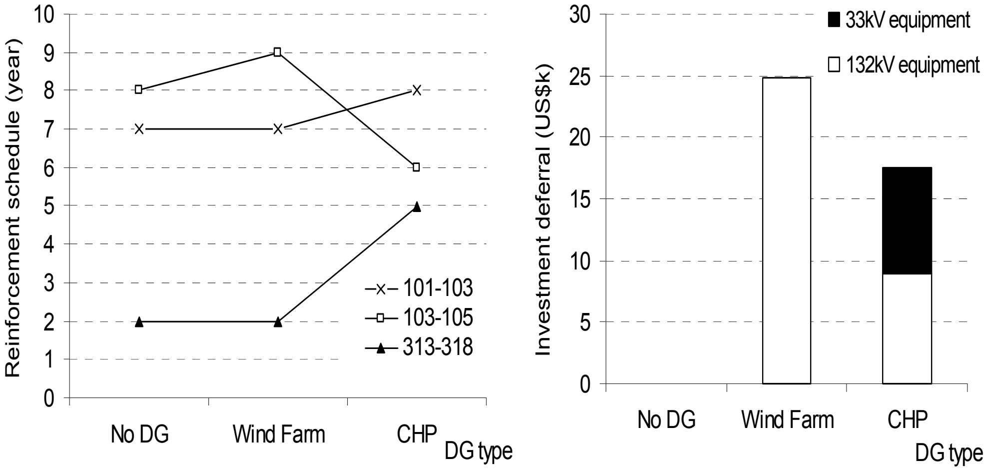


Fig. 3.6. Schedule of reinforcements (Left) and investment deferred (Right) by a 10MW CHP and wind farm connected to bus 1135.

To understand how sensitive the schedule of reinforcements and investment deferral are in relation to the capacity contribution of a given DG connection, the F-factor of the 10MW generator at bus 1135 is varied. Fig. 3.7 shows that a capacity contribution above 4MW, i.e., F-factor more than 40%, reduces the ability to defer reinforcements, and bringing forward the need for a new line 103-105. As the F-factor increases beyond 80%, it in fact imposes net economic losses to the network as a result of the DG-driven reinforcement.

It is clear from the cases above that despite the fact that immediate network upgrades not being required to integrate a small penetration of DG into the system, DG could still impose adverse impacts on the network by making some reinforcements more urgent than previously scheduled. It usually requires a time period to get the permission from concerned authorities, e.g. environmental authorities, local residents and councils etc., to connect the reinforcements to the network, while the reinforcement rescheduling due to DG may result in DNOs failing to get the permission before the reinforcements are needed. As a consequence, the original cost-effective network planning would become unfeasible and DNOs could spend significant extra money to adopt another planning solution. Therefore it is important for DNOs to observe such impact caused by DG and respond to the potential changes in network planning as early as possible.

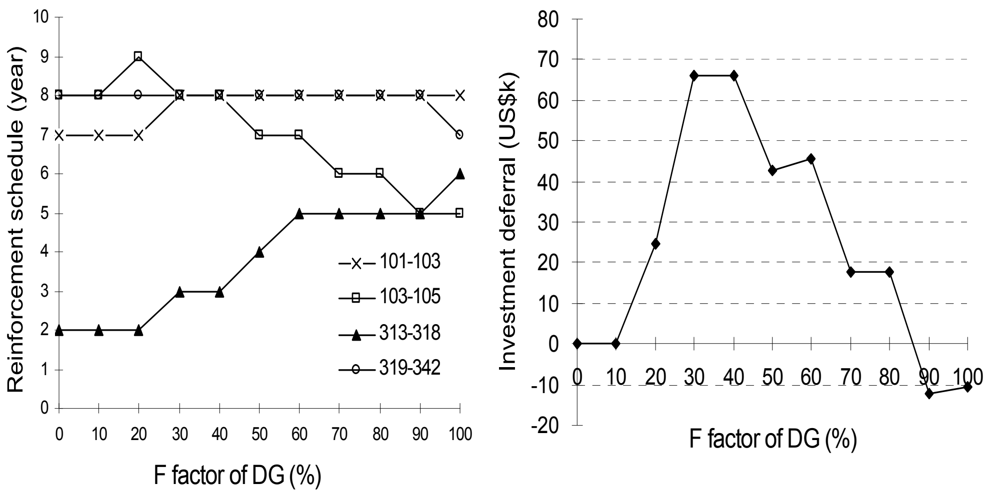


Fig. 3.7. Varying the F-factor of a 10MW DG plant connected to bus 1135. (Left) Schedule of reinforcements and (Right) investment deferred.

The total investment deferral produced by the connection of a single 10MW DG plant is presented in Fig. 3.8, considering the contribution factors of CHP, wind power and the hypothetical case of 100% F-factor. It is noted that, in a similar manner as bus 1135, larger security contributions from a DG unit connected at bus 306 does not result in more investment being deferred. DG at buses 1132 and 6610 would also yield very little investment deferral regardless of the F-factors. Nonetheless, many locations do show substantial deferral of reinforcements with higher security contributions, as is the case of CHP against wind power.

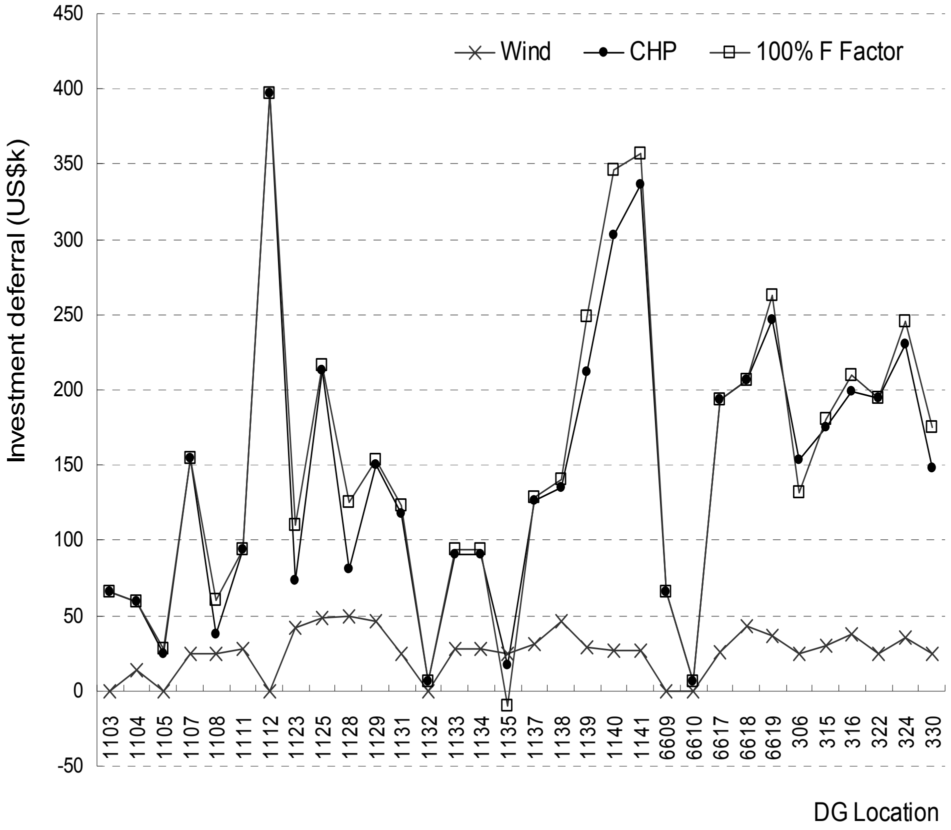


Fig. 3.8. Range of potential investment deferral obtained per MW increases of DG at different locations.

3.4.5 Impact of DG Power Factor Control

In real practice, smaller DG is operated at constant pf due to stability issue while large DG is operated with automatic voltage regulator (AVR) installed. However, there could be times that larger reactive power needs to be produced by DG for mitigating network problems but the requirement has exceeded the reactive power capability of DG. In such circumstance there show be enough incentives for DG owner to improve the reactive capability of DG, such as installing power electronic devices or limiting the DG real output.

The power factor (pf) of DG output was adjusted and its impact on investment deferral has been analysed. Three different power factor settings were attempted: 0.9 leading, unity and 0.9 lagging, for DG at different locations. Again, the impact of different pf settings depends on the location of DG. The results of two remarkable cases are presented in the following paragraphs. In this analysis the 'effective generation capacity (EGC)' of DG is used, which is the contribution capacity after considering its F-Factor.

DG connected at bus 1140 is able to defer the investment in line 313-319 and 341-342 effectively. Table 3.5 shows the impact of different DG pf on the connection schedule of the two reinforcements. The schedule of the reinforcements when DG output is at 0.9 lagging pf is slightly later than it is if controlled at unity pf. However, it is obvious that as EGC increases, DG with 0.9 leading pf is relatively ineffective to postpone the investment in line 313-319 and 341-342 compared with 0.9 lagging and unity pf. As EGC output increases to 10MW, line 341-342 is delayed to the end of the planning horizon if it is 0.9 lagging or unity pf controlled, while with 0.9 leading pf the line 341-342 is postponed to year 6. The total investment deferral benefits obtained by the DG from delaying the schedule of line 313-319 and 341-342 are depicted in Fig. 3.9. For DG with the installed capacity of 10MW, the benefits from DG of CHP type (F-factor 69%) to change its output from 0.9 leading to unity pf would be approximately twice that obtained by changing from unity to 0.9 lagging pf. There would be no benefits in a wind farm (F factor 24%) to change its output from 0.9 leading to unity pf, while there is relatively small amount benefit to change the output pf from unity to 0.9 lagging. As expected, DG controlled at 0.9 lagging pf produces reactive power which directly supplies the demand located in the vicinity hence clearing extra capacity in the conductors that carry energy to the demand from the GSP; as a result, the reinforcements are postponed further than when DG is controlled at 0.9 leading pf, which increases the reactive power demand and offsets the beneficial impact of real power production by DG on reducing the real power flow in the conductors.

	unity pf		0.9 pf lagging		0.9 pf leading	
MW	*313-319*	*341-342*	*313-319*	*341-342*	*313-319*	*341-342*
0	0	0	0	0	0	0
1	0	0	0	0	0	0
2	0	0	0	0	0	0
3	0	1	0	1	0	0
4	1	2	3	5	0	0
5	3	5	3	7	1	2
6	3	7	4	9	2	4
7	4	9	5	10	3	5
8	5	10	6	10	3	5
9	6	10	7	10	4	6
10	7	10	8	10	4	6

Table 3.5. Year of connection of reinforcements for DG with different controls.

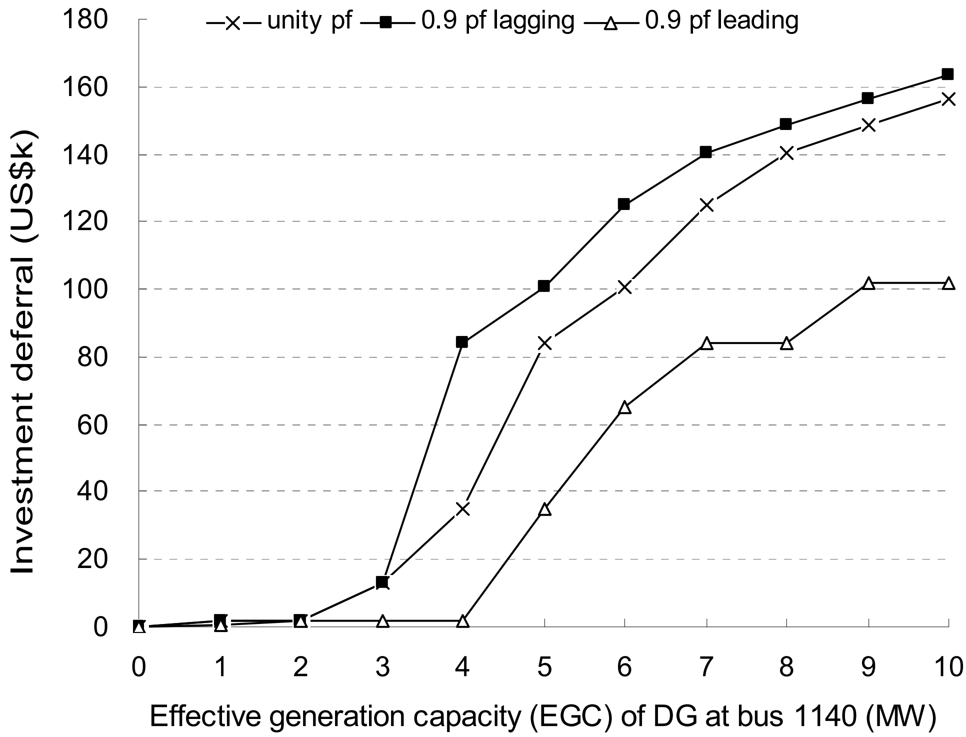


Fig. 3.9. Impact of DG net declared capacity and control at bus 1140 on quantified benefits.

The impact of DG at bus 306, along with various power factor controls and real outputs, on the investment deferral of line 103-105 is depicted in Fig. 3.10. Prior to a new line 103-105 being connected, the outage of the existing line 103-105 sees the real power flow from bus 103 to 314 while the reactive power flows in the opposite direction. Despite increasing the output from bus 306, DG operated at 0.9 lagging pf would increase the real power flow through line 306-301, but sees the amount of reactive power delivered from bus 314 to 306 drops. DG operated in such a manner slows the net power flow reaching the maximum MVA loading of line 306-301 compared to a DG operated at unity and 0.9 leading pf. The latter sees additional reactive power demand of the DG overload the line 306-314 d sooner and the connection of the new line 103-105 needs to be carried out earlier.

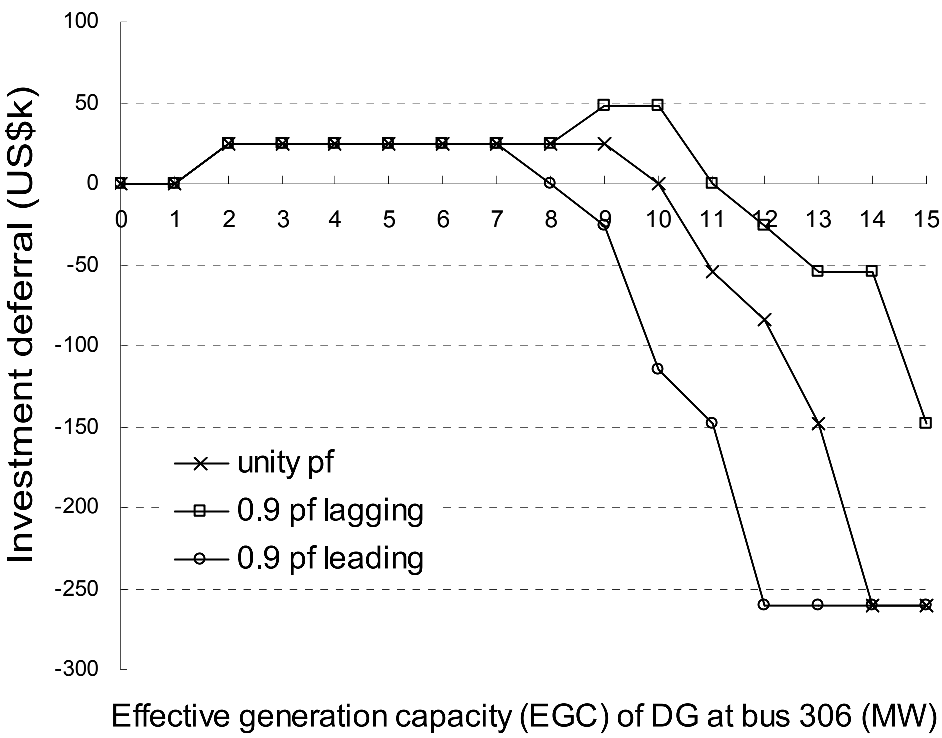


Fig. 3.10. Impact of DG size and pf controls on line 103-105.

According to Fig. 3.10, there are no differences in investment deferral for changing power factor controls if its EGC is below 7MW. As the EGC of DG further increases, there is clear additional mitigation of adverse impact caused by DG if DG operates at a lagging pf. As the EGC is above 14MW, it is highly desirable for the network operator if the DG increases its reactive power production to limit the adverse impact on investment deferral of line 103-105.

It is expected that during the condition of maximum demand DG operating with lagging pf would assist in mitigating network loading problems. However, according to the two cases above, detailed analysis like the above is required to determine whether there is sufficient motivation for the DNO and the DG owner to change the power factor setting.

3.4.6 Strategies to Maximise Investment Deferral

Provided that DNOs are capable of (or can influence) the schedule of deployment, size and location of DG units, it would be valuable to have a strategy that maximises the investment deferral. Conversely, for DNOs that are not allowed to own DG, such analysis is useful in developing cost-reflective DG connection charging schemes. Here, a simple sensitivity analysis is used to maximise investment deferral, focusing on the security-related planning requirements where major deferments can be achieved.

Starting with those locations where a DG connection is able to defer the most expensive reinforcements (e.g., bus 1112 due to transformer T112-1112), the capacity contribution from the generation unit is continuously incremented by 1MW until no additional reinforcements are deferred. The same process is repeated for the DG plant at the next most beneficial location and so on (Step 1). Then for each DG technology, the corresponding F-factor determines the net declared capacities required (Step 2). While this approach clearly would not result in a globally optimal solution it illustrates the idea. The results of this deployment strategy are shown in Table 3.6, where the locations are arranged in order of benefit.

	Step 1	Step 2	
DG location	Capacity Contribution (during N-1)	Declared Capacity	
		CHP	Wind
	(MW)		
1112	7.0	10.14	29.17
1141	8.0	11.59	33.33
6618	5.0	7.25	20.83
6619	5.0	7.25	20.83
1111	5.0	7.25	20.83
1125	7.0	10.14	29.17

Table 3.6. DG deployment to maximise total benefit.

The maximum possible investment deferral would be achieved if all the reinforcements in Table 3.4 are postponed to year 10 or beyond, representing capital expenditure savings of around US$811k (28% of the total). Depending on the DG technology, the deployment strategy (in terms of capacity contribution) presented in Table 3.6 is able to provide such gains. If all DG is assumed to be CHP, a capacity of 53.6MW would be required, representing a 36% DG penetration level (relative to peak load) during the base year.

However, if the same capacity contribution is to be provided by wind farms the corresponding nominal capacities would exceed the thermal limits of the transformers (S_{max} of 10MVA), necessitating further reinforcements.

Without DG, the connection of line 311-337 (see Table 3.4) has multiple functions. Firstly, it prevents the overloads of line 301-311 during the outage of line 312-333. Secondly, it also prevents overloading of line 312-336 when line 103-105 is tripped until the reinforcement of line 103-105 relieves this. When DG is strategically connected in this manner, one important observation is that the investment deferral does not simply depend on the location and size but is also contingent on the existence of other DG developments. For instance, although DG units connected at and close to bus 1111 could effectively solve the first contingency scenario (disconnection of line 312-333), significant deferment only occurs when line 311-337 is no longer required to service the second contingency (disconnection of line 103-105). To achieve this, capacity contributions of 8, 5 and 5MW are required at buses 1141, 6618 and 6619, respectively. These contributions are jointly capable of solving the second contingency and relieving the power flow through line 312-336 needed to support the demand in the left side of the network, and preventing its overloading even without the connection of line 311-337. Regardless of the location a single DG cannot be considered to defer investment in line 311-337 by itself; it is the combination of DG at the selected locations that could defer the connection of line 311-337 from year 0 to beyond year 10.

When an active network management (ANM) is applied to the network, implying that DG owners who participate the ANM scheme may have their DG output curtailed if a network constraint is close to the regulatory limit due to the DG. As a result DNOs could prevent significant investment in DG-driven reinforcements required for allowing the DG to produce any level of output at any time without any constrains violation. However, to increase the willingness of DG owners to participate in the ANM scheme enough incentives needs to be given to them to at least cover the economic loss from the output curtailment. The quantified impacts in this section are useful for the DNOs to assess adequate amount of incentives to motivate DG owners to participate the ANM scheme.

3.4.7 Observing the Risks of Sharing Investment Deferral from the Results

As mentioned previously, under the circumstance where DNOs are not allowed to own DG themselves, providing enough incentives to the DG owners is necessary for utilising DG to improve network efficiency and stability while postponing the need to invest in new reinforcements. The major concern in this is that the incentives given to DG owners cannot be greater than the benefits yielded. As the real output from DG can be uncertain due to the failure rate of the DG technology and the nature of renewable resources, it is difficult to work out the exact benefits over time. Therefore there is a risk that benefits would be over-estimated. The F-factor table in ER P2/6 provides important information about the minimum output that DNOs can expect from DG with high confidence. To quantify the investment deferral based on the F-factor would tend to minimise the risks, if increasing DG capacity would create more savings for the DNOs. However, in the situation where there are adverse impacts on the investment deferral as the DG capacity increases, the investment deferral impacts quantified by taking the F-factor into account may not be at their minimum and the risk of over-estimation is raised. In this case, the incentive shared between DNO and DG owner should be the based on the minimum quantified investment deferral value found when DG produces an output between its net declared capacity (after considering F-Factor) and its installed capacity.

3.5 Discussion

The analysis clearly demonstrates that DG can defer investment in network assets whether these are thermal or security-driven. It also shows that the level of deferment that can arise depends strongly on the location and size of the DG; analyses, such as [55, 98] that assume investment deferral benefits to be independent of DG location are over-simplified.

The security standard was a major driver of network upgrades and the level of security contribution assumed for the DG played a large role in allowing investment deferment. Despite the existence of the updated standard there is evidence that widespread recognition and use of DG security contribution is lacking within UK DNOs. Confidence over the value of the security contributions could be one factor and improved location-specific figures (other than indicative ones) may be required. The prevailing planning culture or that networks being compliant at present without DG contribution may also explain this. However, with the potential for stricter regulatory efficiency targets implying continued downward pressure on DNO capital expenditure, it will be of increasing value for DNOs to integrate DG within the planning process.

Earlier work [55, 98] showed that recognition of the investment deferral benefits plays a crucial role in minimising apparent conflicts in deciding desirable penetrations of DG from the DNO and DG developer point-of-view. One of the premises behind this work was to characterise the range of benefits for DNOs. In jurisdictions where distribution companies can invest in DG the benefits can be realised directly. In other places like the European Union where unbundling rules preclude DNOs from owning DG, capturing such benefits is more subtle, relying on frameworks of incentives for developers and for DNOs themselves. The analysis provides an approximate means of valuing the locational benefit of DG capacity and could be used as the basis for connection or use of system charging to achieve strategic distribution network planning with DG.

The approach taken here with the successive elimination method and multistage planning is deliberately simple. Its rule-based approach mimics real planning processes and offers a clear audit trail. It also automatically handles the complexity inherent in meshed distribution networks taking it beyond simple feeder approaches.

One criticism is that there is a mismatch in treatment of costs between the two stages of the analysis: successive elimination ranks the cost effectiveness without reference to the timing of the investments (i.e., discounting is ignored), while scheduling of the investments explicitly includes discounting. While this could have an impact where the cost effectiveness measures for two competing upgrades are very similar, there was no evidence here that it affected the outcome of the analysis.

The assessments shown here all assume DG connections at the outset of the planning period.

This is driven by the need for reinforcement in the first year in this particular example. There may be additional useful information arising from exploring the influence of the timing of DG connection on the benefits like the analysis conducted in the previous chapter.

Although an 'optimal' capacity of DG was derived for this network the approach is not especially well suited to such applications. However, the idea of maximising benefits from deferred investment can be exploited using optimisation approaches.

The process as outlined and demonstrated here is largely deterministic and ignores the evident uncertainties surrounding planning. However, the relative simplicity of the approach means it could be extended to consider a range of scenarios for use in determining actual investment profiles.

3.6 Chapter Summary

An approach for quantifying the impacts that DG may have on the deferment of demand- and system security-related network reinforcements was developed. The successive elimination technique along with a multistage planning analysis was adopted in order to determine the required investment (due to both demand growth and system security) and their corresponding scheduling. Knowledge of the required assets and their commissioning time along the planning horizon enables identification of those assets affected by the connection of DG, making it possible to obtain the corresponding new total investment cost. Security of supply standards increase the need for reinforcements in distribution networks. Results demonstrated that significant benefits, in terms of investment deferral, can be harnessed if the capacity contribution of DG to system security is taken into account. The more integrated approach for assessing the planning expansion problem clearly demonstrates that deferment varies with the location and size of the DG as well as the technology. It highlights the value for DNOs in integrating DG into the planning process. Furthermore, the adverse impact of DG on the investment deferral of reinforcements has been observed in the example of this chapter. The small penetration of DG may not require immediate network upgrades, however, it could actually make the need to connect the reinforcements more urgent than the originally planned schedule. This could require immediate response from DNOs to check the feasibility of the original network planning strategy and make appropriate changes.

So far voltage has not been the major problem that drives reinforcement plans in the analysed networks in Chapter 2 and 3. The ability of DG to provide a voltage support service to affect the planning of voltage-related reinforcements has not yet been valued in detail. Although an additional transmission line or transformer with on-line tap changer, or even changing the network structure from radial to ring, might mitigate the voltage to be out of regulatory limits. However, the limitations such as space and environmental concerns may make such solutions unfeasible. The next chapter will contemplate how DG could be utilized for specifically solving voltage problems within a network therefore affecting the planning of voltage-driven reinforcements, and assess the economic benefit for DG acting as a voltage support device.

CHAPTER 4 – Impact of DG on Voltage-Driven Reinforcement Planning

4.1 Introduction

In the previous two chapters, the main drivers for upgrading the distribution networks adopted were to meet thermal and security constraints as the demand increases. Voltage problems appeared to be of minor concern in these cases. However, in many transmission and distribution networks, the problem of voltage at some buses exceeding the statuary limits would emerge before parts of the networks have used up their whole thermal capacity. Unhealthy network voltage profile could damage the connected electrical equipment while voltage collapse leading to disastrous blackouts has become a major issue [99, 100]. Under such circumstances, investment in equipment, such as FACTS (flexible AC transmission) devices and transformers, for supporting the network voltage profile will increase and may become the major part of capital expenditure for DNOs. When the voltage problem are a major issue in a network, it would be important to analyse the impact of DG on the network voltages and assess how DG will affect the planning of voltage-driven reinforcements.

Connection of DG further complicates the problem of network voltage. Depending on DG operation and the load characteristics of the network, the network voltage profile could be either degraded or enhanced [101, 102]. Therefore, DG has the potential to provide a valuable service to improve network voltage profile under various circumstances [18, 103, 104]. Furthermore, the bi-directional power flows caused by DG could also require the modification of well-established distribution network voltage control mechanisms [60]. Several voltage control strategies considering DG have been proposed [105-108].

In [109] and [43], the impact of DG on network voltage had been assessed and quantified using voltage indexes. While a change in voltage index values due to the DG connection clearly shows the degree of severity of the technical impact imposed by DG, it cannot

indicate whether the DG connection affects the original investment plan. Besides, the ability of DG to support network voltages after various contingencies needs to be quantified if DG is expected to continuously provide voltage-supporting services in post-contingency conditions.
Again, as in the EU DNOs cannot own DG, the economic benefit of utilising DG for voltage support needs to be assessed for DNOs to make the right decision and incentivise DG owners.

In this chapter, an economic assessment of the investments required for maintaining distribution networks with DG within regulatory limits of voltage and voltage step change is proposed, in order to investigate any possibilities for DNOs to utilise DG to prevent additional voltage-driven reinforcements. By adopting the concept that in terms of voltage support, DG and static Var compensators (SVCs) can be substituted for each other, i.e. that both affect network voltage by injecting reactive power to the connected bus. The economic assessment is done by comparing the cost differences between the investment plans for SVCs due to DG connection. Although in real practice, an investment plan for enhancing network voltage profile would consider devices other than SVCs, such as capacitor banks, however the approach provides a consistent assessment and would give sensible results and comparisons according to different DG characteristics.

This chapter is structured as follows: Section 4.2 gives a brief introduction to SVCs. Section 4.3 compares the ability for voltage support of SVCs and DG, followed by an explanation of the two statuary voltage limits which the network operators in the UK need to comply with. The modified sensitivity method is used to find optimal SVC deployment and is explained in Section 4.5. Section 4.6 shows the proposed algorithm, followed by its application and result.

4.2 Static Var Compensators

The static Var compensator (SVC) is a device which provides reactive power, either in capacitive or inductive form, to the network at where it is connected. It is called static because there are no mechanical moving parts in the device except the circuit breakers. Fig. 4.1 shows the basic structure of SVCs. The device consists of multiple capacitors and reactors connected together in parallel through thyristor-controlled switches, whose purpose is to control the amount and type (capacitive or inductive) of reactive power exported from the SVC. SVCs are mainly used for power factor correction and voltage stabilisation in a power transmission network, in order to ensure efficient and secure power delivery. SVCs can provide their services almost instantly when they are required, which makes them capable of supporting the network operation during both static and dynamic periods.

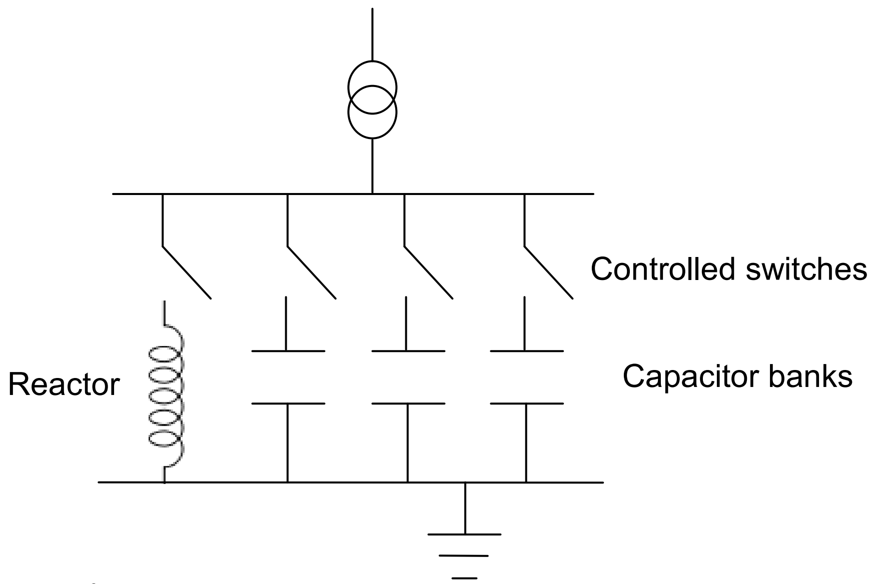


Fig. 4.1. Basic structure of a SVC.

Although SVCs are expensive, during recent decades SVCs have attracted attention and installation has been increased worldwide. One major reason is that permission for using new right-of-way for connecting new transmission lines has gradually become less likely to be granted by government authorities due to environmental and social concerns. As a consequence, installing SVCs is one of the remaining effective alternatives to mitigate the stress caused by the increasing demand on the transmission network [110, 111]. References [110-112] show real examples which involved the installation of large quantity of SVCs to improve the voltage stability of the networks near Dallas metro area and in the southern part of California.

Historically, SVCs were connected in high voltage transmission or sub-transmission networks. However, like generation technologies, the advances in power electronics and semiconductor technologies have made SVCs more suitable to connect them to distribution networks. Kincic and Ooi *et al.* [113, 114] analysed the advantages of placing SVCs at distribution level over transmission level of power networks. Distributed SVCs are more reliable and effective in controlling network voltages, in terms of total MVar installed, than one bulk SVC in high voltage network. Furthermore, connecting SVCs at distribution network could be a lot cheaper than at transmission network as transformers may not be required. In conclusion, it is possible that in the near future the major deployment of SVCs will be on distribution networks at where most of DG is connected. Should DG be considered to support network voltages, the planning of SVCs connected at the same distribution network will need to be changed. The next section compares the similarities between DG and SVCs in terms of their voltage support capabilities.

4.3 Voltage Support Capability – DG vs. SVCs

DG and SVCs can affect network voltages in a similar way, by injecting reactive power into the part of network where they are connected. In Chapter 1, Fig. 1.3 showed an example of how DG would affect the network voltage. The example is extended to consider the impact of SVCs which provides reactive power Q_C, as shown in Fig. 4.2 below.

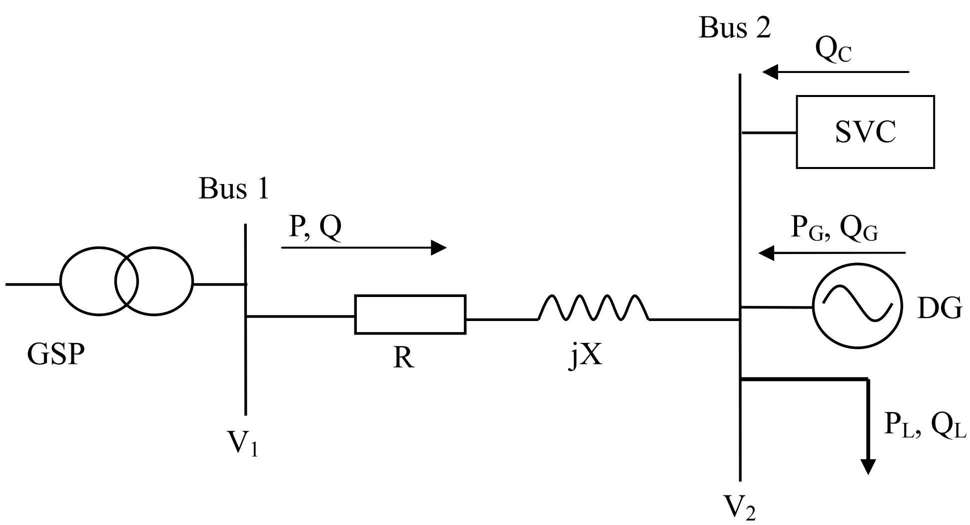


Fig. 4.2. A 2-bus system.

In addition to DG, SVCs are connected to the same connection boundary where the load (P_L, Q_L) is connected. The power from the grid supply point (GSP) is transported to the load site from bus 1 through an overhead line, which has impedance of R+jX, resulting in losses (P_{Loss}, Q_{Loss}) when the power flows through the conductor. Unlike DG, SVCs would only affect the reactive power flowing through the line, as (1.1) is modified into:

$$\mathrm{V}_1 - V_2 = \Delta V \approx (P_L + P_{Loss} - P_G) \cdot R + (Q_L + Q_{Loss} - Q_G - Q_C) \cdot X \qquad (4.1)$$

Another similarity between DG and SVC, in terms of the contribution to the changes of network voltages, is that both of them can be fast-acting devices. They have the capability to respond immediately after any disturbances occurring within the network. In the British regulatory documents *'GB Security of Supply Standard'* [1] and *'Engineering Recommendation G75/1'* [115], both DG and SVC are mentioned and allowed to contribute to network voltage stabilisation during the transient state after a contingency.

In summary of the comparisons in previous paragraphs, SVCs and DG are capable of providing largely similar services to support and affect network voltages, and can be placed in similar locations. Therefore SVCs and DG can, to some extent, be substituted for one another .

4.4 Steady-State Voltage Regulation in UK

Voltage is a critical indicator of network stability and power transferring efficiency. Voltages which are too high or too low compared with the nominal voltage could damage the connected equipment and lead to network collapse following a disturbance. In the UK, the distribution networks are bound to two voltage statuary limits during the operation at steady-state. First, all the bus voltages are kept within ±6% of the nominal at 33kV and 11kV network (.±10% at 132kV). Another voltage limit at steady-state is voltage step change and is introduced to reduce the possibilities of network instability after a contingency. Voltage step change of a bus is measured by the change in the steady-state voltages of the bus as measured immediately before and after a disturbance. UK Engineering Recommendation

G75/1 [115] defines voltage step change as *"Following system switching, a fault or a planned outage, the change from the initial voltage level after all the Generating Unit voltage regulator and static VAR compensator actions, and transient decay (typically 5 seconds after the fault clearance or system switching) have taken place, but before any other automatic or manual tap-changing and switching actions have commenced."* As the penetration of DG in a network increases, the violation of the voltage step change limits could become a dominant problem caused by the disconnection of DG or loads which prohibits more DG connections and requires extra network upgrades [116].

The voltage step change limits imposed to an UK distribution systems are guided by P28 and shown in Table 4.1. According to 'GB Security of Supply Standard', the term *secured events* refers to *a contingency which would be considered for the purposes of assessing system security and which must not result in the remaining GB transmission and distribution system being in breach of the security criteria*. In general, the voltage step change limits are bound to ±6% for the network operators to operate the networks across the UK.

Area	Voltage Fall	Voltage Rise
England, Wales, following secured events	-6%	6%
England & Wales, following operational switching less frequent than specified	-3%	3%
Scottish Power Transmission Ltd	-6%	6%
Scottish Hydro Electric Transmission Ltd	-6%	6%

Table 4.1. The voltage step change limits in planning timescales in UK.

4.5 Optimal Placement of SVCs

Several optimisation methods and approaches have been proposed for the optimal placement of SVCs for different purposes, such as enhancing the network loading margin [117-119], steady-state or dynamic voltage stability [120], loss reductions [121], and to maximise the profit of reactive power generation [122].

Here, the focus is on to whether optimal MVar planning using SVCs can comply with the steady-state voltage constraints while keeping the total capacity of SVCs installed into the system minimal. The conventional voltage sensitivity approach [123] is modified to achieve this objective. The traditional voltage sensitivity method measures the voltage change of a bus before and after a SVC is connected to the bus. The bus which has the maximum voltage increase per MVar connected is considered to be the most effective location to connect a SVC. The method will cause the SVCs to be installed at multiple locations due to the most effective location to support voltage will change as the network condition is changed each time another MVar of SVC is installed. As a result the total capacity of SVCs required to solve the voltage problem will be less if SVCs are distributed than just a single bulk SVC installed in one location. Furthermore, the modified voltage sensitivity method will not only measure the voltage change of the bus where a SVC is connected, but the total voltage changes in all of the buses. As a result the location of a SVC is decided where the connection would have maximum support to the system voltage. Furthermore, the voltage step change constraint has been included, and the capacity of SVCs is not only measured and shown in total MVar, but further classified into amount of capacitive and inductive power the SVCs are required to produce under various conditions. The differential equation below can be derived from conventional power flow equations [123]:

$$\begin{bmatrix} dP_i \\ dQ_i \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} d\theta_i \\ d|V_i| \end{bmatrix}, \quad i = 1 \ldots N \tag{4.2}$$

where P_i, Q_i are the real and reactive power injected into bus i, which has voltage equal to $V_i \angle \theta_i$, N is the number of buses in the network excluding the slack bus; $J_1 = \frac{\partial P}{\partial \theta}$, $J_2 = \frac{\partial P}{\partial |V|}$, $J_3 = \frac{\partial Q}{\partial \theta}$, $J_2 = \frac{\partial Q}{\partial |V|}$ are the $N \times N$ sub matrices of the Jacobian matrix.

Since the interest is in finding the voltage changes due to SVC connection, (4.2) can be rearranged as follows:

$$\begin{bmatrix} d\theta_i \\ d|V_i| \end{bmatrix} = \begin{bmatrix} K_1 & K_2 \\ K_3 & K_4 \end{bmatrix} \begin{bmatrix} dP_i \\ dQ_i \end{bmatrix} \tag{4.3}$$

where $K_1 = (J_1 - J_2 J_4^{-1} J_3)^{-1}$, $K_2 = -J_1^{-1} J_2 (J_4 - J_3 J_1^{-1} J_2)^{-1}$, $K_3 = -J_4^{-1} J_3 (J_1 - J_2 J_4^{-1} J_3)^{-1}$, $K_4 = (J_4 - J_3 J_1^{-1} J_2)^{-1}$.

There, only the changes in bus voltages due to reactive power injections are of interest, therefore, (4.3) is further simplified to:

$$\left[d\left|V_i\right| \right] = K_4 \left[dQ_i \right] \tag{4.4}$$

The change in voltage of each bus within the network due to the SVC connected at bus k can be derived as follows:

$$\begin{bmatrix} d\left|V_i\right| \\ \vdots \\ d\left|V_N\right| \end{bmatrix} = \begin{bmatrix} K_4(i,k) \\ \vdots \\ K_4(N,k) \end{bmatrix} dQ_k \quad , \quad k \in i \ldots N \tag{4.5}$$

To introduce the steady-state voltage and voltage step change constraints, let V_{no_SVC} and V_{SVC} be the steady-state voltages at bus i before and after the installation of a SVC at bus k respectively;

$$V_{no\_SVC} + d\left|V_i\right| = V_{SVC} \tag{4.6}$$

Let ΔV_i be the voltage change at bus i after taking the constraints into account. Thus,

$$\Delta V_i = \begin{cases} 0 & \text{If } V_{\min} \le V_{no\_SVC}, V_{SVC} \le V_{\max} \\ d|V_i| & \text{If } V_{no\_SVC}, V_{SVC} \le V_{\min} \\ -d|V_i| & \text{If } V_{no\_SVC}, V_{SVC} \ge V_{\max} \\ V_{\max} - V_{SVC} & \text{If } V_{no\_SVC} < V_{\max} < V_{SVC} \\ V_{no\_SVC} - V_{\max} & \text{If } V_{no\_SVC} > V_{\max} > V_{SVC} \\ V_{\min} - V_{no\_SVC} & \text{If } V_{no\_SVC} < V_{\min} < V_{SVC} \\ V_{SVC} - V_{\min} & \text{If } V_{no\_SVC} > V_{\min} > V_{SVC} \end{cases} \tag{4.7}$$

where V_{max} and V_{min} are the upper and lower voltage limits for either steady-state voltage or step change constraints depending on the analysis. In this way, during normal operating conditions, V_{max} and V_{min} are equivalent to the steady-state statuary limits, while following a contingency, if the voltages do not fall out of the steady-state limits, then the values are bound by the maximum voltage change allowed. The total voltage increase at all the buses due to the connection of a SVC at bus k, ΔV_{SVC_k}, which provides an indication of the cost-effectiveness of investing in 1MVar SVC at bus k, is calculated as:

$$\Delta V_{SVC\_k} = \sum_{i}^{N} \Delta V_i \tag{4.8}$$

Thus, the final location of extra MVAr capacity of SVC will correspond to a bus providing the largest improvement on the overall system voltages while fulfilling voltage constraints:

$$\mathrm{M}ax(\Delta \mathrm{V}_{\mathrm{SVC}\_k}) \tag{4.9}$$

$$k = 1,2,3,.........N$$

4.6 Proposed Algorithm

The benefits of utilizing DG for voltage support are quantified by analyzing the impact of a DG connection on the SVCs planning. The approach is developed in the Python computer language that interacts with the power system analysis software PSS/E to run AC power flows to check the voltage profile of the network under different planned outages. The algorithm is comprised of three basic steps described below. The corresponding flow chart is presented in Fig. 4.3.

Step 1: Read network data and perform an AC power flow to evaluate the voltage profile during normal operation. In case voltage drops (or rises) result in values outside the limits, execute the modified voltage sensitivity method to determine the SVC capacity required to satisfy the voltage requirements.

Step 2: The network voltage profile after each possible contingency is examined, i.e. loss of a single line, transformer, load or generator are considered. For each contingency, the modified voltage sensitivity method is performed to assess the siting and sizing of SVCs connected throughout the network. The total cost of the required SVCs in the case is calculated.

Step 3: Finally, the analyses performed in the previous steps will now consider DG units at specific locations. The economic impact of DG on network voltage will correspond to its ability to offset the need for SVCs, and, therefore, to decrease the corresponding investmen

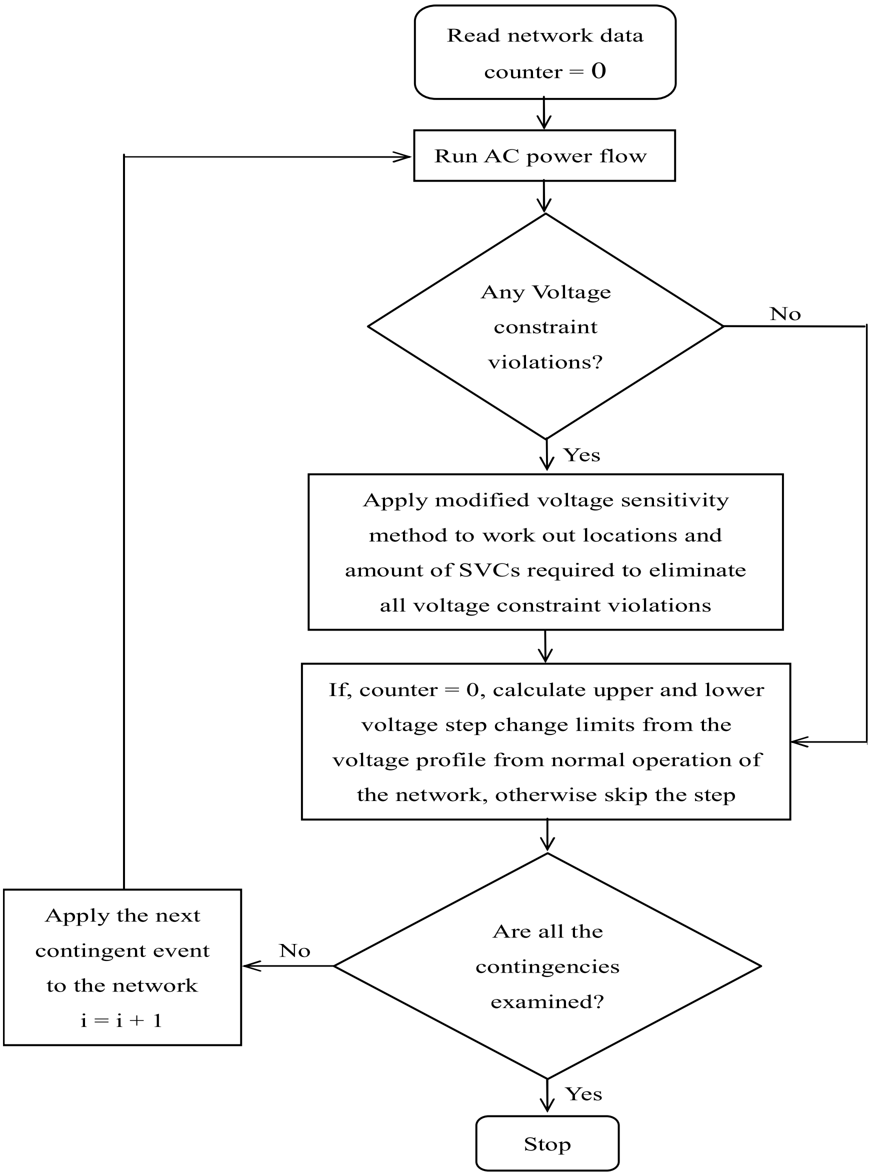


Fig. 4.3. Flow chart of the proposed algorithm.

4.7 Application – Quantifying DG Voltage Impact on 33kV Distribution Network

4.7.1 Network Model and Assumptions

The methodology is applied to the distribution network shown in Fig. 4.4, a sub-network of the UK Generic Distribution System “EHV Network 2” developed by [90]. Power is supplied to the 33kV circuit via three parallel 132/33kV transformers. Major loads are at 11kV level and connected to either single or double 33/11kV transformers. The network is described in the introduction of [90] as *"some of the 33kV networks are looped but voltage problems still arise and are alleviated with shunt capacitors."*

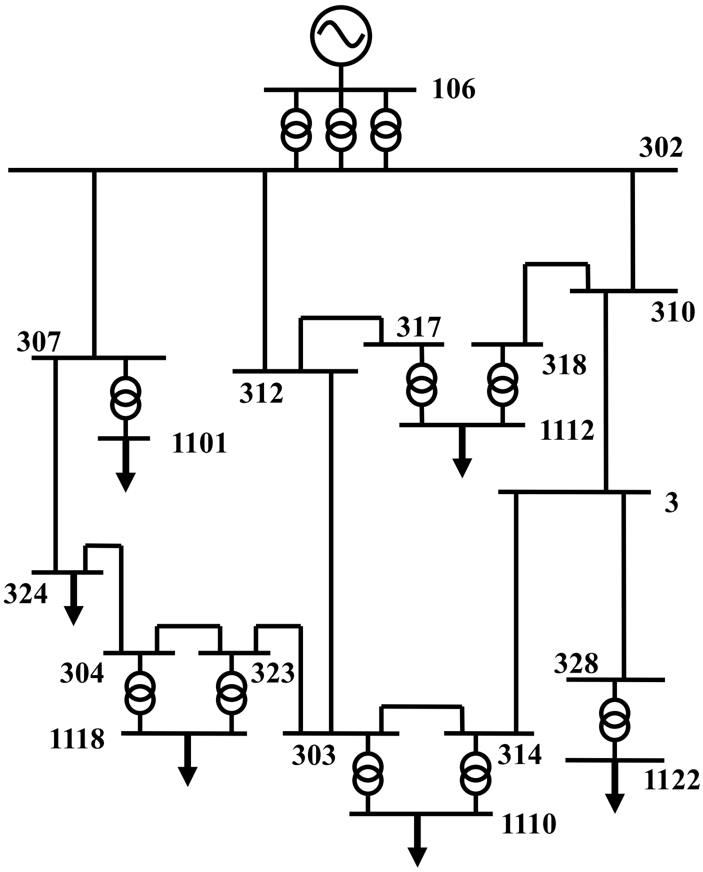


Fig. 4.4. UK 33kV sub-network of the generic "EHV Network 2".

Table 4.2 shows the demand characteristics of this network. The major load centres are located at bus 1110, 1118 and 1122 which are on the outer ring of the network. The load demand is at peak. Table 4.3 indicates the planned outages after which the network would need SVCs to support its voltage within regulatory limits.

Load Bus	Voltage Level (kV)	Real Power (MW)	Reactive Power (MVar)
324	33	0.47	0.16
1101	11	1.73	0.57
1110	11	6.26	2.06
1112	11	8.31	2.73
1118	11	15.43	5.07
1122	11	3.81	1.25

Table 4.2. Load profile of the 33kV Distribution Network.

Contingency	Description	Contingency	Description
1	No Contigency	16	Disconnect 303-1110
2	Disconnect 302-307	17	Disconnect 304-1118
3	Disconnect 302-310	18	Disconnect 307-1101
4	Disconnect 302-312	19	Disconnect 314-1110
5	Disconnect 303-312	20	Disconnect 317-1112
6	Disconnect 303-314	21	Disconnect 318-1112
7	Disconnect 303-323	22	Disconnect 323-1118
8	Disconnect 304-323	23	Disconnect 328-1122
9	Disconnect 304-324	24	Disconnect load at 324
10	Disconnect 307-324	25	Disconnect load at 1101
11	Disconnect 310-318	26	Disconnect load at 1110
12	Disconnect 310-329	27	Disconnect load at 1112
13	Disconnect 312-317	28	Disconnect load at 1118
14	Disconnect 314-329	29	Disconnect Load 1122
15	Disconnect 328-329	30	Disconnect DG

Table 4.3. Contingencies studied.

To perform the simulations, the following considerations are taken into account:

1. Thirty possible contingencies (Table 4.3) are analysed. This includes loss of a single line, transformer and DG.
2. Voltage drop and rise must not exceed ±6% of the nominal value. Voltage step change is limited to ±6% of the voltage during normal operating conditions, i.e., before any contingency.
3. SVCs can be connected at any buses apart from bus 106. It is assumed that SVC costs \$30k and \$35k per MVAr [92] when connected to 11 and 33kV circuits, respectively.
4. DG scenarios will consider non-intermittent generation with capacity up to 20MW. Here, the availability and reliability issues are neglected.

4.7.2 Economic Assessments based on Various DG Locations

Three different cases considering the connection of a single 20MW DG unit (unity power factor) to the 33kV buses 314, 323 and 324, are studied separately. Fig. 4.5 shows the maximum amount of capacitive (+) and inductive (-) reactive power of SVC required at each load bus in order to comply with the constraints for voltage drop and rise, and voltage step change after examining the 30 contingencies. Buses 1101, 1110, 1112, 1118 and 1122 are the most effective locations to install SVCs, where the capacity of SVCs installed at these load buses accounts for over 90% of the total capacity installed throughout the network in all cases. The number on the top (or bottom) of each bar indicates the maximum capacitive (or inductive, i.e. negative in this case) reactive power provided by the SVCs. The contingencies causing the SVCs to produce maximum output are also labeled, e.g. C2.

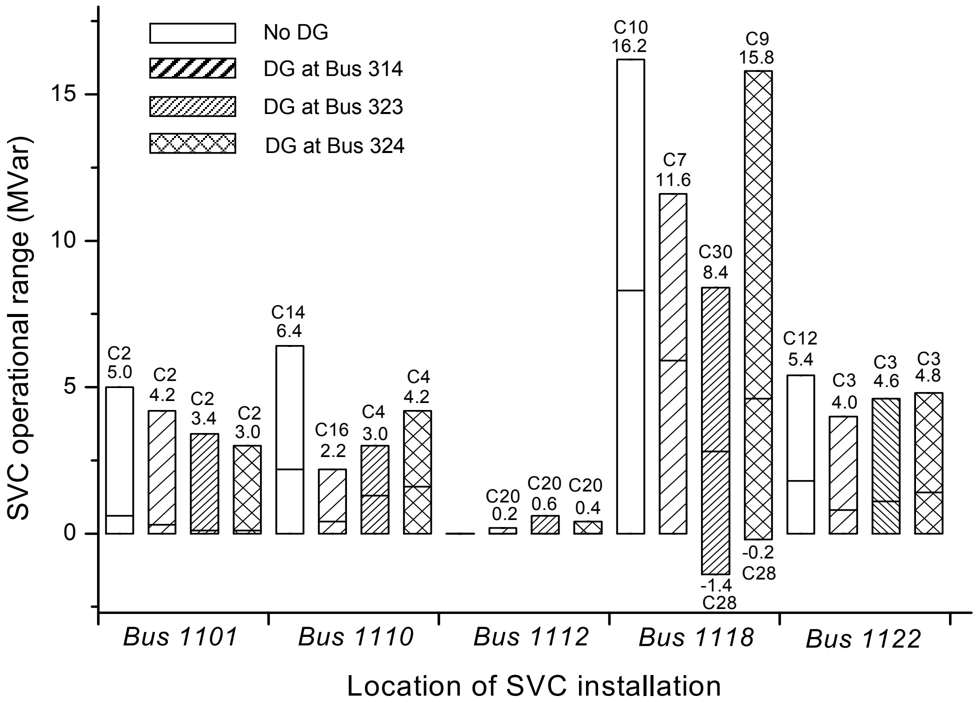


Fig. 4.5. The SVC operational range at each load bus based on various DG locations.

One observation from Fig. 4.5 is that the maximum capacitive reactive power required from SVCs varies significantly according to different DG locations. This is because changing the DG location alters the types of critical contingencies hence affecting the maximum SVC capacity installed at each bus. Nevertheless, the most effective location to install SVC is bus 1112, which is also most prone to voltage problems under both normal and contingent events. Although the average production from SVCs at bus 1118 when DG is at bus 314 is less than when the generator is located at bus 324, the contribution of DG in supporting voltage at bus 1118 after contingency C9 (outage of line 304-324) is very limited in the former case. Indeed, the DG unit connected to bus 324 cannot effectively decrease the SVC capacity required at bus 1118 mainly due to the constraints imposed by contingency C9. Furthermore, the voltage step change becomes influential when DG (unity pf) is connected to bus 323. The contingency C28 (disconnection of load at 1118) could cause abrupt voltage rise at bus 1118 and the presence of DG tends to further worsen the situation. Therefore, in this case, after contingency C28 an SVC at bus 1118 is required to produce 1.4 MVar inductive reactive power to prevent the violation of the voltage step change constraint. In practice, the chance of losing the entire load at 1118 would be small due to the security of supply concern by the DNO, while even if the contingency happens the network would require only a little inductive power injection into bus 1118. As a result, despite the high penetration of DG here, the problem of violating the voltage step change constraints seems, in this case, to be not a major issue.

Table 4.4 shows the total SVC installations and costs corresponding to different DG locations. DG at bus 314 and bus 323 induce great benefits by saving around 40% of the investment costs required in the case without DG. This allows the DNO to establish proper economic signals in favour of DG to connect at these sites for voltage support rather than at bus 324, which leads to 7% of cost reductions.

Location of DG	Total SVC Installation (MVar)	Total Cost ($k)	Cost Savings %
No DG	*37.8*	*1158*	*0*
Bus 314	*23.4*	*708*	*38.86*
Bus 323	*23.2*	*705*	*39.12*
Bus 324	*34.8*	*1076*	*7.08*

Table 4.4. Total cost of SVC installation based on DG locations.

4.7.3 Economic assessment based on various DG sizes and power factor control modes

Here, impacts of DG are quantified based on scenarios of changing the penetration of DG at bus 323 associated with different power factor control modes (0.9 leading, lagging and unity pf). The results are shown in Fig. 4.6. It can be seen that even if the DG penetration is at the highest (20MW) assumed here, a DG unit controlled at 0.9 lagging pf. (providing reactive power) could contribute an additional 20% cost reduction comparing to a DG that is operated at unity power factor. Clearly, this assists DNOs in evaluating the motivation to modify DG operation through appropriate market mechanisms.

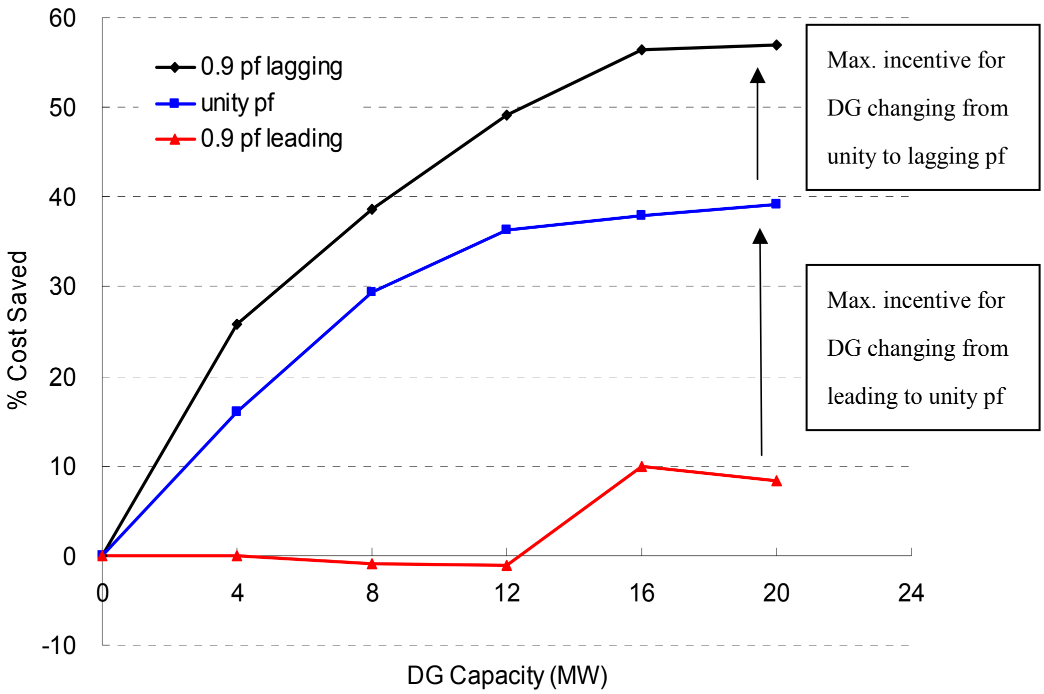


Fig. 4.6. Quantified investment savings according to the size and power factor control modes of DG.

The low X:R ratio of the branches (close to 2:1) for this particular distribution network boosts the effectiveness of real power injection to affect the voltage profile comparing to the situation at transmission voltage. Therefore, DG operating at leading power factor (producing reactive power) resulted in little impact on the voltage profile. Generators that absorb reactive power (inductive generators), power electronics equipment, such as pulse-width-modulation (PWM) converter, could be installed in order for DG to operate at the required power factor to support network voltages. While as shown in the graph, there are greater benefits for DG power factor correction from the leading to unity pf than from the unity to lagging pf. The reward for the DG owner changing the DG operation from lagging to unity pf can be approximately as twice as the reward for DG correcting its pf from unity to 0.9 leading pf.

Generally speaking, the quantified economic benefits for the studied cases increase with the DG capacity, mainly with unity and lagging power factor. However, such gains become relatively stable as DG capacity increases beyond 12MW. The observation can be justified according to Fig. 4.7, showing the changes in the output ranges of SVCs installed at the five buses caused by the increase of DG penetration at bus 323 and operated at 0.9 lagging pf. As the DG output increases, the contingency of loss of DG (C30) becomes the critical event causing maximum capacitive power required by SVCs at some buses. Since C30 becomes critical, further increase of DG size has no effect on reducing the maximum sourcing capability required by SVCs. Besides, the loss of load at bus 1118 (C28) would become more severe causing violation of the voltage step change constraint, which leads to additional capacity of SVC to produce inductive reactive power. As a consequence, further economic savings have been nullified. To mitigate the impact of increasing DG capacity, higher security is required to limit the amount of load lost at bus 1118.

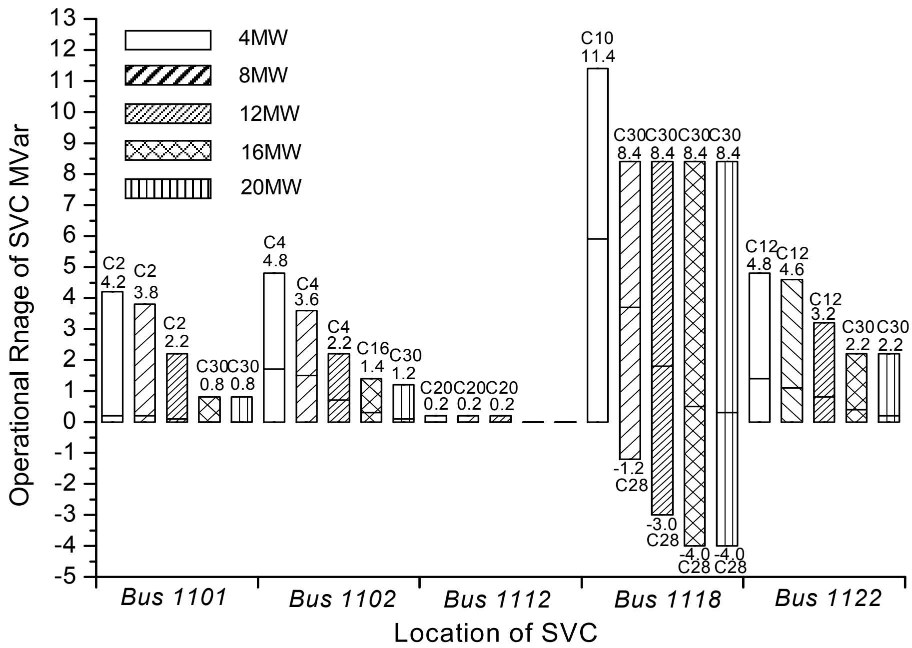


Fig. 4.7. SVC operational range at each load bus based on different DG sizes at bus 323 operating at 0.9 lagging pf.

4.7.4 Economic assessment based on different transformer tap-changer settings

Transformer tap-changers are vital equipment for network voltage corrections. According to [1], they are not allowed to be activated during the transient state. However, it is possible that the tap-changer positions in the pre-contingent steady-state could affect the voltage supporting ability of DG. To analyse this, different settings of the network tap changers are applied to the distribution network. The results would give the planner an idea about the suitability of current voltage control mechanism when accommodating the 20MW DG at bus 323. Three different voltage settings for each tap changer of the 33/11kV transformers are adopted. In the first case T1, the tap changers are set to regulate the secondary bus voltage between the steady state limits, i.e. ±6% of nominal. The voltage tolerances then changed to ±1% of nominal in the second case T2, which is the more common and practical situation. For the third case, T3, it is assumed the operator requires the tap changers to regulate bus voltages between 1.02pu to 1.06pu, intending to boost up the overall network voltages to minimize the additional investment required under C1 (normal operation condition).

The results are shown in Fig. 4.8. T0 indicates the network operation without enabling the tap changers. In the case without DG, enabling the existing transformer tap changers decreases the investment further by 30 to 40%. However, the presence of DG has a significant impact on the quantified benefit. The cost is reduced by 60% when T3 is applied, while T1 is the worst control scheme which when combined with DG the overall cost increases slightly.

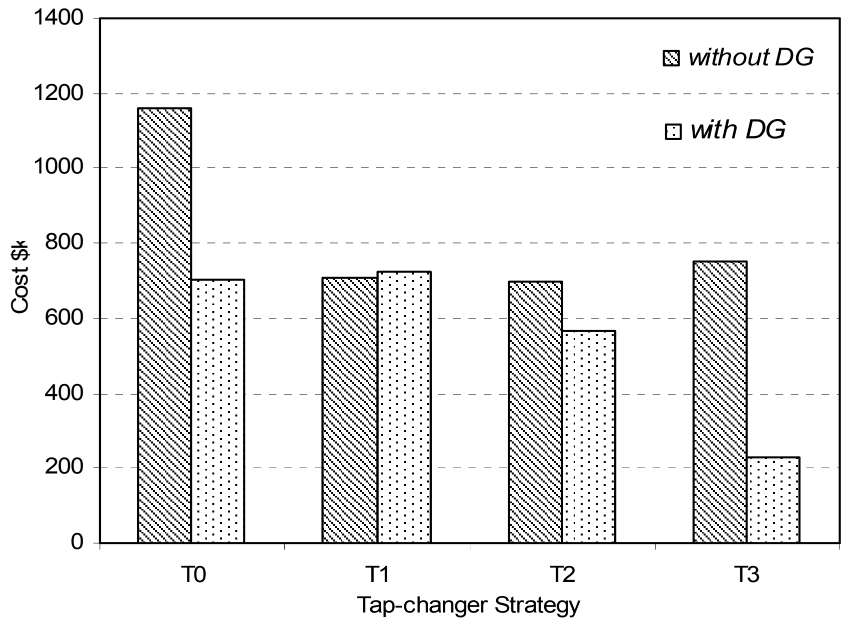


Fig. 4.8. The economical impacts of changing tap changer control strategies and the presence of DG.

Fig. 4.9 indicates the capacity of SVC installation in the cases of T1, T2 and T3 including DG. From T1 to T3, in general, the maximum capacitive power required by the SVC of each bus reduces as the transformers do more of the steady state voltage control. However, as loss-of-load contingencies become a more critical event, an extra few MVAr of inductive power of SVC, especially at bus 1118, is required to avoid unacceptable voltage step change. In the case of T3, C28 (loss of load at bus 1118) is the contingency that causes the maximum amount of inductive power support by SVC at bus 1118. Since DG has the ability to control its connected bus bar voltage, if, after C28, the DG is able to keep the voltage rise within the statutory limits, further cost reduction is possible. The benefit can be observed in Fig. 4.9. If such control strategy is established, the quantified benefits for the DG would be increased further by 6 x \$30 = \$180k.

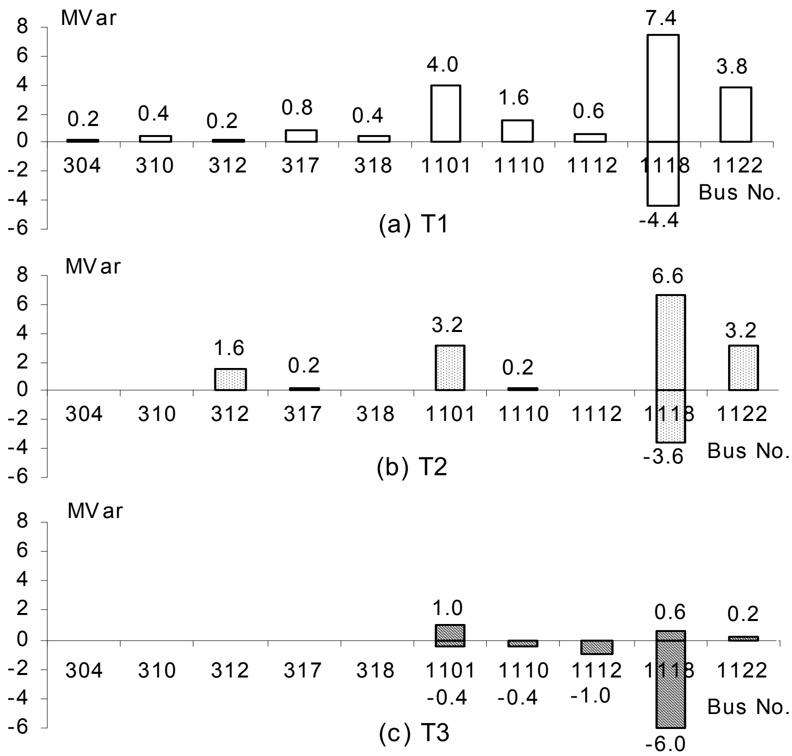


Fig. 4.9. Range of SVC operation adopting (a) T1 (b) T2 (c) T3 considering DG.

4.8 Chapter Summary

In this chapter, a methodology is proposed to quantify the impact of DG on planning of voltage-driven reinforcements for meeting statutory voltage constraints. It is assumed a SVC is used to solve voltage problems within a distribution network. The conventional voltage sensitivity equations are modified in order to determine the most cost-effective SVCs allocation (sizes and locations) while fulfilling constraints for voltage rise and drop, and voltage step change. The studied cases consider the connection of single DG units to different locations. The economic benefits of DG are investigated taking into account different generation capacities and power factor control modes. The results identified the relevance of certain contingencies that become more important depending on the size and location of the DG unit, changing significantly the need of SVCs, and, therefore, the corresponding investment costs. The interaction between different tap changers settings and DG were also examined. Results showed that DG could affect the effectiveness of the voltage control scheme adopted in a network. The proposed methodology could form the basis for deriving efficient incentives for DG to provide voltage support services, as well as to assist in analyzing the degree of coordination between potential voltage control mechanisms and DG.

As mentioned previously, the assumption here is that DNOs only consider investing in SVCs as the only type of equipment for supporting network voltages. If this approach is used for developing the pricing mechanisms for DG, a proper scaling method will be required for adjusting the potential over-estimated quantified results into reasonable values, since depending on the design of a network, there could be more cost-effective solutions for improving the network voltage profile than merely considering SVC installations. However, the approach gives consistent economic evaluations for DG influencing network voltages while using SVC as a measure.

The results showed the optimum deployment and the total costs of SVC installation could be significantly changed by DG. However under the circumstance that DNOs cannot own DG, to change the investment plan specifically in response to DG connection could be risky, as DG characteristics could be different from those previously expected. Therefore, it would be of great value for DNOs to develop the network planning strategy which could take advantage of DG for network support to some extent but should be flexible enough to accommodate uncertain DG characteristics. In the next chapter an approach to network planning considering uncertainties will be introduced.

CHAPTER 5 - Expansion Planning of Distribution Networks Considering Uncertainties

5.1 Introduction

The primary objective of traditional electrical network expansion planning is to invest in new equipment, such as lines and transformers, for the purpose of cost-effectively maintaining secure and efficient energy supply. With load largely passive, the annual growth could be, more or less, accurately predicted by planners. Therefore, the best expansion plan found to fulfil the current requirements will also be expected to function efficiently in the near future. Several deterministic approaches to search for the best network expansion plan, including mathematical programming and evolutionary algorithms, have been proposed [80, 89, 124, 125].

However, in the last decade, the circumstances around distribution and transmission systems have changed rapidly, due to (1) the connection of intermittent or non-intermittent distribution generation; (2) the introduction of new regulation to mitigate the environmental hazards and promote connection of distributed generation; and, (3) the changing behaviour of demand and its response to climate change, economic concerns, connection of advanced equipment and new loads. Such reasons have increased the uncertainties associated with network planning. These added future uncertainties have increased the risks of relying on deterministic approaches. A planning strategy, which seems to be more efficient and economic than the others at the present stage, could require significant extra costs to accommodate the changes in the future environment. Therefore, considering uncertainty in network planning is necessary.

Genetic algorithms (GAs) are meta-heuristics used to search for the optimal solution of a given problem. GAs have been widely utilised in the context of power systems such as to find the optimal network planning strategy, allocation and sizing of DG considering specific economical and technical constraints, etc [53, 67, 126]. Here, a new approach based on a novel balanced genetic algorithm (BGA) has been developed. By limiting the diversification and promoting the intensification of the searching process, the BGA efficiently mitigates the disadvantages of the conventional GA, resulting in better quality solutions. Furthermore, in the BGA, higher intensification causes slower information losses and results in a final solution pool containing a wide variety of solutions for consideration by the users; it is therefore useful for solving problems considering uncertainties. Comparing with other improved GA, the BGA is easier to implement which concentrates on only modifying the methods used in a conventional GA without inserting additional pieces of algorithms like other improved GA for improving the quality of the optimal solution. A more detailed explanation will be provided later in this chapter. To assess the overall performance of each plan under different uncertain scenarios and thus assist the planner in deciding the best solution to adopt, traditional data envelopment analysis (DEA) is modified and improved. A combination of the BGA and an improved and modified data envelopment analysis (IMDEA) is put forward for expansion planning under uncertainties, guiding the planner from the generation of expansion plans, to evaluation of the plans under various future uncertain scenarios, to the selection of the best strategy.

This chapter is structured as follows: In Section 5.2 the approaches proposed in the literature for solving the power systems planning considering different types of future uncertainties are described. Section 5.3 outlines the general steps required to tackle this type of problem. An overview of existing optimisation methods has been given in Chapter 2, Section 5.4 explains GAs in detail. Some of the improved versions of GAs developed by other researchers are shown in Section 5.5. The novel BGA developed within this PhD work is presented in Section 5.6, followed by the data envelopment analysis and its developments in Section 5.7. The complete approach to tackle the planning problem considering uncertainties is described in Section 5.8, while its application and results are presented in Section 5.9 and concluded in Section 5.10.

5.2 Existing Approaches to Power Systems Network Planning Considering Uncertainties

This section introduces some inspiring approaches which have been proposed to solve the network planning problems under various types of uncertainties.

Silva *et al.* [71] contemplated transmission network planning considering the uncertainty of future demand. Instead of using constant demand values, the range of possible demands at each load bus was considered and inserted into a traditional DC power flow model as variables. The Chu-Beasly GA, see Section 5.5.2, was used to find the optimum planning strategies by minimising the costs. The results indicated that it is possible to have multiple planning strategies obtained according to different load combinations that share the same minimal costs. However, although the approach is able to find the load combination in the network which results in minimum planning costs, in practice the demand combination is not something that DNOs can control. It would be more desirable to find out the best planning configuration which is cost-effective regardless of the future demand variations.

Celli and Pilo [127] proposed an approach to optimum distribution network planning considering different DG penetration levels at the end of the planning horizon. The uncertainties were treated as different possible scenarios identified by the planner. The approach consists of two phases. For each scenario, an optimum planning strategy with minimum cost was obtained by using a Branch and Bound optimisation method. In the second phase, a decision theory was applied to evaluate the performance of each optimum planning strategy under other scenarios. The expected cost of each planning strategy was calculated considering its performance under all the identified scenarios regarding to their relative probability of occurrence. The complete evaluation of a planning strategy was then the sum of its expected cost and the maximum regret felt by the planner to adopt the strategy, defined as the cost difference between the adopted planning and the best strategy under a scenario.

Carvalho *et al.* [128] modified a conventional GA to tackle the multi-stage planning problem under uncertainties of future loading locations. It is assumed that as time progresses, the future information becomes less uncertain. The uncertain future information associated at the same time along the planning horizon was represented as different mutually-exclusive scenarios. The overview of the problem is depicted in Fig. 5.1. The objective was to find the optimal planning strategy for stage 1 where the information is assumed to be deterministic, however this strategy at the 1st stage must also lead to a satisfactory 2nd stage planning strategy regardless of which scenario will happen. Three GAs were executed in parallel to find the optimal planning solutions for each scenario in 2nd stage. After the population of the first generation for each scenario has been created, each solution's fitness is evaluated. A penalty is introduced to the fitness function of a solution if the solution of the 2nd stage does not contain the sub-solution, which also solves the problem of the 1st stage that is commonly found in the current 2nd stage solutions of all three scenarios. The penalty factor would become stricter after each generation. As the algorithm is completed the optimum solution for each scenario would share the same 1st stage solution, which is then regarded as the best planning strategy the planner should adopt.

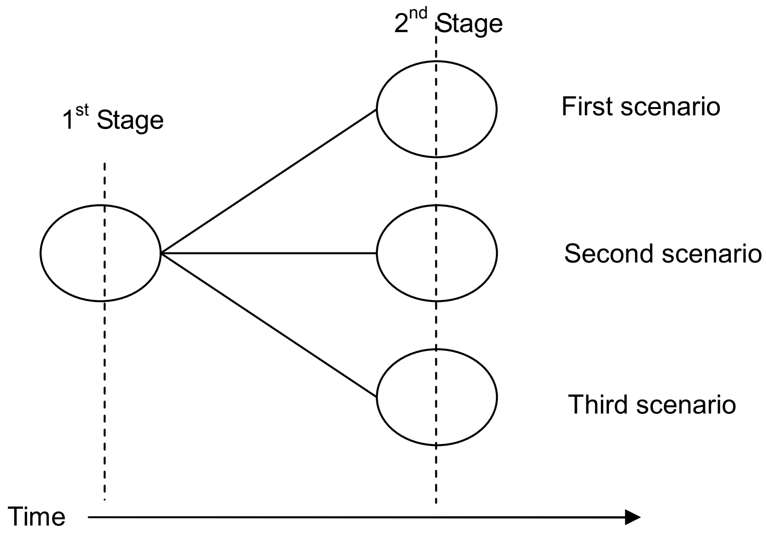


Fig. 5.1. Three scenarios information structure. First-stage information is indistinguishable as good forecasts are expected.

One major problem of the approach proposed by Carvalho *et al.* is that the 1st stage solution will be strongly driven by the scenarios identified at the 2nd stage, in which the information is in fact less deterministic. As there would be limited future scenarios identified, if in reality, none of the identified scenarios actually happen, then not only does the adopted 1st stage solution fail to be the optimal future-proof choice, it is also not the optimal one if only the scenario at the 1st stage is considered.

Carrano *et al.* [129] adopted an artificial immune system (AIS) algorithm, which belongs to the category of evolutionary computation, to find the optimum network configuration under the uncertainties of load demand and energy tax in each considered node. The uncertainties here were also represented as different scenarios. Comparing with other evolutionary algorithms, such as conventional tabu search, simulated annealing, etc., the AIS algorithm is able to find the sub-optimum solutions alongside the optimum, allowing the planner to have several feasible and satisfactory solutions to consider for final decision-making. The approach starts with finding the good solutions for a scenario which the planner thinks is the most probable one among all the scenarios. Then the solutions obtained were evaluated under different scenarios generated by Monte Carlo simulation, based on the assumption that the load and energy tax possibility distributions are available. It can be perceived that the approach requires high computational time and the detailed possibility distributions may not be available and could be difficult to calculate therefore affecting the results.

5.3 General Guidelines for Solving Power Systems Network Planning under Uncertainties

It can be noticed from the literature in the previous section that there are several general steps involved in tackling planning problems under uncertainties. Fig. 5.2 shows the flow chart of the general procedure. Each step is described in detail as follows:

Step 1. The primary objective function for network planning is defined. There could be multiple objectives, such as to minimise the cost as well as losses in the network. Then the planner considers any type of uncertainties which could affect the efficiency of network planning, such as load growth, future DG locations and penetrations, etc. The uncertainties are often modelled as scenarios using the probabilistic approach [130] if the probabilistic data for the input variables are available, otherwise the planner can draw out the possible scenarios based on his own experience and knowledge using the fuzzy set theory [131] .

Step 2. Choose an optimisation method and define the objectives and constraints, then generate the optimum planning strategies according to different combinations of uncertainties. In the case where uncertainties are presented, it can be perceived that optimisation methods , which could produce several solutions at once are more advantageous over the optimisation methods that produce only one optimal solution. Evolutionary algorithms such as an immune system algorithm [132] and a modified GA [133] have been developed for this purpose.

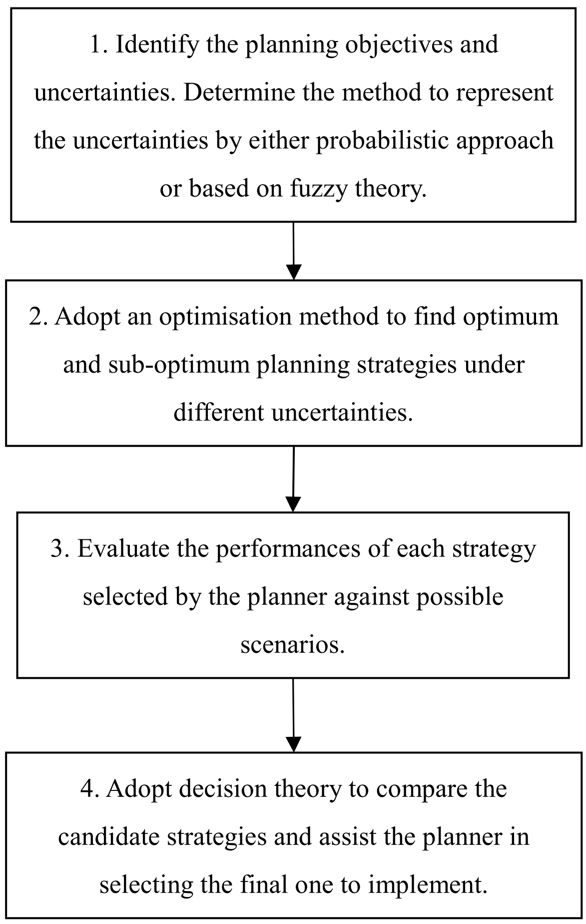


Fig. 5.2. Flow chart showing general procedures to solve network planning problems under uncertainties.

3. The planner selects some or all solutions generated by the optimisation method as the candidates for the final planning strategy. The performances of the candidates, such as losses, voltage levels etc, under various combinations of uncertainties, are evaluated and recorded for comparison.

4. It is useful to integrate all the results from all the evaluations of one planning solution into a single value (decision factor), so the planner can more easily rank the solutions by comparing their decision factors. A decision factor can be the sum of all the resultant values multiplied by the corresponding weighting factors. The value of weighting factor given to each result would depend on the relative importance between the results, which can be either based on their probability of occurrences or the planner's own judgement.

5.4 Genetic Algorithms

The genetic algorithm (GA) is one of the optimisation methods using artificial intelligence and belongs to the class of evolutionary algorithms. The searching procedure of the GA towards the optimum solution imitates the process of biological evolution and natural selection based on Charles Darwin's theory, which stated that the organisms which have better adaptation to the surrounding environment, i.e. capable of running away from predators or controlling food resources, will have a better chance to survive and produce offspring. Over many generations the offspring of the surviving organisms will dominate the population due to the hereditary survival abilities.

5.4.1 Terminologies

Before the full explanation of GA, some major terminologies used in GAs are explained in this section.

Chromosome

An organism is represented as a *chromosome* which consists of sequence of *genes*. Each *gene* controls a certain characteristic of the organism, e.g. eye colour, height, etc. In GAs, a solution to the optimisation problem is modelled as a *chromosome* and the information about the solution is encoded as *genes*.

Parents and Offspring Chromosomes

The surviving organisms would have chances to produce descendents together. In GAs, the *parents* refer to the existing *chromosomes* from which the new *chromosomes*, known as *offspring*, are generated.

Fitness

The *fitness* of a *chromosome* indicates how well the organism can adapt to the surrounding environment and is therefore related to the chances to survive and produce *offspring*. The *fitness* of a *chromosome* is measured by the *fitness* function, which is equivalent to the objective function of an optimisation problem.

5.4.2 Generation of Initial Population

The GA starts with generating a group of chromosomes, named a population. The size of the population depends on the complexity of the optimisation problem. At this stage a chromosome is formed by inserting random gene values. The number of genes in a chromosome and their range of values are decided based upon the number of variables in the problem. There are several ways to encode a gene. Fig. 5.3 shows the binary encoding method, in which the value inside a gene can only be represented by binary numbers 0 and 1.

Chromosome X: 1001011011

Chromosome Y: 0111101100

Fig. 5.3. Chromosomes X and Y with binary codification.

Other methods of encoding genes include permutation encoding (integers) [134] and value encoding (symbols). Which method to adopt is dependant on the type of optimisation problem and should be able to assist in improving the efficiency of the algorithm.

5.4.3 Selecting Parent Chromosomes

In order to produce new offspring, two chromosomes, known as the parents, are selected by a stochastic process from the current population. Many methods were introduced, such as roulette wheel selection, tournament selection, Boltzman selection and rank selection, etc. Here, the roulette wheel selection and tournament selection are explained.

Roulette Wheel Selection

In nature, male organisms will compete with each other to mate with females. The organisms with higher fitness will have higher chances to win and produce offspring. In roulette wheel selection, the probability of picking a parent chromosome in the population is based on its relative fitness in the population.

Tournament Selection

In tournament selection, a set of chromosomes are randomly selected. The chromosomes are sorted according to their fitness. The top chromosomes with the best fitness are then chosen to become the parents.

5.4.4 Producing Offspring from the Parent Chromosomes

New chromosomes, namely offspring, are produced from the parents through processes called cross-over and mutation. During the cross-over process, some genes at random locations in the parent chromosomes are copied and recombined together to form the offspring. Again there are several methods available, here, the single-point and two-point cross-over are explained.

Single-point Cross-over Operator

Fig. 5.4 shows the offspring produced using the single-point cross-over method. Firstly a cross-over point between two genes along the full gene sequence of a chromosome is randomly selected. In this example the point is between the third and fourth gene. The first offspring is born from the combination of genes of Parent 1 before the cross-over point and genes of Parent 2 after the point, and vice versa for producing Offspring 2.

Parent 1	**1001011011**
Parent 2	0111101100
Offspring 1	**100**1101100
Offspring 2	011**1011011**

Fig. 5.4. Offspring generation using single-point cross-over method.

Two-point Cross-over Operator

Two cross-over points are randomly selected. In this case the Offspring 1 is produced by recombining the genes of Parent 1 between the two cross-over points and the genes of Parent 2 that are not between the two cross-over points. Fig. 5.5 shows the offspring produced by this method, by which one cross-over point is between the third and fourth genes and another is between the seventh and eighth genes.

Parent 1	**1001011011**
Parent 2	0111101100
Offspring 1	**100**1101**011**
Offspring 2	011**1011**100

Fig. 5.5. Offspring generation using two-point cross-over method.

After the cross-over, mutation could occur in the offspring. In mutation one gene in the offspring is selected and its value is modified randomly. The purpose of mutation is to prevent the chromosomes from being trapped into local optima as well as to offer possibilities to recover important genes which had already become extinct in the population. The mutation rate is kept low, typically below 1%, as a high mutation rate would cause the GA to be more exposed to stochastic errors.

5.4.5 Population of Next Generation and Requirements for GA Convergence

The offspring is put into the population of the 2^{nd} generation that is created for the newly generated chromosomes, either if the fitness of the offspring is superior to the fitness of the parents, or by some random chances. The process of producing offspring showed in the previous steps repeats itself until the population for the 2^{nd} generation is full. Then the chromosomes in the population of the 2^{nd} generation will be selected as parents to produce the offspring of the next (3^{rd}) generation.

In a conventional GA, generally a gene is said to be converged if a high percentage of the chromosomes, e.g. 95%, in the population share the same gene. The population is converged if all the genes are converged and under this condition the GA is completed. The chromosome with the best fitness in the final converged population is regarded as the optimum solution found.

5.5 Improved Versions of Genetic Algorithms

The search procedures of evolutionary algorithms can be measured by two dimensions: intensification and diversification. Intensification refers to the detailed searching around the solution space that it is close to the existing solutions, while diversification allows the search to traverse across the solution space to explore completely untouched territory. Time constraints imply that to enhance the ability in one aspect usually needs sacrifice in the other. The search procedure with good intensification but weak diversification, like tabu search (TS) algorithm, would strengthen the links between the existing and new solutions and therefore decrease the risk of losing important information; however the lack of diversification could lead to local optima.

Due to the stochastic processes involved in a conventional GA, it has excellent diversification but poor intensification. As a consequence, it could avoid the solutions being trapped into local optima and converge to the global optimum. Conversely, crucial information could be permanently discarded randomly between each generation. With a limited mutation rate, the information may not be recovered and, as a result, may converge to a solution far from the optimal. Therefore, it is common to execute a conventional GA several times to increase the chance of getting optimal solutions.

Improvements to the GA are therefore concentrated on enhancing its intensification ability. This has been done by introducing some new methods into the algorithm or modifying the existing operators, in order to either decrease the chances of permanently losing important genes, or increase the chances to recover the important genes which could have been lost through previous generations due to stochastic errors. Two improved versions of GA, which have been adopted to tackle the problems in the power systems context successfully, are explained in the following sub-sections.

5.5.1 Improved Genetic Algorithm

The improved genetic algorithm (IGA) was first introduced by Yamamoto and Inoue [135] and applied to the power economic dispatch problem [136]. Two new operators were introduced into GA; they are the evolutionary direction operator (EDO) and migration operator. The EDO is used to produce the chromosome that could become the parents, while the migration operator creates an additional population of chromosomes for additional consideration if the current population contains too many similar chromosomes.

Evolution Direction Operator

In IGA, the parents are selected from the populations of three previous generations. In each of the three populations, three chromosomes are randomly selected. Then a new chromosome is produced from the three chromosomes selected by EDO. Suppose the three chromosomes C_1, C_2, C_3, consist of n sequence of genes g, are represented as:

$$C_1 = [\ g_{11}\ g_{12}\ g_{13}\ g_{14}\ldots\ldots g_{1n}\ ]$$
$$C_2 = [\ g_{21}\ g_{22}\ g_{23}\ g_{24}\ldots\ldots g_{2n}\ ]$$
$$C_3 = [\ g_{31}\ g_{32}\ g_{33}\ g_{34}\ldots\ldots g_{3n}\ ]$$

Assuming the order of fitness F_1, F_2, F_3 of the chromosomes C_1, C_2, C_3 is $F_1>F_2>F_3$. The gene g_{newi} of the new chromosome C_{new} is produced by the following equation:

$$g_{newi} = g_{3i} + D_1 \cdot (g_{3i} - g_{2i}) + D_2 \cdot (g_{3i} - g_{1i}) \tag{5.1}$$

where D_1 and D_2 are the evolution directions and i is the number of the *gene n* in a gene sequence. D_1 and D_2 determine whether the newly generated *gene* is more similar to the gene in C_1, C_2 or C_3. Smaller D_1 and D_2 also imply a smaller step size therefore intensifying the search locally. However, it is said the value of g_{newi} should be between the maximum and minimum values of the three genes (g_{1i}, g_{2i}, g_{3i}) provided. Therefore,

$$g_{newi} = \begin{matrix} \max(g_{1i}, g_{2i}, g_{3i}), & if \quad g_{newi} \geq \max(g_{1i}, g_{2i}, g_{3i}) \\ g_{newi}, & if \quad \min(g_{1i}, g_{2i}, g_{3i}) < g_{newi} < \max(g_{1i}, g_{2i}, g_{3i}) \\ \min(g_{1i}, g_{2i}, g_{3i}), & if \quad g_{newi} \leq \min(g_{1i}, g_{2i}, g_{3i}) \end{matrix} \tag{5.2}$$

If the fitness of the new chromosome F_{new} is better than F_1, the chromosome is accepted. Otherwise,

- If $F_{new} < F_3$, replace g_{3i} by g_{newi}.
- If $F_3 < F_{new} < F_2$, replace g_{2i} by g_{newi}.
- If $F_2 < F_{new} < F_1$, replace g_{1i} by g_{newi}.

Then another new chromosome will be created by EDO until $F_{new} > F_1$. After one new chromosome, known as the preferred parent, has been produced from each population of the last three generations, roulette wheel selection can be adopted to select two chromosomes to become the parents from the three new chromosomes and the chromosomes in the population of the current generation. In this case the authors recommended the probability of selecting the three preferred parents is set equal or higher than the aggregation of all the probabilities of selecting the chromosomes in the population of current generation, so the three preferred parents with good fitness have large chances of being selected and produce better offspring.

Migration Operator

The migration operator creates a new population to further diversify the chromosomes in the population. The operator is applied if the overall fitness of the current population has not been improved after several generations. Then a local search around the chromosome which has the best fitness in the population of current generation is activated, while each new chromosome found is placed into another newly-created population until the size of the population specified is reached.

5.5.2 Chu-Beasley Genetic Algorithm

The Chu-Beasley genetic algorithm (CBGA) was invented by Chu and Beasley [137], and has been successfully implemented by many researchers to solve various power systems problems such as optimal network planning and reconfiguration [71, 138]. Similar to IGA, the improvements are made by enhancing the local searching ability of GA while preventing fast degradation of gene diversity in the population after iterations. The modifications and new methods introduced in CBGA are explained as follows.

Unfitness Function

During the creation of the initial chromosomes of the CBGA, the unfeasible chromosomes are not discarded and are put into the population. Therefore, in addition to the fitness function used to evaluate how near the feasible chromosomes are to meeting the defined problem objectives, the unfitness function is used to measure how much extra effort is required for the unfeasible chromosomes to become feasible. The purpose of incorporating the unfeasible chromosomes into the population is to decrease the risks of generating similar feasible chromosomes which become dominant in the population, in other words, to maintain good gene diversity in the population.

Local Improvements of Offspring Chromosomes

After the offspring chromosomes are produced via cross-over and mutation, another procedure, called local improvement, is introduced intending to improve the fitness of the new chromosomes before they are placed into the population. Optimisation methods are utilised in the local improvement, such as linear programming or simple heuristic approach, to try to increase the fitness of the offspring by exploring the solution space adjacent to the applied offspring chromosomes. Two methods are employed for executing the local improvement. If a chromosome is unfeasible, a method is applied trying to correct its unfeasibility. On the contrary if the chromosome is already a feasible solution, instead another method will be carried out to improve the fitness of the feasible chromosome.

Non-generational Substitution

The conventional GA adopts the generational population substitution method by which the offspring is put into the newly-created population for the chromosomes of the same generation only. Conversely, in CBGA the non-generational substitution is used, with the new offspring produced inserted back into the same population from where the parents are selected, if all the following requirements below are met:

1. If the new offspring is identical to any chromosomes in the population, the offspring is discarded.
2. If the new offspring chromosome is unfeasible and it is less unfeasible than the most unfeasible chromosome in the population, then the offspring would replace the most unfeasible chromosome into the population, otherwise the offspring is discarded.
3. If the new offspring chromosome is feasible, it would replace the most unfeasible chromosome in the population. If there are no unfeasible chromosomes in the population and the fitness of the offspring is better than the chromosome with the least fitness in the population, then that chromosome is replaced by the offspring. Otherwise the offspring is discarded.

Advantages and Disadvantages of Chu-Beasley Algorithm

The idea of incorporating unfeasible chromosomes into the population, more efficient evolution of newly produced offspring by performing local improvements, and the non-generational population substitution method make the CBGA able to keep greater gene diversity in the population than the conventional GA and therefore further preventing premature convergence that is common in conventional GA.

However, as the optimisation problem becomes more complicated and has larger solution space, the methods used for measuring the unfitness of chromosomes and performing local improvements for offspring would be more difficult to implement and could result in the significant increase in computational burden.

5.6 Novel Balanced Genetic Algorithm

An improved version of the genetic algorithm, named the 'balanced genetic algorithm' (BGA), was developed here specifically for the purpose of efficiently solving the power systems planning under uncertainty problem. It is presented in this section.

Similar to IGA and CBGA, BGA attempts to prevent fast degradation of gene diversity in the population to minimise the risk of premature convergence. However, unlike IGA and CBGA, instead of inserting new methods to further complicate the algorithm and therefore increase the computational burden, BGA merely modifies the methods originally existing in the conventional GA. In BGA, the diversification searching ability is limited in a trade-off with the enhancement of intensification. The phases in the BGA are explained as follows.

Generation of Initial Population

New solutions are generated by a random process and put into a pool if those solutions are feasible and there are no identical solutions already existing in the pool. This solution generation process stops as the specified pool size is reached.

Parent Solution Selection

Two solutions from the pool are selected randomly known as the parents. In BGA the solutions have equal probability of being selected.

Cross-over and mutation Operator in Balanced Genetic Algorithm

In BGA, the number of genes allowed to cross-over, is strictly limited. First, x genes are identified which contain different information between the parents. Then an integer z is randomly generated with the following constraint:

$$z \leq (x, y) \tag{5.3}$$

where y is the predefined maximum number of genes allowed to participate in the crossover process and should be relatively small comparing to the total genes in a solution. An example is shown in Fig. 2 where the parents X and Y each consists of nine genes. After the comparison between the parents there are five genes (x = 5) identified to have different information between the parents, as indicated by the dashed arrows. In this case y is set to 3, indicating only a maximum three of the five identified genes will be allowed to crossover. However, in this crossover z is randomly generated and equal to 2, and two of the identified genes (gene 3, 7) are randomly selected in which the information is exchanged between the parents. As a result, two new solutions, offspring XX and YY are created.

Since there is strict limitation on the numbers of genes allowed to crossover in the BGA, the structure of the offspring XX would be very similar to the parent X, and the offspring YY would have great resemblances to the parent Y.

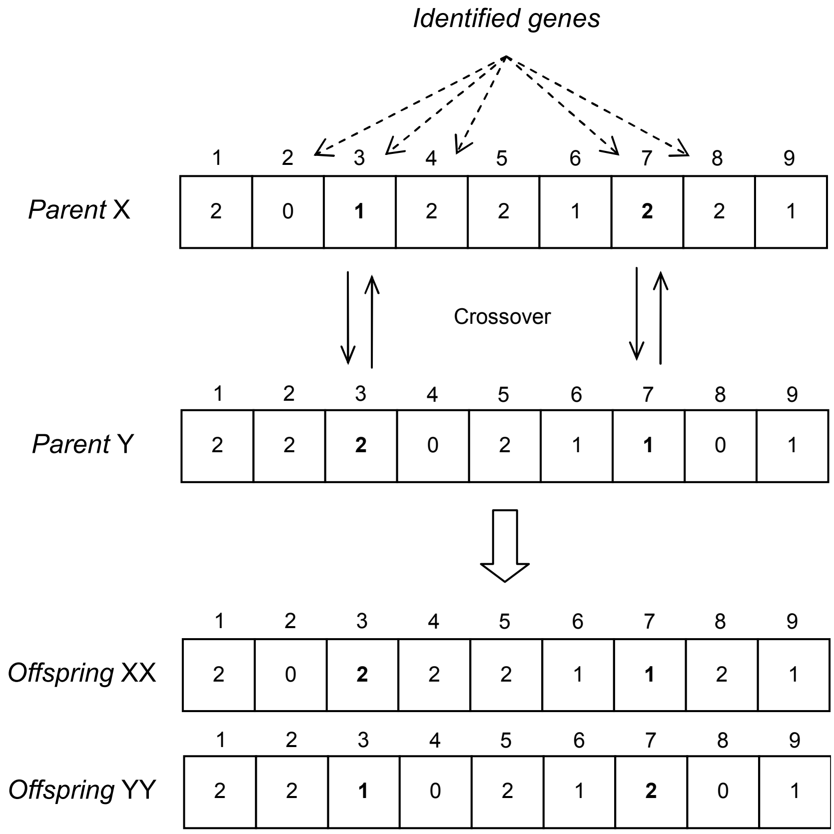


Fig. 5.6. Cross-over in BGA.

The mutation rate is kept low, typically below 1%. If it occurs, a stochastic process is again applied to select one gene in each offspring and alter the information inside the gene.

Modified Non-generational Substitution

The BGA uses the non-generational substitution method, but this differs from the method adopted in the CBGA by which the chromosome with the worst fitness in the population is replaced by the offspring with better fitness. In the BGA, Parent X can only be replaced by Offspring XX of Fig.5.6 into the population if the following requirements are met:

- There are no identical chromosomes to Offspring XX already existing in the population.
- The fitness of Offspring XX is better than the fitness of Parent X.

Otherwise Offspring XX will be discarded. The same rule applies to the substitution of Offspring YY to Parent Y.

<u>Comments on the Potential Advantages and disadvantages of the Balanced Genetic Algorithm</u>

Overall, the combination of the cross-over and substitution methods in BGA result in slow degradation of gene diversity in the population and minimise the risks of premature convergence. In a conventional GA, when a large section of genes are swapped to form offspring, only the overall effect on the section of genes to the fitness of the offspring is known. However, it is possible if the overall fitness of the offspring turns out to be worse, but the section of genes does contain some essential genes which are included in the true optimum solution, then under this condition the offspring has a small chance to be placed into the population, and therefore the risk of losing the essential genes will rise. Conversely, even if the offspring turns out to have better fitness, it could carry some genes which are not required in the true optimum one (non-essential), and in this condition those non-essential genes would have a chance of dominating the population and threatening the existence of the essential genes.

These drawbacks of the conventional GA mentioned are diminished in BGA by using the novel cross-over and chromosome substitutions. Since the offspring would be very similar to one of its parents and it would replace the parent chromosome if the offspring has better fitness, then in this case the genes which are inserted into the population are more likely to be the essential ones than the replaced old genes. Conversely if the offspring is discarded, then the genes of the abandoned offspring which are different from those of the parent chromosome are more likely to be the non-essential ones in the true optimum solution. Furthermore, the modified-generational population substitution in BGA decreases the chances of placing new chromosomes into the population where similar or the same chromosomes already exist. The purpose is to prevent genes becoming rapidly dominant in the population to minimise the danger of converging into local optimum. Another perceived advantage of BGA compared with other improved GAs in Section 5.5 is that BGA is relatively simple to implement since it merely modifies the original methods in conventional

GA without introducing any new methods that would complicate the algorithm and increase the computational burden.

5.7 Multi-criteria Decisions Tool - Data Envelopment Analysis

Data envelopment analysis (DEA), a linear programming methodology, measures the relative efficiencies of decision-making units (DMUs), which refer to the entities having the same types of inputs and outputs and allows them to be compared and ranked. In this case a DMU represents a planning solution. DEA was first introduced by Charnes, Cooper and Rhodes in 1978 [139]. The fundamental concept of DEA is that the efficiency of a DMU can be measured by the ratio of its output and input. An example of network expansion planning is used, where the planner would like to compare the planning strategies according to their costs and loss reduction (MW) within the network, as shown in Table 5.1. The efficiency of each strategy implies the effectiveness of reducing the network losses per $1k investment. Therefore, based on the efficiencies, the planner could easily adopt strategy 3 as the final planning strategy if its cost is within the budget.

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Planning Strategy	Cost (US$k)	Loss Reduction (MW)	Efficiency 1 (MW/US$k)
Strategy 1	400	8	0.020
Strategy 2	500	14	0.028
Strategy 3	600	23	0.038
Strategy 4	700	25	0.036

Table 5.1. Comparisons between four network planning strategies.

DEA would further compare the strategies by working out the relative efficiencies. Regarding the highest efficiency (Strategy 3) as the reference, the relative efficiency (RE_X) for Strategy *X* is computed by:

$$\mathrm{RE}_X = \frac{Efficiency \quad of \quad \mathrm{S}trategy \quad X}{Efficiency \quad of \quad \mathrm{S}trategy \quad 3} \times 100$$

(5.4)

By using the equation above, the relative efficiency for the four planning strategies are calculated and shown in Table 5.2. One could conclude that Strategy 3 is twice as efficient as Strategy 1. In this case, it is obvious which planning strategy is the most efficient strategy merely by comparing the efficiencies of the strategies in Table 5.1 without actually calculating the REs.

Planning Strategy	Relative Efficiency
Strategy 1	52.17%
Strategy 2	73.04%
Strategy 3	100.00%
Strategy 4	93.17%

Table 5.2. Relative efficiency of the planning strategies.

Another output is considered to complicate the example. Suppose, the planner is also concerned about the security of supply of the four planning strategies, which is measured by the additional load each strategy could handle without violating the security of supply constraint under the critical contingencies. Table 5.3 shows the second efficiency index of the planning strategies.

Planning Strategy	Cost (US$k)	Additional Load (MW)	Efficiency 2 (MW/US$k)
Strategy 1	400	25	0.063
Strategy 2	500	30	0.060
Strategy 3	600	38	0.063
Strategy 4	700	50	0.071

Table 5.3. Comparisons of security of supply improvements between four network planning strategies.

Now it is not obvious which strategy the planner should adopt, given that Strategy 3 has the highest efficiency for loss reduction, but it is less effective in enhancing the security of supply than Strategy 4.

In this extended case, RE can be worked out by plotting the graph of Efficiency 1 against Efficiency 2, as depicted in Fig. 5.7. In this figure, a line is drawn to link the X and Y axis through the efficiency points of Strategy 3 and Strategy 4. The line is known as the *efficient frontier* as DEA is also called frontier analysis. It is assumed that any points lying on this *efficient frontier* would have 100% relative efficiency. Therefore, both Strategy 3 and Strategy 4 would have 100% relative efficiency while Strategy 1 and Strategy 2 are the less efficient strategies to adopt. The dashed lines, which cross the efficient points of Strategy 1 and Strategy 2, indicate the path for the two strategies to the *efficient frontier*, if the ratio of Efficiency 1 and Efficiency 2 is maintained. The relative efficiency for Strategy 1 ($RE_{Strategy1}$) can be calculated using the following equation:

$$RE_{Strategy1} = \frac{\text{length of dashed line from origin to the point of Strategy 1}}{\text{length of dashed line from origin to the Best of Strategy 1}} \times 100 \tag{5.5}$$

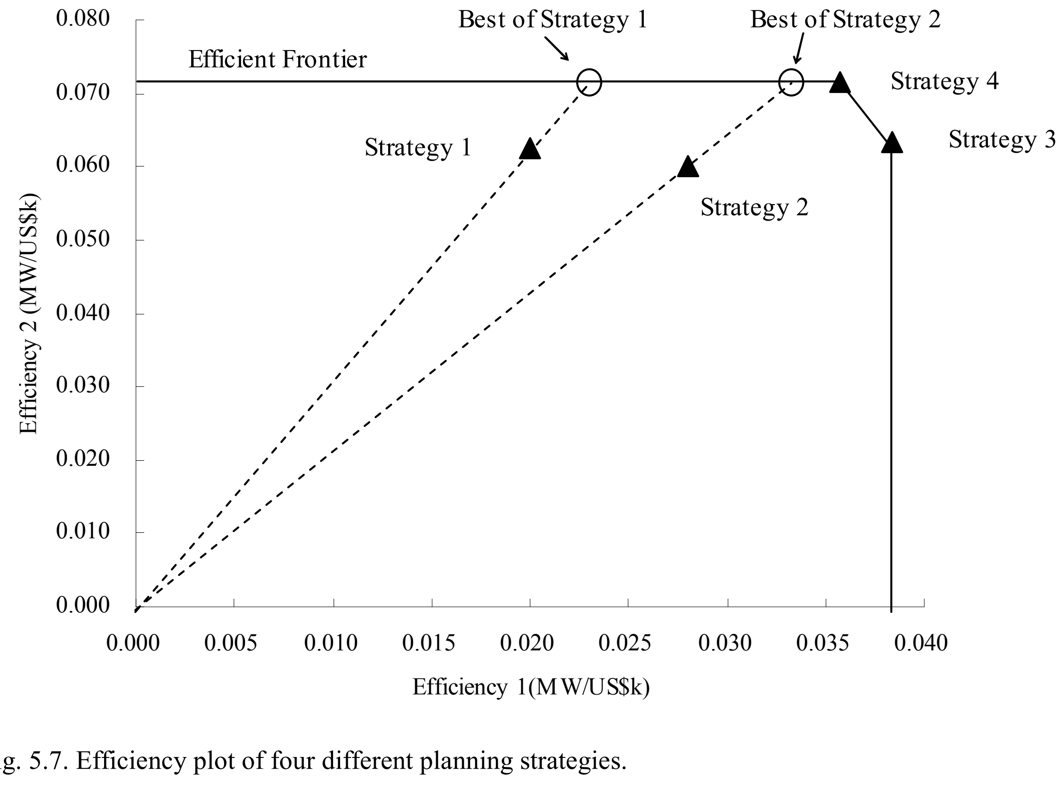

Fig. 5.7. Efficiency plot of four different planning strategies.

As the number of inputs and outputs increase, it becomes impossible to work out the relative efficiency by graphical methods. Therefore, in DEA, the relative efficiency of a DMU is calculated by using mathematical equations in order to handle multiple inputs and outputs. Assuming there are *n* DMUs with one input and two outputs, the RE of DMU1 can be calculated by [140]:

$$RE = MAX((B1_{DMU\_1}Y1_{DMU\_1} + B2_{DMU\_1}Y2_{DMU\_1})/A_{DMU\_1}X_{DMU\_1}) \tag{5.6}$$

s.t. $(B1_{DMU\_i}Y1_{DMU\_i} + B2_{DMU\_i}Y2_{DMU\_i})/A_{DMU\_i}X_{DMU\_i} \leq 1$

$A1_{DMU\_i}, B1_{DMU\_i}, B2_{DMU\_i} \geq 0$

$i = 1.....n$

where *X* and *Y* represent the input and output of a DMU, and *A* and *B* are the weighting factors for the input and outputs, respectively. The constraint ensures the efficiencies of all DMUs are in the range between 0 and 1. To solve the optimisation problem by linear programming, the formulation above is transformed as follows:

$$RE = MAX\ (B1_{DMU\_1}Y1_{DMU\_1} + B2_{DMU\_1}Y2_{DMU\_1}) \tag{5.7}$$

s.t. $A_{DMU\_1}X_{DMU\_1} = 1$

$B1_{DMU\_i}Y1_{DMU\_i} + B2_{DMU\_i}Y2_{DMU\_i} - A_{DMU\_i}X_{DMU\_i} \leq 0$

$A_{DMU\_i}, B1_{DMU\_i}, B2_{DMU\_i} \geq 0$

$i = 1........n$

It is worthwhile to compare the concept of DEA and dominance theory [132], a popular method used to assist in decision-making. In a dominance theory, a DMU_a is said to be completely dominated by another DMU_b, if the performance of DMU_a is worse than DMU_b in every aspect concerned. DMU_a can be simply eliminated since DMU_b is always preferable than DMU_a in any circumstances. The concept is similar to DEA since DMU_a will definitely not lie on the efficient frontier line therefore will never be the best choice. However, DEA will still assign DMU_a an efficient score to indicate the degree of inferiority of DMU_a compared with the best choice. Furthermore, DEA can be modified so those dominated DMUs identified by the dominance theory can be further distinguished by an improved DEA as a result to assist in the decision making of selecting the best DMU. The modification of DEA is explained in the next section.

5.7.1 Modified Data Envelopment Analysis

According to the features of DEA described above, there must be at least one DMU which has 100% relative efficiency. In practice, when the number of DMUs increases, it is very likely to have several DMUs forming the *efficient frontier* and their RE would all be at maximum. Under such circumstance the problem emerges that it becomes impossible to distinguish between the performances of these DMUs in terms of which is the best overall.

In order to further distinguish between the performances of DMUs which all have maximum efficiency, modified data envelopment analysis (MDEA) was introduced in [141] and [142]. Fig. 5.8 shows the efficiency plot to evaluate the relative efficiency of DMU4 among six DMUs (DMU1 to DMU6). For conventional DEA the *efficient frontier* would pass through DMU2, DMU4 and DMU5, implying that these three DMUs would have 100% relative efficiency. In MDEA, the frontier efficiency would be modified and will not pass through the DMU that is currently under evaluation. In this example, where DMU4's relative efficiency is currently under evaluation, the modification of the frontier line, as the dotted line in Fig.5.8, links directly from DMU2 to DMU3 and skips DMU4.

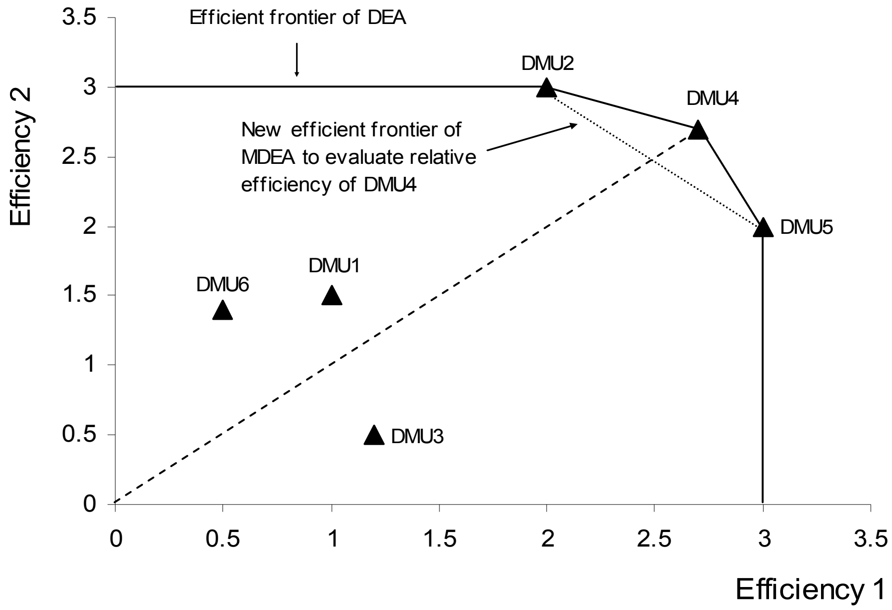

Fig. 5.8. Efficient plot of MDEA.

Suppose *a* indicates the length of the dashed line from the origin to its intersection with the new efficient frontier, and *b* is the length of the dashed line from the origin to DMU4. The relative efficiency of DMU4 in MDEA is calculated using the the following equation, and is now allowed to be over 100%:

$$\mathrm{RE}_{\mathrm{DMU4}} = \frac{b}{\mathrm{a}} \times 100 \tag{5.8}$$

In linear programming, the constraint for DMU4 is relaxed and the formulation becomes: RE

$$RE = MAX\ (B1_{DMU\_4} Y1_{DMU\_4} + B2_{DMU\_4} Y2_{DMU\_4}) \tag{5.9}$$

s.t. $A_{DMU\_4} X_{DMU\_4} = 1$

$$B1_{DMU\_i} Y1_{DMU\_i} + B2_{DMU\_i} Y2_{DMU\_i} - A_{DMU\_i} X_{DMU\_i} \le 0$$

$$A_{DMU\_i}, B1_{DMU\_i}, B2_{DMU\_i} \ge 0$$

$$i = 1........6, i \ne 4$$

MDEA allows the DMUs, which would have 100% relative efficiency in conventional DEA, to exceed this 100% threshold and therefore allows those DMUs to be compared and ranked. In this example, the relative efficiency DMU2, DMU4 and DMU5 will be all over 100%.

5.7.2 Improved Modified Data Envelopment

Although MDEA is able to distinguish the relative efficiencies between the DMUs on the *efficient frontier*, another problem affecting the fairness of comparing DMUs has also been perceived [140]. If there are multiple outputs for a DMU, linear programming would assign the weighting factors to each output in order to maximise the RE of the DMU. However, the weighting factors given to each output should be dependant on the relative importance between the outputs of a DMU. If one output is considered more important than the other, then the weighing factor assigned to the output should be greater. Using the example in Fig. 5.8, additional constraints can be placed into the linear formulation to restrain the weighting factors B1, B2 given to the output Y1 and Y2 as follows:

$$RE = MAX \ (B1_{DMU\_4} Y1_{DMU\_4} + B2_{DMU\_4} Y2_{DMU\_4}) \tag{5.10}$$

s.t. $A_{DMU\_4} X_{DMU\_4} = 1$

$$B1_{DMU\_i} Y1_{DMU\_i} + B2_{DMU\_i} Y2_{DMU\_i} - A_{DMU\_i} X_{DMU\_i} \leq 0$$

$$A_{DMU\_i}, B1_{DMU\_i}, B2_{DMU\_i} \geq 0$$

$$W_{\min} \leq B1_{DMU\_i} \big/ B2_{DMU\_i} \leq W_{\max}$$

$$i = 1........6, i \neq 4$$

where W_{max} and W_{min} are the maximum and minimum ratios allowed between weighting factors $B1$ and $B2$ respectively and are based on the judgment of the user with regard to the relative importance of the two outputs $Y1$ and $Y2$.

5.8 The Approach to Multi-Stage Planning Under Uncertainties

Network planning is a continuous task to ensure the system is delivered efficiently considering mid and long term challenges, such as demand growth. This task can be separated into multiple-stages based on the major requirements that are identified. It is important in terms of cost-efficiency that an expansion planning solution for one stage also leads to another efficient development for the next stage. However, the process becomes more complicated if the information associated with the later stages is uncertain. Here, two stage planning is considered, where uncertainties are treated as different possible (and mutually exclusive) scenarios in the second stage (stage 2).

5.8.1 Application of Balanced Genetic Algorithm

Firstly, the BGA is used to find optimal planning strategies to fulfil the requirements of stage 1. Due to the special features of the BGA, it can also be used to evaluate the performance of the strategies under each scenario in stage 2. In the solution generation phase in stage 2, each new solution generated will carry one of the stage 1 strategies. An example of 2-stage network expansion planning is shown in Fig. 5.9. In the 1st stage a load is required to be connected from the grid supply point. Fig. 5.9 (a) indicates a solution for stage 1 representing as a chromosome, where the name of the gene sequence (1,2,3) indicates the potential right-of-way and the value 1 or 0 shows whether the route taken is (1) or not (0). As a result, the first stage solution involves the construction of lines 1 and 3 connecting the grid point to the load. In stage 2 another load is required to be connected and Fig.5.9 (b) shows one solution for the 2nd stage. This 2nd stage solution is assumed to be developed based on the 1st stage solution and therefore carries the information of the stage 1 solution. The information of the stage 1 strategy carried by the new configuration of stage 2 cannot be selected or changed during the cross-over and mutation operations when running BGA to find the optimal stage 2 solutions.

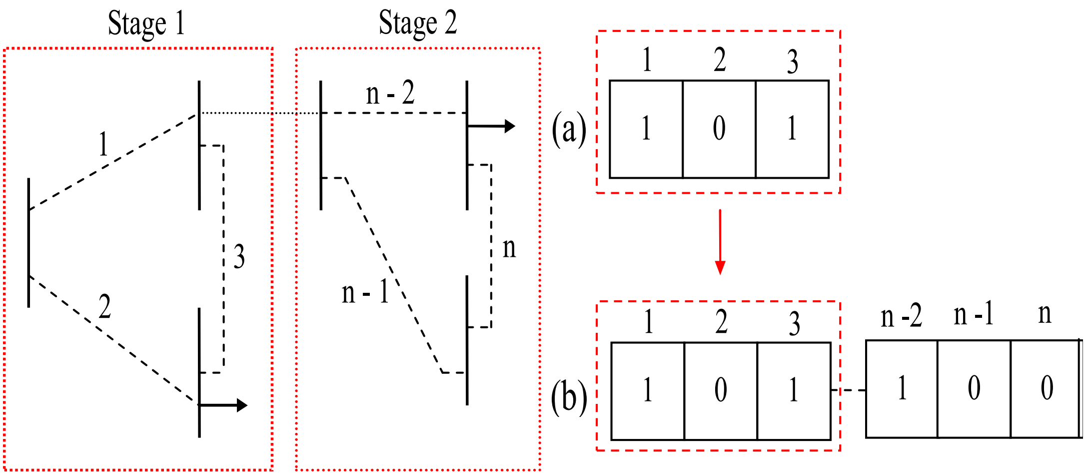

Fig. 5.9. Example of multi-stage expansion planning with (a) solution of stage 1 (b) solution of stage 2 which carries the solution of stage 1.

As the result, all the solutions obtained under a scenario in stage 2 must be developed from one of the stage 1 strategies. The performance of a stage 1 planning strategy under a given scenario can be evaluated by evaluating their performance during stage 2. After the optimum configurations for each scenario in stage 2 are obtained, a modified data envelopment analysis is used to compare the performance among the planning options found in stage 1.

5.8.2 Filtering of the Final Population

The top solutions found after the stop criterion (e.g. a given number of generations) has been met may be very good quality in terms of cost for the expansion planning problem, but they may not also represent the best ones that guard against future uncertainties. It is useful to explore the benefits of all the configurations in the final population against future scenarios. The procedure for 'filtering' the final population will assist in identifying those solutions that have a certain 'degree of uniqueness' which could be more beneficial in the long run.

After the set of final solutions is obtained, the configurations are sorted by their performance, from the best to the worst. A term 'degree of uniqueness' is introduced to define the amount of differences necessary between the structures of two solutions for them to be regarded as two distinct solutions. Starting from the solution with the best performance as a reference, other solutions that have fewer than the number of differences specified by the degree of uniqueness, are said to be similar solutions to the best one and are eliminated. ‘Similar solutions’ does not necessary mean alike performance, but the similar structure implies that they can be switched to each other without too much effort. Then the remaining solutions are compared with the solution with the second best performance in the pool. The size of the pool is further reduced by eliminating the solutions similar to it. The process continues until all the configurations left in the pool have been selected as reference and each solution possess a certain degree of ‘topology’ uniqueness compared with others.

The searching procedure of BGA combined with the filtering process above can be visualised in Fig. 5.10. In this example, initially there are five numbered candidates (solutions) in a solution space aiming to find the global optimum (GO). Each time two candidates randomly exchange information with each other, the exchanged information is limited relative to the whole information carried by the candidates. If the exchanged information improves the performance of a candidate, then the candidate accepts the information otherwise the candidate returns to its previous state. However, no more than one candidate can occupy a single solution space at the same time, so if the solution space where a candidate intends to move to is already occupied, the candidate would cancel the information exchanged. The same procedure is repeated until the defined criteria is met, which might be the number of consecutive repetitions during which no advancements of candidates have taken place. This example assumes that candidate 4 reaches the global optimal point, while candidate 2 finds the solution that is very similar to the optimum GO. Candidates 1 and 3 have found the solutions which are possibly local optimums, since further information exchange does not improve the performances of the candidates. These solutions, if their performances still meet the minimum requirement, possess a certain degree of uniqueness and could lead to useful results under future uncertainties which are very different from the global optimal solution. Depending on the strictness of the solution filtering, candidate 2 may be filtered out due to its similarity to candidate 1.

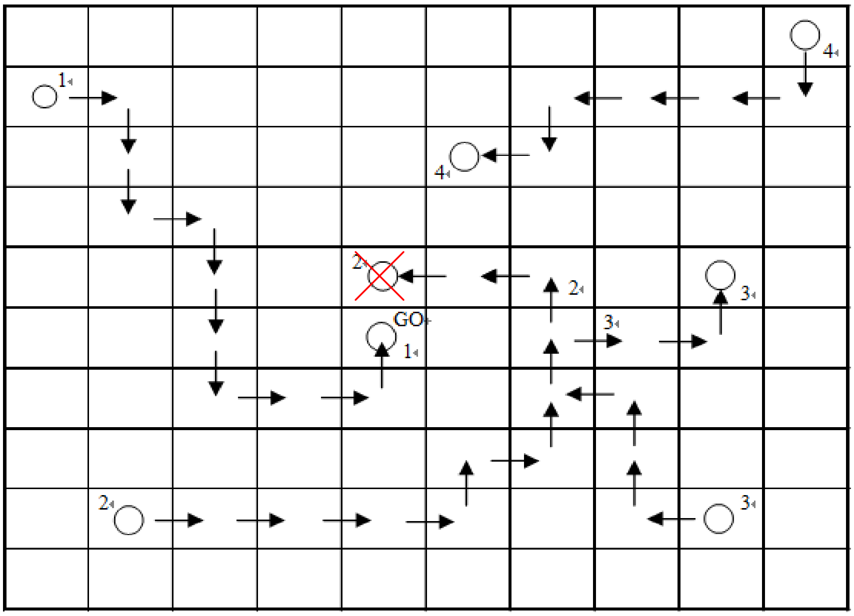

Fig. 5.10. Visualisation of the searching procedure of BGA with solution filtering.

5.8.3 Application of Improved Modified Data Envelopment Analysis

The relative efficiency of each planning strategy selected, regard as a DMU, will be calculated using IMDEA, i.e. MDEA with value judgment. The input of a DMU would be its efficiency to solve the problem in stage 1, while outputs would be the performances under different scenarios identified in stage 2. In terms of value judgement, the relative weighting factors between the outputs would be constrained based on the relative probability of occurrences of scenarios. The final planning strategy would be the one with the highest relative efficiency among all the candidates.

The perceived strengths of adopting the approach are:

- The search of BGA is from population to population, given not only the optimum but also the sub-optimum solutions at the end.
- The increase of intensification of BGA would result in good varieties of sub-optimum solutions found, as well as higher chance to converge into the real optimum solution than conventional GA.
- IMDEA does not require detailed equations to assess DMUs; it only needs the outputs and inputs of a DMU in order to calculate its relative efficiency. The planner would

simply choose the final planning strategy which has the best relative efficiency among all other candidates.

5.9 Application – Green-field Distribution Network Planning

5.9.1 Description of Network Planning Problem

The methodology is applied to the example of 'green-field' multi-stage network expansion addressed by Carvalho *et al.* [128]. Such planning problem may not be common in a more civilized Country, nevertheless it shall be a good starting case to examine the feasibility and strength of the approach developed. The approach will be applied to the network planning problem which considers adding reinforcements for accommodating more DG and loads within an existing network. The problem consists of two stages. At the first stage, two different load locations are confirmed and required to connect to the existing network. However, three additional major industrial loads are expected to emerge in the near future but their exact locations are unclear. Two scenarios of possible site loading for the second stage are identified. Therefore, the objective of this example is to find out the best planning strategy at the first stage, which will also lead to satisfactory results at the second stage regardless of the uncertain future scenarios.

BGA and the solution filtering algorithm are programmed using the programming language *Python*. As shown in Fig. 5.11, the program interacts with PSS/E to model the network and run AC power flows under specific voltage and thermal constraints. To apply IMDEA, the linear programming is formulated using the optimisation tool in Microsoft Excel to calculate relative efficiency.

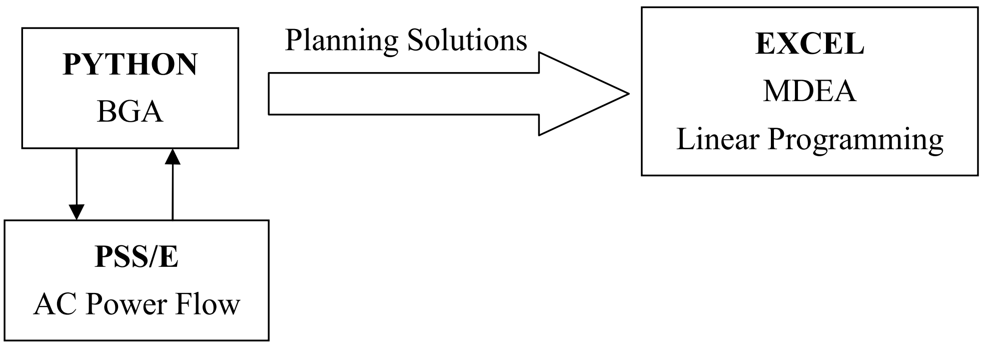

Fig. 5.11. Interaction between the tools used for the approach.

5.9.2 Network Expansion Planning – Stage 1

The expansion problem of the 1st stage is illustrated in Fig. 5.12. The existing network consists of the solid lines connecting the nodes 1-2-3-4. The power is imported from bus 1 to supply the load at bus 4. At the 1st stage, two new loading locations are confirmed at bus 15 and 16, which are required to be connected to the network. There are in total potentially 34 new routes linking possible substations, loads and existing buses. Table 5.4 shows the length of each potential branch and the co-ordinates (X, Y) of each node.

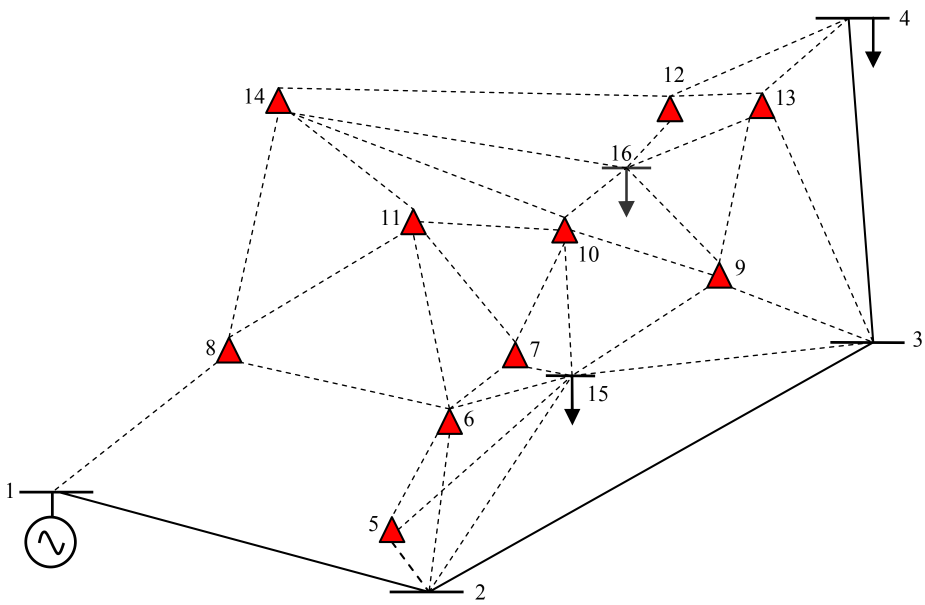

Fig. 5.12. Network planning problem of 1st stage.

Branch	Node 1	X	Y	Node 2	X	Y	Length(Km)
1	1	13	15	8	36	31	28.02
2	6	60	23	8	36	31	25.30
3	5	54	7	6	60	23	17.09
4	2	62	0	5	54	7	10.63
5	2	62	0	6	60	23	23.09
6	5	54	7	15	74	28	29.00
7	2	62	0	15	74	28	30.46
8	6	60	23	15	74	28	14.87
9	6	60	23	7	69	30	11.40
10	6	60	23	11	62	48	25.08
11	8	36	31	11	62	48	31.06
12	8	36	31	14	50	67	38.63
13	3	113	33	15	74	28	39.32
14	9	92	41	15	74	28	22.20
15	7	69	30	15	74	28	5.39
16	10	77	47	15	74	28	19.24
17	7	69	30	10	77	47	18.79
18	7	69	30	11	62	48	19.31
19	10	77	47	11	62	48	15.03
20	11	62	48	14	50	67	22.47
21	3	113	33	9	92	41	22.47
22	9	92	41	10	77	47	16.16
23	10	77	47	14	50	67	33.60
24	14	50	67	16	83	57	34.48
25	12	86	63	14	50	67	36.22
26	3	113	33	13	102	65	33.84
27	9	92	41	13	102	65	26.00
28	9	92	41	16	83	57	18.36
29	13	102	65	16	83	57	20.62
30	12	86	63	16	83	57	6.71
31	12	86	63	13	102	65	16.12
32	4	108	82	12	86	63	29.07
33	4	108	82	13	102	65	18.03
34	10	77	47	16	83	57	11.66

Table 5.4. Branch Data of the network for 1st stage planning (X, Y are coordinates).

In order to show the advantages of the BGA, the results are compared with those obtained by using a conventional GA with single crossover point and non-generational population substitution technique used in the CBGA. The initial population for both algorithms is set to contain 60 configurations. The search stops if no solution substitutions occur after 200 consecutive runs. Ten trials for each algorithm are attempted. For the BGA, only at most two *genes* are allowed to be exchanged. The filtering procedure is applied to both algorithms for showing the advantage of BGA, in which the degree of uniqueness is set to 2 branches, so there are no network configurations in the final pool that share more than two routes. The results are summarized in Table 5.5, while the cost data used can be found in [143].

	Best Solution (US$k)		No. of Distict Solutions		Solution Range		No. of Distinct Solutions under $834.20	
Trial No.	BGA	GA	BGA	GA	BGA	GA	BGA	GA
1	$613.60	$613.60	22	5	$613.60~$1209.70	$613.60~$717.30	17	5
2	$613.60	$613.60	20	11	$613.60~$1363.70	$613.60~$801.50	18	11
3	$613.60	$662.40	16	6	$613.60~$1050.00	$662.40~$804.50	15	6
4	$613.60	$630.30	17	10	$613.60~$1526.00	$630.30~$807.40	16	10
5	$613.60	$613.60	16	8	$613.60~$792.10	$613.60~$804.80	16	8
6	$613.60	$613.60	24	6	$613.60~$1494.60	$613.60~$705.30	21	6
7	$613.60	$613.60	18	6	$613.60~$849.20	$613.60~$804.80	17	6
8	$613.60	$630.30	25	6	$613.60~$1200.00	$630.30~$834.20	21	6
9	$613.60	$613.60	18	8	$613.60~$1226.50	$613.60~$804.80	16	8
10	$613.60	$613.60	18	5	$613.60~$1383.60	$613.60~$705.30	17	5
Summary	10/10	7/10	AVG: 19	AVG: 7	$613.60~$1526.00	$613.60~$834.20	AVG: 17	AVG: 7

Table 5.5. Summary of the optimum solution found in 1st Sage using BGA and conventional GA.

The best expansion strategy of stage 1 has a cost of $613.60k. BGA found this optimal solution in every trial, while it only appears in seven out of the ten trials of the GA. On average 19 viable solutions are found after the solution filtering phase from BGA compared with only 7 obtained by GA. This implies that, when the planner needs to generate a good variety of solutions, the BGA could be at least 2.7 times more efficient than the GA in this particular case, provided that the latter needs to generate no repeated solutions between each trial, which is very unlikely. Due to limited information exchange and the substitution method adopted in the BGA, some solutions may converge to local optimum points, producing solutions that are very expensive. In such occasions those solutions could become future-proof and may be of interest to the planner. However, despite the wider solution range produced by BGA, the last column of the table shows that if the solutions costing less than $834k (the maximum range of the GA) are compared between the two algorithms, the search conducted by BGA within this range is more thorough than the GA, proving that the intensification has been much improved in BGA in this case.

The greater intensification and limited randomness in BGA also results in a more consistent search towards final solutions. Fig. 5.13 shows the frequency of appearance of the top 10 solutions found in all the trials. On account of the greater randomness of GA, apart from the best solution, the chance of getting other solutions is between 0-50%, comparing with at least 70% for the BGA algorithm.

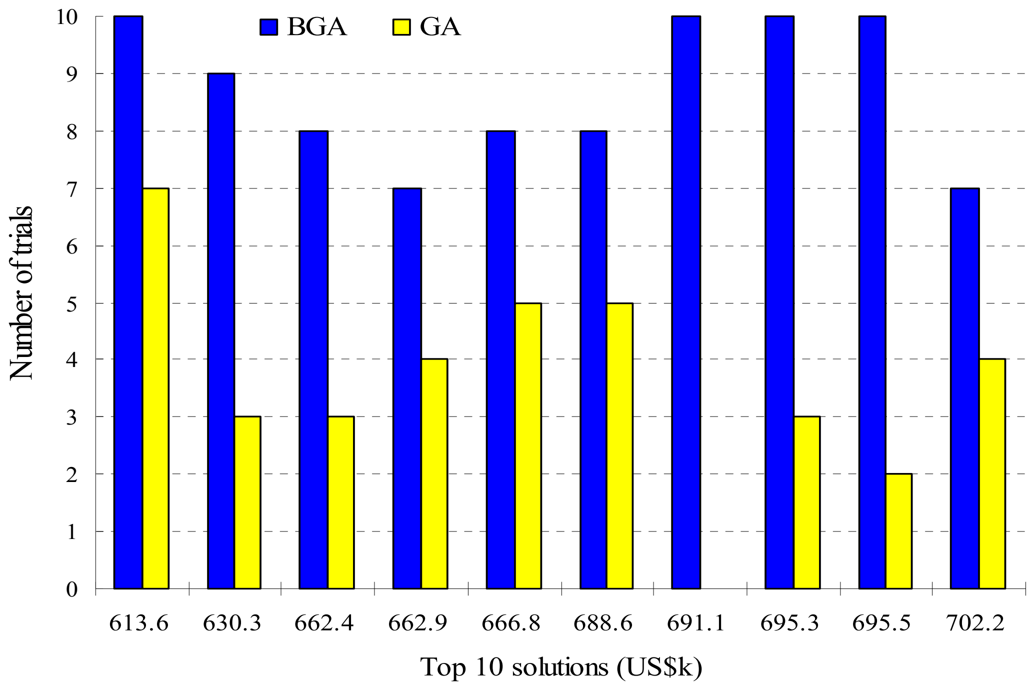

Fig. 5.13. Number of trials in which the top 10 solution are found by GA and BGA.

Fig. 5.14 shows the top five planning strategies of 1st stage, P1 to P5, obtained by the BGA algorithm in one of the ten trials executed. They are assumed here to be the candidates considered by the planner in making a final decision. The five planning strategies will be applied to the problem at the next stage by inserting their information into the solutions found at the 2nd stage. Their efficiency under each scenario will be evaluated.

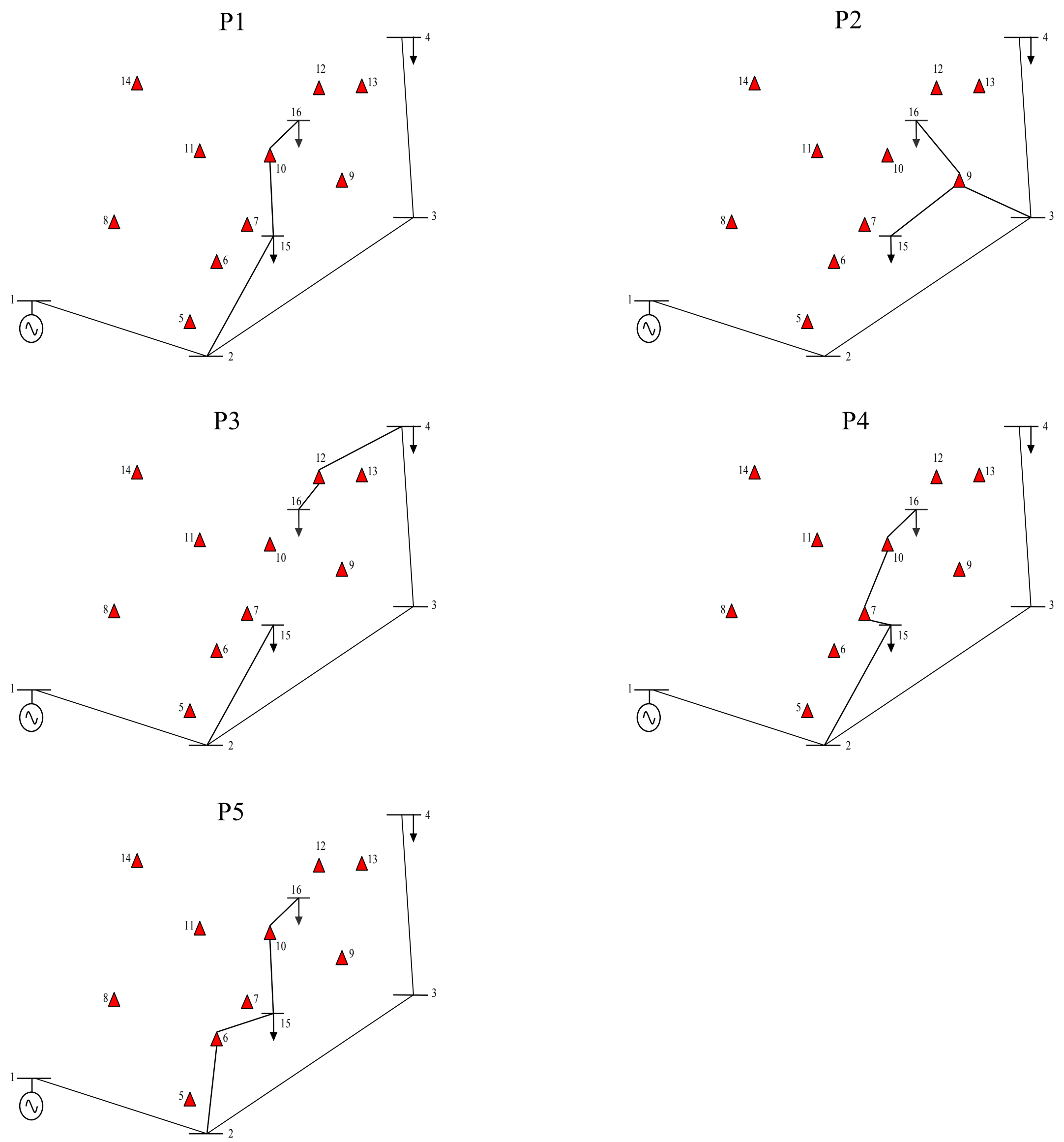

Fig. 5.14. Five top solutions for stage 1 obtained by BGA algorithm.

5.9.3 Network Expansion Planning – Stage 2

The 2nd stage problem is illustrated in Fig. 5.15, where three additional loads are expected to be connected in the near future but it is unclear where the exact locations are. Two scenarios of possible combinations of the loading sites are identified, namely S1 and S2. The objective is to determine the best planning strategy to meet the requirements in stage 1, which will also lead to satisfactory results in stage 2 regardless of the scenario. In additional to the routes shown in Table 5.4, Table 5.6 (a) and (b) indicate the potential branches connecting to the three additional loads under scenario S1 and S2 respectively.

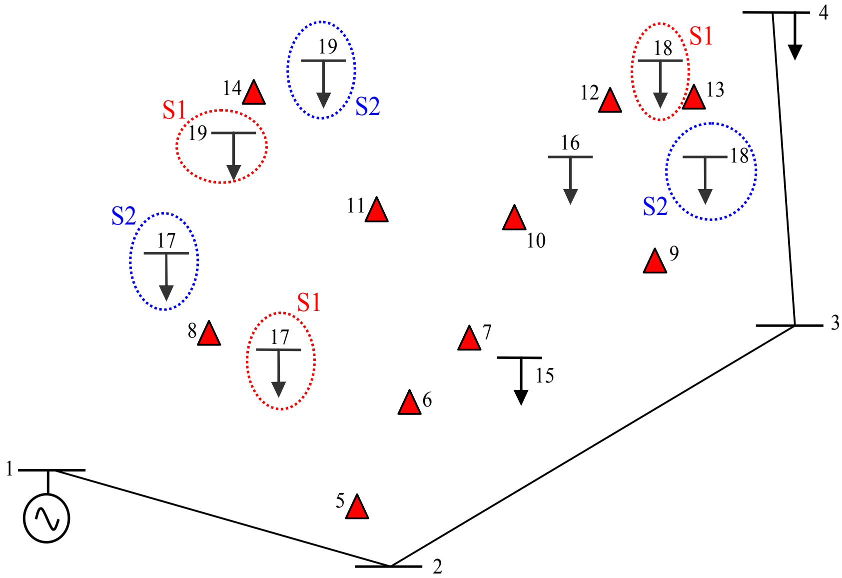

Fig. 5.15. Network expansion problem in stage 2 – two identified scenarios of future loading locations.

Branch	Node 1	X	Y	Node 2	X	Y	Length(km)
35	5	54	7	17	44	30	25.08
36	6	60	23	17	44	30	17.46
37	8	36	31	17	44	30	8.06
38	11	62	48	17	44	30	25.46
39	13	102	65	18	95	66	7.07
40	12	86	63	18	95	66	9.49
41	8	36	31	19	52	58	31.38
42	10	77	47	19	52	58	27.31
43	12	86	63	19	52	58	34.37
44	14	50	67	19	52	58	9.22

(a)

Branch	Node 1	X	Y	Node 2	X	Y	Length(km)
35	8	36	31	17	35	47	16.03
36	11	62	48	17	35	47	27.02
37	14	50	67	17	35	47	25.00
38	14	50	67	19	59	71	9.85
39	12	86	63	19	59	71	28.16
40	3	113	33	18	101	58	27.73
41	9	92	41	18	101	58	19.24
42	13	102	65	18	101	58	7.07

(b)

Table 5.6. Potential routes for connecting additional three loading locations under (a) scenario 1 (b) scenario 2.

The performance of the five planning strategies P1 to P5 are examined under each scenario identified in stage 2. For each planning strategy selected in stage 1 (P1 to P5), fifty feasible solutions for stage 2 are generated from the stage 1 candidate, resulting in 250 initial solutions in the pool. The search stops after there are no substitutions in the pool after 500 iterations. The maximum genes allowed to cross-over and the degree of uniqueness are set as before.

Ten trials are attempted for each scenario and the top solutions found are shown in Table 5.7. Regardless of which stage 2 solution is developed from which stage 1 strategy, the final planning cost is considerably more if scenario S2 occurs instead of S1. This is because there are different route options between S1 and S2 (Table 5.6) and it could be more difficult to connect the three loads under S2. If S1 happens, the best planning strategy is developed from P5, which is the most expensive among all the five stage 1 strategies. Although the best solution developed from P3 ranked only fifth under S1, there are four of the top solutions based on P3. If S2 occurs, the best expansion option found contains the structure of P2. Under S2, solutions originated from P1 and P2 perform very well, in terms of both quality and quantity. Contrary to its performance under scenario S1, P5 under S2 is the worst strategy which expands into only one low-ranked stage 2 solution.

Rank	Senario 1	Developed from:	Scenario 2	Developed From:
1	$1298.30	P5	$1516.00	P2
2	$1372.00	P1	$1524.40	P3
3	$1386.70	P4	$1549.10	P1
4	$1387.30	P5	$1559.40	P2
5	$1424.30	P3	$1560.40	P1
6	$1431.90	P3	$1592.10	P4
7	$1458.10	P3	$1611.90	P2
8	$1459.30	P2	$1624.10	P5
9	$1466.90	P2	$1624.80	P4
10	$1470.30	P3	$1633.80	P1

Table 5.7. Top solutions found for stage 2 and scenario analysis using the BGA.

Fig. 5.16 illustrates the optimum network configurations under the two scenarios. In this case the stage 1 planning strategies P2 and P5 have completely different network configurations. This underlines the risks of adopting a deterministic approach. However, while it is difficult to consider all the possible scenarios, this approach ensures that even if the final stage 1 strategy turns out to be less effective in stage 2, it is still one of the best strategies in stage 1 and the planner would at least not regret adopting such strategy to solve the 1st stage problem.

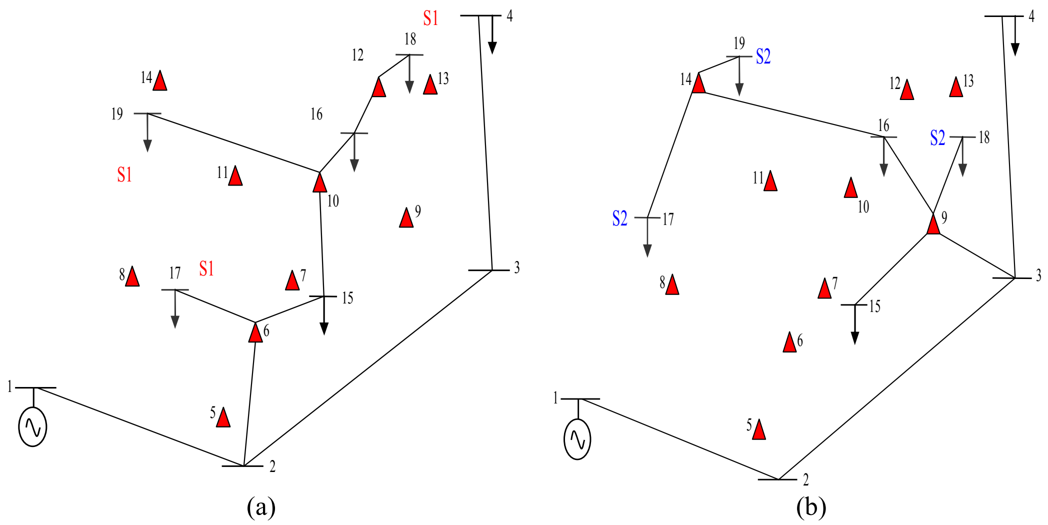

Fig. 5.16. The best configurations under (a) S1, developed from P5 (b) S2, developed from P2.

5.9.4 Selecting the best stage 1 planning strategy

The five strategies (P1 to P5) of stage 1 are regarded as the DMUs. One input and two outputs are taken to measure the efficiency of each strategy, as shown in Table 5.8. The input X is the cost of the stage 1 strategy, while the outputs, Y1 and Y2, are the reciprocals of the cost of the best solutions multiplied by 10^6 found in S1 and S2 respectively, that developed from the stage 1 strategy. The reason of multiplying 10^6 is so the final values of Y1 and Y2 closer to the values of X, making the ratio of Y1/X or Y2/X not too small or too large which is easier for comparison. The reason to invert the costs is for the purpose of maximising the relative efficiency while in this case a DMU with cheaper cost is regarded as better.

DMU	X	Y1	Y2
P1	613.6	728.86	645.54
P2	630.03	685.26	659.63
P3	662.4	702.1	656
P4	663	721.14	628.1
P5	688.6	770.24	615.73

Table 5.8. Input and output for each solution

The possibility of each scenario occurring will be a matter of judgment for the planner. If they are not able to allocate likelihood then a 50:50 chance will be used. Here the probability of S1 is between the range of 0.4 and 0.8. Since the two scenarios are mutually exclusive and the weighting factors for the two outputs should depend on the relative probability of the scenarios, W_{min} and W_{max} would be 0.67 and 4 respectively. The linear programming formulation to calculate the relative efficiency of P1 is:

$$
\begin{aligned}
&Max\ \ 728.86B_1 + 645.54B_2 \\
&s.t.\ \ 613.60A_1 = 1 \\
&\qquad 685.26B_1 + 659.63B_2 - 630.03A_1 <= 0 \\
&\qquad 702.10B_1 + 656.00B_2 - 662.40A_1 <= 0 \\
&\qquad 721.14B_1 + 628.10B_2 - 663.00A_1 <= 0 \\
&\qquad 770.24B_1 + 615.13B_2 - 688.60A_1 <= 0 \\
&\qquad A_1, B_1, B_2 \geq 0 \\
&\qquad 0.67 \leq {B_1}/{B_2} \geq 4
\end{aligned}
$$

The RE of each strategy is calculated by the DEA, MDEA and IMDEA methods, and the results are compared and presented in Table 5.9.

	DEA		MDEA		IMDEA	
DMU	RE	Rank	RE	Rank	RE	Rank
P1	1.00	1	1.08	1	1.04	1
P2	1.00	1	1.00	2	0.98	2
P3	0.94	2	0.94	3	0.93	3
P4	0.92	3	0.92	4	0.91	4
P5	0.94	2	0.94	3	0.89	5

Table 5.9. Evaluation of P1 to P5 obtained by DEA, MDEA and IMDEA.

Compared to DEA, MDEA is able to further distinguish the RE between P1 and P2, indicating P1 as the better strategy. However, since the performance under S1 is better than S2 for all the strategies, DEA and MDEA tends to assign a much larger weighting factor to Y1 than Y2. As a consequence P5 appears to be an attractive strategy to adopt under both methods (DEA and MDEA) since P5 performs very well in S1. By limiting the ratio of the output weighting factors based on the relative probability of occurrence of scenarios S1 and S2 using the IMDEA, P5 becomes the least efficient strategy to adopt because its excellent performance in S1 is weighted much lower than its performance in S2. As the results, P1 is the best network planning strategy in this case.

5.10 Chapter Summary

Approaches, such as this, that provide better understanding of the robust cost-effective expansion plans are highly desirable to distribution planners. In addition, the use of industry-standard power flow software driven by advanced use of its programming capability provides a robust method that lends itself to direct application in network planning. While the analysis here is limited to checking voltage and thermal limit feasibility using the power flow engine, additional aspects such as fault level checks, can be considered. The method lends itself to capturing the uncertainties brought about by incorporating distributed generation (DG) within the expansion planning process which will be contemplated in the next chapter.

This work demonstrates the effectiveness of using a balanced genetic algorithm combined with modified data envelopment analysis to provide the distribution planner with a minimum-cost set of network configurations that are robust to uncertainty. While the method is applied here to a greenfield cases, it is expected that problems involving highly developed distribution networks with smaller search spaces due to limited new paths can also benefit, particularly using the MDEA approach. While only a pathway search was demonstrated here, the methodology can handle alternative expansion options, such as reconductoring, needed to cope with local demand growth. With few modifications the approach is also applicable to transmission planning problems.

The novelty in the work arises from (1) the development of the balanced GA that uses strict limits on crossover and solution substitution to promote higher intensity searching and (2) the filtering of solutions an excluding those that are insufficiently unique; and (3) the combination of a multistage with MDEA to allow differentiation between alternatives under uncertainty. It would be interesting to compare BGA with other algorithms designed to improve the quantity of optimal and suboptimal solutions. However, the results showed that BGA only requires simple modification from a conventional GA to achieve the purpose. Nevertheless, BGA will suffer from a certain degree of stochastic errors and could be still trapped into a local optimum, despite more discreet information addition and elimination in the crossover and solution substitution phases. To counter this potential disadvantage, a large pool size would be normally required to ensure good information diversity in the initial solutions. The enhanced intensification of the BGA along with an application with a much larger network will increase the computational burden significantly, however the time concern is in trade of better and more reliable final solutions while using the BGA.

CHAPTER 6 - Network Planning Considering Uncertainties about Intermittent DG to Minimise Network Loss

6.1 Introduction

The previous chapters have highlighted the potential effects of DG on the network and that network operators need to take DG into consideration in network planning. The European Directive 2003/54/EC Article 14/7 [144] states that: "when planning the development of the distribution network, energy efficiency/demand-side management measures and/or distributed generation that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator". Nonetheless, there is no further specification in the Article on how to implement it. It would be of great interest for network operators to utilise DG connecting to their networks to meet the network operation standards required of them.

Generally speaking, the perspectives of the network operators in considering DG in network planning will differ according to different regulatory policies. Under the circumstance that network operators are allowed to own DG, DG can be regarded as a direct alternative to traditional electrical upgrades (transmission lines, transformers, capacitor banks), to maintain network efficiency and meet regulatory requirements.

As mentioned previously, Brown *et al.* [51] proposed a successive elimination method to find optimum network planning considering the investment in DG as well as other types of upgrades. Thermal, reliability and budget constraints were imposed on the optimisation method. Two network planning strategies with and without DG were generated by the method and compared. The results showed that the total expansion costs were greatly reduced if the investment of DG was considered.

Favuzza *et al.* [145] applied the dynamic ant colony optimisation method to a MV radial distribution network to obtain the optimum reinforcement plan. Gas micro-turbines were considered as one of the reinforcement options. The objective was to maximise the profit while taking the cost of reinforcements, cost of losses, as well as the prices of selling and buying electricity or heat produced by the DG into account. The results showed that the economical attractiveness of utilising DG as a reinforcement option would depend on the price of selling heat produced by the DG. As the price of heat was above a certain threshold, the reinforcement sets determined by the optimisation method would start to include DG at the most effective locations.

El-Khattam *et al.* [146] investigated the economic feasibility of considering DG in the planning of a 132/33kV distribution system. Two strategies were examined. The first strategy was to import and buy power from the main grid, with the necessary upgrade of the substations connecting the distribution system and the main grid supply point. The second strategy however, was to purchase power from the intertie connecting with the distribution system, which required to be upgraded. A mixed-integer non-linear optimisation tool was adopted to minimise the capital and O&M costs while keeping the voltage and thermal constraints within the defined limits. The profits gained from DG and its ability to reduce network losses were also considered. The results have showed that regardless of which strategy was adopted, the network planning approach that incorporated DG would cost significantly less than the planning which ignores DG as one of the reinforcement options.

However, under the circumstance where the network operators are precluded from owning DG, such as in the EU, the planning would not include the investment cost of DG or the profits gained from its generation. Therefore, the benefits or incentives of taking DG that is owned by other private entities into the network planning approach would only consider the savings in reinforcements which are otherwise required to mitigate the network stresses but then become unnecessary due to the presence of DG. Such benefits are difficult to predict since in many cases the characteristics of the DG technology would not be deterministic with the location and capacity uncertain. Therefore, approaches to network planning considering uncertainty have to be adopted if the network operators want to utilise the potential of DG to reduce network costs while minimising the risks associated with the DG uncertainties. A planning strategy which took the wrong characteristics of DG into account could become either unfeasible or ineffective and require additional investment to properly solve the problems in the network.

There is very little research on optimum network planning considering DG uncertainties. Celli *et al.* [147] adopted a probabilistic heuristic optimisation method to find the optimum network plan considering the uncertainties of DG penetration. To do so, the probability density functions of load profile and DG penetration were presented. Because the exact locations of DG were known, DG was utilised to support the thermal capability of the network. The results clearly showed that the capital costs of the reinforcements were greatly reduced when planning considered DG despite its uncertain penetration relative to planning that excluded DG. However, their assumption was that the penetration of DG was linearly proportional to the load demand, which would not be the case if the DG is powered by intermittent resources.

6.1.1 Incorporating Intermittent DG into Planning: Considering F-Factor Vs Output Probabilities

In Chapter 3 the impact of a wind farm on reinforcement deferment was analysed. To minimise the risk associated with the continuously varying output of the wind farm, the P2/6 contribution factor (F-factor) was used so only a fraction of its total installed capacity was taken into the power flow analysis. As such, the planner can have high confidence that the wind farm will at least produce this output during the peak demand period. Using the F-factor therefore reasonably eliminates the need to consider the uncertainty of output of intermittent DG.

In this chapter the DNO's attitude towards utilising DG in network planning becomes aggressive, i.e. DG is not only considered to temporary mitigate any network problems as in Chapter 2 and 3, but it is regard as a reinforcement option in the network planning. Therefore, using the concept of F-factor is not suitable here. For example, a wind farm of

100MW installed capacity has an F-factor of 20%. Adopting the F-factor approach implies that only planning strategies which assume 20MW DG will be derived. Although those strategies might be the least risky one, they will only be the true optimum ones if DG is producing 20MW and such strategies could overall have unsatisfactory performance when DG output deviates from 20MW, which is likely since it is the least output level DG is expected to produce on average. Therefore, only considering the planning strategies that assume 20MW DG output could lose the chance of examining all the possible planning strategies. As a result, optimum planning solutions are contemplated here across all the possible DG outputs relative to their probabilities during the period when the planning is concerned, aiming to find the one which not only maximises the benefits brought by the DG, but also has bearable risks. As a result, the variable DG outputs will be considered as uncertainties associated with network planning that incorporates intermittent DG.

6.1.2 Chapter Scope

In Chapter 5 the BGA was introduced and demonstrated to produce quality suboptimal and optimal solutions. The algorithm was applied successfully to a distribution network expansion planning problem considering uncertainties about the future load locations. However, as this thesis concentrates on the impact of DG on network planning, this chapter will develop the approach to facilitate the uncertainties associated with intermittent DG. The uncertainties relate to the intermittent DG's output at peak demand and its location further complicating the problem.

Here, the objective of planning is not only to minimise the network capital costs, but also to utilise DG to reduce network losses below a certain level in terms of the percentage of the demand. However, as the DG output will vary and with its location uncertain, it would be expected that the optimal plan will also change to minimise the losses depending on the DG output levels. The difficulty is that the planner can only implement one planning solution, implying that the network plan adopted could only be optimal when the DG is operating at a certain output level in a considered location. Apart from this ideal situation, the network solution may either perform inefficiently or even be infeasible in other situations, raising the risks associated with incorporating intermittent DG into network planning. In fact, the network operators may prefer to adopt a network planning strategy to minimise the network losses that does not utilise DG at all, despite the strategy being nominally more expensive.

This chapter will endeavor to understand whether it is possible and beneficial for DNOs to take advantage of intermittent DG of uncertain location in planning their networks in order to decrease the planning costs while maximising network efficiency under bearable risks.

6.1.3 The Assumptions and Approach

When analysing the impact of an intermittent DG on a network, it is vital to simulate all the possible network conditions considering various demand levels and the time-varying DG output, in order to ensure the network is able to accommodate the DG without breaking any regulatory constraints at any time. However, for simplicity, only the network planning for peak demand conditions is contemplated here, as it is the main period which usually requires additional reinforcements. To mitigate the potential impracticality due to the assumption, low penetration of an intermittent generation will be used, making it unlikely that reinforcements will be needed when the condition of maximum output and minimum demand occurs. The uncertainties about the outputs of an intermittent DG during the period of peak demand and its location will be modelled within scenarios. The BGA introduced in the last chapter will be adopted to search for quality suboptimal and optimal network plans in each identified scenario. The benefit and risk analysis will be applied to the optimal network plans obtained by the BGA in each of the scenarios. If the best plan is found in the scenario when there is no output from the DG, then it implies that there is no incentive for the network operators to consider intermittent DG within planning; otherwise it suggests that even where DG is intermittent and its location uncertain, the network operators should still consider the DG within network planning to gain benefit from it to a certain extent.

The approach will be applied to a simple 6-bus network and then a more complicated 46-bus system. For both applications it is assumed that the DG is a wind farm with a 200MW installed capacity, while the number of possible DG locations is increased from the 6-bus system to the 46-bus network. Therefore the conclusion about the impact of the increase of uncertainties on the results can be drawn. Each application will further be separated into four case studies including assumptions about various wind distribution patterns which change the probability of wind farm output during the period of peak demand.

6.1.4 Structure of the Chapter

In the next section the risks and benefits of incorporating intermittent DG into network planning will be identified, which lead to the problem formulation including the objective function and constraints for the BGA to generate optimum and sub-optimum network plans (Section 6.3). The benefit-risk analysis adopted to measure the net benefit of each candidate plan is explained in Section 6.4 and the four different probability distributions of output levels of a wind farm at the peak demand are derived in Section 6.5. The results of applying the method to a 6-bus network and 46-bus real system are given in Sections 6.6 and 6.7, respectively.

6.2 Incorporating DG into Network Planning: Identifying Risks and Opportunities

Network operators are obliged to operate their networks efficiently without breaking thermal and voltage constraints under normal circumstances. Therefore, as DG location and its output during the period of peak demand are uncertain, utilising DG to remain within statutory limits will be risky as DG is not controlled by the network operators themselves. However, in the UK, there are incentives for the network operators from the electricity authority Ofgem to continuously improve the efficiency and security of their networks to reduce the losses and the customer interruption frequency [57]; the annual revenues of the power network companies are capped by Ofgem through detailed calculations based on kWh distributed, electrical losses, number of connected customers and the asset base. The price control method also includes a loss incentive mechanism that directly rewards or penalises losses that are below or above a specified annual target rate. Network operators can therefore benefit from any changes in network components or configuration that result in an improvement in network losses. Furthermore, the results in [148] showed that investment in additional reinforcements for reducing network losses can be economically-justified as it is likely the system will also meet the security standard in the future without extra costs. Harrison *et al.* [149] assessed the life cycle carbon emissions of the transmission networks in Great Britain. The results showed that the amount of carbon equivalent emissions during electricity transmission is approximately nineteen times more than the amount used for network construction, while network losses are responsible for over 80% of the emissions from the electricity transmission.

Since DG could contribute effectively to either increase or reduce the network losses, it would be of great value to incorporate DG in deriving optimum network planning aiming to achieve the ideal target losses. Under the circumstances that DG would reduce the network losses, not only could significant investment costs be saved but the network operators can also be rewarded from the loss incentive scheme. As a consequence, here DG is utilised for the purpose of deriving the optimum planning strategies which reduce the network losses to a specified desired level. It is assumed that any reinforcements which assist in reducing the losses to the level will be considered as a cost-effective investment, however, any additional reinforcements that further reduce the losses below the level become less economic attractive and unnecessary.

6.3 Balanced Genetic Algorithm: Objectives and Constraints

The uncertainties associated with DG locations and various output levels during the period of peak demand are classified into different scenarios which will be explained in the later sections. Under each scenario BGA is executed to find the corresponding optimum and sub-optimum planning strategies. As stated in the previous sections, the objective is to minimise the total planning cost while subject to the following technical constraints:

- network connectivity;
- voltage;
- thermal;
- network losses below target level.

The voltage, thermal and network connectivity limits are regarded as the 'hard' constraints implying that they cannot be violated at any time. Therefore, a planning solution has to satisfy all of the hard constraints whether DG is connected or not, otherwise the solution is an unfeasible one and will immediately be discarded. As a result a planning solution found by BGA needs to be examined twice, with and without the presence of DG, to make sure the constraints are not violated regardless of DG operation. Fig. 6.1 depicts the process for classifying a newly-generated solution's feasibility.

On the other hand, decreasing losses below a specified level is a 'soft' constraint as a network can afford to break the constraint without actually threatening the technical network operation. As a result, a planning solution generated by BGA with its resulting network losses above the target level will not be discarded immediately as an unfeasible solution. It could still be put into a solution pool; however, as its network losses will contribute towards the fitness of the solution along with its planning costs, the solution would easily be replaced by its offspring with smaller network losses. At the stage of solution substitution in BGA, suppose a new solution offspring X is generated which will replace its similar parent Y into the population, if the following requirements are met:

- If the losses of both offspring X ($loss_X$) and parent Y ($loss_Y$) exceed the target level ($loss_T$), i.e. $loss_X$, $loss_Y > loss_T$, then offspring X substitutes parent Y in the population if $loss_X < loss_Y$. Otherwise offspring X is discarded.
- If $loss_X < loss_T$ and $loss_Y > loss_T$, offspring X replaces parent Y in the population. Otherwise offspring X is discarded.
- If $loss_X$, $loss_Y < loss_T$, parent Y is substituted by offspring X in the population if the cost of offspring X is less than the cost of parent Y. Otherwise offspring X is discarded.

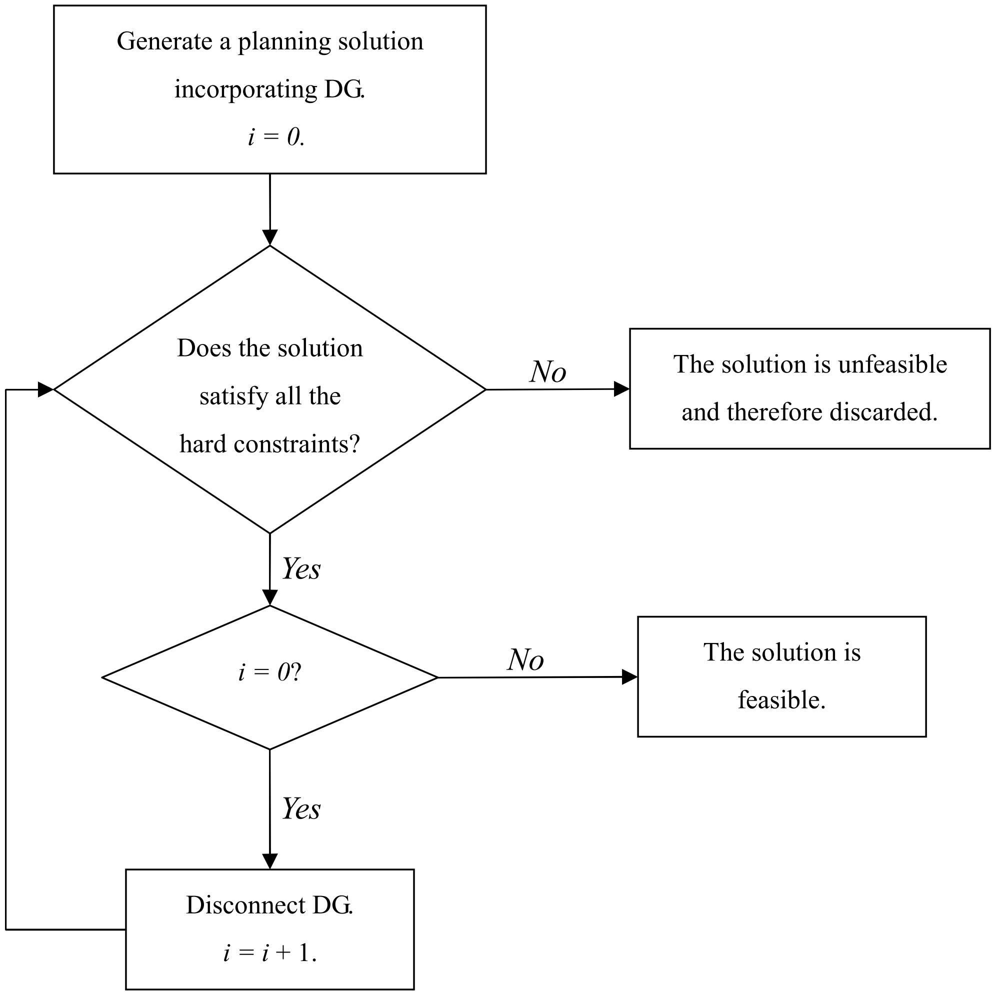

Fig. 6.1. Solution feasibility classification (*i* is a planning solution).

The first two requirements ensure a solution in the pool which violates the loss constraint will be replaced by a new solution which either meets the loss constraint, or also breaks the loss constraint but its network losses are closer to the target level. The third requirement implies that as both the existing and new solutions are feasible, the pool will keep the one which is more economical.

The idea of relaxing the loss constraint in the BGA is similar to the Chu-Beasley GA (see Section 5.5.2) which considers unfeasible solutions as well as feasible ones. This results in more efficient generation of solutions to reduce the chance of generating an unfeasible solution and discarding it immediately which further increases the gene diversity in the population.

6.4 Method of Selecting Final Planning Strategy

Under each identified scenario, a converged population containing optimum and sub-optimum planning strategies is obtained by BGA. Only the optimum solution will be considered as the candidate of a final planning strategy, implying that the number of candidates will equal the number of scenarios. The sub-optimum solutions will be involved in the method proposed for assessing the benefits and risks of adopting each candidate explained in the following sections.

6.4.1 Benefit Index

The benefit of utilizing DG would be the reduction of planning costs to meet the loss constraint. A benefit index (BI) is introduced to each candidate for measuring its relative cost attractiveness compared with the other candidates. Suppose there are *n* candidates, the BI of the candidate *i* (BI_i) is calculated using the following equation:

$$\mathrm{BI}_i = \frac{1}{\left(C_i / C_{Base} \right)} \tag{6.1}$$

where C_i is the planning cost of candidate *i*, C_{Base} is the minimum planning cost found among all the candidates:

$$C_{Base} = \min(C_1, C_2, C_3, \cdots\cdots, C_n) \tag{6.2}$$

Therefore, a candidate whose planning cost is at the minimum will have its BI equal to 1, indicating the largest benefit.

6.4.2 Regret-felt and Risk Index

As the true optimum planning strategy will change according to the location and output of

DG, the planner would have a certain degree of regret after adopting a candidate as a final planning strategy, if the scenario where the candidate was obtained by BGA does not occur in practice. Under this circumstance the magnitude of the regret of the planner (regret-felt) would depend on the difficulty of changing the candidate to the true optimum strategy. Here, the regret-felt is measured by the network configuration differences between the adopted candidate and the true optimum one. The method is similar to the way of measuring the 'degree of uniqueness' between two planning solutions introduced in Section 5.8.2 of the last chapter, apart from that the costs of the reinforcements used are now considered.

An example is given in Fig. 6.2 to calculate the regret-felt between the optimum solutions found under scenario A and B. As in the BGA, the strategies are represented as chromosomes, whose number on each block indicates a potential right-of-way, while a value inside the block refers to the number of lines constructed in each path. The planning solution under Scenario A (Strategy A) adopts paths 1 and 3, while paths 2 and 3 are the solution under Scenario B (Strategy B). Suppose Strategy A has been adopted by the planner but Scenario B occurs, then the investment in new line in path 1 appears to be unnecessary, and the cost of the line would be incorporated into the final regret-felt because of the over-investment. Next, the planner would regret not considering path 2, which is taken by the optimum Strategy B. Therefore, the cost of the line in path B will also be added into the regret-felt. Finally the planner would not have any regret in taking path 3, as path 3 is used in both Strategy A and Strategy B. The regret-felt of Strategy A towards Strategy B would be therefore the sum of the costs of the lines in path 1 and 2.

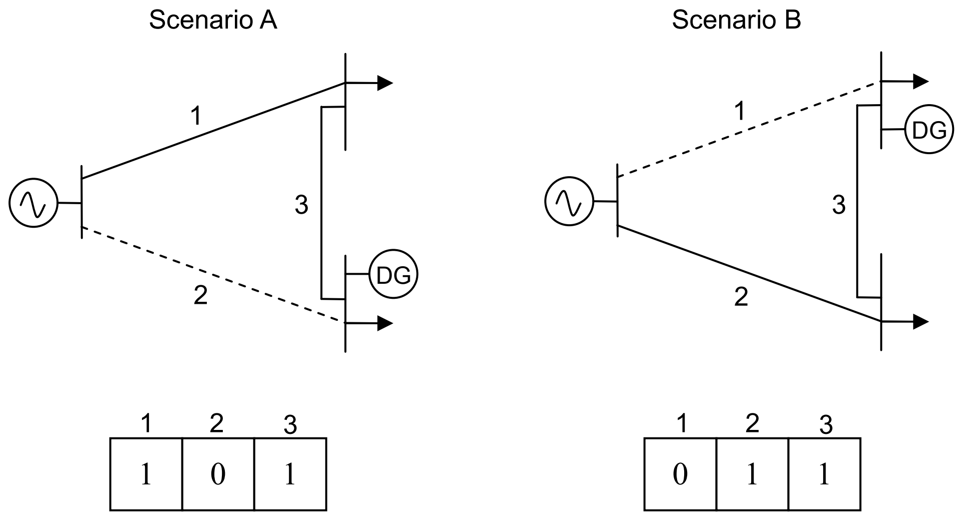

Fig. 6.2. An Example – Representation of optimal solutions for Scenario A and B.

It is possible that some of the optimum solutions under Scenario B have similar network configurations to the Strategy A and their performances under Scenario B, despite being worse than the Strategy B, are still satisfactory. Under such circumstance the regret-felt of Strategy A would not seem to be that great as it is compared with those sub-optimum solutions rather than Strategy B. Therefore, in this approach the regret-felt of Strategy A if Scenario B occurs would be the minimum one found when comparing with Strategy B and the qualified sub-optimum solutions which have their planning costs close to the cost of Strategy B. The explanation can be visualized in Fig. 6.3. First, all of the optimum and sub-optimum strategies found under Scenario B by BGA are ranked from least (optimum) to most expensive ones (Sub-optimum). It is assumed the sub-optimum strategies which cost within a given quantifying threshold (e.g. 5%) more than the cost of Strategy B are considered.

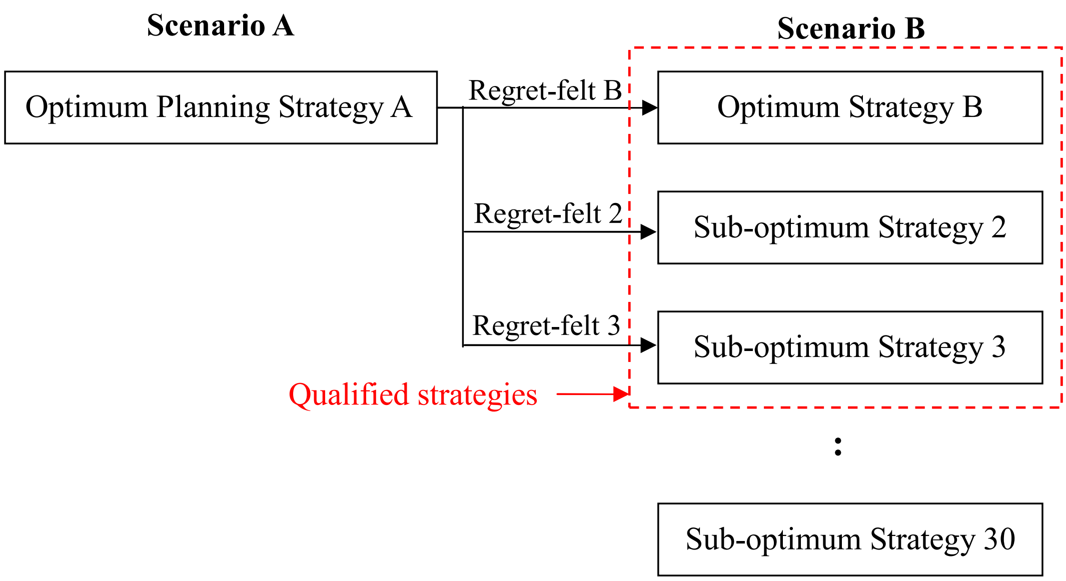

Fig. 6.3. Calculation of regret-felt between a candidate based on Scenario A if Scenario B occurs.

The minimum regret-felt found would be the final regret-felt of adopting Strategy A when Scenario B occurs (Regret-felt$_{AB}$), as shown in the following equation.

$$\text{Regret-felt}_{AB} = \min\,(\text{Regret-felt B, Regret-felt 2, Regret-felt 3}) \tag{6.3}$$

For each candidate, there will be n sets of regret-felt calculated between the candidate against n different scenarios. After all of the regret-felt are obtained, the expected regret-felt of a planning strategy i (ERegret-felt$_i$) is then calculated according to the following equation:

$$\text{ERegret-felt}_i = \sum_{k=1}^{n} P_k \text{Regret-felt}_{ik} \tag{6.4}$$

$$n \in i$$

where P_k is the probability of the occurrence of scenario k, Regret-felt$_{ik}$ is the regret-felt of planning strategy i if the scenario k occurs.

After the expected regret-felt for each planning candidate has been calculated, a risk index

(RI) for the planning strategy *i* can be worked out as:

$$\mathrm{RI}_i = \frac{\text{ERegret - felt}_i}{\text{ERegret - felt}_{\text{Base}}} \tag{6.5}$$

where ERegret-felt$_{\text{Base}}$ is the maximum expected regret-felt found among all the planning candidates:

$$\text{ERegret-felt}_{\text{Base}} = \max\left(\text{ERegret-felt}_1, \text{ERegret-felt}_2, \cdots, \text{ERegret-felt}_n\right) \tag{6.6}$$

A planning candidate which has its expected regret-felt equal to ERegret-felt$_{\text{Base}}$ will therefore have RI = 1, indicating it is the most risky one to adopt.

6.4.3 Net Benefit Index

After both BI and RI have been determined for a planning candidate, the net benefit index (NBI) assigned to candidate *i* can be calculated as follows:

$$\mathrm{NBI}_i = W_1 \mathrm{BI}_i - W_2 \mathrm{RI}_i \tag{6.7}$$

where W_1 and W_2 are the adjusting factors for BI and RI respectively. It is assumed here that W_1 and W_2 are both equal to 1. Comparing the NBI between the planning candidates would assist the planner in deciding which planning candidate to adopt, as a candidate is considered as a better solution if it has higher NBI value. However, in a real practice the values of the weighting factors should be selected based on the decision maker’s knowledge to reflect the true economic benefits and risks of adopting the planning strategy, which would be difficult to assess due to the complexity of the electricity market system. As a result NBI could be very inaccurate if the weighting factors given for BI and RI are far from the true values.

6.5 Modeling Uncertainties of DG as Scenarios

The intermittent DG is assumed to be a wind farm with an installed capacity of 200MW. To simplify the analysis, the output of DG during the period of peak demand is categorised into the five discrete output levels shown in Table 6.1. It is assumed that the optimum planning strategies considering similar DG outputs which are categorized into one output level will be the same. In other words, if there are *m* possible DG locations, then the total number of scenarios is equal to *m* x 5.

Real Time DG Output (MW)	Assumed DG output level (MW)
0-25	0
25-75	50
75-125	100
125-175	150
175-200	200

Table 6.1. Classified DG output levels.

To perform the analysis the probability of each scenario needs to be calculated. It is assumed the probability of DG connecting at a location is equally distributed although differences in resource, access etc. will influence this in practice. However, three different probability patterns of DG output level during the peak demand are assumed, giving three distinct cases (Case 1 to Case 3) for analysis in which the probability of occurrence of the scenarios are different. In the first case (Case 1), it is assumed that the probability of DG producing at different output levels is equally distributed. The assumption is obviously impractical for intermittent DG and Case 1 will only be used to compare with the results of Case 2 and Case 3, for which the probability of DG output level is based on real statistical data in [150] (which includes recorded hourly output of the ten wind farms at different sites in US from 1987 to 2006). As the network planning for peak demand is considered, only the recorded outputs of the wind farms during the period of peak demand are required, which would be between 16:00 and 19:00 in winter in the UK, as depicted in Fig. 6.4 [43].

As a result, the recorded hourly output during the period of peak demand in winter between years 2002 to 2006 is extracted from the whole dataset. As the ten wind farms have different installed capacities, the selected hourly outputs are then first normalised into MW per MW installed capacity; these are then scaled up to the output level. Then the manipulated recorded outputs are categorised into the five discrete output levels in Table 6.1 and the probability for each DG output level is calculated.

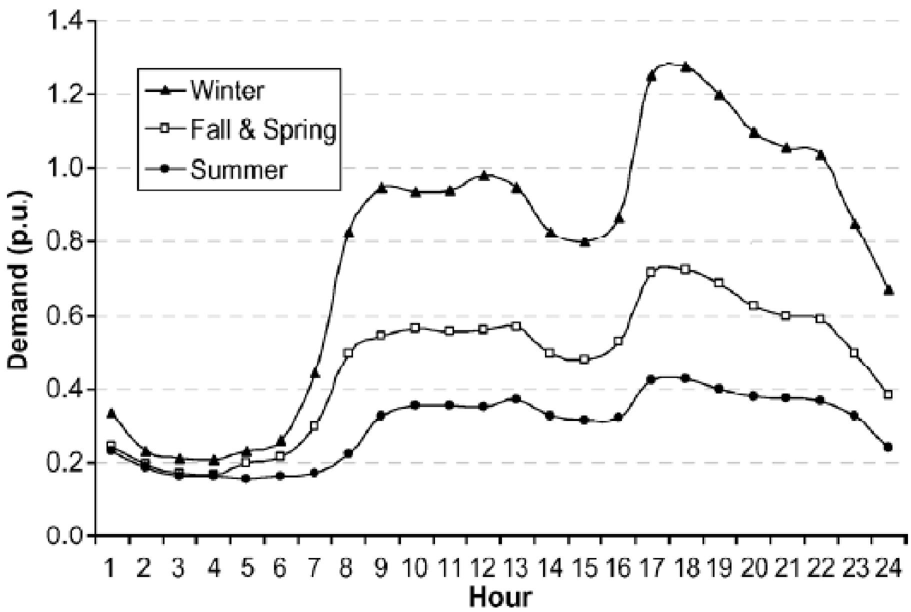

Fig. 6.4. UK seasonal daily demand profile.

The results (probability distribution) from two of the ten wind farms are selected for Case 2 and Case 3, as shown in Table 6.2. In Case 2, during the period of peak demand the wind farm is very likely to produce more than 50% of its installed capacity, while in Case 3, there is a more than 65% chance that the DG produces between zero and 50MW (25% of the installed capacity).

Assumed DG output level (MW)	Probability		
	Case 1	Case 2	Case 3
0	0.20	0.17	0.32
50	0.20	0.35	0.34
100	0.20	0.24	0.19
150	0.20	0.20	0.13
200	0.20	0.03	0.02

Table 6.2. The probability pattern of DG outputs in Case 1, 2 and 3.

For example, as there are m possible DG locations, the probability of occurrence of a scenario i (P_i) which considers DG connecting at a specific location and producing at 100MW will be:

$$\mathrm{P}_i = \frac{1}{m} \times P_{100MW}$$

where P_{100MW} is the probability of DG producing at 100MW during the period of peak demand, i.e. P_{100MW} = 0.20 in Case 1, 0.24 in Case 2 and 0.19 in Case 3.

The approach is applied to two networks; one is a simple 6 bus system and then followed by a more complicated 46-bus Brazilian transmission network, as they are well-known systems for testing expansion algorithms with detailed cost and line data provided. Furthermore, it is expected the practicality and attractiveness of utilising an intermittent generation for network planning would be different as the uncertainties associated with DG locations will increase significantly from the simple 6-bus to the 46-bus systems. Note that these two systems are in fact the transmission networks, the reason of using the systems is that it is relatively difficult to obtain distribution network models with detailed information suitable for comprehensive network planning exercises. Nevertheless, in recent years large onshore and offshore wind farms are connected to transmission networks therefore it will also be a major concern for transmission network operators to consider the wind farms into network planning. Apart from the voltage difference between distribution and transmission networks, traditionally distribution networks are operated in a radial configuration while transmission networks are meshed. However, distribution networks could become more and more meshed due to the impacts of DG as mentioned in Chapter 1. Consequently, the results and conclusions in the following two applications should be able to apply to both transmission and distribution network operators. The term 'DG' will still be used despite that it is connected to the transmission system for the reason of consistency and as some have also referred DG depending on the technology used, normally refering to the type of technology which could be installed with a small capacity, e.g. wind turbines or photovoltaic panels.

6.6 Application 1: Garver 6-Bus System

The approach is first applied to the 6-bus Garver network with its initial configuration shown in Fig. 6.5. The 230kV system is slightly modified from the original network [151], by taking out the smaller generators at bus 1 and 3 but keeping the largest one at bus 6 as the slack generator of the network. Such modification in this first application is for the purpose of further clarifying the impacts of uncertainties that future DG connections would bring to network planning.

The power is transported from bus 6 to the rest of the load buses. It is assumed that the total peak demand forecast will be 740 MW and the major load centres are at bus 2, 4 and 5. The current network configuration cannot support such an amount of load without violating voltage and thermal constraints. Therefore, investment in additional electrical equipment for the system is unavoidable. There are 15 potential routes for connection of new circuits, as depicted in Table 6.3, where specifications of conductors for each path are also shown. It is assumed that no more than three parallel transmission lines including the existing ones in the initial configuration are allowed to occupy a single path.

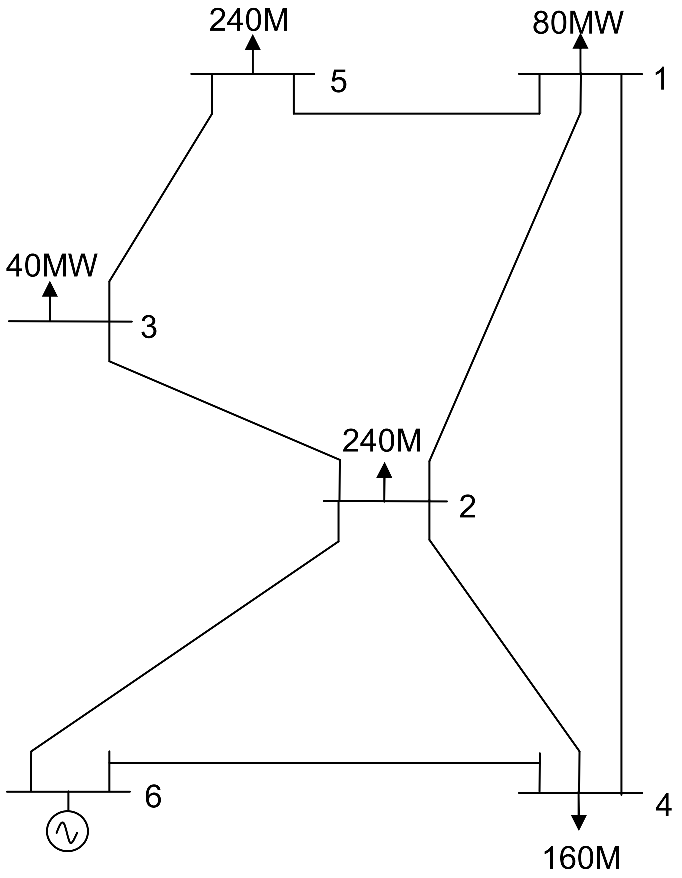

Fig. 6.5. Initial configuration of Garver network.

From - To	Reactance (P.u.)	Thermal Capacity (MVA)	Cost (US$k)
1-2	0.40	100	40
1-3	0.38	100	38
1-4	0.60	80	60
1-5	0.20	100	20
1-6	0.68	70	68
2-3	0.20	100	20
2-4	0.40	100	40
2-5	0.31	100	31
2-6	0.30	100	30
3-4	0.59	82	59
3-5	0.20	100	20
3-6	0.48	100	48
4-5	0.63	75	63
4-6	0.30	100	30
5-6	0.61	78	61

Table 6.3. Branch data of Garver network [151].

6.6.1 Modeling DG Uncertainties as Multiple Scenarios

Apart from bus 6 where the main supply point is, buses 1 to 5 are all considered as potential DG connection points. As mentioned previously, the probabilities of DG connecting at the selected locations are assumed equally distributed, and with the DG output classified into five discrete levels (Table 6.1) there are, in total, 25 scenarios (S1 to S25) identified in this first application, as depicted in Table 6.4.

	0MW	50MW	100MW	150MW	200MW
Bus 1	S1	S6	S11	S16	S21
Bus 2	S2	S7	S12	S17	S22
Bus 3	S3	S8	S13	S18	S23
Bus 4	S4	S9	S14	S19	S24
Bus 5	S5	S10	S15	S20	S25

Table 6.4. The identified 25 scenarios in the first application.

6.6.2 Optimum Planning Strategy under each Scenario and the Benefit Index

BGA is activated to obtain both optimum and sub-planning strategies for each of the 25 identified scenarios. The bus voltage in the Garver network is kept between $\pm 10\%$ of nominal voltage level and the power flow cannot break the thermal limits of any of the conductors indicated in Table 6.3. The target loss level is set to 2.5% of the forecasted peak demand. The optimum planning strategy under each scenario would have minimum costs but also comply with the technical constraints. The population size in BGA is set to 30 *chromosomes*, which implies that there will be 30 planning solutions generated under each scenario.

Table 6.5(a) shows the cost ($k) of the optimum planning strategies obtained by BGA under the 25 identified scenarios which are regarded as the candidates for a final planning strategy. According to the table, BGA found the same optimum planning strategy under multiple scenarios. This is due to the relatively small size of the Garver network, which makes the impact of DG at different locations and output levels less distinguishable. The benefit index

(BI) for each planning candidate is calculated and shown in Table 6.5(b).

	0MW	50MW	100MW	150MW	200MW
Bus 1	834	595	527	527	537
Bus 2	834	643	547	527	527
Bus 3	834	655	547	527	537
Bus 4	834	663	595	565	527
Bus 5	834	595	527	527	527

(a)

	0MW	50MW	100MW	150MW	200MW
Bus 1	0.63	0.89	1.00	1.00	0.98
Bus 2	0.63	0.82	0.96	1.00	1.00
Bus 3	0.63	0.80	0.96	1.00	0.98
Bus 4	0.63	0.79	0.89	0.93	1.00
Bus 5	0.63	0.89	1.00	1.00	1.00

(b)

Table 6.5. (a) Costs ($k) and (b) benefit index (BI) of the optimum planning strategies under 25 identified scenarios found by BGA.

Regardless of which bus DG is connected to, in this case increasing the output level of DG generally leads to cheaper optimum planning strategies, as the DG penetration is low and increasing the output would still assist in reducing the network losses. The ideal planning strategy, from the planner’s viewpoint, would cost $527k and is the optimum solution found under several scenarios. Table 6.6 shows the usage of the right-of-way in this ideal planning strategy, where the new lines added are concentrated on the right-of-way linking the main power supply point at bus 6 and the rest of the load buses.

From - To	No. of lines	Cost per line (US$k)	Investment (US$k)
1-2	0	40	0
1-3	0	38	0
1-4	0	60	0
1-5	0	20	0
1-6	0	68	0
2-3	0	20	0
2-4	0	40	0
2-5	0	31	0
2-6	3	30	90
3-4	0	59	0
3-5	1	20	20
3-6	3	48	144
4-5	0	63	0
4-6	3	30	90
5-6	3	61	183
		Total	527

Table 6.6. Lines added in the planning strategy of $527k under S16, S17, S18, S20, S22, S24, and S25.

A conventional GA with non-generational population substitution was also executed to search optimum planning solutions under the identified scenarios, and the results are shown in Table 6.7. The results marked in red colour are the optimum strategies found by conventional GA which have costs higher than the optimum strategies found by BGA under the same scenarios. There are no scenarios under which the optimum planning strategies obtained by the BGA are inferior to the optimum strategies obtained by conventional GA in this case.

	0MW	50MW	100MW	150MW	200MW
Bus 1	834	595	537	565	537
Bus 2	834	643	558	537	527
Bus 3	834	655	547	537	537
Bus 4	834	663	613	565	537
Bus 5	834	595	537	548	527

Table 6.7. Optimum planning strategies in $k under 25 identified scenarios found by conventional GA.

6.6.3 Risk Index and Net Benefit Index for the Candidates

Case 1

In the first case the probability of DG generating at different categorized output levels is assumed to be equally spaced, as shown in Table 6.2 (Case 1). As mentioned previously, the probability of DG connecting at any of the five locations (bus 1 to bus 5) is also equally distributed; as a result, Table 6.8 indicates the probabilities of the occurrences for the identified scenarios.

	0MW	50MW	100MW	150MW	200MW
Bus 1	0.04	0.04	0.04	0.04	0.04
Bus 2	0.04	0.04	0.04	0.04	0.04
Bus 3	0.04	0.04	0.04	0.04	0.04
Bus 4	0.04	0.04	0.04	0.04	0.04
Bus 5	0.04	0.04	0.04	0.04	0.04

Table 6.8. Probabilities of the occurrences of 25 identified scenarios.

The expected regret-felt of each planning candidate (Table 6.5(a)) is then calculated using (6.4) and is shown in Table 6.9 (a). Table (b) indicates the risk index (RI) derived for each of the candidates. The first remarkable observation from Table 6.9 is that, it clearly shows that adopting an optimum planning strategy that does not take DG into consideration would yield higher expected regret-felt. In other words, the planner would have a much higher chance of regret if they selected the candidates assuming no DG connection (under S1 to S5, DG = 0MW) rather than other candidates considering DG producing at different output levels regardless its location (under S6 to S25, DG = 50 to 200MW).

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	202.20	85.76	105.44	105.44	99.28	119.62
Bus 2	202.20	121.12	108.56	105.44	105.44	128.55
Bus 3	202.20	108.48	81.28	105.44	99.28	119.34
Bus 4	202.20	107.52	85.76	130.80	105.44	126.34
Bus 5	202.20	109.68	105.44	105.44	105.44	125.64
Average	202.20	106.51	97.30	110.51	102.98	

(a)

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	1.00	0.42	0.52	0.52	0.49	0.59
Bus 2	1.00	0.60	0.54	0.52	0.52	0.64
Bus 3	1.00	0.54	0.40	0.52	0.49	0.59
Bus 4	1.00	0.53	0.42	0.65	0.52	0.62
Bus 5	1.00	0.54	0.52	0.52	0.52	0.62
Average	1.00	0.53	0.48	0.55	0.51	

(b)

Table 6.9. (a) Expected regret-felt ($k) (b) RI for each candidate.

The planning candidate with minimum expected regret-felt of $81.28k is the one found under scenario 13 (100MW at bus 3). The analysis shows that the optimum strategies found by assuming DG is producing 100MW regardless of the location (S10 to S15) would, on average, yield the least expected regret-felt. On the other hand, the planner would feel the least regret if they adopted the optimum planning strategies found under the scenarios when DG is connected at bus 1 or bus 3. The reason is that the optimum strategies under those scenarios are either similar to or the same as the optimum or qualified sub-optimum strategies under many other scenarios, therefore minimising the regret-felt of those candidates against those other scenarios.

Based on the BI and RI, the net benefit index (NBI) is derived for each of the candidates as indicated in Table 6.10. The candidates that do not take DG into account have negative NBI due to their BI being smaller than their RI, and are the most risky ones to be adopted among all the candidates. The maximum NBI is assigned to the planning strategy which is found assuming DG is producing 100MW output at bus 3, which while it does not have the maximum BI it has the smallest RI and is regarded as the best planning solution. However, one needs to be reminded that the conclusion from Table 6.10 should not be interpreted as '*the best planning strategy is to assumed DG will be producing 100MW at bus 3*', but rather '*the optimum planning strategy found under S13 appears to be the most beneficial one even when risks associated with future uncertainties are considered*.'

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	-0.37	0.46	0.48	0.48	0.49	0.31
Bus 2	-0.37	0.22	0.43	0.48	0.48	0.25
Bus 3	-0.37	0.27	0.56	0.48	0.49	0.29
Bus 4	-0.37	0.26	0.46	0.29	0.48	0.22
Bus 5	-0.37	0.34	0.48	0.48	0.48	0.28
Average	-0.37	0.31	0.48	0.44	0.48	

Table 6.10. The net benefit index (NBI) of the planning candidates in Case 1.

Case 2

In the second case it is assumed that the probability of DG output levels during the period of peak demand is based on Case 2 of Table 6.2. As a result, Table 6.11 is the probability table of the occurrences of the scenarios for the second case, where DG is most likely to produce output around 25%~50% of its installed capacity.

	0MW	50MW	100MW	150MW	200MW
Bus 1	0.035	0.070	0.049	0.041	0.006
Bus 2	0.035	0.070	0.049	0.041	0.006
Bus 3	0.035	0.070	0.049	0.041	0.006
Bus 4	0.035	0.070	0.049	0.041	0.006
Bus 5	0.035	0.070	0.049	0.041	0.006

Table 6.11. Probabilities of occurrences of the identified scenarios in Case 2.

Based on the probability table above, the expected regret-felt and RI for each optimum planning strategy is calculated for each candidate as indicated in Table 6.12(a) and (b) respectively. In this second case, the minimum expected regret-felt is \$81.26k from the optimum strategies found under S6 (50MW at bus 1) and S14 (100MW at bus 4). The two optimum planning strategies are actually identical. The minimum average expected regret-felt has shifted from the optimum planning strategies found under S11 to S15 (100MW) in Case 1 to the optimum ones obtained under S6 to S10 (DG = 50MW) here, because of higher probabilities of occurrences of S6 to S10 in the second case. Notwithstanding that the probability of the occurrences of the scenarios S1 to S5 (assume no DG) are slightly lower than in Case 1, the expected regret-felt for the planning candidate under S1 to S5 are actually decreased in the second case. This is also due to the significant increase of the probabilities of occurrences of S6 to S10 as well as the reduced chance of having high DG output levels (100 to 200 MW) in this case. The planning candidates that assume zero DG output still have the highest regret-felt and result in maximum RI. Generally speaking, the RI for the planning candidates in this case is higher compared with the RI in Case 1.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	193.54	81.26	109.40	109.40	108.70	120.46
Bus 2	193.54	104.14	110.74	109.40	109.40	125.44
Bus 3	193.54	98.94	88.18	109.40	108.70	119.75
Bus 4	193.54	93.17	81.26	123.72	109.40	120.22
Bus 5	193.54	101.22	109.40	109.40	109.40	124.59
Average	193.54	95.74	99.79	112.26	109.12	

(a)

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	1.00	0.42	0.57	0.57	0.56	0.62
Bus 2	1.00	0.54	0.57	0.57	0.57	0.65
Bus 3	1.00	0.51	0.46	0.57	0.56	0.62
Bus 4	1.00	0.48	0.42	0.64	0.57	0.62
Bus 5	1.00	0.52	0.57	0.57	0.57	0.64
Average	1.00	0.49	0.52	0.58	0.56	

(b)

Table 6.12. (a) Expected regret-felt (b) RI of the candidates under identified scenarios in Case 2.

The net benefit index (NBI) of the planning candidates is shown in Table 6.13. Despite the decrease of NBI for the planning strategy found under S13 compared with the previous case, it is still the best network planning strategy to adopt. However, compared with the results in Case 1, the NBI of the planning strategies found under S6 (50MW at bus 1) and S14 (100MW at bus 4) has surpassed the NBI of the candidates assuming DG is producing at high output levels and clearly become the second best choices here.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	-0.37	0.47	0.43	0.43	0.42	0.28
Bus 2	-0.37	0.28	0.39	0.43	0.43	0.23
Bus 3	-0.37	0.29	0.51	0.43	0.42	0.26
Bus 4	-0.37	0.31	0.47	0.29	0.43	0.23
Bus 5	-0.37	0.36	0.43	0.43	0.43	0.26
Average	-0.37	0.34	0.45	0.41	0.43	

Table 6.13. The net benefit index (NBI) of the planning candidates in Case 2.

Case 3

Here the probabilities of the DG output levels are changed to case 3 in Table 6.2. The difference between case 2 and case 3 is that now the chance of DG producing nothing (32%) is much higher than in Case 2 (17%). As a result, in the third case during the period of peak demand the DG has more than 65% chance of producing at output levels less than 25% of its installed capacity (200MW). The probabilities of the occurrences of the identified scenarios for case 3 are shown in Table 6.14.

	0MW	50MW	100MW	150MW	200MW
Bus 1	0.064	0.068	0.038	0.026	0.004
Bus 2	0.064	0.068	0.038	0.026	0.004
Bus 3	0.064	0.068	0.038	0.026	0.004
Bus 4	0.064	0.068	0.038	0.026	0.004
Bus 5	0.064	0.068	0.038	0.026	0.004

Table 6.14. Probabilities of the occurrences of the identified scenarios in case 3.

The expected regret-felt and RI of the optimum planning strategies in this case are shown in Table 6.15(a) and (b) respectively. Comparing with the previous two cases, the risks associated with adopting the planning strategies assuming DG at the period of peak demand would produce at least 150MW output are significantly higher in this case. Furthermore, their expected regret-felt and RI here are very close to those of the planning strategies assuming no DG, due to the probabilities of occurrences of the scenarios that assume high DG output levels are further decreased. Meanwhile the chance of DG producing nothing is also increased significantly in Case 3 compared with the precious two cases. The planning candidate obtained under the scenario when the DG produces 50MW output at bus 4 has the smallest regret-felt and RI among all the candidates.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	154.14	109.93	150.12	150.12	147.49	142.36
Bus 2	154.14	115.33	146.66	150.12	150.12	143.27
Bus 3	154.14	111.26	127.89	150.12	147.49	138.18
Bus 4	154.14	103.09	109.93	149.94	150.12	133.44
Bus 5	154.14	124.82	150.12	150.12	150.12	145.86
Average	154.14	112.89	136.94	150.08	149.07	

(a)

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	1.00	0.71	0.97	0.97	0.96	0.92
Bus 2	1.00	0.75	0.95	0.97	0.97	0.93
Bus 3	1.00	0.72	0.83	0.97	0.96	0.90
Bus 4	1.00	0.67	0.71	0.97	0.97	0.87
Bus 5	1.00	0.81	0.97	0.97	0.97	0.95
Average	1.00	0.73	0.89	0.97	0.97	

(b)

Table 6.15. (a) Expected regret-felt (b) RI of the optimum planning strategies under identified scenarios in Case 3.

The NBI for each planning candidate is then calculated as indicated in Table 6.16. Due to the significant increase of RI in this case, the NBI of the planning candidates relying on DG producing some output have decreased dramatically. However, the planning strategies which do not consider DG (0MW) are still the worst to adopt, due to their high planning costs and therefore extremely low BI. In this case, the planning strategies found under S6 (50MW at bus 1) and S14 (100MW at bus 4) have exceeded the NBI of the planning candidate found under S13 (100MW at bus 3) and become the best planning strategy to adopt. Nevertheless, the planning strategy found under S13, which was the best one to adopt in the previous two cases, will still be a good choice in this third case.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 1	-0.37	0.17	0.03	0.03	0.02	-0.02
Bus 2	-0.37	0.07	0.01	0.03	0.03	-0.05
Bus 3	-0.37	0.08	0.13	0.03	0.02	-0.02
Bus 4	-0.37	0.13	0.17	-0.04	0.03	-0.02
Bus 5	-0.37	0.08	0.03	0.03	0.03	-0.04
Average	-0.37	0.11	0.07	0.01	0.03	

Table 6.16. NBI of the optimum planning strategies under the identified scenarios in Case 3.

6.6.4 Application 1 – Results Discussion

The approach is firstly applied to a simple 6-bus Garver network with 25 scenarios identified. On account of the uncomplicated network structure, the network planning strategies found under the scenarios assuming similar DG outputs and close locations could be either very similar or identical. This would limit the expected regret-felt calculated and the risks of adopting a planning candidate which has the same network configuration with some other candidates. As the probabilities of DG generating at low output levels during the period of peak demand increases along with the decrease of the chances of DG producing at high output levels (150 to 200MW) from Case 1 to Case 3, the NBI of the planning strategies assuming high DG output level has dropped significantly. As a result, those candidates are only competitive in Case 1 and clearly become the least desired ones which should be avoided as a final planning strategy, i.e. the planner should not select a planning solution which places too much reliance on DG. Due to the high investment costs of the planning strategies which do not consider DG, their NBI is always the lowest in all of the three cases, implying that it is relatively less beneficial or more risky to adopt them compared to other planning strategies which take the contribution of DG outputs into account. Regardless which case it is, the NBI of the planning strategy found when considering DG producing 100MW at bus 3 is always one of the highest among all the planning candidates therefore it is the best planning strategy to adopt in this application. Although the best planning solution will only become a true optimum one if DG is located at bus 3 and at the instant when its continuously varied output is at 100MW, it would give the best overall performance under different conditions.

6.7 Application 2 - 46-bus Brazilian Network

The approach is applied to a more complicated Brazilian network including 46 buses. The initial configuration of the network is illustrated in Fig. 6.6. There are 79 rights-of-way for new circuits. The dotted lines indicate the possible routes which have not been used. No more than three parallel lines can occupy the same path. The peak forecasted demand is 6880MW, while the initial configuration will not be able to support such load without breaking the thermal (100%) and voltage (±10%) constraints. The largest generator is connected at bus 16. The generation, load and branch data of the network can be found in [151].

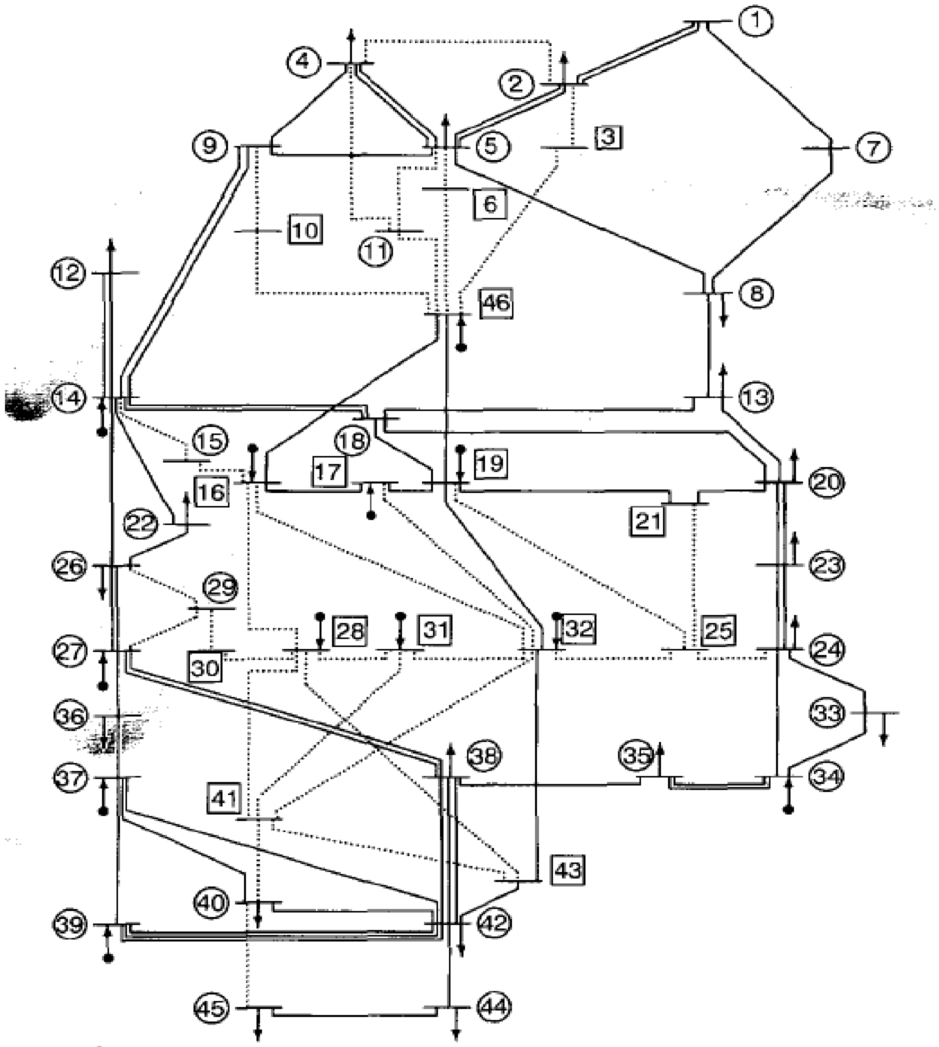

Fig. 6.6. Initial configuration of the 46-bus Brazilian network.

The purpose of applying the approach to a larger system is that the optimum planning strategies (candidates) found under identified scenarios could be more dissimilar than in the first application. The increase of the dissimilarities between the planning candidates would therefore increase the regret-felt and risks of adopting a planning strategy which has a more distinct network configuration. It would be interesting to observe whether under this circumstance it is still attractive and possible to adopt a solution that utilises intermittent DG to some extent.

6.7.1 Modelling DG Uncertainties as Multiple Scenarios

The three (Case 1 to Case 3) DG probability patterns in Table 6.2 are applied to the Brazilian network. There are in total 18 load buses in this system and all of them are considered as potential connection points for DG, while the probabilities of connecting DG to these locations are assumed to be equally distributed. As a result, the considered uncertainties are modelled into 90 different scenarios as depicted in Table 6.17.

	DG Capacity (MW)				
	0	50	100	150	200
Bus 2	S1	S19	S37	S55	S73
Bus 4	S2	S20	S38	S56	S74
Bus 8	S3	S21	S39	S57	S75
Bus 12	S4	S22	S40	S58	S76
Bus 13	S5	S23	S41	S59	S77
Bus 20	S6	S24	S42	S60	S78
Bus 22	S7	S25	S43	S61	S79
Bus 23	S8	S26	S44	S62	S80
Bus 24	S9	S27	S45	S63	S81
Bus 26	S10	S28	S46	S64	S82
Bus 33	S11	S29	S47	S65	S83
Bus 35	S12	S30	S48	S66	S84
Bus 36	S13	S31	S49	S67	S85
Bus 38	S14	S32	S50	S68	S86
Bus 40	S15	S33	S51	S69	S87
Bus 42	S16	S34	S52	S70	S88
Bus 44	S17	S35	S53	S71	S89
Bus 45	S18	S36	S54	S72	S90

Table 6.17. The identified scenarios in application 2.

6.7.2 Optimum Planning Strategies under each Scenario

Due to the larger system, the size of population in BGA is set to 60 compared with 30 in the last application. The constraints are set the same as in the first application. The optimum planning strategy in $m obtained by BGA and its BI under each scenario is shown in Table 6.18(a) and (b) respectively. The least costly planning strategy is found under the scenario S55 assuming DG producing 200MW at bus 33. On average the planning costs shrinks as a planning candidate is able to utilize larger DG output. Note that the DG penetration is much smaller in this network compared with in the 6-bus Garver System in the first application.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	382	359	355	338	322	351.22
Bus 4	382	360	348	338	323	350.11
Bus 8	382	359	347	338	326	350.17
Bus 12	382	359	349	336	325	350.11
Bus 13	382	357	341	329	316	345.01
Bus 20	382	359	342	331	320	346.88
Bus 22	382	361	359	350	345	359.27
Bus 23	382	350	333	312	301	335.41
Bus 24	382	357	348	325	312	344.76
Bus 26	382	358	342	334	318	346.97
Bus 33	382	352	325	303	288	329.83
Bus 35	382	350	340	311	304	337.23
Bus 36	382	358	341	331	320	346.42
Bus 38	382	348	326	311	295	332.20
Bus 40	382	364	348	325	309	345.41
Bus 42	382	352	331	313	296	334.63
Bus 44	382	354	324	306	295	332.08
Bus 45	382	348	324	319	302	335.06
Average	381.78	355.81	340.13	324.96	311.97	

(a)

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	0.75	0.80	0.81	0.85	0.89	0.82
Bus 4	0.75	0.80	0.83	0.85	0.89	0.82
Bus 8	0.75	0.80	0.83	0.85	0.88	0.82
Bus 12	0.75	0.80	0.82	0.85	0.88	0.82
Bus 13	0.75	0.81	0.84	0.87	0.91	0.84
Bus 20	0.75	0.80	0.84	0.87	0.90	0.83
Bus 22	0.75	0.80	0.80	0.82	0.83	0.80
Bus 23	0.75	0.82	0.86	0.92	0.96	0.86
Bus 24	0.75	0.81	0.83	0.88	0.92	0.84
Bus 26	0.75	0.80	0.84	0.86	0.90	0.83
Bus 33	0.75	0.82	0.88	0.95	1.00	0.88
Bus 35	0.75	0.82	0.85	0.92	0.95	0.86
Bus 36	0.75	0.80	0.84	0.87	0.90	0.83
Bus 38	0.75	0.83	0.88	0.93	0.98	0.87
Bus 40	0.75	0.79	0.83	0.88	0.93	0.84
Bus 42	0.75	0.82	0.87	0.92	0.97	0.87
Bus 44	0.75	0.81	0.89	0.94	0.98	0.87
Bus 45	0.75	0.83	0.89	0.90	0.95	0.86
Average	0.75	0.81	0.85	0.89	0.92	

(b)

Table 6.18. (a) The optimum planning strategies in $m, (b) BI under the 90 identified scenarios by BGA.

The optimum strategies generated by BGA are then compared with the optimum strategies obtained by conventional GA, as indicated in Table 6.19. For this network the capability of BGA to search for optimum solutions is clearly significantly better than using conventional GA. By comparing the results between Table 6.18(a) and Table 6.19, there are no optimum planning strategies found by the conventional GA that under the 90 scenarios have lower costs than the optimum planning strategies obtained by BGA under the corresponding scenarios. Using the optimum planning strategies obtained by the conventional GA would lead to a worse final decision.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	478	475	428	414	371	433.20
Bus 4	478	430	372	421	429	425.91
Bus 8	478	451	434	422	393	435.50
Bus 12	478	464	388	391	379	420.08
Bus 13	478	440	405	373	383	415.80
Bus 20	478	507	440	400	462	457.23
Bus 22	478	553	430	422	372	450.98
Bus 23	478	413	481	390	451	442.58
Bus 24	478	415	429	436	402	432.03
Bus 26	478	430	399	402	343	410.52
Bus 33	478	441	425	430	365	427.82
Bus 35	478	416	469	515	348	445.35
Bus 36	478	537	429	421	388	450.68
Bus 38	478	426	442	354	454	430.73
Bus 40	478	475	473	394	385	441.16
Bus 42	478	375	472	400	370	419.09
Bus 44	478	368	392	398	347	396.64
Bus 45	478	451	495	353	384	432.12
Average	477.93	448.19	433.65	407.49	390.36	

Table 6.19. The optimum planning strategies in \$m under the 90 identified scenarios obtained by the conventional GA.

6.7.3 Calculate the Risk Index and Net Benefit Index for the Candidates

Case 1

Case 1 assumes the probability of DG producing at different output levels is equally distributed, as shown in Table 6.2 (Case 1). The expected regret-felt and RI of the 90 candidates are shown in Table 6.20 (a) and (b) respectively. For the first time the planning candidates without considering DG do not yield the greatest regret-felt and maximum RI. The planning strategy found when DG produces 150MW at bus 45 has the highest regret-felt (\$146m). There are other candidates which also have regret-felt exceeding \$100m. The high risk is because those planning strategies consist of more distinctive network configurations but such configurations turn out to be ineffective where a scenario occurs other than the one the strategy is optimised for. Note that a distinctive network configuration may also result from the premature convergence of the BGA, since the BGA will still suffer from stochastic errors to a certain extent. The locational impact of DG has been clearly shown in Table 6.20 since the expected regret-felt of the planning candidates assuming the same DG output level but different locations could vary significantly.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	91	80	100	90	82	88.73
Bus 4	91	77	86	82	63	79.82
Bus 8	91	80	54	83	60	73.83
Bus 12	91	80	94	79	100	88.89
Bus 13	91	56	61	77	64	69.92
Bus 20	91	62	61	57	62	66.57
Bus 22	91	89	87	82	73	84.25
Bus 23	91	76	70	61	78	75.33
Bus 24	91	82	116	58	64	82.27
Bus 26	91	59	64	86	67	73.73
Bus 33	91	65	61	68	77	72.52
Bus 35	91	76	97	62	129	90.99
Bus 36	91	59	61	62	67	68.08
Bus 38	91	75	60	74	73	74.68
Bus 40	91	134	75	58	125	96.51
Bus 42	91	64	70	90	72	77.65
Bus 44	91	126	59	65	74	83.13
Bus 45	91	75	59	$\boxed{146}$	101	94.59
Average	91.43	78.63	74.37	76.53	79.44	

(a)

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	0.63	0.55	0.69	0.62	0.56	0.61
Bus 4	0.63	0.52	0.59	0.56	0.43	0.55
Bus 8	0.63	0.55	0.37	0.57	0.41	0.51
Bus 12	0.63	0.55	0.64	0.54	0.68	0.61
Bus 13	0.63	0.39	0.42	0.52	0.44	0.48
Bus 20	0.63	0.42	0.42	0.39	0.42	0.46
Bus 22	0.63	0.61	0.59	0.56	0.50	0.58
Bus 23	0.63	0.52	0.48	0.42	0.53	0.52
Bus 24	0.63	0.56	0.80	0.39	0.44	0.56
Bus 26	0.63	0.41	0.44	0.59	0.46	0.50
Bus 33	0.63	0.44	0.42	0.47	0.53	0.50
Bus 35	0.63	0.52	0.66	0.42	0.88	0.62
Bus 36	0.63	0.41	0.42	0.42	0.46	0.47
Bus 38	0.63	0.52	0.41	0.50	0.50	0.51
Bus 40	0.63	0.91	0.51	0.39	0.85	0.66
Bus 42	0.63	0.44	0.48	0.62	0.50	0.53
Bus 44	0.63	0.86	0.40	0.44	0.51	0.57
Bus 45	0.63	0.52	0.40	$\boxed{1.00}$	0.69	0.65
Average	0.63	0.54	0.51	0.52	0.54	

(b)

Table 6.20. (a) Expected regret-felt in \$m (b) RI of the optimum strategies in Case 1.

The NBI for each planning candidate is calculated and shown in Table 6.21. In this case the planning strategy the planner should adopt is the one obtained under the scenario when DG produces 150MW at bus 23, which has the highest NBI of 0.51. Comparing with the results in application 1 the planning strategies that consider no DG output are not the worst ones to adopt, while the worst planning strategies are the ones under the scenarios S33 (50MW at bus 40) and S72 (150MW at bus 45), which have NBIs of -0.12 and -0.10 respectively, as marked with crosses in the table. However, there are still many better choices than choosing the planning strategies which do not take the impacts of DG into account.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	0.13	0.25	0.12	0.23	0.33	0.21
Bus 4	0.13	0.28	0.24	0.29	0.46	0.28
Bus 8	0.13	0.25	0.46	0.28	0.47	0.32
Bus 12	0.13	0.25	0.18	0.31	0.20	0.22
Bus 13	0.13	0.42	0.42	0.35	0.47	0.36
Bus 20	0.13	0.38	0.42	0.48	0.47	0.38
Bus 22	0.13	0.19	0.21	0.26	0.34	0.23
Bus 23	0.13	0.30	0.38	$\boxed{0.51}$	0.42	0.35
Bus 24	0.13	0.25	0.03	0.49	0.48	0.28
Bus 26	0.13	0.40	0.40	0.27	0.44	0.33
Bus 33	0.13	0.38	0.47	0.48	0.47	0.38
Bus 35	0.13	0.30	0.18	0.50	0.07	0.24
Bus 36	0.13	0.40	0.42	0.45	0.44	0.37
Bus 38	0.13	0.31	0.47	0.42	0.48	0.36
Bus 40	0.13	-0.12	0.31	0.49	0.08	0.18
Bus 42	0.13	0.38	0.39	0.30	0.48	0.34
Bus 44	0.13	-0.05	0.48	0.49	0.47	0.31
Bus 45	0.13	0.31	0.48	-0.10	0.26	0.22
Average	0.13	0.27	0.34	0.36	0.38	

Table 6.21. NBI of optimum planning strategies in Case 1.

<u>Case 2</u>

In this second case the probability of DG producing at different output levels is based in Table 6.2 (Case 2). The expected regret-felt for each candidate is shown in Table 6.2(a). The highest expected regret-felt is assigned to the planning candidate found under the scenario S72 (150MW at bus 45), which is the same strategy as in the last case but with slightly increased expected regret-felt. Here, the minimum RI (0.36) has been found for the planning strategy under the scenario S23 (50MW at bus 13), compared with under scenario S39 (100MW at bus 8) in the last case. This shift is because of the significant increase of the probability of DG generating at 50MW.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	94	74	98	89	82	87.21
Bus 4	94	68	81	83	63	77.97
Bus 8	94	74	53	79	61	72.06
Bus 12	94	74	86	79	101	86.68
Bus 13	94	53	60	77	66	69.88
Bus 20	94	58	60	56	62	66.16
Bus 22	94	82	80	83	71	82.29
Bus 23	94	69	70	63	82	75.75
Bus 24	94	76	113	57	66	81.36
Bus 26	94	57	65	86	69	74.41
Bus 33	94	62	62	72	81	74.15
Bus 35	94	69	98	64	129	90.98
Bus 36	94	57	60	61	68	68.04
Bus 38	94	70	61	75	77	75.48
Bus 40	94	127	72	57	125	95.14
Bus 42	94	62	70	91	75	78.62
Bus 44	94	121	58	67	78	83.80
Bus 45	94	70	58	148	106	95.28
Average	94.38	73.56	72.48	77.00	81.26	

(a)

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	0.64	0.50	0.66	0.60	0.55	0.59
Bus 4	0.64	0.46	0.55	0.56	0.43	0.53
Bus 8	0.64	0.50	0.36	0.53	0.41	0.49
Bus 12	0.64	0.50	0.58	0.53	0.68	0.59
Bus 13	0.64	0.36	0.40	0.52	0.44	0.47
Bus 20	0.64	0.39	0.41	0.38	0.42	0.45
Bus 22	0.64	0.56	0.54	0.56	0.48	0.56
Bus 23	0.64	0.47	0.48	0.43	0.55	0.51
Bus 24	0.64	0.52	0.76	0.39	0.45	0.55
Bus 26	0.64	0.39	0.44	0.58	0.47	0.50
Bus 33	0.64	0.42	0.42	0.48	0.54	0.50
Bus 35	0.64	0.47	0.66	0.43	0.87	0.61
Bus 36	0.64	0.39	0.40	0.41	0.46	0.46
Bus 38	0.64	0.47	0.41	0.51	0.52	0.51
Bus 40	0.64	0.86	0.48	0.39	0.84	0.64
Bus 42	0.64	0.42	0.47	0.62	0.51	0.53
Bus 44	0.64	0.82	0.39	0.45	0.53	0.57
Bus 45	0.64	0.47	0.39	1.00	0.71	0.64
Average	0.64	0.50	0.49	0.52	0.55	

(b)

Table 6.22. (a) Expected regret-felt in \$m (b) RI of the optimum strategies in Case 2.

According to Table 6.23, which shows the NBI for each of the planning candidates, there are three planning strategies which share the highest NBI of 0.5, as marked in a square in the table However, it is noticed that those three do not have identical network configurations. One of them is the best strategy in the last case (150MW at bus 23), while the other two strategies are found under S63 (150MW at bus 24) and S69 (150MW at bus 40), which have more expensive planning costs but with smaller expected regret-felts than the first strategy mentioned. As with the last case, the strategy found under the scenario S72 (150MW at bus 45) remains the worst one to adopt with an NBI of -0.1.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	0.12	0.30	0.15	0.25	0.34	0.23
Bus 4	0.12	0.34	0.28	0.29	0.46	0.30
Bus 8	0.12	0.30	0.47	0.32	0.47	0.34
Bus 12	0.12	0.30	0.24	0.32	0.20	0.24
Bus 13	0.12	0.45	0.44	0.35	0.46	0.36
Bus 20	0.12	0.41	0.43	0.49	0.48	0.39
Bus 22	0.12	0.24	0.26	0.26	0.35	0.25
Bus 23	0.12	0.36	0.39	0.50	0.40	0.35
Bus 24	0.12	0.29	0.06	0.50	0.47	0.29
Bus 26	0.12	0.42	0.40	0.28	0.44	0.33
Bus 33	0.12	0.40	0.47	0.47	0.46	0.38
Bus 35	0.12	0.36	0.18	0.49	0.07	0.24
Bus 36	0.12	0.42	0.44	0.46	0.44	0.37
Bus 38	0.12	0.35	0.47	0.42	0.46	0.36
Bus 40	0.12	-0.07	0.34	0.50	0.09	0.19
Bus 42	0.12	0.40	0.40	0.30	0.46	0.34
Bus 44	0.12	-0.01	0.49	0.48	0.45	0.31
Bus 45	0.12	0.35	0.49	-0.10	0.24	0.22
Average	0.12	0.31	0.36	0.37	0.37	

Table 6.23.NBI of the optimum planning strategies in Case 2.

<u>Case 3</u>

In the third case the probability of DG producing different output levels is based on Table 6.2 Case 3, in which the chance of DG generating zero output has increased significantly compared with Case 1 and Case 2. As a result the expected regret-felt (Table 6.24 (a)) and RI (Table 6.24 (b)) for the planning candidates that assume no DG has dropped significantly and in general the RI of the other planning candidates have increased dramatically.

The planning candidates which do not consider DG now have the minimum average expected regret-felt and RI, and they are clearly less risky than many other planning strategies that assume DG will produce some output. The candidate that assumes DG generating 150MW at bus 45 again has the highest expected regret-felt and RI (shown in a square in the table). The minimum RI of 0.39 is still assigned to the planning candidate found under S23 (50MW at bus 13), which is the same strategy despite the slight increase in RI from the last case.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	77	79	102	96	84	87.41
Bus 4	77	85	87	92	66	81.46
Bus 8	77	79	64	84	76	75.86
Bus 12	77	79	104	87	114	92.04
Bus 13	77	63	70	90	80	76.09
Bus 20	77	68	71	69	74	71.65
Bus 22	77	89	87	79	85	83.15
Bus 23	77	88	75	64	83	77.43
Bus 24	77	81	119	71	81	85.73
Bus 26	77	65	75	102	68	77.40
Bus 33	77	72	75	86	93	80.52
Bus 35	77	88	111	78	134	97.65
Bus 36	77	65	70	74	70	71.08
Bus 38	77	75	76	89	89	81.13
Bus 40	77	129	75	71	128	96.04
Bus 42	77	72	73	96	90	81.56
Bus 44	77	125	73	69	80	84.42
Bus 45	77	75	73	160	116	100.10
Average	76.72	81.98	82.15	86.50	89.52	

(a)

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	0.48	0.49	0.64	0.60	0.52	0.54
Bus 4	0.48	0.53	0.54	0.58	0.41	0.51
Bus 8	0.48	0.49	0.40	0.52	0.48	0.47
Bus 12	0.48	0.49	0.65	0.54	0.71	0.57
Bus 13	0.48	0.39	0.44	0.56	0.50	0.47
Bus 20	0.48	0.42	0.44	0.43	0.46	0.45
Bus 22	0.48	0.55	0.54	0.49	0.53	0.52
Bus 23	0.48	0.55	0.47	0.40	0.52	0.48
Bus 24	0.48	0.50	0.74	0.44	0.51	0.53
Bus 26	0.48	0.41	0.47	0.64	0.42	0.48
Bus 33	0.48	0.45	0.47	0.54	0.58	0.50
Bus 35	0.48	0.55	0.69	0.49	0.84	0.61
Bus 36	0.48	0.41	0.44	0.46	0.43	0.44
Bus 38	0.48	0.46	0.48	0.56	0.55	0.51
Bus 40	0.48	0.80	0.47	0.44	0.80	0.60
Bus 42	0.48	0.45	0.45	0.60	0.56	0.51
Bus 44	0.48	0.78	0.45	0.43	0.50	0.53
Bus 45	0.48	0.46	0.45	1.00	0.72	0.62
Average	0.48	0.51	0.51	0.54	0.56	

(b)

Table 6.24. (a) Expected regret-felt in $m (b) RI of the optimum strategies in Case 3.

The NBI of the planning candidates in this final case is shown in Table 6.25. Comparing with the previous two cases it appears more attractive to adopt the planning strategies assuming no DG output in this case, as their NBI is higher than many other planning candidates. The planning strategy that the planner should consider is the one found under S62 (150MW at bus 23), which is also the best one in Case 1 and 2.

	0MW	50MW	100MW	150MW	200MW	Average
Bus 2	0.28	0.31	0.17	0.25	0.37	0.28
Bus 4	0.28	0.27	0.28	0.27	0.48	0.32
Bus 8	0.28	0.31	0.43	0.33	0.41	0.35
Bus 12	0.28	0.31	0.18	0.31	0.18	0.25
Bus 13	0.28	0.42	0.40	0.31	0.41	0.36
Bus 20	0.28	0.38	0.40	0.44	0.44	0.39
Bus 22	0.28	0.24	0.26	0.33	0.30	0.28
Bus 23	0.28	0.27	0.40	$\boxed{0.52}$	0.44	0.38
Bus 24	0.28	0.30	0.08	0.44	0.41	0.30
Bus 26	0.28	0.40	0.37	0.22	0.48	0.35
Bus 33	0.28	0.37	0.42	0.41	0.42	0.38
Bus 35	0.28	0.27	0.15	0.44	0.11	0.25
Bus 36	0.28	0.40	0.40	0.41	0.46	0.39
Bus 38	0.28	0.36	0.41	0.37	0.42	0.37
Bus 40	0.28	-0.01	0.36	0.44	0.13	0.24
Bus 42	0.28	0.37	0.42	0.32	0.41	0.36
Bus 44	0.28	0.04	0.44	0.51	0.48	0.35
Bus 45	0.28	0.36	0.44	-0.10	0.23	0.24
Average	0.28	0.30	0.33	0.35	0.37	

Table 6.25. NBI of optimum planning strategies in Case 3.

6.7.4 Application 2 – Result Discussion

In application 2 the approach is applied to a 46-bus Brazilian system, which is much larger. The locational impact of DG on network planning has been clearly illustrated in the second application, where the expected regret-felt and RI could vary significantly between the two planning candidates which consider DG producing the same level but connected at different locations. A planning strategy could have a distinct network configuration which is derived especially for the assumed DG characteristics, but as a result it could have extremely high expected regret-felt and RI and end up with low NBI. In this application, the planning strategies assuming no DG output are not the worst strategies to adopt in these three cases; instead, they become more attractive as a final planning strategy as the NBI increases along the three cases. Across all three cases, the planning strategy found under the scenario assuming DG produces 150MW at bus 23 would be the best strategy to adopt; despite the strategy will not be the true optimum solution at all times as the output of DG will vary continuously during the period of peak demand, however the analysis shows it has the overall best performance regardless of the DG uncertainties as it has relatively satisfactory BI and RI and results in the highest NBI.

6.8 Chapter Summary

In this chapter an approach to optimum network planning for peak demand considering uncertainties about DG locations and outputs is developed. DG is only utilised to minimise the network losses below a desired level and does not contribute to the network meeting statutory voltage and thermal constraints. The uncertainties are modelled as different scenarios, while BGA is executed to find the optimum and sub-optimum planning strategies for each of the identified scenarios. The optimum planning strategies are considered as the candidates of the final planning strategy to be adopted by the planner. The benefit index (BI) is calculated for each planning candidate based on its total spending on the reinforcements relative to the minimum cost found among all the candidates. The risk of adopting a planning strategy is measured according to the expected difference in the network configurations in cost (expected regret-felt) between the planning strategy and other optimum strategies found under other scenarios and the probability of the occurrences of the scenarios. The risk index (RI) is assigned to a planning candidate to measure the relative risks to adopt the planning strategy comparing with the other candidates. Finally the net benefit index (NBI) is introduced by subtracting the RI from the BI of the planning candidates. The best planning strategy to adopt would be the one with the highest NBI. Three cases of different probability patterns of DG outputs are derived (Table 6.2) where the probability of DG generating a low level of output has increased from Case 1 through to Case 3. The approach is applied to a 6-bus Garver system and a 46-bus Brazilian network.

In the first application the planning candidates which do not take DG output into account are always the worst ones to adopt in the three cases despite their NBI becoming relatively closer to the other planning candidates as Case 1 moves towards Case 3. Due to the small network the locational impact of DG on the network planning is limited; as a result many planning candidates assuming DG producing the same output level at different buses in fact have either identical or similar network configurations. A planning strategy which has a more general network configuration normally does not have high expected regret-felt and therefore could be quite risk-resistant.

In the second application the locational impact of DG on the network planning of the 46-bus Brazilian system is much more profound than in the first application. A planning strategy could have a distinctive or unique network structure compared with other planning candidates. This planning strategy could have extremely high expected regret-felt and RI and be relatively less attractive to adopt as the probability of occurrence of the scenario under which it is obtained decreases through Case 1 to 3. In this application the planning strategies that assume no DG output are not the worst strategies in all of the three cases; they are most expensive but they do not have the highest expect regret-felt and RI. However, they still do not represent the best ones that the planner should choose under any of the cases in both applications.

According to the results of the two applications, one could conclude that for a power systems network where it is likely to have intermittent DG connected in the future, it could be possible and beneficial to adopt a network planning strategy that utilises DG to increase the network efficiency without additional investment in the extra reinforcements. While the locations and output of DG are uncertain, however, it might also be risky to adopt a planning strategy which could only be effective under a specific circumstance. Therefore thorough analysis and evaluation of different planning strategies under many possible situations are required in order to select one that would take the advantages of the presence of DG to a certain extent without exposing itself to too much risk induced by the uncertainties.

In this chapter the network planning for peak demand is considered, however, as DG is of an intermittent type, it is important to consider other situations such as when the DG output is at the maximum during the period of minimum demand for which the generation-related reinforcements could be required. The approach could be expanded for the time-series analysis without major difficulties. One assumption made is that the risk of adopting a wrong planning strategy is based on how different its network configuration is from the real best planning strategy. In real practice the risks should be more related to the economic losses for DNOs such as receiving less rewards form the network loss incentive scheme and other factors due to the inefficient strategy adopted. The real economic losses could be difficult to assess, however. Despite this, the difference in network efficiency between the two planning strategies could be related to their structural differences to a reasonable degree. However, the index introduced in the approach only measures the planning candidates' relative benefits and risks and is used for comparing the relative advantages between the planning candidates rather than indicating their true benefits or risks.

CHAPTER 7 - Thesis Discussion and Conclusion

7.1 Thesis Summary

The research concentrated on the quantification of DG impacts on distribution network planning, which is a necessary and preliminary step towards developing a cost-reflective market charging scheme for DG and is the key to effectively promoting DG connections within UK networks in pursuit of government CO_2-reduction targets. The work is based in the EU context where DNOs are not allowed to own DG. Different approaches were developed to examine the changes in the reinforcements caused by DG for DNOs to comply with the thermal, regulatory voltage and security of supply constraints as well as to improve network losses. Factors such as DG location, outputs, power factor as well as its contribution to the network security of supply have been considered.

First, an approach was introduced to quantify DG impacts on the deferment of demand-related reinforcements in Chapter 2 and 3. The approach consists of the successive elimination method, multistage planning analysis and present value economic analysis. The successive elimination algorithm is used to generate a reinforcement plan at the end of the planning horizon and the multi-stage planning analysis determines the connection schedules of those reinforcements in time within the considered planning period. The change in the costs between the reinforcement plans with and without DG is regarded as the economic impact of DG on the planning. In Chapter 2 the planning did not consider the network security of supply, with DG affecting the reinforcements required for network thermal capacity release and voltage support. However, in Chapter 3 the network planning considered the security-related reinforcements and the contribution of DG to network security was contemplated. The results showed that DG could generate benefits for DNOs by deferring the reinforcement schedules effectively. However, different DG characteristics (location, output, security contribution factor and power factor) could change the results significantly and in some cases DG would force some reinforcements to become more urgent than they were planned without DG. It is of importance that DNOs identify such adverse impacts brought by DG to the network planning otherwise the original network planning strategy may become infeasible.

There were several limitations identified with the approach. The DG-related reinforcements were not considered due to an assumed small DG penetration, but the approach can be modified without encountering major difficulties. The successive elimination method cannot guarantee the global optimality of a network planning solution it generated; however, by assigning a cost-effectiveness index to each of the reinforcements considered the method is transparent and can be understood easily by DNOs and DG investors.

The impact of DG on network voltages has not been analysed comprehensively as the networks used in Chapter 2 and 3 did not have serious voltage problems. However, DG could also be an effective option to support network voltages with a view to avoiding network upgrades. In Chapter 4, an approach was developed to evaluate the economic and technical benefits of utilising DG to support the distribution network voltage profile. Specifically SVCs were considered to solve any voltage problems which occur in the network, while the economic impact of DG is evaluated by comparing the cost differences between the SVCs deployments with and without the DG. The modified voltage sensitivity method was used for the optimum allocation of SVCs to minimise the investment costs meanwhile satisfying the steady-state voltage and step change constraints. It is believed that the voltage step change constraint could become a major issue in limiting the DG penetration within a network. The results showed that DG could be an extremely valuable asset for DNOs to improve the network voltages, but its effectiveness depends on the DG characteristics. Another important observation was the shift of the range of reactive power capacity of SVCs caused by DG. The increase of DG penetration and the change of power factors could break the voltage step-change constraint after disturbances, in particular if DG is tripped or due to the loss of the load connected at the same bus with the DG, resulting large voltage rise or drop that exceeds the statutory limits. In response to such conditions, SVCs connected at some locations were required to produce inductive reactive power to limit the voltage step change. The impacts of DG on the transformer tap-changer settings were also investigated. The preliminary analysis showed that the effectiveness of currently adopted network voltage control mechanisms could be affected considerably due to the DG connection and therefore required to be modified by DNOs to maintain the effectiveness of the control mechanisms. While SVCs are expensive and there are other options to solve the voltage problems, the quantified results could be over-estimated. Therefore before considering to integrate the result into a charging system, it should be scaled to a more practical value based on the relative cost between SVC and the device which the DNOs consider to install in a real situation.

Although DNOs are not allowed to own DG, it could still be possible to utilise DG in place of some reinforcements to save capital expenditure. However, in these circumstances the primary problems are that the DG characteristics will be uncertain and cannot be controlled by DNOs while there are undoubtedly potential risks of adopting a planning strategy that utilises DG, since if the predictions of some of the features of DG are wrong, then the planning strategy could become technically and economically ineffective or in the worst cases infeasible. Therefore, an approach to network planning which takes future uncertainties into account is required, and one was introduced in Chapter 5. The future uncertainties were captured as different alternative scenarios. As uncertainties are considered in the network planning, it is possible that the effectiveness of the sub-optimum solutions may surpass the effectiveness of the optimum solution found under the same scenario when another different scenario in fact happens in the future. Therefore it would be advantageous for an optimisation method which can produce both optimum and sub-optimum solutions each time it is executed. With the genetic algorithm fitting into this category, a new form of GA, the 'balanced GA (BGA)', was specifically developed to intensify the search for both optimum and sub-optimum solutions. It aims to correct the drawbacks of conventional GA by limiting diversification by trading off enhancement of the intensification of the searching procedure. An improved and modified data envelopment analysis (IMDEA) was created to rank the planning candidates by evaluating their relative efficiencies. The advantage of the DEA is it only requires the information of a planning solution's inputs and outputs to calculate its relative efficiency without knowing the potential complicated functions relating the inputs and outputs, and avoids the need for exact weighting factor values to be assigned to each input and output. The IMDEA proposed allowed greater ability to distinguish the efficiencies of those decision-units which originally were assigned to the same efficiency score calculated by the DEA. Furthermore, the IMDEA limited the range of weighting factors given to each input and output in order to reflect the relative importance between the inputs and outputs in reality or based on the decision-maker's judgment.

In Chapter 5, the approach has been successfully applied to a multi-stage green-field planning situation considering the uncertainties of possible locations of load centres in the near future. The objective was to find the planning strategy which has not only got acceptable planning costs to connect the new deterministic load centres to the existing distribution network, but also leads to an effective network expansion plan in the near future where additional load centres will emerge despite their exact locations being still uncertain. The optimum and sub-optimum planning strategies generated from BGA were compared with those obtained from a conventional GA. Not only did the BGA generate a more diversified set of solutions than conventional GA, it also offered a more reliable and consistent searching progress towards the final solutions. In our case, there were no optimal solutions generated by the BGA which fitness is worse than the optimal solutions generated by the conventional GA. The variety of the sub-optimal solutions, i.e. the degree of differences between the solutions, found by the BGA much better than those found by the conventional GA, implying that under a time constraint the BGA can offer more solutions which could be worthwhile for a decision maker to consider as the candidates of the final solution.

Both the conventional DEA and IMDEA were used to calculate the efficiency score for the candidate plans. The result showed that IMDEA has further distinguished the performance between two candidates which had the same efficient score calculated by the DEA, enabling the planner to compare the candidates. The planning strategy which was given the highest relative efficiency would be regarded as the best one to adopt by the planner due to its all-around effectiveness under the scrutinized scenarios.

As the ability of the BGA to generate quality solutions has been proved in Chapter 5, it was then used in Chapter 6 to tackle network planning problems considering the uncertainties of location and output of an intermittent DG. The purpose was to show whether it is possible for DNOs to rely on intermittent DG (wind farms) within network planning and save capital expenditure. While it is important to consider the impact of the intermittent DG on the network in the circumstance such as when the demand is at the minimum and DG is producing at its maximum output, to simplify the problem an assumption was made that only the period of peak demand was considered in process. Since the installed capacity of the wind farm was relatively low (low DG penetration) compared with network demand, as a result it is unlikely that DG-driven reinforcements will be required. To further simplify the problem the varying output of the wind farm was categorised into five discrete output levels. Given the five categorised output levels along with potential DG locations, numbers of scenarios were then identified to represent different possible combinations of the uncertainties. The BGA was then used to search for optimum and suboptimum planning solutions in each of the identified scenarios. The optimum solutions were considered as the candidates of a final planning strategy. Decision theory was applied to assist the planner in selecting the best planning strategy. A series of indices are calculated for each candidate: a benefit index (BI), a risk index (RI) and a net benefit index (NBI). The benefit index measures the relative cost of a planning strategy compared with the minimum planning costs found among all the candidates. The RI is calculated for a planning strategy based on the expected structural differences measured in cost between the planning strategy and other planning candidates. It is assumed that if a wrong planning strategy is adopted, the economic loss and risks would be related to the degree of differences in the network configurations between a wrong adopted planning strategy and the true optimum planning strategy for that scenario. Finally a NBI was calculated by subtracting RI from BI of a planning strategy, and was used to compare the planning candidates (the highest NBI indicates the best planning strategy).

The value of NBI will heavily depend on the weighting factors given to the BI and RI and therefore have significant impact on the final results. In our case the weighting factors given to BI and RI are assumed to be 1:1. Inaccurate weighting factors will cause misjudgment of the relative competitiveness between the solution candidates and the erroneous results will mislead the decision maker to make the wrong decision. However, in real practice it is difficult to choose the weighing factors. For example, if BI and RI are not independent to each other, then the weighting factors given will be based on the relationship between BI and RI. Finding this mathematical relationship between BI and RI could involve complicated calculations and it would be difficult to get accurate values. On the contrary if BI and RI are independent to each other (not true in our case), then the weighting factors will be based on their relative importance judged by the decision maker leading to subjective results. In conclusion, due to the difficulty of selecting the weighing factors which can reflect the truth or agreed by other concerned people, the evaluation of a solution by using an aggregated objective index is often biased in a multi-objective context.

The approach was applied to a 6-bus Garver system and a 46-bus Brazilian network. The results showed that even though the wind farm output will vary continuously; it is still possible to rely on the wind farm to some extent to save additional planning costs. However, It requires a detailed analysis and comprehensive evaluation of every possible network planning strategy in order to find the best one which is able to take advantage of the DG without inducing risks which offset the benefits. In fact, in some circumstances the analysis showed that DNOs would feel deep regret by adopting planning strategies which do not take the intermittent DG into account.

The limitations of the approach include the assumption that the risks of adopting a planning strategy depends on the differences in the network configurations between the adopted strategy and the real optimum is only an approximate evaluation on the real economic loss if a planning strategy that is not in fact an optimum one is adopted. Indeed, the differences between the network configurations cannot capture the entire economic risks if a wrong strategy is selected which could affect the fairness of the results. Again, scaling factor is necessary to apply to the results by the planner based on his knowledge about the true planning and electricity market environment. Furthermore, despite the performance of BGA has been shown to be more efficient than the conventional GA, it belongs to the class of evolutionary algorithm and will still suffer from stochastic errors. Therefore the planning solutions generated by the BGA may still not be the global optimum, which will indeed also affect the final results.

7.2 Overall Conclusion

The potential technical impacts of DG on distribution networks have been recognised world-wide. Such impacts can be either beneficial or adverse to the networks depending on the DG characteristics (technology, location, capacity etc.) and the design of the networks. As a result, DG can be a powerful reinforcement option that assists in improving the network efficiency, or additional reinforcements will be needed for the DG connection without violating any network constraints. In the countries where DNOs are allowed to invest and own DG, such as in the US, DG characteristics can be decided and controlled by the DNOs in order to bring benefits to their networks in a straightforward manner. However, in the EU DNOs cannot own DG and the characteristics of DG are decided by private DG developers for their own profits. In these circumstances it is more difficult to utilise DG to improve the network efficiency by incorporating it into network planning.

The purpose of the work done in this thesis was therefore to prove that even though DG is not directly controllable by the DNOs, there could still be economic benefits by incorporating DG into network planning. Based on this hypothesis, several new methods have been developed to quantify the benefits if DG is utilised in network planning compared with the network planning that does not try to take any advantages of DG:

1. The combination of a new successive elimination method, multistage planning analysis and present value method for quantifying the benefits of using DG to defer the connection schedule of the planned thermal- and security-led reinforcements.
2. The modified voltage sensitivity analysis to measure the benefits in saving additional costs of SVCs installation due to the ability of DG in supporting the network voltages.
3. A novel balanced genetic algorithm specifically designed for tackling network planning problems under uncertainties. The algorithm is able to generate quality planning solutions in which DG is utilised to reduce network losses. Improved modified data envelopment analysis provides an objective and flexible way to compare the performance between different planning solutions.

These new approaches do not only analyse the technical impacts of DG on distribution networks, but also convert the technical impacts into economic assessment, offering DNOs the robust and transparent models to generate results sensitive to different DG characteristics. It is indeed critical and valuable to know how a DG connection could affect the capital expenditure on network planning of distribution network companies. The results showed that DG is a powerful reinforcement option that can be utilised for different purposes, such as to improve the network voltage profile, thermal capability and security of a network as well as to reduce network losses. There were also some conditions in which certain DG characteristics triggered additional spending due to its adverse impact on the network, while the costs quantified by the approaches would also assist DNOs in judging the necessity in incentivising the DG developer to limit the DG operation for mitigating the negative impact. Even if the DG is of an intermittent type, it is still possible to rely on its time-varying output to some extent to improve network efficiency under reasonable risks. The final conclusion is that, it is essential for DNOs to incorporate DG into network planning. To do so the DNOs not only able to determine the most cost-effective ways to invest in DG-driven reinforcements to accommodate a new DG in order to comply with the statutory obligations, but it is also likely that through comprehensive analysis, DNOs can derive a network planning strategy that can take advantage of the DG connection to save significant capital expenditure.

7.3 Future Work

All applications in this thesis concentrated on quantifying the DG impacts on the distribution networks during the period of annual peak demand. However, the statutory network constraints may also be threatened in other times such as when DG is generating at its maximum output meanwhile the demand is low, therefore triggering additional DG-driven reinforcements. Such conditions have to be included for conducting a thorough economic assessment of DG. Furthermore, if the quantified results shall be used to derive real-time cost-reflective distribution use of system charges, the analysis needs to be done under all possible network conditions throughout a year. As a result, the models need to be further developed to accommodate the feature of time-series analysis to identify all the potential reinforcements that are required and affected by the DG connection under different conditions. For doing so, load and generation profiles for a full year are required. Probability density functions for load and generation might also be used to simulate all the possible network operating conditions that could happen in a year by using a Monte Carlo method.

The impact of DG on the network dynamics also has not been considered, while as explained in Chapter 4, DG has the potential to affect the transient stability of the network it is connected. Such impacts of DG are also potentially driving changes in reinforcements to stabilise the system and protect equipment during transients following contingencies. Therefore, the approaches developed in the last chapters could be further extended to quantify the impacts of DG on the need of such reinforcements required for taking care of any network disturbances such as voltage sags, fault currents or equipment outages.

As shown in the applications in Chapter 5 and 6, the balanced genetic algorithm (BGA) developed has proven its advantages and better performances in finding the optimal planning solutions over a conventional GA. Comparing with other improved GA, the main obvious advantage of the BGA is that it is much simpler to implement. To further prove the applicability of the BGA, it must be compared with the other improved GA by applying the methods to the same optimization problem and compare the performances in terms of (1) computational burden in a more complicated problem; (2) quality of final solutions including both optimal and suboptimal ones and; (3) consistency in finding good final solutions. The comparisons would point to the direction at which the BGA shall be further developed and improved. As shown in Chapter 5, the BGA at this stage consists of only few modifications from the conventional GA, therefore it has the potential to be further developed to improve its performances in finding an optimal solution, such as to develop a more efficient initial solution generation method and adjust the degree of similarity between offspring and the parent chromosomes for improving the computational speed.

Most of the optimal network problems tackled in this thesis are formulated with a single-objective function, i.e., to minimise the planning costs. Indeed, in real practice the total planning costs may not be the only concern for DNO to derive a reinforcement plan, on the other hand the DNO may increase the planning costs in order to improve other network performances, such as loss reduction, security improvement etc., up to a certain extent where the DNO thinks those additional reinforcements will be economically justified in the future. As a result, the network planning should be formulated as a multi-objective optimization problem which will change the final optimal solution and the quantified impacts of DG obtained under the single objective optimization frame. Furthermore, to use multi-objective optimal planning approach would allow the DNO to compute the sensitivity analysis between the quantified impact DG and different weighting factor values assigned to each of the objective considered by the DNO. The sensitivity analysis would be useful to assess the severity of impacts of DG on the different technical aspects of the distribution network, while the results will assist the DNO in identifying the most effective way to utilise the DG in the network planning.

Finally, the future research should concentrate on developing methods to integrate the various quantified DG impacts into new charging mechanisms for DG connection or distribution use of system in order to establish more cost-reflective DG connection and operation price signals. It would be very valuable to analyse any potential changes in the behaviour of DG investors and DNOs in terms of the agreement on DG characteristics between the new proposed charging schemes and the existing one and compare the efficiency of promoting DG connections between different charging approaches.

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Appendix - Publications

Journal:

[1] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "DG Impact on Investment Deferral: Network Planning and Security of Supply", IEEE Trans. on Power Systems, May, 2010, in Press.

[2] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Modified GA and Data Envelopment Analysis for Multistage Power Systems Network Expansion Planning Under DG Uncertainties", IEEE Trans. on Power Systems, submitted.

Conference Proceedings

[1] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison, C.J. Dent, A.R. Wallace; "Evaluating investment deferral by incorporating distributed generation in distribution network planning", PSCC'08, 7pp, 14-18 July 2008.

[2] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Assessing the economic impact of distributed generation on voltage regulation in distribution networks", AUPEC'08, 6pp, 14-17 December 2008.

[3] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Distributed generation and security of supply: Assessing the investment deferral", IEEE/PES PowerTech 2009, 28 June-2 July 2009.

[4] D. T.-C. Wang, L.F. Ochoa, G.P. Harrison; "Expansion planning of distribution networks considering uncertainties", UPEC 2009, 1-4 September 2009.